BEFORE THE
OIL CONSERVATION COMMISSION
SANTA FE, NEW MEXICO

IN THE MATTER OF:

CASE NO. 1294

TRANSCRIPT OF PROCEEDINGS

May 8, 1958

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Page

NEW MEXICO OIL CONSERVATION COMMISSION

Mabry Hall

Santa Fe, NEW MEXICO

REGISTER

HEARING DATE Examiner May 7, 1958 TIME: 9:00 a.m.

NAME:	REPRESENTING:	LOCATION:
Jack M Campbell	Campbell & Russell	Roswell NM
W. E. Stiles	W.E. Stiles Engineering	Tulsa Okla
John F. Buckwalter	Ryder Scott Company	Wichita Falls, Texas
John L. Ross	Gulf Oil Corp.	Ft Worth, Texas
Geo H. Edgerton	Edgerton & Stearns	Austin Texas
C. L. McCracken	Ambassador Oil Corp.	Ft. Worth, Texas
J. H. Hoover	Gulf Oil Corp	Roswell N.M.
John Hampton	Great Western Drlg	Midland, Texas
Ed Chávez	St. Engr. Office	S. Fé
E. J. Miller	Cities Service	Hobbs, N.M.
[illegible]	Brazidge Corp	Breckenridge, Tex
Rogers Aston	Franklin, Aston & Fair	Roswell, N.M.
Don Layton	Ambassador Oil Corp	Caprock, N.M.
Bert Murphy	Self	Fort Worth, Texas
Frank Darden	Newmont Oil Co.	Ft. Worth, Texas
Nancy Royal		Santa Fe

I N D E X

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico
May 8, 1958

IN THE MATTER OF: Application of Ambassador Oil Corporation, et al., for an order authorizing the capacity production for certain wells within a pilot water flood project in the Caprock-Queen Pool, Chaves and Lea Counties, New Mexico. Applicant, in the above-styled cause, seeks an order authorizing capacity production for twelve wells in the pilot area of the water flood project authorized by Order No. R-1053, said wells being located in Sections 1, 11, and 12, Township 13 South, Range 31 East, and Section 6, Township 13 South, Range 32 East, Chaves and Lea Counties, New Mexico.	CASE NO. 1294

BEFORE:

Daniel S. Nutter, Examiner.

TRANSCRIPT OF PROCEEDINGS

MR. NUTTER: The Hearing will come to order please. The first case on the docket this morning will be Case No. 1249.

MR. PAYNE: Case 1249. Application of Ambassador Oil Corporation, et al., for an order authorizing the capacity production for certain wells within a pilot water flood project in the Caprock-Queen Pool, Chaves and Lea Counties, New Mexico.

MR. CAMPBELL: Mr. Examiner, I am Jack M. Campbell, Campbell & Russell, Roswell, New Mexico, appearing on behalf of the applicant in this case.

We have three witnesses to be sworn at this time. Mr. Buckwalter, Mr. Edgerton, and Mr. Stiles.

(Witnesses sworn.)

MR. CAMPBELL: I would like to make a very brief preliminary statement.

As the Examiner knows, this pilot project was approved sometime ago by order of the Commission. Recently, the water project began to have some effect on the wells in the pilot area, and we sought and obtained an emergency order, which by its terms will expire tomorrow, and this hearing was called at our request for the purpose of seeking additional authority to produce these wells to capacity beyond the fifteen day period.

Mr. Buckwalter, will you take the stand please.

I might also say, that as the Examiner knows, this area involved is immediately adjacent to the area that was involved in the original Graridge hearing, and the amount of testimony that we are going to put on today insofar as it involves the principal of capacity flooding is going to be limited to some extent. Most of the testimony that we will present will involved the question of the amount of production that may be anticipated, and our views on the impact of capacity flooding on the general supply of crude oil in New Mexico.

<u>JOHN F. BUCKWALTER</u>

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

DIRECT EXAMINATION

BY: MR. CAMPBELL:

Q Will you state your name, please?

A John Buckwalter.

Q Where do you reside, Mr. Buckwalter?

A Wichita, Falls, Texas.

Q What is your profession?

A I am a consulting petroleum engineer.

Q You previously testified before this Commission, have you not?

A Yes, sir, I have.

Q And you testified before them in connection with the original application of Graridge in the North Caprock-Queen Pool, did you not?

A Yes, I did.

Q Are you acquainted with the application of Ambassador Oil Corporation and others in this case for capacity production from wells in the pilot area of the Ambassador pilot flood?

A I am.

Q Is it correct that this area is immediately adjacent to the southwest from the area involved in the prior hearing?

A Yes, it is.

Q Do you know of any circumstances involving this particular area that makes it differ in any material respect from the other area insofar as the geology and engineering reservoir conditions are concerned?

A No, it is very similar.

Q In the other hearing you testified that in your opinion, the restriction of production from the wells in that area might result in waste and loss of ultimate recovery of oil. Does that opinion hold for this area involved in this application also?

A Yes, it does.

Q Is there any reason at all why you can't see that same principal would not apply here as applied in the other case?

A I see no reason why the same principal would not apply here.

Q Now, Mr. Buckwalter, I am going to refer to what has been marked on that board there as Applicant's Exhibit No.1 and ask you to refer to it and state what it represents.

A Exhibit 1 represents a map of a portion of the Caprock field showing in particular, outlined in red, the Graridge unit area, and outlined in green the Ambassador unit area. Also shown on the map, outlined in yellow, is the beginning of a unit area which might be called the Great Western area for which a unit is in a very tenative state of being formed, according to my understanding. All the wells are shown on the map, and the character of the wells are designated by key. The injection wells are shown and the producing wells.

Q Now, refer, if you will, to what has been marked Applicant's Exhibit No. 2 and state what that shows.

A Exhibit 2 is a similar map, base map, but in addition, we have marked in color various wells on these two unit areas. We show the pilot injection wells in red on the Ambassador unit. There are six of those, and then in yellow, the Graridge water injection wells are shown. The future injection wells for the full-scale pattern in the Ambassador flood area are shown in blue, these wells that will be necessary to turn into water injection in the year 1958. In addition, there are some of the offset conversions which would be required in 1958. There are four of those which are off the unit area, but will be essential to completion of development in this area.

Q Now, referring to the wells that are shown on Exhibit No. 2, which will reflect the wells involved in this application, do you have available production data on the twelve wells in the pilot, affected by the pilot project?

A Yes, I do. I have production data here for the twelve wells, which are daily tests, during the month of April, starting April 13 and going through until April the 30th.

Q Would you briefly, for the Examiner, give the production data only as to the first day on which you have it, and the most recent daily test?

A All right. Ambassador Oil Corporation's wells will be given first. State "H" 1, April 13th, two barrels a day, April 30th, 351 barrels a day. State "L" 2, ten barrels and eighty-nine barrels. State "G" No. 1, ten barrels and seven barrels. State

"M" 2, eight barrels and five barrels. State "J" 1, four barrels and five barrels. State"D" 1, a half barrel and a half barrel. Gulf Oil Corporation's Chaves State "A" 1, twenty-five and forty-two. Great Western Maxwell State No. 1, four and five. Great Western State "L" 2, seven and seven. Graridge Malco State "F" 3, five barrels and fifty-four barrels. Graridge Malco State "E" 1, five barrels and two barrels. Graridge Livermore State "J" 3, two barrels in both instances.

Q Mr. Buckwalter, I noticed that there are apparently four wells out of the twelve that recent tests indicate produce in excess of the present top normal unit allowable, is that correct?

A That is correct.

Q And I notice there are some wells to which you made reference to which there has been a decline of production during that period. How do you account for that?

A Well, the one well, in particular, State "G" 1 of Ambassador's shows a decline because of clean-out prior to this time, and this is a decline of production following clean-out on that well. The other could be interpreted as primary decline.

Q Primary decline, and they have not yet been affected by the water flood project, is that correct?

A No, they have not.

Q Now, Mr. Buckwalter, will you please refer to what has been identified as Applicant's Exhibit No. 3, which is on the platform there, and state to the Examiner what it is and what it reflects?

A Exhibit No. 3 is a history of the area designated as the North Caprock-Queen Unit No. 2, which is the name given to the Caprock-Queen Unit, as I understand. This Exhibit shows the primary history, starting in 1945. The history is plotted here in thousands of barrels per month, and you will notice, in 1947, for the end of the year, it reached a peak of forty-five thousand barrels per month production, and then we have a decline in primary production until the end of 1957, at which time we have about four thousand barrels per month production by primary. In addition, the number of wells which are represented by this production are shown at the top of the graph, and we have cumulative production shown, which reached a primary about 290 barrels cumulative as of the end of 1957. The cumulative scale is shown on the right in the millions of barrels. In addition to this primary history, I have also shown on this exhibit our best estimate of the water flood oil production rate during -- following the start of water injection in November of 1957.

Now, this oil production is for the eighteen hundred acres, which comprises this particular unit. The peak, the anticipated peak being reached in 1959 about the middle of the year is about one hundred twenty thousand barrels of oil per month, for this peak, and is about three times the primary peak. Following peak water flood oil production, we always have decline, and that decline history is shown through 1964 on this Exhibit. In addition, the

the cumulative production is plotted, suspected production for this water flood, and we show that the total cumulative will be reaching about six million barrels at the end of 1964. That shows water flood expectancy here of twice the primary, or four million barrels by water flooding as opposed to two million barrels under the primary period.

Q Now, refer to what has been marked Applicant's Exhibit No. 4 and state what that is.

A Exhibit No. 4 is a more detailed picture on different units for the estimated water flood oil production, which is the same curve as shown in the estimated figure from Exhibit 3.

We have shown this, however, in barrels per day rather than barrels per month, then we start to show that the November 1957 water is injected, and this is the estimated rate of increase of production for this unit, providing, of course, that the wells are turned in the proper manner, and that continuous development is carried out.

The peak here is forty-one hundred barrels per day at the time of peak, in the middle of 1959. Also shown on this exhibit is the allowable production which would be available if we applied thirty-three barrels per well per day multiplied by the number of unit wells in this unit, and we find about fourteen hundred and eight-five barrels a day for the forty-five wells, and this is indicated on this particular exhibit showing that that is quite a bit lower than our anticipated peak for the year 1959. Also, it shows thirty-nine barrels per day per well. Thirty-nine barrels, as I understand, is about last year's average well production allowable in this state.

Q Mr. Buckwalter, have you made any effort to compare the possible results of water flood in this Caprock-Queen Pool with other areas in the country insofar as water flood is concerned, have you done that?

A Yes, I have, insofar as it is possible at this time. Of course, we are just really starting water flooding here in Caprock. In other areas, we have considerable amount of history, but to the best of my ability, I have made that comparison.

Q Have you, in that study, found anything to indicate that this particular unit, this particular pool is exceptional insofar as what might be expected with regard to oil that might be available with regard to secondary recovery methods?

A I don't think I found anything exceptional. I think the Caprock has demonstrated, in my opinion, reasonable good results. I think the results are in line with results in other areas, and I pay particular attention to the injection rate performance here compared to similar permian sands and well sands and floods in other parts of the country.

Q Will you refer to what has been identified as Applicant's Exhibit No. 5, 6, 7, and 8, the bar graphs, and state to the Examiner what they reflect in that regard.

A Yes. Exhibit 5 is shown here. This exhibit -- I've taken a number of water floods in different parts of the country and I have studied these water floods at the time of the peak oil production and plotted on this bar graph the rate at which the injection wells were taking water in barrels per day, and also the rate in which the oil wells were producing oil in barrels per day. Now, the first flood that I have at the top of the sheet shows that the Standard of Texas' York Flood in the South Ward Field in Texas, which is a Yates sand,flood comprising of sixteen injection wells and twenty-three producing wells, at the time of peak oil production, which is shown here, had an injection rate of eight hundred barrels per day. Now, the oil producing rate at that time was about one hundred forty barrels per well per day for the average of twenty-three wells that were on flood.

The next one shown is the Standard of Texas' Durgin in the same field as the prior one, and this shows six hundred barrels per day injection rate per well, and the oil production rate was about one hundred and twenty barrels per well per day. This particular operation had twenty-one injection wells and twenty-seven producing wells.

Now, just for reference, while we don't have the peak history in the Caprock-Queen, for references, I've shown the Ambassador's Pilot Caprock current injection rate figures on this same graph, and we see here that the Ambassador's pilot has about an average of about five hundred and eighty barrels per day per injection well.

The next one shown is that for the Atlantic Flood in the South

Ward Field, their Johnson Lease, sixteen injection wells, sixteen producing wells, and at the time of peak, it had about five hundred and thirty barrels per well injection rate. The oil production was about two hundred and ten barrels per well per day.

The next one is the flood in Illinois, the Forest Allendale Flood; five hundred barrels per well injection, oil production there was about eighty barrels per well per day, and the next one shown is our Ambassador Pilot experience, which shows about three hundred and fifty barrels injection rate.

Q Just a moment. Is that the Graridge Caprock?

A I am sorry, you are right, that is the Graridge. I have already given Ambassador's, thank you. This is the Graridge pilot history, or current rate of water injection, which is about three hundred fifty barrels of water per day.

At this time I would like to point out that about six months ago, when we were looking at the Graridge pilot, at that time the injection rates were higher, they were more like we have on the Ambassador's now, they were up to five hundred, and as I recall, six hundred barrels per day per well. This is very normal in water floods. The initial injection rates, it is not possible to maintain those rates if you keep constant pressure on your injection wells. If you start out with a high injection rate at we'll say a thousand pounds pressure at the well head and maintain that constant pressure, you will have to have a decline in injection rate, so at the time we reach peak oil production, these rates have been considerably lower, or are considerably lower than what they were when water was intially injected into the well. Therefore, that is pointed out as a comparision, probably, between these two units in the Caprock.

The next one I show is a Payton Flood, the Payton Unit, Payton Pool, Texas, another Yates sand. Injection rate here is about two hundred and ten barrels per well per day. Oil production peak there was about thirty barrels per day per well.

The Nance, Foot Sand, Texas, a little over two hundred barrels per day injection rate, and about ten barrels per day per well at the peak.

The Sunray's Dora Roberts in Glassock Field shows two hundred barrels and about ninety barrels of oil, two hundred barrels per day on water.

Then we have the Roberts Flood, Bluff Creek, Texas, which shows about ninety barrels per day injection rate, and about twenty barrels of oil.

The Alexander, Bluff Creek, eighty barrels on water and about forty barrels of oil.

Here is a Pennsylvanian Flood in the Bradford Field. Injection rate was about seventy barrels per well per day, and the producing rate about twenty-five.

The lowest one I have on the chart here is for Siggins No. 9, Siggins Field. Injection rate there is about thirty barrels, and the oil production rate is about twenty barrels per day at the peak.

Q Does that confirm you statement and opinion that the Caprock-Queen area, the two units that are shown on there, do not present any exceptional situation insofar as general water flood experience is concerned?

A I think they fall in line with what might be expected with reference to conditions. This is put on barrels per well basis, and this really is not the answer. It shows what you do about individual wells, but we always felt the important thing was the injection and producing rate in barrels per day per acre foot, bringing in more than individual well experience, bringing in considerations and comparisons based on acre feet per sand being flooded.

Q Will you go ahead with that, and I don't think it is necessary to refer to each of those, if you can generalize, please do so.

A All right. These are the same water floods plotted that I have shown on the previous exhibit plotted on a different basis. They are simply plotted on barrels per day per acre foot. I would like to point out that there are some high ones in Allendale in Illinois, almost three barrels per day per foot water injection at the time of peak.

The Bradford Field, the Coit, about two and a half barrels per acre feet per day water injection at the time of peak, and then these others, there are a large group of them that fall in in the range of about seven-tenths to one and one-tenth barrels per day per acre foot. This is the large group in Texas. As a matter of fact, I suppose they are all Texas floods. Yes, sir, they are, they are all Texas floods.

The lowest one here is this Siggins in Illinois, and on the barrels per day per acre foot, it is relatively quite low. I had a hard time, to tell you the truth, in finding one this low, but I did, and yet that is the maximum injection rate possible in this particular field. The reason being the sand is only three hundred feet in depth. Now, it isn't possible to put a high pressure on the injection wells if the flood is successful--I don't say it wouldn't be more successful if they could put more water in, I believe it would--but it is an economically successful flood, and the history has been published in literature for comparision. I again, show these two Ambassador pilot floods. First, the Ambassador and then the Graridge, and you'll not that the Ambassador shows around six-tenths of a barrel per day per acre foot. In my opinion, that is on the low side of the injection rate, particularly for this permian type sand, and it certainly is for the comparison of other permian sands.

The Graridge shows about four-tenths of a barrel per day per acre foot, and I certainly hope, for the good of water flooding in the Caprock, that they can maintain these injection rates in any way that it is possible in order to have comparable results to other floods in the permian area. I believe we are getting to the low side of injection rates in this Caprock, as demonstrated by these two pilot floods, and the operators, I certainly feel, should make every effort to maintain these injection rates. They certainly can't reduce them and be save about them.

Exhibit 7, I have shown more detail on this. Barrels per day per acre foot in the South Ward Field. I would like to point out that they are all listed here, all the floods that I have stated, ten, the ten major floods in that field, and it will show that all these floods in the South Ward Field, with the exception of one, have higher injection rates in barrels per day per acre foot than the two in the Caprock. Now, even that one in the Caprock is lower than the Texas Pacific James and Barker, which is one of the poorer floods in South Ward Field, but just to show the entire South Ward Field's history on this basis, I presented this exhibit, to show where we are in Caprock by comparison.

I have one more exhibit of this general type, which is over here, and this exhibit shows the current water injection rates in New Mexico water floods. I simply took the data from your engineering reports for the four months period November, December of 1957, and January, February, 1958, took the average data for those four months and plotted here the injection rates in barrels per day per well for each of the operations listed, and I find, of course, that the Caprock shows the highest; Ambassador pilot here, for that period, shows around five hundred and seventy barrels per injection well per day, and the next one being the Graridge, around three hundred and ninety barrels per day per injection well, and the Grayburg-Jackson field shows around three hundred and fifty, and these others drop off quite rapidly on a well basis. The lower ones down here being the High Lonesome Pool, for the average injection rate is only about seventy barrels per day per injection well, and the Russell Pool, Neil Wills operation, about eight barrels. This Penrose Skelly was the Humble flood which has been abandoned. The project was abandoned in August of 1956, so I used injection rates for that one of January, February, March, and April of 1956, and that showed about one hundred and ten barrels per injection well per day. I do not have the flood on here, the oil producing rates, except in the case of the Graridge pilot, which shows an average rate of about sixty barrels per day per well at that time. The reason I don't have the others is because the oil producing rates are quite low. This is the only one that showed any significant oil production rates on the barrel per well per day basis.

This exhibit here, I believe, points out something to me, at least, and I think to anyone that would study it, and that would be that in the Caprock we have pretty good injection rates, compared to other fields in New Mexico at the present time. I believe there is a relation between your injection rate and your oil producing rate. There are many factors involved in that relation, but certainly we can expect that oil producing rates are going to be as high on these low injection rate flows as they are on the high injection rate flow, so your per well production problem is not a big problem in the state at this time, and I think these data here would indicate that the chances are it will be a limited problem, more limited to the Caprock, and those that can attain those high rates, although they are more in the minority at this time.

Q Is it customary that the newer floods, such as the Caprock flood, will show a higher injection rate for the initial period?

A Yes, that's customary in any water flood. Now, there are different ways in which operators inject water in water flood operations. Some will decide on what rate they would like to inject into the well, and they will limit the well to that manner of water injection. I don't think that is a good method personally, I have not found it to be as satisfactory as if you apply a constant pressure at all your wells in an area, and permit the wells to take the water that they will take under that pressure, which would be the same pressure for all the wells. Now, if you apply a constant pressure at wells early in their history, they will take two, three, even four times as much water as they will be taking at the time of peak oil production rate in that same flood.

Q Mr. Buckwalter, is it your opinion that if the production from the wells in this area is restricted, that it will reduce the amount of ultimate recovery?

A Yes, it is my opinion that if these wells are restricted, by restricting injection rates or producing rates, that ultimate oil will be lower, and you'll have waste of oil in the reservoir which will not be obtained.

Q Based upon this study that you have made, do you feel that we have any reason to fear any greater impact of additional oil from the Caprock-Queen Pool than from any other water flood projects that you have had occasion to examine?

A No, I don't think that there is anything in that connection that is abnormal about the Caprock. I believe that the important thing is to maintain these injection rates in order to have proper water flooding in this particular field to make it comparable to other floods in other areas, and I believe that the important thing is that these rates be maintained and not reduced. If the operators can maintain the rates, they'll get satisfactory flood results, and I believe this exhibit which is No. 8 that I have presented, shows that other floods in New Mexico at this time do not present the same problem because of the injection rates they are experiencing, the problem being the oil production per well, which is resulting from injection rates.

Q Do you have anything further that you wish to state?

A I don't think I have anything else.

MR. CAMPBELL: Mr. Examiner, that is all the questions I have of this witness.

MR. NUTTER: Does anyone have any questions of the witness?

MR. COOLEY: I have one question.

MR. NUTTER: Mr. Cooley.

