STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
COMMISSION FOR THE PURPOSE OF
CONSIDERING:

APPLICATION OF EXXON CORPORATION FOR
A WATERFLOOD PROJECT, QUALIFICATION
FOR THE RECOVERED OIL TAX RATE PURSUANT
TO THE "NEW MEXICO ENHANCED OIL RECOVERY
ACT" FOR SAID PROJECT, AND FOR 18 NON-
STANDARD OIL WELL LOCATIONS,
EDDY COUNTY, NEW MEXICO CASE NO. 11297 (DeNovo)

APPLICATION OF EXXON CORPORATION FOR
STATUTORY UNITIZATION,
EDDY COUNTY, NEW MEXICO CASE NO. 11298 (DeNovo)

ORDER NO. R-10460-B

APPLICATION FOR REHEARING
BY
PREMIER OIL & GAS, INC.

This Application for Re-Hearing is submitted by W. Thomas Kellahin, Esq. of Kellahin and Kellahin on behalf of PREMIER OIL & GAS, INC. ("Premier").

In accordance with the provisions of Section 70-2-25 NMSA (1978), Premier requests the New Mexico Oil Conservation Commission grant this Application for ReHearing in Case 11297 (DeNovo) and in Case 11298 (DeNovo) to correct erroneous findings and conclusions set forth in Order R-10460-B, attached as Exhibit "A" and to substitute Premier's proposed Commission Order attached as Exhibit "B" hereto, and IN SUPPORT PREMIER STATES:

INTRODUCTION

On March 12, 1996, the New Mexico Oil Conservation entered its decision in these cases and in doing so, the Commission made errors of fact and of law which require that another hearing be held.

GROUNDS FOR REHEARING

POINT I:

THE COMMISSION'S ULTIMATE DECISION IS BASED UPON ERRONEOUS FINDINGS OF FACT SET FORTH IN FINDINGS (20)(a) AND (20)(c) OF ORDER R-10460-B WHICH ARE INCONSISTENT WITH UNDISPUTED TESTIMONY

The primary issue in dispute between Premier and Exxon is the geological pick of the base of the Upper Cherry Canyon ("UCC") reservoir in the Premier FV3 Well.

Mr. Stuart Hanson, Premier's expert geologic consultant, concluded that Exxon's geological interpretation mistakenly excluded some 82 feet of net UCC pay from Premier's FV Well by picking the base of the UCC reservoir (at 2768 feet instead of at 2852 feet) some 82 feet too high and as a result of this mistake, Exxon had failed to properly credit the Premier Well with sufficient reservoir thickness. (See Transcript Vol. II, Page 315, lines 14-19).

In addition, Mr. Hanson demonstrated the geologic similarity and common depositional environment between the Premier FV3 Well and the Yates EP7 Well. (See Premier Exhibits 2, 6, & 7, Transcript Vol II, Pages 311-346)

In Finding (20)(c) of Order R-10460-B, the Commission concluded that "the geological interpretation of Premier's was a more believable and scientifically sound interpretation." But then, the Commission explains that "Unfortunately, for Premier, the production results shows the additional potential pay to be uneconomic;"

In Finding (20)(a) of Order R-10460-B, the Commission finds that a workover attempt in October, 1995 "overlies the disputed 82 feet" and that it "correlatives with uneconomic production" from the Yates ZG1 Well.

The Commission uses this workover attempt to **negate** the potential in the FV3 Well and then discounted the Premier geologic interpretation because the Commission mistakenly believed that the October 1995 test was a "workover" test of the disputed 82 feet of additional pay in the UCC reservoir.

The Commission has an **incorrect** understanding of the FV3 Well's history. The work conducted in October 1995 does not overlay the dispute 82 feet. (See Vol. II, Page 302, lines 13-18).

In October, 1995, Premier attempted to test its FV3 Well for oil production in Delaware intervals **other than in the disputed 82 feet in the lower UCC reservoir** in order to support its contention that it had other Delaware pay below Exxon's base of the Upper Brushy Canyon which was not accounted for in the Unit participation formula proposed by Exxon. (See Transcript Vol. II., page 291, lines 14-23).

Gulf originally completed the FV3 Well in only three zones:

Zone #1:

Location-some 900 feet below the disputed 82 feet interval

Perf:	3764-3828--Brushy Canyon below Exxon's UBC Base.
Completion:	Acidized & Frac
Results:	Zone flowed back 2 days and was swabbed 1 day. Frac load recovered was about 60%. Oil stain reported on last 75 BBLs swabbed. Placed CIBP the next day.
Note:	zone was incompletely tested.

Zone #2:

Location: some 58 feet above the disputed 82 feet interval

Perf:	2710-2740--Cherry Canyon above Exxon's pick of the UCC base.
Completion:	Acidized & Frac
Results:	72 BO & 369 BW
Note:	Acid job was 50 feet above the top perf. Frac job was a high rate 25 BPM & pressure 5000 psi Treatment out of zone. TA'd in 1986

Zone #3:

Location: some 269 feet above the disputed 82 feet interval
Perf: 2491-99--Above UCC
Completion: Acidized & Frac
Results: All water
Note: Zone was squeezed. This zone was cored by Exxon in their wells and it has a high RW which leads to log SW miscalculations.

In October, 1995, Premier did not add additional perforations nor did it stimulate any zone. Premier removed both bridge plugs uncovering both Zones #1 and #2. Zone #2 had no pressure while Zone #1 had fluid flow up the casing due to the incomplete testing by Gulf. This Zone #1 is the "pay not accounted for in the unit production formula" because it is **below** Exxon's Upper **Brushy Canyon** base located some 900 feet below the disputed 82 feet interval in the UCC reservoir. (**See Exhibits 1-A & 1-B**, being a copy of the log of the Premier FV3 Well with annotations from evidence introduced before the Commission and **Exhibit 1-C** taken from OCD files).

Mr. Terry Payne, a petroleum engineer, testified for Premier that the acid treatment log of Zone #2 of the Premier FV-3 Well shows that some of the water produced from the well was channeling down from an upper zone and should not be attributed to the UCC reservoir. See Premier Exhibit 10 (testimony of Terry Payne).

When evaluating the treatment of Zone #2, the Cement Bond Log for the Premier FV3 Well confirms that the disputed 82 feet interval is protected with cement and along with the acid treatment log demonstrates that the disputed 82 feet interval remains "virgin reservoir" before and after the October 1995 test.

The Commission compounds its mistake of fact by concluding that the Premier FV3 Well is going to be uneconomic because the disputed 82 feet of pay correlates to the Yates ZG1 Well to the south which is "uneconomic". The Commission forgot that the Yates ZG1 Well is only perforated in the top 3 feet of the "disputed 82 feet interval" and therefore is not relevant to how the FV3 Well might have performed had it been properly drilled and cemented by Gulf.

In terms of reservoir thickness, porosity, water saturations and therefore original oil in place, waterflood target oil and CO2 target oil, the Premier tract compares favorably to the Yates tracts (EP 5,7,8, & WM 5& 6) which Exxon credits with substantial waterflood reserves.

Yet when Exxon imputes this data into its reservoir simulation program (computer model), it chose to increase the water saturation for the Premier FV3 Well from 39.1% to 59.9% and in doing so made the Premier tracts appear to have less value than comparable Yates' tracts.

In addition, at the OCC hearing, Mr. Payne testified that Yates tested every major part of the UCC reservoir in the EP7 Well (3 tests) with the well IP'd for 10 BO and 100 BW (a 9% initial cut compared to the FV3 Well at 16% cut) and which has produced less than 2,000 barrels to date. Notwithstanding those poor results, Exxon credits this well with 266,600 barrels of UCC workover target oil and 145,000 barrels of waterflood target oil for a total credit of 411,600 barrels towards the waterflood portion of the participation formula. Exxon testified that the EP7 Well was (a) under Frac'd; (b) fits their Delaware water model even though December's production of 31 days equalled only 50 BO and 875 BW; and (c) it will make up the reserves once the flood begins.

Furthermore, Exxon attributes the same type of reserves for the untested UCC in the EP5 Well, the EP8 Well, the WM5 Well and the WM6 Well. The waterflood and workover target oil attributed to the UCC in these wells account for approximately 20% of the total waterflood reserves in the participation formula.

Three of these wells border the Premier Tract 6 (EP7,5 & WM6). Exxon's report shows UCC waterflood target oil for Premier's Tract 6 is 2,320,000 barrels while Yates adjoining tract are credited with 2,680,00 barrels of oil.

By Exxon mislocating the UCC base and concluding the reservoir is ending, and by exaggerating the water saturation in the Premier FV3 Well, Exxon discriminates in its Report against Premier by not giving the same waterflood reserve credits to the Premier acreage as it does for the Yates' tracts.

Because the Commission agreed with but then discounted the net 82 feet disputed interval and failed to draw comparisons of the Premier acreage with the Yates acreage, the Commission has made a substantial errors of fact in Findings (2)(a) and (20)(c) which affects its ultimate decision in this case. Therefore, the Commission needs to withdraw Order R-10460-B and correct its mistake.

POINT II:

THE COMMISSION'S ULTIMATE DECISION IS BASED UPON FINDINGS (17)(h) AND (19)(a) WHICH ARE WRONG AND ARE NOT SUPPORTED BY SUBSTANTIAL EVIDENCE AND ADOPTS ARBITRARY AND CAPRICIOUS REASONS TO SUPPORT ITS REJECTION OF PRIMER'S ENGINEERING EVIDENCE

At the Commission hearing, Mr. Terry Payne, a consulting petroleum engineer, who correctly analyzed the Exxon Technical Report DID NOT equate waterflood target oil-in-place with incremental recoverable waterflood oil reserves. Both Mr. Payne testifying for Premier and Mr. Gilbert Beuhler testifying for Exxon agreed on the engineering method by which to calculate recoverable reserves based upon volumetric calculations of original oil in place and incorporate recovery factors and sweep efficiencies.

However, in Findings (17)(h) and (19)(a), the Commission erroneously mischaractized Premier's petroleum engineering testimony presented to the Commission when it described his testimony as equating waterflood target reserves with waterflood target oil in place and then unfairly dismisses Premier's claim because it "excluded recovery efficiency."

The mistakes in Findings (17)(h) and (19)(a) formed the basis for the Commission to reach the wrong conclusion in Finding (20)(b) when it incorrectly finds that "Premier's arguments and proposed participation formula is limited to oil-in-place calculations.

In fact **both** Exxon and Premier's proposed formula are based **in part** on oil-in place calculation **while neither** is limited only to oil in place calculation. The Commission has made a mistake of fact which has affected its ultimate decision in this case.

POINT III:

FINDINGS (20)(f) IS NOT SUPPORTED BY SUBSTANTIAL EVIDENCE AND EXXON'S PARTICIPATION FORMULA WILL NOT PROTECT CORRELATIVE RIGHTS

Contrary to Finding (20)(f) of Order R-10460-B, Exxon's Unit participation formula does not protect correlative rights. The Commission should have remembered that Mr. Payne used Exxon's own Technical Report and demonstrated that:

> The Exxon-Yates participation formula is flawed because it fails to allocate the total unit waterflood reserves equitably among the tracts:

Operator	Waterflood target	Assigned percentage
Premier	8.29%	-0-%
Exxon	41.09%	59.71%
Yates	49.63%	40.29%
MWJ	1.07%	-0-%

(See Premier Exhibit 9 page 4)

Exxon's proposed 50% flood factors for Tract 6 (Exxon Technical Report Exhibit E-7) are arbitrary because they assume that the outer ring tract's producing wells will be located in the center of each 40-acre tract when in fact those wells could be located 330 feet from the outer boundary and be assigned a 75% flood factor without adversely affecting flood efficiency.

Premier's Tract 6 can be excluded from the unit without any reduction in ultimate recovery if the four lease line CO2 flood injection wells are drilled between Premier Tract 6 and the Yates' Tracts #3, 3b, 5a,and 5b (See Premier Exhibit 9 pages 9-12). Furthermore, Premier will have the ability to flood part of its that is being excluded from the Exxon Avalon (Delaware) Unit.

POINT IV:

THE COMMISSION'S ULTIMATE DECISION IS BASED UPON ERRONEOUS FINDINGS OF FACT SET FORTH IN FINDING (20)(b) WHICH ARE INCONSISTENT WITH UNDISPUTED TESTIMONY

In Finding (19)(g), the Commission finds that Premier's proposed participation formula was based upon 50% on original oil in place with the remaining 50% attributed to actual recoveries.

Then in Finding (20)(b), the Commission finds that Premier's arguments and proposed participation formula is limited to oil-in-place calculations.

These two findings are inconsistence and mutually exclusive. Finding (20)(b) is factually wrong. Premier's arguments and proposed participation formula is not "limited to oil-in-place calculations."

BOTH Exxon and Premier arguments are founded in original oil in place calculations.

POINT V:

COMMISSIONER BAILEY WAS DISQUALIFIED TO PARTICIPATE IN THIS CASE BY PRIOR EXPARTE DISCUSSION, BIAS AND PREJUDGMENT

Premier was denied procedural due process because Commissioner Bailey was disqualified to participate as a member of the Commission. ***See Santa Fe Exploration Co. v. Oil Conservation Comm'n, 114 N.M. 103 (S.Ct 1992).***

On May 24, 1995, Commissioner Bailey in her capacity as the Deputy Director of the oil and Gas and Mineral Division for the Commission of Public Lands for New Mexico ("SLO") met with Exxon's attorney and Exxon personnel who included Exxon witnesses who later testified at the Commission hearing. **(See Exhibit 2).**

The purpose of this meeting was to obtain preliminary approval from Commissioner Bailey for the inclusion of the State of New Mexico oil & gas leases into the Avalon (Delaware) Unit.

In response to this Exxon request, by letter dated May 15, 1995, Commissioner Bailey concluded that the Exxon proposal "meets the general requirements of the Commission of Public Lands" and on behalf of the SLO, approved the Exxon request. **(See Exhibit 3)**.

By her actions, the SLO agreed to include the State Oil & Gas lease which it has leased to Premier and which Premier objects to being included in the unit.

Over the objections of Premier, the Commission voted to allow Commissioner Bailey to participate as a member of the Commission in an administrative agency adjudication of the same issue in which Commissioner Bailey had been involved and had already reached a decision and by doing so denied to Premier is procedural due process rights to have its dispute adjudicated by a Commission composed of members who could satisfy the principles set forth in ***Santa Fe Exploration Co. v. Oil Conservation Comm'n, 114 N.M. 103 (S.Ct. 1992).***

Commissioner Bailey was disqualified from participation on the Commission because of (a) prior exparte conferences with witnesses and Exxon's attorney; (b) bias (b) prejudgment of this matter; and (c) that it is a conflict of interest for the Commissioner of Public Lands to have designated a member of the Commission who has already acted on this matter.

By letter dated December 13, 1995, Jan Unna, as General Counsel for the Commissioner of Public Lands, admits that "we do recognize that parties litigating before the Oil Conservation Commission are entitled to have their constitutional rights including procedural due process, respected. As a transactional matter, this means that the Commissioner's designed should be free from bias and prejudgment." Further, Mr. Unna advised that "we will try to make sure that the Commissioner's designee has not participated in the Land Office decision or transaction that is the subject of the Oil Conservation Commission hearing." **(See Exhibit 4)**.

It is of no comfort to Premier that the State Land Office plans to change its practices after this case.

POINT VI:

THE COMMISSION'S APPROVAL OF THE CO2 PROJECT IS PREMATURE AND IS NOT SUPPORTED BY SUBSTANTIAL EVIDENCE

The Commission has prematurely approved a Tertiary CO2 Project. The Secondary Recovery Project ("waterflooding") is the reason for the Unit, while the Tertiary Recovery Project ("CO2") has only some probability of happening/not happening.

It is undisputed that Exxon intends to institute a Secondary Recovery Project for recovery of oil by waterflooding an interior portion of the unit containing 1100 acres utilizing 27 existing producing wells, 19 injection wells which will be surrounded by an outer ring of 40-acre tracts which will not contain producing wells nor contain or be offset by injection wells.

Exxon proposes not to extend the waterflood pattern so as to recover any of Premier's secondary ("waterflood target") oil and therefore give Premier "0" credit for waterflood target oil.

Exxon proposes possibly at an undetermined time in the future to convert the Secondary Recovery Project to a Tertiary Recovery Project by expanding the original waterflood project area by drilling 18 CO2 injection wells, 18 new producing wells, and adding 10 existing wells to include an additional 1000 acres and commencing the injection of carbon dioxide ("CO2") at which point the outer ring tracts (including Tract 6) will contain producing and adjacent injection wells.

Exxon proposes to extend the CO2 injection in such a pattern so as to flood only 25% of Tract 1109 and 50% of the balance of Premier's tracts thereby reducing Premier's share of tertiary ("CO2 target") oil recovery by a factor of 25% to 50%.

It is of particular concern to Premier that Exxon's uses the same reservoir simulation model for both the waterflood project and the CO2 project which results in "equal value" for both projects, yet chooses in its participation formula to credit 50% to waterflood target oil and only 25% to CO2 target oil.

The Commission criticized Premier for giving equal value to the waterflood and the CO2 projects yet overlooks the fact that Exxon's own technical report did exactly the same thing.

