BEFORE THE
OIL CONSERVATION COMMISSION
ROSWELL, NEW MEXICO
OCTOBER 14, 1959

IN THE MATTER OF:

CASE 1787 In the matter of the hearing called by the Oil Conservation Commission on its own motion to consider the promulgation of statewide rules governing the operation of water flood projects including the assignment of project or unit allowables.

BEFORE:

Mr. A. L. Porter
Mr. Murray Morgan
Gov. John Burroughs

T R A N S C R I P T   O F   P R O C E E D I N G S

MR. PORTER: We finally come to what I guess we could call the feature of the program, Case 1787.

MR. PAYNE: Case 1787. In the matter of the hearing called by the Oil Conservation Commission on its own motion to consider the promulgation of statewide rules governing the operation of water flood projects including the assignment of project or unit allowables.

MR. PORTER: I have a statement which I would like to read at this time before the presentation of any testimony in the case.

At the time the first capacity allowable application was approved some two years ago, it was contemplated by the Commission that it might be desirable or necessary to docket a case of this nature after sufficient time had elapsed for all concerned to evaluate the effect of capacity allowables upon ultimate recovery of oil, primary drilling and exploration, statewide allowables, and so forth.

The Commission is aware that this case deals with a matter that can have a tremendous effect upon the oil industry within this state. Accordingly, it is our intention to give full consideration to any reasonable proposal from any interested party.

In every case, but particularly in important cases such as this one, the Commission is desirous of getting before it all available relevant evidence, including testimony from all segments of the industry as well as testimony from Commission personnel. It has been our observation that no matter how thin a pancake is, it always has two sides.

Mr. Nutter, working with other members of the Commission staff, has prepared a proposed revision of Rule 701 of the Commission Rules and Regulations. His proposal was sent to our entire mailing list on September 25 and should have been in the hands of all interested parties for at least two weeks. Mr. Nutter will take the stand for the purpose of testifying in regard to his proposal and will, of course, be available to answer any pertinent questions that may be raised concerning the proposed rule.

Now, I have been asked by several parties what the order of the testimony will be. Mr. Nutter will present his proposed

Rule at the outset. Those who concur in Mr. Nutter's proposal and who wish to support it by testimony will come next. Then, those who favor capacity allowables or continuation of the Commission's present policies; after that, any who propose any other rule.

At this time, I would like the appearances in the case.

MR. CAMPBELL: If the Commission please, Jack M. Campbell, Campbell & Russell, Roswell, New Mexico. I would like to enter an appearance on behalf of the following operators: Gra-ridge Corporation, Newmont Oil Company, Ambassador Oil Corporation, John H. Trigg, Delfern Oil Company, J. W. Brown. In connection with the appearance for Ambassador Oil Corporation, that company has an attorney from out of the State of New Mexico, and I would like to associate with him insofar as Ambassador Oil Corporation is concerned, Mr. Tom Lowry of Fort Worth.

MR. HINKLE: If the Commission please, Clarence Hinkle, Roswell, New Mexico, representing the Humble Oil & Refining Company. I would like to enter an appearance on behalf of Howard Bratton and Charles C. Keeble, an attorney of the Humble from Houston, who will be associated with us in representation of the case.

MR. PORTER: Mr. Hinkle, would you give us the spelling --

MR. HINKLE: Charles K-e-e-b-l-e.

MR. PORTER: Thank you.

MR. HINKLE: Also I would like to enter an appearance on behalf of Sun Oil Company, Hervey, Dow & Hinkle, Mr. Bratton and myself and Mr. Randall Dutton, who will be associated with us in representation of the case.

MR. LOSEE: H.L. Losee, Artesia,New Mexico. I would like to enter the appearance of myself and T.E. Lusk of Reese, McCormick, Lusk and Payne, Carlsbad, New Mexico, for the following companies: Western Development Company of Delaware, E.J. Sivley, Simms & Reese Oil Company, Tom Boyd, Jack Clemens, Don Angle, Mesa Retailers, Inc.

MR. PORTER: Just a minute, I'm getting behind. I got Clemens.

MR. HINKLE: T.J. Sivley.

MR. PORTER: I got Sivley, but Clemens was the last one I got.

MR. HINKLE: Don Angle, Jerry Curtis, Mesa Retailers, Inc. Clarence Roach, E.J. Sheppard, Kinkaid & Watson, William Hudson, Ralph Nix, G. Kelly Stout and W.N. Price.

MR. McBROOM: Curtis McBroom, M-c-B-r-o-o-m, Water Flood Associates, Incorporated, Artesia and Fort Worth.

MR. PORTER: Water Flood Associates,Inc?

MR. McBROOM: Inc., it is a private company.

MR. PORTER: Artesia and Fort Worth?

MR. McBROOM: Yes, sir.

MR. ERREBO: Burns Errebo, and I would also like to enter the appearance of Mr. James E. Sperling, Modrall, Seymour, Sperling

Roehl & Harris of Albuquerque, appearing on behalf of Sacony Mobil Oil Company and the British American Oil Producing Company.

MR. WHITE: Charles White of Gilbert, White & Gilbert, Santa Fe, New Mexico, appearing on behalf of Texaco, Inc. I should also like to enter an appearance of Sunray Mid-Continent, and associated with me in that respect will be Mr. Bill Loar of Tulsa, attorney. I should also like to enter an appearance of Sinclair, and in that connection Mr. Jim McGowan, attorney of Oklahoma City, will be associated with me.

MR. PORTER: Mr. Kastler, it is kind of dark back there.

MR. KASTLER: Bill Kastler, Roswell, New Mexico, appearing on behalf of Gulf Oil Corporation.

MR. SETH: Oliver Seth, Atlantic Refining Company.

MR. PORTER: Representing whom, Mr. Seth?

MR. SETH: Atlantic Refining.

MR. NEWMAN: Kirk Newman of Atwood & Malon. Guy Buell, a member of the Texas Bar, representing Pan American Petroleum Corporation.

MR. PORTER: Maybe I should ask here if there is anybody here who doesn't have representation?

MR. PAYNE: Oliver Payne, representing the Commission staff.

MR. PORTER: Mr. Payne, will you call your first witness?

MR. HOLL: I'm Alfred O. Holl, Bartlesville, Oklahoma, member of the Oklahoma Bar and Kansas Bar. I have associated with me Mr. Jason Kellahin of Santa Fe, New Mexico, representing Cities Service Oil Company.

MR. DIPPEL: Mr. Porter, I thought Mr. Kellahin would be here. I'm Harry Dippel, Texas Bar, Fort Worth, representing Continental Oil Company, associated with Mr. Kellahin.

MR. CHRISTIE: Also in the absence of Mr. Kellahin, R. S. Christie, representing Amerada Petroleum Corporation.

MR. PORTER: Are there any other appearances? Mr. Kellahin. Do you want him to go on record?

Mr. Spann, did you desire to make an appearance in this water flood?

MR. SPANN: Yes, I would. For the record, my name is Charles Spann of Grantham, Spann & Sanchez, Albuquerque, New Mexico, appearing for Phillip Petroleum Company.

MR. PORTER: Mr. Payne, would you call Mr. Nutter to the stand?

MR. KELLAHIN: If the Commission please, I would like to enter an appearance. Jason Kellahin, Kellahin & Fox,Santa Fe, New Mexico, representing Cities Service Oil Company, and I have associated with me Mr. Al Holl, who will handle the case on behalf of Cities Service. I would also like to enter an appearance for Standard of Texas and Amerada Petroleum Corporation. I believe the appearance has already been entered on behalf of Continental Oil

Company.

MR. PORTER: And also the others, Mr. Kellahin.

(Witness sworn)

DANIEL S. NUTTER,

called as a witness, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. PAYNE:

Q Will the witness please state his name and position?

A Daniel S. Nutter, Chief Engineer for the Oil Conservation Commission.

Q Mr. Nutter, are you a graduate petroleum engineer?

A Yes, sir, I am.

Q Have you had field experience in water flood operations?

A Yes, sir, I have.

Q Are you a member of the Secondary Recovery and Pressure Maintenance Committee of the Interstate Oil Compact Commission?

A Yes, I am.

Q Do you attempt to stay up to date on the literature that is available on water floods?

A Yes, sir.

Q Now, Mr. Nutter, have you, in conjunction with the Commission staff, prepared a proposed Rule governing water flood operations in the State of New Mexico?

A Yes, sir, I have.

Q Has this proposed Rule been circulated to the industry?

A Yes, sir, this proposed Rule was mailed along with a memorandum which was attached to it on September the 25th, 1959.

Q All right, sir, if you will turn to your proposed Rule. I would like to have you go through it briefly, if you would.

A Proposed Rule 701 is entitled the INJECTION OF FLUIDS INTO RESERVOIRS. It is divided into several paragraphs, being A through E. Paragraph A is entitled Permit for Injection Required. This is essentially the same as the first portion of Rule 701 as it is presently included in the New Mexico Oil Conservation Commission Rules. We have changed it somewhat, however, and included liquefied petroleum gas and other medium as the subjects for hearing before it is possible to inject them into reservoirs.

Paragraph B is essentially the same as it was before. We have also, however, included liquefied petroleum gas and other medium in the requirements there.

Sub-paragraph 1. of Paragraph B requires that all offset -- that the plat that is sent in with the application show the location of other wells within a radius of two miles of the proposed injection well, and also indicate the lessees, if any there be, within said two-mile radius. The existing Rule calls for a one-half mile radius. This was changed to comply with another portion of 701, which requires a two-mile modification. That is an existing Rule that is just to make it uniform throughout the Rule.

Sections 2, 3 and 4 of sub-paragraph B, Method of Making Application, are essentially the same. There is a slight rearrangement of the information that is required, but essentially, it is identical to the existing Rule.

Paragraph C of the proposed Rule 701 is identical to the present Rule regarding Salt Water Disposal Wells. We have not changed that Rule at all.

Paragraph D of the proposed Rule 701 defines Pressure Maintenance Projects. I would like to read that. "Pressure maintenance projects are defined as those projects in which fluids are injected into the producing horizon in an effort to build-up and/or maintain the reservoir pressure in an area which has not reached the "stripper" state of depletion. 2 The project area and the allowable formula for pressure maintenance projects shall be fixed by the Commission on an individual basis after notice and hearing.

Q Why have you proposed, Mr. Nutter, that pressure maintenance projects be defined in this Rule?

A It appears that there is a need for the definition of a pressure maintenance project as opposed to bona fide water flood projects and salt water disposal projects. We have, therefore, attempted to define a pressure maintenance project so that there wouldn't be any confusion with that project with a salt water disposal project. We also feel that project areas and allowable for newly -- for pressure maintenance projects shouldn't be governed by a single statewide rule, but should be the subject of a hearing on an individual basis at the time that the pressure maintenance project is proposed. So we've made provision there that the allowable and project area would be fixed on a separate and individual basis after hearing.

The next section of the proposed Rule 701 is entitled -- it is Paragraph E and it is entitled Water Flood Projects. Subparagraph 1. there reads as follows: "Water flood projects are defined as those projects in which water is injected into a producing horizon in sufficient quantities and under sufficient pressure to stimulate the production of oil from other wells in the area, and shall be limited to those areas in which the wells have reached an advanced state of depletion and are regarded as what is commonly referred to as "stripper" wells."

Now, that first portion there requires that water be injected into a producing horizon in sufficient quantity and under sufficient pressure to stimulate production of oil from other areas -- from other wells in the area. This is to distinguish a water flood project from a salt water disposal project. It is limited to those areas in which the wells have reached an advanced state of depletion to distinguish the water flood project from a pressure maintenance project.

Section 2. provides that a project area shall be established and reads as follows: "The project area of a water flood project shall comprise the 40-acre tracts upon which injection wells are located plus all 40-acre tracts which directly or diagonally offset the injection tracts and have producing wells completed on them."

Q Now, in regard to No. 2, -- Paragraph 2 of E, would you go to what we will designate as Exhibit 1 and explain it in relation to this Paragraph?

A Yes, sir. Exhibit 1, this checkerboard shows the proposed project areas. Now, each one of these one-inch squares we will call a 40-acre tract. The black 40's are the injection wells, the red area plus the black constitutes the project area under this proposed Rule. Now, here we have one single injection well and the offsetting 40-acre tract, including the diagonal offsets constitute nine complete units. Now, the allowable formula that is proposed later provides that this single injection well under this proposal for Southeast New Mexico would effect an allowable of 378 barrels per day.

The next square to the left, or next project area to the left, is a four-well five spot pattern in which you have four injection wells, a single producing well in the center, and the offsetting 40s diagonal and direct all the way around it. The four-acre -- the four-well five spot pattern gives you twenty-one units in the project area, and under the Southeast allowable which is proposed later in the Rule, would have a total allowable of 882 barrels per day.

The next pattern to the left is an eight-well pilot project or eight-well water flood in which the one-inch squares are 40-acre tracts again, and it contains thirty-five units all told. The total allowable assigned to this for Southeast New Mexico under the proposed Rule would be 1470 barrels per day.

Q That is if there is a well on each forty acres?

A Provided there is a well on each forty acres. If there is no well on this 40-acre tract, it is exempt from being in the project area. Directly below this, we have a staggered six-well pattern in which there are twenty-nine units for a total of 1218 barrels per day, Southeast New Mexico under the proposed Rule, and to the right of that being in the lower right-hand side portion of the Exhibit, we have a six-well injection pattern which has twenty-eight 40-acre units in it, and allowable under the proposed Southeast formula of 1176 barrels per day.

Q Now, these are just examples of what units you might have; you could have an indefinite variety?

A You could have any number of different combinations. These are typical patterns that you would have.

Q All right. Proceed to Paragraph 3, please.

A Paragraph 3 provides that the maximum -- I'll read it in its entirety. "The maximum allowable assigned to any water flood project area shall be determined by multiplying the number of 40-acre tracts in the project area times the Area Allowable

Factor times the 40-acre proportional factor for the pool. The allowable assigned to any water flood project area in which there are 40-acre tracts containing more than one well shall be increased by an amount of oil equal to 0.333 times the Area Allowable Factor for each such additional well on a 40-acre tract, provided, however, that the additional allowable for any such 40-acre tract shall not exceed the Area Allowable Factor."

Q Why have you proposed that the project allowable be determined in this manner?

A Well, you'll notice the first part of it contains three components. The project allowable shall be determined by multiplying (1) the number of 40-acre tracts, (2) the area allowable factor, and (3) the 80-acre proportional factor.

Q The 40-acre proportional factor --

A The 40-acre proportional factor. Those three components, I think I have an explanation for each of them. In the first place, we want to include all of the 40-acre tracts that are in the project area. That's to give the operator who goes out to water flood the area an incentive, so we take -- now we take the Area Allowable Factor that is to provide a constant allowable to the operators,if they bought the equipment that they need for the injection of water,plus the production of the wells. Many don't like to change their producing rates. Another thing, sometimes they hate to make drastic changes in the injection rates, so we feel that a constant allowable, being the Area Allowable Factor is -- will is -- will provide for a more uniform operation of the water flood than fluxuation of allowables as you have for primary depletion, when the allowables change from month to month.

The third component of this sentence is the 40-acre proportional factor, and we feel that this is the depth factor. In other words, we feel that the additi onal depth for which extra money must be spent must be compensated for, so we have thrown in the depth factor as well.

Q Now, what is the reason for the -- this allowable provision for areas developed on less than 40 acres?

A This is to allow the additional compensation for the drilling of the extra wells on the tract. I don't know if it is actually necessary to provide it or not. I know that if you've got a 40-acre tract that you've got four wells drilled on, you don't need four times the allowable, but I feel that two times the allowable is certainly additional compensation for the development of the tract on a smaller scale in its primary stage.

Q All right. Proceed to the next Paragraph, would you?

A The next Paragraph states that the project Area Allowable may be produced from any well or wells in the project area in any proportion.

Q Now, what is the reason for this proposal?

A When you start a water flood, all the wells don't always respond at the same rate. And this is to allow the operator an opportunity to produce his oil from any well in that red area that he sees fit, depending on the response that that individual well has had. It wouldn't really do any good to assign a project allowable if you didn't permit the production of the oil in some proportion other than equal proportion from each 40, so we would permit the operators to produce the project allowable from any well or wells in any proportion.

Q Would you read the next Paragraph there?

A The next Paragraph, "Nothing herein contained shall be construed as prohibiting the assignment of special allowables to wells in buffer zones, after notice and hearing." Buffer zone is not explained right here in this Paragraph. However, the memorandum that was sent with the letter mentions the buffer zone. I'll read the last Paragraph of the memorandum. "It is proposed that these rules will apply only to new floods, not yet authorized by the Commission. Your suggestions as to the operation of buffer zones between new floods and old floods, as well as any other recommendations or proposed rules which you wish to submit, will be welcomed."

Now, the buffer zone that we have mentioned very briefly in the Rule is the zone that would exist when you have two projects coming together. You have a water flood project right here adjoining this eight-well project area. Now, since the rules would apply only to floods that are not yet authorized by the Commission, existing floods would be exempt. Assuming that an existing flood has a capacity production, this capacity production is offsetting this well that is coming under from this project allowable. So, therefore, we should -- this should be a buffer zone probably comprising some 40-acre tract in this project as well as some 40-acre tract in the adjoining project in which allowables could be set after notice and hearing, special allowable could be set for those wells. There is also the instance where you have a pool that is partially developed on 10-acre spacing, for example, and the rest of it is developed on 40-acre spacing. Now, the project allowable is assigned on the basis of 40-acre tracts. If you didn't receive any additional incentive for it or any additional allowable bonus for the extra wells that were drilled on the 10-acre tract, there would be no need for the buffer zone. However, the man can receive up to twice the allowable for the Southeast if the allowable factor is 42, and the Northwest allowable factor is 52, and a man, if he is developed on ten-acre spacing or less could receive up to 84 or 104, depending on Northwest or Southeast barrels per day for each of the 40-acre tracts. Therefore, on a pool that is developed on two different acre spacings, 10 and 40, you could have two allowables on projects that are abutting each other.

Q As I understand your testimony, then, this buffer proposal would not only apply to new flood offsetting an old flood which is producing at capacity, it may also apply to two new floods which have different spacing?

A Which have different spacing, correct.

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Q Let's go to Paragraph 4.

A Paragraph 4 is taken almost verbatim from several Orders that the Commission has written which make it possible -- oh, wait a minute -- I'm sorry. Paragraph 4 is the Area Allowable Factor. It reads as follows: "The Area Allowable Factor for the counties of Lea, Eddy, Chaves, and Roosevelt shall be 42. The Area Allowable Factor for the counties of San Juan, Rio Arriba, Sandoval, and McKinley shall be 52.

Q How did you choose these figures of 42 and 52?

A The 42 figure, as I mentioned before, we would like to see a constant allowable so the equipment could be purchased and made on a uniform basis. The 42 basis per day is the average allowable that has been assigned to wells in these four counties in Southeast New Mexico for the last ten years. Although the present allowable is 35, the average allowable for the last ten-year period has been 42 barrels. The average Area Allowable Factor for Northwest New Mexico is 52, and it is based on the average allowable that we've had in the San Juan Basin since market outlets were available in that area. Now, there was a period of prorationing prior to the time that we had outside market outlets; we didn't consider those periods. The allowable for three months was 10, 12 and 11 barrels. We didn't include that because it was not a realistic allowable and shouldn't be included in any average. It is not representative of the true allowable figures and the actual market demand for the San Juan as it presently exists.

Q Now, why didn't you pick a single figure that would apply to the entire State?

A Because the Commission has in the past, and as I noted in the testimony this morning of Mr. Kaptenia, he is continuing to regard Northwest New Mexico and Southeast New Mexico as two separate and distinct marketing areas. The allowables are set differently in the two areas, the market demand is different, not only for the counties, as a whole, but for the wells, individually speaking. So we have picked a figure for Northwest and Southeast New Mexico based on the actual market demand for those two areas.

Q All right. Now, what does Paragraph 5 provide in essence, and what is its purpose?

A Paragraph 5, as I started to say a while ago, is taken almost verbatim from several Orders that the Commission has written, which authorizes administrative approval for the expansion of water flood projects. In essence, it requires that when the operators desire to put additional wells on injection, that the well must be one that has received a substantial response from the water flood project, or it must diagonally or directly offset such a well that has received such a response. We feel that the inclusion of Paragraph 5 in the revised Rule 701 will save the operators as well as the Commission unnecessary expense and trouble in having hearings every time it is necessary to expand the project. We do feel, however, there should be some control on the extension of water flood projects, and this added procedure grants that.

Q Do you have anything else with regard to your proposed Rule at this time?

A No, I haven't.

Q Mr. Nutter, were you present when Case 1324 was heard by the Commission in October of 1957?

A Yes, I was.

Q Do you recall the testimony of Mr. Buckwalter in that case, to the effect that the development of the Caprock-Queen Pool on a capacity basis would not cause any serious problem on the market situation?

A Yes, I recall that.

Q Now, have you also read an article in the October 5th, 1959 Oil and Gas Journal by Kenneth L. Smith, Vice-president of Ambassador?

A Yes, I read an article.

Q Are you familiar with a statement contained therein that water flood production has had very little insignificant effect on the New Mexico oil market?

A Yes.

Q Do you agree with the conclusions of those gentlemen?

A No, I can't say that I do.

Q Now, referring to what we will designate as Exhibit 2, would you discuss that?

A Exhibit 2 is this large Exhibit on the top of the board here, and it has one line on it. It is a continuous red line which commences in September of 1954 and goes through to July of 1959. The selection of September, 1954, or the beginning of this line, was the occasion in which the Commission authorized capacity allowables for a water flood project that was operating in the Russell Pool. This red line depicts water flood production in excess of top unit allowable.

Q This is not total water flood production?

A No, sir, this is water flood production in excess of top unit allowable for the 40-acre tracts since 1954. Now, you'll see that the Russell Pool rocked along at just, just very insignificant quantities of oil in excess of the top unit allowable, per 40-acre tracts. And this situation continued until 1957. In 1957 the Commission heard the first case for capacity allowable in the Caprock-Queen Pool in September, and it was continued to October, and an Order was entered authorizing capacity allowable for several wells in the Caprock-Queen Pool. Since that time there have been several other water flood projects in which the Commission has authorized capacity allowables. Now, since that occasion in 1957, when the first capacity allowables were authorized in the Caprock-Queen Pool, we can see that this red line has climbed quite sharply. The scale on this Exhibit, it runs from zero to 240,000 at the top of the graph. The July production --

Q This chart shows monthly production --

A This is total monthly production. The July production in excess of top unit allowable is 227,000 barrels. This is not water flood oil, this is production in excess of top unit allowable in these water floods.

Q Now, what would that figure out to on a daily basis?

A For the month of July this figures out to something better than 7,000 barrels per day.

Q 7,000 barrels.a day. What impact do you think this has had on the Southeast allowable?

A In working with allowables, we commonly, as a rule of thumb, use the figure that one barrel of normal unit allowable is equal to 3500 barrels of production. So I would say that this 73 barrels of excess allowable for water floods represents two barrels of normal unit allowable for Southeast New Mexico.

Q In other words, the allowable for July of this year would have been two barrels higher but for this excess production--

A Correct. I would also like to point out that the allowables are in the range of 34 and 35 barrels at this present time, and this represents -- this two barrel difference represents six percent of the normal unit allowable; two barrels, six percent.

Q Now, Mr. Nutter, is it your opinion that the capacity allowables have had an adverse effect on primary exploration and development?

A Primary exploration and development is down, and that's not due solely to water floods; I don't want to give that impression at all. There are a number of factors that enter into this. Among them is imported oil, the increased production of natural gas, and increased production of oil that is not controlled by market demand prorationing. Now, this would include non-prorated states. This would also include non-prorated oil in prorated states, and I would consider excess production of water flood oil non-prorated in prorated states.

Q Has less likelihood an operator would drill wildcat wells, is that correct?

A Yes, sir.

Q And this has had a two-barrel effect thus far in the Southeast, or up to July. Do you figure that that line will go straight up?

A That line doesn't show any indications at the present time of going down or even leveling off. There has been no decrease whatsoever since 1950 on that line.

Q Mr. Nutter, I would like to read you another statement by Mr. Smith in the article of October 5 Oil and Gas Journal, and I am quoting now. "When a field is totally under waterflood operation, the oil producing rates for the field as a whole seldom go above that field's highest primary producing rate." Now, in that regard, what is the situation in the Caprock-Queen Pool?

A This is a statement that we hear quite frequently, and the Exhibits for the Caprock-Queen Pool are right over here.

Now, this green line on this Exhibit -- this is Exhibit 3, I believe -- this green line shows the production in the Caprock-Queen Pool since the pool was discovered back in 1944. It had a peak in 1956 of some 464,000, 465,000 barrels. It then started on the downgrade and reached its low point in 1958. Now, the water flood operations started in 1957, but the full impact of the water flood operations to date -- the impact to date was not felt until 1959, when it started going up, of course, however, the impact was there because this decline curve would have been going down at a sharper rate had it not been for the fact that several projects were in operation in 1957 and early '58.

MR. PORTER: Mr. Nutter, visibility isn't too good. I wish you would take your pointer and draw the line, the course of the green line on the chart.

A Yes, sir. 1944 through 1959 are shown on the chart. The green line is the production from the Caprock-Queen Pool. You can see it continues on a slight increase up to 1947, and then it decreases again, gets down to about 50,000 -- no -- about 25,000 barrels per month. Before the new development occurred in the Caprock-Queen, the high point on primary production is right there and then it decreases to a point here and then it is back up to here right now.

Q What is that point?

A That point is some 475,000 barrels, roughly, per month.

Q Now, that's higher than this pool was producing at the peak rate on primary?

A This is higher than when the peak had its peak primary rate. This is due to water flood activity, as I said before. Now, this little map right here shows the Caprock-Queen Pool.

Q Is the majority of it under water flood?

A The water flood project is colored. The injection wells are green, the producing wells that have had a substantial response to the water flood are marked in red. There are three projects in the north end of the field. All of the acreage in these three projects has not yet responded. There is another project in the center portion of the field, being the one that is operated by Cities Service, and there is another water flood project authorized. An injection is being made at the present time on the west side pool just west of the Cities Service flood. However, no response has been felt to the water flood by those wells, to my knowledge. In other words, we have these two projects in the north, this project right here, south of it, the northernmost one, and this little project operated by Cities Service, and all of the response and all of the increased production from the Caprock-Queen Pool since 1957 is due to these projects right here.

Q It would be reasonable to assume, would it not, that your green line is going to continue to rise as there are additional water flood projects in the Caprock-Queen which receive a response?

A That's the way I see it.

Q Now, Mr. Nutter, are there other pools in Southeast New Mexico which are being water flooded and which make oil in excess of top unit allowable?

A Yes, there are.

Q Would you refer to some of your Exhibits there showing those?

A I have several Exhibits here showing the production as well as injection and proposed allowable rate for existing water floods. I would liked to have prepared these for all of the floods we have in existence, I didn't have time to do it, however. Now, all of these are not making oil in excess of the authorized allowable, or in excess of the top unit allowable. I should point that out. Some of these floods haven't had a response. I'll start here first with this particular Exhibit. It is labeled North Caprock-Queen Unit No. 1.

Q Is this Exhibit No. 5?

A This is Exhibit 5-A.

Q What do the various colored lines depict, Mr. Nutter?

A The green line is the water injected in the water flood project. The black line is the production of oil from the wells in the project area, and the project area is,as determined by this proposed Rule 701, being the area that would either be colored in black or in red for the individual water flood project. Now, that's the black line, production from the project area alone. The red line is the proposed allowable.

Q That is the allowable which that project would be receiving if your proposed Rule was in effect?

A Yes. All of these floods happen to be in Southeast New Mexico, so this is the allowable of the project area times the area allowable factor for Southeast New Mexico, being 42 times the depth factor for the pool, and in all of these pools the depth factor is one. So, Exhibit No. 5-A is for the North Caprock-Queen Unit No. 1. This is the water flood project that is operated by the Graridge Corporation in the northern part of the Caprock-Queen Pool. Now, we can see that injection of water started in April of 1957. This is the green line at the top. The flood did not respond to the injection of water, it is apparent, until about August of 1957, at which time the production started going up. Since then, the production has climbed constantly with the exception of a brief period in June and July of 1958. Injection was increased at that time, and production has gone up since then. It is also interesting to note that under the proposed allowable for the Graridge project in the Caprock-Queen Pool, that this project would have stayed within the proposed allowable every month of its operation; except the last four months, it would have stayed within its proposed allowable. There is a possibility that maybe this allowable I am proposing is too high.

Q You are discussing projects that are now in operation, are you not?

A Yes, sir. These are projects that are all in operation.

Q And even though we are discussing these, your proposed Rule would not apply to these water floods, is that correct?

A This proposed Rule would not apply. This is merely to show what would have happened if these projects had been covered by the proposed allowable. Now,the green line and the black line being the injection and the production, are the actual injection and production for these projects. The red line is merely the proposed allowables that would have been assigned if the projects had been operating under this system.

Q All right, please go to 5-B, then.

A The next one is the water flood project in the Red Lake Pool, and runs from 1959 through the current production figures available for Red Lake Pool, and shows that injection from 1955 until the early part of 1957 was slowly decreased. It finally took a rather sharp decrease right in here. Shortly after that they increased the injection rate, and production, at the same time, went up. You can see there is a rather marked correlation there between injection and production. In looking at the red line, we see that it ran rather uniformly for a period of about two years.

Q That would have been the project allowable?

A This would have been the project allowable. The first increase in the project allowable is when the operators in the Red Lake Pool unitized and they were able to assign more 40-acre tracts to the project, so the allowable went up. It reached its maximum, then, in about June of 1957 or May of 1957, and has remained rather constant since that time. Production hasn't even begun to approach the proposed allowable for that pool.

Q Just looking at that Exhibit and not considering any engineering principles, doesn't it appear to you that you can increase your injection rate and production will go right up?

A This appears to be the case right here.

Q From proportion --

A There is correlation between the green line and black line.

Q It is shown very definitely there?

A It is there.

Q The next Exhibit is Exhibit 5-C. This is for the Vacuum Pool. Is this a project that is operated by Magnolia?

A Now, this water flood has had no response to the injection of water as yet. The green line shows the injection rate, the black line shows the production rate. As a matter of fact, there has been a decrease in the production from the last three or four months. This is probably a decrease due to the natural decline of the wells prior to the time that they felt the response from the flood. Of course, the black line is still well under the red line.

The next Exhibit is Exhibit 5-D and is for the North Caprock-Queen Unit No. 2. This is a water flood project operated in the Caprock Pool by the Ambassador Oil Corporation. You'll see that the injection of water has increased from the time the water flood was first instituted. Production is still going up. The proposed allowable covers the water flood project during the early part of its life, and then production in the flood fell off, and the red line is again above the black line. And then in February of 1959 production exceeds the proposed allowable, and it is still in excess of the proposed allowable. This is the case when the proposed allowable for the existing injection rates isn't sufficient to cover the production.

The next Exhibit is No. 5-F. This is the Drickey-Queen Unit area. It is a water flood operated by the Cities Service in the central portion of the Caprock-Queen Pool. You'll see that the injection of water commenced there in July of 1958. Injection was maintained at a rather high rate. They had four injection wells. Injection was carried on at about 60,000 barrels per month, which is around 500 barrels per day, per well. Production came up. This project had a project allowable rather than capacity allowables assigned to it for a period of time, and the allowable in the project, that was assigned to the project, was not sufficient to cover the production of oil. Cities

Service reduced the injection rates from 60,000 to 30,000 barrels per month, and production didn't increase as fast as it had been increasing.

Q Now, the allowable --

A However, production is still going up.

Q The allowable that was assigned to that project was less than the allowable that would be assigned under your proposed Rule,was it not, --

A Yes, sir, it was less.

Q -- because the allowable was --

A It was less for two reasons. Well, actually, just one reason. It was assigned on the basis of the current allowable which was thirty some odd barrels, and this project allowable that I have drawn here is for the 42-barrel Area Allowable Factor for Southeast New Mexico.

The next Exhibit is No. 5-G, and it is for the High-Lonesome Pool. Here is another pool that although some of the wells in this pool had a good response to the water flood and produced substantially in excess of standard allowables for wells of that depth, the project allowable exceeds the project production. This water flood has been a comparative success, I believe, even though the black line constantly remains below the red line.

Q Now, summarizing Exhibits 5-A through 5-G, doesn't it establish that in many water floods your proposed project allowable would be entirely adequate?

A Yes, sir, I would say that in most of the water floods, at least the ones we've got the Exhibits for here.

Q Producing less than they would be allowed under your proposed Rule?

A Yes, sir, that is true.

Q Now, Mr. Nutter, you are fully aware, or probably will become more aware as this hearing goes on, that engineers of unquestioned ability and integrity can't entirely agree on this question of restricted versus capacity rates and the results therefrom; you are aware of that, are you not?

A Yes, sir, that's my understanding, that there is a difference of opinion on that subject.

Q Isn't it true that the Sub-committee of the Interstate Oil Compact Commission couldn't even agree on this issue?

A That Sub-committee of the Interstate Compact Commission, secondary Recovery and Pressure Maintenance Committee has been considering this very problem for a number of years now, and I just had a letter the other day that includes the program for the Secondary Recovery and Pressure Maintenance Committee for the Philadelphia meeting December the 3rd. And I note that here on this program, one of the items is another report of the Sub-committee on the studies of effect of curtailment production on recovery from water flood projects. So, this issue is still being considered by the Compact too.

Q Now, without going into too much engineering detail -- I imagine that will follow -- is it generally your opinion that high injection rates give too much emphasis to -- well, that they give too little emphasis to capillary imbibition, and that lower rates of injection give too much emphasis to gravity?

A This seems to be the crux of the argument that goes on in this topic. The one side maintains that by a slow injection rate you have additional effect by the imbibition and more efficient sweep of the oil. The other side maintains that the gravity has high impact on the water, causes the water to go down to a lower level in the reservoir, and probably cuts through if it's injected at too low a rate. So, I think that this is probably the crux of the argument, and perhaps each side gives a little too much emphasis to the point that they are considering.

Q Now, Mr. Nutter, has it come to your attention that there are authorized water flood projects in this State, authorized to produce at capacity which are actually producing at the capacity of the equipment and not at the capacity of the formation?

A Yes, sir, this has been called to the attention of the Commission.

Q Now, if the capacity proponents are correct, and it causes waste to produce at less than capacity, then it is causing waste by having equipment installed that is not large enough to let the formation produce at capacity, is that correct?

A Yes, sir. This capacity brings up the question, what is capacity, what is the well supposed to produce at the capacity of the reservoir, the capacity of the pump, the capacity of the pumping unit, the capacity of the tubing to handle the production, or what is the capacity? If the argument is correct, that the well should be produced at the capacity of the formation to deliver oil into the well bore, then undersizing equipment would be causing waste.

Q Now, Mr. Nutter, do you feel that your proposed project allowable would give sufficient incentive to prospective water flood operators?

A Yes, sir, I feel that it would.

Q Now, do you also feel that it would restrict water flood production somewhat and, therefore, would lessen the impact of water flood oil on the market situation?

A It allows -- it allows water flood projects a high level of production. As seen by these red lines on this chart, it allows a high level of production, and yet it allows the project to be carried on. Now, there is some factor in here that allows the project to be established and to be expanded at a little slower rate than maybe would be the normal procedure. This permits wells in part of the project that have peaked out to absorb the overproduction that other wells in the project area are experiencing, and I think that it provides ample incentive for an operator to institute a water flood project.

Q The Commission is getting more and more applications for water flood projects all the time, is it not?

A Yes, sir. Where, a matter of two, three years ago, we had two or three active water flood projects in operation, there is considerably more than that right now. The Commission since January the 1st, 1958 has processed eighteen applications for water flood. Prior to that time, there were two or three. So, water floods are definitely becoming more prevalent in the State of New Mexico, and we expect, unless something is done about it, we expect this red line to go higher and higher, and the share of the market demand that is taken by the water flood oil to become larger and larger as time goes on.

Q Do you have anything further you would like to offer?

A I don't believe so.

MR. PAYNE: That concludes the direct testimony of this witness. However, I would like to reserve the right to call him in rebuttal and perhaps call some other witnesses too.

MR. PORTER: We are going to recess the hearing at this time until two o'clock, and I realize that some of these Exhibits are on a small scale, necessarily. We just don't have a display room, so some of you may want to return a little bit early and take a closer look at them.

MR. McBROOM: Excuse me, are we going to call Mr. Nutter back for questioning?

MR. PORTER: He will be called back.

AFTERNOON SESSION

MR. PORTER: Does anyone have a question of Mr. Nutter?

CROSS EXAMINATION

BY MR. CAMPBELL:

Q Mr. Nutter, in the letter of transmittal transmitting the proposed rule, there is reference, as you have noted, to the proposal that the rules will apply only to new floods not yet authorized by the Commission, and in your testimony you have made reference to old floods and new floods. Would you state what your interpretation of that is?

A Yes, sir, I think the interpretation is right here in this memorandum that a flood that has been authorized by the Commission at the time that this rule would be adopted, if it were adopted, any flood that was authorized by the Commission up to that date would be considered an old flood.

Q What I was wondering about, there are several floods that are in the pilot stage, and I presume would come within that, having been authorized by the Commission.

A They have been authorized by the Commission, and I would consider them an old flood, yes, sir.

Q Let us assume that you have a pilot flood authorized by the Commission and there is expansion of that pilot water flood, and the expansion requires the acquisition of additional acreage at a date later than the entry of this order. Which rule would it come under? Assume it is contiguous and is a normal expansion of the pilot project but is not owned or controlled by the one who got the project authorized, do you have any views on that?

A Just off hand, Mr. Campbell, I would imagine, well, let's take the case of a pilot area that is being operated by one operator and he is negotiating at the present time for a unit --

Q Yes.

A -- that will cover more acreage and this pilot water flood would be expanded into the unit that is going to be created. I would imagine the flood on that acreage would be an old flood.

Q Would that be, same thing be the same if he acquired the acreage rather than unitizing with someone else?

A I would imagine so, yes.

Q Now, Mr. Nutter, with regard to the proposal that you have made concerning the allowables to be granted to new water floods in New Mexico, and referring to your Exhibit No. 1, am I correct in assuming that of course in order to be entitled to the allocations that you have shown on Exhibit No. 1, the operator of the project, the one who is doing the injecting, the water injecting, must own or control all of the acreage in order to get the maximum amount --

A Yes, sir.

Q -- of acreage assigned as allowable, is that correct?

A Yes, sir.

Q If there is a divergency of leasehold interest, he would not be entitled to attribute someone else's developed tract to his project?

A That's correct.

Q Do you feel that that would lead to a result where people would feel more obliged to unitize their acreage in order to acquire allowable?

A I think it may contribute to unitization, Mr. Campbell. However, I frequently hear that unitization is very beneficial to the efficiency of a secondary recovery, so that would be a good feature of it.

Q You feel if that is the result, then that would be a worthwhile thing?

A I think so.

Q One of your concerns here seems to be that over the years the impact of water flood oil will create a problem,, or has created one with regard to general primary production and to drilling, exploratory and drilling activity, is that correct?

A Not in its entirety, Mr. Campbell. I tried to make it very clear this morning that I wasn't talking about water flood oil. I'm talking about excess production over the allowable of water flood oil.

Q That's what I, we will use the term excess water flood oil.

A I think any water flood is entitled to come up from a stripper state of producing maybe two or three barrels a day up to five barrels. That's like a man going out and drilling a new well. He has invested some money and he's entitled to come up to some level, and when you start going up above that you have to take another look at it.

Q We will get to that in a minute. Do you not think that the encouragement of unitization of large areas might actually accelerate the impact of water flood oil rather than decrease it?

A It perhaps would if you put the entire project on water flood all at the same time. If you take a 6,000 acre unit and put a hundred wells on injection on next Monday morning, that would have a terrific impact.

Q Let's take the Caprock-Queen Pool as an example, and let us assume that the entire pool is unitized rather than fairly large units as are now being developed, and there's no restriction to my knowledge on the number of injection wells you may install in a unit or in the project that you have under control, am I not correct in that?

A That's right.

Q Would not the tendency be then in order to acquire the maximum allowable, even though you didn't put it all under flood at the same time, to separate injection wells over large areas in order to get the maximum pattern for the maximum allowable for the project?

A There's a possibility that could occur.

Q That, in fact, would encourage the acceleration of expansion of water flood projects to acquire allowable rather than reducing it, which I think must be part of your intention here, isn't that correct?

A Well, I don't know how they would expand too fast, Mr. Campbell, because if you have a restriction on the rate of expansion of the things --

Q Which is presently in existence.

A -- which we presently have, yes.

Q Do you believe that there's any possibility that the proposal you make, and again referring to your Exhibit 1, might make it impossible for the owner of a fairly small tract to protect his correlative rights in the event a larger project was moving toward him?

A Protect his correlative rights in what manner, Mr. Campbell?

Q Be able to install a project or injection well himself and acquire enough allowable in his limited acreage situation to permit him to produce his well at as rapid a rate as his neighbor.

A Well now, if he were installing a new one in the existing flood with an old flood, then he would have a problem probably. I think that situation is recognized by this paragraph that states that "Nothing herein contained shall be construed as prohibiting the assignment of special allowables to wells in buffer zones, after notice and hearing."

Q It is obvious I would think from your proposal of the twenty-one well maximum on the five-spot or contributing direct diagonal acreage, that it is to the advantage of anyone proposing a project to install his injection wells as far inboard as he can, assuming a five spot program in order to acquire the maximum amount of allowable, is it not?

A Yes, sir, if you were right on the edge of the field perhaps those red zones wouldn't have any wells on them and you wouldn't get a credit.

Q So to that extent, if you use a program of this sort are you not to a certain extent controlling or undertaking to control indirectly the manner in which these projects are developed in order to acquire allowable as distinguished possibly from the best engineering approach?

A Well, I don't, really don't know.

Q That would certainly be a factor in deciding where you placed your injection wells, would it not?

A Some operators may give that some consideration prior to the institution of the water flood project.

Q One other thing, on your Exhibit 1 are you assuming, generally speaking, a five spot program of water flooding?

A Well, that's what you would call this I guess except for this one injection well deal and this staggered six well injection area. I don't know what you would call that thing. Maybe it's an off balanced five spot perhaps.

Q You are aware, of course, that there are different methods of flood such as peripheral floods?

A Yes, sir.

Q If you were making a decision as to whether you should flood an area by peripheral flood or by five spot flooding, pattern flooding, the nature of this formula would have a considerable bearing upon that conclusion, wouldn't you think?

A Yes, sir, I imagine it could.

Q If you were to start at the north end of the field say and move the water and oil to the south, at least in the initial stages you would have little acreage to which you could attribute the project for purposes of allowable, isn't that correct?

A That's correct. However, Mr. Campbell, it's been my experience that the bulk of the bonafide water flood projects are usually five spot or seven spot or some kind of an arrangement of interior wells, and generally speaking now, this isn't always the case, but generally speaking when you go to a line drive or peripheral flood it is more of a pressure maintenance project than water flood. I think when they go for water floods they get right in and mix it with the boys and mix the producing wells and the injection wells altogether there in a real actual water flood.

Q Are you saying that there are no peripheral water floods?

A No, sir, I said generally speaking.

Q If there were such a bonafide water flood on peripheral basis, this order would not provide for any possible exception, would it?

A Yes, sir, this order has a penciled-in rule that I didn't read this morning.

Q Perhaps if you had mentioned that it would have saved some time.

A No, sir. I have been giving some consideration to this. These line drive floods could conceivably create a problem, and I think that one way of solving it would be the inclusion of some additional acreage.

Q Excuse me, would be to what?

A The line drive type of flood could create a problem and one way to solve it would be the inclusion of some additional acreage. I'll show you what I was thinking of. Here we have a pool that has twenty-four wells in it, and under this proposed rule without the penciled notation the project area would comprise these forties.

Q You are assuming that those forty marked with x's are the injection in?

A These are injection. The project area would comprise those rows of forties, two rows, the one being the injection well plus the offsetting producing forty. I think that this rule could be made to operate better for that type of flood if upon receiving a response to the water flood that the next row of forties could be added to the project area if they have a response. You will have a response in the second row away from the injection wells in a flood like that.

Q You are talking now about the response to the wells in the second row?

A Yes, sir. As soon as they had a response you could add the added area to the injection area.

Q Do you have that proposal you say written into the proposed order?

A Yes, sir, it's just penciled in on this one over here.

Q I don't want to push you into recommending something necessarily unless you are in fact recommending it.

A No, sir, I think it's proper. I would have to give this more consideration than I have given it so far, but I think, upon further study I think this would be completely feasible and not improper at all, and this thing says plus forty acre tracts that have wells that have received a response. You would want to word it a little differently, but in essence to be able to add the forty acre tracts which may be more than one forty acre tract away from an injection well if the forty has had a response.

Q Now, Mr. --

A Did you want me to remove this so you can refer to this again?

Q You probably will want to, I don't need it there any more, but someone else probably will.

MR. CAMPBELL: Do you wish to have that put in evidence?

MR. PAYNE: It makes no difference to me.

MR. PORTER: Does anybody have a question as to whether it was prepared by Mr. Nutter or not?

Q Now, Mr. Nutter, with regard to your Exhibit No. 2, I believe that's the number of the excess water flood production?

A Yes, sir.

Q In arriving at your July, 1959 figure for water flood oil in excess of top unit allowable, would you state how you did that?

A Yes, sir. I went to the statistical report that the Commission puts out, and every well that made more than top unit allowable for the pool in which it was located was listed and the difference between top unit allowable and its production was totaled up, and that total came to 277,000 barrels.

Q So you included in that figure only the producing wells and not the injection wells?

A That's correct.

Q Is that correct? A That's correct.

Q Is it not true, Mr. Nutter, that at least in most of the projects which have been installed in New Mexico to date that in the vast majority of instances the injection wells are in fact producing wells that have been converted?

A Yes, sir, in most cases however they were producing maybe two or three barrels a day.

Q They were producing wells?

A Lots of them were.

Q Do you think it is improper to consider that those should be determined in excess production whenever those wells are taken off production and converted?

A You could take the hundred or so injection wells that we have right now and take the amount of production they had before they were converted and multiply that by the number of total wells and subtract it from that total and you wouldn't be able to tell the difference in that line up there.

Q In your proposal you are simply giving credit to wells that have been used for injection wells?

A Absolutely giving them a full 42 barrels, yes, sir.

Q Excuse me. While we're on that point, I don't like to revert to that first exhibit, particularly, when you speak of producing wells, suppose a well has been plugged and abandoned but the acreage has been developed. The investment has been made. Do you consider that a proper unit?

A No, sir, I wouldn't consider that well.

Q It has to have a producing well at what point?

A During the current month that you are figuring the allowable.

Q In arriving at the impact of this 7,000 barrels on the basis of producing wells only which you have considered as excess water flood oil upon the overall New Mexico production, you came to the conclusion that at 7,000 barrels a day would be approximately two barrels per day added to the top unit allowable, is that correct?

A Yes, sir.

Q Have you made any calculations as to the number or percentage of marginal as distinguished from non-marginal wells in New Mexico?

A Oh, gee, I had that figured the other day and I don't remember just how many non-marginal wells we had. I was looking --

Q Is it a relatively small percentage?

A Yes.

Q In Southeast New Mexico?

A Yes, I would say it is. It is probably 20% of the total.

Q And so that 80% of the wells, unless they were right at the margin, at the point of becoming non-marginal wells, would receive no benefit if that 7,000 barrels were reallocated, would they?

A That's correct.

Q Isn't it true also that a considerable portion of the non-marginal wells in New Mexico are wells of some considerable depth?

A Yes, sir, and have depth factors.

Q And those wells have already economic depth factors, do they not?

A Yes.

Q If you reallocated the 7,000 barrels a day that you are referring to here, a sizeable portion of it would go to the deep wells, deep non-marginal wells which already received a considerable economic advantage, isn't that correct?

A I don't know what a sizeable portion is. I wish I had a proration schedule handy. We could more or less get an estimate on them.

Q Well, certainly -- okay.

A To be specific, to an answer awhile ago, there are 2,485 non-marginal wells in Southeast New Mexico in the October proration schedule.

Q What is the total number?

A That's out of a total of 10,830 wells. So it's about 25% rather than 20. Now, of that total of 2,000, I'll just read the larger figures. Of the total -- non-marginal wells here is 40 with a depth factor of one. Here is 205 with a depth factor of one. Here's 40 with a depth factor of 3.77, here's 49 with a depth factor of one, here is 52 with a depth factor of one, here is 30 with a depth factor of 3. Here is 95 with a depth factor of one, and here is some 20's and 22's, here is 26 with a depth factor of 1.33, 19 with a depth factor of one. 292 with a depth factor of 1, 58 with a depth factor of one, 79 with a depth factor of 6.75. 234 with a depth factor of one, 64 wells with a depth factor of 5.67. 26 wells with a depth factor of one, 106 wells with a depth factor of one, and some 11's and 12's, various categories, but those are all the major wells. It seems as though the bulk of the top allowable in Southeast New Mexico have a depth factor of one.

Q Doesn't the allowable increase arithmetically as you deepen your well?

A Yes, the six some odd wells that had the depth factor of 6.75 I think it was, that would be the same as what was it, 6.75 times 60 wells would be 420 wells with a depth factor of one actually.

Q How would you allocate? Would the deep wells get 6.75 in relationship to the --

A If you are redistributing the 7,000 barrels that this represents a well that had a depth factor of one would get one barrel of that and a well that had a depth factor of 6.75 would get six and three quarters barrels of it.

Q Now, Mr. Nutter, you referred to the concern that you have that water flood operations are resulting in a decline in exploratory drilling activity or contributing to a slowdown in drilling activity in Southeastern New Mexico I believe?

A Yes.

Q You stated that there were several other factors?

A Yes.

Q That also probably were contributing to that?

A Yes.

Q I do not believe you included in that any reference to the situation with regard to distillate being produced from unprorated gas wells, do you think that's a factor also?

A Oh, I'm sure that gas as well as gas liquids are a factor be they prorated or not.

Q Of course gas liquids in non-prorated gas fields aren't prorated?

A Gas liquids aren't prorated in any gas field.

Q Do you have any idea of the amount of that being produced in New Mexico at this time?

A No, sir, I don't have.

Q And in speaking of the situation in the Caprock-Queen Pool as related to the impact of water flood development, I believe you made the statement that the only reason for the increase in the total production from the Caprock-Queen Pool from that low point on your Exhibit No. 3 to the present point was water flood activity. Is that the statement that you intended to make?

A Well, there may have been a few new wells drilled, Mr. Campbell, but I sure don't know about very many of them. That pool reached the peak of development in that drilling boom that they had back in 1954 and '55, and you can see the pool's production peaked out in 1956 and since then there has been very sporadic drilling of new wells. There's a few, but not many.

Q How many would you estimate?

A I wouldn't even estimate.

Q You haven't made any study to determine that?

A No, sir.

Q But any new wells drilled in the pool during the period that we're talking about from the low point to the present point would, of course, have a bearing upon that amount of total production from the pool, would they not?

A Oh, yes, absolutely. They would be in there.

Q And to the extent that that was the case, it would, of course, decrease the impact of water flood oil as a factor in that, would it not?

A Yes, sir.

Q With regard to your Exhibit 5-b, I believe it is on the Red Lake Pool?

A Yes, sir, that's 5-b.

Q I think you pointed out, as you testified, that there was a decline or a sharp increase in the water injection rate and that resulted in the sharp increase in the production?

A Yes.

Q Toward the middle of the flood?

A Yes, sir.

Q Wouldn't the fact that you put additional injection wells on by virtue of expansion explain that rather than assuming that it all came from the same wells?

A Yes, sir, it actually would. Now, the thing was unitized right here at this point, this is December of 1956, the following month, January, reflected the unitized allowable, the injection rates didn't go up then of course. The injection rates went up from February to April and there were additional wells put on at that time.

Q And that would have a bearing upon the relationship between water injection and production, of course, would it not?

A Yes, sir. I think there may have been some new injection wells put on in this period too.

Q No, Mr. Nutter, you, in the course of your testimony, stated the very obvious fact that there is, to say the least, some disagreement between engineers with regard to the question of rate of injection and pressures and rate of withdrawals from these water flood projects?

A Yes.

Q And that there were reputable engineers who had opposite views in that regard?

A Yes.

Q I think you then further stated that if your formula had been in effect during this period of time, that we have had water flooding in New Mexico, actually from the project you studied, there would only be two which would be adversely affected with regard to not being permitted to produce all they apparently needed to produce, is that right?

A That's correct. I think of these seven exhibits there are only two in which the black production line goes above the red allowable line.

Q Now, if that is the case and if there is a serious question without even deciding at this point who is correct, there is a serious question as to whether physical waste might occur, do you not think it would be in the interest of conservation to adopt the most conservative approach insofar as running the risk of physical waste is concerned, unless the impact is of very serious consequence?

A My own personal opinion, Mr. Campbell, is that these water floods can have a reasonable amount of restriction without causing any waste. Now I didn't say complete restriction and I also didn't say they ought to be produced wide open I don't think.

Q You say wide open, what are you referring to?

A That the capacity of the formation to deliver oil into the well bore at the bottom of the hole with no pressure on the well bore, in other words keep the thing pumped off, let it come in.

Q While we are on that point, if you will, what do you consider the maximum injection rate as an engineer?

A Well, there isn't any such thing for a general statement to apply to all floods. This depends on a lot of thing, residual oil, saturation, porosity and lots of things.

Q Has it been stated in the previous hearing that what is being referred to as high rate of injection is actually the rate of injection on a particular well and a particular reservoir which is the highest rate that can be obtained without a water break-through?

A I have heard that theory advanced, yes.

Q Do you agree that that is what is being talked about with regard to rate of injection here?

A High injection rates?

Q Yes. A That is high.

Q Then the production rate is whatever is produced at that rate, is that not what has been talked about by those --

A That's correct, you push it in at one end. All you can push in without breaking the formation down and you push out all you can out the other end.

Q What comes out the other end varies widely between the different projects?

A It varies in the projects.

Q And between the wells, does it not?

A Yes.

Q You have stated, I believe, Mr. Nutter, that there are projects operating in New Mexico to your knowledge that have equipment that will not permit production at that rate that we have been talking about. Would you state what fields those are?

A Those are in the Caprock-Queen.

Q Which projects?

A There's a transcript of a hearing that was held before a Commissioner Examiner in which an engineer for one of the companies testified that they hadn't replaced the pumps in their wells and they hadn't increased the size of the pumping units and the wells were not capable of producing all the oil or pumping all the oil that they could produce.

Q Do you recall what hearing it was?

A No, sir, I don't remember the case number.

MR. PAYNE: I believe it was Case 1304, Mr. Campbell.

MR. CAMPBELL: What pool did that involve, what project?

MR. PAYNE: Cities Service.

MR. CAMPBELL: I believe that's all the questions I have at this time.

MR. PORTER: Mr. McGowan.

BY MR. McGOWAN:

Q Mr. Nutter, I'll attempt insofar as possible to avoid any repetition of matters referred to by Mr. Campbell. As I read your proposed rule I gather that you anticipate within this project area the transfer of allowables from lease to lease as an automatic thing within your lease, is that correct?

A If it's consolidated under one operation, yes, sir.

Q Let's assume that it was three Sinclair leases owned where the royalty ownership under each lease was different, would we still be allowed to have a project allowable and in effect transfer allowables from lease to lease within the project?

A That's one of those problems that I don't have the answer to, Mr. McGowan. That would have to be something that would be worked out. It would have to be worked out.

Q For your rule to work that would have to be the result, would it not?

A Yes, sir, it would have to be the result of a project area now, whether it could be done without pooling these royalties or not I don't know. I don't know if it would be legal and I don't have the answer to that.

Q You are aware that the Commission does not have authority to force pool those royalties, are you not?

A Yes, sir.

Q Now, your exhibits I believe 5-a through g are individual charts on various water flood projects showing injection rate, production rate and then what would be the allowable for that project under your proposed rule, is that correct?

A That's correct.

Q And I believe only two of them have exceeded in producing rate above what would have been their allowable?

A Yes, sir.

Q Have those two projects reached what we commonly refer to as their peak of production do you think?

A I don't know. Now this is the North Caprock-Queen Unit No. 2 and this black line is still going up, so I would say this one hasn't reached its peak. I want to point out something here that I didn't mention this morning. These charts are drawn on semi log papers, when you get into the upper ranges on semi log the difference is more substantial than it appears.

I want to point out that this red line for this unit occurs at about fifty, I would say it's about 55,000 barrels per month. I want to point out that the black line occurs at 142,000 barrels. I think that's a significant point to mention here. This other flood perhaps has peaked out, it's leveled off, anyway it appears now there was some additional wells that have recently been put on injection, there's an area in the Caprock-Queen Unit No. 1 that hasn't had a peak yet. It's illustrated by this exhibit, it is down in most of the east half of Section 6 and all of Section 7 and all the west half of Section 8 with the exception of one 40. There has been no response there so when that area comes in, if it comes in before another area has fallen off enough, this pool, this project may have higher peak.

Q Of course the area would be increased by that, would it not?

A Not very much. They are almost at the saturation point right now. They have sixty-two 40 acre tracts assigned allowable right now and there's not many more than sixty-two 40 acre tracts in there, there was a few more but not many.

Q Out of those seven projects only two of them have exceeded and it appears that they are probably the only two with the possible exception of one more that will, is that not correct?

A This one looks like it's going to and that would be the third.

Q And that would be the third one?

A This one looks like it's going to.

Q Probably to some extent? A Yes.

Q I believe that those are the initial floods in the Caprock-Queen Pool, aren't they?

A The two that have exceeded the allowable are the two initial floods.

Q Well, would it not be logical to assume that they are probably the best flood projects that existed since they were chosen first?

A Well, I don't know, I wouldn't go so far as to say that, Mr. McGowan, because the acreage that was owned in those two areas was owned by companies that specialize in water flooding. Now, if the companies that owned that acreage, or if the companies that specialized water flooding had owned acreage some place else in the pool, you might have had water flooding starting there.

Q You did have more than fifty percent of the floods that you have graphed up there which have not, and it appears will not, exceed the allowable they would get under your formula?

A That's correct.

Q And even those that have, obviously are going to do so only for a relatively short period of time in their life, generally speaking there may be exceptions, but assuming that A, for instance has essentially peaked, it's not going to stay above the red line very long, is it?

A No, it managed to stay just below the red line in this whole period through here, all of '58 and first part of '59. It was crowding the line kind of close, but it stayed under.

Q Now, it crossed the line what, about three months ago?

A It crossed the line first in, well, May's production was the first production in excess of the red line. It's been above since May.

Q Well, that's about five months. If it really is peaked now then probably it will stay above for another five months and then gradually decline away from it?

A That is probably true.

Q So then actually an insignificant part of its life it would have been above the red line?

A An insignificant part of its life if you are talking about months.

Q A more significant of its total production?

A It's very significant if it's total production.

Q Now, I believe in discussing Exhibit 5-b you made the point that the decline and increase in production seemed to follow the decline and increase in injection rates, which to some extent you qualified on questions by Mr. Campbell by the fact that additional acreage had been added. I believe you did assign some significance to that, did you not?

A Yes, there are various times that you can more or less correlate. There is a decrease in injection and decrease in production followed by about two months. You had a decrease in injection here. You had a decrease in production following it by two months. You had a decrease in injection and you had a decrease following it here and here. It parallels rather closely.

I don't know what the actual significance of this is.

Q That's what I want to get to. Now, if you'll look at 5-d I believe the production seems to decline at a point when the injection was increasing, at least at one point.

A I would say that the production decline here is attributed to this injection decline here. It's just a lag that's following it.

Q Now, if we move over to 5-g, do you see any significant correlation between increase and decrease injection rates there?

A Here is a decrease in production and decrease in injection.

Q The decrease in production is before injection?

A No, they are simultaneously.

Q That wouldn't normally follow. Normally your lag in production or increase follows, it is not simultaneous with it.

A That is true. There's actually a possibility that this decline right here was a decline in the primary life of the wells. There may not have been any response to the water flood at the time this decline was registered. There is a decline here which follows by about at least a month this decline in injection. These others, they just go up and down, injection rates fluctuate and production maintained relatively rate there for better than a year.

Q That's right. Now that's the point I wanted to make from that, if I wanted to take the seven exhibits, if I wanted to support the fact that production decline and increase followed injection declines and increases, I could pick 5-b and do so very eloquently, couldn't I?

A I imagine you could find a spot on almost all of these exhibits where you could probably find have correlation.

Q I use 5-b in support of the proposition that there was correlation between injection and production rates that could consistently follow that, illustrate that principle.

A It illustrates that principle, whether it's true or not I don't know.

Q If I want to say that seemingly injection rates had no increase on production rates, I could take 5-g.

A Yes, you can find an example to support anything when you start drawing charts.

Q Wouldn't the logical conclusion be that each project is a separate thing and has to be considered and treated separately?

A The only thing these things have in common is that they've all got a red line and green line and black line actually.

Q And that they are water flood projects?

A And that they're all water flood projects. I sure wish I had had time to draw curves on all of them.

Q It makes it tough to write general rules for all of them?

A It's difficult.

Q Now, Mr. Nutter, what are you going to do, when and if areas are water flooded that are spaced on 80 acres?

A That really isn't treated in this rule too well or too thoroughly, I should say. It does say the maximum allowable assigned to any water flood project area shall be determined by multiplying the number of 40-acre tracts in the project times the area allowable factor times the proportional factor. I'm reading the wrong one. Rule 2, "The project area of a water flood project shall comprise the 40-acre tracts upon which injection wells are located plus all 40-acre tracts which directly or diagonally offset the injection tracts and have producing wells completed on them."

You can see there that the 80 acre pool actually isn't included in this. Now we have only got one 80 acre pool that's in the range they are water flooding at the present time. That's Bisti. I don't know, it's in its primary life, I don't know of any plans to water flood it right now.

Q That's one reason I raised that question. I just wondered why you didn't, or if you would be agreeable in your proposed rule to substituting proration unit for 40-acre tract. I think that would solve that problem.

A It possibly would, yes, sir.

Q That's the reason, if you had something special for 80 acres because New Mexico is allocated on proration units, as I understand it; for instance, if you had on 80 acre spacing, if one of your examples on Exhibit 1 was on 80 acre spacing there might not be a well on the adjoining 40, but one on the adjoining proration unit.

A Well, there probably shouldn't be any designation made.

Q It would seem possible that the 40-acre tract in your rule might probably be changed to 40 acre proration unit. That might solve that problem, I offer that. Now, looking at your Exhibit 1, the smallest area that you have there illustrated I believe is 360 acres?

A Yes, sir.

Q What would I do with my little isolated 360-acre lease in between two of those projects?

A I don't know. It could be unitized and then all three of the projects could make one.

Q Assume that my royalty owner is ornery, he wouldn't go for that?

A That's a problem.

Q Now, in talking about the impact on total production and market demand, you have got some floods now that are right at their peak or beginning to reach their peak, have you not?

A Yes, sir.

Q You've got, I think, twelve or thirteen floods in the state. If we add another six or eight floods in the next twelve months, by the time those floods reach their peak the ones that are producing at their peak now are going to have declined considerably, won't they?

A Well, it depends on how fast we authorize these new projects, how fast they get the actual water going into the ground and how fast it takes the wells to respond.

Q The actual acreage that is presently producing this water flood oil will not be producing at the rate it is now?

A A year from now it won't be, no.

Q So actually you will not maintain this production and these projects and keep multiplying as you add new projects. There will be continual decline in there, and therefore a deterioration of the total as against projects just like there is on primary projects?

A Sure, sure, it depends on whether the rate of growth exceeds the rate of decline. Frankly I think the rate of growth right now is exceeding the decline. I think this line shows it right now. I don't see any evidence of the line breaking.

Q You are in the early stage of water flood in New Mexico, aren't you? You have no significant floods that are over the peak points?

A Sure, but we have a lot on the drawing boards.

Q In a year or two you will have a lot going over the peak periods?

A Yes. And some of them will be off the drawing board then too.

Q At the present time yourfloods are relatively new and they are essentially going up?

A Right.

Q That wouldn't be true through the next ten years as new floods are added and depleted, all of them won't be going up at the same time?

A No, they sure won't, Mr. McGowan.

Q Now, turning to your rules, I have two or three little questions that are probably unimportant. In your Rule B-1 where you talk about location of oil wells within a radius of two miles, I'm thinking now about administration, I assume you mean completed to the same formation you are going to water flood?

A It says all wells within two miles and the formation from which the wells are producing or have produced, so actually that would indicate that you would want all the wells that are in a two mile radius shown on that plat. And show which formation they're producing from.

Q In D and E-1 I assume that the intent of this rule would be that the Commission would decide whether a particular project was a pressure maintenance project or a water flood project at the original hearing thereon?

A Yes, sir, I think so.

Q Now we've previously discussed possibly the substitution of proration units for the term 40-acre tracts throughout the rule. I'll make no further reference to that. Now in E-3, I believe this morning that you stated that you felt that in a water flood project the operator should have some idea at least of what he could count on so he could maintain some consistency in his project. That was one of the reasons for the rule?

A Right.

Q However, you used the word maximum allowable, does that indicate that this allowable could be reduced but never increased?

A That would be the maximum allowable. That allowable wouldn't be assigned unless the wells needed it. In other words, if you had a project like this, the red line would be down here where the, I mean the allowable that would be assigned to the well would be down here where the production line is in its earlier life, and then as the production came up it would reach a maximum point and the allowable would not be increased above that point.

