

CASE NO. 14981**TESTIMONY OF RICHARD EZEANYIM, P.E.**

My name is Richard Ezeanyim. I reside in Santa Fe, and I have worked for the New Mexico Oil Conservation Division as the Chief Engineer and Chief Hearing Examiner for twelve (12) years. I have a M.S. degree in Petroleum Engineering from the University of Wyoming, Master of Business Administration (MBA) from the University of Wyoming. I also have a B.S. degree in Chemical Engineering, and a B.S. degree in Natural Gas Engineering from Texas A. & I University.

I have over thirty-five (35) years' experience in Engineering, Management, and Environmental Regulatory Issues. I am a Registered Professional Engineer in New Mexico and Colorado.

I have previously testified numerous times before the New Mexico Oil Conservation Commission (OCC), and have been accepted as an expert in Petroleum Engineering by the OCC.

In Case No. 14981, Occidental Permian Limited Partnership ("OXY", "Applicant", or "Operator") has applied to the Oil Conservation Commission (OCC) to implement a Tertiary Recovery Project in the South Hobbs Grayburg-San Andres Unit. My testimony in this case will address the pertinent technical issues requested in the application, and my review of Form C-108 associated with the application.

(A) Request for the authority to inject up to the maximum surface injection pressures for the following injectants:

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CO2 injection only: 1250 psi

Water injection only: 1100 psi

Produced gas injection: 1770 psi

The Division Order IPI-340 has already approved the maximum surface injection pressure of 1100 psi for water for the South Hobbs Grayburg-San Andres Unit after careful evaluation of the Step-Rate Test. Water is heavier than carbon dioxide (CO2), and produced gas, therefore, surface injection pressures of the above magnitude for CO2 and produced gas should not fracture the formation and should be approved. However, any further requests for injection pressure increases should be accompanied with an approved Step-Rate Test conducted with produced water, **NOT** produced gas or purchased gas.

(B) Request to Increase the limiting gas-oil ratio (GOR) to 75,000 cubic feet of gas per barrel of oil produced.

The provisions of Division Rule 19.15.20.13 NMAC (**GAS-OIL RATIO LIMITATION**) only applies to production during the Primary Depletion Stage, and does not apply to any Enhanced Oil Recovery Projects such as the tertiary recovery project contemplated in this case. The limiting GOR imposed by this provision is to prevent waste, protect correlative rights, and protect the reservoir from damage by any aggressive production scheme during this primary depletion stage. After the primary depletion stage at which the wells have reached their economic limit, the operator can walk away or implement some kind of Enhanced Oil Recovery (EOR) projects (if technically and economically feasible). Therefore, during the EOR Stage, the pools should not be subject to limiting GOR, because Rule 19.15.20.13 NMAC does not contemplate imposing this limit at this Stage. Incidentally, for tertiary recovery projects of this

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nature, CO₂, and produced gas is injected into the reservoir to enhance oil recovery. This injected gas is produced back at the surface and re-injected back into the reservoir in a closed loop system, hence requiring GOR limitation here is inappropriate. Likewise, Rule 19.15.20.12 NMAC (**DEPTH BRACKET ALLOWABLES**) should not apply to EOR Projects, because the operator is trying to recover hydrocarbons that could be left in the ground unrecovered. As long as the EOR projects are conducted in a safe and environmentally friendly manner, imposing the provisions of Division Rules 19.15.20.12, and 19.15.20.13 NMAC will in fact induce waste, and impair correlative rights.

This application is requesting amendments to Commission and Division Orders Nos. R-4934 through R-4934-E. I noticed that in Commission Order No. R-4934 issued in Case No. 5372 on December 3, 1974, the Commission imposed allowable for wells as shown in Rules 2 through 7 of this order. Allowables are only imposed on units not wells during the Primary Depletion Stage only, not during EOR Stage. I also noticed that in Division Order No. R-4934-E issued in Case No. 8082 on May 21, 1984, the Division imposed allowable for Project Area and Unit Area as shown in Rules 6, and 17 of this Order. Again these allowables have no meaning during any EOR Project Stage. I hereby recommend that any Order issued in this Case... supersede Order Nos. R-4934 through R-4943-E to remove these unnecessary requirements.

(C) Request to allow three (3) years for the Commencement of Injection Operations:

Currently the Division allows two (2) years for commencement of injection operations for salt water disposal wells, and other injection operations. The South Hobbs Grayburg-San Andres Tertiary Recovery Project is a big project, which will require replacing old pipelines, building new facilities, and drilling, converting, and equipping injection wells. It is therefore reasonable to allow three years for commencement of injection operations in the South Hobbs Grayburg-San

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Andres Tertiary Recovery Unit. However, for any well covered by the order issued in this case in which injection operations had not commenced for more than five (5) years from the date of issuance of this order, the operator shall submit a statement describing any changes to the Area of Review of such wells before injection commences. Furthermore, in accordance with Division Rule 19.15.26.12 C NMAC (**Abandonment of Injection Operations**), whenever there is a one-year period of non-injection into all wells in the project area, the Division shall consider the project abandoned, and the authority to inject shall terminate **ipso-facto**

(D) Request for a Five (5) year frequency of MIT Tests for Temporarily-Abandoned Wells:

Mechanical Integrity Tests (MITs) for Temporarily-Abandoned wells in the South Hobbs Grayburg-San Andres Tertiary Recovery Project Area shall be conducted every five (5) years in accordance with Division Rule 19.15.25.13 E NMAC, provided that the operator equips these wells with Real-Time Pressure Monitoring System to detect any changes in pressure. Any changes in pressure should be investigated by the operator, and should fix any problems detected in a real-time manner.

