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WDWs-1, 2 & 3 PERMITS, RENEWALS, & MODS (17 of 18)

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REENTRY AND COMPLETION REPORT
WASTE DISPOSAL WELL NO. 1

NAVAJO REFINING COMPANY
ARTESIA, NEW MEXICO

Envirocorp Project No. 70A4614

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EXECUTIVE SUMMARY

Navajo Refining Company (Navajo) contracted Envirocorp Well Services, Inc. (Envirocorp) to prepare an application for permit to reenter a plugged and abandoned Class II well to conduct injection testing within the Wolfcamp, Cisco, and Canyon Formations. The permit application was submitted to the State of New Mexico Oil Conservation Commission (OCD) in February 1998.

The OCD granted approval for the reentry and testing on the wellbore by letter dated May 21, 1998. In June 1998, Navajo contracted Envirocorp to prepare a detailed engineering plan to reenter, test and complete the plugged and abandoned Mewbourne Oil Company Chalk Bluff State "31", Well No. 1.

Under contract with Navajo, Envirocorp commenced field operations on July 6, 1998. An area was cleared and a drill pad was constructed for the drilling rig. The abandoned wellbore was located and a riser was welded on for the installation of a blowout preventer assembly. A lined reserve pit was constructed for the containment of drill cuttings and fluids.

A rotary drilling rig was moved in and rigged up and the OCD was notified, and verbally approved the commencement of reentry operations on July 8, 1998. An 8-3/4 inch bit was lowered into the wellbore to drill out cement plugs within the 9-5/8 inch intermediate casing. The 9-5/8 inch intermediate casing was successfully pressure tested to 900 pounds per square inch (psi) prior to drilling out the cement plug across the shoe.

The 8-3/4 inch bit was lowered into the open-hole portion of the wellbore and drilled out cement plugs were drilled out to a total reentry depth of 9160 feet. A cement bond log was conducted within the 9-5/8 inch intermediate casing. A fracture identification log, 4-arm caliper, and gamma-ray log were conducted within the open-hole portion of the wellbore.

The seven inch protection casing was installed with cement circulated through the annular space from bottom to the surface using a two-stage pump and plug method on July 14, 1998. Good returns were observed at the surface while cementing. The rotary drilling equipment was released and moved off site.

A completion rig and blowout preventers were moved in and rigged up on July 20, 1998. A 6-1/8 inch bit was lowered into the wellbore to clean out and pressure test the seven inch protection casing. On July 20, 1998, the seven inch casing was successfully pressure tested

to 1559 pounds per square inch gauge (psig) above the differential valve tool at 5498 feet. On July 21, 1998, the seven inch casing was successfully pressure tested to 1573 psig from surface to the plugged-back total depth of 9004 feet.

The wellbore was displaced with a clean brine fluid and a baseline temperature and casing inspection survey were performed. A cement bond log was performed over the length of the seven inch protection casing. The injection interval (Cisco Formation) was perforated from 8220 feet to 8476 feet at two jet shots per foot. A sample of the formation fluid was obtained for analysis and the lower injection interval was stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter.

The injection interval (Cisco Formation) was perforated from 7924 feet to 8188 feet at two jet shots per foot. A retrievable bridge plug and packer were set to isolate the newly perforated interval. A sample of the formation fluid was obtained for analysis and the perforations were stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter. The packer and bridge plug were removed from the wellbore in preparation for the pressure buildup portion of the falloff test.

On July 30, 1998 and July 31, 1998, an injection pressure buildup and falloff test was conducted. Upon completion of the falloff test a differential temperature log was conducted from surface to a total depth of 8997 feet. A radioactive tracer log was conducted and the results obtained from the survey confirmed external mechanical integrity of the wellbore.

A 4-1/2 inch outside diameter (OD) injection tubing and packer were installed in the well to 7879 feet. An extended annular pressure test was performed to confirm stabilization within the well system. On August 4, 1998, an annular pressure test was performed in accordance with the requirements of the OCD. The OCD witnessed the annular pressure test which successfully confirmed internal mechanical integrity at a pressure of 704 psig.

Upon conclusion of the annular pressure test, the wellhead tree assembly was installed and all equipment was rigged down and moved out.

1.0 INTRODUCTION

Navajo reentered, tested and completed the plugged and abandoned Mewbourne Oil Company Chalk Bluff State "31", Well No. 1 wellbore for injection of plant waste effluent. The name of the new waste disposal well will be designated as Waste Disposal Well No. 1 (WDW-1). The wellbore is located in Section 31, T17S, R28E, Unit Letter O, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. A surveyor's plat of the well location is shown on Figure 1.0-1. The construction and testing of this well were performed in compliance with the provisions of the New Mexico Water Quality Control Commission Regulations (NMWQCCR), dated November 15, 1996, Subpart V, Section Nos. 5204 and 5205, and the United States Environmental Protection Agency Code of Federal Regulations, 40 CFR 146.12, Subpart B.

Envirocorp was contracted by Navajo to reenter and test WDW-1. The construction and testing of this Non-Commercial Class I Nonhazardous Waste Disposal Well were permitted by the New Mexico Energy, Minerals, and Natural Resources Department, OCD by letters dated May 21, 1998 and July 2, 1998 (Appendix 1.0-1). All work associated with WDW-1 was completed in accordance with the provisions specified in the permit approved by the OCD.

The work for WDW-1 was designated as Envirocorp's Project No. 70A4614. This report summarizes all work performed on WDW-1 and includes the filing of the necessary documents.

2.0 SUMMARY OF DAILY OPERATIONS

The original wellbore was designated as the Mewbourne Oil Company, Chalk Bluff "31" State, Well No. 1, installed July 1992 to September 1993. The Daily Reports are presented in Appendix 2.0-1. The wellbore was constructed with a 13-3/8 inch OD surface casing set at 390 feet and cemented to surface. Table 2.0-I presents the 13-3/8 inch surface casing detail.

A 12-1/4 inch hole was drilled to a depth of 2555 feet. Open-hole logs were conducted to include resistivity, spontaneous potential, porosity, and gamma ray as presented in Exhibits 2.0-1 through 2.0-3.

A 9-5/8 inch intermediate casing was installed across the salt sections to a depth of 2555 feet and cemented to surface. Table 2.0-II presents the 9-5/8 inch intermediate casing detail. An 8-3/4 inch hole was drilled to a depth of 10,200 feet to test potentially productive hydrocarbon zones. Subsequently, the wellbore was abandoned in September 1993, as presented on Figure 2.0-1.

A well completion report, OCD Form C-105, is presented as Appendix 2.0-2. The Sundry notice, OCD Form C-103, following plug and abandonment operations, is presented as Appendix 2.0-3.

The reentry, testing, and completion operations for WDW-1 are presented in this section. Details of certain operations are referenced in the text and included as figures, exhibits, tables, and appendices.

Figure 2.0-2 is the current wellbore schematic for WDW-1. Table 2.0-III contains the detailed tubular program for WDW-1.

2.1 Preparation of the Drill Site

From June 26, 1998 to June 29, 1998, the location was prepared for the selected rig. An 80-foot by 50-foot divided reserve pit, lined with six-mil plastic, was constructed for circulating while drilling the cement plugs. An extension to the 9-5/8 inch casing and rental wellhead was installed as a base for the blowout preventers. A rathole and mousehole were constructed as specified by the selected drilling contractor.

2.2 Mobilization of the Drilling Equipment

From July 6, 1998 to July 8, 1998, the drilling rig was moved in and rigged up. A double ram and annular blowout preventer were installed and tested for pressure control.

2.3 Reentry Operations

On July 8, 1998, drilling operations commenced at 4:00 PM. The top of the first cement plug was encountered at 374 feet and drilled out at 445 feet. The drillpipe was lowered into the hole to 1620 feet and a pressure test within the 9-5/8 inch surface casing was performed. The surface casing was successfully pressure tested to 900 psi for 30 minutes with a loss of only 35 psi (-3.89%). The drillpipe was lowered into the well to tag the top of the second cement plug at 2188 feet.

On July 9, 1998, the cement plug was drilled out at 2465 feet. The drillpipe was lowered into the well to tag the third cement plug at 3543 feet. The plug was drilled out at 4479 feet. The drillpipe was lowered into the well to tag the top of the fourth cement plug at 5092 feet. The cement plug was drilled out at 5220 feet. The wellbore was washed down to tag the top of the fifth cement plug at 5785 feet. The cement plug was drilled out at 5840 feet. The drillpipe was lowered into the hole to 6240 feet and became differentially stuck.

On July 10, 1998, 50 barrels of oil were spotted around the drill collars and the drill string worked free. The drillpipe was washed in hole to tag the top of the sixth cement plug at 6395 feet. The cement plug was drilled out at 6745 feet and the drillpipe was washed in hole to 6808 feet.

On July 11, 1998, the drillpipe was washed in hole to tag the top of the seventh cement plug at 7613 feet. The cement plug was drilled out at 7726 feet and the drillpipe was washed in the hole to tag the top of the eighth cement plug at 8293 feet. The cement plug was drilled out to 8385 feet and the drillpipe was washed in hole to 8635 feet.

On July 12, 1998, the drillpipe was washed in hole to the final reentry depth of 9160 feet. The drillpipe, collars, and bit were removed from the well in preparation for logging operations. Schlumberger performed a cement bond, gamma ray, casing collar locator survey within the 9-5/8 inch surface casing from 2548 feet to surface.

On July 13, 1998, Schlumberger performed a fracture identification survey from 9144 feet to 4000 feet (Exhibit 2.3-1). Schlumberger's interpretation describing the results obtained from the Formation Microscanner Imaging results is also presented in Exhibit 2.3-1. A 4-arm caliper survey was processed from 9143 feet to the base of the 9-5/8 inch surface casing. Cement volumes were determined based on the results from the caliper survey plus 20% excess as shown in Exhibit 2.3-2.

The drillpipe was lowered into the well to 9115 feet and the wellbore was circulated and cleaned prior to pulling out of the hole and laying down the drillpipe and collars.

2.4 Installation of the Protection Casing

On July 14, 1998, 259 joints of seven inch 26- and 29-pound-per-foot casing were installed to 9094 feet. Table 2.4-I presents the seven inch protection casing detail. The float collar was placed two joints above the pack-off float shoe at 9007 feet. A stage tool was emplaced at 5498 feet. Halliburton Energy Services pumped the first-stage cement consisting of 600 sacks of Modified Class H cement plus additives mixed at 13 pounds per gallon (ppg). The stage tool was opened and a total of 142 sacks of cement were observed circulating back to the surface. Good returns were observed during the first stage cement operations.

The well was circulated for eight hours and the second-stage cement was pumped consisting of 220 sacks of Interfill Class C plus additives mixed at 11.7 ppg; followed by 163 sacks of Modified Class H plus additives mixed at 13 ppg. The second stage was circulated to surface in excess of 75 sacks. A one inch tremie line was lowered into the well annulus to 20 feet. A total of 20 sacks of premium cement plus 3% calcium chloride cement were circulated to the surface.

On July 15, 1998, waited on the cement, cleaned the mud pits, cut the casing and removed the blowout preventers. The drilling rig was released at 15:00 hours. A seven inch Type "R" Larkin wellhead was installed and the drilling rig was rigged down.

On July 16, 1998, the drilling rig was stacked adjacent to the wellsite location. Anchors were installed and the seven inch casing was stabilized at the surface with six yards of ready mix cement.

On July 20, 1998, the completion rig, reverse unit, work string, and blowout preventers were moved in and rigged up. A 6-1/8 inch OD bit was picked up on six 4-1/8 inch

OD drill collars and lowered into the well on the work string to 5455 feet. The well system was pressurized to 1580 psig and monitored for test. A loss of six psi per 30 minutes was observed (-0.38%) during the pressure test. The differential valve tool was partially drilled out.

On July 21, 1998, the differential valve tool was drilled out and the bit was lowered into the well to drill and wash to a plugged-back total depth of 9004 feet. Table 2.4-II presents the plug-back record. The well system was pressurized to 1600 psi and monitored for test. A loss of eight psi per 30 minutes was observed (-0.51%) during the pressure test.

On July 22, 1998, a bit and casing scraper were lowered into the wellbore to 8823 feet. A total of 250 gallons of 15% HCl inhibited acid preceded displacement of 350 barrels of clean brine water. Fluid returns were circulated to the reserve pit.

On July 23, 1998, a differential temperature log was conducted within the seven inch protection casing from surface to 8997 feet. The well system was pressurized to 1000 psi and a cement bond log was conducted from 8997 feet to 135 feet. A casing inspection survey, consisting of an electromagnetic thickness tool and multi-finger casing caliper tool, was conducted from 8991 feet to surface.

2.5 Perforating and Testing the Cisco Formation

On July 24, 1998, the wellbore was perforated within the injection interval at two jet shots per foot using retrievable casing guns. The selected intervals were as follows: 8220-54 feet, 8260-70 feet, 8280-8302 feet, 8370-78 feet, 8360-66 feet, 8400-10 feet, 8419-23 feet, 8430-46 feet, 8460-64 feet, and 8470-76 feet (Table 2.5-I). The wellbore fluid level dropped during the perforating operations.

On July 25, 1998, a packer was set above the perforated interval with tailpipe to 8479 feet (bottom perforation at 8476 feet). A swab line was rigged up and a total of 139 barrels (2.39 tubing volumes) were recovered. Samples of the formation fluid were retained for analysis, which is presented as Appendix 2.5-1. The fluid level maintained approximately 1700 feet to 1800 feet during the swabbing operations.

On July 26, 1998, an initial step-rate test was performed down the 2-7/8 inch work string using an 8.7 ppg brine water. A maximum rate of 4.85 barrels per minute (bpm) was attained within the permitted injection pressure. The well was acidized in four stages using 5000 gallons of 15% HCl and 2400 pounds of gelled rock salt as

diverter. Injectivity significantly improved as the well accepted fluid on a vacuum at four bpm to 10 bpm. The pump-in pressure at 12 bpm was 73 psi after friction pressure was subtracted from the surface injection pressure.

On July 27, 1998, the wellbore was perforated within the injection interval at two jet shots per foot using retrievable casing guns. The selected intervals were as follows: 8170-88 feet, 8160-64 feet, 8118-27 feet, 8132-40 feet, 8066-80 feet, 8050-56 feet, 7974-8030 feet, and 7924-42 feet (Table 2.5-I). A total of sixteen 500-barrel storage tanks were moved in and manifolded together. An 8.7 ppg brine water was loaded into each tank.

On July 28, 1998, a retrievable bridge plug and packer were lowered into the wellbore. The packer assembly began hanging up at 4830 feet and was removed from the wellbore and replaced.

On July 29, 1998, the retrievable bridge plug was set at 8214 feet and pressure tested to 500 psi with the packer set at 8193 feet. The packer was pulled up hole and set at 7852 feet. A swab line was rigged up and a total of 112 barrels (2.33 tubing volumes) were recovered. Samples of the formation fluid were retained for analysis, which is presented as Appendix 2.5-1. The fluid level maintained approximately 1500 feet to 1600 feet during the swabbing operations.

An initial step-rate test was performed down the seven inch casing using an 8.7 ppg brine water. A maximum rate of 4.36 bpm was attained within the permitted injection pressure. The well was acidized in four stages using 5000 gallons of 15% HCl and 2300 pounds of gelled rock salt as a diverter. Injectivity significantly improved as the well accepted fluid on a vacuum at four bpm to four bpm.

On July 30, 1998, a digital quartz surface readout pressure gauge and memory backup were lowered into the wellbore to 7924 feet. The initial bottom-hole pressure was 2928.16 pounds per square inch absolute (psia) at 125.41°F. Injection of an 8.7 ppg brine water was initiated at 10 bpm on a vacuum and continued for 12.45 hours. The final injection pressure was 3071.85 psia at 90.80°F. Injection of brine was discontinued and the bottom-hole pressure falloff was monitored at the surface.

On July 31, 1998, the pressure falloff test was discontinued and the tools were removed from the wellbore while making static gradient stops at 6000 feet, 3000 feet, 1700 feet, and at the surface. A differential temperature survey was performed from

the surface to a wireline total depth of 8997 feet. A radioactive tracer survey was performed below 7800 feet. The results from the radioactive tracer survey confirmed external mechanical integrity of the seven inch casing and provided an injection profile across the perforated intervals.

On August 1, 1998, the 2-7/8 inch work string was laid down and the 4-1/2 inch, 11.60 lb/ft, N-80, LT&C injection tubing was delivered and tallied. The wellbore was displaced with an 8.7 ppg corrosion inhibited brine water as packer fluid. The corrosion inhibitor was a Unichem TECHNI-HIB 370, as presented in the product information and Material Safety Data Sheets presented in Appendix 2.5-2.

2.6 Installation of Injection Tubing

On August 2, 1998, a 7" x 3.5" EVI Oil Tools Model X-1 packer (Figure 2.6-1) was lowered into the wellbore on the 4-1/2 inch injection tubing (Table 2.6-I). The packer was set at 7879 feet with 15,000 pounds of compression and the annulus was pressurized to 700 psig. The annular pressure was monitored for stabilization through August 4, 1998.

On August 4, 1998, an annulus pressure test was performed. The OCD elected to witness the test. The annulus was pressurized to 704 psig and monitored for 30 minutes. The final test pressure was 705 psig for an increase of 1 psi (0.14%) per 30 minutes, which is within the 10% allowed by the regulations. The wellhead tree assembly was installed and all rig and ancillary equipment were rigged down and moved off site.

The installation of WDW-1 was completed on August 4, 1998. The wellhead was secured and the well remained shutin pending approval of the permit by the OCD.

2.7 Chronology of Daily Operations

Appendix 2.7-1 is a Chronology of Daily Activities from the Field Activity Reports.

3.0 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of WDW-1, required by NMWQCCR Subpart V, Section 5204(A) to (D) and Section 5205(A)(1)(a), included a casing inspection log of the seven inch protection casing, pressure testing of the seven inch protection casing, cement bond log of the 9-5/8 inch and seven inch casings, a radioactive tracer survey, a differential temperature survey, and an annular pressure test. Results of these tests demonstrated that the well had internal and external mechanical integrity.

3.1 7 Inch Protection Casing Inspection Log

On July 23, 1998, Wedge Dia-Log,Inc. conducted a casing inspection log from 8997 feet to the surface (Exhibit 3.1-1). A 60-arm multi-finger caliper tool and an electro-magnetic thickness tool were used to conduct the casing inspection survey. The data obtained from the survey may be used as a baseline for future comparison.

3.2 7 Inch Protection Casing Pressure Test

The protection casing was successfully pressure tested to 704 psig on August 4, 1998 for 30 minutes. A pressure gain of 1 psi was observed, as indicated on the pressure test chart shown on Figure 3.5-1.

3.3 Cement Bond Logging

A cement bond log was conducted within the 9-5/8 inch intermediate casing during the reentry operations from 2548 feet to the surface. Upon installation of the seven inch protection casing, a cement bond log was conducted. There are a total of three strings of casing which were successfully installed and cemented across the base of the underground source of drinking water (USDW).

3.3.1 9-5/8 inch Cement Bond Log

On July 12, 1998, a cement bond with variable density log was performed within the 9-5/8 protection casing from 2548 feet to the surface (Exhibit 3.3.1-1). The data obtained from the cement bond log confirmed a continuous column of cement with good bonding characteristics behind the 9-5/8 protection casing from 2548 feet to 400 feet. The hydraulic coupling was lost above 400 feet and the tool would not respond. A letter of interpretation of the intermediate casing cement bond/variable density log is presented as Exhibit 3.3.1-2.

3.3.2 7 Inch Cement Bond Log

A cement bond with variable density log was conducted on the seven inch protection casing on July 23, 1998 (Exhibit 3.3.2-1). As indicated on the log, a continuous column of cement extends from the base of the protection casing at 8997 feet to the surface. Cement bonding was indicated to be sufficient for completion of the well. A letter of interpretation of the protection casing cement bond/variable density log is presented as Exhibit 3.3.2-2.

The adequacy of the cement above the top of the perforations was successfully confirmed in the subsequent radioactive tracer survey discussed in Section 3.4 and differential temperature survey discussed in section 3.6.

The results obtained from the cement bond and variable density logs conducted on the surface casing and the protection casing established that a continuous column of cement, with good compressive strength and cement bond, existed behind both casings. The installation of three casing strings across the base of the USDW, two of which demonstrate a continuous column of cement from surface to bottom, assures protection of the USDW.

3.4 Radioactive Tracer Survey

A radioactive tracer survey for WDW-1 was performed on July 31, 1998, following the reservoir evaluation testing operations and prior to the installation of the injection packer. The radioactive tracer survey consisted of running statistical checks, two baseline gamma ray surveys, and ejecting four slugs of radioactive material. Two (2) of the slug tests were stationary time-drive surveys and two were moving surveys. The radioactive tracer log, conducted July 31, 1998, is presented as Exhibit 3.4-1. An injection profile analysis log is presented as Exhibit 3.4-2. All tests were conducted while injecting a nonhazardous brine water into the well.

The radioactive tracer tool was lowered into the well to tag the total depth at 8997 feet. A pre-survey baseline gamma ray log was conducted from 7800 feet to 8997 feet. A pre-survey statistical check was performed at 7904 feet (20 feet above the top perforation) for five minutes.

The moving surveys were conducted with the radioactive tracer tool initially positioned at 7800 feet (above the intended packer setting depth). The injection of a nonhazardous brine was initiated at a rate of one bpm. A slug of radioactive

material was ejected and verified for intensity. The slug's downward movement was recorded by logging upward through the slug intermittently as it moved downward and dissipated into the perforated interval. This test was repeated at an injection rate of one bpm. The results obtained from the moving surveys determined that the ejected radioactive material was exiting into the permitted injection interval; therefore, mechanical integrity was confirmed between the intended packer setting depth and the top of the injection interval.

The injection of a nonhazardous brine was increased to 10 bpm. The radioactive tracer tool was positioned with the bottom detector at 7904 feet, which is 20 feet above the top of the top perforation, and a stationary time-drive survey was conducted. The tool remained stationary across the interval and the well was monitored for upward migration above 7904 feet for 15 minutes. This test was repeated and monitored for upward migration above 7904 feet for 15 minutes. No upward migration of radioactive material was observed during either survey.

A post-survey baseline gamma ray log was performed from 8997 feet to 7800 feet, with no residual radioactive material.

3.5 Annular Pressure Test

The official annular pressure test was conducted on August 4, 1998. The injection packer and tubing had been installed and the wellbore allowed to attain a thermal equilibrium. A Barton circular chart recorder (Serial Number MFG-1438), scaled from 0 psig to 1000 psig, was installed to monitor the annulus pressure. The OCD representative was present to witness the annulus pressure test. At 0900 hours, the initial annulus pressure was 704 psig. At 0930 hours, the final annulus pressure was 705 psig. This represents a pressure gain of 1.00 psi in 30 minutes, which is within the limit of 10% in 30 minutes allowed by the OCD. An annulus pressure test chart is presented as Figure 3.5-1.

3.6 Differential Temperature Survey

A baseline differential temperature survey was performed on July 23, 1998 (Exhibit 3.6-1) following the cleanout of the seven inch protection casing to 8997 feet. On July 31, 1998, a second differential temperature survey was performed following the reservoir evaluation testing, which included 12-hour injection of an 8.7 ppg brine water into the permitted injection interval (Exhibit 3.6-2).

As indicated on the July 23, 1998 baseline differential temperature log, the wellbore temperature increased steadily from 78.0 degrees at the surface to 137.9 degrees at 8993 feet. A temperature gradient of 0.01 degrees per foot was observed.

On July 31, 1998, a second differential temperature log was performed following the injection of brine water into the injection interval. A temperature gradient of .01 degrees per foot was observed from surface to the top perforation at 7924 feet. A significant cooling anomaly was observed within the perforated injection interval as temperatures cooled to 95.2 degrees. The data obtained from the differential temperature survey confirmed external mechanical integrity of the seven inch protection casing and may be used for comparison during future surveys.

4.0 RESERVOIR EVALUATION

4.1 Bottom-Hole Pressure Testing

The bottom-hole pressure testing which was conducted on WDW-1, following the completion of the well, was designed to obtain the best estimate of permeability and transmissibility in the reservoir. The pressure testing on WDW-1 consisted of a static gradient survey and an injectivity/falloff test. Appendix 4.1-1 lists the time and pressure data recorded during the static gradient survey, injection period, and falloff period.

4.1.1 Static Gradient Survey and Bottom-Hole Pressure Analysis

On July 31, 1998, static gradient measurements were performed after conducting the injection/falloff test on WDW-1. Pressure data from the gradient stops made at the surface, 1700 feet, 3000 feet, 6000 feet, and 7924 feet are shown on Table 4.1.1-I. The gradient data are presented graphically as Figure 4.1.1-1. The static fluid gradient at 7924 feet was determined to be 0.456 psi per foot. The fluid level was at approximately 1500 feet.

4.1.2 Analysis of the Falloff Test

On July 30, 1998, an Eccossetex surface readout digital quartz pressure transducer was positioned at 7924 feet in WDW-1 and allowed to stabilize for approximately 45 minutes. Injection into WDW-1 commenced at 0920 hours at an injection rate of 420 gallons per minute (gpm). WDW-1 was shut in at 2153 hours and the bottom-hole pressure and temperature were recorded for 9.2 hours.

The pressure data obtained during the falloff test were analyzed with the assistance of the commercially available pressure transient analysis software program "PanSystem2, Version 2.5". Appendix 4.1.2-1 contains the output from this software program. Figure 4.1.2-1 shows the pressure response recorded by the surface pressure tool from the time the tool was in place through the 9.2-hour shutin period. Figure 4.1.2-2 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure derivative versus equivalent shutin time. The radial flow period is denoted on Figure 4.1.2-2.

The reservoir permeability was determined from the radial flow region of the superposition Horner plot (Figure 4.1.2-3). The radial flow regime begins at a Horner time of 23.9 and continues to 12.0. Figure 4.1.2-4 shows an expanded view of the

superposition Horner plot. The slope of the radial flow period was determined to be 4.356711 psi per cycle.

An estimate of mobility-thickness, kh/μ, for the reservoir was determined from the following equation:

$$\frac{kh}{\mu} = 162.6 \frac{qB}{m}$$

where,

kh/μ	=	transmissibility, md-ft/cp
q	=	flow rate, barrels per day
μ	=	viscosity, centipoise
B	=	formation volume factor, reservoir vol/surface vol
m	=	slope of semi-log straight line, psi/cycle

Using an injection rate of 420 gpm (14,400 barrels per day) and the information previously mentioned results in a transmissivity of 537,433 md-ft/cp:

$$\frac{kh}{\mu} = 162.6 \frac{(14,400)(1.0)}{4.356711}$$

$$= 537,433 \text{ md-ft/cp}$$

Multiplying this value by the viscosity, μ, results in transmissibility, kh:

$$kh = \left(\frac{kh}{\mu} \right) \mu$$

$$= (537,433)(0.53)$$

$$= 284,839 \text{ md-ft}$$

And finally, permeability is determined by dividing transmissibility by the formation thickness. The formation thickness is 253 feet, which results in a permeability of 1126 md.

$$k = \frac{(k\,h)}{h}$$

$$= \frac{284{,}839}{253}$$

$$= 1126 \text{ md}$$

The skin factor was determined from the following equation:

$$s = 1.151\left[\frac{p_{wf} - p_{1\,hr}}{m_1} - \log\left(\frac{k_p}{\phi\,\mu\,c_t\,r_w^2}\right) + 3.23\right]$$

where,

s	=	formation skin damage at open perforations, dimensionless
1.151	=	constant
p_{wf}	=	flowing pressure immediately prior to shutin, psi
$p_{1\,hr}$	=	pressure determined by extrapolating the first radial flow semi-log line to a Δt of one hour, psi
m_1	=	slope of the first radial flow semi-log line, psi/cycle
k_p	=	permeability of the formation opposite the open perforations, md
ϕ	=	porosity of the injection interval, fraction
μ	=	viscosity of the fluid the pressure transient is traveling through, centipoise
c_t	=	total compressibility of the formation plus fluid, psi^{-1}
r_w	=	radius of the wellbore, feet
3.23	=	constant

The final flowing pressure, p_{wf}, was 3071.61 psia. The pressure determined by extrapolating the radial flow semi-log line to a Δt of one hour, $p_{1\,hr}$, was 2930.27 psi. The porosity of the injection interval, ϕ, is 0.10 and the total compressibility, c_t, is 8.4 x 10^{-6} psi^{-1}. The wellbore radius, r_w, is 0.3646 feet. Using these values in addition to the previously determined parameters, m and k, results in a skin of 29.23:

$$s = 1.151\left[\frac{3071.61 - 2930.27}{4.356711} - \log\left(\frac{1126}{(0.10)(0.53)(8.4 \times 10^{-6})(0.3646)^2}\right) + 3.23\right]$$

$$= 29.23$$

The "Auto-Match" feature of PanSystem2 was used to improve upon the reservoir parameters. The final results of the auto-match are shown on Figures 4.1.2-5 through 4.1.2-7. These figures show the falloff data in cartesian, superposition Horner, and log-log formats with the simulated pressures overlaid.

5.0 REGULATORY COMPLIANCE

The construction of WDW-1 was performed in accordance to the regulatory considerations and standards specified in the approved permit application dated February 27, 1998; the NMWQCCR, dated November 15, 1998, Subpart V, Section Nos. 5204 and 5205; and the United States Environmental Protection Agency 40 CFR 146.12.

5.1 Siting

Navajo reentered, tested, and completed a plugged and abandoned wellbore located in Section 31, T17S, R28E, Unit Letter O, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. The disposal well permit, dated February 27, 1998, includes provisions for the location, depth of injection, and specific reentry and completion requirements. The Navajo WDW-1 will inject plant effluent into a formation which is beneath the lowermost formation containing, within one quarter of a mile of the wellbore, ground water having 10,000 mg/l total dissolved solids or less. A plat of the Navajo WDW-1 well location is shown on Figure 1.0-1.

5.2 Casing and Cementing

Installation and cementing of the casing were completed in accordance with NMWQCCR Subpart V, Section 5205(B)(2).

Table 2.0-III is the detailed tubular program for WDW-1. Table 5.2-I is the Cement Program for WDW-1.

A 17-1/2 inch surface hole was drilled to a depth of 390 feet RKB. A 13-3/8 inch OD, 48 lb/ft, J-55 grade surface casing was installed to a depth of 390 feet RKB and cemented in place using the pump and plug method. The surface casing was cemented with a lead slurry of 375 sacks of Class "C" Lite cement containing 3% calcium chloride and 1/2 pound per sack (lb/sx) Flocele. This was followed by a tail slurry of 150 sacks of Class C cement containing 3% calcium chloride. The cement was circulated to surface. A total of 525 sacks of cement was used and recorded on Form C-105 (Appendix 2.0-2).

A 12-1/4 inch intermediate hole was drilled to a depth of 2555 feet RKB. A 9-5/8 inch OD, 36 lb/ft, J-55 grade intermediate casing was installed to a depth of 2555 feet RKB and cemented in place using the pump and plug method. The intermediate

casing was cemented with a lead slurry of 800 sacks of Class "C" Lite cement containing 1/2 lb/sx Flocele, two lb/sx Gilsonite, and 12% salt. This was followed by a tail slurry of 200 sacks of Class C cement containing 2% calcium chloride. The cement was circulated to surface. A total of 1000 sacks of cement was used and recorded on Form C-105 (Appendix 2.0-2).

An 8-3/4 inch hole was drilled to a total depth of 10,200 feet and the wellbore was originally plugged and abandoned to surface. The abandoned 8-3/4 inch wellbore was reentered and cleaned out to 9160 feet RKB. A seven inch OD, 26 lb/ft and 29 lb/ft, N-80 and P-110 grade protection casing was installed to a depth of 9094 feet RKB. A differential valve tool was positioned at 5498 feet and the protection casing was cemented in two stages. The first stage, from 9094 feet to 5498 feet, consisted of 600 sacks of modified Class "H" cement containing 0.4% CFR-3, five lb/sx Gilsonite, 0.5% Halad-344, and one lb/sx salt mixed at 13 ppg. The differential valve tool was opened and cement returns were observed at the surface. The well was circulated for approximately eight hours prior to performing the second stage. The second stage, from 5498 feet to surface, consisted of two cement slurries. The lead slurry consisted of 220 sacks of Interfill C (35% Pozalin, 65% Class "C" cement, and 6% gel). The tail slurry consisted of 550 sacks of a modified Class " H" cement containing 0.4% CFR-3, five lb/sx Gilsonite, 0.5% Halad-344, and one lb/sx salt mixed at 13 ppg. The cement were circulated to the surface in excess of 75 sacks of cement returns. A total of 1370 sacks of cement were used to cement the protection casing in place. A CBL/VDL log was run on the protection casing and established a full column of annular cement from the bottom to the surface.

5.3 Tubing and Packer

Installation of the tubing and packer were conducted in accordance with NMWQCCR Subpart V, Section 5205(B)(3).

The WDW-1 injection tubing is a 4-1/2 inch OD, 11.60 lb/ft, N-80, LT&C connection, carbon steel pipe. The injection tubing was connected directly into an EVI Oil Tools Model X-1 injection packer set at 7879 feet. The tubing was designed to withstand possible future corrosion due to the injected fluids and the maximum burst and collapse pressures and tensile stresses, which may be experienced during the operational life of the well. Table 2.0-III is the detailed tabular program for WDW-1. Figure 2.6-1 is a schematic of the EVI Oil Tools Model X-1 injection packer installed in WDW-1.

5.4 Description of the Logging Program and Tests in the Intermediate and Long-String Sections of WDW-1

5.4.1 Directional Surveys

Deviation checks were obtained during the reentry of WDW-1, which were in accordance with NMWQCCR Subpart V, Section 5205(A)(4)(a).

The deviation checks were conducted within the 8-3/4 inch open-hole interval below the 9-5/8 inch surface casing. Deviation checks were obtained during the reentry of WDW-1 at frequent intervals to determine the location of the borehole and to assure that vertical avenues for fluid movement, in the form of diverging holes, were not created.

Table 5.4.1-I contains the deviation survey data obtained by a Totco survey tool from the surface to 9160 feet RKB.

5.4.2 Logging Program

The logging program for WDW-1 was completed in accordance with the regulations specified in NMWQCCR Subpart V, Section 5205(A)(4)(b).

TYPE OF LOG	TYPE OF HOLE LOGGED	INTERVAL (ft)	REFERENCE
	Intermediate Casing		
Cement Bond Log Variable Density Log Gamma Ray	Cased Hole	0 to 2548	Exhibit 3.3.1-1
	Long-String Casing		
Dual Laterolog Gamma Ray Micro-Spherically Focused Electric Log	Open Hole	2546 to 10,182	Exhibit 2.0-1
Spectral Density Dual Spaced Neutron Log Gamma Ray	Open Hole	350 to 10,139	Exhibit 2.0-2
Compensated Sonic Log Gamma Ray	Open Hole	350 to 10,181	Exhibit 2.0-3
Formation Microscanner Imaging Results	Open Hole	4000 to 9143	Exhibit 2.3-1

TYPE OF LOG	TYPE OF HOLE LOGGED	INTERVAL (ft)	REFERENCE
	Long-String Casing		
Caliper Log Gamma Ray	Open Hole	2553 to 9143	Exhibit 2.3-2
Cement Bond Log Variable Density Log Gamma Ray	Cased Hole	0 to 8990	Exhibit 3.3.2-1
Casing Evaluation Log w/Multi-Finger Caliper Tool w/Electromagnetic Casing Caliper Thickness Tool	Cased Hole	0 to 8997	Exhibit 3.1-1
Temperature Log	Cased Hole	0 to 8997	Exhibit 3.6-1
Temperature Log	Cased Hole	0 to 8997	Exhibit 3.6-2

5.5 Mechanical Integrity Testing

The demonstration of the mechanical integrity of WDW-1, required by NMWQCCR Subpart V, Section 5204(A) to (D) and Section 5205(A)(1)(a), is discussed in detail in Section 3.0 of this report. The associated logs and interpretation of results obtained from the mechanical integrity tests are also included in Section 3.0 of this report.

5.6 Pressure Tests Conducted on WDW-1

The 9-5/8 inch and seven inch casing strings were tested for internal mechanical integrity using a liquid medium. These tests were conducted in accordance with NMWQCCR Subpart V, Section 5204(A) and (B)(1)(a).

On July 8, 1998, the 9-5/8 inch intermediate casing was successfully pressure tested to 900 psig for 30 minutes using an 8.3 ppg freshwater-based mud system. A pressure loss of 35 psi was observed during the test period, which is below the 10% tolerance allowed by the OCD.

The seven inch protection casing was successfully pressure tested to 704 psig on August 4, 1998 for 30 minutes using an 8.7 ppg brine water system. A pressure gain of one psi was observed, as indicated on the pressure test chart shown on Figure 3.5-1.

5.7 Physical and Chemical Characteristics of the Formation Fluids

In accordance with NMWQCCR Subpart V, Section 5205(A)(3)(h), an analysis describing the physical and chemical characteristics of the formation fluids, extracted from the Cisco Formation, is presented as Appendix 2.5-1.

The well materials used to construct WDW-1 were compatible with fluids with which the materials may be expected to come into contact. Well materials would be deemed to have compatibility as long as the materials used in the construction of the well meet or exceed standards developed for such materials by the American Petroleum Institute (API), The American Society for Testing Materials (ASTM), or comparable standards acceptable to the NMWQCC.

5.8 Regulatory Witnessing

In accordance with NMWQCCR Subpart V, Section 5205(A)(5), notification prior to commencement of the reentry, cementing and casing, well logging, and mechanical integrity tests was communicated with the OCD, Artesia, New Mexico office. The OCD had an opportunity to witness all installation, logging, and testing as required in NMWQCCR Section 5205(A)(5).

6.0 CERTIFICATION

I certify under penalty of law that I have personally examined and am familiar with the information submitted in this document and all attachments and that, based on my inquiry of those individuals immediately responsible for obtaining the information, I believe that the information is true, accurate, and complete. I am aware that there are significant penalties for submitting false information, including the possibility of fine and imprisonment.

NAME: _____

TITLE: _____

SIGNATURE: _____

DATE: _____

TABLES

TABLE 2.0-I

13-3/8 INCH SURFACE CASING DETAIL

JOINTS	DESCRIPTION	LENGTH (feet)	DEPTH TO TOP (feet)
	KB to Top of Casing		-3.25
8	13-3/8 inch, 48 lb/ft, J-55, STC	348.21	+3.25 (above KB)
1	13-3/8 inch, 48 lb/ft, J-55, STC SJ w/If	43.83	344.96
1	13-3/8 inch, Notched Texas Pattern Shoe	1.21	388.79
	Casing Bottom at 390 feet KB		

TABLE 2.0-II

9-5/8 INCH INTERMEDIATE CASING DETAIL

JOINTS	DESCRIPTION	LENGTH (feet)	DEPTH TO TOP (feet)
	KB to Top of Casing		-8.18
56	9-5/8 inch, 36 lb/ft, J-55, STC	2518.23	+8.18
1	Davis-Lynch Float Collar	1.40	2510.05
1	9-5/8 inch, 36 lb/ft, J-55, LTC	42.55	2511.45
1	Davis-Lynch Guide Shoe	1.00	2554.00
	9-5/8 inch casing bottom at 2555 feet KB		

TABLE 2.0-III

DETAILED TUBULAR PROGRAM, WDW-1

TYPE	DEPTH[1]	DESCRIPTION
Surface Casing	0 feet to 390 feet	13-3/8 inch outside diameter, 0.330 inch wall, 48 lb/ft, J-55, STC
Intermediate Casing	0 feet to 2555 feet	9-5/8 inch outside diameter, 0.400 inch wall, 36 lb/ft, J-55, STC
Protection Casing	0 feet to 5845 feet	7 inch outside diameter, 0.362 inch wall, 26 lb/ft, P-110, LTC
	5845 feet to 7031 feet	7 inch outside diameter, 0.408 inch wall, 29 lb/ft, P-110, LTC
	7031 feet to 9094 feet	7 inch outside diameter, 0.408 inch wall, 29 lb/ft, N-80, LTC
Injection Tubing	0 feet to 7879 feet	4-1/2 inch outside diameter, 0.250 inch wall, 11.60 lb/ft, N-80, LT&C
Packer	Set at 7879 feet	EVI Oil Tools (Arrow) Model X-1 Retrievable Packer, 7 inch x 3.5 inch, minimum inside diameter = 3.0 inches, carbon steel

[1] All depths are relative to the Kelly Bushing.