Q Then assuming that you used the word maximum intentionally, which apparently you did, except for your reference on the next page, what did you call it?

A Special allowables in buffer zones.

Q Buffer zones, you contemplate no exceptions whatsoever, is that correct?

A Yes, sir.

Q Mr. Nutter, you are aware, I assume, that the statutes of New Mexico and the rules of the Commission prohibit waste as therein defined?

A That's right.

Q I assume that you are further aware that among the definitions of waste is the following: "The locating, spacing, drilling, equipping, operating or producing of any well or wells in a manner to reduce or tend to reduce the total quantity of crude petroleum oil or natural gas ultimately recovered from any pool". So what you are saying is that no matter how convinced the Commission was of the merits of a particular application, nor how much proof a particular applicant could adduce, that the allowable assigned under this rule was reducing the ultimate recovery from a project, the Commission would be prohibited from granting him an exception?

A It's my firm conviction that a project can be made to operate at a level below that red line without causing waste. Therefore there would be no need for deviation from the rule.

Q But you would write a rule that would prohibit the Commission from granting that exception even if I could put on enough proof to change your mind, is that correct?

A Well, I don't know about that.

Q Well, that's what your rule would be if written.

A Well, it sets a maximum and it doesn't make any provision for deviations from the maximum.

Q Now, I further assume that you are aware that correlative rights is defined in the statutes of New Mexico in the rules of this Commission?

A Yes, sir.

Q And that you are generally familiar with that definition?

A Yes, sir.

Q And that the Commission is charged with the statutory duty of protecting those correlative rights?

A Protecting correlative rights.

Q Now, let's go back for a minute to my little 160-acre units where I have ornery royalty owners who won't let me unitize, or maybe I have some incompetent royalty owners who can't unitize, and my allowable that you would give me under this rule won't let me produce the oil from my land but continues to run it off my land on to somebody else's. Your rule would nevertheless, no matter what the proof would be, would prohibit the Commission from granting me an exception, is that correct?

A I don't know about these incompetent royalty owners. There may be some, but most royalty owners I think would be willing to unitize if it meant that those wells were going to get more allowable.

Q Whatever the reason, let's assume we can't unitize.

There are some such instances, I assure you.

A That's a problem, it has to be ironed out.

Q Don't you think that both of those problems might be solved, and I don't ask you to agree to it or recommend it, but if for instance in your proposed rule we struck the word maximum out of Rule E-3 or put in its place the original or the project or the minimum, or just left it out entirely and inserted at the end of that paragraph a statement that the Commission will or may, it doesn't make any difference, grant to any such project such additional allowable as in its opinion is necessary from the evidence adduced at a hearing thereon to prevent waste and to protect correlative rights, don't you believe that striking the word maximum and adding that provision would give the Commission a means of alleviating such instances as we have just been discussing?

A That would be all right if that is what it was limited, alleviating situations like that, but I'm just afraid that privilege, if that provision were made in the rule, that that privilege might be abused and you would have this red line going a little higher than it is now.

Q Well, I hesitate to say this because I know you don't mean it in that sense, but I don't believe people can, with any great consistency, take advantage of the Commission and its staff.

A There are attempts made to do that.

Q It would appear, however, that the striking of the word maximum and the adding of that clause that I just read would give the Commission a means of granting exceptions where it was proved to be absolutely necessary?

A Well, if it were provided for that's what it would do, yes.

MR. McGOWAN: I believe that's all I have.

MR. PORTER: Anyone else have a question of Mr. Nutter?

MR. LORRY: I have one question of Mr. Nutter.

MR. PORTER: Would you give us your name?

MR. LORRY: I'm Tom Lorry with Ambassador Oil, Fort Worth.

BY MR. LORRY:

Q On your exhibits of the seven floods 5-a through g, Mr. Nutter --

A Yes, sir.

Q -- is there any relationship, taking any one of those floods up there, isn't there a relationship between the ability of that reservoir to take fluid and the ability to give up fluids? In other words, varying degrees of permeability and so forth?

A Yes, sir, those exhibits reflect.

Q Also you stated that within any one of those you can have varying degrees of permeability within that one project?

A Yes.

Q As well as from project to project?

A I have seen that happen many times within one project.

MR. LORRY: Thank you, sir.

MR. PORTER: Mr. White.

BY MR. WHITE:

Q One question, please. Mr. Nutter, the applicability of your proposed rule to a very large extent would depend upon the definition of a well which has reached its state of depletion, or what you referred to as a stripper well. Would you give us your definition as to what you define a stripper well as being, as well as a well which has reached its advanced state of depletion?

A You can't pin it down in terms of barrels. A well that's producing 30 or 40 barrels per day from 12 or 14,000 feet isn't a very economic venture, but a well that's producing from 700 feet and making one barrel a day is making money lots of times. So I think it depends on the reservoir and on the operating costs in that reservoir as to whether you decide whether an operation is a stripper operation or not.

Q That would be purely economics?

A I think stripper gets down to the matter of economics, yes, sir.

MR. SMITH: Thank you.

MR. PORTER: Mr. Spann.

BY MR. SPANN:

Q Mr. Nutter, you have defined project area and have referred to water flood project and I take it that the overall water flood project is made up of a number of so-called project areas under your definition?

A No, sir. No, sir. Do I understand you correctly, Mr. Spann, that a water flood project is made up of a bunch of project areas?

Q Under your definition.

A No, sir, there was one project area for a water flood.

Q And there is no overall water flood project made up of these various project areas?

A No, sir, you could have a situation where an operator had a large unit and he started his flood right here and this unit abutted against another unit where water flood operation was going on. He had to put a well on maybe to have a line agreement to put wells on on the opposite sides of this unit line as the wells received responses, and this would be a project area over here and this would be a project area over here. In that case you might have two project areas in a water flood.

I haven't thought this out, perhaps both of those areas should stand on their own feet as far as allowables is concerned. Maybe you can amalgamate the allowables and produce them from either side of the unit, I don't know. That's another new one I hadn't thought of, Mr. Spann. There's lots of problems attached to this. I don't have the answers to all of them.

Q Under 5, you refer to the procedure of expanding a water flood project. Now are you talking there about a project area as you have defined it under 2?

A Well, in answer to that I would have to remind you that this is taken from orders that are in existence today and govern the expansion of actual water floods that are working, and where it is expansion of the water flood area, if they bring in a well on this unit as a result of a kick from a water flood well over on this side of the line, that's an expansion of the project. But it's really a separate water flood from the main water flood that this unit operator is operating over here.

I really don't know now, a water flood project is defined as a project in which water is injected in the ground. They are injecting water over here so maybe that's a project and they're injecting water over here, that's a project. I expect they are both projects. But normally an operator has only one water flood project or one project area in his project.

Q Well, if I had a unit comprising 640 acres, how many project areas under your definition would I have within that unit?

A Well, let's assume that you start off with a couple of wells over in one corner, you have one project and as your project area expands and develops out and you add more injection wells on to it and you have a 640 acre unit, you would have 16 allowables, 16 - 40 acre allowables is what you would have.

Q Could I produce that allowable from any well or wells in the unit?

A Yes, sir, if it was in the project area you could in any proportion that you desired.

Q Would that result even though I had not converted all of the injection wells that I ultimately intended to convert?

A As long as, now what you would have to have to have that 16 - 40 acre allowables, all of those wells would either have to be directly or diagonally offsetting an injection well or be an injection well 40. That's the only way it can become a part of the project area. See, the project area is defined as the 40-acre tracts upon which injection wells are located plus all the 40-acre tracts that directly or diagonally offset those injection wells.

Q And until I have an injection well I would not have a so-called project area?

A There would be no project area if you didn't have an injection well.

Q Converted, I mean a well converted for injection purposes?

A That's right.

MR. PORTER: At this point we are going to have a short recess.

(Whereupon a short recess was taken.)

MR. PORTER: The meeting will come to order, please.

FURTHER CROSS EXAMINATION of
Mr. Nutter

BY MR. HALL:

Q Mr. Nutter, turning to your Exhibit No. 2, briefly, I believe you stated on cross examination that you had not considered water injection wells, is that correct?

A That is correct.

Q Now, going a little further, going a little further, did you take into consideration wells that had been stimulated by water injection and yet had not exceeded their unit allowable?

A No, sir, that's excess allowable only.

Q And yet wouldn't it be proper to consider wells that had been stimulated by water in view of the fact that they are technically water flood wells?

A Yes, sir, but if I had considered that it would have just made the line go higher and it wouldn't have been a realistic picture of what I was trying to portray, I'm trying to portray water flood production in excess of top unit allowable. Now, production --

Q Possibly I haven't clarified my question. If a stimulated well was being produced and yet hadn't exceeded the unit allowable, it would be under the unit allowable, isn't that correct?

A That's right.

Q And that should be balanced to get a real true picture against the wells that hadn't been stimulated beyond the point of top unit allowable, that's the question I wanted you to clarify.

A No, sir, Mr. Hall, I wanted a chart that shows the amount of oil that is produced by oil wells in excess of the allowable that would be assigned to that oil well if it weren't in a water flood project, and that is what this line is. It shows the amount of oil that is produced.

Let's take the month of July of this year, the allowable was 1085 barrels for a well in the zero to 5,000 foot range. Now, if that, if any well made more than 1085 barrels, it was tabulated and recorded here. That's all that this is, is production in excess of allowable.

Q I understand that, Mr. Nutter. I'm just saying the point of my question is that you didn't then take into this interpretation input wells nor did you take into consideration the wells that were actually being stimulated by water and yet had not built up their production beyond the top unit allowable, you didn't take into consideration those two types of wells in this exhibit?

A No, sir, I didn't. This is only excess oil that is produced by wells in excess of allowables.

Q Now, did you, I missed in your direct examination this morning your discussion of Exhibit 5-E. Did you ever discuss that and name what --

A Perhaps I overlooked that one, I do not know, this is the North Central Caprock-Queen Unit, this is the one that is operated by Great Western Drilling Company. They haven't been putting water in the ground very long, just since March, 1959, and they had a response after sixty days.

Q No, then, taking that one into consideration, you have four exhibits that depict performances in the Caprock-Queen Field out of the seven exhibits I believe?

A That is right.

Q And the other three are from other separate common sources of supply?

A Yes, all the other three are in other pools.

Q And as I understood your discussion, the only projects that have exceeded your red line have been in the Caprock-Queen Field, am I correct in that assumption?

A The only ones that I have exhibits on. Like I said, I wanted to draw them on all the floods, I think there is possibly another one or two that might have, but I wouldn't make that statement for sure.

Q But from what we have here then, only one project in one common source of supply have exceeded the top unit allowable?

A Yes, sir, of these seven exhibits.

Q Do you suppose the average in the industry might be something in that order, one out of say four fields, one out of four projects?

A Oh, I would hesitate to say, Mr. Hall. You'd have to take this red line and draw it for every water flood project in existence to see what the actual figure would be, and I couldn't make a guess on it.

Q Well, the only conclusion we can draw from this now is that only one field has projects that are exceeding the top allowable in the State of New Mexico from these exhibits that you have here?

A It appears that way.

Q Now, on cross examination, you talked briefly and mentioned this reasonable amount of restriction of the input rate. Would you care to clarify that a little bit further? What do you mean by reasonable amount of restriction of input water, input rate?

A Well, you take an injection rate of ten or fifteen barrels a day, that's low, that's an unreasonable restriction in my estimation. There is no arbitrary figure that you can say is reasonable and another one that is unreasonable. It depends on the reservoir, it depends on the actual conditions, of course, what the minimum is. I think any time, any time you inject in the range of three tenths to five tenths that that is reasonable, that's per barrels, barrels per acre foot. You might be able to go below that, in lots of reservoirs, I'm sure you can.

Q You might call it the minimum efficient water injection rate possibly, would that be another way of stating it?

A That could possibly be such a term.

Q Now, in your rules you talk, there is a discussion mentioned, made, of injection of air, gas or L.P.G. Now, on the allowable for those, and assuming these are stripper projects, wouldn't that be on the entire unit or project basis?

A I'm not sure, gas injection couldn't very well come under water flood rules. L.P.G. projects, to my knowledge, have been, well at least in New Mexico, have been confined to areas that weren't stripper areas, so they came under the classification, by this rule, of pressure maintenance projects. Air injection projects, I do not know anything about. I only know of one that has been tried in New Mexico and it wasn't a success, so I do not know what kind of a program you would come up for regulation of air injection projects. I do not think with air injection, however, nor with gas, that you are going to get the massive response that you get from water floods.

Now, L.P.G. projects, possibly, yes, I just do not know if these rules should apply to L.P.G. projects in stripper areas or not.

Q Now, dealing briefly with this allowable for a project area, as defined by you, as opposed to an allowable for the entire project, do you feel that by, there might be the inclination of some operators to manipulate injection wells just for the purpose of allowable advantage, isn't that possible under this project area as defined by you?

A That would depend on the operators, some operators would probably manipulate them.

Q Don't you feel that a rule that would possibly eliminate that, might be a little more feasible?

A The injection pattern must be approved by the Commission, Mr. Hall, and the expansion of the injection area would be approved by the Commission. If an operator were manipulating it to take advantage of an allowable situation, I think the Commission could become aware of that and possibly prevent his doing so.

Q In other words, tell him how he should locate his injection wells?

A Yes, sir. As a matter of fact, this rule does provide that the proposed injection well be located on a water injection pattern which will result in a thorough and efficient sweep of oil by the water flood, so an operator won't be permitted to go into some haphazard injection pattern just for allowable reasons.

Q Thank you. Now, dealing only briefly with Rule, I believe it is E-5, where administrative approval may be granted for conversions of an area to water injection, now, in some of these old fields I believe operations have proved that in some cases you just never receive the stimulus in some of these wells, possibly mechanical trouble or what has happened over the years at the bottom of the hole. Now, in order to show, to get around, you couldn't then under this rule get administrative approval, you would have to come to the Commission for a special hearing?

A That is correct, if the operator came in and showed that every other well around there had received a response and for some reason one well hadn't and he wanted to put an injection well on the far side of that well, and the only way he could do it would be to go by the administrative route and show a response which he couldn't do, or have a hearing, certainly the Commission would docket that case for a hearing, and if those were the circumstances, I don't know what the Commission would do, but I would recommend that it be authorized.

MR. HALL: Thank you, that's all the questions I have.

MR. PORTER: Anyone else have a question of Mr. Nutter?

MR. McBROOM: Mr. Commissioner, for the record, I made an appearance this morning, but I'm associated with E. Kirk Newman, I need to get that in the record, as local counsel.

BY MR. McBROOM:

Q I would like to, just for clarification, it wasn't clear to me in the questions that were asked before, taking as an example from your No. 1 exhibit the typical five spot, your No. 2

item there on the exhibit with only four injection wells, and I'm posing this as a hypothetical question, but it is not hypothetical at all because in my experience of getting started some fifty water flood projects, this is the sort of thing we have run into even in Caprock, supposing that the top tier and the second tier belong to an operator A, the third tier belonged to operator B, and the bottom two tiers belong to operator C. They had filed, each of them, for a permit to water flood their leases and their pattern has worked out for offset cooperation to get the thing started, as you show it. Then you have set an allowable for that unit of, what is that total?

A That would be 882.

Q Of 882 barrels as a daily allowable for some nine 40-acre units, covers almost, over a section actually. Now, let's supposing that, to add to the hypothetical question, that there had been a diligent attempt to unitize because the top tier of leases had produced primary, some 500,000 barrels of oil. The middle tier had produced only 100,000 and the outer had only, had produced only about 150,000, which explains why unitization was not possible. They couldn't agree on what would be an equitable basis for unitization.

Now you have set an allowable under your rules and regulations that are proposed here of the, what's that figure again, nine hundred and --

A 882.

Q 882 barrels per day. As response comes and that unit gets up to the 882 barrels a day, how are the operators and how are you and how is the pipeline going to determine what oil can be run from whose leases?

A That shouldn't be any different than operating them under primary production, if they are not unitized they are going to be run into individual tanks.

Q Each would be run into single tanks. You have an allowable to 882 barrels, but, we'll say that the center five spot there, which is on C leases, is making all that oil. Say it gets up to the 800, following our hypothetical question, I should have added that, that is the well that would normally be expected to get up and it gets up to 882 barrels and the others are still making 100 barrels, or whatever their primary production was at the time?

A Well, if these men hadn't unitized that well wouldn't have an allowable of 882 barrels.

Q I know it wouldn't, but it is making, what is going to happen to that 882 barrels?

A It wouldn't be produced.

MR. McBROOM: Thank you.

A I might add it wouldn't be produced in that month.

MR. LOSEE: Mr. Nutter, A. J. Losee, Artesia, New Mexico.

BY MR. LOSEE:

Q Mr. Campbell, I think, made a point of the fact that the proposed rule would tend to promote operation of floods as a unit. Out of existing floods, what approximate percentage, if you know, are operated under a unit or cooperative agreement?

A I haven't actually made a study to determine that particular thing, Mr. Losee, but I would judge that at least 75% of our water floods are operated under units or cooperative agreements.

Q I believe certain of counsel have proposed factual situation which you have admitted do not fit into this rule, as you have suggested. In general would you state that the situations which have been proposed to you, hypothetical or otherwise, are exceptions rather than the rule as applied to existing water floods in New Mexico?

A Well, when we talk about two 360-acre leases with a hundred-acre lease in between and the problem comes up what are we going to do with 160-acre leases and then we talk that about 75% of water flood, or probably 75%, somewhere in that neighborhood, are in units, I don't think that problem is going to occur very often. Some of these situations wouldn't occur as frequently as it has been intimated that they might.

Q Does the Commission have the power to amend or modify any rule or order it may adopt at this hearing after notice as provided by law?

MR. McGOWAN: I object to that question. He is not qualified as an expert.

MR. LOSEE: I believe the witness, at least in my opinion, erroneously made such a statement that he didn't think the Commission could change the rule, and I am merely trying to obtain an answer which would indicate the incorrectness of his prior statement.

MR. McGOWAN: I believe the answer he gave was what he intended by the rule. I did not ask him what the Commission could do.

MR. PORTER: Objection overruled.

Q (By Mr. Losee) We assume then the Commission, excuse me.

A What was the question again, please?

Q Does the Commission have the power to amend or modify any rule or order adopted at this hearing after notice as provided by law?

A Yes, sir, it does.

Q Thank you.

MR. PORTER: Anyone else have a question of the witness?

MR. PAYNE: I have a few questions on redirect examination.

REDIRECT EXAMINATION

BY MR. PAYNE:

Q Mr. Nutter, it has been indicated here that your proposed rule would encourage unitization, is that right?

A Yes, sir.

Q Now, don't you think that is a desirable thing?

A As I stated this morning, I'm frequently told that secondary recovery operations are more efficiently carried out on a unitized basis, so if this rule would encourage unitization, I think that that is a good thing.

Q Do you know whether or not the Interstate Oil Compact Commission, in its proposed oil and gas conservation statute, has a provision in it for forced unitization or secondary recovery?

A I believe that it does.

Q Now, Mr. Nutter, Mr. Campbell indicated this morning that marginal wells would receive no benefit from this 7,000 barrels of oil daily, which presumably could be allocated if oil wells were held to the allowable. Now, marginal wells receive no, would receive none of this reallocation for what reason?

A They are not capable of making.

Q They are allowed to produce everything they can make?

A They produce at capacity, marginal wells do.

Q Now there was also some implication that deep wells would get an undue economic advantage. Do you feel that is the case?

A As I stated this morning, I believe that if you take 6% off of the normal unit allowable, you have taken 2 barrels off of the incentive to drill a shallow well, and you've taken 12 or

14 barrels off the incentive to drill a deep well. I think that a deep well, as a result of more expensive drilling cost, is entitled to more oil.

Q That is the reason for the depth factor, is it not?

A That is correct.

Q Now, in regard to this waste question, Mr. Nutter, isn't it also possible that you can cause waste and get less ultimate oil by injecting at too high a rate?

A I believe so.

Q And I mean at a rate considerably less than that which would cause formation breakdown.

A Well, I don't know if you are going to get any actual waste by injecting at too high an injection pressure or not. There is a very, I don't know what I'd say, I think it is a theory that has a lot of weight to it, and it's practical and it has, it can't be completely discarded, this theory of slower rates getting more capillary action on the water flood, and I think that possibly if you inject it too fast you might lose some of that capillary action.

Q Now, Mr. Nutter, the Commission has in the past, has it not, assigned project allowables and allowed them to be produced from any well or wells?

A Yes.

Q Now, there are going to be considerably more floods, water floods in the Caprock-Queen Pool, are there not?

A Yes, sir, I'd say, probably 20% or 25% maybe of the pool is on flood right now.

Q Now, while we only have two water floods that are producing in excess of your proposed allowable at the present time, don't you anticipate even a greater number in the future?

A We have two floods that have presently shown a response to the water injection, this North Central-Caprock Queen; at the rate that this black line seems to be coming up it is going to intercept this red line next month. Actually, we haven't mentioned this before, but this Drickey-Queen Unit area flood that is operated by Cities Service actually did go over the red line for the month of August. Instead of two floods that passed this red line, three have, and the next one is going to do it next month I anticipate.

Q Isn't there a great deal of interest shown on water floods in New Mexico at the present time?

A Yes, sir.

Q Are you aware there are six operations pending at the present time for pilot water floods?

A Yes, sir.

Q And we have no reason to believe that these other floods will be any less successful than the existing floods, isn't that right?

A You never know until you try it out, they didn't know Caprock was going to get such good response until it was put on injection.

Q You have no reason to believe, do you, that the south end wouldn't prove just as effective as the north end when it is water flooded?

A I think it will be an efficient flood in the south end.

Q Now, Mr. Nutter, the fact that your Exhibits 5-A through 5-G do vary in what they show, doesn't that just tend to indicate that nobody actually knows what the ideal injection rate is?

A It shows considerable variation in injection rates from one project to the other and shows a variation of injection rates within projects from time to time.

Q Now, Mr. Nutter, it was determined two years ago that capacity allowables, that waste might result in the absence of capacity allowables, that doesn't resolve that issue for all times, does it? The fact that everybody believed the world was flat at one time, everybody doesn't believe it is flat now, do they?

A No, sir, I believe it is round.

MR. PAYNE: I believe that's all. I move for the introduction of Commission's Exhibits 1 through 4 and 5-A through 5-G at this time.

MR. PORTER: Without objection the Commission's Exhibits

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will be entered into the record.

Does anyone else have a question of Mr. Nutter? The witness may be excused.

(Witness excused.)

Who wants to be first? Do we have anyone desiring to present testimony in concurrence with Mr. Nutter's testimony or in support? If not we will hear at this time the testimony in regard to capacity allowable.

MR. CAMPBELL: If the Commission please, I guess that's me. I have a number of witnesses, if the Commission wishes to swear them all at this time.

MR. PORTER: Yes, sir.

MR. CAMPBELL: Mr. Buckwalter, Mr. Edgerton, Mr. Stills, Mr. Yates, Mr. Russell.

(Witnesses sworn.)

MR. CAMPBELL: If the Commission please, before presenting this testimony I would like to make a brief opening statement on behalf of the clients for whom I have entered an appearance. The presentation of this testimony is going to be confined to the question of allowables as related to the proposal for allowables.

MR. PORTER: Mr. Campbell, so many in back are having difficulty, would you go to the mike?

MR. CAMPBELL: The testimony that we are going to produce will relate to the question of allowables and to the question of impact present and future of excess water flood production upon the general production in New Mexico and upon market demand for oil from the State of New Mexico.

The presentation of these witnesses does not indicate that any or all of these people I represent are opposed to the entire order. There are some features of it I'm sure with which I would certainly agree, but with regard to the allowables, which we think is obviously the crux of this situation, we do want to present this testimony. And I would like first to call Mr. John Buckwalter.

Before proceeding with examination of this witness I would like to offer in evidence in this case the transcript of testimony and exhibits in Commission Cases No. 1324 and Case No. 1294. 1294 is the Ambassador flood application for capacity, and the first case of course is the Graridge case.

MR. HINKLE: If the Commission please, we would like to object to the introduction of the transcript in Case 1324 in which Humble was not a party. We have no objection to the other one.

MR. CAMPBELL: If you were a party to 1294, Mr. Hinkle, that was the Graridge case and if you were not a party to the other, it is just because you didn't appear. I think notice was given. I can't see where it --

MR. HINKLE: I didn't participate.

MR. CAMPBELL: I can't see where participation by matter of choice should determine the admissibility of the testimony that was offered before the Commission on a public hearing.

MR. McGOWAN: If the Commission please, I submit on that point that this is a hearing to write general rules or amend general rules. It occurs to me that all knowledge or information of the Commission in its file is before it for that purpose, and whether or not it could be admitted by evidenciary rules into this record, it certainly can be referred to by reference in part of these proceedings. This is a legislative proceedings.

MR. PORTER: The Commission rules that the counsel's motion will be granted, the record in these two cases will be incorporated and made a part of this record.

JOHN BUCKWALTER

called as a witness, having been previously duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q Will you state your name, please?

A John Buckwalter.

Q Where do you live, Mr. Buckwalter?

A Wichita Falls, Texas.

Q What is your business association?

A I'm a partner of Rider-Scott Company, petroleum engineers.

Q And what is your profession?

A Consulting petroleum engineer.

Q Will you give the Commission a brief summary of your education and professional background as a consulting engineer?

A Well, in 1929 at the age of seventeen started to work in the oil fields at Bradford, Pennsylvania for Rider-Richman Oil Company. This was summer work. In 1931 I did laboratory work under the direction of Harry Rider. In 1935 I was graduated from the Pennsylvania State College. Since graduation from Pennsylvania State I have attended summer school at M.I.T. and I have taken advance courses in reservoir engineering under Drs. Calhoun and Stall. In 1939 I took a position with Rider-Scott Company as a field engineer. This work consisted of experimental injection of air into water flood projects and led to reservoir engineering of water flood projects with that company.

In 1943 I was asked to join the company as a partner and do consultation with clients. In 1946 I became a member of A.M.I.E. and became a registered professional engineer in the State of Pennsylvania. I have been chairman of the Eastern District A.P.I. Committee on petroleum technology and was recently awarded a citation for work with that committee. I'm a member of the Interstate Oil Compact Commission Secondary Recovery and Pressure Maintenance Committee in the State of Texas.

In 1949 our company opened operations in Wichita Falls, Texas.

I worked on Texas water floods from that time, but did not become a resident of Texas until 1955. In 1950 I made my first appearance before the Texas Railroad Commission on behalf of Forrest Oil Corporation. I have been consultant to Forrest Oil Corporation on all of their water floods in all of their areas on a continuous retainer basis since 1952.

My consulting career has been devoted to the service of the independent oil producers, and particularly in water floods where planning of projects, evaluation of the results, the operations of them, research estimates and so forth have been worked on. I have written about fifteen or more technical papers which have been published on water flooding. I've taught oil production practices in secondary recovery at evening schools in Bradford, Pennsylvania under the program of the Pennsylvania State University Evening Extension.

In all I have made engineering decisions on over 500 different water flood projects in all of the major water flooding areas in all of the United States. I have done some work in Canada and also in South America. Neither myself nor my company had ever owned a barrel of oil or gas or royalty and we do not intend to start to purchase oil or gas. We do not enter into deals for fraction of a participation on any of the work we do.

Q Mr. Buckwalter, you've testified previously before the Commission in Case No. 1324 and before an examiner for the

Commission in Case No. 1294 in connection with capacity for maximum production from water flood wells, have you not?

A Yes, I have.

Q And at that time you presented a number of case histories based upon your experience concerning your opinion as conclusions relative to the requirement for producing water flood wells at the maximum dependent upon the rate of injection you were able to obtain, have you not?

A Yes, I have.

Q Now, have you, since the last hearing two years ago in the Caprock case, made a study of the results of water flooding in the Caprock Field water floods?

A Yes, I have.

Q You heard Mr. Nutter's testimony this morning and this afternoon in connection with some of the features of those results, did you not?

A I did.

Q I refer you to what has been identified as Exhibit No. 6 on the bulletin board and ask you if you will state what that is and proceed to advise the Commission as to what it reflects.

A This is a chart which shows the production histories, or part of the production histories, of four water floods in the Caprock Field. The upper left-hand corner we have Caprock No. 1 depicted in graphic form. The scale here is barrels per day oil production, 500 barrels, 1,000, 1500 and so on up to the top of the page 5500 barrels per day. Now, you'll notice that during the period from 1951 through the latter part of '57 why there has been a low rate of production from the wells in this particular unit. Of course, upon institution of the water flood, why the producing rate increased, and we show the rise of oil production month by month as this flood progresses.

Now, the reason for showing this graph is to relate the production history, but I believe more important is to come back to some unit by which we can compare these water floods. Mr. Nutter spoke of the water floods that we are speaking of here, and I'd like to use a unit of comparison which is basically the amount of oil produced per total well in each project per day.

Now, in the unit No. 1 we have 69 wells and at this time of July, 1959, we have a production rate per total well of 46.2 barrels per day per well. I have shown 46.2 on that graph. Now, this particular unit is having injection rates which I've averaged during the months of April, March, April, May and June of 1959, and the average injection rate is 307 barrels per day per well. So we see a large difference, of course, between the oil producing rate per well and the water injection rate per well.

Now I'd like to proceed to do the same thing at Caprock Unit No. 2 which is shown on the lower part of the graph, and the figures look like this: Barrels per day per well, 92.2. We have

92.2 barrels per day per well oil production and 434 barrels per day injection rate. Now the injection rate, of course, is per injection well, but the producing rate is per total well. I'd like to say that on a producing well basis, Unit No. 1 is 74 barrels per day per producing well, and this Unit No. 2, 163 barrels per day per producing well.

Q Now, Mr., at that point, Mr. Buckwalter, will you state why you have used the total number of wells in the project rather than using just the producing wells in the project?

A Well, all of the wells are contributing oil to the project. After all, the oil from underneath the areas below the injection wells or in the proration units around an injection well is moving toward the producing wells, so I believe that the total well is a better gauge of the producing rate.

Now, for the other two units I have changed the scale in order that we could see what the rates look like. This is 100 barrels per day instead of the 500 barrels, for the Caprock Unit No. 3 operated by Great Western. Now, on this particular project, of course the producing rate is considerably lower, it is 10 barrels per day per well, and the injection rate 266 barrels per injection well. The last one I have of this type is on a City Service pilot flood and there we have 15 wells, I have taken as the number of wells, 55 barrels per day per well with injection rates of 352 barrels per day per injection well.

Now you'll notice there is quite a bit of difference between these numbers, the one unit No. 2 is the highest one and the one unit No. 3 is the lowest. This is new and will reincrease. There is no question about that. However, I do believe that Unit No. 1 is just about at its peak oil producing rate. I also believe Unit No. 2 is essentially at its producing maximum rate too. You'll notice the higher injection rates here could be a good reason why we have higher producing rates at No. 2 as compared to those of No. 1.

Q What basis do you conclude that Caprock Unit No. 1 is about at its peak rate, Mr. Buckwalter?

A Well, there are a few wells yet to be stimulated in the flood area, I think as Mr. Nutter pointed out. However, there are wells in this area which are declining in oil production rate, and of course as wells decline and others increase, why you have a balance. Also as we look at most recent data, in August it was less than in July, the production had decreased in August over July, I have plotted July here and September is just about what it was in July, so we are, we have reached a flat place on our curve here which I believe shows its peak. And this No. 2 Unit, there is just a couple of more wells to be stimulated here too. However, this unit is, it's producing about 90% of what is being injected in total fluids, and so I'm quite certain that it can't go much higher than what is shown here. So I believe these are just about at their peak.

Q And when those reach their peak what results do you expect with regard to the leveling out period and the decline production?

A Well, I think the leveling out period will be approximately, in No. 1 for example, I think it will be three or four months. Then I think the decline will set in. On No. 2 I believe that a similar length of time, maybe five months or six months at the most in No. 2, but certainly these units are limited as to the length of time that they will be at peak.

Q Now, when the leveling off period is terminated, what has been your experience with regard to the rate of decline of oil production?

A Well, I believe that the decline rate will be somewhat similar, not exactly of course, to what the pickup on producing rate was. In other words, the back side of the curve will be somewhat similar to the type of thing you have on the front side of the production rate curve.

Q Now does that curve indicate to you that the experience of water flooding in Caprock Unit No. 1 and Caprock Unit No. 2 has been successful?

A Definitely so, yes, sir.

Q Does it indicate to you that that particular reservoir lends itself to water flooding?

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A It does.

Q Does it indicate to you that same condition is necessarily present in each and every other potential water flood area in the State of New Mexico?

A It doesn't.

Q Based upon your experience in New Mexico and in other areas, do you believe it is reasonable to assume that that same condition may exist insofar as rate of increase of production and ultimate production is concerned?

A Well, I believe that Caprock is a champion from what I've seen in New Mexico. Now there could be one or two others that would lend themselves quite well to water flooding, but I don't see anything that is going to match Caprock at this point as far as its performance is concerned.

Q Have you made a study of the performance of other water floods in the State of New Mexico?

A Yes, I have.

Q Mr. Buckwalter, I refer you to what is marked Exhibit No. 7 and ask you to state what that is.

A This is a production chart of New Mexico water floods other than in Caprock Field. These water floods, this is not a complete list, but it is the ones that I picked out to take a look at. I think they are the significant ones, I couldn't find any others that were significant other than these six.

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Q ~~Will you refer to Exhibit No. 2 and state, Exhibit No.~~ 7 and state to the Commission what it reflects with regard to the other water floods?

A This shows, the scale values on these production charts are 100 barrels at the first line in each case, reaching 700 barrels on the top ones and 1100 barrels at the bottom charts. Now we have here Langly-Mattix shown here at the top of the page on the left-hand side, and the producing rate for the number of wells there turns out to be 4.2 barrels per day.

Q That is a July producing rate?

A That's the July producing rate. And the Red Lake I have 4.3 barrels per day per well. And the Maxwell Oil Company Schugart, I have 5.7 barrels per day per well. And in the entire Russell Field I have 7 barrels per day. And the Artesia I have 10.9 barrels per day per well. This is the Graridge leases in Artesia.

Now, the High Lonesome Field is kind of an enigma in a way, taking the entire field, and I have plotted the entire field's production here, which includes more than water flooding, if I were to show just the water flooding production on this curve, you'll find that the peak rate as Mr. Nutter showed on his is somewhere around, oh, 190 to 200 barrels a day. I think it is 192 barrels from the water flood the way I have it figured in July. And immediately you see we have some additional 500 barrels

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here, which comes out of the reports for July. And I discovered that those are new wells which are drilled in that field. So this is really primary production, the water flood production is quite low.

So when we take the water flood alone, we are taking about 6.3 barrels per day per well. Well now, with these producing rates here, in current months, now granted at some of these peaks it would be somewhat higher, but not anything like we had in Caprock. I think experience shows that water floods in New Mexico, other than Caprock, are contributing a minor amount really of production to the state's total.

Q Do the additional studies on Exhibit 7 indicate also that many of those floods apparently have peaked out and are now on decline?

A Yes, sir, they do. On Schugart and in Russell particularly, also High Lonesome, I believe, is kind of level, but I believe it has peaked out, looks like Red Lake here somewhat has too. Langley-Mattix looks like it has come over, Artesia looks like it is at a peak or could go a little higher.

Q Does that indicate to you that there is a marked difference in the reaction of particular project to water flooding in New Mexico?

A Yes, that's true in New Mexico the same as in other areas.

Q Each of these, and in the Graridge project did you

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undertake to exclude from your computations what might reasonably be considered to be remaining primary oil before you arrived at what actually was water flood oil?

A No, I just took total production in these cases here.

Q In some instances at least is there some primary oil, at least, that is recovered by water flooding?

A Yes, in some cases there is.

Q Do you have anything further to add with regard to Exhibit No. 7 as related to Exhibit No. 6 on the Graridge water flood?

A No, I think that covers it, I might say this one thing, on injection rates, I didn't put them all on these different floods. In all cases the injection rates into these particular water floods are considerably lower than injection rates into Caprock, and I'm told, I haven't made this study, but engineers have told me that thickness of the pay is generally greater everywhere than it is in Caprock, which indicates that these lower peak producing rates mean that we are actually not able to get enough water in to many of the projects in New Mexico as depicted here.

MR. PORTER: Mr. Campbell, I would like to interrupt you at this point. We are going to have to vacate the hall at five o'clock. That means we have to be out of here by five. When we recess the hearing we will reconvene tomorrow morning at

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eight thirty, at that hour instead of our usual nine o'clock hour. There have been a few who expressed a desire to make a statement of position prior to the recess later this afternoon. In order that we may estimate the time that it might take, I would like for those to stand who desire to make a statement before the recess this afternoon. Will those people stand?

Mr. Lusk, would you give us the reason why you would like to make a statement at this time instead of at the close of the hearing?

MR. LUSK: Mr. Porter, I am with the Lincoln Oil Company. Mr. Wilson, whom I represent, does not desire to offer any testimony. It is our thought that if we could get the statement of position into the record which has been agreed upon, that it would be possible for those clients not to be burdened with additional fees for attorneys.

MR. PORTER: Mr. Lusk, I would like to ask you how long do you anticipate your statement will take?

MR. LUSK: Approximately forty-five seconds to a minute, sir.

MR. PORTER: We will give you five minutes just before five o'clock.

Q (By Mr. Campbell) Mr. Buckwalter, at the time of the original hearings on the Graridge application in Caprock Unit No. 1, you made certain estimates of what you believed might be

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the results of water flooding in that particular project based upon the plans then in existence and your knowledge of the reservoir conditions and the then existing rules of the New Mexico Oil Conservation Commission?

A I did.

Q And you presented an exhibit to that effect?

A I did.

Q Have you prior to this hearing taken a facsimile of that exhibit and superimposed on it the actual results that have occurred in the Caprock-Queen Unit No. 1?

A I have.

Q I refer you to what has been identified as Exhibit No. 8 and ask you to state what that is and explain it to the Commission.

A Well, this is an estimated oil production rate and cumulative oil production curve for 1760 acres water flooded at an average intake rate of 400 barrels of injection rate per day. This was on the Graridge Unit which was to the north part of the Caprock Field known as Unit No. 1. You will note that I had anticipated that the producing rate would reach a peak of around just under 5,000 barrels per day, that this peak would occur about eighteen months or sixteen months after the start of the flood.

When I have superimposed on the estimated curve the actual data which is shown by months, and you will note that the oil production rate increased to about a thousand barrels a day and

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then started to decrease and came back to, closer to 700 barrels a day and then started a secondary increase and has generally increased until the present time. Now last line shown here is August, 1959. I said that it decreased in barrels per day after July, so this shows a considerably lower and considerably slower rate of production than I had anticipated. This happens sometimes, we don't always get them exactly right.

Q Do you have any explanation for why that may have occurred in that particular project?

A Well, there are several factors I am sure that enter into it. There was difficulty in getting the pilot area under unitization, and this dropoff here in production was because they didn't get unitized as soon as they had anticipated and hoped, so we had a delay due to inability to get the operators unitized.

Then, due to the rules and regulations of the Oil Conservation Commission in New Mexico there is a delay in the expansion of any water flood from the pilot area outward. This delay, I'm sure, has contributed to the slower rate of increase and consequently I believe some to the lower peak.

Now, another factor I believe that is quite important, I figured this on 400 barrels per day per injection well and they have not maintained that 400 barrels. It's been more closer to 300 barrels at the present time, although there were periods when they did have 400 barrels per day injection rate, but they have

73-p

not maintained the 400 barrels per day injection rate.

Q So based on your predictions at the time of the original hearing, the rate of increase in oil production has been slower and the peak has been reached sooner than you had actually anticipated?

A Well, the peak hasn't been reached sooner, it has been reached really later than I anticipated. I anticipated about this point about a year and a half after the start of the flood and now the peak is more like a little over two years after the start.

Q What I meant to say was the peak has been lower than you had anticipated.

A It is lower, yes, sir.

Q Do you anticipate that the rate of decline will be somewhere in the vicinity of the general rate of increase in the future, Mr. Buckwalter?

A Yes, we will have some leveling off, this will come off and then have a decline. The whole curve will be offset to the right on my graph, which means it is all happening later than we anticipated.

Q Would you say that what has occurred here has been actually less impact on the oil production and on the market than you had anticipated at the original hearing when this permit was granted?

A That is what I would say, yes, sir.

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Q ~~Have you made a similar study with respect to North~~ Caprock-Queen No. 2?

A I have.

(Marked Exhibit No. 9, for identification.)

Q Mr. Buckwalter, I refer you to what has been marked Exhibit No. 9 and ask you to state what that is.

A This is a production history and estimated water flood oil recovery graph on some of semi arithmetic papers, the history starting back in 1945. This represents the production from the area which is now the North Caprock-Queen No. 2.

Q Is everything on there except the red marks something that was presented by you at the original hearing in that case?

A Yes, sir, it is. The only thing I have added is the red curve.

Q Will you proceed now, please?

A Well, we can see the expected oil production rate I had drawn here to reach a peak in barrels per month of around 125,000 barrels per month, and then expected a decline from this particular unit. Now this particular unit, the production has gone to a little over 125,000 barrels per month. I believe the rate here in July is somewhere around 143,000 barrels per month, but in general the rate of increase is pretty similar to what I had anticipated at that time except we had a little delay here

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which caused a drop in production and then a subsequent increase, although the peak is pretty close to where I had figured it, but I believe that this could increase a little more and could go a little higher, I guess it might go up here to 160,000 barrels a month just at this time and then start a decline, but it will take several more months I believe to do that.

Q Do you have any particular reason why this Unit No. 2 seemed to progress more in accordance with your prediction and to a higher peak than Unit No. 1?

A Well, the injection rates is what I give credit to the performance here. You recall on the previous exhibit we had I think an average at this time of 434 barrels per injection well per day, and this is the highest injection rates that have been attained to my knowledge in New Mexico.

Q Do you have anything further with regard to that particular exhibit?

A No, I guess that completes that one.

Q I'll refer you to what has been marked Exhibit No. 10 and ask you to state what that is and what it reflects.

A This is really the same data as on the previous exhibit except I have shown it on an arithmetic block. I was afraid it might be misleading with the semi-log scale. Also I wanted to show something else I presented at a previous hearing. I had shown what the level of production would have to be in order to

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stay below 33 barrels per day per total well on this unit.

Now we can see our actual production rate is many times above what would have been 33 barrels per day per well. It would have been in my opinion impossible to have a good water flood with this type of restriction on the rate of production.

Q If you added to that the 42 barrel per day figure, it would have the same result even if you base it upon the total number of wells in the entire project?

A That is correct, it would be slightly higher, but it would be about where I had shown of pointer which would be over 2,000 barrels per day for the project.

Q If that restriction had taken place would there have been a waste of otherwise recoverable oil?

A Yes, there would in my opinion.

MR. PORTER: Mr. Lusk, the Commission will hear your statement at this time.

MR. LUSK: The statement which we desire to read into the record is a statement agreed upon by all those persons whom Mr. Losee announced we represented today, and in addition thereto the Wilson Oil Company. The statement is as follows: "Based upon the existing facts and circumstances, we go on record as favoring the proposed revision of Rule No. 701 covering water flood operations, and request the adoption of the proposed revision in its entirety." I thank you.

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MR. PORTER: We're going to recess the hearing at this time until eight-thirty tomorrow morning. The hall will remain undisturbed.

(Whereupon a recess was taken until eight-thirty Thursday morning, October 15, 1959.)

MORNING SESSION

October 15, 1959

MR. PORTER: The meeting will come to order, please. We'll continue with 1787, Mr. Campbell.

CONTINUED DIRECT EXAMINATION OF MR. BUCKWALTER

BY MR. CAMPBELL:

Q Mr. Buckwalter, when we concluded yesterday you had discussed the production situation in the Caprock-Queen Units as they now exist. You were present, were you not, when Mr. Nutter testified yesterday?

A Yes, I was.

Q Did you hear his testimony with regard to Exhibit No. 3 which I have placed on your right-hand side of the board there?

A Yes, I heard that testimony.

Q In which he referred to the decline in production in the Caprock-Queen Pool during a period prior to the time water flooding was instituted and an increase since that time?

A Yes, sir.

Q Did you hear his testimony that although he had not made a study of it, it was his impression that there had been a very limited amount of new drilling in the Caprock-Queen Pool during that period?

A Yes, I heard him say that.

Q Have you made a study of the Caprock-Queen Pool production history and drilling history since January 1st of 1956?

A Yes, I have.

Q Would you state how many wells were in the Caprock-Queen Pool on January 1st, 1956?

A 512 wells.

Q How many wells were in the pool in July, 1959?

A 684 wells.

Q How many new wells is that from January, 1956 to July, 1959?

A That's 172.

Q Out of a total of six hundred and what?

A 684.

Q That's somewhere in the vicinity of 20% increase in the number of wells?

A I believe it's more than 20%. It's about 32%.

Q In other words, there is approximately an increase of a third actual new wells that were completed in the Caprock-Queen Pool between January, 1956 and July, 1959, is that correct?

A That's correct.

Q Did those wells contribute considerably to the production from that pool during that period of time?

A Yes, I believe they did.

Q Would that, to some extent, account for increase in production as shown on Exhibit No. 3 there during that period?

A Yes, I think that the important point is the rate of production at this time compared to the previous time.

Q What was the rate of production per well per day in January, 1956?

A 28 barrels per well per day.

Q In the entire Caprock-Queen Pool?

A In the Caprock-Queen Pool.

Q That was prior to the institution of any water flooding in that pool, was it not?

A Yes, it was.

Q What was the average production per barrel per day per well in that pool in July, 1959?

A 22 barrels per well per day in July of 1959.

Q So that by the inclusion of the new wells and the production therefrom and the water flooding during that period, there was actually a decline in production of oil per well per day in the Caprock-Queen Pool during that period, is that correct?

A That's correct.

Q Now, will you refer to what has been identified on the board as Exhibit No. 11 and state what that is and point out to the Commission what it reflects?

A Yes, sir. This exhibit is a map of the Caprock Field in two parts. They're both of the field and they are both on current maps, but the color on each map depicts the development at the time indicated. On the left we have August, 1957, and so each colored square on this map shows the wells which were drilled at that time. On July, 1959, the map on the right, we show additional wells have been drilled between these dates, and again the colored squares are the wells drilled, and in addition the checkerboarded area shows where the water floods are now located and the white squares are the injection wells in those areas.

I would like to point out that this area in the part of the field here was developed during this interim of time, and you will note that a good group of these wells are colored yellow. Now, the wells that are yellow, the production on those wells ranges from 25 to 32 barrels per well per day. We have other areas where new wells have been drilled, most of them of course are on the edge of the field, but we understand that this depicts just the change from 1957 to 1959. Of course prior to 1957, during the year 1956 some of the wells shown on this map had been drilled, and you will notice the color blue on the map. Now blue are wells which are higher than 33 barrels per well per day, and at August, 1957 we had a sizeable blue area of the map just somewhat south of the red area which is the northern part of the field.

We have other blue areas depicted farther south, and in the time between August, 1957 and July, 1959, these areas have changed color. That simply means that they're producing now at a lower rate of production from what they were at the previous map. So you'll see that the areas which previously were blue are generally yellow and brown or green as shown by comparing the two maps. The areas which were generally yellow on the previous map and green have become generally red. This simply shows decline in natural production, and this is to be expected, and this is an orderly decline and the water floods having started in the northern part of the field generally in the original red area now show that there are additional stripper areas available for further water flooding.

I believe the maps show where the water floods are indicated and where the floods have started at the time and the stage of depletion in the various wells in the various areas of the field. The red is from zero to 8 barrels per day, the green from 9 to 16 and the brown from 17 to 24, the yellow from 25 to 32 and those blue are above 33. I believe it's interesting to note that with the water flood production, and the fact is today we are at a higher level of production for the field than any time in its history, but even so we are at a lower level of producing rate per well so that today with 22 barrels per well per day for wells in the field this is considerably below the 28 barrels back in January, 1956.

Q So that would you say that the institution of water flooding in the Caprock-Queen Pool can reasonably be said to be the only cause for increase in production from that field during this period?

A Well, I would say the waterflooding has contributed a major part of it, but the new wells drilled for primary purposes are contributing to it too.

Q During that same period of time there had been a natural decline in the primary production from the wells that are not to water flood?

A That is correct.

Q So the total impact would you say had been serious or not serious insofar as the one pool is concerned?

A I don't think it's serious. I think the water flooding is progressing in the orderly fashion as we anticipated. I don't believe that we are producing as much oil as I had figured previously we would be producing at this time under the water flood operation.

Q Do you have anything further on this exhibit?

A No, I have another one.

(Marked Commission's Exhibit No. 12, for identification.)

Q Mr. Buckwalter, I refer you to what has been identified as Exhibit No. 12 and ask you to state what that is, please.

A This is an exhibit which is similar to the one we presented at a previous hearing, the Graridge application for capacity water flood allowables. On this exhibit I had shown the entire history of the Caprock Pool's primary production starting back in 1944 showing a small peak in about '46 and then, as Mr. Nutter pointed out, the drilling program in 1955 which brought us to a peak production of around 15,000 barrels per day in 1956.

Since 1957 we have started decline in primary and then the water flood production has been added to the total primary at that time. Back at the time of the Graridge application when I prepared this exhibit to estimate the amount of water flood oil production that might be obtained in Caprock Field, and by going back and comparing the actual water flood production with my estimate I find that I was considerably higher in my estimate at this time than the actual production shows. For example, in July of 1959 I estimated about 14,500 barrels a day from water flooding in the Caprock Pool. Now I have plotted the actual water flood production in the pool which lies over just 7,000 barrels per day, and so I missed this by about 50%, I mean just half as much water flood production now as this exhibit showed at the time we made the application.

Q Would you state what you think the reason is for that?

A Well, I think some of it is the delay again in forming the units in getting the water flood going in Caprock, and in addition I believe the rules that are set up by the Commission which requires this stimulation of offsetting wells prior to conversion to injection has delayed the curve from my previous estimate so that we now have a case of water flood being about half of what we anticipated.

Now, on this same exhibit I have shown the excess above normal unit allowable in Caprock. When I calculated the normal unit allowable I wasn't sure whether we should use all the wells in the units or we should use just the stimulated wells. So I used both and plotted the two curves, they, of course, run pretty much on top of each other, but this shows about 4300 barrels per day excess above normal unit allowable in the Caprock Field.

If you base it entirely on the total wells in the units which are under flood, that drops down to around 3700 barrels per day excess above the normal unit allowable. I believe that this shows to be about half of the production from Caprock Field. It's interesting that the water flood production itself is just about half of the total production in the field.

Q In calculating the excess water flood oil, I presume that you included injection wells as well as producing wells, did you not?

A Yes, I sure did.

Q Which explains the difference between your result of some 4300 barrels and Mr. Nutter's result of some 7,000 barrels?

A Yes, I think Mr. Nutter's figure referred to the entire State of New Mexico and this is for Caprock Field, although the greater, practically all of it is in Caprock at this time. So we have that difference, but the main difference in Mr. Nutter's approach would be to take the individual producing wells and arrive at the excess above each well.

Now, I feel that the injection wells should be figured in this calculation because the injection wells are contributing oil to the operation and to the results, so I just, it just seemed to me correct to use the injection wells along with the producing wells.

Q Do you have anything further on that exhibit?

A No, I think that about covers it.

Q Let's proceed to your last exhibit there.

(Marked Commission's Exhibit No. 13, for identification.)

Q Mr. Buckwalter, I refer you to what has been identified as Exhibit 13 and ask you to state what that is, what it reflects.

A I had a State of New Mexico oil production history chart prepared starting 1946 and to the present, 1959, the month of July. These figures, of course, came from the engineer's reports. This exhibit shows first of all the top curve, the total oil production from the State of New Mexico. As we know, the Northwestern part of New Mexico is a different situation, a different area of production, and so the second curve shown is the total oil production from Southeastern New Mexico. This shows that the present, around 244,000 barrels per day in Southeastern New Mexico, and this rate of production has held approximately that for the last year or so.

Now I wanted to show what the water flood production amounted to in the State of New Mexico compared to the total production, so on the same curve at the bottom in the lower right-hand corner I have shown the water flood oil production. I didn't go back, I couldn't show it, the line doesn't show up prior to 1957, but in late '57 we start picking up some water flood oil production, and at the present time we reached this point here in the state and that comes out to 10,500 barrels per day or about 325,000 barrels of water flood production in July. This amounts to about 4.3% of the total production in Southeastern New Mexico or 3.7% of the total state.

Well, in addition to that I have my excess over normal unit allowable for the state, and that is about 4500 barrels per day in July of 1959 and that, of course, is less than 2%, that is about 1.7% in Southeastern New Mexico.

Q Do you consider that that excess oil, as related to total production in Southeastern New Mexico, at the present time presents a serious impact on the general producing situation in that area?

A No, I don't. I don't see how it possibly could in view of the small amount of production that it is as a percent of the total.

Q Based upon your studies in the Caprock-Queen Pool and the delays that have been experienced with regard to the unitization areas in the Caprock-Queen Pool, do you anticipate in the future any serious change in that situation in regard to that relationship?

A No, I don't. If I may refer back to Exhibit 12, at the time that I prepared the recent study of statistics of the Caprock Pool I re-examined my estimate which was made back in 1957 as to the amount of water flood production that might be obtained in the entire pool, and try as I could, I couldn't make much change in it. Now granted we're only half of what we anticipated now, but I don't believe we will ever come to a higher peak in Caprock from a water flood than what I had shown on the original exhibit, so I restudied and I discussed with the various engineers and companies directly associated with the planning of the water floods, and my tabulations of the predictions which were made do not show that we'll ever punctuate that estimate that I made.

I just don't believe it will ever happen, so I couldn't change it, so I didn't think it was a big impact then, I still don't think it is now.

Q There has been considerable discussion here in this hearing and in prior hearings, Mr. Buckwalter, as you are aware of the fact that some of this water flood oil which you described presently as being approximately 4300 barrels a day from the Caprock Pool which provides almost all of the excess oil at the present time. I believe you stated that not being prorated, that it's not proper because it violates the provisions of our proration system. Have you made a study of the allowable statistics and producing statistics in New Mexico to determine whether there is any other oil presently being produced that is not subject to market demand prorationing?

A I don't know that I made an exhaustive study, but I did look over the gas fields, the prorated and non-prorated gas fields to see how much oil might be produced from them.

Q What did you find with regard to oil produced from non-prorated and prorated gas pools in New Mexico?

A Well, I found that in January, 1959 this amounted to about 117,000 barrels of oil. That's January. It drops some in months until it reached a low this year of 77,000, now excuse me, 70 barrels in June, but in July is back up to 87,000 barrels of oil from these fields.

Q Is that distillate and similar liquids produced from natural gas wells?

A That's right. Those are liquids produced from gas wells.

Q Did you determine any particular unprorated gas pools where such production is taking place?

A Well, I just kind of looked over the statistics and I do find there are some pretty high producing rate wells.

Q Did you examine the Four Lakes-Devonian Pool in that regard?

A Yes, I did.

Q What did you find with regard to that particular pool?

A Well, I found that there are two wells in that pool and they're each making around 200 barrels of liquid per day at about 3,000 to 1 gas-oil ratio.

Q Who was the operator of those wells?

A Humble Oil and Refining Company.

Q Mr. Buckwalter, based upon your study of the present water flooding projects in the State of New Mexico, considering the estimates you made at the time of the original hearings as related to what has occurred in the pools on which you testified, and based upon your experience in the operation and the engineering of other water flood projects throughout the country, do you believe that the present and future anticipated water flooding situation in New Mexico will result in a serious impact upon the primary production in this state or upon the exploratory or drilling activity in that regard?

A No, I don't see how it could for several reasons. I think yesterday I showed that previous floods have been not too high rate producing floods, and it seems to me that we have to come down to somewhat classify those fields which will be susceptible to water flooding in the future.

Q Are all the fields in New Mexico or any other state suitable for water flooding from an engineering point of view, let alone the economic factor?

A No, we have to throw out certain types of fields as general classes for water flooding, and those classes, well you take a water drive field, if you have a water drive there is no sense in putting a water flood to work because you are going to get your oil by the water drive. Then, of course, if you have an effective gas cap that can be utilized and you can produce your oil through that mechanism, why your chances of a water flood are pretty poor then.

Then we found other types of field, you have segregation type drives which lend very poor results generally to water flood because the amount of oil remaining is not sufficient to set up oil banks as a general class. So when you look at New Mexico, if you look over and realize that some of these are water drive fields and other types which are not susceptible, why it kind of limits the field that you have say available to develop for water flooding. I just don't see it's going to be a tremendous figure.

Q You have experience in water floods in other states, have you not?

A Yes.

Q Which have been in the water flooding business for a longer period of time than has New Mexico?

A Yes, of course.

Q Do you consider that your experience in those states, that over a longer period of years the ratios that you have referred to between water flood production and primary production, result in any more serious situation with the passage of time in those states?

A The only states that have ever gone to you might say a large percentage of water flood production are those in the far east. New York and Pennsylvania, for example, the States of Kansas, Oklahoma, Texas, those states have been in water flood business for a long time, but they still do not have high percentage of water flood oil production. I believe that this is indicative of what New Mexico will show.

I think the fields here are more like those in the states I have mentioned. I believe that the amount of primary reserves that are remaining here are a big factor in that picture too. So I just don't see this tremendous problem, when I look down at the bottom of that little line on that curve I have a hard time finding it. I don't just see where the big problem exists.

Q You testified in the previous Graridge hearing and the Ambassador hearing with regard to your opinion concerning the requirement for producing water flood wells once you had established the optimum rate producing the water flood wells at their maximum production rate. Will you state that opinion and whether or not your experience since that time has caused you to change that opinion in any regard?

A Well, I believe my opinion might be summed up like this: in a water flood operation where you are building an oil bank and driving the oil to producing wells, any manner of curtailment of the producing of those wells will result in less ultimate recovery of oil, and thereby create waste. I have made studies in fields in the past, and my entire history of my entire background in water flood work has led me to this definite conclusion, and I have found nothing in the last two years to change my mind one bit. I find that every opinion I had at that time has been confirmed from what I have been seeing in results.

Q Mr. Buckwalter, in your experience in working, I believe you said with over 500 floods throughout the country and in South America and Canada, have you ever seen two water flood projects in different fields which you felt were identical and could be properly operated and managed in the same fashion?

A Now, Mr. Campbell, there's just no two alike.

As a matter of fact I think you can take it beyond that, I think it is difficult to find any two wells that resemble each other, particularly when you put them to water flooding, the difference in the reservoir, the differences of the characteristic of the rock in the reservoir are so great that we just find that differences are the rule. The similarities are just rank, rank exceptions. I won't say that you will find two production curves that you can superimpose one upon the other.

I also believe if you do find this there will be several different reasons why they do coincide. What I'm saying is the variations in geologic rocks is just so tremendous that we just don't find similarities that we can be sure that any two fields or even two wells are alike.

Q Oh, Mr. Buckwalter, were all these exhibits which you have presented here prepared by you or under your supervision?

A Yes, they were.

MR. CAMPBELL: I would like to offer Exhibits 6 through 13 in evidence.

MR. PORTER: Without objection the exhibits will be admitted. Does anyone have a question of Mr. Buckwalter?

MR. HINKLE: Yes, sir, I would like to ask some questions here.

MR. PORTER: Mr. Hinkle.

CROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Buckwalter, would you please refer back to your Exhibit No. 7?

A Yes, I have an Exhibit No. 7.

Q Is it convenient to turn that over on the board? Now, Mr. Buckwalter, in your testimony yesterday in referring to the Langley-Mattix Field, you stated there were 4.2 barrels per day production average?

A Yes, I believe I did.

Q How many wells are there in the Langley-Mattix Field?

A In the pilot flood area I took 28 wells.

Q That's where you got your average of 4.2?

A That's correct.

Q How many wells are there in the entire field, do you know?

A I have to look that up in reports.

Q Do you think about 787 wells is about right?

A I'll take your word for it if you looked it up.

Q But you only averaged 28 in to get your 4.2 average, is that right?

A That's correct.

Q Those are the only ones that are closed in the present injection area?

A Well, there are wells in and around the six injection wells in the project area. There are six injection wells and 22 producing wells.

Q How many closed producers are there?

A I don't recall.

Q Do you know what percentage of the total field is under water flood?

A It would be a very small fraction.

Q It would be about one percent, would it not?

A That's correct.

Q Now, refer to your plat of the Artesia Field, which is the lower one on the left I believe.

A Yes.

Q On Exhibit No. 7. How many wells are there in the Artesia Field?

A I don't have the figures here on the entire field. I simply took the operated leases by Graridge.

Q You think about 416 wells would be about the right number?

A I'll take your word for it if you looked it up.

Q How many wells, or how many acres are presently under water flood in the Artesia Field?

A Well, I took the 88 wells which are operated by Graridge in their projects. 27 of those are injection and 61 producing wells.

Q About how many acres would that involve?

A Well, it would be about 40 times that.

Q Can you calculate there just about the number of acres that are involved?

A I have a map, I can refer to that.

Q If you will, please.

A I don't have that map readily available.

Q Would you think that it is 600 acres or less that's under flood in the Artesia Field? Do you think that would be about right?

A Well, that sounds reasonable.

Q What is the spacing that is being used in the Artesia Field in connection with the pilots there?

A They're converting alternate wells to water injection.

Q Some of those on ten acre spacing?

A I wish I had my map. I'm not sure.

Q Do you know what the total, the percentage of the total acreage in the Artesia Field is under flood?

A Well, it would be about five percent, wouldn't it?

Q Well, I think that's about right. We calculate it to be about four percent.

A All right.

Q Referring to the Red Lake plat which is the upper right-hand plat --

A Yes, sir.

Q -- I note in your testimony yesterday you stated that the average production was about 4.3 barrels. How many wells are there in the Red Lake Field?

A Well, I have 46 wells under the water flood operation.

Q But how many are there in the entire field?

A I don't have those figures here.

Q Do you think about 140 is about the right number?

A It sounds all right.

Q And you say there are about how many wells under flood?

A I have 13 injection and 33 producers.

Q Are those the closed producers, closed by injection well?

A Well, they would be closed in the area that's been flooded, yes.

Q Is that closed or just in the area?

A There would be some closed and not closed.

Q Does that include the wells that have received some kick or response up to date?

A Yes, or closely associated to them.

Q What percentage is that of the total acreage in the Red Lake Area?

A Well, let's see, I have, you said a hundred and how many wells?

Q 140.

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A That would be 46 over 140, about 30% I guess.

Q Now, refer to your Exhibit No. 10. Let's go back to 6 instead. Before referring to Exhibit No. 6, your testimony which you have just given there, it indicates that there's a pretty low percentage of all of the fields which were under water flood at the present time, isn't that right?

A That's right, of the ones you mentioned, but of course the producing rates are very low too which means that they're kind of small; as Mr. Nutter pointed out yesterday, the same fields, that those are low producing rate fields.

Q But it's only a matter of time, of course, until the rest of these fields will be brought under water flood, is that not right?

A Well, I don't know. I'll take a second look at some of those as to whether they are economical to continue water flood and development in some of those fields.

Q Isn't it a fact that practically every field in New Mexico that's not a water drive field has a potential as far as water flooding is concerned?

A Well, if you put it on a case that you should look at it, I think you should look at it. Whether or not it's going to be economically developed over some period of years, well, that's another consideration.

Q In your experience have you found very many fields that you couldn't water flood?

A Well, quite a few, yes, sir.

Q Any in New Mexico?

A I don't know of any other than the ones we've shown which are questionable economic ventures in some of these, and whether or not this is indicative of entire New Mexico.

Q You don't question any of the fields which you have just testified to as not being successful, do you?

A At least they produce oil by water flooding. As to how much a person can afford to get that oil is another question.

Q They are a potential as far as being put under water flood is concerned?

A I think parts of them are, certainly.

Q Mr. Buckwalter, you showed on Exhibit No. 6 that the production from the Caprock Unit No. 1 currently is about 3300 barrels per day. On Exhibit 8 you showed that the unit embraces 1760 acres. This means that the current production amounts to 1.9 barrels per acre per day, does it not?

A Sounds right.

Q Now on Exhibit No. 7 you show that the current production for the Graridge leases in the Artesia Field is 980 barrels per day. We established a few minutes ago that there is about 600 acres, or approximately that, under flood. This would indicate that the production currently amounts to 1.6 barrels per day per acre, is that correct?

A Sounds all right.

Q On what basis then did you draw the conclusion that the Caprock flood is the only spectacular one in New Mexico?

A Well, the point is that barrels per acre on the Caprock are not really very high, but the injection rates attainable are quite good compared to other fields.

Q You mean that you could inject at a higher rate than 400 barrels if you wanted to?

A Well, of course there are injection wells that are considerably more than 400 barrels. The average is 434 barrels.

Q Is it possible to inject at a high rate in those fields?

A I think it is possible in some places. I believe it could go higher, yes, sir.

Q But that's true under your theory of getting the most oil by the highest rate of injection, why isn't that being done?

A Well, I don't control all those floods. I would recommend that they go to higher rates.

Q Those that you do control, why haven't you injected at a higher rate?

A I don't control any of them.

Q You said you didn't control them all.

Q Well, all of them is what I mean. I don't control all of them.

Q Have you recommended to your clients and those that have consulted with you that you inject at a higher rate in those fields?

A Yes, I have.

Q Why haven't they done it?

A That's their decision, not mine.