CROSS EXAMINATION

BY: MR. COOLEY:

Q Mr. Buckwalter, on Exhibit 4 you have depicted the level at which production would be restricted if the Ambassador unit is held to a thirty-three barrel allowable. Would you go into that just a little bit further and tell me how you calculated that?

A Well, there are forty-five wells in this unit area.

Q Is that forty-five developed forty acre tracts?

A That's correct.

Q Both injection and producing wells?

A Yes. That is my understanding. I multiplied thirty-three times forty-five, and I obtained fourteen hundred and eight-five barrels per day.

Q You are familiar with the North Caprock unit No. 1 Flood, are you not?

A Yes, I am.

Q Would you anticipate that its performance would be similar, compared to the daily normal unit allowable of thirty-three or thirty-nine barrels, would it exceed it to that degree at peak production?

A Well, I believe it would have had it been developed continuously as we testified previously at the time of the Graridge hearing last October. However, as I see it now, there has been a delay in the development rate in that particular flood, and I believe that that will reduce the peak, the sum in that particular flood, so that I don't believe there will be quite a big difference there as would be anticipated here.

Q What was the total peak production you expected?

A About forty-one hundred barrels per day for the unit.

Q Then would you estimate that the -- What would you estimate the daily production at peak to be from the North Caprock Unit No. 1? Just roughly?

A I think it comes out around ninety-two barrels per day per unit well.

Q And there are seventy-two unit wells in that area, is that correct?

A I am sorry, we must be talking --

Q Are you referring to Graridge or --

A The Graridge.

Q Oh, the Graridge.

A On the Graridge I testified I believed that that would be approximately five thousand barrels a day previously, if they had continuously developed it, but I believe it will be lower than that.now.

Q Well, how much lower? Just give us a rough estimate, I understand that that is a projection --

A I haven't really made a study on this, but if I would make a guess, I would say it would be in the order of four thousand barrels a day, the peak, the way it has been handled.

Q Do you feel that that reduction of a thousand barrels on the peak is going to affect the ultimate recovery from that unit?

A I do, yes, sir.

Q Are you familiar with the other pilot water flood projects that are developing in the Caprock-Queen Pool?

MR. PORTER: Let's persue this matter just a little further, Mr. Cooley, how many wells on that unit. I believe you mentioned seventy-two?

MR. COOLEY: Seventy-two is the figure I recall. I was going to estimate total production from the Caprock-Queen Pool.

MR. PORTER: That's all I needed, if that is the correct answer, approximately.

Q (By Mr. Cooley) Are you aware of how many developed acre tracts there are --

A I believe there are seventy-two in the Graridge unit. That is my understanding.

Q Are you familiar with the other water flood projects that are being developed?

A I don't know of any water being injected into Caprock at this time other than the wells shown on these two units.

Q That is correct, I believe, but there are two other proposed projects that should be in operation shortly that have been authorized by the Commission.

A I don't have first-hand information on that. I believe there is a Cities Service Unit, there has been an application -- Is it for four injection wells? -- I don't know if that is what the thinking on that is and when it is going into effect and so on.

Q Maybe this will expedite this question. Have you made an estimate of what you feel the peak production from the, let's say about the north half of what you might call the north portion where you have two existing water floods and a proposed water flood by Great Western, what the production from that area will be, the peak production from all three of them. They might not all peak at the same time, but there would be a point where the combined production of the three floods would peak.

A I haven't made that study, no, but of course, the combined peaks depend on the time that the water is injected into each, basically.

Q Do you feel that the North Caprock Unit No. 1 and Unit No. 2 will peak at approximately the same time?

A Yes, I believe there will be an approximate similar time for the peak because they started at a similar time, although I believe the Graridge was started first, and although there has been a delay in expanding the development of that one, and for that reason I think they will be coming more together than had the development been expanded consistently and without delay, that peak would have been over at the time this peak comes in, but now I believe that we will have more of a similar time of peaking.

Q Then you would anticipate something in the order of eight thousand, nine thousand, from the two floods sometime during the year of 1959?

A I believe it would be quite coincidental if they peaked at the same time. I would say there would be six or seven thousand barrels a day from those two. I doubt that they would peak both at the same time. There is only a couple of months there in which it is at the top level.

Q What would that average production be as portrayed on your Exhibit No. 3 during the year 1959? Just roughly.

A Let me take a look. I guess around thirty-six hundred barrels per day.

Q If the performance of the North Caprock Unit No. 1 were similar, you would end up something like seven thousand barrels a day from the two floods?

A That is a very good possiblity, yes, sir.

Q Do you have any figures on what the peak production from this area was on primary?

A Well, I have the peak on the primary for the Unit No. 2, the Ambassador, shown on Exhibit 3, and that was about forty-five thousand barrels a month, which is, I would say, about, that's about fifteen barrels a day. May I say something?

Q Yes, please.

A I think it will be interesting. There is another exhibit here, which will be used later by Mr. Stiles, but it shows the North Caprock area peak by primary was three thousand barrels a day for the entire north area, and that is considerably more than just the Unit No. 2 represented by the Ambassador. I think that points out the very thing we are talking about; even under primary, the wells don't all get into operation at the same time, so when you take the entire area, you can expect that the unit peak is considerably lower, and we take any one project. In other words, the area represented by this Unit No. 2 is not half of the North Caprock area, but the oil production peak under primary was half of the primary for the entire area. The same thing happens on water flood, but the peaks are not coincidental, they are spread out, and I believe, in general, this entire Caprock area is going to have that history right down the line. I know that these units are set up to be formed, but there is a long delay between that andactually getting them under unitization and getting water injected into the ground, so that I don't see any problem as far as large amount of oil production at any one time is concerned.

Q Well, at peak production, or the average production, we'll say, during the year 1959, as you project it, it would be something in the order of two to three times the peak production during primary, is it not?

A For the same area?

Q For the same area.

A That's right, and that's normal water flood experience.

Q Well, I understand that that is the case there, but are you aware of what facilities are available for the removal of this oil from this area, or will another witness testify as to that. Mr. Campbell, do you have anyone who will do that?

MR. CAMPBELL: Yes.

Q I withdraw the question.

A I am not familiar enough.

MR. COOLEY: That's all the questions I have at this time.

MR. NUTTER: Anyone else have any questions? Mr. Campbell.

REDIRECT EXAMINATION

BY: MR. CAMPBELL:

Q Mr. Buckwalter, how long does this peak situation normally exist, how long do you anticipate it would exist assuming that there was a coincidence of both floods reaching a peak at the same time, how long would that condition exist, normally?

A Of course, theoretically, the actual peak would probably be one day, if you want to take the actual top peak, and if they are coincidental, it would only be one day, but they would be at a high level for a long period.

Q How much longer?

A I think we can see there that after the peak, it will be over four thousand barrels a day, and will last in the order of three months, four months at the most. Does that answer your question?

Q Yes.

MR. CAMPBELL: That is all.

MR. NUTTER: Does anyone else have any questions?

RECROSS EXAMINATION

BY: MR. NUTTER:

Q Mr. Buckwalter, those tests that you gave on the twelve wells on the pilot flood project were all on comparative dates, on 4/14 and 4/30?

A That is correct.

Q On your Exhibit No. 8 you haven't depicted the amount of oil production from any of the water floods, except the North Caprock-Queen Unit No. 1 Flood. You stated that the oil producion from some of the others was very small, and for that reason you didn't show it.

A Yes, it was either very small or I wasn't sure, by examining the data, which wells were actually being affected by the flood, and so I couldn't make a very good comparative history without going into more detail, which I didn't have available at the time I made it up.

Q Aren't some of those water floods that you have shown there relatively new and haven't experienced any effect from the water flood as yet?

A That's correct.

Q That would explain why --

A It does, why we might expect a decline on the production rate, which means a lower oil production rate in the case of the Caprock Pool. On the North Caprock Unit operated by Graridge, the oil production rate there is approaching peak, and I can't see that it is going to go too much higher at the peak for that unit, and that isn't a very high level, in my opinion, for the water injected, and that does give me some concern as far as the efficiency is concerned.

QUESTIONS BY MR. COOLEY:

Q Mr. Buckwalter, you say you feel that the North Caprock Unit No. 1 has reached a peak at this point. Do you mean that that is the greatest amount of production that will come from the North Caprock Unit during any one given month?

A From the pilot flood --

Q From the pilot flood.

A --in the North Caprock Unit, and these figures are taken, averaged for four months on production as well as injection. Now, when I say the four months, I mean the four months approaching peak.

Q This peak that you speak of now is far short of the peak the unit will experience when you have pratically the entire unit under flood, is it not?

A This is on a per well basis, Mr. Cooley, and this is the average per well. Now, I am saying that this may have some relation between the per well performance in the North Caprock. I hope it is much better than this, and I think it will be if they get it under flood, but this is what per well will do, and that is some indication as to what they might expect.

Q As far as the production of the oil we have to deal with, it is certainly an amount far in excess of that isn't it?

A I have there about seventy barrels per day per well.

Q For how many wells?

A For the twelve wells.

Q And how many wells will be producing when they have the whole unit under flood?

A I forget how many producing wells there are. The Graridge has thirty-six, I understand, so we would multiply thirty-six times seventy, and that's around one hundred twenty-five barrels a day. Now, I believe it should be better than that. I believe it will be, if they get it under flood, but that is why I say somewhere around thirty-five hundred barrels would be reasonable, maybe four thousand.

MR. COOLEY: That is all.

QUESTIONS BY MR. NUTTER:

Q Are you generally familiar with the Graridge water flood?

A In general, yes, sir.

Q Referring to your Exhibit No. 2, the two wells which are enclosed by the eight injection wells in that pilot flood project--

A Yes, sir.

Q --what generally has been the producing history of this Gulf No. 1 Well?

A That's --

Q Since the water flood started?

A That has been the champion well in that area, as I understand it, reaching a peak of approximately five hundred barrels a day or more per day.

Q Do you think this has been normal, to expect that in a water flood of this type?

A In a water flood of this type, yes, sir.

Q Now, I would like to go --

A Going along there a little bit more, putting in a pilot flood is not like putting a large area under development, there is a difference, and in pilot floods, you can get quite a difference in behavior from what you would get in a larger development. I think it is unusual in this respect, that the one well has produced in that pilot, one enclosed well, produced considerably more than the others, but when you look at it from the reservoir standpoint, the possible variation, variations like that are more the rule than the exception, and they are augmented many times in a pilot set up, and I believe that the average condition is more important and more indicative of probable behavior in the pilot area, more indicative when the entire area is put under water flood.

Q Do you think that thetype of reservoir that the Caprock-Queen Pool consists of has a wide enough variation in permeability and porosity that an average of one well that has been affected like the Gulf Oil has, and the other wells, which has very little effect, is to be expected thoughout the reservoir as the average case?

A I would say for this reason, yes.

Q This will be the average situation where you have one well that is affected like that?

A In a pilot operation I would say yes; in a continuous and complete development I would say there would be less difference, but the one big difference in my book as to why this occurs here is the wide spacing. You know this is wider than many water floods have been practiced all over the country, and with this wide spacing variation in the reservoir you control more places; where you have closer spacing you don't have a closer control within the reservoir because you have the wide spacing injection.

Q Has Graridge experienced any mechanical difficulty with the Livermore well which is the only well enclosed in the pilot area?

A I don't have first-hand information as to the mechanical situation there. I believe they have done some work on the well to go after it.

Q Have they experienced any difficulty in injecting water into the Malco State "A" No. 5 due to the mechanics of the well?

A I don't have first-hand information on that. I have some Graridge information here on the current injection rates of those wells. I know there is considerable difference between them.

Q A while ago when you were discussing your Exhibit No. 8 Mr. Buckwalter, I caught the impression that you might expect that oil production is generally correlated with the rate of injection in these water flood projects, is that --

A Well, I would say this, that on an average, you never get more oil production than you would get water injection.

Q You expect more oil as a general rule when you have a higher rate of injection?

A In general we do.

Q Do you think that that exhibit of yours over there on the corner depicts such a correlation?

A Not directly, but in general it does. There are many other variables beside the injection rate that have a bearing on that; saturation of the oil in the reservoir, variations in other characteristics of the reservoir would have another bearing on it; the mechanical conditions of the wells, and so on, but in general, yes, the higher injection rates, the higher the producing rates.

Q But there is a possibility that some of these water floods that have lower injection rates will have higher producing rates?

A As a percentage that is possible, yes, sir, as a percentage of injection rate. There will be a variation from field to field, flood to flood, well to well. Variations are more the rule than the exception.

Q Mr. Buckwalter, is there a lot of talk these days about putting a large part of the Caprock-Queen Pool on water flood?

A I think there is considerable talk about it. My observation in that connection is that there is quite a long span between the talk about getting one of these things going and the actual accomplishment, and I think we have other witnesses who will give some information on that experience in other areas, but I think the same is true in the Caprock, it will be a long time. For example, I have heard people who have wells in these proposed units that haven't even been contacted by those that are proposing the units. There is a big gap between being contacted and accepting a unitization agreement, and for that reason, I don't believe that you are going to have a tremendous production from that area.

Q This is relatively a large pool, isn't it?

A Yes.

Q Some six hundred wells?

A Yes, it is a good sized pool.

Q And this peak production of some four thousand barrels per day --

A Yes.

Q --represents --

A Eighteen hundred acres.

Q --forty-five wells, is that correct?

A That is correct.

MR. NUTTER: Does anyone have any further questions?

MR. COOLEY: Yes, sir.

MR. NUTTER: Mr. Cooley.

QUESTIONS BY MR. COOLEY:

Q Mr. Buckwalter, again referring you to Exhibit 3, you show the peak of production in 1955 from the North Caprock-Queen Unit No. 2. That is not a well figure, is it, that is from the unit?

A That is for the whole unit.

Q Does that peak in the year 1959 assume that the entire unit will be under flood in 1959?

A It does, yes, sir.

Q How many injection wells in addition to the six presently authorized will be necessary to accomplish --

A On the unit it's, I believe there will be seventeen additional.

Q Seventeen more, and what about those three offsetting it in the North Caprock Unit No. 1? I believe that was shown on your Exhibit No. 2.

A Well, really, to complete it, there will be more than three offsetting, there will be one, two, three, four, five, six, seven, eight, nine, ten, eleven; I would say about eleven wells offsetting the entire unit.

Q There will be seventeen inside the unit itself?

A Yes, sir.

Q At the original hearing, which we refer to as the Graridge hearing, for the North Caprock -- what is now the North Caprock unit No. 1, there was considerable talk that the ideal method of controlling the ultimate peak production from waterflood projects was through, not through the means of controlling the production from the affected wells during the life of the flood, but rather through controlling the rate of expansion?

A Yes.

Q Do you still feel that that is a valid observation?

A Yes, sir, I do.

Q And you feel that the -- in what will be about an eighteen month period, then, that the expansion, the inclusion of seventeen additional water injection wells in the Ambassador is a reasonable rate of development?

A It certainly is.

Q If the whole Caprock-Queen Pool were developed at such a rapid rate, production will be seven or eight times what is was originally, I mean peak production?

A No, I don't believe so. I have testified in that Graridge hearing concerning the peak for the entire Caprock, and I was taking the full sum of twenty-two thousand acres into consideration, and I considered that the peak would be around nineteen thousand one hundred barrels per day for the entire field and that was at a development rate of forty-four hundred and eighty acres per year or five years to develop the entire Caprock Field. Now, that is the most rapid rate that I could possibly imagine for the development of the field. I believe that we have this to say about development rate, It isn't a matter of rate of development well by well that keeps the peak down, but it is the development of project by project.

Q Well now, instead -- you are qualifying the rate of expansion that was referred to in the original hearing, on the Graridge hearing,not therate of expansion of presently authorized floods,but the authorization of new floods to come into existence?

A That's right. Now, within a flood unit, you should have a regular orderly rate of development within that flood, and this nineteen thousand, one hundred was assuming that its entire field would follow that same orderly rate of development, but I doubt that they are going to follow that orderly rate of development so that instead of getting it in five years, I imagine it would be six, eight or ten years until it is entirely developed, which will have a bearing.

Q Why do you feel it would be longer --

A Beg pardon?

Q Why do you feel it would be longer rather than a shorter period, broken up into five, six or eight different floods?

A The reason I think it will be longer is because the operators will not be able to effect unitization in these areas in order to get their floods under way. That's my basic thinking on the time to unitize. I believe that history will show that unitization takes time; people are human and they have differences of opinion as to the unitization factors, and in water flooding in particular, the history shows that it takes a long time. Now, in these two units here we have an unusual situation in that connection. In the Graridge unit and in the Ambassador unit, the same people are involved, and they are experienced in water flooding. They know the factors, they know the story about water flooding. But when you get down to other places where other operators are not familiar with this water flooding, they are going to hesitate a long time before they sign up a unitization agreement in order to put a unit into operation. They heaven't -- many of the units being talked about, I know operators haven't even been contacted concerning them, so all that would mean delays. As a matter of fact, if we take just the development rate at this time, we are way behind schedule, according to my calculations at the first hearing.

Q On the North Caprock Unit No. 1?

A On the whole field. On my Graridge Exhibit showing the nineteen thousand, five hundred peak, for five years after this time, and we are way behind that schedule now, taking the whole field.

Q What factors have you taken into consideration in recommending that these seventeen additional injection wells be put on within the next eighteen months?

A The performance of the wells indicates the time in which new injection wells should be put on. The performance shows that we are getting peak oil production, and we -- now is the time to convert additional wells to water injection offsetting.

Q Go into that a little more in detail, Mr.Buckwalter, which wells must be affected surrounding the six present injection wells to give you an indication that present expansion is needed.

A Present expansion is needed offsetting any of the wells that show a kick. As soon as a well shows a kick, in my opinion, you should put in an offsetting well for best results, and if you don't do that, your flood gets unbalanced and you have a chance of losing oil within the five spots by so pocketing, so these wells that show kicks on the offsetting, the present pilots in both of these, by all means should have their new injection wells turned in.

Q Any well that shows a peak should be made the center of a five spot?

A Absolutely. That is a good way to see it. Just as soon as you see that kick, you should turn in these five injection wells.

Q What has been your experience in this pool of the amount of time, in terms of months, days or years, it takes for an offsetting well to experience a kick?

A It looks like four to six months. It is in that period, about four to six months' time.

MR. COOLEY: That's all. Thank you, sir.

MR. NUTTER: Any further questions of the witness?

QUESTIONS BY MR. LAMB:

MR. LAMB: Raymon Lamb with Wilson Oil Company. I gather that you are considering a forty-five well unit in the final No. 2 project?

A That is correct.

Q This application deals only with the eighteen wells and the pilot project, as far as the allowable is concerned?

A That is my understanding.

MR. COOLEY: Twelve.

MR. CAMPBELL: Twelve.

Q Twelve production wells and six wells which is eighteen total. Have any of the fields, which are on the bar graphs up here had restricted production, or have they been unlimited production as far as oil is concerned?

A There has been no restriction of any of these bar graphs, everything here has been at capacity producing rates.

Q Has there been any restriction on the rate of water input?

A There has been no restriction unless an operator would voluntarily restrict a given well.

Q That is what I had in mind. There is no regulatory body to set up restrictions?

A There is no regulatory restriction.

Q Have all of these projects been what you call five spot or the type of system that you carry in the No. 2 in the North Caprock?

A Yes, sir, they are all five spot operations.

Q And the production curves which appear in the background, are they for the entire forty-five well unit and for the pilot project?

A For the entire forty-five well unit, yes, sir.

MR. LAMB: That is all.

MR. DARDEN: I would like to ask one question, please. Frank Darden with Newmont Oil Company.

QUESTIONS BY MR. DARDEN:

Q In these fields, has there been any restriction as to the projects put under development in these fields by regulatory bodies?

A No, there has been no restriction as to when these fields are put into operation by any regulatory body, nor has the development rate of any ever been restricted in any manner that I know of.

MR. LAMB: Therefore, you have no history as to what would happen if they were restricted?

A Not on this particular one, but we have many examples where restrictions have been imposed on oil production in water flooding, yes, sir.

Q But they are not presented here?

A They are not presented here, no, sir.

QUESTIONS BY MR. NUTTER:

Q Mr. Buckwalter, why have you not shown future injection water wells in the extreme southwest corner of the unit?

A The map prepared doesn't have those injection wells on it and I can't say why it doesn't.

Q There are some injection wells proposed down there, aren't there?

A They just weren't marked on the map, but they are proposed, yes, sir.

Q In other words, where we were talking about seventeen injection wells for a full scale pattern a while ago, it would be twenty then, probably?

A No, sir, the seventeen includes some wells that are not circled.

Q Oh, I see. I believe that's about nineteen circles on there.

A I get twenty circles, but six of them are in the pilot already. That leaves fourteen of the circles yet to be turned in and three more that are not circled.

Q So there would be seventeen additional wells to the six that are currently on production?

A That's correct.

MR. CAMPBELL: Will you please correct Exhibit No. 2 to reflect the seventeen, Mr. Buckwalter?

A Yes, sir, I will do that right now.

MR. COOLEY: Would you name those wells as you circle them and locate them?

A Yes, sir. Ohio State 29, operated by Graridge, Well No. 1. And Well No. 3. Graridge's Ohio State 33, Well No. 6.

MR. NUTTER: Are there any questions of Mr. Buckwalter?

MR. UTZ: Yes, sir.