TABLE 2.4-1

NAVAJO REFINING COMPANY, WDW-1

7" CASING TALLEY TD=9160 FEET 7/12/98

PROTECTORS OFF - 7/12/98

JT #	LENGTH		BOTTOM	TOP
Flt Shoe	2.60	N-80	9094	9091
1	42.00	29#N-80	9091	9049
2	42.02	29#N-80	9049	9007
Flt Collar	0.60	N-80	9007	9007
3	38.19	29#N-80	9007	8969
4	39.13	29#N-80	8969	8929
5	47.14	29#N-80	8929	8882
6	41.84	29#N-80	8882	8840
7	40.76	29#N-80	8840	8800
8	42.11	29#N-80	8800	8758
9	38.83	29#N-80	8758	8719
10	40.84	29#N-80	8719	8678
11	38.70	29#N-80	8678	8639
12	41.50	29#N-80	8639	8598
13	42.00	29#N-80	8598	8556
14	41.93	29#N-80	8556	8514
15	39.56	29#N-80	8514	8474
16	39.15	29#N-80	8474	8435
17	42.50	29#N-80	8435	8393
18	43.99	29#N-80	8393	8349
19	41.44	29#N-80	8349	8307
20	40.20	29#N-80	8307	8267
21	43.25	29#N-80	8267	8224
22	42.15	29#N-80	8224	8182
23	40.66	29#N-80	8182	8141
24	40.48	29#N-80	8141	8101
25	39.02	29#N-80	8101	8062
26	42.19	29#N-80	8062	8019
27	41.54	29#N-80	8019	7978
28	43.03	29#N-80	7978	7935
29	39.43	29#N-80	7935	7895
30	40.84	29#N-80	7895	7855
31	39.06	29#N-80	7855	7815
32	46.05	29#N-80	7815	7769
33	40.45	29#N-80	7769	7729
34	36.64	29#N-80	7729	7692
35	38.20	29#N-80	7692	7654
36	37.60	29#N-80	7654	7617
37	47.55	29#N-80	7617	7569
38	43.78	29#N-80	7569	7525
39	41.25	29#N-80	7525	7484
40	47.07	29#N-80	7484	7437
41	42.02	29#N-80	7437	7395
42	41.40	29#N-80	7395	7354
43	40.96	29#N-80	7354	7313
44	39.20	29#N-80	7313	7273
45	45.89	29#N-80	7273	7227
46	39.31	29#N-80	7227	7188
47	35.37	29#N-80	7188	7153
48	40.95	29#N-80	7153	7112
49	40.90	29#N-80	7112	7071
50	40.00	29#N-80	7071	7031
51	34.48	29#P-110	7031	6996
52	34.51	29#P-110	6996	6962
53	37.19	29#P-110	6962	6925
54	33.14	29#P-110	6925	6892
55	34.4	29#P-110	6892	6857
56	34.51	29#P-110	6857	6823
57	34.38	29#P-110	6823	6788
58	34.51	29#P-110	6788	6754

JT #	LENGTH		BOTTOM	TOP
59	35.13	29#P-110	6754	6719
60	34.37	29#P-110	6719	6684
61	34.43	29#P-110	6684	6650
62	34.34	29#P-110	6650	6616
63	37.16	29#P-110	6616	6578
64	34.42	29#P-110	6578	6544
65	34.40	29#P-110	6544	6510
66	36.65	29#P-110	6510	6473
67	37.03	29#P-110	6473	6436
68	34.50	29#P-110	6436	6401
69	34.51	29#P-110	6401	6367
70	32.63	29#P-110	6367	6334
71	34.36	29#P-110	6334	6300
72	34.40	29#P-110	6300	6265
73	37.12	29#P-110	6265	6228
74	36.62	29#P-110	6228	6192
75	34.09	29#P-110	6192	6157
76	34.40	29#P-110	6157	6123
77	34.42	29#P-110	6123	6089
78	34.50	29#P-110	6089	6054
79	34.45	29#P-110	6054	6020
80	34.50	29#P-110	6020	5985
81	37.13	29#P-110	5985	5948
82	34.49	29#P-110	5948	5914
83	34.46	29#P-110	5914	5879
84	34.48	29#P-110	5879	5845
85	34.46	26#P-110	5845	5810
86	34.50	26#P-110	5810	5776
87	34.54	26#P-110	5776	5741
88	34.42	26#P-110	5741	5707
89	34.45	26#P-110	5707	5672
90	34.57	26#P-110	5672	5638
91	34.51	26#P-110	5638	5603
92	34.48	26#P-110	5603	5569
93	34.42	26#P-110	5569	5534
94	34.52	26#P-110	5534	5500
DV Tool	2.20	26# N-80	5500	5498
95	34.51	26#P-110	5498	5463
96	34.28	26#P-110	5463	5429
97	34.57	26#P-110	5429	5394
98	34.40	26#P-110	5394	5360
99	34.48	26#P-110	5360	5325
100	33.70	26#P-110	5325	5292
101	34.45	26#P-110	5292	5257
102	34.48	26#P-110	5257	5223
103	34.35	26#P-110	5223	5188
104	34.43	26#P-110	5188	5154
105	34.50	26#P-110	5154	5119
106	34.62	26#P-110	5119	5085
107	34.39	26#P-110	5085	5050
108	34.36	26#P-110	5050	5016
109	34.42	26#P-110	5016	4982
110	34.49	26#P-110	4982	4947
111	34.30	26#P-110	4947	4913
112	34.40	26#P-110	4913	4878
113	34.36	26#P-110	4878	4844
114	34.48	26#P-110	4844	4810
115	34.55	26#P-110	4810	4775
116	34.46	26#P-110	4775	4741
117	34.52	26#P-110	4741	4706

Shoe to 58 2340.19 FEET

Joint # 59 to 117 2047.75 FEET

TOTAL PIPE FOOTAGE= 9266.69 FEET

15-Jul-98DATE

NAVAJO REFINING COMPANY, WDW-1

JT #	LENGTH		BOTTOM	TOP
118	34.40	26#P-110	4706	4672
119	34.51	26#P-110	4672	4637
120	34.38	26#P-110	4637	4603
121	34.43	26#P-110	4603	4568
122	34.46	26#P-110	4568	4534
123	34.47	26#P-110	4534	4499
124	34.46	26#P-110	4499	4465
125	38.50	26#P-110	4465	4428
126	34.52	26#P-110	4428	4394
127	34.42	26#P-110	4394	4360
128	34.45	26#P-110	4360	4325
129	34.50	26#P-110	4325	4291
130	34.44	26#P-110	4291	4256
131	34.42	26#P-110	4256	4222
132	34.56	26#P-110	4222	4187
133	34.40	26#P-110	4187	4153
134	34.55	26#P-110	4153	4118
135	34.45	26#P-110	4118	4084
136	34.60	26#P-110	4084	4049
137	34.44	26#P-110	4049	4015
138	34.40	26#P-110	4015	3980
139	34.54	26#P-110	3980	3946
140	34.44	26#P-110	3946	3911
141	34.41	26#P-110	3911	3877
142	34.56	26#P-110	3877	3842
143	33.78	26#P-110	3842	3809
144	34.43	26#P-110	3809	3774
145	34.44	26#P-110	3774	3740
146	34.46	26#P-110	3740	3705
147	34.46	26#P-110	3705	3671
148	34.46	26#P-110	3671	3636
149	34.54	26#P-110	3636	3602
150	34.49	26#P-110	3602	3567
151	34.46	26#P-110	3567	3533
152	34.44	26#P-110	3533	3498
153	34.40	26#P-110	3498	3464
154	34.55	26#P-110	3464	3429
155	34.48	26#P-110	3429	3395
156	34.40	26#P-110	3395	3361
157	34.48	26#P-110	3361	3326
158	34.5	26#P-110	3326	3292
159	34.44	26#P-110	3292	3257
160	34.49	26#P-110	3257	3223
161	34.48	26#P-110	3223	3188
162	34.42	26#P-110	3188	3154
163	34.36	26#P-110	3154	3119
164	34.09	26#P-110	3119	3085
165	34.45	26#P-110	3085	3051
166	34.35	26#P-110	3051	3016
167	34.48	26#P-110	3016	2982
168	34.42	26#P-110	2982	2948
169	34.18	26#P-110	2948	2913
170	34.48	26#P-110	2913	2879
171	34.46	26#P-110	2879	2844
172	34.51	26#P-110	2844	2810
173	34.40	26#P-110	2810	2776
174	34.33	26#P-110	2776	2741
175	34.38	26#P-110	2741	2707
176	34.44	26#P-110	2707	2672
177	34.44	26#P-110	2672	2638

JT #	LENGTH		BOTTOM	TOP
178	34.40	26#P-110	2638	2604
179	34.41	26#P-110	2604	2569
180	34.53	26#P-110	2569	2535
181	34.40	26#P-110	2535	2500
182	34.48	26#P-110	2500	2466
183	34.43	26#P-110	2466	2431
184	34.45	26#P-110	2431	2397
185	34.33	26#P-110	2397	2363
186	34.45	26#P-110	2363	2328
187	34.52	26#P-110	2328	2294
188	34.02	26#P-110	2294	2260
189	34.48	26#P-110	2260	2225
190	33.97	26#P-110	2225	2191
191	34.40	26#P-110	2191	2157
192	34.27	26#P-110	2157	2122
193	34.40	26#P-110	2122	2088
194	34.44	26#P-110	2088	2054
195	34.56	26#P-110	2054	2019
196	34.53	26#P-110	2019	1984
197	34.33	26#P-110	1984	1950
198	34.48	26#P-110	1950	1916
199	34.47	26#P-110	1916	1881
200	34.47	26#P-110	1881	1847
201	34.45	26#P-110	1847	1812
202	34.44	26#P-110	1812	1778
203	34.45	26#P-110	1778	1743
204	34.50	26#P-110	1743	1709
205	34.45	26#P-110	1709	1674
206	34.53	26#P-110	1674	1640
207	34.52	26#P-110	1640	1605
208	34.44	26#P-110	1605	1571
209	34.39	26#P-110	1571	1537
210	34.41	26#P-110	1537	1502
211	34.46	26#P-110	1502	1468
212	34.53	26#P-110	1468	1433
213	34.42	26#P-110	1433	1399
214	34.33	26#P-110	1399	1364
215	34.52	26#P-110	1364	1330
216	34.36	26#P-110	1330	1296
217	34.57	26#P-110	1296	1261
218	34.45	26#P-110	1261	1227
219	34.45	26#P-110	1227	1192
220	34.25	26#P-110	1192	1158
221	34.40	26#P-110	1158	1123
222	34.36	26#P-110	1123	1089
223	34.43	26#P-110	1089	1055
224	33.75	26#P-110	1055	1021
225	34.38	26#P-110	1021	986
226	34.43	26#P-110	986	952
227	34.40	26#P-110	952	918
228	34.55	26#P-110	918	883
229	34.40	26#P-110	883	849
230	34.50	26#P-110	849	814
231	34.45	26#P-110	814	780
232	34.48	26#P-110	780	745
233	34.40	26#P-110	745	711
234	34.47	26#P-110	711	676
235	31.48	26#P-110	676	645
236	32.67	26#P-110	645	612
237	34.44	26#P-110	612	578

Joint # 118 2066.12 FEET
to 177

Joint # 178 2050.13 FEET
to 237

15-Jul-98DATE

NAVAJO REFINING COMPANY, WDW-1

JT #	LENGTH		BOTTOM	TOP
238	34.5	26#P-110	578	543
239	34.4	26#P-110	543	509
240	34.39	26#P-110	509	475
241	34.49	26#P-110	475	440
242	34.46	26#P-110	440	406
243	34.41	26#P-110	406	371
244	34.44	26#P-110	371	337
245	34.5	26#P-110	337	302
246	34.5	26#P-110	302	268
247	34.46	26#P-110	268	233
248	34.55	26#P-110	233	199
249	34.5	26#P-110	199	164
250	34.48	26#P-110	164	130
251	34.47	26#P-110	130	95
252	34.40	26#P-110	95	61
253	31.59	26#P-110	61	29
254	34.43	26#P-110	29	-5
255	32.07	26#P-110	OUT	
256	34.32	26#P-110	OUT	
257	33.41	26#P-110	OUT	
258	33.22	26#P-110	OUT	
259	34.44	26#P-110	OUT	
260				
261				
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263				
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Joint # 238 750.44 FEET
to 297

15-Jul-96DATE

TABLE 2.4-II

PLUGGED-BACK RECORD

DATE	PLUGGED-BACK DEPTH[1] (feet)	DESCRIPTION OF WORK
7/21/98	9004	Top of Cement. Did not drill out float collar.

[1] All depths relative to the Kelly Bushing.

TABLE 2.5-I

PERFORATION RECORD

DATE	ZONE	DEPTH INTERVALS[1] (feet)	SHOT DENSITY (shots/foot)	NO. OF HOLES
7/24/98	Cisco	8220 to 8254	2	70
7/24/98	Cisco	8260 to 8270	2	22
7/24/98	Cisco	8280 to 8302	2	46
7/24/98	Cisco	8370 to 8378	2	18
7/24/98	Cisco	8360 to 8366	2	14
7/24/98	Cisco	8400 to 8410	2	22
7/24/98	Cisco	8419 to 8423	2	10
7/24/98	Cisco	8430 to 8446	2	34
7/24/98	Cisco	8460 to 8464	2	10
7/24/98	Cisco	8470 to 8476	2	14
7/27/98	Cisco	7924 to 7942	2	38
7/27/98	Cisco	7974 to 8030	2	114
7/27/98	Cisco	8050 to 8056	2	14
7/27/98	Cisco	8066 to 8080	2	30
7/27/98	Cisco	8132 to 8140	2	18
7/27/98	Cisco	8118 to 8127	2	20
7/27/98	Cisco	8160 to 8164	2	10
7/27/98	Cisco	8170 to 8188	2	38

[1] All depths are relative to the Kelly Bushing.

TABLE 2.6-I

NAVAJO REFINING COMPANY, WDW-1

4-1/2", 11.60 lb/ft, N-80, SMLS, LT&C (NEW) TALLY
PROTECTORS OFF - 8/1/98 PACKER @ 7879'

JT #	LENGTH		BOTTOM	TOP	
Packer	9.01	Packer	7879	7870	
1	40.13	Tubing	7870	7830	
2	41.00	Tubing	7830	7789	
3	41.00	Tubing	7789	7748	
4	40.07	Tubing	7748	7708	
5	40.13	Tubing	7708	7668	
6	40.53	Tubing	7668	7627	
7	41.00	Tubing	7627	7586	
8	40.65	Tubing	7586	7545	
9	41.00	Tubing	7545	7504	
10	40.90	Tubing	7504	7463	
11	40.72	Tubing	7463	7423	
12	40.55	Tubing	7423	7382	
13	41.07	Tubing	7382	7341	
14	40.42	Tubing	7341	7301	
15	40.54	Tubing	7301	7260	
16	40.58	Tubing	7260	7220	
17	40.50	Tubing	7220	7179	
18	41.02	Tubing	7179	7138	
19	40.55	Tubing	7138	7097	
20	40.50	Tubing	7097	7057	
21	40.27	Tubing	7057	7017	
22	40.63	Tubing	7017	6976	
23	40.91	Tubing	6976	6935	
24	41.00	Tubing	6935	6894	
25	41.02	Tubing	6894	6853	
26	40.87	Tubing	6853	6812	
27	41.02	Tubing	6812	6771	
28	40.94	Tubing	6771	6730	
29	40.58	Tubing	6730	6690	
30	40.12	Tubing	6690	6650	
31	40.52	Tubing	6650	6609	
32	41.02	Tubing	6609	6568	
33	40.63	Tubing	6568	6527	
34	0.00	Tubing	6527	6527	out
35	39.64	Tubing	6527	6488	
36	40.50	Tubing	6488	6447	
37	40.52	Tubing	6447	6407	
38	40.90	Tubing	6407	6366	
39	41.02	Tubing	6366	6325	
40	41.00	Tubing	6325	6284	
41	39.76	Tubing	6284	6244	
42	41.02	Tubing	6244	6203	
43	40.58	Tubing	6203	6162	
44	40.95	Tubing	6162	6122	
45	41.00	Tubing	6122	6081	
46	40.91	Tubing	6081	6040	
47	40.95	Tubing	6040	5999	
48	41.00	Tubing	5999	5958	
49	41.04	Tubing	5958	5917	
50	41.02	Tubing	5917	5876	
51	41.01	Tubing	5876	5835	
52	40.55	Tubing	5835	5794	
53	41.00	Tubing	5794	5753	
54	41.00	Tubing	5753	5712	
55	41.00	Tubing	5712	5671	
56	40.97	Tubing	5671	5630	
57	40.17	Tubing	5630	5590	
58	41.01	Tubing	5590	5549	
59	40.20	Tubing	5549	5509	
60	41.00	Tubing	5509	5468	

JT #	LENGTH		BOTTOM	TOP
61	40.30	Tubing	5468	5427
62	39.60	Tubing	5427	5388
63	40.54	Tubing	5388	5347
64	41.00	Tubing	5347	5306
65	40.95	Tubing	5306	5265
66	41.00	Tubing	5265	5224
67	40.50	Tubing	5224	5184
68	40.71	Tubing	5184	5143
69	40.55	Tubing	5143	5103
70	40.17	Tubing	5103	5062
71	40.87	Tubing	5062	5021
72	40.55	Tubing	5021	4981
73	41.02	Tubing	4981	4940
74	41.00	Tubing	4940	4899
75	41.00	Tubing	4899	4858
76	40.70	Tubing	4858	4817
77	41.00	Tubing	4817	4776
78	40.82	Tubing	4776	4735
79	40.98	Tubing	4735	4694
80	41.00	Tubing	4694	4653
81	41.00	Tubing	4653	4612
82	41.00	Tubing	4612	4571
83	41.00	Tubing	4571	4530
84	40.65	Tubing	4530	4490
85	41.00	Tubing	4490	4449
86	41.00	Tubing	4449	4408
87	41.02	Tubing	4408	4367
88	40.62	Tubing	4367	4326
89	41.00	Tubing	4326	4285
90	41.00	Tubing	4285	4244
91	39.70	Tubing	4244	4204
92	40.15	Tubing	4204	4164
93	41.00	Tubing	4164	4123
94	40.12	Tubing	4123	4083
95	41.00	Tubing	4083	4042
96	40.60	Tubing	4042	4001
97	41.05	Tubing	4001	3960
98	40.53	Tubing	3960	3920
99	40.62	Tubing	3920	3879
100	41.00	Tubing	3879	3838
101	40.80	Tubing	3838	3797
102	40.57	Tubing	3797	3757
103	40.87	Tubing	3757	3716
104	40.30	Tubing	3716	3675
105	40.55	Tubing	3675	3635
106	41.00	Tubing	3635	3594
107	40.55	Tubing	3594	3553
108	40.54	Tubing	3553	3513
109	40.97	Tubing	3513	3472
110	41.00	Tubing	3472	3431
111	40.70	Tubing	3431	3390
112	41.00	Tubing	3390	3349
113	41.00	Tubing	3349	3308
114	40.55	Tubing	3308	3268
115	41.00	Tubing	3268	3227
116	40.57	Tubing	3227	3186
117	40.54	Tubing	3186	3145
118	40.98	Tubing	3145	3104
119	40.50	Tubing	3104	3064
120	40.60	Tubing	3064	3023
121	41.00	Tubing	3023	2982

Pkr-#60 2411.32 FEET

JT 61-121 = 2466.31 FEET
TOTAL PIPE FOOTAGE = 4896.63 FEET
IN HOLE

02-Aug-96DATE

NAVAJO REFINING COMPANY, WDW-1

JT #	LENGTH		BOTTOM	TOP
122	40.55	Tubing	2982	2942
123	40.45	Tubing	2942	2901
124	41.00	Tubing	2901	2860
125	40.60	Tubing	2860	2820
126	41.00	Tubing	2820	2779
127	40.17	Tubing	2779	2739
128	41.00	Tubing	2739	2698
129	41.00	Tubing	2698	2657
130	40.05	Tubing	2657	2617
131	41.00	Tubing	2617	2576
132	40.40	Tubing	2576	2535
133	40.85	Tubing	2535	2494
134	40.55	Tubing	2494	2454
135	41.00	Tubing	2454	2413
136	40.10	Tubing	2413	2373
137	40.55	Tubing	2373	2332
138	41.00	Tubing	2332	2291
139	41.00	Tubing	2291	2250
140	40.60	Tubing	2250	2209
141	40.12	Tubing	2209	2169
142	40.97	Tubing	2169	2128
143	40.12	Tubing	2128	2088
144	40.85	Tubing	2088	2047
145	41.00	Tubing	2047	2006
146	40.97	Tubing	2006	1965
147	40.10	Tubing	1965	1925
148	40.97	Tubing	1925	1884
149	40.56	Tubing	1884	1844
150	40.56	Tubing	1844	1803
151	40.55	Tubing	1803	1763
152	41.00	Tubing	1763	1722
153	41.00	Tubing	1722	1681
154	39.90	Tubing	1681	1641
155	41.00	Tubing	1641	1600
156	39.57	Tubing	1600	1560
157	41.00	Tubing	1560	1519
158	40.55	Tubing	1519	1479
159	40.55	Tubing	1479	1438
160	40.60	Tubing	1438	1398
161	40.55	Tubing	1398	1357
162	41.00	Tubing	1357	1316
163	40.85	Tubing	1316	1275
164	41.00	Tubing	1275	1234
165	40.15	Tubing	1234	1194
166	41.00	Tubing	1194	1153
167	40.90	Tubing	1153	1112
168	40.94	Tubing	1112	1071
169	40.90	Tubing	1071	1030
170	40.60	Tubing	1030	989
171	40.92	Tubing	989	949
172	41.00	Tubing	949	908
173	41.00	Tubing	908	867
174	40.54	Tubing	867	826
175	40.85	Tubing	826	785
176	41.00	Tubing	785	744
177	41.00	Tubing	744	703
178	40.82	Tubing	703	662
179	41.00	Tubing	662	621
180	40.15	Tubing	621	581
181	41.00	Tubing	581	540
182	41.00	Tubing	540	499

JT 122-182 = 2463.24 FEET
68-126 IN HOLE = 7379.87 FEET

JT #	LENGTH		BOTTOM	TOP	
183	40.55	Tubing	499	459	
184	40.80	Tubing	459	418	
185	41.00	Tubing	418	377	
186	0.00	Tubing	377	377	out
187	40.55	Tubing	377	336	
188	41.00	Tubing	336	295	
189	40.50	Tubing	295	255	
190	41.00	Tubing	255	214	
191	41.00	Tubing	214	173	
192	40.55	Tubing	173	132	
193	40.55	Tubing	132	92	
194	40.50	Tubing	92	51	
195	41.01	Tubing	51	10	
196	0.00	Tubing	10	10	out
197	0.00	Tubing	10	10	out
	12.50	RKB	10	-2	

JT 183-197 = 501.51 FEET
183-197 IN HOLE = 7881.38 FEET

02-Aug-98DATE

TABLE 4.1.1-I

Bottom-Hole Pressure Survey, Static Gradient Measurement

DEPTH (feet)	PRESSURE (psia)	PRESSURE GRADIENT (psi/ft)	TEMPERATURE (°F)	TEMPERATURE GRADIENT (°F/ft)
0	14.12	--	82.82	--
1700	85.30	0.042	83.40	0.0003
3000	679.62	0.457	87.81	0.0034
6000	2050.61	0.457	102.63	0.0049
7924	2928.40	0.456	104.06	0.0007

Note: Static gradient survey performed following the pressure buildup/falloff test.

TABLE 5.2-I

CEMENTING PROGRAM FOR WDW-1

Type Casing	Casing Size (inches)	Hole Size (inches)	Depth (feet)	Cementing Detail
Surface	13-3/8	17-1/2	390	Single stage, cemented to surface. Lead Slurry: 375 sacks Class 'C' Lite + 3% calcium chloride + 1/2 lb/sx Flocele Tail slurry: 150 sacks Class 'C' + 3% calcium chloride 86 sacks cement returns to surface
Intermediate	9-5/8	12-1/4	2555	Single stage, cemented to surface Lead Slurry: 800 sacks Class 'C' lite + 1/2 lb/sx Flocele + 2 lb/sx Gilsonite + 12% salt Tail Slurry: 200 sacks Class 'C' + 2% calcium chloride 133 sacks cement returns to surface
Protection	7	8-3/4	9094	Two stage, DV tool at 5498 feet Stage 1: 600 sacks modified Class 'H' + 0.4% CFR-3 + 5 lb/sx Gilsonite + 0.5% Halad-344 + 1 lb/sx salt mixed at 13.0 ppg Caliper volume plus 20% excess, circulated 142 sacks cement to surface. Stage 2 (lead): 220 sacks Interfill C (35:65:6) mixed at 11.7 ppg Stage 2 (tail): 550 sacks modified Class 'H' + 0.5% Halad - 344 + 0.1% HR-7 + 0.4% CFR-3 + 5 lb/sx Gilsonite + 1 lb/sx salt mixed at 13.0 ppg Caliper volume plus 20% excess, circulated 75 sacks cement to surface

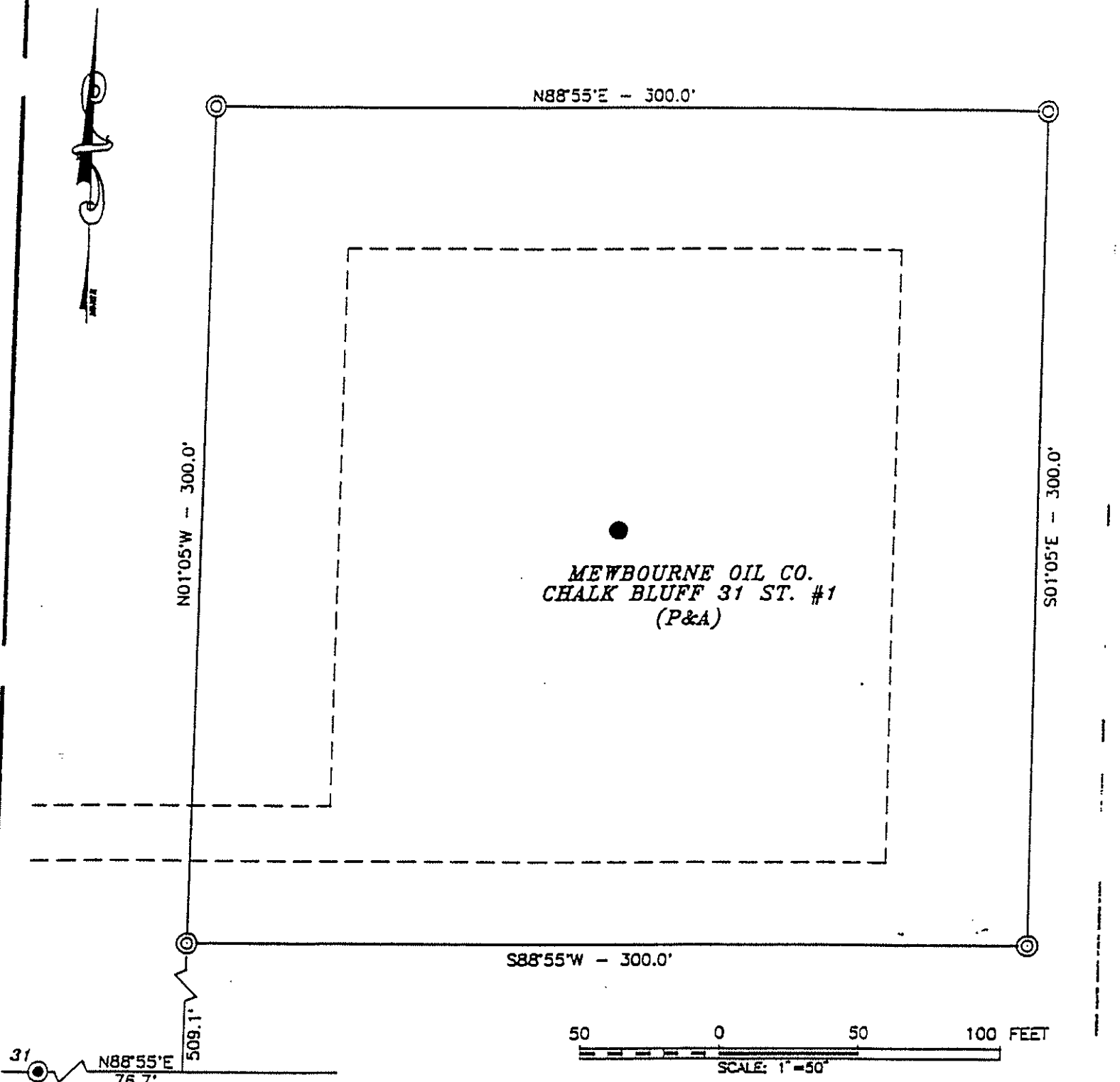
TABLE 5.4.1-I

DEVIATION SURVEYS

DEPTH (feet)	DEVIATION (degrees)
2481	1
3441	1-1/4
4432	1-3/4
5277	4-1/4
6768	3-1/2
7571	1-3/4
8604	1-1/4
9160	1

FIGURES

SECTION 31, TOWNSHIP 17 SOUTH, RANGE 28 EAST, N.M.P.M.,
EDDY COUNTY NEW MEXICO



◎ DENOTES: SET 1/2" IRON ROD, W/ PVC CAP MARKED "PS 3239 PS 12641"

JOHN W. WEST ENGINEERING COMPANY
CONSULTING ENGINEERS & SURVEYORS – HOBBS, NEW MEXICO

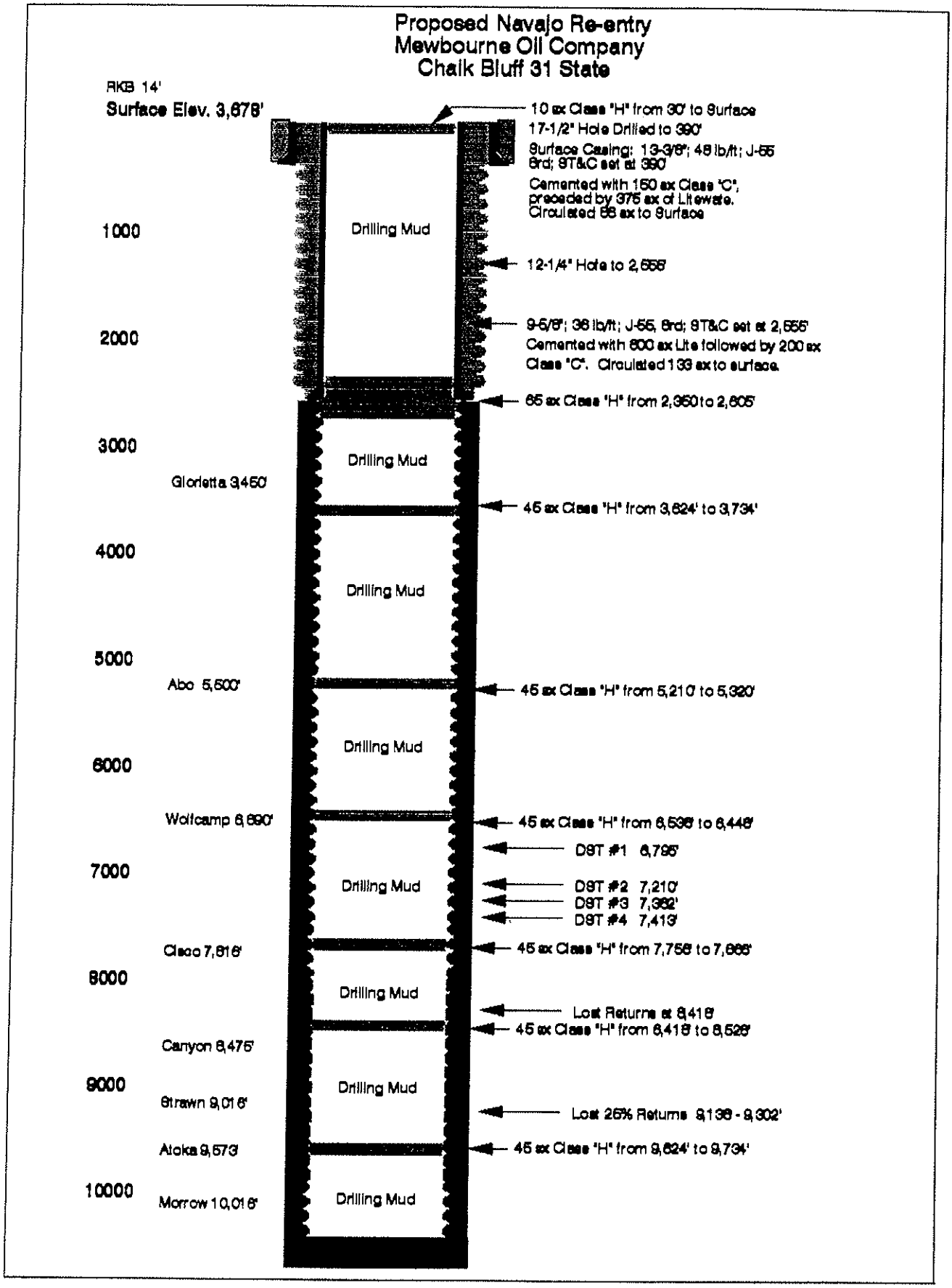
NAVAJO REFINING COMPANY

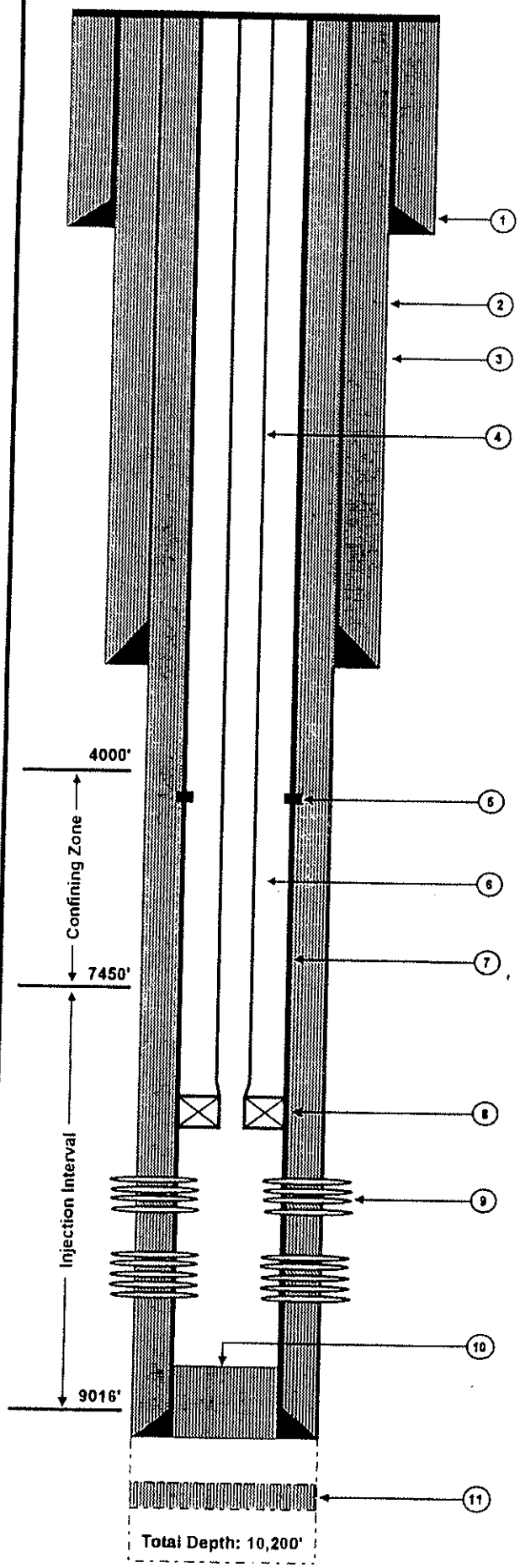
CHALK BLUFF 31 STATE #1 LOCATED 660 FEET FROM THE SOUTH LINE AND 2310 FEET FROM THE EAST LINE SECTION 31, TOWNSHIP 17 SOUTH, RANGE 28 EAST, N.M.P.M., EDDY COUNTY, NEW MEXICO.

FIGURE 1.0-1

Survey Date: 11/24/97		Sheet 1 of 1 Sheets	
W.O. Number: 97-11-1922		Drawn By: CDG	
Date: 12/1/97	DISK: NAVAJO	NAV1922	

FIGURE 2.0-1


Proposed Navajo Re-entry
Mewbourne Oil Company
Chalk Bluff 31 State
RKB 14'
Surface Elev. 3,678'
10 sx Class "H" from 30' to Surface
17-1/2" Hole Drilled to 390'
Surface Casing: 13-3/8"; 48 lb/ft; J-55
8rd; STC set at 390'
Cemented with 150 sx Class "C",
preceded by 375 sx of Litewate.
Circulated 68 sx to Surface
Drilling Mud
12-1/4" Hole to 2,555'
9-5/8"; 36 lb/ft; J-55, 8rd; STC set at 2,555'
Cemented with 600 sx Lite followed by 200 sx
Class "C". Circulated 139 sx to surface.
65 sx Class "H" from 2,360 to 2,605'
Drilling Mud
Glorietta 3,450'
45 sx Class "H" from 3,624' to 3,734'
Drilling Mud
Drilling Mud
Abo 5,500'
45 sx Class "H" from 5,210' to 5,320'
Drilling Mud
Wolfcamp 6,690'
45 sx Class "H" from 6,536' to 6,446'
DST #1 6,795'
Drilling Mud
DST #2 7,210'
DST #3 7,362'
DST #4 7,413'
Cisco 7,816'
45 sx Class "H" from 7,758' to 7,666'
Drilling Mud
Lost Returns at 8,418'
Canyon 8,475'
45 sx Class "H" from 8,418' to 8,528'
Drilling Mud
Strawn 9,016'
Lost 25% Returns 9,136 - 9,302'
Atoka 9,573'
45 sx Class "H" from 9,624' to 9,734'
Morrow 10,016'
Drilling Mud
1000
2000
3000
4000
5000
6000
7000
8000
9000
10000



BELOW GROUND DETAIL

All depths are referenced to the kelly bushing elevation of 12.5 feet. Surface elevation is 3678 feet.

1. Surface Casing: 13-3/8", 48 lb/ft, J-55, ST&C set at 390' in a 17-1/2" hole. Cemented with 150 sx Class C with 3% calcium chloride, 375 sx Class C Litewate w/ 3% calcium chloride and 1/2 lb/sx flocele. Circulated 86 sx to surface.

2. Intermediate Casing: 9-5/8", 36 lb/ft, J-55, ST&C set at 2565' in a 12-1/4" hole. Cemented w/ 800 sx of Class C Lite w/ 1/2 lb/sx flocele and 2 lb/sx Gilsonite and 12% salt. Followed by 200 sx of Class C w/ 2% calcium chloride. Circulated 133 sx to surface.

3. Base of the USDW at 493'.

4. Injection Tubing: 4-1/2", 11.6 lb/ft, N-80, SMLS, R3, LT&C set at 7879'.

5. DV Tool: at 5498'.

6. Annulus Fluid: 8.7 lb/gal brine water mixed w/ UniChem Techni-Hib 370 corrosion inhibitor.

7. Protection Casing: 7", 29 lb/ft, N-80, LT&C: 9094' to 7031'. 7", 29 lb/ft, P-110, LT&C: 7031' to 5845'. 7", 26 lb/ft, P-110, LT&C; 5845' to surface. Set in 8-3/4" hole. Casing cemented in two stages as follows:

First Stage
600 sx modified Class H w/ 0.4% CFR-3, 5 lb/sx Gilsonite, 0.5% Halad-344, and 1 lb/sx salt mixed at 13.0 ppg. Opened DV tool at 5498' and circulated 142 sx to surface.

Second Stage
Lead Slurry: 220 sx Interfill 'C' (35:65:6) mixed at 11.7 ppg. Tail Slurry: 550 sx modified Class H w/ 0.4% CFR-3, 5 lb/sx, Gilsonite, 0.5% Halad-344, 0.1% HR-7, and 1 lb/sx salt mixed at 13.0 ppg. Circulated 75 sx to surface. Top out w/ 20 sx premium plus 3% calcium chloride.

8. Packer: 7" x 3.5" EVI Oil Tools (Arrow), Model X-1 retrievable packer set at 7879'. Minimum I.D. is 3.0". Wireline reentry guide on bottom. To release: turn 1/4 turn to the right and pick up.

9. Perforations (2 SPF):

Upper Zone:

7924-7942', 7974-8030', 8050-8056', 8066-8080', 8118-8127', 8132-8140', 8160-8164', 8170-8188'.

Lower Zone:

8220-8254', 8260-8270', 8280-8302', 8360-8366', 8370-8378', 8400-8410', 8419-8423', 8430-8446', 8460-8464', 8470-8476'.

10. PBTD: 9004'

11. Cement Plug: 45 sx Class H from 9624' to 9734'.

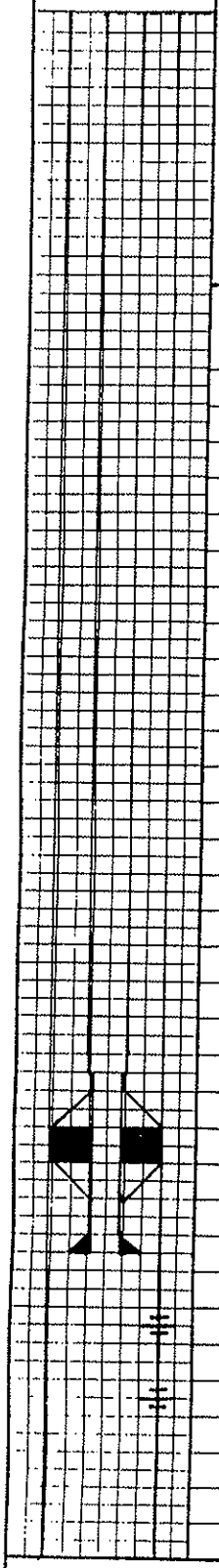
ENVIROCORP® HOUSTON, TX. SOUTH BEND, IN. BATON ROUGE, LA.