The Commission's approval of the CO2 project is **premature**. Exxon's analysis of the CO2 potential is based solely on a waterflood model and therefore is speculative and has not been the subject of any scientific study to determine its feasibility and therefore any forecasted increase in ultimate recovery of tertiary oil from the unit by including the Premier Tract 6 is speculative.

At such time as firm plans are formulated for a tertiary recovery project, then Exxon should return to the Commission for either (a) a lease line injection agreement with Premier and/or (b) including the Premier acreage in the CO2 project.

POINT VII:

THERE IS NO SUBSTANTIAL EVIDENCE TO SUPPORT INCLUDING PREMIER'S TRACT

Under the Exxon analysis, the inclusion of Premier's Tract 6 is **not necessary** in order to effectively carry on the Secondary Recovery Project and that it is **premature** to include this Tract 6 for a Tertiary Recovery Project.

Under the Exxon analysis, there is **no increase** in ultimate recovery of secondary oil from the unit by including the Premier Tract 6.

Under the Exxon analysis the inclusion of the Premier Tract 6 is **not necessary** in order to effectively carry on the Secondary Recovery Project.

Exxon's Secondary Recovery Plan provides no means for the recovery of any oil west of the existing Yates' wells.

Since recovery of any such oil is thereby deferred to a tertiary recovery phase for which no commitment has been made, the implication that correlative rights would be impaired and that waste would occur if the Premier acreage were deleted from the proposed unit is groundless.

Exxon operates or owns working interests in all tracts except Tracts 6, 7, and 8, seeks to include the Premier Tract 6 only as a "protection buffer" and assigns no "contributing value" for secondary oil recovery. (See Section 70-7-4(J) NMSA 1978).

POINT VIII:

THE COMMISSION VIOLATED CORRELATIVE RIGHTS BY FAILING TO COMPLY WITH THE STATUTORY UNITIZATION ACT

Exxon proposes to include a column of 40-acre tracts including four 40-acre tracts (Tract 6) operated by Premier within the western boundary the Avalon Unit but does not intend to attempt to recovery from those tracts any remaining primary oil or any secondary oil by waterflooding.

Exxon's geologic interpretation along with Exxon's volumetric calculations of original oil in place established the "relative value" of Premier's Tract 6 on the western boundary of the reservoir as follows:

Original oil in place:	13,730,000 BO
Remaining Primary Oil in place:	-0-
Waterflood Target Oil in place:	2,950,000 BO
Workover Target Oil in place:	-0-
CO_2 Target Oil in place:	10,070,000 BO

See Exxon Exhibit 10 Vol 1 Exhibit E-6

Based upon its analysis of Premier's FV #3 Well, Exxon further determined that Premier's Tract 6 had no potential for waterflood target oil and only 1.626 million barrels of CO_2 target oil by applying a weighted factor of 50% and 25% to Tract 6. See Exxon Exhibit 10- Vol. 1 Exhibit E-7 and E-6)

The Commission adopted Exxon's unit participation formula predicated upon the intention to allow each tract to recover its percentage of remaining primary oil, its percentage of secondary oil and workover oil potential and its percentage of tertiary oil potential by a weighted formula of 25% primary, 50% secondary/workover and 25% tertiary.

The result, however, is to give 1.0192% of all unit production to Tract 6 operated by Premier despite the fact that Exxon said Tract 6 has 7.6 percent of the unit acreage and 4.16% of the total remaining reserves (See Exxon Exhibit 10 (G-19). Such a participation formula does not allocate unitized hydrocarbons on a fair, reasonable and equitable basis. Such a result violates the Statutory Unitization Act.

The Commission attempts to excuse this inequity by arguing that the Exxon participation formula is "fair" because Premier will receive income from the start of the unit even though Premier's acreage will provide no benefit to the unit until the CO2 project. The Commission ignores the statutory definition of "fairness":

> Section 70-2-33(H) NMSA of the Oil and Gas Act defines Correlative Rights as "...the opportunity afforded, as far as it is practicable to do so, to the owners of each property in a pool to produce without waste his just and equitable share of the oil or gas or both in the pool, being an amount so far as can be practicably determined and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas or both under the property bears to the total recoverable oil or gas or both in the pool and for such purpose, to use his just and equitable share of the reservoir energy;"

As much as the Commission wants to avoid the difficult task of determining relative value, it is no excuse to accept the Exxon participation formula when it is based upon an albeit expensive and time consuming but still fatally flawed technical report.

The Commission in Finding (20)(f) refused Premier's request that the Commission determine "relative value from the evidence introduced at the hearing and instead has approved the Exxon participation formula as "fair" despite the following evidence:

> (a) Reserves are established for the unit by utilizing Exhibit G-19 of the Exxon's August 1992 Technical Report (as amended by G-24) in which Premier's Tract 6 is assigned "0" remaining primary recovery, "0" workover reserves, "0" waterflood reserves and 1,626.0 MSTBO CO2 reserves; and

(b) Exxon proposes to include a column of 40-acre tracts including four 40-acre tracts (Tract 6) operated by Premier within the western boundary of the Avalon Unit but does not intend to attempt to recover from those tracts any remaining primary oil, any workover oil or any secondary oil by waterflooding.

The Commission has allowed Exxon to confiscate Premier's property rights in this oil & gas lease and has failed to " determine relative value, from the evidence introduced at the hearing taking into account the separately owned tracts in the unit area, exclusive of physical equipment for development of oil and gas by unit operations, and the production allocated to each tract shall be the proportion that the relative value of each tract so determined bears to the relative value of all tracts in the unit area." (emphasis added--See Section 70-7-6(B) NMSA 1978).

The Commission should have approved the waterflood unit **but excluded** the Premier Tract from the waterflood project because under Exxon's proposal the Premier Tract will make no contributing value to the waterflood and should not receive any compensating value.

CONCLUSION

Premier petitions the Commission to:

(a) withdraw Order R-10460-B (**See Exhibit 6)** and substitute Premier's proposed order which is attached hereto as **Exhibit 5** and incorporated herein by reference;

(b) to vacate Order R-10460-B and grant a Rehearing to address all of the issues set forth in this Application for Rehearing;

(c) to order Exxon to amend its simulation program by substituting Premier's geologic interpretation and water saturation for the Premier tracts; or in the alternative,

(d) to appoint a qualified petroleum engineer acceptable to all parties to act as a mediator in order to resolve the technical differences between the Exxon study and the Premier study.

In order to preserve Opponents' right to further appeals of this matter, all of the issues set forth in our proposed Order R-10460-C **(See Exhibit 5)** are made a part of this Application for Rehearing.

Respectfully submitted,

W. Thomas Kellahin, Esq.
KELLAHIN & KELLAHIN
P.O. Box 2265
Santa Fe, New Mexico 87501
(505) 982-4285

Type Log
Eddy "FV" State No. 3
Premier Oil and Gas, Inc.

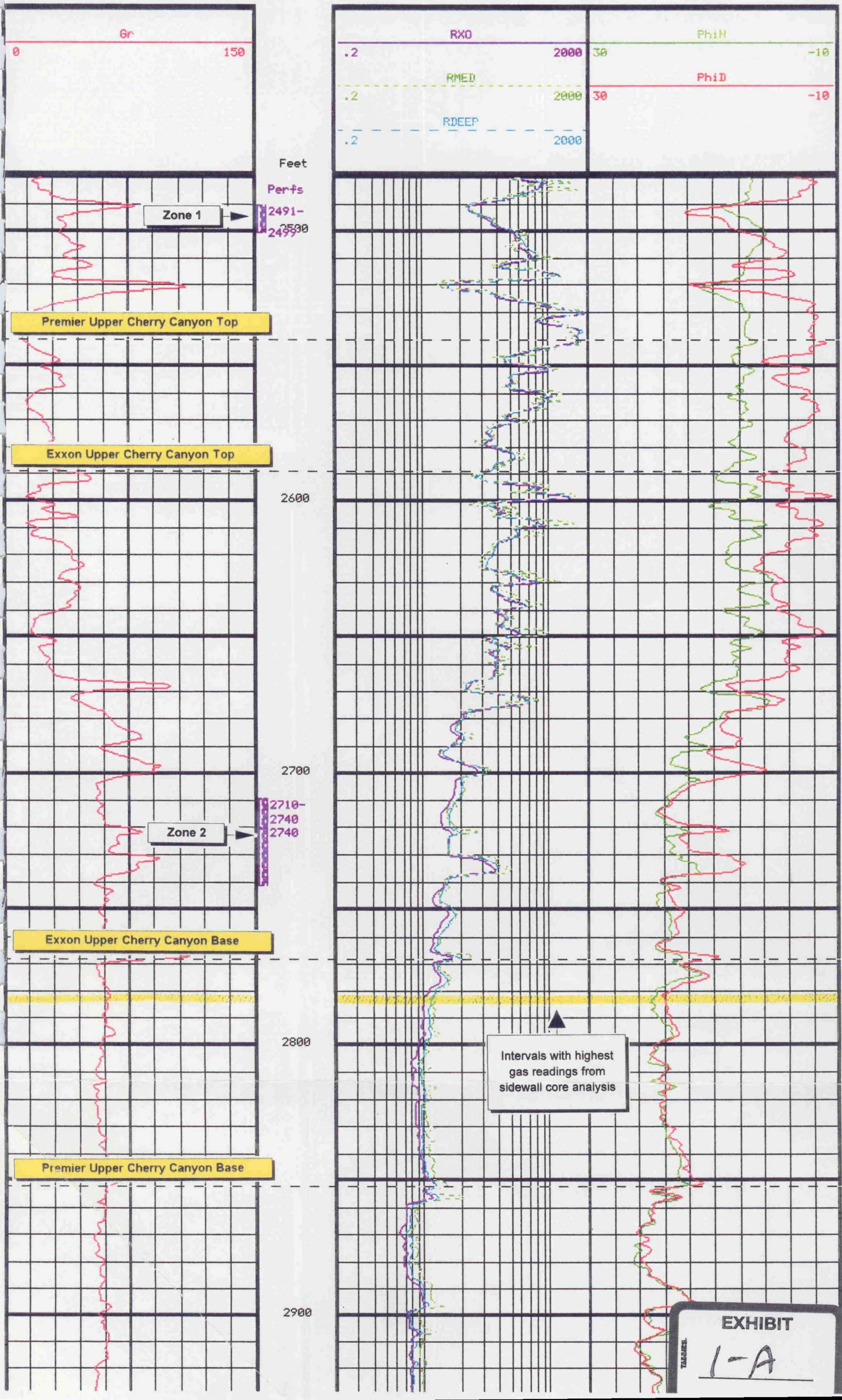


EXHIBIT
1-A

Type Log
Eddy "FV" State No. 3
Premier Oil and Gas, Inc.

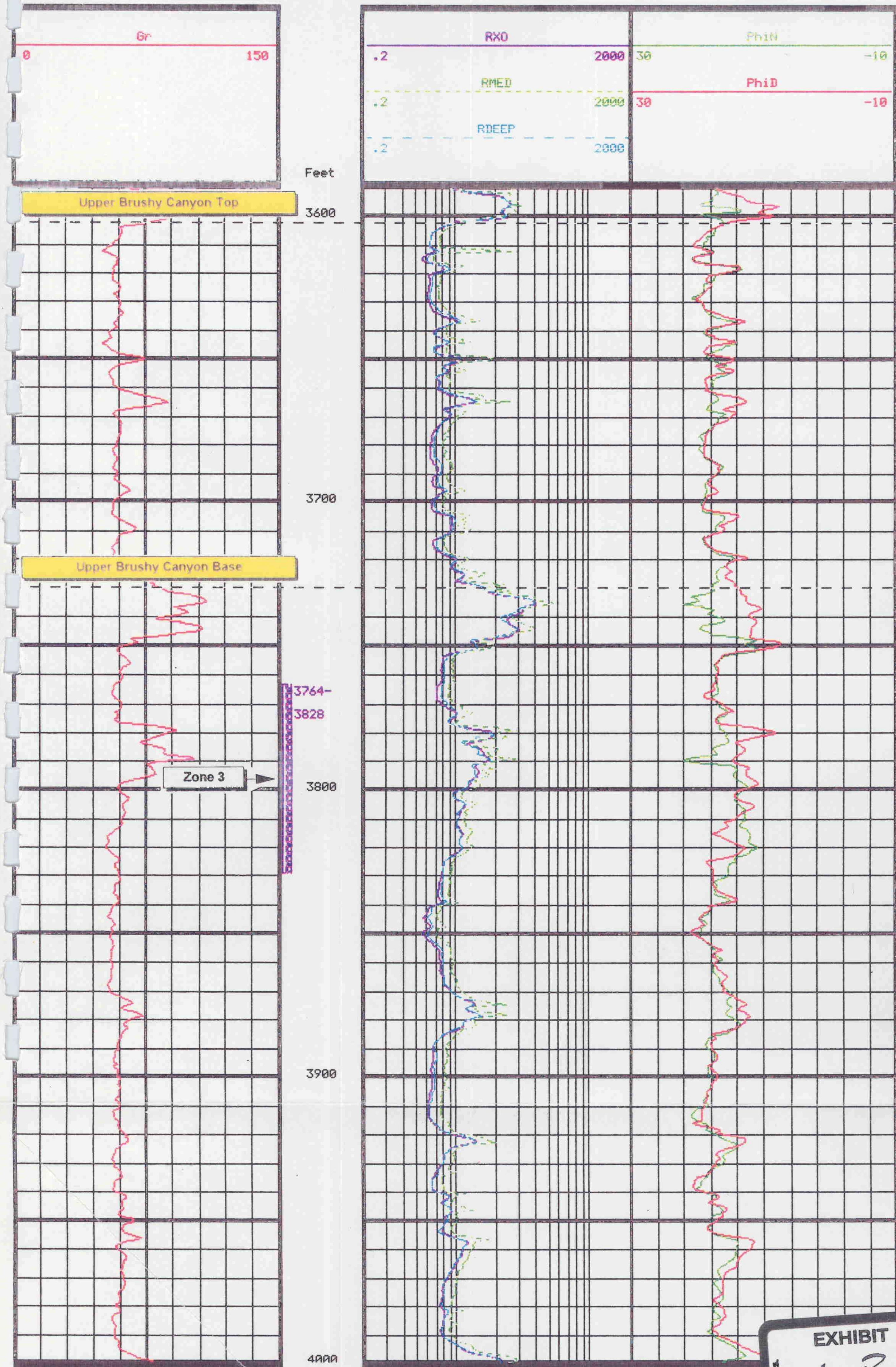


EXHIBIT
1-B

bmit 3 Copies
Appropriate
strict Office

DISTRICT I
P.O. Box 1980, Hobbs, NM 88240

DISTRICT II
P.O. Drawer DD, Artesia, NM 88210

DISTRICT III
1000 Rio Brazos Rd., Aztec, NM 87410

State of New Mexico
Energy, Minerals and Natural Resources Department

OIL CONSERVATION DIVISION

P.O. Box 2088
Santa Fe, New Mexico 87504-2088

Form C-103
Revised 1-1-89

WELL API NO. 30-015-24770

5. Indicate Type of Lease STATE [X] FEE [ ]

6. State Oil & Gas Lease No. K-6527

SUNDRY NOTICES AND REPORTS ON WELLS

DO NOT USE THIS FORM FOR PROPOSALS TO DRILL OR TO DEEPEN OR PLUG BACK TO A DIFFERENT RESERVOIR. USE "APPLICATION FOR PERMIT" (FORM C-101) FOR SUCH PROPOSALS.)

7. Lease Name or Unit Agreement Name: Eddy "FV" State

1. Type of Well: OIL WELL [ ] GAS WELL [X] OTHER

2. Name of Operator: Premier Oil and Gas, Inc.

8. Well No. 3

3. Address of Operator: P.O. Box 1246, Artesia, NM 88210

9. Pool name or Wildcat: Avalon Delaware

4. Well Location
Unit Letter P : 660 Feet From The South Line and 330 Feet From The East Line
Section 25 Township 20S Range 27E NMPM Eddy County

10. Elevation (Show whether DF, RKB, RT, GR, etc.) 3302.5 GR

11. Check Appropriate Box to Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:				SUBSEQUENT REPORT OF:			
PERFORM REMEDIAL WORK	[ ]	PLUG AND ABANDON	[ ]	REMEDIAL WORK	[X]	ALTERING CASING	[ ]
TEMPORARILY ABANDON	[ ]	CHANGE PLANS	[ ]	COMMENCE DRILLING OPNS.	[ ]	PLUG AND ABANDONMENT	[ ]
PULL OR ALTER CASING	[ ]			CASING TEST AND CEMENT JOB	[ ]		
OTHER:			[ ]	OTHER:			[ ]

12. Describe Proposed or Completed Operations (*Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work*) SEE RULE 1103.

Rigged up well service unit. Used 4 3/4" bit on 2 7/8" tubing. Drilled out cast iron bridge plug at 2480'. Drilled out cast iron bridge plug at 3725. Cleaned out 5½" casing to 3900'. Pulled out of hole. Ran tubing, pump and rods. Started well pumping at 5:00 p.m., September 28, 1995.

RECEIVED
OCT 03 1995
OIL CON. DIV.
DIST. 2

I hereby certify that the information above is true and complete to the best of my knowledge and belief.