MR. NUTTER: Mr. Utz.

QUESTIONS BY MR. UTZ:

Q Mr. Buckwalter, you may have answered this before now, but I wasn't here. How many wells have you experienced a kick on at the moment?

A There are four wells.

Q Four wells. Would you name those wells, please?

A Yes, sir. They are Ambassador's State "H" No. 1, State "L" No. 1, --

Q Your Ambassador State "L" No. 1?

A Correct. Gulf Oil's Chaves State "A" No. 1, and Graridge Malco State "F" 3.

Q Those are the only four wells that have responded to the water flooding at the moment?

A Yes, sir.

Q Now, in your expansion of this project, which is the converting of water injection wells, which of those wells would you convert to water injection wells first?

A I would convert all wells offsetting any well which shows response to the water flood. In other words, I would convert to injection the proposed wells which offset these four just mentioned.

Q Am I correct in saying that you enlarged your unit now by three injection wells?

A I believe it is three wells in the unit, yes, sir.

Q Do you have any control over the off unit wells?

A Your wells off of the unit?

Q Yes.

A No, we wouldn't have any control on those.

Q In other words, I am referring specifically to the Livermore State, that is not within your unit, is it, the Livermore State?

A No, that is not in the unit, that is the other unit, in

Unit No. 1.

Q That offsets your Malco State "F" 3?

A That is correct.

Q You would not convert that?

A Beg pardon?

Q You would not convert that?

A I would certainly convert it if I had the control.

Q But you don't have the control?

A I don't have the control for this unit, no, sir.

Q Mr. Buckwalter, I believe you stated in answer to Mr. Cooley's question that the time to expand would be to surround a well with injection wells as quickly as possible after it had shown response?

A Yes, sir.

Q Now, how long, in your opinion, can you wait after the well shows response without losing any oil?

A Well, if you say "any oil," I don't believe you could wait more than a month. I think a month would be a long time. But if you wanted to take it to the other extreme, when the well starts to make water you are too late to turn in the injection well without affecting all the leases. So if the water projection starts, then you are absolutely, in my opinion, losing ultimate recovery if that well is not backed up. So, you have the time, the first pickup or I will give you a month's grace, and then by the time the water shows up, there is some question as to how much oil you might lose in that interval. But I think the longer you wait, the more you lose. At the time you produce water you are then in trouble, the way my experience shows.

Q Any appreciable amount of water?

A Just any water.

Q Can you explain why this is true, why you would lose oil?

A Well, I believe I can. Once water has broken in to a producing well in a water flood, you now have the condition that in part of the five spot the water has invaded to the point where it has reached a producing well. Now, if you then inject water into offsetting wells, you have no way to deliver the oil in that part of the formation to which water has broken in from these other directions. Now, you don't stop the movement of oil in that five spot, and as you build up your pressure on the offset wells, oil approaches the producing wells, but it has no outlet in the part that water is being produced. Now, this is what we call pocketed or trapped oil. In a five spot we know this condition exists by places where we have gone back in and drilled wells after water flooding is complete, and we find pockets of oil trapped back in positions within the five spot, and this has been demonstrated to be a result of that trapping by converting wells too late to back up the water.

Q In other words, the oil would not move the water back out?

A It doesn't do that, no, sir.

MR. UTZ: That's all I have.

MR. PORTER: Mr. Buckwalter, I believe you stated that you had control of this Livermore well?

A Yes, sir.

MR. PORTER: Do you think there will be waste of oil if that well isn't converted into an injection well?

A I think if the time arrives when water starts to be produced, we certainly will lose oil, that is, if the "F" -- the Malco State "F" Well No. 3 in unit No. 2 starts to produce water before the Livermore State No. 1 in unit No. 1 has water injected, I do believe there will be ultimate loss of oil at that well.

QUESTIONS BY MR. NUTTER: Mr. Buckwalter, did you say that you thought -- what is it, some seventy barrels a day that you depicted there for unit No. 1 in Caprock-Queen Pool was probably the peak per well per day production in that area?

A No, I didn't say that I thought it was the peak.

Q I mean the average.

A It is the average for those four months, and those are the four months which are approaching peak in the pilot. Now, if you take just the one peak month, it will be higher than that because you have some lower months averaged in, if you see what I mean. In other words, you have an average here of four months, and this production was increasing in that four-month period. Therefore, the average of the four months is lower than the peak month will be.

Q What do you estimate will be the average per well production at a time of peak -- this word peak -- at the high stabilized rate of flow that you will have for a short period of time that you will have in this area?

A I would guess between eighty and eighty-five barrels per day per well.

Q Would the pilot apply to the rest of the pool too?

A No, I don't believe that the pilot will do as well as the rest. That's the nature of pilots. You see you are counting twelve wells, you don't have these other wells backed up. When you back up these other wells, you should experience better oil production.

Q So if you take the average rate for the twelve wells, it would be lower than the universal rate throughout the pool?

A That's correct.

Q The inner wells would probably be averaged?

A I have seen places where they have been and places where they haven't been. Hence, here it would be much off of average. If you take fifteen and thirty and divide it by two -- divide it by two, that couldn't be the figure -- that couldn't be the average. I believe it would be lower than that.

MR. NUTTER: Any further questions?

QUESTIONS BY MR. COOLEY:

Q Mr. Buckwalter, you stated, I believe, that you felt it was reasonably safe to wait at least one month --

A Yes.

Q -- to put on an injection well offsetting a well that shows a kick?

A Yes.

Q Then, you feel if a hearing should be held within that one-month period, application to be made to this Commission for the conversion to injection wells -- as you realize, I believe, it requires permission of this Commission to convert a well to injection well -- if a hearing were had pretty quick on the heels of discovering the kick in the particular well, that,assuming a hearing would be held in a month, that it would not result in waste to follow that pattern that is now established?

A Of course, when I say a month, that's a very general figure. I believe there are cases where it may happen that you would have less time available before the water even would arrive in some instances. You take and think of water flood as a whole, in general, why that month might impose a problem in some instances. I would look --

Q You think that would be the exception rather than the rule?

A Yes. I think a month is a general average, isn't bad. However, I think New Mexico is unique in this respect, that other states and other areas that I know of, no one requires this type of procedure, and I would say that it would work a considerable hardship on water flooding technically and managerially and any other way if they would have to make application every time an injection well was put on. In other states that is not required.

Q In the event that we broke from that rule and allowed the conversion to injection wells at any time, we would lose control of the expansion of the water flood project program, would we not?

A I don't believe you would. Each project itself is an expansion, and I believe when you give a permit to water flood a given area which has been outlined on the map and your plans are well presented and known, that the operators within that area should be permitted to, at will, convert their wells to water injection and continue the development up to the limits that are outlined in their original application. I believe that is a workable plan and what that will do -- will permit an operator to do the best injecting job in order to recover the maximum and lose less oil than any other method that I would know of within that project area. So I believe project, by project, you should consider them developed. In other words, once you give an application with the plans laid out, then you should go ahead at the will of the operator, and then when you have the control and development is when the next application comes up. I think that is where your control might come in.

Q It would be pretty difficult to water flood in that project, wouldn't it?

A I think the logical thing would be when an operator needs to water flood because a water flood is approaching him. That is when that water flood should come in, in my opinion, in this type of reservoir.

Q What if his production has reached the marginal point where primary production has decreased to the point where it is not economical to operate it as a primary project?

A In that case, surround his property, and if he has reached a --

Q Stripper state.

A -- stripper state, I think he should be permitted to go ahead. What you will have is in the very nature of the starting of this project, all start at different times and, therefore, just by the statistical nature of that time, delay between starting, you wouldn't have this exceptionally high peak.

MR. COOLEY: Mr. Campbell, have you any witness here who is prepared to testify as to whether there has been an agreement with the operator of the North Caprock unit concerning the conversion of injection on any wells in the North Caprock-Queen?

MR. CAMPBELL: I don't know. Perhaps somebody can say whether there has been any discussion or not. I don't know right at the moment.

MR. COOLEY: Off the record.

(Discussion off the record)

MR. NUTTER: Are there any further questions of the witness?

MR. LAMB: On that same line, in answer to my question yesterday as to having any immediate plans to move to the southwest, I believe Mr. Vick said there was none. That would be a backup to this No. 2 project?

MR. McCRACKEN: The operators involved in the two projects are essentially the same, the interests there are the same in both projects.

MR. NUTTER: Mr. Utz, did you have a question?

MR. UTZ: Are we back on the record?

MR. NUTTER: Yes, sir, we are on the record.

QUESTIONS BY MR. UTZ:

Q Mr. Buckwalter, what is your intention as to expansion of this unit? Are you going to expand, or is it your plan to expand as necessary, based on your previous testimony that you have to back up, or is it your intention to expand faster than necessary?

A Well, I would say that my recommendation to the operators of this unit would be that they should expand as necessary, and when a well kicks, that is when they should put on the next well on injection, and when a well doesn't kick, I believe it's only reasonable that they delay the turning of that well into injection. In this particular instance -- in this particular flood, now, there are many floods that are put in all wells at the same time, that is, if you have sixteen injection wells, you put sixteen on the first day. That is done many places and I believe that is the ideal way, but I believe in lieu of the performance here and in view of the rates of oil production which have been demonstrated, it is only sensible that they do wait until a well shows a kick before they put it in because it will help, you see, to keep the peak down if that is done.

Q That would be your recommendation?

A That would be my recommendation.

Q Do you have any indication whether Management intends to follow your recommendation?

A I believe Management thinks that's a reasonable approach.

MR. UTZ: That's all.

MR. NUTTER: Are there any further questions of Mr. Buckwalter?

MR. MURPHY: Bert Murphy, consulting petroleum engineer from Fort Worth.

MR. COOLEY: Whom do you represent?

MR. MURPHY: I represent myself.

QUESTIONS BY MR. MURPHY:

Q Back on this question of turning wells in, as you get response, has it been your experience in some floods that you need to back up a well before you get response on fringe producers?

A Well, I would say this. In some floods, it certainly is advisable to back them up before you get response. As a matter of fact, I believe it is always the best policy to put in such areas as you can at a time although I believe the operators here in this unit are sympathetic with the question of just what the rate will be here for the unit. So in these conditions here, I would think that this would be a sensible way to go about it, but in general, now, I would like to see all the wells that you can put in put in at the same time for the best water flood behavior.

Q There might be other areas where it would be necessary --

A There might be other areas where it might be necessary to put them in earlier, that is right.

MR. NUTTER: Let's us take a fifteen minute recess.

(Recess)

MR. NUTTER: The hearing will come to order, please. Does anyone else have any further questions of Mr. Buckwalter? If not, the witness may be excused.

MR. ASTON: Rodgers Aston of Franklin, Aston & Fair. If I may ask one question.

Q In reference to the delay of composit units, in other words, staggering the new development projectsas they come in, isn't it true that basically, beyond a certain point, when the wells begin to approach the stripper phase, the sooner you can get your water flood on them the greater the potential recovery under water flood projects? I base this, for example, on the fact that there seems to be more and more of an opinion that you can commence water flood even in the primary phase of production when primary production is high, as when you wait until your reservoir energy is completely dissipated. I am asking a basic principal here.

A I think it is a matter of degree. Now, when we think of injecting water into a reservoir, if we start with an injection early, we'll say before a well's bubble point pressure might be reached before we'll reach a definite pressure maintenance, you wouldn't call that water flooding. If we have what we call stripper, it would be called definitely water flooding. Now, there is a region between these two, between the stripper stage and we'll say the high producing rate by primary. I don't believe that in this region it makes too much difference really as to when injection rate is started as to the ultimate oil recovery. There may be a slight difference in reservoir factors of viscosity, the crude at different pressures, but I believe this is offset by other factors of saturation. In the reservoir, high rate fill up in water floods and so on, so that I don't believe that anyone has demonstrated in the field a large advantage in starting earlier.

Q Well now, give me your idea. Of course, there is a great latitude when you begin to class a field as a stripper field and when it is economically at the vanishing point, and we will say you are still at the stripper phase, but you are still able to pay the bills and come out with something extra and go to the bank each month, but if your development of that field were delayed further, could it not result in ultimate loss? Say you are definitely a stripper, but you are not prevented from operating possibly for another twelve months or eighteen months or something, you might still pay your bills but could you not have less result under those circumstances?

A I don't think the difference in those two cases is great, no, sir, I don't.

MR. LAMB: In a rough figure, do you have any idea what your above ground cost of equipment of installation is, including your plant, your treating system and your input lines and so forth for this forty-five well unit in No. 2 unit?

A Well, I don't have the actual figures that have been worked out for this particular project, but I can give you what I think they are, approximately. If we'd say approximately ten thousand dollars per injection well, per total well, I think we'll come pretty close. Ten thousand dollars per total well in the project.

Q In other words, about half a million dollars installation costs?

A It approaches that, yes, sir.

MR. NUTTER: That's all.

Any further questions of Mr. Buckwalter? If not, he may be excused.

(Witness excused)

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 live, Mr. Edgerton?

A Austin, Texas.

Q What is your profession?

A I am a consulting petroleum engineer.

Q Do you have a firm there or do you operate individually?

A A firm, Edgerton & Stearns.

Q You have not previously testified before this Commission, have you?

A I have not.

Q Have you testified before other regulatory commissions?

A Before the Texas Commission, yes, sir.

Q Would you give the Examiner a brief review of your education and professional background, please?

A Yes, sir. I graduated from the University of Texas in 1940 with a degree in petroleum engineering. I was thereafter employed by the Railroad Commission of Texas as a field engineer, and later as a district engineer in Corpus Christie up until April, 1942, at which time I entered the military service. I came out of the Army in October, '45, and returned to the employ of the Commission there in Austin in November, 1945 as a senior engineer. I remained there until March, '46, at which time I left to go into the consulting work in which I am now engaged. My work in that connection during the past ten or twelve years has been largely associated with the proration aspects of production of all types. In connection with water flooding, we didn't have anything that particularly came to our attention until 1950, or the latter part of 1949, at which time Forrest had initiated a flood in the South

Ward Field. And since that time I have been associated with various people in studying and working out the regulations and problems relating to water flooding and in connection with that, of course, I have had many opportunities to discuss various aspects with a number of people, consultants, in the water flooding business and people that are engaged in that operation. I've followed it, of course, rather closely both in the literature and in relation to the matters as they have been presented to the Commission there in Austin.

Q Have you become acquainted with the general procedures that are used in the State of Texas with regard to water flooding?

A I have become acquainted with those, and having been involved in the initial allocation in Texas for a capacity flood, I am also familiar with the general evolution of the policy which has been adopted in that state.

Q Would you briefly state what general procedures are followed for production from water flood projects?

A The general procedure has been outlined in a memorandum dated August, '53. However, that procedure had been used actually prior to the time that the initial hearing was held to consider an application to flood a property or perhaps several properties. At the time that that hearing is held, there is general data sheets submitted to the Commission, maps, data to indicate the initial pilot area and also the general pattern which is anticipated, although it isn't essential that the general pattern be fully developed at that time because there may be changes. Now, subsequent to approval of that application, the allowable of the unit or the lease or the property remains as it appears then on the schedule. However, as-simulance occurs, the Commission has a stepwise procedure in which the allowable is increased initially. An operator requests an allowable increase based on the number of producing wells multiplied by the top allowable for the field and subject -- if that field is subject to shutdown days. That's merely a stepwise procedure. Actually, the flood is producing at capacity all through this period.

Q This does not require a hearing, does it?

A No, sir, this does not require a hearing. In the mean-time, if the operator adds injection wells in this period, he does not come back for further hearing, he submits a letter of application showing the new injection wells which he proposes to add for the Commission's approval. Now, of course, the Commission could, if they saw some well which they felt they should hear more on, set a hearing, but as a matter of practice, I don't recall any instance where that has been done, unless a well happened to be what is called a line well; closer than the regular spacing distance to a lease line. The operation proceeds in that manner until the number of producing wells times the top allowable is insufficient, and then the operator usually attempts to maintain a curve so that he can forecast a little in advance what his allowable requirements will be. When he sees that he will be short of allowables within a short time, he then requests that the injection wells be added to the list of multiples in order to obtain the allowable. Under the memorandum, as I recall, that procedure requires a hearing. However, as a matter of practice, the Commission has dispensed with that. They see no reason for setting a hearing. They add in the injection wells, and then when the allowable has reached a point where that is insufficient, then he must request a hearing for capacity allowable, and in Texas, if the field is not exempt it goes hand in hand with exemptions, if the field is already exempt, that is not essential, but for capacity, of course, it would have to be exempt. At that hearing, whoever is present, gives his production history, up-to-date charts, and requests that the allowable be set at a figure which will meet his production requirements at capacity for the immediate future, and that future increases in allowable be granted by letter of request without further hearing, and that procedure is generally adopted. The application is approved in that respect, and from that point forward, the application -- I mean the operation, that is allowable-wise, is controlled generally entirely by letter administratively without any further hearing.

Q During this entire period of time, they are producing at capacity, is that correct?

A That is correct.

Q Do you know of any bonified stripper water floods in Texas that are restricted in production?

A No, sir.

Q During all that procedure, after the original hearing to the time that you seek capacity beyond these points at which you can administratively get the authority to add additional wells to your multiple, there are no hearings?

A That's right.

Q Now, you have made a study of -- general study of the water flood projects in the Caprock-Queen Pool, have you not?

A I have a general familiarity with those, yes, sir, in our discussion of the matter, but I haven't made any -- I don't have a strict recollection of what the individual wells are producing, that is, well by well, and that sort of thing.

Q You did make some study at the time of the Graridge, study in connection with allowable, in fact, did you not?

A I did that, yes, sir.

Q And you have continued that study in connection with this particular application, have you not?

A I have.

Q Have you made some studies relative to primary and secondary production and the relationships between them and pools in Texas with which you are acquainted?

A Yes, sir, I have.

Q I am going to refer you to what has been identified as Applicant's Exhibit No. 9 over here, and 10 together, and ask you to state what they are and explain to the Commission what they are intended to illustrate, to the Examiner.

A Exhibits 9 and 10 show -- 9 shows the performance history of a particular lease in South Ward Field, Ward County. It is the Atlantic Refining Company, W. D. Johnson lease; that's a 320-acre tract.

Exhibit 10 shows the primary and secondary production history for the South Ward Field as a whole. Now, to illustrate the leveling out effect of water flooding within a field as a whole, we selected South Ward in particular because it is probably the highest rate operation of that type in the state, and just to illustrate that by comparison here in the South Ward Field, I've been advised that wells there, individual wells have actually reached peaks as high as eight hundred barrels a day, and bearing in mind this is on a 20-acre five spot pattern, if you were going to put the Caprock floods on a comparative acre basis you would have potentially individual peaks by comparison of as high as over three thousand barrels from a well. In other words, this is an extremely high rate field as compared to others taking into account all the factors. You'll notice here that W. D. Johnson lease peaked at five thousand barrels a day although it is contained entirely within 320 acres. Notice that the primary peak was in the order of a thousand barrels a day so that the secondary peak of the project was approximately five times the primary peak. Now, referring over to Exhibit 10, for the South Ward Field as a whole, you'll notice that the secondary peak is approximately one-third higher than the primary peak. You'll also notice that the secondary production appears to already reach primary and perhaps slightly exceeded in the South Ward Field as a whole. Going back to 9, you can see that the secondary recovery on the Atlantic property has already exceeded twice primary and, as a matter of fact, it was over two and a half times primary at the time the primary was written, which contained this chart and still producing five hundred barrels a day, so that it appears not only from this particular project but from the other projects in that field that the secondary recovery will probably reach or exceed two hundred percent of primary. The reason I mention this is because when you compare the secondary history and the primary history you should consider the relative reserve involved there, recovery, The secondary history here will be equal to two South Ward Field primarywise, so that if you were going to put those on a comparable basis you would anticipate that they would be at the same level with respect to recovery if the secondary peak had actually doubled the primary peak, which it did not. Peakwise in relation to recoverable oil, the secondary history is actually lower than the primary top in the South Ward Field. Another factor which might be noted in connection with South Ward is that there were no unitization problems in that field. It was generally flooded on a lease basis. There were a few tracts which were pooled, that is to say, up to perhaps a half section. There were some individual forty-acre leases that were flooded, that is adjoining larger tracts, so that there were no factors which would tend to delay the normal rate of development which the operators might adopt. Another thing is that when the Forrest initial pilot flood came in, one of the wells came in after they started production; within a week it was up to around five hundred barrels a day. It was an incentive to develop this field at as high a rate as possible and yet the secondary history is not high in relation to the primary history for the field as a whole. Now, I have here -- I didn't tabulate it for this hearing, but we do have some information on at least ten or twelve of the floods as to the relative dates in which they were begun, but the rates were fairly rapid. Now, in addition to this history we did get a few more which I have here, which tend to illustrate the same thing, but I think if you take South Ward and considering all the factors there you'll note that the relationship between what an individual project might do and field as a whole, you can immediately see that you can't get any reasonable relationship in the peak of the field by taking what an individual well might do or an individual project might do and begin to try to multiply. There are too many other factors which affect it, and we find, and you can find in the literature numerous cases where there is a repeat of this type of history. You must note, of course, that in the literature we do have quite a few individual projects which might indicate something like the Atlantic history here because as you get smaller and smaller in your high rate flood in your project the peak gets naturally higher in secondary than it would in primary.