FIGURE 2.0-2
NAVAJO REFINING COMPANY
WDW-1
ARTESIA, NEW MEXICO

Date: 09/15/98	Checked By: B.R.	Job No.: 70A4614
Drawn By: LKM	Approved By: B.R.	File: WDW1.DS4

FIGURE 2.6-1

WELL PROFILE



OPERATOR Envirocorp
COMPANY REP. Brian Rogers
WELL # Chalk Bluff 31 State
FIELD
COUNTY Eddy
STATE New Mexico
DATE 8-1-98
☐ New Completion ☑ Workover

		SIZE	WEIGHT	GRADE	THREAD
CASING		7"	23.0#	N-80 P-110	
LINER		—	—	—	—
TUBING	LONG STRING	4½	11.6#	N-80	LT&C
	SHORT STRING	—	—	—	—

TYPE COMPLETION FLUID IN CASING

TUBING WT ON	LONG STRING	SHORT STRING
	15,000# ↓	—

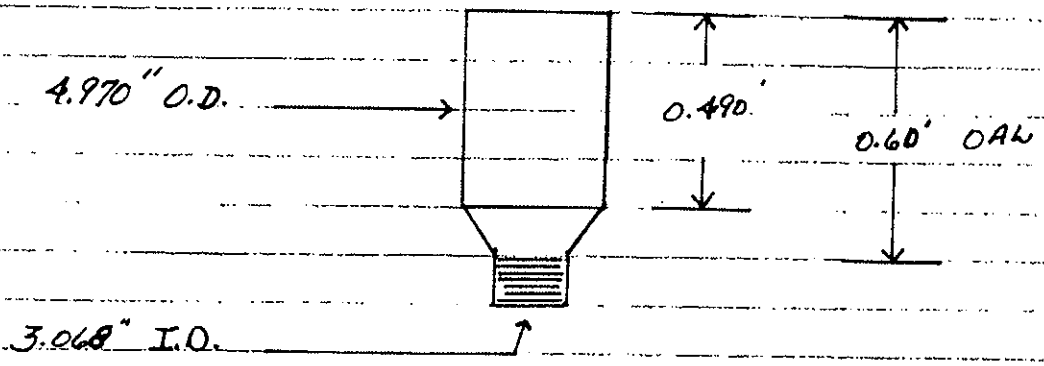
ITEM	LENGTH	FROM	TO	DESCRIPTION	OD	ID
	10.50'	12.50'	2.0' A.G.L.	K. B. Correction		
	7859.86'	10.50'	7870.36'	193 Jts. - 4½" - 11.6# N-80 LT&C Casing	5.0"	4.0"
	0.60'	7870.36'	7870.96'	4½" LT&C Box X 3½" EU 8rd Pin	4.97"	3.068"
	7.90'	7870.96'	7878.86'	7" X 3½" Arrowset I-X Packer	5.844"	3.068"
	0.51'	7878.86'	7879.37	Wireline Re-Entry Guide	5.5"	3.5"
	7879.37			Total Depth of Tubing		
		7924'	8188'	Perforations		
		8220'	8476'	Perforations		

WATSON PACKER
P.O. BOX 60690
MIDLAND, TX 79711
1-800-777-7957

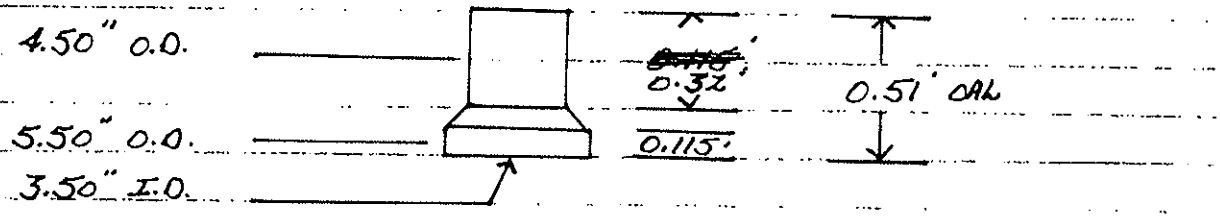
PREPARED BY	OFFICE	PHONE
Mitch Johnson	Artesia	748-1341

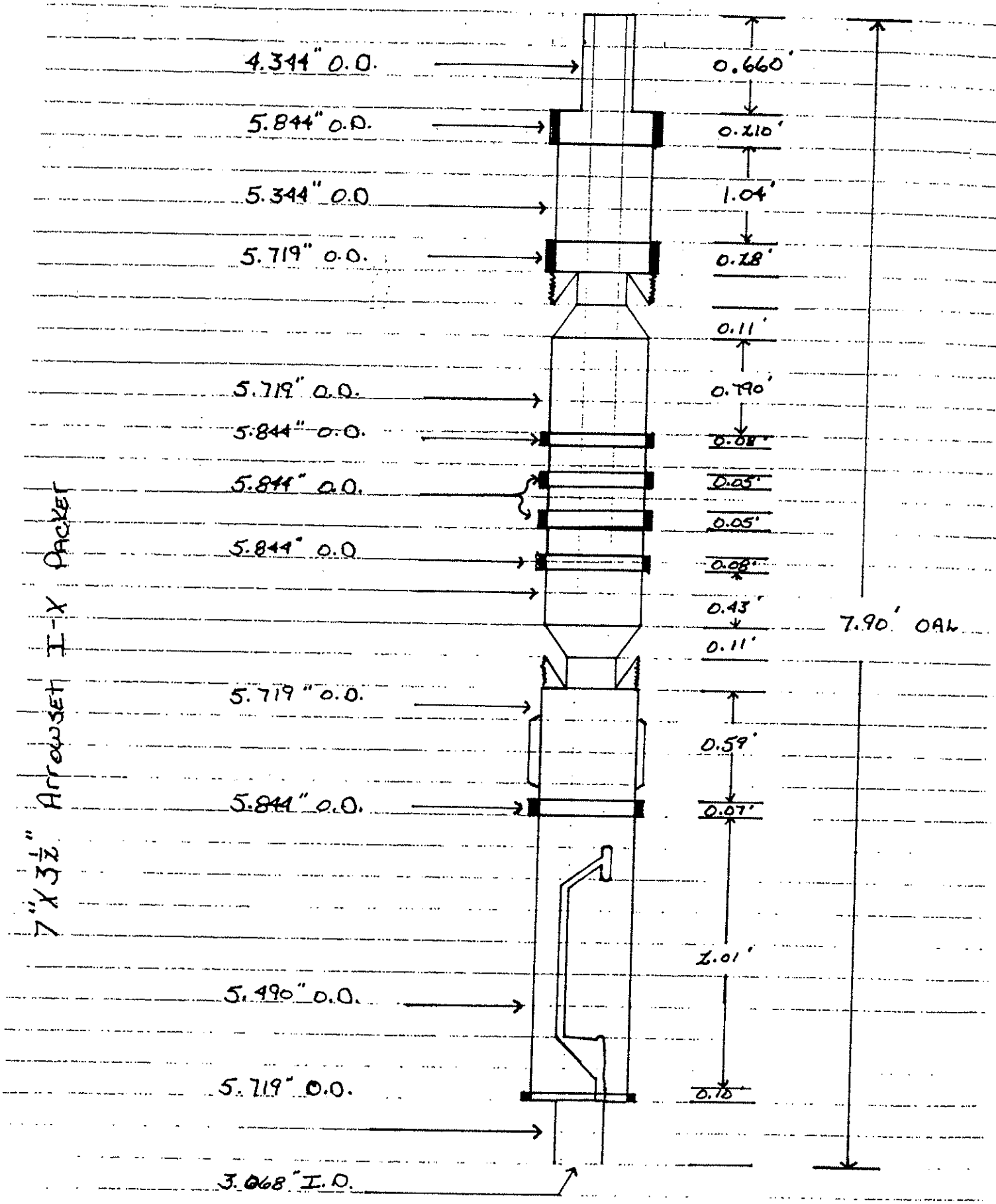
REMARKS:
-7' for Wireline Correction

4½" LTC Casing Box X 3½" EU 8rd Pin X-over



Wireline Entry Guide





Lengths IN = Lin. ft.

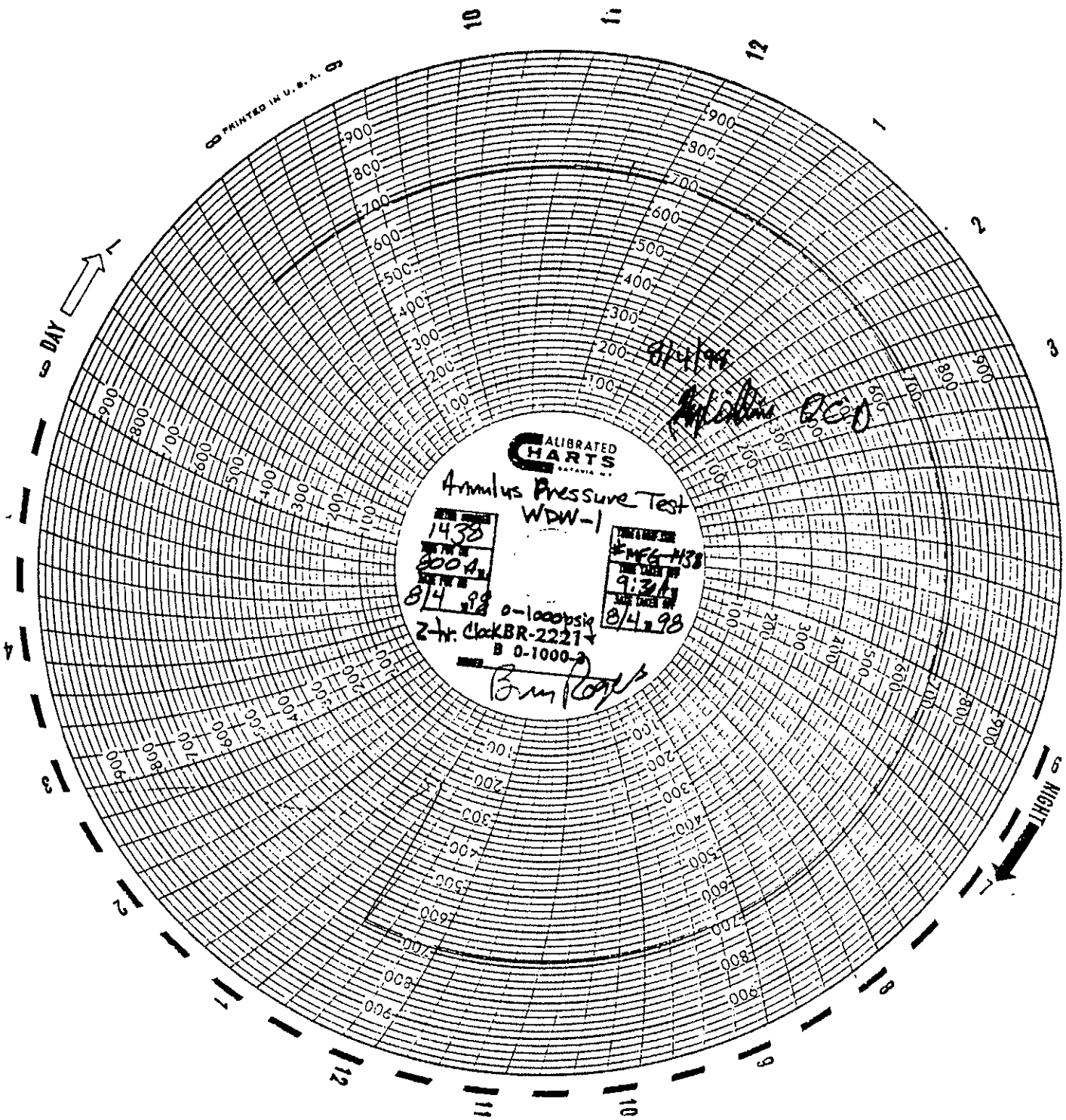

PRINTED IN U.S.A.
DAY
NIGHT
CALIBRATED CHARTS
Annulus Pressure Test
WDW-1
1438
8/4/98
9:34
8/4/98
0-1000psig
2-Hr. ClockBR-2221
B 0-1000-2
8/4/98

FIGURE 3.5–1

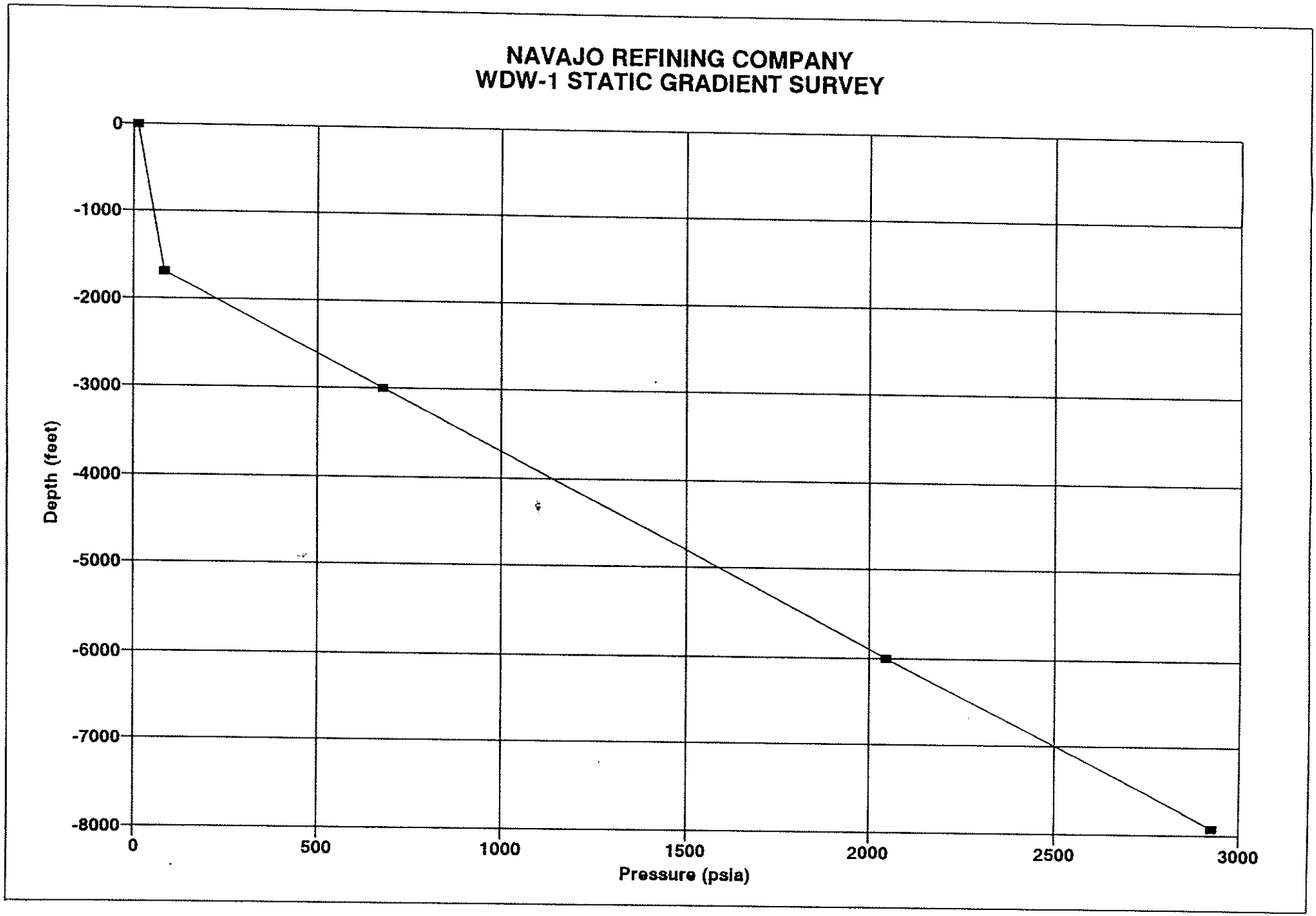

NAVAJO REFINING COMPANY
WDW-1 STATIC GRADIENT SURVEY
Depth (feet)
0
-1000
-2000
-3000
-4000
-5000
-6000
-7000
-8000
0
500
1000
1500
2000
2500
3000
Pressure (psia)

FIGURE 4.1.1-1

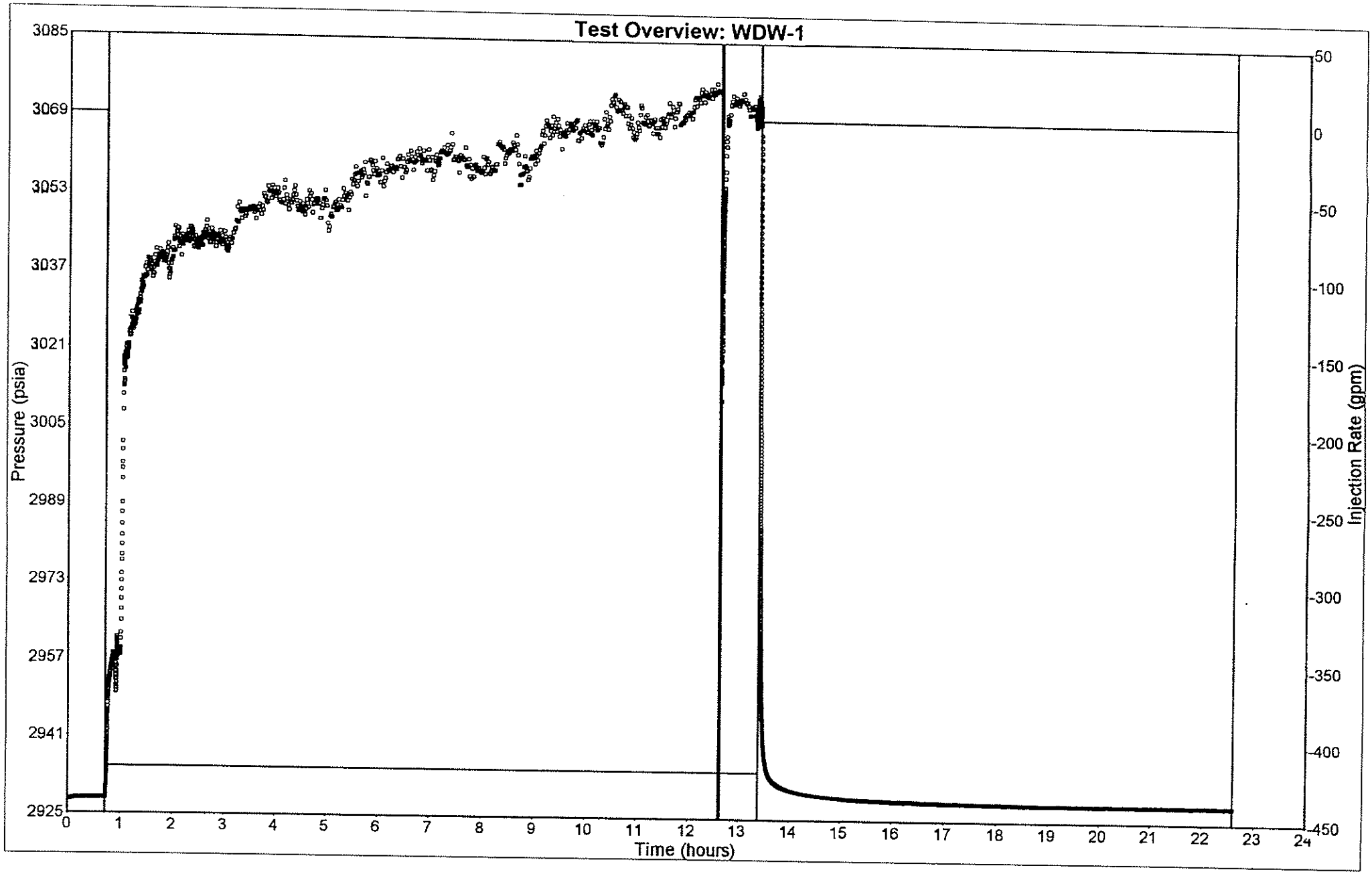

Test Overview: WDW-1
Pressure (psia)
3085
3069
3053
3037
3021
3005
2989
2973
2957
2941
2925
Injection Rate (gpm)
50
0
-50
-100
-150
-200
-250
-300
-350
-400
-450
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Time (hours)

FIGURE 4.1.2–1

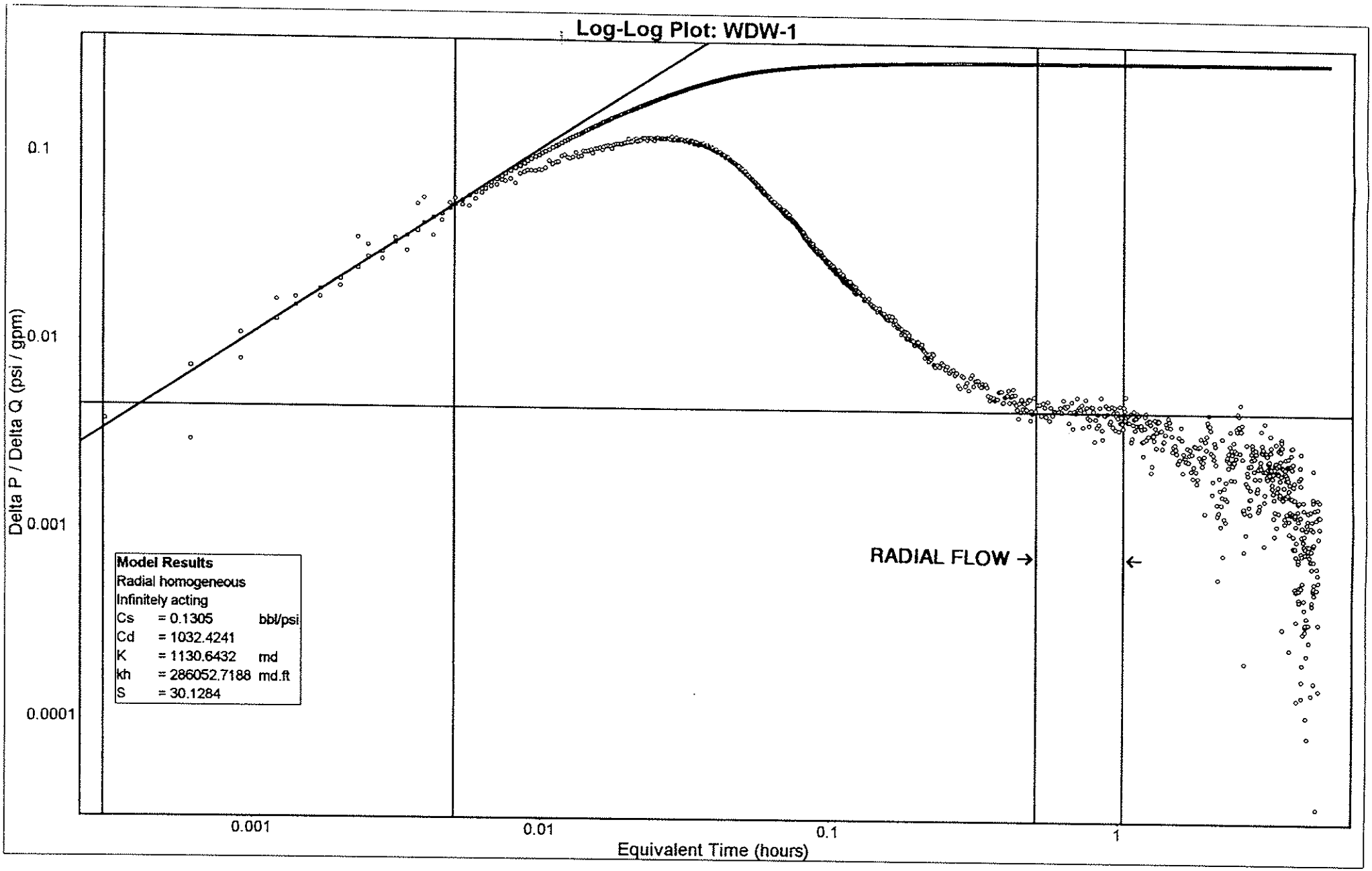

Log-Log Plot: WDW-1
Delta P / Delta Q (psi / gpm)
0.1
0.01
0.001
0.0001
0.001
0.01
0.1
1
Equivalent Time (hours)
RADIAL FLOW →
←
Model Results
Radial homogeneous
Infinitely acting
Cs = 0.1305 bbl/psi
Cd = 1032.4241
K = 1130.6432 md
kh = 286052.7188 md.ft
S = 30.1284

FIGURE 4.1.2-2

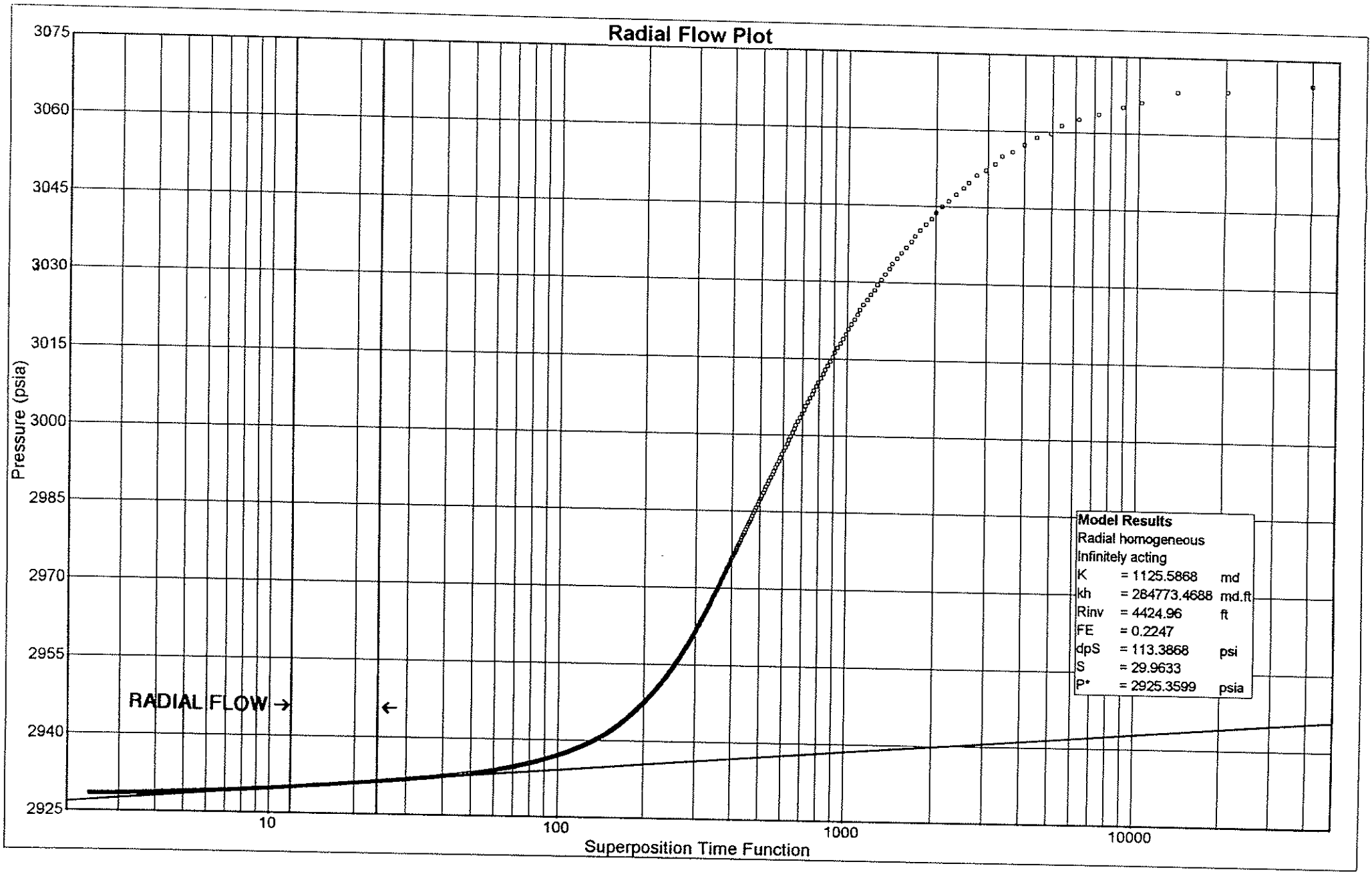

Radial Flow Plot
Pressure (psia)
3075
3060
3045
3030
3015
3000
2985
2970
2955
2940
2925
10
100
1000
10000
Superposition Time Function
RADIAL FLOW →
←
Model Results
Radial homogeneous
Infinitely acting
K = 1125.5868 md
kh = 284773.4688 md.ft
Rinv = 4424.96 ft
FE = 0.2247
dpS = 113.3868 psi
S = 29.9633
P* = 2925.3599 psia

FIGURE 4.1.2-3

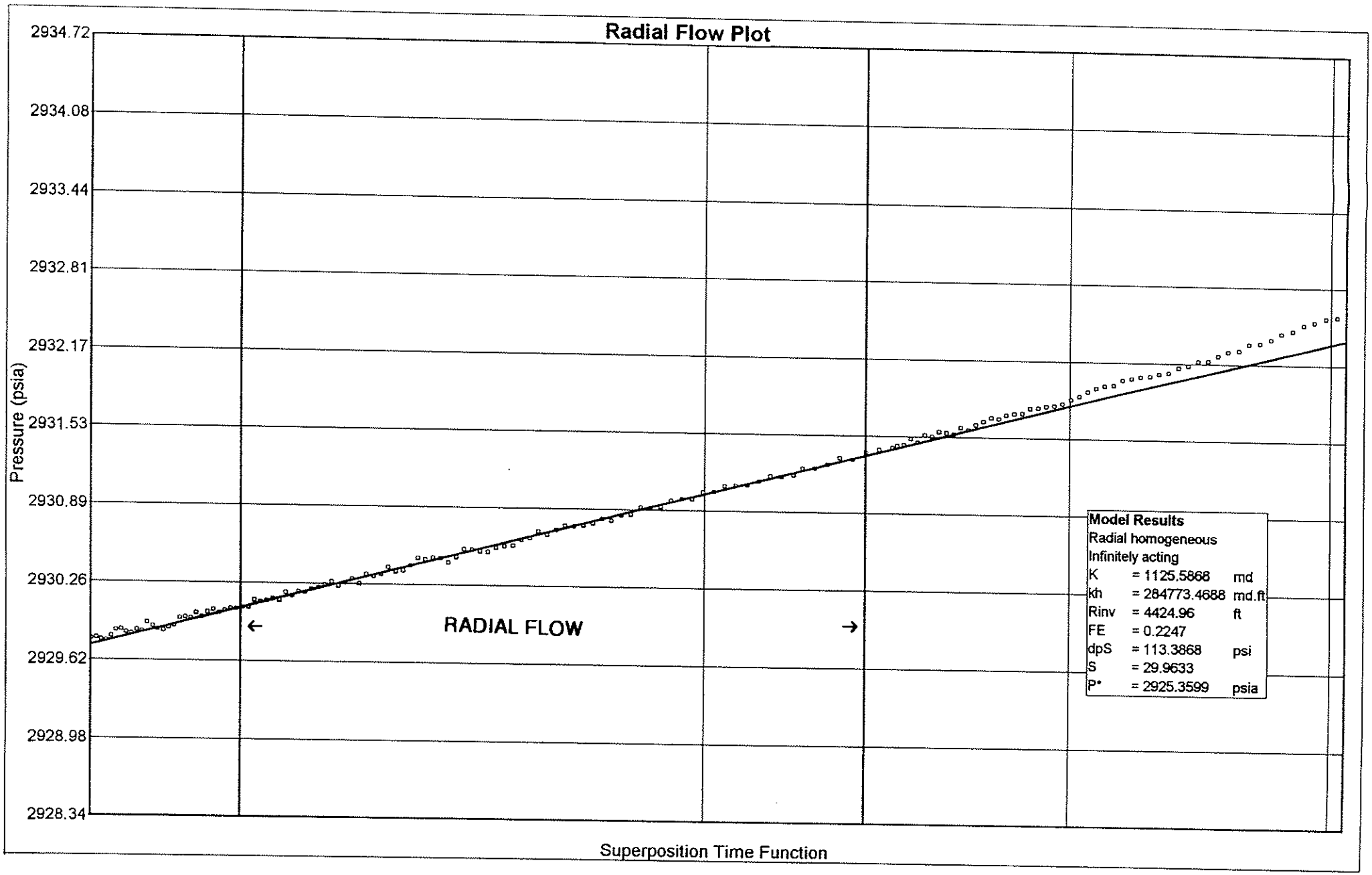

Radial Flow Plot
2934.72
2934.08
2933.44
2932.81
2932.17
2931.53
2930.89
2930.26
2929.62
2928.98
2928.34
Pressure (psia)
RADIAL FLOW
Model Results
Radial homogeneous
Infinitely acting
K = 1125.5868 md
kh = 284773.4688 md.ft
Rinv = 4424.96 ft
FE = 0.2247
dpS = 113.3868 psi
S = 29.9633
P* = 2925.3599 psia
Superposition Time Function

FIGURE 4.1.2–4

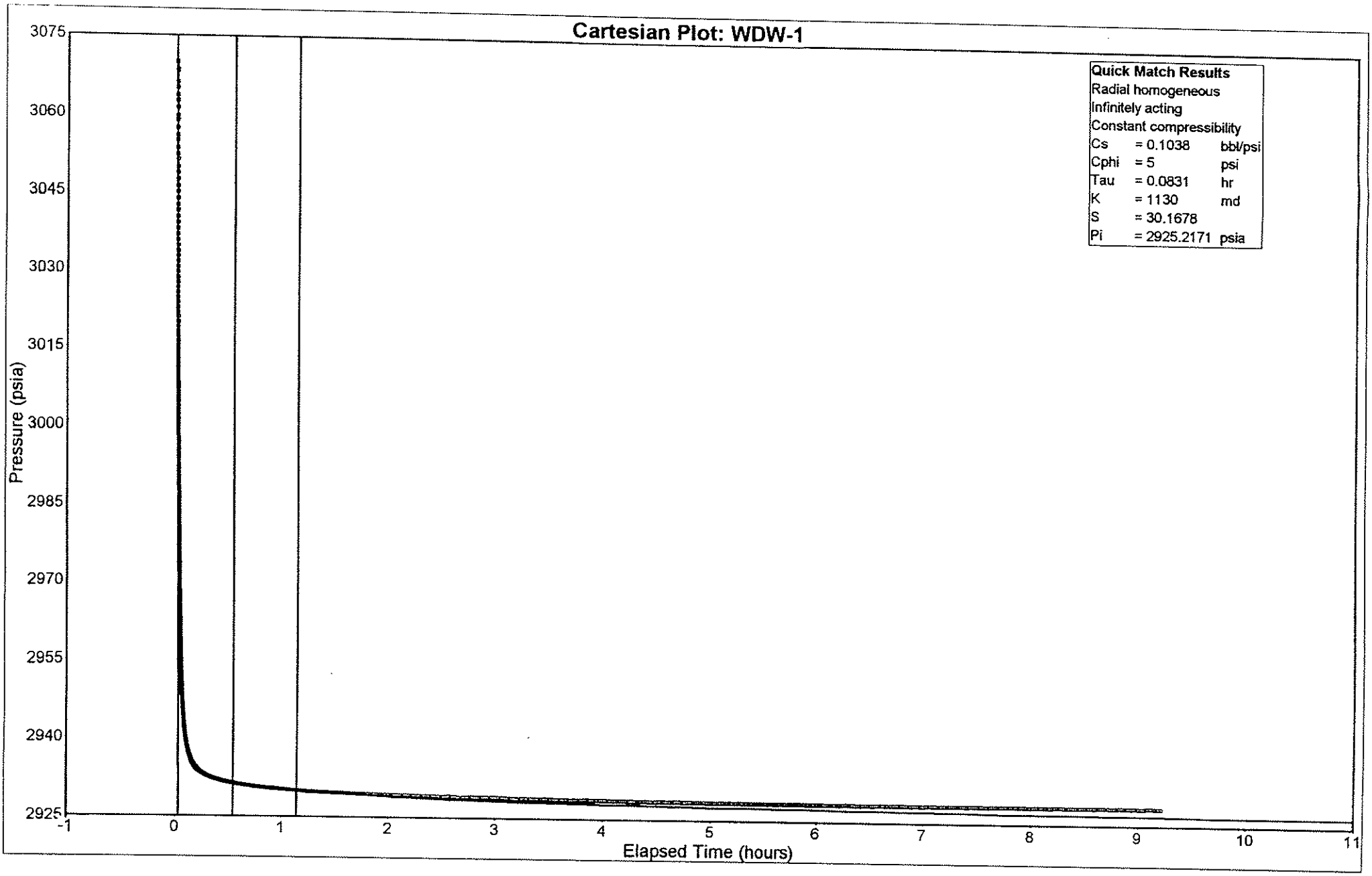

Cartesian Plot: WDW-1
Quick Match Results
Radial homogeneous
Infinitely acting
Constant compressibility
Cs = 0.1038 bbl/psi
Cphi = 5 psi
Tau = 0.0831 hr
K = 1130 md
S = 30.1678
Pi = 2925.2171 psia
Pressure (psia)
3075
3060
3045
3030
3015
3000
2985
2970
2955
2940
2925
-1
0
1
2
3
4
5
6
7
8
9
10
11
Elapsed Time (hours)

FIGURE 4.1.2–5

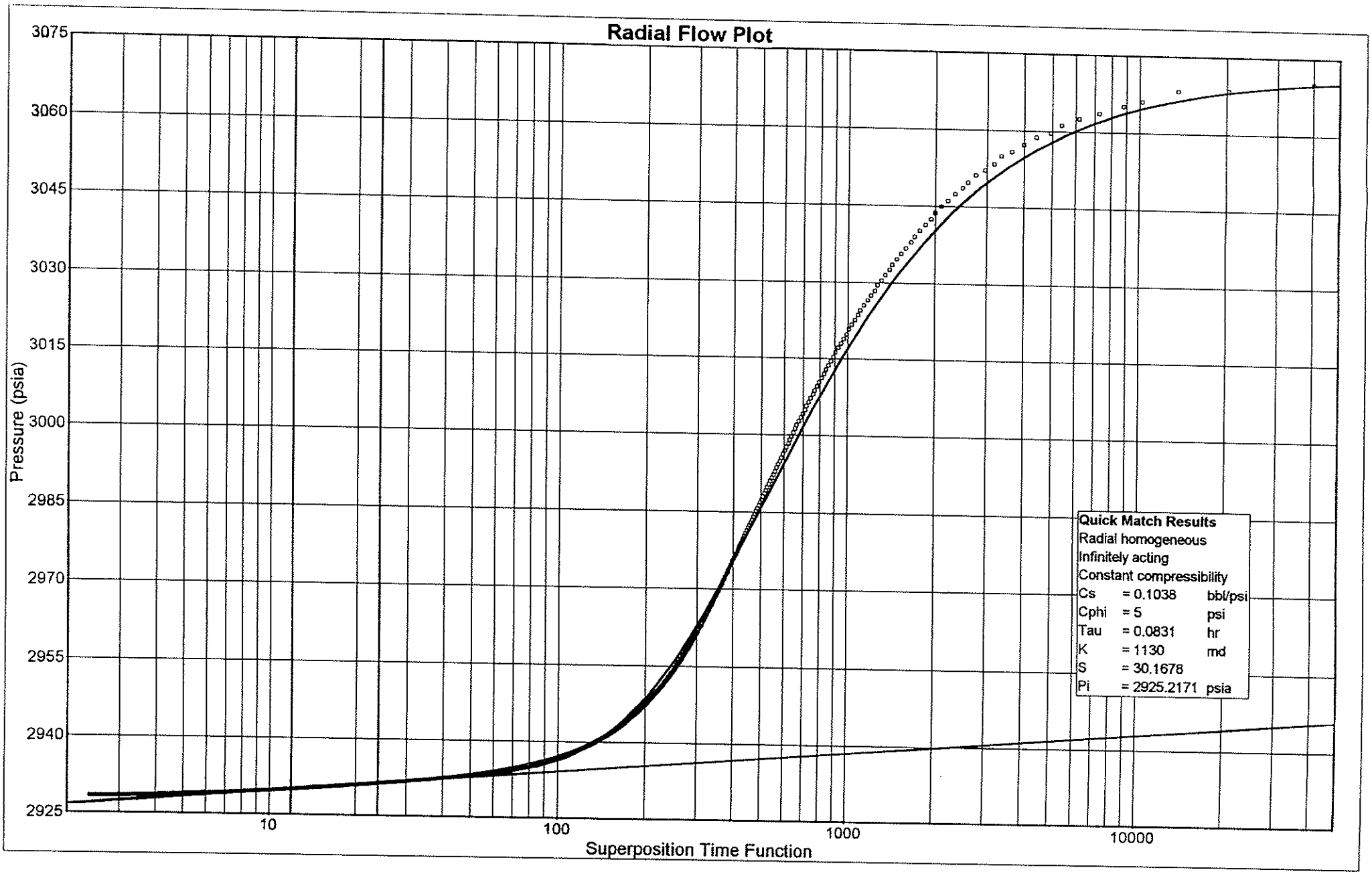

Radial Flow Plot
Pressure (psia)
3075
3060
3045
3030
3015
3000
2985
2970
2955
2940
2925
10
100
1000
10000
Superposition Time Function
Quick Match Results
Radial homogeneous
Infinitely acting
Constant compressibility
Cs = 0.1038 bbl/psi
Cphi = 5 psi
Tau = 0.0831 hr
K = 1130 md
S = 30.1678
Pi = 2925.2171 psia

FIGURE 4.1.2-6

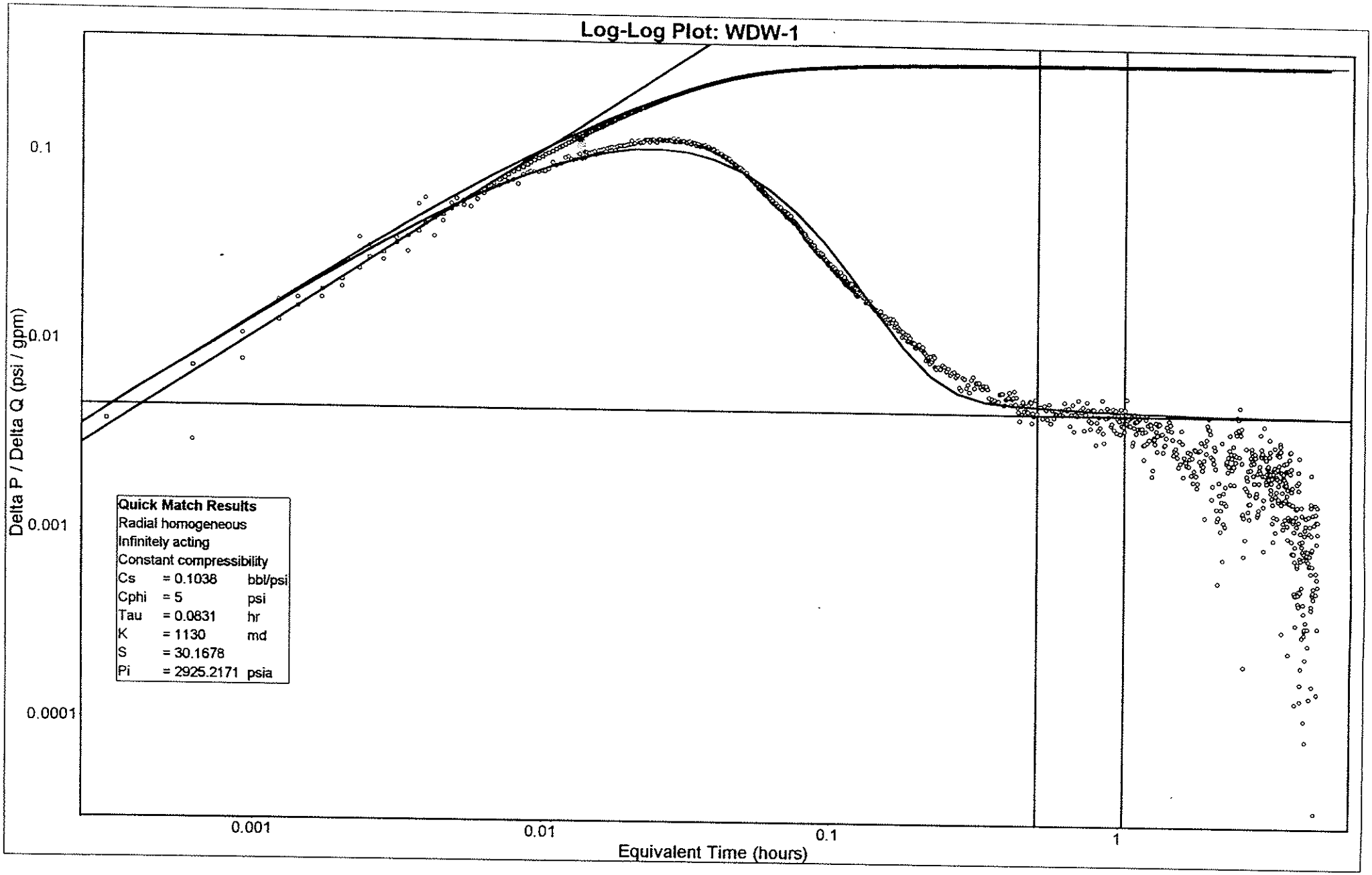

Log-Log Plot: WDW-1
Delta P / Delta Q (psi / gpm)
0.1
0.01
0.001
0.0001
Quick Match Results
Radial homogeneous
Infinitely acting
Constant compressibility
Cs = 0.1038 bbl/psi
Cphi = 5 psi
Tau = 0.0831 hr
K = 1130 md
S = 30.1678
Pi = 2925.2171 psia
0.001
0.01
0.1
1
Equivalent Time (hours)

FIGURE 4.1.2–7

APPENDICES

APPENDIX 1.0-1

APPROVAL LETTERS FROM THE NEW MEXICO WATER QUALITY CONTROL COMMISSION, DATED MAY 21, 1998 AND JULY 2, 1998

APPENDIX 1.0–1

NEW MEXICO ENERGY, MINERALS
& NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION
2040 South Pacheco Street
Santa Fe, New Mexico 87505
(505) 827-7131

RECEIVED
JUN 0 1 1998
Envirocorp Services & Technology Inc.
Houston

May 21, 1998

GOA4305

CERTIFIED MAIL
RETURN RECEIPT NO. P-288-259-070

Mr. Darrell Moore
Navajo Refining Company
P.O. Box 159
Artesia, New Mexico 88211

Re: Recent Request for Injectivity Tests

Dear Mr. Moore:

Reference is made to your recent request to conduct tests on the Mewbourne Oil Company, Chalk Bluff 31 No. 1 located in Section 31, T17S, R28E to determine approximately stable injection rates and pressures. My staff has reviewed your request and the same is hereby approved for a period of 90 days, concluding on August 20, 1998. Fluids for testing will be limited to fresh water. The wellhead pressure will not exceed 1,490 psi.