Q Now refer to Exhibit No. 10, please, Mr. Buckwalter. Mr. Buckwalter, referring to Exhibit No. 10, I believe in your testimony yesterday that you explained that the black line curve was your projected or estimate of the performance of the North Caprock-Queen Unit No. 2?

A Yes, sir.

Q And that the red line was your actual production up to date or to recent date?

A Yes, sir.

Q Now, you also, in your testimony as I recall it, stated that if you had tried to level off the production at 33 barrels and the other one at what, 39 barrels, that this would probably have resulted in waste. Is that about your testimony?

A Yes, sir.

Q What is there on that exhibit that shows that there would be any waste if it were leveled off at that point?

A I don't see anything on the exhibit, sir, that would indicate that.

Q Mr. Buckwalter, in your testimony this morning you referred to Mr. Nutter's Exhibit No. 3, or Commission's Exhibit No. 3, which was in regard to the Caprock Field. How many wells drilled in the Caprock Field were drilled between October, 1957 which was the time of the Graridge hearing, and July, 1959?

A Let's see, I believe there's probably 600 wells, did you say July or August of '57?

Q Yes, July, 1959. No, October, 1957 to --

A October.

Q -- to July, 1959. I believe in your testimony this morning you said there were 684 wells drilled July of '59, total.

A 684 and July of 1959. Yes. Now which other date do you require?

Q October, 1957.

A October, 1957 I have 598 wells. So the difference would be 186 or 86 wells.

Q Well, now, that's different from the 172 which you stated this morning had been drilled, is it not?

A Well, the dates I gave were from January, 1956 until July of 1959, and there were 172 wells drilled in that period.

Q In the Graridge case didn't you testify that there had been 612 wells drilled?

A I believe that's possible.

Q Your water flood really got started in October, 1957, did it not?

A Yes, that's true.

Q The first water flood. Now, the point I'm making is how many wells have been drilled since the water flood has actually started. I think you left the impression this morning that there had been 172 wells drilled.

A Well, if I left that impression I didn't mean to, because I believe I stated specifically that was January, 1956, which was following Mr. Nutter's time of primary drilling, which was at a good rate of drilling. Now I went from January, 1956 until July of 1959. In that period I have 172 new wells drilled in Caprock Field.

Q The way we figured it, actually there has been only 72 wells drilled during this period of time since you started the water flood up until --

A Oh, yes, that sounds right. I don't see anything wrong with that. I went back to the time we had peak primary production. What I was showing was that the peak primary was 28 barrels per day per well at that time, and now under water flooding with this half of the field producing half of the oil production of the field with water flood oil we only have 22 barrels per day per well. So I don't see why all the excitement about producing rates.

Q Now, let's refer to your Exhibit No. 11 which is the first exhibit you covered this morning. I think in your testimony this morning you indicated that there had been considerable change in the colors from the left-hand map to the right-hand map.

A That is correct.

Q Now, in the change of the colors toward the red, does that indicate that in a fairly short time that there's more and more area in the Caprock Field that's going to be susceptible to water flooding?

A I would say it's happening in an orderly fasion. I think that's the word I used, that they are moving from the green color to the red and from the yellow to the green and from the blue to the brown and so on, which is what we expect. So I think water flooding will proceed in an orderly fashion. I would say this is about 23 months of time and difference in 23 months there, two years, there has been changes, but it's not been anything that you wouldn't expect.

Q Are you familiar with the Cities Service unit in the Caprock area there?

A Yes, it's located where I point.

Q Do you know when it was approved?

A Did you say the unit?

Q The unit, yes, put into operation.

A This is a pilot flood of the Cities Service, they have about 13, 14 wells involved in the pilot flood area.

Q How many acres does it involve down the unit?

A 14 times 40, what's that, 560.

Q But in the entire unit, isn't it a fact that the entire unit is about 5,000 acres?

A I don't have the recent figure on that unit. I believe it's probably less than that.

Q But there is potential there of about 5,000 acres of being put under water flood as rapidly as possible?

A The units located in this general area (indicating).

Q Are you familiar with the hearing that is now set for the Great Western Unit which includes approximately 5,000 acres of the Caprock area?

A Yes, I have heard that there is a pending hearing.

Q There's no reason why that shouldn't go forward immediately?

A Well, of course that's up to the Commission. I wouldn't presume to say yes or no.

Q Yesterday, you heard the testimony of Mr. Nutter yesterday I assume?

A Yes, sir.

Q Mr. Nutter seemed to be very much concerned with the water flood oil replacing the primary oil, and showed by his graph, I think it was Exhibit No. 2, that it already had replaced about two barrels, about 6% of the present allowable, is that not right?

A I believe that's what he testified to and what his graph showed.

Q Do you agree with Mr. Nutter's conclusion or with his graph that he had there yesterday?

A Well, he didn't calculate it the same way that I did. I believe that the injection wells are contributing oil and should be counted when you talk about unit, and therefore I believe that the figure that I had was realistic from the standpoint of evaluation of just how much excess there really is. I think he's high because of the way he did it.

Q Now, refer to your Exhibit No. 13, which I believe is your last one.

A Yes, sir.

Q Now, Mr. Buckwalter, on your Exhibit No. 13, at the right-hand corner you have a very small curve there, two of them, which shows the excess oil over normal unit allowable. How many barrels does that represent, what does it show in barrels?

A Well, it showed about 4500 barrels per day in the month of July, which is the highest month that's shown.

Q What percentage would that be of the allowable for July?

A I don't have the allowable figure here for July.

Q Well, now, do you recall Mr. Nutter stating that in effect that about 3500 barrels would take one barrel off the normal unit allowable?

A I heard his statement to that effect.

Q Under your own figures there you have already taken more than one barrel off the unit allowable under your figure, have you not?

A I haven't taken any barrels off of anything.

Q I know, but you represent the excess oil over the normal unit allowable?

A I believe the oil belongs there, after all, water flooding is the way of producing oil and producing it properly and economically. I don't see anything wrong with this.

Q How many barrels would be off the normal unit allowable by reason of the 4500 figure which you have shown on your Exhibit No. 13, using Dan's 3500 barrels, that is Mr. Nutter's 3500 barrels as equal to one barrel off of the allowable?

A Well, I suppose what you want me to say is that if we were to take 4500 and divide it by 3500 we come out with one plus, is that your answer?

Q That's exactly what I want you to say. Now, I think by your testimony you've indicated that the water flood oil is making some inroads as far as your allowable is concerned, and cutting down the allowable. Don't you think that it would be better for the Commission to take some steps at this stage in view of the potential acreage that can be put under water flood than to go on indefinitely and get into an intolerable situation as far as the primary oil is concerned?

A No, I don't think that the situation will become intolerable, it hasn't elsewhere, I don't see how it possibly can here. That's the crux of my testimony, so I don't agree with you, sir.

Q Mr. Buckwalter, you mentioned the wide variation in reservoir characteristics from field to field, from reservoir to reservoir, and from well to well. Does this occur only in secondary fields or do primary fields have to suffer to these conditions also?

A I think, of course, the primary fields vary too, but when you come to a water flood and build up an oil bank and start to move oil towards producing wells, you have a different mechanism of recovery than what you would in primary, and with that difference in mechanism I believe that makes it more important that we take our oil from the wells which will produce it and not be restricted in the water flood.

Q Now, can the water drive fields be prorated, and haven't they been prorated, along with other fields?

A That's correct.

Q There has been no exception made in the case of water drive fields?

A There are some exceptions I believe in the water drive.

Q There never has been an exception in New Mexico, has there?

A I am not sure about that, I don't know.

MR. HINKLE: I believe that's all.

MR. PORTER: Does anyone else have a question?

MR. PAYNE: Yes, sir.

BY MR. PAYNE:

Q Mr. Buckwalter, I believe it's your testimony that if you don't produce these wells at capacity in a water flood, that waste will result, is that correct?

A That is correct.

Q Now, are you talking about producing at the capacity of the formation?

A Yes, sir.

Q Do you recall your testimony in Case 1324 where you stated as follows: This is a quote from your testimony in Case 1324, "I certainly don't recommend starting a flood with a pressure which would be one that would overtake the capacity of the pumping equipment that might be installed in that particular operation." Now, is that producing at capacity?

A I don't know what you mean, I'm sorry.

Q Are you going to leave it to the operator to determine what size pumps he should install even though the formation will not be producing at capacity?

A Well, my position is very definitely that the pumping equipment should be capable of producing the fluids that come to the producing wells, and there should be no restriction to these producing wells.

Q But if the pump equipment is not such as to produce the formation at capacity, would you recommend that they install the larger equipment?

A I certainly would.

Q This doesn't seem to jibe with this statement in your previous testimony.

A I think it does. You put it around the other way. You said in one case that it's after the flood is in progress. I think before it was the matter of the design.

Q Mr. Buckwalter, I believe you testified that the number of fields in New Mexico available for effective water flooding are limited, is that correct?

A I think they are limited.

Q For what reason?

A Well, I think there are a number of water drives in New Mexico.

Q Have you ever recommended the installation of a water flood project in a water drive pool?

A Not that I recall.

Q Do you know of any water drive pools where there are water flood later?

A I don't call them water flood.

Q What do you call them?

A Well, that would be pressure maintenance.

Q Mr. Buckwalter, do you agree with this statement contained in an article by Mr. Smith in the October 5th Oil and Gas Journal? "The old permian fields in Southeast New Mexico are receiving industry-wide attention for their water flood potential." Do you agree with that?

A Well, I think it is evidenced by the people here today that's true.

Q What do you think about the title of this, "Water Flood Potential Gives New Glamour to Old New Mexico Fields"? Does that indicate to you that water floods are going to increase in New Mexico?

A I think there will be some increase, but I don't believe it's anything like has been depicted by some parties.

Q Mr. Buckwalter, I believe that you testified that about half of the production from the Caprock-Queen Pool is from the area being water flooded, is that correct?

A That is correct.

Q Is half of the acreage in the pool being flooded at this time?

A No, it isn't.

Q It's considerably less, is it not?

A It is.

Q I believe you made the statement, Mr. Buckwalter, you felt Mr. Nutter's calculations were too high because of the way he did it. Isn't it possible that yours are too low because of the way you made your calculations?

A Well, it's a matter of which is right.

Q His could be right just as well as yours, could it not?

A I think it's a matter of opinion. Also I do believe, to me, I always count injection wells, after all they are contributing oil, the oil is coming from under those and around those injection wells to production. I don't see how you can ignore them, they're part of the whole process, without the injection wells as wells we couldn't operate a water flood. Therefore I think they should be included.

Q Isn't the important thing the production in excess of top unit allowable when you are trying to determine the impact on the market?

A Yes, it is.

Q Now, referring to the two Humble wells in the South Four Lakes-Devonian Pool, do you know the depth of those wells?

A Well, let's see, they're Devonian, I suppose they are deep wells.

Q They would be getting a deep allowable even if they were oil wells, would they not?

A I don't think they get an allowable.

Q If they were oil wells?

A You mean if they were prorated?

Q Because of their depth they would be getting a high allowable.

A I imagine they would. I don't know how high exactly.

Q Now, Mr. Buckwalter, your Exhibit 12 shows that the excess production above normal unit allowable of some 4300 barrels here today. Have you made any calculation of the total production from the water flood wells which are producing in excess of the top unit allowable?

A I think my last exhibit showed the excess for the entire state.

Q Now, you are attributing top unit allowable to every well, are you not, to the injection well, to every producing well?

A Yes, In July I took the barrels per well per day, which is the normal unit allowable per well, and I multiplied that by the number of wells in the project and subtracted that number from the production in the project.

Q Mr. Buckwalter, in all of your calculations in preparing your testimony, did you see any indication that the production in excess of top unit allowable is leveling off, not in any particular pool, as a whole?

A You mean for the entire state?

Q Yes, sir, Southeast New Mexico.

A There has been a general, very, very gradual increase in that figure as shown on this exhibit in the lower right-hand corner. I do believe that that will not continue to increase in the same fashion as the oil production will increase. I believe each of these projects will have its term of being over the normal unit allowable, but then it will decline below what would be the normal unit allowable and another project will come along, so this thing, this will flatten out. It's pretty difficult to calculate, and I have given some consideration to calculating, but it's a little early to do that here. I think it can be done, however.

Q Is there any reason to believe that one water flood will necessarily peak out before another one has started?

A Yes, there is.

Q Why is that?

A Well, that's just the nature of the water flood.

Q Couldn't you start them all at once?

A Well, that's a physical impossibility.

Q Why?

A People just don't do things all at the same time.

Q Are you aware that we have six applications pending for pilot water floods?

A Yes, that was stated yesterday.

Q That would indicate that a number of them will be started in a relatively short time?

A Maybe. Sometimes people make application before they actually put the project in. I think that happens many times.

Q In calculating your figures on Exhibit 13, the excess oil over normal unit allowable --

A Yes, sir.

Q -- did you take in other wells that have not received a response?

A No. In that one I took the wells that had received the response. As mentioned on the previous exhibit, I had done it two ways, but on this one these are the wells that are, had received a response.

MR. PORTER: Mr. Buckwalter, I have one question.

BY MR. PORTER:

Q If a project is granted capacity allowables, do you believe it should be mandatory that the operator produce those wells at capacity rather than capacity of the equipment?

A Well, that's a good question. I would say, yes. I think that that is in conservation procedure, and I believe I would certainly say yes to that.

MR. PORTER: Anyone else have a question?

MR. McGOWAN: I just want to ask one question.

MR. PORTER: Mr. Dutton, will you come up? You are next.

MR. McGOWAN:

Q Mr. Buckwalter, in looking at your Exhibits 8, 9 and 10, you don't need to refer to them. They were basically comparison between what you predicted would happen and what has happened on certain floods, as I recall. Would it not be logical to draw the conclusion from those exhibits that you just can't predict what's going to happen in a water flood?

A Well, you are right to a great extent, it's very difficult. Although I don't think my predictions are too bad as predictions go.

Q Well, I'm not criticizing your predictions in that sense at all. The point I want to make is that even with the error that you show in your own predictions from actual results, would you draw the conclusion then that you could plan a project to get your ultimate performance and still stay within a predetermined allowable?

A No, that's the big problem. I don't think you could.

MR. McGOWAN: Thank you.

MR. PORTER: Mr. Dutton.

BY MR. DUTTON:

Q Mr. Buckwalter, I believe you presented ten water flood histories in your various exhibits, these were contained on two separate exhibits. Out of these ten water flood histories, how many of these water floods would have actually been restricted had they been instituted under the proposed rule before the Commission?

A Well, at the present time I believe there are two of them. Yes, two of them.

Q Two out of ten. Are both of these in the Caprock-Queen Pool?

A Yes, sir.

Q Have you characterized the Caprock Pool as the probable champion of the water flooding potential in Southeast New Mexico?

A I believe I did make a statement like that.

Q So then this proposed rule would actually not restrict any of your ideas with respect to 80% of the water flood histories you've presented here today, is that correct?

A Those histories are, of course, early water floods, and I think we'll come to a place where others may be involved. I think other fields will, of course, go over.

Q But you don't think that they will go over so far as to create any impact on the allowable situation?

A No, that is true, I don't.

Q Then you don't think the majority of them will go over, do you?

A No, I don't.

Q So this rule would actually cover the majority of the water floods that is proposed today?

A I believe it would from what we have seen today.

Q Thank you, sir. Now, in discussing the difference per average well production for Units 1 and 2 in the Caprock Field, I believe you attributed the higher peaks in Unit 2, possibly among other things, but certainly you mentioned the fact that Unit 2 has experienced a higher per well injection rate?

A Yes, I did.

Q Then can we say that per well production peaks are certainly limited by the total injection rates?

A Yes, sir, but there is a wide variation in those peaks because of the variations in the reservoir.

Q But they will ever exceed the total injection in a bonafide water flood, will they?

A You mean in average, no.

Q Then with your experience as a water flood engineer, it would be possible if a client employs you to do so, to design a flood which the average per well would peak out, with reasonable accuracy, below any given limit that the client might specify?

A I think he has come to the wrong consultant for that kind of advice.

Q My question wasn't relative to advice, it was relative to design. I said would it be possible for you to design such a program that would peak out at any given requirement he specified within reasonable accuracy.

A Yes, although you must remember, let's take 400 barrels per day per injection well. Now, it is possible that a thousand barrels can be produced at a producing well, when you only have 400 barrels per day at each injection well, I think we must recognize that.

Q From the project area, I said the average well production peak.

A Oh, yes, I think, when you have the more wells to bring into the picture, of course the better you can do.

Q It all boils down to the fact that a bonafide water flood, if you don't inject over 400 barrels total in the project area, you are not likely to produce over 400 barrels of total fluid?

A That is correct.

Q Now, further discussions of water flood history, I understood you to state that had that particular flood been restricted to either 33 or 39 barrels per day per well, in you opinion this would have resulted in waste?

A Yes, sir.

Q Would you tell the Commission what you mean by waste?

A I mean loss of ultimate recoverable oil. That is oil which will not be recovered at any time in the future.

Q Sir, had you designed Unit 2 from its inception at your client's request to peak at a 35 barrel per day average well, would there have been any loss of otherwise recoverable oil?

A I believe there would have been.

Q How much?

A I wish I could give that answer, it is pretty difficult to calculate it right here.

Q Sir, are you aware that in New Mexico, production in excess of the market demand constitutes waste just as does the underground resources, the waste of recoverable hydrocarbons?

A That sounds legal to me. I'm not in a position to quite answer that.

MR. DUTTON: I request the Commission to take administrative notice of Section 6533, Paragraph C, which I would like to read into the record at this point, sir.

MR. PORTER: You may proceed.

Q "The production of crude petroleum oil in this state in excess of the reasonable market demand for such crude petroleum oil, this is included in the term waste in addition to its ordinary meaning."

Now, sir, with that information we can now assume that you are aware that production in excess of the market demand constitutes waste in New Mexico?

A That's a kind of statutory waste or something that's not the waste I'm talking about.

MR. CAMPBELL: If the Commission please, I don't know what this line of questioning is leading up to, it is quite obvious this witness is not qualified as a legal expert, certainly the definition of what is meant by that is a rather complicated legal matter, and unless he has something particular, it seems to me we are getting into a line of questioning that can lead to a long hearing, longer than apparently we are going to have.

MR. DUTTON: If the Commission please --

MR. PORTER: Mr. Dutton, just what are you trying to develop?

MR. DUTTON: I was trying to develop that among Mr. Buckwalter's many qualifications were memberships on industry committees, and with respect to these industry committees, I was going to develop that if his opinion as such, a spokesman for the industry, that one segment of the producing industry, the flushing production should bear the entire burden of preventing waste by exceeding market demand, by preventing the excess production above market --

MR. CAMPBELL: It occurs to me that is the statutory duty and statutory duty of the Commission to determine from time to time rather than at this hearing or the witness.

MR. PAYNE: May it please the Commission, I see no reason why the witness should not answer the question.

MR. MORGAN: I think that Mr. Dutton is arguing with the witness in my opinion.

MR. DUTTON: I will withdraw the question.

Q (By Mr. Dutton) Referring to the Caprock Field increase and the question as to whether or not Mr. Nutter's exhibit showed an overall increase as a result of water flood, or as a result of increased number of wells, I believe you testified that there was approximately 4300 barrels per day above the normal unit allowable, the way you calculate, in July of this year?

A Yes, sir.

Q I wonder if you would point out what the total increase in the Caprock Field has been from the period in 1957 when it reached the bottom until today?

A Yes, sir, I will refer to my exhibit. Well, we had a low in 19 -- you said '57. We went lower in '58, after the water flooding started we were lower than before it started. '58 is the low here, isn't that right? Which year do you want?

Q I was unable to read the numbers from where I was sitting. Actually the period I'm interested in is the period which I believe now shows up as early 1959 where your curve starts excess above normal unit allowable.

A I show January, 59 as the first month.

Q Yes, sir. Now, how much has that increase been from January to July, sir?

A Well, it was very small in January.

Q Well, over the six-month period, sir.

A Over the seven-months' period we went from nothing to about 4300 barrels per day.

Q And during that same period how much did the total production from the Caprock Pool increase?

A From about 10,400 to about 15,300.

Q So even the way you calculate it, 86% approximately of the total increase in Caprock Pool production has been a result of production in excess of the normal unit allowable, approximately?

A Of the increase?

Q Yes.

A Yes, I think that is pretty close.

Q Thank you very much.

MR. PORTER: Take a ten minute break.

(Whereupon a short recess was taken.)

MR. PORTER: The meeting will come to order. Does anyone else have a question of Mr. Buckwalter?

BY MR. BUELL:

Q Mr. Buckwalter, my name is Guy Buell, I'm with Pan American Petroleum Corporation, and so that you can properly evaluate my questions, let me tell you now that Pan American will support Nutter's rule. How many exhibits did you introduce, Mr. Buckwalter, just the total number?

A I think it was 11, no, excuse me, about 7.

Q Eleven? A Seven.

Q Seven. Which, if any, of those seven exhibits, Mr. Buckwalter, show this Commission that they should not adopt Nutter's rule?

A Well, I don't have Mr. Nutter's rule on any of my exhibits, I don't have his approach depicted anywhere.

Q Well, as I understand your position, you oppose Nutter's rule, do you not?

A No, I wouldn't say that.

Q Are you recommending to the Commission that they adopt it?

A No, I'm not, I'm saying that, simply, you can't restrict the water floods. Now, I can conceive of places where you can have a water flood, and Mr. Nutter's rule would never apply, and I can see other floods where it can be applied, but my job isn't rules, my job is water flooding.

Q And none of your exhibits contain any data that shows the Commission that they should not adopt Nutter's rule?

A My testimony does, I believe.

Q But none of your exhibits do, do they?

A I don't have any comparison of his rule.

Q In your testimony I believe you said there was one or two places that your engineering opinion, the Nutter rule would be, detrimentally affect?

A That's right.

Q You also, in answering Mr. Campbell's question, said that you had evaluated all water floods in New Mexico?

A I didn't say that.

Q I misunderstood you. Did you not testify that your opinion, no other water flood would approach these two from the standpoint of the ability to produce?

A I said at this time.

Q Yes, sir. So then these two units that Nutter's rule would detrimentally affect, in your opinion are exempt, are they not, under Nutter's proposal are exempt?

A No, I don't believe they are.

Q Is it not your understanding, Mr. Buckwalter, that floods presently approved will not be governed or regulated by the Nutter rule?

A I thought you were using the rule as a comparison here as Mr. Nutter did, I believe, in his testimony, but if these would be exempt from the rule, then the two that I'm referring to then, of course, the rule would not apply.

Q Then they were not detrimentally effective, were they?

A Not on that basis.

Q Do you see any prospective flood, and in your analysis and evaluation of New Mexico prospects, that would equal these two?

A I think there are other floods in Caprock.

Q You think there are? A Yes.

Q And I believe you all used the word allowable impact. There will be an allowable impact comparable to these two, is that right?

A Yes, I think allowable impact has just more than two floods, I mean you have floods declining, others are increasing, and so the impact is really the composite of all floods. Now, if the floods are started following the decline of the two that we are speaking of, now then the two balance out, and I believe that is the type of thing we are going to experience. In other words, I do not believe this coincidence of all the floods coming to some peak at a given time, I just don't believe that will happen.

Q Is your engineering opinion, Mr. Buckwalter, that a location under the Nutter rule would not be detrimental to the majority of the water floods in New Mexico both present and future?

A Well, I can speak for the present ones and the future ones, I haven't made an exhaustive study and prediction and that sort of thing, but it is my understanding that there are a limited number of fields which are susceptible to water flooding, and therefore I think that it will be a matter of each field's own character as to how it responds to flooding, what its injection rates will be and so on, so I just don't think that I can fairly answer that directly.

Q I recall an earlier answer of yours where you said in your opinion it would cover the majority and adequately allocate the majority of the floods. Are you changing your mind?

A I think from the experience we have, and from what amount of study I have made at this time, I would say yes.

Q It will cover the majority?

A Yes.

Q Equitably and fairly?

A From what I know, yes.

MR. DUTTON: Thank you, sir.

MR. PORTER: Does anyone else have a question? Mr. Campbell.

REDIRECT EXAMINATION

BY MR. CAMPBELL:

Q Mr. Buckwalter, assuming this, that your prediction of the future is correct with regard to this particular rule covering future projects, could you mean by covering future projects that it will permit the production of oil from the producing well at the maximum rate, is that what you mean?

A No, I mean it would have to be on a project basis.

Q But you are saying that the majority of them will not reach a point where under this formula they will not be able to produce the maximum, is that correct?

A Well, we get into a problem here of the size of the project, and I don't think I brought that up in the last question. We have a problem of size here, according to Mr. Nutter's rule, he will multiply the 42 barrels times the number of wells, and if they only have a couple of barrels we are sure in trouble in many, many places, but if we talk about larger units, why of course we do have, and do have some latitude.

Q So you are saying then that in the future projects that will be covered by this rule, if you have enough acreage to attribute it and receive enough allowable to produce that maximum under the optimum rate of injection, then of course it will cover it, will it not?

A If you have large enough projects, certainly.

Q Now isn't it the minority, whatever that percentage may be with which you are primarily concerned as an engineer, where the allowable is not sufficient to provide maximum production with the optimum rate of injection?

A Those would be the serious cases, yes, sir.

Q And do you find -- well, I won't ask you about the rule.

MR. CAMPBELL: That's all.

M MR. PORTER: Anyone else have a question of the witness? The witness may be excused.

(Witness excused.)

MR. PORTER: Mr. Campbell, call your next witness, please.

MR. CAMPBELL: Mr. Edgerton.

GEORGE H. EDGERTON

called as a witness, having been first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q Will you state your name, please?

A George H. Edgerton.

Q Where do you reside, Mr. Edgerton?

A Austin, Texas.

Q What is your profession and in what manner are you now engaged in it, please?

A I am a petroleum engineer. I'm in partnership, consulting partnership in Austin dealing largely with engineering and geological matters concerned with the regulation aspects.

Q Will you give the Commission a brief resume of your educational and professional background?

A Yes, sir. I graduated from the University of Texas in 1940 in Petroleum Engineering. Thereafter was employed by the Railroad Commission in Corpus Cristi, Texas, and in 1941 I was made District Engineer in Corpus Cristi. In 1942 I entered military service and returned to Commission employment as a senior engineer in 1945 in November. March, 1946, I left the Commission and went into the consulting business and have remained in the consulting business since that time.

Q In connection with your consulting work, have you had occasion to work on water flood projects?

A Yes, sir, primarily from the standpoint of the regulatory questions which have arisen, and the reasons for these questions.

Q Now, Mr. Edgerton, in connection with this hearing, I have heard the remark that one reason for the concern here in New Mexico is that we don't want to happen to us what has happened to Texas. There was a lot of comment made with a lot of regard that I'm talking about; I'm talking now about water flood oil, particularly with regard to excess water flood oil, and its impact on the market. Have you made a study of the records of the Texas Railroad Commission with regard to this particular question?

A I have.

Q Now I hand you what has been identified as Exhibit No. 14 and ask you to state what that is, please.

A Exhibit No. 14 is a summary tabulation of stripper water flood allowables in Texas for September, 1959. Now this study was made as of September, 1959; however, to include all the projects on which applications had been made, we used hearing summaries extending back to 1933, so we tried to include all the water flood applications which had been made for the past twenty-six years in Texas.

Q And does Exhibit 14 contain a summary of the statistics in that regard?

A It does.

Q Now, Mr. Edgerton, referring as much as necessary to the exhibit, Exhibit No. 14, will you state what the actual bona fide water flood situation is in the State of Texas with particular regard to water flood oil produced in excess of your state-wide yardstick or allowable, or what you may call it there?

A The flood allowable above yardstick in Texas as of this time, or as of September, amounted to 1.44 percent of the total state allowable in September, 1959.

Q So that the amount of percentage of water flood oil in Texas after a number of years of experience in that state with water flooding at this point is 1.44 percent excess to the total production?

A No, well, that is the percentage which is allowable in excess of the yardstick. Now the total water flood production in the state amounts to about 5.044 percent of the total State production, speaking of stripper water floods.

Q And do you consider on the basis of the study that you have made and the compilations contained in Exhibit 14 that the percentage of water flood oil in excess of yardstick in the State of Texas presents a serious impact question upon market demand or upon primary production in that State?

A No, sir, and the figure speaks for itself.

Q Oftentimes a figure is referred to with regard to exempt production in Texas, and is then transposed into the amount of water flood oil which is in some people's mind flooding the market in Texas. All of the exempt production in Texas is not water flood production, is it?

A No.

Q As a matter of fact, what -- generally what other types of production above yardstick was permitted in the State of Texas?

A To give you a little idea of that, the amount of exempt production in Texas amounts to about 1,100,000 barrels daily. Now the amount of water flood production, stripper water flood production in Texas is about 141,000 barrels, so you see it is around, perhaps twelve percent of that total exempt figure. The production which makes up the balance of that exempt figure comes from discovery allowables, about 118,000 barrels; from marginal wells, about 324,000 barrels; and then from exempt fields and in the exempt field the stripper water flood production is included, that figure amounts to about 705,000 barrels. In the past eighteen months the exempt field figures included about 45,000 barrels, the marginal allowable increased in that same period by about 100,000 barrels. Now I should probably make a little distinction here. Marginal in Texas doesn't refer to a well that won't make the top allowable, but is a statutory definition setting certain minimum allowables on wells which are listed initially with certain depth brackets attached thereto, and those wells are exempt from shutdown days by statute, as I understand.

Q Then would you say that the amount of excess water flood oil as related to other exempt production in the State of Texas represents a very small percentage?

A That's right, it is a small percentage because the total water flood production amounts to about twelve percent, and the excess or the exempt production, five percent of the total State; the excess of course is 1.44 percent, which would be about three, four, five percent, perhaps, of the exempt production.

Q Now what has been the experience in the State of Texas with regard to fluctuation, in regard to this percentage in State-wide allowable over a period of years?

A The marginal figure has, of course, increased, indicating that we have an increase in the number of low capacity wells. Now in that connection, we've noted that during the past approximately seven years there has been an increase in the total number of wells in Texas from about one hundred thirty-five odd thousand to about one hundred ninety thousand, with no appreciable change in the reserves as determined by the A. P. I. Now that, I haven't analyzed that figure in detail, but one possible analysis in connection with the increase in the marginal wells is that we are getting greater number of stripper wells; another inference might be that perhaps there has been more than enough development from primary areas.

Q Mr. Edgerton, I notice from these figures that some particular areas seem to indicate a much larger amount of allowable in excess of yardstick than others. Are there certain fields in Texas that are contributing a large portion of what excess exists over there?

A Yes, the more outstanding water flood fields have contributed a larger part of the excess figure. Now in previous years the South Ward Field was the field which contributed more to excess. The Kermit Field was another field which had good performance. The North Ward-Estes at this time contributes a substantial part. In other words, we have field-wide, this balancing effect of one field declining as another increases, but the other point is that most of this excess comes from the outstanding water flood fields rather than from, small portions from a great number of fields, a great number of the water flood projects never reach ever the yardstick value.

MR. CAMPBELL: I believe that's all.

MR. PORTER: Does anyone have a question of the witness? The witness may be excused.

(Witness excused.)

MR. CAMPBELL: I would like to offer Exhibit No. 14 in evidence.

MR. PORTER: Is there objection to the admission of this exhibit? It will be admitted.

MR. CAMPBELL: I would like to call Mr. Stiles.

MR. HINKLE: If the Commission please, we would like to ask Mr. Edgerton a question or two.

MR. PORTER: Mr. Edgerton, would you return to the stand, please?

GEORGE H. EDGERTON

called as a witness, having been previously sworn, resumed the stand and testified as follows:

CROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Edgerton, referring to your Exhibit No. 14, on the first column there, column 1, you've listed the Railroad Commission Districts. Where is District No. 8 located?

A It is in the West Texas area.

Q That is comparable to the New Mexico area, as far as the characteristics of the field reservoirs are concerned?

A I believe it is in the same geological province. I haven't made a study to see how comparable.

Q It is the Permian Basin?

A That's right.

Q Now in Column No. 9, you show that in District 8 there was 96,841 barrels exempt from allowable on account of water flood production, is that right?

A That's right.

Q And the total allowable above the yardstick were leases under water flood in column 11, was 31,408 barrels, is that correct?

A That is correct.

Q That's a little less than a third of exempt production, is it not?

A You mean referring to District 8, yes.

Q No, I mean three-fourths of your total in your Column 11.

A You mean, Column 11 is approximately a third of Column 9 in District 8, which means that the excess in District 8 is approximately a third of the total water flood production.

Q Yes, but the 31,000 is also about three-fourths of your total allowable above the yardstick in Column 11?

A Oh, yes, yes.

Q So the biggest areas that you got as far as water floods are concerned are in West Texas and District No. 8, is that right?

A The biggest amount of allowable above yardstick is in District 8, yes, sir.

Q Now if New Mexico had 31,000 barrels, what percentage of the total New Mexico production would that be?

MR. PORTER: Mr. Hinkle, would you rephrase that question, please? The noise cut me out.

Q (By Mr. Hinkle) If New Mexico had 31,000 barrels of production in excess of the normal allowable on account of water flood projects, what percentage of the total production, average daily production in New Mexico would that be?

A I didn't check the last, the most recent daily production figure in New Mexico. Would you give me that figure?

Q I think it is about 250 in Southeastern New Mexico, approximately.

A In Southeastern New Mexico, 250, if 31,000 barrels were the amount above yardstick, we would have, let me get a slide rule.

Q We don't need an exact, just approximately.

A Thirty is approximately an eighth of the two hundred --

Q Now, you heard Mr. Nutter's testimony that he figures about 3500 barrels of water flood oil will reduce the daily, the normal allowable by about one percent?

A I heard that.

Q What percentage would that be, if we had an excess of 31,000 barrels?

A You didn't mean one percent, you mean one barrel, I think.

Q One barrel, yes, that's right.

A Well, 30,000 divided by 3500 would be approximately seven or eight, would be a seven or eight barrel figure. I might say this in -- to further offer some explanation in that respect with reference to this comparison; we have noted that in those particular fields, in the West Texas District, which have contributed the greater part of this excess, that the rate of reduction there per acre and injection rate per acre are considerably higher than they are in Caprock-Queen. That was the reason that I said to you a while ago that while it was the same geologic province, I didn't know that they would necessarily be in any exact sense comparable; that is, the West Texas District and the New Mexico Southeast area.

MR. HINKLE: That's all.

REDIRECT EXAMINATION

BY MR. CAMPBELL:

Q Mr. Edgerton, do you have a figure on the total allowable assigned to District 8 in Texas for the same month?

A I think so. I don't find that tabulation at the moment, just a moment, maybe I can. Mr. Campbell, I have here some place the September, '59 figure, the State-wide allowable in September of '59 was about 2,795,000 barrels daily. I have here a figure which would probably give us a reasonable basis, or in proportion, although it is of January, '58, I happened to pick up, I find this particular figure at that time, based on State-wide allowable for a million barrels, the District 8 was 881,000 barrels.

Q Which is somewhere in the neighborhood of three and a half times more overall allowable for that District than in Southeastern New Mexico, is it not?

A Yes.

Q So if you make the comparison, certainly the relationship should be established between those figures, should it not?

A Oh, yes. Not only relationship between the figures from the District, the size it covers, the number of fields, in total production, but also the relative water flood potential.

Q And despite the amount of oil in excess produced in District 8, the per well per calendar day producing and injection wells in that District was only 16.7 barrels per day, was it not?

A The average was 16.7 barrels per day per well.

MR. CAMPBELL: That's all.

MR. PORTER: Any further questions of the witness?

MR. PAYNE: Yes, sir.

RECROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Edgerton, referring again to your Exhibit No. 14 in West Texas, the areas we have been talking about in District 8, they have ten-acre spacing for each well, do they not?

A That varies considerably, Mr. Hinkle, in the water flood areas.

Q In the South Ward Field?

A Yes.

Q Each well then is entitled to an allowable of 60 barrels?

A I believe the, I have the yardstick here, I think the allowable there on ten-acre well was 45, Mr. Hinkle.

Q Even if that is right, that would be four and a half barrels an acre, would it not?

A Well --

Q That would be approximately four and a half barrels?

A Mr. Hinkle, bear in mind that when we talk about yardstick here for comparison purposes, we apply shutdown days, it is nine-thirties, about thirty percent.

Q These are exempt, are they not? We are talking about your exempt figure here?

A That is true, this is exempt because being on the water flood, but if you are relating it to the amount of excess above yardstick, then we determine what the allowable would be in this field subject to shutdown days without the exception to determine that figure, which would change that 45-barrel figure to about fifteen barrels, a little under fifteen barrels.

Q Well, if you relate that to New Mexico's forty-acre allowable, it would mean that it would be about at least 160 barrels for the forty acres, would it not, in New Mexico?

A No, sir, it would be thirty percent of 45, would be about thirteen and a half barrels times four would give us about fifty, fifty barrels -- fifty-two, something like that.

Q If you multiply four and a half by forty, it would be 180. I don't see how you get that figure.

A That's right, if you are going to exempt it.

Q We are talking about exempt oil.

A Yes, but that's not the way we determine the excess here at all. We made our calculations based on not exempting, to arrive at the amount produced in excess of the exempt figure.

Q What we are doing is making comparisons in West Texas and New Mexico. Do you apply your normal allowable in Texas in that particular field to New Mexico -- it would be 180 barrels?

A If we are going to take the exempt figure, certainly it is going to be four times forty-five.

Q Which would be 180?

A That's right.

Q Now on this 31,000 barrels we are talking about, is in excess of your normal allowable, so that's in excess of allowable in Texas, that's much in excess of the normal allowable in New Mexico?

A Not at all, not at all, Mr. Hinkle. That's what I have been trying to explain, that the excess was calculated based on nine-thirties, based on shutdown days. In order to calculate this excess, we took this assigned allowable and calculated it, what it would be at the yardstick subjected to shutdown days, took that figure to subtract from the actual allowable to arrive at the excess, so that you have --

Q The Commission, though, has excepted this field, have they not?

A Yes.

MR. HINKLE: That's all.

MR. PORTER: Mr. Payne.

BY MR. PAYNE:

Q Mr. Edgerton, do you have the figure of the total allowable assigned to prorated wells during September in District 8?

A I think so.

Q I don't want to include any marginal wells there.

A That's the paper I was looking for a while ago. I can give it to you approximately.

Q That will be fine.

A On a calendar day basis, there is about two and a half, I mean the total is in the order of two and a half million to two million seven per day for the field. I'll break that down. At the present time in Texas the exempt figure is about a million one hundred thousand. The difference there is about, the calendar day allowable for the wells subject to shutdown days.

Q Now you are giving me the State-wide figure, aren't you?

A That's right.

Q Do you have the figure for District 8?

A If I can find it, if I can't find it for you I can certainly furnish it to you a little later.

Q For the purpose of the impact on the market, shouldn't your comparison be the 31,408 barrels to the total allowable assigned to the prorated wells in District 8?

A Well, you could certainly make an analysis along that line. The so-called impact is a portion of the total. In other words, the amount that water flood production furnishes becomes a part of the total figure. I think perhaps what you are getting at is what would happen if you removed the exempt, and it would go back down to the shutdown days.

Q Yes, sir.

A In that respect, I think you should apply the figure to the prorated allowable portion.

Q Now most of the water flood production in Texas is in the West Texas area, isn't it?

A Well, when you say most production wise, yes.

Q Now --

A If you talk about number of projects, there are a great number of projects in other Districts.

Q And Eastern New Mexico and West Texas make up the Permian Basin, do they not?

A Yes.

Q Which has proven very susceptible to water flood?

A Yes.

Q They do have the equivalent sands, do they not?

A To some degree. I don't know yet of any performance in New Mexico necessarily comparable to the Yates sand performance in the South Ward, some of those areas.

MR. PAYNE: Thank you.

MR. PORTER: Does anyone else have a question of the witness? If not, we will excuse him again and proceed with Mr. Stiles.

(Witness excused.)

W. E. STILES

called as a witness, having been first duly sworn, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q Will you state your name, please?

A W. E. Stiles.

Q Where do you live, Mr. Stiles?

A Tulsa, Oklahoma.

Q What is your profession and your present business association?

A I'm a consultant petroleum engineer.

Q Would you give the Commission a brief background of your educational-professional history?

A I'm a petroleum engineer, graduated from Texas A. and M., class of 1938. For the three years following graduation I did well testing and bottom hole pressure testing all over the United States. 1941, I joined Core Laboratories, Inc., and was with them for ten years and did a lot of different things in Core Laboratories, mostly reservoir engineering and a lot of reservoir engineering and development and supervision of water floods.

In 1951 I joined Buffalo Oil Company as vice-president in charge of engineering and production, and during that period of time, eight years, we installed many water floods and engineered many of them.

Q At the hearing in connection with the Ambassador-Caprock Unit No. 2, did you testify with regard to some statistics concerning water flood production in the State of Oklahoma?

A Yes, I did.

Q Have you, at my request, more recently compiled some statistics from the records of the Oklahoma Service Commission concerning this matter?

A Yes, I have compiled those for the month of May, 1959.

(Exhibit No. 15 marked for identification.)

Q I will refer you to what has been identified as Exhibit 15 on the board and ask you to explain by way of summary what your conclusions are in that regard.

A Exhibit 15 shows a summary of the May, 1959, status of water flooding in Oklahoma. It is an analysis of 643 projects reporting for the month of May. I don't know if those in the back of the room can see all that, but the top line shows that the average daily production for all of Oklahoma during that month was 556,856 barrels a day, and during that month the minimum allowable in the State was twenty barrels per day per well.

As to the water flood production during that same month, the average daily water flood production was 139,544 barrels, or 25.06 percent of the State's total daily production.

There were reported 17,136 oil wells in authorized water flood projects, and 11,400 input wells, making a total of 28,536 wells. In authorized water flood projects during the month of May, the average production per oil well in authorized water flood projects was only 8.14 barrels.

If we add in the input wells, then the average daily production per well is only 4.89 barrels.

Q How long has water flooding been going on in the State of Oklahoma, Mr. Stiles?

A I don't know the exact number of years, but many, many years.

Q And you have been acquainted with it for how many years?

A Oh, fifteen to sixteen years in Oklahoma.

Q During that period of time, in the State of Oklahoma, do you consider that the water flood oil in excess of what the minimum allowable has been in the State of Oklahoma has presented any serious impact upon the market demand picture in that State?

A No, I don't think it has ever had any serious impact upon the State's total market, and I don't think it has a serious impact today.

Q Now I refer you to Exhibit No. 15 -- Exhibit No. 16 and ask you to state what that is.

(Exhibit No. 16 marked for identification.)

A This is again the data for the month of May, 1959, during which time we had no proration on water floods, and its statistical analysis of where is the water flood production coming from in all of these projects.

The top line groups all the projects in which the average daily rate of production was sixty barrels per well or more, and the exhibit shows that there were only four projects in the entire state wherein the production was greater than sixty barrels per day per total well. Of the four projects, the highest producing was a project producing seventy-four barrels per day per well, and it reported no input wells and only one producing well, so I don't think we can consider that a water flood. Of those four projects, however, the average daily rate of production per total well was 64.9 barrels, and if we presumed that the Oklahoma Railroad Commission had applied restriction to water floods during that month and had given each oil well and each input well the minimum allowable for any well in the State, that being twenty barrels per day, then these four highest producing water floods would have produced only 494 barrels per day in excess of that minimum allowable.

The second line of the exhibit shows the number of projects that are producing between 50 and 59 barrels per well per day, and there's only one of those projects.

The next line are those projects producing between 40 and 49; the next line is 30 to 39; the next line is 20 to 29, so let's stop here for a moment and examine all those projects that are producing in excess of 20 barrels per day per total well. There are 39 such projects out of 643 in the entire State. That's about six percent of the total projects. The amount of oil that they are producing in excess of a hypothetical 20 barrels per day allowable restriction on water floods is 10,596 barrels per day. That amount of oil is 1.9 percent of the State's total daily production, 7.6 percent of the total water flood production.

Q Do you consider that that presents a serious problem with regard to oil in the State of Oklahoma produced from water floods in excess of your minimum allowable?

A No, I do not. As a matter of fact, at the Ambassador hearing last year, I presented similar data for the month of January, 1958, at which time I showed that the excess production over 20 barrels per day per total well in January, 1958, was 10,300 barrels per day. At that time we had 480 projects. Now, eighteen months later, roughly, we have 643 projects and we still have about the same amount of excess production.

Q Now, Mr. Stiles, I believe that the Ambassador hearing, you expressed an opinion with regard to the question of producing water flood wells at their maximum rate contingent upon the optimum rate of injection of water. Would you please restate that opinion and state if it still is your opinion at this time?

A Yes, I'm still of the very firm opinion and have been for all the years I have been in water flooding, that water floods must be operated at the optimum injection rate and generally an optimum injection rate is a high rate, in order to recover and to produce the maximum rate of oil production. I think equally important with injection rate is the amount of pressure applied to the formation.

Q But I assume you are saying once the pressure is at the best rate, then you must produce the wells as the oil reaches them, is that right?

A Yes, you should produce the wells at maximum rate from whichever wells the oil may come.

Q Since the last hearing in which you expressed that opinion, have you continued to work with water flood projects in the State of Oklahoma?

A Yes, sir.

MR. CAMPBELL: That's all.

MR. PORTER: Anyone have a question of the witness?

MR. HINKLE: I have a question.

CROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Stiles, referring to your Exhibit No. 16, in Footnote No. 2, you show there the total State production during May, 1959, averaged 556,856 barrels per day?

A Yes, sir.

Q Is that right?

A Correct.

Q Roughly that is about twice the production in New Mexico, is it not?

A Right.

Q Now in Footnote No. 3, you say the total water flood production during May, 1959, averaged 139,545 barrels per day, or 25.06 percent of the State's total production?

A Yes, sir.

Q If New Mexico continues with their water flood project, it's reasonable to suppose that they would reach the same rate, which in this case would be twelve and a half percent of the total production in New Mexico, is that not right? That is, within a relatively short time?

A Well, I believe you are saying, Mr. Hinkle, that water flood production in New Mexico, if given as much time as we have had water flood production in Oklahoma -- are we talking about the same number of years?

Q I don't know that it would be necessary to give it as much time. I think it's reasonable to suppose that at the rate we are going that within a reasonable time we will soon have twelve and a half percent of our production from water flood?

A I don't agree that necessarily follows. It has taken Oklahoma twenty years to get up to this rate of water production.

Q Now your total daily in excess of twenty barrels production, as shown on your next to last column, is 10,596?

A Yes, sir.

Q Using Mr. Nutter's formula of producing the allowable, one barrel for every 3500, that would amount to about three percent in New Mexico?

A Three.

Q Three barrels?

A Three barrels, yes, sir, Mr. Hinkle. I think we ought to bring out that we're talking about twenty barrels per day. You are talking about a unit allowable of 35 barrels. If I use 35 barrels here, I would get a much lower figure than 10,596.

Q New Mexico, of course, is relatively new as far as an oil producing State, as compared with Oklahoma?

A Yes, sir.

Q Do you know of any orders that have been entered by the regulatory body in Oklahoma restricting water flood allowables?

A Recently?

Q What's that?

A Recently?

Q Well, at any time, or recently, yes.

A I know of all of them, I think. I can't recall all of them in the past.

Q How many of them have there been, how many orders have been entered?

A Three, I think.

Q Three?

A Yes.

Q What kind of restrictions were placed upon water floods in these orders?

A I have got all that here somewhere, if I can fish it out. But generally, back in about 1957 we had our first one, at which time the Commission said that each input and each oil well would be allowed to produce twenty barrels and no more. That was the first one. Maybe I didn't go far enough back on that first one. In '57 I think we had one which said that water floods, like all production in the State of Oklahoma, will be curtailed by eleven percent. Now, you want me to go on with the rest of them?

In June of this year the Commission placed in their order the words, "that water floods starting September 1st would be curtailed by 10 percent of their June production." That order was never put in operation, it was voided in August, I believe it was.

Q That's all you know about the orders that have been entered in Oklahoma?

A There has been one since then, the last one, starting in July, having to do only with new water floods authorized thereafter.

MR. HINKLE: That's all the questions.

BY MR. PORTER:

Q Mr. Stiles, you say that you have had water flooding, I believe the last twenty years?

A Well, I don't know the exact number of years, but quite a long time, yes, sir.

Q Would you say that this 139,545 barrels has been the result of a steady increase or has the most of that development come about in say the last three to five years?

A Well, there has been a great deal of water flood development in the last three to five years, what percentage of the total I don't know, Mr. Porter, but I will agree that the emphasis on water flood has probably been in the last ten years in Oklahoma.

Q Do you know how much the maximum allowables in Oklahoma have decreased during the last five years?

A I think generally from 25 barrels down.

Q Down to what figure now?

A Right now it's 17, Mr. Porter.

MR. PORTER: Thank you. Anyone else have a question?

MR. PAYNE: Yes.

MR. PORTER: Mr. Payne.

BY MR. PAYNE:

Q Mr. Stiles, in an article which you co-authored in the

June 16, 1958, edition of the Oil and Gas Journal, this statement is contained therein: "The amount of daily production in excess of twenty barrels per day per total well was 5,755 barrels." Now this is referring to Oklahoma. Now your exhibit shows that this production in excess of twenty barrels per day now is 10,596?

A Right.

Q So it's almost doubled since March of 1957?

A That's correct.

Q Is it not also true, Mr. Stiles, that while allowables have continued to go down in Oklahoma, water flood production has continued to increase?

A Yes, sir.

Q I note that the total State allowable for March, 1957, 625,000 barrels, in January of 1958, it was down to 562,000?

A Right.

Q Can you tell me what the allowable was, the most recent allowable was for Oklahoma?

A I can't tell you precisely, no, I'm sorry.

Q About 510,000?

A I think that's approximate, yes.

Q Now in this same month, March, 1957, water flood production was 115,570; January, 1958, it was 127,771. Do you have the figure on what it is now?

A Yes, 139,000.

Q You don't feel that this decrease in allowables and increase in water flood oil has had an impact on the Oklahoma market situation?

A Well, if you want to use the word "impact", that's all right with me, but I don't think you can deny that these people have a right to place their property under water flood. I think I have shown that none, that very few of the projects are producing anything in excess of a hypothetical allowable restriction that might be placed on them.

Q That being the case, couldn't every water flood in Oklahoma operate under the project allowable such as the Commission staff has proposed?

A This will show that a great many of them can, most of them can, yes.

Q Isn't that correct, that even though water flooding is an old and established practice in Oklahoma, the trend is continually increasing?

A The number of projects?

Q Yes.

A Yes, sir.

MR. PAYNE: That's all, thank you.

MR. PORTER: Mr. McGowan.

BY MR. McGOWAN:

Q Mr. Stiles, so that the Commission might more properly understand some of the figures you have given here, is it not correct that the minute or the day that a water flood permit is issued in Oklahoma that all oil thereafter produced from that acreage subject to that order is automatically classified as water flood oil, whether or not any water is being injected?

A That is correct.

Q That would probably be the explanation for the project you have on your Exhibit 16 that has no injection wells, is that correct?

A That's right.

Q Have you ever had occasion to make an estimate of how much of the total reported water flood oil in Oklahoma is actual water flood oil?

A Well, I do know this, Mr. McGowan, I have said that in the absence of water flooding these 17,136 oil wells now operating in water floods would probably be producing somewhere in the range of two barrels per well per day. Let's say they were all stripper production.

Q Well, now, I think we have that problem in each State, Mr. Stiles. That's not what I was getting at. Were you present at the market demand hearing in Oklahoma about three months ago when the Director of Conservation estimated that between 70 and 80 per-cent of the reported oil was actually water flood oil, and the rest was from projects that had no injection?

A No, sir, I wasn't there. I didn't hear that.

Q I believe other reference was made to the orders restricting water flood, I believe the first order you referred to was that one issued in February of 1958 where the Commission applied eleven percent across the board cut on all production, is that correct, is that the order you are referring to?

A Yes, correct.

Q Do you know of any water flood in Oklahoma that was ever actually restricted under that order?

A No, the Commission left the door wide open for operators at an informal hearing to plead their case for relief from this restriction. I believe that all operators that did appear got the relief they asked for.

Q Did the demand order for the following month contain any continuing restriction on water floods?

A No, sir.

Q I believe the next curtailment order you referred to was an order that was issued in June of 1959 which provided that starting the month of September all water flood projects would be cut ten percent. Is that the order, the second order that you referred to?

A That's correct.

Q Was that ten percent cut ever put in effect?

A No, it was rescinded in the August order.

Q The September order contained no restrictions on water floods?

A No, sir.

Q I believe the next restriction you referred to was the restriction in the most recent market demand order where the allowable was fixed for new water floods as being that allowable that it would have on project basis, based upon the number of wells times the minimum allowable, is that correct?

A That's correct.

Q That order has just recently been put into effect, has it not?

A Yes, sir.

Q Does not that same order contain a provision whereby any operator may file forms and show the M.E.R. of a water flood project?

A Yes, sir.

Q Are you aware, Mr. Stiles, that for some two years the Oklahoma Commission has been holding hearings and various committee studies for the purpose of writing and promulgating new rules and regulations?

A Yes, I am very familiar with those meetings.

Q Are you further familiar that one of the main points that has been discussed at many of those hearings is water flood rules?

A Yes, sir.

Q Were you present at the September meeting, the market demand hearing, pursuant to which this last order you referred to was issued, and did you hear the statement of the Chairman of the Commission that such provision was intended only as an interim provision until new rules were enacted to take care of water floods?

A I was not present personally at that time, but I got the message.

Q Do you know of any water flood project in Oklahoma that has ever been restricted below its minimum efficient producing rate?

A I do not.

MR. PORTER: Does that conclude your testimony, Mr. McGowan?

MR. McGowan: I apologize to the Commission if I have imposed on them. I can take forty-five minutes of your time and establish those facts with a Sinclair witness, but I thought this was easier.

MR. MORGAN: Thank you, Mr. McGowan.

MR. PORTER: Does anyone else have a question? The witness may be excused.

(Witness excused.)

MR. CAMPBELL: I would like to offer Exhibits 14, 15, 16 in evidence.

MR. PORTER: Without objection the exhibits will be received.

MR. CAMPBELL: I would like to call Mr. Yates.

MR. PORTER: Mr. Yates, will you take the stand, please?

GEORGE L. YATES

called as a witness, having been first duly sworn on oath, was examined and testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q State your name, please.

A George L. Yates.

Q Where do you live, Mr. Yates?

A Wichita, Kansas.

Q What is your profession?

A I'm a consulting petroleum engineer.

Q Will you give the Commission a resume of your professional and educational background, please?

A I attended Lehigh University and then later Oklahoma University, where I was awarded a B. S. in Petroleum Engineering in 1934, and 1935 I got a Master's Degree there. Thereafter I was at the University of Pittsburgh as an instructor, and later on as Professor in the Department of Oil and Gas from the Fall of 1935 to Spring of 1943. Then I was in Illinois as a petroleum engineer with an independent drilling contractor for six months; thereafter, in January 1st of 1944 I went to work for the Standard Oil Company of Ohio as a reservoir engineer, and later as a chief of the reserves and evaluation section until the end of October, 1947, at which time I resigned and became a consultant and moved to Wichita, Kansas where I have been in the consulting business up to the present time with our current firm Armstutz and Yates.

Q In your consulting work, have you had occasion to work on water flood projects in the State of Kansas?

A Yes.

Q How long has water flooding been in operation in the State of Kansas, Mr. Yates?

A The law legalizing water flooding in Kansas was passed in 1935. The first legal water flood project was started a few months thereafter. By 1942, the Kansas water flood production averaged about 13,700 barrels per day.

Q Have you prepared some statistics with regard to the present situation on water flood production -- first let me ask you another question. Is Kansas a market demand prorationing State?

A Yes, it is.

Q Have you prepared some statistics with regard to the present situation in the State of Kansas on water flood oil being produced and water flood oil being produced in excess of allowable?

A Yes, I have.

Q I refer you to what has been identified as Exhibit No. 17 and ask you to state what that is, please.

(Exhibit No. 17 marked for identification.)

A Exhibit No. 17 reflects the current Kansas oil production statistics for the first eight months of 1959. You will note that we have three classifications of pools in our proration system in Kansas. One, of the Table B pools which are those, generally speaking, where the average adjusted productivity is greater than 25 barrels per well per day, and the individual wells are assigned allowable based upon productivity and attributable acreage. You will note that the average number of wells in this category for the eight months of 1959 are 6,416, and the production which these wells have made has averaged 121,723 barrels, which is an average of 19 barrels per well per day.

The next classification I call Partially Restricted, or Table C Pools, and these include pools where the average per well production is between 15 and 25 barrels per day. You will note that there are 4,563 wells in that category and their production, average production during 1959 has been 57,033 barrels per day or a per well average of 12 barrels.

The third classification is unprorated or Table D Pools and these include the strippers, and there are 35,377 wells in that category producing an average of four barrels per well per day, or a total of 151,120 barrels.

In total, we have 46,357 wells in Kansas producing an average of seven barrels per well per day on a State-wide basis, or a total daily production of 326,126 barrels.

Q Where do the water flood wells fit into those categories?

A Almost all of your water flood wells are in the Table D group. The four barrel average of that group would be considerably less than that if you took the water floods out of it. There are a few in Table C, and I think possibly one periphery flood and unit in Table B.

(Exhibit No. 18 marked for identification.)

Q I refer you now to what has been identified as Exhibit 18 and ask you to state what those statistics relate to.

A Exhibit No. 18 is a history of a relationship of the water flood to the total oil production in Kansas. You will recall that a little while back I said that the flooding first started in 1935, and that by 1942 there was an estimated average of about 13,700 barrels per day of water flood oil and this increased gradually until 1949, as reflected by Exhibit 18, the bottom figures, there was 19,000 barrels of water flood oil per day, which represented seven percent of the total State production; and this was derived from approximately 150 projects. The number of projects are listed under the projects reported there.

We know there are a few that aren't reported for one reason or another, but these are basically the figures. You'll note that year by year there's, or rather I should put it this way -- there has been a slow upward trend to this water flood production until in 1958, the last year in which the complete statistics are available, there was 47,000 barrels per day of water flood oil being produced in Kansas, which represents 14.25 percent of the total State production, and that came from 240 projects.

Q Do you find it unusual that as the State proceeds with this development of its oil that over a period of that time that the amount of secondarily recovered oil will increase? Isn't that a natural result of depletion of primary reserves?

A Oh, yes.

Q During that period of time, has there been any marked reduction in the rate of exploratory activity for primary reserves in the State of Kansas?

A No, sir, not to my knowledge.

Q Other than those which have resulted elsewhere during the same period, is that correct?

A Yes. Due to general economic conditions, they have nothing to do with the water flood.

Q Do you believe that the water flood projects in the State of Kansas have resulted in a bad effect on the exploratory and drilling activity for primary drilling in those states?

A No, I do not believe they have had any effect.

Q Have you made any attempt to come up with a figure with regard to water flood oil produced in excess of what the top unit allowable or the equivalent may be in the State of Kansas, Mr. Yates?

A Yes. I took the year 1958 and using the reported production and number of oil wells in the projects, and checked all these 240 and found that our minimum allowable, or what would correspond, I guess, to the yardstick figure that the other witnesses have been talking about is twenty-five barrels per well per day, and using that figure I found that out of the 240 projects there were only, there were eleven that produced any excess oil. Yes, eleven water floods produced any excess oil, and tht total amount of excess oil produced by these eleven was 4,000 barrels per day and of this 4,000 barrels per day, 2220 barrels or 57 percent was produced by two floods, and 2780 barrels per day or 71 percent came from three floods, as you had just a very minor number of floods during 1958 which during 1958 were above this figure.

Then when we take the 4,000 barrels of excess over minimum allowable and divide it by the average total daily production in Kansas during 1958, the percentage figure arrived at is 1.22.

Q Mr. Yates, does your concern confine its engineering work exclusively to secondary recovery or water flood projects?

A Did you say "we" --

Q Do you confine your work exclusively to secondary recovery or water flood projects?

A No, sir.

Q You also do engineering work in connection with primary recovery efforts, do you not?

A Yes, I would say more of our work is of that nature than water flood.

Q Has the allowable for water flood in the State of Kansas ever been restricted, Mr. Yates?

A Back, this question became of interest to the Kansas Corporation Commission back in 1957 and at that time there was a hearing held in regard to the feasibility of restricting production from stripper water flood and they decided then that they would not restrict the water flood production from the stripper sand water floods.

Q Did you participate in that hearing?

A Yes, I did.

Q At that time did you testify in the State of Kansas with regard to the Browning Unit?

A Yes, sir.

Q Though you have not previously testified before this Commission in person, your name has been used at a prior hearing in that regard in connection with the Browning Unit and the transcript of testimony in the Graridge case, I believe it is, contains some quotations from your testimony in that case. Have you had occasion to read that portion of the transcript of testimony in the Graridge case?

A Yes, I read briefly.

Q It was used in connection with a discussion as to whether or not the circumstances requiring maximum production from stripper water flood wells were also present in natural water drive reservoir or pressure maintenance projects, as you will recall. Will you state to the Commission what your opinion is with regard to that particular point?

A The question was asked of me why we, why I believe that we could not or should not restrict the production of these stripper water floods, while at the same time the Commission was restricting the production from a very large amount of Arbuckle Pools in the State of Kansas, which are water drive pools. I was asked if that would not be harmful on these water drive pools. My answer was that no, on the contrary it would be helpful. We were dealing with an entirely different situation there, you had a reservoir that was essentially hundred percent saturated with liquids, that is, oil and water. As a matter of fact, the Arbuckle oil has ten to twelve or fifteen cubic foot of gas per barrel in solution, most of it up in the arch country, and a hundred percent of the, almost 100 percent of the energy used to or available to produce this oil is from the water drive, and they have found from past experience in those, and in that connection I well recall that in the earlier days in the late 1937's and the early 1940's it was the practice in Kansas to take physical potentials on all wells and if you wanted a big physical potential on the well, you had to put a large unit on it and tie it down and rev it up and let it go, and physically pump that oil, and during many of these tests on the larger wells, they produced 2,000 and 2,500 and 3,000 barrels a day, actually pumped it; and it was observed that in many cases a well which was initially water free, before the end of that test was producing appreciable quantities of water which had been pulled in due to this rapid rate of withdrawl, creating a pressure differential, a rather sharp one right around the well. So as a matter of fact, I think the restriction on the slower rates on these water drive fields such as that have actually helped to increase their recovery.

Q Why isn't that same situation true in your opinion with regard to stripper water flood?

A Well, in a stripper water flood you have, let's say, thirty percent water saturation and perhaps forty percent oil and the remaining thirty percent is gas. And so in order to produce this oil by water flooding, you've got to provide the energy with the water and in order for the water to work effectively, the push has got to be continuous and hard, and if you let it up, this bank that is built up which is critical to your water flood recovery will be dissipated and in my opinion that push should never let up, it should be continuous insofar as possible at a high rate from the start of the project to the finish of it.

Q Go ahead.

A I was just going to say that the main difference there is you are dealing in one case with a hundred percent fluid saturation condition, hundred percent liquid saturation condition, oil and water, where you have high effective permeabilities to the oil in the water drive reservoirs, and in the stripper depleted reservoirs, you have a much lower effective permeability to your oil and you have got to increase that by ramming it with the water and building up a bank so that it will flow easier.

Q Is it your opinion that if water flood projects are restricted to the point where wells are not permitted to produce at their maximum, that it will result in physical waste?

A Yes, I think so. I think on the basis of the performance of the many floods that I have had occasion to look at over the years, that the better recoveries have generally been from those fields where they have used high injection rates and pressures and I thought that was very well brought out in this Browning Unit history which you mentioned earlier, where for five years they put in water at a low rate and did no good; the decline curve did not deviate from the projected, the projections which was made before the flood started with the remaining primary, and when they finally got their water supply ironed out and had available plenty of water and started to inject it at much more rapid rates, the results were very evident from the performance of that flood.

MR. CAMPBELL: That's all.

MR. PORTER: I believe we will recess the hearing at this time until 1:00 o'clock.

(Whereupon, a recess was taken.)

AFTERNOON SESSION
October 15, 1959 - 1:00 P. M.

MR. PORTER: The meeting will come to order, please. Does anyone have any questions of Mr. Yates? Mr. Hinkle.

CROSS EXAMINATION

BY MR. HINKLE:

Q Will you please refer to your Exhibit No. 18, Mr. Yates. As I understand it, this Exhibit shows relation of water flood and total oil production in the State of Kansas for a ten-year period, from 1949 to 1958, inclusive, is that right?

A Yes, sir.

Q I believe that you stated in your testimony this morning that Kansas had progressed, as far as water flooding is concerned, at a rather slow rate.

A A rather steady rate, I think. I may have said slow or implied that.

Q I understood you to say it had not progressed too fast, but at a slow rate. In your second column you show the barrels per day in 1949, 19,000; in 1958 there were 47,000 produced by waterflood. Now, that shows an increase over the ten-year period of about two and a half times, does it not?

A Yes, sir.

Q Now, your next column you show the percentage of the waterflood produced with relation to the total. In 1949 you show it was seven percent and in 1958 you show it was fourteen and a quarter percent. That amounts to about double what it was in 1949, or double in the ten-year period, is that not right?

A That's correct. One reason for the higher figure during 1958, the high percentages, you'll note that the total oil production in Kansas went down due to the general market situation. I'll say it was more severly restricted than it had been previously.

Q According to your figures, it did show that it did double in the last ten years?

A When you talk about percentages, yes.