Q Do you feel that there has been some tendency in connection with this problem to view the example such as the Johnson lease there on Exhibit 9 and assume or multiply the number of leases or wells in the project, coming up with the figure that perhaps isn't realistic insofar as the total impact is concerned in the pool?

A Yes, sir. At the time of the initial hearing in 1950 for the Forrest project which had a well making five hundred barrels a day, of course, there was considerable discussion of that point and considerable concern along that line which we advised the Commission at that time would not be any representative way of anticipating what the field would do, based on histories of fields which had already been placed under water flooding in other states.

Q Your experience since that time has shown that that was correct, is that right?

A That's right, and I might point out, Mr. Campbell, that we had a number of high peaks. This is probably the highest peak. There were a number of high peak projects. This is not an extreme exception to the general run on South Ward. That is illustrated by this here on the number of projects shown on Mr. Buckwalter's Exhibit entailing water floods on the South Ward Field.

Q Now, Mr. Edgerton, there has been some concern in connection with the hearings in New Mexico relative to water floods about the initial injection rate being established and how that might affect the future of the project. Have you made some study in connection with that matter?

A I have. And --

Q I'll refer you to -- I don't believe it has been marked yet. Would you hand a copy of that Exhibit to the Reporter to mark it as Applicant's Exhibit No. 11.

I am going to refer you to what has been identified as Applicant's Exhibit No. 11 and ask you to identify and state to the Examiner what it illustrates?

A This is a reproduction.

Q Do you have some copies of that, please?

A Yes. This Exhibit is a chart entitled "Typical Injection Well Performance Data." It is taken from the same reference that the Atlantic W. D. Johnson lease performance history was taken from. It shows the performance of an injection well in the South Ward Field on the W. D. Johnson lease. You'll notice here that the initial injection rate per day was as high as eighteen hundred barrels. I mean -- yes, in a single well. This is a single well history right here, eighteen hundred barrels per day. Bear in mind that this development was on a 20-acre five spot. Now, that -- you will notice also that after approximately a year from the beginning of the initial injection, injection rate dropped down. Now, there was one point where there was some plugging which caused the rate to drop lower, but after that plugging was remedied, the injection rate still remained down to about six hundred barrels a day, and actually declined thereafter. You'll notice on the top part of the chart that the tubing pressure or the injection pressure during this period was increasing from zero during the entire time up to close to eight hundred pounds at the well head and in spite of that increase in pressure it was only possible to hold an injection rate here in the order of four hundred barrels per day for most of the history. In other words, this illustrates the point Mr. Buckwalter was stating earlier, that you can't look at the fill up rates and necessarily assume that a later rate will follow. As a matter of practice, you will find that it is considerably lower in both cases.

Q Do you have anything further on that particular Exhibit?

A No, sir.

Q Would you then say that it would not be a reasonable approach to cut the original injection rates that have been discussed here and make assumptions of a continuation of that injection rate throughout the life of flood?

A That's right.

MR. CAMPBELL: Now, would you please have him mark this Exhibit No. 12?

A Yes, sir.

Q Would you refer to what has been identified as Applicant's Exhibit No. 12 and state what that is?

A Exhibit No. 12 is another production history. You'll notice that it is a project. It doesn't apparently contain the entire field. It may; I am not familiar with this particular field, but it shows this -- that shows the primary peak of the project, and then where it shows the secondary production you make reference to the legend and then to the production as indicated from the legend of various additional leases which were added progressively. You'll see the leveling effect of the progressive development and this chart illustrates two things. Again it illustrates a reasonable relationship between secondary peak and primary peak, and also illustrates the effect of progressive additional development of leases on a project. It illustrates the same thing that we have shown on the South Ward Field here except that in that case we didn't add projects together to show how one decline offsets another increase.

Q Now, will you refer to the Olympic Pool Waterflood Exhibit you have there? Have that marked as Applicant's Exhibit 13.

A (Witness complies)

Q I refer you to Applicant's Exhibit No. 13 and indicate to the Examiner what that reflects?

A This is again another field of primary and secondary production history taken from the literature showing that the secondary peak was actually slightly lower than the primary peak in that field, and I am advised by Mr. Stiles who is more familiar with this particular field that the rate of development in that field was relatively rapid. You'll also notice that from the area under the curves that the secondary recovery appears to be considerably more than the primary. That is -- that it will be because it has some decline and the area under the curve appears to be in the direction of being substantially greater. In other words, this illustrates again the same thing that the others illustrated except in another field and in a field in which I understand the development was rapid.

Q You computed from that, when you related the peak and rate of recovery from secondary effort to the primary effort, that the impact that we talk about was not as great as it seems to be?

A That is correct, and I think a review of the literature will show that there are many more examples of this same sort of thing. We picked cases where we tried to get -- where we could get a full history, field history, if possible.

Q Now, refer to the Oklahoma Water Floods and Kansas Water Floods data that you have there, and have those marked Applicant's Exhibit 14 as to the Oklahoma information and Applicant's Exhibit 15 as to the Kansas Water Floods situation.

A All right, sir, I have here, here in my hand the Oklahoma Water Floods.

Q That's Exhibit No. 14?

A Exhibit No. 14. The particular publication from which this was taken is shown on the side of the Exhibit. This was prepared by, I believe it was Mr. Al Sweeney with Interstate Compact Commission from data which he obtained. There are several interesting things which these show from the standpoint of the state as a whole, which has developed a considerable water flood history. First, we might note that in Oklahoma for the year 1956 there were four hundred million barrels of water injected in water flood projects. For that same year there were about thirty-six million barrels of oil produced, that would give you a ratio, over a broad speed of floods in all stages of development, of approximately 10 or 11 to 1; that is, if you are injecting four hundred million, you'll get in the range of thirty-five to forty million barrels of oil. You'll notice that the curves parallel to a degree here so that you have a ratio there in which you can place some relations after you get some history behind it. The purpose of that is to show that we can't take initial responses in a particular field and arrive at anything again which would indicate the overall pattern which will develop after we have a larger number of projects initiated and start getting projects in various stages of development. Now, you'll notice on this chart that the oil wells and the water input wells are plotted. You will notice that the curves follow each other very closely. From that information you can reasonably infer that the vast majority of these projects are of five spot type. That is the type in which you have one injection well for one producer.

Q Does the information contained in Exhibit No. 15, the Kansas Water Floods, confirm this relationship between water injected and production, generally?

A That is correct. You will notice about one hundred sixty million barrels of water for an annual production rate of about seventeen million barrels of oil, which again is in the approximate -- the range of 10 to 1. And you will also see a fairly close relationship between the water of input wells and the number of oil wells.

Q So you cannot take the figure of water injected and assume that that amount of oil is going to be produced?

A No.

Q Do you have anything further on those two Exhibits?

A No, sir.

Q Now, Mr. Edgerton, there has been considerable discussion and talk with regard to the effect of unrestricted water flood production as related to future supply and demand situation. In the course of your work, have you had occasion to consider this matter?

A Yes, sir. We have, of course, examined information which might throw some light on whether or not the rate of development which we now have would be commensurate with what we might -- perhaps should have to maintain proper domestic level of production, all related to this impact matter. In other words, how much water flooding should we have? Should we have more rather than less, or should -- is it a big factor, is it an undesirable factor, is it a desirable thing in that connection? Some work has been done by Mr. Al Sweeney, again, with Interstate Compact.

Q Will you have that marked as Exhibit No. 16, which you are going to refer to there, please?

A (Witness complies)

Q Do you know, first, what figure his estimates to base his curves are on?

A Yes, sir. These curves are made on a study of Chase Manhattan Bank on anticipated future production for the United States as a whole. He has molded his water-flood production curve in line with the Chase Manhattan Bank estimate of overall production.

Q Would you refer to Exhibit 16 and go ahead with your discussion of that particular question?

A Yes, sir. This curve is plotted, as you notice, on semilog paper. The peak water flood production which he shows about 1980 here is approximately 25 percent of the peak overall production, although it appears to be considerably higher because of the scale. Particularly interesting is the period more near to the time the present -- that is, if you look at 1960 on this scale and read up, we find that the water flood production according to this curve for the United States should be in the order of two hundred fifty million barrels annually. We've taken the four states, Oklahoma, Kansas, Illinois and Texas and adding Pennsylvanian production in, we have a figure that appears to be under one hundred fifty million barrels right now, and it doesn't appear that that is going to reach two hundred sixty million in 1960, and this scale being semilog rythmic, we could go to

1963, and my particular reference there was in relation to the exhibits which Mr. Stiles will show here, showing the peak in 1963, and we will find that we should have water-flood production in the order of three hundred million barrels a year. Now, of course, this is an estimate, but nevertheless, I think it is realistic when we take a further look at the Chase Manhattan study of the requirements to meet the total peak which they have shown on this curve. They point out, for example, that for the United States to meet ninety percent of domestic demand during the periods from now to 1966, based on a great deal of data discovery ratios, so forth, it would require the drilling during that period of a million two hundred thousand wells, and in projecting such a program they indicate that the only reasonable projection or reasonable one would be to start drilling at the rate of eighty-six thousand wells a year in 1957, whereas actually there were less than fifty thousand wells drilled, and the drilling rate has been declining. They conclude that the goal probably cannot be reached, which further lends emphasis to the necessity for attempting to meet our future demand requirements with water-flood production. That can also be noted in some of the states which have had more water-flood productions; when we examine their producing history down through several years, we find that they would tend to be falling behind their rate of increase, rate of supply furnished to the United States total, if they didn't have some water-flood development now in this connection. We made another study to see what might be attributable to Texas, and Texas would seem to be falling considerably behind, which would lend more emphasis to increase elsewhere.

Q Would you have that marked Exhibit No. 17, please, and identify and state what it shows in regard to the state of Texas?

A Yes, sir. Now, this chart, Exhibit 17 was prepared somewhat over a year ago. It was modeled in part after Mr. Sweeney's curve except that we got away from the semilog scale in order to give it a more realistic exhibit visionally, and we also made some minor changes in order to plot it on the basis of an equation which was merely for the purpose of facilitating the changing of the peak. The peak rate or the peak date and then the heavy line down on the left-hand corner is the actual water-flood production increase in Texas. Now, notice the last year shown there is '55. In 1957, the figure would be around thirty-five to thirty-eight million barrels, so that it falls about in line with this trend. This low trend, now, to explain the calculated curve here, we base that on the proposition that Texas having approximately half of the overall reserves would have approximately half of the water-flood reserves becoming available during the next -- during the period which Mr. Sweeney uses up to about 1980. He shows the production of ten billion barrels water-flood. If we give Texas the five billion, we will have to follow the calculated curve here to reach a figure comparable to his estimate, and the state as a whole is considerably behind, at least at this time in that respect, although we have capacity flooding for all stripper fields in Texas.

Q Considering the estimates of future demand on the basis of the Chase Manhattan study and your experience and knowledge with regard to the development of water-flood projects, do you believe that there is any serious danger of water-flood-reduction absorbing more than a reasonable portion of the total market demand in the future?

A I don't think there is at all, Mr. Campbell. It would be generally higher in one state in relation to its total than in another because of the number of stripper wells that may exist in one state as compared to another, but in that connection you rather have to look at the whole picture, the whole domestic picture, and if you seem to be generally somewhat behind there and if the overall estimate would appear to be made on a conservative basis, both demandwise and productionwise, then I think you would say that perhaps instead of supplying sufficient, it may be a little behind. Now, I want to point out here that it is a little difficult to consider this future information in the light of the current slacking in demand, but the Chase Manhattan study shows that we've had some of these flat demand intervals, but in the years prior to -- in the interval between World War I and World War II they averaged the increase and domestic demand at six percent a year, averaging out these slack periods which we had in 1957 and which we will probably have in 1958 throughout the rest of the year. Since World Was II we have the same picture. At the time of their study in October, 1957, I think is when they gave the paper at an API meeting. They stated that the demand again was increasing at an annual rate of six percent averaged over the history. The publication has a chart and you will see some little dips that cover a period of a year or two in there, but it would be a little bit -- I think a little bit incautious of twenty years' history that they have there to assume that our flattening demand picture is going to continue in the United States with polulation increase and all the factors which they have taken into account. I think the reasonable thing would be to go fairly well along with that study, particularly since they point out that the discovery rate in terms of effort, not age, drilled is going constantly down in the United States, and, of course, they also include in that study how much -- if our domestic production falls short, how much would have to be supplied from outside sources and show that to be an increased figure.

Q Based on your studies with individual pools, projects within pools, the estimated future demand for domestic crude oil and your knowledge of the development of water flooding in this country, is it your opinion that the possible impact as we've called it of water flood oil is going to have any serious effect upon the supply and demand picture?

A No. I want to preface that with this statement. In a period such as we have right now, of course, many people will say one barrel is one barrel too much. In other words, that is easy to understand, but you can't -- if you go and look at the picture five years from now in terms of current conditions, then you are operating on false premises. You should then take your demandwise five years from now and look at the picture, the demand picture in relation to what you think the peak will be five years from now. At this time, if you are going to relate it to current supply and demand picture, you should restrict yourself as to what will occur within the next year to eighteen months.

Q And, of course, are you in a position to state whether your experience has shown that these projects can be developed -- put together and developed into operating projects within a limited period of that kind?

A My experience has been that the development rate has just, without any restrictions, no imposed restriction, has been slow enough so that the sum total effect as reflected by the production histories is that the secondary history is comparable to the primary history and peak, taking into account, of course, if there is a large increase in reserves, which everybody hopes, we will get a much higher secondary recovery than primary, that you might have some secondary peak.

Q Do you have anything further that you would like to offer to the Examiner in connection with this application?

A Yes. I would like to just -- I've already mentioned here what 1957 production in Texas was. I would like to mention this. We made a further study of that figure to see what we called the excess allowable was or that over normal, that over what the yardstick prorated would be in that state at this time. Now, it is eight years -- a little over eight years since the capacity policy was established in Texas, and the total water-flood allowable, stripper water-floods is a hundred and twenty-one thousand barrels. Now, because of the forecast method, and you can understand that no one wants to forecast less than what he might need, you have to apply a little under production reduction to that figure. The exact reduction, for example, is twenty-five percent under production history. In recent months, in the overall states, about 12 or 13 percent, so that the production is in the order of a hundred thousand barrels per day. This amounts to between four and five percent of the state total. We also counted the total number of producing wells in the project and based on this allowable figure, the allowable for producing wells in Texas and all water floods, stripper water floods was seventeen barrels daily. Now, of course, again, if you apply the under production factor there, you would have a figure in the order of fifteen barrels and the average well in the entire state of Texas, including primary and secondary, is about fifteen barrels daily. Now, if you add in here injection wells on a one to one ratio, of course, it would cut that figure in half. We went further than that in connection with this impact question to see what -- how much allowable if you would just arbitrarily reduce all floods and hold them at a prorated level, what effect that would have on the rest of the state. We found that between fifteen and twenty-five barrels a day, or under one percent of the state total could be found in projects which were producing in excess of what their allowable would be at the yardstick for their depth and subject to shutdown days. Now, of course, when you see that the average producing well is only making about fifteen barrels you naturally infer that there must be a great number of projects which are well under prorated levels and there are a great number of projects for which capacity allowable has not yet been requested because they have not been stimulated to that point, and there are probably a large number of projects in which application has been granted and no action taken. It is reflected by the proration schedule. They received no stimulants, although their application has been approved some months past. Now, that about sums it up, that completes the picture as to Texas, I think. In a general way, we do have a breakdown by districts and wells here, but I think in over-all picture, I think that pretty well covers the thing in this state.

MR. CAMPBELL: That's all.

MR. NUTTER: We will recess this hearing until one o'clock.

(Recess)

MR. NUTTER: The hearing will come to order,please.

MR. CAMPBELL: May I ask him one or more questions?

MR. NUTTER: Yes, sir.

QUESTIONS BY MR. CAMPBELL:

Q Mr. Edgerton, before the recess you had been referring to the Exhibit 16 which was Mr. Sweeney's analysis of the requirements in the future to meet the estimated demand picture as extimated by the Chase Manhattan Bank and that reflects that the total amount of water flood oil at the peak period would be approximately 25 percent of the total requirements, isn't that correct?

A Not exactly, Mr. Campbell. This is domestic production rather than demand. This still allows room for other oil. In other words, this domestic rate of production does not supply one hundred percent of domestic demand.

Q What is the 25 percent?

A The 25 percent is the maximum rate of water flood production in terms of all production, and I would like to point out that with a fairly smooth increase in that rate from a low point up to the 25 percent figure, that would merely mean that of the total production during the period, the water flood production would be twelve and a half percent approximately. In other words, if you go from a low point to a peak at 25, your average for the entire period is approximately half of that, so that it would be misleading to take the 25 and take that as a fraction of the total for the entire period.

MR. CAMPBELL: That's all I have, Mr. Nutter.

MR. NUTTER: Are there any questions of Mr. Edgerton?

CROSS EXAMINATION

BY MR. COOLEY:

Q Mr. Edgerton, since we are in the area of predictions of the effect of water-flooding here, do you feel that the impact of water-flooding will have any adverse affect on the future exploration of development for new reserves?

A Mr. Cooley, I have given some thought to that question, and your first thought would be that it would be. However, just looking at some recent figures, I noticed mentioned that the rate of drilling for 1957 had declined over the United States as a whole. I noticed, however, I believe, in New Mexico there was an increase. Now, in Texas there would have been a decline and the amount of water-flood production which we have in Texas, that is the four percent figure, wouldn't, in my mind, be a significant factor relating to that decline. In other words, if you took four percent back in and actually you wouldn't be speaking in terms of four, it would be that one percent excess that you could throw back. It would be -- not be significant.

Q That's one further point I would like to have clarified, sir. Is this one percent of which you speak the allowable excess over and above what would be top unit allowable that is assigned to all water-flood projects in Texas?

A Yes, sir. In other words, if you took the Caprock-Queen unit here, the period of time there above thirty-three barrels, if you took that figure, that amount -- that excess would be on that project for that period. Now, I call it a flooding excess because after you begin to go below that point and before you reach it, that excess is carried by another project, and that figure is estimated in the range of fifteen to twenty-five thousand barrels a day, more or less maximum in the order of 25 percent of the total.

Q Fifteen to twenty-five thousand barrels a day of allowable over and above what would be necessary -- over and above what would be allowed on primary?

A On primary, that's right. For the same depth spacing.

Q That's more or less a flooding factor that is used as necessary by all of the water-floods in Texas?

A That is the figure that we found in our latest survey, and I call it flooding because it necessarily is. You have projects going below and projects going above.

Q So if you limited all of the water-floods in Texas to top allowable for their depth and the other factors that are considered -- I mean giving them no consideration whatsoever for water-flooding, you would only have fifteen to twenty-five thousand barrels that you could allocate to the total top allowable wells in the state to increase their allowable?

A That's right, that's correct.

Q That is what percent of their --

A Twenty-five thousand would be in the order of one percent.

Q Do you think that would be a negligible effect as far as any allowable incentive to go out and expend more monies for development?

A I think there are many economic factors that outweigh that as far as the effect of water flooding. Of course, the availability of prospects, the success ratio, the going down trends tend to discourage it. In other words, there are many more significant factors affecting the rate of drilling than the production itself.

Q Comparing the economics of water flooding and primary development, wouldn't you say that water flooding is a more attractive economic venture?

A I would say offhand, in places it is and in places it is not. I think if you carry that -- I see what you might be getting to -- that is, to carry that to its effect. In other words, the incentive effect, you would end up with that sort of a proposition on a state-wide basis excluding all other factors. Incentivewise alone, is the incentive sufficient to encourage the rate of water flood development? That would appear to go desirable on a long range basis. Now, I know I didn't answer your question on cost directly, but I think in the long run that is what you would be interested in.

Q I was thinking of a little different factor, of the investment. I believe if you answer the question directly, we could proceed from there. Do you feel that you have a sure bet? As a general rule, say you were the President of Edgerton Oil

Corporation and you had half a million dollars to expend for obtaining additional production in the year 1958, and you had some good water-flood prospects and also had some good primary prospect for exploration and development, don't you feel you would be a little bit safer and get a better return for your money if you invest in water-flood?

A There are a lot of factors. If you are talking about comparing a primary prospect as related to a secondary prospect to develop independently, you would have an acquisition cost. In your secondary you would have some, but in your wild cat prospect, it wouldn't be relatively the same as acquiring the other property. You would have to evaluate the risk involved in the particular project.

Q The risk angle is more what I am referring to. Is there less risk involved? Generally speaking, you are doing real well if you are getting one out of five producers; one producer out of five wild cats, aren't you?

A If you take a field that shows response or in the Caprock, it is pretty sound ground. If you are experimenting over the state, if you take for example, before you knew anything about flooding,as in the Yates sand,the Queen Sand,the Permian Sand,in West Texas in 1950,it didn't appear offhand to be very attractive. The risk factor relates to how much you know at the time about the water flood prospect for the particular field and the acquisition cost of the properties will also vary with that factor. It is a pretty difficult thing to say. I think you might look at it this way, that the people that are in the business, that are on both sides flooding and primary, there are a few people that concentrated more on water-flood but there are other people who continued to concentrate to a great extent on primary where they have both available to them and are doing both.