If my staff may be of further assistance, please do not hesitate to call Mr. Mark Ashley at (505) 827-7155.

Sincerely,

Lori Wrotenbery
Director

LW/mwa

xc: OCD Artesia Office

NEW MEXICO ENERGY, MINERALS
& NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION
2040 South Pacheco Street
Santa Fe, New Mexico 87505
(505) 827-7131

RECEIVED
JUL 0 6 1998
Envirocorp Services & Technology Inc.
Houston

July 2, 1998

CERTIFIED MAIL
RETURN RECEIPT NO. P-288-259-084

Mr. Darrell Moore
Navajo Refining Company
P.O. Box 159
Artesia, New Mexico 88211

Re: Modification of Recent Request for Injectivity Tests

Dear Mr. Moore:

Reference is made to your recent request to use light brine (approximately nine pounds per gallon) or fresh water for injectivity testing on the Mewbourne Oil Company, Chalk Bluff 31 No. 1 located in Section 31, T17S, R28E to determine approximately stable injection rates and pressures. Based on the information received, your request is hereby approved.

If you have any questions, please call me at (505) 827-7155.

Sincerely,

Mark Ashley
Geologist

xc: OCD Artesia Office
Ms. Nancy Niemann, Envirocorp, 7020 Portwest Dr., #100, Houston, Texas 77024

APPENDIX 2.0-1

ORIGINAL WELL INSTALLATION DAILY REPORTS, MEWBOURNE OIL COMPANY, CHALK BLUFF STATE "31", WELL NO. 1

HEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL
County Eddy State New Mexico Section 31
Block Township 17S Range 28E Page 1

DATE	DAILY REPORTS
OCT 31 1992	Staked well @ 660' FSL & 2310' FEL of Sec 31-17S-28E in Eddy County, New Mexico. Location drillable.
JUL 27 1993	Move in construction equipment. Will start building location today.
JUL 28 1993	Continue building location.
JUL 31 1993	Continue building location.
AUG 01 1993	Continue building location.
AUG 02 1993	Continue building location.
AUG 03 1993	Continue building location.
AUG 04 1993	Continue building location. Should finish today.
AUG 05 1993	390' (350'). Circ in Red Beds & Anhydrite. MW 10.4, Vis 32. Bit #1, Size: 17 1/2", Type: R-1, SN: RT, Jets 3/12's, IN @ 40' OUT @ 390' (made 350' in 6 3/4 hrs). PP 1025#, SPM 59, WOB All, RPM 100, Collars 42,000#. (Drilling 6 3/4, Circ 1/4, Idle 6, RU 11). REMARKS: Spud 17 1/2" hole @ 11:00 PM, 8/04/93. DAY 1
AUG 06 1993	815' (425'). Drilling in Red Beds & Anhydrite. Dev. @ 390' - 1/2 deg. MW 8.4, Vis 28, CL 4,000, pH 10. Bit #2, Size: 12 1/4", Type: F37, SN: RR, Jets 10/11/11, IN @ 390' (made 425' in 7 3/4 hrs). PP 1375#, SPM 60, WOB 65,000#, RPM 55, Collars 71,000#. (Drilling 7 3/4, Trip 3/4, Circ 1/4, RU Ran Csg & Cmt 3 1/4, WOC & NU BOP 12). Ran 13 3/8" surface casing as follows: 13 3/8" Notched Texas Pattern Shoe 1.21' 1-13 3/8" 48# J-55 8rd STAC SJ w/IF 43.83' 8-13 3/8" 48# J-55 8rd STAC Casing 348.21' Total Casing 393.25' Less KB Correction 3.25' Casing Set At 390.00' Halliburton cmtd w/375 sks Class "C" Lite containing 1/2#/sk + 3% CaCl2 followed by 150 sks Class "C" containing 3% CaCl2. PD to 348' @ 10:15 AM 8/5/93. Circ 86 sks to pit.
AUG 07 1993	1735' (920'). Drilling in Anhydrite & Dolomite. Dev. @ 867' - 3/4 degs; @ 1338' - 3/4 degs. MW 8.5, Vis 28, CL 2000, pH 10. Bit #2 (made 1345' in 31 1/4 hrs). PP 1375#, SPM 59, WOB 65,000#, RPM 55, Collars 71,000#. (Drilling 23 1/4, Totco 1/2). DAY 3
AUG 08 1993	2150' (415'). Drilling in Dolomite. Dev. @ 1839' - 1 1/4 degs; @ 1988' - 1 1/2 degs. MW 8.6, Vis 28, CL 6000. Bit #2, OUT @ 1988' (made 1598' in 42 1/2 hrs). Bit #3, Size: 12 1/4", Type: J44, SN: RR, Jets 3/11's. IN @ 1988' (made 162' in 8 hrs). PP 1300#, SPM 59, WOB 65,000#, Collars 71,000#. (Drilling 19 1/4, Trip 2 3/4 hrs, Totco 1/2, Wash 120' to Btm w/100' Fill 1 1/2). DAY 4
AUG 09 1993	2555' (405'). Circulating in Dolomite. Dev. @ 2201' - 3/4 degs. MW 8.6, Vis 28, CL 16,000, pH 9. Bit #3, Size: 12 1/4", Type: J44, SN: RR, Jets 3/11's. IN @ 1988' OUT @ 2201' (made 213' in 10 1/2 hrs). Bit #4, Size: 12 1/4", Type: J55, SN: RR, Jets 3/12's. IN @ 2201' OUT @ 2555' (made 354' in 17 3/4 hrs). PP 1100#, SPM 59, WOB 65,000#, RPM 55, Collars 71,000#. (Drilling 20 1/4, Trip 2 3/4, Circ 3/4, Wash 60' to Btm w/45' of Fill 1/4). REMARKS: Preparing to TOOH & Run 9 5/8" casing. DAY 5

NEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL

County Eddy State New Mexico Section 31

Block Township 17S Range 28E Page 2

DATE	DAILY REPORTS
AUG 10 1993	1700' (145'). Drilling in Dolomite. Dev. @ 2555' - 0 deg. MW 8.6, Vis 28, CL 16,000, pH 11.5. Bit #4, Size: 8 3/4", Type: Varel B537C, SN: 15789, Jets 3/11's, IN @ 2555' (made 145' in 3 hrs). PP 1475#, SPM 58, WOB 60,000#, RPM 55, Collars 68,000#. (Drilling 3, Trip 2, Circ 1/2, Run Csg & Cmt 6 1/2, WOC & NU BOP 12). Ran 9 5/8" csg as follows: Davis-Lynch Guide Shoe 1.00' 1-9 5/8", 36#, J-55, 8rd, LTC Shoe Jt 42.55' Davis-Lynch Float Collar 1.40' 56-9 5/8", 36#, J-55, 8rd, STC Casing 2518.23' Total Casing 2563.18' Less KB Correction 8.18' Casing Set At 2555.00' Halliburton cmtd w/800 sks Howco Lite "C" containing 1/2#/sk flocele + 2#/sk Gilsonite + 12% NaCl followed by 200 sks Class "C" Neat containing 2% CaCl2. Plug down to 2518' @ 3:00 PM, 8/9/93. Circ 133 sks to pit.
AUG 11 1993	3545' (845'). Drilling in Dolomite. Dev. @ 3051' - 1/2 degs; @ 3520' - 3/4 degs. MW 8.4, Vis 28, CL 16,000, pH 11.0. Bit #5, Size: 8 3/4" (made 990' in 26 1/2 hrs). PP 1475#, SPM 59, WOB 60,000#, RPM 55, Collars 68,000#. (Drilling 23 1/2, Totco 1/2). DAY 7
AUG 12 1993	4120' (575'). Drilling in Dolomite. Dev. @ 3983' - 1 1/4 degs. MW 9.0, Vis 29, CL 35,000, pH 9.5. Bit #5, Size: 8 3/4" OUT @ 3900' (made 1433' in 41 hrs). Bit #6, Size: 8 3/4", Type: B547, SN: 19373, Jets 12/12/11. IN @ 3988' (made 132' in 5 3/4 hrs) PP 1425#, SPM 58, WOB 60,000#, RPM 55, Collars 68,000#. (Drilling 20 1/4, Trip 1/4, Totco 1/4, Wash to Btm w/no fill 1/4). DAY 8
AUG 13 1993	4635' (515'). Drilling in Dolomite. Dev. @ 4635' - 1 3/4°. MW 9.0, Vis 29, CL 63,000, pH 9.5. Bit #6, Size: 8 3/4", Type: B547, SN: 19373, Jets 12/12/11. IN @ 3988' (made 647' in 129 1/4 hrs) PP 1475#, SPM 58, WOB 60,000#, RPM 60, Collars 68,000#. (Drilling 23 1/2, Totco 1/2). DAY 9
AUG 14 1993	5055' (430'). Drlg in Dolomite. Dev. @ 4995' - 3 1/4°. MW 9.1, Vis 29, CL 65,000. Bit #6 OUT @ 5005' (made 1017' in 47 hrs). Bit #7, Type: 8 3/4", Type: V547, SN: 19480, Jets 12/12/11. IN @ 5005' (made 50' in 2 hrs). PP 1475#, SPM 58, WOB 50,000#, RPM 60, Collars 68,000#. (Drlg 19 3/4, Trip 3 3/4. Wash 40' to Btm w/No Fill 1/2). DAY 10
AUG 15 1993	5315' (260'). Drilling in Dolomite. Dev. @ 5120' - 3 3/4°; @ 5215' - 4 1/4°; @ 5310' - 4 1/4°. MW 9.1, Vis 29, CL 80,000. Bit #7, (made 310' in 24 1/2 hrs). PP 1475#, SPM 58, WOB 20,000#, RPM 60, Collars 68,000#. (Drilling 22 1/2, Totco 1 1/2). DAY 11
AUG 16 1993	5503' (187'). Drilling in Dolomite. Dev. @ 5403' - 4°; @ 5497' - 4 1/2°. MW 9.2, Vis 29, CL 81,000, pH 10. Bit #7, (made 497' in 47 1/2 hrs). PP 1475#, SPM 58, WOB 20,000#, RPM 60, Collars 68,000#. (Drilling 23, Totco 1). DAY 12
AUG 17 1993	5595' (92'). Drilling in Dolomite. Dev. @ 5527' - 4 1/4°. MW 9.1, Vis 29, CL 93,000, pH 10. Bit #7, OUT @ 5527' (made 625' in 53 3/4 hrs). Bit #8, Size 8 3/4", Type: J44C, SN: RR, Jets 11/12/12, IN @ 5527' (made 68' in 12 1/4 hrs) PP 1475#, SPM 58, WOB 20,000#, RPM 60, Collars 68,000#. (Drilling 18 3/4, Trip 4 1/2, Totco 1/4, Ream 75' to Btm 1/2). REMARKS: Picked up RT tool and installed on top of collars during bit trip.

MEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL
County Eddy State New Mexico Section 31
Block Township 17S Range 28E Page 3

DATE	DAILY REPORTS
AUG 18 1993	5786' (191'). Drilling in Dolomite. Dev. @ 5529' - 4°, @ 5722' - 3 1/4°. MW 9.2, Vis 29, CL 89,000, pH 10. Bit #8, Size 8 3/4", Type: J44C, SN: RR, Jets 11/12/12, IN @ 5527' (made 259' in 35 1/4 hrs) PP 1475#, SPM 58, WOB 30,000#, RPM 60, Collars 68,000#. (Drilling 22 3/4, Totco 1 1/4). DAY 14
AUG 19 1993	6225' (439'). Drlg in Dolomite. Dev. @ 5786' - 3 1/2°; @ 5879' - 3°; @ 5974' - 3°; 6195' - 3 1/2°. MW 9.2, Vis 29, CL 90,000, pH 9. Bit #8, Size 8 3/4", Type: J44C, SN: RR, Jets 11/12/12, IN @ 5527' (made 698' in 50 hrs) PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drlg 19 3/4. Trip. hole in DP 2 1/4, Totco 2). REMARKS: @ 5849' hole in DP 30 stds dwn. No fill after trip. DAY 15
AUG 20 1993	6790' (565'). Drilling in Dolomite. Dev. @ 6352' - 3 1/4°. MW 9.2, Vis 29, CL 88,000, pH 10. Bit #8, (made 1263' in 78 1/2 hrs) PP 1500#, SPM 58, WOB 65,000#, RPM 65, Collars 68,000#. (Drilling 23 1/2, Survay 1/2). REMARKS: Circulated through steel pits for 30 minutes on evening tower, had full returns. DAY 16
AUG 21 1993	6825' (35'). Drlg in Dolomite. Dev. @ 6795' - 2 1/2°. MW 9.1, Vis 29, CL 87,000, pH 9. Bit #8 OUT @ 6795' (made 1260' in 79 hrs). Bit #9, Type: 8 3/4", Type: ATJ44C, SN: D48WC, Jets 12/12/12. IN @ 6795' (made 30' in 1 hrs). PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drlg 1 1/2, Trip 10 1/2, Circ 2, PU DST Tools 2, DST #1 5 1/4, Reverse Out 3/4, LD DST Tools 2). REMARKS: Ran DST #1 in Wolfcamp fmn from 6605' to 6795'. IHP 3088#, IFP 421-1149#, ISIP 1795#, FFP 1121-1795#, FSIP 1823#, FHP 3088#, Temp 94°. Opened tool w/good blow off btm of bucket increasing to 6#. No shows to surface. FF had max of 2# in 30 mins, decreasing to 10 ounces at end of flow. No shows to surface. Rec 4002' of fmn fluid. Sample chamber recovery: 2400 cc's of fmn wtr. DAY 17
AUG 22 1993	7210'(385').TOH.DST #2. Dolomite & Lime. MW 9.1, Vis 29, CL 88,000, pH 9. Bit #9, (made 415' in 19 hrs). PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drlg 18, Trip 2 1/4, Circ 3 3/4). DAY 18
AUG 23 1993	7350' (140'). Drilling in Lime & Dolomite. MW 9.1, Vis 29, CL 88,000, pH 9. Bit #9, (made 555' in 24 3/4 hrs). PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drilling 5 3/4, Trip 8, Wash 86' to bottom w/no fill 1/2, Cut Drlg Line 3/4, Run DST #2 2, PU Toot Tools 3 1/2, Pull On Stuck Pipe 1, LD Toot Tools 2 1/2). REMARKS: Checked for loss thru steel pits @ 7230'. Lost 4 bbls in 30 mins. Ran DST #2 in Wolfcamp fmn from 7016'-7210', IHP 3305#, IFP 44-67#, ISIP 986#. Attempted to open tool for final flow. Unable to open tool due to collars above tool being hydrostatically stuck. Worked pipe and were unable to work loose. Dropped bar and opened circ sub. Were able to work collars loose and TOOH w/tools. Opened tool w/weak blow increasing to 16 3/4 ounces at end of IF period. No show to surface. Rec 20 stds of drill string w/small show of gas. Sample Chamber Recovery: 70#, 1000 cc's of gas-cut drlg mud. Temp 120°. DAY 19
AUG 24 1993	7382' (32'). TIH w/bit. Dev. @ 7382' - 2 1/4°. MW 9.1, Vis 28, CL 82,000, pH 8.5. Bit #9, (made 587' in 26 1/2 hrs) PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drilling 1 3/4, Tripping 9 3/4, Circ 4 1/4, Run DST #3 4 1/2, PU Toot Tools 1 1/2, Reverse Out 3/4, LD Toot Tools 1 1/2). REMARKS: Ran DST #3 in Wolfcamp Fmn from 7230'-7382' (152'). IHP 3451#, IFP 2094-355#, ISIP 2418#, FFP 555#-924#, FSIP 2435#. Surface Action: Opened tool w/weak blow increasing to hhm of bucket in 8 mins. Max surface press 14 1/2 ozs. FF: opened w/weak blow. Max surface press 12 ozs. No show to surface on either flow period. Drill Pipe Recovery: 406' of slightly gas-cut drlg mud & 1533' of fmn wtr w/strong sulfur smell. Sample Chamber Recovery: 330#, 1.01 cuft of gas, 1600 cc's of wtr.

NEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL
County Eddy State New Mexico Section 31
Block Township 17S Range 28E Page 4

DATE	DAILY REPORTS
AUG 25 1993	7441' (59'). Drlg in Lm & Dolo. MW 9.1, Vis 29, CL 82,000, pH 10. Bit #9, (made 646' in 28 3/4 hrs) PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drlg 2 1/4, Trip 11 1/4, Wash 90' to Btm W/No Fill 3/4, Circ 2 1/2, Run DST #4 4 1/2, PU Test Tools 1, LD Test Tools 1 3/4). REMARKS: Ran DST #4 in Wolfcamp Fmn from 7385'-7413' (28'). IHP 3405#, IFP 191#-156# in 30 mins, ISIP 991# in 60 mins, FFP 122#-174# in 60 mins, FSIP 488# in 120 mins. Surface Action: Initial opening w/weak blow increasing to btm of bucket in 2 mins. Built to 15# in 30 mins thru 1/8" bubble hose. Shut tool in. Gas to surface in 38 mins, volume TSTM. FF: opened w/weak blow turned thru 1/4" choke. 12# in 5 mins; decreasing to 4# in 50 mins. Remained 4# to end of final flow. Gas volume TSTM, 1 1/2' 2' lazy flame. Drill Pipe Recovery: Rec 300' of slightly gas-cut rat hole drlg mud w/trace of sulfur water. Sample Chamber Recovery: 80#,.57 cuft of gas, 350 cc's of wtr. CL 63,000 ppm. DAY 21
AUG 26 1993	7851' (410'). TO for DST #5 in Dolomite. MW 9.1, Vis 28, CL 80,000, pH 9. Bit #9. (made 1056' in 46 1/2 hrs) PP 1500#, SPM 50, RPM 60, Collars 68,000#. (Drilling 17 3/4, Tripping 2 1/4, Circ Samples @ 7840' 1, Circ for DST #5 3). DAY 22
AUG 27 1993	8215' (364'). Drilling in Dolomite. Dev. @ 7851' - 1 1/4°. MW 9.1, Vis 28, CL 80,000, pH 9.5. Bit #9, (made 1420' in 53 1/4 hrs) PP 1575#, SPM 58, WOC 65,000#, RPM 60, Collars 68,000#. (Drilling 6 3/4, Tripping 0 1/4, Wash 70' to btm w/no fill 1/4, RR 1/2, DST #5 4 1/2, PU test tools 1 1/4, Reverse out 3/4, LD test tools 1 3/4). REMARKS: At 7995', lost 25-30% returns. At 8028' circ thru steel pits & lost 34 bbls in 30 mins. At 8123' pumped 30 bbl. LCM sweep. At report time, drilling w/95% returns. Ran DST #5 in Cisco Fmn from 7015'-7051' (34'). IHP 3832#, IFP 1633#-2913#, ISIP 2913#, FFP 2913#-2913#, FSIP 2913#, FHP 3804#. SURFACE ACTION: IF started w/good blow on 1/4" choke beginning w/5.5# increasing to 40# in 25 mins, decreasing to 30# in 30 mins. No gas to surface. FF started w/good blow on 1/4" choke beginning w/6 oz. in 5 mins, decreasing to 0 oz. in 20 mins, remained dead throughout rest of FF. DRILL STRING RECOVERY: Rec 6060' (70.7 bbls) FW. No show of oil. Mud pit sample: RW=.11 @ 60°, CL 78,000. Sample Recovery: RW=.35 @ 60°, CL 25,000. SAMPLE CHAMBER RECOVERY: 1100#, .08 cuft of gas, 2575 cc's fmn wtr.
AUG 28 1993	8494' (279'). Working stuck drill string. Dolomite. Dev. @ 8342' - 1 1/2°. MW 9.3, Vis 37, WL 20, CL 80,000, pH 9. Bit #9, (made 1699' in 59 hrs). PP 1500#, SPM 58, WOB 65,000#, RPM 60, Collars 68,000#. (Drilling 5 3/4, Trip 5 1/2, Totco 1/2, Mix LCM 7 1/4, Work Stuck String 3, Spot Oil & Work Stuck String 2). REMARKS: Hit 5' void while drlg @ 8414', lost complete returns. Pumped LCM pill & regained 95% returns. Lost complete returns @ 8475'. Pumped LCM pill & regained partial returns. TOOH & removed jets from bit & built up 400 bbl LCM pill containing 70#/bbl LCM material. TIH & spotted pill @ 8434'. While spotting pill & rotating, drill string became stuck. Attempted to work string loose unsuccessfully. Spotted 70 bbls oil around collars & let soak. Periodically working string in an attempt to get loose. At report time all efforts have been unsuccessful. DAY 24
AUG 29 1993	8494' (0'). Laying down fishing tools. Dolomite. MW 9.3, Vis 37, WL 20, CL 80,000, pH 9. (Tripping 8, Working Stuck Drill String 8 1/4, Run Free Point & Make Back Off 4 1/4, PU & LD Fishing Tools 3, Jar on Fish 1/2). REMARKS: Continued working drill string unsuccessfully. RU Jerrel Services & ran free point. Found collars stuck @ 8300'. Backed off collars @ 8255'. TOOH w/collars & PU fishing tools. TIH. Engaged fish & jarred same loose. TOOH & started laying down fishing tools. DAY 25

NEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL
County Eddy State New Mexico Section 31
Block Township 17S Range 28E Page 5

DATE	DAILY REPORTS
AUG 30 1993	8650' (356'). Drilling in Lime. MW 9.2, Vis 38, WL 10, CL 80,000, pH 9, PV 6, YP 10, Gels 7/18, FC Film, Calcium 1560, Solids 2.2%, LCM 8#. Bit #9 (made 1855' in 73 1/2 hrs). PP 1625#, SPM 54, WOB 60,000#, RPM 60, Collars 63000# (840'). (Drilling 14 1/2, Tripping 3 1/4, Wash 20 jts to Btm 4 1/4, Finish LD Fishing Tools 2). REMARKS: Rejetted Bit #9. TIH & washed 20 jts to btm. Had loss of 2 bbls on evening tour & 15 bbls on morning tour. DAY 26
AUG 31 1993	8895' (245'). Drilling in Lime. Dev. @ 8876' - 1 1/4°. MW 9.2, Vis 38, WL 12, CL 78,000, pH 9.5, PV 7, YP 9, Gels 6/14, FC 1/31, Calcium 1480, Solids 2.5%, LCM 7#. Bit #9, (made 2100' in 97 hrs) PP 1650#, SPM 54, WOC 60,000#, RPM 60, Collars 63,000#. (Drilling 23 1/2, Totco 1/2). REMARKS: Lost 3 bbls on daylights, 15 bbls on evenings, 20 bbls on morning tour. DAY 27
SEP 01 1993	9077' (182'). Circ & mixing LCM in Lime. MW 9.3. Vis 38, WL 12, CL 79,000, pH 9.5, PV 9, YP 8, Gels 7/17, FC 1/32. Bit #9, (made 2202' in 110 hrs) PP 1500#, SPM 54, WOC 60,000#, RPM 60, Collars 63,000#. (Drilling 21, Mix LCM Mud 1 1/2, RR 1 1/2). REMARKS: At 9060' lost 40 bbls mud. Pumped sweept & regained full returns. Resumed drlg w/full returns but started losing returns. Pumped additional sweep. At report time have 85% returns. In last 6 hrs, lost 90 bbls mud.
SEP 02 1993	9138' (61'). Drilling in Lime. Dev. @ 9077' - 1/2°. MW 9.3, Vis 39, WL 12, CL 75,000, pH 10. Bit #9 OUT @ 9077' (made 2282' in 118 hrs). Bit #10, Size: 8 3/4", Type: HP62, SN: TH6443, Jets 3/13's. IN @ 9077' (made 61' in 8 3/4 hrs). PP 1250#, SPM 59, WOC 60,000#, RPM 60, Collars 63,000#. (Drilling 8 3/4, Tripping 6, Totco 1/4, Circ 3 3/4, Cut Drlg Line 1, Test BOP Stack 4, Jet Pits 3/4). REMARKS: Have lost 86 bbls mud in 16 hrs. DAY 29
SEP 03 1993	9302' (164'). Drilling in Lime. MW 9.4, Vis 41, WL 10, CL 70,000, pH 9.5, PV 12, YP 15, Gels 14/29, FC 1/32, Solids 3.3%, LCM 8#. Bit #10, Size: 8 3/4", Type: HP62, SN: TH6443, Jets 3/13's. IN @ 9077' (made 225' in 32 3/4 hrs). PP 1375#, SPM 58, WOC 60,000#, RPM 60, Collars 63,000#. (Drilling 24). REMARKS: Lost 170 bbls on daylights, 75 bbls on evening, 12 bbls on morning tour. Total loss for past 24 hrs is 257 bbls. At report time drilling w/95% returns. DAY 30
SEP 04 1993	9474' (172'). Drilling in Lime. MW 9.4, Vis 45, WL 10, CL 65,000, pH 9.5, PV 14, YP 15, Gels 18/34, FC 1/32, Calcium 1000, Solids 3.8%, LCM 10#. Bit #10, Size: 8 3/4", Type: HP62, SN: TH6443, Jets 3/13's. IN @ 9077' (made 397' in 56 3/4 hrs). PP 1375#, SPM 58, WOC 60,000#, RPM 60, Collars 63,000#. (Drilling 24). REMARKS: Lost 40 bbls on daylights, 30 bbls on evening, 20 bbls on morning tour. Total loss for past 24 hrs is 90 bbls. At report time drilling w/95% returns. DAY 31
SEP 05 1993	9568' (158'). Drilling in Lime & Shale. MW 9.4, Vis 48, WL 12, CL 68,000, pH 9.5, PV 14, YP 19, Gels 16/30, FC 1/32, Calcium 880, Solids 4.0%, LCM 9#. Bit #10, Size: 8 3/4", Type: HP62, SN: TH6443, Jets 3/13's. IN @ 9077' (made 555' in 80 1/4 hrs). PP 1375#, SPM 58, WOB 60,000#, RPM 60, Collars 63,000#. (Drilling 23 1/2, Totco 1/2). REMARKS: Lost 25 bbls on daylights, 50 bbls on evening, 8 bbls on morning tour. Total loss for past 24 hrs is 83 bbls. At report time drilling w/95 % returns. Rigged up mud filter and put in service at 3:30 PM. DAY 32
SEP 06 1993	9791' (159'). Drilling in Lime & Shale. MW 9.3, Vis 38, LS 12, CL 81,000, pH 9.5, PV 13, YP 21, Gels 15/28, FC 1/32, Calcium 1100, Solids 2.8%. Bit #10 (made 714' in 104 1/4 hrs). PP 1375#, SPM 58, WOB 60,000#, RPM 60, Collars 63,000#. (Drlg 24). REMARKS: No mud lost in last 24 hrs. DAY 33

NEWBOURNE OIL COMPANY
P. O. BOX 7698
TYLER, TEXAS 75711

Lease Chalk Bluff "31" State Well No. 1 Location 660' FSL & 2310' FEL
County Eddy State New Mexico Section 31
Block Township 17S Range 28E Page 6

DATE	DAILY REPORTS
SEP 07 1993	9945' (164'). Drilling in Lime & Shale. MW 9.5, Vis 39, WL 7, CL 82,000, pH 9.5, PV 15, YP 19, Gels 16/31, FC 1/32, Solids 3.4%, LCM 7#. Bit #10 (made 868' in 128 1/4 hrs). PP 1325#, SPM 57, WOB 60,000#, RPM 60, Collars 63,000# (840'). (Drilling 24). REMARKS: No mud lost past 24 hrs. DAY 34
SEP 08 1993	10,039' (94'). Drilling in Lime & Shale. MW 9.5, Vis 40, WL 97, CL 81,000, pH 9.5, PV 16, YP 18, Gels 17/34, FC 1/32, Solids 3.5%, LCM 6#. Dev. @ 9959' - 1 3/4°. Bit #10, OUT @ 9959' (made 714' in 104 1/4 hrs). Bit #11, Size 8 3/4", Type: RR. IN @ 9959' (made 80' in 13 hrs) PP 1350#, SPM 57, WOB 60,000#, RPM 60, Collars 63,000# (840'). (Drilling 15 3/4, Trip 6 1/2, Totco 1 1/4, Wash 60' to Btm w/No Fill 1/2). REMARKS: Lost 25 bbls in last 13 hrs. DAY 35
SEP 09 1993	10,177' (138'). Drilling in Lime & Shale. MW 9.5, Vis 40, WL 8, Cl 80,000, pH 9.5, PV 16, YP 15, Gels 12/26, FC 1/32, Calcium 800, Solids 3.7%, LCM 6.5#. Bit #11, Size 8 3/4", Type: RR. IN @ 9959' (made 218' in 37 hrs) PP 1350#, SPM 57, WOB 60,000#, RPM 60, Collars 63,000#. (Drilling 24). REMARKS: Lost 29 bbls mud past 24 hrs. DAY 36
SEP 10 1993	10,200' (23'). Drilling in Shale. MW 9.6, Vis 40, WL 8, CL 85,000, pH 8.5, PV 12, YP 14, Gels 11/25, FC 1/32, Solids 3.6%, LCM 5#. Bit #11, Size 8 3/4", Type: RR. IN @ 9959' (made 218' in 37 hrs) PP 1350#, SPM 57, WOB 60,000#, RPM 60, Collars 63,000#. (Drilling 1 1/2, Trip 5 1/2, Circ 2, Logging 13). REMARKS: TD @ 9:30 AM on 9/9/93. Steel line TD 10,197'. Logger's TD 10,184'. DAY 37
SEP 11 1993	10,200' (0'). Plugging well. (Trip 3 1/4, Circ 2 1/2, Logging 1, WOO 9, LDDC's 1 3/4, Plugging Well 6 1/2). REMARKS: Set 45 sk "H" Neat @ 9734' & 8528'. Set 55 sk "H" Neat @ 7866'. Set 45 sk "H" Neat @ 6648', 5320' & 3734'. DAY 38
SEP 12 1993	10,200' (0'). IDLE. (WOC 4, ND & Clean Pits 4, Plugging Well 5 Idle 11). REMARKS: Set 65 sk "H" + 2% CaCl2 @ 2605'. WOC 4 hrs Tagged cmt @ 2350'. Set 40 sk "H" Neat @ 440'. Set 10 sk "H" Neat at surface. P&A operations complete @ 3:00 PM 9/11/93. Released rig @ 7:00 PM 9/11/93. DAY 39

APPENDIX 2.0-2

WELL COMPLETION OR RECOMPLETION REPORT AND LOG, FORM C-105

APPENDIX 2.0-2

Submit to Appropriate District Office
State Lease – 6 copies
Fee Lease – 5 copies
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

Form C-105
Revised 1-1-89

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

WELL API NO. 30-015-27592

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

6. State Oil & Gas Lease No. B-2071-28

WELL COMPLETION OR RECOMPLETION REPORT AND LOG

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

b. Type of Completion: NEW WELL [ ] WORK OVER [ ] DEEPEN [ ] PLUG BACK [ ] DIFF RESVR [ ] OTHER

7. Lease Name or Unit Agreement Name: Chalk Bluff "31" State

2. Name of Operator: Newbourne Oil Company

8. Well No. 1

3. Address of Operator: P.O. Box 5270 Hobbs, New Mexico 88241

9. Pool name or Wildcat: Illinois Camp Morrow, North

4. Well Location
Unit Letter O : 2310 Feet From The East Line and 660 Feet From The South Line
Section 31 Township 17S Range 28E NMPM Eddy County

10. Date Spudded	11. Date T.D. Reached	12. Date Compl. (Ready to Prod.)	13. Elevations (DF & RKB, RT, GR, etc.)	14. Elev. Casinghead
08/04/93	09/09/93	----	3678' GR	---

15. Total Depth	16. Plug Back T.D.	17. If Multiple Compl. How Many Zones?	18. Intervals Drilled By	Rotary Tools	Cable Tools
10,200'	----	---		All	----

19. Producing Interval(s), of this completion - Top, Bottom, Name: ---------

20. Was Directional Survey Made: No

21. Type Electric and Other Logs Run: Dual Laterlog, Density Neutron, Sonic (Already Submitted)

22. Was Well Cored: No

23. CASING RECORD (Report all strings set in well)

CASING SIZE	WEIGHT LB./FT.	DEPTH SET	HOLE SIZE	CEMENTING RECORD	AMOUNT PULLED
13-3/8"	48#	390'	17-1/2"	375 sks. "C" Lite +	None
				150 sks. "C" Neet	
9-5/8"	36#	2555'	12-1/4"	800 sks. "C" Lite +	None
				200 sks. "C" Neet	

24. LINER RECORD

SIZE	TOP	BOTTOM	SACKS CEMENT	SCREEN

25. TUBING RECORD

SIZE	DEPTH SET	PACKER SET

26. Perforation record (interval, size, and number)

N/A

27. ACID, SHOT, FRACTURE, CEMENT, SQUEEZE, ETC.

DEPTH INTERVAL	AMOUNT AND KIND MATERIAL USED

28. PRODUCTION

Date First Production	Production Method (Flowing, gas lift, pumping - Size and type pump)	Well Status (Prod. or Shut-in)

Date of Test	Hours Tested	Choke Size	Prod'n For Test Period	Oil - Bbl.	Gas - MCF	Water - Bbl.	Gas - Oil Ratio

Flow Tubing Press.	Casing Pressure	Calculated 24-Hour Rate	Oil - Bbl.	Gas - MCF	Water - Bbl.	Oil Gravity - API - (Corr.)

29. Disposition of Gas (Sold, used for fuel, vented, etc.)

Test Witnessed By

30. List Attachments: Deviation Report

31. I hereby certify that the information shown on both sides of this form is true and complete to the best of my knowledge and belief

Signature Bill Pierce Printed Name Bill Pierce Title Drlg. Supt. Date 09/23/9

INSTRUCTIONS

This form is to be filed with the appropriate District Office of the Division not later than 20 days after the completion of any newly-drilled or deepened well. It shall be accompanied by one copy of all electrical and radio-activity logs run on the well and a summary of all special tests conducted, including drill stem tests. All depths reported shall be measured depths. In the case of directionally drilled wells, true vertical depths shall also be reported. For multiple completions, Items 25 through 29 shall be reported for each zone. The form is to be filed in quintuplicate except on state land, where six copies are required. See Rule 1105.

INDICATE FORMATION TOPS IN CONFORMANCE WITH GEOGRAPHICAL SECTION OF STATE

Southeastern New Mexico				Northwestern New Mexico			
T. Anhy		T. Canyon	8782'	T. Ojo Alamo		T. Penn. "B"	
T. Salt		T. Strawn	9016'	T. Kirtland-Fruitland		T. Penn. "C"	
B. Salt		T. Atoka	9573'	T. Pictured Cliffs		T. Penn. "D"	
T. Yates	506'	T. Miss		T. Cliff House		T. Leadville	
T. 7 Rivers	596'	T. Devonian		T. Menefee		T. Madison	
T. Queen	1176'	T. Silurian		T. Point Lookout		T. Elbert	
T. Grayburg	1462'	T. Montoya		T. Mancos		T. McCracken	
T. San Andres	[illegible]	T. Simpson		T. Gallup		T. Ignacio Otzte	
T. Glorieta	3386'	T. McKee		Base Greenhorn		T. Granite	
T. Paddock		T. Ellenburger		T. Dakota		T.	
T. Blinebry		T. Gr. Wash		T. Morrison		T.	
T. Tubb		T. Delaware Sand		T. Todilto		T.	
T. Drinkard		T. Bone Springs		T. Entrada		T.	
T. Abo	5398'	T. Barrow	10016'	T. Wingate		T.	
T. Wolfcamp	6593'	T.		T. Chinle		T.	
T. Penn		T.		T. Permain		T.	
T. Cisco (Bough C)	7816'	T.		T. Penn "A"		T.	

OIL OR GAS SANDS OR ZONES

No. 1, from.....to..... No. 3, from.....to.....

No. 2, from.....to..... No. 4, from.....to.....

IMPORTANT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from.....to.....feet.....

No. 2, from.....to.....feet.....

No. 3, from.....to.....feet.....