SIGNATURE Paul G. White TITLE Consulting Engineer DATE Oct. 2, 1995

TYPE OR PRINT NAME Paul G. White TELEPHONE NO. 746-9507

(This space for State Use) ORIGINAL SIGNED BY TIM W. GUM
DISTRICT II SUPERVISOR

APPROVED BY ______ TITLE ______ DATE OCT 10 1995

CONDITIONS OF APPROVAL, IF ANY:

EXHIBIT
1-C

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT

OIL CONSERVATION DIVISION
P. O. BOX 2088
SANTA FE, NEW MEXICO 87501

RECEIVED BY
MAY 02 1984
O. C. D.
ARTESIA, OFFICE

Form C-104
Revised 10-1-78

REQUEST FOR ALLOWABLE
AND
AUTHORIZATION TO TRANSPORT OIL AND NATURAL GAS

Operator: Gulf Oil Corp.

Address: P. O. Box 670, Hobbs, NM 88240

Reason(s) for filing (Check proper box)

New Well	[X]	Change in Transporter of:			
Recompletion	[ ]	Oil	[ ]	Dry Gas	[ ]
Change in Ownership	[ ]	Casinghead Gas	[ ]	Condensate	[ ]

Other (Please explain): New Well

CASINGHEAD GAS MUST NOT BE FLARED AFTER 7-16-84 UNLESS AN EXCEPTION TO RULE 306 IS OBTAINED

If change of ownership give name and address of previous owner

DESCRIPTION OF WELL AND LEASE

Lease Name	Well No.	Pool Name, Including Formation	Kind of Lease (State, Federal or Fee)	Lease No.
Eddy "EY" State	3	~~Hackberry Bone Spring~~ Avalon Delaware	State	K-6527

Location: Unit Letter P : 660 Feet From The South Line and 330 Feet From The East

Line of Section 25 Township 20S Range 27E, NMPM, Eddy County

DESIGNATION OF TRANSPORTER OF OIL AND NATURAL GAS

Name of Authorized Transporter of Oil [X] or Condensate [ ]	Address (Give address to which approved copy of this form is to be sent)
Permian Corp.	Box 3119 Midland TX 79701
Name of Authorized Transporter of Casinghead Gas [X] or Dry Gas [ ]	Address (Give address to which approved copy of this form is to be sent)
El Paso Natural Gas	Box 1492 El Paso TX 79999

If well produces oil or liquids, give location of tanks.	Unit	Sec.	Twp.	Rge.	Is gas actually connected?	When
	P	25	20S	27E	No	

If this production is commingled with that from any other lease or pool, give commingling order number:

COMPLETION DATA

	Oil Well	Gas Well	New Well	Workover	Deepen	Plug Back	Same Res'v.	Diff. Res'v.
Designate Type of Completion – (X)	X		X					

Date Spudded	Date Compl. Ready to Prod.	Total Depth	P.B.T.D.
3-15-84	4-26-84	4975'	3700'
Elevations (DF, RKB, RT, GR, etc.)	**Name of Producing Formation**	**Top Oil/Gas Pay**	**Tubing Depth**
3302.5' GL	Delaware	2710'	2791'
Perforations			**Depth Casing Shoe**
2710'-2740'			—

TUBING, CASING, AND CEMENTING RECORD

HOLE SIZE	CASING & TUBING SIZE	DEPTH SET	SACKS CEMENT
17 1/2"	13 3/8"	500'	500
12 1/4"	8 5/8"	2450'	1800
7 7/8"	5 1/2"	4975'	800
	2 3/8	2791	

TEST DATA AND REQUEST FOR ALLOWABLE
(Test must be after recovery of total volume of load oil and must be equal to or exceed top allowable for this depth or be for full 24 hours)

OIL WELL

Date First New Oil Run To Tanks	Date of Test	Producing Method (Flow, pump, gas lift, etc.)	
4-26-84	4-29-84	Pump	
Length of Test	**Tubing Pressure**	**Casing Pressure**	**Choke Size**
24 hrs	20#	20#	W.O.
Actual Prod. During Test	**Oil-Bbls.**	**Water-Bbls.**	**Gas-MCF**
441	72	369	40

GAS WELL

Actual Prod. Test-MCF/D	Length of Test	Bbls. Condensate/MMCF	Gravity of Condensate
Testing Method (pitot, back pr.)	**Tubing Pressure (Shut-in)**	**Casing Pressure (Shut-in)**	**Choke Size**

CERTIFICATE OF COMPLIANCE

I hereby certify that the rules and regulations of the Oil Conservation Division have been complied with and that the information given above is true and complete to the best of my knowledge and belief.

R L Pitre
(Signature)
AREA ENGINEER
(Title)
5-1-84
(Date)

OIL CONSERVATION DIVISION

APPROVED MAY 1 6 1984, 19

BY Original Signed By Leslie A. Clements

TITLE Supervisor District II

This form is to be filed in compliance with RULE 1104.

If this is a request for allowable for a newly drilled or deepened well, this form must be accompanied by a tabulation of the deviation tests taken on the well in accordance with RULE 111.

All sections of this form must be filled out completely for allowable on new and recompleted wells.

Fill out only Sections I, II, III, and VI for changes of owner, well name or number, or transporter, or other such change of condition.

Separate Forms C-104 must be filed for each pool in multiply completed wells.

WELL NO. Eddy "F" State 3 FIELD/POOL Avalon Delaware DATE 6-7-84

LOCATION 660 FEET FROM South LINE AND 330 FEET FROM East LINE

SEC 25 T20S - R27E COUNTY Eddy STATE NM

GE 3303'
KDB to GE 13'
DF to GE ______'

13 3/8" OD Surface Pipe set @ 500' w/ 625 sx
Cmt. Circulated? Yes

8 5/8" OD 24 # 8rd Thd
Gr. K-55 Csg
set @ 2450 w/ 1300 sx
Cmt Circulated? No
TOC @ 30' by TS

2491- Prop to perf's
2773 circulating this proc

2710-16
2723-25
Baker Mod "C" RBP 2731'
2738-40

CIBP @ 3735' w/ 6 sx

3764-68
3773-77
3813-17
3824-28

Orig. PBTD 4882'

5 1/2" OD 15.5 # 8rd Thd
Gr. K-55, CLA Csg.
set @ 4975' w/ 300 sx
Cmt Circulated? NO
TOC @ 200' by TS

PBD 3700'
TD 4975'

Date Completed ______
Initial Formation Cherry Canyon Delaware Sand
From: 3764' to 3828' GOR ______
Initial: Production ☒ -0- bopd ______ bwpd
Or: Injection ☐ ______ bwpd @ ______ psi

Completion Data:
4-09-84 Perf 3764-68; 73-77; 3813-17; 24-28 w/ 2-½" JHPF. Brk down w/ Acetic Acid - 300 gals. ISIP - 950 psi w/ KCL wtr Flsh
Acdz w/ 4000 gal: 10/90 mix of 10% Acetic & 15% HCL ISIP 950 psi
4-11-84 - Foam Frac w/ 50000 gal. 75% N2 - 30000 gal foamed fluid and 52000# 20-40 snd. @ 30 BPM Flsh w/ N2 ISIP-2300 psi
- cont below -

~~Subsequent Workover or Reconditioning:~~
4-16-84 - Set CIBP @ 3735' w/ 6 sx cmt on top of plug. Perf 2710-16; 23-25; 38-40 w/ 2 JHPF
Brk dwn perfs w/ 300 gal 7½% NEFE ISIP 950 psi
Acdz w/ 3000 gals 7½% NEFE HCL

4-18-84 - Frac w/ 38000 gal 750 foam & 64000# 20/40 sd. Flsh w/ N2 ISIP 2200 psi

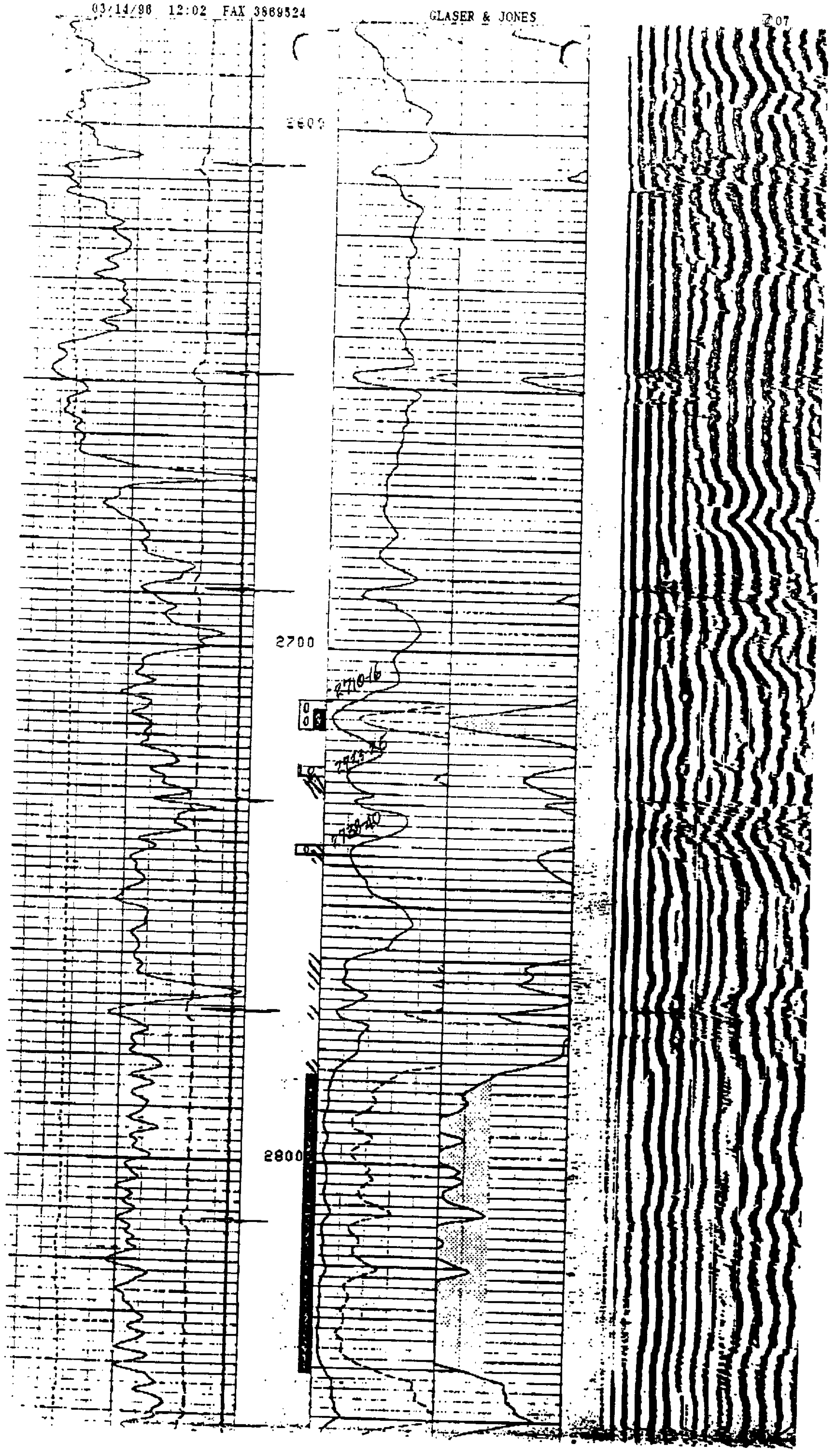
4-25-84 - Ran Conv PE. Set Pmg Unit
5-17-84 Well pmp 3 BO 192 BW

5-25-84 - LD 5 jts tbg to bring pmp intake above perfs. Run prod logs

6-06-84 Set Baker Mod C RBP @ 2731' GIH w/ PE & Put well to pmpg to check for decrease in wtr prod.

Present Inj. ☐ ______ bwpd @ ______ psi Date ______
Present Prod. ☐ ______ bopd ______ bwpd Date ______
GAS ______ MCFPD ______

Remarks Or Additional Data: ______


2600
2700
2710-16
2738-40
2800

STATE LAND OFFICE

MEETING RE AVALON (DELAWARE) Unit

JOE B THOMAS	(915) 688-7162	EXXON
Ron Mayden	" 688-7841	Exxon
Bill Duncan	" 688-6174	"
Jeff Albers	505 827-5759	SLO
Janet Richardson	505-748-1471	Yates Petroleum
JAMI BAILEY	505-827-5745	SLO
PETE MARTINEZ	505-827-5791	SLO
ELEANORE NESTLERODE	505-827-5748	SLO
CHARLES D. ENGELKE	827-5880	OSC
DAVE BONEAU	505-748-1471	YATES PETROLEUM
Jim Bruce	505-982-4534	Exxon (Hinkle firm)
Scott Lansdown	915-688-4982	Exxon

EXHIBIT

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State of New Mexico
Commissioner of Public Lands
310 OLD SANTA FE TRAIL P.O. BOX 1148
SANTA FE, NEW MEXICO 87504-1148

R Y POWELL, M.S., D.V.M.
COMMISSIONER

(505) 827-5760
FAX (505) 827-5766

~~May 15, 1995~~

RECEIVED
LAND SERVICES
MAY 17 1995
MPO - MIDLAND

MDA		MPC
RLA		RGG
RKF		RTL
SHJ		TAL
PLK		JBE
DCR		SHK
JBT		LLM
		SES
		JHT
HANDLE	REVIEW / SEE ME / CIRC	FILE

Exxon Company USA
P.O. Box 1600
Midland, Texas 79702-1600

Attention: Mr. Joe Thomas

Re: Request for Preliminary Approval
Avalon Delaware Unit
Eddy County, New Mexico

Dear Mr. Thomas:

This office has reviewed the unexecuted copy of the unit agreement for the proposed Avalon Delaware Unit, Eddy County, New Mexico. This agreement meets the general requirements of the Commissioner of Public Lands who has this date granted you preliminary approval as to form and content.

Preliminary approval shall not be construed to mean final approval of this agreement in any way and will not extend any short term leases until final approval and an effective date are given.

When submitting your agreement for final approval, please submit the following:

1. Application for final approval by the Commissioner setting forth the tracts that have been committed and the tracts that have not been committed.

2. Two copies of the Unit Agreement.

3. All ratifications from the Lessees of Record and Working Interest Owners. All signatures should be acknowledged before a notary. One set of ratifications must contain original signatures.

4. Initial Plan of Operation.

5. Order of the New Mexico Oil Conservation Division. Our approval will be conditioned upon subsequent favorable approval by the New Mexico Oil Conservation Division.

6. A copy of the Unit Operating Agreement.

Exhibit No. 6-A
Exxon Corporation
NMOCD Cases 11297 & 11298
Hearing Date: June 29, 1995

EXHIBIT
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7. Per your telephone conversation with Pete Martinez of this office, please revise Exhibit "A" & "B" to coincide with the BLM's survey plats. The following unit acreage should be changed: Federal Acreage, State Acreage, Fee Acreage and Total Acreage.

8. In Unit Agreement Page 3, Section 2(a), the acreage should be changed to 2,118.78.

9. Please date the unit agreement on Page 1.

10. A redesignation of all well names and numbers. The list should include the OCD property name, property number, pool name , pool code and API number.

If you have any questions, or if we may be of further help, please contact Pete Martinez at (505) 827-5791.

Very truly yours,

RAY POWELL, M.S., D.V.M.
COMMISSIONER OF PUBLIC LANDS

BY:
JAMI BAILEY, Deputy Director
Oil/Gas and Minerals Division
(505) 827-5745

RP/JB/cpm
Enclosure
cc: Reader File
BLM-Roswell--Attention: Mr. Armando Lopez
OCD-Santa Fe--Attention: Mr. Roy Johnson

State of New Mexico
Commissioner of Public Lands
310 OLD SANTA FE TRAIL P.O. BOX 1148
SANTA FE, NEW MEXICO 87504-1148

RAY POWELL, M.S., D.V.M.
COMMISSIONER

Legal Division
(505) 827-5713
Fax (505) 827-5852

December 13, 1995

VIA FACSIMILE & U.S. MAIL

W. Thomas Kellahim, Esq.
Kellahin & Kellahin
117 North Guadalupe
P.O. Box 2265
Santa Fe, NM 87504-2265

Re: *NMOCD cases 11297 and 11298, Application of Exxon Corporation for Waterflood Project, Carbon Dioxide Project and Statutory Unitization Avalon-Delaware Unit, Eddy County, New Mexico*

Dear Mr. Kellahin:

Your letter of December 11, 1995 to Jami Bailey has been referred to me for reply. In your letter you raise certain questions about Ms. Bailey's participation in a State Land Office decision to approve this particular Unit. You are concerned that her participation may have created a conflict of interest precluding her from sitting on the Oil Conservation Commission as the Commissioner of Public Lands' designee. See Sec. 70-2-4 NMSA 1978.

We share your concern that procedural due process of law be accorded parties appearing before this agency and any others on which a designee of the Commissioner sits. We are mindful of our responsibilities to the public in this regard. See Santa Fe Exploration Co. v. Oil Conservation Comm'n, 114 NM 103 (S.Ct. 1992).

In this instance Ms. Bailey and I are satisfied that she can participate as a member of the Commission and hear the matter with complete professionalism and impartiality. In response to the first two questions you pose in your letter, Ms. Bailey has no reservations about participating in this case. Any decision she may make as the Commissioner's designee will be based on the evidence in the record of the case. She had very little personal involvement in the Land Office process concerning this particular unitization. She attended one meeting internally and as a formality signed a letter of preliminary approval prepared by staff. The documents

BEFORE THE
OIL CONSERVATION COMMISSION
Case No.11298 DeNovo Exhibit No. 8
Submitted By:
PREMIER OIL & GAS INC.
Hearing Date: December 14, 1995

EXHIBIT
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concerning the unitization in question are, of course, public records and you are free to examine them if you wish. In that event please call me at 827-5715 to arrange a time for you to inspect the documents.