Q That is what I was trying to get at. What I was worried about is the possibility that the rosy prospects of water-flooding compared with the risks of primary exploration and development might entice the operators and the companies to take a rather shortsighted view and spend their budget, spent a disproportionate share of the budget on water flooding and later neglect the exploration and development with the consequent result of going down the road in ten or fifteen years in having even worse reserve calculations than we expect now.

A Well, if the company is in a position where they already have, of course, a considerable stripper production and they don't have any desirable primary prospects come to them or they don't find any, I think you would anticipate that they would probably go to flooding. If you have -- in order to get the broad picture, I don't believe that the primary drilling is going to be significantly affected by water flooding. In the first place, bear in mind this, this figure I gave you a little while ago in total production, even if we were to keep this peak which we are not approaching at this time, we would still be furnishing only approximately twelve and a half percent, twelve or thirteen percent of the total production required to meet this domestic picture. That gives you a more reasonable relationship there of what the amount of the water-flood would be in relation to the total. You couldn't, to furnish twelve and a half percent, drop all this primary that is required to furnish the eighty-seven percent in the overall picture.

MR. COOLEY: Thank you very much, Mr. Edgerton.

MR. NUTTER: Are there any further questions of Mr. Edgerton?

MR. LAMB: I have a question, Mr. Nutter.

MR. NUTTER: Mr. Lamb.

QUESTIONS BY MR. LAMB:

Q I will take them in reverse so that we follow on back down the testimony. You are familiar with the present system which we now have in New Mexico as a basis of allocation along with the deep well system that we have?

A I am familiar. I might say briefly, I understand there is a unit figure based on forty acres down to a fixed depth, and then there is a multiplying factor for deeper wells. Is that correct, substantially?

Q Yes. I want to point out that in 1945, on the basis of this deep oil adaptation, the shallow production was based on economic factors. Do you think that the allocation that you are asking for here will give you a faster payout than this allocation which we now have in existence for primary production?

A You said it was based on what?

Q Economics, payout basis. Between various depth ranges.

A Do I think it might give a faster payout?

Q On the secondary recovery projects?

A Well, of course, if I exclude acquisition costs on many floods, I presume that it would. I am not familiar with all the economics that entered into that original factor you speak of. It's certainly possible that it might in one instance and not in another. The economics in different floods can differ very very substantially. In water-flooding normally the -- a relative payout is a desirable thing because it is generally considered that -- the risk venture in terms of the oil to be recovered; it doesn't mean that you don't recover anything but in terms of what you might estimate is considered fairly high by the broad, you might say, spectrum of opinion. I think you have to judge these things on what occurs rather than what one individual thinks. You might find some people that don't want to flood at all. They don't think that economics are favorable, they'd rather do it the other way. I don't think you can take any one set of conditions or any one company and try to draw a conclusion from it as to whether or not it's comparatively favorable or unfavorable.

Q Do you think on the specific project that we have in mind that your payout would be at a faster rate than a primary drilled property?

A Deep well or --

Q Either. Doesn't make any difference.

A I haven't actually checked it. I really don't have that answer. It may be, it may not be.

Q In following your testimony, the one percent factor, in other words, it is over and above what the property would normally produce. Do you think that one percent is important enough to upset the entire proration system which we now have in existence in New Mexico?

A Well, I wouldn't think so. We don't think it is in Texas.

Q In other words, there wouldn't be any need for us to deviate from our present system to make allowance for that one percent?

A Well, it is one percent. I mean --

Q On the exhibits which you presented, I don't recall the exact number, were they prepared by you or under your supervision?

A Most of these exhibits are taken from the literature and the reserve is placed on each exhibit. The South Ward Field history was prepared by Mr. George Buckles applying the field production. Exhibit 17, the prediction of water flood production in the state of Texas, and the actual production was prepared by me.

Q In your opinion, the five spot project which is now in effect in North Caprock 1 and North Caprock 2, is it the most efficient method of water flooding to recover the maximum ultimate reserves or to recover the maximum amount of oil in the shortest period of time?

A I believe it is the most efficient to get the maximum recovery, Mr. Lamb. We get our experience from a pretty broad area,you notice. I pointed out specifically in Kansas and Oklahoma close relationship between producers and input wells to show that the greatest number of people in the business are using the five spot system. I might point out, too, if you will look at the Atlantic production history, they used the five spot high rate system and they have recovered in excess of two hundred fifty percent of primary. You can't look at that kind of information without being pretty well convinced that they have an excellent procedure there.

Q On the water-floods which you have discussed here, have any of them produced on a restricted daily capacity -- I mean, restricted production basis. Do you have any history on any that has been restricted as to the effect and so forth?

A None that I know of. Now, I didn't check the full history of some of these that I took from the literature. South Ward Field, I know, in Texas, has not been restricted.

Q On the South Ward, what is the producing zone in that water-flood?

A It is the Yates and they have two zones, the Pennsylvanian Green net and the Grand Falls that have flooded in part together and in part separate flooding. They are sand zones.

Q How does it compare with the physical characteristics of the producing horizons in the Caprock-Queen?

A I made no direct comparison. They are Permian sand; they are more or less in the same series. They would -- I would anticipate there would be some similarity there in floodability. I don't recall exactly what comparative permeability or porosity might be, but I would judge it would be generally in a similar nature, at least in a general way.

MR. LAMB: That's all. Thank you.

MR. NUTTER: Are there any questions of Mr. Edgerton?

QUESTIONS BY MR. NUTTER:

Q Mr. Edgerton, referring to your Exhibit No. 10, I note that the South Ward Field reached its peak in the year 1937 on primary production.

A Yes, sir.

Q Do you know how many wells were producing from that pool at that time?

A No. No, I didn't check that. I would suppose that if it followed the usual history that it was probably pretty close to the full development. I think there has been a little drilling since that time.

Q What is the number of wells in the South Ward Field?

A The number of wells that were producing in water-floods at the time that we checked the total water-flood production in Texas was 405, but there were still some leases that hadn't been developed, and I don't have the total figure with me, but there were 405 producing wells within water flood projects this past fall.

Q How about -- how many wells were in water flood -- producing wells were in water flood projects when the South Ward Field reached what it appears to be its peak on secondary recovery in the year 1952?

A I don't have that figure. I have some floods. Maybe Mr. Buckwalter might have it with reference to a portion of the field in which he made a study.

A If at all possible, I would like to have --

A If we don't have it, we will be glad to furnish it.

Q I would like to see a comparison between the average production per well when the pool reached its peak on primary recovery and when the pool reached its peak on secondary recovery.

A I will be glad to get it and send it to you.

Q On your Exhibit No. 12, you indicate the primary production and the secondary recovery in the Bryden-Ladd waterflood projects in Kansas?

A Yes.

Q Now, that field reached its peak in 1925 on primary recovery. Do you know how many wells were producing there at that time?

A No. I just took this picture from the literature and I don't know how many wells were producing at that peak.

Q This was probably during a period of unrestricted production so far as primary production was concerned --

A So far as primary --

Q -- in those days?

A It likely was. Yes.

Q Likewise, do you know how many wells were producing when this Olympic Pool reached its peak in the year 1937?

A No, sir. Mr. Stiles may be able to give you that figure.

Q And how many water-flood wells were producing when the secondary recovery reached its peak in the years 1953 and '54?

A No, sir, I don't have that figure either.

Q Mr. Edgerton, in regard to your tabulation that you had there, I think you stated that the average water-flood production in the state of Texas was some fifteen barrels per day per well or seventeen. What was that figure?

A Fifteen barrels production, seventeen barrels production for producing total stripper water-floods.

Q At what stage is water-flood development in, in the state of Texas today?

A It's been -- of course, we have had some water flooding in North Texas, Mr. Nutter, to a lesser degree for a number of years. I believe in 1950 the total water flood production was in the order of a million or a million and a half barrels a year, or 1949, along that time, at the time the Commission adopted a capacity policy in 1950 or thereafter. That production has increased now to the rate in the order of about thirty-five or thirty-eight million barrels a year. Although we have some prior history over some years past, the substantial water flood production, you might call it, the four or five percent, has been close to 1950, which would give us about eight years of history backlog there.

Q Well, do you think that this fifteen barrels per day average rate of production for the wells in water flood projects represents the -- what I am trying to say is, I realize it is the average rate of production for the wells, but are there a larger number of wells that produce in that range or are there a larger number that produce below that with a few producing much above that to bring the average up to fifteen or seventeen barrels? What range are the bulk of the wells in?

A I see what you are getting at. I think the bulk of the wells are fairly low range. I think you can take the figure of fifteen to twenty-five thousand as a measure. In other words, if it's as high as twenty-five, you have a hundred thousand, roughly, total. You would have twenty-five percent of the total being produced above. That doesn't give a direct figure on the number of wells, but the larger proportion of wells are down at lower wells.

Q Are the larger proportion of wells in Texas today in old water floods or in new water floods?

A Well, I don't have a count on the total project. I would say greater part of production was coming from new floods in this respect; that there were new floods after 1950, judging from the --

Q The greater part of production comes from those newer floods?

A That's right.

Q How about the larger number of wells, is it new flood or the old flood?

A I have a tabulation here by districts from which that tabulation was derived. I might be able to give you some idea. District 9 is the North Texas district where we had the earlier greater -- the more extensive water-flooding, and we had there around twenty-two hundred producing wells. Now, I have a tabulation; I'll just give you this. This is a tabulation. It shows the number of producing wells by districts. 9 is the old area, you might say. The rest of it would probably be relatively new.

Q Where is district 8?

A District 8 is the West Texas district in which we have the South Ward Field, the Yate Sand flood, our best or highest rate flood area, you might call it. Permian basin area.

Q The average per well allowable in there is considerably in excess of the average for the state, isn't it?

A That is correct. I think it is about 25, is it not, or something like that?

Q 29.4.

A 29.4.

Q Water-flooding is relatively new in New Mexico, is it not?

A Yes, sir, that is my understanding.

Q So we could expect a higher per well average than the 15 well average that you have in Texas for a considerable number of years?

A Well, I'll say initially it might be for several years. I don't know. You say necessarily considerably for a number of years. Unless we have quite a number of water flood productions in that West Texas district -- well, you could draw that inference. In other words, eight years in Texas, and we have 29 barrels in the West Texas district. Eight years in New Mexico, that might be a reasonable conclusion. I might mention this, too, Mr. Nutter. Of course, in New Mexico where you have 40-acre pattern universally, you might have -- on a per well basis, you might have a higher average because many of our fields in Texas are flooded on 20-acre spot. In West Texas the most universal pattern has been the 20-acre five spot.

Q Would you anticipate that water flood production during the next ten years in New Mexico would amount to less percentage or greater percentage than the total production than it has in Texas for the last several years?

A I think in New Mexico it would be a higher percentage because in Texas we have considerable reserves on the gulf coast. In other words, New Mexico potentially has larger areas which may tend to become stripper, that is the solution drive type field. I think in Texas as a whole; in other words, it is more comparable to our West Texas areas and our West Central Texas area. On the gulf coast, we, of course, have a lot of water drive fields which wouldn't reach stripper status, so as a part of the total production I would anticipate that in fractions of the totals, that would be water-flood, would go up faster than Texas.

Q And it is what percentage in Texas today?

A Four to five.

Q So we may expect more than four to five percent water-flood production in New Mexico?

A I think so. That's why I mentioned earlier in my testimony that I don't think you can look at the state of New Mexico or any particular state and gauge what would be a reasonable percentage to another state. You probably have to look at the total United States to see how it fits in with the total water-flood projections and see if it is reasonable figure. If you want to gauge it on the individual state, you would have to have some relative basis. In other words, how much marginal or stripper production you have in this state compared to that one. You will find that in Oklahoma and Kansas they have a larger share and their development has occurred to their great extent in the last ten, twelve years.

Q You stated, I believe, that the water-flood allowable in Texas was some one percent more than what it would be if it were normally allowable?

A Yes. In other words, -- now, I don't mean as a whole. If you took the average, of course, you could see that it would be below, but if you took the particular projects that have excess allowable and took it away from it and added it up, you would have a figure in the range of 15 to 25 thousand barrels daily.

Q Would that same percentage apply to the allowables for water-flood projects versus primary projects in the state of Oklahoma?

A In Oklahoma?

Q Yes, sir.

MR. CAMPBELL: I think Mr. Stiles is going to offer some testimony on Oklahoma, Mr. Nutter.

MR. NUTTER: I see.

A He has some figures on that.

Q I will defer that question to Mr. Stiles then.

MR. NUTTER: Does anyone else have any questions of Mr. Edgerton?

MR. LAMB: I would like to ask one more.

QUESTIONS BY MR. LAMB:

Q From the graph there behind you covering the entire Caprock Pool, when it reaches its peak, what percentage of the state's production would this production rate be?

A When Caprock Field reaches nineteen thousand barrels a day, approximately?

Q Yes.

MR. CAMPBELL: In 1963.

A In 1963.

Q What percentage would it be of New Mexico?

A It would be in the order of three hundred.

Q What is the New Mexico daily rate, three hundred thousand?

A Not that much now. It has been 250.

MR. CAMPBELL: May I clarify that? He would like to have you estimate what percentage in 1963, nineteen thousand one hundred barrels a day will be to the then demand?

MR. LAMB: To the then rate of production in New Mexico.

A I think Mr. Stiles did a little work on that, and he has the figures. I might not recall them exactly.

MR. CAMPBELL: Mr. Stiles will give it to you.

MR. LAMB: I am talking about the Caprock alone, the water flood on the Caprock.

A I might mention one thing that, of course, the rate of change in Caprock wouldn't be the same as the total figure because you'll have cut short the dip there shown on the remaining primary and come back up, so that the change -- what it is doing now, and what it will go down, wouldn't be near the figure of what the total figure would be.

MR. NUTTER: Are there any other questions?

MR. STAMETS: I have one.

QUESTIONS BY MR. STAMETS:

Q Do you believe that there may be a saturation point, say, in the percentage of the total daily production of the state daily production?

A In other words, --

Q A point beyond which on exploration might be somewhat lower or shut downs might seriously affect this water flood operation? In other words, say, at the point beyond which you should let water floods get?

A It is certainly conceivable that the point could be reached. Even as low as it is in Texas, there has been from time to time some concern expressed along that line. No determination of how you would arrive at that has been made in any place that I know of. In time, something along that line could develop. I don't -- it's not inconceivable at all. It is quite possible. I don't think that we are at the point now where it would be necessary to make such determination.

MR. STAMETS: That's all I have.

MR.NUTTER: One question, Mr. Edgerton. Has the 15 barrels per day average water flood production been relatively uniform throughout the years?

A I don't have those figures, Mr. Nutter. I would suppose that it had not been for this reason. I think when the first --

when capacity flooding was first permitted and we had a relatively rapid rise in production and then a leveling out in those years when more new projects were being added, I think the per well figure would have been higher. I don't have the figures. That seems logical to me. Texas doesn't separate all these data. It is quite a job to go through one hundred eighty thousand wells in their schedule and pick those out, and we just haven't done it through the years.

MR. NUTTER: Any further questions? If not, Mr. Edgerton may be excused.

(Witness excused)

MR. CAMPBELL: Mr. Stiles, please.

W. E. STILES

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 W. E. Stiles.

Q Where do you live, Mr. Stiles?

A Tulsa, Oklahoma.

Q What is your profession?

A Consultant petroleum engineer.

Q You have testified previously before this Commission, have you not?

A Yes, sir.

Q You testified in the Graridge hearing?

A In the Graridge hearing in October.

Q At that time you were employed by Buffalo Oil Company?

A Buffalo Oil Company.

Q Have you had considerable experience in water-flooding in the state of Oklahoma?

A Yes, sir, I have.

Q Would you very briefly state what that -- the extent of that experience?

A In Oklahoma only?

Q Yes.

A Starting about 1944, I was doing reservoir engineering for Core Laboratories, Incorporated, much of which involved water flooding in Oklahoma as well as other states. During my experience with Buffalo Oil Company over a seventeen-year period of time, we operated water floods in the state of Oklahoma as well as elsewhere.

Q You operated water floods in the state of Texas and New Mexico?

A Yes, sir. Excuse me, not New Mexico.

Q Have you made any studies of the water flood project in the state of Oklahoma with regard to their number and the production per well from those projects?

A Yes, sir, I have.

Q May I first ask you this? Has Oklahoma perhaps had water-flooding as a sizeable factor in their production picture to a greater extent and longer than perhaps any other state?

A I think so, yes. For many many years water-flooding has been taking the place in Oklahoma. Today it is a sizeable water-flood production -- is a sizeable portion of the state's total production.

Q With that background, would you have marked your Exhibit -- first Exhibit, Exhibit No. 18, please?

A Yes.

Q State what it is and referring to it give your interpretation of what it reflects.

A Exhibit 18, the first page -- it's a two-page Exhibit. The first page of it is a summary of the status of what I call true water-flood projects in the state of Oklahoma. Now, I would like to explain what I call a true water-flood project first. In Oklahoma there is very little differentiation as between pressure maintenance, water-flood projects in depleted primary fields and salt water projects. Now, in making an analysis of water-flood projects in Oklahoma, you must first eliminate what are truly salt water disposal projects because in many instances operators, when really needing a salt water disposal permit, ask and receive a salt water -- or a water-flood permit, so that in the event that an underground disposal of salt water should result in an increased production rate, the allowable restrictions will have been removed by the water-flood permit and they can produce the increased production. So in making the study of the water-floods, I have excluded from the study all projects which reported less than two input wells. Now, in Oklahoma, each operator for each authorized project must turn in an affidavit type monthly report showing among other things the acres developed, the number of input wells, the number of producing wells, the daily average rate for the month of water injection, of water production and oil production, and the pipeline runs for the last six months. So, using these monthly reports for each authorized project, we went through them and deleted each project wherein there were less than two input wells. In many cases, no input wells were reported. So, this first sheet of Exhibit 18 shows the summary of the remaining projects which I call true water-flood projects. I show the data for two monthly reporting periods. First, for March, 1957, and this summary was made by the Oklahoma Corporation Commission staff themselves. I also show the same type of data for the January, 1958 reports. And I made that summary myself and have given a copy of it to the Oklahoma Corporation Commission. So that it shows that for March, 1957, the totals at which times the total state allowable from all sources was six hundred twenty-five thousand barrels a day, that the true water-flood projects were producing one hundred fifteen thousand, five hundred and seventy barrels per day, which is about 18.5 percent of the total state's production. There were, during that month, three hundred and forty-four true water-floods out of a total of four hundred sixty-seven projects reporting. So we have knocked out a hundred and twenty-five out of four hundred sixty-seven projects because they were really salt water disposal projects. Among other data, this summary will show that the number of oil wells in March, 1957 was fifteen thousand four hundred twenty-seven, and the number of water input wells was ten thousand, eight hundred eighty-one, for a total number of wells in true water-flood projects during that month of twenty-six thousand, three hundred eight.

Now, the average oil production per oil well was 7.49 barrels per day. And if you add in the input wells along with the oil wells, then the average production per well is 4.39 barrels per well per day. Now, the same data is shown for the January, 1958, at which time the state's total production was five hundred and sixty-two thousand barrels per day, and the true water-floods were producing 22.7 percent of that or a hundred and twenty-seven thousand, eight hundred barrels a day. We had a few more true water-flood projects reporting that month, that is, we had three hundred and fifty-seven true projects out of a total of four hundred and eighty projects in the state. The hundred and twenty-three again that we knocked out were those that we considered to be salt water disposals. Again, the average production per oil well for this month was 7.96 barrels, not much different that it was in March, 1957, and the average production per total well was

4.76 barrels per well per day, slightly higher than in March, 1957.

Now, you might be interested to know that of the number of projects that were deleted from this summary, in March, 1957 we deleted 26.3 percent of the projects because they contained less than two input wells. And in January, '58 we deleted 25.6 percent of the projects because they contained less than two input wells. Now, water-flooding in Oklahoma, with the exception of two instances, has always been on a capacity basis. An operator is allowed to produce all the oil he can from wherever he can in a water-flood project. The two exceptions were first in the summer of 1954, at which time the Corporation Commission prorated all water-floods in the state on the basis of twenty barrels per well per day, including both input and oil wells. This proration went on for about two months. That was the first instance of water-flood proration. The second and latest instance was in March of this year,at which time the Corporation Commission prorated water-floods as well as other types of production in the state by limiting them to produce 89 percent of what they delivered to the pipeline in January, 1958. Now, the Corporation Commission got a lot of fussing when they did that to water-floods in March, and they made it known that an operator who felt that he was being hurt or was losing recovery because of the water-flood restrictions, could in an informal meeting with the Commissioners plea his case and ask for an increase in the capacity allowable. All during the month of March the Corporation Commission had informal hearings all day long almost every day because of -- many operators came in and plead their case. I know of no instance in which the operator did not get what he was asking for. It is my understanding that everybody got what they asked for. And on March the 25th the usual State Market Demand hearing was had, and the courtroom was considerably crowded with water-flood operators who put on a great amount of testimony, expert witnesses and so forth, showing that water-floods could not be curtained without impairing ultimate recovery. Following that hearing the Commission listed restrictions on water-floods. While other types of production in the state since March have still been under considerable restriction, water-floods have been entirely removed.

Q Has your study included some determination as to the effect of water-flood production on the general situation in Oklahoma?