LITHOLOGY RECORD (Attach additional sheet if necessary)

From	To	Thickness in Feet	Lithology	From	To	Thickness in Feet	Lithology
0'	400'	400'	Surface rock, Anhydrite				
400'	6900'	6500'	Dolomite, Chert, Sandstone, Shale				
6900'	7800'	900'	Limestone, Shale, Chert				
7800'	8500'	700'	Dolomite, Shale				
8500'	9600'	1100'	Limestone, Shale				
9600'	10200'	600'	Limestone, Sandstone, Chert, & Shale				

APPENDIX 2.0-3

SUNDRY NOTICE FOR PLUG AND ABANDONMENT, FORM C-103

APPENDIX 2.0-3

Submit 3 Copies to Appropriate District Office

State of New Mexico
Energy, Minerals and Natural Resources Department

Form C-103
Revised 1-1-89

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

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

WELL API NO.
30-015-27592

5. Indicate Type of Lease STATE ■ FEE ☐

6. State Oil & Gas Lease No.
B-2071-28

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
Chalk Bluff "31" State

1. Type of Well: OIL WELL ☐ GAS WELL ■ OTHER

2. Name of Operator
Mewbourne Oil Company

8. Well No.
1

3. Address of Operator
P. O. Box 5270 ; Hobbs, New Mexico 88241

9. Pool name or Wildcat
Illinois Camp Morrow, North

4. Well Location
Unit Letter O : 2310 Feet From The East Line and 660' Feet From The South Line

Section 31 Township 17S Range 28E NMPM Eddy County

10. Elevation (Show whether DF, RKB, RT, GR, etc.)
3678' 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	☐	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.

9-9-93: Drilled 8 3/4" production hole to a T.D. of 10,200' K.B. Ran electric logs and evaluated well.

9-10-93: Decided to plug well. Received verbal permission from Mike Stubblefield w/NMOCD office in Artesia to plug well. Placed cement plugs at following depths:

45 sacks of Class "H" Neet @ 9734'
45 sacks of Class "H" Neet @ 8528'
55 sacks of Class "H" Neet @ 7866'
45 sacks of Class "H" Neet @ 6648'
45 sacks of Class "H" Neet @ 5320'
45 sacks of Class "H" Neet @ 3734'
65 sacks of Class "H" Neet W/2% $CaCl_2$ @ 2605'. WOC 4 hours. Tagged top of cement plug @ 2350'.
40 sacks of Class "H" Neet @ 44
10 sacks of Class "H" Neet From 30' to surface.
Rig released @ 7:00 PM, 9-11-93
Installed dry hole marker.

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

SIGNATURE Bill Price TITLE Drilling Superintendent DATE Sept. 13, 1993

TYPE OR PRINT NAME TELEPHONE NO.

(This space for State Use)

APPROVED BY Mike Stubblefield TITLE Field Rep. I DATE Apr. 1 11:24

CONDITIONS OF APPROVAL, IF ANY:

APPENDIX 2.5-1

FORMATION FLUID ANALYSIS

TRACE ANALYSIS, INC.
6701 Aberdeen Avenue Lubbock, Texas 79424 806•794•1296 FAX 806•794•1298

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

ANALYTICAL RESULTS FOR
NAVAJO REFINING
Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Prep Date: 08/02/98
Analysis Date: 09/11/98
Sampling Date: 07/31/98
Sample Condition: Intact & Cool
Sample Received by: MS
Project Name: NA

After 16 hours @ 130 F

TA#	Field Code	POTASSIUM (mg/L)	MAGNESIUM (mg/L)	CALCIUM (mg/L)	SODIUM (mg/L)
T103911	Upper Zone	120	152	215	4,470
T103912	Lower Zone	403	166	372	11,000
T103993	Upper Zone 2:1	92	111	175	2,960
T103994	Upper Zone 1:1	74	91	156	2,280
T103995	Upper Zone 1:2	55	70	170	1,630
T103996	Lower Zone 2:1	284	122	314	8,300
T103997	Lower Zone 1:1	203	98	272	6,230
T103998	Lower Zone 1:2	139	77	237	4,400
ICV		24	25	26	25
CCV		24	26	25	26
Reporting Limit		0.50	0.50	0.50	0.50
METHOD BLANK		<0.50	<0.50	<0.50	<0.50
RPD		2	1	1	5
% Extraction Accuracy		120	93	94	105
% Instrument Accuracy		99	102	104	104

METHODS: EPA 200.7.
CHEMIST: RR
SPIKE: 1,000 mg/L POTASSIUM, MAGNESIUM, CALCIUM, SODIUM.
CV: 25 mg/L POTASSIUM, MAGNESIUM, CALCIUM, SODIUM.

Director, Dr. Blair Leftwich

9-16-98
Date

APPENDIX 2.5-1

TRACE ANALYSIS, INC.
6701 Aberdeen Avenue Lubbock, Texas 79424 806•794•1296 FAX 806•794•1298

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

ANALYTICAL RESULTS FOR
NAVAJO REFINING
Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Prep Date: 08/11/98
Analysis Date: 08/16/98
Sampling Date: 07/31/98
Sample Condition: Intact & Cool
Sample Received by: MS
Project Name: NA

ROOM TEMPERATURE

TA#	Field Code	POTASSIUM (mg/L)	MAGNESIUM (mg/L)	CALCIUM (mg/L)	SODIUM (mg/L)
T103911	Upper Zone	61	126	276	4,785
T103912	Lower Zone	213	143	390	12,770
T103993	Upper Zone 2:1	26	80	214	3,114
T103994	Upper Zone 1:1	18	65	282	2,491
T103995	Upper Zone 1:2	5.3	39	213	1,675
T103996	Lower Zone 2:1	138	99	364	8,920
T103997	Lower Zone 1:1	89	70	277	6,778
T103998	Lower Zone 1:2	54	43	291	4,547
ICV		25	25	25	26
CCV		25	25	25	26
Reporting Limit		0.50	0.50	0.50	0.50
METHOD BLANK		<0.50	<0.50	<0.50	<0.50
RPD		2*	0*	0*	0*
% Extraction Accuracy		96*	100*	104*	101*
% Instrument Accuracy		100	100	100	104

*NOTE: Used LCS for Extraction Accuracy and RPD due to high concentration in sample.
METHODS: EPA 200.7.
CHEMIST: RR
SPIKE: 100 mg/L POTASSIUM, MAGNESIUM, CALCIUM, SODIUM.
CV: 25 mg/L POTASSIUM, MAGNESIUM, CALCIUM, SODIUM.

Director, Dr. Blair Leftwich

9-16-98
Date

TRACE ANALYSIS, INC.

8701 Aberdeen Avenue, Suite 9 Lubbock, Texas 79424 800•378•1296 806•794•1296 FAX 806•794•1298
4725 Ripley Avenue, Suite A El Paso, Texas 79922 888•588•3443 915•585•3443 FAX 915•585•4944
E-Mail: lab@traceanalysis.com

ANALYTICAL RESULTS FOR
NAVAJO REFINING
Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

ROOM TEMPERATURE

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103911	Upper Zone	<10	46	15,000	3.7	8,500	1,800
T103912	Lower Zone	<10	170	33,000	2.6	19,000	2,200
T103994	Upper Zone 1:1	<10	230	9,000	19	3,900	1,200
ICV		4.8	---	---	0.97	12	12
CCV		4.8	---	---	0.94	12	12
RPD		4	0	8	8	0	1
% Extraction Accuracy		95	---	---	104	96	99
% Instrument Accuracy		97	---	98	97	98	98
REPORTING LIMIT		10	---	---	0.1	0.5	0.5
PREP DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/06/98	08/06/98
ANALYSIS DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/06/98	08/06/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103911	Upper Zone	1,400	<1.0	1.018	27,000	7.6
T103912	Lower Zone	1,000	<1.0	1.034	62,000	6.1
T103994	Upper Zone 1:1	410	8	1.006	13,000	8.5
ICV		1,100	1,100	---	1,396	7.0
CCV		1,130	1,080	---	1,387	7.0
RPD		1	1	0	1	0
% Extraction Accuracy		---	---	---	98	---
% Instrument Accuracy		91	91	---	99	100
REPORTING LIMIT		---	---	---	---	---
PREP DATE		08/11/98		08/06/98	08/07/98	08/09/98
ANALYSIS DATE		08/11/98		08/06/98	08/07/98	08/09/98

*NOTE: Out of holding time for NO3-N.
METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 312.5 mg/L CHLORIDE.
SULFATE SPIKE: 312.5 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

9-16-98
DATE

TRACE ANALYSIS, INC.

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4726 Riplev Avenue, Suite A El Paso, Texas 79922 888•588•3443 915•585•3443 FAX 915•585•4944
E-Mail: lab@traceanalysis.com

ANALYTICAL RESULTS FOR NAVAJO REFINING

Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

ROOM TEMPERATURE

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103993	Upper Zone 2:1	<10	560	11,000	14	5,000	1,400
ICV		4.8	---	---	0.97	11	12
CCV		4.8	---	---	0.94	11	12
RPD		4	0	8	8	5	1
% Extraction Accuracy		95	---	---	104	93	99
% Instrument Accuracy		97	---	98	97	93	98
REPORTING LIMIT		10	---	---	0.1	0.5	0.5
PREP DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/10/98	08/06/98
ANALYSIS DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/10/98	08/06/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103993	Upper Zone 2:1	700	<1.0	1.010	16,000	8.2
ICV		1,100	1,100	---	1,396	7.0
CCV		1,130	1,060	---	1,387	7.0
RPD		1	1	0	1	0
% Extraction Accuracy		---	---	---	98	---
% Instrument Accuracy		91	91	---	99	100
REPORTING LIMIT		---	---	---	---	---
PREP DATE		08/11/98		08/06/98	08/07/98	08/09/98
ANALYSIS DATE		08/11/98		08/06/98	08/07/98	08/09/98

*NOTE: Out of holding time for NO3-N.

METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 1,260 mg/L CHLORIDE.
SULFATE SPIKE: 312.5 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

9-16-98
DATE

TRACE ANALYSIS, INC.

6701 Aberdeen Avenue, Suite 9 Lubbock, Texas 79424 800•378•1296 806•794•1296 FAX 806•794•1298
4725 Ripley Avenue, Suite A El Paso, Texas 79922 888•588•3443 915•585•3443 FAX 915•585•4944
E-Mail: lab@traceanalysis.com

ANALYTICAL RESULTS FOR
NAVAJO REFINING

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

ROOM TEMPERATURE

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103995	Upper Zone 1:2	<10	320	6,000	24	2,600	950
T103996	Lower Zone 2:1	<10	530	23,000	13	14,000	1,700
T103997	Lower Zone 1:1	<10	430	18,000	20	12,000	1,500
T103998	Lower Zone 1:2	<10	230	13,000	23	13,000	1,100
ICV		4.8	---	---	0.97	12	12
CCV		4.8	---	---	0.94	12	12
RPD		1	0	8	8	1	4
% Extraction Accuracy		106	---	---	104	90	109
% Instrument Accuracy		97	---	98	97	97	97
REPORTING LIMIT		10	---	---	0.1	0.5	0.5
PREP DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/06/98	08/06/98
ANALYSIS DATE		08/06/98	08/09/98	08/06/98	08/07/98	08/06/98	08/06/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103995	Upper Zone 1:2	340	4	1.010	9,300	8.5
T103996	Lower Zone 2:1	570	<1.0	1.018	44,000	8.2
T103997	Lower Zone 1:1	540	2.0	1.023	34,000	8.4
T103998	Lower Zone 1:2	370	10	1.009	20,000	8.6
ICV		1,100	1,100	---	1,396	7.0
CCV		1,130	1,060	---	1,387	7.0
RPD		1	1	0	1	0
% Extraction Accuracy		---	---	---	98	---
% Instrument Accuracy		91	91	---	99	100
REPORTING LIMIT		---	---	---	---	---
PREP DATE		08/11/98		08/06/98	08/07/98	08/09/98
ANALYSIS DATE		08/11/98		08/06/98	08/07/98	08/09/98

*NOTE: Out of holding time for NO3-N.
METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 312.5 mg/L CHLORIDE.
SULFATE SPIKE: 312.5 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

9-16-98
DATE

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E-Mail: lab@traceanalysis.com

ANALYTICAL RESULTS FOR
NAVAJO REFINING

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

After 16 hours @ 130 °F

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103911	Upper Zone	<10	3,200	17,000	2.7	7,200	1,800
T103912	Lower Zone	<10	1,040	38,000	2.0	22,000	2,100
T103993	Upper Zone 2:1	<10	1,900	11,000	12	49,000	1,300
ICV		4.7	---	---	0.97	11	12
CCV		4.7	---	---	0.96	11	11
RPD		3	3	1	0	5	0
% Extraction Accuracy		105	---	---	100	93	110
% Instrument Accuracy		96	---	101	97	93	97
REPORTING LIMIT		10	---	---	0.1	0.5	0.5
PREP DATE		08/28/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98
ANALYSIS DATE		08/28/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103911	Upper Zone	720	36	1.018	27,000	8.6
T103912	Lower Zone	570	8.0	1.036	68,000	8.4
T103993	Upper Zone 2:1	480	24	1.016	18,000	8.6
ICV		1,080	1,100	---	1,335	7.0
CCV		1,040	1,120	---	1,327	7.0
RPD		1	1	0	2	0
% Extraction Accuracy		---	---	---	94	---
% Instrument Accuracy		90	90	---	94	100
REPORTING LIMIT		---	---	---	---	---
PREP DATE		09/14/98		09/11/98	09/10/98	09/12/98
ANALYSIS DATE		09/14/98		09/11/98	09/10/98	09/12/98

*NOTE: Out of holding time for NO3-N.
METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 1,250 mg/L CHLORIDE.
SULFATE SPIKE: 1,250 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

9-16-98
DATE

TRACE ANALYSIS, INC.

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4725 Piedras Drive East, Suite A El Paso, Texas 79922 888•588•3443 915•585•3443 FAX 915•585•4944
E-Mail lab@traceanalysis.com

ANALYTICAL RESULTS FOR
NAVAJO REFINING

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

After 16 hours @ 130 °F

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103994	Upper Zone 1:1	<10	370	8,700	17	3,500	1,100
T103995	Upper Zone 1:2	<10	300	8,500	24	2,400	880
T103996	Lower Zone 2:1	<10	300	27,000	12	14,000	1,900
ICV		4.7	—	—	0.97	11	11
CCV		4.7	—	—	0.98	11	11
RPD		3	3	1	0	2	2
% Extraction Accuracy		105	—	—	100	92**	95**
% Instrument Accuracy		98	—	101	97	93	95
REPORTING LIMIT		10	—	—	0.1	0.5	0.5
PREP DATE		08/26/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98
ANALYSIS DATE		08/26/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103994	Upper Zone 1:1	520	58	1.012	14,000	8.7
T103995	Upper Zone 1:2	370	20	1.004	11,000	9.0
T103996	Lower Zone 2:1	430	8.0	1.021	46,000	8.5
ICV		1,080	1,100	—	1,335	7.0
CCV		1,040	1,120	—	1,327	7.0
RPD		1	1	0	2	0
% Extraction Accuracy		—	—	—	94	—
% Instrument Accuracy		90	90	—	94	100
REPORTING LIMIT		—	—	—	—	—
PREP DATE		08/14/98		08/11/98	08/10/98	08/12/98
ANALYSIS DATE		08/14/98		08/11/98	08/10/98	08/12/98

*NOTE: Out of holding time for NO3-N.
**NOTE: Chloride and Sulfate spikes % Extraction Accuracy low. LRB spikes % Extraction Accuracy used due to matrix difficulties. LRB spikes in range.
METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 312.5 mg/L CHLORIDE.
SULFATE SPIKE: 312.5 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

9-16-98
DATE

TRACEANALYSIS, INC.

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4725 Ripley Avenue, Suite A El Paso, Texas 79922 888•588•3443 915•585•3443 FAX 915•585•4944
E-Mail: lab@traceanalysis.com

ANALYTICAL RESULTS FOR
NAVAJO REFINING

September 16, 1998
Receiving Date: 08/01/98
Sample Type: Water
Project No: NA
Project Location: Wastewater Wells - Artesia

Attention: Darrell Moore
501 E. Main
Artesia, NM 88210

Sampling Date: 07/31/98
Sample Condition: I & C
Sample Received by: MS
Project Name: NA

After 16 hours @ 130 °F

TA#	FIELD CODE	NO3-N* (mg/L)	TSS (mg/L)	TDS (mg/L)	FLUORIDE (mg/L)	CHLORIDE (mg/L)	SULFATE (mg/L)
T103997	Lower Zone 1:1	<10	160	22,000	16	11,000	1,500
T103998	Lower Zone 1:2	<10	340	15,000	22	7,100	1,000
ICV		4.7	---	---	0.97	11	11
CCV		4.7	---	---	0.98	11	12
RPD		3	3	1	0	1	1
% Extraction Accuracy		105	---	---	100	91	93
% Instrument Accuracy		98	---	101	97	94	97
REPORTING LIMIT		10	---	---	0.1	0.5	0.5
PREP DATE		08/28/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98
ANALYSIS DATE		08/28/98	08/12/98	08/10/98	08/12/98	08/10/98	08/10/98

TA#	FIELD CODE	ALKALINITY (mg/L as CaCo3) HCO3	ALKALINITY (mg/L as CaCo3) CO3	SPECIFIC GRAVITY (g/mL)	SPECIFIC CONDUCTANCE (uMHOS/cm)	pH (s.u.)
T103997	Lower Zone 1:1	340	22	1.012	37,000	8.8
T103998	Lower Zone 1:2	300	16	1.009	28,000	8.8
ICV		1,090	1,100	---	1,335	7.0
CCV		1,040	1,120	---	1,327	7.0
RPD		1	1	0	2	0
% Extraction Accuracy		---	---	---	94	---
% Instrument Accuracy		90	90	---	94	100
REPORTING LIMIT		---	---	---	---	---
PREP DATE		08/14/98		08/11/98	08/10/98	08/12/98
ANALYSIS DATE		08/14/98		08/11/98	08/10/98	08/12/98

*NOTE: Out of holding time for NO3-N.

METHODS: EPA 150.1, 300.0, 160.2, 160.1, 340.2, 120.1, 310.1; ASTM D854-92.
CHEMIST: pH/TSS: BP NO3-N/FLUORIDE/CHLORIDE/SULFATE/SPECIFIC GRAVITY: JS
TDS/SPECIFIC CONDUCTANCE/ALKALINITY: RS

NO3-N SPIKE: 125 mg/L NO3-N.
FLUORIDE SPIKE: 10 mg/L FLUORIDE.
CHLORIDE SPIKE: 62.5 mg/L CHLORIDE.
SULFATE SPIKE: 62.5 mg/L SULFATE.

NO3-N CV: 5.0 mg/L NO3-N.
FLUORIDE CV: 1.0 mg/L FLUORIDE.
CHLORIDE CV: 12.5 mg/L CHLORIDE.
SULFATE CV: 12.5 mg/L SULFATE.

Director, Dr. Blair Leftwich

5-16-98
DATE

ANALYSYS INC.

4221 Freidrich Lane, Suite 190, Austin, TX 78744
& 9320 Up River Road, Corpus Christi, TX 78409
(512) 444-5896 • FAX (512) 447-8716

Client: Trace Analysis, Inc.
Attn: Nell Green
Address: 6701 Aberdeen Ave, Ste. 9
Lubbock, Tx 79424

Phone: (806) 794-1296 FAX: (806) 794-1298

Report #/Lab ID#: 92840 Report Date: 8/31/98
Project ID:
Sample Name: 103911
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specific Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.6	cps			8/26/98	Brookfield				

Room Temperature - Upper Zone

Note: Could not run heated sample due to sulfide hazard.

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Respectfully Submitted,

Richard Laster

Richard Laster

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6. Method numbers typically denote USEPA procedures. Less than ("<") values reflect nominal quantitation limits, adjusted for any required dilution.

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Lubbock, Tx 79424

Phone: (806) 794-1296 FAX: (806) 794-1298

Report #/Lab ID#: 92841 Report Date: 8/31/98
Project ID:
Sample Name: 103912
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specific Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.7	cps			8/26/98	Brookfield				

Room Temperature - Lower Zone
Note: Could not run heated sample due to sulfide hazard

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Client: Trace Analysis, Inc.
Attn: Nell Green
Address: 6701 Aberdeen Ave, Ste. 9
Lubbock, Tx 79424

Phone: (806) 794-1296 FAX: (806) 794-1298

Report #/Lab ID#: 92842 Report Date: 8/31/98
Project ID:
Sample Name: 103993
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specific Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.6	cps			8/26/98	Brookfield				

Room Temp – Upper Zone 2:1

Note: Could not run heated sample due to Sulfide hazard

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Lubbock, Tx 79424

Phone: (806) 794-1296 FAX: (806) 794-1298

Report #/Lab ID#: 92843 Report Date: 8/31/98
Project ID:
Sample Name: 103994
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specifie Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.6	cps			8/26/98	Brookfield				

Room Temperature - Upper Zone 1:1
Note: Could not run heated sample due to Sulfide hazard

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6. Method numbers typically denote USEPA procedures. Less than ('<') values reflect nominal quantitation limits, adjusted for any required dilution.

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Lubbock, Tx 79424

Phone: (806) 794-1296 FAX: (806) 794-1298

Report #/Lab ID#: 92844 Report Date: 8/31/98
Project ID:
Sample Name: 103995
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specifie Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.6	cps			8/26/98	Brookfield				

Room Temperature - Upper Zone 1:2
Note: Could not run heated sample due to sulfide hazard

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Richard Laster

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AnalySys Inc.

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Lubbock, Tx 79424

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Report #/Lab ID#: 92845 Report Date: 8/31/98
Project ID:
Sample Name: 103996
Sample Matrix: water
Date Received: 8/5/98 Time: 10:00:00
Date Sampled: Not specifie Time: 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.1	cps			8/26/98	Brookfield				

Room Temperature – Lower Zone 2:1
Note: Could not run heated sample due to sulfide hazard

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Richard Laster

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Attn: Nell Green
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Lubbock, Tx 79424

Phone: (806) 794-1296 **FAX:** (806) 794-1298

Report #/Lab ID#: 92846 **Report Date:** 8/31/98
Project ID:
Sample Name: 103997
Sample Matrix: water
Date Received: 8/5/98 **Time:** 10:00:00
Date Sampled: Not specifie **Time:** 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.6	cps			8/26/98	Brookfield				

Room Temp - Lower Zone 1:1

Note: Could not run heated sample due to sulfide hazard

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Richard Laster

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& 9320 Up River Road, Corpus Christi, TX 78409
(512) 444-5896 - FAX (512) 447-4766

Client: Trace Analysis, Inc.
Attn: Neil Green
Address: 6701 Aberdeen Ave, Ste. 9
Lubbock, Tx 79424

Phone: (806) 794-1296 **FAX:** (806) 794-1298

Report #/Lab ID#: 92847 **Report Date:** 8/31/98
Project ID:
Sample Name: 103998
Sample Matrix: water
Date Received: 8/5/98 **Time:** 10:00:00
Date Sampled: Not specifie **Time:** 00:00:00

REPORT OF ANALYSIS

QUALITY ASSURANCE DATA[1]

Parameter	Result	Units	RQL[5]	Blank	Date	Method	Prec.[2]	Recov.[3]	CCV[4]	LCS[4]
Viscosity	0.5	cps			8/26/98	Brookfield				

Room Temp - Lower Zone 1:2

Note: Could not run heated sample due to Sulfide Hazard

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Respectfully Submitted,

Richard Lester

Richard Lester

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APPENDIX 2.5-2

PACKER FLUID CORROSION INHIBITOR

TECHNI-HIB™ 370

UNICHEM
A Division of BJ Services Company

PRODUCT BULLETIN

DESCRIPTION:

TECHNI-HIB 370 is a cationic blend of water soluble, film forming corrosion inhibitors, formulated for use in water, and water/oil systems.

USES:

TECHNI-HIB 370 is recommended for the inhibition of corrosion caused by carbon dioxide, hydrogen sulfide and bacterial deposits. TECHNI-HIB 370 has been developed for use in water floods, brine disposal operations, producing oil wells with a high water-to-oil ratio and gas transmission lines. TECHNI-HIB 370 also has excellent solubility and dispersibility for use under static conditions such as packer fluids.

APPLICATION:

1. TECHNI-HIB 370 should be fed continuously with a chemical injector for all surface applications.

2. For gas transmission lines, TECHNI-HIB 370 should be injected with a spray nozzle or atomizer. The use concentration is normally 10-60 ppm. Gas transmission lines will require ½ pint to 1 quart per 1 MM cubic feet of gas.

3. Optimum treatment is determined by monitoring with corrosion coupons, electronic instruments, or iron/ manganese counts.

4. For use as a packer fluid inhibitor, TECHNI-HIB 370 should be mixed with fresh water or brine at a rate of 1/4% to 1% of the fluid volume.

TYPICAL PROPERTIES:

Specific Gravity @ 60°F	0.96
Pounds Per Gallon @ 60°F	7.97
Pour Point	-5°F
Flash Point	98°F
pH	6-7
SOLUBILITIES:	
Fresh Water	Soluble
2% Brine	Soluble
15% Brine	Dispersible
Crude Oil	Insoluble
Appearance	Clear Amber Liquid

HANDLING:

WARNING! FLAMMABLE. Keep away from heat, sparks, and open flame. Keep container closed when not in use. Do not breathe vapors, use with adequate ventilation. Avoid contact with eyes, skin, and clothing. Refer to Material Safety Data Sheet for additional information and first aid.

PACKAGING:

TECHNI-HIB 370 is sold in 55-gallon drums and bulk.

3/92

8701 New Trails Drive, The Woodlands TX 77381 Office (713) 362-4499 FAX: (713) 363-7586

Product Name: TECHNI-HIB 370

Section: 01 PRODUCT IDENTIFICATION

UNICHEM
A DIVISION OF BJ SERVICES CO.
707 N. LEECH
HOBBS, NM 88241-1499

Emergency Telephone 505-393-7751
Previous Version Date 9/21/93
Date Prepared 10/01/96
Version: 0000005

Product Name: TECHNI-HIB 370

Trade Name: Corrosion Inhibitor

Chemical Description:
Proprietary blend of cationic compounds

Section: 02 HAZARDOUS INGREDIENTS

Component Name	CAS#	% Range
isopropyl alcohol	00067-63-0	< 25%
methanol	00067-56-1	< 5%

Section: 03 PHYSICAL DATA

Freezing Point: 2 Deg.F.
Boiling Point, 760 mm Hg: appx 190 Deg.F
Specific Gravity(H2O=1) : 0.956 Solubility in water: Complete
Appearance and Odor: Clear amber liquid; pungent odor.

Section: 04 FIRE AND EXPLOSION HAZARD DATA

Flash Point (Test Method): 98 Deg.F TCC

Extinguishing Media

CO2, dry chemical, water spray or fog, or foam. Use water to keep containers cool. Isolate "fuel" supply from fire. Contain fire fighting liquids for proper disposal.

Special Fire Fighting Procedures

Do not enter confined fire space without proper personal protective equipment including NIOSH approved self-contained breathing apparatus with full facepiece operated in the positive pressure demand mode. Do not inject a solid stream of water or foam into hot, burning pools; this may cause splattering and increase fire intensity. Evacuate personnel to a safe area. Keep unnecessary people away.

Unusual Fire and Explosion Hazards

This material is volatile and readily gives off vapors that may travel along the ground or be moved by ventilation and ignited by pilot lights, other flames, sparks, heaters, smoking, electrical motors, static discharge, or other

Product Name: TECHNI-HIB 370

Section: 04 FIRE AND EXPLOSION HAZARD DATA CONTINUED

ignition sources at locations distant from material handling point. Never use welding or cutting torch on or near drum (even empty) because product (even just residue) can ignite explosively. Containers may explode from internal pressure if confined to fire. Keep containers cool. Keep unnecessary people away.

Section: 05 HEALTH HAZARD DATA

Effects of Overexposure

Eye Contact: the liquid is irritating to the eyes and produces intense stinging and burning. If not promptly removed, may cause eye damage.

Skin Contact: repeated or prolonged contact with the skin may cause irritation and dermatitis.

Inhalation: vapors may cause irritation of the eyes, nose, and throat. Prolonged exposures may cause nausea, headache, dizziness, unconsciousness, cardiac depression, optic complications and death.

Ingestion: can cause burning of the gastrointestinal tract, nausea, vomiting, bleeding, CNS depression, hemolysis, blindness and pulmonary damage. Can be fatal.

Chronic Exposure: For methanol, chronic poisoning from repeated exposure has been manifested by conjunctivitis, headache, giddiness, sleeplessness, gastric disturbances and failure of vision.

Emergency and First Aid Procedures

SKIN

Wash with soap and water. Remove contaminated clothing and launder contaminated clothing before reuse. Get medical attention if redness or irritation develops.

EYES

Flush eyes immediately with large amounts of water for at least 15 minutes. Lift lower and upper lids occasionally. Get medical attention.

INHALATION

Remove victim to fresh air. Give artificial respiration if not breathing. If breathing is difficult, administer oxygen. Keep person warm, quiet and get medical attention.

INGESTION

Call a physician immediately. Give victim a glass of water. Do NOT induce vomiting unless instructed by a physician or poison control center. Never give anything by mouth to an unconscious person.

Section: 06 REACTIVITY DATA

Product Name: TECHNI-HIB 370

Section: 06 REACTIVITY DATA CONTINUED

Stability -- Conditions to Avoid
None known.

Incompatibility (Materials to Avoid)
Avoid contact with strong oxidizing agents, strong alkalies, and strong mineral acids.

Hazardous Decomposition Products
Thermal decomposition or combustion may produce smoke, carbon monoxide and carbon dioxide.

Hazardous Polymerization May Occur(Y=Yes/N=No): N

Hazardous Polymerization -- Conditions to Avoid
None

Section: 07 SPILL OR LEAK PROCEDURES

Steps to be Taken if Material is Released or Spilled
Eliminate sources of ignition. Persons not wearing suitable personal protective equipment should be excluded from area of spill until clean-up has been completed. Shut off source of spill if possible to do so without hazard. Prevent material from entering sewers or watercourses. Provide adequate ventilation. Contain spilled materials with sand or earth. Recover undamaged and minimally contaminated material for reuse or reclamation. Place all collected material and spill absorbents into DOT approved containers.
Advise authorities. If this product is an EPA hazardous substance (see Section 10), notify the U.S.EPA and/or the National Response Center. Additional notification pursuant to SARA Section 302/304 (40 CFR 355) may also be required.

Waste Disposal Method
Treatment, storage, transportation and disposal must be in accordance with EPA or State regulations under authority of the Resource Conservation and Recovery Act (40 CFR 260-271).

Section: 08 SPECIAL PROTECTIVE INFORMATION

Respiratory Protection
If workplace exposure limit(s) of product or any component is exceeded, an NIOSH/MSHA approved air supplied respirator is advised in absence of proper environmental control. OSHA regulations also permit other NIOSH/MSHA respirators (negative pressure organic vapor type) under specified conditions. Engineering or administrative controls should be implemented to reduce exposure.

Ventilation

Product Name: TECHNI-HIB 370

Section: 08 SPECIAL PROTECTIVE INFORMATION CONTINUED

The use of mechanical dilution ventilation is recommended whenever this product is used in confined spaces, is heated above ambient temperatures or is agitated. When applicable, sufficient local ventilation should be provided to maintain employee exposures below safe working limits (TWA's).

Protective Gloves

Neoprene, nitrile, polyvinyl alcohol (PVA), polyvinyl chloride (PVC)

Eye Protection

Chemical splash goggles or face shield in compliance with OSHA regulations is advised; however OSHA regulations also permits safety glasses under certain conditions. The use of contact lenses is not recommended.

Other Protective Equipment

Eye wash and safety shower

Section: 09 SPECIAL PRECAUTIONS

Precautions to be Taken in Handling and Storing

Avoid contact with eyes, skin or clothing. Avoid breathing vapors or mist. Keep away from heat, sparks, and open flames and never use a cutting torch on or near container (even empty) or explosion may result. Vapors may travel to areas away from the work site and ignite.

Other Precautions

Containers of this material may be hazardous when emptied. Since emptied containers retain product residues (vapor, liquid, and/or solid), all hazard precautions given in the data sheet must be observed. Do not transfer to improperly marked container. Do not use pressure to empty container. Do not cut, heat, weld, or expose containers to flame or other sources of ignition. Keep container closed. Use with adequate ventilation. Wash thoroughly after handling. Containers should be grounded and bonded to receiving container(s) when being emptied. Containers should not be washed out and used for other purposes.
FOR INDUSTRIAL USE ONLY

Section: 10 REGULATORY INFORMATION

Superfund Amendments and Reauthorization Act Of 1986(SARA) Title III

Section 302/304-Extremely Hazardous Substances (40 CFR 355)

SARA requires emergency planning based on Threshold Planning Quantities (TPQs) and release reporting based on Reportable Quantities (RQs) in 40 CFR 355 (used for SARA 302, 304, 311

Product Name: TECHNI-HIB 370

Section: 10 REGULATORY INFORMATION CONTINUED

and 312). These values are subject to change and the regulations should be consulted to verify current statutory requirements.

Components present in this product at a level which could require reporting under the statute are:

Component Name	RQ	TPQ	% Range
NONE			

Section 311/312 Chemical Inventory Reporting Requirements (40 CFR 370)

The Superfund Amendments and Reauthorization Act (SARA) may require submission of reports (chemical list, MSDS, Tier I & Tier II) to the State Emergency Response Commission, Local Emergency Response Committee and the local fire department. The SARA physical and health hazards related to this product are:

X Acute Health Hazard
X Chronic Health Hazard
_ Sudden Release of Pressure
_ Reactive
X Fire

Section 313-List of Toxic Chemicals (40 CFR 372)

This product contains the following toxic chemicals subject to the reporting requirements of Section 313 of the Emergency Planning and Community Right-to-Know Act of 1986 (40 CFR 372). This information should be included in all MSDSs that are copied and distributed for this material.

Component Name	CAS #	% Range
methanol	00067-56-1	< 5%

CERCLA, 40 CFR 261 AND 302

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (CERCLA) requires notification of the National Response Center 1-800-424-8802 of any release of a Hazardous Substances equal to or greater than the reportable quantities (RQs) listed in 40CFR 302.4. Values are given in pounds for the component and not the mixture, if applicable. (These values are subject to change and the regulations should be consulted to verify current statutory levels.)

Component Name	CAS #	CERCLA RQ
methanol	00067-56-1	5000

OSHA Exposure Limits

Component Name

isopropyl alcohol
TWA ppm: 400.0 TWA MG/M3: 980.0 STEL ppm: 500.0 STEL MG/M3: 1225.0

methanol
TWA ppm: 200.0 TWA MG/M3: 260.0 STEL ppm: 250.0 STEL MG/M3: 325.0 Skin: X

National Fire Protection Agency

2 Health
0 Reactive
3 Fire
____ Other

Product Name: TECHNI-HIB 370

Section: 10 REGULATORY INFORMATION CONTINUED

Department of Transportation Shipping Information

Proper Shipping Name: Flammable liquids, n.o.s.
Hazard Class: 3 Identification: UN1993
Packaging Group: PG III
Contains: methanol, isopropyl alcohol
Hazardous Substance RQ: 100000# Emergency Response Guide Number: 128
Labels: Flammable liquid

Toxic Substances Control Act (TSCA), 40 CFR 261

This product, or components if product is a mixture, is/are listed on the Toxic Substance Control Act (TSCA) inventory.

- -

Section 10 information is to remain attached to the material safety data sheet for this product.

- -

While UNICHEM believes that the above data is correct, UNICHEM expressly disclaims liability for any loss or injury arising out of the use of this information or the use of any materials designated.

- -

END OF MSDS

APPENDIX 2.7-1

CHRONOLOGY OF FIELD ACTIVITIES

APPENDIX 2.7-1

CHRONOLOGY OF FIELD ACTIVITIES

Monday, July 6, 1998

Brian Rogers traveled to Artesia, New Mexico. Met with the drilling contractor during move-in and rig-up. L&M's Rig No. 1 was moved in and rigged up the steel mud pits, pumps, and substructure.

Tom Ball traveled to Artesia, New Mexico. Rigged up L&M's Rig No. 1.

Tuesday, July 7, 1998

Tom Ball arrived on site. Continued to rig up. Nippled up the blowout preventer and flow line. The location had been prepared for the selected rig. A divided reserve pit, lined with a 6-mil plastic and fenced, was complete. An extension was welded onto the 9-5/8 inch surface casing with a rental 9-5/8" sow x 11" 3000 flange to the blowout preventer. A cellar was completed with a rathole and mousehole.

Brian Rogers arrived on site. Continued nippling up the blowout preventer and flow line. Went in the hole with Kelly to 40 feet. Did not tag cement. Filled the hole with water. Picked up a Smith 8-3/4 inch FDSH+ (Journal Bearing bit with gauge protection) dressed with 13-13-13-blank (Serial No. LS0625). Went in the hole. Attempted to test the hydril. Test failed. Pulled out of the hole with the bit and drill collar. Closed blind rams and attempted to test. Test failed. Ordered out a replacement hydril. Nippled down the flow line and blowout preventers.

Wednesday, July 8, 1998

Tom Ball arrived on site. Replaced the ring gasket on the flange. Received the replacement Hydril. Nippled up same. Tested casing to 1000 psi for 30 minutes. Test okay. Started at 1600 hours. Picked up the bit and 13 drill collars. Tagged top plug at 374 feet. Washed the cement from 374 feet to 445 feet.

Brian Rogers arrived on site. Went in the hole with 13 drill collars. Worked through the cement plug at 445 feet. Tallied 4-1/2 inch drillpipe and went in the hole to 1620 feet. 0115 hours, closed the pipe rams and pressured up the well system to 750 psi at the standpipe. 0115 hours, Test No. 1 at 750 psi. 0145 hours, Test No. 1 ended at 690 psi. Pressure loss was -60 psi per 30 minutes. 0150 hours, Test No. 2 started at 900 psi. 0220 hours, Test No. 2 ended at 865 psi. Pressure loss was -35 psi per 30 minutes (-3.89%).

Continued in the hole with the 4-1/2 inch drillpipe. Tagged the top of plug at 2188 feet with 10 feet out on Joint No. 72 and no kelly. Picked up kelly and drilled cement plug to 2301 feet. 0700 hours, changed shifts.

Thursday, July 9, 1998

Tom Ball arrived on site. Drilled the cement to 2465 feet. Washed to 2521 feet. Ran mud sweep. Totco survey was 1° at 2481 feet. Washed to 3543 feet. Survey at 3441 feet was 1-1/4°. Drilled 3543 feet to 3573 feet. Went in the hole to 4200 feet. Washed down the bridges to 4440 feet.

Brian Rogers arrived on site. 1900 hours to 2200 hours, drilled to 4479 feet. Survey at 4432 feet was 1-3/4°. 2200 hours to 2400 hours, went in the hole. Tagged to the top of the cement at 5092 feet. Drilled cement from 5092 feet to 5220 feet (128 feet). Washed to 5296 feet. Swept the hole clean and surveyed at 5277 feet, 4-1/4°. 0130 hours to 0300 hours, washed in the hole 5317 feet to 5785 feet. Tagged. Circulated hole for one hour while moving the drill collar and drillpipe on the rack. 0400 hours to 0430 hours, drilled cement from 5785 feet to 5840 feet (55 feet). Felt spotty. 0430 hours to 0530 hours, went in the hole with the pipe to 6265 feet. Tagged hard. Picked up to circulate with the kelly. The pipe stuck at 6240 feet. Rigged up the kelly. Circulated with full returns. Worked the pipe. Mixed gelled pill for the sweep.

Friday, July 10, 1998

Tom Ball arrived on site. Pumped sweep while working the pipe 140,000 lbs down to 40,000 pounds (pipe weight 115,000 pounds). Circulated heavy concentration of drilling detergent around the drill collars. Did not free pipe. Pipe was stuck near the bit from stretch calculations. Spotted 50 barrels of oil with 30 barrels around the drill collars. Worked the pipe and moved 2 barrels oil each hour.

Brian Rogers arrived on site. 1900 hours, pumped two barrels (20 strokes) and worked pipe, 40,000 pounds to 190,000 pounds. 1930 hours, the pipe was free. Circulated and rotated the kelly down. Continued washing in the hole. 2015 hours, tagged hard cement at 6395 feet. Drilled cement with ±15,000 pounds WOB, 52 strokes per minute, 900 psi, 8.6 ppg, 45-second viscosity, 10.5 pH. Drilled to 6475 feet. Washed from 6475 feet to 6635 feet. Tagged hard cement at 6635 feet. Drilled to 6650 feet. Washed in the hole to 6745 feet. Spotted the gelled pill and swept the hole. Attempted to survey at 6705 feet. Failed twice. Mud was too thick and would not allow the tool to be lowered into the well before setting. Continued washing in the hole to 6808 feet. Mud was extremely thick. Jet mud to reserve

pit and added fresh water to dilute. Rotated and worked the pipe while conditioning the mud. Surveyed at 6768 feet, 3-1/2°.

Saturday, July 11, 1998

Tom Ball arrived on site. Continued to wash in the hole. Circulated and conditioned the mud as the pipe was worked downhole. Washed to 7274 feet and circulated to thin the mud. 1545 hours, tagged the cement at 7613 feet. 1545 hours to 1725 hours, short tripped 16 stands. No bridges or tight spots. 1725 hours to 1830 hours, surveyed at 7571 feet, 1-3/4°. 1830 hours to 1900 hours, drilled the cement at 7613 feet.

Brian Rogers arrived on site. 1900 hours, drilled the cement at 7613 feet. 2115 hours, broke out of the cement at 7726 feet (113 feet). Continued washing in the hole. Mud weight was 8.7 pounds per gallon (ppg), viscosity was 34 seconds, pH was 12, string weight was 130,000 pounds. 0200 hours, washed in the hole to tag cement at 8293 feet. 0200 hours to 0320 hours, drilled cement at 8293 feet to 8385 feet (92 feet). Conditioned mud with SAPP and Desco, as needed. Added premix at suction while drilling. Set marker in the pit. Did not observe loss of circulation or pit gain while washing to 8635 feet. Slowly regained full returns. Circulated the hole clean. Spotted a 25-barrel (42 viscosity) gelled pill for sweep. Mud weight was 8.9 ppg, 37 viscosity. Survey at 8604 feet was 1-1/4°.