Q You have testified that in a natural water drive or pressure maintenance project there is only liquid saturation present, while in the secondary recovery case you have both liquid and gas saturation present. You further stated that this is the principal difference in the two mechanisms. Now, you testified that in the secondary flood it is necessary to push the oil at a high injection rate. Why is it necessary to do this?

A You got to build up that bank of oil and it takes some force to do it. The oil doesn't flow as easily under those conditions as it does under the waterflood. Water drive reservoir, when I was speaking of the water drive reservoirs, you recall I was talking more specifically about the Kansas water drive reservoirs, and there you do have easily one hundred percent fluid saturation at all times on the active drive reservoirs and furthermore they're largely bottom water reservoirs. You get some vertical movement and some lateral movement of your water into the oil reservoir, but largely from the bottom, I would say.

Q Well, now, what happens to the oil bank in a secondary project if it's pushed at a slow rate?

A There are a couple of things that happen. In the first place I don't think it banks up as effectively and in the second place, when you say it's pushed at a slow rate, that implies lower pressures and I don't believe that you get the water into the tighter lower permeable portions of your reservoir, and so you go right on by some of that.

Q In other words, you by-pass some of the oil?

A I think that's correct.

MR. HINKLE: That's all.

MR. PORTER: Anyone else have a question of the witness?

MR. PAYNE: Yes, sir.

MR. PORTER: Mr. Payne.

BY MR. PAYNE:

Q Mr. Yates, do you know whether allowables have declined in Kansas in recent months and recent years?

A Well, when you say allowables, what do you mean? We still have a basic twenty-five barrel minimum there that we have had ever since I have been there and longer.

Q Twenty-five minimum.

A Twenty-five barrel minimum.

Q How do they prorate their wells, don't they have a maximum?

A They have a -- yes, I think there is supposed to be a two hundred barrel well a day maximum figure in Kansas on prorated production.

Q Now, has the --

A There's also, I might add further explanation there, there's also a depth, depth allowable factors below four thousand feet, similar to what you apparently have in New Mexico.

Q There is a figure that's a total allowable for the month, isn't there, for all the prorated wells?

A Yes.

Q Has that figure decreased in recent months or recent years?

A Well, now on Exhibit 17, I have the production on the recent months, that is the first eight months of 1959 and you'll note that there is some decrease there. A portion of that undoubtedly is due to lowering of the allowables, a portion of it also is due to the fact that the good wells, or rather the high productivity wells are rather severely restricted and the poorer wells, of course, if they cannot make their twenty-five barrels in a prorated field, they make what they can, they are allowed to produce what they can, and so that portion of it has become more important. That accounts for the drop in the average barrels per well per day you see here.

Q Well, the average allowable has declined, the average waterflood production has increased, has it not --

A Yes.

Q -- some two hundred forty-seven percent over 1949?

A I mentioned a little while ago in connection with the explanation on Exhibit 18 that the production in the state due to market demand conditions has been rather severely restricted during 1958 and '59 also, and a portion of '57. That's evident in the total state figures you see there.

Q Do you feel that as the allowable declines, there's less incentive for an operator to conduct wildcat operations?

A All I can say is that what's happening there doesn't indicate that that's affected the plans or operations of the people that are doing the wildcatting. There are one hundred forty rigs running in Kansas the last few weeks and that's fairly normal for the state and it's varied from there up to perhaps one hundred fifty or sixty over the past several years. It's been pretty steady except for this one drop during '57 and portions of '58 when everything seemed to have declined development in many areas.

Q If the allowables were doubled, do you think there would be more rigs running than that?

A I would have no opinion on that.

Q I don't know whether you testified to this or not, so correct me if I'm wrong. I believe you testified that you think you should have constant injection rates.

A I said, put it this way -- I believe that I wanted to keep a constant hard push on this thing, which I meant, essentially constant high injection rates.

Q Now, I take it that you feel that the ideal way to produce the waterflood pool is to have a high injection pressure and have no pressure on a producing well, in other words keep it pumped off?

A Yes, but give your greater differential.

Q What is your sweep pattern if you produce them in that manner, is it elliptical?

A Well, I don't know whether that is the exact correct term or not, but somewhat like that I would say.

Q If you used a lower injection rate or back pressured your injection well, wouldn't you increase the diameter of the sweep pattern?

A Would I increase the diameter of the sweep pattern?

A Yes.

A What is the diameter?

Q Of the ellipse.

A Well, I don't think your producing wells begin to affect the ellipse until after you are pressured up because if your reservoirs are depleted, your water is going to tend to move in all directions when you put it in there, I mean radially, and gradually tends to form these cusps, I guess the correct term is.

Q Well, the greater the pressure differential between your producing well and your injection well, the less broad is going to be your pattern of sweep, isn't it, because the oil and water are going to tend to go from the high pressure injection well right straight to the producing well?

A I think it's pretty well established, and you see these little patterns you are talking about, they draw in the laboratories and these articles, these are generally up to a point of water break through, you produce an appreciable amount of oil after your producing well is making water and that area is wide, working out all that time. We do find some dead spots in your five-spot patterns where some oil is collected and I think they have done a fairly considerable amount of drilling up in Bradford on those to try to find out what was there and how much, if it was worth going after, as I understand it, the consensus of their experience was that there was not enough there to justify the drilling of the additional wells. There's undoubtedly some oil in there, not much question about that.

Q If you employed back pressure to a producing well, wouldn't you flush a larger area?

A I don't think so.

MR. PAYNE: Thank you, that's all.

MR. PORTER: Any further questions of this witness? Mr. Sperling.

MR. SPERLING: Mr. Porter, I have just a couple of questions.

BY MR. SPERLING:

Q Mr. Yates, I am J. E. Sperling, representing British-American Oil Producing Company. I have two questions. You testified in your opinion that water drive reservoirs need not be produced at high rates to attain maximum ultimate recovery because of one hundred percent liquid saturation in the reservoir. On the other hand you testified that the relatively high initial free gas saturation in stripper floods is the characteristic which necessitates that these stripper floods be operated at maximum. How much, or at what point do you determine how much free gas saturation should be present in a reservoir in order for the distinguishing feature to be present?

A I couldn't give you a specific figure I don't believe, but in my thinking, it's somewhere in the range of twenty percent upwards.

Q Do you feel that certain water injection projects which are initiated in the volumetric reservoir when it is in a semi-depleted state, when it will require maximum injection rates and maximum production rates in order to obtain the greatest ultimate recovery?

A I'm a little confused by your question. Would you mind restating it?

Q Well, do you feel that when a water injection project is initiated in a volumetric reservoir which is in a semi-depleted state at that time, do you feel that when the injection is initiated that it should be continued at maximum production rates at that time, that is, both injection and withdrawal?

A You say semi-depleted, what do you mean by that, that's partially depleted? How far down are you talking about, are you talking about stuff that's down, almost depleted or stripper?

Q Almost depleted.

A I feel that injection rates should be high and be kept high.

Q There's no particular line at which you fix this point, that is the semi-depletion or stripper, or do you have a definition in mind by which we could determine at what point water injection should be continued at maximum rate in a reservoir which has been depleted?

A I don't have a specific point. I think in order to answer that question I have to look at a specific situation and base my conclusion on what I saw there.

MR. SPERLING: Thank you.

MR. PORTER: Any more questions? Mr. McGowan.

MR. McGOWAN: I would like to ask a couple

BY MR. McGOWAN:

Q Mr. Yates, if you will refer again to your Exhibit 18, I believe that on Cross Examination, Mr. Hinkle and Mr. Payne pointed out that in the ten years shown on that Exhibit, the waterflood total production had increased and that the percentage of waterflood production as opposed to total production had consistently increased, I believe Exhibit 18 also reflects that the total number of projects have increased during that same period of time, is that correct?

A Yes, it is, has increased from one hundred fifty to two hundred forty, increase of ninety projects.

Q Am I correct in assuming from that Exhibit then that the present waterflood production is coming from more wells and more productive acres than it was two years, or five years or nine years ago?

A Oh, yes, very definitely.

Q Is it unusual for a particular designated type of production to increase in total amount as the number of productive wells and productive acres in that designation increases?

A No, not at all.

MR. PORTER: Any more questions? The witness may be excused.

MR. CAMPBELL: I would like to introduce Exhibits 17 and 18 in evidence.

MR. PORTER: Without objection the Exhibits 17 and 18 may be admitted for the record.

(Exhibits 19, 20, 21 and 22 marked for identification.)

GEORGE BUCKLES

called as a witness, being first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q State your name, please. A George Buckles.

Q Where do you live, Mr. Buckles? A Monahans, Texas.

Q What is your profession and your business association?

A I'm the owner of the George L. Buckles Company, which is a consulting firm specializing in waterflood recovery and we're also independent operators.

Q Are you operating at the present time in New Mexico?

A Yes, I have some primary production in New Mexico.

Q Will you give the Commission a brief background of your professional and educational experience?

A My formal education is confined to an A.B. Degree in Economics and a B.S. Degree in Geology. I graduated from the University of Oklahoma in 1932, went to work in the Seminole Oil Fields as a roustabout, and have been in the operating portion of the oil business ever since. In 1945 I specialized one hundred percent to waterflood recovery. I put in the first waterflood owned by the Pure Oil Company in Illinois, moved to west Texas in 1948 and saw the first waterflood for the Forrest Oil Corporation in the State of Texas, that is, the first Forrest waterflood, not the first waterflood in Texas. At that time the Forrest Oil Corporation had produced some seventy million barrels of water flood oil. In 1951 I entered the consulting business with a partner. This partnership was dissolved in June, 1957, and I have been operating the George L. Buckles Company since that time.

Q Then the bulk of your experience in waterflood has been in the West Texas area, is that correct?

A Recently, the waterflood experience I had originally where I had complete charge was in Illinois.

Q Have you become acquainted with the operation of various waterfloods in the West Texas area?

A Yes, sir.

Q Have you personally been responsible for the operation of some of those floods?

A I have.

Q In what pools in West Texas, Mr. Buckles?

A In the Pecos Valley High Gravity Field, Pecos County, the South Ward Field in Ward County, the Kermit Field in Winkler County, the Scarborough Field in Winkler County, the North Scarborough Field in Winkler County.

Q You testified before this Commission in the original hearing in regard to this matter, did you not, Mr. Buckles?

A I did.

Q Would you very briefly, to set the background for your testimony here today, review for the Commission the testimony that you presented at that time?

A In general, I stated that in my business I had become associated with reservoir engineers, waterflood operators and field personnel, and I know their thinking. Waterflooding has always been a controversial subject, but we have, over the years, eliminated some of the controversies. Originally, the controversies including spacing and pattern, well completions, water treating, rates, pressures and so forth. The operators, early in the life of waterflooding, unanimously agreed that waterflooding had to be a continuous uninterrupted operation. During the last fifteen years the big majority of the operators have come to the conclusion that the waterflood oil can be produced by a high pressure waterflood, that is, a high, safe waterflood pressure. It wasn't necessary to know why, except for an academic reason or curiosity, until we come to the recent controversies which involve rates. Now some laboratory technicians and scientists have concluded from laboratory experiments that the rate at which a piece of oil sand or core or assimilated formation is flooded has no relationship to the production that will be produced out of that core. They have applied this to a generalization, to field operations and have stated that, therefore, you do not have to regulate rates in any manner in the field and waterflood production can be prorated. In the face of these contradictory statements you will have to admit that because of the caliber of the people involved and their integrity and intellect, and that they have factually reported what they witnessed; if that is true, both sides must be correct. Then it became necessary to attempt to find why a slow rate flood would not produce as much oil as a high rate flood. In my experience I noted that some wells that we were injecting water into would not take water at a commercial rate while other wells in the same lease, in the same field would.

Q Mr. Buckles, Just a moment. This information that you are going to present here is information that you have obtained by virtue of operations in the field since the last hearing, is it not?

A Yes, sir.

Q Will you go ahead then and refer, if you will, to the extent necessary to what has been identified there as Exhibit 18, or 19, which is a log of a well, and identify where it is and explain to the Commission to what extent it tends to corroborate your previous opinion to this Commission concerning relationship between rate and ultimate recovery?

A Since the hearing I have attempted to find additional field data to support my original contention. In the southern portion of the Kermit Field in Winkler County, Texas, the waterfloods include two zones. This gamma ray neutron log is merely for the purpose to show that there are two zones in this area. The red zone is in the lower Yates Formation and the yellow zone is in the Queen Formation below the Yates. In all of the waterfloods in that area up to recent times, both of these sections were open in the injection wells, and the producers--this particular well is owned by Ambassador Oil Corporation. They are flooding about a half mile north of where I have some operations myself. This flood was instigated in the latter part of 1954 and the early part of 1955. Very recently, that is, in early 1959, the field engineer in charge of this project noted that he was experiencing high water cuts in his producing wells. He took some breakdown pressure curves on these wells and noticed there was a break in the curve in some instances, slightly above six hundred pounds, and concluded that at that pressure the water was going in some other pore space than it was going in before and his principal object in doing this work was to cut down on his high water production. It wasn't specially done to increase production. In the early history of this portion of the Kermit Field it was noted by all operators that the Yates sand which is shown on the Exhibit in red was the tighter of the two pay formations, and this engineer assumed that if he could isolate this and inject into it separately that he might be able to inject higher rates into the upper sand and produce the oil and not increase his injection rate in the lower sand, which would be the case if he merely increased pressure at the injection wellhead. Therefore, he set a packer and a dolomite stringer below the Yates, put in two meter runs and injected water through the annulus into the Yates and through the tubing below the packer into the Queen sand. He found in all instances, and there were several, that the pressures that they were using prior to installing this packer at that pressure, the

Yates sand took no water whatsoever. Therefore, all the water he was injecting had been going into the Queen sand. Now this Yates sand is admittedly tighter and lower permeability, but the porosity is sufficient to produce large quantities of oil and if this condition had been allowed to continue, it is conceivable that the operators in that area would have flooded out the Queen sand entirely without producing any water flood oil from the Yates and thereby losing the oil. This also corroborates my contention that the tighter sands in any formation, and formations of a high range of permeability, that until you get sufficient pressure to make all of these sands take water that you will eventually lose oil, and if rates are restricted in any manner arbitrarily it would tend to lose ultimate oil recovery in any waterflood.

Q Does this example tend to corroborate your previous opinion with regard to the imbibition of water by oil sands of low permeability?

A I testified in the original Graridge hearing that in all of the tests I made pesonally of cores taken from the Yates sand and the Queen sand that there was no imbibition in these sands. In other words, where they came in saturated core, coming in contact with water for any period of time, the water did not enter the core and force oil out, so I assumed that there was no such thing as imbibition, in at least the Yates and Queen sands that I examined and this corroborates my testimony one hundred percent.

Q Have you observed any further examples with regard to the testimony you gave at the previous hearing?

A It has been contended that even though my contention is correct that it takes higher pressures to inject water into these high permeable sands, it has been suggested that, why not set a rate, an injection rate and later increase this rate to maintain a certain rate of production and eventually you would produce all of your oil through gradually increasing higher pressures. This next Exhibit --

Q Just a minute, let's get this other one in first. I hand you what has been identified as Exhibit No. 20 and ask you to state what that is, please.

A This Exhibit 20 is a plat showing the location of the two leases as shown in each one of these exhibits. The top exhibit is the production, the waterflood production history of the twenty-acre lease at the bottom of the plat. The lower exhibit is the waterflood production history of the north forty-acre lease. These exhibits are for the purpose of explaining what might happen, and often does happen, in the event we attempt to inject water at low pressures and later increase the pressures to produce the oil that was not produced at the lower pressures. Now, it's been the history of waterfloods in general in the South Ward Field, the North Ward Estes Field and the Kermit Field and other Permian sand fields in West Texas, that if the wells were originally drilled approximately at the same time and produced on the same spacing that the water floodproduction was in some proportion to the primary production. In other words, if one lease produced an equal primary production to another lease, the water flood production from the two leases would be identical. These leases here were both in the same section, were both put under forty acre, I mean twenty acre five spot waterflood pattern, the well spacing was one well to each ten acres, the primary production is very similar. In other words, the twenty acre lease, the primary production amounted to two hundred forty-seven thousand barrels, the primary production from the south' from the north lease or the forty acre lease was two hundred fifty-one thousand barrels, almost identical. These leases were produced down to approximate economic limit of less than two barrels per well per day before this waterflood was installed. We anticipated that the accumulated waterflood production from these leases would be approximately the same. The operators in this area, when these water floods were instigated, made an agreement among themselves to curtail injection rates to approximately three hundred barrels per well per day after fluid fill-up. In other words, after the producing well started to increase in production they had agreed to limit it to approximately three hundred barrels per day. Therefore, their plants were built to accommodate this amount of injection water, their producing equipment was installed to produce this amount of fluid. I strongly objected to it at the time because I had an interest in both of these leases and also I had a royalty interest in the entire section or the entire Hathaway lease. I explained at the time that if we limited this injection rate to three hundred barrels a day in the lower lease which had approximately twice the thickness of pay as the north lease, that we would have approximately half of the rate and possibly no injection pressures at the surface. Therefore, we would flood out only the permeable sand and would by-pass the tight sands which contained, in my opinion, approximately the same amount of oil per acre foot as the permeable sands. In the north lease it wasn't a problem, but I'll explain the history of these two floods. The blue line on the left is the water injection in rate in barrels per day injected into the lease during the early stages of high injection. We considered this as fillup. Now this lease, incidentally, is the twenty-acre lease at the south of the section. Now it took approximately almost a year and a half of injecting at those high rates to get an increase in production at the producing well. Simultaneously with oil production at the producing well, it started producing water with the oil. The oil production increased to a maximum of about one hundred thirty-five barrels a day and took a rather sharp drop. The water production itself increased enormously to approximately four hundred fifty barrels per day from this well. You'll notice at the top we have a pressure curve, this pressure line here is zero, so no pressure was inserted on this wellhead until the early part of 1958. At that time we had produced an enormous quantity of water and had a very, very gradual decline in producing rates from one hundred thirty-five barrels down to about sixty, which it is at the present time producing four hundred fifty barrels of water per day. During the latter stages of this flood, or say in the early part of 1958, the injection rate was increased considerably and also the well started showing pressure. Now, if the theory is correct that we can apply this pressure at a later date and get our oil you can notice that this injection did not affect at all the general slope of the oil production curve, so I maintain that it's dangerous to assume that we can later inject higher pressures and produce the oil that we would have produced if the higher pressures were instigated in the early part of the flood. It indicates to me that this particular well the water was going into the more permeable streaks in the sand and since we had no surface pressure and unknown pressure at the sand face, which is an unknown hydrostatic pressure, that the tight sands were not taking any water. The lower curve is the production from the north forty-acre lease. Water injection there was started in the latter part of 1954. Now, there has been injection on the lease to the west which probably stimulated this production just prior to the time that water was injected onto this lease, however, workover jobs also contributed to the early increase in production in the last half of 1958. But you'll notice that the red line or the producing line went up at a rather rapid rate to a maximum production of about three hundred seventy barrels per day and took a gradual decline. It was approximately a year later in this particular lease that we produced any water at all with the oil. But you'll notice from the pressure line that we had pressure from the beginning of this flood, therefore, since this sand was about half as thick, as evidenced by primary production, since we had surface pressure to make this well take water, that we had pressures sufficient to inject water into the tighter pay sand in this area, that was not true of the other lease. Now the waterflood production to the present time from the north lease, which is the forty-acre lease, is three hundred sixty-eight thousand barrels. From the beginning of waterflood on the south lease, which we expected to be the same, it amounted to one hundred forty-eight thousand barrels. Now, it's inconceivable to me that we can in later years produce that oil on this lease that we have already by-passed.

Q Does that confirm your opinion that the difference in the rate on the south forty, south tract had an effect upon the ultimate recovery of oil from that tract?

A In this manner, Mr. Campbell, the rate was insufficient to put enough pressure on the sands in this well to make the tighter sands take any water and to me it's a matter of pressure or pressure drop rather than rate, as such, since the rate was the same per well in this instance and the sand was twice as thick or the area to produce was twice as good as it was in the north lease, the rate was insufficient to create a pressure on this pay sand in this well to let it produce waterflood oil.

MR. CAMPBELL: That's all.

MR. PORTER: Any questions of the witness? What are these Exhibit numbers?

MR. CAMPBELL: The Hathaway lease No. 2 is 21, the Hathaway Lease No. 1 is 22. The log which I didn't distribute copies on is number 19 and the plat number 20.

MR. PORTER: Thank you.

CROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Buckles, referring to your Exhibit No. 20, which shows the North Harlan and the South Harlan leases, how many acres in the North Harlan lease?

A Forty.

Q How many acres in the South Harlan?

A Twenty.

Q What was the date which each flood was begun, that is the flood on the North Harlan and the flood on the South Harlan?

A On the South Harlan lease September 1953, on the north Harlan lease in December 1954.

Q There was about a year's difference then in the time they were commenced?

A Yes, sir.

Q What is the recovery to date from each project expressed in barrels per acre?

A Roughly seven thousand four hundred barrels per acre for the twenty-acre lease.

Q How much was that?

A Seven thousand four hundred barrels and nine thousand seven hundred from the forty acre lease.

Q Are both of these floods depleted or either one of them depleted?

A No, sir.

Q They both have some oil to be produced yet?

A Yes, sir.

MR. HINKLE: That's all.

BY MR. PAYNE:

Q Mr. Buckles, Lease No. 1 has twice the acreage in it that lease No. 2 has, has it not?

A Yes, sir.

Q Yet on primary the production was just about the same?

A Yes, sir.

Q Does it stand to reason that the No. 2 lease simply produced more of the oil that was under it on primary?

A Per acre foot, no, sir.

Q How much original oil was in place under each one of these leases?

A I don't know, I would have to calculate it. I would say that it was approximately, stock tank oil, approximately sixty-five percent of the pore space.

Q How much residual oil saturation under each lease?

A Now?

Q No, at the beginning of the flood.

A I would say at least fifty percent. We find that these leases here in this area under a complete primary program, the way they were completed, which means the pipe was set on top and the wells were shot and cleaned out and produced, the economic limit would be approximately fifteen percent of pore space, if they were drilled on ten acre spacing.

Q You feel then that it was the same under each lease, the residual oil saturation?

A Approximately.

Q Now you have heard the testimony here today that each well is an individual, that no two are alike, that no two leases are alike and no two reservoirs are entirely alike, do you agree with that?

A Yes, sir.

Q Could this not explain why one lease would produce more than another on secondary recovery?

A No, sir.

Q Why not?

A I believe I testified that the history of the water-flood production in this area had the same relationship to primary production regardless of what that was if the wells were drilled on twenty acre spacing and approximately the same time. We expected the secondary recovery to be in the same percentage of primary recovery on each lease.

Q From some of your opening remarks, Mr. Buckles, I took it that you are not too impressed with laboratory experiments regarding waterfloods, is that a fair statement?

A Well --

Q I mean you are more impressed with seeing how the field actually responds rather than experiments in the laboratory?

A Yes, sir, I think it's more indicative of what happens if you can have accurate field histories. These laboratory experiments are very necessary and somebody is going to come up with something that's very valuable, but today I feel that field experience is far a better yardstick of what a lease will do than laboratory experiments.

Q How did you determine that capillary imbibition is something that can practically be ignored in waterfloods, at least in the Yates and Queen --

A I read an article in one of the Trade Journals, I believe it was the Oil and Gas Journal, where a Company took several cores from the Grayburg formation --

Q Isn't that a laboratory experiment?

A Yes, they put these cores under water and took X-rays of them at various intervals and tended to show that the water imbibed, the cores, imbibed water and forced the oil out. I made the same experiment on some Yates sand cores and Queen sand cores that were fairly well saturated with oil and left them under water for several weeks and no oil came out. That's the conclusion they drew, that they would not imbibe water. The experiment, I believe, was about the same.

MR. PAYNE: That's all, thank you.

MR. PORTER: Any further questions of this witness? Mr. Dutton.

BY MR. DUTTON:

Q Mr. Buckles, as the first point, on the log up there, wouldn't you say that the section designated in the red and the section designated in yellow each constitute a separate source of supply?

A Yes.

Q Isn't it fairly uniform engineering procedure to treat the development and production of each separate source of supply separately?

A In new fields I believe that would be correct. However, in this particular field these wells were drilled back in the early thirties and the Railroad Commission of Texas included both these zones as a common reservoir, even though they were actually separated by a considerable distance, some dolomite streaks and thin shale stringer, tight sand stringers, they considered them as one reservoir. Now, it was the practice in those days to shoot these wells with nitroglycerin and clean them out and to isolate these two zones. Later, on the old wells, it was considered impractical to attempt to set through and perforate because due to the big shock holes they felt the perforations would not penetrate the cement, so in waterflooding they continued in primary in early waterflooding up until very recently and decided to waterflood this zone all at the same time. Now, if rates or pressures made no difference it would never make any difference to keep these zones open simultaneously if you could keep them clean and open.

Q In other words, if you were developing this particular well today with the same situation, you would leave the two open?

A No, sir, I would separate them if I could.

Q You mentioned in your testimony, I hope that I'm quoting it properly, that if you arbitrarily reduced the production from a waterflood project would result in waste.

A I may have used the wrong word. Any restriction in rate, in my opinion, arbitrary or otherwise, would result in a lower element of recovery.

Q So any reduction, you didn't mean to use the word arbitrary?

A Possibly not.

Q With respect to this comparison of the twenty-acre and forty-acre lease, have either one of those reached ultimate recovery yet?

A No. This forty acre lease right now is producing about a hundred and twenty barrels a day of oil and about, I would say eight hundred seventy barrels of water a day. The north lease, that is the south lease, the twenty acre lease is producing about sixty barrels of oil and about four hundred fifty barrels of water per day.

Q In fact, in all of your field experience, this sounds completely obvious, but I think we should make the point, you have never produced an oil field reservoir to its ultimate recovery at one rate of injection and production and then re-instituted the initial conditions and produced it a second time at a different rate of recovery, have you?

A No, sir. May I elaborate on that?

Q Surely, I wish you would because it confuses me how you can conclude anything about ultimate recovery without ever having reached it.

A If you flooded one field to economic limit in a waterflood and it's a good waterflood prospect, and took a similar field and flooded it to economic limit, you would waste a lifetime, the way we determine those things and most of these conclusions we come to are caused by accidents. Several years ago and even today many operators flood their fields by volume, in other words, they calculate how much each well should take. In many instances it's the same rate as in this case, set at an arbitrary figure of three hundred barrels per day after fill-up.

I have observed many floods where they were conducted in that manner and many wells in this flood would have more permeable streaks and thicker sands than others, but they all took approximately the same rate of water and disregarding pressures then, I have observed the production history of the five spots that were in the regular area that had no pressure against the five spots that we had to put pressure on to make them take that amount of water. In every instance the ones that were flooded with the higher rate responded much better and from extrapolation of curves and economic limits we could not help but come to the conclusion that ultimate oil would be lost. Then most of the operators, I don't say most of them, but we tried to operate our floods at the same bottomhole pressure regardless of rate to balance the flood, and make these tight sections take water.

Q Then you clearly believe that you can establish a comparison between waterfloods that would allow you to conclude from one waterflood what is going to happen in another?

A Yes, sir.

Q Were you here when Mr. Buckwalter testified essentially to the contrary?

A As far as I know my testimony has not contradicted Mr. Buckwalter's in any manner.

Q He mentioned that merely because one waterflood was successful in a particular formation you could not assume that another one in the same formation, in fact, he said even another well in the same project area, do you recall that testimony?

A Yes.

Q You don't think that is contradictory to your comparisons that you made?

A I think what Mr. Buckwalter meant, and the way I interpret that to be, is that he wasn't talking about very similar conditions. That is, I believe that Mr. Buckwalter, or I would say, that if the conditions were the same that the second area will flood, he meant that there is a great deal of variation between bottomhole conditions from one well to another or from one field to another.

Q Yes, sir, well, now then with respect to southeastern New Mexico you have heard the testimony as to whether or not the addition of new floods would create an impact upon the allowable. Judging by the Caprock Queen success, would you say that the increase in the number of floods would increase the amount of allowable produced in excess of the top unit allowable?

A You say, would it increase the amount of oil in excess of the top allowable?

A Yes, sir.

A Yes, sir.

Q You think it would?

A Yes, sir.

Q One last question, sir, hypothetical nature, if we should assume for the moment that there were no differences in the ultimate recovery between recovering the oil at a low rate and at a high rate, in your opinion, which project would result in the greater profit to the operator?

A The high rate or the low rate?

Q Yes.

A Obviously the high rate.

MR. DUTTON: Thank you.

MR. PORTER: Any further questions of this witness? You may be excused.

MR. CAMPBELL: I have one more witness, very brief, Mr. Russell.

I would also like to introduce in evidence Exhibits Nos. 19, 20, 21, and 22.

MR. PORTER: Without objection the Exhibits will be admitted.

JAMES E, RUSSELL

called as a witness, being first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. CAMPBELL:

Q State your name, please. A James E. Russell.

Q Where do you live? A Abilene, Texas

Q What is your profession and business association?

A I'm a Petroleum Engineer, owner of Russell Engineer Consulting Firm specializing in waterflooding.

Q Would you give the Commission a brief resume of your educational, professional background?

A Just to dispel any fears of whether I'm old enough to testify, I am forty-two. Some people have asked me how old I am. Started working in the oil fields at an early age back in the early thirties, drilling and production operations in Kansas, was graduated from the University of Kansas in 1941 with a B.S. Degree in Petroleum Engineering. I worked for the Texas Company, South Texas Division during two summer vacations and after graduation until entering the Air Force in 1942. In the late thirties I participated in the installation of one of the first floods in Kansas. Upon leaving the Air Force I worked for Urlocker Engineering in Tulsa until 1948, when I entered my own consulting practice. Came to Abilene, Texas in 1949 and I have been in the consulting business in Abilene since.

Q Have you had occasion in connection with your consulting work to work on waterflood operations in this area?

A I have.

Q Is your firm presently engaged in consulting work in connection with any waterfloods in the State of New Mexico?

A Yes, sir, we are.

Q Which one?

A At the present time the Coyote Queen Field or pool in Chavez County and we have done work and are still doing work from time to time on the High Lonesome Field.

Q During the course of your experience in waterfloods as a consulting engineer, Mr. Russell,have you formed an opinion as to the rate production relationship that has been discussed here today and the many other places, many other times?

A Yes, sir, I have.

Q What is your opinion in that regard?

A It is my opinion that high rates and pressures are more effective in recovering the ultimate oil that's in a reservoir and will no doubt prevent the waste of petroleum.

Q What is your opinion with regard to producing rates on the producing well?

A In my experience where wells have not been pumped to capacity there is strong evidence that oil is being lost.

Q Have you recently had any occasion in the work you are doing with regard to perhaps adding some evidence to support the conclusions that you have just expressed?

A Yes, sir, I have.

(Exhibit No. 23 marked for identification.)

Q Just a minute. I have handed you what has been marked Exhibit No. 23. Will you please state what that is and explain it to the Commission in relation to the question I asked you concerning the opinion you just stated?

A Exhibit 23 is a core graph of an injection well which has been drilled in a pilot flood area in Jones County, Texas.

This well was drilled in conjunction with several other wells in the area. It is a typical core graph of wells in this particular area. The formation is composed of both sand and limestone. In the laboratory, ordinary and conventional analyses were run on this core. On this particular well the average permeability was two hundred seventy-two millidarcies in the sand. The average permeability of the limestone was 5.6 millidarcies. Representative samples were also subjected to laboratory flood pot tests and the results of these tests were normal, in our opinion, for the type of formation involved and on the basis of the cores that we took, the tests that we ran in the laboratory, we decided to institute a pilot waterflood. The four wells were completed with four and a half inch casing and injection started into these wells after perforating both the sand and the limestone sections, however, because of the nature of the reservoir, both sand and lime, we left provision by spacing our perforations at the contact between both formations so that a packer could be set if necessary. Injection was started and after several months premature production was noticed at some of the oil wells and it was decided to run some impeller surveys in these injection wells to see what the injection performance was doing. This particular Exhibit illustrates in one well, No. 1, that through most of the entire sandstone section at an injection rate of 625, injection pressure of one hundred pounds per square inch, that a very small portion of the injected water was going into the sand. About ninety percent of the water injected was going into the lower, lower permeability limestone.

This Exhibit illustrates that taking laboratory results of core analyses directly to the field can sometimes be misleading. I don't want to leave the impression that all of these wells exhibited this same performance, only two out of the four showed this performance and so, to further check the injectivity of this particular well a string of tubing on a packer was set in the spacer between the two sets of perforations and injection again commenced and it was found that by increasing the wellhead pressures to as high as six hundred fifty pounds per square inch that reasonable rates of injection could be obtained into the sand.

Q Did this tend to confirm your opinion that at least in this particular situation there is a relationship between rate and the ability to flush the sands in the reservoir?

A I might state it this way, that in this particular well at the low rates of injection we were by-passing a considerable amount of productive formation, and that had we continued to inject into this well at this rate and at this pressure we would have by-passed a considerable amount of oil and would have had an early abandonment of reserves in this particular area.

MR. CAMPBELL: That's all

MR. PORTER: Any questions of Mr. Russell?

CROSS EXAMINATION

BY MR. HINKLE:

Q Mr. Russell. A Yes, sir.

Q Referring to your Exhibit No. 23, in the Jones County well in that Exhibit you were really dealing with two reservoirs, is that right?

A Lithologically you are correct, sir. These were two reservoirs, however, are contiguous in connection.

Q The upper one was the sand reservoir and the other the limestone reservoir?

A That is correct.

Q Had you conducted your spinner or impeller surveys on the same well over a number of years or just do it one time?

A No, sir, this is a relatively new well and this is the first test made on this well.

Q Have you conducted the impeller surveys in other wells?

A On this lease?

Q No, just generally.

A Generally, yes, sir.

Q Have you had experience with them?

A Yes, sir.

Q Do you find that the profile changes from time to time?

A Yes, sir.

MR. HINKLE: That's all.

MR. PAYNE: No questions.

MR. PORTER: Any further questions of this witness? Mr. Dutton.

BY MR. DUTTON:

Q Granville Dutton Sun Oil Company. Mr. Russell, I understand that you are of the same opinion as Mr. Buckles that laboratory data cannot be utilized to judge field performance, is that correct?

A Not exactly, I think that the laboratory data must be used judicially.

Q And in this judicial use of laboratory data do you feel that in this particular area, particularly in your New Mexico Reservoir, that there will be no imbibition or does the judicial use indicate there will be?

A I have made no experimental tests insofar as imbibition is concerned.

Q Well, the next question that I probably should have been asking all the witnesses, but I didn't realize there was a difference of opinion from the opponents to the rule, but what is your position, if you can compare the performance of one waterflood in determining what the second is likely to do?

A I think that when you use the method of comparison of one flood that has already performed against a lease or a project that you intend to put under flood that certainly the performance of that flood and a comparison of the reservoir characteristics in that flood is a good indication to use.

Q Yes, sir.

A In other words, if you are in a new area where you have no prior performance you have less information to be guided by.

Q Now, if we can return from Texas, Kansas, Oklahoma for a moment to our experience here in New Mexico, is it your opinion that the capacity waterfloods will continue to contribute production in excess of the normal unit allowable to offset the market demand for southeast New Mexico crude?

A I can only speak for certain floods with which I am familiar in southeastern New Mexico, and it is my opinion that the reservoir characteristics of those particular floods are such that the producing rates will not have considerable influence upon the market.

Q Then, actually there would be no detriment to these floods that you anticipate if the proposed rule were adopted, is that correct?

A I think under those conditions that is correct.

MR. DUTTON: Thank you.

MR. PORTER: Any other further questions of the witness?

MR. McGOWAN: I would like to make one statement. I think it should be recognized that the testimony of the various witnesses as disclosed in the record will reveal whether there is a conflict or not, rather than a stated assumption by an examining attorney.

MR. PORTER: The witness may be excused.

MR. CAMPBELL. That's all I have at this time. I would like to offer in evidence Exhibit No. 23.

MR. PORTER: Without objection, Exhibit 23 will be admitted.

I would like to ask at this time will there be further testimony in favor of capacity allowables?

MR. HOLL: If the Commission please, we have one witness that will be along this nature with some modification. Our testimony shouldn't take over ten minutes.

MR. McGOWAN: It isn't our present intention to put on testimony unless by reason of other testimony we deem it necessary, because of our testimony in the previous Graridge hearing which is part of this record, and it is our present intention not to put on any testimony. We may deem it necessary should some controversy develop over our previous testimony, which is a part of this record.

MR. PORTER: Right now we're going to take a ten minute break.

(Recess.)

MR. PORTER: The hearing will come to order, please. Mr. Holl.

MR. HOLL: I don't believe our witness has been sworn, Mr. Chairman.

E. E. FUNK

called as a witness, being first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. HOLL:

Q Would you state your name, please?

A E. E. Funk.

Q By whom are you employed?

A Cities Service Oil Company, Bartlesville, Oklahoma.

Q In what capacity?

A Chief Secondary Recovery Engineer.

Q Mr. Funk, will you briefly recite your educational and professional background?

A I received a B.S. in Chemical Engineering from Kansas State College in 1935, been employed by Cities Service Oil Company in various capacities since early in 1936. For the past eleven years I've been working in the present capacity in a section which has certainly been a growing section due to the increasing amount of waterflood oil that Cities Service has. I have testified before, do I need to go any further?

Q You have previously testified before this Commission in that capacity?

A Yes, I have.

Q Now, Mr. Funk, in connection with the matter that's before this Commission have you made a study and do you have an opinion and any information that you would like to give to this Commission?

A I merely wish to read a statement which would serve as prepared testimony:

"Cities Service, as a fully integrated oil company, producing much of its oil by secondary methods, wishes to compliment the staff of the New Mexico Oil Conservation Commission for proposing rules designed to regulate waterfloods so that these projects will receive their fair share of the State's allowed oil production

From our experience, operating a number of waterflood projects, we conclude that oil production rates can be controlled on many waterflood projects on a long term basis if the operator is informed of the control in advance and if the operator is given permission to develop his project in stages so that stimulated wells produce at capacity while the project as a whole does not exceed a pre-set oil production rate. The project production rate to be fair and workable, should be the standard state spacing unit allowable times the number of developed spacing units in the project without regard to each well's actual use or performance. This same level of oil production on a project basis is also fair and workable and should be applied to all other injection processes whether called secondary recovery or primary pressure maintenance and for all commonly injected fluids such as air, gas, LPG, and water

The operator needs considerable leeway on development rate to permit him to initiate timely cooperative injection agreements with adjacent operators and to permit the use of peripheral or line drive injection well arrangements if such arrangements are deemed better than a pattern arrangement for the particular project.

A system of assigning allowables on a project basis is best suited to large projects. To This end it is recommended that the Legislature be asked to amend the statutes to authorize the Commission to conduct hearings, and after finding that the basis proposed is fair and reasonable, issue orders setting up a unitized project for a logical unit area in which a representative majority of the owners have voluntarily agreed to unitize.

We also recognize that in any recovery system conditions may arise under which special allowables and exceptions to the rules are necessary to protect correlative rights or prevent waste. The necessity for special treatment should be established through the normal hearing and Commission order procedure."

Q Now, Mr. Funk, do you care at this time to make any other observations that you deem pertinent to this matter?

A Oh, I think the issue has been thoroughly covered.

MR. HOLL: That's all the questions I have of this witness.

MR. PORTER: Does anyone have a question of the witness? Mr. Campbell.

CROSS EXAMINATION

BY MR. CAMPBELL:

Q Mr. Funk, am I correct in interpreting your statement, that as an engineer for Cities Service, you consider that it is necessary to produce the producing wells in a waterflood at the maximum rate in order to obtain the greatest ultimate recovery?

A The stimulated wells, yes.

Q Do you believe it is necessary once the rate is attained that it is necessary to continue to operate the project in that fashion?

A I think it is advisable to maintain a rate once it has been established.

Q Do you believe that that is necessary in order to prevent waste?

A In the majority of the cases that I can think of, I would answer, yes. I wish to qualify that slightly. I believe there are a few cases where the rate might be adjusted, might be reduced during the life of the flood without suffering an ultimate loss. However, those few cases cannot be determined in advance since we can't ascertain before hand that there is, or is not, going to be any losses. It's dangerous to ever reduce rates.

Q As I understand, you are suggesting to the Commission, I wasn't quite certain whether you were agreeing with the project area proposal that has been made here, or whether you are referring to a different matter when you speak of project. Do you mean to say a unitized area is the project area, or do you mean the area referred to in the proposal here?

A I mean to differ slightly with the proposed rules. I'm thinking in terms of a unit area or a large lease rather than just the wells that are involved in the injection program, either as input wells or directly offsetting input wells.

Q And, of course, as you indicated, that assumes under your engineering opinion that you have enough acreage so that under the formula you are able to produce your stimulated wells at maximum rates, does it not?

A That is correct and that is why we recognize the need for an aid to unitization to obtain the necessary large project.

Q What is it that you propose to do pending such time as you may be able, or others, to convince the Legislature that a compulsory pooling unitization statute should be enacted?

A About all you can do is to endeavor to work out your large project voluntarily, which is what we have done in the few cases we are interested in, in New Mexico.

Q In your experience in connection with working out the formation of voluntary units, do you occasionally run into difficulty with regard to unitizing sizable areas, Mr. Funk?

A We always do.

Q And if that situation occurs and it is impossible to obtain voluntary unitization over an area large enough to give maximum production to the stimulated wells, would you then propose that the Commission have a hearing to determine whether such exception is necessary to the rule that you suggest?

A I would say that's a correct procedure, yes.

MR. CAMPBELL: That's all.

MR. PORTER: Does anyone else have a question of the witness?

MR. PAYNE: Yes sir.

MR. PORTER: Mr. Payne.

BY MR. PAYNE:

Q Mr. Funk, I believe that you testified that in certain instances you could probably curtail the rate of production in a waterflood below that it had been producing at, without causing waste, but in a majority you could not. What are the physical factors that determine whether you can, or cannot, cut back without causing waste?

A Well, I think my testimony almost implied that we don't know all the factors that are involved there. If we did, I think I could answer your question for you.

Q Well, we don't know the factors that are involved, how do we know that it ever causes waste to cut them back?

A That is based on performance experience. As one of the earlier witnesses testified, you don't find these things out purposely, you find them out accidentally, and unfortunately many things occur which causes a waterflood at one time or another to have a reduction in input rate and when those events occur, why it is pretty obvious from the performance that you did, or did not, suffer any ultimate loss.

Q In other words, the performance data also indicates that in some instances there is no loss of ultimate oil?

A That is correct.

MR. PAYNE: That's all, thank you.

MR. PORTER: Anyone else have a question? Mr. Dutton.

BY MR. DUTTON:

Q Mr. Funk, I understood at the beginning of your statement that you had a reference to the fact that if such advance knowledge were had of a rate reduction within a waterflood, that such reduction could probably be effected without loss, did I misunderstand your statement, and if so, would you clarify what you did say?

A You misunderstood. I was referring to controlling the production from a unitized or waterflood project that the allowed rate of production could be set and the operator, knowing that that rate was what he had to look at, could develop only his project, could stay within that allowed rate and still operate at what he considers the efficient input rate and operate his oil wells or producing wells at their fluid production capacity.

Q Of course, knowing that a statewide rule existed which stated such rate, it would allow him to evaluate that, would it not?

A Yes, it would.

Q As a matter of interest, Mr. Funk, were you present two years ago when Case No. 1324, Graridge, I believe, initial application for capacity waterflood was held?

A I was not.

Q Our records indicate that at that time your company opposed that application for capacity waterflood, is that correct, to your knowledge?

A I am not absolutely certain what the statement was that was made at that time. I would say that the Cities Service position is essentially the same now as it was then.

MR. DUTTON: Thank you.

MR. PORTER: Any further questions of this witness? The witness may be excused. Mr. Hunter, just one moment, please. Mr. Holl, does that conclude your testimony?

MR. HOLL: Yes, sir, it does.

MR. PORTER: I have a request from Mr. Hunter that he would like to make a statement for Phillips Petroleum Company. Mr. Hunter.

MR. HUNTER: My name is S. S. Hunter, Director of Secondary Recovery for Phillips Petroleum Company. I find myself out of pocket for an attorney today and have asked the indulgence of the Commission to let us introduce a statement into the record. If it becomes necessary to restrict oil production from waterflood projects, we would like, in New Mexico, we would like to suggest that the Commission consider a basis of regulation essentially as outlined by Mr. Funk. That is, an operator or group of operators would come before the Commission and have a project delineated and allowable established based on the developed proration units within that project. To us that would give the operator the elective of conducting that operation as he sees fit. There are operators who believe in a periphery type drive. There are others who like the five-spot or the line drive. An operator might elect to convert all of the proposed input wells and inject at low rates, that would be his prerogative. Another operator might prefer to develop only a portion of it, inject at high rates and produce his well to capacity. They would be permitted to follow that so long as they stayed within their allowable granted. We also recognize that such an approach is not going to solve all of the problems, some of those that have been mentioned here, instances where you are unable to unitize. It may be that a project may have to be a hundred sixty acre tract. We have been successful in other parts of the country of conducting waterfloods on a cooperative basis, although we prefer and think the best approach is a unitized basis. In any event we think that provision should be made for hearings in hardship cases or unusual cases where the general rule would not be applicable. I doubt that any rule can be established that would cover every conceivable circumstance.

MR. PORTER: Thank you, Mr. Hunter. We've heard testimony from Mr. Nutter who proposed the rule. We have heard testimony from those who favor capacity allowables. At this time we'll hear from anyone who has any other proposal. Mr. Hinkle.

MR. HINKLE: If the Commission please, the Humble has different rules to propose than those proposed by Mr. Nutter, and that's the reason we find ourselves in this order of procedure announced by the Commission. At the outset I would like to commend the Commission and Mr. Nutter for proposing these rules and calling this hearing and giving an opportunity to everybody to be heard after two years of trial on the policy of the Commission in granting capacity allowables, we have several witnesses, three of them we can have sworn at this time. Our first witness is Dr. C.R. Hocott, who appeared as a witness at the Graridge hearing two years ago. He has with him the same exhibits that were introduced in evidence at the last hearing; insofar as some of them are concerned, in order to save time and inasmuch as the Graridge transcript has been made a part of this hearing, Dr. Hoctott will eliminate from his testimony the first seven exhibits, which I believe were introduced in evidence in the Graridge case. However, they are here and if anybody wants to question Dr. Hocott concerning those exhibits, we will welcome the opportunity for them to do so. Dr. Hocott's testimony will be confined to new research data and exhibits that have been compiled as a result of studies which have been made since the Graridge case two years ago. I would like to have sworn at this time Dr. Hocott, Mr. Greenwald and Roy Bass and Frank Cole.

MR. HINKLE: Dr. Hocott, will you please take the stand.

CLAUDE HOCOTT

called as a witness, being first duly sworn on oath, testified as follows:

DIRECT EXAMINATION

BY MR. HINKLE:

Q State your name, please.

A Claude Hocott.

Q By whom are you employed?

A Humble Oil and Refining Company.

Q In what capacity?

A As a Research Director, Production Department.

Q Are you the same C.R. Hocott who testified on behalf of Humble before the Commission in October 1957 in the Graridge case.

A I am.

Q Since giving your testimony in the Graridge case in October 1957, have you continued your research program with respect to the effect of injection rates in connection with waterflood projects?

A That has been a part of our research program, yes.

MR. HINKLE: Are the qualifications acceptable?

MR. PORTER: Yes, sir.

Q Dr. Hocott, have you prepared Exhibits as a result of your laboratory research since your testimony in the Graridge case?

A Yes, I have prepared for this hearing some additional exhibits covering additional pertinent experimental evidence based on our own research since that time, plus some published information from other research establishments. I might say that it has been my purpose in the Exhibits that I have prepared to present such pertinent experimental evidence as will at least partially, or tend to answer some of the questions that have been raised in regard to recovery from secondary oil projects. I find myself, if possible, somewhat more confused today than before, because there actually are, I guess, more sides to this question than I had thought and I'm not sure that it will be possible for me to try to, out of these exhibits, to adduce conclusions that will bear on some of the technical aspects. However, I will try to explore as many of them as are possible. I would like to say as a preliminary statement with regard to these Exhibits that it is my opinion that there is very definitely a rate effect in the displacement process of oil and gas by water from normal reservoirs, and I think that it is possible to make a general statement that for normal heterogeneous reservoirs such as are usually encountered in our oil and gas fields that a reduction in rate will tend to enhance ultimate oil recovery from the reservoir as a whole rather than to promote waste. It is further my conclusion that interruptions or curtailment of the rates of injection or production will not impair the recovery efficiency of a secondary recovery project. For this reason we think that, based on this type of reasoning, we think there's no technical basis why secondary recovery waterfloods cannot be curtailed or prorated and there's no physical basis why they should not be treated in the same manner as primary recovery operations, so far as proration is concerned, and share in a uniform manner with them the market demand. Now, to the exhibits that I have prepared, we have, in attempting to come nearer to actual field practices, field conditions, to answer some of the questions that have a bearing on the influence of rate on waterflood recovery we have gone to, as nearly as possible, fully scaled models. Now dimensional analysis is a real old science and scaled models have been used for a great many years in lots of industries, the aircraft industry for instance and aerodynamics making very effective use of this procedure and this technique for the design and testing of airplanes and jets and rockets. Some of these speed boats that we see on the lakes of our country have had the benefit of this type of simulation model testing to arrive at the best design. In effect these are a type of computer where numerical models or analogue models could not effectively depict an operation, we can use a simulation model properly scaled to give us certainly, insofar as the model simulates actual conditions, quantitative values, quantitative results on the behavior or performance in the actual case. Now in order for a simulation model to depict the results in the actual field case there are several things that must be scaled. I don't know that I can think of all of them right now, but I think it would occur to all of us that the ratios of the gravitational, the capillary and the applied forces must be appropriately scaled. They must be the same both in the model and in the actual field case.

It's necessary for us to set the geometric conditions and the boundary conditions the same in the model and in the actual field case. As far as the fluids are concerned, the viscosities of the two fluids must be in the same ratio in the model and in the actual case. While we recognize it is not possible most of the time to scale every possible parameter, we think that without doubt we are able to scale those factors which have first order, effects which are the predominant factors in controlling the performance of a flooding operation or displacement process. To give you the description and to illustrate what we have done in the model work that I'm going to describe to you now, I would like first to give you the characteristics of the model and why we arrive at them. What is this?

Q That is marked as Humble's Exhibit No. 1.

(Marked as Humble's Exhibit No. 1 for identification.)

A Our laboratory work here we have not attempted to set a simulation model of any particular reservoir. What we were anxious to do was to build into this model characteristics which fall within the range of naturally occurring reservoirs both with regard to formation characteristics and fluid characteristics and we took nine Humble floods as an example to determine these characteristics and we, for this model work we had already reported to this Commission some linear model, scaled model results, and in order better to answer the pattern in the sweep efficiency problem, we have chosen five spots for this simulation model work. So these nine water floods were all five spots and we have chosen to represent a five spot. The areal extent in acres was twenty, forty, eighty. We have chosen to simulate a twenty acre five spot. The net stratum thickness ranged from four to thirty feet. In our model we have two strata of ten feet each, so we have a simulation model twenty feet thick. The porosity in our waterfloods ranged from fourteen to thirty-three and we selected twenty;

absolute permeability from sixteen to three hundred thirty-nine millidarcies, we have simulated with one of our strata sixteen millidarcies and one hundred sixteen millidarcies in the other. A connate water saturation in our field floods ranged from twenty to fifty and we selected thirty. The residual oil saturation, these are core analyses behind the flood front in some of our water floods, the residual oil saturation ranged from twenty-six down to two and we are in the range of twenty percent. The oil densitive ranged from 0.15 to .30 grams per centimeter and have put in our model two-tenths of a gram.

Water viscosity in the field case depending primarily on the temperature ranged from .48 to .95 centipose and we have selected five-tenths centipose. The oil viscosity ranged from .46 to 10. We have chosen five-tenths for one oil viscosity giving us an oil water viscosity ratio of one, and for the other 2.17 centipose or about 4.5 - 4.5 ratio; the interfacial tension dyne per centimeter, twenty-five to thirty-five, and we simulated twenty-five dynes per centimeter.

I would like to place in evidence Humble's Exhibit No. 2 and this is one I made after I came out here and I think it will show you what we are, give you a picture of what we have the dimension in the shape of our model. Since in our model we have not assimilated areal heterogenity, each of our strata are of uniform permeability laterally, so in that case each of the quadrants, or each eighth of a five spot has symmetry. In other words this eighth to the left here would behave just exactly like this eighth that I have colored yellow. Here where these four, these are injection wells and these are producing wells. This then is a normal five spot enclosed in a sixteen well array there. So our model is of one-eighth where we're injecting in one corner and producing in the other, simulating the center well.

Now, just for maybe a little further illustration and clarification I thought some of you might be interested in looking further at it, this is an actual graph of the model. It is thirty-three inches on each side here and 1.4 inches in thickness. Each of these sand members are .7 inches thick.

Q Would you mind explaining a little further to the Commission there just how it's made up as far as your sand and so forth?

A This model has a steel plate on the bottom and then we put one permeability sand uniformly distributed, to the best of our ability uniformly distributed over the entire surface area and then put another sand, another permeability sand over that and then it is covered with a plastic plate. It's bolted around each of those edges with appropriate gaskets and we have here a triangular frame that serves as a support to keep this plastic side from buckling. We wanted to observe it, they are plastic sides and you can observe the edge too. Just over the steel plate that's on the bottom there we have a flexible sheet that we can inject pressure from the bottom side to insure that sand will be contacting both faces at all times and we'll get no by-passing of the fluids along the edges or boundaries of this sand, but the fluids will go through the permeable media.

Q Are the edges sealed?

A The edges are sealed with a gasket.

Q Where is your water injected?

A I believe the injection is at this end and the production is at this corner here.

Q Where would the wells be located?

A Those are the wells at each corner, as I illustrated from the previous slide. There has been quite a little bit of discussion of the incluence of gravity and the influence of the capillary forces in controlling the displacement from heterogeneous sands like this and when I finish with these in summary I would like to make a few more remarks about that; but I would like to call your attention here to the fact that this first displacement, we have deliberately designed the reservoir in such a way that capillarity works for you but gravity works against you so far as uniform displacement is concerned. By that I mean that the low permeability is on top and the high permeability is on the bottom and the reservoir is set in a perfectly horizontal condition, so the tendency of the oil to underrun in the high permeability sand so that it would not contact the interface and be imbibed across the interface is what I mean by gravity working against you. Also in this case we have the unfavorable mobility ratio of the oil viscosity is 2.17 or more than five times the viscosity of the water. Now, we have used here two production rates. One other thing that is of pertinence, and these are liquid fill, these are liquid fill runs, there's no gas saturation in these runs. I'll talk about that a little bit in a moment. It poses another parameter that for laboratory purposes does admittedly depose some difficulty, but we think that we have the answer to that, too, but I do want to make it clear that these are liquid fill models. In other words there's no gas saturation. We have chosen four hundred barrels per day and forty barrels per day for this situation. I think you can check me on this, but as I calculated it, forty barrels per day is one-tenth of a barrel per day per acre foot. Four hundred barrels per day is one barrel per day per acre foot of injection in production. Since they are liquid filled, they are equal in these cases. You will notice here that with capillarity working for you, of course, because the gravity wouldn't completely destroy the interface capillaries, promoting, to promote uniformity of displacement to give effective flooding and the gravity is working to permit the water to underrun the lower sand and to cause early breakthrough and to work a little against uniformity; and that there is a very definite improvement in the recovery to three pore volumes of water injected where we have fluid oil produced, and percent recoverable oil against the water injected in pore volume. Actually for some other reasons the data was presented to A.I.M.E. the last week and as percentage of recoverable oil, I had them made and didn't change them, I would like to tell you that this is 78.7 percent of pore volume. This is 75 percent of pore volume. In other words, three percent pore volume difference is recovery in this case.

Q Before you leave Humble's Exhibit 4, just summarize to the Commission what that Exhibit shows or what it is designed to illustrate.

A That Exhibit shows very clearly that for a sand configuration and a reservoir of these dimensions that reduction in rate from one barrel per day per acre foot to one-tenth of a barrel per day per acre foot improved the recovery efficiency. Now, I present now Humble's Exhibit No. 5. The solid lines, both forty barrels per day and four hundred barrels per day are the same lines that were on Exhibit No. 4. We have plotted again oil produced and percent recoverable oil against water injected in pore volume. On this we have put the results of another flood where we had the oil viscosity equal to the water viscosity; in other words, unit mobility ratio of the two fluids, but the gravitational capillary relationships are the same in so nearly as we could repack this column. We got this time, the permeability of the top in ratio to the permeability of the bottom layer is .127 as compared to .129 in reservoir Number 1. Incidentally, these numbers here apply to the different packings. This was the fifth time we had packed this reservoir when we run these equal mobility cases here. In this instance we were not able to adjust out in the laboratory, our fluid injection rates didn't come out nearly as perfectly as they did in the case of reservoir number one, but the ratio of the injection rates in the fast flood and the slow flood, if you wish to refer to them as that or the faster or the slower rate we have used is still about ten to one. In the lower recovery curve in this dotted line we have 396 barrels against 44 in the lower rate. On the basis of pore volume, this is 98.8 percent pore volume and 92.7. So there is not six difference in the recovery effectiveness at the lower rate when you had the more favorable mobility ratio. So here at both of those mobilities the end result is the same, that a reduction in rate injection, in production rate resulted in a greater recovery.

In order to give you the magnitude of some of these effects and put this capillary gravity effect in its proper relationship we ran these turned over the other way where gravity and capillarity were working to help you get effective and efficient sweep.

Q What exhibit are you referring to?

A This is Exhibit No. 6.

Q Humble's Exhibit No. 6.

A Humble's Exhibit No. 6. Excuse me. We have this time turned, this was reservoir number 2, second time we packed it, we got about eight, a ratio of about eight-fold difference in the permeabilities, about the same we had before except this time it is turned over with the more permeable member on the top. Plotting again the oil produced percent recoverable oil against water injection with 390 barrels per day, the higher rate, and 44 barrels per day the lower rate, and you will notice as in the previous case that the lower rate resulted in the greater recovery efficiency from the model. If you are writing these down and want them, the pore volume in the lower rate is 87.7 against 83.6, about four pore volume percent difference at these two rates. This was, I may have failed to mention that in this Exhibit No. 6, we had the unfavorable mobility ratio, the higher viscosity of the oil face. Now, to go quickly to Humble's Exhibit No. 7, we have again the same thing that we have done in Exhibit No. 5. We have the same, the more favorable permeability configuration and with the favorable mobility ratio used, the dotted curves to show you the better displacing efficiency or the better mobility ratio and actually when they were both working together this is what we had calculated to be the hundred percent recoverable oil and we got it with both gravity and capillary working together, we obtained it a little more than two pore volumes. At the higher rate of 393 barrels per day at three pore volumes injected, residual oil saturation is 96.4 percent, the oil recovered percent pore volume is 96.4.

Q Is that pore volume or percent?

A Percent of pore volume. We have one othek model with the liquid fill case that I would like to show you and this one is one of the simulation, resimulation of one of the previous cases and this case we have a curtailed flood demonstrated. This, I guess, is Humble's Exhibit No. 8.

Q That's right.

A And here we have again plotted the oil produced percent recoverable oil against water injected pore volume, we have the permeability ratio of eight op permeability and bottom, and the viscosity ratio of one, and the solid lines here are the, the solid line in the 393 barrel per day water flood at a constant rate. The dotted line is 44 barrels per day constant rate. The data points are for the black circles if they're visible back there, the black dots 393 barrels per day and then the excess was 44 barrels per day. We reduced at this point right here, we reduced the rate. You will notice that insofar as we can depict the results that there is no impairment of recovery. I would like further to say that insofar as we can depict the results there was no improvement in recovery. We would expect -- and unfortunately, as Mr. Nutter pointed out, he hadn't had time for some things, we haven't had time to do all the things we would like to do, the time and manpower -- we have not run, other than this; we would expect, if we changed the rate back here, that we would be able to see this curve, this result, migrate to the other upper curve. It becomes insensitive after you get the high oil saturation, it will arrive at that point I feel confident, but this certainly doesn't show it, but it does show without doubt that there was no impairment in recovery from this experiment by the cutback, a tenfold-reduction or to one-tenth of the rate of injection or production.

The next subject that I wish to talk about is this influence of the presence of free gas. I've been amazed from time to time at all of the discussion of the influence of free gas on the displacement efficiency of secondary recovery water-floods. One would think that in no natural drive waterflood or pressure maintenance project or pressure restoration project that there was ever any free gas saturation, whereas as a matter of fact I think it's a fair statement that in most natural drive water-floods free gas is present. Now, it is true that there are a large number of waterfloods in fields where the oil is under-saturated with gas. That is, the bubble point is below the saturation pressure and in the reduction of reservoir pressure no free gas is evolved. And in that case, why, I believe Mr. Yates mentioned one where they had an extremely low saturation pressure and that at the pressures involved, there would be no free gas. However, in a great many, I think it's fair to say that most of the natural water drive reservoirs of the world, that they were just about, they were pretty nearly saturated with gas at the reservoir pressure. But whether there were most of them or there are some of them, in every one of those it is necessary, of course, to produce the oil and to cause the water to encroach to recuce the pressure. In so doing, gas is evolved, and in most instances I think sufficient gas is evolved to exceed the equilibrium gas saturation. Some free gas will actually flow, but in any case they build up a free gas saturation in all those natural drive cases; the flood takes place with that gas continuously present at the water interface and some of it, the interface goes through it and we have a residual gas saturation behind the front so if there were ever going to be an influence of gas saturation we should see it there. I think it is pretty universally admitted that natural water drives are more efficiently produced with controlled rates so that we don't have the by-passing and trapping of oil and the unequal encroachment of the water and premature waste of the displacing medium. In the secondary recovery case, the gas is the low pressure and it's not possible to build up sufficient pressure to build up the oil bank or to drive the oil without putting that gas back in solution. I think it is fair to state that in practically every case at the time you get fillup the free gas has disappeared from the reservoir. I believe that if not completely, almost so, and if you've built the pressure up why you have no free gas and then you have just the liquid displacement process from there on. However, in order to investigate this we have also run this same laboratory model to simulate the effect of presence of free gas, does it introduce any kind of a different sort of rate effect?

Q The Exhibit you are referring to is Humble's Exhibit No. 9?

A Exhibit No. 9, I would like to put in. Here we have saturated this model with an oil containing a dissolved gas and we have produced it by dissolved gas drive to create a gas saturation. I might say that throughout the reservoir, throughout this model we can see that gas bubbles, it comes out throughout the reservoir. This is one of the things, one of the difficulties that I mentioned to you in working with these models, why we don't always with free gas, we did not get the same free gas or dissolved gas drive recovery, but the residual oil saturation and the final condition, the results of the flood show that the low rate still gives much better recovery. I would like for you to note that at the time we got fillup that they were back on the same line, and I would like further to say that at the time we got fillup we could see no free gas present. It had all gone back into solution, which is what you would expect at the low pressure involved. There's not very much gas present and the pressure gradient necessary to displace the oil puts that amount of gas back in solution. Here the -- incidentally, this experiment was still going on yesterday when I got the last data point right here. I think that you can see that it's about through and that the recovery at forty barrels per day starting with free gas present definitely gives a lower residual oil saturation or better recovery than the higher rate of production. It has certainly been my feeling that one of the important problems always of a waterflood is the evaluation of a pilot or five-spot and we've recognized from the beginning that with a five spot operation, if you have a completely depleted reservoir, you have an extremely low pressure reservoir, you have a problem of the injection of fluids forcing oil out of the five spot which would not be recovered at your center injection well and give you too low recovery compared to what you would get if you had a continuous development, a completely surrounded and completely developed series of five spots. There has been a lot said and a lot of speculation about this. We have demonstrated time after time in the laboratory that the thing that moves fluids is pressure gradient. Oil doesn't have the ability to move itself through reservoir rock, it has to be displaced with gas or water, the gravity, of course, there is a gas face involved and most gravity are a separate face involved, so we know that the pressure moves from region, fluids move from regions of high pressure to regions of low pressure. In order to illustrate what's involved in this five spot evaluation and in the fluid migration problem as a whole, I would like now to present some results of a Shell paper, Shell Research Laboratory paper presented, I believe, a year ago at an A.I.M.E. meeting. I'm not sure -- has it been published? It has not yet been published, but this has been made public and printed and this is taken from the reprint. This will illustrate some of the things that we have been trying to elucidate through cross examination at this hearing and will, I think, explain some of the phenomena that we were trying to gain a clear understanding about. You will notice in this Humble Exhibit No. 10 a fluid migration out of a five spot in a pressure depleted dissolved gas drive reservoir. We have a sequence of six illustrations of the shape of the oil gas and water-oil interfaces. This was a pressure depleted reservoir so in here the red is the gas, the black is the oil bank and the blue is the water. In here at this stage of this game, as long as there is gas pressure there, why this pressure is still zero, this pressure out here is low, you will also notice this first picture number "A;"letter "A" is at the first point of oil bank contact or interference, the first time now, and that we have perfectly radial symmetry about the injection wells, both the oil bank and the water-oil interface. Now as injection continues the fluids start mutually, we get mutual interference and you will notice that the lines where they have been drawn is a square between the injection wells on the five spot. Now, they have curvature. Now that curvature, according to the Shell people, is the dividing line dividing stream line, all of the stream lines of flow from the injection well that's inside of this line are flowing toward the production well. The lines outside of that curved line are carrying fluid away from the injection well, and you will notice that the curvature increases as the injection proceeds. At the moment of fillup, there's no more gas.