A Yes. The second sheet of Exhibit 18 will show that -- the answer to that. We had the one instance when the state prorated water-floods on the basis of 20 barrels per day per well. Back in 1954, the usual minimum allowable for any well in the state of Oklahoma was 20 barrels per well per day. There are some who have suggested that if a water-flood proration plan is used in Oklahoma, that maybe that 20 barrels per well per day including input and oil wells would be the kind of plan that they might impose, and that would be the very minimum type allowable plan that the state could impose because any well is allowed 20 barrels and I don't think that they could prorate a water-flood well below that. Certainly so, if we assume for the moment that that very minimum allowable plan was imposed upon Oklahoma floods. Then I made an analysis to find out how much oil would be produced over and above such a minimum allowable plan. In March, 1957 there were 27 projects; out of the total of three hundred and forty-four true water-flood projects, only 27 in which the wells, counting inputs and producers were averaging more than 20 barrels per well per day. And the second column under March, 1957 on that Exhibit shows the amount of oil being produced per day by those projects in excess of the 20 barrels per well per day, so that the total of 27 projects which were producing in excess of 20 barrels the total amount by which they were producing was only fifty-seven hundred and fifty-five barrels per day in the whole state. That's about 5 percent of the total water-flood production and about 1 percent of the total state production. So, had the water-floods in March, 1957 been prorated on that minimum basis, there would have been only fifty-seven hundred barrels a day that could be allocated to other types of production. And while we don't know the exact number of other types of wells in the state of Oklahoma, we think it is about seventy thousand wells. Incidently, if you tried to allocate that fifty-seven hundred barrels per day back to all the other types of wells in Oklahoma, it would amount to a very small fraction of one barrel per well per day of additional allowable for each well.

Now, for January, 1958, the same sort of a study was made, and we find that only 17 projects during that month were averaging more than 20 barrels per well per day, and the amount of oil in excess -- the amount of oil that they produced per day in excess of the 20 barrels were ten thousand, three hundred, fifty-nine barrels per day. Now, this -- in the state of Oklahoma we have a depth yardstick also for primary type wells, allocated wells. I have not used any depth yardstick in this 20 barrel business, but had I used -- had I taken the depth of these projects that are producing more than 20 barrels and had applied the yardstick and said this one because of its depth is entitled to 23 barrels and this one to 27 barrels, the amount of oil by which they would be exceeding that yardstick would be considerably less than what I have shown here.

Q Do you consider that the amount of oil, January, 1958, in excess of the 20 barrel a day minimum allowable had any significant effect upon the primary exploratory activities in the state of Oklahoma?

A No, I don't think so. No. This 10,000 barrels that I show here would represent, would be -- represents about 2 percent of the total state production, that's all.

Q Is Oklahoma continuing to initiate new water-flood projects as the fields reach the stripper stage?

A Oh, yes, yes. You might like me to say what Oklahoma does about water-floods.

Q Yes, would you briefly state what the procedure is in the state of Oklahoma with regard to allowable?

A The procedure is, if I had a group of leases, contiguous leases that I wanted to place under water-flood, I would file an application with the state for a hearing concerning -- let's say it is a thousand acres I am talking about, contiguous leases, and I would file an application for a water-flood permit. I'd show a typical well log or electric log or core analysis, whatever I had. I would indicate my intent in the way of developing this stuff, these leases, that is, the pattern that I intended to use. I might make some statement as to what rate I might develop for water-flooding, although that is not necessary at all. I would show that by developing the properties for water-flooding that I would recover more dollars in oil than I spent in the development in operation of the properties. I've got to show that I am not going to lose money on the project. The Commission will then give me a water-flood permit, and from the day I get -- from the date of that permit, I'm free to go ahead and drill oil wells and input wells at any place that I want to on the thousand acres, and at any rate I want to, and to inject water at any rate that I want to, and to produce the oil as fast and from wherever it might come.

Q And then you make your sworn monthly reports on what you have done the previous month, is that correct?

A Yes. Yes.

Q Now, Mr. Stiles, at my request, did you make some studies of the New Mexico daily oil allocations with reference to depth groups and with reference to margins on a nonmarginal well?

A Yes, sir, I did.

Q Would you have that bar graph marked Exhibit No. 19?

A Using the Commission's April, 1958 allocation schedule, I have prepared the bar graph to show the distribution of the April, 1958 allocation in Southeastern New Mexico. At this point I would like to say from here on when I am talking about New Mexico I am talking about the southeastern part of New Mexico, and that would cover Lea, Eddy, Chaves and Roosevelt counties.

Q Now, did you -- referring to that Exhibit No. 19, briefly state what these bar graphs reflect with regard to the distribution of allowable in New Mexico as between wells in the various depth brackets, as between marginal and nonmarginal units.

A You will notice that the horizontal scale is depth group of wells, the vertical is oil production barrels per day. For each depth group we have two bars shown, one of which is crosshatched, and the crosshatched bar is the oil production for the nonmarginal wells in that depth group in terms of total barrels by such classification of wells. For instance, in the zero to 5,000 foot depth group, the crosshatched bar representing the nonmarginal wells showed that they produced -- they were allocated, rather, in April, 62,500 barrels a day. That was from 1,892 nonmarginal wells in that depth group, whereas 5,741 marginal wells in that depth group will produce or will be allocated only 59,900 barrels a day.

Q And those marginal wells, in most instances, I assume, would not be affected one way or another, even assuming there is some impact on the total available market?

A No, I don't believe that they would be affected at all, if there should be some impact of water-flood production upon the state's total market. We show similar bar graphs for the other depth groups or as we call them in this state, the deeper wells.

Q Does it generally appear from that that as you approach the deeper wells at the right side of the Exhibit, that the number of marginal wells as related to nonmarginal wells decreases?

A Yes, that's correct. As it goes deeper and deeper, the number of marginal wells is lesser and lesser in that group.

Q Are you acquainted with the fact that the deeper wells are permitted an additional allowable for economic reasons in New Mexico?

A Yes, sir. Yes, sir.

Q What does that indicate with reference to the percentage of the total production in New Mexico, that is allocated to wells less than 5,000 feet?

A Well, at the top of this bar graph is shown the total daily production allocated to each of the depth groups as well as the percentage of that depth group allocation to the state's total allocation. For instance, in the zero to 5,000 depth foot the allocation goes 123,335 barrels per day, which is a total of 45 percent, 45.6 percent of the total allocation for southeastern New Mexico, so that the shallow wells which we will call the zero to 5,000 are allocated almost half of the total production for the southeastern part of New Mexico.

Q And over half of the production comes from wells that are deep enough to receive deep well allowable credit?

A Yes.

Q Now, will you have those tables marked Exhibit 20, please?

A (Witness complies)

Q Now, Mr. Stiles, at my request, did you undertake to make several different types of statistical analyses of the allocation of allowables in the state of New Mexico?

A Yes, sir, we have.

Q Will you refer to what has been identified as Applicant's Exhibit 20 and point out to the Examiner the basis for these tables and any significant factors that you note? I might say, Mr. Examiner, that someof this data is perhaps not especially pertinent to this hearing, some of it is. However, it was my feeling that this type of analysis might serve some beneficial purpose in determining what effect any increased production from water floods might have in the state of New Mexico. Go ahead, Mr. Stiles.

A Exhibit 20 consists of six tables, and, again, this is data taken from the April, '58 allocation schedule for southeastern New Mexico. Table No. 1 shows the division of daily oil allocation as between the depth groups. For instance, the zero to 5,000 foot depth group receives 45.6 percent of the total allocation for southeastern New Mexico.

MR. UTZ: Are we talking about May?

A April. April allocation. All of these figures are April, '58.

MR. COOLEY: Mr. Stiles, just to verify this, every time the word production occurs on both Exhibits 19 and 20 they really mean allowable, don't they?

A Allocation, yes.

MR. COOLEY: Allocation for production?

A Allocation for production, that's right.

MR. COOLEY: It is not an allocation record?

A I will tell you the significant thing about Table 1. It shows where the allocation is coming from and it shows that almost half of it is coming from the shallow well class.

Q Also shows that over half is coming from wells that are accredited with deep well allowable factors, does it not?

A Yes. You are a little ahead of me, Mr. Campbell.

Q The second Table.

A The second Table shows where these wells are, what depths they are producing from. The schedule shows that -- the allocation schedule for April shows the figure for southeastern New Mexico. Of that total, 76.8 percent are in the zero to 5,000 depth group. That shows that 23.2 percent of them must be in the deeper groups. From 6,000 --

Q Two and two-tenths percent are receiving 54 and 4 tenths percent of the allocated production?

A Yes, sir.

Q Go ahead.

A Table No. 3 divides the production as between marginal and nonmarginal and by depth groups. For instance, in the zero to 5,000 foot group, the marginal production is almost 60,000 barrels per day. The nonmarginal production from that same depth group is more than that, or 62,400 barrels a day. The percentage column shows the percentage. For instance, -- the marginal production, it shows the percentage of the total marginal production that is coming from the total depth group. For instance, zero to 5,000 where we show 43 percent of the total, that is the percent on the total marginal production, not the total state production.

I don't know what the production is or was for April. All I had was the allocation schedule to work from. While I called it production, it is truly allocation. Table No.4

divides up the marginal and nonmarginal wells by depth groups. For instance, in the zero, again in the zero to 5,000 foot group there are 5,741 marginal wells, and there are 1,892 nonmarginal wells. On the marginal column the 5,741 marginal wells constitute 77.5 percent of all the marginal wells, or let me put it another way, 77.5 percent of all the marginal wells are in the zero to 5,000 foot depth group.

Q What does that show with reference to the percentage of marginal wells in the state, in the southeastern portion in the state of New Mexico?

A Out of the total wells?

Q Yes.

A Well, it would show that 74.7 percent of all the oil wells in southeastern New Mexico are marginal and they are receiving about 44 percent of the total allocation, only 44 percent whereas the marginal wells constitute only 25.3 percent of the total wells in southeastern New Mexico, yet they are receiving 55 percent, about 55 percent of the total allocation.

Q You are referring there at the last to nonmarginal wells, weren't you?

A Yes, sir, excuse me.

Q Mr. Stiles, does the fact that 75 percent, approximately, of the oil wells in southeastern New Mexico are marginal wells indicate to you that perhaps it may be time for us to undertake to stimulate wells by secondary recovery methods in order to retain our position in the oil supply picture?

A I think we have to do everything we can to encourage stimulation of those wells. For instance, in the next Exhibit I am going to show you that the marginal wells in the zero to 5,000 foot depth group which is the depth group that will receive most of the water flood development because of its shallow depth, that those wells -- those marginal wells in that depth group are averaging only 10 barrels a day of oil. Now, if all of those wells -- if the 5,741 of them are averaging only 10 barrels per day per well, it's obvious that many of them must be very low producers. Just a few barrels per day, meaning that they are at the stripper and uneconomic stage, and something is going to have to be done to stimulate those wells. Otherwise, they will have been plugged out and maybe secondary production forever lost.

Q Do you have anything further with regard to Table No. 5?

A Table No. 5 is the Table that shows the average daily production for the marginal and nonmarginal wells in each depth group. I think one of the significant things is that the marginal wells -- that in all depth groups the marginal wells are operating considerably below the depth allowable given to that depth group. For instance, the 13 to 14,000 foot marginal wells are averaging only 98.5 barrels per day per well, whereas the allowable given to a well on 40 acres for that depth is 264 barrels.

Q That represents, however, only two-tenths of one percent of the wells in that depth bracket, does it not, according to your

Table No. 4?

A Yes, sir, that's right.

Q Now, what comment do you have with regard to Table No. 6?

A Table No. 6 shows the -- in the middle column, the total number of wells in each depth group, and extreme right-hand column shows the percentage of those wells in each depth group that are incapable of making the depth allowable assigned. For instance, using the zero to 5,000 foot group again as an example, there are 7,633 wells in that depth group in southeastern New Mexico, and 75.2 percent of those wells cannot make the 33 barrels per day assigned. I think another significant thing is that except for about four of these depth groups that the majority of the wells in the other depth groups cannot make the depth allowable assigned.

Q Now, Mr. Stiles, based upon your study of the allocation of production in New Mexico and any other studies you may have made with regard to the impact of water flood oil market in New Mexico, do you consider that that impact possibility is a significant one?

A No, I do not. I don't think there is going to be any significant impact of water flood production upon New Mexico's total demand.

Q Why do you say that?

A I think the experience that we've had in other states will illustrate that there is not too much cause for concern.

For instance, at the present time there is only some 2500 barrels a day of water flood oil produced in the state of New Mexico, which is less than 1 percent of the total production in the state. Obviously water flood production is going to increase in the state, and I think the state ought to be hopeful that it does. It is going to have to increase, it is going to need to increase.

Q Have you made any study with regard to the possible amount of oil that will be produced from the entire Caprock-Queen Pool at this peak? Are you aware of the figures?

A Yes. I wonder if I could get into something ahead of that, please.

Q Go ahead.

A It might come in a little better. We have examined the allocation and the production of New Mexico oil, the southeastern part of it, over the last six or seven year period, and it appears from the curves that we have found in the literature that the production of crude in southeastern New Mexico is increasing about 6 percent per year and has for the last six or seven years. Now, that's pretty much consistent with all the predictions for increase in domestic demand for crude. They all range close to 6 percent. Mr. Edgerton testified this morning on some of the Chase Manhattan predictions which are about 6 percent. So if -- if it is reasonable to assume that the trend we've had in the past is going to continue in the future, then five years from now the demand for New Mexico crude will be about 350,000 barrels a day instead of its present 270,000 barrels in southeastern part of New Mexico. So, I think we are talking about an 80,000 barrel per day increase in demand five years hence. Now, that increase in demand and in production is going to have to come from probably just two sources, new drilling and secondary recovery oil. Surely there must be a part of that that can be assigned to secondary recovery production. Now, for instance, Mr. Edgerton testified earlier that now in the state of Texas there are some 15 to 25,000 barrels per day of water flood oil in excess of what there would be if we prorated the water floods in the state. I gave you a figure a while ago that in Oklahoma in January '58 there was about 10,000 barrels per day of water flood oil in excess of what we would produce if we had a minimum allowable plan, the very minimum we could have in Oklahoma. So that I think it is fair to assume that in New Mexico five years hence they will have gained five years of water flood history. That may be the amount of oil in New Mexico. That would be above some unit allowable plan. It would not be more than 10 or 15 barrels per day either. That has been the history in these other two states, and it is reasonable to assume it will be the same history in New Mexico. If it is thar big, we've got to remember that in Texas and in Oklahoma we've got a lot more floods going on; lot of them. We have a lot more wells to flood than we have in the state of New Mexico. So, at the most, I think you can say that the amount of water flood production five years hence in New Mexico over and above some unit allowable plan would not be more than 10 or 15,000 barrels a day. Now, Mr. Campbell, I think we can go on to that other one.

Q Well now, taking that figure, 15,000 barrels per day allowable production in 1963, and using the figure that was given in the Graridge hearing of 19,000 barrels at peak in the entire Caprock Pool, would you analyze that insofar as impact is concerned?

A This is the exhibit that Mr. Buckwalter used in the Graridge hearing last October wherein he says this: "If this field could be developed for water flooding that the fastest rate that he could comprehend --

Q Just a moment, Mr. Stiles. I think you'd better mark that Exhibit No. 21.

A And "the fastest rate that he could comprehend or that he could see at the rate of 4,480 acres per year." Now, I'd like to talk a little bit about how fast this field could be developed for flooding. Mr. Buckwalter made this prediction in October of last year, and there has been about six months of time passed since then, and I think there has been a very insignificant amount of additional water flood development since October of last year; certainly nowhere near the 4,480 acres per year. Now, because the Caprock-Queen Field is going to be developed on 80-acre five spots, which means a conversion of every other well for water input, it means that we are going to move oil across lease lines, necessarily, and the only way to stay out of trouble in that event is to unitize. So, as I see it, the entire field is going to have to be unitized before water flood development can take place. I think because of the diversity of interest in the field, that there we are going to wind up with many separate units in the field; not great big ones because when you start trying to unitize a big field you've got so many people involved you just can't get agreement on anything. And we know that some of the operators in the field are not very sympathetic toward unitization. So, in order to develop for water flooding and to unitize for development, the operators who are in agreement to water flood are going to have to get together and form whatever unit they can to take in the lease that they are going to agree on and leave out these other people that won't agree. So, the point I am trying to make is, that many units will have to be formed in order to completely develop the Caprock Field. Past history of forming units showed that it can't be done quickly, it takes a long time. I've got a few examples here of typical situations that I want to read to you. In the Mason and north Mason, in Leon County, Texas, Eddy and Lea County, New Mexico, the first meeting regarding unitization was held in November, 1954. Today the engineering study has been made and the negotiations are under way to agree upon a participant formula. Now, that's almost four years and that's how far they have gotten so far on that unit on the whole field in Leon County, Texas. The first unitization meeting was held in February, 1957. The unit agreement has finally been written and is now being circulated for signature. That is five years old, and in the K.M.Field, Wichita County, Texas, there is a sizeable water flood development. The first meeting was held in March, 1952. The unit agreement is now being circulated for -- I will take it back -- it has been signed by the operators and approval by the Texas Railroad Commission has just been received. So there is about six years involved in that one. That's extra long, I'll agree. Now, a major company made a study not long ago and this major company has been involved in many units. They made a study to determine how long it took from the date of first meeting until the unit was formed and they found that the average time was four and a half years. The shortest that they were able to do any of them in was in eighteen months, so when we talk about unitizing the Caprock Field, I think we might as well talk about taking four years on the average unit to get the -- to reach agreement and get the thing going. So the rate of development that we have used here which is 4,480 acres per year, would, in five years, completely develop this field for water flooding. Now, that is unreasonable. It can't be done and it won't be done. How long it will take, I don't know, but I guess eight or nine years.

If you start it today and if everything worked right, you might get the whole field developed in eight or nine years, but for the same example,

example, let's say you can develop at the rate of 4,480, everything agreed, let's get going. Five years hence you would have completely developed the field for 80-acre five spot flooding, you would have reached your peak rate of production. According to Mr. Buckwalter's calculation, that is at a 400 a day injection rate, a fast rate of injection. Now, what does that 19,100 barrels a day mean? Today there are 612 wells at Caprock. If we divide the 612 wells into the 19,100 barrels a day, we come out with 31 barrels per well per day, including input wells, less than the present unit allowable for shallow wells. So I can't see even the very fastest development of the Caprock would result on an impact upon state's market because the average well is still producing less than its unit allowable at peak rate of production.

Q Mr. Stiles, do you have anything further that you would like to add with regard to this application?

A No, sir. I believe that's it.

MR. CAMPBELL: That's all the questions I have.

MR. NUTTER: Anyone have any questions of Mr. Stiles?

CROSS EXAMINATION

QUESTIONS BY MR. COOLEY:

Q Mr. Stiles, your last conclusion, that you can't see how water flooding can possibly have any impact upon the primary wells in this state seems to assume that there is a demand in this state for 33 barrels of oil for every well that we can possibly get to produce in this state. Now, as the facts stand, according to your calculations, which I assume are correct in Table 4 of Exhibit 20, I believe it is, isn't it?

A Yes, right.

Q Nearly 75 percent of the wells in the state of New Mexico or in southeast New Mexico, which is the major producing area today --

A Yes, sir.

Q -- are marginal and are not affected in any way. First, let's establish that marginal means that they are not capable of producing the current top unit allowable?

A Yes.

Q That means that 75 percent of the wells in the state are not capable of producing the allowables that were assigned as top unit allowables in the state of New Mexico?

A Yes.

Q And that, consequently, 25 percent of the wells in the state are bearing any reduction in demand that might occur.

A Correct.

Q If a demand should -- should fall off, shall we say, 50,000 barrels next month, disregarding the fact that an extreme reduction in allowables would make certain of the marginal wells under 33 barrels allowable --

A Become nonmarginal.

Q Disregarding that fact, approximately 25 percent of the wells in the state are in the southeast are going to bear this entire cut and if water flood production comes in and displaces 50,000 barrels of demand, the same thing would be true, the cuts would have to be borne by 25 percent of the wells rather than all of the wells in the southeast, is that correct?

A That's correct.

Q And your conclusion drawn from the 19,000 barrels' peak that you anticipate at top optimum rate of development in the Cap-rock, your conclusion that it would have no impact on the market demand in the state of New Mexico seems to assume that your top unit allowable would remain at 33. Now, Mr. Stiles, we start with an amount of oil that we can sell from this state and then we take the number of wells in the state that are marginal and subtract that off first, and then allocate the remainder to the nonmarginal wells in the state, and whatever that figure turns out to be is going to be the top unit allowable with a few minor adjustments. So, any reduction in the amount of market available to this 25 percent of the wells that are nonmarginal in southeast New Mexico would result in an immediate reduction of their allowable, would it not?

A That's right, but Mr. Cooley --

Q That would be a very real and very direct impact on the allowable for nonmarginal wells in the southeast?

A But bear in mind we are talking about five years hence when we are -- at which time we predict the state's demands and allocation is going to be 350,000 barrels a day. Now, it's true that New Mexico, of all the major producing -- oil producing states in the United States, New Mexico is one of the two which increased its reserves in 1957.

Q Yes, sir.