Sunday, July 12, 1998

Tom Ball arrived on site. Installed an overflow for the reserve pit. Lined over flow with 6-mil plastic. Circulated the well clean. 1930 hours to 1330 hours, washed in the hole at 8635 feet to 9160 feet. 1330 hours, attained total depth of 9160.95 feet. 1330 hours to 1700 hours, circulated and swept the hole clean. 1700 hours to 1900 hours, short tripped 20 stands. No fill, bridges, or tight spots observed. 1900 hours, changed shift.

Brian Rogers arrived on site. 1900 hours to 2100 hours, circulated well and tallied seven inch casing. 2100 hours to 2115 hours, spotted a gelled pill. 2115 hours to 2130 hours, pumped gelled pill out of the drillpipe and into the bottom of the hole. 2200 hours, started pulling drillpipe out of the hole. Strapped the pipe as it was pulled from the well. Survey at 9160 feet was 1°. 2400 hours, moved in and rigged up Schlumberger. 0300 hours, pulled out of the hole. Went in the hole with 9-5/8 inch casing cement bond log, gamma ray, and casing collar locator logging tool to log 2548 feet to 400 feet. Correlated depths to the gamma ray curve/casing setting depth on the Halliburton spectral density, dual-spaced neutron log, dated September 8, 1993.

Monday, July 13, 1998

Tom Ball arrived on site. Performed a fracture identification survey with gamma ray from 9144 feet to 4000 feet. Integrated the four-arm caliper survey from 9144 feet to 2555 feet. Calculated the cement volume from the log and added 20% excess cement. Went in the hole with drillpipe and broke circulation at 5000 feet and 7000 feet. Continued in the hole. Good returns with no lost circulation.

Brian Rogers arrived on site. Set bit at 9115 feet and circulated the hole. Monitored returns. Swept the hole with 100 barrels, 40-second viscosity gelled pill. Monitored returns. Spotted a viscous gel pill at 9105 feet. Rigged up a lay-down machine. Pulled out of the hole. Laid down drillpipe and drill collars.

Tuesday, July 14, 1998

Tom Ball arrived on site. Rigged up Bull Rogers' casing crews. Picked up a seven inch packoff float shoe, Baker weld to the Bottom Joint No. 1. Ran two joints, float collar at 9007 feet and differential valve (DV) tool at 5498 feet. All equipment was Baker welded to the pipe. Ran Joint Nos. 1-50, 29 lb/ft N-80; Joint Nos. 51-84, 29 lb/ft, P-110; Joint Nos. 85-259, 26 lb/ft, P110. Torque turned and monitored each connection. 1550 hours, positioned float shoe at 9094 feet. Circulated well and reciprocated pipe for one seven inch casing volume. 1615 hours, dropped the ball and set a packoff float shoe at 9094 feet. Moved in and rigged up Halliburton. Cemented 7 inch casing with 20 barrels of fresh water, 12 barrels of mud flush, 20 barrels of fresh water, 12 barrels of Super Flush, 20 barrels of fresh water, and 600 sacks (171 barrels) modified Class H + 0.4% CFR-3 plus five pounds per sack (lb/sx) Gilsonite +0.5% Halad-344, + one lb/sx of salt mixed at 13.0 ppg (yield at 1.66 ft^3 per sack). Displaced with 150 barrels of fresh water and 194 barrels of mud. Did not bump plug. Floats were holding. Dropped dart and opened the DV tool at 824 psi. Circulated well with good returns throughout.

Brian Rogers arrived on site. Circulated through the DV tool for eight hours. Observed 42 barrels (142 sacks) of cement circulated to the surface. 0310 hours, pumped 20 barrels of fresh water, 12 barrels of super flush, 20 barrels of fresh water, Mixed (103 barrels) 220 sacks interfill C (lead slurry) at 11.7 ppg, followed by 163 barrels (550 sacks) Modified Class H + 0.5% Halad-344 + 0.1% HR7 + 0.4% CFR-3, + 5 lb/sx Gilsonite + one lb/sx salt at 13.0 ppg. Released the closing plug and displaced with 210 barrels of fresh water. Landed the plug and closed the DV tool with 3000 psi. Checked flowback. Okay. Tool closed. Circulated 35 barrels (75 sacks) to the surface. Picked up 1 inch tremie line and lowered to 20 feet (could not work past 7 inch collar) and cemented the 9-5/8" x 7" annulus

with 20 sacks of premium cement containing 3% calcium chloride. Waited on cement. Cleaned the mud pits.

Wednesday, July 15, 1998

Brian Rogers arrived on site. Waited on cement. Mud pits were clean. 1215 hours, slacked off on casing and cut to remove the blowout preventers. 1500 hours, released the drilling rig. Installed the seven inch Larkin Type R tubinghead. Returned the surplus mud inventory and inspected 13 drill collars. Rigged down the drilling rig.

Thursday, July 16, 1998

Brian Rogers arrived on site. Rigged down, moved out the drilling rig. Installed anchors and stabilized the seven inch casing with cement and filled in the rathole and mousehole. Delivered two 6-1/8 inch bits an coordinated completion operations.

Monday, July 20, 1998

Brian Rogers arrived on site. Moved in and rigged up Real Well Service's completion rig; Star Tool Company's pump, tank, pipe racks, catwalk, power swivel, and tools; and Knight Oil Tools' 2-7/8 inch, 6.50 lb/ft, N-80 work string. Purchased wellhead valves and fittings. Picked up the 6-1/8 inch bit, sub, six drill collars, and x-over (BHA at 183.80 feet) on the 2-7/8 inch work string. Went in the hole to tag soft bottom at 5455 feet. Picked up and pressure tested the well system above the DV tool at 5498 feet as shown below in Test Nos. 1 and 2:

Pressure Test No. 1 above DV tool at 5498 feet. Bottom of work string at 5450 feet:

Time (hours)	Pressure (psig)	Δ P (psi)
1441	1580	--
1446	1574	-6
1451	1571	-3
1456	1568	-3
1501	1565	-3
1506	1563	-2
1511	1561	-2
	TOTAL	-19 psi/ 30 minutes

Pressure Test No. 2 above DV tool at 5498 feet. Bottom of work string at 5450 feet:

Time (hours)	Pressure (psig)	ΔP (psi)
1516	1559	--
1521	1558	-1
1526	1556	-2
1531	1555	-1
1536	1555	0
1541	1554	-1
1546	1553	-1
	TOTAL	-6 psi/ 30 minutes

Washed in the hole to tag the top of the DV at 5498 feet. Drilled out the DV tool part way, circulated the tubing clean, and installed the TIW valve. 1900 hours, shut down for the night.

Note: Monitored the well system pressures using an Adalet digital pressure gauge (Catalog No. XIHFGCXZ-54967) with an Iniex Certificate Rating No. EX88B103703U. Pressure range was 0 to 2000 psig.

Tuesday, July 21, 1998

Brian Rogers arrived on site. 0700 hours, finished drilling out the DV tool. Went into the hole to tag soft bottom at 8896 feet. Drilled and washed in the hole to 9004 feet. Circulated the well clean. Picked up and pressure tested the well system above the top of the float collar, as shown below in Test Nos. 3 and 4.

Pressure Test No. 3 above the float collar at 9007 feet. Bottom of the work string at 8972 feet.

Time (hours)	Pressure (psig)	Δ P (psi)
1405	1600	--
1410	1592	-8
1415	1588	-4
1420	1584	-4
1425	1580	-4
1430	1577	-3
1435	1575	-2
	TOTAL	-25 psi/ 30 minutes

Pressure Test No. 4 above the float collar at 9007 feet. Bottom of the work string at 8972 feet:

Time (hours)	Pressure (psig)	Δ P (psi)
1440	1573	--
1445	1571	-2
1450	1569	-2
1455	1568	-1
1500	1567	-1
1505	1566	-1
1510	1565	-1
	TOTAL	-8 psi/ 30 minutes

Monitored the well system pressures using an Adalet digital pressure gauge (Catalog No. XIHFGCXZ-54967) with an Iniex Certificate Rating No. EX88B103703U. Pressure range was 0 to 2000 psig.

Pulled out of the hole. Laid down the drill collars. Cleaned out the rig tank and filled it with clean fresh water.

Wednesday, July 22, 1998

Brian Rogers arrived on site. 0700 hours, went in the hole with a bit and scraper to 8823 feet. Reverse circulated bottoms up. Pickled the wellbore with six barrels 15% HCl (inhibited) pumped down the tubing and up the casing. Displaced the well with an 8.7 ppg brine water. Laid down 11 joints and tripped out of the hole. Secured the well for the night. Loaded the storage tank with 500 barrels of 8.7 ppg brine.

Thursday, July 23, 1998

Brian Rogers arrived on site. 0600 hours, moved in and rigged up Wedge Wireline. Performed a differential temperature survey from the surface to total depth. Performed a cement bond log from 8997 feet to 135 feet. Cement bond log performed with 1000 psi applied to the well system. Conducted a casing inspection survey from 8997 feet to the surface.

Friday, July 24, 1998

Brian Rogers arrived on site. Moved in and rigged up Wedge Wireline with eight 4 inch retrievable cased-hole perforating guns. Perforated selected intervals at two jet shots per foot as follows:

Run No.	Feet
1	8470 to 8476
	8460 to 8464
2	8430 to 8446
3	8419 to 8423
	8400 to 8410

Run No.	Feet
4	8360 to 8366
	8370 to 8378
5	8280 to 8302
6	8260 to 8270
7 & 8	8220 to 8254

All shots were fired. Fluid level dropped from the surface to ±1380 feet. Bottom-hole pressure at 8220 feet was measured at 3176 psia. A static gradient survey was performed as the tool was pulled out of the well. Static stays were conducted at 6000 feet, 3000 feet, 1500 feet, and at the surface. The well was secured for the night.

Saturday, July 25, 1998

Brian Rogers arrived on site. 0700 hours, strapped in the hole with nine joints 2-7/8" work string (287.56 feet), Arrow X-1 packer (6.25 feet), seating nipple (one foot), and 133 joints 2-7/8 inch work string (8178.32 feet) to set the end of the tubing below the bottom perforation (8476 feet) at 8479 feet. Packer element was at 8189 feet. Rigged up swab line and went into the hole to tag the fluid level at 1700 feet. Swab tested the perforated interval and recovered two tubing volumes of fluid. Strong hydrogen sulfide smell was observed while swabbing. Retained samples of the formation water for analysis. A total of 139 barrels of fluid was recovered. Secured the well for the night.

Sunday, July 26, 1998

Brian Rogers arrived on site. 0700 hours, set end of tubing at 8158 feet (top perforation was 8220 feet). Moved in and rigged up Dowell Schlumberger and performed step rate test using 8.7 ppg brine water. Results of Step Rate Test No. 1 (before acid) are as follows:

Rate (bpm)	Volume Pumped (barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
2	50	560	285	+ 275
4	35	2020	734	+1286
4.85	35	2673	1020	+1653
5	3	+2850	1020	+1830

Maximum allowable pump-in = 8220 ft x 0.2 psi/ft = 1644 psig.

Acidized perforations 8220 feet to 8476 feet in four stages as follows:

Spotted acid (9.5 barrels) across perforations and pulled out of the hole to set end of the tubing at 8158 feet. Stage 1: 27 barrels of 15% HCl + 20 barrels of gelled salt for block at 800 pounds; Stage 2: 27 barrels of 15% HCl + 26 barrels of 8.7 brine pad + 21 barrels of gelled salt for block at 800 pounds; Stage 3: 27 barrels of 15% HCl + 26 barrels of 8.7 brine pad + 20 barrels of gelled salt for block at 800 pounds; Stage 4: 27 barrels of 15% HCl + 65 barrels of 8.7 brine for displacement at 10 bpm and 2450 psi. Allowed acid to soak for two hours and performed Step Rate Test No. 2. Results of Step Rate Test No. 2 are:

Rate (bpm)	Volume Pumped (Barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
4	20	86	734	-648
7	130	1085	1632	-547
10	35	2674	2774	-100
12	50	3948	3875	+ 73

Well went on a vacuum following both tests.

Laid down nine joints and pulled out of the hole with the tubing and the packer.

Monday, July 27, 1998

Brian Rogers arrived on site. Moved in and rigged up Wedge Wireline with eight 4 inch retrievable cased-hole perforating guns. Perforated selected intervals at two jet shots per foot as follows: 8170 feet to 8188 feet, 8160 feet to 8164 feet, 8118 feet to 8127 feet, 8132 feet to 8140 feet, 8066 feet to 8080 feet, 8050 feet to 8056 feet, 7974 feet to 8030 feet, and 7924 feet to 7942 feet. Started loading the tanks with an 8.7 ppg brine water. Secured the well and shut down for the night.

Tuesday, July 28, 1998

Brian Rogers arrived on site. Went into the hole with an Arrow retrievable bridge plug and packer on the work string. Tool hung up at 4830 feet. Pulled out of the hole. Lower slip cage on the plug was broken. Called for a replacement. Went into the hole with a 6-1/8 inch bit on the work string. Did not encounter any obstructions. Pulled out of the hole. Went into the hole with a replacement retrievable bridge plug and packer on 88 stands. Had mechanical failure on rig. Shut down. Secured the well for the night.

Wednesday, July 29, 1998

Brian Rogers arrived on site. Went into the hole with an Arrow retrievable bridge plug and packer. Set the retrievable bridge plug at 8214 feet. Set the packer at 8193 feet. Pressure tested between the packers at 500 psi. Tested okay. Pulled up the hole. Set the packer at 7852 feet. Swab tested the perforated interval and recovered 112 barrels (more than two tubing volumes). Moved in and rigged up Dowell Schlumberger to perform Step Rate Test No. 1 using an 8.7 ppg brine water. Acidized perforations 7924 feet to 8188 feet in four stages as follows: (1) 30 barrels 15% HCl + 10 barrels of gelled salt at 500 pounds; (2) 30

barrels 15% HCl + 20 barrels 8.7 brine pad + 16 barrels of gelled salt for block at 800 pounds; (3) 30 barrels 15% HCl + 20 barrels 8.7 brine pad + 21 barrels of gelled salt for block at 1000 pounds; and (4) 30 barrels 15% HCl + 60 barrels 8.7 brine for displacement at 6.5 bpm and 1050 psi.

Allowed acid to soak for one hour and performed Step Rate Test No. 2. Lowered the retrieving head onto the retrievable bridge plug. Unset the retrievable bridge plug and pulled out of the hole with the tools. Laid down the retrievable bridge plug and the packer. Secured the well for the night.

All storage tanks were loaded with an 8.7 ppg brine, totaling 7840 barrels.

Results of Step Rate Test No. 1 (before acid):

Rate (bpm)	Volume Pumped (barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
2	47	400	275	125
4	15	1780	706	1074
4.36	2	2416	706	1710

Maximum allowable pump-in = 7924 ft x 0.2 psi/ft = 1585 psig.

Step Rate Test No. 2 (after 5000 gallons 15% HCl acid):

Rate (bpm)	Volume Pumped (Barrels)	Pressure (psig)	Friction Pressure (psig)	Pump-in Pressure (psig)
4	25	7	706	-700
7	25	1070	1570	-500

Well went on a vacuum following both tests.

Thursday, July 30, 1998

Brian Rogers arrived on site. 0600 hours, moved in and rigged up Wedge Dia-Log with a digital quartz surface readout gauge, Eccosse Tex, Serial No. 009, 0 psia to 5000 psia and a Z.I. Probe memory recorder, Serial No. P59, 0 psia to 5000 psia with a casing collar

locator for depth control. 0700 hours, went into the hole and correlated logging depths to the July 23, 1998, cement bond log. Set the surface readout gauge at 7924 feet (top perforation). 0830 hours, bottom-hole pressure was 2928.16 psia at 125.41°F. Moved in and rigged up Halliburton's pump truck and booster pump. 0920 hours, started pumping 8.7 ppg brine at 10 bpm. Well on vacuum at surface. 2153 hours, final bottom-hole pressure injection pressure at 7924 feet was 3071.85 psia at 90.80°F. Shut down injection. Pumped a total of 7490 barrels of 8.7 ppg brine while monitoring the bottom-hole pressure. Monitored the pressure falloff.

Friday, July 31, 1998

Brian Rogers arrived on site. 0700 hours, discontinued the pressure falloff test. Pulled out of the hole making static gradient stops at 6000 feet, 3000 feet, 1700 feet and at the surface. Rigged up a differential temperature tool and casing collar locator and conducted a survey from the surface to wireline total depth at 8997 feet. Pulled out of the hole and laid down the temperature tool. Picked up a dual detector gamma ray tool configured with an upper detector, ejector, casing collar locator, and lower detector. Went into the hole. Performed a pre-survey baseline 7800 feet to wireline total depth at 8997 feet. Conducted a five-minute statistical survey at 7904 feet. Performed two injection profile surveys at 1 bpm. Conducted two stationary surveys at 7904 feet, pumping at 10 bpm. No upward migration was observed behind the casing. Performed a post-survey baseline. Rigged down and moved out wireline and pump equipment. Note: Released all 16 frac tanks at 0900 hours.

Saturday, August 1, 1998

Brian Rogers arrived on site. Laid down the 2-7/8 inch work string and returned to Knight Oil Tools. Delivered 197 joints, new 4-1/2 inch, 11.60 lb/ft, N-80, SMLS, R3, LT&C injection tubing.

Sunday, August 2, 1998

Brian Rogers arrived on site. Picked up an Arrow Model X-1 (7" x 3.5") retrievable packer (minimum ID = 3.0 inches) with a wireline reentry guide on bottom and a X/O 3.5 EUE 8rd pin x 4-1/2" LTC box on top. Total length was 9.01 feet. Made up and went in the hole with 193 joints, 4-1/2 inch, 11.60 lb/ft, N-80, SMLS, R3, LT&C injection tubing. Set the packer at 7879 feet and loaded the annulus with 8.7 ppg corrosion inhibited brine water. Slacked off 15,000-pound compression on the packer. Pressure tested the annulus at 600 psi. Lost 90 psi/30 minutes. Repressurized the annulus and lost 20 psi/30 minutes. Released the pump truck and left the annulus open during stabilization. Shut down for the night.

Monday, August 3, 1998

Brian Rogers arrived on site. Pressurized the annulus to 700 psi and monitored overnight. Notified the New Mexico Oil Conservation Division (OCD) of the test to begin at 0700 hours on Tuesday, August 4, 1998. Returned the rental tools and moved out the tanks.

Tuesday, August 4, 1998

Brian Rogers arrived on site. Continued monitoring the annulus pressure. 0700 hours, annulus pressure was 702 psig. 0900 hours, the OCD representatives witnessed the annulus pressure test. Mr. E. L. Gonzales and Gerry Williams represented the OCD. 0900 hours, started the annulus pressure test at 704 psig. 0930 hours, ended the annulus pressure test at 705 psig. Pressure change was +1 psi/30-minute period (0.14%), which is within the regulatory guidelines.

Rigged down and released the completion unit and all ancillary equipment.

APPENDIX 4.1-1

BOTTOM-HOLE PRESSURE FIELD DATA RECORDED DURING THE INJECTIVITY/FALLOFF TEST FOR WDW-1

APPENDIX 4.1-1
Navajo Refining Company
Pressure Falloff Data

Well Name : WDW-1
Started on : 07/30/1998
Ended on : 07/31/1998

Time	Pressure (Psia)	Temperature (°F)
0.0000	2927.912	123.434
0.0003	2927.912	123.439
0.0006	2927.904	123.444
0.0008	2927.904	123.444
0.0011	2927.903	123.459
0.0014	2927.899	123.457
0.0017	2927.899	123.467
0.0019	2927.877	123.462
0.0022	2927.894	123.474
0.0025	2927.886	123.485
0.0028	2927.889	123.487
0.0031	2927.892	123.500
0.0033	2927.881	123.497
0.0200	2927.845	123.822
0.0367	2927.879	124.129
0.0533	2927.914	124.377
0.0700	2927.958	124.595
0.0867	2928.012	124.782
0.1033	2928.041	124.924
0.1200	2928.073	125.036
0.1367	2928.096	125.124
0.1533	2928.120	125.208
0.1700	2928.117	125.256
0.1867	2928.131	125.299
0.2033	2928.158	125.352
0.2200	2928.158	125.379
0.2367	2928.162	125.410
0.2533	2928.178	125.438
0.2700	2928.169	125.448
0.2867	2928.184	125.470
0.3033	2928.195	125.483
0.3200	2928.211	125.501
0.3367	2928.202	125.506
0.3533	2928.191	125.508
0.3700	2928.208	125.521
0.3867	2928.207	125.526
0.4033	2928.193	125.521
0.4200	2928.203	125.534
0.4367	2928.205	125.541
0.4533	2928.190	125.546
0.4700	2928.199	125.559
0.4867	2928.220	125.574
0.5033	2928.196	125.556
0.5200	2928.189	125.556
0.5367	2928.209	125.572
0.5481	2928.219	125.584
0.5647	2928.232	125.594
0.5814	2928.215	125.582
0.5981	2928.202	125.572
0.6147	2928.205	125.574
0.6314	2928.212	125.579
0.6481	2928.219	125.584
0.6647	2928.218	125.594
0.6650	2928.214	125.587
0.6653	2928.214	125.587
0.6656	2928.208	125.577
0.6658	2928.218	125.594
0.6661	2928.221	125.592
0.6664	2928.218	125.589
0.6667	2928.201	125.577
0.6669	2928.218	125.594
0.6672	2928.221	125.592
0.6675	2928.214	125.587
0.6678	2928.214	125.587
0.6681	2928.211	125.584
0.6683	2928.211	125.589
0.6686	2928.214	125.587
0.6689	2928.238	125.604
0.6692	2928.183	125.569
0.6694	2928.231	125.599
0.6697	2928.208	125.582
0.6700	2928.221	125.597
0.6703	2928.208	125.582
0.6706	2928.225	125.594
0.6708	2928.214	125.592
0.6711	2928.214	125.587
0.6714	2928.214	125.587
0.6717	2928.207	125.587
0.6719	2928.225	125.594
0.6722	2928.207	125.587
0.6725	2928.236	125.597
0.6728	2928.194	125.577
0.6731	2928.235	125.602
0.6733	2928.211	125.584
0.6736	2928.221	125.592
0.6739	2928.204	125.584
0.6742	2928.232	125.594
0.6744	2928.214	125.592
0.6747	2928.221	125.592
0.6750	2928.218	125.589
0.6753	2928.214	125.587
0.6756	2928.221	125.592
0.6758	2928.207	125.587
0.6761	2928.228	125.597
0.6764	2928.214	125.592
0.6767	2928.207	125.587
0.6769	2928.228	125.597
0.6772	2928.204	125.584
0.6775	2928.221	125.597
0.6778	2928.207	125.587
0.6781	2928.228	125.597
0.6783	2928.214	125.592
0.6786	2928.211	125.589
0.6789	2928.214	125.592
0.6792	2928.218	125.594
0.6794	2928.214	125.592
0.6797	2928.218	125.589
0.6800	2928.210	125.594
0.6803	2928.214	125.587
0.6806	2928.224	125.599
0.6808	2928.214	125.592
0.6811	2928.214	125.592
0.6814	2928.214	125.592
0.6817	2928.221	125.597
0.6819	2928.203	125.589
0.6822	2928.218	125.594
0.6825	2928.221	125.597
0.6828	2928.200	125.587
0.6831	2928.228	125.602
0.6833	2928.204	125.584
0.6836	2928.217	125.599
0.6839	2928.211	125.589
0.6842	2928.235	125.607
0.6844	2928.196	125.584
0.6847	2928.211	125.589
0.6850	2928.207	125.592
0.6853	2928.231	125.604
0.6856	2928.207	125.592
0.6858	2928.218	125.594
0.6861	2928.203	125.589
0.6864	2928.218	125.594
0.6867	2928.210	125.594
0.6869	2928.231	125.604
0.6872	2928.200	125.587
0.6875	2928.214	125.592
0.6878	2928.224	125.599
0.6881	2928.210	125.594
0.6883	2928.207	125.592
0.6886	2928.211	125.589
0.6889	2928.224	125.604
0.6892	2928.214	125.592
0.6894	2928.218	125.594
0.6897	2928.199	125.592
0.6900	2928.214	125.592
0.6903	2928.220	125.602
0.6906	2928.218	125.594
0.6908	2928.207	125.592
0.6911	2928.210	125.594
0.6914	2928.224	125.599
0.6917	2928.213	125.597
0.6919	2928.203	125.589
0.6922	2928.218	125.594
0.6925	2928.213	125.597
0.6928	2928.220	125.602
0.6931	2928.221	125.597
0.6933	2928.203	125.589
0.6936	2928.213	125.597
0.6939	2928.224	125.599
0.6942	2928.217	125.599
0.6944	2928.207	125.592
0.6947	2928.218	125.594
0.6950	2928.217	125.599
0.6953	2928.210	125.594
0.6956	2928.227	125.607
0.6958	2928.218	125.594
0.6961	2928.203	125.589
0.6964	2928.224	125.604
0.6967	2928.213	125.597
0.6969	2928.224	125.599
0.6972	2928.200	125.587
0.6975	2928.220	125.602
0.6978	2928.217	125.599
0.6981	2928.210	125.594
0.6983	2928.220	125.602
0.6986	2928.207	125.592
0.6989	2928.224	125.604
0.6992	2928.210	125.594
0.6994	2928.224	125.599
0.6997	2928.196	125.589
0.7000	2928.234	125.612
0.7003	2928.213	125.597
0.7006	2928.213	125.597
0.7008	2928.210	125.594

Time	Pressure (Psia)	Temperature (°F)
0.7011	2928.217	125.599
0.7014	2928.220	125.602
0.7017	2928.220	125.602
0.7019	2928.210	125.594
0.7022	2928.207	125.592
0.7025	2928.230	125.610
0.7028	2928.209	125.599
0.7031	2928.220	125.602
0.7033	2928.210	125.594
0.7036	2928.217	125.599
0.7039	2928.213	125.602
0.7042	2928.217	125.599
0.7044	2928.217	125.599
0.7047	2928.213	125.597
0.7050	2928.220	125.602
0.7053	2928.224	125.604
0.7056	2928.217	125.599
0.7058	2928.202	125.594
0.7061	2928.224	125.604
0.7064	2928.220	125.602
0.7067	2928.220	125.602
0.7069	2928.202	125.594
0.7072	2928.213	125.597
0.7075	2928.224	125.604
0.7078	2928.217	125.599
0.7081	2928.209	125.599
0.7083	2928.217	125.599
0.7086	2928.209	125.599
0.7089	2928.228	125.602
0.7092	2928.213	125.602
0.7094	2928.209	125.599
0.7097	2928.224	125.604
0.7100	2928.217	125.599
0.7103	2928.217	125.599
0.7106	2928.209	125.599
0.7108	2928.220	125.602
0.7111	2928.213	125.597
0.7114	2928.227	125.607
0.7117	2928.210	125.594
0.7119	2928.235	125.607
0.7122	2928.218	125.594
0.7125	2928.238	125.610
0.7128	2928.228	125.597
0.7131	2928.235	125.602
0.7133	2928.231	125.599
0.7136	2928.260	125.610
0.7139	2928.236	125.597
0.7142	2928.250	125.597
0.7144	2928.261	125.604
0.7147	2928.262	125.599
0.7150	2928.279	125.607
0.7153	2928.280	125.602
0.7156	2928.298	125.604
0.7158	2928.292	125.594
0.7161	2928.313	125.610
0.7164	2928.332	125.607
0.7167	2928.275	125.554
0.7169	2928.406	125.640
0.7172	2928.380	125.610
0.7175	2928.381	125.599
0.7178	2928.410	125.604
0.7181	2928.412	125.594
0.7183	2928.469	125.615
0.7186	2928.464	125.594
0.7189	2928.514	125.615
0.7192	2928.527	125.597
0.7194	2928.560	125.604
0.7197	2928.594	125.602
0.7200	2928.634	125.610
0.7203	2928.657	125.599
0.7206	2928.716	125.610
0.7208	2928.736	125.597
0.7211	2928.783	125.610
0.7214	2928.822	125.599
0.7217	2928.884	125.607
0.7219	2928.915	125.602
0.7222	2928.981	125.607
0.7225	2929.026	125.607
0.7228	2929.083	125.599
0.7231	2929.138	125.607
0.7233	2929.192	125.597
0.7236	2929.276	125.615
0.7239	2929.315	125.599
0.7242	2929.375	125.599
0.7244	2929.449	125.599
0.7247	2929.526	125.612
0.7250	2929.580	125.602
0.7253	2929.672	125.615
0.7256	2929.719	125.594
0.7258	2929.803	125.607
0.7261	2929.867	125.604
0.7264	2929.938	125.602
0.7267	2930.021	125.597
0.7269	2930.105	125.610
0.7272	2930.187	125.610
0.7275	2930.252	125.602
0.7278	2930.335	125.597
0.7281	2930.427	125.604
0.7283	2930.517	125.604
0.7286	2930.602	125.612
0.7289	2930.693	125.597
0.7292	2930.771	125.599
0.7294	2930.876	125.599
0.7297	2930.986	125.615
0.7300	2931.084	125.604
0.7303	2931.164	125.592
0.7306	2931.282	125.602
0.7308	2931.387	125.602
0.7311	2931.502	125.610
0.7314	2931.596	125.607
0.7317	2931.684	125.589
0.7319	2931.802	125.599
0.7322	2931.902	125.602
0.7325	2931.999	125.607
0.7328	2932.064	125.589
0.7331	2932.160	125.604
0.7333	2932.232	125.597
0.7336	2932.313	125.607
0.7339	2932.345	125.587
0.7342	2932.398	125.582
0.7344	2932.513	125.617
0.7347	2932.568	125.602
0.7350	2932.628	125.592
0.7353	2932.710	125.597
0.7356	2932.789	125.594
0.7358	2932.859	125.597
0.7361	2932.930	125.594
0.7364	2933.021	125.594
0.7367	2933.082	125.584
0.7369	2933.191	125.599
0.7372	2933.271	125.592
0.7375	2933.372	125.594
0.7378	2933.469	125.584
0.7381	2933.596	125.589
0.7383	2933.711	125.592
0.7386	2933.853	125.592
0.7389	2933.992	125.584
0.7392	2934.154	125.582
0.7394	2934.347	125.587
0.7397	2934.537	125.589
0.7400	2934.721	125.582
0.7403	2934.927	125.579
0.7406	2935.135	125.584
0.7408	2935.341	125.582
0.7411	2935.516	125.584
0.7414	2935.723	125.572
0.7417	2935.905	125.579
0.7419	2936.066	125.577
0.7422	2936.261	125.577
0.7425	2936.384	125.574
0.7428	2936.534	125.574
0.7431	2936.687	125.572
0.7433	2936.808	125.584
0.7436	2936.935	125.562
0.7439	2937.105	125.572
0.7442	2937.249	125.562
0.7444	2937.452	125.574
0.7447	2937.648	125.564
0.7450	2937.816	125.562
0.7453	2938.067	125.559
0.7456	2938.285	125.572
0.7458	2938.499	125.564
0.7461	2938.740	125.549
0.7464	2938.964	125.554
0.7467	2939.239	125.559
0.7469	2939.503	125.567
0.7472	2939.693	125.541
0.7475	2940.009	125.554
0.7478	2940.275	125.546
0.7481	2940.555	125.554
0.7483	2940.929	125.549
0.7486	2941.198	125.539
0.7489	2941.552	125.546
0.7492	2941.918	125.546
0.7494	2942.199	125.539
0.7497	2942.610	125.539
0.7500	2942.928	125.536
0.7503	2943.233	125.541
0.7506	2943.578	125.531
0.7508	2943.777	125.529
0.7511	2944.113	125.529
0.7514	2944.344	125.534
0.7517	2944.557	125.526
0.7519	2944.823	125.519
0.7522	2944.906	125.513
0.7525	2945.171	125.544
0.7528	2945.240	125.501
0.7531	2945.321	125.506
0.7533	2945.559	125.521
0.7536	2945.596	125.526
0.7539	2945.647	125.498
0.7542	2945.746	125.516
0.7544	2945.845	125.496
0.7547	2945.852	125.506
0.7550	2945.953	125.503
0.7553	2945.980	125.496
0.7556	2945.995	125.496
0.7558	2946.076	125.501
0.7561	2946.059	125.488
0.7564	2946.064	125.481
0.7567	2946.118	125.498
0.7569	2946.123	125.486
0.7583	2946.342	125.470
0.7597	2946.994	125.450
0.7611	2947.771	125.445
0.7625	2948.461	125.420
0.7639	2948.858	125.415
0.7653	2948.980	125.385
0.7667	2949.150	125.372
0.7681	2949.417	125.321
0.7694	2949.969	125.326
0.7708	2950.390	125.296
0.7722	2950.584	125.268
0.7736	2950.593	125.258
0.7750	2950.695	125.213
0.7764	2950.717	125.190
0.7778	2951.029	125.167
0.7792	2951.606	125.142
0.7806	2952.135	125.124
0.7819	2952.151	125.081
0.7833	2952.090	125.053
0.7847	2952.004	125.023
0.7861	2952.313	124.987
0.7875	2952.483	124.937
0.7889	2952.800	124.912

Time	Pressure (Psia)	Temperature (°F)
0.7903	2952.953	124.876
0.7917	2953.042	124.838
0.7931	2953.086	124.805
0.7944	2953.169	124.767
0.7958	2953.278	124.722
0.7972	2953.527	124.696
0.7986	2953.581	124.643
0.8000	2953.920	124.613
0.8014	2954.069	124.575
0.8028	2954.117	124.534
0.8042	2954.151	124.494
0.8056	2954.156	124.443
0.8069	2954.193	124.405
0.8083	2954.189	124.370
0.8097	2954.570	124.316
0.8111	2954.921	124.278
0.8125	2955.347	124.235
0.8139	2955.368	124.169
0.8153	2955.231	124.152
0.8167	2954.919	124.093
0.8181	2955.019	124.053
0.8194	2955.359	123.997
0.8208	2955.763	123.954
0.8222	2955.726	123.901
0.8236	2955.528	123.855
0.8250	2955.282	123.797
0.8264	2955.435	123.761
0.8278	2955.962	123.700
0.8292	2956.361	123.660
0.8306	2956.432	123.604
0.8319	2956.200	123.566
0.8333	2955.780	123.500
0.8347	2955.514	123.459
0.8361	2955.708	123.406
0.8375	2956.395	123.342
0.8389	2956.842	123.304
0.8403	2957.140	123.251
0.8417	2956.879	123.198
0.8431	2956.312	123.144
0.8444	2956.119	123.076
0.8458	2956.432	123.027
0.8472	2957.045	122.997
0.8486	2957.226	122.903
0.8500	2957.202	122.875
0.8514	2956.952	122.814
0.8528	2956.556	122.761
0.8542	2956.357	122.715
0.8556	2957.170	122.651
0.8569	2957.904	122.611
0.8583	2958.026	122.544
0.8597	2957.821	122.483
0.8611	2957.392	122.422
0.8625	2956.841	122.382
0.8639	2956.793	122.305
0.8653	2956.997	122.265
0.8667	2957.455	122.198
0.8681	2957.569	122.132
0.8694	2957.542	122.081
0.8708	2957.231	122.020
0.8722	2957.063	121.959
0.8736	2957.150	121.916
0.8750	2957.417	121.852
0.8764	2957.461	121.788
0.8778	2957.437	121.725
0.8792	2957.331	121.681
0.8806	2957.143	121.613
0.8819	2957.406	121.557
0.8833	2957.795	121.501
0.8847	2957.838	121.442
0.8861	2957.710	121.383
0.8875	2957.324	121.322
0.8889	2957.073	121.256
0.8903	2957.414	121.192
0.8917	2957.747	121.138
0.8931	2957.890	121.072
0.8944	2957.880	121.019
0.8958	2957.673	120.957
0.8972	2957.375	120.911
0.8986	2957.168	120.830
0.9000	2957.337	120.771
0.9014	2957.499	120.723
0.9028	2957.574	120.656
0.9042	2957.307	120.595
0.9056	2956.637	120.528
0.9069	2955.792	120.460
0.9083	2955.081	120.411
0.9097	2954.180	120.355
0.9111	2953.331	120.288
0.9125	2952.516	120.219
0.9139	2951.436	120.143
0.9153	2950.818	120.112
0.9167	2950.159	120.028
0.9181	2950.051	119.984
0.9194	2950.249	119.915
0.9208	2950.860	119.869
0.9222	2951.833	119.800
0.9236	2952.802	119.754
0.9250	2953.647	119.649
0.9264	2954.265	119.613
0.9278	2955.349	119.565
0.9292	2956.813	119.501
0.9306	2958.861	119.439
0.9319	2960.637	119.391
0.9333	2961.325	119.311
0.9347	2961.391	119.255
0.9361	2960.984	119.186
0.9375	2960.515	119.150
0.9389	2959.948	119.083
0.9403	2959.645	119.019
0.9417	2959.294	118.973
0.9431	2958.920	118.901
0.9444	2958.670	118.832
0.9458	2958.468	118.791
0.9472	2958.429	118.740
0.9486	2958.353	118.668
0.9500	2958.032	118.627
0.9514	2957.896	118.545
0.9528	2957.842	118.463
0.9542	2958.121	118.440
0.9556	2958.234	118.381
0.9569	2958.132	118.312
0.9583	2957.911	118.268
0.9597	2957.622	118.204
0.9611	2957.602	118.140
0.9625	2957.599	118.073
0.9639	2957.851	118.027
0.9653	2957.711	117.963
0.9667	2957.627	117.927
0.9681	2957.565	117.850
0.9694	2957.845	117.783
0.9708	2958.126	117.737
0.9722	2958.239	117.678
0.9736	2958.267	117.631
0.9750	2958.097	117.572
0.9764	2957.674	117.513
0.9778	2957.626	117.457
0.9792	2958.149	117.403
0.9806	2958.800	117.325
0.9819	2959.014	117.290
0.9833	2958.896	117.225
0.9847	2958.507	117.179
0.9861	2958.154	117.127
0.9875	2957.775	117.063
0.9889	2957.828	117.019
0.9903	2958.438	116.955
0.9917	2958.908	116.906
0.9931	2958.983	116.852
0.9944	2958.689	116.796
0.9958	2958.214	116.747
0.9972	2957.764	116.690
0.9986	2957.772	116.631
1.0000	2958.427	116.577
1.0014	2959.110	116.551
1.0028	2959.156	116.469
1.0042	2958.985	116.389
1.0056	2958.925	116.345
1.0069	2960.832	116.339
1.0083	2962.101	116.333
1.0097	2964.754	116.327
1.0111	2966.967	116.255
1.0125	2968.985	116.211
1.0139	2970.896	116.180
1.0153	2972.739	116.137
1.0167	2974.210	116.095
1.0181	2976.977	116.049
1.0194	2978.117	115.998
1.0208	2980.255	115.952
1.0222	2982.153	115.911
1.0236	2984.456	115.832
1.0250	2986.898	115.721
1.0264	2988.887	115.525
1.0278	2993.896	115.296
1.0292	2995.964	115.027
1.0306	2997.171	114.998
1.0319	2999.813	114.735
1.0333	3001.492	115.290
1.0347	3011.142	115.320
1.0361	3015.741	115.377
1.0375	3007.901	116.068
1.0389	3018.019	116.347
1.0403	3018.755	117.125
1.0417	3018.801	117.119
1.0431	3017.091	117.473
1.0444	3017.476	117.980
1.0458	3017.145	117.703
1.0472	3017.984	117.881
1.0486	3012.824	117.259
1.0500	3012.926	117.698
1.0514	3013.444	117.466
1.0528	3013.021	117.467
1.0542	3015.803	117.279
1.0556	3018.625	117.169
1.0569	3014.113	117.325
1.0583	3018.374	116.198
1.0597	3017.375	116.322
1.0611	3016.556	116.394
1.0625	3018.841	116.978
1.0639	3013.757	116.861
1.0653	3017.574	117.857
1.0667	3016.946	117.635
1.0681	3017.526	117.771
1.0694	3018.244	117.516
1.0708	3019.199	116.794
1.0722	3019.124	116.383
1.0736	3019.331	116.438
1.0742	3019.550	116.744
1.0783	3018.981	116.123
1.0825	3016.417	115.808
1.0867	3020.184	115.714
1.0908	3020.730	115.556
1.0950	3018.411	111.400
1.0992	3021.348	111.126
1.1033	3018.552	111.506
1.1075	3019.752	111.173
1.1117	3019.509	111.124
1.1158	3018.809	110.957
1.1200	3021.578	110.478
1.1242	3020.136	109.912
1.1283	3020.964	109.987
1.1325	3021.163	109.687
1.1367	3020.681	109.491
1.1408	3021.506	108.302
1.1450	3024.089	107.316
1.1492	3023.971	105.586
1.1533	3023.281	105.557