Your letter is the first occasion that this particular conflict of interest question has come to my attention. As you may know, I have been general counsel here for a relatively short time, and I am continually discovering new areas requiring legal attention. This is one of them.

It seems to me that the Legislature created a statutory conflict of interest, or at least a potential one, when it provided for the Commissioner to participate as a member of the Oil Conservation Commission under Sec. 70-2-4 NMSA 1978. It seems to me that the Legislature was concerned enough for the welfare and protection of public lands that, as a secondary consequence of its action, it created this form of institutional conflict. One of the purposes of having the Commissioner of Public Lands or his designee on the Oil Conservation Commission is to look after the interests of public land trust beneficiaries. There is nothing, of course, that the Land Office can do about this legislative framework.

At the same time, however, as we stated earlier, we do recognize that parties litigating before the Oil Conservation Commission are entitled to have their constitutional rights, including procedural due process, respected. As a transactional matter, this means that the Commissioner's designee should be free from bias and prejudgment. We are satisfied that such is the case with Ms. Bailey in this case. In addition, as to the future, we will try to make sure that the Commissioner's designee has not participated in the Land Office decision or transaction that is the subject of the Oil Conservation Commission hearing. The issues before the Land Office may be different from the questions before the Commission, which would mean that participating in a Land Office decision would not preclude a designee from hearing a different issue, albeit arising out of the same facts, before a different administrative body. We haven't researched this issue at this point, partly in the interest of turning around your letter request as soon as possible. We understand that you have a hearing in this matter before the Oil Conservation Commission tomorrow and we would not want to delay that by our review. In any case, we think it is the wiser choice for the Land Office to simply avoid any transactional conflict whenever it can by making sure the Commissioner's designee has not worked directly on the matter before the Commission.

W. Thomas Kellahin, Esq.
Page 3
December 13, 1995

If there is anything further we can do for you on this matter, please give me a call.

Sincerely,

Jan Unna
General Counsel

JU/jc

cc: Jami Bailey
Rand Carroll, Esq.

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

APPLICATION OF EXXON CORPORATION FOR A WATERFLOOD PROJECT AND EOR QUALIFICATION, EDDY COUNTY, NEW MEXICO — **CASE NO. 11297**

APPLICATION OF EXXON CORPORATION FOR STATUTORY UNITIZATION, EDDY COUNTY, NEW MEXICO — **CASE NO. 11298**

ORDER NO. R-10460-C

PREMIER OIL & GAS, INC.'S PROPOSED ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9:00 a.m. on December 14, 1995, at Santa Fe, New Mexico before the Oil Conservation Commission of New Mexico, hereinafter referred to as the "Commission".

NOW, on this ____ day of January, 1996, the Commission, a quorum being present, having considered the testimony presented and the exhibits receive at said hearing, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) Division Case Nos. 11297 and 11298 were consolidated at the time of the hearing for the purpose of testimony.

EXHIBIT
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(3) The applicant, Exxon Corporation ("Exxon"), seeks the statutory unitization, pursuant to the "Statutory Unitization Act", Sections 70-7-1 through 70-7-21, N.M.S.A. (1978), of 2,140.14 acres, more or less, being a portion of the Delaware Mountain Group of the Avalon-Delaware Pool, Eddy County, New Mexico, said portion to be known as the Avalon Delaware Unit; the applicant further seeks approval of the Unit Agreement and the Unit Operating Agreement which were submitted in evidence as applicant's Exhibit Nos. 2 and 3 in this case.

(4) Exxon proposes that the horizontal limits of said unit area would be comprised of the following described Federal, State and Fee lands in Eddy County, New Mexico:

Tract 1:	SW/4 Sec 29, T20S, R28E
Tract 2:	Sec 31, T20S, R28E
	Lot 4(NW/4NW/4) Sec 4 T21S, R27E
	Lots 1&2 (N/2NE/4) Sec 5 T21S, R27E
Tract 3-A:	Lot 1 (NW/4NW/4) Sec 30, T20S, R28E
Tract 3-B:	Lot 2 (SW/4NW/4) Sec 30, T20S, R28E
Tract 3-C:	NE/4NW/4 Sec 30, T20S, R28E
Tract 3-D:	SE/4NW/4 Sec 30, T20S, R28E
Tract 3-E:	SW/4NE/4 Sec 30, T20S, R28E
Tract 4-A:	NW/4SE/4 Sec 30, T20S, R28E
Tract 4-B:	NE/4SE/4 Sec 30, T20S, R28E
Tract 5-A:	Lot 3 (NW/4SW/4) Sec 30, T20S, R28E
Tract 5-B:	Lot 4 (SW/4SW/4) Sec 30, T20S, R28E
Tract 5-C:	NE/4SW/4 Sec 30, T20S, R28E
Tract 5-D:	SE/4SW/4 Sec 30, T20S, R28E
Tract 5-E:	SW/4SE/4 Sec 30, T20S, R28E
Tract 5-F:	SE/4SE/4 Sec 30, T20S, R28E
Tract 6:	E/2E/2 Sec 25, T20S, R27E
Tract 7:	E/2NE/4 Sec 36, T20S, R27E
Tract 8:	E/2SE/4 Sec 36, T20S, R27E
Tract 9:	Lots 1 & 2 (N/2NE/4) Sec 6, T21S, R27E
Tract 10:	W/2W/2, NE/4NW/4, SE/4SW/4 Sec 32, T20S, R28E
Tract 11:	SE/4NW/4 & NE/4SW/4 Sec 32, T20S, R28E
Tract 12:	E/2SE/4, SW/4NW/4 Sec 32, T20S, R28E

(5) Exxon proposes that the vertical limits of said unit area would comprise that interval which includes the "Upper Cherry Canyon Reservoir" ("UCC") and the "Lower Cherry Canyon/Upper Brushy Canyon Reservoir"

("LCC-UBC") and extends from an upper limit between 100 feet above the base of the Goat Seep Reef to the top of the Bone Springs formation to a lower limit of the base of the Brushy Canyon formation which are defined at all points under the unit area correlative to a depth of 2,378 feet and 4,880 feet, respectively, as identified on the Compensated Neuron/Litho density /Gamma Ray Log dated September 14, 1990 for the Exxon Yates "C" Federal Well No. 36, located in Unit A of Section 31, T20S, R28E, NMPM, Eddy County, New Mexico.

(6) Exxon, with approximately 61 percent of the unit acreage and Yates Petroleum Corporation ("Yates") with approximately 13-1/2 percent of the unit acreage appeared and presented evidence in support of approval of the unit.

(7) Premier Oil & Gas Inc. ("Premier"), the operator of Tract 6 with 7.6 percent of the unit acreage and 4.16% of the total remaining reserves (by Exxon's calculation--See Exxon Exhibit 10 (G-19) **but credited by Exxon with only 1.0192% of unit production** appeared and presented evidence in opposition to including Tract 6 with the unit.

EXXON PROPOSAL

(8) Exxon proposes to:

(a) **Statutory Unitization:** compel Premier Oil & Gas Inc. ("Premier") to include its property (Tract 6) in both projects by resorting to statutory unitization, pursuant to the "Statutory Unitization Act", Sections 70-7-1 through 70-7-21, N.M.S.A. (1978);

(b) **Correlative Rights:** that Premier has forfeited its correlative rights by failing to further develop its lease and now the Commission pursuant to the statutory unitization act can allow Exxon to hold Tract 6 without further development pending the possibility of a tertiary recovery project in the future.

(c) **Relative Value:** to fix the "relative value" of Premier's Tract 6 in the Upper Cherry Canyon Reservoir ("UCC") based its determination of a total net thickness of 55 feet for the Premier FV-3 Well, from log analysis in which Exxon estimates a total gross thickness of 179 feet by picking the top of the Upper Cherry Canyon Downlap at 2589 feet in depth and the base of the Upper Cherry Canyon at 2768 feet in depth and by using a 10% percent Gamma Ray porosity and a 75 API Gamma Ray unit cutoffs;

(d) **Reserves:** to establish reserves for the unit by utilizing Exhibit G-19 of the Exxon's August 1992 Technical Report (as amended by G-24) in which Premier's Tract 6 is assigned "0" remaining primary recovery, "0" workover reserves, "0" waterflood reserves and 1,626.0 MSTBO CO_2 reserves;

(e) **Workover Potential**: to credit certain tracts with workover potential as set forth in Exhibit E-19 of Exxon's Technical Report dated August 1992 and then include that potential with the waterflood reserves which are assigned a 50% weighted factor thereby increasing the value of Yates' Well EP-7 (number tract 1111);

(f) **Waterflood:** institute a Secondary Recovery Project for recovery of oil by waterflooding an interior portion of the unit containing 1100 acres utilizing 27 existing producing wells, 19 injection wells which will be surrounded by an outer ring of 40-acre tracts which will not contain producing wells nor contain or be offset by injection wells;

(g) **CO_2 flood:** possibly at an undetermined time in the future to convert the Secondary Recovery Project to a Tertiary Recovery Project by expanding the original waterflood project area by drilling 18 CO_2 injection wells, 18 new producing wells, and adding 10 existing wells to include an additional 1000 acres and commencing the injection of carbon dioxide ("CO_2") at which point the outer ring tracts (including Tract 6) will contain producing and adjacent injection wells;

(h) **Flood Factors**: to adopt flood factors as set forth in Exhibit E-7 of Exxon's Technical Report dated August 1992 which results in a 50% increase in participation for the original waterflood tracts and a correspondingly 25% to 50% decrease for the outer ring of 40-acre tracts including the Premier Tract;

(i) **Exxon-Yates' formula:** adopt a unit participation formula predicated upon the intention to allow each tract to recovery its percentage of remaining primary oil, its percentage of secondary oil and workover oil potential and its percentage of tertiary oil potential by a weighted formula of 25% primary, 50% secondary/workover and 25% tertiary.

(j) **Exxon Percentages:** to give 1.0192% of all unit production to Tract 6 operated by Premier Oil & Gas Inc. ("Premier"), said tract having 7.6 percent of the unit acreage and 4.16% of the total remaining reserves (by Exxon's calculation--See Exxon Exhibit 10 (G-19). Exxon, with approximately 61 percent of the unit acreage and Yates Petroleum Corporation ("Yates") with approximately 13-1/2 percent of the unit acreage appeared and presented evidence in support of approval of the unit.

(k) **Waste**: that waste will occur because the entire unit plan and the recovery of this potential oil is predicated upon having Premier's tract in the unit.

PREMIER'S POSITION

(9) Premier is the working interest owner of oil & gas leases for all of Section 25, T20S, R27E, NMPM with the E/2E/2 of said Section 25 constituting Unit Tract 6 (numbered tracts 1109, 1309, 1509 and 1709) under the Exxon proposed Avalon-Delaware Unit and proposes:

(a) **Statutory Unitization:** that Exxon's proposed unit shape, determination of the distribution of hydrocarbon pore volume and the primary and secondary production estimates fail to provide "relative value" to Tracts 1109. 1309, 1509 and 1709 as required by Section 70-7-4(J) NMSA (1978), as amended and, unless corrected by the Commission, the correlative rights of Premier will be violated;

(b) **Correlative Rights:** that Premier is still the current lessee of a valid State of New Mexico oil & gas lease who has postponed its development plans pending the outcome of unitization commenced by Exxon in 1991, should not be denied its opportunity to further develop its lease just because Exxon wants to hold this tract without further development pending the possibility of a tertiary recovery project in the future.

(c) **Relative Value:** to fix the "relative value" of Premier's Tract 6 in the Upper Cherry Canyon Reservoir ("UCC") based its determination of a total net thickness of 137 feet for the Premier FV-3 Well (which is some 82 net feet more than attributed by Exxon) from log analysis in which Premier estimates a total gross thickness of 308 feet by picking the top of the Upper Cherry Canyon Downlap at 2544 feet in depth and the base of the Upper Cherry Canyon at 2852 feet in depth and by using a 10% percent Gamma Ray porosity and a 75 API Gamma Ray unit cutoffs;

(d) **Reserves:** to establish reserves for the unit by utilizing Exhibit G-19 of the Exxon's August 1992 Technical Report (as amended by G-24) in which Premier's Tract 6 is assigned "0" remaining primary recovery, "0" workover reserves, "0" waterflood reserves and 1,626.0 MSTBO CO_2 reserves;

(e) **Workover Potential**: to credit certain tracts with workover potential as set forth in Exhibit E-19 of Exxon's Technical Report dated August 1992 and then include that potential with the waterflood reserves which are assigned a 50% weighted factor thereby increasing the value of Yates' Well EP-7 (number tract 1111);

(f) **Waterflood:** approve the waterflood unit **but**

exclude the Premier Tract from the waterflood project because under Exxon's proposal the Premier Tract will make no contributing value to the waterflood and should not receive any compensating value;

or in the alternative, include the Premier Tract **but adopt:**

(i) Premier's geologic evidence as the appropriate reservoir pore volume for Premier's Tract 6:

(ii) exclude the workover reserves assigned to Yates' number tracts 1111, 1311, 1313, 1511 and 1513;

(iii) move the location of proposed outer ring producers and increase the food factors for the outer ring tracts including Premier Tract 6;

(iv) **adopt Premier's participation formula:**
50% original oil in place;
10% 1/93 rate;
20% remaining primary and
20% future production

(g) **Premier Percentages:** to credit 4.52% of all unit production to Tract 6 operated by Premier Oil & Gas Inc. ("Premier"), said tract having 7.6 percent of the unit acreage, 6.14% of the original oil in place, 6.19% of the CO_2 reserves and 5.17% of the total remaining reserves (by Premier's calculation--See Premier Exhibit 9 page 49;

(h) **CO_2 flood:** deny the CO_2 tertiary project because it is premature.

(i) **Waste**: that excluding the Premier tract does not cause waste. The only waste issue is whether "statutory unitization" is the **proper** means by which the drilling of certain lease line CO_2 injection wells which can take place or whether those wells can be drilled by adoption of a cooperative lease line agreement.

PREMIER'S OBJECTIONS

(10) Premier contends that its Tract 6 should be **excluded** because:

(a) Exxon proposes to include a column of 40-acre tracts including four 40-acre tracts (Tract 6) operated by Premier within the western boundary of the Avalon Unit but does not intend to attempt to recover from those tracts any remaining primary oil, any workover oil or any secondary oil by waterflooding;

(b) Exxon based its plan upon a Technical Report dated August, 1992 (Exxon Exhibit 10) which was prepared exclusively by Exxon personnel and submitted to Yates and the other working interest owners in September, 1992;

(c) the Secondary Recovery Project ("waterflooding") is the reason for the Unit, while the Tertiary Recovery Project ("CO2") has only some probability of happening/not happening (See Exxon Exhibit 7--letter dated 10/10/94);

(d) on June 17, 1994, in Premier's absence, the working interests owners met to discuss the Exxon Technical Report and unanimously agreed to **exclude** Premier's Tract 6 from both the Secondary Recovery and Tertiary Recovery project in the Avalon Unit and Exxon has made no change in its Technical Report to now justify including the Premier Tract in the Unit;

(e) under the Exxon analysis, the inclusion of Premier's Tract 6 is **not necessary** in order to effectively carry on the Secondary Recovery Project and that it is **premature** to include this Tract 6 for a Tertiary Recovery Project

(f) under the Exxon analysis, there is **no increase** in ultimate recovery of secondary oil from the unit by including the Premier Tract 6;

(g) the Exxon analysis of the CO2 potential is speculative and not been the subject of any scientific study to determine its feasibility and therefore any forecasted increase in ultimate recovery of tertiary oil from the unit by including the Premier Tract 6 is speculative;

(h) Exxon operates or owns working interests in all tracts except Tracts 6, 7, and 8, seeks to include the Premier Tract 6 only as a "protection buffer" and assigns no "contributing value" for secondary oil recovery; See Section 70-7-4(J) NMSA 1978;

(i) because Premier, as owner of all of Section 25, T20S, R27E, is not receiving any "contributing value" for primary or secondary oil, it does not want to divide its property for Exxon's satisfaction.

(j) Yates wants the Premier Tract included in order to shift the risk of being a edge CO2 flood tract from Yates to Premier.

(k) that Premier's Tract 6 can be excluded in accordance with the New Mexico Statutory Unitization Act.