Q Which figure are you referring to now?

A The oil, the figure "D", letter "D;" where the moment of first oil production is noticed in this completely pressure depleted reservoir, you'll notice the curvature is pretty great. In the case of the picture depicted under "F", which is just about the time of water breakthrough, why you can see that the stream lines are even more distorted. This also demonstrates where your injection water goes. You will notice here until you get oil interference that you have, as I mentioned, this circular configuration and one-fourth of the water was going in this quadrant and three-fourths of it was going into the reservoir outside of the five spot rather than inside the five spot. But, as interference increased, you will notice how much more of the injected water is outside the five spot than inside the five spot. Now, the equations and the things you can deduce from the results that they have given in this paper is that so long as this pressure at this production well is equal to the pressure at this point, that is, the oil bank interface outside of the five spot; and, of course, that should be for all practical purposes identical with the pressure throughout the remainder of the unaffected portion of the reservoir because that's as far as the pressure drop has extended due to the injection, so long as that pressure relationship obtains there is no difference in the fluid movements caused by rate of injection. Do I make myself clear? So long as the pressure at this well is equal to the pressure out here, whether you have done this at tenfold rate or even a hundredfold rate, there is no difference in the shapes of these oil-water interfaces, these oil banks nor the fluid migration out of there. In other words, it is a pressure phenomena and not a rate phenomena. There is the thing that we have tried to illustrate, and I'm sure from the facts that we have had, very ineffectively, that it wasn't the rate, but the ratio of rates that controlled the pressure and that you could control the ratios of the pressures just as well by controlling injection pressure, the migration as you could by controlling this. Of course, if you have zero pressure out here it's desirable to keep this pumped off. And if you mean by that capacity production, why I think everybody would agreed that it would be desirable, but there's no relationship between that capacity production necessarily and the maximum amount of oil that this reservoir can deliver given sufficient pressure gradient. In other words, you don't have to shove so much oil to the well. If you can keep it pumped down to one barrel a day, ten barrels a day, one hundred, so long as you keep the pressure here equal to pressure out there, there is no difference in migration. It's inevitable it will be some if this is zero. If there is some pressure out there, if it is not a complete depleted reservoir under certain conditions you could suck fluids back into, out of this region, into this five spot and get a greater amount of fluid from the production well that was contained originally in that five spot and this is the type of data that I presented, you will recall, at the Graridge hearing. The migration can be controlled at any absolute rate. The thing you have to control is the pressure because that is what moves fluids within the range of rates normally encountered. We all recognize that even in homogeneous sands down in extremely low rates, particularly in laboratory models and some well samples of certain types of permeability that you can go at a slow enough rate and this rate is down in the range of ten thousandths to hundred thousandths of feet a day where end effects, boundary effects become important, you can have rate effects in the individual pores. In other words, connate water could flow through the connate water rim around the oil and then, of course, if you go to extremely high rates up above, I don't know how high, it depends on the permeability, but exceedingly high, thousands of feet per day, you can get at your length flow and then again you could strip a little of the residual oil from the core but in the range of ordinary rates, it is pressure drop alone that causes movement of fluids.

In Humble Exhibit No. 11, I have here pictured some results of a paper that was presented at the A.M.I.E. meeting in Dallas last week by Research Engineers of the Jersey Research Engineers in Tulsa. Where they have shown the effects of operating conditions on areal recovery factor of secondary recovery waterfloods. Now, I want to limit for the discussion at present my explanation here to the normal five spot. This is at your discretion, we can talk about others, but let us just look at the normal five spot. This is the one I think we are all interested in. You will notice that we have plotted here a pi ratio against the areal recovery factor; by this areal recovery factor, the author's comment, "the fraction of the oil originally contained within a five spot that could be produced from the production well, well or wells, with different pi ratios." Now, you will notice that the normal five spot is relatively insensitive and its areal factor, recovery factor, with pi compared to some of the others, but it does illustrate this, that with the lower pi you get lower, a lower areal recovery factor. Now, this, I think, can be used very clearly to maybe shed just a little more light and certainly give a little different explanation of what I was just telling you a moment ago. Now, we talked about in capacity floods, keeping the pressure of the well low. First, let me define, give you what the author defines as pi here. Pi is equal to a ratio in the numerator PS is the static reservoir pressure, PWP is the producing well pressure. In the denominator PI is the injection well pressure and PS again is the static reservoir pressure. Now, in capacity floods in trying to get this recovery factor, this areal factor as high as we can and we want to get good recovery, so we can say we have to produce at capacity, we have to keep that producing well pumped off and I agree that it certainly has to be as low, it really ought to be as low as the static reservoir pressure.

I think you ought to keep it that low. We will demonstrate that if you get it lower than that you can take oil in out here, you will notice that the areal recovery factor does go above one, because when you keep this, say you keep this at zero, PWP at zero, why then you have the numerator as large as you can possibly get it with the reservoir as you find it. So you want to keep this numerator high to get a high pi rating. Let me show you another way you can keep the pi value high. If you keep pi high, the pressure of injection well low, you likewise get a high pi value so one of the best ways is to go at the lower rates. If you are having difficulty controlling the pressure in your producing wells, if you are having pump trouble, cut back on your injection wells in pressure and you won't shove any more oil out of there than you normally would. If you notice that the static pressure is zero you keep your areal recovery factor at zero, I told you that it will be inevitable that you keep migration out. So this number, the numerator becomes zero and pi is zero and you are back on this linear, when you are below nine-tenths, so your areal recovery factor is less than one, which is the Shell case.

Q You mean the Shell case?

A I mean the Shell way was the zero in the Exhibit 10. The Shell case, that is the case that they were depicting. This concludes my Exhibits and I think that insofar as these laboratory results are pertinent and as I mentioned earlier, I think they are pertinent so far as the dominant first order conyrolling factors are concerned, we can see that reduction in injection rate improved recovery. We saw that a curtailment of injection rate and production rate did not impair the recovery efficiency. We saw also that the presence of free gas did not change the rate effect, did not induce any adverse effects in the displacement process and we have seen from data of competent observers what the influence of pressure drops on fluid migrations would be in normal five spot or secondary recovery operations. So, on the basis of this and all of the other information that I have seen, every field case that I have ever observed had sufficient data on which to draw what I considered to be conclusive, very firm conclusions, that there is no technical or physical basis why floods cannot be controlled. In fact, I think that it is possible to impair the recovery efficiency by going too high, and that reduction will never impair it, but would tend always to improve it in the range of normal field rate in natural reservoirs. I mentioned one case about the gravity case and I think that this is important that I modify my conclusion in this case. If we had a horizontal reservoir of sufficient thickness and sufficient permeability that gravity induced an adverse rate effect, that is an adverse recovery efficiency at low rate caused by extreme under-running of the water and premature breakthrough, I think that in those cases we would have sufficient thickness of reservoir, that we ought to control our injection positions and our completion interval and take full advantage of that gravity and make it work for us and displace, use bottom water drive and displace it upward. If you have a reservoir tilt, not a completely horizontal reservoir, and we hardly ever have completely horizontal, we always have dip, if you have dip in the thick homogeneous case, reduction in rate would permit you to take full advantage of the gravity by keeping a horizontal water interface, but in the heterogeneous case normally encountered, this conclusion, I think, needs no modividation; that reduction in rate universally tends to improve the displacement efficiency and improve the recovery. Consequently, we think there is no technical physical basis why they should not, as a matter of fact they should be controlled, must be controlled. There's no reason why they can't be prorated, no physical reason why they shouldn't share the market uniformly with the remainder of the production, that we can see from a technical basis, the market in any operating area.

MR. HINKLE: Thank you, Doctor. That's all.

MR. PORTER: Any questions of the witness?

MR. McGOWAN: I have a question or two, I believe.

MR. PORTER: Mr. McGowan.

CROSS EXAMINATION

BY MR. McGOWAN:

Q As I, in my uninformed way, understand your testimony, Doctor, based upon these laboratory tests, you have reached conclusions which you feel are applicable to the normally encountered heterogeneous reservoir in the field?

A Right.

Q Now, the results you get in your laboratory will be applicable to the field only insofar as you are able to simulate field conditions in the laboratory. Could we agree on that?

A This is true, quantitatively, in absolute equality. Quantitatively they apply everywhere always.

Q As I understood your explanation, you placed two layers of sand reservoir or simulated sand reservoir on top of one another.

A That's right.

Q Each layer having a different permeability?

A That is right.

Q The permeability, however, was uniform throughout each layer?

A That is right.

Q Do you normally find in the field layers of uniform permeability throughout?

A We do not.

Q Do you normally find in reservoirs in the field uniform permeability from a lateral standpoint, that's about the same thing I asked you before. Let me put it this way. Do you not usually find in field reservoirs non-uniformity of permeability both in a horizontal and lateral direction?

A It is practically universal, although I would say that we probably have a greater uniformity within a given stratum horizontally than we do vertically, although this is not necessarily true.

Q No, I believe you talked about the necessity of avoiding water breakthrough on the bottom and I understood that, correct me if I'm mistaken to mean, to avoid water breakthrough in the high permeable area on the bottom is that correct?

A That is right.

Q Now, if our high permeable area circled up and down and around and around through the reservoir, could we not get the same water breakthrough, through that permeable chain or channel as we would if it was laying on the bottom or top?

A Well, if we had a horizontal affair -- you introduce some other complication. But the laterla heterogenity that we encounter doesn't weave like you talk about, but the types of lateral differences in permeability that we encounter have the effect of increasing the importance of capillarity and reducing the importance of gravity. Universally we know this, qualitatively we can't simulate it completely, quantitatively, and we don't have the horizontal variations, but we do know qualitatively that those horizontal heterogenities that we have in a strata would increase the importance of capillary forces and minimize the importance of gravity forces and would help you to that extent.

Q What you are saying is that, to the effect that you have time to get the benefit from capillary forces, it aids you that much?

A That's right. If you slow the flood down enough to get full benefit of capillary forces.

Q While we are on that point on slowing down, did you calculate how long it would take to flood a normal forty-acre five spot at your forty barrel per day rate?

A No, I sure didn't.

Q Of course, that would enter into it in the field from economic standpoint?

A That's right. I don't remember what the ultimate recoveries were. I do not have that figure.

Q Well, now, in your normal heterogeneous reservoir you will have spots and pockets in many of them, at least where you hit practically no permeability at all, maybe a little round ball or oblong island?

A That's right.

Q As water moves through the reservoir in a lateral position it has to move from injection to producing well; if you are injecting under no or very low pressure, will the water not normally enter into that formation at probably the most permeable sections out of the well bore?

A That is right.

Q As it moves through the reservoir it will follow the path of least resistance and continue following in the areas of higher permeability, will it not?

A Oh, in the absence of capillary contact, yes, sir.

Q Let's disregard capillary action.

A Not with capillary action because the capillary forces will rob the more permeable section of the oil at slow rates and keep the displacement front equal to that in the more permeable section. In fact, at sufficiently slow rate the displacement front will lead in the least permeable section so you can't say it tends to flow under pressure gradient, yes, through the more permeable section, but given time for capillary equilibrium, it will not run off and leave the displacement front in the less permeable section.

Q That seems to me to be the key to this, is this factor of time. I think nobody, certainly our own experts, to my knowledge, don't challenge or disagree with your proposition on that respect. Given sufficient time, but what time are we talking about, that's why I asked you if you calculated forty barrels, because if it's going to take you a hundred years to get across the forty acres to get the full capillary benefit, we can't afford to wait on it.

A Unfortunately, Mr.McGowan, I have not calculated that. If you will bear in mind that you have a large surface area of contact horizontally between these different areas for interchange of fluids and for the first day of injection, and you have got that interface in there, the capillary interchange across that interface is at the rate of fifteen barrels per day; at the end of six months' time, where you have, of course, a little interference, it changes as the square root of time across any given cross sectional area, because as the water saturation goes up the imbibition of the oil across that goes down. At the end of six months the volume across that interface is at the rate of one barrel per day per acre. In a forty acre, it would be at the rate of forty barrels per day across the interface.

Q You've lost me.

A That is oil moving from the tight sand into the more permeable sand across the capillary contact to be into the flowing stream a --

Q You are talking about the rate at which oil moves or is displaced by capillary action out of the tight section into the low section?

A Into the low section across that interface, that's right.

Q Now, then, assuming you had ten feet of tight pay section that you had to get the oil out of by capillary action?

A This is for a ten foot sand. These rates are for a ten foot sand.

Q How long would I have to keep injecting water to get it across the ten feet? You have to break it down for me, you lost me.

A Well, I don't remember just what the section is like. Actually, you see, at normal rates in advance the fluid front keeps plumb up at forty barrels per day, it would all of it come across as fast as you were, essentially all of it, as fast as you were moving, you see. I don't know just exactly. I haven't calculated the time at which you would have equilibrium between the two sections behind the front. I haven't calculated that.

Q You would have to inject a sufficiently low rate and therefore have a sufficiently slow movement of water too low to keep the water from by-passing and closing of a tight area that it took for that tight area to fill with water by capillary action?

A If it were sealed off and not continuous, you would need to give time, sufficient time. You would have to go at a sufficiently slow rate. I think fortunately for the normal field case, and this is another factor that probably I should have mentioned, that even at the highest rates that you can inject in the well bore, by the time you get out into a forty area five spot, for instance, midway between the wells the arc of that oil bank, that water-oil displacement front, your rate of advance through the rock is sufficiently slow to give you the benefit of capillary action. That's what saves you. That's what saves me.

Q Then it didn't matter how fast you inject, you still get it?

A In the range of normal field rates we have not found field evidence that there was oil waste being caused. I have admitted the insensitivity absence, in a lot of cases we do not have sufficient data to make a complete reservoir study, but you will recall my testimony at the previous hearing I did not say that the rates that you were talking about, four hundred barrels per day injection rate, or five hundred, were sufficient to cause waste in the normal field case. What I said was that reduction in rate would not cause waste, but if you were in the danger zone, reduction in rate would not cause waste, but if you were in the danger zone, reduction in rate would always tend to improve the recovery efficiency.

Q Now, Doctor, do I understand correctly then that what you are saying is that, say at three hundred barrels a day or one hundred barrels a day, you are probably going to get the same benefit from capillary action?

A I said that in the cases that I have studied -- few of which have had ample data, I would say that these things are subject to calculation. I agree completely with Mr. Nutter that each one must be considered on its own individual basis and a categorical statement could not be made. I say there is danger always in too high rate of injection. Where that dividing line is would have to be determined for each individual field case.

Q Of course, the rate at which you would still get benefit of capillary action, I assume then, would differ if you were talking about a variation of permeability of say from twenty to thirty millidarcies or if you were talking of a variation from five to a hundred?

A Surely.

Q And, of course, the thickness --

A The thickness of these sands, those are amenable to calculation, of course, if sufficient data are available.

Q I think as you are very well aware, today you referred to your laboratory work as -- maybe you didn't mean it this way, and it's unimportant, but in the sense that we are building many things today such as airplanes, rockets and so forth in the lab, and I think any intelligent person realizes our country would be in a very difficult position if we didn't have technicians and laboratories, the thing that laymen like me, who have to stake their existence on these type of people, always look at is that we have to pay the bills. So we would like to see it proved.

A Okay.

Q I believe I'm correct that when they design a rocket it oftentimes doesn't perform as the laboratory or the theory said it would perform, is that correct?

A Sometimes they blow up.

Q I believe then I am not being unreasonable when I say that when a man in your field comes up with a theory or laboratory test, the real proof of whether you have overlooked something or whether you have by necessary limitation had to leave something out of your experiment, the proof of whether you had to do that or not is whether it works in the field?

A That's right.

Q This may not even be important. I am not sometimes smart enough to catch the significance of these things, but from what observation I have had of water floods, it occurs to me that we produce much more water free, and much more water ratio oil in a high rate flood than in a low rate flood. Why would that be so if your capillary action at low rates is going to sweep the reservoir in front of it?

A I do not agree with your observation. I think they are not correct interpretations. I have been asking for this type of evidence for some number of years and as we have analyzed the data that has been made available to us and this does not agree with my observation.

Q Well, I obviously am not in a position to argue with you, but it has been, I don't have the supporting data with me, but it has been my observation that in many of our own floods we get much oil early in the flood that is practically water free and we will get the high oil ratio after the water breakthrough and are pretty much on the decline or the end of the flood.

A Depending on reservoir characteristics you can go both ways. In the average heterogeneous case I would suspect that you would not be able to tell much difference in the point of water breakthrough on a cumulative property of oil production against water injection, nor would you be able to tell any difference in water oil ratio at any given point of the cumulative, depending on the rate. This thing, of course, here again you get the differences that we've talked about. I think that they have been overstated, that these differences are so great that you can't draw any generalization, that they differ so widely among wells and among fields that you don't know where you are going, but I do think that these things youh have to analyze all of the factors many times, which they haven't been taken into consideration. I think that one -- I have talked many times with a number of people that have appeared here already in this hearing about the extreme dangers of interpreting some of these rate-time curves for evaluating these reservoirs. It is my firm conviction that it's fraught with a lot of danger and that this is the one thing that is leading to the greatest amount of difference of opinion among us. These things do not, cannot be substituted for a complete and thorough reservoir analysis of any type of recovery process.

Q Would you agree with me that, I think in a sense, the thought that I got from what you said, at least, and I certainly agree with you, is that we shouldn't be afraid to form conclusions from information available to us and in a sense rely on them or at least determine if we can't rely on them?

A We must do that and I can certainly conceive of a case where the gravitational force would be such where you would get an earlier water breakthrough at low rate than you would at high rate. But, boy, just think how dangerous it would be to interpolate that over to a condition where the capillary forces were such that you would not have this condition where the gravity was not the dominating factor and basing your conclusions there. You need to study each one of these things individually.

Q Well, I certainly agree with you. I'm certain that our company does. We don't scorn experts and technicians; by the same token when one of our bright young boys, and we have many of them, come up with an idea that departs from what we've proven to be workable, we don't go out and change all of our leases the next day on it. We let him test it and prove it to us first and then we accept it, and it occurs to me that you here have what, certainly I'm not intelligent enough to determine its validity, I accept it as a theory that is different from apparently the experience of most of the people who have had considerable years in waterflood. It occurs to me that we would be much wiser either on a company or state wide basis of doing a little field experimenting with that theory before we turned the whole company's leases or the whole state's leases loose on it. I think that is the reason for the hesitation and the fear expressed by the experts, it is Sinclair's reason.

A I certainly agree with you wholeheartedly and I certainly agree that in my own opinion, I am speaking for Claude Hocott now, all of these things are my opinions, they are not the company's opinions. Most of them, I would say they do agree with the company's opinion, I help formulate the company's opinion, but I would certainly say that the field performance is the thing that counts and we have relied on it, I believe, as greatly as any other company in the industry. In fact most of our conclusions are based on field evidence. I have analyzed, as I mentioned, in the previous testimony I presented the results of my analysis of every published waterflood on which sufficient data was made available. I'm not prepared at this time to present additional field data, but such will be forthcoming before our case is finished and certainly I would agree wholeheartedly, in relying on field information, I agree wholeheartedly that it is necessary many times for us to draw conclusions and exercise judgment and make decisions on insufficient information because we haven't the timet to gain more information, but we don't have to like it.

Q Doctor, then actually, as I gather from your testimony, to the best of your ability, and I think you have very forthrightly shown where it may be weak, you have, however, simulated field conditions in the laboratory and from your experiments have drawn the conclusion that if there is any difference in ultimate recovery as between rates, you will get a higher recovery at a low rate?

A That is my conclusion.

Q And that curtailment or interruption of the flood will not effect its ultimate recovery?

A That's right.

Q The questions I have heretofore asked you have been for my own interest and curiosity. Now, not to disappoint the crowd, I will ask if Humble has cut down the injection rate in their flood?

A I have not made any study of that. At this time I do not know and we'll have to defer the answer to that question. I haven't -- I'm not prepared to answer that question.

MR. McGOWAN: That's all I have.

MR. PORTER: Mr. Campbell.

BY MR. CAMPBELL:

Q Dr. Hocott, I certainly am not in any position to question you very much about your Exhibits. I do want to clarify in my own mind your position in this last. I was confused about it at the last hearing as you may recall. I am still somewhat confused.

A I regret that.

Q It is difficult for me to see how you can say on the one hand that you have no indication or evidence of waste at rates within the range you have heard discussed, or are being used in New Mexico, and to say on the other hand that lower rates will enhance recovery; I cannot see how there can be an enhancement of recovery without a loss of ultimate recovery with the other method. What are you actually saying here?

A What I'm actually saying, if the field conditions are such that the rate of displacement, the rate that a project is operating is sufficiently great that you do not get the water into the oil portions of the reservoir rock uniformly to displace uniformly all segments of the reservoir, then you have lost recoverable oil. However, if the rate that you have dropped to permits the full benefit to be obtained from capillary forces, that you do definitely invade all the portions of the reservoir rock and displace the oil from it, then further reduction will not help you. This is all that I'm saying, so if you are already down at that, rate reduction won't help you, but it won't hurt you.

Q And you have already said, I believe, that the rates that we are talking about here will receive the full benefits of any capillary action so far as your observations are concerned, have you not?

A So far as any field results that I have observed, I said that I could not detect in such variations in rate as we are able to analyze any impairment of recovery. I would hesitate to say, certainly, if we had a reservoir with the conditions that I have simulated in this five spot, a four hundred barrel per day would result in the loss of recoverable oil, but I have never seen any clear evidence like that from field studies. So this leads me to believe that the heterogenity of the normal formation, certainly the ones that we have analyzed are such that we get this benefit of capillary and uniform displacement.

Q If you say on the one hand that you have never found field or reservoir conditions where the present injection rates or the range of rates that we're talking about here has deprived the project of the benefits of capillary action, and then say on the other hand that your simulated model in the laboratory has brought these drastic results, aren't you in effect saying that you have an unrealistic model in the laboratory?

A We admitted in the very beginning that we did not simulate all of the reservoir heterogenities. I mentioned, I believe, in response to a previous question that horizontal or lateral variations would improve the benefit to be obtained by capillary and minimize the effects of gravity. However, I did not wish to go on record as saying that I have not seen by-passing of oil in the high rates causing inefficient floods.

In fact we have many fields that we have asked to be cut back to an MER because of too rapid and non-uniform encroachment of water and the danger of by-passing and trapping and leaving oil unrecovered, so we know it can happen at reservoir rates is all I have said. In the field five spot floods that I have had sufficient data to examine and I wish I had a hundred more, I have never been able to isolate this kind of an effect. I wouldn't go so far as to say that there was not danger of it, it ought to be, each one of these reservoirs ought to be analyzed in advance and determine if there is any danger of it. I think from the type of models that we have talked about here today you can go into the laboratory and simulate your permeability relationships and determine whether you need to go slower or not. You don't have to guess at it.

Q Well, I wish you hadn't said that now. Now, I feel like you have reversed your position again. Are the answers that you gave me when I started my questions about whether or not within the ranges of rates that we have been discussing here there is evidence, to your knowledge, of waste, your answer was no?

A That is right.

Q Is that still your answer?

A I do not know of any such. What I have said is I wouldn't say that at these rates there wouldn't be danger of it in another field.

Q You have conceded that there are limitations to the laboratory models that you are able to create?

A Right.

Q And the laboratory results that you have described here today, insofar as you have studied field results elsewhere on which you base the conclusion you first gave me, do not indicate that in the field there are any such drastic results taking place?

A Well, sure, we are talking about two or three, four percent, difference in ultimate oil recovery and maybe some of our field things are insensitive, these were not so drastic that you are talking about here, but the trend was obviously there and very clearly there in every instance.

Q All right, now, we are down to the point where we agree that the high rates, so-called, that are now being referred to within this range that we talked about the last hearing and this hearing, there's no indication that those are causing waste and we are down to the question of whether or not lower rates might enchance recovery?

A May I ask you to modify your question before I answer, to the extent that the fields that are now being flooded that have been studied, that have had published information, I would not want to draw this same conclusion that you are trying to put into my mouth from current floods that have not been studied. I am talking about the fields that we have studied and have evidence on.

Q Of course, I meant to confine it to ones you knew about and have studied.

A That's right.

Q You have stated that you studied a large number of what records you could obtain.

A That's right.

Q What evidence is now available.

A That's right.

Q That's all I am asking you to say. We are down to the point whether low rates will enhance recovery or cause waste, that is the basic argument between the two groups of engineers, as I understand it.

A It's a little more basic than that, but that was one of the differences.

Q Well --

A The real crux of the matter, as I understand it, is that high rate is necessary to prevent waste.

Q Yes. All right, let's put it on that basis, it's the same as saying that low rates will enhance recovery. I can't grasp the difference between those two, but we will go on your basis.

A Low and high are relative terms.

We are talking in the range that we are able to obtain and have obtained in the field studies that are referred to here. Do you agree that the laboratory work that you have done is conclusive as to your conclusion about the rate sensitivity matter?

A The rate sensitivity, I do agree wholeheartedly.

Q You think it is conclusive as to your laboratory work or as to its application to the field?

A As I mentioned a moment ago in the direct examination, I say that qualitatively, it is directly applicable, quantitatively, it is applicable insofar as it depicts point to point conditions in the reservoir.

Q Dr. Hocott, you are acquainted I'm sure, intimately, in many instances with these engineers and field men who have considered this matter at some length and have studied it with you informally, I'm sure, and presented papers that were not in accord with your conclusion, have you not?

A That's right.

Q I presume that you consider that within the range of their abilities or educational background they are qualified, many of them at least, qualified engineers, will you not?

A Some of them are my best friends and we certainly differ as to their qualifications in this regard.

Q Well, I'm certain it works both ways, but none the less, what I am getting at, you really consider it to be an honest difference of opinion among technicians in regard to this matter.

A I don't think that I ever have and certainly I never intended, if I did, to impugn the motives of a single one of my friends who hold the opposite position.

Q Well, that isn't exactly what I asked you. Certainly I have never heard yourself impugned, and I am not doing it myself, of course. I'm just asking you if you have completely discredited the opinions of all of these people that have expressed opinions based upon their best knowledge and study of field histories of actual operations of waterfloods in which they have been involved?

A Let me say this, that I have examined every bit of evidence that they have based their conclusions on that they would furnish me. I draw the opposite conclusion and I have told them about it and told them why, so I am forced to the conclusion that their conclusions are erroneous.

Q Then you do conclude that they are all wrong, that they are wrong, and you are all right?

A That's obvious.

Q Well, you certainly can see that there is a difference of opinion?

A I surely do.

Q Let's assume that there is a difference of opinion and assume that you do think that these men are qualified, apparently you give some limitation to that, but their educational and professional background qualify them to some extent.

A Many times it's not a matter of competence or incompetence, I didn't mean to imply that. I was being a little facetious and I apologize.

Q That's all right. I do that occasionally. And you were talking about risks and dangers involved in adopting one method or the other, doesn't that analysis apply if there is a legitimate possibility that flooding at low rate will cause physical waste and assuming the impact of what you produce in excess of this market demand business, assume that that is not excessive at some point?

A Right.

Q Do you think that the risk should be taken of experimenting with low rate floods based upon the opinions of people, not only consultants, but people with companies who also have research laboratories, do you feel that risk is worth taking?

A I think you will find some low rate floods being encountered and maybe some later evidence will be put in to that effect and certainly, of course, my opinion is that there is no risk involved in curtailment, so, and I have tried to the best of my ability to submit evidence to support the position. I have never asked anyone to take categorically any opinion or conclusion of mine to let it be weighed completely on the basis of the evidence submitted, that's what I have tried to submit in this hearing, only those things that have a bearing on this case and if sufficient information that have a bearing on this question are submitted to this Commission I would think they would be remiss if they did not weigh it all and exercise the judgment to the best of their ability to make the decision that the evidence at hand dictated.

Q Dr. Hocott, I believe you stated that you concurred with some of the indications here that reservoir conditions in different waterflood operations can vary considerably from reservoir to reservoir?

A They sure do.

Q And within the reservoir?

A They sure do.

Q Let's assume that there are floods, history of floods with low rates which produced sizable amounts of waterflood oil, or there are floods that have during the course of their operation reduced rates and increased them again and have regained a rate of production on your ultimate recovery that is satisfactory. Do you feel that either the field histories, one way or the other, conclusively establish the point any more than your field studies have conclusively established it yet, do you feel that is the case?

A If I ran across some evidence that to the best of my ability and the best of my knowledge showed conclusively that I ought to increase the rate to improve the recovery I would so recommend to my company. I have never seen any such.

Q You heard Mr. Buckle's testimony?

A Yes, I have.

Q Have you ever made any laboratory studies of the quality of the sands in the Yates and Queen Formations in this area to indicate whether there might be imbibition under low rates or not? Have you made any studies of particular types of reservoir sand?

A Oh, I have run, I've run, I've observed on their run, and I have had run under my supervision literally thousands of cores. Where properly taken and handled I have not found any oil wet cores, that is, completely oil wet. I think that certainly cores that were improperly taken deteriorated through either fluids or were allowed to dry out or allowed to aerate with certypes of crude oil. You can produce cores that will not imbibe water. I think that this is an extremely important question, that it's one that is, I would like to explore more and one that we intend to explore more. I would like, if I may with your indulgence, I would like to talk just a little bit about the water wetness, the ability to imbibe water if you are interested in the information.

Q Well, I have heard it. The Commission may be. I don't think I would absorb any more of it than I usually do, Doctor.

A Most of the cores, let me say, that I have examined from the Permian Basin will imbibe water.

Q To varying degrees, of course?

A To varying detrees, depending on the conditions, yes.

Q Are there some you have examined which will not?

A I don't recall any that I have examined. I will hesitate to say that we haven't had cores that will not imbibe. I think that the way the cores are handled influences, it doesn't influence the capillary phenomena, I might say, but certainly some of my friends have furnished me cores which I had no control in their acquisition, that would not imbibe water. Most of our fields do have connate water saturation at the oil water interface which forces you to the conclusion that they are water wet.

Q I have only one last question, Dr. Hocott, in your laboratory work and in establishing the basis for these experiments, for instance, your forty barrel per day and your four hundred barrel a day, are you in those, and in the conclusions that you draw, are you in your position called upon to take into consideration the economic or business aspects or are your efforts and your conclusions wholly in the research realm?

A Quite naturally, even the selection of our research projects and determination of what we work on has to be in the realms where there is a possibility of an economic return and we are concerned, but I do not and I'm not involved, this is not my assignment to make economic analyses of the application of technological developments in Humble's operations. This is not my assignment. Of course, we're always concerned that our developments be economic and we try to analyze them that far, but the specific economics, that is not my job.

MR. CAMPBELL: That's all.

MR. PORTER: Anyone else have a question of the witness?

MR. McGOWAN: I would like to ask one more question that came up from the cross examination, if I might.

BY MR. McGOWAN:

Q Dr. Hocott, you made the statement and I have heard you make it before, that you have analyzed all the information that has been furnished to you concerning the various projects and you wish you could get more. You wish these experts who have a different opinion than yours would furnish you more information. Now, the thought just occurred to me when you and Mr. Campbell were discussing that, that some of the information that it may be impossible for them to furnish you, is their twenty, twenty-five years of field experience and if I may be permitted an analogy, for instance, Mr. Hinkle is a very well recognized authority on public land law. I am not. He could furnish to me all of the information concerning a public land law question that he had available to him, but I could never draw the reliable conclusion from it that he could because I lack his experience in the field of working with it. Could that possibly account for some of the differences of opinion between you and some of the other experts?

A Certainly it is possible.

Q That is one set of information you can't give them, twenty years of experience in the lab, and they can't give you their twenty years of experience in the field.

A We cannot unless we had a duplicated experience, of course, in a short exchange or in a long exchange completely, fully acquaint each other with our respective backgrounds, that is correct.

MR. McGOWAN: Thank you.

MR. PORTER: Any further questions? Mr. McBroom.

MR. McBROOM: Yes, sir.

BY MR. McBROOM:

Q In regard to your Exhibits 4 and 6, I just want to get it clear because most of us, some of this is ivory towers to us, and in order for the Commission and for us who are involved in this thing day after day, it becomes quite important. You have the two curves on Exhibits 4 and 6, which -- would you mind just putting one of them up. Now, am I to understand that that is dimensionalivity time?

A No. We, this was as time assimilated, too. I plotted it against the volume injected. I have forgotten just exactly the time assimilation, quite naturally a number of years are assimilated.

Q I'm talking just about your scale experiment now.

A No.

Q Not correlating it to a field?

A When you put it on barrels per day you have to assimilate time into it, also.

Q Then in one procedure you put your water in at the rate of three hundred ninety barrels per day, is that right?

A Right.

Q Do your records reflect how quick you could break through or flood out?

A They sure do, but I don't have it. I think I can get it right here if you'll just give me a moment.

Q It seems to me that it's very important to us and the only point I want to make in connection with this.

A This is probably certainly within twenty-four hours or thirty-six. It's a short time.

Q Very short time.

A Yes, short time.

Q But the relative time is what I am concerned about.

A Relative time.

Q How much longer percentagewise did it take for you to get the breakthrough at three hundred ninety barrels a day than the forty-four barrels a day?

A I haven't plotted it on here. I did not have the figures for the difference in time of water breakthrough on these curves, but they're both back on, roughly in the same order of a water injected. Certainly these start curving over and when they leave linearity, that's the point of water breakthrough. I did not illustrate it and if it did occur at the same saturation at the same point of water injected, why there would be a tenfold difference in the time of water breakthrough and it's the difference in the recovery here determines the amount of difference in the total run time.

Q Were your runs made to breakthrough or to ultimate production?

A All of them were made to three pore volumes of water injected in breakthrogh was always back early. These, ultimate production, is on out here. You can see how little oil is being produced per unit amount of water injected and we felt this was sufficiently far to depict the story, the water oil ratios are extremely high.

Q You were dealing in this markup with two permeabilities, as I understand it?

A Two.

Q What was it?

A Sixteen and one hundred sixteen.

Q Sixteen and one hundred sixteen. When you had in your title on your forty-four barrels per day, when you had breakthrough, did you have any way to correlate whether you had flushed anything from the tight zone?

A We have to get out of here in a few minutes. We have got about five minutes. I won't presume to be - I want to get the one that has the adverse gravity. I want to get the one that has the adverse permeability on the bottom, the adverse gravity case is what I wanted to show you. This I think, will illustrate what you want to see. This is the observed flood fronts in the reservoir at four hundred barrels a day and at forty barrels a day. Actually this one, this gravity that I had here was not the favorable gravity effect, but here we have on the bottom is the one hundred sixteen millidarcy and on the top the fifteen millidarcy. You will notice that the low rate, it is tending to underrun. It's move at one-tenth of a pore volume. At four-tenths of a pore volume you will notice how much of this section --

Q That's the low rate?

A This is the low rate. Here is the high rate. You see there the gravity effect and you come on here at one pore volume injected, you see the relative amounts of water in the two cases at the two, in the two sands. You'll notice here that at the low rate we have flooded a lot more out of both the low rate and the high rate at one pore volume injected with the unfavorable gravity permeability on the bottom.

Q Well, now, you pictured just exactly what I, as a layman would have expected to see, and the point that I was trying to get was the fact that it's very clear from the pictures that you draw that the fast flood gets more oil quicker and less water to handle it than --

A Not all the way along.

Q Less water to handle in the early stages?

A In the early stages.

Q Now, the question, where in this economic-wise against a time plot would you have so much water to handle that you couldn't afford to get the oil out of your top reservoir?

A Oh, I don't know, maybe somewhere.

Q That's what we all need to know.

A Maybe somewhere, maybe a little less water than you can tolerate on the primary field. Maybe a little difference.

Q If we had the answer to that we would know where we were.

MR. PAYNE: I have one question.

BY MR. PAYNE:

Q Dr. Hocott, are you familiar with the testimony presented in case 1324 by Mr. Erlocker?

A Well, sure, generally familiar.

Q Where he testified that large amounts of water could be handled at relatively low cost, do you agree with that?

A Oh, I think you can handle a lot of water at low cost.

MR. PAYNE: That's all.

MR. PORTER: Anyone else have a question? The witness may be excused. The hearing will recess until 8:30 tomorrow morning.

FRIDAY, OCTOBER 16, 1959

MR. PORTER: The meeting will come to order. Mr. Hinkle, will you call your next witness, please.

MR. HINKLE: If the Commission please, before calling the next witness, I don't believe that I offered in evidence Humble's Exhibits 1 through 12 inclusive, which I would like to do at this time.

MR. PORTER: Without objection, these Exhibits will be admitted into the record.

MR. HINKLE: The next witness is Mr. W. J. Greenwald.

W. J. GREENWALD,

called as a witness, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HINKLE:

Q State your name, please.

A I'm W. J. Greenwald.

Q By whom are you employed, Mr. Greenwald?

A Humble Oil & Refining Company.

Q What is your present position with the Humble?

A I'm chief reservoir engineer, located in the Houston office.

Q Are you a graduate engineer?

A I am.

Q What year did you graduate?

A 1940.

Q What school?

A Texas A & M with a B. S. degree in petroleum engineering.

Q Have you practiced your profession since your graduation?

A Yes.

Q Since your employment with Humble, what have;been your positions with Humble?

A Well, I went to work with Humble in 1940, upon graduation, as a roustabout, worked as a roughneck, and then about a year after going with Humble, I was -- came into the engineering department as a Junior Petroleum Engineer. Since that time I have worked in various engineering capacities, both in the field and in the field of reservoir engineering until -- I've had my present position for about a year and a half.

Q Have you had any experience with water flood and pressure maintenance projects?

A I have.

Q State briefly to the Commission the experience you've had and work you have been engaged in, in connection with the work that you have done in pressure maintenance projects.

A Well, for the past ten years I have worked primarily in the field of reservoir engineering, and in various capacities. I have made studies recommending pressure maintenance and secondary recovery operations in various areas of Humble's operations. And as I advanced from one position to the next for the past, oh, I would say five years, I have been in the capacity of reviewing the work of others, passing final recommendations to management relative to the initiation and operation of all of Humble's pressure maintenance and secondary recovery projects.

Q Has the Humble, as an operator and company, had considerable experience with maintenance and pressure projects?

A They have.

Q Can you give the Commission an idea as to the extent that Humble has been interested in pressure maintenance projects?

A At the present time, the Humble Company has an interest either as operator or non-operator in forty-four water injection projects. Of these, twenty-eight are of the secondary recovery type, and sixteen are of the pressure maintenance type. In Humble's operations, the projects actually operated by Humble, we inject daily some one hundred and thirty thousand barrels of water and produce about thirty thousand barrels of oil per day from the secondary recovery and pressure maintenance projects. In addition, the Company produces about a hundred and thirty-five thousand barrels of oil per day from water drive fields. So you can see that our Company's combined daily production from oil affected by the water displacement process is in the order of a hundred and seventy-five thousand barrels per day. Now, this represents a sizeable portion of our total production. Consequently, for many years it has been necessary for Humble to concentrate on this particular displacement process both in our research laboratory as well as in our engineering effort, and to that end the Company has devoted many many many years in the study of the water displacement process, both from the laboratory viewpoint as well as from the actual field operations.

MR. HINKLE: Are the qualifications of the witness acceptable?

MR. PORTER: Yes, sir.

Q For the purpose of this hearing, have you prepared any Exhibits to present to the Commission?

A I have.

Q Now, refer to the Exhibit which has been identified as Humble's Exhibit No. 13; place it on the board and explain to the Commission what it shows.

A (Witness complies)

MR. PORTER: Did you say this would be Exhibit No. 13?

MR. HINKLE: Yes, the first one will be Exhibit No. 13.

A This is Humble's Exhibit No. 13. Now, we have plotted here some data on Humble's operated secondary recovery projects. You'll remember I mentioned in my summary that Humble had an interest in twenty-eight such projects. Of these, we operate twenty, and the other eight are operated by others in which we have an interest. We have listed these floods; they are all types of secondary recovery floods. We have the pattern type flood which has been most in evidence in this hearing. We have the line drive type flood, and we have the peripheral type floods, but all of these projects are of the depleted type, and we'll call them, as far as my discussion is concerned, the secondary recovery type project. I haven't added them up for you here, but we operate some 6100 acres of the flood. We have around 41,000 barrels of injection per day in these projects, and we have a daily oil production of some 4600 barrels per day from the twenty projects. You'll notice also that I have divided them into the various types of prorationing. Now, all of these projects happen to be located in Texas, and it might be a little confusing as to the words that we've selected here, but they refer to the various types of prorationing systems that are applied in Texas. Basically, these Arthur groups are non-prorated. They are more of an uninterrupted type, if you want to call them that. Now, here in these three projects, the wells are subject to a per well top, but the project is exempt from shutdown days, so this would be one form of prorationing, both subject to a per well top and subject to shutdown days. So you see that our floods in Texas run the full range of types of prorationing. I might add here that Humble has never asked for any form of exemption order in our water floods. In these fields up here we have had to go along with the other operators who have asked and been granted exemption from prorationing. In these particular cases here, these are County, regular fields that come under no shutdown days, so this is really going along with the prorationing system for that particular type of field.

Down here, most of these are Humble owned and operated, and we use the prorationing system that applies statewide.

Now, a great deal of attention has been given, not so much in this hearing, but in the hearing two years ago which I believe is called the Graridge case. Mr. Hinkle, is that not correct?

MR. HINKLE: That's right.

A A lot of attention was given to a magic rate of injection. I use the word "magic" rate, they may not have referred to it as that. But in reading the testimony, I got the impression that there must be an injection rate to get maximum recovery, and as I read from the testimony, I believe the figure was one barrel per day per acre foot as being the absolute number that you had to go to. And there was another number, I believe, of five-tenths of a barrel per day per acre foot, and that was the absolute low number. Anything below that you just couldn't go.

Well, for the purposes of this Exhibit, and incidentally, we never look at them this way at all in our Company, but for the purposes of this Exhibit, we have examined all our floods in terms of the injection rate in barrels per day per acre foot. You'll notice that they run the complete range, from a low of .04 barrels per day per acre foot in this particular project, to a high of 1.79 barrels per day per acre foot in this particular project, but you see -- I would say that we have the complete range of injection. Now, from this data we tried to examine to see if there was any effect, to see if these low rates were not doing any good at all and if the higher rates were our bonanza floods, and we could find no correlation whatsoever. I would like to call to your attention an area I think that most of the operators here are familiar with. It is the Kermit Field. Now, the Kermit Field is located in the so-called sand belttrend, Yates and Queen production that runs right on up here into New Mexico. The Kermit Field is just south of the New Mexico line, so this would be a flood that I would say would be quite comparable to a flood that you would have in the sand belt trend in New Mexico. Now, our best flood at Kermit is the Walton "D" Lease. This flood has responded very well, and our injection rate has been .2 barrels per day per well. Now, the only unsuccessful flood that Humble has is in the Kermit Field, and it is the Humble's Colby "C" Lease, and it has an injection rate of .49 barrels per acre -- I mean barrels per day per acre foot. Now, the Colby "A" Lease and the Howe Lease are both very successful floods. We have injection rates of .17 and .18. Now, I'm not leaving the inference here before this group that we attribute the failure of the Colby "C" to the injection rate, we certainly do not. But I was just calling that to your attention that if you play with data like this, and only this way, you might draw the conclusion that the highest rate we've had at Kermit has given us the worst flood. I'm not drawing that conclusion.

Q Mr. Greenwald, now, from this Exhibit 13, can you state to the Commission that you've arrived at any definite conclusion that any particular rate is the most efficient?

A I certainly have not. I think that rate is only one variable in the recovery process. Dr. Crawford has made a list of these variables, and there are some twenty-eight of them that effect recovery, rate being only one of twenty-eight, so I can't -- without much more detailed analysis of this -- I can't pin any particular effect here on rate. And I might add, Mr. Hinkle, that our floods have ranged all the way from one unsuccessful one to some very successful floods.

Q Mr. Greenwald, have you made any studies of field case histories in connection with water flood projects?

A We have had such studies made, Mr. Hinkle, under my supervision and under the supervision of Dr. Holcott. Our Company has analyzed all of the field case histories that have been put in the literature and on which sufficient data were available to the Humble to thoroughly analyze the results.

Q Have you anything to present to the Commission with respect to these studies that you made?

A Yes, I would like to discuss the field history case if I might. I would like to make a few remarks before getting into this subject because perhaps a great deal of emphasis has been placed on this subject that I want to discuss. I think the general feeling is that on the one side of this case one group of engineers have attempted to prove their testimony with laboratory results, and another group of engineers have tried to prove their case with field results. Now, that is the reason I think it is important that we look at the field result case. Now, as Dr. Holcott mentioned yesterday, and as I'm sure all of you are aware of, the field case history leaves a lot to be desired. I mentioned there are some twenty-eight variables in the recovery process. Now, these things -- these variables go along through the life of the project, and it is very difficult, if not impossible, to isolate one variable and make the change in it in a field case history because we are unable to control all of these other variables at the same time. This can only be done in the laboratory where you have actual control of all of the variables. So this is the difficult part of the field case history point now. Many such field case histories have been presented. It was mentioned yesterday that quite often the experience factor was gained through accident. A pump broke down, and we got the dope, or the Commission shut us in and we got the dope quite by accident, but now we know because of the twenty odd years' experience in actual floods.

Well, I would like to show one example here of how a very honest interpretation can be misleading because this is one of the accident cases. Most of you are familiar with this case. This information was presented by a Mr. Simmons who is an actual water flooding operator in Pennsylvania, and this is one of his cases.

Q You are referring to Exhibit 14, are you not?

A This is Humble's Exhibit No. 14, and we have here also -- and incidentally, this information was presented before the I.O.C. Committe on recovery, and Dr.Weinaug of the University of Kansas analyzed Mr. Simmon's field case and presented a paper also before the I.O.C. and I have just selectively taken, which I think are the key points from Simmon's report and the key points from Dr. Weinaug's report. If you'll bear with me, I'll run over this field case history because I think it is most interesting. This was a flood in Pennsylvania, as I mentioned, and the flood was on decline, as you can see here. Early in 1942 the pump broke, we had the mechanical difficulty, the accident happened, and they had to shut down the water flood for a big part of the year, and the production fell off and they finally got the pump repaired and they put it back on flood, and the production came right back here, and this was the subsequent history after the breakdown. Now, Mr. Simmons drew a smooth curve, and I would like to show you, if I could, just what this type of extrapolation is, or interpolation, rather. This is called the French curve approach. The analysis curves along here until he can strike an arc that in his opinion, in his visual opinion, will take care of most of the points, and then he removes the curve and he begins to think about his result. And he says, "Gosh, look, I never did get back that oil I lost." You see, I've made my study. He might even have had two or three curves. He may have had a complete set, you see, but anyway, he struck at oil, you see. And he may have even been more fortunate and had one of these. Now, he very honestly feels that he lost this oil. Mr. Simmons, I'm sure, really feels it, you see, and I'm not questioning his analysis, but I would like to point out what Dr. Weinaug has done, and this, I think, is interesting, too. Now, let's say that this is all the information we have. Let's move ourselves back to 1942. We are rocking along here, and let's ask a young engineer, one of these young engineers with the new ideas, to analyze this back history and this young engineer knew about the Lease Means Square method of analyzing past data. He had been told about the difficulties you get into with this type of analysis and that there is a mathematical way of analyzing data, so he would come back here with the Lease Means Square method and he'd say, "Well, this is my past dope and I'll match it by the Lease Means Square method, and he would make a report that this is the way it is going to do, but here is the way it actually happened. Incidentally, this particular equation is of the first order type, they call it. Most of us would understand a straight line as being a better description of it, but this is a description of the State Order, and here he comes along here, and one may conclude from this that, well, from this accident that happened, we really learned something. We learned that if we shut them in, it is this much better. I don't draw that conclusion, I'm just pointing out some of the dificulties we get into with this type of analysis. The wrong man might have gone on here and said, "Well, this past performance is better matched with an equation of the second order," This type of an equation, you see, and he uses the Lease Means Square method of averaging all his data point not trusting his eye to even them in there, and he comes out with this sort of a curve, and again, the only conclusion that he might come up with is that by curtailing the flood here, he got lots more oil subsequently.

I would like to just point out one other thing. There is no mathematical equation that can describe this line; there is a discontinuity right here. If you examine it closely, you can see it visually. This is where perhaps he slid the curve to get the smooth point. Now, I would to show one other thing, if I might, here. I don't want to belabor this point too long, but let's just say -- let's just say, if you will permit me, that this is what actually happened to the flood afterwards, you see; let's say that the flood did that. Then you can come up here. Now, in the -- all these data points here, just these points here, and you can come through here with a curve. This one doesn't do it. I think I'm going to have to -- you can slide these back on in here, and you come to the same conclusion that you lost your oil, you see, and let's say that the data points went this way afterwards. You see, all I'm trying to do here is to show the fallacy of this type of analysis, is that either way -- you cannot -- you cannot draw a line through this point and come to any conclusion other than you lost your oil here. This is just one of the difficulties that you get into in this type of extrapolation. And Dr. Weinaug has done a very careful job, I think. There is one other point I would like to make that even with this curve the analyst did not match his future point. There are more points above the line than there are on the line. There is only one point below the line, and if you take just the data above the line, there was more oil produced in the subsequent decline than was lost during this half year period. Now, this is the type of field case history oil that describes about half of them which is the decline curve approach, and this approach has been used in many many articles. We've analyzed all of them, and we can't conclude from the examination that oil was lost due to interruption of the project.

Q Now, Mr. Greenwald, in connection with the Graridge case, which the Commission heard in October, 1957, the Browning unit that was referred to by the porponents of water flooding as being an outstanding case, showing the necessity for a higher rate of injection, have you made an independent study of the Browning case?

A Yes, I've had a study made under my supervision and Dr. Holcott's supervision. We have studied that case as carefully as we could with the data that has been made available.

Q Have you prepared any Exhibits to present to the Commission in connection with it?

A Yes, I have. We thought that the Browning case would be of particular interest to all concerned because in reading the testimony it was referred to as "the proof of the pudding." I believe one said that it is the most outstanding example that has ever been shown, that increase in injection rate enhanced ultimate recovery, so I thought it would be of interest to examine that here together and to again show that when all the facts are in that one might conclude a little bit differently.

In this Exhibit No. 15, this is the identical Exhibit that was shown in the Graridge case as Exhibit No. 2, I believe, except that there has been six months of data added. Now, this data we took from an AIME paper that was presented at Wichita Falls sometime in 1958, I believe. Now, this was the information that was presented in the Graridge case, and I'll give the conclusions that were drawn. The Browning unit, as you all remember, was discovered back in the 20's. It went back through a period of decline due to dissolved gas-oil production. It was gas driven for ten, twelve years, and then it was unitized, and water flooding started here, oh, say the middle of 1949, and water was injected and has been injected since in this reservoir. Now, this was the data that was presented, and it shows that between 1949 and 1955, that there was little response from the water flood. It shows here under daily water injection that they had some ups and downs in it, but that the water injection was generally low in terms of total volume of water put into the reservoir. This was explained by the difficulties that they went through in obtaining source water, but once they got an adequate source they were able to increase the water injection and they finally got results. Now, all -- the best that I can find out -- all of the success of the flood measured in this vertical scale, the up part of it was attributed to the increase in water injection. We carefully examined the data, and we found that there was another factor coincident with the increase in oil production, and that is that fillup of the reservoir occurred right here. I believe I have it right -- somewhere in this first upswing, and I think all of us who have played with these water floods know that you get your response when your reservoir fills up and the water injection -- and we also know too, of course, that if you increase your water injection rate that you will increase your oil production rate, that is uncontroverted; you put more in, more comes out. Now, as far as ultimate recovery is concerned, I think that the real question in the case is the ultimate recovery. Notice this, this is water-oil ratio. As the injection rate was increased, there was not a corresponding increase in oil production. As a matter of fact, oil production went down. There was less oil produced per barrel of water injected when they fogged her to it. Now, one might draw the conclusion, and I'm not drawing it, one might draw the conclusion from that that the high injection rate was less efficient.

Before I leave this Exhibit, there is one other point that I would like to make, and I think I'm quoting the testimony correctly, this statement was made in the Graridge case. From 1949 to 1955, I believe the question was aked, had there been any response to the water injection, and the answer was there had been no response to the water injection. This indicated no response. I would like to show the information on the pilot area.

Q Mr. Greenwald, was substantially that same statement made here, too, in connection with the Browning unit?

A I think that is correct. Was it Mr. Yates? It doesn't make any difference. I think the statement was made that there was no response. Now, it depends on what you want to make your division, on when you want to show things. If you analyze a pilot flood over here and choose to divide by the size of the field, you can get one answer. If you've got a large pilot, you might have to divide by the whole state. But, anyway, the point is that you've got to examine what is happening, where the water is being injected before you can draw real conclusions. This is the performance of the pilot flood.

Q Now, what Exhibit are you referring to?

A This is the next one, Mr. Hinkle.

Q Is that Exhibit No. 16?

A No. 16. Now, we notice here that this particular response in the pilot area had just been about what I think anyone would expect from this pilot. The first response, actually, I think they had earlier response, if you want to take the fact that decline was arrested, they got immediate response, but certainly that response -- I think all of this is response. I think this is to be expected; due to their water source trouble they had to decrease their injection rate, you see, and then they increased the injection rate and here came the production up and the production is climbing on up. So I suspect that the performance on the pilot area is as much as could be expected, particularly if you take a look at the pattern. I would like to show you the pattern just very briefly. Certainly this isn't being critical because we've got many of them that look like this too. These things happen. Sometimes you can't control them when you are experimenting in the field. But you see here the size of these circles are representative of the amount of water that is injected. So you see you had a very unbalanced condition in the pilot, and you had these wells out here finally put on, but undoubtedly a lot of oil was pushed out of the pilot area, and consequently, a measure of the oil produced from wells in the pilot cannot necessarily be taken to mean that that's the efficiency of the flood in the pilot.

Q Mr. Greenwald, this Exhibit is a little out of order than those that we had marked by the Reporter.

A This would be No. 18.

Q That's right, Humble's Exhibit 18.

A That's right. I just wanted to show that because of the water source problems and other problems they got into a very unbalanced condition in the pilot, but I think the information from the pilot would help to expand the flood, and it has all the earmarks of being a successful flood. This would be Humble's Exhibit No. 17.

Q That's right.

A Now, I think the statement was made that the increased response in the Browning unit was due to the increase in injection rate, and of course, when you say injection rate, sometimes you wonder if you are talking about total barrels per day or barrels per well or barrels per acre foot. We don't know -- The statement, I think, was made that the injection rate was increased from two-tenths of a barrel per day per acre foot to seven-tenths, I believe, was the statement that was made about this. And from what statement we have, and let me hurry to say that we don't have all the data on the Browning unit, this is just trying to analyze the information that we were able to get from the literature on three published statements on the Browning unit. But we went back and we couldn't match at all in our analysis about the increase in injection rate. We notice that they started out at .85 barrels per day per acre foot. Now, of course, if you are going to divide the water injected in say one or two pilot wells by the whole acre net in the field, maybe you would come with a point down here. So what we tried to do is, we tried to find out the acre foot affected by the water injection, and, of course, that's a number that is increasing all the time, and we found that there was quite a bit of variation in the injection rate throughout the project. As the operators mentioned, it was due to this water source difficulty, and here was the point at which they got their water source problem worked out, and here was the increase in injection rate. Coincident with working out this water source, they put on a lot of other injection wells, too, you see, so it was hard for us to see that the barrels per day per acre feet went up an awful lot. As a matter of fact, if you just want to take points, it started out at 85 and it's down about 52 now, and we also took the liberty of averaging these, but on the average we would have to say yes, the injection rate goes up from about .58 to about .62, so I think all we would like to say about that is that our examination of the same data, and again I hurry to say, we don't have all of the data. We can't find this increase in injection rate, you see. Now, I think the statement was made that because of the low injection rate that there would be very little recovery in the pilot area because it had suffered so long under the low injection rates. I would like to show this information that we got from the data, and that is as of --

Q This is Humble's Exhibit No. 19 that you are referring to?

A Yes, sir, as of 1/1/58, the last information that we have. The pilot area had recovered about forty barrels per acre foot, and outside the pilot area was thirty-two barrels per acre foot. Now, of course, we all know that the pilot area should have recovered more than that outside the area. This isn't the point. The only thing that we can't see is how the operator can draw the conclusion that he is going to get no, or substantially no recovery in the pilot area while outside the pilot area it is going to be real large. I am also glad to know that we've had, as I mentioned to you, available to us about six months additional data, and we noted subsequently that the analysts for the operator have changed their minds a little bit about this project as we changed our minds about ours, as we get more information, and certainly this is normal. As we get more information on a project, we are prone to draw different conclusions. I would like to state the opinions of the operators in this case, in three different places, so that we can touch on that point. In the Graridge case, the statement was made that there was no response in the field from the water injection. I think in the Wichita Falls paper the operator said yes, there was some response.

Q When was the Wichita Falls paper published?

A It was -- well, I've got it here. This was a symposium on secondary recovery at the third biannual meeting in Wichita Falls of the North Texas section May the 5th and 6th, 1958.

Q Is he talking about response at low rates or high rates?

A It was the response during this six-year period which was the low rate dates. There was some response which, of course, we noted in the pilot area, but that the recovery in the pilot area was going to be real low. That's moved from no recovery, practically no recovery to a real low recovery, and then, I believe, before the Oklahoma Oil Commission the statement was made by the operator that recovery outside the pilot area in some instances might be as great as twenty-five percent more than in the pilot area. So, as we've gotten more information, we are all beginning to see that there is going to be production from the pilot area and that outside the area might be in some places as much as twenty-five percent more. Now, this is normal, and I'm certainly not trying to be critical here, I'm just trying to show that these field case histories are faced with a lot of difficulty in analyzing. We take certain data and one operator analyzes it one way and another operator can take the same data and sometimes come up with slightly different conclusions.

Q Mr. Greenwald, do you have any other case histories of Humble to present to the Commission?

A Yes, I do, Mr. Hinkle. I would like to show three cases of Humble's operations that we think show fairly well certain things as best we are able to analyze them. This is our Exhibit No. 20?

A Yes, that's right.

A This is Humble's Exhibit No. 20, and this is a small field in North Texas in Shackelford County that is one hundred percent Humble oil. And this field, like the Browning case, was gas driven, was first produced by dissolved gas drive, and then gas driven, and subsequently water flooded. There was only one royalty owner and one operator, there was no unitization problem here. The only point I would like to show from this Exhibit, and this is the one that I mentioned to you that had the per well top, so it was a prorated case. I just wanted to show here that here is a flood that was prorated, and we think it is operating fairly successfully. During fillup, you see, we had injection rate up here between four hundred and five hundred barrels per day, and as we got fillup here, we cut the rate back for the proration case. In other words, we control the production by the amount of water that we put in, and this was during the flush period here, the prorated case, we had water break through back in here, and then, of course, as more water was produced, we had to increase the injection rate to keep the total fluid balanced. So here is a case of one that is, oh, I would say probably half through or a little better. And one thing that I thought was of particular interest here was the fact that after the formation had gotten kind of used to taking water here at about 300, that it could take some more. You know a lot of the information has been published in the literature that once you get things going a certain way that you can't change them. Well, of course, I'm not applying this everywhere, I'm just saying that these particular sand grains that didn't know that, they went ahead and took the water as the pressure was put back on the formation. Of course, this is just one case, and it is a sandstone in Central Texas, so I wouldn't want to draw any conclusion from that at all, other than to say that this one has been done.

Now, we move to the limestone case. This is another little field in which Humble is the only operator. This was a little reef in Throckmorton, Texas.

Q You are referring to Humble's Exhibit No. 21?

A Yes, sir. This case was quite a bit like the case up at Coates Ranch, it is a prorated case. We have the injection rate during fillup, and we cut it back here to -- and we have operated this under proration since that time. The increasing proration rate was to offset it. Now, in the North Central floods, here again is the limestone case, and we have been able to increase the injection rate after the sharp curtailment here, so we find here even in the limestone case that the water will go back up in the injection wells.

I think that's about all. I would like to show here just another prorated case that you can fill up at any rate you wish, but once you get the fillup, if the oil comes you can cut back and amazingly enough you can increase your water injection to off-set your wells.

Mr. Hinkle, I would like to put up two Exhibits at this time, if I may.

Q Sure.

A These would be Humble's Exhibits --

Q 22 first one, and 23 --

A 22 on your left, and 23 on your right.

Q That's right.

A Now, this is a little field in Southwest Texas, a little sandstone field, Jackson Sand. Humble is the owner of this lease down here, and there were two operators above. Now, this is one that we worked on in a cooperative basis. The field is South 76 in Duval County of Southwest Texas. We thought this one would be of real interest to you in that we suffered a little problem here, one of these little accidents that we might mention. This one was a litigation case. This particular lease went under litigation.

Q Is that the one shown on the plat as "B," the lease you pointed to?

A Operator "B," right. The lease was under litigation for about a year and after water flood started, so they had to shut in the water injection wells and the oil wells, too, for a whole year. Now, each operator then had to scratch his head and figure out what would be the best thing to do because this was out of the control. This is, I suppose, the force majure case, if I might not be reprimanded for using a legal term. But this operator couldn't help it. He was taken into Court. So this operator decided, well, he wanted to --

Q That's the one shown on the plat as "A?"

A Operator "A,", yes, sir. This operator said, well, he believed he'd stop his injection, but he would keep producing during this period, and Humble -- we scratched and said, "I expect we'd better go ahead, inject water and produce. So during this year we have three different things happen. One operator completely shut-in because his hands were tied. This one had a tough decision, but decided not to inject. We had an equally tough one, and we decided, well, we will go ahead. Well, I would like to show you the performance that has taken place because they are rare cases. This is operator "A," the operator who decided to produce but not inject, you see.

Q You are referring to Humble's Exhibit 23, now?

A I suppose so. This is the production history during this period. This field peaked early and went on dissolved gas production, as you can see operator's "A" lease. And here was the subsequent response due to the water flooding, and he was coming up pretty nicely here, you see, and he decided to stop injecting water, and it fell off, as you might expect, but then the litigation was over and he got things going back again. And this operator was able to restore his production back up to the point that he had it before, and then the project went on decline. Another thing that I would like to point out, and, of course, again, this is only one case, and a sandstone case too. But after keeping those wells shut-in for a whole year, they did take water here about as good as they took back here, and I think that's a point that we want to remember. I would like to leave this Exhibit up, if I may, as I show different performances here.

Q You are leaving No. 22 up?

A Yes, sir. And I'm coming with 24. Now, again, one way that you have of trying to analyze the before and after performance of a flood is the cumulative oil curve where you plot your cumulative oil production against your cumulative water injection to see if there is any radical difference in the slope of your curve. That's one way that you have of doing it, it is not the only way, but it is one criteria. Now, you'll notice here, of course, this oil. This is cumulative water injected curve, you see.

Q You are referring to operator "A", now?

A Operator "A," yes. This is the same information except it is on a cumulative basis. This is because water was stopped for a whole year, so when you are plotting against cumulative water, you see, the curve, the oil went up, but the water didn't. So you have this discontinuity in the curve, but I think the point is is to measure the slope of this curve before and after the shut-in. And we can't tell any real difference. The average slope of this curve is slightly better than the average slope of this curve. This does not, of course, make us conclude that the shut-in was beneficial, but if you are not careful, one might come to that conclusion. Now, I think this is the one that is particularly interesting.

Q This is Exhibit 25?

A Right. This is a complete cessation of operators.

Q This is still in the South 76 water flood?

A That's right, and lease "B." Now, here, again, lease "B" went through the same general performance to build up during the drilling, the falloff due to the production decline, the response to the water flood, and look what happened to him. You see he was going real good, and then the litigation took place, so he had it shut-in.

Q How long did you say that was shut-in?

A Just about a year. I think it is actually -- let's call it a year. It is so close to a year it would be a year. Now, he had to set there and suffer for a year, you see, and then he put his flood back on a year later, and he built his oil right back up and it is leveled out up here. So just from that you can't see too much except that it did respond. And the other thing that I notice here, too, these things continue to amaze me as I examine these data, is that after that whole year the well was able to take water and then even more water. Those things, I think, are important. Now, this is Exhibit No. --

Q 26.

A -- 26, and it is the "B" lease, and it is the South 76 field on a cumulative basis, you see. Now, here is that shut-in period. You notice we don't have that breakup because here everything stopped, oil production and water injection, so on a cumulative basis it is just stopped. This black line here represents one year because nothing happened during that year. Now, let's examine the slope again before and after, and we come up with a slightly greater slope here than there, which means that the flood was a little bit better afterwards, but we are not concluding that, we are just saying that nothing has happened here that this flood was not irreparably damaged as a result of cessation of operations for the one year period; this I would like to conclude.

Now, this is just put on to complete the picture. You know a lot of us get accused of selecting a data, we engineers, and I'm not accusing anybody, even myself, for doing it, but I would like to complete the picture because I know what's going on in your mind, you see, as to what happened to that Humble lease down there.

Q You are referring, now, to Exhibit No. 27?

A Yes. And, incidentally, I would like to make this point on field case histories in general. If you are showing the results of one five spot versus another five spot, like if you happened to take a 40-acre lease up here, and, say, a 20-acre lease down here, and you are trying to compare the results, you can't get the complete picture, and I know all of you will agree with this, until you examine all the five spots around that one here; and all of the ones down here you have to run a complete oil balance on these things because if you don't you might -- someone might think you were selecting data, not that you were, but you've got to look at all of this stuff, you see.