Time	Pressure (Psia)	Temperature (°F)
1.1575	3023.140	106.178
1.1617	3023.929	107.811
1.1658	3024.548	107.693
1.1700	3023.795	107.720
1.1742	3023.765	107.105
1.1783	3023.355	106.822
1.1825	3024.549	106.277
1.1867	3025.226	105.650
1.1908	3026.732	105.276
1.1950	3024.874	105.712
1.1992	3027.866	105.525
1.2033	3025.389	105.162
1.2075	3025.660	104.956
1.2117	3025.544	104.650
1.2158	3025.892	104.426
1.2200	3026.531	104.151
1.2242	3024.534	103.890
1.2283	3025.066	103.615
1.2325	3025.537	103.493
1.2367	3025.488	103.102
1.2408	3026.308	102.850
1.2450	3025.981	102.585
1.2492	3025.807	102.578
1.2533	3026.400	102.114
1.2575	3026.094	101.867
1.2617	3025.542	101.700
1.2658	3028.294	101.440
1.2700	3026.430	101.187
1.2742	3028.150	100.922
1.2783	3028.556	100.696
1.2825	3028.904	100.483
1.2867	3027.725	100.185
1.2908	3027.367	99.996
1.2950	3027.972	99.941
1.2992	3029.438	99.524
1.3033	3029.510	99..570
1.3075	3029.722	99.386
1.3117	3030.407	98.881
1.3158	3027.983	98.609
1.3200	3027.677	98.406
1.3242	3028.238	98.230
1.3283	3028.190	98.080
1.3325	3029.915	97.797
1.3367	3030.180	97.633
1.3408	3030.952	97.616
1.3450	3031.439	97.160
1.3492	3029.839	96.921
1.3533	3029.834	96.720
1.3575	3032.410	96.490
1.3617	3030.239	96.299
1.3658	3032.472	96.084
1.3700	3034.314	95.870
1.3742	3032.960	95.671
1.3783	3031.984	95.469
1.3825	3033.338	95.335
1.3867	3034.104	94.999
1.3908	3032.794	94.889
1.3950	3033.671	94.765
1.3992	3033.674	94.320
1.4033	3033.823	94.326
1.4058	3035.134	94.186
1.4142	3033.250	93.776
1.4225	3035.015	93.296
1.4308	3034.955	93.005
1.4392	3035.091	92.594
1.4475	3037.052	92.270
1.4514	3035.447	92.118
1.4597	3037.855	91.782
1.4681	3035.232	91.517
1.4764	3035.322	91.674
1.4847	3036.387	90.845
1.4931	3038.930	90.623
1.5014	3037.500	90.405
1.5097	3037.682	90.215
1.5181	3038.093	89.995
1.5264	3038.751	89.824
1.5347	3038.824	89.686
1.5431	3036.912	89.571
1.5514	3036.623	89.490
1.5597	3037.738	89.373
1.5681	3036.297	89.286
1.5764	3037.434	89.394
1.5847	3035.125	89.082
1.5931	3035.666	89.038
1.6014	3037.004	89.003
1.6097	3035.659	88.916
1.6181	3038.110	88.829
1.6264	3039.499	88.961
1.6347	3037.330	88.752
1.6431	3037.409	88.583
1.6514	3040.908	88.510
1.6597	3038.173	88.412
1.6681	3037.366	88.284
1.6764	3038.583	88.232
1.6847	3038.404	88.090
1.6931	3039.049	87.850
1.7014	3039.678	87.796
1.7097	3039.370	87.637
1.7181	3040.737	87.512
1.7264	3039.796	87.373
1.7347	3038.973	87.184
1.7431	3040.045	87.017
1.7514	3039.806	86.903
1.7597	3039.804	86.766
1.7681	3040.195	86.673
1.7764	3039.878	86.473
1.7847	3038.912	86.356
1.7931	3038.322	86.328
1.8014	3039.569	86.241
1.8097	3038.612	86.090
1.8181	3038.244	85.907
1.8264	3038.553	85.855
1.8347	3038.958	85.721
1.8431	3039.434	85.630
1.8514	3039.398	85.526
1.8597	3040.171	85.441
1.8681	3041.009	85.359
1.8764	3041.993	85.318
1.8847	3037.846	85.175
1.8931	3036.729	85.327
1.9014	3034.890	85.085
1.9097	3035.590	84.925
1.9181	3036.662	84.873
1.9264	3036.072	84.020
1.9347	3037.825	84.785
1.9431	3038.485	84.799
1.9514	3038.499	84.684
1.9597	3038.805	84.645
1.9681	3041.017	84.591
1.9764	3039.103	84.544
1.9847	3040.425	84.522
1.9931	3042.733	84.500
2.0014	3043.406	84.407
2.0097	3040.577	84.398
2.0181	3045.565	84.913
2.0264	3042.995	84.321
2.0347	3043.057	84.723
2.0431	3044.380	84.231
2.0514	3042.977	84.102
2.0597	3045.221	84.192
2.0681	3044.350	84.168
2.0764	3045.273	84.137
2.0847	3045.161	84.099
2.0931	3041.219	84.030
2.1014	3042.338	84.113
2.1097	3042.890	84.014
2.1181	3043.374	83.994
2.1264	3042.878	83.978
2.1347	3041.991	83.975
2.1431	3039.606	83.382
2.1514	3041.945	83.582
2.1597	3043.861	83.937
2.1681	3041.760	83.981
2.1764	3043.330	83.917
2.1847	3042.952	83.956
2.1931	3043.226	83.538
2.2014	3042.726	83.909
2.2097	3043.066	83.917
2.2181	3043.071	83.162
2.2264	3043.461	83.417
2.2347	3043.209	83.699
2.2431	3043.886	83.931
2.2514	3042.495	83.926
2.2597	3044.604	83.989
2.2681	3044.086	83.950
2.2764	3043.688	83.753
2.2847	3042.371	83.989
2.2931	3043.476	83.994
2.3014	3045.483	83.948
2.3097	3045.507	84.000
2.3181	3044.056	84.005
2.3264	3045.295	84.137
2.3347	3044.419	84.033
2.3431	3045.022	84.000
2.3514	3044.383	84.258
2.3597	3043.324	84.077
2.3681	3042.898	84.077
2.3764	3041.400	84.195
2.3847	3041.271	84.397
2.3931	3042.685	84.484
2.4014	3043.691	84.191
2.4097	3043.496	84.297
2.4181	3042.208	84.228
2.4264	3041.602	84.297
2.4347	3041.343	84.310
2.4431	3041.845	84.360
2.4514	3042.751	84.228
2.4597	3041.123	84.277
2.4681	3043.033	84.255
2.4764	3042.552	84.165
2.4847	3041.961	84.449
2.4931	3043.229	84.121
2.5014	3042.517	84.066
2.5097	3042.448	84.091
2.5181	3041.935	83.992
2.5264	3042.856	83.945
2.5347	3043.422	83.901
2.5431	3041.623	83.857
2.5514	3044.156	83.761
2.5597	3044.138	83.711
2.5681	3043.213	83.667
2.5764	3043.504	83.585
2.5847	3044.707	83.576
2.5931	3044.258	83.447
2.6014	3043.549	83.464
2.6097	3044.815	83.414
2.6181	3045.537	83.312
2.6264	3046.855	83.296
2.6347	3043.623	83.221
2.6431	3043.977	83.656
2.6514	3043.534	83.133
2.6597	3042.998	83.100
2.6681	3044.393	83.056
2.6764	3043.873	83.252
2.6847	3042.308	83.252
2.6931	3043.370	83.131
2.7014	3042.106	83.147
2.7097	3042.819	82.861
2.7181	3045.122	82.852
2.7264	3043.116	82.167
2.7347	3044.347	82.862
2.7431	3044.093	82.811
2.7514	3043.776	82.657
2.7597	3043.144	82.615
2.7681	3042.837	82.778

Time	Pressure (Psia)	Temperature (°F)
2.7764	3044.088	82.728
2.7847	3043.743	82.972
2.7931	3043.438	82.000
2.8014	3041.471	82.624
2.8097	3042.180	82.739
2.8181	3043.030	82.329
2.8264	3043.897	82.025
2.8347	3043.851	82.665
2.8431	3043.827	82.646
2.8514	3043.657	82.704
2.8597	3042.292	82.759
2.8681	3043.461	82.720
2.8764	3042.224	82.772
2.8847	3044.702	82.912
2.8931	3042.674	82.748
2.9014	3042.667	82.726
2.9097	3042.508	82.753
2.9181	3043.637	82.511
2.9264	3041.833	82.753
2.9347	3042.665	82.411
2.9431	3041.757	82.814
2.9514	3042.854	82.593
2.9597	3042.363	82.717
2.9681	3044.638	82.830
2.9764	3044.493	82.087
2.9847	3043.438	82.367
2.9931	3043.282	82.872
3.0014	3041.746	82.186
3.0097	3040.899	82.833
3.0181	3041.585	82.951
3.0264	3042.053	82.954
3.0347	3040.582	82.913
3.0431	3041.713	83.034
3.0514	3041.299	83.062
3.0597	3042.729	83.064
3.0644	3042.914	83.380
3.0811	3043.342	83.180
3.0978	3042.185	83.252
3.1144	3043.144	83.610
3.1311	3044.276	83.758
3.1478	3044.367	83.788
3.1644	3045.007	83.810
3.1811	3045.209	83.214
3.1978	3046.833	83.656
3.2144	3049.644	83.964
3.2311	3046.539	84.394
3.2478	3050.614	84.244
3.2644	3049.021	84.151
3.2811	3048.756	84.574
3.2978	3047.335	84.750
3.3133	3049.331	84.997
3.3300	3048.990	84.873
3.3467	3049.280	85.038
3.3633	3047.765	84.871
3.3800	3048.272	85.008
3.3967	3049.124	85.019
3.4133	3049.177	85.038
3.4300	3049.410	85.052
3.4467	3049.138	85.052
3.4633	3049.792	85.158
3.4800	3049.545	86.048
3.4967	3049.490	85.952
3.5133	3049.762	85.723
3.5300	3049.841	85.308
3.5467	3048.697	85.074
3.5633	3049.177	85.368
3.5800	3047.381	85.378
3.5967	3049.007	85.019
3.6133	3049.731	85.180
3.6300	3049.625	85.661
3.6467	3050.298	85.159
3.6633	3049.042	85.148
3.6800	3048.232	85.139
3.6967	3049.957	85.183
3.7133	3049.163	85.268
3.7300	3052.430	85.282
3.7467	3051.838	85.257
3.7633	3051.778	85.216
3.7800	3050.998	85.282
3.7967	3050.755	85.608
3.8133	3054.032	85.397
3.8300	3053.021	85.414
3.8467	3052.927	85.739
3.8633	3053.045	85.504
3.8800	3051.540	85.564
3.8967	3054.196	85.685
3.9133	3052.310	85.723
3.9300	3053.646	85.479
3.9467	3052.703	86.174
3.9633	3051.997	86.008
3.9800	3052.528	86.454
3.9967	3053.634	86.317
4.0133	3052.678	86.224
4.0300	3051.165	86.153
4.0467	3051.147	87.085
4.0633	3050.755	87.012
4.0800	3050.658	87.173
4.0967	3051.353	87.378
4.1133	3053.614	87.392
4.1300	3055.224	87.463
4.1467	3050.471	87.386
4.1633	3052.273	87.446
4.1800	3051.510	87.304
4.1967	3050.180	87.405
4.2133	3049.304	87.045
4.2300	3051.355	86.864
4.2467	3050.774	86.673
4.2633	3050.729	86.534
4.2800	3051.275	86.348
4.2967	3052.208	86.194
4.3133	3053.225	86.049
4.3300	3054.157	85.896
4.3467	3052.284	85.729
4.3633	3051.154	85.767
4.3800	3049.935	85.611
4.3967	3049.195	85.493
4.4133	3049.593	85.430
4.4300	3051.028	85.375
4.4467	3049.987	85.403
4.4633	3049.325	85.246
4.4800	3048.921	85.183
4.4803	3050.515	85.268
4.4969	3049.733	85.252
4.5136	3048.830	85.145
4.5303	3048.368	85.175
4.5469	3049.562	85.244
4.5636	3051.426	85.194
4.5803	3050.590	85.213
4.5969	3049.895	85.271
4.6136	3053.192	85.255
4.6303	3052.078	85.312
4.6469	3052.681	85.353
4.6636	3051.436	85.463
4.6803	3048.765	85.562
4.6969	3050.467	85.564
4.7136	3050.647	85.737
4.7303	3051.339	85.838
4.7469	3051.653	86.057
4.7636	3050.594	86.181
4.7803	3051.686	86.298
4.7969	3051.355	86.440
4.8136	3050.615	86.539
4.8303	3047.648	86.605
4.8469	3047.671	86.695
4.8636	3049.646	86.709
4.8803	3050.338	86.758
4.8969	3051.481	86.752
4.9136	3051.716	86.763
4.9303	3053.402	86.791
4.9469	3051.347	86.725
4.9636	3050.159	86.700
4.9803	3046.631	86.689
4.9969	3045.079	86.670
5.0136	3045.848	86.624
5.0303	3048.133	86.646
5.0469	3048.508	86.575
5.0636	3048.016	86.564
5.0803	3049.940	86.577
5.0969	3050.082	86.605
5.1136	3050.649	86.553
5.1303	3051.024	86.512
5.1469	3049.343	86.479
5.1636	3050.472	86.523
5.1803	3049.409	86.509
5.1969	3051.556	86.539
5.2136	3049.948	86.536
5.2303	3050.280	86.575
5.2469	3049.901	86.580
5.2636	3051.438	86.640
5.2803	3053.698	86.657
5.2969	3052.255	86.719
5.3136	3052.829	86.780
5.3303	3052.729	86.867
5.3469	3052.330	86.930
5.3636	3051.326	86.985
5.3803	3049.407	87.105
5.3969	3051.986	87.247
5.4136	3053.035	87.310
5.4303	3052.592	87.531
5.4469	3055.729	87.752
5.4636	3054.580	87.313
5.4803	3055.518	88.338
5.4969	3056.766	88.281
5.5136	3058.369	88.515
5.5303	3056.976	88.624
5.5469	3054.276	88.712
5.5636	3055.348	88.657
5.5803	3057.091	88.600
5.5969	3057.154	88.420
5.6136	3057.515	88.235
5.6303	3056.112	88.066
5.6469	3056.574	87.823
5.6636	3057.765	87.615
5.6803	3056.989	87.463
5.6969	3059.323	87.250
5.7136	3052.330	87.080
5.7303	3055.072	86.930
5.7469	3054.807	86.799
5.7636	3056.186	86.621
5.7803	3056.285	86.525
5.7969	3059.622	86.312
5.8136	3059.826	86.457
5.8303	3059.311	86.233
5.8389	3058.792	86.167
5.8556	3057.597	86.142
5.8722	3056.813	86.098
5.8889	3059.578	86.044
5.9056	3057.426	85.970
5.9222	3058.054	85.923
5.9389	3056.522	85.940
5.9556	3057.658	85.923
5.9722	3056.761	85.882
5.9889	3055.153	85.920
6.0056	3055.280	85.940
6.0222	3057.643	85.923
6.0389	3060.250	85.978
6.0556	3054.375	86.033
6.0722	3055.430	86.098
6.0889	3055.999	86.208
6.1056	3057.295	86.276
6.1222	3059.083	86.438
6.1389	3057.820	86.558
6.1556	3057.509	86.763
6.1722	3057.783	86.933
6.1889	3058.601	87.151

Time	Pressure (Psia)	Temperature (°F)
6.2056	3058.084	87.394
6.2222	3058.719	87.637
6.2389	3057.404	87.894
6.2556	3058.265	88.197
6.2722	3057.987	88.398
6.2889	3058.386	88.551
6.3056	3057.976	88.703
6.3222	3060.124	88.684
6.3389	3060.048	88.793
6.3556	3060.656	88.758
6.3722	3060.785	88.638
6.3889	3058.583	88.592
6.4056	3056.252	88.475
6.4222	3060.231	88.379
6.4389	3058.454	88.267
6.4556	3058.410	88.180
6.4722	3057.377	88.047
6.4889	3057.845	87.992
6.5056	3059.517	87.899
6.5222	3061.076	87.831
6.5389	3059.939	87.738
6.5556	3059.673	87.651
6.5722	3061.874	87.667
6.5889	3060.659	87.561
6.6056	3060.060	87.525
6.6222	3057.875	87.457
6.6389	3059.385	87.435
6.6556	3060.672	87.424
6.6722	3059.781	87.337
6.6889	3061.686	87.345
6.7056	3061.056	87.433
6.7222	3060.234	87.400
6.7389	3062.373	87.482
6.7556	3061.115	87.452
6.7722	3060.753	87.515
6.7889	3059.322	87.539
6.8056	3059.726	87.599
6.8222	3061.977	87.678
6.8389	3060.193	87.763
6.8556	3060.230	87.842
6.8722	3059.938	87.976
6.8889	3057.843	88.142
6.9056	3060.619	88.284
6.9222	3062.188	88.436
6.9389	3059.951	88.660
6.9556	3057.811	88.842
6.9722	3058.086	88.973
6.9889	3060.646	89.125
7.0056	3055.850	89.229
7.0222	3056.868	89.272
7.0389	3057.698	89.332
7.0556	3059.821	89.376
7.0722	3061.181	89.406
7.0889	3059.448	89.362
7.1056	3060.363	89.435
7.1075	3058.949	89.446
7.1242	3059.304	89.425
7.1408	3060.328	89.433
7.1575	3061.714	89.571
7.1742	3062.085	89.493
7.1908	3061.729	89.529
7.2075	3061.807	89.877
7.2242	3062.704	89.520
7.2408	3061.664	89.230
7.2575	3061.543	89.152
7.2742	3061.263	89.040
7.2908	3063.188	89.672
7.3075	3061.533	89.691
7.3242	3062.009	89.740
7.3408	3062.764	89.735
7.3575	3065.635	89.941
7.3742	3063.368	89.941
7.3908	3060.067	90.012
7.4075	3060.302	90.115
7.4242	3060.878	90.215
7.4408	3060.812	90.308
7.4575	3060.811	90.615
7.4742	3060.176	90.617
7.4908	3059.929	90.631
7.5075	3057.564	90.861
7.5242	3061.129	91.062
7.5408	3061.180	91.208
7.5575	3060.650	91.909
7.5742	3060.746	91.975
7.5908	3060.177	91.590
7.6075	3060.307	91.674
7.6242	3062.727	91.723
7.6408	3059.009	91.739
7.6575	3058.792	91.726
7.6742	3058.808	91.769
7.6908	3060.375	91.780
7.7075	3056.728	91.799
7.7242	3059.133	91.777
7.7408	3056.258	91.834
7.7575	3058.459	91.799
7.7742	3056.764	91.476
7.7908	3056.631	91.077
7.8075	3058.991	91.842
7.8242	3059.292	91.869
7.8408	3058.386	91.985
7.8575	3058.021	91.991
7.8742	3058.444	91.512
7.8908	3058.608	92.021
7.9075	3058.002	92.067
7.9242	3057.604	92.280
7.9408	3057.931	92.215
7.9575	3057.931	92.251
7.9742	3060.932	92.318
7.9908	3058.629	92.903
8.0075	3057.258	92.475
8.0242	3060.492	92.440
8.0408	3060.750	92.616
8.0575	3059.308	92.718
8.0742	3059.817	92.824
8.0908	3057.458	92.894
8.1075	3057.320	92.219
8.1242	3057.928	92.345
8.1408	3058.671	92.994
8.1575	3058.861	93.283
8.1742	3058.028	93.648
8.1908	3058.168	93.585
8.2075	3058.067	93.771
8.2242	3059.409	93.916
8.2408	3059.373	94.035
8.2575	3063.637	94.226
8.2742	3063.749	94.927
8.2908	3064.091	94.898
8.3075	3063.377	95.155
8.3242	3063.190	95.155
8.3408	3062.925	95.381
8.3575	3063.098	95.970
8.3742	3062.569	95.714
8.3908	3059.613	95.348
8.4075	3060.685	95.940
8.4242	3061.353	95.756
8.4408	3061.834	95.534
8.4575	3062.265	95.347
8.4742	3061.771	94.751
8.4908	3062.548	94.690
8.5075	3062.693	94.443
8.5242	3062.338	93.930
8.5408	3063.956	93.556
8.5575	3063.528	93.194
8.5742	3063.386	92.725
8.5908	3062.462	92.656
8.6075	3065.505	92.418
8.6242	3063.634	92.686
8.6408	3061.454	92.053
8.6575	3059.610	91.977
8.6742	3055.146	91.574
8.6908	3057.271	91.495
8.7075	3055.253	91.352
8.7242	3057.361	91.295
8.7408	3057.642	91.195
8.7575	3058.939	91.075
8.7742	3061.209	91.000
8.7908	3059.166	91.013
8.8075	3058.057	90.964
8.8242	3058.193	90.812
8.8408	3056.277	90.823
8.8575	3056.803	90.900
8.8742	3058.675	90.062
8.8908	3060.719	90.766
8.9075	3061.221	90.810
8.9242	3061.086	90.850
8.9408	3060.782	90.403
8.9575	3061.430	90.703
8.9742	3059.534	91.021
8.9908	3062.381	91.162
9.0075	3061.406	91.238
9.0242	3060.401	91.387
9.0408	3061.894	91.571
9.0575	3062.645	91.815
9.0742	3063.075	92.026
9.0908	3063.479	92.286
9.1075	3065.755	92.613
9.1242	3066.590	92.918
9.1408	3063.935	93.261
9.1575	3065.623	93.650
9.1742	3067.499	93.946
9.1908	3068.557	94.216
9.2075	3068.100	94.436
9.2242	3067.748	94.485
9.2408	3067.413	94.480
9.2575	3065.157	94.412
9.2742	3066.536	94.318
9.2908	3067.631	94.170
9.3075	3065.674	93.968
9.3242	3069.410	93.747
9.3408	3067.098	93.528
9.3575	3066.980	93.364
9.3742	3068.198	93.126
9.3908	3066.476	92.940
9.4075	3068.926	92.778
9.4242	3067.596	92.553
9.4408	3065.438	92.410
9.4575	3066.773	92.213
9.4742	3066.150	92.156
9.4908	3062.874	92.091
9.5075	3066.233	91.939
9.5242	3065.744	91.969
9.5408	3066.357	91.904
9.5575	3065.514	91.845
9.5742	3066.710	91.788
9.5908	3068.191	91.761
9.6075	3066.280	91.728
9.6242	3066.925	91.777
9.6408	3068.180	91.755
9.6575	3067.760	91.774
9.6742	3068.075	91.758
9.6908	3067.114	91.717
9.7075	3066.758	91.810
9.7242	3068.269	91.926
9.7408	3067.216	91.926
9.7575	3068.622	91.945
9.7742	3068.853	92.013
9.7908	3064.671	91.967
9.8075	3064.622	92.159
9.8242	3066.186	92.459
9.8408	3066.512	92.261
9.8575	3065.120	92.386
9.8742	3066.778	92.562
9.8908	3067.148	92.586
9.9075	3066.679	92.645
9.9242	3067.773	92.834

Time	Pressure (Psia)	Temperature (°F)
9.9408	3067.109	92.897
9.9575	3067.073	93.202
9.9742	3066.307	93.315
9.9908	3066.481	93.404
10.0075	3068.025	93.590
10.0242	3068.577	94.022
10.0408	3066.137	93.935
10.0575	3066.909	94.178
10.0742	3065.875	94.315
10.0908	3068.625	94.375
10.1075	3068.123	94.528
10.1242	3067.381	94.407
10.1408	3067.812	94.275
10.1575	3068.601	94.224
10.1742	3066.908	94.059
10.1908	3067.231	93.854
10.2075	3067.318	93.650
10.2242	3064.288	93.539
10.2408	3064.215	93.339
10.2575	3063.793	93.194
10.2742	3064.216	93.372
10.2908	3065.438	92.807
10.3075	3069.127	92.713
10.3242	3067.208	92.345
10.3408	3070.536	92.383
10.3575	3067.712	92.253
10.3742	3068.163	92.029
10.3908	3067.055	92.004
10.4075	3069.578	92.099
10.4242	3068.679	91.785
10.4408	3071.913	91.820
10.4575	3073.201	91.677
10.4742	3072.445	91.647
10.4908	3072.565	91.878
10.5075	3073.824	91.711
10.5242	3074.177	91.590
10.5408	3071.608	91.471
10.5575	3070.959	91.509
10.5742	3070.764	91.531
10.5908	3073.096	91.506
10.6075	3071.159	91.653
10.6242	3072.777	91.682
10.6408	3071.086	91.746
10.6575	3070.939	91.948
10.6742	3070.328	92.056
10.6908	3071.822	92.307
10.7075	3072.232	92.656
10.7242	3069.797	92.678
10.7408	3071.714	93.072
10.7575	3071.573	93.196
10.7742	3068.343	93.391
10.7908	3069.877	93.493
10.8075	3067.356	93.520
10.8242	3068.069	93.582
10.8408	3069.349	93.428
10.8575	3067.341	93.516
10.8742	3065.518	93.053
10.8908	3066.575	92.848
10.9075	3065.131	92.540
10.9242	3065.492	92.310
10.9408	3066.298	91.905
10.9575	3068.507	91.923
10.9742	3067.556	91.617
10.9908	3066.910	91.425
11.0075	3070.101	91.214
11.0242	3072.009	90.964
11.0408	3071.600	90.897
11.0575	3068.523	90.739
11.0742	3068.605	90.571
11.0908	3068.361	90.452
11.1075	3069.621	90.376
11.1242	3068.267	90.245
11.1408	3070.100	90.142
11.1575	3068.823	90.090
11.1742	3067.900	90.001
11.1908	3068.090	89.974
11.2075	3069.125	89.968
11.2242	3068.899	89.947
11.2408	3068.394	89.933
11.2575	3066.408	89.903
11.2742	3068.777	89.952
11.2908	3069.252	89.985
11.3075	3067.561	90.020
11.3242	3066.398	90.066
11.3408	3067.536	90.126
11.3575	3066.323	90.237
11.3742	3067.538	90.226
11.3908	3065.623	90.367
11.4075	3069.189	90.419
11.4242	3067.737	90.571
11.4408	3069.502	90.758
11.4575	3068.592	90.910
11.4742	3068.419	91.162
11.4908	3067.618	91.206
11.5075	3068.415	91.422
11.5242	3069.106	91.615
11.5408	3069.803	92.031
11.5575	3070.423	92.315
11.5742	3072.575	92.456
11.5908	3070.472	92.664
11.6075	3069.708	92.156
11.6242	3070.427	92.691
11.6408	3071.865	92.575
11.6575	3071.152	92.191
11.6742	3067.785	91.985
11.6908	3069.490	91.685
11.7075	3070.776	91.390
11.7242	3070.897	91.272
11.7408	3071.436	90.538
11.7575	3072.568	90.139
11.7742	3072.516	89.773
11.7908	3068.239	89.318
11.8075	3068.467	89.226
11.8242	3068.557	88.613
11.8408	3068.895	88.352
11.8575	3068.670	88.082
11.8742	3069.740	87.831
11.8908	3069.286	87.689
11.9075	3070.070	87.444
11.9242	3070.297	87.244
11.9408	3070.239	87.072
11.9575	3070.832	86.884
11.9742	3070.095	86.025
11.9908	3070.566	86.692
12.0075	3070.772	86.446
12.0242	3069.519	86.389
12.0408	3070.886	86.265
12.0575	3071.867	86.230
12.0742	3073.390	86.186
12.0908	3073.844	86.096
12.1075	3072.016	86.030
12.1242	3073.813	86.014
12.1408	3073.938	85.953
12.1575	3073.434	85.948
12.1742	3072.785	85.899
12.1908	3074.881	85.929
12.2075	3075.575	85.893
12.2242	3074.177	85.948
12.2408	3074.501	85.915
12.2575	3072.843	85.983
12.2742	3074.960	86.087
12.2908	3074.526	86.559
12.3075	3074.018	86.202
12.3242	3074.554	86.265
12.3408	3073.849	86.337
12.3575	3074.641	86.391
12.3742	3074.731	86.482
12.3908	3075.619	86.575
12.4075	3073.700	86.462
12.4242	3074.443	86.781
12.4408	3075.559	86.577
12.4575	3074.530	86.618
12.4742	3074.979	86.607
12.4908	3074.833	86.575
12.5075	3076.600	86.643
12.5242	3075.087	86.498
12.5408	3075.438	86.064
12.5575	3075.022	86.465
12.5742	3075.219	86.446
12.5908	3075.122	86.367
12.6075	3074.793	86.353
12.6242	3046.591	86.339
12.6408	3011.372	86.287
12.6433	3015.056	86.427
12.6436	3015.329	86.175
12.6439	3016.249	86.435
12.6442	3017.002	86.369
12.6444	3017.489	86.167
12.6447	3017.918	86.735
12.6450	3019.651	86.525
12.6453	3020.694	86.317
12.6456	3021.832	86.484
12.6458	3022.917	86.424
12.6461	3023.740	86.304
12.6464	3024.128	86.296
12.6467	3025.468	86.375
12.6469	3026.277	86.263
12.6472	3026.679	86.337
12.6475	3027.435	86.317
12.6478	3028.048	86.334
12.6481	3028.619	86.328
12.6483	3029.769	86.274
12.6486	3030.742	86.399
12.6489	3030.997	86.293
12.6492	3032.000	86.298
12.6494	3032.051	86.298
12.6497	3032.223	86.326
12.6500	3034.044	86.378
12.6503	3034.468	86.320
12.6506	3035.256	86.309
12.6508	3035.795	86.306
12.6511	3035.959	86.383
12.6514	3035.105	86.304
12.6517	3035.654	86.287
12.6519	3036.930	86.353
12.6522	3037.325	86.304
12.6525	3038.330	86.246
12.6528	3037.590	86.405
12.6531	3037.941	86.326
12.6533	3038.054	86.334
12.6536	3037.840	86.334
12.6539	3040.107	86.290
12.6542	3040.824	86.555
12.6544	3041.117	86.408
12.6547	3041.216	86.290
12.6550	3039.648	86.315
12.6553	3039.240	86.279
12.6556	3041.112	86.304
12.6558	3041.673	86.380
12.6561	3042.608	86.298
12.6564	3042.223	86.331
12.6567	3040.360	86.153
12.6569	3041.516	86.383
12.6572	3044.474	86.410
12.6575	3044.411	86.356
12.6578	3043.845	86.304
12.6581	3043.241	86.317
12.6583	3043.338	86.315
12.6586	3043.965	86.372
12.6589	3044.060	86.282
12.6592	3045.908	86.339
12.6594	3046.452	86.268
12.6597	3045.627	86.421
12.6600	3043.927	86.233
12.6603	3044.240	86.430

Time	Pressure (Psia)	Temperature (°F)
12.6606	3045.188	86.246
12.6608	3047.291	86.276
12.6611	3045.929	86.350
12.6614	3044.858	86.378
12.6617	3046.621	86.328
12.6619	3047.507	86.263
12.6622	3048.854	86.402
12.6625	3047.634	86.290
12.6628	3046.591	86.309
12.6631	3047.244	86.331
12.6633	3049.520	86.213
12.6636	3050.042	86.416
12.6639	3048.207	86.372
12.6642	3046.919	86.323
12.6644	3047.677	86.241
12.6647	3048.662	86.342
12.6650	3049.281	86.380
12.6653	3048.211	86.265
12.6656	3048.174	86.337
12.6658	3049.965	86.309
12.6661	3050.420	86.361
12.6664	3049.830	86.323
12.6667	3049.143	86.317
12.6669	3049.823	86.293
12.6672	3051.353	86.271
12.6675	3051.499	86.424
12.6678	3051.413	86.339
12.6681	3051.346	86.290
12.6683	3049.452	86.265
12.6686	3050.276	86.378
12.6689	3051.744	86.391
12.6692	3050.750	86.260
12.6694	3050.261	86.326
12.6697	3051.317	86.361
12.6700	3051.896	86.312
12.6703	3051.111	86.331
12.6706	3050.756	86.293
12.6708	3052.371	86.378
12.6711	3052.109	86.282
12.6714	3053.111	86.279
12.6717	3053.347	86.369
12.6719	3053.159	86.345
12.6722	3053.638	86.394
12.6725	3053.599	86.224
12.6728	3053.090	86.298
12.6731	3052.095	86.372
12.6733	3052.649	86.358
12.6736	3052.337	86.282
12.6739	3051.995	86.317
12.6742	3052.445	86.408
12.6744	3052.358	86.375
12.6747	3052.650	86.265
12.6750	3053.396	86.342
12.6753	3054.092	86.285
12.6756	3053.952	86.254
12.6758	3055.238	86.367
12.6761	3055.096	86.369
12.6764	3054.914	86.378
12.6819	3057.137	86.364
12.6875	3058.577	86.345
12.6931	3062.026	86.342
12.6986	3064.924	86.287
12.7042	3063.784	86.361
12.7097	3065.968	86.369
12.7153	3068.587	86.315
12.7208	3069.581	86.293
12.7264	3070.134	86.413
12.7319	3068.316	86.345
12.7375	3069.079	86.389
12.7431	3069.067	86.405
12.7486	3068.654	86.304
12.7539	3069.175	86.181
12.7706	3070.451	86.391
12.7872	3072.322	86.479
12.8039	3073.071	86.740
12.8206	3074.289	86.451
12.8372	3072.556	86.479
12.8539	3072.593	86.050
12.8706	3072.926	86.183
12.8872	3073.772	86.629
12.9039	3073.265	86.304
12.9206	3072.788	86.047
12.9372	3072.335	86.156
12.9539	3072.764	86.065
12.9706	3073.509	86.843
12.9872	3073.217	87.037
13.0039	3073.426	87.863
13.0206	3074.675	87.411
13.0372	3074.774	87.626
13.0539	3073.653	87.801
13.0706	3072.921	88.210
13.0872	3072.715	88.682
13.1039	3072.923	88.464
13.1206	3072.149	88.611
13.1372	3071.611	88.580
13.1539	3070.229	89.085
13.1706	3070.311	89.748
13.1872	3070.243	89.762
13.2039	3072.074	89.868
13.2206	3071.697	90.058
13.2372	3072.195	90.240
13.2539	3071.670	90.270
13.2706	3070.499	90.384
13.2808	3070.002	90.443
13.2811	3069.367	90.538
13.2814	3070.407	90.706
13.2817	3070.317	90.639
13.2819	3069.654	90.492
13.2822	3069.954	90.495
13.2825	3069.402	90.457
13.2828	3070.206	90.465
13.2831	3071.059	90.503
13.2833	3071.066	90.121
13.2836	3070.441	90.075
13.2839	3070.478	90.484
13.2842	3069.869	90.378
13.2844	3069.871	90.563
13.2847	3070.993	90.484
13.2850	3070.322	90.541
13.2853	3068.969	90.400
13.2856	3069.504	90.560
13.2858	3069.268	90.441
13.2861	3070.569	90.509
13.2864	3069.676	90.427
13.2867	3069.070	90.606
13.2869	3069.522	90.473
13.2872	3069.510	90.479
13.2875	3068.922	90.479
13.2878	3069.363	90.525
13.2881	3068.579	90.557
13.2883	3067.832	90.433
13.2886	3067.821	90.492
13.2889	3068.227	90.776
13.2892	3068.537	90.536
13.2894	3068.986	90.435
13.2897	3069.264	90.557
13.2900	3068.574	90.471
13.2903	3068.401	90.522
13.2906	3068.964	90.509
13.2908	3069.057	90.503
13.2911	3068.759	90.544
13.2914	3069.484	90.400
13.2917	3069.204	90.595
13.2919	3068.122	90.465
13.2922	3069.531	90.620
13.2925	3069.530	90.500
13.2928	3069.532	90.498
13.2931	3069.757	90.538
13.2933	3068.249	90.593
13.2936	3069.409	90.457
13.2939	3069.575	90.528
13.2942	3069.670	90.519
13.2944	3069.802	94.049
13.2947	3069.184	90.259
13.2950	3070.109	90.587
13.2953	3069.957	90.454
13.2956	3069.531	90.536
13.2958	3069.372	90.598
13.2961	3068.524	90.525
13.2964	3068.657	90.487
13.2967	3069.673	90.598
13.2969	3069.434	90.741
13.2972	3069.800	90.568
13.2975	3069.961	90.449
13.2978	3069.702	90.682
13.2981	3070.522	90.465
13.2983	3069.889	90.576
13.2986	3070.079	90.522
13.2989	3070.661	90.568
13.2992	3069.390	90.566
13.2994	3069.108	90.568
13.2997	3070.416	90.460
13.3000	3070.476	90.617
13.3003	3069.779	90.473
13.3006	3069.455	90.650
13.3008	3070.208	90.574
13.3011	3070.461	90.506
13.3014	3070.071	90.736
13.3017	3070.646	90.430
13.3019	3070.682	90.571
13.3022	3070.068	90.528
13.3025	3070.764	90.541
13.3028	3070.467	90.655
13.3031	3070.667	90.533
13.3033	3070.667	90.625
13.3036	3069.729	90.509
13.3039	3070.599	90.536
13.3042	3070.308	90.642
13.3044	3070.141	90.528
13.3047	3069.710	90.579
13.3050	3069.780	90.547
13.3053	3068.718	90.568
13.3056	3068.103	90.666
13.3058	3068.517	90.506
13.3061	3068.611	90.582
13.3064	3068.005	90.604
13.3067	3069.465	90.536
13.3069	3069.089	90.666
13.3072	3068.582	90.471
13.3075	3068.493	90.008
13.3078	3069.941	90.511
13.3081	3070.290	90.609
13.3083	3071.036	90.495
13.3086	3069.990	90.560
13.3089	3070.781	90.650
13.3092	3071.708	90.623
13.3094	3070.735	90.595
13.3097	3071.178	90.492
13.3100	3071.630	90.701
13.3103	3070.523	90.650
13.3106	3070.687	90.555
13.3108	3071.382	90.606
13.3111	3071.364	90.593
13.3114	3071.017	90.639
13.3117	3071.611	90.549
13.3119	3071.335	90.582
13.3122	3070.794	90.633
13.3125	3071.451	90.585
13.3128	3072.054	90.669
13.3131	3071.106	90.547
13.3133	3071.513	90.663
13.3136	3071.556	90.647
13.3139	3071.853	90.579
13.3142	3072.236	90.606
13.3144	3071.521	90.552