(11) In the alternative, Premier contends that if Tract 6 is to be included in the unit, then and in that event, the application for unitization must be **denied** because:

(a) the horizontal and vertical limits of said unit have **not** been reasonably defined by development;

(b) Exxon's Technical Report is flawed because it incorrectly correlates the top of the Upper Cherry Canyon-Downlap Unit and the base of the Upper Cherry Canyon Reservoir in Premier's FV #3 Well (identified as Unit Well 1709) located within Premier's Tract 6;

(c) Exxon mistakenly uses a high gamma ray reading at 2768 feet on the log of the Premier FV-3 Well as an indication of the base of the UCC reservoir when in fact the average porosity within the 82 feet below that point is equal to or greater than the average porosity within the 55 feet picked by Exxon;

(d) this mistake causes Exxon only to attribute 55 feet of net thickness to the UCC reservoir for the FV-3 Well which in turn affects the contouring of the various geologic maps, including the "TOTAL NET RESERVOIR HYDROCARBON THICKNESS AT RESV COND MAP" (Exxon Exhibit 10 map 20 from which Exxon concludes that Premier's Tract 6 acreage has no remaining primary oil potential;

(e) Premier's FV-3 Well when correctly correlated indicates a net porosity thickness in the Upper Cherry Canyon Reservoir of 137 feet which is some 82 feet more than attributed by Exxon; (See Premier Exhibit 2)

(f) Exxon has determined that 131 feet of net pay thickness is the average for wells in the UCC reservoir but only credits Premier's FV #3 Well with 55 feet; (See Exxon Exhibit 10 B-1)

(g) **BOTH** Exxon's and Premier's hydrocarbon pore volume map shows that there is substantial recoverable oil remaining under Premier's
Tract 6.

(h) Exxon's Technical Report in assigning "relative value" to each tract, determined that based upon logged derived water saturations there are 2,320,00 barrels of waterflood target oil to be recovered underlying the Premier Tract 6 (See Premier's Exhibit 8) **but** then arbitrarily eliminated all of that incremental oil in their reservoir model by increasing the water saturation (Sw=0.60) based upon water production volumes reported by Gulf when it operated the Premier FV-3 Well; (See Exxon Exhibit 10 G-19)

(i) Premier has determined that Sw should be derived from log analysis and not actual water production because the actual water production from the FV-3 Well is attributed to water encroachment from above the Upper Cherry Canyon Reservoir;

(j) The log of the Premier FV-3 Well shows that the water produced from the well was channeling down from an upper zone and should not be attributed to the UCC reservoir. See Premier Exhibit 10 (testimony of Terry Payne).

(k) Exxon gives workover reserves in the UCC reservoir to Yates' Tracts 1111, 1311, 1313, 1511 but excludes workover reserves for Premier's Tract 6 which has the same reservoir parameters with identical Sw values (See Exxon Exhibit 10 Map 19);

(l) Exxon is biased in distributing waterflood reserves;

(m) Exxon has incorrectly mapped the UBC reservoir's gross thickness on Premier's acreage;

(n) The granting of the application with the deletion of Tract 6 as proposed by Premier in this case will have no adverse effect upon the Delaware formation.

(o) The deletion of Premier's Tract 6 from the Avalon Unit Agreement and the Avalon Unit Operating Agreement provide for unitization and unit operation of the Avalon Unit Area upon terms and conditions that are fair, reasonable and equitable.

(p) The Exxon's request for approval of a tertiary recovery ("CO2") project is premature and should be **denied.**

BACKGROUND-UNITIZATION NEGOTIATIONS

(12) On May 21, 1991, Exxon commenced unitization plans for the Avalon Area and announced its schedule to commence waterflood operations by June, 1992.

(13) In November, 1991 Exxon issued its first Technical Report, but progress towards unitization was delayed until August, 1992 when Exxon issued its Second Technical Report (Exxon Exhibit 10) and circulated that report to the working interest owners.

(14) The Exxon technical Report was undertaken exclusively by Exxon without requesting participation or involvement by Premier.

(15) On November 25, 1992, David Boneau on behalf of Yates advised Exxon that:

(a) Yates considered the engineering work in the August-1992 Technical Report to have "cut a few corners" and expressed concern that the modeling work required that permeability be increased by a factor of two or more and "cast doubt on the shaly-sand analysis of the logs which reduced log porosity and indirectly log permeability. Maybe a different log analysis would have given permeabilities that fit the computer model without modification. Probably you all believe there is no change that the basic geologic picture can be wrong." See Yates Exhibit 6 (2-A).

(b) Yates expressed concern that the areas outside the wells where primary production has been established in the UCC-LBC may not be developed economically by CO2.

(c) Yates questioned Exxon's workover reserve credited to Yates' Tracts 1111, 1311, 1313, 1511 and 1513 **but** states "Since the assumed workover reserves benefit Yates, we are willing to believe the Exxon explanation and leave the workover reserves in the Engineering Report (ie, Exxon Exhibit 10 part 2).

(16) On December 22, 1992, Exxon advises Yates that Exxon has increased the primary reserves credited to Yates Wells EP-5 (Unit E-Sec 30), Well EP-8 (Unit F-Sec 30) and C-36 (Unit A-Sec 31).

(17) By January 7, 1993 Yates has withdrawn its concerns about the Exxon Technical Report, but continues to express concerns over Exxon's AFEs, Exxon's participation formula and states "Exxon's voting procedures stinks."

(18) On April 8, 1994, Exxon with a working interest owner with 73.92% of the unit area and the proposed unit operator proposed to Yates other major working interest owner with 12.01% of the unit area, the formation of the subject unit utilizing a Two Phase Tract Participation Formula whereby for Phase I remaining primary oil per tract was weighted by 62.34%; waterflood reserves which included workover potential per tract was weighted by 37.56% and tertiary reserves were weighted by -0-% and then a Phase Two were the weighted percentages were 23.45%, 20.6375% and 55.9073% respectively.

(19) Under the Exxon participation formula Exxon would receive 79.71 % of Phase One oil recovery and 72.529% of Phase Two oil recovery while Yates would receive 9.837% of Phase One oil recovery and 11.55% of Phase Two oil recovery with Premier receiving -0-% of Phase One oil recovery and 2.279% of Phase Two oil recovery.

(20) On May 18, 1994, Premier withdrew its tracts from unit consideration because of inability to agree with the geology in the Exxon Technical Report and Premier did not enter into equity negotiations.

(21) On June 17, 1994, in Premier's absence, all other Working interest owners agreed to exclude Premier's tracts when discussing Premier's

letter of May 18, 1994. Yates then took the lead in developing a single phase formula using traditional parameters, including original oil in place. See Yates Exhibit 7, Sec 3(f) page 1)

(22) On January 18, 1995, Exxon and Yates agreed to a single phase Participation Formula whereby primary oil is weighted by 25%, secondary oil and workover potential is weighted by 50% and tertiary oil is weighted by 25% which results in Exxon receiving 73.92% of unit production, Yates receiving 12.01% of unit production and Premier receiving 1.0192% of unit production.

(23) Exxon/Yates proposed formula is predicated upon the intention to allow each tract to recovery its percentage of remaining primary oil, its percentage of secondary oil and workover oil potential and its percentage of tertiary oil potential by a weighted formula of 25% primary, 50% secondary/workover and 25% tertiary.

(24) In October, 1995, Premier attempted to test for oil production in its FV-3 Well in zones other than the UCC reservoir and produced approximately 10 BOPD until the test was terminated when Exxon disputed Premier's operational practices.

(25) Once Exxon commence its unitization study in 1991, no operator including Exxon, Yates or Premier, drilled any further wells pending the outcome of the unitization issues.

THE EXXON-PREMIER DISPUTE

EXXON'S TECHNICAL DATA:

(26) Under its analysis and adjustment factors, Exxon contends as to Premier's tracts 1109, 1309, 1509 and 1709 (Unit Tract 6) that:

(a) there is no remaining primary recovery potential and therefore gives Premier "0" credit for any remaining recovery of primary oil;

(b) Exxon proposes not to extend the waterflood pattern so as to recover any of Premier's secondary ("waterflood target") oil and therefore give Premier "0" credit for waterflood target oil.

(b) Exxon proposes to extend the CO_2 injection in such a pattern so as to flood only 25% of Tract 1109 and 50% of the balance of Premier's tracts thereby reducing Premier's share of tertiary ("CO_2 target") oil recovery by a factor of 25% to 50%.

(27) Exxon in support of its contention that neither the Premier FV-3 nor the Premier FV-1 is productive of primary oil in the UCC reservoir and that addition west-side injectors are probably not appropriate presented the following geologic/engineer evidence:

(a) that the UCC reservoir reveals that the hydrocarbon distribution is a function of both structure, which controls the downdip, southern and eastern limits of production and stratigraphy which controls the updip pinchout of the reservoir quality sands into tight carbonates on the northern and western sides of the reservoir; (Exxon Exhibit 10-Vol 1)

(b) that there is no apparent updip closure of structural contours in the north and west portions of the proposed unit;

(c) that the "relative value" of Premier tract on the western boundary of the reservoir is based upon log analysis of the Premier FV-3 Well from which Exxon has determined that there is a total gross thickness of 179 feet based upon picking the top of the Upper Cherry Canyon Downlap at 2589 feet in depth and the base of the Upper Cherry Canyon at 2768 feet in depth and therefore a total net thickness of 55 feet;

(e) When its interpretation of net thickness for the Premier FV-3 well is integrated into its hydrocarbon pore volume map (Exxon Exhibit 10 map 22) and its volumetric calculations (Exxon Exhibit 10-Vol 1 Exhibit E-4), **EXXON** concludes that Premier's Tract 6 has:

Original oil in place:	*13,730,000 BO*
Remaining Primary Oil in place:	*-0-*
Waterflood Target Oil in place:	*2,950,000 BO*
Workover Target Oil in place:	*-0-*
CO_2 Target Oil in place:	*10,070,000 BO*

See Exxon Exhibit 10 Vol 1 Exhibit E-6

(f) Exxon concluded that the average Water saturation for the UCC Reservoir by log calculations was 39% but for the Premier FV-3 well, but in its reservoir modeling adjusted the Sw factor to 60% because Gulf reported higher water production in that well than the averages; See Exxon Exhibit 10, Vol 1 Exhibit D-12,D-13, D-14)

(g) By increasing the Sw factor, Exxon calculated the Premier numbered tract 1709 (UCC) to have only 1,580,000 barrels of oil in place and that based upon a total cumulative recovery by the FV-3-Well of 5,100 barrels of oil Tract 6 has no remaining primary oil to be recovered;

(h) Based upon its analysis of Premier's FV #3 Well, Exxon further determined that Premier's Tract 6 had no potential for waterflood target oil and only 1.626 million barrels of CO_2 target oil by applying a weighted factor of 50% and 25% to Tract 6. See Exxon Exhibit 10- Vol. 1 Exhibit E-7 and E-6)

(i) Finally, based upon decline curve analysis (Exxon Exhibit 10 Vol 1 Exhibit G-9), and an 85% watercut, Exxon concluded that the Premier Tract 6 had no workover Target oil. See Exxon Exhibit 10 Vol 1 Exhibit G-19).

PREMIER'S TECHNICAL DATA:

(28) Premier, the owner/operator in Tract 6, appeared in opposition to the case.

(29) Premier contends that the revised Exxon proposed unit shape, reservoir parameters and participation formula fail to provide "relative value" to Tract 6 as required by Section 70-7-4(J) NMSA (1978), as amended, and unless corrected by the Division will be violated.

(30) Premier contends that Exxon failed to directly correlate the FV-3 Well with its direct east offset well, the WM-4 Well, and thereby made mistakes in correlation which reduced the net UCC reservoir for the FV-3 Well. (See Exxon Technical Report Exhibit C-6)

(31) Premier provided geologic and petroleum engineer evidence which demonstrates that:

(a) Stuart Hanson, Premier's expert geologic consultant, based upon regional geologic studies he has conducted for the Delaware and upon log correlations including log analysis of the Premier FV-3 Well, Premier has determined that the Premier FV-3 Well has a total gross thickness of 308 feet based upon picking the top of the Upper Cherry Canyon Downlap at 2544 feet in depth and the base of the Upper Cherry Canyon at 2852 feet in depth. (See Premier Exhibits 1, 2, and 3)

(b) Mr. Hanson concludes that:

1. the correct correlations will also increase reservoir quality and quantity for Premier location 1509 and that additional UCC reservoir potential exists in Premier's Section 25 (See Premier Exhibit 1)

2. the additional 82 net feet averages 53% SW and 15.4% porosity and by attributing the correct net thickness to the FV #3 Well changes the contouring of the "UPPER CHERRY CANYON HYDROCARBON THICKNESS MAP" which results in a significantly larger areal extent of the UCC reservoir extending to the north and northwest than that which the Exxon Technical Report attributes to the Premier's Section 25. (See Premier Exhibits 4, 4A,6, and 6A)

3. that the FV-2 Well log demonstrates potential for UCC reservoir extending westward into other acreage in Section 25 which Exxon excluded from the unit.

4. that Exxon has incorrectly correlated the log of the Premier FV #3 Well and as a result had failed to give the Premier FV #3 Well its correct total net thickness of UCC reservoir and failed to properly value the reservoir quality and quantity for Premier's Tract 6;

(c) Stuart Hanson, based upon calibrating and scaling the mudlog for the Premier FV #3 Well and to correlate the Mudlog with the Compensated Neutron Density Gamma Ray Log for that same well, concluded that:

1. the Premier FV #3 Well had an untested portion from 2777 feet to 2791 feet of the UCC reservoir which correlate to a productive portion from 2717 feet to 2730 feet in the offsetting WM #4 Well (Unit M) Section 30, (See Premier's Exhibit 5) and which, in terms of core analysis and log derived water saturations, showed this interval to be consistent with UCC primary production in the Unit area thereby invalidating Exxon's UCC base pick at 2668 feet.

2. that Exxon had incorrectly correlated these wells and in doing so have failed to properly credit the Premier Well with sufficient reservoir thickness.

3. that there is no barrier in the UCC reservoir which would isolate the Exxon's 55 net feet from the 82 net feet of additional pay thickness in the FV-3 Well.

(d) Mr. Hanson determined that Gulf improperly drilled and completed the FV-3 Well as a Delaware Well:

1. the FV-3 Well was drilled with fresh water (RW=.13 @ 76 degrees). This procedure caused the clays within the Delaware sand to swell and created damage around the wellbore;

2. the acid job channeled 50 feet above the top perforation;

3. the frac job was at such a high rate (25 BPM) and pressure 5100 psi) that the frac further extended the channeling created by the acid work.

(e) Mr. Terry Payne, Premier's expert petroleum engineering witness, based upon Exxon's Technical Report dated August 1992, concluded that:

1. Exxon failed to use traditional participation parameters including original oil in place such as those adopted by the Division for use in the Parkway Delaware Unit (NMOCD Case 10619)

2. The Exxon-Yates participation formula is flawed because it assigns waterflood & CO2 percentages based upon numbers assigned to tracts which are not adjusted for geological changes in the reservoir modeling study

3. The Exxon-Yates participation formula is flawed because it fails to allocate the total unit waterflood reserves equitably among the tracts:

Operator	Waterflood percent	assigned percentage
Premier	8.29%	-0-%
Exxon	41.09%	59.71%
Yates	49.63%	40.29%
MWJ	1.07%	-0-%

(See Premier Exhibit 9 page 4)

4. The Exxon-Yates participation formula is flawed because it fails to allocate the total unit CO2 flood reserves equitably among the tracts:

Operator	CO2 flood percent	assigned percentage
Premier	5.88%	4.08%
Exxon	56.49%	60.26%
Yates	36.01%	35.25%
MWJ	1.62%	0.42%

(See Premier Exhibit 9 page 6)

(f) Mr. Terry Payne, compared the following three options:

USING THE EXXON GEOLOGIC AND EXXON FORMULA the total remaining future production is allocated as follows:

Operator	percent of future production	assigned percentage
Premier	3.30%	1.02%
Exxon	60.63%	64.79%
Yates	35.74%	34.07%
MWJ	0.34%	0.12%

(See Premier Exhibit 9 pages 32-35)

USING THE EXXON GEOLOGY but SUBSTITUTING PREMIER'S PROPOSED FORMULA, the total remaining future production is allocated as follows:

Operator	percent of future production	assigned percentage of future production
Premier	3.03%	3.42%
Exxon	60.63%	59.28%
Yates	35.74%	36.20%
MWJ	0.34%	1.09%

(See Premier Exhibit 9 page 41)

USING PREMIER'S GEOLOGY AND PREMIER'S PROPOSED FORMULA, the total remaining future production is allocated as follows:

Operator	percent of future production	assigned percentage of future production
Premier	5.17%	4.52%
Exxon	57.80%	58.29%
Yates	36.70%	36.10%
MWJ	0.32%	1.08%

(See Premier Exhibit 9 page 49)

(g) Mr. Terry Payne concluded that of the above three options, the Premier geology and participation formula is fair because:

(i) it uses more traditional parameters like those adopted for Parkway Delaware Unit while the Exxon proposal dos not;

(ii) it allocates the total unit future oil production equitable among the tracts while the Exxon participation formula is flawed because it fails to do so.

(h) Mr. Payne further concluded that:

1. the Exxon's proposed 50% flood factors for Tract 6 (Exxon Technical Report Exhibit E-7) are arbitrary because they assume that the outer ring tract's producing wells will be located in the center of each 40-acre tract when in fact those wells could be located 330 feet from the outer boundary and be assigned a 75% flood factor:

2. Premier's Tract 6 can be excluded from the unit without any reduction in ultimate recovery if the four lease line CO_2 flood injection wells are drilled between Premier Tract 6 and the Yates' Tracts #3, 3b, 5a,and 5b (See Premier Exhibit 9 pages 9-12)

3. the average water saturation ("Sw") for the Premier FV-3 Well should be 39.1% because it is incorrect to use actual water production which is attributed to a poor cement job acid/frac height and water production from a squeezed zone and therefore Sw should not be increased to 59.9% as Exxon did.