A Louisiana being the other, that is a very enjoyable position. But how long is New Mexico going to increase its reserves, each year? Perhaps this year or next year they may fall off, all of which to me, means that exploration program is not going to continue to be as successful as it has been, and perhaps in order to meet your market for oil you are going to have to have secondary oil into the picture.

Q Wouldn't it be one of the major factors in this favorable position, is that we have a favorable climate for exploration and development?

A Yes.

Q As long as we can maintain that climate, we can maintain our favorable position?

A You also have a favorable discovery rate, and I am not sure that has anything to do with favorable position for drilling wells. Your discovery rate is a little better here, regardless of what your depth allocation might be.

Q But the only point that I wanted to make in cross examination is that there would be a very direct and a very real impact on the nonmarginal wells in the state for every barrel of oil that water flood project produces, that barrel of oil is going to have to come out of the well if that is allocated in the state of New Mexico.

A Yes, that's true. I am saying that five years hence, when this is going to take place, that perhaps -- perhaps you are going to be glad to have a barrel of water flood oil, that you can't otherwise make it in the state.

Q I am not saying that this is an undesirable thing or that it is bad, but the fact remains that every barrel of water flood oil that is produced is going to have come out of the amount of oil that is allocated to the nonmarginal wells.

A That is correct. I think it has to be recognized that there is going to be water flood development in the state and room must be made for some water flood production. I don't think you can deny that.

Q I don't believe that the climate in the state of New Mexico has been too unfavorable at this point for water flood development either.

A No, it is not.

Q I am not trying to discourage it.

A I am not saying that you are trying because five years hence you are going to be happy that you have the water flood development.

MR. NUTTER: Any further questions of Mr. Stiles?

QUESTIONS BY MR. STAMETS:

Q Mr. Stiles, do you know of any pool in the state of New Mexico that has been abandoned and secondary recovery lost forever?

A No. I think I heard of one, but I can't pull the name out of the air, so I wouldn't say.

Q Is there any significant reason why a field could not be abandoned and later reentered for secondary recovery?

A No, no. I don't think I made the direct statement that it would be lost. I think I qualified -- I qualified that it might be a favorable loss.

Q Do you believe that lower normal unit allowable would encourage new drilling and exploration?

A Let me put it a different way. I think that higher ones would encourage it.

MR. CAMPBELL: Rather a leading question.

Q I will withdraw it. Do you believe that the small amount of secondary recovery in this state might be a factor in the primary exploration that we have?

A Small amount of secondary recovery?

Q Compared to some of the other states, the fact that we are getting start --

A Might encourage primary development. I think your primary development is being encouraged by your depth allowable, and I think that's a healthy situation too. I am not saying there is anything wrong with it.

Q Do you believe that the Commission would be right in requiring a plan of development from all future water flood operators so that all water flood units will not exceed what would be total top unit allowable for all input and production wells? Now, I mean right smack dab from the start, this project and all.

A You are going to assign them a top allowable --

Q Right.

A -- including input wells?

Q Right.

A And they can't go up above that in any case? Yes, Are you going to regulate the rate of development?

Q We are not going to do anything. We are going to say you can have 15,000 barrels a day.

A On this project.

Q Right.

A That's a compromise position. It is a heck of a lot better than some other things I have heard suggested. Let me -- I don't like the plan that you suggested, but it is a lot better than some of the others that I have heard.

Q You believe that it is a reasonable plan?

A No.

Q No?

A In the first place, I don't believe capacity water flood production is going to hurt New Mexico any more than it has hurt Oklahoma or Texas. It certainly hasn't hurt any of those states.

It hasn't hurt Kansas. Their experience in water flood production is further along than in New Mexico. The experience is that it has not been hurt. It has taken up part of the market, but it is entitled to a port of market. Very few of the wells are producing more than 20 barrels per well per day. In Oklahoma, you must remember that most of the fields were originally drilled on 10-acre spacing or less, a lot of them on less, so that our water flooding in Oklahoma is taking place generally on 10-acre five spots or less. There are very few 10-acre, and approximately no 80-acre five spots in Oklahoma, and they are all operating insofar as possible at high injection rates on close spacing. Therefore, the producing rate per oil well ought to be high, but it isn't.

Q Can you tell me somewhat specifically exactly what it is that you believe is unreasonable about this plan?

A I don't believe you ought to curtail any --

Q We are not curtailing, we are saying that you can have this much.

A As a top allowable for the unit?

Q Right.

A I say that is much better than some I have heard, but I still don't like it.

Q What is it that is wrong with that plan?

A I think the operator of this unit ought to be allowed to develop that project as rapidly as he needs to.

Q Mr. Buckwalter has made calculations on development of the whole field --

A Right.

Q -- and at the present time we are somewhat behind that. Certainly he can make a calculation like that on a unit, and we would not expect the operators to exceed that to any great degree.

A What you are saying is that when you have developed this unit 50 percent and you are already producing at this top unit allowable, I've got to stop developing because I have used up all my allowable. How about all this back stuff I ought to be doing on these edge producing wells that are being peaked by two input wells? It is time for me to start converting these two input wells, and if I don't do it quickly I am going to lose oil -- forever lose oil, but I can't do it because I have already used up my allowable.

Q I am assuming in this plan that was taken into consideration at the beginning, before the flood was approved, that there would be a small chance of waste which could be taken care of. In other words, if your flood started to run over a little bit, you could come in and say, "Well look, I have to have a little extra allowable for this." Well, I am sure that the Commission would give it to you. I mean, it has happened before. They come in and say, "This well produced a hundred barrels a day over night and we have to have a little extra allowable." I am saying that if the operator comes in and he has taken all these things into consideration, say he starts out his pilot flood, he is not making his 15,000 a day, he builds up to it, that's his peak, and he comes down, he has developed his unit, he has never exceeded what his allowable is. Maybe it is not that exact, no. The unit allowable -- the unit allowable fluctuates, but it is a number close to it.

A One of the troubles you get into with a plan like that is -- take me over here, for instance, with a very small unit, maybe 80-acre is all I have, maybe 160. You have given me a unit allowable based on unit allowable times a number of wells, but I don't have many wells to spread it over or to multiply it by. If one of my wells gets up pretty high because it was affected most favorably by water injection, I have had it, I have to shut that well in. If you will qualify your suggestion when I have run out of allowable I can come into this Commission and get an increased allowable to take care of all the oil over and above that allowable that I can produce, then you've got a reasonable plan.

MR. NUTTER: That's capacity allowable, Mr. Stiles?

A Yes, when needed, but only when needed. That's reasonable.

Q (By Mr. Stamets) In other words, if I can clarify your answer, tell me if I am right. The thing that you believe is unreasonable about this plan is that you don't believe that every person who wishes to water flood can get a large enough unit to stay within the allowable?

A Putting it another way, the larger the unit the more reasonable that plan, for sure, but there is going to be times when either your field is small or you must, of some necessity, form a small unit, and then you can't operate under that plan where you have just a very few wells to spread this allowable over. You have no flexibility as to rate of development. If the unit is big enough, sure you can. The operator can control his own rate of development to live within the allowable, maybe, but when he can't, when he must back up wells to prevent loss of recovery, then you've got to give him more allowable, if he's got to have it, and to me, he has to have it if he otherwise is required to curtail his production.

Q Will you agree that with a large enough unit, this is a reasonable plan?

A It is workable.

Q Workable?

A With a large enough unit.

Q I'll substitute workable.

A Workable.

MR. NUTTER: Any further questions of Mr. Stiles?

MR. LAMB: I have a question.

QUESTIONS BY MR. LAMB:

Q I gather that from what you and Mr. Buckwalter and the others have testified to, that what you would like would be the most efficient rate to recover the maximum ultimate recovery from this particular type of operation?

A Oh, yes. I think we are all charged with that.

Q Let me ask you this question. Under the present allowable system, Texas, New Mexico and Oklahoma and the rest of them put together, do you think that the primary production fields are producing under a similar rate to give us the greatest maximum ultimate recovery and most efficient operation?

A Let's see if I understand that question. Let me pose it back to you. Are you saying that under the present allowable of primary wells in the various states that we -- at those allowables, we are producing at the rate which will recover most ultimate oil?

Q Most efficient operation.

A I think so. Of course, there is going to be exceptions on this either way. I think generally --

Q Was that true --

A I don't think you can hurt primary production too much by slowing down the rate.

Q Not even to keep the water drive?

A You didn't qualify that.

Q I meant the entire operation.

A Well, there are --

Q In other words, on your present water drive activity, water drive fields come under this same category as allowables, natural water drive, gas drive and so forth, they all come under that category.

A First, -- this might get into some important argument, but I don't agree that natural water drives are exactly the same as man-made secondary recovery projected.

Q I agree with that because you have little control on the encroachment of water; you have none whatsoever.

A In lots of cases, natural water drive is an upward movement of the thing. I will say it this way. Whereas in a water flood you are trying to create somewhat of a vertical bank and move it and you have gravity segregation working against you.

Q Therefore, consideration should be given to active water drive fields for additional allowables?

A I will have to say no. I don't feel that way. There may be exceptions to that case, but generally I don't think that natural water drive fields must receive the same allowable treatment as water floods. I think you've got different sets of physical forces taking place.

Q You are familiar with the type of water drives we have in southeast New Mexico?

A Fairly so. I am more familiar with the gulf coast.

Q One other thing. In your tabulation for marginal and nonmarginal wells, did you take into consideration the wells which were voluntarily reduced?

A I had no way of knowing whether they were voluntarily reduced or not.

Q Specifically, I had in mind Maljimar. In other words, they, -- as far as this tabulation is concerned, are marginal?

A That's right. That's right.

Q Neither was there consideration given to the age of the wells?

A No, sir.

Q In other words, the zero to 5,000 feet were drilled considerably high prior to --

A Obviously, those are the older wells. Generally, those are the older wells.

Q Am I right in thinking that there were not wells below 5,000 feet prior to 1945 in New Mexico?

A I wouldn't know. I can't answer that.

Q In your figures, in March of 1958, in the Oklahoma Commission, how many actual wells were affected when the production was reduced to 20 barrels out of the total number of water flood wells? As I understood you to say, they reduced the rate to 20 barrels per day in March of 1958. How many wells were actually affected at that time?

A We are talking about different things. The proration on water floods in March, 1958 was not on a 20-barrel per well per day basis. Water floods, like all other production in the state for that month, were allowed to produce 89 percent of what they ran into the pipeline in January of '58. Every lease in the state took an 11 percent cut in March.

Q Therefore, all wells on water floods were affected to that degree?

A That's right.

Q I have one other question, which is along the line that has already been reviewed. By the time we reach our maximum peak in Caprock, we will have additional water floods probably in other areas and so forth. Do you have any idea what the effect will be on new -- newly drilled production in the zero to 5,000 foot range?

A No, sir.

Q In other words, the effects on the unit allowable?

A Raymond, right there let me make a point, that we must bear in mind that Caprock-Queen Field is the third largest field in aerial extent in southeastern New Mexico, and we are talking about developing one of your biggest fields, in developing the darn thing very fast, unreasonably fast. It just can't be done and it won't be done. Now, in addition to the development of Caprock, obviously, there are going to be a lot of other leases and tracts and units developed for water flood, but to me, Caprock is a little bit unusual. It has had a wonderful response from a few wells in a short period of time, even on 80-acre spacing and I can't foresee that there are going to be very many projects in this state that will respond as well. We are talking about 500 a day wells on this field. That is very unusual to me on 80-acre spacing. For instance, in the Olympic Field, I think, Mr. Nutter, you asked Mr. Edgerton about Olympic, and I said I would answer that. Olympic Field has about 3200 productive acres. The pilot water flood comprising 70 acres was started on injection in late 1948, and good results had been obtained from that pilot, such that by early 1950 we started developing the entire field, and we developed it just as far as we could. And Buffalo Oil Company owned 96 percent of the acreage and it was developed on 10-acre five spots, which means we could drill. All the water injection wells were newly drilled wells, the oil wells were used as oil wells. So we had a lot of new wells to drill, lot of input wells to drill and because it was 10-acre five spot development we could drill those input wells on lease lines and not have to unitize. So at the time that peak production rate was reached in this field, no tracts had been unitized. And we -- again we developed it just as far as humanly possible, we thought, and by 1953 the peak water flood producing rate was reached. And during that year it averaged about 11,200 barrels per day, and at that time we had developed about 216 oil wells and 216 input wells so that, as I recall, on a producing well basis, that was about, no, it was 52 barrels per producing well per day, at the peak rate of production. Now, if you add in the input wells to that, it would be 26 barrels per well per day after peak rate of water flood production. So here is a field, sizeable field, almost entirely operated by one operator. No problem except getting the well drilled as fast as possible, and yet the average well, including input wells, averaged only 26 barrels per well, at peak, and we had some wells that averaged 500 barrels per day, too. So, I don't think we can take the 500 barrels we will -- we have in Caprock and say that every well will be 500. The average is going to be much lower than that.

Q It isn't too surprising because the potential on some were -- we were capable of producing 500 barrels of oil per day with 500 barrels of sand.

A I don't know much about the pilot producing history of the Graridge, but I understand that in the two five spots, constituting a pilot there, that the Gulf Well is up to 500 barrels per day but the other well which is fully enclosed by inputs has never been much over 30 barrels per day. There is two adjacent producing wells, one 500 and one 30. I understand they went and did some remedial work on the 30-barrel well and increased it very little, if any. I think is what is worrying us is that 500 barrels per day, and to me, that doesn't mean anything. I have seen a lot of other floods where a few wells were very high.

MR. NUTTER: Any further questions?

A Does that answer your question, Mr. Nutter?

MR. NUTTER: Yes, sir.

MR. ASTON: I have two questions I would like to ask Mr. Stiles.

QUESTIONS BY MR. ASTON:

Q Back in the hearing in Oklahoma of May, '58 concerning possible proration of water flood, 87 percent cut, and all that, at that hearing, did you run into any situations where, for example, pipeline connection companies, major pipeline companies appeared in support of the request of the water flooding companies to support their placing those projects back on full flood?

A I think it would be a fair statement to say that all pipeline companies who also had water flood operations agree that water flood should not be prorated. For instance, Magnolia imposed pipeline proration in Oklahoma in 1953 or somewhere back in there, at which time their chief engineer told their crude department that you couldn't hurt water flood; you could turn them on and off like a faucet. It just so happened that Magnolia had the Yale Quay Pool in Oklahoma, and they prorated their own water flood just like they did. Also, since then and since they suffered a tremendous loss of recovery, they have not prorated water floods if they can possibly agree.

Q Mine is rather a loaded question because our pipeline appeared in agreement. I merely wanted to get that viewpoint in the record, tha t even the pipelines that are responsible are suffering a market impact. The second question I want to ask has to do with general experience in Oklahoma. Isn't it true that in many many cases companies that are capable primary explorations and producers are not capable secondary recovery concerns, they don't have the technical knowledge. Therefore, if the property is put under a secondary program, it has to be put under some company that has the staff and the personnel capable to do that. Therefore, freeing its exploration personnel from the smaller independent, we'll say, to go on and explore also where possible with returns received from secondary recovery? I am tying back into this question as to whether or not there would be a negative impact on exploration and development of primary oil reserves in the state of New Mexico by water flood. It's my feeling, and I would like to get your response to that. For example, in our case I feel that a water flood project would free us to go on with things in which we were far more qualified which might develop new reserves for oil in the state of New Mexico and therefore would be a stimulous to exploration rather than a determent effect.

A Certainly, a company that is going into water flooding should not go into it unless they are versed in it because it is no sure thing at all. I think the statement ought to be put in this record that many, many, many, many water floods are not successful, many of them are, and while in some floods an operator may be able to recover his investment faster than he could in the primary, it must be remembered that he got investment in a bunch of water floods that is not going to recover his investment. It is just like wild catting, some of them will pay off and some of them won't. So that if a company is going to get involved in water flooding, they'd better get some people with experience behind them because they can't get it out of textbooks as to whether a company ought to free themselves from secondary so that they can work on primary alone. I don't know, Rogers. I think companies have to work both sides of it myself. I think they have to explore for new oil at the same time they are developing secondary, their own secondary reserves, or going out and buying stripper properties that are susceptible to flooding. I think you have to play both sides, and while you might discover a nice new primary prospect that is going to hurt you, maybe on the secondary allowable, on the other hand, you may develop a secondary thing and there is some thought it might hurt you on the primary level. I think you have to play both sides.

MR. ASTON: That is all.

MR. NUTTER: Are there any questions of Mr. Stiles?

QUESTIONS BY MR. UTZ:

Q Mr. Stiles, has the lag in anticipated development of water floods, particularly in this Caprock area, been due to the unitization?

A I can't answer that question, Mr. Utz, for sure. I don't know what -- just what problems they ran into in unitization. I am saying that henceforth they are going to have some problems in unitization from looking at the diversity of ownership and knowing who the operators are. Some of them are not going to agree, some are going to be babies in the woods in this unitization business, and it is going to take some time to get those fellows convinced.

Q What is the reason that your projected water flood activity is behind schedule, so to speak?

A I really don't know. Maybe -- maybe we have been sitting back waiting for better pilot results to make sure we had a good floodable prospect. I have not been directly involved in engineering of either one of those pilots.

Q Has the Commission's hearing -- has Commission hearings or Commission activities been a determinate?

A I don't know that they have, but I could see where they could be. I think every operator ought to have the right to drill or convert wells to input when he sees the need and not have to wait to file an application. He is not going to file that application until he has seen maybe the need, and by the time he has had his hearing and then get the work done, two or three months could have gone by and a lot of damage could have been done in that two or three months' time. Ideally, and I think Mr. Buckwalter mentioned this this morning, ideally, the way to develop the property for water flooding is to drill up all the inputs and producers and do all your work before you put any water in the ground, get the whole thing developed, and then start putting the water into it. Then you are sure. Lately we couldn't do that because of shortage of money. If you wait until water breaks through in some edge producing wells and then start backing it up with inputs, you may already be too late. You may have trapped some oil that will never be recovered. And I think the operator ought to have complete flexibility and liberty to do things when he sees that they need to be done.

Q Can you explain the curtailing influences of water flood activities in New Mexico?

A No, sir, I can't.

Q You know of no reason?

A I am inclined to believe it might have a little something to do with water source availability. Maybe water has become available recently.

Q Would allowable have anything to do with this?

A No.

Q Would economic advantage have anything to do with it?

A No.

Q Is that a place to put your money?

A You are talking about water floods in general? I am not sure that it is a better place to put your money. The company that is involved in water flooding in many areas does not find that all floods are more profitable than primary at all.

Q You wouldn't say, then, that it is a better risk than exploration?

A No, sir. Not on the overall broad picture, no. Not from big operations. I think a lot of your major companies bear that out. A lot of your major companies are not very strong in water flooding, they are still going after that new oil. Incidently, I think companies' history over the last, say past two or three years, has a lot to do with how they look today, water flooding versus exploration. If they had been pretty successful on exploration, that is probably what they are going to do for the next three or four years, but if they have been more successful on secondary, that is probably what they are going to do for the next three or four years.

Q On the water flood, you do know that it is all there, it is a matter of whether you can get it out with a wild cat?

A That's right. It is there. That's the only thing you know about. You know the oil is there.

MR. UTZ: That's all the questions I have.

MR. NUTTER: Any further questions?

QUESTIONS BY MR. NUTTER:

Q Mr. Stiles, your figure of approximately 8 barrels per day for the average water flood oil well in the state of Oklahoma is not meant to be the average production that we would expect from water flood wells in New Mexico for the next several years, is it?

A No, I didn't intend that.

Q Aren't a lot of these water flood projects in Oklahoma rather old and have been in operation for a long -- number of years?

A I wouldn't say the majority of them are old, no. The water flooding is growing in Oklahoma now.

Q The water flooding?

A We have a curve here for Oklahoma that showed an increase in water flood production. It has been terrific in the last five year.

Q There are a number of old water floods in Oklahoma?

A Oh, yes, definitely.

Q You stated that a large number of water floods are unsuccessful. Do you think that some unsuccessful water floods may be included in this tabulation of Oklahoma projects?

A I am sure there are.

Q So maybe some unsuccessful projects have brought this figure down to 8 barrels per day?

A Oh, yes. There must be some wells that are producing two or three wells to offset those that are producing 15, 18 barrels per day in order to have an average of 8 barrels.

Q I believe you stated that the average increase in demands for the last several years has been approximately 6 percent per year for New Mexico?

A That's a curve that is in the brand new issue of AMIE petroleum statistics. That curve is in there and it shows the last seven years' allocation and production history for southeastern New Mexico, and that figures out about 6 percent.

Q And the demand has gone up 6 percent per year as well as the production has gone up 6 percent per year?

A That's right.

Q Assuming that this 6 percent increase in demands continues and that as a result of primary recovery there would be a 6 percent increase in production, the normal unit allowable would have to go down to accommodate the new oil which would be derived from water floods, would it not?

A No. Wait a minute.

Q The demand has gone up in the last several years by 6 percent per year, has it not?

A Yes, sir.

Q And the primary production has gone up 6 percent to keep up with the demand, has it not?

A Must have, yes.

Q Assuming that these two conditions continue in the future, unless the demand increases by more than 6 percent, the normal unit allowable would have to be reduced and primary recovery reduced in order to make room for the secondary recovery, would it not?