Now, here is the performance, and I'll show you the cumulative curve on the Humble lease. We went right on through this shut-in period, and we think our flood is performing just about normally for the area. All of the floods there are now on decline; they are over the hump, and they have been successful.

Q Mr. Greenwald, the proponents of capacity floods have stated that water flooders try to inject one barrel per day per acre foot to obtain the maximum recovery. Have you made a study of the rates that most operators have used?

A Yes, sir, our Company has made such a study.

Q Do you have any Exhibit to present to the Commission in that connection?

A Yes, sir. I would like to show what information we have been able to get from the file record, public record. This is an -- Exhibit No. --

Q 28.

A -- 28. Now, this is information on Oklahoma water floods that was published, I believe, by the I. O. C., and this is the latest information we have because I.O.C. has not put out any subsequent information. But this is a report on a hundred and fifteen Oklahoma projects in which there was sufficient information included in the I.O.C. report that you could arrive at what the injection rate was in terms of barrels per day per acre feet -- acre foot. Now, all I would like to do in this instance is call attention to what I've called the magic number here; I don't know what it is, but it is this one barrel per day per foot of acre sand; you'd like to have that or more. And I'd like to call attention to the five-tenths which is the rate, I think, below which you shouldn't ever operate. I hope I'm describing these right, but this is the way that I got it from the transcription. Well, we notice here that the magic number or above has thirty-two projects operating above and about, or more than half of them operating at five-tenths or below, you see. So that this is just a statistical report of getting some information together, and all it says here to me is that most operators do not operate at one barrel per day per acre foot of sand.

Q Have you compiled any information with respect to Texas along the same line?

A Yes, sir, I have.

Q The Exhibit you have there is Humble's Exhibit 29?

A Yes, sir. Now, this is the same information treated in the same way as projects in Texas reported by the

Texas Railroad Commission. Now, these are projects that were put -- initiated during a two-year period, so that would include '56 and '57 data. These are projects initiated in '56 and '57. And, again, we are only able to analyze two hundred and four of the projects. There were more projects reported, but we didn't have sufficient data to calculate this here, so we had to limit our data here to the two hundred and four projects. Now, let me call your attention, if you please, to the magic number of one barrel per day per acre foot, and this is the point of no return. If you operated one down here, well, you've had it. Well, apparently, this information hasn't gotten really widespread because you'll notice that most of the projects are operated at five-tenths or below. That's one point, but I think an equally important point might be made here, and that is most operators in Texas have asked for and have been granted capacity allowables. And yet the operators in Texas do not operate at capacity, so I'm just wondering if maybe the question is not capacity flooding but self proration. This might be what one might draw from this, that they want to be operated the way they want it and not by the day, as they have the next. So what they want is self proration and uninterrupted proration is what they want to do. Again, going through the minds of some of the engineers this morning is, "Ah," but yet the reason they are down here is because the sand wouldn't take it. They are going at it as efficiently as they can, but they don't do that. But I just happened to have my fiddle on that one, save the other side to embarrass you by asking this question, and it coming out later. This is the pressure information on each project.

Q You are referring to the overlay over Exhibit 29?

A Yes, sir. Now, what this shows, in the red, these are the projects with one pound per square inch per foot or less. The one pound per foot is less than the overburdened pressure. If you would go over that, you would break open the formation and fracture. We notice again from the red curve that the pressure in the formation tightness is not the limiting factor. Operators are still asking for capacity but still not injecting as much as they could, so most of the projects are not limited by pressure, is the only point I wanted to make here, you see. Now, I would like to show one more Exhibit, Mr. Hinkle, if I may, on this rate question.

Q That is your study of injection rates in Southeastern New Mexico?

A Yes, sir. Now, I would like to apologize for this one a little bit.

Q That's Humble's Exhibit No. 30 you have reference to?

A Yes, sir. We had to compile this information from data that's been submitted to the Conservation Commission, and I would like to say here that it may not be exactly right. All we have is the reported information, which sometimes in our state is not as factual, but this is what we had to go on in this particular case. Now, these are injection rates in Southeast New Mexico floods in barrels per day per acre foot. Now, I'm sure the operators here are doing the best they can, but only one of them has gotten up above the point of no return. The other ones are all operating down here at less than this one barrel per day per acre foot of sand, and also less than the five-tenths of a barrel per day per acre foot. And, again, one might conclude from this that the operators aren't really asking for capacity; they are asking for capacity, but it is really a self proration sort of an idea.

Q Now, Mr. Greenwald, the non-prorated flooders have said that a great deal of difference exists between pressure maintenance and secondary recovery. What are your views in regard to this matter?

A Mr. Hinkle, I have given this question considerable thought, considerable study through the years. Actually, I can't find any evidence at all that secondary recovery is any different from the pressure maintenance case. Now, this is a point of disagreement among the engineers, as you know. The proponents of capacity floods have said in testimony and in conferences and at technical meetings and all, when asked the question, "Is there any difference between secondary recovery and pressure maintenance," they say, "Oh, yes, there is a great difference between secondary recovery and pressure maintenance." And then you ask the question, "Why?" And this is the thing that we have used a lot, and quite a few of them say, "I don't know why, I just know that there is." Some do venture an explanation. My memory is not too good, and I can't quote directly, but I think one engineer in favor of capacity floods said that it is because of the gas saturation that is present, that under the low rate the water just sort of trickles by, triddes through, nothing happens, but that under the high rate the water beefs itself up and gets to be real efficient, you see. Well, that's not -- you can't find that explanation in your textbooks, and you can't describe that in any way in your physical phenomena, your calculation, so it makes you fuss a little bit and worry about it, so then you say, "Well, golly, bum, this gas saturation is present and that seems to be the only difference, the only problem here is the gas saturation," so you ask one of your boys and say, "Look, let's take a reservoir like the Caprock-Queen, or any of these Queen fields in New Mexico, and let's figure out how much pressure you have to increase the reservoir to get all of the gas back in solution. Maybe that's the way to approach this thing. So we calculate the thing, and he comes back and tells me it only takes 75 pounds elevation in pressure. Let me set the figures here for you so that you could check these. The original pressure is 1700 pounds, 1636 to be exact, and the reservoir pressure is a hundred pounds per square inch at the end, and the gas saturation ranges anywhere from 20 to 40 percent, so we use 30 percent in our calculation. So the engineer comes back and says it only takes 75 pounds elevation and pressure from one hundred pounds to a hundred and seventy-five to get all the gas back in solution, and of course, you tell him he is wrong, go back and calculate that again. It can't be wrong. These people that are hanging their hat in the gas saturation peg couldn't be wrong, go back, you see. So, he goes back and comes back, and he says, actually if you take everything into consideration, it is only 25 pounds, but I took the worst case, and none of the gas left the reservoir during the fillup period, it just stayed in there, so I had to find the point, and I didn't really believe it, so we had the boys in the laboratory fix us up a model that shows this, Mr. Hinkle, and after I show this next Exhibit, I want to show this model because this thing really was surprising to me, that it doesn't take any pressure to put this gas back in solution, you see, for those of us who like a yardstick. Now, you take a 1500 foot well, you see, that gives you 750 pounds, just the waterhead; that is, if you just poured it in there with a bucket, you would get 750 pounds, and we are only talking about 75 pounds and, actually, it is less than that, it could be as low as 25 pounds and that gas has got to be back in solution the first day that water hits that formation. So then, where are we? We are right back with the pressure maintenance case.

I've shown this schematically.

Q This is Humble's Exhibit No. 31 that you have reference to?

A Yes. I'll show this schematically, if you'll permit. This is what the model -- this is what the actual model is going to show, but I would like to run through a minute with it. This is the reservoir at a hundred pounds per square inch. The oil is in black, and these dots are the gas. So this is the condition at depletion. Now, here we have the case when you first start water injection into your depleted reservoir. You see the oil bank that's been referred to building up here, this oil bank is, in effect, this oil that's denuded of gas because the gas has gone back in solution. This is the condition where you get fillup and this is your residual oil being left behind. Now, here all of the oil, the gas is back in solution, and all of the oil at fillup. Now, this isn't just theoretical laboratory stuff. All operators have noted this in the field, and let me tell you how they noted it. In this fillup case, or at this point they don't denote any high gas-oil ratio production. See, your relative permeability relationship would tell you if you had gas saturation present, your production would have to be high gas-oil ratio, but the wells are not high gas-oil ratio after fillup, you see, than the other points. And this all of us have observed that have played with this water flood. Your gravity goes up, the gravity of the oil goes up.

Now, this shows from your field information, your field man can arrive at this same conclusion, as I have arrived here, as his gravity goes up. That's because the gas went back into solution in the oil, so the only point I want to make here, and I'll set the stage here for a subsequent Exhibit, Mr. Hinkle, is the fact that when you get your secondary recovery project in this condition after fillup, this little droplet of oil here doesn't really know whether he is a secondary recovery droplet or pressure maintenance droplet, you see, because he is being produced just the same, he wants to get out of there.

Q You have identical situations in the pressure maintenance and the secondary recovery method?

A Identical in every respect. Now, I want to, if I could, Mr. Hinkle, I would like to show the next Exhibit and then come back to the model demonstration, if you think we have time for it.

Q You meant that the displacement process was the same?

A Yes, identical. And that, of course, is what the argument has been about in the past.

Q Now, you are referring to Humble's Exhibit No. 32?

A I would like to run over this one very briefly. I would like to run through this one and then we will go into the model.

Q You are referring to Humble's Exhibit 32?

A Yes, sir. Now, these are pressure maintenance projects, as we pointed out before in our thinking, and we've given a lot of study to this, and in our thinking, there is no difference in this displacement process between pressure maintenance and secondary recovery. So I want to show the Commission the secondary project that Humble has an interest in in Texas.

Q Humble has an interest in all of the projects that are shown on Exhibit 32, is that right?

A Yes, sir. So I want to -- first want to show you the largest water flood in the U. S. and that's the East Texas Field where water is, four hundred and seventy-three thousand barrels a day of water is injected in the field to maintain the pressure. A hundred and thirty thousand barrels of oil is taken out of that reservoir every day. And they are using an injection rate of one-tenth of a barrel per day per foot of sand. Now, the second largest water flood in the U. S. is the Sacroc unit. There we have one hundred seven thousand barrels of water going in every day. Fifty-eight thousand barrels of oil comes out of this project every day, and look, the injection rate is only one-hundredth of a barrel per day per foot of formation in that pay. Now, this information that we've had proved to us from the field case histories and the information that you've got to inject at this rate, you see, concerns us an awful lot because for many years we had the idea that we were doing pretty good in East Texas. The recovery in East Texas, for your information, is eleven hundred barrels per acre foot. Now, I just don't believe any of these Permian formations will ever get to that fast or slow. That's an awful lot of oil per acre foot, eleven hundred barrels per acre foot, and we thought we were doing the right thing by controlling that reservoir and injecting at this low rate, you see. Now, we probably will run -- after listening to the testimony that has been given, we probably should increase this up to one, you see, and we ought to take a million and a half barrels out of the East Texas to prevent waste and really have efficient recovery. We should take a million and a half barrels out of East Texas. There is wanton waste going on there because of this low injection rate. Now, the Kelly Snyder, we have really got a problem because, look, we've got to take six million barrels out of Kelly Snyder to get it up to the efficiency of this secondary recovery flood. Kelly Snyder has another problem that is real serious, and there is nothing we can do about it, but Kelly Snyder had gas saturation present. Actually, there were high gas-oil ratio wells in the field at the time of the flood, and with this high gas-oil saturation we were afraid, you know, that this water would begin to sashay through the reservoir and we would have a terrible flood, but fortunately something happened there that wasn't just right, that we are not getting that sashay at Kelly Snyder. As a matter of fact, one of the Commissioners in Texas, I believe it was General Thompson, said this thing stands as a monument to conservation. Of course, he didn't know at this time that we were injecting but -- .01 -- but he did say that this was a monument to conservation. So, this thing has disturbed Holcott and myself a lot, and we've discussed it with our management. They are worried too. You see, we did this figuring. You all can do it too, to get all of these converted to one barrel per day acre foot flood. You see, we would have to take nine million barrels a day out of these floods, and we know that would have a -- it is a terrible impact on everything. So I guess we are just going to have to go on and operate this inefficiently because there is really no way that we can get the nine million barrels on it and market under the proration -- the market demand statute, there is no place for this oil in the market. This is one, two, three, seven fields, and nine million barrels. Well, it would be, we'll just have to go ahead and suffer in East Texas at the eleven hundred barrels per acre foot, I guess.

Now, I would like to show this model, Mr. Hinkle, if you think we have the time.

Q Yes.

A It is a very nice job the boys did to visually show this thing that I was talking about, the thing that the field pumper knows about because of his gravity and gas-oil ratio, but this is the thing that I want all of you to see, that this thing actually does happen.

Q I think if you will put your Exhibit 31 back on the board there, it would be helpful.

A All right, sir, I sure will. If you will push that over towards you so that they can see it on the back.

Now, this model duplicates -- this is Mr. Joe Richardson from our production research division, Mr. Hinkle, and this model was prepared under his supervision. He is going to actually run the model for us. I'll run it for the people here, just what it is.

This is a glass cylinder that is twenty-four inches long and it's one and a half inches internal diameter, isn't that right, Joe? And it is filled with little glass beads to stimulate porosity and permeability. Now, in that is an oil, and it's filled with oil that has been colored so that you can see the oil, and it is saturated with carbon dioxide. Now, the reason we use carbon dioxide instead of methane is that we -- because carbon dioxide is more soluble than methane; two to one factor, so you won't ask me that question.

Q Mr. Greenwald, does the model have connate water too?

A Yes, it does. This was done as a safety precaution so that we can run the experiment at lower pressure. This would be identical with methane and an oil system, I'll assure you, because we have done it. This is a reservoir that has just been discovered. Now, we are going to produce this reservoir for you, and this demonstration doesn't take too long, and the oil is going to come up in this burette here, and you'll notice the production -- you'll notice the high gas-oil ratio production toward the end of the life of the reservoir, you'll see the clouding of the burette. That will put the reservoir in this condition, and this is where it will be ready for water flood, you see.

Q That simulates a horizontal reservoir?

A That simulates a horizontal reservoir. We are not putting any dip in this case. Notice what happens up at the top here. The gas is breaking out of the solution, you see, and pretty soon it is going to be all over here, and see the oil going into the tank. Now, you see the first bubble of gas. That is when he had to report his first G O 2, see. At first he had low ratio, then it begins to be a little higher ratio. It is going right along here. Now, this is the whole life of the reservoir. This might be -- look at the gas coming, and that's when you face the big question, should I report it or should I not. See how it is frothing here. See how the reservoir is in this condition. About in this point in the life, that's when you put your flare out, you know, you put it out so somebody can see it. Now, it is just about depleted. If we would carry it out, this thing will trickle and bubble, you know how it is with stripper production, and it might recover a little more oil here, but this is essentially, as Mr. Yates said, this would be essentially depleted, it is not completely, but essentially depleted. Now, I might explain here, Joe, if I might, this is a tube of air under pressure that will go into this beaker and force the water into it through this regulator into this. This is the injection well, now, you see. Now, this would simulate a water pump, but we are just doing it with a little manipulation, but it does the same thing at this end right here. It wouldn't know whether it was a gas charged chamber or water pump, but the water is coming in. Joe, you have it coming in now.

Q What about the pressure gauge?

A Now, the pressure gauge only denotes the injection pump pressure. It is not the pressure of the cylinder, is that right? Now, you'll notice in here that the gas has gone back in solution. How far over, Joe, can you see it? It is practically all the way over -- no, just a little bit right here at the well. Now, this well would still be a stripper deal, you see. This is the fillup period. Your gas is just about gone back in solution. Here is your water front right through here, and there is no water here or here.

Q How is that shown on your Exhibit 31 there?

A Right here. You see, when you start here, it is like this and this. I should have been giving you the commentary right on through it. Joe, read a real rapid case for me. But this goes on right across until it gets to this shape. Well, practically all of the gas has gone back in solution except a few bubbles up here. During fillup, your wells fills and finally she goes like that. It is about at the place now where your well would respond in the field. You see, all I'm trying to show is what is the phenomena during buildup so, Mr. Hinkle, I think that concludes our testimony.

MR. HINKLE: Thank you very much. That's all we have of this witness.

MR. PORTER: Let's have a ten minute break.

(Short recess)

MR. PORTER: The meeting will come to order.

MR. HINKLE: If the Commission please, before proceeding with cross examination, I would like to offer in evidence Humble's Exhibits 13 through 32 inclusive.

MR. PORTER: Does that include the model?

MR. HINKLE: No.

MR. PORTER: Without objection, the Exhibits will be admitted. Does anyone have a question of the witness?

MR. McGOWAN: I would like to ask one or two.

CROSS EXAMINATION

BY MR. McGOWAN:

Q Now, Mr. Greenwald, in listening to your very complete and illustrative testimony, I heard you mention many times that you didn't draw certain conclusions. I did not end up in my own mind with a clear impression of what conclusions you do draw in connection with the hearing that is under way here. Just what are your conclusions or your recommendations to the Commission with what they should do with water floods?

A Mr. McGowan, we have a subsequent witness who is going to present testimony relative to what my Company's position is relative to this hearing, so I would like to defer to the next witness in that respect.

Q In other words, then, am I to assume that, in effect, your testimony has been for the purpose of presenting certain information and engineering summations and instances, at least conclusions in support of the, or part of the background in support of the recommendation that will later be made?

A That is correct.

Q Now, I'm not interested or concerned with the particular details of any of them, but on many of your Exhibits you refer to injection rates per acre foot, showing various figures for various projects. Was that at a particular time, or was that over the average life of each of those projects?

A Well, I'm not able to answer that question with respect to the total information. On the reported information that we got from the literature, it was the rate that was reported at the time of the report. Now, that could have been an instantaneous rate or it could have been an average rate over the project history to that point, but the rate of injection that was reported was used in arriving at the barrels per day per acre foot.

Q But you don't know, then, whether the project -- each of those projects that you have used that right through its life or the day before or the day after, or if it was just reported information applied to acre feet?

A This was reported information.

Q Now, in determining your acre feet, that, of course, calls for an interpretation of affected areas, doesn't it?

A That's right.

Q How did you determine the affected area in each of those instances?

A In the case of the reported information, we took what was reported, I believe, as the project area. In many instances that was one single five spot. In other instances, it was maybe a double five spot or several.

Q And you didn't know, then, whether or not the whole project area in any one of them was being affected or whether only a small portion of it was being affected?

A The report in the case of the Texas Railroad Commission, I believe, has an -- a total unit area and a project affected area. I believe I'm correct on that in the cases of the Texas report. We used the lesser area, as indicated in the report.

Q And, as I recall, you actually drew no conclusions, as an expert, from the information on those Exhibits, other than just the fact that they showed different rates per acre foot for different projects at some particular time with a more or less indefinite determination of the affected area?

A I drew -- you might call it a conclusion, if you wish. I drew the observation, if you recall, that since most operators in Texas have asked for and have been granted capacity allowables, one must presume from the information that the operators do not wish to operate at capacity, but that it appears that they wish to operate at a rate of their choosing both injection and oil production, and I used the term self proration.

Q Assuming that the operators of all of those projects believed in and desired capacity operation as we refer to it here, which I believe, generally, it is agreed that it means injection at the most efficient rate with unrestricted production, assuming that all of those operators desire to operate in that manner, I, even though I'm not even close to being an expert in the field, might also draw an assumption from that that maybe they were injecting at the most efficient rate for that particular reservoir, might I not?

A I think you could draw that conclusion.

Q Now, I don't remember just, in connection with what Exhibit or even in connection with what point -- I got fotentimes kind of lost in your points, but I believe at one time you commented on some type of activity or evaluation by your -- I believe you used the term "Bright young man," at least leaving with me the impression that oftentimes their first idea wasn't necessarily acceptable because of their lack of experience. Would I be correct in concluding from that that you place a great deal of importance upon experience?

A I certainly do.

Q And that, of course, would be experience in the type of matter or problem that would be under consideration?

A That is right.

Q Well, it wouldn't make too much difference, then, whether it was a young man or an old man, it would be his experience rather than his age that would give value to his conclusions, wouldn't it?

A Not necessarily.

Q Well, I mean from an experience standpoint. Obviously you've got to have education and creativeness and all the other factors, but insofar as, experience is important -- in other words, an old man with no experience would probably be no better than a young man with no experience, would he?

A I think along this experience factor, if I might comment, I would like to -- I've had a lot of experience in the oil business, I'm forty-one years old. I would have had more experience if I were fifty, but I'm continually amazed every day with the new ideas that are coming forward that changed my old preconceived notions. I think that in this business one must keep an open mind, and interpret their experience in the light of information. You'll recall that we had to fly blind in the early days of the oil business. We are learning more and more every day. And some of the things that -- when I was roustabouting on the lease -- that were told to me to be the gospel truth by the pumper, I found out later wasn't so, although at that stage of my experience I was willing to accept that thought from the experienced mind, and continually investigate and continually tie that back to the new information, so I think it is very important that we analyze experience in the light of new data continually. I might just mention this. We all remember it. You remember when prorationing first came in Texas?

A No.

A You don't? Well, I don't either, but I have read a lot of the background of that time and some of the testimony that was put in before the Texas Commission, and I'm sure it was put in before the New Mexico Commission, although I would hurry to say that I have not read the history of the early prorationing days in New Mexico. But we had experienced men at that time who came forward and said that "you can't shut my twenty thousand barrel per day well in," it would ruin it, because once you get this oil coming, it's just got to come. Now, some of the younger engineers at that time had made calculations and had laboratory information available, and they said, "Yes, you can cut it back," and we went through that, and we did cut them back, and those East Texas wells were cut back and although I did point that out with some doubt, but we think that this Texas field has operated successfully. Incidentally, for your information, the wells in East Texas now are allowed to produce six barrels of oil per day, and some of those wells are still capable of making twenty thousand barrels, so that oil when it slowed down, it still wants to get on out and get counted with the rest.

Q I agree with everything you have said in that point, but the point I wanted to make was that -- if I might use an example, I've had some twelve years' experience as an attorney. Now, let's assume that next fall I go to school and study engineering, and not being too smart, it takes me about five years to get through, and at the age of forty-three I get out of law -- out of school with an engineering degree, and another fellow went right on through from high school, and he is just twenty-three. The fact that I had twelve years' experience as a lawyer and was twenty years older wouldn't give me any more experience in reservoir engineering, would it?

A I think with the background that you have had --

Q I will exclude that I haven't had any.

A Mr. McGowan, I guess I missed your point. I got the impression that you said that with your twelve years' experience as a lawyer.

Q Well, let's just assume that I never heard of oil and gas. Now, the point that I am trying to make is the experience that counts is the experience in connection with the field that you are working or drawing conclusions in.

A Sometimes it comes to my mind the fact that the person who invented the electric icebox was not a man that worked with the ice company, so that doesn't necessarily follow.

Q Now, you referred to the Browning unit, and since that is a Sinclair operated project and since our witness at the Graridge hearing put testimony on it, I would assume that it is probably proper for me to inquire about it. Did I understand you correctly in that you actually drew no conclusions from the data that you presented or recomputed from the Browning unit?

A I think the only conclusions -- if you would like to call it that -- I think it was an observation, was that an examination of all the data that was made available to us, and I hurry to say it is not all of the information, this was all of the information that we were able to get from these three releases of data on the Browning unit was that there were other variables going on in the reservoir, and that you could not tie this supposed response, but it was a response to injection rate alone; that there were other factors, such as the fillup of the entire reservoir that had to be taken into account before you could draw the conclusion. I think I went further to state that as far as injection rates are concerned, our interpretation from the meager data that we had was the injection rate in barrels per day per acre foot affected acre feet had not materially increased. So with that backdrop of information, we then had to search to see what could we attribute this response to, and, of course, the thing we attributed it to, and our interpretation was that when the reservoir filled up, here she came.

Q You talk about all these other variables; I think we all recognize them. I think you mentioned twenty-eight a while ago. I believe Mr. Wright in the Browning testimony mentioned and listed numerous variables that were considered. Are you considering that the witnesses who testified concerning the Browning unit, to the best of their knowledge, at least, didn't take into consideration all of those variables in reaching their conclusions?

A I'm sure they did. I'm sure they examined their information very carefully, and for one reason or another which isn't available to us, of course, they arrived at the conclusion that this response was due to the increased injection rates. So one must presume, and I am not only presuming, I know that Sinclair engineers are very very capable reservoir engineers, among the top in the industry, so I must assume for one reason or another they analyzed all of the information and came to their conclusion, and we examined a little piece of the information that we were able to gather from the information, and we can't draw the same conclusion, Mr. McGowan.

Q Then, we really are faced with the proposition concerning the Browning unit that one group of engineers on information available to them drew certain conclusions, and that on part of that information, at least, draw different observations?

A I think it was not worthy, Mr. McGowan, and the Sinclair engineers changed their minds slightly after looking at six more months of data, and I don't know what they think about it now, but I noted from reading the testimony and information that the Sinclair engineers put forward that they were changing their minds slightly with subsequent information.

Q Well, I think that I'll stipulate on their behalf if they change their minds as they get more information. Now, I was rather interested in the example that you drew in connection with those three leases you had where one of them was shut down entirely, and one produced but didn't inject, and the other injected and produced. I'm assuming that all three of those leases were part of an interconnected reservoir?

A As far as we know, this is an interconnected reservoir.

Q Do you recall what was the approximate pressure of that reservoir at the time that these different producing, or the time one was shut down and the time the other injection was stopped?

A I don't have the information with me right now. I do know this, that the water flood was started at substantially depleted pressure. It is a shallow reservoir in Duval County, and I do not have the pressure history with me to relate the change in pressure with injection. I --

Q Well, do you suppose that there was enough pressure in the reservoir at that time to allow the creation of pressure differentials?

A Well, there is always a pressure differential when you inject a bucket of water.

Q Now, as you shut-in entirely one part of the reservoir, produce but don't inject into another part, and produce and inject both in another portion, would there not, at least possibly, be considerable movement of fluid from one area to another within the reservoir during that year's period?

A Oh, I'm sure there has been movement of fluids, Mr. McGowan.

Q And that, of course, would affect, at least to some extent, the performance of each of those leases when they went back on operation, wouldn't it?

A I think so, yes.

Q So your ultimate recovery calculations from those leases, then, might or might not bear any real resemblance always to what it would have been before the interruption from the particular lease itself, not from the pool itself?

A That's right. As I mentioned before, you have to run a complete flood balance because this oil has a habit of scooting away from you and on to your lease.

Q Now, in -- I believe you said that you weren't making any particular recommendation, but that from the observations and conclusions that you drew throughout your tests that will contribute to the overall information to which the subsequent witness will make that recommendation?

A That's right.

Q In your illustration that you had your model of up there, did I understand you correctly that the thing you were illustrating was the fact that gas would go back in solution as you build up pressure in the reservoir?

A That's right.

Q That, of course, is one of those. Now, would that have happened -- and I don't know -- but would that have happened had you had the producing end of that tube opened?

A Yes.

Q In the same proportion?

A The reason we kept it closed in was for illustrative purposes. If you keep the valve open, you push all the gas out, so that we showed the worst case that we could possibly show there because immediately I would have been hopped on about the point, "Well, heck, you let the gas all get away." Well, obviously, it is that way, so we had to show it under the most adverse conditions. I showed you, in effect, a seventy-five pound condition. I mentioned to you if you take all factors into consideration, it only takes about twenty-five pounds to do this job because during fillup the gas gets on up your well, most of the gas gets on out and you only have very little gas to put in solution. So we wanted to show the most adverse case so that you wouldn't feel like we were taking undue advantage in this particular case.

Q And it did, then, show only that gas goes into solution under pressure?

A That was the only point that was to be made.

Q To show how such a well -- to show how it would happen in the reservoir itself, you would have to get all those twenty-seven -- twenty-eight variables you mentioned into it?

A That's right. That's what Dr. Holcott has done in his model and his model observed the same thing. He wasn't as surprised as I was, he knew that would happen.

Q You mean he had all the variables in his experiment. I understood him to say he wasn't able to.

A Most of the variables refer to flood property, flood saturation, permeability, porosity, connate water, saturation, I think he's gotten most of the variables in there. I don't think you could possibly get them all in, but he's got most of them.

MR. McGOWAN: I believe that's all.

QUESTIONS BY MR. CAMPBELL:

Q Mr. Greenwald, at the outset, I want to mention I am one year older than you are, but that's not going to make one bit of difference. I have, too, experienced a little difficulty distinguishing between your own conclusions and what you said might be the conclusions of others from the same information. If I failed to question you on your own conclusions, I wish you would correct me. It is my understanding at the outset of your testimony you stated that some paper that had been presented indicated that in analyzing the results of water flood operations by way of reservoir reference, there were some twenty-eight factors and variables that had to be taken into consideration, is that correct?

A I think the statement that I made was that there are numerous variables. The twenty-eight figure isn't mine, that belongs to Dr. Paul Crawford with the Texas Petroleum Research Committee, a very capable young scientist. He listed them, and as I recall, there are twenty-eight. I wish you wouldn't pin me on the twenty-eight, it might be twenty-seven.

Q Or twenty-nine?

A That's right.

Q In any event, there is a sizeable number of variables involved in the determination of what takes place in a reservoir with regard to water flood operations?

A That is correct.

Q Now, as I recall it, you presented a series of Exhibits in which you undertook to establish a basis for your conclusion that rate of injection and interruption of continuous rate would not affect ultimate recovery, did you not, where you plotted the oil production curve and the water injection rate?

A I think the only -- the interruption case was in a series of Exhibits. As I recall, it was -- yes, it was a series of Exhibits, but it related to the South 76 Field.

Q Now, in those Exhibits and in drawing your conclusions from them, obviously you must have left out twenty-six or twenty-seven variables, didn't you?

A We examined all of the data that we had available to us, and we have a lot there because we operate in that field, so we had cognizance of most of the variables, yes.

Q Well, of course, anyone analyzing those conclusions that you draw without being acquainted with what the variables may have been would be in a position of obviously being unable to associate the value of the other factors, would they not?

A I think that someone would have to examine the case very carefully and take into account all of the variables as we did, and all I've tried to show, Mr. Campbell, was the fact that there are very few cases that you can find in field operations that you have this one year interruption. We felt very fortunate that this thing came to pass. Of course, the operator who got shut-in didn't feel so fortunate, but the point is that we were able to examine the performance before and after the shut-in, and we could see no substantial difference in the performance before and after.

Q Which led you, as I understood you, to that conclusion, that there is no evidence there to establish that there was any losss of production by virtue of that delay, is that right?

A We can see nothing there detrimental to the one year shut-in.

Q Did you see anything there that would indicate that you would not have had more production if that interruption had not taken place? Isn't that likewise true as a corollary?

A We see nothing to conclude that the interruption affected the recovery.

Q Either? But you cannot see anything in those to indicate that the curve might not have gone up to a higher peak during that period of interruption, can you? I mean, it works both ways; let's be honest with each other.

A I'm trying very hard to be honest, Mr. Campbell, because I think I'm under oath here. But anyway, I would say this, that the proof of the pudding in the South 76 case will be when the final barrel comes out of the reservoir, and I will say this, that the reservoir is performing in accordance with previous calculations of the displacement efficiency to be expected. And, also, we cannot draw any conclusions as to the relative recovery of the three leases. At the movement, it appears that all three of them are going to come out very close in terms of ultimate recovery in percent of original oil in place, so I can't in all honesty say that the lease would have recovered more oil had it not been shut-in. As a matter of fact, I'm leaning in the direction that there was no effect.

Q Well, like I said before, you can't honestly say there wouldn't have been more from the evidence you have available either?

A I think we can say that when the final recovery --

I don't know what we'll say, but we'll know the story when she's through.

Q Now, you have several times in your testimony stated that you consider that this flood or that flood is a successful flood. What basis does Humble use to establish whether a flood is successful or not?

A We consider a flood successful if it recovers the -- or substantially recovers the amount of oil that we would have predicted that it would have recovered under the displacement process that we are forced upon.

Q Over what period of time do you consider that as a factor?

A Period of time? Time -- the time factor always enters into the economic claculation, Mr. Campbell, because if the time of recovery is too far delayed, it would not be an economic venture, and we wouldn't knowingly go into such a project if the time factor were too lond.

Q You concur that the time factor as a consideration in the determination of a successful or unsuccessful flood will vary, depending upon the owner of the property?

A Would you restate that question?

Q Will the time factor, as far as the successful flood is concerned, vary between the owners of property and their own situation?

A You mean as to whether or not they go into a project or not?

Q Whether they go into the project and when they abandon it, yes, sir.

A Oh, I don't think there would be much variation, Mr. Campbell, because I think most of us look at this economics a lot of the time -- we know what the cost of money is, that's a defined number, and if you can substantially improve your profit, your rate of return will be above your cost of money. I'll say this from reading the Financial Journals and literature on the subject there is some variation between what one operator might call a good economic venture and another, but I cannot find any wide variation in them. If money costs, say, five percent, and if you get ten percent, say, for example, well, I think most operators are pretty well agreed that it is somewhere in that range.

Q Now, I believe you stated in your testimony that you had read the transcript of testimony in the Graridge case, and I believe you stated that since you had a short memory, you sometimes didn't quote correctly, perhaps from the transcript.

A I think I made that statement. I tried to get the substantial point as best as I could remember it.

Q But you are correct that you didn't know whether it was quoted correctly. The magic number that you referred to, of course, was not referred to in those terms in the hearing, was it?

A I think I clearly pointed out that that was my --

the word, "Magic" was my own word.

Q As was "The point of no return?"

A Yes.

Q Do you think that the testimony given at the Graridge hearing established a basis -- a figure of one barrel of water per acre foot per day as a basis on which you could make ultimate comparison, and anything less than that was a poor flood or was not being injected at the proper rate, from your reading of the transcript in the testimony of the Graridge case?

A It was amusing to me, in reading the transcript, that all of the capacity, proponents of capacity floods weren't together on that point. As I recall, one witness was more inclined to go on the pressure as being the best rule of thumb, but I do recall, and my memory is that at least one witness said that one barrel per acre foot per day was the rate that he would try to go after. Again, I'm not -- can't quote exactly, --

Q You are not?

A -- but that five-tenths, certainly you should try to get that.

Q Will you not agree with me after having read the transcript of the testimony that essentially what was said was what you said here this morning, that the effort was in a particular reservoir to reach a point at which you would have the highest rate of injection short of breakthrough, isn't that actually what we have been talking about in these hearings and in which the dispute arises between your approach and these other people's approach, isn't that essentially what it is?

A I think in all fairness that there is no -- at least, I have read no indication from the proponents of capacity floods that they would want to exceed the overburdened pressure, but I think that some of them think the pressure is the main effect, and another one thinks the barrels per day per acre foot is the main effect.

Q Now, Mr. Greenwald, in your capacity as a reservoir engineer for Humble, are you responsible for advising the field operators -- the field operations with the way they operate their project?

A That comes under my responsibility.

Q On the Exhibit which you introduced at the outset reflecting the water floods of Humble in Texas, you have a flood in the Northward Estes Riker lease, is that not correct?

A Yes.

Q Am I correct that at one time Humble started a flood on that particular lease and abandoned it as a failure?

A It was abandoned.

Q And did you not later --

A Let me clarify that point. We quit injecting water into it.

Q Why?

A We had not obtained the response that we had hoped to. This was a pilot operation.

Q Did you go back in later and commence reinjection of water?

A Yes, we did.

Q Why did you do that?

A We got more information that became available to us, and we began to delineate the various cumulations there on the -- this Riker lease. So everybody will know what we are talking about, it is right on the borderline between Southward and Northward Estes. Actually, it is apparently quite an accumulation and it is one of these fence line boundaries between fields that has gone up in Texas, and we are -- our Northward Estes lease is kind of on the east edge of this Penn Bennett zone that Mr. Buckles is quite familiar with, and we found that in our lease that we had other reservoirs -- I forget what they are called -- but they are down there, I think the Queen series Lower Yates, what have you, that we are not connected to this Penn Bennett zone, and consequently, we didn't have our injection gas into the same zones. As the producing wells are completed in, we've had to go back in there and do a lot of well work, drill a lot of wells, selectively complete them, to convert the Riker lease into a better flood.

Q You went back into the Riker lease after other operators had flooded their property with a successful flood, isn't that what it amounts to?

A We noted the successful flood that Forest Oil Corporation put on down to the south of us with much interest, and I might add right here, Mr. Campbell, that I think the industry is quite indebted to the Forest Oil Company, to mention just one, for leading the way in flooding in the sand belt trend. A number of things that we learned from the Forest Company was the fact, the broken up permeability in the Yates formation and how it actually divides up into several leases and members, and we learned a lesson there that we should have known that you've got to put the water where the oil is to get the job done.

Q You are apparently indebted to Forest Oil Company for all of their experience except the rate of injection, is that what you are saying?

A We, in observing their performance and in studying this question very carefully, we do not necessarily conclude with the Forest Oil Company and with others that the rate of injection is the factor that makes a flood successful or unsuccessful.

Q Now, Mr. Greenwald, your list of projects which Humble operates does not include the Colby "B" lease which, I believe, is a new water flood project, is it not?

A That is correct.

Q You heard Mr. Buckles' testimony yesterday with regard to the setting of the packer between the Yates and Queen Sands in that Pool, and the injection of water and separate meeting of water through the two separate -- into two separate zones, did you hear that?

A Yes.

Q Are you operating your Colby "B" lease in the same fashion?

A This I do not know for sure. We'll have to get the data and look at it. I just didn't bring it with me.

Q Have you ever seen the lease property?

A The Colby lease?

Q Yes.

A Yes.

Q Would you recognize it, do you think?

A Oh, yes.

Q Do you believe that is a fair representation of your Colby "B" lease installation?

A It says so right here on the picture. "Colby "B" 15", it says. For the benefit of all of you, this is a picture, and the photography is pretty good. I can't tell whether it is an injection well or not, but it probably is, of one of our wells in the Kermit Field. Now, the Kermit Field is located just north of the Northward Estes Field, and this is a southern portion of the Kermit Field. I've given you this information.

Q I'm aware of it, Mr. Greenwald. Does that photograph indicate the completion of an injection well with two separate meters?

A I can't tell for sure from this picture. We have an engineer here, Mr. Campbell. He is one of the field engineers up there in that regard.

MR. CAMPBELL: I would like to offer in evidence Exhibit No. 24, which has been identified by the witness as a picture of their Colby "A" lease.

A Colby "B" lease, Mr. Campbell, I believe.

MR. CAMPBELL: Excuse me, Colby "B" lease.

MR. PORTER: Without objection, the Exhibit will be admitted.

MR. HINKLE: Mr. Campbell, it is my understanding that Humble has cored some of these wells and is injecting selectively in some of them. As to where this is no one seems to know. We object to the introduction of the Exhibit. It is not based upon anything that Mr. Buckles said.

MR. PORTER: The Exhibit will be admitted.

Q (By Mr. Campbell) Do you know, Mr. Greenwald, how that injection well is completed?

A No.

Q Do you have someone here who does?

A I presume that after the Exhibit sailed down the line no one is quite sure of No. 15, just how it is completed. Mr. Sinton is in charge of our water floods, and Mr. Henry Meadows here, is our engineering coordinator, and Mr. Baze, our reservoir engineer. We will have to look at the date to be sure.

Keep in mind that we operate fifteen thousand seven hundred wells, and I actually, to be honest with you, don't know the completion interval in each of the fifteen thousand seven hundred wells.

Q I think that's reasonable. Let me ask you this. If your theory of rate not having any effect upon the efficiency of a water flood is correct, and assuming that the two zones in a reservoir contain varying degrees of permeability but are both open to the water flood, there would be no reason, would there, why you would have to dually complete the well in order to get the greatest efficiency in your operation of the flood?

A Oh, yes, there could be many reasons.

Q What are the reasons?

A Some of them are mechanical. We selectively inject where we think we have to.

Q Why do you do that? Why do you think you might have to if your sand will imbibe this water and flush out with capillary action this oil, why do you have to be selective?

A Mr. Campbell, I would like to say this, and I'm sure you've had this experience, but when a formation is drilled, we have noted sand face damage or formation face damage right at the well bore, and we know that with the connate water as pressure is depleted, they oftentimes -- solids are deposited such that the condition of your oil well casing, the condition of your mechanical hookup, the sand face problem that you have, all are related to why you selectively inject there or other considerations. For example, if there is a wide difference in -- you understand, do you not, that Mr. Buckles presented a two-reservoir case and not the case that Dr. Holcott is talking about. He is talking about the phenomena that exist in one reservoir.

Q In the laboratory?

A In the laboratory. Now, when you have two reservoirs separated like that, well, oftentimes because of the aggregate difference in the permeability and characteristics, it is better to flood them separately because then you have control over the injection rate to be applied in one versus the other, whereas if you inject simultaneously the one -- now, you understand there is no possibility, Mr. Campbell, for the water injected in the Queen imbibing the Yates when they are separated by two or three hundred feet, I'm sure you are aware of that?

Q Yes.

A Then you have an entirely different situation. Dr. Holcott was talking about this imbibition process of the varying permeability within one strata.

Q Then, where you have the situation such as you have in this field, if included, in theory, they wouldn't apply, would they?

A Certainly they would apply. This phenomena will take place in the Yates and take place in the Queen and practically any strata.

MR. CAMPBELL: That's all.

A And, incidentally, he doesn't control this. This is a natural phenomena, understand.

MR. CAMPBELL: That's all.

MR. PORTER: Anyone else have a question of this witness?

QUESTIONS BY MR. McBROOM:

Q First, Mr. Greenwald, I want to say that your management should be very highly congratulated in having people able to present the type of Exhibit and presentation that you made; it was impressive to all of us, some of us seem to be. However, we are sure that you did not intend in any way to mislead or misdirect the attention of the Commission, particularly in reference to pressure maintenance programs and with specific reference to these Texas fields. I think we can assume that, generally, the Commission, possibly Mr. Nutter, I don't know whether he is familiar with the East Texas situation or not, but we can assume, generally, that these people in New Mexico are not familiar with the vast problems that we are confronted with in the East Texas field.

You presented evidence here that the injected water into East Texas was something like, oh, just a fraction of a barrel per acre foot per day, is that right?

A That's correct.

Q Now, do you know offhand how many wells are producing in the East Texas field, approximately?

A Approximately twenty thousand.

Q About twenty thousand wells are producing in the East Texas field. Are you familiar with the spacing?

A Very.

Q Most of the wells are on ten acres or less, is that right?

A Most of the wells are on five acres or less.

Q I was trying to be generous; so that on forty acres you may have as many as ten wells?

A There are six wells in the Kilgore site on a tenth of an acre.

Q So we are injecting in Texas water at the rate of less than a barrel per acre foot as it affects the whole reservoir and not a pilot flood area, or not a confined area, is that right?

A Are you drawing a conclusion out of me about Texas as a whole or --

Q No. I'm just trying to present to the Commission and make it clear to them what we were talking about when we were talking about the East Texas field, try to educate them a little bit.

A In the case of the East Texas field we are talking about the affected area, yes.

Q Now, the affected area is the thousands of acres, or -- I don't know how many acres we've got for these eighteen thousand wells. Do you know what the overall pressure drop has been since East Texas was first drilled in?

A Yes.

Q How much has it been?

A It has been about six hundred pounds.

Q About six hundred pounds. That drops it from somewhere around twenty-two hundred pounds to sixteen hundred pounds?

A No, you've got six that way, but you can get six other ways. Actually, it has dropped from around sixteen hundred to a thousand, that's another six.

Q Now, at the time East Texas came in, those wells were capable of flooding, is that right?

A Oh, yes.

Q Have you ever driven through East Texas oil fields and seen large pumping units sitting by wells that have never been hooked up? Most of them have been removed by now?

A Those -- I believe most of them have been removed. Those were put in at the time when we had twenty --

Q We thought the pressure was going down, didn't we?

A -- twenty or thirty years of practical experience to know that the wells were going to need pumping, you see, but we made a mistake.

Q Well, we thought we were going to have a lot more pressure drop than we had, is that right?

A Yes, and we would have had had this water flood not been put in.

Q That was my next question. You answered it. So that most of the wells in the East Texas field are still flowing, is that right?

A When you say most --

Q Well, a great many of them are?

A Oh, yes, yes.

Q Now, how can you possibly indicate to the Commission that by putting in less than one barrel per acre foot per day that you could maintain flowing pressures in these wells over this twenty-five, almost thirty year period?

A Would you restate that again?

Q How can you explain to the Commission that by putting in only less than one barrel per day per acre foot in this tremendous reservoir that after thirty years you still have maintained flowing pressures in those wells? What is the explanation by only putting in less than a barrel per acre foot per day?

A It is relatively simple.

Q I know it is simple, but we are trying to get all the facts out here, Mr. Greenwald.

A Well, the facts are, in the case of the East Texas field, that you had to put a certain amount of water injection in relation to the oil production. You see, East Texas is one of these controlled fields where it is prorated.

Q Yes, but answer my question. My question was, how do we explain that by putting in less than a barrel per acre foot per day that we are able to maintain flowing pressures?

A This was done -- this can be done in secondary recovery --

Q Answer my question, please. My question, is how, by only putting a barrel per acre foot per day -- let me restate it a little bit, maybe we don't have communication here -- Does putting in one -- less than one barrel per acre foot per day, does that alone, is that the only pressure factor, putting in less than a barrel per acre foot per day maintain the pressure which permits these wells to flow?

A Oh, no. Everyone knows that the East Texas field is connected to the Woodbine aquifer.

Q That's the answer I have been looking for.

A Well, let's take -- I mean, as long as you brought up the point, I didn't, let's take Sacroc.

Q Well, let's finish with East Texas, because I don't know anything about Sacroc.

A I can illustrate it a little bit by saying we are doing it at Sacroc at .01, you understand, and it is not connected to an aquifer.

Q I'm not familiar with Sacroc, I'm trying to get the facts before the Commission here. This Woodbine aquifer, then, is the reservoir source, and is that encroaching water into the East Texas field?

A Yes.

Q Now, how many barrels per day would you estimate? I know it has been done technically, but I don't expect you to have it available, but approximately how many barrels per day of water is the Woodbine aquifer, with God's help, injecting into these Texas oil fields?

A Just about the amount of oil that is being taken out.

Q About two hundred thousand, two hundred fifty?

A One hundred thirty.

Q One hundred thirty less than we are putting in?

A Actually, the water injection program in East Texas is to maintain the pressure because of the edge water production. You see, the field produces around four hundred thousand barrels of water per day. The encroachment surrounds around one hundred thirty thousand, so that by producing this water -- East Texas would have gone into a dissolved gas drive production and ended up a stripper field -- so this is a pressure maintain water flood for that purpose, maintaining the pressure, and we hope to get higher recovery, you see.

Q Now, wouldn't you say from those facts that, in fact, with the help of the Woodbine aquifer pressure, and what we are putting back in, that you have really very high rates and with your sixteen hundred or two thousand pounds pressure there that we are maintaining, wouldn't you say that, in effect, we have very high rates of injection and very high pressures in the East Texas field today?

A The injection rates in East Texas, even adding the water coming in as you have done, are still relatively low in comparison to one barrel per day per acre feet, if you want to use that number to be high.

Q You would say, then, that you think in the overall aquifer that with the help of the Woodbine aquifer we are injecting less than one barrel per acre foot per day?

A Oh, yes. You add the four hundred and fifty plus the hundred and thirty, and you get five hundred and what, ninety?

Q Five hundred ninety thousand barrels per day?

A See, the four fifty represents a -- didn't you add another hundred thousand? That hardly is going to make a ripple on that number, as you can see.

Q The real point that I'm trying to get to is that for the Commission's benefit, that the performance of the East Texas field with this extreme water drive behind it, would not in any way be similar to the experience that we could expect in the strictly solution gas drive fields that we are working with in the Permian Basin? Am I right or wrong?

A I can't draw that conclusion at all. You drew it.

Q What would be your conclusion?

A My conclusion is that they are identical.

MR. McBROOM: Well, thank you.

MR. PORTER: Anyone else have a question of this witness? The witness may be excused.

(Witness excused)

MR. PORTER: We are going to recess the hearing at this time until one o'clock. We will have to reconvene in the Chaves County Courthouse.

1:00 P.M., FRIDAY, OCTOBER 16, 1959

MR. PORTER: The meeting will come to order. I've had several requests by people who are uncertain as to their accommodations for tonight, to try to determine how much longer the case will run. I know it is difficult for the interested parties to estimate that time, but I would like to -- I believe Mr. Hinkle, you have two or three --

MR. HINKLE: We have two more witnesses. One of them will take from an hour and a half to two hours, and the other one about fifteen minutes. Of course, whatever cross will depend on how long he will stay there.

MR. PORTER: I would like to ask if anyone else is going to present testimony after Humble is finished.

Mr. Hinkle, will you call your next witness?

(Witness sworn)

ROY A BAZE,

called as a witness, having been first duly sworn, testified as follows:

DIRECT EXAMINAION

BY MR. HINKLE:

Q State your name, please.

A My name is Roy A. Baze.

Q By whom are you employed, Mr. Baze?

A Humble Oil & Refining Company.

Q Where are you located?

A At our division office in Midland, Texas.

Q What is your present position with Humble?

A My position is division engineer of reservoir engineering division.

Q Are you a graduate engineer?

A Yes, sir. I graduated from Oklahoma University in 1943 with a degree in Petroleum Engineering.

Q Have you testified before this Commission on a number of occasions?

A I have testified before the Commission.

Q Did you testify in the Graridge case a few years ago?

A Yes.

MR. HINKLE: Are his qualifications satisfactory?

MR. PORTER: The witness' qualifications are acceptable.

Q As a result of the problems with which the New Mexico Oil Conservation Commission has been faced in connection with the allocation of water flood oil, and proposed Rules of the Commission, in connection with this case, have you made a study of the probable future effect of water flood projects on the allocation of the market outlet?

A Yes, sir, a study has been made under my supervision.

Q As a result of this study, did you find anything to be particularly concerned about due to the rate of future production of water flood projects?

A Yes, I would like to talk a little about it today.

Q Have you formed any definite conclusion with respect to the State of New Mexico's future as far as oil development is concerned and with respect to the future water flood projects?

A Yes, sir, I have. And I would like to state that conclusion at the outset, which is on the chart here, and we will leave this until later. The conclusion that we have reached with regard to the future of New Mexico in the water flood business is that the prospects look very bright. I think, actually, that this conclusion is so obvious that it almost precludes discussion. However, there are a few points that are worthy of refreshing our memories at this time. One point is that New Mexico comes into the water flood business with the great heritage of some thirty years of experience by the industry in field operations and in research activities. Now, some of the major points that the industry has acquired and learned through its thirty or more years of water flooding would include such points as the types of injection patterns that can be employed, the types of waters that can be used in injection, the types of equipment that can be used, the general types of recoveries, oil recoveries that may be expected, general ideas as to performances of water flood projects. One other point, I think, that has come in in general industry experience relates to the proper completion of wells for water flood purposes and the elimination of thief zones.

Now, if we bring this industry experience a little bit closer to home, to the State of New Mexico, water flooding in the Permian Basin has been rather active since about 1948. From past experience confidence has been gained in many of these Permian floods. A large number of these reservoirs on the Permian Basin on the Texas side are common and similar to the reservoirs on the New Mexico side. There has been much experience gained in the Permian Basin in the last ten years, just across the back-yard fence of New Mexico. I think a great deal of that experience is directly applicable to New Mexico. And in the last few years there has been an upswing of oil production and well drilling in this part of the State. I think a large number of wells have been drilled in the northwest part of the State that will be under some type of flood in the future. Now, if we stop a moment -- and we have but to realize that in the last few years there have been water flood projects installed in some twelve fields in the southeastern part of New Mexico, and some good responses have been obtained in these southern fields. Now, I don't think that we ought to be surprised that there has been good response in the southeastern New Mexico fields in some cases. As a matter of fact, I would be surprised if there were not good responses obtained. As we view this water flood matter and New Mexico's position on it, the State is standing on the threshold of a new oil province, and that province is water flooding. So, we have no difficulty in reaching our first conclusion that the future for the State of New Mexico in water flooding is a bright prospect.

Q Mr. Baze, in one phase of the study you have made, have you given consideration to the New Mexico allowable to be assigned to water flood oil?

A Yes, sir. As we come into this hearing, one of the most basic questions that the State has is, how are the New Mexico allowables going to be assigned in the future.

Q What are some of the aspects involved in the assignment of allowables to water flood oil?

A Well, in approaching this basic question of how New Mexico allowables are going to be assigned in the future, we have explored several aspects that might bear upon the manner in which allowables are assigned. Now, this was done in order to ascertain if there are some unusual or peculiar conditions associated with water flooding that would make necessary an unusual assignment of allowables. One of the aspects that might be considered is the risk that is involved in water flooding. Now, we ask ourselves a question, if the risk in water flooding is so great as to demand a special treatment of the allowables. Some of these aspects that I'm mentioning have been proposed or suggested at one time or another by the proponents of capacity floods as being reasons for capacity allowables. Now, another aspect that might be involved is the investment that is required in water flooding. This raises a question, if the investment costs in placing into operation water floods is so great that it demands an unusual assignment of allowables. Now, another aspect that we might consider is the profit that is associated with water floods. This raises the question of whether or not the profit in water flooding is so marginal or so shaky that it demands some unusual treatment of allowables. Then, another aspect that I think should be considered is the effect of the future market demand. What will be the effect on New Mexico allowables caused by the assignment of water flooding allowables under different basis.

Well, let's turn to the first aspect that I have mentioned, and that one deals with the risk that's involved in water flooding.

Q Well, now, the first one you mentioned was conservation, was it not?

A Well, excuse me, sir. One aspect certainly is in the assignment of allowables, the aspect of conservation and waste, and this matter has been dealt upon by two earlier Humble witnesses, and I did not intend to dwell on that subject, but rather to turn to another one, and that being the risk in water flooding.

Q The first one you want to discuss is the risk being involved in water flooding?

A That is correct. Now, to get at the risk associated with water flooding, I think we can turn and examine industry's experiences in drilling and ascertain what risk there is in industry drilling in order to get some yardstick of comparison for the risk in water flooding.

Our first Exhibit, which, I believe, is numbered 33, deals with the risk in industry exploratory drilling. These data are for the year 1958. Source of them are shown on the Exhibit. Exploratory drilling, as used on this Exhibit, means more than just range wildcat drilling. It embraces outpost wells, wells drilled deeper in pools, wells drilled shallower in pools and range wildcats. We note here that in the State of New Mexico for the year 1958, 72 percent of the industry exploratory wells drilled were dry holes. We note for the United States that 81 percent of the exploratory wells drilled were dry holes. Now, these embrace all wells, that is, prospects designed both for oil and gas.

Q What is the source of this information?

A This information comes from the A.A.P.G. Bulletin of June 1959. It is shown on the Exhibit. Now, I don't think there is anything basically new on this Exhibit. I believe everybody in the industry recognizes that exploratory drilling is a risky venture. Now, I would like to proceed from here and examine the risk that is associated with field well drilling, and to turn to Exhibit No. 34. This is a chart, with time across the bottom from 1950 through 1958. Plotted on the vertical scale is the percentage of dry holes encountered in field well drilling. Both the United States and New Mexico are shown hereon. Now, again, I would like to point out that this is total field well drilling. It embraces both oil wells and gas wells. We see that for the State of New Mexico, about 10 percent of the field wells drilled are dry holes, and for the United States about 25 percent of the field wells drilled are dry holes. To state it a little bit differently, about one out of every ten New Mexico field wells is a dry hole. About two and a half out of every ten field wells in the United States are dry holes. Now, if we look at the reverse side of this New Mexico curve, that is the 90 percent of the field wells making some sort of a completion. It means just that. It doesn't mean a real good gas well or a top allowable oil well necessarily. It means it made some type of a completion. Now, a New Mexico well -- field well, oil well -- incidentally, I might say, I don't want to mislead anybody here. This includes oil and gas wells prospects. This curve down here is for total field well drilling. I did check Southeastern New Mexico field wells, and about 75 percent of Southeastern New Mexico wells drilled were oil wells. So, fundamentally, I think this represents a pretty good portrayal, in all probability, of the oil well drilling experience as well as the total well drilling experience. Now, a successful well completed in New Mexico doesn't get a guarantee of 42 barrels a day or of 84 barrels per day. It doesn't get a guarantee of an allowable in any magnitude. If we think back to 1951 and 1952, the successful New Mexico well that went into the big allowable pot came out with a 53 barrel allowable. Today, a similar well, successful oil completion comes out with a 35 barrel allowable. We might observe, then, that one form of compensation to the drilling operator in New Mexico in the last five to ten years has been a decreasing allowable. Now, I don't mean, certainly, to imply to the Commission that drilling in New Mexico is not a profitable venture, now. Obviously, it is. And I think I speak for the Humble Company and certainly I feel for the industry that we hope that it remains a profitable drilling venture province. I don't think basically there is anything in the way of real new information on this chart. The only reason we put it up here is to show that there is some risk associated with field well drilling. Now, let's take a look and see if we can determine something about how good a well results from this industry drilling that brings about a successful completion.

This Exhibit 35. This is a chart that tries to give some explanation as to how good a well or how good an oil field results from exploratory drilling. This is for a seventeen-state area. A profitable oil field, as defined by the A.E.P.G. in constructing this chart, is one in which there is at least one million barrels of proved reserve and a field that has six years of developing history. I might also point out that this chart also embraces gas fields in which the liquid proved reserve is a million barrels or more. But in each instance these fields must have six years of history during which time reserves can be revised and recomputed. This is a plot of the dry holes drilled for profitable oil fields, if you recognize the definition of profitable oil fields. In 1944 there were thirty-two dry holes drilled for each profitable oil field, and that ratio has risen to forty-eight dry holes per profitable oil field drilled in the year 1952. In 1952 98 percent of the wildcats drilled were failures with respect to finding a profitable oil field.

Q Is that the last available information that has been published?

A I knew there was something else I wanted to say about that. With six years of development history required in order for a field to come on this chart, you'll notice that 1952 data would be entered on a chart in 1958. So, it won't be very long before we see a bar go on for fields drilled in 1953. I wanted to say also, too, just so that I won't be misunderstood, I told you this includes gas fields and gas reserves, and if we could take out of these wildcats those prospects that were destined for gas, and resulted in gas dry holes or just peal out the gas and leave this only on oil, I feel certain that it would reduce the tops of all these bars somewhat, but I don't think it would take it down very much. All I'm trying to indicate here is that exploratory drilling has a great deal of risk in it, and the caliber of our finds generally is not too great.

Now, we can turn now, and try to explore a little bit the caliber of the field wells, results from successful completions. In order to look at this question, we have to look at it in a broader base and look at the reserve position for the State of New Mexico, and I want to turn to Exhibit No. 36.

Exhibit 36 is a plot of the proven liquid hydrocarbon reserves for the State of New Mexico. The vertical scale lists millions of barrels; it runs from zero to 1.4 billion barrels. Now, in effect, this is a portrayal of net gain or loss in the State's reserves picture. We might say it differently. There is a gain in reserves to offset production. Now, if we look at the year or the bar that is labeled 1/1/53, and look at the bar that is labeled 1/1/59, we see a nice increase in proven liquid hydrocarbon reserves, about 55 percent. Again, I don't want to be misunderstood. This includes gas liquids as well as oil liquids. But if we look at the bars of '54, '55, '56, '57 and '58, from looking at these bars we conclude that the State is just about holding its own in the reserve picture, that is, the gain or the revisions to reserves has just about balanced production. We look at the bar of 1959. With respect to 1958, we see a modest gain in the 1959 bar. Now, each year the reserves can be revised as to existing fields or there can be reserves added on account of new pools drilled. And this API and AGA Committee that computes reserves include water flood reserves when there is successful performance in the field at that time, then water flood reserves can be added. So, the difference between the '58 and '59 bar could represent probable revisions to old reserves, new drilling reserves, and possibly -- I don't know this for certain -- it could include some water flood reserves. Now, this might mean the '59 bar runs just a little bit less than 1.4 billion barrels, and that's about a fifteen years' supply when production is taken out at the rate that it was in 1958. And this difference between the '58 and '59 bar represents about two and a half years' supply when production is taken out at the 1958 rate. Now, I would like to be real clear here. I'm not saying that New Mexico will be out of the oil business in fifteen years, I don't mean to imply that. I simply point out that this bar represents about fifteen years' supply at the 1958 production rate. I think one thing is significant from a chart such as this. New reserves, apparently, could be added in any one year due to the addition of reserves proved up by water floods. However, when drilling ventures get so risky, the profit from drilling gets so marginal, or drilling payouts get so lean as to discourage drilling and the finding of new reserves, the State goes into a liquidation of its oil reserves. I think that requires no explanation there. There must be a continual addition of new reserves. Now, I think I covered the point that we still think that drilling is a profitable venture in New Mexico, and I'm not trying to indicate right this minute, Mr. Campbell, that it's not. I hope it continues that way.

Q What you are saying, in effect, is that if the allowable continues to go down, there is not going to be any incentive for new drilling, and as a result, the State reserves are going to be down and they are not going to be replaced with new reserves?

A I think there is a broad relationship between the level of the allowable that's assigned and the continuation of a healthy drilling program. Now, I know what level the allowable is, particularly at which point drilling is drastically reduced, and upon which point drilling is sharply increased. I don't believe that there is one fixed allowable level in the near future that we will talk about. It gets kind of to this: one man may be able to drill profitably at a 40-barrel level, and he can stay with it to a 35-barrel level, but at 33 barrels, he decides that that's a little too close. Other operators may be able to stay on down to the twenty or even fifteen barrels allowable. I think this is an individual operator's own economic position and availability of investment opportunity. I think we can draw a broad general conclusion that there is some level at which drilling will nose off.

Now, these charts that we've looked at deal with the risk in drilling. Let's talk a few minutes, now, with the risk associated with water flooding. To begin with, water flooding risk is minimized by the installation of small pilot installations in individual fields. I think, secondly, risk is minimized by the successful operation in one field of a reservoir that is similar to another field. Then, I think that the risk in water flooding is minimized by the study of laboratory analysis of rocks and of fluids. I think the risk is minimized by the study of production and geologic records. And here, I think, both fast flooders and slow flooders have something in common. I think we all look at what happens to somebody else's project, and we all look at our core data and our cross sections and laboratory analyses as much as we can get our hands on. We like to do it before even installing pilot flooding. Now, we've examined all the data that is available to us regarding water floods in the Permian Basin. Now, this was all water floods that we could find in the Permian Basin; both pressure maintenance projects and secondary recovery projects, great big ones, little bitty ones, pilots, all of them. The reservoirs embraced were the Yates, Seven Rivers, Queen, San Andres, Clearfork and Devonian. From this study of floods, we found no case where a field was condemned for water flooding. Now, I can't say categorically that there is no field in the Permian Basin that has been condemned for water flooding by performance. I would like to be real clear when I say it, that was all the data we examined, we found no field that was condemned. We did find some cases of failures of individual projects for one reason or another. Of course, we've looked at the risk that is inherent with industry drilling, and the risk as we see it in water flooding, we reach the conclusion that the risk in water flooding is less than the industry drilling experiences.

Here is another point I would like to be real clear on. There is risk in exploratory drilling, there is risk in field well drilling, and there is risk in water flooding. We conclude that the risk in water flooding is less than the drilling experiences, and that's our conclusion No. 2.

Let's turn, now, and look at the investment costs that are associated with water flooding. Again, we can turn to our drilling experiences and get some sort of measure of the investments required for drilling against the investments required for water flooding. That starts on Humble's Exhibit No. 37.

Exhibit No. 37 is the development cost for primary production in typical New Mexico fields. I might say they are Southeastern New Mexico fields. We showed three areas ranging in depth from 3900 feet to 4200 feet. And we show the investment cost for well facilities, that is, the drill and complete cost and attendance and investment cost to put oil in the stock tank. The investment cost is expressed in dollars per acre. These wells were all drilled on 40-acre spacing. I should say also that these costs are based on our actual drilling experiences. Now, this category of area "A" at 3900 feet, which cost a thousand and thirty-eight dollars per acre investment, is just about the cheapest well that we know how to drill. It's got two and seven-eighths inch tubing set in it. Area "B's" cost is twelve hundred and fifty-nine dollars an acre. Area "C," two thousand, two hundred thirty-eight dollars per acre. Now, areas "A" and "B" in the southeastern part of the State at depths less than five thousand feet would receive the same allowable as a well drilled in the fields that are currently being water flooded.

Let's turn and look at the costs that are associated with water flooding, and I would like for you to remember that these numbers run about a thousand dollars -- about twelve hundred and fifty-eight dollars and about twenty-two hundred dollars per acre.

This is Humble's Exhibit 38 and deals with the investment cost for water flood projects. Now, this shows two groupings of projects, one the pressure maintenance project, and the lower portion the five spot water flood. In the upper portion we show four unitized high pressure water injection pressure maintenance projects. These projects were installed in years 1954, '55, and '56. You'll see from the number of wells they run in scale from a fairly small one with fifty-eight wells at Unit "D" to a large one, almost twelve hundred wells in the Unit "B". It runs from 2800 acres, roughly, to almost 50,000. The investment cost of converting these fields to water flood in dollars per acre ranges from one hundred twenty-two dollars to one hundred eighty dollars per acre. I can put the average there. It is one hundred thirty-six dollars per acre thousand. These are for the most part -- well, these are either the peripheral or line drive type project. The bottom portion of the chart deals with lease floods, pattern floods. Floods "A," "B," and "C" are Humble floods in the Permian Basin just across the State line. They run 240 to 350 acres to a project, and the costs to install these floods have ranged from seven hundred forty-six dollars to one hundred two dollars per acre. Flood "A" is seven hundred forty-six dollars per acre and was one we had considerably heavy work-over expenses to put this one into operation. Floods "D" and "E" are five spot pattern floods in the advance stage planning and implementation. We expect to have those operating within the next six to twelve months.