4. By using the proper Sw factor, Premier concludes that the Premier's FV #3 Well has 2,910,000 barrels of oil in place and that based

upon a total cumulative recovery by Premier's FV #3 Well of 5,100 barrels of oil, Tract 6 still has remaining primary oil to be recovered (See Premier Exhibit 9 pages 30-31)

5. when Premier's interpretation of net thickness for the Premier FV-3 well is integrated into its hydrocarbon pore volume map (Premier Exhibit 8) and its volumetric calculations, Premier's VF-3 Well has an estimated 2,910,000 barrels of oil in place, 860,000 barrels of waterflood target oil and 2,380,000 barrels of CO2 target oil.

6. based upon the Exxon Technical Report, the Premier Tract 6 has UCC waterflood target oil of 2,320,000 barrels of oil in place, that Yates operated tracts bordering Premier's tracts have 2,680,000 barrels of UCC waterflood target oil and **therefore** the Exxon Report is biased when it attributed "-0-" waterflood reserves to the Premier Tract 6 (See Exxon Exhibit 10 G-19);

7. that Exxon should have extended the "outer ring-buffer" to include an additional column of 40-acre tracts in Section 25 in order to be consistent with Exxon's inclusion of the Exxon operated tracts in the Southeastern corner of the Unit which contain little or no waterflood target oil;

8. based upon the Exxon-Yates formula, the waterflood reserves improperly favored both Yates and Exxon as working interest owners in Section 30 to the disadvantage of Premier.

9. Exxon has failed to assign "relative value" to certain tracts because decline curve analysis concludes that an excessive amount of UCC remaining primary target oil was credited by Exxon to number tracts 1511, 1915, 1919, 2111, 2113 and 1917; (See Premier Exhibit 9 page 14-25)

10. Exxon has failed to properly calculate "relative value" for waterflood target oil by including excessive workover reserve credit for Tract 1111 because the Yates EP #7 Well (1111) had an estimated workover potential of 266,600 barrels (Exxon Exhibit 10 G-19) but the well has only produced 2,000 barrels to date. Therefore these reserves further biased the Exxon report in favor of Exxon and Yates who are both working interest owners in Section 30. (See Premier Exhibit 9 page 29 and Exhibits 1, 2, 3, showing the logs for the FV-3, EP-7 and EP-6).

(i) Mr. Payne further concluded that from a reservoir engineering perspective, a lease line injection plan is a practical alternative to including the Premier tract in the proposed unit.

(j) Mr. Payne concluded that there were significant recoverable oil reserves underlying Premier's Tract 56 which can be recovered both by waterflooding and by carbon dioxide flooding.

COMMISSION FINDINGS:

(32) The COMMISSION finds that:

(a) Section 70-2-33(H) NMSA of the Oil and Gas Act defines Correlative Rights as "...the opportunity afforded, as far as it is practicable to do so, to the owners of each property in a pool to produce without waste his just and equitable share of the oil or gas or both in the pool, being an amount so far as can be practicably determined and so far as can be practicably obtained without waste, substantially in the proportion that the quantity of recoverable oil or gas or both under the property bears to the total recoverable oil or gas or both in the pool and for such purpose, to use his just and equitable share of the reservoir energy;"

(b) Section 70-7-6(B) NMSA of the Statutory Unitization Act states "If the Division determines that the participation formula contained in the unitization agreement does not allocate unitized hydrocarbons on a fair, reasonable and equitable basis, the Division shall determine relative value, from the evidence introduced at the hearing taking into account the separately owned tracts in the unit area, exclusive of physical equipment for development of oil and gas by unit operations, and the production allocated to each tract shall be the proportion that the relative value of each tract so determined bears to the relative value of all tracts in the unit area.

(c) Section 70-7-4 (J) NMSA of the Statutory Unitization Act says "relative value" means the value of each separately owned tract for oil and gas and its contributing value to the unit in relation to like values of other tracts in the unit, taking into account acreage, the quantity of oil and gas recoverable therefrom, location on structure, its probable productivity of oil and gas in the absence of unit operations, the burden of operation to which the tract will or is likely to be subjected, or so many of said factors, or such other pertinent engineering, geological, operating or pricing facts, as may be reasonably susceptible of determination.

(d) Section 70-7-7 NMSA of the Statutory Unitization Act provides that the Division has the authority and obligation to approve or prescribe a plan or unit agreement for unit operation which **shall include**:

"A. ....area of the pool <u>or part of the pool</u> to be operated as a unit and the vertical limits to be included,..."

"C. an allocation to the separately owned tracts in the unit area of all the oil and gas that is produced from the unit area..."

(33) The COMMISSION further <u>FINDS</u> that:

(a) Exxon proposes to include a column of 40-acre tracts including four 40-acre tracts (Tract 6) operated by Premier within the western boundary the Avalon Unit but does not intend to attempt to recovery from those tracts any remaining primary oil or any secondary oil by waterflooding;

(b) The Secondary Recovery Project ("waterflooding") is the reason for the Unit, while the Tertiary Recovery Project ("CO2") has only some probability of happening/not happening;

(c) on June 17, 1994, the working interests owners met to discuss the Exxon Technical Report and unanimously agreed to **exclude** Premier's Tract 6 from both the Secondary Recovery and Tertiary Recovery project in the Avalon Unit;

(d) Exxon failed to present adequate evidence to demonstrate any substantial change in its Technical Report to now justify including the Premier Tract in the Unit;

(e) under the Exxon analysis the inclusion of the Premier Tract 6 is **not necessary** in order to effectively carry on the Secondary Recovery Project:

(f) Contrary to the testimony of Mr. David Boneau on behalf of Yates that reserves under certain portions of Yates' acreage would remain unrecovered if the Premier acreage were deleted from the unit, the Secondary Recovery Plan as proposed by Exxon provide no means for the recovery of any oil west of the existing Yates' wells.

(g) Since recovery of any such oil is thereby deferred to a tertiary recovery phase for which no commitment has been made, the implication that correlative rights would be impaired and that waste would occur if the Premier acreage were deleted from the proposed unit is groundless.

(h) At such time as firm plans are formulated for a tertiary recovery project, consideration may be given to (a) a lease line injection agreement with Premier and/or (b) including the Premier acreage in that CO2 project.

(i) that Exxon's proposed Tertiary Recovery ("CO2") Project is not supported by substantial scientific evidence, is speculative, inadequately studied and is **premature**;

(j) under the Exxon analysis there is **no increase** in ultimate recovery of secondary oil from the unit by including the Premier Tract 6;

(k) the Exxon analysis of the CO_2 potential is speculative and not been the subject of any scientific study to determine its feasibility and therefore any forecasted increase in ultimate recovery of tertiary oil from the unit by including the Premier Tract 6 is speculative;

(l) Exxon seeks to include the Premier Tract 6 only as a "protection buffer" and assigns no "contributing value" for secondary oil recovery; See Section 70-7-4(J) NMSA 1978; and

(m) that Premier's Tract 6 can be excluded in accordance with the New Mexico Statutory Unitization Act.

(34) The COMMISSION further finds that Exxon's proposal to include the Premier Tract 6:

(a) fails to conform to the statutory requirements set forth in Paragraph (27) above;

(b) fails to appropriately distribute hydrocarbon pore volume with accurate corresponding reservoir parameters and has not established the appropriate relative value to be attributed to each tract including Tract 6; and

(c) fails to submit an appropriate participation formula to allow the owners of Tract 6 to recover their proportionate share of the total remaining recoverable hydrocarbons underlying the unit.

(d) the horizontal and vertical limits of said unit have **not** been reasonably defined by development;

(e) Exxon's Technical Report is flawed because it incorrectly correlates the top and base of the Upper Cherry Canyon Reservoir in Premier's FV #3 Well located as (Unit Well 1709) within Premier's Tract 6 which results in Exxon assigning 55 feet of net thickness to this well which in turn is used to contour the various geologic maps and ultimate the hydrocarbon pore volume map from which Exxon concludes that Premier Tract 6 has no remaining primary oil potential;

(f) Premier's FV #3 Well when correctly correlated has a net porosity thickness in the Upper Cherry Canyon Reservoir of 137 feet which is some 82 feet more than assigned by Exxon;

(g) Premier's hydrocarbon pore volume map establishes that there are substantial additional recoverable oil remaining under Premier's Tract 6.

(h) Premier's Tract 6 contains substantial additional oil which can be recovered by both waterflooding and carbon dioxide flooding.

(i) Premier Oil & Gas Inc. presented geologic and petroleum engineer evidence which demonstrates the appropriate distribution of reservoir pore volume with corresponding adjustments and the proper relative value to be attributed to Tracts 1109, 1309, 1509, 1709 and others to allow the owners of these tracts the opportunity to recover their proportionate share of the total recoverable hydrocarbons from the unit.

(j) Exxon's Technical Report in assigning "relative value" to each tract, determined that based upon logged derived water saturations (Sw=0.46) there are 2,320,000 barrels of waterflood target oil to be recovered from Premier's Tract 6 **but** then arbitrarily eliminated all of that incremental oil by increasing the water saturation (Sw=0.60) based upon water production volumes reported by Gulf when it operated the Premier FV-3 Well;

(k) Premier accurately determined that SW should be derived from log analysis and not actual water production because the actual water production from the FV-3 Well is attributed to water encroachment above the Upper Cherry Canyon Reservoir;

(35) The proposed Secondary Recovery ("waterflood") Project, with the deletion of Premier Tract 6, should result in the additional recovery of approximately 8,269,400 barrels of oil.

(36) The unitized management, operation and further development of the Avalon Unit Area, as modified by this Order, is reasonably necessary to effectively carry on secondary recovery operations and will substantially

increase the ultimate recovery of oil and gas from the unitized portion of the pool.

(37) The unitized method of operation as applied to the Avalon Unit Area (with the deletion of the Premier Tract 6) is feasible and will result with reasonable probability in the increased recovery of substantially more oil and gas from the unitized portion of the pool than would otherwise be recovered without unitization.

(38) The estimated additional costs of such operations will not exceed the estimated value of the additional oil so recovered plus a reasonable profit.

(39) Such unitization and adoption of a unitized method of operation will benefit the working interest owners and royalty owners of the oil and gas rights within the Avalon Unit Area.

(40) The granting of the application with the deletion of Tract 6 as proposed by Premier in this case will have no adverse effect upon the Delaware formation.

(41) The deletion of Premier's Tract 6 from the Avalon Unit Agreement and the Avalon Unit Operating Agreement provide for unitization and unit operation of the Avalon Unit Area upon terms and conditions that are fair, reasonable and equitable, and include:

a) an allocation to the separately owned tracts in the unit area of all oil and gas that is produced from the unit area and which is saved, being the production that is not used in the conduct of unit operations or not unavoidably lost;

b) a provision for the credits and charges to be made in the adjustment among the owners in the unit area for their respective investments in wells, tanks, pumps, machinery, materials and equipment contributed to the unit operations;

c) a provision governing how the costs of unit operations, including capital investments, shall be determined and charged to the separately owned tracts and how said costs shall be paid, including a provision providing when, how, and by whom, such costs shall be paid, including a provision providing when, how and by whom such costs shall be charged to each owner or the interest of such owner, and how his interest may be sold and the proceeds applied to the payment of his costs;

d) a provision for carrying any working interest owner on a limited, carried or net-profits basis, payable out of production, upon terms and conditions which are just and reasonable, and which allow an appropriate charge for interest for such service payable out of production, upon such terms and conditions determined by the Division to be just and reasonable;

e) a provision designating the Unit Operator and providing for supervision and conduct of the unit operations, including the selection, removal or substitution of an operator from among the working interest owners to conduct the unit operations;

f) a provision for a voting procedure for decisions on matters to be decided by the working interest owners in respect to which each working interest owner shall have a voting interest equal to his unit participation; and,

g) the time when the unit operations shall commence and the manner in which, and the circumstances under which, the operations shall terminate and for the settlement of accounts upon such termination.

(42) Section 70-7-7.F. N.M.S.A. of said "Statutory Unitization Act" provides that any working interest owner who has not agreed in writing to participate in a unit could have relinquished to the Unit Operator all of its operating rights and working interest in and to the unit until his share of the costs has been repaid plus an additional 200 percent thereof as a non-consent penalty.

(43) At the time of the hearing, the applicant requested that no 200% penalty be assessed these working interest owners in said unit who have not committed their interests.

(44) The statutory unitization of the Avalon Unit Area is in conformity with the above findings, and will prevent waste and protect correlative rights of all interest owners within the proposed unit area, and should be approved.

IT IS THEREFORE ORDERED:

(1) The application of Exxon for the Avalon Unit Agreement covering 1971.8 acres, more or less, of Federal, State and Fee lands in the Avalon-Delaware Pool, Eddy County, New Mexico, is hereby approved for statutory unitization pursuant to the "Statutory Unitization Act", Section 70-7-1 through 70-7-21, N.M.S.A. (1978), **SUBJECT** to the following:

That Premier's Tract 6 shall be deleted and the same hereby is deleted from this unit.

(2) The lands covered by said Avalon Unit Agreement shall be designated the Avalon Unit Area and shall comprise the following described acreage in Lea County, New Mexico:

Tract 1:	SW/4 Sec 29, T20S, R28E
Tract 2:	Sec 31, T20S, R28E
	Lot 4(NW/4NW/4) Sec 4 T21S, R27E
	Lots 1&2 (N/2NE/4) Sec 5 T21S, R27E
Tract 3-A:	Lot 1 (NW/4NW/4) Sec 30, T20S, R28E
Tract 3-B:	Lot 2 (SW/4NW/4) Sec 30, T20S, R28E
Tract 3-C:	NE/4NW/4 Sec 30, T20S, R28E
Tract 3-D:	SE/4NW/4 Sec 30, T20S, R28E
Tract 3-E:	SW/4NE/4 Sec 30, T20S, R28E
Tract 4-A:	NW/4SE/4 Sec 30, T20S, R28E
Tract 4-B:	NE/4SE/4 Sec 30, T20S, R28E
Tract 5-A:	Lot 3 (NW/4SW/4) Sec 30, T20S, R28E
Tract 5-B:	Lot 4 (SW/4SW/4) Sec 30, T20S, R28E
Tract 5-C:	NE/4SW/4 Sec 30, T20S, R28E
Tract 5-D:	SE/4SW/4 Sec 30, T20S, R28E
Tract 5-E:	SW/4SE/4 Sec 30, T20S, R28E
Tract 5-F:	SE/4SE/4 Sec 30, T20S, R28E
Tract 6:	**[deleted]**
Tract 7:	E/2NE/4 Sec 36, T20S, R27E
Tract 8:	E/2SE/4 Sec 36, T20S, R27E
Tract 9:	Lots 1 & 2 (N/2NE/4) Sec 6, T21S, R27E
Tract 10:	W/2W/2, NE/4NW/4, SE/4SW/4 Sec 32, T20S, R28E
Tract 11:	SE/4NW/4 & NE/4SW/4 Sec 32, T20S, R28E
Tract 12:	E/2SE/4, SW/4NW/4 Sec 32, T20S, R28E

(3) The vertical limits of said unit area shall comprise that interval which includes the "Upper Cherry Canyon Reservoir" ("UCC") and the "Lower Cherry Canyon/Upper Brushy Canyon Reservoir" ("LCC-UBC") and extends from an upper limit between 100 feet above the base of the Goat Seep Reef to the top of the Bone Springs formation to a lower limit of the base of the Brushy Canyon formation which are defined at all points under the unit area correlative to a depth of 2,378 feet and 4,880 feet, respectively, as identified on the Compensated Neuron/Litho density/Gamma Ray Log dated September 14, 1990 for the Exxon Yates "C" Federal Well No. 36, located in Unit A of Section 31, T20S, R28E, NMPM, Eddy County, New Mexico.

(4) The applicant shall institute a waterflood project for the secondary recovery of oil and associated gas, condensate and all associated liquefiable hydrocarbons within and produced from the unit area, and said waterflood project is the subject of Division Case No. 11194.

(5) The applicant's request for approval of a tertiary recovery ("CO2") project is premature and is hereby **denied.**

(6) The Avalon Unit Agreement and the Avalon Unit Operating Agreement, which were submitted to the Division at the time of the hearing as Exhibit Nos. __ and __, respectively, are hereby incorporated by reference into this order.

(7) The Avalon Unit Agreement and the Avalon Unit Operating Agreement provide for unitization and unit operation of a portion of the Delaware formation upon terms and conditions that are fair, reasonable and equitable **PROVIDED** the following amendments are made:

THAT THE PREMIER TRACT NO. 6 SHALL BE DELETED.

(8) This order shall not become effective unless and until seventy-five percent of the working interest and seventy-five percent of the royalty interest owners in the Unit Area have approved the plan for unit operations as required by Section 70-7-8, N.M.S.A., 1978 Compilation.

(9) If the persons owning the required percentage of interest in the Unit Area as set out in Section 70-7-8, N.M.S.A., 1978 Compilation, do not approve the plan for unit operations within a period of six months from the date of entry of this order, this order shall cease to be of further force and

effect and shall be revoked by the Division, unless the Division shall extend the time for ratification for good cause shown.

(10) When the persons owning the required percentage of interest in the Unit Area have approved the plan for unit operations, the interests of all persons in the Unit Area are unitized whether or not such persons have approved the plan or unitization in writing.