(E) Request to set the packer above the uppermost injection perforations or casing shoe, as long as the packer is set below the top of the Grayburg formation.

The Unitized Interval for the South Hobbs Grayburg-San Andres Unit is 3,698 feet to 5,300 feet, and this is also the gross injection interval being requested by OXY in this application. The San Andres formation, (the primary target of this tertiary recovery project) is overlain by approximately 250 feet thick section of impermeable anhydrite and tight-limestones of the upper Grayburg formation. In this area, the Grayburg formation has very poor permeability to take any

injected fluids. There are no geologic faults in this area that would conduct the injected fluids to the shallow sources of drinking water. OXY should be allowed to set packers in injection wells anywhere above the uppermost injection perforations, or casing shoes (in case of open holes), as long as the packer is set below the top of the Grayburg formation, and within the Unitized Interval.

(F) **Request to remove the requirement that Cement Bond Logs (CBL) be run on injection wells, or producing wells whenever the rods and/or tubing are pulled pursuant to**

My review of the injection wells indicate that almost all the wells will be satisfactorily constructed with cement circulated to the surface in the casing strings. There is no need for the operator to run CBL on its injection wells, or producing wells whenever the rods and/or tubing are pulled, therefore the removal of these requirements should be granted.

(G) **Form C-108 Review:**

(1) **Injection Wells:**

The South Hobbs CO2 Tertiary Recovery Project will consist of a total of 53 injection wells of which 30 are existing wells to be converted to injectors, and 23 are proposed wells to be newly drilled injectors. These wells are satisfactorily constructed with cement circulated to the surface in the casing strings in almost all wells. The fresh water bearing zones in this area range in depth from 200 feet to 250 feet. These wells should be approved as injection wells in this project.

(2) **Area of Review (AOR) Wells:**

There are a total of 397 wells in the area of review of the 53 injection wells, of which 276 wells are either active or temporarily plugged and abandoned. As discussed previously, the temporarily

plugged and abandoned wells should be equipped with a real-time pressure monitoring system to detect any changes in pressure. There are 121 wells that are permanently plugged and abandoned. These wells are properly plugged and abandoned and should not act as conduits to the shallow sources of drinking water.

However, based on the data submitted, there is a producing well in the area of review that is exposed to the injection interval without adequate cement. This well, the Herradura Well No. 3 (API No. 30-025-35933) was originally owned by Chesapeake Operating Company but was recently sold to Chevron Oil Company. This well should be evaluated for adequacy of cement by running a Cement Bond Log (CBL), and based on the results of such log, undergo remedial cement work. No injection should occur within one-half mile of this well until a cement bond log is run and submitted to the Division District I Office showing adequate cement across the injection interval, or the remedial cement work is done to adequately confine the injectant to the injection zone.

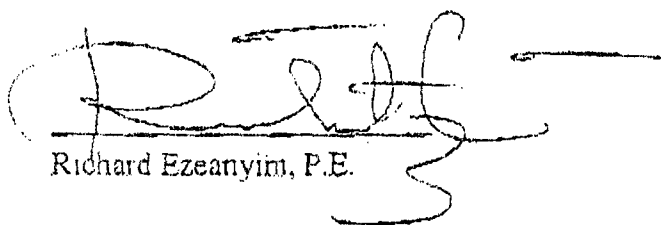
Additional Requirements:

- (3) A one-way automatic safety valve should be installed at the surface of all injection wells to prevent flow-back of the injected acid gas during an emergency, start-up or shut-down operations.
- (4) The operator should use fiberglass lined tubing and nickel plated packer in this corrosive environment.
- (5) Mechanical Integrity Tests (MITs) should be conducted on all injection wells once every two years.
- (6) Injection operations should be conducted in a closed loop system, and trucking of fluids should not be allowed.

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(7) The operator should use a special type of cement designed to withstand the corrosive environment. The cement design should not contain more than three (3%) percent tricalcium aluminate (C3A) in this High Sulfate Resistance (HSR) environment.

(8) The South Hobbs CO2 Tertiary Recovery Project will prevent waste, protect correlative rights, is in the interest of conservation, and the operations will protect human health and the environment, and should be approved.



Richard Ezeanyim, P.E.

Subscribed and sworn to before me this 2 day of May 2013, by Richard Ezeanyim.