A I don't know whether this would be true or not, Mr. Nutter. It seems to me that all the time you got new development wells being completed, you also have old wells getting further and further down on the production.

Q Yes, sir. I was assuming though, that the -- in other words, during the last several years, when this market demand has been met by new production, it has been met without the addition of oil from secondary sources?

A Right.

Q So if -- if these were to continue, then the normal unit allowable would have to be reduced and the primary recovery reduced in order to accommodate secondary recovery?

A That sounds right, but I think there is a catch in there;

but I can't figure out that catch. It sounds reasonable.

Q It was based on an assumption.

A It sounds like it must work that way, but I think there is a catch in there. I don't mean your catch, I mean there is an angle.

Q So you would agree conditionally.--

A Yes.

Q -- until I have had time to work it out. Let me make another statement. I believe it likewise can be shown, and this is probably a facetious thing, that if a number of wells would remain in the future just like they are today, that as you increase production, you would certainly increase the unit allowable, wouldn't you?

A Yes, sir. You would have to. That's a corollary, I think, of what you asked me. I am not sure. Of course, we know the number of wells is going to change. It might go up, it might go down. In the last several years it has gone up, but the trend may be the other way. It may go down, so it is possible that we might wind up five years hence with a bigger demand, but not very many more wells to supply it, too, so that your unit allowable would be even higher than it is now under that set of circumstances.

Q The controlling factor in whether there would be additional wells to meet the market demand would be the desirability of drilling those wells, though, would it not --

A Yes.

Q -- which may be affected by the demand for oil per well?

A Yes. You've got to have incentive for primary exploration, but you also have to have an incentive, I think, for secondary development.

Q Mr. Stiles, in making your calculation that the effect of the peak, or production from the Caprock-Queen Pool would be negligible on the total market demand for oil five years hence, you weren't taking into consideration possible water flood oil from other sources, were you?

A No. Is there a possibility that there will be a rather sizeable production of water flood oil from other sources, too?

Q Yes, sir.

A Yes, sir, but this again is the thir largest field, and we have developed this field as fast as humanly possible; faster, I think, and we are using that as an example. It is the third largest field in this state, and it was developed as quickly as possible. I realize that in addition to Caprock there is going to be others, and I don't know what it is going to produce. I think this is a good example, taking a field like this and developing it quickly. It might represent most of the impact that the water flood may have five years hence.

Q Mr. Stiles, you mentioned that it had taken from four to six years to effect some of these unit agreements in various parts of the country?

A Yes, sir.

Q How long did it take to form the North Caprock-Queen Unit No. 1?

A I am sorry, I can't answer that. I am not familiar with it.

Q You don't know whether that was accomplished in somewhat less than four years?

A I am sure it was, Mr. Nutter. I don't know the exact time, but I am sure it was less than four years because the people involved in that -- the operators involved in that are water flood operators, they know what they had to do and wanted to do in order to get going, and I understand that the No. 2 Unit is going to be approved or something June the 1st of this year, I believe. Now, I am sure it was effected quickly also because the same group of operators are in that one, and I would presume they use the same participation formula as they used in No. 1, so there was not any argument about participation factors.

Q Mr. Stiles, you stated that there had been a fast response to the pilot project in the Caprock-Queen Pool?

A That is my understanding.

Q Do you think that the fast response that has been encountered in that pool might encourage faster development of the flooding of the pool --

A Yes, sir.

Q -- on an overall scale?

A A good response, I think, certainly will encourage faster development of the field.

Q Do you subscribe to the theory that was presented here last fall, in the Graridge hearing, that the water flood production should not be curtailed from the individual wells, but in the event water flood allocation should take a disproportionate share of the total market demand for oil from the state, that perhaps control of the projects themselves and the expansion of the projects might work?

A If there is going to be any control at all imposed upon water flood development, I think it can be imposed by the state only upon the number of projects authorized. Now, I realize that you are going to get into some difficulty there, but let's take it stepwise. First, I don't think you can control the production from a well without impairing loss -- suffer loss of recovery. Secondly, once a project is authorized and some development plan has been shown you and you agree this is a reasonable plan, I think the operator, from the day you give him an order to water flood, you ought to allow him to put that project under flood, if, as, and when he wants to do it, in the order in which he wants to do it, and in the manner he wants to do it because he has to have that flexibility. His responsibility is to get the greatest amount of oil. He is working for you, because you are trying to prevent waste, and that is what he is trying to prevent. In order to get the most ultimate recovery, I think he should do it tomorrow if he has to and not ask permission to do so. So, to take it stepwise, I think the only way you can control water flood production is through the step of authorizing projects, but you've got to be careful there because an operator may have a stripper property that is riding economic limits, and I don't think you can deny him the right to start developing that property for water flooding. You do not control the rate of primary development, and I really don't think you can control the rate of secondary development. New primary development brought into this state has an impact upon the market also, and there is no attempt to control that rate of primary development.

Q You don't advocate any sort of control whatsoever on the rate of expansion on water flood projects --

A Within the authorized --

Q -- within the rate of expansion in the existing projects?

A No, sir. There is no other state that does it. I think an operator must have complete freedom when he needs to put two more input wells to back out that producer that has a little kick or has a little water break through, and he has to do it quickly. He should do it quickly. In fact, he should have done it before he even got any stimulation shown on that well.

MR. NUTTER: Are there any other questions of Mr. Stiles?

MR. UTZ: I have one that I would like to bring out.

QUESTIONS BY MR. UTZ:

Q In your last statement, you compared the primary development and no control on primary development as to water flood development. We have no control of primary development, we have control over the amount of water that can be --

A I agree with that. We weren't talking about allowable. Again, we were talking about rate of development, and since we don't have it on primary, I don't think there ought to be any on secondary at all.

Q We would have no problems in water floods if we could control the amount of water produced from water floods?

A Primarily, in water flooding you do not control the rate of development because each operator has a right to capture his oil before somebody else gets it, and the secondary operator should have that same right, to capture that oil before it is trapped or pushed off his lease into somebody else's.

MR. NUTTER: Any further questions?

QUESTIONS BY MR. MURPHY:

Q Mr. Stiles, you were asked a while back if you knew of any projects that had been plugged out in the secondary oil, are there any reasons why they couldn't be redrilled for secondary, and you said no. I was wondering if you were considering the economic reasons there too. Would you care to make any statement there?

A If we are going to consider the economic aspects, if a field is plugged out, then in order to flood it you've got to start all over with new wells, or go back into the old ones and open it up again, which is a costly proposition.

MR. CAMPBELL: Mr. Stiles, wouldn't you have to buy new leases?

A Yes, you would have to acquire new leases. I presume, Jack, it wouldn't cost you much at that time, after they had been plugged out.

MR. STAMETS: If I may clarify my question in that respect, I had hoped that you had considered the economic aspects, say, within five to ten years after the depletion of a well, or after the depletion of the field, rather. In other words, we've got a field here, it's depleted, it is abandoned, the wells are plugged, the casing is not pulled, it sets five, ten years. Would it be normally an economic proposition to reenter that field?

A It could be, yes, sir. Depends on the sand body. We are talking about oil in place. Depends on any number of things that have taken place; natural encroachment of water through an old plugged well bore, depends on a lot of things, but there are such fields that have been reopened and flooded, but there are many that you wouldn't touch either.

MR. MURPHY: Generally, though, Mr. Stiles, you have to have a lot more reserves on an acre basis?

A Certainly. You have a lot more investment costs on the thing.

Q There are some fields that you couldn't do that on?

A Right.

MR. NUTTER: Are there any further questions? If not, the witness may be excused.

(Witness excused)

MR. CAMPBELL: I would like to offer in evidence Applicant's Exhibits 1 through 21.

MR. NUTTER: Without objection, Applicant's Exhibits 1 through 21 will be entered in this case as evidence.

MR. CAMPBELL: Mr. Examiner, that concludes our testimony. I am sure that the Examiner is aware of the fact that the order in this case expires, I think, tomorrow morning, and we would like to request either an order from the bench, if that can be done, or some kind of interim relief to tide us over until such time as the transcript is ready or whatever recommendation the Examiner makes to the Commission is available for them to consider.

Certainly, at the present time, the record and evidence before the Commission in this case substantiates what was presented in the prior case of another area adjacent to it, on which the Commission made a finding. There has been nothing here that I can see that would change that situation as far as the capacity of the allowable is concerned. We have undertaken to try to present additional evidence to do something to allay this gnawing fear that people seem to have that this is going to be a very serious thing as far as the state-wide market is concerned. I think it is quite obvious that that conclusion is, or that feeling is aggravated by the present immediate market, which in some manner or another I feel is going to have to be alleviated.

It seems to me that this business of secondary recovery and the question of whether capacity allowables should be granted is perhaps the most basic one of conservation that this Commission has ever had before it. While I fully sympathize with the concern that it might reduce to some extent the available market for primary wells and even might have some effect on exploratory activity, it seems to me it is an essential and basic obligation of the Commission, when a question of ultimate recovery is so clearly involved, when they weigh all of those things in the balance, to apply the question of conservation first, and I think all the evidence that has been presented to this Commission, certainly in this hearing, has been that the restricted production from this unit certainly might result in loss of ultimate recovery. I also think that the Commission and the operators of these projects as well as other operators of primary development should have, before not too long, some standards or estimates of what they can anticipate in the future, some procedures which they can follow in making these plans -- making these investments. This is not perhaps the case in which it can be done. The application is limited here, but somewhere down the road I think we all are entitled to some degree of certainty as to what to anticipate in connection, not only with this allowable matter, but with the question of development of the project and how that could be accomplished. I think the Commission itself will have to determine that, unless the case comes up that makes it impossible for them to do it.

I seriously believe that we should do everything feasible to encourage this secondary recovery project commensurate with our recognition to also encourage primary development, and I don't think there has been any evidence offered by anybody in either hearing that bears out this almost panicy concern about what this is going to do to the market situation. Everything that we have been able to find, and we tried every way we could to analyze this, indicates to us that the passage of time and economic factors works the thing out on a reasonable basis everywhere it has been tried, and I see no reason why we should assume that the picture in New Mexico is going to be so much different, so much more serious than it has been in other states that have had a number of years of experience with it, and that we should deny to any that portion of the oil market that I think rightfully belongs to him in the field of secondary recovery.

MR. NUTTER: Does anyone have anything further in this case?

MR. LAMB: I am Raymond Lamb with Wilson Oil Company, and I would like to make a statement under oath, if you will swear me in, please. I have appeared before the Commission before, and if my qualifications are acceptable, I would like to make a statement.

(Witness sworn)

MR. LAMB: As petroleum engineer in New Mexico, I have witnessed the growth of the oil and gas industry under the New Mexico Oil Conservation Commission since 1936 and the growth of the present allocation system which sets out the basic unit allowable with the deep well adoption. This system has encouraged operators to develop shallow as well as deep pools in this state. The basic allocation system takes into consideration engineering and economic factors as well as the state's demand for crude oil. No general rule can be perfect. Therefore, there have been inequalities and will be inequalities, but as a whole, it is the best system, to my knowledge, now in use.

I am familiar with the engineering data in the Caprock Pool, having compiled the first engineering report on that pool. Any deviation from the present allocation system should be studied seriously and earnestly from both the engineering and economic standpoint. It is my understanding, from the operator's request in this case, that wells be permitted to produce at capacity with no restrictions whatsoever on the total production from the wells or the unit. In my opinion, considering my early study of the Caprock Pool and the engineering data presented here today, I see no justification for the unrestricted production for this artificial water flood unit. As you know, there are a number of natural active water drive fields in New Mexico which have been prorated on the established basis. Certainly, the water flood operator will have more control of the water injection rate and encroachment than an operator of an active water drive field with the present restricted allowable. And even with the higher allowables of the past, few pools have been produced at the most efficient rate and at which rate they will recover the maximum ultimate recovery. It is, therefore, recommended that restrictions be maintained over the production rate of the wells or the unitized area. It is felt, however, that the unit operator in a water flood project should be allowed to transfer allowables to producing wells in the unit to compensate him for the use of water injection wells.

It is my opinion and recommendation that operators in water flood units be granted an allowable equal to the number of producing 40-acre units as set out in this application times the top unit allowable as established from time to time by this Commission. And further, from my personal experience in natural water drives in southeast New Mexico, it has been established that control of allowables has not granted the operators the maximum ultimate recovery or the maximum efficient rate. And from my experience in the Caprock Pool, the restricted allowable was not the maximum efficient rate or gave the maximum ultimate recovery.

MR. NUTTER: Does anyone else have any statements to make? Does anyone have any questions of Mr. Lamb?

CROSS EXAMINATION

BY MR. CAMPBELL:

Q Mr. Lamb, were you present at the original hearing in connection with this pool?

A No, Jack, I was not. I am sorry, I wasn't.

Q You didn't hear the engineering data presented at that time, the time of the Graridge hearing?

A No.

Q Have you ever operated a water flood?

A No, I haven't, Jack, but I will say this to you, that I have operated what I consider to be the most complicated reservoir from a water drive standpoint in southeast New Mexico or West Texas. We not only have an active water drive situation, but a limited water drive situation, and an internal gas drive, and gravitational drainage, and I will say that we have in the Wilson Pool left, approximately, in the water drive area, 25 percent of our ultimate recovery of oil due to proration.

Q Do you contemplate that you may want to undertake any secondary recovery to get that?

A In an active water drive, Jack, you will note, from our experience, that we have attempted to recover this additional oil by drilling five spot or alternate wells to recover this oil. We feel that the encroachment of water from the edge will not justify any flooding whatsoever.

MR. CAMPBELL: That's all.

QUESTIONS BY MR. McCRACKEN:

Q What was the nature of the loss, what caused the loss in the ultimate recovery in this Wilson Pool?

A It is by-passing the oil, leaving it in the reservoir. In other words, we have had wells high on structure to start producing water earlier than the wells lower on structure, which indicates that your water is moving faster than your water-oil contacts in the reservoir.

Q Could that have been the result of coning?

A No, there is no coning whatsoever. It is encroachment of water.

MR. NUTTER: Are there any further questions of Mr. Lamb? You may be excused, Mr. Lamb.

(Witness excused)

Are there any statements to be made in this case?

MR. ELLIOTT: I am R. L. Elliott, president and general counsel of Graridge Corporation. I would like the record to show that we are clearly in accord with the application made in this hearing and recommend that the Commission fine what they are requesting. I should also like to place in the record that the Livermore State "J" No. 3 Well, which is included as one of the twelve wells in question for capacity allowable, be given the same treatment as the other eleven wells within their unit. It has been contemplated by Graridge, who is the operator of the Caprock Unit No. 1, as well as working in the Caprock Unit No. 2, that the two operators will work together along the unit lines so as to set up an efficient pattern of injection and producing wells along that line and to give this Livermore State "J" No. 3 Well, which is in the southwest quarter of southwest quarter of Section 6, 13 South, 32 East, the capacity allowable, at least give it the same treatment that you give the other eleven wells in the unit, and as part of the plan of cooperation along the lines of the unit, we would like the record to show that we want to be made a party insofar as necessary to bring this twelfth well in the order, and recommend that you find in accordance with the application by Ambassador.

MR. NUTTER: The record will show Mr. Elliott, that by virtue of this telegram from the Graridge Corporation reading as follows: Re: Ambassador Oil Corporation application. Caprock-Queen Pool. Relative to allowable Ambassador Oil Corporation is authorized to file said application in behalf of Graridge Corporation. Signed Graridge Corporation, by Lester Clark, President.

MR. ELLIOTT: I knew you had that, but I thought you might want some additional evidence.

MR. NUTTER: Any further statement?

MR. ROSS: John Ross, representing Gulf Oil Corporation, Fort Worth, Texas. The Gulf Oil Corporation concurs in the expert testimony presented today on behalf of the Ambassador Oil Corporation. The Gulf Oil Corporation urges that the Commission approve this application as requested.

MR. MURPHY: Bert Murphy, representing myself as a royalty owner in the Caprock Unit No. 2. During the past eight years I have been in the management and had engineering charge of some fifty odd water floods, and my experience has confirmed the testimony given by these water flood experts today, and I wish to concur with their testimony and recommend that the application be granted.

MR. HAMPTON: John Hampton, representing Great Western Drilling Company, Great Western Drilling Company concurs in the application of Ambassador Oil Corporation and urges the Commission to approve it.

MR. DARDEN: Frank Darden, representing Newmont Oil Company of Fort Worth. Although we are not directly interested in the Caprock Pool, we are contemplating water flood operations in the state of New Mexico, and, therefore, are quite concerned with the policies which are being formulated by the Commission concerning regulations of water floods. We would like to state that we agree with the testimony of the recognized water flood authorities that were present today to the effect that (1) capacity allowable and flexibility of development are necessary to achieve maximum efficient recovery from stripper water flood operations without waste, (2) that water flood operations of this type do not have the same physical operating characteristics as natural water drive fields, and (3) that the impact of water flood oil from other states and total market demand will not materially affect the discovery and development of primary reserves in New Mexico.

MR. NUTTER: Any further statements?

MR. PAYNE: Two statements are received, Mr. Examiner. Statement of Sun Oil Company: "SUN OIL COMPANY IS AN OPERATOR IN SEVERAL FIELDS IN THE STATE OF NEW MEXICO AND AS SUCH HAS A VITAL INTEREST, BOTH PRESENT AND FUTURE, IN THE PROBLEMS AND THE POLICIES OF PRORATION AND PRODUCTION IN THIS STATE. WITH REFERENCE TO THE

APPLICATION OF AMBASSADOR OIL CORPORATION THERE IS NO QUESTION BUT THAT AN OPERATOR, KNOWING THAT PRORATION IS IN EFFECT AND WITH ADVANCED KNOWLEDGE OF THE OIL ALLOWABLES AVAILABLE TO HIM, CAN MAKE THE NECESSARY COMPENSATIONS OR ADJUSTMENTS IN WATER INJECTION OPERATIONS TO INSURE THAT HE WILL ACHIEVE THE GREATEST ECONOMIC OIL RECOVERY. THIS FACT HAS BEEN TACITLY RECOGNIZED BY THE COMMISSION IN THE CAPROCK-QUEEN POOL BY ORDER R--1128 DATED FEBRUARY 12, 1958, WHICH CONTAINED THE PROVISION, "THAT THE APPLICANT SHALL REGULATE THE INJECTION OF WATER INTO THE ABOVE-DESCRIBED WELLS SO THAT THE PRODUCTION FROM THE WELLS AFFECTED BY THE INJECTION PROJECT CAN BE PRORATED WITHOUT CAUSING WASTE.".

WE WOULD NOT LIKE TO SEE ANY INDIVIDUAL PROJECT GRANTED A POTENTIALLY LARGE SHARE OF THE AVAILABLE MARKET BY MEANS OF UNRESTRICTED PRODUCTION AND FEEL THAT APPROVAL OF THIS APPLICATION FOR CAPACITY PRODUCTION COULD BE DETRIMENTAL TO SOUND CONSERVATION IN NEW MEXICO"

Signed, A R BALLOU.

Statement of Ada Oil Company. "IN RE CASE NO. 1294, SCHEDULED FOR HEARING MAY 7, IN THE MATTER OF APPLICATION OF AMBASSADOR OIL CORPORATION FOR CAPACITY ALLOWABLE IN THEIR CAPROCK QUEEN PILOT WATER FLOOD, ADA OIL COMPANY RESPECTFULLY REQUESTS YOUR FAVORABLE CONSIDERATION. BASED ON EXPERIENCE, WE HONESTLY BELIEVE THAT PRORATION OF FLOODS IN STRIPPER FIELDS WILL RESULT IN AN INEFFICIENT RECOVERY MECHANISM WHICH WILL RESULT IN UNDERGROUND WASTE IN THE FORM OF LOWER ULTIMATE RECOVERIES THAN IF ALLOWED TO PRODUCE AT CAPACITY. RESULTING INEFFICIENCY IS DUE TO THE FACT THAT PHYSICAL

CHARACTERISTICS OF THE RESERVOIR ROCK CANNOT BE VARIED TO CONFIRM WITH LIMITED OR PRORATED RATES OF PRODUCTION-" Signed E D WHITIS VICE PRESIDENT.

MR. NUTTER: Are there any further statements?

Mr. Campbell, regarding your request and statement pertaining to the expiration of the emergency order and so forth, the Examiner will make a recommendation to the Commission that this case be disposed of as expediciously as possible.

MR. CAMPBELL: Thank you.

MR. NUTTER: Anything further? If not, the hearing is adjourned.

C E R T I F I C A T E

STATE OF NEW MEXICO)
: ss
COUNTY OF BERNALILLO)

I, J. A. TRUJILLO, Notary 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 me in stenotype and reduced to typewritten transcript by me and/or under my personal supervision, and that the same is a true and correct record to the best of my knowledge, skill and ability.

WITNESS my Hand and Seal, this, the 24th day of May, 1958, in the City of Albuquerque, County of Bernalillo, State of New Mexico.

Joseph A. Trujillo
Notary Public

My Commission Expires:
October 5, 1960.

I do hereby certify that the foregoing is a complete record of the proceedings in the Examiner hearing of Case No. 1294, heard by me on 5-7, 1958.

[signature], Examiner
New Mexico Oil Conservation Commission