(11) Any working interest owner who has not agreed in writing to participate in the unit prior to the effective date of this order shall be deemed to have relinquished to the Unit Operator all of his operating rights and working interest in and to the unit until his share of the costs has been repaid. Such repayment shall not include a non-consent penalty (Section 70-7-7.F N.M.S.A. 1978)

(12) The applicant as Unit Operator shall notify in writing the Division Director of any removal or substitution of said Unit Operator by any other working interest owner within the area.

(13) Jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary

DONE in Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

JAMI BAILEY, Member

WILLIAM W. WEISS, Member

WILLIAM J. LEMAY Chairman

S E A L

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION COMMISSION

IN THE MATTER OF THE HEARING CALLED BY THE OIL CONSERVATION COMMISSION FOR THE PURPOSE OF CONSIDERING:

CASE NO. 11297
(DE NOVO)

APPLICATION OF EXXON CORPORATION FOR A WATERFLOOD PROJECT, QUALIFICATION FOR THE RECOVERED OIL TAX RATE PURSUANT TO THE "NEW MEXICO ENHANCED OIL RECOVERY ACT" FOR SAID PROJECT, AND FOR 18 NON-STANDARD OIL WELL LOCATIONS, EDDY COUNTY, NEW MEXICO.

CASE NO. 11298

APPLICATION OF EXXON CORPORATION FOR STATUTORY UNITIZATION, EDDY COUNTY, NEW MEXICO.

ORDER NO. R-10460-B

ORDER OF THE COMMISSION

BY THE COMMISSION:

This cause came on for hearing at 9:00 a.m. on December 14, 1995 at Santa Fe, New Mexico, before the Oil Conservation Commission of the State of New Mexico, hereinafter referred to as the "Commission".

NOW, on this 12th day of March, 1996, the Commission, a quorum being present, having considered the testimony and the record, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Commission has jurisdiction of this cause and the subject matter thereof.

(2) Case Nos. 11297 and 11298 were consolidated at the time of the hearing, and the record from the Examiner hearing held on June 29 and 30, 1995 was incorporated into the record without objection by any party.

EXHIBIT
6

(3) The applicant in Case No. 11298, Exxon Corporation ("Exxon"), seeks the statutory unitization, pursuant to the "Statutory Unitization Act," Sections 70-7-1 through 70-7-21 NMSA (1978), for the purpose of establishing a secondary recovery project, of all mineral interests in the designated and Undesignated Avalon-Delaware Pool, underlying its proposed Avalon (Delaware) Unit Area, comprising 2118.78 acres, more or less, of State, Federal, and fee lands in Eddy County, New Mexico, said unit to henceforth be known as the Avalon (Delaware) Unit Area; the applicant further seeks approval of the Unit Agreement and the Unit Operating Agreement which were submitted in evidence at the time of the hearing as applicant's Exhibit Nos. 2 and 3.

(4) In Case No. 11297, Exxon seeks authority to:

(a) institute a waterflood project in its proposed Avalon (Delaware) Unit Area by the injection of water into the designated and Undesignated Avalon-Delaware Pool through 18 new wells to be drilled as injection wells and one well to be converted from a producing oil well to an injection well;

(b) qualify the project for the recovered oil tax rate pursuant to the "New Mexico Enhanced Oil Recovery Act" (Laws 1992, Chapter 38, Sections 1 through 5); and

(c) drill 18 new producing wells throughout the project area at locations considered to be unorthodox.

(5) The applicant proposes that the unit comprise the following described area in Eddy County, New Mexico:

<u>Township 20 South, Range 27 East, NMPM</u>
Section 25: E½E½
Section 26: E½E½

<u>Township 20 South, Range 28 East, NMPM</u>
Section 29: SW¼SW¼
Section 30: Lots 1-4, E½W½, SW¼NE¼, SE¼
Section 31: Lots 1-4, E½W½, E½ (All)
Section 32: SW¼NE¼, W½, W½SE¼

Township 21 South, Range 27 East, NMPM

Section 4:	Lot 4
Section 5:	Lots 1 and 2
Section 6:	Lots 1 and 2

(6) The proposed Unit Area includes portions of the designated and Undesignated Avalon-Delaware Pool. The pool was discovered in 1983, and no development wells have been drilled in the pool since 1985. The horizontal and vertical limits of the Unit Area have been reasonably defined by development.

(7) The proposed "unitized formation" is that interval underlying the Unit Area described as the Delaware Mountain Group, extending from 100 feet above the base of the Goat Seep Reef to the top of the Bone Spring formation and including, but not limited to, the Cherry Canyon and Brushy Canyon Formations, as identified by the Compensated Neutron/Lithodensity/Gamma Ray Log dated September 14, 1990 run in the Exxon Corporation Yates "C" Federal Well No. 36, located 1305 feet from the North and East lines of Section 31, Township 20 South, Range 28 East, NMPM, Eddy County, New Mexico, with the top of the unitized formation being found in said well at a depth of 2,378 feet below the surface (869 feet above sea level) and the base of the unitized formation being found at a depth of 4,880 feet below the surface (1,633 feet below sea level), or stratigraphic equivalents thereof.

(8) The proposed Unit Area contains twelve separate tracts of land, the working interests in which are owned by forty-three different persons. Prior to October 1, 1995, Exxon operated five of the twelve tracts, five tracts were operated by Yates Petroleum Corporation ("Yates"), one tract was operated by Premier Oil & Gas, Inc. ("Premier"), and one tract was operated by MWJ Producing Company. There are twenty-four royalty and overriding royalty interest owners in the Unit Area.

(9) At the time of the hearing, the owners of 98.66% of the working interest, and the owners of over 98% of the royalty and overriding interest, had voluntarily joined the Unit. The 98% royalty owner approval includes the U.S. Bureau of Land Management and the Commissioner of Public Lands, who are the two largest royalty owners in the unit. The participation formula, proposed by Exxon and Yates and approved by all parties except Premier, is as follows:

25% remaining primary reserves as of 1/1/93;
50% waterflood reserves; and
25% tertiary reserves.

(10) The applicant has conducted negotiations with interest owners within the Unit Area for over four years. Therefore, the applicant has made a good faith effort to secure voluntary unitization within the above-described Unit Area.

(11) All interested parties who have not agreed to unitization were notified of the hearing by applicant. At the hearing on these matters, Yates entered its appearance and presented evidence in support of the applications. Unit Petroleum Company made a statement in support of the applications. At the examiner hearing on these matters, MWJ Producing Company made a statement in support of the applications.

(12) Premier, the working interest owner of Tract 6 of the unit, comprising the E/2 E/2 of Section 25, Township 20 South, Range 27 East, NMPM, entered an appearance and presented evidence in opposition to the application, and requested that Tract 6 be deleted from the Unit Area. In the alternative, Premier requested that the following participation formula be adopted by the Commission:

50% original oil in place;
10% 1/1/93 producing rate;
20% remaining primary; and
20% future production.

Premier did not propose the above formula until December 13, 1995, the day before the hearing. No interest owner has approved this formula.

(13) Exxon is the largest working interest owner in the proposed Unit Area with 61 percent of the unit acreage and approximately 80% of current production. A substantial majority of working interest acreage owners, excluding Exxon, requested that Exxon prepare a technical report of the Avalon-Delaware Pool. Exxon prepared the "Report of the Technical Committee for the Working Interest Owners" (Exxon Exhibit 10, Volumes I and II; hereafter, the "Technical Report") at its own expense which according to testimony, cost Exxon approximately $500,000.

(14) The applicant proposes to institute a waterflood project at an expected initial cost of $14,400,000 for the secondary recovery of oil and associated gas, condensate, and all associated liquefiable hydrocarbons within and to be produced from the proposed Unit Area (being the subject of Case No. 11297). The estimated reserves recoverable from the waterflood project are 8.2 million barrels of oil.

(15) The Unit also has potential as a tertiary (CO_2 injection) project. Evidence presented at the hearing shows that:

(a) estimated recoverable tertiary reserves are 39.9 million barrels of oil;

(b) if such a CO_2 flood is instituted in the proposed Unit Area, it will likely be the first CO_2 project in the area and could facilitate other CO_2 floods;

(c) this project will provide valuable data which could justify additional waterflood projects and tertiary projects in other Delaware pools in New Mexico;

(d) institution of the CO_2 flood depends upon waterflood performance, results of future CO_2 injectivity tests, and perception of future oil prices. A minimum of 3 years of water injection would probably be required to repressure the reservoir prior to commencing a CO_2 injection project;

(e) the risk associated with a successful CO_2 flood in the Avalon Delaware Field is significantly higher than risk associated with the proposed waterflood because CO_2 technology is relatively new to Delaware Sand Fields and there is less data available; and

(f) CO_2 injection in the Delaware is of major importance to the State because primary and secondary recovery in the Delaware amounts to less than 10% of the original oil-in-place. CO_2 could greatly increase the recovery factor. A successful CO_2 project would serve as a catalyst for others in New Mexico.

(16) At issue are the various factors which form the basis for the participation formula which in turn governs the relative ownership of future oil and gas produced from the unit.

(17) <u>Exxon presented evidence that</u>:

(a) the pay in the Avalon Field is Upper Cherry Canyon and Upper Brushy Canyon Sands. There is no Bell Canyon Sand present;

(b) Exxon's geologic model was calibrated by actual production and verified by a reservoir simulation program;

(c) Exxon's geological pick of the base of the Upper Cherry reservoir is consistent with regional geologic markers found throughout the Avalon-Delaware Pool (Exxon Exhibits 16, 19a, and 19b);

(d) the waterflood project area includes 1088.50 acres in the center of the Unit Area. The outer or "fringe" tracts were included in the Unit Area based upon their CO_2 flood potential and not their waterflood potential. The "fringe" tracts will participate in production from inception of the Unit due to their CO_2 potential and the agreement to a single stage formula;

(e) a well critical to both sides' interpretation is the Premier's FV3 Well which produced 5100 barrels of oil prior to ceasing production. The nearest geologically analogous well to the FV3 Well, the Yates Citadel ZG1 Well, located in the NE/4 NE/4 of Section 36, Township 20 South, Range 27 East (Unit Tract 7), immediately to the South of the FV3 Well, produces from an interval similar to the FV3 Well, and is expected to produce equivalent amounts of oil (6000 barrels of primary oil);

(f) Premier claimed that the FV3 Well suffered completion problems, but Exxon claimed that completion problems were highly unlikely and that production is in line with Gulf's initial expectations;

(g) the Technical Report and the Unit Agreement attribute no remaining primary or waterflood reserves to Tract 6, operated by Premier. Primary production data from the Yates Citadel ZG1 Well, and other offset wells, support the Technical Report's estimate of primary and waterflood reserves in Unit Tract 6;

(h) Premier's engineering consultant stated that Tract 6 was not given credit for waterflood target "reserves" (referencing Technical Report Exhibit E-6). However, Technical Report Exhibit E-6 does not set forth "reserves," but rather "waterflood target oil-in-place." "Target oil-in-place" is a volumetric value used as a starting point in calculating recoverable reserves, on which equity is based. In order to obtain recoverable reserves, the "target oil-in-place" must be adjusted by factors such as well-to-well continuity, sweep efficiency, floodable oil, pattern effects, and development costs. This was done on all tracts, including Premier's Tract 6;

(i) The inclusion of Tract 6 in the Unit will enhance CO_2 flood sweep efficiency. Conversely, omitting Tract 6 from the Unit, as Premier advocated will diminish CO_2 flood sweep efficiency in that area of the Unit resulting in waste.

(j) the unit boundary has not changed since 1991.

(18) Yates presented evidence that:

(a) deleting Tract 6 from the Unit would substantially reduce recoverable tertiary reserves under Tracts 3, 5, and 7, which are adjacent to Tract 6;

(b) deletion of Tract 6 from the Unit will decrease the amount of oil produced from the Unit by approximately 2,000,000 barrels, thus causing loss of royalties and severance taxes to the State;

(c) Yates' geologist had done independent work which confirmed Exxon's geologic interpretation in the area contested by Premier;

(d) in June 1994 the working interest owners considered excluding Tract 6 from the Unit, but never agreed to do so. However, Premier thought that they were excluded;

(e) moving the proposed western CO_2 injection wells further west, as advocated by Premier, will diminish the CO_2 sweep efficiency on Unit Tracts 3 and 5; and

(f) negotiations over the equity formula in the Unit Agreement lasted approximately one year. Deleting Tract 6 from the Unit Area would require additional negotiations among working interest owners, revision of unit documents, and other delays. Yates' witness testified that if Tract 6 is deleted, unitization may never occur.

(19) Premier presented evidence that:

(a) Tract 6 has substantial primary and waterflood reserves which were not properly evaluated when participation percentages were formulated. Premier's claim is based upon "oil-in-place" log calculations which excludes recovery efficiency. The only Delaware completion on Tract 6, the FV3 Well, produced only 5100 barrels of oil (the analogous offset well, the Yates Citadel ZG1 Well, will produce an estimated 6000 barrels of oil);

(b) Premier's FV3 Well was drilled and completed by Gulf in 1984, and purchased by Premier in 1990. The interval below the Exxon pick of the base of the Upper Cherry Canyon reservoir is claimed by Premier to be productive in the FV3 Well. Premier's geologist utilizing detailed mapping techniques has made different "picks" in the FV3 Well resulting in an additional 82 feet of net pay which, based upon log analysis, would increase Premier's Unit participation percentage;

(c) Gulf improperly drilled and completed the FV3 Well. They used a fresh water mud which tends to swell clays within the Delaware Sand, thus creating damage and reduced productivity. The acid job channeled 50 feet above the top of their perforations and the frac job further extended the channel behind pipe because of its high pumping rate;

(d) Exxon proposes to include a column of 40-acre tracts including four 40-acre tracts (Tract 6) operated by Premier within the western boundary of the Avalon Unit but does not intend to attempt to recover from those tracts any remaining primary oil, any workover oil or any secondary oil by waterflooding;

(e) Premier's's hydrocarbon pore volume map shows that there is substantial recoverable oil remaining under Premier's Tract 6.

(f) the Exxon - Yates participation formula is flawed because it failed to allocate total unit waterflood and CO_2 reserves equitably among the tracts;

(g) the best formula is Premier's proposed participation formula which distributes equity based upon the following:

50% original oil in place;
10% 1/93 rate;
20% remaining primary and
20% future production

(h) the Premier geology is correct and their participation formula is fair because:

(i) it uses more traditional parameters like those adopted for Parkway Delaware Unit while the Exxon proposal does not;

(ii) it allocates the total unit future oil production equitably among the tracts while the Exxon participation formula is flawed because it fails to do so.

(20) Based upon the foregoing, the Commission concludes that:

(a) Premier's claim of an additional 82 feet of "pay" is refuted by their own workover attempt in October, 1995. Their workover of the FV3 Well in what they considered to be "pay not accounted for in the Unit participation formula", resulted in 6 to 7 barrels of oil and 300 barrels of water per day, which is uneconomic. This section overlies the disputed 82 feet of additional pay, but both zones correlate with uneconomic production from the Yates Citdel ZG "Stat" No. 1, the south offset to this well;

(b) Premier's arguments and proposed participation formula is limited to oil-in-place calculations. The oil-in-place is a log calculation which may or may not be producible. Equal value was given to potential CO_2 reserves compared to primary and secondary recoveries which are far less risky operations.

(c) the geological interpretation of Premier's was a more believable and scientifically sound interpretation. Unfortunately, for Premier, the production results show the additional potential pay to be uneconomic;

(d) Premier has had five years to test the Delaware potential on their marginally economic lease. They have failed to prove additional recoverable reserves, leaving only the risky potential of CO_2 flooding;

(e) Premier did not present their proposal to Exxon in a timely manner, although they were afforded the opportunity from the beginning to do so. Premier did not carry out their responsibilities, by delaying involvement in negotiations. They benefited from Yates' efforts at negotiation, but did not contribute to the process. An estimated six to twenty-four months would be required to re-negotiate a new unitization formula. Such a delay constitutes waste;

(f) the correlative rights of all interest owners are protected by the Exxon Unit participation formula. It is not the Commission's responsibility to change a formula which was the product of negotiation if that formula is "fair". That is not to say that other formulas, derived as a result of negotiations would not be "fair" because there is no one perfect formula. Premier will benefit by receiving income from the start even though their tract is uneconomic today. However, CO_2 "potential" earns Premier the right according to Exxon's formula to receive income from the start of unit operation;

(g) Premier protests the division of its property for the formation of the unit, but no convincing alternative was presented to demonstrate that the ultimate recovery of reserves would result from such proposed division. Excluding Premier's tract would in fact delay unitization and disrupt the orderly development of a CO_2 flood.

(21) The proposed unitized method of operation as applied to the Avalon (Delaware) Unit is feasible and will result with reasonable probability in the recovery of substantially more oil and gas from the unitized portion of the Avalon-Delaware Pool than would otherwise be recovered without unitization.

(22) Such unitization and adoption of applicant's proposed unitized method of operation will benefit the working interest owners and royalty owners of the oil and gas rights within the Avalon (Delaware) Unit Area.

(23) The granting of the applications in these cases will have no adverse effect upon the interest owners in the Avalon-Delaware Pool.

(24) The estimated additional costs of such operations will not exceed the estimated value of the additional oil so recovered.