Those two larger projects, one of them about ten thousand acres, the other one about twenty-four thousand acres, have cost two hundred forty-eight dollars an acre and one zero seven dollars per acre. This flood is -- I thought you might be interested in it, Mr. Campbell -- is a flood in the Graridge case in the Caprock Field, and we took the data here from an Exhibit entered in Case 1324. There were two sets of data entered in that case. One of them was for a fast flood, one of them was for a slow flood. This particular one that we have chosen here of four hundred dollars per acre was for the fast flood, and the slow one was two hundred eighty-three dollars per acre. Now, the average cost of all these is one hundred seventy-five dollars per acre. I would like to point out that down at the bottom of the chart is listed the costs that are included in these conversion or development costs, however you would like to call them, and you'll note that we say that it includes the cost of developing source of injection water, installing facilities and performing the workover to install the flood. It is necessary at times to do some new drilling to install a pattern of flood. The obvious thing to do there is to try to use the existing wells that you have, and to minimize new drilling. I believe that that's a fairly common practice.

Q Mr. Baze, how does that average cost of one hundred seventy-five compare with the average cost of developing primary production, as shown on your Exhibit No. 37, for the same depth rate?

A Well, it's considerably less; in the nature of a fifth, it's about a fifth or a sixth of a -- the drilling cost or a lesser fraction. I wanted to say another point on this drilling before I forget it. New Mexico, I think, is rather fortunate in that many of its wells in large areas are drilled on regular spacing, and this is good with respect to water flooding because it leads to a good pattern arrangement. Now, I realize that there are areas in New Mexico that are not drilled on 10-acre spacing -- that are not drilled on 40-acre spacing -- excuse me, but large areas are drilled on quite regular spacing, and I think insofar as water flooding is concerned that that's fairly fortunate. Now, if we throw the drilling costs that were associated with placing these projects -- if we throw those drilling costs in, it breaks that average up to two hundred and fifty-two dollars per acre. I'm sure if I don't remind the Commission now, that I will be reminded of it later, that we do have some large projects in here, one of them about twenty-three thousand acres, and it's cost us one hundred seven dollars per acre, and I realize that that works on the average that we placed here, but I think you can see if you take them individually or if you take them as groups or if you take them as singular, that the cost runs less dollars per acre than for drilling. Well, we conclude from these two charts, our conclusion No. 3, that the investment for water flooding is less than general industry requirements.

Now, let's talk a little bit about profit in water flooding. I guess the best way to start this is just to show the conclusion. We've concluded for profitable water flooding that the profitability is several fold greater than for primary drilling. In reaching this conclusion, we've examined the profitability of pressure maintenance units, five spot water flooding, and primary drilling. From our own analysis of the floods and of primary drilling, we've determined that the prorated water flood will derive a considerably greater profit per dollar invested than primary drilling. The profitability of a prorated water flood is very attractive. Now, I think that this point profitability, or if we use another yardstick, current income, is one of the most basic questions that's at stake in this hearing. I didn't say the only basic question, but I say it is one of them. The manner in which the profit is derived, the current income is at stake. I think that this is one of the most basic points that the proponents of capacity allowables seek to protect. Now, we conclude that the profitability of a prorated water flood is plenty good to keep water flood going. And I can say this without hesitation that I just wish the Humble Company could make on its average investment opportunity the profit that goes with a prorated water flood.

Q Have you made any further study of the effect on market allocation?

A Yes, we have. We've made a study on the future of the market allocation. In essence, we have made a five year look ahead for the State of New Mexico as to what we think might happen in the water flood business. To start in on this point, we might discuss a little bit the growth of water flood oil in some areas. We've had some discussion earlier about water flood oil in Texas, Oklahoma, Kansas. There has been reference or implication made to some other states, and there has been mention made that you really don't have to worry about this thing now because one of them comes up and the other one goes down, so they just level off. They are going to go up for about two more months and then they are going to level off, and they will come down the same way as they went up. We heard some discussion about the percentage of water flood oil on the State's total market. Well, let's look at some of these a little differently; Humble's Exhibit No. 39. Now, this is a plot of the growth of secondary recovery water flood production for the United States, starting in 1900, going through 1958, daily production in thousands of barrels per day. Now, I'm quite certain that there must be some floods in the United States that are going up while others are coming down, and that we have this leveling effect portrayed here in this graph. Now, if you will look at 1950 compared against 1958, the growth has been a hundred thousand barrels a day up to six hundred thousand barrels a day. That's a five-fold increase or five hundred percent. And there is nothing on this chart right here that indicates that it is going to peak out in about two months or level off. Now, let's come a little bit closer to home, to New Mexico, and look at some of the states. This is Humble's Exhibit No. 40.

This is a plot starting in the year 1956 and going to the year 1958 of the annual production in millions of barrels of water flood oil. I should have mentioned on the United States curve, and on this one as well, that this is secondary recovery oil. I have no reason why we didn't plot this one on barrels per day instead of annual production, but that is what it is, annual production. This has curves for Texas, Illinois, Kansas, and Oklahoma. And I would like to say right now, Mr. McGowan and Mr. Campbell, I've got a feeling you want to talk to me later on about this because I'm roaming around in your Texas, Oklahoma and Kansas back yards, and we added one more back yard, Illinois. I figure you'll have some points to make. Just to save time, I'll try to make them for you right here. As I understand this, this is total oil produced from secondary recovery projects. Without knowing precisely, I assume that most of the wells that were placed on the flood had some marginal allowable, marginal stripper type allowable, so whatever primary production they had is bound to be in here. I don't know how many wells are involved in any one of the states, so I don't know how many barrels per day per well, producing well or barrels per day per total well is involved. I don't know what percent -- no, that is not right -- I do know what percent of the interval, I'll tell you about that.

It is not a plot of excess production over a marginal allowable or a table of "B" "C" or "D" production. It is simply a plot of the total oil produced from water flood projects. Now, I might have missed some points, Mr. Campbell, but I've got the confidence if I did you will be kind enough to remind me later. But, now, if I can come back to the Humble payroll, the Texas and the Illinois curves are raring up pretty good, and the Oklahoma curve was doing pretty good until it got up to 1957, and then it dropped over. We talked to the Compact Commission people about the decline or breakoff in Oklahoma of production, and they told us it was principally due to one project, that being the Olympic Pool. I believe Mr. Stiles would be quite well informed on that one. We asked their opinion, also, as to Oklahoma, and in this respect I would like to be very representative of the I. O.C.C. reply, his opinion, or perhaps we should call it his guess.

It was that the Oklahoma production is in a temporary sag and that it will resume its upper trend. Now, Kansas is not as sharp "up" as these other states, but it has been going up the hill pretty steadily for quite a while. Now, there were a few points of interest here. On this chart Texas has about, for 1958, the average production, has about two and a half million barrels, and Oklahoma had about half a million barrels total production, I mean. Illinois had about a quarter of a million barrels, Kansas had about a third of a million barrels per day. Now, if we look particularly at the Oklahoma, Texas and the Illinois curves, they run up, roughly, in the same order of magnitude, about one hundred forty thousand barrels a day for Texas and one hundred twenty thousand a day for Oklahoma, a hundred and ten thousand a day for Illinois. Now, when you apply that from a state's individual total production, this one hundred fifty thousand, one hundred forty thousand barrels in Texas is real low percentage, it is about five percent. You apply Oklahoma's twenty-five thousand barrels, it is a little bit more, it is twenty-two percent. You apply Kansas' production to its total, why it's fifteen percent. You apply Illinois to its total, it is fifty percent. There doesn't seem to be much relationship between Oklahoma, Texas and Illinois total market in the amount of oil that it has.

Let's go back here to the period of time when these states had about ten thousand barrels a day, somewhere in the order where New Mexico is on this water flood oil. That would be about 3.6 on this chart, place it roughly, over here about 1950 or '51. Now, the increase for the states of Texas, Illinois and Oklahoma in eight years, since 1950, at the time was about ten thousand barrels, the increase has been between eleven and twelve fold. That's about eleven hundred percent. Kansas has had a more modest growth, but it is still going up, and in those same eight years it's gone up about a hundred and fifty percent. Now, I can't tell from looking here at the state of Texas, state of Illinois, state of Kansas, that they're just about to peak another couple of months and they are going to level off. I just see some curves that have a pretty rapid growth.

Well, let's bring this matter down a little bit closer to home, now, New Mexico, and go to Humble's Exhibit No. 41. This is a plot of the number of secondary recovery projects against years for the West Texas-New Mexico area. Now, again, these are just secondary recovery projects, no pressure maintenance included. And let's look at the year, about 1950. Most of these, of course, are on the Texas side on the Permian Basin, and if you look at the year 1950, you see that that's about the time that the growth started pretty good, and that's just about the year that some of the pilots and early operations on the Texas side of the Permian Basin had started an expansion from the start. Now, between 1950 and 1958, there has been between a nine and ten fold increase in the number of projects. Now, I would like to be real clear on the number of projects. That might be a 20-acre lease, it might be a 640-acre section, it is just a project. And, again, you can't see anything on this Exhibit except that it is steadily going up, and there is no evidence here that this is going to peak out in another couple of months and level off. Now, let's try to come home to New Mexico. We made a five-year look ahead, what water flooding might do for the State of New Mexico, and estimated five years hence what the water flood oil production might be for different basis of allocation. Now, the top part of the plot plus actual and estimated total demand for Southeastern New Mexico on the left-hand side vertical scale is barrels per day, thousands of barrels per day. The same production is plotted on the right-hand side there at the upper part in millions of barrels per month. Now, we plotted the actual history in the heavy black line for the years '55, '56 and '57, and '58, and then you notice that we have extended into the future that says "4% per year increase." Now, in the last months there have been articles and authorities speak and say that the national demand in crude will be up three percent per year in the future. Others have said four percent. Others have said five percent. If we look at New Mexico's history for about the last two years, we see that it has a fairly good flood production trend, and that four percent per year is more representative of the last four or five years. Now, we could have worked this matter out using any specified percentage of increase in the future. I don't mean to sit up here as an expert and tell the Commission that it will be four percent per year increase in the future. I simply want to state that that is the basis that we used. It is not justified on the basis of the last couple of years' history.

Well, the bottom part of the chart depicts a five-year look ahead of our estimate of water flood in New Mexico under a system where floods are given capacity allowables and under a system where the floods are prorated on a normal unit allowable. We plotted over on the right-hand side vertical thousands of barrels per day, and it runs from zero to eighty thousand barrels. We plotted a heavy black line here for the years '57, '58, and '59, and the mid-point of '59 is at the point of ten thousand barrels a day. Now, I should point out to you that everything plotted on the bottom part of this Exhibit No. 42 can be construed as additional oil or increase in oil. Let's take this ten thousand barrel a day point, say, at mid fifty-nine. That's our own interpretation from the Commission's records of the increase in oil. It does not include the primary allowable that was assigned to those wells when they went under water flood. You'll notice the top curve has been drawn up to the middle of 1964 and labeled "Floods at capacity allowable," and that end point there is seventy-four thousand barrels per day. The lower curve is labeled "Floods prorated to normal unit allowable" ends up there in the middle of 1964 at twenty-eight thousand barrels per day. You see a couple of points in the year 1962. We were basically interested in the five-year look ahead, but we stopped off at the two and a half years' point, and we have just drawn up to the two and a half year point and five-year point. Now, in making this estimate we went to the fields in Southeastern New Mexico that are under water flood now. There are twelve of them. We went to nine of them. We applied reasonable expansions in those nine fields, during this five-year period. We applied expansion in accordance with actual history in that field, if such were available, and if it wasn't, we applied the expansion in accordance with the rate of expansion in floods just across the line. And we deliberately tracked these individual expansions throughout each field and throughout the five years to take account of this leveling effect of floods. I wanted to mention that with regard to this matter of expansions applied to arrive at the five-year look ahead, we know, all of us know that some of the expansions are already under way. Some of the expansions that are included in these curves did not start until the year 1962.

The next point, or the next step in this process was to tie this estimated future water flood production into the Southeastern market allowable situation and tie it into a normal unit allowable. And in so doing, we've taken into account thirteen percent shortages of production, that is, thirteen percent of allowable shortages. It has been running a little higher than that the last six months or a year, but if you track back for the past several years, you'll find that the history of changes has been about thirteen percent, and we know the Commission has takes steps to eliminate some of the shortages in New Mexico, and we've used thirteen percent for equating estimated production to the allowable situation.

Well, our next chart is where we tied this future estimated production into the normal unit allowable. That would be Humble's Exhibit No. 43. This is a plot of the normal unit allowable for Southeastern New Mexico versus time and expanded five years hence. For the years 1948 through mid '59 it was plotted. The actual history of the normal unit allowable, it had a high of 53 barrels back in '51 or '52. It has come down to the present 35 barrels allowable level, and you'll note that the curve which is labeled "Floods prorated to Normal Unit Allowable," we think that the five-year point from now on will be in the order of 25 barrels. And if floods are given a capacity allowable, the normal unit allowable five years from now will be in the order of 19 barrels. Now, there is 6 barrels difference here between these two systems of allocation. I would like to point out that the absolute level of this normal unit allowable is certainly tied in and geared intimately to the four percent per year increase that we assume in the Southeastern part of the State demand. Now, if the actual demand is more than four percent per year increase, the absolute level of these allowables will be higher, but if the actual demand increase is less than four per cent per year, the absolute level of these allowables will be lower. As I mentioned to you, we could not justify using four percent per year on New Mexico's past two years of history. I just said we used four percent. But whether it be four percent, a little more or a little less, we feel that this six barrels difference in the two systems of allocation is a realistic field approach to the difference that results from these two systems of allocation. Now, we stand here at 35 barrels. We look ahead five years. Normal drilling, based on the State's experience, will reduce the normal unit allowable in the future. Prorationing of water floods, or let me say prorated water floods will reduce the normal unit allowable some more because you bring water flood oil into the picture, it is in essence just like increasing the drilling program. Even the prorationing of water floods takes the normal unit allowable down. One of the basic questions that's at stake here is, do you drive the normal unit allowable down six barrels more just so we can assign capacity allowables to water floods. I think maybe I ought to tear this piece of paper, and that's our conclusion No. 5.

That water flood effect on allowables five years from now is six barrels estimated difference in Southeastern New Mexico, depending on whether the flood oil production is prorated or allowed at capacity.

Q Have you determined any definite conclusions with respect to water flood allowables in New Mexico in the future?

A Yes, we've formed some conclusions, and that's our No. 6. Actually, this one amounts to a summary of the testimony of some earlier Humble witnesses as well as my own. We conclude that the proration of water flood allowables is a sound conservation practice, that it permits an attractive profit, it places flood oil in a uniform market position, and it prevents preferential treatment to water flood operation.

Now, we've attempted to testify and keep straight in this hearing that the proration of floods is a sound conservation practice. We've attempted to convey to the Commission that a prorated water flood gives an attractive profit, and we've attempted to say to you and show to you that considering the risk that's involved in drilling, in water flooding, the profit that results, that the prorating of the water floods places it in a uniform marketing position, the capacity allowables that are given to flood are unnecessary and unwarranted. The capacity allowable is a preferential treatment that's not needed nor is it justified.

Q Mr. Baze, what conclusions, if any, have you formed as to the action this Commission should take with respect to proration of water flood projects?

A This brings us down to the real meat of the question; that's the question of how does the Commission split up the pot, and we have a conclusion, actually, a recommendation to offer in that regard. It is in the form of our conclusion No. 7. Could I say, now, Mr. Hinkle, that this conclusion chart is Exhibit No. 44?

Q Yes, that's Exhibit No. 44.

A This 7th conclusion on Exhibit No. 44 is labeled, "How do we split up the pot," and we recommend to the Commission that it be the same consistent general basis of assigning of allowables to the secondary pressure maintenance production with some limited exceptions to initial pilot operations, and I would like to speak on those exceptions a little bit later.

Now, I think we might just summarize this thing this way. In the future there is going to be some demand for U. S. crude, and we feel certain that New Mexico will get its fair share of whatever that demand is. Now, the Commission can set up procedures whereby New Mexico demand will be filled with primary drilled oil, secondary recovery oil or pressure maintenance oil, and whichever source it comes from, it all looks the same in the stock tank. That leaves the Commission with the question of how to divvy up the pot. We think that if a uniform basis is applied to those secondary recovery pressure maintenance and primary drilling, that it leaves room for primary drilling, it leaves room for secondary recovery, it leaves room for pressure maintenance. Humble Company is happy that the Commission has called this hearing. We think that it is a farsighted approach on the Commission's part, after two years of experience, to stop short and review and attempt to set the proper course for the future, and we recommend to the Commission this general basis -- this general procedure of the assignment of the allowables. To implement this last conclusion, the Humble Company does have a set of proposed rules for the Commission's consideration.

Q I take it from your statement there that you do not agree a hundred percent with the proposed Rules of the Commission.

A There are portions of the Rules that we agree with, and other portions that we would like some revisions.

Q In your opinion, would the proposed Commission Rules give preferred treatment of market demand to water floods?

A Yes, I think it would, sir.

Q Will you point out briefly the manner in which the proposed Rules would give preference before qualified oil is exempt?

A Well, I'll speak for the Southeastern portion of the State. The proposed Rules set out a 42-barrel fixed allowable for a 40-acre spaced well. Now, at the present time we have 35-barrel normal unit allowable. With an assignment of 42, it gives a twenty percent excess allowable, which we feel is not necessary nor justified. Now, if the allowable wanders down to the level of 25, which we've estimated for five years from now, the confined assignment of 42 barrels normal unit allowable to water floods would still give sixty-eight percent more allowable to a water flood well than to a primary drill well, and, as we have concluded, we think that a uniform position for a water flood well and a primary drill well is the same basis of proration.

Do you think -- in your opinion, is there any justification for making a distinction between Southeastern New Mexico and the Northwestern part of the State under the proposed Rule of the Commission?

A Well, the Commission prorates the two areas as separate market areas, and --

Q Does it cost any more to produce water flood oil in the Northwestern part of the State than it does in the Southeastern part of the State?

A Well, I wouldn't think that, as a general statement, at comparable depths, that there should be much difference. There might be some, I don't know.

Q Is there any more reason to make a distinction in the Northwestern part of the State than there is in the Southeastern part of the State?

A You mean between the level --

Q Giving it preferential treatment, water flood oil?

A Well, Mr. Hinkle, basically, I think what we have said here is that we like to play the water flood allowable according to the rules of the game that are established.

Q I mean differential in the market demand there.

A Oh, no, for the same reason that the 42 barrels is not acceptable, in our judgment, the assignment of a fixed level of allowables in the Northwestern part of the State is also objectionable.

Q In other words, in both of these cases, Southeastern

New Mexico and the Northwestern part of the State, under the proposed Rules, these are just arbitrary figures, you might say, to list the allowable as far as water floods are concerned over their normal allowable?

A Well, that's right, sir, I think. Let me say, I believe Mr. Nutter spoke quite clearly as to how they determined the 42. I believe the average ten years' normal unit allowable in the Southeastern part of the State is applicable for that period of time for the Northwest.

Q The proposed Rules of Humble have been marked as Humble's Exhibit 45. Will you refer to these proposed Rules and explain briefly to the Commission what they are, what you propose? I might point out, as you go along, how they differ from the proposed Rules of the Commission.

A Well, in the interest of time -- I'll try to go through these Rules as quickly and briefly as possible, in the interest of time.

This would be Rule 701 that is being proposed. At the outset, I would like to say that there is no delineation or definition included as to pressure maintenance or secondary water floods, and I wish you would bear in mind as I talk, when I talk about a water flood, I mean a water flood, whether it be a secondary recovery or pressure maintenance project.

Part A. deals with the Permit for Injection Required. It's modeled very much after the Staff's proposal. It provides that the permit for injection required comes from notice and hearing. The only thing added here is that such permit may also be granted by special rules that could be adopted for specific pools.

I shall not dwell on Part B. It is the same as the Staff's proposal.

Part C. is the same as the Staff's proposal. It is a copy of existing Rule 701-C.

We come to Part D. which deals with the definition of the project area. I would like to say to you that in writing Rule D. we have attempted to recognize the various and sundry water flood patterns that might be applied; the pattern type, peripheral shape, line-drive combination, or others, to set up procedures by which some of these floods could be handled. I almost want to say automatically -- I guess that's a good word -- and to set up a procedure where, in other cases, the Commission determines the project area upon the basis of evidence in hearing.

Maybe I'd better read this Part D.

> "The project area shall comprise the proration units upon which injection wells are located plus all contiguous proration units which are substantially or totally enclosed by injection wells and which have producing wells completed on them.
>
> In the following cases, the project area shall be limited to a reasonable number of proration units as determined by the Oil Conservation Commission on the basis of evidence submitted at hearing before the Commission:
>
> No. 1. Peripheral injection projects where certain proration units with producing wells on them may be substantially

or totally enclosed by injection wells but are not contiguous with the tracts on which the injection wells are located.

Part 2. Projects of the line-drive type where the injection wells do not enclose contiguous proration units which have producing wells completed on them.

and Part 3. Projects having injection patterns not covered by the above definitions."

Maybe one of the easiest ways to explain -- I guess we'll call it the first paragraph that basically deals with a pattern flood is to turn here to a portrayal of the Staff's proposal, and in this simplified sketch here, this is an area of 40-acre well spacing with the five spot water flood program installed, these black heavy circles being the injection wells, and the red circles being the producing wells. Now, as we understand the Staff proposal, the direct and diagonal offsets to injection wells, those proration units with wells thereon, would become a part of the project area. Now, what this Humble proposal says -- and let's just consider the four injection wells and the enclosed producing well -- that the project area be limited to the 40-acre tracts upon which injection wells are situated and the enclosed center producing well. In this instance -- in this particular instance, I've drawn them embracing five wells in a simple five spot that would be five 40-acre units, or if this pattern were expanded to become a double five spot, then the project area would be two, four, six injection wells and two center enclosed producing wells.

Now, there is another word in that Rule that says a "substantially" enclosed proration unit. I think this little sketch right here will illustrate what we are trying to say. We would normally say in a five spot pattern that, such as this basic one here, that that's closed on four sides. If you take this situation here, we would normally call this one closed on three sides, and we would say that a center producing well closed on three sides would be one substantially enclosed to differentiate it, if there were a -- an injection well right there. Then this well in the center would be totally enclosed. I think that explanation is on this chart.

Q Mr. Baze, for the purpose of the record, I think this Exhibit should be identified as Exhibit No. 46, the one that you have just been talking about. The Rules are 45.

A I see. Now, I might point out, while we are here, the nature of one of the Humble objections, and to take, for example, the Southeastern New Mexico case. You see, that under the Staff proposal, so long as the spacing is regular 40-acre spacing, the allowable that comes out is 1.05 barrels per day per acre. Now, this is the same --

Q Now, let's refer to that as Humble's Exhibit No. 47.

A This -- Humble's Exhibit No. 47 again shows a similar grouping of wells in which a five spot has been imposed on 10-acre spacing, and the only reason I turned back to this chart was to show that under the Staff's proposal, the allowable per project area in this instance is 2.47 as opposed to 1.05 barrels per acre, as shown here on Exhibit No. 46.

Now, I might try to explain here what -- in the second paragraph we tried to take into account other injection patterns that might be employed other than the pattern flood, and this is a broad thing to cover, and we have not attempted to set up specific assignment of areas, but to leave that up to the Commission to assigning a reasonable number of proration units on the basis of evidence that is submitted before the Commission. I think we can all visualize a peripheral flood where injection wells are out on the edge pushing oil toward the middle. If this were the case, it would be brought before the Commission, and the Commission would determine on the basis of that fact -- case what the project area should include, how many proration units. Or, if we had a reservoir somewhat in that shape, and in which this could be a lease, whether or not a line-drive flood placed there or one here, or a line-drive flood with just one row down the middle, that that type of project would be brought before the Commission and evidence submitted, and the Commission decide how many proration units were reasonable to be assigned to the project area. There can be areas when a pattern flood would be installed in a part, say, of the unit, and a line flood in another part, a combination sort of affair. Or maybe they don't fit any of these regular patterns, and Parts 1, 2 and 3 are an attempt to recognize these various patterns and to leave the final assignment of the area to the Commission.

Paragraph E. deals with the manner in which projects may be expanded and additional wells placed on injection. That comes about from Commission hearing or by an administrative procedure, and administrative procedure is set out. Now, this administrative procedure that is set out here says that it must be -- this is in order to expand a project -- it must be established to the satisfaction of the Secretary-Director, that a proposed injection well is located on an injection pattern that will result in a thorough and efficient sweep of oil in the area being enlarged, and also a pattern that is in conformance with the pattern used in other project areas in the pool. So that --

Q Are you referring to Humble's Exhibit No. 46?

A I make reference to Humble's Exhibit no. 46. In order -- for example, on this Exhibit 46, two wells such as this to be added, that evidence will be submitted to the Secretary-Director, showing that these two added injection wells will result in a thorough sweep and that it as well fits the pattern that is employed. We model, I think, reasonably close to the Staff's proposal as to the information that is to be submitted to obtain such enlargement.

Now, paragraph F. deals with the Project Allowable. Part 1. deals with the initial project allowable prior to the demonstration of the effect of injection. It simply says this:

That if this pattern shown here on Exhibit 46 were installed and approved by the Commission as a project area today, the Allowable tomorrow would be the sum of the existing allowables of the various wells that are embraced in that project area, including the allowables of wells that were converted to injection. Now, that's the initial starting allowable.

The second part there provides for the response of a project area to the fluid injection, and maybe I'd better read this one.

> "Upon demonstration of the effect of injection through evidence submitted to the Secretary-Director, the project allowable may be assigned equal to producing capacity as it increases but the allowable shall be limited to a maximum allowable equal to the number of proration units in the project area times the Normal Unit Allowable times the proportional factor for the pool."

Q Mr. Baze, before going further, I wish you would refer back to F. 1. I don't know whether you made it clear that the "allowables from injection wells may be transferred to any well or wells in the project area capable of producing the additional allowable."

A I planned to return to that initial allowable we would assign to a project area. We would propose that it be the allowable assigned to the wells at the time that they are placed on the project and that the allowables assigned to wells placed on injection would be available for transfer to producing wells, if such producing wells could take the transfer.

Now, paragraph F. 2., I think, simply says this. Let's take on this Humble Exhibit 46 these four five spots in which there are two, four, six, eight, nine, ten, and eleven, twelve, thirteen, fourteen wells, I believe. I believe it is fourteen, fifteen -- fifteen, that's right. The maximum allowable that would be assignable to this project under this proposal in Southeastern New Mexico in this current month would be -- and I assume that this field is zero to five thousand feet in depth -- would be fifteen times thirty-five. If this same project were in the Northwestern portion of the State, the maximum allowable assignable to this project would be fifteen wells times fifty-two barrels.

Now, paragraph 3. provides that the project area allowable may be produced from any well or wells in the project area in any proportion, but it shall not exceed the maximum that is defined up above, and in the example fifteen times thirty-five, or the fifteen times fifty-two.

Now, the last portion -- I should asy here that the enlargement portion of these Rules would wind up at the end at the same point as the Staff proposal. When an entire unit, for example, were placed on five spot pattern flood or an entire lease were placed on a pattern flood, we could come up with the same amount of acreage assigned as the Staff proposal. I think we would have the same flexibility for the transfer of allowables and the production of oil within the area. I think we would be in the same place as the Staff's proposal. We wouldn't be in quite the same place on the barrels per day because this Humble proposal ties the water flood allowable to the current normal unit allowable with the applicable depth factors applied.

Paragraph 3. sets out an exception, and it's an attempt to recognize a pilot and the procedure by which the evaluation of a pilot can be speeded up some. It simply says that the Commission can consider the initial pilot project in any pool and give it a temporary allowable in excess of the maximum that would otherwise be assignable under these Rules for such a period of time as the Commission thought it necessary to permit evaluation of the pilot project.

Q Mr. Baze, there is one phase of the proposed Rules of the Commission which you failed to mention, which I believe, Humble may be opposed to, and that is Rule E-3, which provides the allowable assigned to any water flood project area in which there are 40-acre tracts containing more than one well shall be increased by the amount of oil equal to 0.333 times the area allowable factor for each such additional well on a 40-acre tract, and so on --

A The Commission's proposal provides additional allowable on account of dense drilling in the Southeastern part of the State. Now, a 40-acre tract under the Commission's proposal with four wells on it would get an allowable of 140 percent more than the same area, 100 percent more than a 35-barrel basic allowable, and if the allowable gets down to a level of 25 barrels, this dense drilling feature would give a 40-acre tract with four wells

235 percent more than the then unit allowable at 25 barrels. Now, another thing that the Commission's proposal has difficulty with, and this has already been discussed, is, if this be an existing flood operating under capacity, which under the Commission's proposal would continue to operate at capacity, and another project be installed nearby or adjoining, the Commission's proposal provides that this future one would be subjected to regulation, and that calls for a buffer zone. I think the Humble proposal will take care of the buffer zone, and we suggest to you to prorate all of them starting now.

Q Do you have recommendations to make to the Commission with respect to the Humble's proposed Rules as to the effective date and to the floods to which they might apply?

A Yes, sir. As I say, the Humble Company would propose that these Rules be applicable on all floods, both existing ones and future installed ones.

Q Both the Humble Rules and the Commission Rules, you think, are a step in the right direction to allocate and take care of the excess water flood oil?

A Well, I might return to our conclusion No. 7, which is on Exhibit 44. We present to the Commission the recommendation for the basis to assign allowables to place all oil in a uniform market position, and in writing the Rules, we attempted to implement conclusion No. 7 to do that, place them in a uniform market position.

Q No. 6 too?

A And No. 6, yes. Both of these would be taken care of.

MR. HINKLE: That's all we have of this witness.

MR. PORTER: At this time we are going to take a short recess. I would suggest that you not leave the building because we want to get back to work as soon as possible.

(Short recess)

MR. PORTER: The meeting will come to order. Mr. Hinkle, did you offer your Exhibits?

MR. HINKLE: What's that?

MR. PORTER: Did you offer your Exhibits?

MR. HINKLE: No, I don't believe I did. I would like to offer Humble's Exhibits 33 to 47, I believe was the last one.

MR. PORTER: Without objection, the Exhibits will be admitted.

Does anyone have a question of Mr. Baze?

MR. CAMPBELL: Yes, I have.

MR. PORTER: Mr. Campbell.

CROSS EXAMINATION

BY MR. CAMPBELL:

Q Mr. Baze, I gathered from your testimony and from previous matters that involve regulatory agencies that Humble Company is very interested in proper market demand prorationing, is it not?

A Yes, sir.

Q Are all of your recommendations here -- I'll put it this way. What do you believe is the basic responsibility of a regulatory agency such as the New Mexico Oil Conservation Commission? What is their responsibility -- public responsibility?

A Mr. Campbell, I assume that it is set out in the statute somewhere, I don't know.

MR. HINKLE: If the Commission please, that calls for a conclusion of law.

Q Does the Commission have the authority to prevent physical waste?

A I am sure.

Q Are all of your suggestions and recommendations based upon the assumption or on the belief, I am sure in your own minds that your company's engineering conclusions with regard to the waste prevention matters and the ultimate recovery matters of water flooding, that your views are correct inasmuch as you here tend to restrict water flood production?

A Certainly, we think that the Rules that we have offered in evidence will cause no waste.

Q If the restriction of water flood production, would, in fact, cause physical waste or reduce ultimate recovery of oil, then your Company would not favor restricted production, would it?

A On the assumption that you gave me, if we were convinced that the restriction of rate would cause waste, we would not propose restriction of waste.

Q You would not propose a rule simply to control the amount of oil in relation to the market demand?

A No. We are just as interested, I think, in preventing waste as are other operators, regulatory agencies.

Q Would you concede, Mr. Baze, that those who do not agree with your viewpoint in this matter are also just as interested in regard to fair prorationing?

A I think so.

Q In your presentation, you presented your Exhibit No. 36 relating to liquid hydrocarbon reserves in the State of New Mexico. I was not clear when you presented it whether or not those reserves included secondary reserves.

A As I understand the inclusion of secondary by the API AGA, such reserves are added when in a particular field actual water floods have demonstrated any reserves by water flooding or attributing by the same proof.

Q Do you know or have available any estimates of secondary reserves, as such, exclusive of the overall reserve figures?

A No, I do not. I think I know where you are going, Mr. Campbell. I think I tried to make it clear that the increase of the 1959 bar might be due to new drilling or revisions of old reserves or the addition of some water flood oil. It could be any one or all. I don't know.

Q Have you ever examined the reserve estimates of the Interstate Oil Compact Commission with regard to primary and secondary reserves?

A No.

Q Do you know what the estimated primary reserves in the State of New Mexico are in 1958 as compared to the secondary reserves at the same time?

A No.

Q If I told you that the estimates of the Interstate Oil Compact Commission indicate that the estimate of primary reserves to secondary reserves in the State of New Mexico indicate that secondary reserves are thirty-one and four-tenths percent of the total, and that secondary reserves are forty-five and seven-tenths percent of primary reserves, would that seem reasonable to you?

A You said secondary was thirty-one point four percent of the total State reserves, yes, sir. What is the other?

Q Forty-five and seven-tenths secondary primary.

A I take it that is correct.

Q If that is the case, do you feel that the secondary production in New Mexico at this time bears an unreasonable relationship in connection with the secondary reserves as related to primary reserves?

A ~~Mr. Campbell, I think we can say that, as a general~~

statement, the dissolved gas type of reservoir is a prospect for some type of implementation, water flood, LPG injection, others. I am not surprised -- I would not be surprised that a large percent of reserves in any particular area are staked to be of a dissolved gas nature, and in my mind, subject to some type of implementation.

Q Your Company believes that it is in the interest of conservation to develop within reason secondary reserves, doesn't it?

A We certainly do, sir, and we would like to see it take its proper place.

Q Now, with regard to your Exhibit No. 37, which is your development costs and your Exhibit No. 38, which is your Exhibit comparing conversion costs of secondary recovery projects, would you state, again, how you arrived at your figures for Exhibit 37 on the primary development cost?

A Well, I think I pointed out that those were 40-acre spacing wells, and that these costs are based on our actual experiences in drilling cost and complete cost, and the other investment cost to put oil into the stock tank expressed on a per acre basis.

Q And then how did you make your comparison and exactly what did you include in the five spot water flood projects on Exhibit 38, including the Graridge project?

A This would be as the conversion or installation cost applicable. I suppose the best way would be to call it project area or embraced area.

Q Did you include acquisition costs in both figures?

A In neither figure, sir, nor in the drilling cost.

Q Then, the items that you have -- the item that you have excluded from the secondary recovery projects, one of the items is the acquisition costs of the properties, is that right?

A There is no acquisition cost included in the data that we have given you, sir.

Q Don't you think an analysis of comparative acquisition costs might have a considerable bearing upon a reasonable comparison of investment?

A I'd say if we entered acquisition costs for the five spots or the pressure maintenance projects, then we should likewise enter the acquisition cost for the acreage and the geophysical work that goes into the drilling.

Q Don't you think those figures are important in the proper analysis?

A They are important figures.

Q Certainly part of the investment, aren't they?

A Yes, and I take it from your question, Mr. Campbell, that you are assuming that the normal thing is the purchase of the property. Certainly, I'm certain that some projects, some areas are bought for the specific purpose of water flooding, but I don't have any tabulation. It would be my judgment that the purchasers

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of property in large measures are the ones that put it on the flood.

Q Mr. Baze, I don't have the figures here with me either, but let's take the Graridge project to which you called my attention.

A Yes.

Q Most certainly, Graridge did not develop that property on primary basis, you know that?

A I did not, but I'll be glad to assume that they do and I will be glad to agree with you that in instances projects will be brought --

Q And when those projects are brought on properties that have already been developed and equipment and so forth has been installed, certainly that is a major item in the overall cost of the project per acre?

A Yes, that could be considered. Now, most of these things that we are talking about, I suspect, are stripper type of production which are both essential for a salvage type of price.

Q Isn't it true, also, that when you develop a property on primary basis that wells drilled on that and the cost thereof are there to take advantage of the secondary recovery?

A That's right.

Q Which would decrease, actually, on primary secondary basis the original primary investment cost?

A Yes. I might point out to you, Mr. Campbell, that if we went out here to buy some primary production that the allowable that we would get assigned would be the normal unit allowable. We get no bonus because we went and bought some property that was producing under primary.

Q Have you made any analysis of the tax differentials between the acquisition and operation of secondary recovery projects and primary projects?

A No. I know it is an old American custom to pay taxes, and that tax treatment of projects is one that concerns all of us. I think it would not be proper for me to come forward with an after-tax position. Certainly, corporations and individuals, partnerships and the various associations fall in different types of treatments.

Q Don't you believe that is an important element in risk and investment both?

A Well, I don't think there is much risk. We know we are going to pay taxes.

Q Of course, I'm not talking about the risk of paying taxes, we all suffer from that risk. But I'm talking about a comparative analysis which you have undertaken to make here between primary production and secondary production. Certainly, you must concede that you should take into consideration all of the elements that go into the investment.

A If I were an operator putting in a water flood project, certainly I would be interested in the tax treatment, and I might say this to you also, if we are going to take tax treatment into account for water floods, why don't we take it into account for primary production.

Q What I'm saying to you and suggesting to you is that, certainly, if you take one into consideration, you should the other. All I'm asking you, aren't those proper considerations in either case?

A Well, they are certainly important ones.

Q And if they vary from one to the other, they will have an effect upon your conclusion as to a comparative basis, will they not?

A If we took the absolute numbers in one tax bracket and compared it with another tax bracket, they will vary, yes, sir.

Q One other question on that point. Did you consider at all in making your comparisons of investment or profits between primary and secondary endeavors to take into consideration operating costs?

A Yes, as a matter of fact, we did. I'm kind of glad you asked that question, I forgot it. This conclusion right there, No. 4, which deals with profit and which I stated that the profit in water flooding per dollar invested is several fold greater than primary drilling; certainly when you deal with profit, you have to consider investment, operating costs and revenue. And I would like to write you some of the costs up here, operating costs that we considered in arriving at this conclusion. We have seven lease secondary recovery floods in the Permian Basin where

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our operating costs run three hundred dollars per well per month; excluding in that ad valorem taxes or the seven lease floods. I took a look at Case 1324, Exhibit No. 4, and the cost that was presented in that case, two hundred and fifty dollars per well per month, that's on the Graridge. I don't recall whether that was a fast flood or a slow one. On Page 164 of the transcript Mr. Earlough entered some data as to operating costs, and he came out with a three thousand foot depth well costing three hundred dollars per well per month. That's on Page 164. Now, this one, that is, the three hundred dollar one, was listed as less production tax. I don't know whether it has ad valorem tax in or out, nor am I specifically certain on this two hundred fifty dollar figure whether ad valorem and production taxes are in or out. Production and ad valorem taxes are excluded in this three hundred dollar figure. Now, these are the kind of costs right here, operating costs, that we considered in our analysis when we reached this conclusion as to profit.

Q What else did you consider?

A Considered the investment.

Q The investment of what you have discussed here today or including acquisition cost?

A Did not include acquisition cost.

Q So that these determinations of cost per well per month were thrown into calculation of profit without consideration of the matter I talked to you about at the beginning on investment and so forth, is that right?

A Investment costs that we have discussed here were not included for the primary drilling nor for pressure maintenance nor for the secondary recovery project.

Q Now, Mr. Baze, you have --

A I might add, Mr. Campbell, that to put some costs like that into it would be delving into the realm of how good a trader someone was.

Q Certainly, in any phase of the oil and gas business, that is a factor, the acquisition of any property?

A It certainly is.

Q Now, I would like to talk with you for a minute about some of your estimates on the impact of water flood oil in the past and in the future. First, I would like to refer you to Exhibit No. 42, I believe it is -- no, Exhibit No. 43. Now, Mr. Baze, it is apparent from that Exhibit, is it not, that the decline in normal unit allowables in the State of New Mexico, general decline, commenced back in 1952, and except for the brief period of the Suez crisis, has been essentially going down hill, has it not?

A It started about '51 or '52.

Q And it has been declining ever since except for that brief period in 1957, is that correct?

A I believe that is a fair statement, sir.

Q What do you consider caused that decline in the absence of water flood?

A This decline in here?

Q Yes, sir.

A I would suggest that an increase in the number of proration units.

Q And what else? That's one factor, undoubtedly.

A Well, I'm quite certain that in the last five years, I'm pretty certain in the last five years the drilling has been running at an annual increased rate of about nine percent per year, and the increase in the total production has been running about five percent per year, so drilling has been outrunning the increase or growth in production. That's one thing that has had to do with the decline in the unit allowable.

Q Are you saying that drilling activity has been increasing over the last three or four years?

A I said over the last -- about five or six years. If we take the number of wells the increase in the proration units has been in the order of about nine percent, while the production increase spread over the same year average is running about five percent, four and a half.

Q Do you know, just as a matter of information, how many drilling rigs are running in Lea County now?

A No, I do not.

Q Well, would you know approximately what percentage it would be, the number running in Lea County in 1956?

A No.

Q Would you disagree with me if I told you it was less than half the number running at that time?

A No.

Q And would you disagree with me if I told you that the decline commenced in 1957?

A No.

Q We can just look at it. What number is that?

A It doesn't have a number, sir.

Q Go ahead, I want to know what it is.

MR. PORTER: I don't know what number it is. I want to know what it is.

A I thought you were asking me about the number of wells drilled.

MR. HINKLE: For the purpose of identification for the record, let's have it marked as Humble's Exhibit No. 48.

A It's just a plot of field well drilling. Now, this does have the exploratory drilling in it for the United States and New Mexico for the period 1950 through 1958, and it shows a gradual increase in the number of field wells drilled annually. There was a sag in 1954, and there was a sag again there beginning with 1957.

Q And, of course, 1957 was before any of these water flood projects started posing any impact on the State production or allowable, was it not?

A In 1957 the average allowable for the year was 39; in 1958 the average allowable for the year was 34. If that is all we looked at, we might conclude that there was some relation between the number of wells drilled and the allowable. I didn't specifically draw that conclusion.

Q What other factors entered into the decline of the normal unit allowable of New Mexico besides additional wells?

A In this past year?

Q No, the period where it has been declining, which you extrapolated on Exhibit 43?

A Well, I think I tried to say to you on Exhibit 43 a continued drilling program would have the effect of taking the unit allowable down, it could have. And I think I tried to say to you that even if water floods are prorated, additional oil will be brought into the market and have the effect of taking the unit allowable down.

Q Well, do you think imported petroleum had any effect on the decline?

A Now, you just asked me, Mr. Campbell, about the five years ahead. Is this one about the five years behind?

Q I just referred to your extrapolating ahead. I'm still talking about the year 1952 to the present.

A From 1952 on?

Q To the present.

A Well, I didn't set myself up as a market demand expert, and I don't want you to consider me that now, either, as to what makes these things go up and down and around. I assume -- I think it would be a pretty good guess that imports did have something to do --

Q Do you think that the recent decline in normal unit allowables in New Mexico may have been influenced by unprorated oil from other states?

A Mr. Campbell, I thought about this one, and I just don't know how the states get their fair share of the United States demand. I just don't know the answer to that one.

Q Well, I didn't ask you that. I asked you if that had a bearing on the recent declines in top unit allowables in New Mexico?

A I would have to put it this way. Take any one month, there is a certain U. S. demand. As I see it, it gets filled by certain states. If you've just got this one big pot to fill up here, if one state pours so much in, it influences how much is left for another state to pour in.

Q What I'm saying now, wouldn't you concede that in determining past reaction to decreased allowables and in estimating the future of allowables, that there are a great many factors that must be taken into consideration other than water flood oil?

A Oh, I agree with you there on that. I tried to make real clear to you and to the Commission that the absolute level of this 25 and that 19 is geared intimately to whatever this increase in demand or decrease in demand is in the future, and I want to make clear here, too, that we feel like the six barrels here is a realistic difference between these two systems of allocation, and we could have worked it out for a zero percent decrease in demand or a minus one percent or a plus five percent. What would have happened if, for example, we had taken five percent -- well, let's take three percent. I don't know what the number would be if we took three percent. This 25 would have something in the order of that kind of effect. The 25 maybe would be 23, the 19 would be something like 17. I'm saying to you I think that six barrels difference is in there. I don't know whether it is going to be four percent in the future or what.

Q Will you refer to your Exhibit No. 40? I believe you stated in anticipation, to, apparently, one of my questions, that in preparing that particular Exhibit, you had not undertaken to bring the thing down into barrels per day per well, isn't that right?

A That is correct.

Q Don't you think that's an important factor when you are talking about market demand prorationing on a unit basis, as we do in New Mexico, and as they do to a certain extent in the other states like Illinois?

A Yes, it is a factor, Mr. Campbell. What I'm trying to show here, I heard a lot of talk yesterday about the leveling effect that "You really don't have to worry about these things, see, because one flood comes up and another one goes down, and it never does get very high," and I wanted you to see the steeplechase.

I would like to explain that a little more. We had one chart yesterday that was about five feet long and about three feet wide. As I remember, it ran from zero barrels to about three hundred thousand, and right down here in the corner there was a little curve just about that high, and what we did, I got to thinking about that little curve that was right down there, and I kind of got reminded of a termite. You know that's a real small little insect, and if you put enough of them together and give them enough time, they'll eat the house down. So what we did was take that tiny little curve down there and put it on a magnifying glass where we could look at it, and that's where we came up on Exhibit No. 42.

Q I'm glad you finally conceded that you basically look at water flooding and water flooders pretty much as termites.

A Let's just say for the record touche.

Q Mr. Baze, wouldn't you agree that the testimony that has been given here is not that there will not be -- that the amount of water flood oil will remain constant, but that there will be a leveling off of the excess beyond the normal unit allowable points on the basis of production per well per day in these projects? That's all I have intended to portray. Do you feel that there has been something else said about that water flooding entoto was going to stop two months from now?

A Oh, no, I didn't get that. I kept hearing that you don't have to worry about this little curve right here, see, because it just goes another couple of months and then it levels off, and it looks the same way going down as it did coming up. And so we wanted to take a look at this thing and see it. I didn't understand when you said water flooding was going to quit.

Q Now, Mr. Baze, in your closing remark, you made some references to the fact that your company thought that water flood oil was getting some preferential treatment to which it wasn't entitled. Is that correct?

A Under the Rules that we are proposing here, we attempted to set up a system that would give no preferential treatment.

Q But you did say that under the present system, and I assume that's the way you feel, that water flood oil is getting preferential treatment?

A In the essence that it gets a capacity allowable.

Q Now, let's talk a little bit about the market demand prorationing, conceding that neither of us is an expert on it, and let's refer to the State of New Mexico first. Are you acquainted with any oil production or liquid production in New Mexico that is not subject to prorationing at all?

A Condensates, sir.

Q Do you think that's preferential treatment?

A I should have said -- I should have qualified when I said condensate. As I understand the system of allocation in New Mexico -- first of all, condensate is a liquid that comes from a gas. As I understand the system of allocation and prorationing in New Mexico, gas is prorated at the same statewide hearing that oil is prorated, so in that sense the liquid that comes with the related prorated gas, in that sense the liquids are also prorated.

Q You are aware, are you not, Mr. Baze, that there are a number of gas fields in New Mexico and particularly gas distillate fields that are not prorated --

A Yes.

Q -- where the gas is not prorated?

A I think that's right.

Q And at least one of them, Humble operates properties, isn't that correct?

A We have, yes.

Q Have you ever requested that the Commission establish a proration system or ceiling on the amount of distillate that may be produced in those wells?

A You mean in the State of New Mexico?

Q Yes, sir.

A To my knowledge -- to the best of my knowledge, the Humble Company has not entered testimony in New Mexico with regard to the gas allocation system or allocation of liquid associated with gas. I think I could hasten to say that if the Commission ever calls such a hearing, that the Humble Company will come forward with its recommendation.

Q Mr. Baze, Humble is the largest producer of oil in the State of Texas, is it not?

A We used to enjoy that position, but not now.

Q I'm sorry --

A I thought Texaco caught up.

Q Would you like to have me get this straight for the record?

A I'm informed by my colleagues that we are still, in Texas, but not in the U. S.

Q Do you know what percentage of the statewide allowable in Texas, overall percentage is exempt from shutdown days?

A In the State of Texas, that figure varies according to the number of producing days that are assigned. Presently, all forms of exempted production in Texas probably runs in the order of forty percent. That embraces, under Texas statute, discovery allowables, marginal wells, and capacity type water floods.

Q Well, Humble operates a number of such exempt wells on the Gulf Coast area, does it not?

A Yes, sir. I've got a little story to tell you on that Gulf Coast on those exempt wells. I believe that the Railroad Commission two, three -- about two, three years ago there was a round of hearings held by the Texas Commission to consider the exempt nature of a number of fields in that Commission District. One by one they came up for consideration, and in the fields where the Humble had an interest, we went down loaded with just about as many boxes and DC3's as we came up with here, and we were successful in getting one of those fields removed from an exempt status. As I remember, that was the one field which Humble was a predominant operator.

Q What is the situation with regard to MER fields in which Humble operates, the same situation exists?

A Texas has a system of allocation, maybe I should say two broad systems. It has a yardstick basis of the general nature as New Mexico. In addition, it has long had another system of allocation which is called the MER, maximum efficient rate. And the Texas Commission allocates certain fields under one system, certain fields under another system.

Q Is that all? The fields operated under the MER system are not prorated?

A Oh, yes.

Q They are exempt, however?

A Oh, no. I would like to tell you, Mr. Campbell, --

Q That's all right. Let me ask you this. Are the MER fields higher than the yardstick?

A They might be. Let me tell you about this field.

Q Well, that's all right. What I want to ask you is this. There is nothing particularly sacred, is there, about this unit or yardstick or exempt system? There is nothing that points that up in any particular prorated state as a ceiling which cannot under any circumstances be exceeded?

A No. All of these states have

some system. We didn't come out here to fight the battle of the right or wrong of the New Mexico yardstick system or the Texas yardstick system or the Texas MER system. The way we see it, the states have got some Rules that you play by. When we put these Rules -- proposals in here to the Commission, we are just saying, "Let's play by the Rules that are set up."

MR. CAMPBELL: That's the end of my questions, if the Commission please, but I would like to request that inasmuch as these Rules have been presented only this afternoon, that before any decision is reached by the Commission that the interested operators be given an opportunity to examine the Rules and present their comment.

We have been confronted here today as have other people in the past, I can recall, with a tremendous amount of evidence and a tremendous number of Exhibits relating back to background material which we do not have available, obviously. We don't intend to ask for any continuance of the case, but we certainly do feel that we should be given the opportunity to make our views known with regard to the proposed Rules that Humble has submitted to the Commission. I'm speaking for the people that I have entered appearance for.

MR. PAYNE: Make them known by way of comment or by way of testimony?

MR. CAMPBELL: I think by way of comment, if that's agreeable; testimony, I presume, if not.

MR. HINKLE: You mean to continue the case?

MR. CAMPBELL: I didn't ask to continue the case.

MR. PAYNE: When do you propose to come forth with such comments?

MR. CAMPBELL: It would depend upon the Commission.

MR. PORTER: Mr. Campbell, were you suggesting a period of time in which to submit the -- for each company to submit its position in writing to the Commission concerning these Rules?

MR. CAMPBELL: Yes, sir.

MR. HINKLE: Mr. Porter, as I understood Mr. Campbell's proposal, he wants an opportunity to criticize the proposed Rules and make any further suggestions that you want. Is that right?

MR. CAMPBELL: Yes, sir.

MR. HINKLE: Or propose any new Rules?

MR. CAMPBELL: Yes, sir.

MR. HINKLE: If that is the case, I think any proposals that are made should be submitted to Humble, and we should be accorded a reasonable time to make a reply.

MR. CAMPBELL: That's right. And if he makes a reply, I get to make a reply to that. I don't mean to prolong it, but these Rules that they have presented are an entirely new set of Rules.

MR. McGOWAN: Let me say this. I discussed this with Jack. For instance, our position is simply this. I cannot attempt to comment on whether or not Sinclair could agree with Humble's Rules because, obviously, I haven't had time to analyze them; neither has anybody else in my Company. I intend to tell the Commission what rules generally ought to be. If they want to comment on the Humble Rules, we will be glad to submit them within ten days in writing, and they can use them as they see fit; that's what I had in mind. We can't comment on them in this short period of time, like we have the Commission's Rules, for instance.

MR. PORTER: More than two weeks ago the Commission submitted a letter of transmittal along with a proposed Rule revision by the Commission Staff to our entire mailing list. And in that letter of transmittal, we indicated that anyone else could come forward with any rules which they wanted to propose. As a result, we have Mr. Nutter's proposal, we have a proposal by the capacity flood people, we have a proposal by Humble. The Commission rules on this motion that we will allow any interested party fifteen days to submit a statement of position on any one of the three poposals, submit it in writing within fifteen days from this day, and that statement will go into the record and be a part of the record.

MR. CAMPBELL: If the Commission please, I didn't mean to cut off anybody else's statement. I think maybe there may be other questions to be asked.

MR. HINKLE: If the Commission please, I understand that be limited to the position of the Rules that have been proposed.

MR. PORTER: Now, as a part of this ruling, this statement -- the privilege of making this statement will be limited to those parties who have made an appearance here or may make an appearance later in the hearing.

Anyone else have a question of the witness?

MR. McGOWAN: I have just two or three.

QUESTIONS BY MR. McGOWAN:

Q Mr. Baze, what percent of oil in place does Humble usually require by water flooding? What has been your experience?

A Well, the broad range that we associate with, say, natural water drives, this is a very broad category, sixty to eighty percent.

Q That would be the total primary and secondary recovery?

A No, I spoke of a natural water drive. A general rule of thumb for a dissolved gas drive reservoir water flooding, a general rule, one primary barrel, one secondary. So, if we had, say, fifteen percent primary, the general rule would be thirty percent total recovery. Those vary with the project. I just gave you a couple of broad yardsticks.

Q That is a pretty generally accepted yardstick in the industry?

A That's right.

Q Humble, like the rest of the water flooders, doesn't approach the ninety to one hundred recovery that Mr. Holcott got in the field, is that correct?

A Well, in natural water drive?

Q We are talking now about water floods in your known water drive reservoir. I mean, that's what the subject under discussion is.

A We haven't got there yet, Mr. McGowan, but I might tell you this, we haven't given up. I remember an MER hearing about two, three years ago. I believe it was the Midian field, which is a water drive field, and we cored a well behind the water front, took saturation in the core. As I recall, it was about two percent residual oil. We told --

Q That's very interesting.

A I didn't finish. We told the Commission that one of these days we were going to go back up on the other two percent.

Q I think a lot of us have the same idea, but as I say, it is very interesting, but it doesn't change the fact that you can't and aren't getting in your field what Mr. Holcott gets in the laboratory?

A That's correct. But ten years ago, fifteen years ago we thought we had pretty good primary. Today we see thirty percent water flood, tomorrow we may be seeing seventy percent.

Q We are talking about today. Now, on your Exhibit 37, and you don't need to turn to it, that's your Exhibit where you showed the cost per acre for primary development. You could cut that cost about in half simply by doubling your spacing, couldn't you?

A At these depths?

Q Well, at any comparable depths; your cost per acre would be cut in half by doubling your spacing or in proportion as you increase your spacing size units, you decrease your cost?

A That's right. I might point out, I just know one field in New Mexico at the present time below five thousand feet that has 80-acre spacing.

Q I'm not challenging that, but I mean that would be one way of cutting those costs.

A It would be.

Q Now, would you turn to your Exhibit No. 39, on the big one, please?

A Yes, sir.

Q Now, let's see, that shows the increase year by year in secondary recovery water flood production in the United States in red, on the back, is that correct, on the right?

A Yes, sir.

Q If you plotted in a similar manner water flood acres or water flood wells on the left, don't you imagine it would show about a similar increase?

A I would anticipate there would be a similar growth, yes.

MR. McGOWAN: That's all the questions I have.

A I don't know how many barrels per well this represents.

MR. PORTER: Before we proceed further, I would like to amend the Commission's ruling relative to the statements of position. I am reminded that we also had two other proposals, one by Cities Service and one by Phillips. And, of course, anyone desiring to make a statement of position on either one of those proposals, may do so.

Does anyone else have a question of the witness? The witness may be excused.

(Witness excused)

MR. HINKLE: If the Commission please, in the cross examination of Mr. Campbell of Mr. Baze, he had him refer to an instrument which was marked as Humble's Exhibit No. 48. I would like to have that introduced in evidence.

MR. PORTER: What was that?

MR. HINKLE: That's the one that showed the five spot and the one -- it was drilling activity chart.

MR. PORTER: Without objection, Humble's Exhibit 48 will be admitted into the record.

Mr. Hinkle, will you call your next witness?

MR. HINKLE: We have one additional witness, Mr.

Frank Cole.

FRANK W. COLE,

called as a witness, having been first duly sworn, testified as follows:

DIRECT EXAMINATION

BY MR. HINKLE:

Q State your name, please.

A My name is Frank W. Cole.

Q Where do you live, Mr. Cole?

A I live in Norman, Oklahoma.

Q Are you connected with any institute presently?

A I am Assistant Professor of Petetroleum Engineering at the University of Oklahoma.

Q Did you testify in the Graridge case before the Oil Conservation Commission in October, 1957?

A I did.

Q You stated your qualifications at that time --

A Yes, sir.

Q -- and the research work that you had performed and papers that you had written, and so forth?

A Yes, sir.

Q Since your testimony in the Graridge case, have you done any additional reserarch work?

A I continued my basic research work in the same areas ~~which generally include primarily secondary recovery. I've pub-~~

lished two papers dealing primarily with water floods. I will present another paper at the fall meeting of the annual institute American Institute of Mining -- excuse me. This is the chemical engineers, this December, in San Francisco.

Q Do you expect to publish a book?

A I have a reservoir engineering book in press at the present time.

Q Do you have any knowledge, Mr. Cole, of the action or any actions taken by the Oklahoma Corporation Commission in connection with the allocation of water flood projects?

A Yes, sir.

Q How did you obtain your information?

A From the open files of the Corporation Commission in Oklahoma.

Q Did you personally examine those files?

A I did, yes, sir.

Q How recently did you make your examination?

A As recently as last Thursday a week ago. I've forgotten what date that would be, but a week ago yesterday.

Q What did you find in making your examination of the Corporation Commission's files?

A I attempted to obtain all of the recent Orders from the Oklahoma Corporation Commission pertaining to water floods -- new water floods that had been approved by the Commission.

Q Well, how recent -- how far back did you go on that?

A The most recent one I have is dated the 9th day of September, 1959.

Q And how far back did you go?

A I obtained these Orders back to the 25th day of June, 1959.

Q Do you have copies of those Orders with you?

A I do.

Q Will you hand them to the Reporter and have them identified as Exhibits, beginning with Exhibit -- Humble's Exhibit No. 49, please.

A (Witness complies.)

Q Mr. Cole, referring to Humble's Exhibit 49, and the others which have been consecutively marked, will you state to the Commission, briefly, what these show, what they are?

A Until recently, the Oklahoma Corporation Commission has not, as a matter of general policy, restricted the producing rate of water floods. They have issued Orders at various times during the last couple of years which would have had the effect of restricting water flood oil production, but I believe that in all of these cases these Orders were rescinded at a formal hearing prior to the time that they would have gone into force. However, since July of 1959 there appears to have been a definite change in the policy of the Oklahoma Corporation Commission in their attitude toward prorationing water floods. I have with me these fifteen Exhibits which, I think, if you will allow me to read one sentence from each of these, will show you the intent of the Oklahoma Commission regarding the prorationing of these floods.

Q Go ahead and read it, just one sentence.

A First is Order No. 40099. This is dated 25 June, 1959, and in this Order there is no suggestion that floods will be prorated as of the present time. There is, however, one sentence here, sentence 5, in the findings of the Trial Examiner, that says, "It is possible that some restriction will have to be made in the amount of oil that can be produced from water flood properties in the State, and the operator of this water flood should take notice of this condition at this time and conduct the operation of this water flood in such a manner that compliance can be made with any Order of the Commission, placing a restriction on the amount of oil that can be produced from this water flood project." Now, Exhibit No. -- may I just go ahead?

Q Go ahead.

A Exhibit No. 50, which is their Order No. 40100, has precisely the same statement. There is no actual restriction of the oil producing rate, but there is this clause.

Exhibit No. 51 is Oklahoma Corporation Commission's Order No. 40101. Here, again -- this is dated 25 June, 1959. Here again, there is no restriction on the actual production of the water flood oil, but there is this clause that "Some restriction may have to be made."

Exhibit No. 52 is dated the 9th day of July, 1959, and this is the -- this is certainly one of the first Orders which reflected the new attitude. This is Order -- Oklahoma Corporation Commission's Order 40061, dated 9 July, 1959; in the Orders -- the second paragraph of the Order states, and I quote: "It is further ordered that the daily production from this water flood operation shall be limited to that amount of oil calculated by multiplying the number of oil producing wells on the lease times the basic daily oil allowable fixed by the Commission for unallocated wells in the State." That's the end of the paragraph. And you might note that they calculate the allowable for this water flood project by multiplying the number of oil producing wells on the lease, giving no credit at all to injection wells, or, in other words, treating the water flood -- this particular water flood unit identical to the other unallocated areas in the State.

Exhibit No. 53 is the Oklahoma Corporation Commission's Order No. 40128, dated 16th July, 1959. Here again, the second paragraph of the Order on the application: "It is further ordered that the daily production from this water flood operation shall be limited to that amount of oil calculated by multiplying the number of oil producing wells on the lease times the basic daily oil allowable fixed by the Commission for unallocated wells in the State." Here, again, there is -- this particular water flood application is receiving no extra benefit for the injection wells; it is strictly on the oil producing wells.

Q Mr. Cole, in the Order which you just read and the previous ones, the Commission -- the Corporation Commission left out the paragraph which you referred to that they might prorate it in the future?

A That is correct.

Q This is the Order prorating the water flood?

A There is no reference to the effect these Orders -- the last two Orders that I have read contain no statement to the effect that the Commission might at some time restrict the water flood production. This statement has been omitted, and the very simple statement which I have just read is the Order containing the allowable provisions.

Q Now, do you know whether the rest of the Orders are the same as the last one which you read, and contain the same paragraph?

A Mr. Hinkle, I have fifteen of these. The first three were of the type I read where there was no restriction. The last twelve -- eleven of the last twelve contain the identical paragraph. One of the last twelve written since the -- this first week in July, 1959, deals with a large unit, and if I may, would you like me to read that?

Q Yes, read that, please. That is, just the appropriate paragraph.

A This is Humble's Exhibit No. 55, and is the Oklahoma Corporation Commission's Order No. 40245. And it deals with the creation of a unit. And the -- in the Order, paragraph 7 of the Order states that, and I quote: "That the amount of oil to be produced from this unit shall be fixed by the Commission at each regular market demand hearing." It is my understanding that when the Commission encounters these large -- that was the end of the statement -- it is my understanding that when the Commission encounters these large units, they prefer to fix the allowable of the unit at their monthly market demand hearing, as the allocated production is also fixed at the same time.

Q I believe you stated that you obtained these copies very recently?

A Yes, sir.

Q Did you make any inquiry of the Corporation Commission to determine whether any action had been taken by the Commission with respect to modifying or changing or revoking any of these Orders?

A I have.

Q What investigations did you make?

A On Tuesday evening, before the hearings began on Wednesday morning, that would be October the 12th, I believe I called the attorney for the Oklahoma Corporation Commission and asked him if the Commission, to his knowledge, had changed their opinion since writing these Rules and Regulations. He said that in his opinion they had not, that at five o'clock that afternoon he had written two additional Orders which contain the same basic paragraph where the statement, if I may repeat it, is "It is further ordered that the daily oil production from this water flood operation shall be limited to that amount of oil calculated by multiplying the number of oil producing wells on the lease times the basic daily oil allowable fixed by the Commission for unallocated wells in the State."

MR. HINKLE: If the Commission please, we would like to offer in evidence Humble's Exhibits 49 to 53 inclusive.

MR. PORTER: Without objection, the Exhibits will be admitted.

MR. HINKLE: That's all of this witness.

MR. PORTER: Anyone have a question of Mr. Cole?

MR. McGOWAN: I would like to ask a question.

CROSS EXAMINATION

BY MR. McGOWAN:

Q I believe the last Order you read from was 40245?

A I have an Order like that.

Q That was the one where the Commission fixed the allowable?

A Yes, sir.

Q Who is the applicant in that Order?

A I believe --

Q I believe it is in the caption.

A -- the Nortex Oil & Gas Company.

Q I believe you said you had all of the Orders approving water floods since the date of that first one?

A No, sir. I hope I did not say that. I have most, if not all, of the Orders. It is my impression, as you, Mr. McGowan, know very well, you can't walk into the Oklahoma Corporation Commission and ask for the water flood Orders they have issued in the last month. They file all of their findings by Order number, and a water flood Order may be some Order fixing spacing or something else. I asked for a list of the recent water flood Orders and was given this particular list, but I'm quite sure that there are probably one or two missing. However, I was told that the general policy of the Commission has, in recent months, in fact, since this first week in July, has been to write in this particular sentence which I read two or three times.