(25) The applicant's Exhibit Nos. 2 and 3 in this case, being the Unit Agreement and the Unit Operating Agreement, should be incorporated by reference into this order.

(26) The unitized management, operation and further development of the Avalon (Delaware) Unit Area, as proposed, is necessary to effectively increase the ultimate recovery of oil and gas from the unitized portion of the Avalon-Delaware Pool.

(27) The Avalon (Delaware) Unit Agreement and the Avalon (Delaware) Unit Operating Agreement provide for unitization and unit operation of the Avalon (Delaware) Unit Area upon terms and conditions that are fair, reasonable and equitable, and include:

(a) a participation formula which will result in fair, reasonable and equitable allocation to the separately owned tracts of the Unit Area of all oil and gas that is produced from the Unit Area and which is saved, being the production that is (i) not used in the conduct of unit operations, or (ii) unavoidably lost;

(b) a provision for the credits and charges to be made in the adjustment among the owners in the Unit Area for their respective investments in wells, tanks, pumps, machinery, materials and equipment contributed to unit operations;

(c) a provision governing how the costs of unit operations including capital investments shall be determined and charged to the separately-owned tracts and how said costs shall be paid, including a provision providing when, how and by whom such costs shall be charged to each owner, or the interest of such owner, and how his interest may be sold and the proceeds applied to the payment of his costs;

(d) a provision for carrying any working interest owner on a limited or carried basis payable out of production, upon terms and conditions which are just and reasonable, and which allow an appropriate charge for interest for such service payable out of production, upon such terms and conditions determined by the Commission to be just and reasonable;

(e) a provision designating the Unit Operator and providing for supervision and conduct of the unit operations, including the selection, removal and substitution of an operator from among the working interest owners to conduct the unit operations;

(f) a provision for a voting procedure for decisions on matters to be decided by the working interest owners in respect to which each working interest owner shall have a voting interest equal to his unit participation; and

(g) a provision specifying the time when unit operations shall commence and the manner in which, and the circumstances under which, the operations shall terminate and for the settlement of accounts upon such termination.

(28) The applicant requested that a 200 percent penalty of cost incurred be assessed against those working interest owners who do not voluntarily agree to join the proposed unit.

(29) Section 70-7-7.F NMSA (1978) provides that the unit plan of operation shall include a provision for carrying any working interest owner subject to limitations set forth in the statute, and any non-consenting working interest owner so carried shall be deemed to have relinquished to the unit operator all of his operating rights and working interest in and to the unit until his share of the costs has been repaid plus an amount not to exceed 200 percent thereof as a non-consent penalty.

(30) The Unit Operating Agreement contains a provision whereby any working interest owner who elects not to pay his share of unit expense shall be liable for his share of such unit expense plus an additional 200 percent thereof as a non-consent penalty, and that such costs and non-consent penalty may be recovered from each non-consenting working interest owner's share of unit production.

(31) A non-consent penalty of 200 percent should be adopted in this case. The applicant should be authorized to recover from unit production each non-consenting working interest owner's share of unit expense plus 200 percent thereof as provided in the Unit Operating Agreement.

(32) The statutory unitization of the Avalon (Delaware) Unit Area is in conformity with the above findings, and will prevent waste and protect the correlative rights of all interest owners within the proposed Unit Area, and should be approved.

(33) The proposed Avalon (Delaware) Unit Area contains undeveloped acreage and acreage that will not be part of the initial waterflood project. Therefore, in compliance with Division General Rule 701.G(3), the initial waterflood project area for allowable and tax credit purposes should be reduced to include the following described 1088.50 acres in Eddy County, New Mexico:

Township 20 South, Range 28 East, NMPM
Section 30: Lots 1 through 4, SE¼NW¼, E½SW¼, and S½SE¼
Section 31: Lots 1 through 3, NE¼, E½NW¼, NE¼SW¼, N½SE¼, and SE¼SE¼
Section 32: W½NW¼, N½SW¼, and SW¼SW¼

(34) Exhibit "A", attached hereto and made a part hereof, lists the 19 proposed injection wells (18 of which are to be new drills and one of which is to be a conversion) for the initial waterflood project. It is the applicant's intent to drill the 18 new wells and initially complete them first as oil producing wells and eventually convert them to water injectors. Approval of the unorthodox locations is necessary for "start-up" of said waterflood project.

(35) The waterflood pattern to be utilized initially is to be a 40-acre inverted five-spot comprising the 19 aforementioned water injection wells and 27 producing wells.

(36) The present Delaware oil producing wells within the subject project area and interval are in an advanced state of depletion and should therefore be properly classified as "stripper wells."

(37) The operator of the proposed Avalon (Delaware) Unit Waterflood Project should take all steps necessary to ensure that the injected water enters and remains confined to only the proposed injection interval and is not permitted to escape from that interval and migrate into other formations, producing intervals, pools, or onto the surface from injection, production, or plugged and abandoned wells.

(38) Injection should be accomplished through lined or otherwise corrosion-resistant tubing installed in a packer set within 500 feet of the uppermost injection perforation; the casing-tubing annulus in each well should be filled with an inert fluid and equipped with an approved gauge or leak-detection device. The supervisor of the Artesia District Office of the Division may authorize the setting of the casing-tubing isolation device at a shallower depth if appropriate.

(39) Prior to commencing injection operations, each injection well should be pressure tested throughout the interval from the surface down to the proposed upper-most perforation to assure mechanical integrity of each well.

(40) The injection wells or pressurization system for each well should be so equipped as to limit injection pressure at the wellhead to no more than 490 psi; however, the Division Director should have the authority to administratively authorize a pressure increase upon a showing by the operator that such higher pressure will not result in the fracturing of the injection formation or confining strata.

(41) The operator should give advance notification to the supervisor of the Artesia District Office of the Division of the date and time of the installation of injection equipment and of the mechanical integrity pressure-tests in order that the same may be witnessed.

(42) The proposed waterflood project should be approved and the project should be governed by the provisions of Rule Nos. 701 through 708 of the Oil Conservation Division Rules and Regulations.

(43) The applicant further requests that the subject waterflood project be approved by the Division as a qualified Enhanced Oil Recovery Project ("EOR") pursuant to the "Enhanced Oil Recovery Act" (Laws 1992, Chapter 38, Section 1 through 5).

(44) The evidence presented indicates that the subject waterflood project meets all the criteria for approval.

(45) The approved "project area" should initially comprise that area described in Finding Paragraph No. (33) above.

(46) To be eligible for the EOR credit, prior to commencing injection operations the operator must request from the Division a Certificate of Qualification, which Certificate will specify the proposed project area as described above.

(47) At such time as a positive production response occurs and within five years from the date of the Certificate of Qualification, the operator must apply to the Division for certification of a positive production response, which application shall identify the area actually benefitting from enhanced recovery operations, and identifying the specific wells which the operator believes are eligible for the credit. The Division may review the application administratively or set it for hearing. Based upon evidence presented, the Division will certify to the Department of Taxation and Revenue those lands and wells which are eligible for the credit.

(48) The injection authority granted herein for the proposed injection wells should terminate one year after the effective date of this order if the operator has not commenced injection operations into the subject wells, provided, however, the Division, upon written request by the operator, may grant an extension thereof for good cause shown.

(49) Division Order No. R-10460, entered September 18, 1995, approved statutory unitization, and unitization became effective October 1, 1995.

IT IS THEREFORE ORDERED THAT:

(1) The application of Exxon Corporation for the Avalon (Delaware) Unit, covering 2118.78 acres, more or less, of State, Federal, and fee lands in the Avalon-Delaware Pool, Eddy County, New Mexico, is hereby approved for statutory unitization pursuant to the "Statutory Unitization Act," Section 70-7-1 through 70-7-21 NMSA (1978).

(2) The Avalon (Delaware) Unit Agreement and the Avalon (Delaware) Unit Operating Agreement, which were submitted to the Commission at the time of the hearing as Exhibits 2 and 3, are hereby incorporated by reference into this order.

(3) The lands herein designated the Avalon (Delaware) Unit Area shall comprise the following described acreage in Eddy County, New Mexico:

Township 20 South, Range 27 East, NMPM
Section 25: E½E½
Section 36: E½E½

Township 20 South, Range 28 East, NMPM
Section 29: SW¼SW¼
Section 30: Lots 1-4, E½W½, SW¼NE¼, SE¼
Section 31: Lots 1-4, E½W½, E½ (All)
Section 32: SW¼NE¼, W½, W½SE¼

Township 21 South, Range 27 East, NMPM
Section 4: Lot 4
Section 5: Lots 1 and 2
Section 6: Lots 1 and 2

(4) The vertical limits or "unitized formation" of the unitized area shall include that interval underlying the Unit Area described as the Delaware Mountain Group, extending from 100 feet above the base of the Goat Seep Reef to the top of the Bone Spring formation and including, but not limited to, the Cherry Canyon and Brushy Canyon Formations, as identified on the Compensated Neutron/Lithodensity/Gamma Ray Log dated September 14, 1990 run in the Exxon Corporation Yates "C" Federal Well No. 36, located 1305 feet from the North and East lines of Section 31, Township 20 South, Range 28 East, NMPM, Eddy County, New Mexico, with the top of the unitized formation being found in said well at a depth of 2,378 feet below the surface (869 feet above sea level) and the base of the unitized formation being found at a depth of 4,880 feet below the surface (1,633 feet below sea level), or stratigraphic equivalents thereof.

(5) Since the persons owning the required statutory minimum percentage of interest in the Unit Area have approved, ratified, or indicated their preliminary approval of the Unit Agreement and the Unit Operating Agreement, the interests of all persons within the Unit Area are hereby unitized whether or not such persons have approved the Unit Agreement or the Unit Operating Agreement in writing.

(6) The applicant, hereby designated as Unit Operator, shall notify in writing the Division Director of any removal or substitution of said Unit Operator by any other working interest owner within the Unit Area.

(7) A non-consent penalty of 200 percent is hereby adopted in this case. The unit operator shall be authorized to recover from unit production each non-consenting working interest owner's share of unit expense plus 200 percent thereof as provided in the Unit Operating Agreement.

IT IS FURTHER ORDERED THAT:

(8) Exxon is hereby authorized to institute a waterflood project in its Avalon (Delaware) Unit Area by the injection of water into the designated and Undesignated Avalon-Delaware pool, as found in that stratigraphic interval between 2378 feet to 4880 feet and identified by the Compensated Neutron/Lithodensity/Gamma Ray Log dated September 14, 1990 run in the Exxon Corporation Yates "C" Federal Well No. 36, located 1305 feet from the North and East lines (Unit A) of Section 31, Township 20 South, Range 28 East, NMPM, Eddy County, New Mexico. Injection will be through nineteen wells described in Exhibit "A" attached hereto and made a part hereof.

(9) In compliance with Division General Rule 701.G(3), the initial waterflood project area, for allowable and tax credit purposes, shall comprise the following described 1088.50 acres in Eddy County, New Mexico:

Township 20 South, Range 28 East, NMPM

Section 30: Lots 1 through 4, SE¼NW¼, E½SW¼, and S½SE¼
Section 31: Lots 1 through 3, NE¼, E½NW¼, NE¼SW¼, N½SE¼, and SE¼SE¼
Section 32: W½NW¼, N½SW¼, and SW¼SW¼

(10) The applicant must take all steps necessary to ensure that the injected water only enters and remains confined to the proposed injection interval and is not permitted to escape to other formations or onto the surface from injection, production, or plugged and abandoned wells.

IT IS FURTHER ORDERED THAT:

(11) Injection shall be accomplished through lined or otherwise corrosion-resistant tubing installed in a packer set within 500 feet of the uppermost injection perforation; the casing-tubing annulus in each well shall be filed with an inert fluid and equipped with an approved gauge or leak-detection device. The supervisor of the Artesia District Office of the Division can authorize the setting of the casing-tubing isolation device at a shallower depth if appropriate.

(12) The 19 water injection wells or pressurization system shall be initially equipped with a pressure control device or acceptable substitute which will limit the surface injection pressure to no more than 490 psi.

(13) The Division Director shall have the authority to administratively authorize a pressure limitation in excess of the 490 psi herein authorized upon a showing by the operator that such higher pressure will not result in the fracturing of the injection formation or confining strata.

(14) Prior to commencing injection operations, each injection well shall be pressure tested throughout the interval from the surface down to the proposed upper most perforation to assure mechanical integrity of each well.

(15) The operator shall give advance notification to the supervisor of the Artesia District Office of the Division of the date and time of the installation of injection equipment and of the mechanical integrity pressure-test in order that the same may be witnessed.

(16) The applicant shall immediately notify the supervisor of the Artesia District Office of the Division of the failure of the tubing, casing or seal bore assembly in any of the injection wells, the leakage of water or oil from or around any producing well, or the leakage of water or oil from any plugged and abandoned well within the project area, and shall take such steps as may be timely and necessary to correct such failure or leakage.

(17) The applicant shall conduct injection operations in accordance with Division Rule Nos. 701 through 708 and shall submit monthly progress reports in accordance with Division Rule Nos. 706 and 1115.

FURTHERMORE:

(18) The subject waterflood project is hereby approved as an Enhanced Oil Recovery Project ("EOR") pursuant to the "Enhanced Oil Recovery Act" (Laws 1992, Chapter 38, Sections 1 through 5).

(19) The approved "project area" shall initially comprise that area described in Decretory Paragraph No. (9) above.

(20) To be eligible for the EOR credit, prior to commencing injection operations the operator must request from the Division a Certificate of Qualification, which certificate will specify the proposed project area as described above.

(21) At such time as a positive production response occurs and within five years from the date of the Certificate of Qualification, the operator must apply to the Division for certification of a positive production response, which application shall identify the area actually benefitting from enhanced recovery operations, and identifying the specific wells which the operator believes are eligible for the credit. The Division may review the application administratively or set it for hearing. Based upon evidence presented the Division will certify to the Department of Taxation and Revenue those lands and wells which are eligible for the credit.

(22) The injection authority granted herein for the proposed injection wells shall terminate one year after the effective date of this order if the operator has not commenced injection operations into the subject wells, provided, however, the Division, upon written request by the operator, may grant an extension thereof for good cause shown.

FURTHERMORE:

(23) The applicant is authorized to drill the first eighteen wells listed on Exhibit "A" attached thereto. The applicant may complete the wells as producers and later convert them to injection.

(24) Division Order No. R-10460 is hereby affirmed.

(25) Jurisdiction of this cause is retained for the entry of such further orders as the Commission may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION COMMISSION

Jami Bailey

JAMI BAILEY, Member

Bill Weiss

WILLIAM W. WEISS, Member

William J. LeMay

WILLIAM J. LEMAY, Chairman

S E A L

EXHIBIT "A"

CASE NO. 11297
ORDER NO. R-10460-B

EXXON CORPORATION
PROPOSED WATER INJECTION WELLS/UNORTHODOX OIL WELL LOCATIONS
AVALON (DELAWARE) UNIT WATERFLOOD PROJECT AREA

TOWNSHIP 20 SOUTH, RANGE 28 EAST, NMPM,
EDDY COUNTY, NEW MEXICO

WELL NO.	ORIGINALLY PROPOSED LOCATION	SECTION	ACTUAL STAKED LOCATION	PROPOSED PERFORATED INTERVAL FEET
1212	1668' FNL & 1455' FWL	30	1665' FNL & 1452' FWL	2486 - 4817
1412	2310' FSL & 1485' FWL	30	2301' FSL &1485' FWL	2509 - 4832
1612	992' FSL & 1489' FWL	30	1152' FSL & 1489' FWL	2492 - 4798
1614	1046' FSL & 2677' FWL	30	NO CHANGE	2498 - 4853
1812	183' FNL & 1397' FWL	31	101' FNL & 1355' FWL	2467 - 4774
1814	123' FNL & 2673' FEL	31	NO CHANGE	2496 - 4844
1816	46' FNL & 1402' FEL	31	43' FNL & 1458' FEL	2520 - 4902
2012	1386' FNL & 1314' FWL	31	NO CHANGE	2481 - 4800
2014	1335' FNL & 2681' FWL	31	1388' FNL & 2750' FWL	2495 - 4843
2018	1317' FNL & 97' FEL	31	1310' FNL & 97' FEL	2501 - 4924
2212	2600' FSL & 1322' FWL	31	NO CHANGE	2496 - 4817
2214	2699' FSL & 2549' FWL	31	2610' FSL & 2549' FWL	2509 - 4841

EXHIBIT "A"
PAGE TWO

WELL NO.	ORIGINALLY PROPOSED LOCATION	SECTION	ACTUAL STAKED LOCATION	PROPOSED PERFORATED INTERVAL FEET
2216	2566' FNL & 1377' FEL	31	2564' FNL & 1377' FEL	2505 - 4885
2218	2423' FSL & 78' FEL	31	2517' FSL & 78' FEL	2477 - 4918
2220	2648' FSL & 1127' FWL	32	2658' FSL & 1127' FWL	2489 - 4945
2412	1337' FSL & 1324' FWL	31	NO CHANGE	2535 - 4826
2418	1356' FSL & 99' FEL	31	NO CHANGE	2478 - 4911
2420	1323' FSL & 1107' FWL	32	1333' FSL & 1107' FWL	2479 - 4935
2016*	1305' FNL & 1305' FEL	31	NO CHANGE	2478 - 4880

*Already drilled under prior Division Order (previously designated the Exxon Corporation Yates "C" Federal No. 36).