Q Are you aware of any Orders that they have issued in that interim that did not restrict water flood projects?

A No, sir.

Q You are not aware that -- did you find the Order where the Commission established the Stroud sand unit in Lincoln and Creek Counties?

A What Order was this?

Q Unfortunately, I don't have the Order number.

A No, I don't remember all of the companies involved in these particular Orders, and it may or may not be here. Would you like to look to see?

Q I looked, and they are not there.

A You don't have all of my copies here. There are only ten or twelve there.

Q It would be the application of Sunray Mid-Continent.

A I could thumb through here.

Q If it had the provision you read, it is not there.

A Well, then, it is not here.

Q Are you aware, Mr. Cole, that the Commission is also looking for the adoption of new Rules and Regulations?

A I am.

Q Are you aware that one of the major points of those hearings has been water flood rules?

A Yes, sir.

Q Would you agree with me, then, that probably anything the Commission is doing in individual water flood Orders now will probably be replaced by such general rules?

A I would agree with you that they may be replaced, but the general rules -- but these general rules, as far as I know, may read identical to the way the present Rules are set up.

Q Do you know of any instance where the Oklahoma Commission has denied an application for exception of a proration Rule that restricted a water flood project below its capacity to produce?

A I do not.

MR. PORTER: Does anyone have a question of the witness? ~~The witness may be excused.~~

(Witness excused)

MR. HINKLE: If the Commission please, that concludes our testimony.

MR. PORTER: Does anyone else desire to present testimony in this case?

Any statements to be made at this time?

MR. McGOWAN: If the Commission please, in the interest of time and since Sinclair did present testimony in the Graridge hearing, which has been made part of this record, we will submit no information or no testimony in this matter. I would, however, like very briefly to state Sinclair's position and recommendations to the Commission.

As evidenced by the testimony given by Sinclair in the Graridge hearing, we believe that it is necessary to operate a water flood of a depleted field in such a manner as to allow the injection of water at the most efficient rate for the reservoir being flooded, and to produce the oil moved by such injection water as, if and when it comes to a producing well. We believe that this is necessary in order to obtain the greatest ultimate recovery from any such reservoir, and further necessary where it is not unitized to protect the correlative rights of various owners in the various leases and projects within a pool. Now, in connection with that, we feel that the evidence here at this hearing has, while a lot of it has, I believe not, in my opinion, at least, been directed to the point, hinges on whether or not waste will occur or correlative rights will be violated if water flood projects are restricted. Now, there has been a, I believe, preponderance of testimony to the effect that in many instances restriction of water flood projects either by the injection rate or by restricting the producing well has, in the opinion of the expert testifying, resulted in waste. I believe it has been demonstrated, and the only reason that I have heard assigned for not restricting water floods is the impact it will have upon market demand. The only testimony that could, in my view, be claimed to support the restriction of floods is generally that offered by Mr. Nutter and the Humble. Mr. Hocott in his testimony stated that you get full benefit of capillary action in water flooding at the rates that have been discussed in these two hearings or that are in effect in the New Mexico projects. Therefore, it would seem that the fast rate by that admission certainly would not result in waste.

Mr. Greenwald stated in connection with his Exhibits 20 through 25, which involved the field that was shut down, produced and injected and produced that unquestionably oil did move from one lease to another. Therefore, very obviously correlative rights were violated by reason of that interruption in that water flood project. It seems to me, then, that we have positive evidence from both the Humble and the so-called capacity water flooders that correlative rights can be violated by restriction. We have testimony by many witnesses that waste will occur if the rate is too low or they are restricted, and no testimony that high rates cause waste. That is basically the reason for the position that we took in the Graridge hearing and that we take now. Now, I might state this, and since Oklahoma has been brought into this hearing, I can state that I have, on behalf of my company, taken exactly the same position before the Oklahoma Commission, and the orders put in here today are partially a result, I think, of that position that we have taken, and that is that we have not, never and do not now maintain that water floods cannot be regulated or controlled or that they should not be regulated or controlled. We use the terms regulated or controlled judiciously as opposed to the word prorated. We also feel that the total production from a water flood project, if it is sizeable enough and unitized, can be held within certain limits, generally speaking, without possibly causing waste. We certainly feel that the -- in complete sympathy with the Commission and its staff's position, that they need rules and regulations to regulate and control water floods. We have no water floods in New Mexico. Therefore, I'm not intimately familiar with the way your present rules operate, only in a general way. My limited knowledge of it is it seems to be working pretty well. If the water floods increase, there probably will be an increase of burden on the Commission and its staff, and much of that burden might be eliminated by some changes in your existing rules. We don't feel that the injection of water in the ground or the expenditure of money on a water flood project entitles anybody to any allowable. We do feel that where a water flood project has started to produce, that it must be allowed to produce at its most efficient rate in order to avoid waste. We have no objection to an approach of rules such as those suggested by Mr. Nutter. If Mr. Nutter would make the one change in his rule, which I examined him about on cross examination, Sinclair would have no objection to it. We suggest that he change forty-acre tract to proration units, but those things are more or less incidental. If the Commission feels, and we do not advocate it, but if the Commission feels that you are allegating sufficient water flood programs that you need a general rule to put those water flood projects into effect, and control and regulate those projects, at least in their initial stages, then the rule that Mr. Nutter has asked, generally, we feel is acceptable. It will, I think, as the evidence disclosed here, cover or take care of most of your floods. We feel, however, that the Commission will be going, in the face of the complete preponderance of the testimony, be going against its statutory mandate if they do not in such rule recognize the principal that a particular project may have to produce at a particular rate, at a particular time in order to prevent waste and recognize that principal in such rules, and set up a procedure whereby when an operator feels a particular project has reached that stage, he can come before the Commission without a closed mind on the mission he -- if he can submit sufficient proof that correlative rights will be violated or that waste will occur if he is not allowed an allowable in excess of that granted by any general rule that he can get it if he puts on the proof that those situations exist. That is the reason I asked the questions of Mr. Nutter that I did. We are not nearly so opposed to His rules as our appearance here and our questions would probably suggest. We feel his rules are a logical approach. If you think you need those rules at this time, it would seem that you probably don't have enough water flood programs at this time to need it, but we certainly feel that you must recognize that basic principal that a water flood is not like any other type of production, that each project is an entity of its own and must be treated that way. Thank you.

MR. CAMPBELL: If the Commission please, I would like to first offer two statements which were left with me by two different parties who have left the meeting, one from Mr. Tom L. Ingram and one from Mr. Harold Kersey of Artesia, New Mexico. These are both written, and I'll just leave them with the Commission.

If the Commission please, I don't suppose I need to state in much detail what my position is in this matter. I do feel and have some concern that in this argument over the amount of allowable which will be permitted water flood operations, we are a little inclined to lose sight, at least it seems to me, of what I consider to be the basic responsibility of the Oil Conservation Commission. Essentially, this Commission has the obligation to prevent physical waste of oil, and to see to it that we obtain the greatest possible ultimate recovery of oil in the State of New Mexico. Coincident to that, though perhaps a part of it, it seems to me what the effect of carrying that sort of a provision out will have upon the market demand.

I'm somewhat concerned that if we continue to use market demand as the sole, as it appears to me, basic responsibility of our regulatory agencies, that it will be to the detriment not only of the states, but to the detriment of the industry itself. I cannot agree that the impact of water flood oil, particularly in New Mexico, will justify the risk that is obviously involved in connection with the prevention of physical waste and the greatest ultimate recovery of oil. Certainly, it is apparent to anyone, and I think all the witnesses will admit in all candor and honesty that this is an honest disagreement among engineers. Nonetheless, the disagreement exists, it is a definite one. One side ultimately, perhaps, will be proved right or wrong, but I cannot conceive that New Mexico should take the chance, and in effect, be the first state to take the chance that they will be permitting any physical waste by restricting the producing rates of water flood projects. I am particularly convinced of that because I do not believe that the impact on the market in New Mexico is as great as has been considered by some people. There is a tendency for someone to look at the best water flood project and the best well in that project and multiply by the number of wells in the State of New

Mexico or in Southeastern New Mexico, and consider that ultimately that is what we are looking at. The evidence simply does not bear that out on a per well per day basis, and I think anyone will concede that at least the producing wells are entitled to a top unit allowable, but on that basis it presents an entirely different picture. Further than that, I think there are a number of built-in restrictions on the rate at which water floods can be developed and expanded. In the first place, as has been indicated, there are a number -- the number of potential projects is definitely limited by the very nature of the reservoir and by a number of economic factors. In the second place, it takes time to unitize projects. That has been demonstrated many many times. You cannot start one day, have a unit the next day, and commence injecting water the following day. It just doesn't happen. It might happen, I'm afraid, as I indicated to Mr. Nutter, if the size of the project determines the amount of allowable that you are entitled to obtain, but it certainly is not happening at this time. In New Mexico, a further built-in restriction is the limited supply of water. I know this Commission is well aware of that, and goes into it in all their hearings, and I think it is a definite restriction on what we may anticipate in the future with regard to the impact of water floods upon the general producing situation here, and finally, the Commission already in its rules and regulations and its individual orders has provided a pretty effective rate upon the rate of expansion of water floods, and that has been demonstrated in the floods that are now in existence in the State.

It appears to me that from the evidence that has been presented, if it's analyzed properly, that New Mexico getting started some twenty years behind other states in secondary recovery is perhaps being called upon to lead the way on a mission to distribute the allowable to divvy up the pot, split the pot, as it has been called, when we have not had enough experience in our own state to determine whether we are adopting the right course. There are some features of the proposal by Mr. Nutter with which I certainly am in complete sympathy. I think we need in every case to define whether it is a bona fide stripper water flood that we are talking about. I think we need to have some administrtive procedures to relieve the administrative burdens of the Commission, but after all we get back to this one basic question that is involved here today, and I simply cannot, in my mind at this time, feel that the impact of this water flood oil now or in the foreseeable future in New Mexico is sufficient to take the risk that the Commission is being called upon to take, of causing waste and perhaps reducing the ultimate amount of recoverable oil in our state.

MR. HINKLE: If the Commission please, --

MR. PORTER: Mr. Hinkle.

MR. HINKLE: -- I think the Commission knows very well the position of the Humble in this case. All I need to refer you to are the conclusions that are before the Commission there on Exhibit 44. I just want to thank the Commission for calling this hearing and giving everybody an opportunity to be heard, and for your patience in taking the time to hear it through.

MR. PORTER: Anyone else have a statement to make?

MR. LOAR: If the Commission please, W. R. Loar, representing Sunray Mid-Continent Oil Company. First of all, approximately ten percent of our total production is under water flood out in the State of New Mexico. We only have an interest in the Graridge unit. We have one other small project that consists of one injection well. We hope this condition is improved as time goes on. As the Commission, I believe is aware, Sunray Mid-Continent is in favor of unitization. Frankly, we recommend unitization, in most cases, asthe most efficient form of operation where secondary recovery is concerned. If we were able to form units of any size, the staff Rules will work satisfactorily. However, Sunray Mid-Continent, as well as most of the other operators in New Mexico, has many small tracts and leases which we will probably be unable to unitize, but we will want to flood. On these small tracts it may be necessary to have allowables above the normal unit allowable and perhaps even above the allowable contemplated in the staff suggested Rules in order to conduct an effective water flood and equally important to protect the correlative rights of the operators and the royalty owners who are water flooding. Therefore, there will be some few cases which the staff's proposed Rules will not work allowing the operator to operate the flood efficiently, and we believe that the Rules should be as Mr. Nutter suggested. However, they should recognize that exceptions might be necessary.

MR. PORTER: Mr. Errebo, would you come up front, please?

MR. ERREBO: If it please the Commission, I have a statement on behalf of the British American Oil Producing Company. British American is primarily concerned with the effect of any Rules which the Commission might adopt on pressure maintenance units. British American is now involved along with some other interested operators in the development of plans for pressure maintenance as defined by Mr. Nutter's Rule. These plans relate to two fields, namely, the Bisti-Gallup San Field in San Juan County, and the Yates Sand Field of Lea County. Now, it appears that British American will be the operator of at least that portion of each of these Fields that includes the British American leases. We have no prospects for development of water flood projects in New Mexico, as defined in these proposed Rules. Therefore, our comments will be limited to the economic considerations of pressure maintenance as they relate to the allowable rate of production. Naturally, both the operating companies and the New Mexico Oil Conservation Commission are interested in obtaining maximum recovery from a field. Of necessity, however, the companies must consider the economics, that is, they must have affirmative answers to both of the following questions before deciding to start a secondary recovery project. Will the ultimate increase in oil recovery be sufficient to pay for the extra cost involved in the injection program plus a suitable profit? And does the project offer promise of a sufficient annual rate of return on the money invested? An oil producing company cannot afford to invest its money in water injection facilities if the expected annual rate of return is not sufficiently profitable commensurate with the risk. The return must be sufficient to include the going rate of interest and also the additional risk hazards and uncertainties involved in such projects. Therefore, it is important that the Commission reasonably assure operators that they will be allowed to produce sufficient oil to realize an adequate return annually on the money invested in injection facilities. We consider the pressure maintenance has the following advantages as compared to water flooding: (1) Shorten operating life which lowers total operating costs. (2) Production of more oil before it shrinks in the reservoir may result in increased recovery. (3) Produced gas may be utilized more completely by maintaining a more stable rate of gas production. In view of these advantages, we believe the Commission should encourage pressure maintenance by applying no greater degree of restriction than is used on water flood projects. It is also particularly important that the Commission grant allowable for pressure maintenance on a projectwide rather than an individual well basis.

The following statement which I have is in behalf of

Socony Mobil Oil Company. "Socony feels that the evidence presented at this hearing shows that water flood oil production in excess of allowables for primary production does not constitute a threat to allowables for primary production in New Mexico either now or in the foreseeable future. The so-called impact of such production upon total New Mexico production is negligible, being, according to testimony, only 1.7 percent of production; so there is no present problem. We have heard testimony as to this situation in other major water flood states which have had already water flood production for almost twenty-five years. Excess water flood production in these states is also relatively small and has no real impact upon total production. Does New Mexico then have any real reason to fear that a wave of water flood oil will engulf the state as some people would have us believe? We think not. In any event, this Commission may again review this situation at any time in the future, should the need arise.

The primary function of this Commission being to prevent waste and protect correlative rights, it is our opinion that subjecting all future water flood projects to the proposed Rules would in many cases cause underground waste and impair correlative rights. How do the proponents of these rules propose to prevent oil migration from non-unitized leases whose producing capacity has increased above the proposed limits when this increased capacity is the result of water injected on offset leases? The very existence of these situations is sufficient reason not to adopt such rigid rules. Time after time during the course of this hearing witnesses representing both sides of this controversy have agreed that each individual water flood project represents a separate and distinct problem. In view of this -- in view of this agreement, it remains our opinion that restrictive rules such as those proposed cannot be applied to all water flood projects without hampering the operator in the proper development of his water flood operations, and thus prevent him from obtaining the most efficient results in accordance with proper engineering practices. Since rules are not now needed and because of the grave risk of leaving recoverable oil in the ground and causing violations of correlative rights, we ask the Commission not adopt additional water flood rules.

MR. BUELL: May it please the Commission, in the interest of saving time, may I briefly state that Pan American recommends to the Commission that they adopt the rule proposed by Mr. Nutter. If our experience, under this rule, indicates that it should be changed or modified, the Commission docket is always open.

MR. HOLLRAH: W. M. Hollrah, Atlantic Refining Company. I have a statement that I would like to read into the record.

While a great deal of progress has been made in proration practices in the past thirty years, one of proration's biggest deficiencies is being touched upon this hearing today, namely, the allowables given the injection projects.

We believe that a sound proration system has three objectives. They are:

(1) the prevention of waste.

(2) the protection of oil and gas property rights.

(3) the provision of reasonable incentives to find and produce the most oil and gas.

The allowables rules that the New Mexico Oil Conservation Commission has adopted in the past applying to wells in reservoirs under primary depletion generally meet the three criteria for sound proration. First, they forbid the production of excessive amounts of oil, thereby preventing waste. Secondly, they assign allowables in accordance with the size of the tracts, thereby protecting oil and gas property rights. Thirdly, Rule 505 sets out your depth allowable yardstick, thereby clearly providing the incentive necessary to carry out deep exploration.

Injection projects are becoming more and more important to us every day -- accordingly, we need an additional allowable yardstick that will do the same for secondary recovery operation or injection operations as the depth yardstick and the field allocation formulas do for our primary recovery operations--namely, prevent waste, protect oil and gas property rights, and provide an incentive to produce the most oil. We would hope that this new yardstick would provide the correct incentive to undertake the best injection program at the best time, thereby increasing recovery and preventing waste.

In many reservoirs, a higher ultimate recovery can be effected if an injection program is undertaken early in its life rather than when it is near depletion. Take, for example, a deep reservoir with an undersaturated crude. It might be determined early in the life of this field that the highest recovery could be attained by commencing the injection of high pressure gas early in the life of the field in order to obtain miscible displacement drive. But suppose the wells in the field are capable of producing for say ten years at top allowable without any type of injection. If this project is then to be undertaken and no additional allowable is to be assigned over the then current primary allowable, the operator would receive no return on his investment for ten years. The result would be that the operator would choose not to enter into this injection program but would wait until such time as his wells no longer had the capacity to produce top allowable.

Another type of situation that operators may find themselves in is where they may have a choice between different types of injection program into the same reservoir with one type giving a higher recovery than another but at the same time costing more money to undertake. In this type we need a higher rate for the one that gives the higher recovery to make it worth the extra expenditure. Otherwise, the return on the expenditures is too far down the line to make it worth while.

We propose that an allowable system be developed that would create an incentive to undertake bona-fide injection programs in all reservoirs where such is beneficial regardless of the reservoir depletion stage. A formula might be developed whereby a "new reserve allowable" over and above the primary rate of production could be earned by instituting a secondary recovery or a bona-fide pressure maintenance program. The amount of "new reserve allowable" to be earned should be commensurate with the amount of new reserves added as a result of the new program. We believe that such a formula can be worked out through a series of meetings and hearings, and we would like to see the Commission work in this direction.

We generally concur with your aims in proposed Rule 701, but we do wish to state one exception. The one exception is that we think additional allowable should not be given for additional wells on a 40-acre tract. We are afraid that this might give an incentive to drill unnecessary wells. We would, therefore, omit the sentence starting in the second line at the top of Page 3.

In conclusion, we wish to say again that as far as proposed Rule 701 goes, we generally concur, however, we beg that further meetings and hearings be held in an attempt to complete the picture and give us a proper, realistic and determinable incentive for undertaking any fluid injection program that will increase recovery of oil and thereby prevent waste--regardless of the reservoir's state of depletion.

MR. DUTTON: Randall Dutton for Sun Oil. Chapter 65 of the New Mexico Statutes prohibits waste, whether it be underground, surface or production in excess of market demand. Articles 12 and 13 require that, where allowable production has been limited in the State and in a field to prevent waste, that the allocation among the fields in the State and among the producers in a field must be upon a reasonable basis. It is our belief that the Staff's proposed Rule 701 provides an excellent framework for meeting these statutory mandates.

As a result of independent research and engineering studies, Sun Oil Company long ago took the position that waterflood projects can be designed for any reasonable production rate without sacrificing one barrel of the maximum ultimate oil recovery of which this displacement mechanism is capable. At this hearing the technical evidence relating to ultimate recovery - as opposed to opinions based upon observations of producing rate fluctuations - clearly corroborates our position.

However, even should these observed rate fluctuations - which really affect the amount of profit and not the amount of ultimate recovery - be translated, or should I say "experiences," into a concept of underground waste, two reasons would continue to advocate the adoption of the framework of the proposed rule. First, it is patently unreasonable to permit one class of fields or properties to produce at physical capacity while other classes having similar or superior reserves are drastically restricted to prevent market demand waste. Second, it has been shown that the proposed rule is so liberal that it would permit a maximum allowable far in excess of that required by the great majority of the floods currently in operation or contemplated. Since the rule is of Statewide effect, it should provide for the majority and not the exception. Although we share Mr. Nutter's fears or abuse of an exception provision, we have yet to discover a bona-fide rule without an exception. To make abuse more difficult, we would recommend that an applicant would have to prove not only that the exception was necessary to prevent waste or to protect correlative rights but also that the flood was not deliberately designed to require an exception.

Other minor modifications of the proposed rule which we recommend are the establishment of the normal unit allowable at the time of instituting the flood as the "floor" of the Area Allowable Factor - that is the rate below which it would not be decreased so long as the normal unit allowable does not decline so far as to make such a floor unreasonable. Another recommended modification is the elimination of additional allowable for additional wells. You will recall that Mr. Nutter indicated that the Area Allowable Factor of 42 might be too high and that the additional well allowable might be unnecessary. We believe that the evidence confirms these indications.

We agree with Mr. Nutter that a stabilized project allowable provides the incentive necessary for an operator to undertake a waterflood and believe a similar incentive should be available to pressure maintenance and miscible flood programs.

Since we came into contact with Humble's proposed rules too late in the day to make more than a cursory evaluation of them, we would like, if possible, to reserve a decision to recommend that Sun adopt certain provisions or recommend the adoption of certain provisions of this Rule since it appears to us that the Humble Rule has the same essential framework as Mr. Nutter's Rule, and perhaps upon a closer evaluation would indicate to us that it has the additional flexibility which their witness claimed for. Thank you very much.

MR. McBROOM: I have a statement which I will not read, but merely ask the Reporter to put in the record.

MR. KASTLER: I am Bill Kastler, representing Gulf Oil Corporation.

Gulf Oil Corporation is one of the major producers of primary oil in New Mexico, and, as such, advocates market demand proration. However, in this case we believe that the evidence presented shows that oil produced by water flood has not created a significant market demand problem, and based on the experience gained from many years of water flooding in other oil prorating states, it appears that oil resulting from water floods in New Mexico may never create a significant market demand problem.

Certainly, from the evidence presented in this case and in Case 1324, we see no reason to change our belief that reduction of producing rates from water floods in depleted reservoirs may cause waste.

Since water flood oil is not now or may never be of sufficient magnitude to create a problem on market demand, and because curtailment may cause permanent waste, Gulf recommends that the Commission continue its practice of permitting capacity allowables for bona fide water floods in essentially depleted or depleted reservoirs.

Gulf strongly advocates approval of the Commission's recommendations that administrative procedures be adopted whereby approved projects may be expanded without the necessity for additional hearings.

MR. NESTOR: Mr. Porter, as per the Commission's ruling, I request that my name be entered as making an appearance in this case and take advantage of your fifteen days.

MR. PORTER: The record will so show, Mr. Nestor.

MR. NESTOR: T. W. Nestor for Shell Oil Company. We want to support the Rules proposed by Mr. Nutter for the Commission. We do have two suggestions we would like to make. The first one is we think it might be wise for the Commission to adopt some annual yardstick for maintaining a fixed ratio between the area allowable factor and the unit allowable. We feel this ratio should be on the order of one to one point two five. The second recommendation, we feel that existing floods for which capacity allowables have been granted be limited to the area included at the time of adoption of the Rules, this area being the project area as defined by those Rules. We feel that all expansion areas in any new projects in the same pool should come under the regulation of the Rules.

MR. SNYDER: Sam Snyder, Union Oil Company of California. Union Oil Company of California is a full integrated oil company operating in this area, principally as an exploration and producing company, with the bulk of our production being of the primary character. In fact, all of our production at the present time in New Mexico is primary production. Basically, Union believes that any energy injection effort should be governed by the particular physical characteristics of the reservoir involved. This consent requires a certain amount of freedom in determining optimum injection volumes, withdrawal rates, and well utilization and locations on the part of the operator of the project.

Accordingly, Union supports the adoption of Rule 701 as proposed by the Staff of the New Mexico Oil Conservation Commission, subject to the following exceptions: (1) The scope of the proposed Rule should be enlarged to provide for the granting of exceptions to the Rule upon notice and hearing and showing that such exception is necessary to prevent waste and/or protect correlative rights. (2) No distinction regarding allowables should be made between now and old floods producing from the same common source of supply. Union is of the opinion that it will be a gross violation of correlative rights to allow one project producing from a common source of supply to produce without restricting -- without restrictions -- pardon me -- without restrictions at the same time to restrict another project producing from the same common source of supply, and this can be done even if buffer zones were created between the two projects.

MR. WHITE: Charles White for Texaco, Inc. Texaco's operations in New Mexico are strictly limited to primary recovery. However, Texaco is interested in any Rule or Regulation which might affect water flood production from its interest not only as a measure of conservation, but at sometime in the future, it, too, will be engaged in some type of operation. We concur, in general, with the testimony presented by Mr. Campbell's witness, insofar as that testimony alerts the Commission to the possibility of waste resulting from restriction of production under certain conditions. We also concur with the statement made by those witnesses to the effect that water flood production does not create any impact on the market demand. We, in our own minds, are not entirely convinced that the present Rules and Regulations should be changed, except possibly, insofar as certain administrative matters such as definition of a stripper well. Should, however, the Commission believe that the Rule should be amended, we seriously urge that the Commission amend the proposed Rule to include a provision whereby an exception can be obtained upon the proper showing that waste will occur or where correlative rights might be impaired. In adopting this revision, the Commission will be spelling out their policy that it recognizes that waste might occur or that correlative rights might be impaired under a strict interpretation of a Rule. This, we believe, is a sound and logical policy for the Commission to adopt in view of all of the conflicting testimony that has been presented at this hearing. In other words, Texaco can operate under Mr. Nutter's proposed Rule and under most reservoir conditions. However, the proposed Rule, as presently written, overlooks the ever important principal that exceptions should be granted to unusual reservoir conditions or where it is demanded to protect correlative rights.

Texaco does feel that it or any operator should be precluded from obeying any Rules, when a proper showing is made that either waste or correlative rights might be impaired. We feel that this result could be covered under the proposed Rules unless the Commission's policy in this regard is spelled out.

In conclusion, the Commission's past actions and the proposed Rule infer that pilot projects are a standard necessary prerequisite to a successful water flood project. Texaco submits that such an alleged policy can result in unnecessary delays and oftentimes in distorted devaluation and in economical and physical waste. We, therefore, feel that the new Rule and the Commission's policy in this regard should dispel this inferred prerequisite. We take advantage of the fifteen days in responding to Humble's proposal.

MR. KELLAHIN: If the Commission please, Jason Kellahin, Kallahin & Fox, Santa Fe, representing Standard Oil Company of Texas. Standard Oil Company of Texas is in favor of and in support of the case presented by those supporting capacity allowables. They would restrict this to those instances where there is a bona fide secondary recovery project at the later stage of depletion in the pool. Standard Oil Company feels that secondary recovery is a conservation measure of the highest order which should be adopted by the Commission, and they do not advocate the restrictions on a true water flood project. The dangers involved in the possibilities of waste in underground reservoirs, we feel, are too great to be imposed in a situation, whereas the evidence appears to show in this case the impact of the production on the market demand is negligible. Certainly, we agree that there is a difference of opinion in this case. We do not presume to guess as to what the Commission's ultimate decision may be. However, if an Order is entered which would result in a restriction upon the production from these reservoirs under secondary recovery, Standard Oil strongly urges that the Commission likewise adopt a procedure whereby exceptions can be granted in order to prevent waste and to protect correlative rights.

MR. DARDEN: I am Frank Darden, manager of operations for Newmont Oil Company. Newmont Oil Company wishes to commend Mr. Porter and the members and staff of the Oil Conservation Commission on the way they have conducted this hearing and on the effective manner in which they are regulating the state's oil production to prevent waste and to encourage the development of New Mexico's primary and secondary reserves. These policies were a decisive factor in New mont's decision to expand its investment in New Mexico.

Mr. Campbell and our technical witnesses have eloquently expressed our position ont the portion of the staff-proposed revision of Rule 701 which pertains to the regulation of producing rates in a waterflood.

We do feel, however, that the portion of this revision covering the administrative procedure for the expansion of water flood projects would be beneficial to both the Commission and the operators.

Since the bulk of Newmont's production comes from primary operations, we are naturally concerned that primary and secondary production share equitably in the state's market demand. In our opinion, water flood production in New Mexico does not constitute a threat to primary production either now or in the foreseeable future. Actually, we believe that the development of profitable water floods furnishes additional incentive for exploration by increasing the potential reserves to any new field discovered. Thank you.

MR. PORTER: Anyone else desire to make a statement?

MR. SMITH: I am Kenneth Smith with Ambassador Oil Corporation, Fort Worth, Texas. An observation in our statement here, we wanted to state that the money we've spent collectively at this hearing has greatly already increased the cost of water floods. We feel if a lot of us had spent the time and effort that we've spent here in an effort to get some of the non-prorated states to prorate and had spent some of these efforts in trying to restrict imports, that none of us would be here today, and we wouldn't be worried about this one and a fractional percent of water flood production that is over-allowed.

I think it was very clearly presented during this hearing that the one group that was more or less against the capacity flooding admitted that there was no waste at the present operating procedure set up in New Mexico at this time. But there is a great preponderance on the other side that clearly showed and fairly showed that if rates are restricted in stripper water flooding type of operations, that waste will result. And that is the consensus of practically anyone that is in the operating business. Now, there is an exception or two, as has been shown by these statements here today, but I feel that the Commission must weigh all the evidence; I'm sure they do, too, that is presented.

We have one group in the middle that says, well, they don't know or they don't think waste is being created, but then we have this other group who is very firm in their convictions that waste is being created when you restrict these stripper water flood operations. I can see no other way to go, without creating waste, that it will be necessary to permit these floods to operate at their maximum efficient rates of injection and production.

Now, even those who might disagree with the waste question, those one or two or three, the question of correlative rights, we think, is most important because of the twelve fields being flooded in New Mexico; I believe there has only been partial units formed in three of these fields that are being water flooded. We have properties in some of these areas that might be water flooded on down the line, and we foresee great difficulties of forming units. And we have many small tracts. And if we cannot produce our water flood oil when we create these oil banks and start our oil moving when it comes by our well bore, it is going to go off our lease and go off into somebody else's lease, and maybe sometime we might be in a position where it might be heading our way, and we might not complain so much.

We feel that the present Rules in existence in New Mexico at this time have adequate strength to prevent water flooding, water flood production from becoming excessive. I think it was clearly pointed out that in the other three states in this general market area of Texas, Oklahoma and Kansas, that after years of flooding and some states up as high as twenty-five percent like Oklahoma, still they only see there that figure of one to two percent in excess of what the normal allowable would be. And even at this early stage in New Mexico, they, too fall within that small range. We think that is a small price to pay to prevent waste and to watch out for your own correlative rights. And we also feel that there ought to be some additions made to the present

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November 19, 1959

Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

Re: Case 1787, before Oil Conservation Commission October 14,15,16, 1959.

Gentlemen:

We have this date received a letter from Mr. M. W. Keathley concerning his statement in the above case heard before the New Mexico Oil Conservation Commission on October 14,15,16, 1959.

On page 493 of this transcript he has called to our attention that the wording in the following sentence is incorrect.

> "As a producer at both primary and water flood oil, we are in full accord with the market demand proration program in this and other states." **The word <u>proration</u> should be substituted for <u>prevention</u> shown in your transcript.**

Very truly yours,

DEARNLEY-MEIER REPORTING SERVICE, INC.

BY Marianna Meier
MARIANNA MEIER

MM:s

Rules, a few small additions. We think that anyone putting in a water flood installation should show that he has sufficient water to properly flood his properties the maximum pressure that he can attain below breakdown pressures, and we also believe that there ought to be a strict policing by the Commission of these floods to see that the producing wells are produced at capacity because it clearly is shown here that waste will be created if you don't produce these wells at capacity. That's all.

MR. PORTER: Anyone else have a statement?

MR. KEATHLEY: Marshall Keathley with Forest Oil Corporation. As a producer at both primary and water flood oil, we are in full accord with the market demand prevention program in this and other states.

From the statistical data that has been presented at this hearing, it is apparent to me that the impact of water flood oil on the market has been and is small in those states which have had water flooding for as long as twenty-five years, and in New Mexico where water flooding is comparatively new.

Based on the experience Forest has gained from developing and operating water flood projects in Pennsylvania, Oklahoma, Kansas, Illinois and Texas over the past thirty-six years, it is our firm conviction that in order to prevent waste, protect correlative rights, and to produce the greatest ultimate amount of oil, any state regulatory body in determining allowables for water flood projects must permit an operator to use injection rates and pressures which he considers to be the most efficient for his project and which will permit him to produce stimulated wells at the capacity of the formation to deliver oil to these wells.

MR. PORTER: Anyone else desire to make a statement?

MR. BRUSTREET: Mr. Examiner, I would like to file a statement for the record on behalf of the Graridge Corporation, in favor of capacity allowables.

Graridge Corporation as a primary and water flood operator in New Mexico, wishes to reaffirm its stand that the most-efficient method of waterflooding is at maximum injection rate below breakdown and to operate the producing wells at capacity. It has been demonstrated at the hearing that the excess waterflood production has not and probably will not be of major importance. This curtailment of floods below capacity as demonstrated by operating water flood consultants can result in waste, and, therefore, any rule or order which will not permit capacity flooding should not be enacted. It is our opinion that the controls on rate of expansion of waterflood projects now maintained by the New Mexico Oil Conservation Commission are adequate in controlling waterfloods.

Evidence presented at this hearing shows that there is not now and may never be a serious impact on market demand by excess waterflood production. This has been demonstrated by statistical data from our neighboring market demand states who have had many years of capacity type flooding.

The proposed rules are envisioned for application to large unitized projects under pattern flood. It does not lend itself to efficient operating practices in line drive or peripheral type programs, nor does it provide for the protection of the correlative rights of the small lease owner who is unable to unitize. It has been our experience where there is a wide diversity of ownership and numerous small tracts, that this rule would retard secondary recovery operations as well as to allow correlative rights of individual ownership to be violated.

MR. LOVELESS: I would like to file a statement for Charles Loveless, an independent operator on behalf of the applicant and Humble's water flood.

It must be increasingly clear to the Commission there is credible technical testimony on both sides of instant case, enough to make a finding either for or against unrestricted production from water flood projects. Those opposed to unrestricted production have called upon technologists with enviable credentials to support their positions not only at this hearing but in others in New Mexico and elsewhere. Usually this opposition has been constituted by one, or as today, by a few operators who I am told do not have a large part of their total investments in water floods in New Mexico at this date but rather have leaned heavily on theoretical formulations in support of their position. On the other hand, you have heard testimony from numerous operators deeply involved in water flooding who have abundantly demonstrated the danger of cutting back water injection rates in order to limit production to some empirical rate particularly one dictated by exigencies in the market place.

Since 1954 I have owned interest in water flood projects in New Mexico. Therefore, from a practical standpoint I can speak with some authority both as to technological and economic factors involved. I recall one instance in the Red Lake Premier Sand Unit when it became necessary to shut-in operations during the relocation of the water plant. The Thompson No. 5, a production well located in the center of the four pilot injection wells, dropped in production and we were never successful in a return to the rate of oil production which had been observed prior to the shut-in even though injection pressures were re-established at previous levels.

Aside from technical reasons for allowing unrestricted production, I sincerely believe this Commission would be remiss in its duties if it did not take into consideration practices followed in other oil producing states and particularly as these practices affect the common market. Insofar as I am aware, no other state, except Oklahoma, has limited water flood production.

In conclusion, I respectfully pray that this Commission not take hasty action in this most important decision until it is convinced that a limitation of production in water flood projects will not result in irreparable harm to present and future projects in a great many of which the State is a royalty owner. Further, it is my sincere hope the Commission will go further and consider the disadvantages which may inure to New Mexico through a retreat by the Commission from its present policy pertaining to water flood prorationing due to outside pressures dictated by competition in the common market.

After Humble's testimony of October 16, which showed that New Mexico is very new in water flooding and represents such a very small portion of total water flood oil in the total market, I submit that New Mexico may b e wise to watch developments in pioneer states where flood oil has exerted greater pressures in that state's market. The single factor of effectiveness of mandatory control of imports is much more to be considered by this Commission than the relatively minor effect that flood oil has on New Mexico's overall market.

MR. FLOYD: Walt Floyd with Tidewater. I have no comment other than entering into the record my appearance.

MR. PORTER: In other words, you are making an appearance for Tidewater?

MR. FLOYD: Yes, sir.

MR. BUMGARDER: Art Bumgarder, Skelly Oil Company. I would like to make an appearance.

MR. TRIGG: John H. Trigg, independent, Roswell. I would like to be entered in the record and later submit a statement supporting the capacity allowable.

MR. GREGG: Mr. Gregg. I would like to make an appearance for Hudson & Hudson, and their statement will be submitted later.

MR. PORTER: Does anyone else desire to make a statement?

MR. PAYNE: Yes, sir. The staff urges the adoption of the staff's proposed Rule.

MR. PORTER: If there are no other statements to be made, I would like to make one myself.

I would like to take this opportunity to thank all of those who have been of assistance to us in bringing this hearing to Roswell and setting up the physical facilities for the hearing, and the many courtesies which we have received while we were here. I have never conducted a hearing at which more interest was manifested than has been in this case. Of course, that's understandable because of the nature of the hearing, but I think the fact that interest did not fade out during the hearing is attributed to the witnesses who were certainly well prepared and gave an orderly presentation of their testimony. The witnesses are to be commended. I think also that the attorneys are to be commended for maintaining their composure while handling a matter which has been as controversial as this one has.

We are going to recess the hearing at this time. We will take the matter under advisement.

STATEMENTS NOT READ INTO RECORD

Tom L. Ingram's statement:

Gentlemen:

We have been engaged in water flooding in Southeastern New Mexico since 1955. Currently we are working interest owners in four water flood projects in Eddy County. We also have primary oil production and prospects for future floods.

After three days of testimony by qualified personnel, we feel that there is a preponderance of data that if water flood production is curtailed that oil will be lost in some projects.

Therefore, we request that the Commission weigh this matter carefully before approving an order arbitrarily limiting water flood production which may promote waste.

Statement of Harold Kersey:

My name is Harold Kersey. I live in Artesia, New Mexico and have been engaged in the business of finding and producing oil in this area for many years. As an oil operator whose total activity is confined to this State and whose major interest is in primary production, I wish to submit a statement in behalf of capacity type waterflood operations.

It has been most satisfying to me to see the advance made in this, my home State, in secondary recovery operations.

My major concern is that the Commission proposed rule would prevent the orderly development of water flood prospects in which I am interested. Also, this rule would not allow me to protect my correlative rights where I am offset by larger leases.

I recommend that the Commission continue its existing policy for capacity type water flood operations.

Statement of Curtis McBroom:

Qualification:

In New Mexico I have an interest in the Caprock Field, Loco Hills Field, and Empire Field. I have engaged in management of Waterflood Projects for the past eight years, covering some 50 projects involving 20,000 acres of production on hundreds of leases in New Mexico, Texas, Oklahoma and Kansas.

Statement:

Under the proposed regulation no qualified waterflood operator will be able to operate efficiently in New Mexico.

Discussion:

Altho New Mexico has millions of barrels of estimated waterflood reserves, they have no market value until an actual flood program responds. I am sure no bank anywhere will loan on undeveloped waterflood reserves. Waterflood projects are generally initiated by small independent operators in an area. Only after they have proved an area do major companies start flooding their leases.

Under the proposed regulation no one could start a waterflood until several leases were unitized or a large block was owned by one operator. Independent waterflood operators cannot assemble or unitize as would be required. Even in starting to flood Caprock joint operator agreements were necessary to get a pilot going. It was only after success was indicated that unitization was possible among the many operators.

Waterflood production is a follow up to primary operations and many of the reserves estimated in New Mexico lie in fields now so high in primary production that it will be many years before they are ready for waterflood operations. There is no indication that total waterflood production will ever exceed the total well allowable which would be assigned to those wells under their primary allowables. This is not a question of excessive production, but only of how the oil is to be produced from wells already drilled. If allowed to follow the normal present procedure the wells already drilled will be allowed to produce their reserves without adverse effect on the over-all market.

I believe that in accepting the proposed regulation, the Commission will as effectively stop waterflood projects in new areas as if they said, "No, you cannot waterflood."

By leaving the present rules your stripper wells will be allowed to produce their reserves using only their fair share of the market demand.

Any regulation on waterflood operations should take into consideration the fact that most projects cannot be unitized and any allowable set must permit producing wells to be pumped off. That is, when a regulation permits an operator to waterflood, then a corresponding allowable must permit capacity production.

BUFFALO PETROLEUM CORP FT WORTH TEXAS

REPORT DELY ALSO REPORT WHO SIGNS FOR MSG ROSWELL N MEX.

GENTLEMEN: REGARDING CASE NUMBER 1787 BUFFALO PETROLEUM CORP. REGRETS THAT PRIOR COMMITMENTS PREVENT THEIR PRESENCE AT THIS HEARING BUT WISH TO GO ON RECORD IN SUPPORT OF CAPACITY PRODUCTION OF OIL THAT IS PRODUCED AS A DIRECT RESULT OF A SECONDARY RECOVERY PROGRAM WE ARE OF THE OPINION THAT SECONDARY OIL PRODUCTION CANNOT BE RESTRAINED WITHOUT CAUSING WASTE. WE BELIEVE IT WILL NOT BE PRACTICAL TO COMMENCE SECONDARY RECOVERY PROJECTS IN MANY NEW MEXICO OIL POOLS ON A CURTAILED PRODUCTION CAPACITY BASIS. THE NON-PRODUCTION OF THIS OIL CONSTITUTES A WASTE OF NATURAL RESOURCES. THEREFORE BUFFALO PRAYS THAT THE COMMISSION WILL CONTINUE TO ENCOURAGE THE NEW MEXICO OPERATORS TO RECOVER THE MOST OIL POSSIBLE FROM THE KNOWN DEPOSITS BY NOT SUBJECTING SECONDARY OIL PRODUCTION TO THE RULES AND REGULATIONS SUGGESTED FOR CONSIDERATION AT THIS HEARING.

BUFFALO PETROLEUM CORPORATION, FORT WORTH, TEXAS.

STATEMENTS, LETTERS AND TELEGRAMS RECEIVED IN
CASE 1787

FROM THE ATLANTIC REFINING COMPANY

New Mexico Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

RE Case 1787, Regular Hearing
Docket 35-59, October 14, 1959

Gentlemen:

This letter is in accordance with permission given by the Commission to submit written comments on rules proposed in Case 1787 concerning proration of waterfloods. At this hearing The Atlantic Refining Company read into the record the attached statement giving our position relative to allowable allocation for injection projects. Briefly stated, we proposed that incentive be given for pressure maintenance programs as well as "stripper" type waterfloods. We stated that for the immediate situation, we generally concurred with the Commission Staff's proposed Rule 701 but that future meetings and hearings should be held for writing an allocation formula for all types of injection programs.

The Humble Oil and Refining Company presented a proposed Rule 701 at this hearing and it is on this rule that we specifically wish to comment. We do not object to Humble's proposed rule insofar as it applies to "stripper" type waterfloods only. It is similar to the rule proposed by the Commission staff in that it does prorate waterfloods. However, we do strongly oppose the Humble rule insofar as it applies to pressure maintenance projects. Our reason for this is that it gives no incentive for starting a pressure maintenance program at the proper time to attain maximum ultimate recovery. In this respect, the Humble proposed rule does not encourage the prevention of waste. As we understand it, it would give only the normal unit allowable with the appropriate depth factor for all types of injection programs the same as would be applied to primary production.

We urge, then, that the Humble proposed rule not be adopted for pressure maintenance type injection programs but that more study be given by the industry and the Commission toward adoption of an allocation formula that would give incentive to all types of injection programs. We refer you to our statement for more detail on this subject.

Yours very truly,
/s/ V. M. Hollrah

BEFORE THE OIL CONSERVATION COMMISSION, STATE OF NEW MEXICO

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION ON ITS OWN MOTION TO CONSIDER THE PROMULGATION OF STATEWIDE RULES GOVERNING THE OPERATION OF WATERFLOOD PROJECTS INCLUDING THE ASSIGNMENT OF PROJECT OR UNIT ALLOWABLES

CASE NO. 1787

STATEMENT OF HUMBLE OIL & REFINING COMPANY RELATIVE TO PROPOSED RULES

At the conclusion of the above case on October 16, 1959, Mr.A.L. Porter, Jr., Secretary-Director of the New Mexico Oil Conservation Commission, stated that anyone who had entered an appearance in the case might file a statement commenting upon the rules proposed by Mr. Dan Nutter and upon any rules or proposals made by any of the parties to the case. The Humble desires that the following statement be included as a part of the case:

The principal differences between the rules proposed by Mr.Nutter hereinafter referred to as the "Commission's proposed rules" and the rules proposed by the Humble are as follows:

(a) The number of wells to be included in each waterflood project.

(b) The arbitrary factors used in the Commission's proposed rules in arriving at the maximum allowable to be assigned to any waterflood project whereas Humble's proposed rules are based solely on the number of proration units in each project.

(c) The Commission's proposed rules would not be applicable to existing waterflood projects whereas Humble's proposed rules would be applicable.

It is believed that the rules proposed by Humble are more realistic and more flexible and that it will not be necessary under the proposed rules of Humble for the Commission to make as many exceptions as would be the case in the application of the Commission's proposed rules.

Furthermore, it would not be necessary under Humble's proposed rules for the Commission to give special consideration to buffer zones and to deal with special problems of unitization which will exist in the application of the Commission's proposed rules.

Using Mr. Nutter's rule of thumb estimate that 3500 barrels per day will affect the normal unit allowable by one barrel per day, the application of Humble's proposed rules will have the effect of increasing the normal unit allowable more than the Commission's proposed rules and would reduce the current production of only four waterflood projects, namely, Ambassador, Cities Service and the Graridge Units in the Caprock Queen field and the Graridge Unit No. 2 in the Artesia field.

Respectfully submitted,
HERVEY, SOW & HINKLE
/s/ by Clarence E. Hinkle

FROM GRARIDGE CORPORATION

New Mexico Oil Conservation Commission
P. O. Box 871
Santa Fe, New Mexico

Re: Humble's Proposed Rules
For Waterflood

Gentlemen:

The waterflood rules which Humble has proposed have been reviewed, and it is our feeling that the adoption of such rules will retard the development of waterflooding in New Mexico. In reviewing our own projects in New Mexico, it is doubtful if we would have started the floods that are now successful if the rules as proposed by Humble were in effect. Any such rule which tends to retard waterflood development is felt by this company to be detrimental to New Mexico economy as well as to the ultimate oil to be recovered by all methods of secondary recovery.

We feel that Humble is more or less admitting the fact that their rules are not workable in that they suggest a special credit be given to pilot waterfloods. This in itself indicates that they feel that pilot flooding should not be undertaken at slow rates, and, therefore, the bonus allowable.

Graridge still maintains its position of capacity flooding in order to effectively and adequately recover the ultimate reserve from a depleted field. It has been our experience that unless floods are carried out in this manner that the maximum recovery will not result, and, therefore, waste will be encountered. Graridge recommends adoption of the Commission proposed rules except the portion of Section E pertaining to allowables.

Very truly yours,
GRARIDGE CORPORATION
/s/ O. H. Reaugh

FROM E. BRUCE STREET

Mr. Pete Porter
New Mexico Oil & Gas Commission
Santa Fe, New Mexico

Dear Mr. Porter:

The hearing in Roswell demonstrated one of the most important assets that the oil industry has in New Mexico and that is, a regulatory body willing to hear at length the controversial position that inevitably arise within a dynamic growing area. I wish to commend you, Murry Morgan, and the Governor for your non-partisan and through study of the question of capacity type allowables for waterfloods in New Mexico.

Humble made the most interesting, dramatic, and massive presentation that I have ever seen made and as Frank Homesley of Humble indicated, he thought Gulf, Sinclair, Texaco, Continental, and the other companies should develope their talents to other phases of scientific investigations as there was no question as to Humble's position. Maybe he is right - time will tell.

One of these unanswered questions to me is why reservoirs under a natural effective water drive recover 70 to 80 per cent of oil in place, and the best that a secondary recovery project has ever been able to do, including primary, is an estimated 40 to 50 per cent of oil in place. These questions are for better brains than mine, and I will be content to operate the best I can under the rules established by your commission.

With kindest regards,

Yours truly,
/s/ E. Bruce Street

FROM SKELLY OIL COMPANY

Oil Conservation Commission
State Capitol Office Building
Post Office Box 871
Santa Fe, New Mexico

Re: Case 1787

Gentlemen:

Skelly Oil Company wishes to submit the following statement in this case:

We are of the opinion that oil production rates can be controlled on many water flood projects on a long-term basis if the operator is informed of the control in advance, and development of a project is in stages so that certain stimulated wells may produce at capacity while the project as a whole can be produced with a pre-set oil production rate. The project production rate should be the standard unit allowable times the number of developed spacing units on the project without regard to each well's actual use of performance, or the average normal unit allowable during the last ten years for each Southeast New Mexico and Northwest New Mexico as suggested by the proposed revision of Rule 701 of the Commission's rules and regulations.

We recognize the adviseability of adopting a system of assigning allowables on a project basis, preferably a unitized project, and consequently feel that oil production rates can be controlled on some project long-term basis where the operator is sufficiently informed of the control in advance.

Very truly yours,
/s/ George W. Selinger

STATEMENT OF SUN OIL COMPANY
CONCERNING HUMBLE'S PROPOSED RULE 701 IN CASE 1787

Preliminary to our comments on the subject proposal, we would like to reemphasize our general beliefs relative to waterflood projects.

1. Market demand waste is prohibited by statute just as is underground waste. To maintain the reasonable allocation required by statute where market demand proration is in effect, fields and units having similar reserves must have reasonably similar allowables. To permit production at capacity for one class of property while drastically restricting other classes having similar reserves is patently unreasonable.

2. Our independent studies corroborate the evidence in this case showing that a waterflood can be designed to obtain the maximum recovery of which this displacement mechanism is capable at any reasonable production rate.

3. The factual evidence clearly indicate the capacity waterflood allowable has affected the Southeast New Mexico normal unit allowable and that such effect will increase unless waterfloods are allocated.

At the close of the hearing we indicated our support for the staff's proposed Rule 701 with some slight modifications. Our study of Humble's proposal indicates that Humble has utilized the framework of the staff rule while eliminating the necessity for our recommended modifications relating to reduction of the Area Allowable Factor and elimination of additional allowables for additional wells on the proration units involved. We also believe that the Humble proposal is somewhat more flexible in its definition of project areas and that the project allowable more nearly limits its benefits to the area actually affected.

We continue to agree with Mr. Nutter that the stabilized project allowable is an incentive to secondary recovery and pressure maintenance projects which should be retained.

We still recommend that -- barring an unreasonable decline in the normal unit allowable -- the project allowable established upon instituting the waterflood be retained throughout the life of the project.

Therefore, we recommend the adoption of Humble's proposed Rule 701 with the above modification. We continue to believe that a statewide rule is subject to exception; but would recommend that such exception be granted only after the applicant has shown it to be necessary for reasons which are beyond his control.

A L PORTER JR
SECRETARY OF THE NEW MEXICO OIL CONSERVATION
COMMISSION SANTA FE N MEX

IN CASE #1787 SINCLAIR RECOMMENDS THE ADOPTION OF THE STAFF PROPOSAL ON WATER FLOODS MODIFIED BY THE INCLUSION OF THE CHANGES AND EXCEPTIONS SUGGESTED BY US AT THE HEARING PARTICULARLY A PROVISION FOR THE GRANTING OF ADDITIONAL ALLOWABLES WHERE SUCH IS NECESSARY THIS WILL GIVE THE COMMISSION EFFECTIVE CONTROL AND REGULATION OF WATER FLOODS WITHOUT PENALIZING THEIR DEVELOPMENT AND GROWTH
F F WRIGHT SINCLAIR OIL AND GAS CO.

FROM CAMPBELL & RUSSELL

New Mexico Oil Conservation Commission
Capitol Building
Santa Fe, New Mexico

RE: Case No. 1787
State-wide Rules Governing the
Operation of Waterflood Projects

Gentlemen:

Pursuant to the Commission's ruling that parties to the captioned case might have 15 days following the hearing in which to submit comments, we have been authorized by Newmont Oil Company, whom we represent, to advise the Commission as to their views relative to the matter.

1. Newmont Oil Company is in full agreement with that portion of the rules proposed by Mr. Nutter pertaining to administrative procedures in the expansion of waterflood projects. It is felt that the procedures as set out in the proposed rule definitely provide a "built in" restriction on the rate of expansion of waterflood projects in that they require proof of substantial stimulation as a result of the waterflood effort before any expansion will be authorized. While this provision causes some delay, we feel that it is a much better method of restricting the rate of growth of waterflood projects than is the effort to restrict producing rates.

2. Based upon its experience and the opinion of its engineers, Newmont is of the definite opinion that restriction of the production rate in a waterflood project will cause a loss of ultimate recovery of oil and that any rules or orders which restrict this rate are not in the interest of good conservation practices. The only reason presented for the proposed rule was that waterflood oil in excess of what would normally be allowed might result in a serious impact upon primary exploration and primary production in the state. This concern was expressed at a time when two projects, admittedly exceptional in their nature, were at their peak of production and, as testimony revealed, were leveling off and would commence a marked decline in the near future. Newmont does not believe that waterflood production from these projects or those contemplated in the future, above the allowable normal unit production, will create a threat to primary exploration or production sufficient to justify the serious risk of loss of ultimate recovery of oil and a decline in the interest in secondary recovery in the State of New Mexico.

3. It is the opinion of Newmont that the rules proposed by Mr. Nutter, as he conceded under cross-examination, do not have sufficient flexibility to apply to the many conditions which occur in actual waterflood development. It is not safe or proper to assume that all waterflood projects can or will be unitized and the proposed rule, if it is to work fairly, makes such an assumption. At the very least, any state-wide rule should contain specific provision for exceptions in order that projects not unitized or not developed on 40-acre spacing or planned in any other manner than the conventional 5-spot pattern, may be operated in the interest of prevention of waste and protection of correlative rights.

4. Newmont feels that the proposal submitted by Humble at the conclusion of the hearing is undesirable for several reasons. This proposal obviously restricts waterflood producation to an even greater extent than does the proposal by Mr. Nutter. As has been indicated, Newmont believes that any such restriction will create waste. The rule proposed by Humble would also provide for fluctuating allowables depending on the normal unit allowable in

any month. It is the considered opinion of Newmont that this may cause severe damage to the reservoir by interruption or change in producing rate and will have serious wasteful results. Humble's proposal that their rule apply to existing waterflood projects would, in our opinion, be most inequitable and would have the effect of applying what we consider to be a rule contrary to good conservation practices upon a retroactive basis and would seriously affect development of secondary reserves for the State of New Mexico.

5. Newmont believes that it is virtually impossible to design rigid regulations which may be applied to the wide differences which exist in contractual arrangements, spacing, reservoir characteristics and development patterns in the State's waterflood projects. Newmont recommends that the present system be continued with administrative procedures set up to reduce the work load on the Commission and the operators.

We very much appreciate the opportunity of expressing these views to the Commission and we congratulate the Commission for its patience and diligence in this very important matter of conservation and development of secondary oil reserves which can play such an important part in the future of New Mexico.

Very truly yours,
CAMPBELL & RUSSELL
/s/ Jack M. Campbell

FROM AMERADA PETROLEUM CORPORATION

TO: NEW MEXICO OIL CONSERVATION COMMISSION

Statement Pertaining to Proposed
<u>Water Flood Rules</u>

Amerada Petroleum Corporation agrees with the Commission's proposed water flood rules except for portions of Section E which we suggest the following changes or additions (as indicated by the underlines" for the reasons stated.

<u>Section E 2 and 3</u>: The term "40-acre" as there used should be substituted by the term "proration" unit or tract in order that these rules can apply to any pool regardless of the size of proration unit authorized:

<u>Section E 2</u> should contain an additional provision per-

mitting exceptions to this general rule, so that Rule 2 shall read as follows:

> "The project area of a water flood project shall comprise the proration units upon which injection wells are located plus all proration units which directly or diagonally offset the injection tracts and have producing wells completed on them; <u>provided, however, the Commission may authorize the inclusion of one or more proration units not directly nor diagonally offsetting an injection tract and having producing wells completed thereon, after notice and hearing and where the evidence shows there is a substantial response in such well or wells as a result of the water flood project</u>."

<u>Section E 3</u>: In order to discourage the drilling of additional wells for the sole purpose of increasing the allowable, the additional allowable for any proration unit having two or more additional wells should be limited to not exceed one-half of the area allowable factor times the appropriate proportional factor for the pool. Accordingly, this section should read:

> "The maximum allowable assigned to any water flood project area shall be determined by multiplying the number of proration units in the project area times the Area Allowable Factor times the appropriate proportional factor for the pool. The allowable assigned to any water flood project area in which there are proration units containing more than one well shall be increased by an amount of oil equal to 0.333 times the Area Allowable Factor times the appropriate proportional factor for the pool for each such additional well on a proration unit, provided however, that the additional allowable for any such proration unit shall not exceed <u>one-half</u> the Area Allowable Factor times the appropriate proportional factor for the pool."

<u>Section E 3, continued</u>: Referring to next to the last unnumbered paragraph in this section, we concur with Humble's proposed exception, noted in paragraph 3 of its draft, but suggest a rewording of same to be inserted as a separate unnumbered paragraph in this Section 3, as follows:

> "<u>In order to permit rapid evaluation of the effectiveness of injection and the feasibility of entering into a secondary recovery or pressure maintenance project, the initial pilot project in any pool</u>

may be granted a temporary increase of allowable for only such a period of time as is deemed necessary by the Oil Conservation Commission to permit adequate evaluation of the project."

Section E 4: We suggest that the area allowable factor for the southeastern counties named in this rule be reduced from 42 to 38 barrels, because this lower figure is above the present allowable factor and higher than the average allowable factors which we can expect in the future.

"The Area Allowable Factor for the counties of Lea, Eddy, Chaves, and Roosevelt shall be 38; and the Area Allowable Factor for the counties of San Juan, Rio Arriba, Sandoval, and McKinley shall be 52."

AMERADA PETROLEUM CORPORATION
By H. D. Bushnell

FROM AMBASSADOR OIL CORPORATION

New Mexico Oil Conservation Commission
Post Office Box 871
Santa Fe, New Mexico

Attention: Mr. A. L. Porter, Jr.
Secretary-Director

Re: Comments on Waterflood Rules Proposed by Humble Oil and Refining Company at the October 14 Waterflood Hearing

Gentlemen:

The time you have allowed for comments on the proposed rules has been most helpful since most of us had not seen this proposal prior to the hearing. We are very appreciative of the interest you have taken pertaining to waterflooding in New Mexico and also of the fair and unbiased manner in which you conducted all of the hearings. In order for us to propertly comment on the Humble proposed rules, we feel we must preface our comments with some observations we made during the waterflood hearing.

It was our understanding the main reason for calling a statewide waterflood hearing was to determine the effect water flood production might be having on the total state oil market and allowables, and the effect waterflood production might be having on incentive of primary producers and drillers within the state. Producing stripper waterfloods at capacity has been called controversial in some quarters mainly because it was thought there was considerable disagreement within the producing industry as to its necessity. From the number and type of statements made at the conclusion of the waterflood hearing, it is evident there is practically no controversy as to the necessity of producing stripper-type waterfloods at capacity. The only controversy appears to be between Humble and the rest of the oil industry. Many of the large primary producers in the state who do not have one barrel of waterflood production, stood up and stated it was their belief that if stripper floods were not permitted to operate on a capacity basis, not only waste would occur but an operator could not protect his correlative rights unless he operated under unitized projects. It is interesting to note very few fields conducting waterflood operations are operated on a unitized basis. These operators are not only large primary producers but do a large percentage of the primary drilling. They feel, almost to a man, that the small excess waterflood production above yardstick is having no effect on primary drilling and development.

Another interesting observation is the attitude of the major crude purchasers of oil in the State of New Mexico. They were practically unanimous in stating that capacity allowables are necessary in stripper waterflooding and only one or two stated they thought proration rules should be applied, and then only with a provision for permitting capacity when such was necessary to prevent waste and protect correlative rights. It is also quite interesting to note that Humble, who has taken such an adamant stand on this matter, buys no crude oil (to the best of my knowledge) within the confines of the state.

Now as to the rules suggested by Humble--in the first place it was apparent from their interpretation of actual field performance that they have not had sufficient experience in flooding stripper reservoirs to propose workable waterflood rules. This inexperience is also confirmed by their inability to even recognize the basic differences between a stripper waterflood and a pressure maintenance type of operation. Humble has proposed a project allowable on a somewhat lower basis than that proposed by the Commission. Putting such an allowable on a waterflood project will only work if, due to the characteristics of the reservoir itself, it is not capable of producing that amount of production. The Commission proposal might take care of 80% of future flooding in New Mexico, but the Humble proposal would probably take care of less than 25% of the future flooding in New Mexico. In order to prevent waste and protect correlative rights, there would have to be far more exception hearings on the Humble rule than on the proposed Commission rule.

In summation, we do not believe the general effect of the Humble rule would be in the best interest of the State of New Mexico or to the oil producing industry. It is clearly evident that no waste is being incurred under present regulations and methods of operating floods in New Mexico and that waterflood production is having little or no adverse effect on the statewide allowable. The present method of requiring an initial waterflood hearing and then not permitting expansion of the pilot area until response is received outside of it appears to be more than an ample "brake" to prevent any possible flood of oil on the market. We do feel that rather than have a hearing for flood expansion, it could be done more efficiently on an administrative basis, saving both the Commission and operators money and time. We also request the Commission to include in any rules which they might prepare that an operator be required to inject water into a depleted producing formation at or near capacity, and also that he pump his producing wells at capacity in order to prevent waste.

I am sure the industry appreciates the time you have taken in reviewing stripper waterflooding within the State of New Mexico and as in the past, we truly believe you will come up with a decision that will be fair and equitable to both the State of New Mexico and all those companies who are operating within your state.

Respectfully submitted,
/s/ Kenneth L. Smith
Vice President

FROM TEXACO, INC.

BEFORE THE OIL CONSERVATION COMMISSION
OF THE STATE OF NEW MEXICO

IN THE MATTER OF THE HEARING CALLED
BY THE OIL CONSERVATION COMMISSION
ON ITS OWN MOTION TO CONSIDER THE
PROMULGATION OF STATEWIDE RULES GOVERN-
ING THE OPERATION OF WATER FLOOD PRO-
JECTS INCLUDING THE ASSIGNMENT OF PRO-
JECT OR UNIT ALLOWABLES CASE No. 1787

TO: THE HONORABLE OIL CONSERVATION COMMISSION

STATEMENT SUBMITTED BY TEXACO INC. IN THE
ABOVE MATTER.

Comes now Texaco Inc. and respectfully submits for the

Commission's consideration the following Statement:

Texaco Inc. as an interested party and participant in the above matter takes this opportunity to make further comment on the rules proposed at the hearing held on this matter recommending changes in Rule 701. Our comments are made in the light of our position expressed at the close of the hearing whereby the Commission was informed that Texaco was not convinced that there was a need for altering the present Rule 701, except to provide administrative procedures which would work to the benefit of the Commission and the operators. It was further stated that if, however, the Commission finds it advisable to adopt the rules proposed by the Commission's staff, it should include provisions for exceptions to cover those instances where waste or the impairment of correlative rights can be shown to be imminent if the restrictions of the staff's proposed rules are imposed.

It is obvious from our statement that Texaco does not favor unreasonable, arbitrary restrictions on water floods. The Humble proposed rule changes, being more restrictive than the staff's proposals, are in Texaco's estimation unreasonable and impractical from an operational standpoint. As an example of the unreasonableness, the Commission is referred to the first paragraph of Section D of Humble's proposed rules whereby it is required that a proration unit be "substantially or totally enclosed" by injection wells before such proration unit can be considered within a project area for allowable purposes. Assuming that this rule would require that the producing unit be offset by three injection wells, and that is our understanding of the intent, it is immediately obvious that those producing wells on the edge of a pool having only two possible offsetting injection wells on the normal pattern would never be included within a project area. Texaco feels that the suggestion of Cities Service Oil Company that the proposed rules define a project area as consisting of all the productive wells on a lease or unitized tract has merit, and we suggest that the Commission give full consideration to this means of regulation. It would provide the flexibility which would be desirable for operating the bulk of the waterfloods in the State of New Mexico.

All of which is respectfully submitted.

TEXACO INC.
BY GILBERT, WHITE AND GILBERT
/s/ By L. C. White
/s/ L. C. White
P. O. Box 787
Santa Fe, New Mexico

STATE OF NEW MEXICO)
) ss
COUNTY OF BERNALILLO)

We, ADA DEARNLEY and J. A. TRUJILLO, Notaries Public in and for the County of Bernalillo, State of New Mexico, do hereby certify that the foregoing and attached Transcript of Proceedings before the New Mexico Oil Conservation Commission was reported by us in Stenotype and reduced to typewritten transcript by us, and that the same is a true and correct record to the best of our knowledge, skill and ability.

WITNESS our Hands and Seals this, the 10th day of November, 1959, in the City of Albuquerque, County of Bernalillo, State of New Mexico.

Ada Dearnley
NOTARY PUBLIC

My Commission Expires:
June 19, 1963

J.A. Trujillo
NOTARY PUBLIC

My Commission Expires:
Oct 5, 1960

I N D E X

I N D E X (Continued)