Time	Pressure (Psia)	Temperature (°F)
13.3147	3071.910	90.655
13.3150	3071.950	90.614
13.3153	3071.626	90.614
13.3156	3071.582	90.642
13.3158	3071.233	90.617
13.3161	3071.527	90.628
13.3164	3072.310	90.633
13.3167	3072.359	90.806
13.3169	3072.615	90.666
13.3172	3073.032	90.726
13.3175	3072.551	90.525
13.3178	3071.914	90.623
13.3181	3071.242	90.865
13.3183	3071.472	90.669
13.3186	3070.440	90.587
13.3189	3071.830	90.644
13.3192	3070.719	90.606
13.3194	3072.298	90.723
13.3197	3071.280	90.614
13.3200	3070.990	90.571
13.3203	3071.301	90.717
13.3206	3072.342	90.492
13.3208	3072.041	90.723
13.3211	3072.632	90.701
13.3214	3072.503	90.623
13.3217	3072.404	90.617
13.3219	3072.592	90.623
13.3222	3071.956	90.652
13.3225	3072.437	90.631
13.3228	3072.603	90.914
13.3231	3072.569	90.828
13.3233	3072.177	90.755
13.3236	3070.609	90.652
13.3239	3071.866	90.590
13.3242	3070.756	90.717
13.3244	3070.059	90.631
13.3247	3071.240	90.582
13.3250	3070.960	90.720
13.3253	3072.051	90.644
13.3256	3072.136	90.696
13.3258	3071.254	90.536
13.3261	3072.923	90.761
13.3264	3071.907	90.631
13.3267	3071.183	90.644
13.3269	3072.694	90.623
13.3272	3073.576	90.764
13.3275	3071.804	90.669
13.3278	3072.288	90.541
13.3281	3072.269	90.731
13.3283	3072.280	90.717
13.3286	3072.791	90.658
13.3289	3073.411	90.647
13.3292	3072.596	90.671
13.3294	3072.946	90.704
13.3297	3072.418	90.563
13.3300	3073.240	90.723
13.3303	3073.102	90.647
13.3306	3072.812	90.780
13.3308	3072.222	90.487
13.3311	3072.007	90.254
13.3314	3072.266	90.745
13.3317	3071.675	90.701
13.3319	3071.292	90.636
13.3322	3071.146	90.957
13.3325	3071.188	90.628
13.3328	3071.021	90.617
13.3331	3070.834	90.739
13.3333	3071.907	90.677
13.3336	3071.655	90.680
13.3339	3072.379	90.992
13.3342	3072.880	90.612
13.3344	3072.479	90.791
13.3347	3072.470	90.506
13.3350	3073.574	90.812
13.3353	3072.510	90.642
13.3356	3073.063	90.723
13.3358	3072.561	90.726
13.3361	3072.314	90.685
13.3364	3072.953	90.704
13.3367	3073.070	90.696
13.3369	3072.678	90.652
13.3372	3073.070	90.742
13.3375	3073.074	90.709
13.3378	3072.919	90.682
13.3381	3073.368	90.655
13.3383	3072.508	90.736
13.3386	3072.826	90.745
13.3389	3071.836	90.938
13.3392	3071.487	90.734
13.3394	3071.719	90.636
13.3397	3071.895	90.693
13.3400	3070.984	90.717
13.3403	3072.567	90.717
13.3406	3072.669	90.709
13.3408	3071.512	90.693
13.3411	3072.524	90.680
13.3414	3073.234	90.758
13.3417	3072.316	90.709
13.3419	3073.399	90.717
13.3422	3072.999	90.693
13.3425	3072.632	90.793
13.3428	3072.188	90.685
13.3431	3072.635	90.734
13.3433	3072.490	90.685
13.3436	3073.628	90.745
13.3439	3072.609	90.693
13.3442	3072.521	90.987
13.3444	3073.098	90.699
13.3447	3072.117	90.952
13.3450	3072.268	90.769
13.3453	3072.299	90.666
13.3456	3072.048	90.777
13.3458	3071.503	90.685
13.3461	3073.305	90.753
13.3464	3072.059	90.690
13.3467	3072.586	90.731
13.3469	3071.616	90.051
13.3472	3071.948	90.663
13.3475	3072.968	90.769
13.3478	3073.152	90.769
13.3481	3072.666	90.650
13.3483	3072.729	90.005
13.3486	3072.888	90.712
13.3489	3071.948	90.821
13.3492	3072.975	90.761
13.3494	3071.426	90.579
13.3497	3072.203	90.804
13.3500	3072.961	90.981
13.3503	3072.862	90.829
13.3506	3072.838	90.701
13.3508	3072.983	90.685
13.3511	3073.257	90.804
13.3514	3072.966	90.726
13.3517	3073.173	90.761
13.3519	3072.042	90.720
13.3522	3074.347	90.766
13.3525	3073.709	90.726
13.3528	3072.673	90.742
13.3531	3073.166	90.761
13.3533	3073.366	90.769
13.3536	3073.170	90.682
13.3539	3073.973	90.875
13.3542	3073.092	90.576
13.3544	3073.581	90.878
13.3547	3073.711	90.807
13.3550	3072.915	90.707
13.3553	3073.027	90.769
13.3556	3073.229	90.747
13.3558	3073.411	90.758
13.3561	3072.304	90.761
13.3564	3072.208	90.734
13.3567	3072.393	90.807
13.3569	3071.941	90.736
13.3572	3072.363	90.807
13.3575	3072.122	90.712
13.3578	3071.525	90.723
13.3581	3071.989	90.769
13.3583	3071.733	90.859
13.3586	3072.027	90.766
13.3589	3073.179	90.726
13.3592	3071.512	90.785
13.3594	3073.951	90.755
13.3597	3071.780	90.717
13.3600	3071.980	90.826
13.3603	3073.267	90.745
13.3606	3073.303	90.810
13.3608	3073.177	90.747
13.3611	3073.146	90.804
13.3614	3072.789	90.799
13.3617	3072.714	90.783
13.3619	3071.960	90.750
13.3622	3071.389	90.764
13.3625	3071.282	90.769
13.3628	3071.109	90.902
13.3631	3070.774	90.696
13.3633	3070.261	90.774
13.3636	3070.659	90.728
13.3639	3071.628	90.861
13.3642	3071.328	90.766
13.3644	3071.444	90.769
13.3647	3070.918	90.736
13.3650	3071.435	90.945
13.3653	3072.828	90.704
13.3656	3072.598	90.845
13.3658	3071.085	90.701
13.3661	3072.975	90.880
13.3664	3071.448	90.717
13.3667	3070.678	90.769
13.3669	3072.225	90.842
13.3672	3071.919	90.810
13.3675	3070.810	90.761
13.3678	3071.555	90.804
13.3681	3071.622	90.785
13.3683	3071.564	90.812
13.3686	3071.424	90.008
13.3689	3071.700	90.826
13.3692	3071.726	90.831
13.3694	3070.622	90.747
13.3697	3071.402	90.766
13.3700	3070.584	90.878
13.3703	3070.550	90.745
13.3706	3071.424	90.793
13.3708	3070.618	90.853
13.3711	3070.915	90.796
13.3714	3071.677	90.864
13.3717	3070.410	90.745
13.3719	3071.514	90.736
13.3722	3071.595	90.929
13.3725	3070.450	90.796
13.3728	3070.915	90.804
13.3731	3070.496	90.878
13.3733	3070.295	90.723
13.3736	3070.061	90.850
13.3739	3069.498	90.818
13.3742	3069.464	90.823
13.3744	3068.753	90.856
13.3747	3068.567	90.766
13.3750	3069.693	90.878
13.3753	3069.207	90.777
13.3756	3070.271	90.818
13.3758	3070.700	90.861
13.3761	3070.093	90.755
13.3764	3070.892	90.861
13.3767	3070.747	90.793
13.3769	3069.943	90.869

Time	Pressure (Psia)	Temperature (°F)
13.3772	3070.879	90.747
13.3775	3071.741	90.840
13.3778	3070.426	90.772
13.3781	3070.447	90.727
13.3783	3070.613	90.490
13.3786	3071.313	90.812
13.3789	3070.718	90.821
13.3792	3070.975	90.859
13.3794	3071.262	90.840
13.3797	3070.486	90.834
13.3800	3071.297	90.796
13.3803	3071.384	90.826
13.3806	3070.873	90.848
13.3808	3070.546	90.842
13.3811	3071.594	90.840
13.3814	3070.604	90.780
13.3817	3071.435	90.918
13.3819	3071.062	90.823
13.3822	3071.571	90.859
13.3825	3071.262	90.812
13.3828	3070.750	90.707
13.3831	3070.846	90.964
13.3833	3071.309	90.864
13.3836	3070.924	90.886
13.3839	3071.764	90.783
13.3842	3071.922	90.861
13.3844	3071.323	90.883
13.3847	3071.607	90.804
13.3850	3070.648	90.880
13.3853	3070.995	90.823
13.3856	3070.919	90.845
13.3858	3069.965	90.878
13.3861	3070.609	90.902
13.3864	3071.626	90.826
13.3867	3071.226	90.867
13.3869	3070.879	90.812
13.3872	3071.850	90.869
13.3875	3071.864	90.842
13.3878	3071.812	90.880
13.3881	3071.630	90.812
13.3883	3071.161	90.883
13.3886	3071.898	90.856
13.3889	3071.538	90.872
13.3892	3071.067	90.872
13.3894	3071.090	90.853
13.3897	3070.029	90.872
13.3900	3068.561	90.848
13.3903	3068.290	90.883
13.3906	3066.185	90.845
13.3908	3065.160	90.875
13.3911	3063.679	90.867
13.3914	3062.587	90.869
13.3917	3061.271	90.867
13.3919	3059.736	90.872
13.3922	3058.903	90.872
13.3925	3057.352	90.869
13.3928	3055.996	90.880
13.3931	3055.061	90.861
13.3933	3053.468	90.875
13.3936	3052.206	90.878
13.3939	3051.227	90.878
13.3942	3049.744	90.872
13.3944	3048.665	90.886
13.3947	3047.397	90.869
13.3950	3046.087	90.878
13.3953	3044.987	90.872
13.3956	3043.783	90.886
13.3958	3042.563	90.875
13.3961	3041.499	90.888
13.3964	3040.290	90.880
13.3967	3039.149	90.880
13.3969	3038.077	90.886
13.3972	3036.920	90.886
13.3975	3035.850	90.880
13.3978	3034.775	90.888
13.3981	3033.661	90.883
13.3983	3032.650	90.886
13.3986	3031.605	90.894
13.3989	3030.531	90.883
13.3992	3029.541	90.897
13.3994	3028.481	90.878
13.3997	3027.510	90.894
13.4000	3026.536	90.897
13.4003	3025.527	90.897
13.4006	3024.527	90.878
13.4008	3023.626	90.907
13.4011	3022.622	90.883
13.4014	3021.716	90.902
13.4017	3020.773	90.894
13.4019	3019.857	90.905
13.4022	3018.929	90.897
13.4025	3018.019	90.894
13.4028	3017.140	90.897
13.4031	3016.289	90.910
13.4033	3015.372	90.888
13.4036	3014.528	90.902
13.4039	3013.694	90.905
13.4042	3012.827	90.902
13.4044	3012.013	90.907
13.4047	3011.157	90.891
13.4050	3010.393	90.915
13.4053	3009.568	90.907
13.4056	3008.742	90.899
13.4058	3007.959	90.902
13.4061	3007.222	90.921
13.4064	3006.424	90.915
13.4067	3005.640	90.902
13.4069	3004.879	90.905
13.4072	3004.163	90.915
13.4075	3003.410	90.918
13.4078	3002.660	90.907
13.4081	3001.946	90.915
13.4083	3001.205	90.913
13.4086	3000.505	90.921
13.4089	2999.763	90.902
13.4092	2999.085	90.921
13.4094	2998.377	90.921
13.4097	2997.673	90.918
13.4100	2996.990	90.915
13.4103	2996.326	90.926
13.4106	2995.643	90.924
13.4108	2994.960	90.913
13.4111	2994.327	90.929
13.4114	2993.680	90.929
13.4117	2992.993	90.913
13.4119	2992.371	90.926
13.4122	2991.738	90.926
13.4125	2991.114	90.932
13.4128	2990.475	90.921
13.4131	2989.851	90.918
13.4133	2989.271	90.934
13.4136	2988.654	90.924
13.4139	2988.091	90.945
13.4142	2987.448	90.913
13.4144	2986.904	90.937
13.4147	2986.342	90.940
13.4150	2985.760	90.940
13.4153	2985.143	90.913
13.4156	2984.662	90.951
13.4158	2984.069	90.937
13.4161	2983.524	90.937
13.4164	2982.951	90.918
13.4167	2982.467	90.951
13.4169	2981.926	90.945
13.4172	2981.393	90.940
13.4175	2980.867	90.934
13.4178	2980.367	90.943
13.4181	2979.861	90.948
13.4183	2979.341	90.937
13.4186	2978.853	90.948
13.4189	2978.349	90.943
13.4192	2977.880	90.948
13.4194	2977.377	90.943
13.4197	2976.900	90.940
13.4200	2976.460	90.964
13.4203	2975.983	90.953
13.4206	2975.476	90.934
13.4208	2975.065	90.959
13.4211	2974.611	90.956
13.4214	2974.144	90.951
13.4217	2973.687	90.943
13.4219	2973.285	90.956
13.4222	2972.864	90.967
13.4225	2972.401	90.948
13.4228	2972.004	90.964
13.4231	2971.576	90.956
13.4233	2971.155	90.959
13.4236	2970.767	90.964
13.4239	2970.341	90.953
13.4242	2969.931	90.951
13.4244	2969.589	90.981
13.4247	2969.171	90.962
13.4250	2968.763	90.956
13.4253	2968.385	90.959
13.4256	2968.047	90.975
13.4258	2967.659	90.972
13.4261	2967.243	90.951
13.4264	2966.917	90.970
13.4267	2966.577	90.981
13.4269	2966.213	90.975
13.4272	2965.832	90.964
13.4275	2965.496	90.970
13.4278	2965.155	90.972
13.4281	2964.834	90.986
13.4283	2964.470	90.964
13.4286	2964.146	90.972
13.4289	2963.825	90.978
13.4292	2963.521	90.989
13.4294	2963.160	90.962
13.4297	2962.855	90.975
13.4300	2962.583	90.991
13.4303	2962.263	90.986
13.4306	2961.953	90.978
13.4308	2961.632	90.975
13.4311	2961.380	90.994
13.4314	2961.083	90.989
13.4317	2960.775	90.978
13.4319	2960.496	90.986
13.4322	2960.221	90.989
13.4325	2959.956	90.997
13.4328	2959.653	90.981
13.4331	2959.386	90.983
13.4333	2959.151	91.000
13.4336	2958.871	90.991
13.4339	2958.621	91.000
13.4342	2958.334	90.981
13.4344	2958.097	90.991
13.4347	2957.872	91.005
13.4350	2957.629	91.005
13.4353	2957.345	90.983
13.4356	2957.145	91.002
13.4358	2956.913	91.008
13.4361	2956.667	91.002
13.4364	2956.420	90.989
13.4367	2956.215	91.005
13.4369	2955.984	91.000
13.4372	2955.781	91.013
13.4375	2955.557	91.008
13.4378	2955.316	90.997
13.4381	2955.128	91.010
13.4383	2954.931	91.016
13.4386	2954.705	91.005
13.4389	2954.509	91.010
13.4392	2954.301	91.013
13.4394	2954.116	91.013

Time	Pressure (Psia)	Temperature (°F)
13.4397	2953.925	91.021
13.4400	2953.693	91.000
13.4403	2953.527	91.013
13.4406	2953.336	91.013
13.4408	2953.205	91.046
13.4411	2952.921	90.989
13.4414	2952.818	91.032
13.4417	2952.609	91.019
13.4419	2952.427	91.016
13.4422	2952.268	91.021
13.4425	2952.075	91.013
13.4428	2951.954	91.035
13.4431	2951.755	91.027
13.4433	2951.618	91.032
13.4436	2951.400	91.010
13.4439	2951.276	91.027
13.4442	2951.147	91.040
13.4444	2950.964	91.029
13.4447	2950.807	91.024
13.4450	2950.645	91.024
13.4453	2950.543	91.048
13.4456	2950.361	91.029
13.4458	2950.216	91.035
13.4461	2950.098	91.043
13.4464	2949.914	91.027
13.4467	2949.801	91.037
13.4469	2949.664	91.043
13.4472	2949.511	91.032
13.4475	2949.404	91.054
13.4478	2949.246	91.032
13.4481	2949.139	91.054
13.4483	2948.978	91.035
13.4486	2948.861	91.043
13.4489	2948.734	91.046
13.4492	2948.630	91.054
13.4494	2948.483	91.046
13.4497	2948.360	91.043
13.4500	2948.238	91.048
13.4503	2948.142	91.056
13.4506	2948.017	91.056
13.4508	2947.879	91.046
13.4511	2947.771	91.051
13.4514	2947.666	91.054
13.4517	2947.568	91.065
13.4519	2947.450	91.065
13.4522	2947.312	91.046
13.4525	2947.231	91.062
13.4528	2947.119	91.065
13.4531	2946.995	91.054
13.4533	2946.895	91.059
13.4536	2946.797	91.062
13.4539	2946.709	91.070
13.4542	2946.599	91.070
13.4544	2946.498	91.067
13.4547	2946.365	91.051
13.4550	2946.307	91.075
13.4553	2946.183	91.065
13.4556	2946.128	91.086
13.4558	2945.977	91.056
13.4561	2945.931	91.084
13.4564	2945.783	91.059
13.4567	2945.750	91.089
13.4569	2945.601	91.065
13.4572	2945.546	91.078
13.4575	2945.438	91.075
13.4578	2945.349	91.075
13.4581	2945.286	91.089
13.4583	2945.160	91.073
13.4586	2945.099	91.084
13.4589	2945.003	91.084
13.4592	2944.918	91.089
13.4594	2944.856	91.092
13.4597	2944.723	91.075
13.4600	2944.662	91.086
13.4603	2944.579	91.089

Time	Pressure (Psia)	Temperature (°F)
13.4606	2944.488	91.084
13.4608	2944.435	91.103
13.4611	2944.295	91.067
13.4614	2944.273	91.103
13.4617	2944.176	91.094
13.4619	2944.123	91.105
13.4622	2944.010	91.092
13.4625	2943.936	91.092
13.4628	2943.870	91.100
13.4631	2943.814	91.113
13.4633	2943.720	91.103
13.4636	2943.598	91.073
13.4639	2943.579	91.113
13.4642	2943.479	91.092
13.4644	2943.481	91.132
13.4647	2943.292	91.078
13.4650	2943.298	91.113
13.4653	2943.220	91.111
13.4656	2943.098	91.089
13.4658	2943.110	91.127
13.4661	2942.991	91.103
13.4664	2942.912	91.100
13.4667	2942.904	91.127
13.4669	2942.785	91.103
13.4672	2942.749	91.119
13.4675	2942.677	91.116
13.4678	2942.604	91.108
13.4681	2942.572	91.127
13.4683	2942.478	91.116
13.4686	2942.462	91.135
13.4689	2942.361	91.116
13.4692	2942.279	91.108
13.4694	2942.233	91.119
13.4697	2942.227	91.143
13.4700	2942.133	91.124
13.4703	2942.066	91.124
13.4706	2941.977	91.108
13.4708	2941.956	91.124
13.4711	2941.922	91.138
13.4714	2941.868	91.141
13.4717	2941.776	91.119
13.4719	2941.753	91.138
13.4722	2941.696	91.135
13.4725	2941.632	91.132
13.4728	2941.588	91.132
13.4731	2941.549	91.143
13.4733	2941.472	91.130
13.4736	2941.413	91.130
13.4739	2941.415	91.154
13.4742	2941.330	91.141
13.4744	2941.301	91.149
13.4747	2941.219	91.132
13.4750	2941.178	91.138
13.4753	2941.149	91.146
13.4756	2941.100	91.151
13.4758	2941.079	91.159
13.4761	2940.981	91.135
13.4764	2940.920	91.130
13.4767	2940.949	91.165
13.4769	2940.870	91.154
13.4772	2940.853	91.165
13.4775	2940.761	91.143
13.4778	2940.706	91.138
13.4781	2940.700	91.162
13.4783	2940.664	91.162
13.4786	2940.620	91.162
13.4789	2940.558	91.157
13.4792	2940.485	91.138
13.4794	2940.502	91.170
13.4797	2940.453	91.168
13.4800	2940.396	91.165
13.4803	2940.374	91.173
13.4806	2940.285	91.149
13.4808	2940.263	91.157
13.4811	2940.259	91.178

Time	Pressure (Psia)	Temperature (°F)
13.4814	2940.177	91.162
13.4817	2940.168	91.173
13.4819	2940.129	91.176
13.4822	2940.060	91.162
13.4825	2940.053	91.178
13.4828	2939.999	91.173
13.4831	2939.982	91.184
13.4833	2939.945	91.184
13.4836	2939.835	91.149
13.4839	2939.847	91.178
13.4842	2939.823	91.181
13.4844	2939.788	91.187
13.4847	2939.744	91.187
13.4850	2939.695	91.176
13.4853	2939.652	91.173
13.4856	2939.628	91.184
13.4858	2939.609	91.189
13.4861	2939.575	91.195
13.4864	2939.496	91.176
13.4867	2939.479	91.178
13.4869	2939.465	91.195
13.4872	2939.425	91.189
13.4875	2939.411	91.206
13.4878	2939.366	91.197
13.4881	2939.299	91.181
13.4883	2939.250	91.178
13.4886	2939.293	91.214
13.4889	2939.189	91.181
13.4892	2939.225	91.216
13.4894	2939.153	91.197
13.4897	2939.104	91.187
13.4900	2939.086	91.197
13.4903	2939.055	91.200
13.4906	2939.058	91.214
13.4908	2938.988	91.200
13.4911	2938.976	91.206
13.4914	2938.935	91.203
13.4917	2938.893	91.200
13.4919	2938.898	91.219
13.4922	2938.836	91.206
13.4925	2938.842	91.216
13.4928	2938.772	91.203
13.4931	2938.753	91.208
13.4933	2938.734	91.214
13.4936	2938.692	91.211
13.4939	2938.713	91.230
13.4942	2938.638	91.214
13.4944	2938.605	91.208
13.4947	2938.554	91.200
13.4950	2938.587	91.230
13.4953	2938.550	91.230
13.4956	2938.518	91.225
13.4958	2938.473	91.216
13.4961	2938.449	91.219
13.4964	2938.410	91.214
13.4967	2938.406	91.227
13.4969	2938.409	91.241
13.4972	2938.346	91.227
13.4975	2938.329	91.230
13.4978	2938.280	91.219
13.4981	2938.261	91.225
13.4983	2938.258	91.235
13.4986	2938.240	91.241
13.4989	2938.192	91.235
13.4992	2938.175	91.238
13.4994	2938.113	91.216
13.4997	2938.113	91.233
13.5000	2938.116	91.246
13.5003	2938.117	91.262
13.5006	2938.037	91.235
13.5008	2938.008	91.235
13.5011	2937.980	91.233
13.5014	2937.958	91.233
13.5017	2937.954	91.246
13.5019	2937.930	91.249

Time	Pressure (Psia)	Temperature (°F)
13.5022	2937.928	91.260
13.5025	2937.879	91.249
13.5028	2937.852	91.246
13.5031	2937.797	91.233
13.5033	2937.812	91.249
13.5036	2937.801	91.262
13.5039	2937.763	91.254
13.5042	2937.767	91.268
13.5044	2937.664	91.225
13.5047	2937.695	91.257
13.5050	2937.673	91.257
13.5053	2937.656	91.260
13.5056	2937.646	91.271
13.5058	2937.619	91.268
13.5061	2937.547	91.241
13.5064	2937.549	91.254
13.5067	2937.538	91.260
13.5069	2937.515	91.260
13.5072	2937.516	91.276
13.5075	2937.489	91.273
13.5078	2937.469	91.271
13.5081	2937.410	91.254
13.5083	2937.405	91.260
13.5086	2937.406	91.276
13.5089	2937.376	91.268
13.5092	2937.392	91.292
13.5094	2937.316	91.260
13.5097	2937.317	91.276
13.5100	2937.280	91.268
13.5103	2937.275	91.273
13.5106	2937.264	91.279
13.5108	2937.257	91.287
13.5111	2937.235	91.287
13.5114	2937.187	91.273
13.5117	2937.180	91.281
13.5119	2937.150	91.273
13.5122	2937.143	91.281
13.5125	2937.137	91.290
13.5128	2937.122	91.298
13.5131	2937.089	91.284
13.5133	2937.062	91.281
13.5136	2937.016	91.276
13.5139	2937.026	91.281
13.5142	2937.031	91.300
13.5144	2936.979	91.284
13.5147	2937.009	91.309
13.5150	2936.962	91.295
13.5153	2936.920	91.284
13.5156	2936.926	91.295
13.5158	2936.881	91.287
13.5172	2936.817	91.300
13.5186	2936.735	91.311
13.5200	2936.641	91.309
13.5214	2936.558	91.311
13.5228	2936.462	91.311
13.5242	2936.409	91.330
13.5256	2936.333	91.333
13.5269	2936.247	91.330
13.5283	2936.176	91.336
13.5297	2936.128	91.349
13.5311	2936.051	91.352
13.5325	2935.985	91.360
13.5339	2935.927	91.368
13.5353	2935.838	91.360
13.5367	2935.785	91.371
13.5381	2935.689	91.363
13.5394	2935.672	91.390
13.5408	2935.604	91.393
13.5422	2935.553	91.401
13.5436	2935.489	91.398
13.5450	2935.443	91.409
13.5464	2935.407	91.425
13.5478	2935.315	91.411
13.5492	2935.302	91.436
13.5506	2935.232	91.430
13.5519	2935.153	91.420
13.5533	2935.137	91.447
13.5547	2935.086	91.447
13.5561	2935.052	91.460
13.5575	2934.968	91.447
13.5589	2934.949	91.460
13.5603	2934.890	91.460
13.5617	2934.883	91.485
13.5631	2934.802	91.468
13.5644	2934.785	91.487
13.5658	2934.691	91.468
13.5672	2934.677	91.485
13.5686	2934.636	91.490
13.5700	2934.581	91.485
13.5714	2934.565	91.504
13.5728	2934.541	91.514
13.5742	2934.479	91.509
13.5756	2934.448	91.520
13.5769	2934.416	91.523
13.5783	2934.375	91.528
13.5797	2934.346	91.536
13.5811	2934.329	91.547
13.5825	2934.302	91.552
13.5839	2934.273	91.560
13.5853	2934.216	91.558
13.5867	2934.194	91.566
13.5881	2934.180	91.574
13.5894	2934.133	91.577
13.5908	2934.094	91.579
13.5922	2934.060	91.585
13.5936	2934.003	91.574
13.5950	2934.012	91.598
13.5964	2933.959	91.590
13.5978	2933.943	91.601
13.5992	2933.931	91.615
13.6006	2933.867	91.596
13.6019	2933.883	91.628
13.6033	2933.836	91.623
13.6047	2933.809	91.628
13.6061	2933.809	91.644
13.6075	2933.775	91.650
13.6089	2933.740	91.647
13.6103	2933.714	91.653
13.6117	2933.687	91.658
13.6131	2933.668	91.663
13.6144	2933.641	91.669
13.6158	2933.632	91.680
13.6172	2933.605	91.685
13.6186	2933.575	91.685
13.6200	2933.556	91.690
13.6214	2933.540	91.701
13.6228	2933.510	91.701
13.6242	2933.490	91.707
13.6256	2933.483	91.715
13.6269	2933.466	91.726
13.6278	2933.442	91.720
13.6319	2933.394	91.742
13.6361	2933.330	91.755
13.6403	2933.254	91.758
13.6444	2933.246	91.801
13.6486	2933.187	91.810
13.6528	2933.129	91.818
13.6569	2933.048	91.818
13.6611	2932.994	91.828
13.6653	2932.968	91.850
13.6694	2932.946	91.875
13.6736	2932.871	91.877
13.6778	2932.844	91.891
13.6819	2932.782	91.893
13.6861	2932.774	91.921
13.6903	2932.753	91.945
13.6944	2932.689	91.942
13.6986	2932.677	91.964
13.7028	2932.638	91.975
13.7069	2932.566	91.964
13.7111	2932.555	91.994
13.7153	2932.523	92.004
13.7194	2932.497	92.010
13.7236	2932.450	92.013
13.7278	2932.426	92.031
13.7319	2932.377	92.029
13.7361	2932.343	92.034
13.7403	2932.334	92.053
13.7444	2932.282	92.053
13.7486	2932.270	92.067
13.7528	2932.236	92.072
13.7569	2932.192	92.072
13.7611	2932.190	92.091
13.7653	2932.151	92.094
13.7694	2932.131	92.099
13.7736	2932.090	92.096
13.7778	2932.080	92.115
13.7819	2932.058	92.123
13.7861	2932.051	92.140
13.7903	2932.037	92.148
13.7944	2932.023	92.156
13.7986	2931.978	92.156
13.8028	2931.969	92.167
13.8069	2931.949	92.172
13.8111	2931.917	92.175
13.8153	2931.878	92.178
13.8194	2931.851	92.175
13.8236	2931.817	92.180
13.8278	2931.797	92.186
13.8319	2931.790	92.202
13.8361	2931.778	92.207
13.8403	2931.772	92.224
13.8444	2931.732	92.218
13.8486	2931.727	92.232
13.8528	2931.716	92.245
13.8569	2931.684	92.240
13.8611	2931.692	92.264
13.8653	2931.662	92.264
13.8694	2931.632	92.264
13.8736	2931.591	92.261
13.8778	2931.609	92.283
13.8819	2931.554	92.270
13.8861	2931.565	92.291
13.8903	2931.573	92.307
13.8944	2931.533	92.302
13.8986	2931.544	92.324
13.9028	2931.486	92.305
13.9069	2931.512	92.334
13.9111	2931.463	92.324
13.9153	2931.456	92.332
13.9181	2931.440	92.332
13.9264	2931.421	92.345
13.9347	2931.395	92.359
13.9431	2931.338	92.356
13.9514	2931.346	92.388
13.9597	2931.290	92.378
13.9681	2931.258	92.388
13.9764	2931.256	92.416
13.9825	2931.199	92.397
13.9908	2931.185	92.413
13.9992	2931.188	92.434
14.0075	2931.141	92.437
14.0158	2931.110	92.440
14.0242	2931.103	92.464
14.0325	2931.100	92.483
14.0408	2931.051	92.472
14.0492	2931.049	92.491
14.0575	2930.987	92.478
14.0658	2930.986	92.497
14.0742	2930.973	92.510
14.0825	2930.919	92.505
14.0908	2930.909	92.516
14.0992	2930.913	92.537
14.1075	2930.854	92.529
14.1158	2930.846	92.545

Time	Pressure (Psia)	Temperature (°F)
14.1242	2930.802	92.537
14.1325	2930.815	92.564
14.1408	2930.778	92.564
14.1492	2930.758	92.570
14.1575	2930.752	92.586
14.1658	2930.754	92.599
14.1742	2930.720	92.597
14.1825	2930.678	92.594
14.1908	2930.706	92.621
14.1992	2930.649	92.610
14.2075	2930.634	92.618
14.2158	2930.588	92.613
14.2242	2930.580	92.621
14.2325	2930.566	92.629
14.2408	2930.531	92.626
14.2492	2930.534	92.648
14.2575	2930.549	92.672
14.2658	2930.552	92.686
14.2742	2930.483	92.672
14.2825	2930.439	92.664
14.2908	2930.474	92.699
14.2992	2930.477	92.721
14.3075	2930.462	92.729
14.3158	2930.475	92.764
14.3242	2930.411	92.745
14.3325	2930.367	92.745
14.3408	2930.360	92.761
14.3492	2930.395	92.797
14.3575	2930.341	92.783
14.3658	2930.323	92.786
14.3742	2930.336	92.805
14.3825	2930.259	92.783
14.3908	2930.297	92.824
14.3992	2930.265	92.818
14.4075	2930.236	92.818
14.4158	2930.273	92.851
14.4242	2930.249	92.853
14.4325	2930.224	92.856
14.4408	2930.209	92.864
14.4492	2930.185	92.875
14.4575	2930.190	92.894
14.4658	2930.158	92.888
14.4742	2930.181	92.913
14.4825	2930.119	92.899
14.4908	2930.127	92.915
14.4992	2930.114	92.921
14.5075	2930.105	92.932
14.5158	2930.118	92.951
14.5242	2930.059	92.934
14.5325	2930.058	92.942
14.5408	2930.047	92.956
14.5492	2930.049	92.969
14.5575	2930.030	92.975
14.5658	2930.012	92.978
14.5742	2930.037	93.007
14.5825	2930.015	93.007
14.5908	2929.976	93.002
14.5992	2930.008	93.032
14.6075	2929.967	93.021
14.6158	2929.974	93.045
14.6242	2929.967	93.053
14.6325	2929.907	93.037
14.6408	2929.888	93.034
14.6492	2929.865	93.042
14.6575	2929.874	93.067
14.6658	2929.898	93.096
14.6742	2929.926	93.131
14.6825	2929.857	93.110
14.6908	2929.869	93.137
14.6992	2929.835	93.134
14.7075	2929.848	93.161
14.7158	2929.870	93.185
14.7242	2929.863	93.202
14.7325	2929.816	93.196
14.7408	2929.780	93.188
14.7492	2929.787	93.212
14.7575	2929.802	93.237
14.7658	2929.794	93.245
14.7742	2929.795	93.261
14.7825	2929.776	93.266
14.7908	2929.739	93.258
14.7992	2929.711	93.264
14.8075	2929.741	93.288
14.8158	2929.734	93.296
14.8242	2929.744	93.318
14.8325	2929.737	93.326
14.8408	2929.690	93.320
14.8492	2929.702	93.339
14.8575	2929.710	93.355
14.8658	2929.690	93.361
14.8742	2929.683	93.369
14.8825	2929.671	93.374
14.8908	2929.671	93.391
14.8992	2929.651	93.396
14.9075	2929.659	93.412
14.9158	2929.624	93.409
14.9242	2929.632	93.426
14.9325	2929.646	93.450
14.9408	2929.625	93.450
14.9492	2929.622	93.461
14.9533	2929.590	93.447
14.9700	2929.652	93.517
14.9867	2929.605	93.520
15.0033	2929.588	93.539
15.0200	2929.598	93.569
15.0264	2929.524	93.544
15.0431	2929.535	93.582
15.0597	2929.495	93.593
15.0764	2929.495	93.633
15.0931	2929.500	93.668
15.1097	2929.498	93.703
15.1264	2929.466	93.714
15.1431	2929.496	93.771
15.1597	2929.459	93.795
15.1764	2929.422	93.811
15.1931	2929.412	93.838
15.2097	2929.402	93.873
15.2264	2929.400	93.908
15.2431	2929.410	93.954
15.2597	2929.397	94.000
15.2764	2929.371	94.022
15.2931	2929.380	94.076
15.3097	2929.357	94.108
15.3264	2929.362	94.159
15.3431	2929.318	94.183
15.3597	2929.330	94.243
15.3764	2929.346	94.305
15.3931	2929.352	94.356
15.4097	2929.300	94.380
15.4264	2929.284	94.428
15.4431	2929.310	94.488
15.4597	2929.266	94.504
15.4764	2929.263	94.539
15.4931	2929.292	94.587
15.5097	2929.250	94.617
15.5264	2929.249	94.649
15.5431	2929.249	94.681
15.5597	2929.266	94.743
15.5764	2929.230	94.781
15.5931	2929.244	94.846
15.6097	2929.214	94.886
15.6264	2929.204	94.921
15.6431	2929.203	94.945
15.6597	2929.222	94.964
15.6764	2929.198	94.967
15.6931	2929.197	94.991
15.7097	2929.192	95.012
15.7264	2929.169	95.029
15.7431	2929.178	95.058
15.7597	2929.173	95.080
15.7764	2929.175	95.101
15.7931	2929.149	95.160
15.8097	2929.159	95.252
15.8264	2929.128	95.332
15.8431	2929.106	95.402
15.8597	2929.083	95.459
15.8764	2929.095	95.531
15.8931	2929.101	95.580
15.9097	2929.110	95.625
15.9264	2929.104	95.663
15.9431	2929.112	95.709
15.9597	2929.154	95.773
15.9764	2929.106	95.808
15.9931	2929.051	95.851
16.0097	2929.066	95.913
16.0264	2929.008	95.942
16.0431	2928.961	96.015
16.0597	2928.970	96.168
16.0764	2928.959	96.302
16.0931	2928.970	96.398
16.1097	2928.983	96.468
16.1264	2929.030	96.535
16.1431	2929.050	96.575
16.1597	2929.071	96.600
16.1764	2929.063	96.600
16.1931	2929.006	96.567
16.2097	2929.017	96.648
16.2264	2928.983	96.720
16.2431	2928.968	96.790
16.2597	2929.011	96.851
16.2764	2929.035	96.881
16.2931	2929.026	96.905
16.3097	2929.044	96.932
16.3264	2929.015	96.916
16.3431	2929.023	96.916
16.3597	2928.985	96.894
16.3764	2929.009	96.908
16.3931	2929.040	96.913
16.4097	2929.016	96.892
16.4264	2929.015	96.841
16.4431	2928.954	96.774
16.4597	2929.056	96.843
16.4764	2928.976	96.827
16.4931	2928.930	96.843
16.5097	2928.960	96.897
16.5264	2928.909	96.926
16.5431	2928.883	97.036
16.5597	2928.848	97.170
16.5764	2928.859	97.310
16.5931	2928.814	97.409
16.6097	2928.822	97.529
16.6264	2928.850	97.612
16.6431	2928.871	97.636
16.6597	2928.902	97.657
16.6764	2928.897	97.647
16.6931	2928.889	97.625
16.7097	2928.845	97.639
16.7264	2928.887	97.724
16.7431	2928.841	97.786
16.7597	2928.819	97.853
16.7764	2928.828	97.895
16.7931	2928.825	97.936
16.8097	2928.823	97.930
16.8264	2928.859	97.909
16.8431	2928.886	97.845
16.8597	2928.908	97.778
16.8764	2928.874	97.692
16.8931	2928.862	97.660
16.9097	2928.803	97.660
16.9264	2928.821	97.708
16.9431	2928.798	97.732
16.9597	2928.779	97.751
16.9764	2928.808	97.797
16.9931	2928.766	97.831
17.0097	2928.750	97.914

Time	Pressure (Psia)	Temperature (°F)
17.0264	2928.783	97.970
17.0431	2928.787	98.010
17.0597	2928.756	98.064
17.0764	2928.758	98.166
17.0931	2928.716	98.267
17.1097	2928.730	98.371
17.1264	2928.758	98.425
17.1431	2928.803	98.446
17.1597	2928.802	98.417
17.1764	2928.798	98.414
17.1931	2928.799	98.406
17.2097	2928.779	98.411
17.2264	2928.802	98.417
17.2431	2928.824	98.395
17.2597	2928.790	98.393
17.2764	2928.757	98.433
17.2931	2928.722	98.497
17.3097	2928.739	98.540
17.3264	2928.768	98.540
17.3431	2928.785	98.516
17.3597	2928.759	98.438
17.3764	2928.758	98.358
17.3931	2928.744	98.313
17.4097	2928.746	98.296
17.4264	2928.741	98.264
17.4431	2928.722	98.232
17.4597	2928.731	98.200
17.4764	2928.700	98.166
17.4931	2928.681	98.184
17.5097	2928.693	98.187
17.5264	2928.704	98.168
17.5431	2928.701	98.171
17.5597	2928.731	98.141
17.5764	2928.716	98.149
17.5931	2928.694	98.208
17.6097	2928.674	98.243
17.6264	2928.642	98.305
17.6431	2928.663	98.379
17.6597	2928.676	98.403
17.6764	2928.659	98.398
17.6931	2928.637	98.435
17.7097	2928.644	98.494
17.7158	2928.624	98.521
17.7325	2928.663	98.585
17.7492	2928.646	98.588
17.7658	2928.680	98.561
17.7825	2928.680	98.532
17.7992	2928.676	98.529
17.8158	2928.624	98.588
17.8325	2928.615	98.692
17.8492	2928.629	98.759
17.8658	2928.640	98.799
17.8825	2928.608	98.801
17.8992	2928.614	98.788
17.9158	2928.652	98.772
17.9325	2928.652	98.743
17.9492	2928.660	98.764
17.9658	2928.586	98.823
17.9825	2928.595	98.916
17.9992	2928.609	98.953
18.0158	2928.621	98.927
18.0325	2928.662	98.908
18.0492	2928.644	98.889
18.0658	2928.653	98.903
18.0825	2928.664	98.884
18.0992	2928.668	98.873
18.1158	2928.638	98.852
18.1325	2928.611	98.871
18.1492	2928.529	98.879
18.1658	2928.617	98.916
18.1825	2928.625	98.879
18.1992	2928.596	98.849
18.2158	2928.587	98.865
18.2325	2928.577	98.868
18.2492	2928.622	98.868
18.2658	2928.583	98.825
18.2825	2928.605	98.855
18.2992	2928.583	98.884
18.3158	2928.583	98.913
18.3325	2928.571	98.940
18.3492	2928.536	98.967
18.3658	2928.542	98.991
18.3825	2928.542	98.991
18.3992	2928.576	99.007
18.4158	2928.563	98.999
18.4325	2928.530	98.980
18.4492	2928.552	99.039
18.4658	2928.537	99.089
18.4814	2928.558	99.097
18.4981	2928.573	99.097
18.5147	2928.564	99.084
18.5314	2928.527	99.063
18.5481	2928.540	99.087
18.5647	2928.574	99.119
18.5814	2928.529	99.119
18.5981	2928.562	99.167
18.6147	2928.544	99.177
18.6314	2928.563	99.188
18.6481	2928.540	99.167
18.6647	2928.582	99.170
18.6814	2928.507	99.177
18.6981	2928.538	99.255
18.7147	2928.538	99.263
18.7314	2928.493	99.271
18.7481	2928.530	99.300
18.7647	2928.557	99.316
18.7814	2928.522	99.322
18.7981	2928.509	99.407
18.8147	2928.497	99.497
18.8314	2928.498	99.540
18.8481	2928.498	99.612
18.8647	2928.536	99.676
18.8814	2928.524	99.695
18.8981	2928.521	99.676
18.9147	2928.508	99.681
18.9314	2928.452	99.721
18.9481	2928.487	99.852
18.9647	2928.488	99.937
18.9814	2928.476	99.985
18.9981	2928.509	99.996
19.0147	2928.472	99.932
19.0314	2928.487	99.966
19.0481	2928.492	99.948
19.0647	2928.508	99.961
19.0814	2928.517	100.009
19.0981	2928.456	100.004
19.1147	2928.473	100.030
19.1314	2928.490	100.006
19.1481	2928.499	99.977
19.1647	2928.518	99.937
19.1814	2928.510	99.852
19.1981	2928.522	99.804
19.2147	2928.575	99.796
19.2314	2928.477	99.719
19.2481	2928.515	99.711
19.2647	2928.521	99.727
19.2814	2928.517	99.716
19.2981	2928.479	99.724
19.3147	2928.487	99.716
19.3314	2928.454	99.684
19.3481	2928.501	99.703
19.3647	2928.452	99.679
19.3814	2928.506	99.727
19.3981	2928.454	99.684
19.4147	2928.463	99.711
19.4314	2928.492	99.761
19.4481	2928.458	99.801
19.4647	2928.420	99.817
19.4814	2928.429	99.823
19.4981	2928.441	99.897
19.5147	2928.435	99.932
19.5314	2928.454	99.934
19.5481	2928.407	99.916
19.5647	2928.425	99.927
19.5814	2928.479	99.910
19.5981	2928.476	99.892
19.6147	2928.462	99.913
19.6314	2928.445	99.929
19.6481	2928.432	99.934
19.6647	2928.484	99.956
19.6814	2928.513	99.977
19.6981	2928.432	99.956
19.7147	2928.460	99.993
19.7314	2928.490	99.993
19.7481	2928.478	100.004
19.7647	2928.386	100.036
19.7814	2928.400	100.129
19.7981	2928.448	100.246
19.8147	2928.387	100.283
19.8314	2928.404	100.331
19.8481	2928.464	100.374
19.8647	2928.409	100.411
19.8814	2928.403	100.509
19.8981	2928.447	100.595
19.9147	2928.392	100.605
19.9314	2928.428	100.712
19.9481	2928.442	100.754
19.9647	2928.437	100.738
19.9814	2928.480	100.746
19.9981	2928.508	100.741
20.0147	2928.440	100.693
20.0314	2928.427	100.733
20.0481	2928.433	100.770
20.0647	2928.419	100.783
20.0814	2928.447	100.813
20.0981	2928.467	100.794
20.1147	2928.446	100.743
20.1314	2928.470	100.693
20.1481	2928.481	100.661
20.1647	2928.492	100.629
20.1814	2928.464	100.571
20.1981	2928.486	100.557
20.2147	2928.460	100.525
20.2314	2928.478	100.536
20.2481	2928.480	100.563
20.2647	2928.459	100.597
20.2814	2928.385	100.597
20.2981	2928.428	100.648
20.3147	2928.419	100.664
20.3314	2928.400	100.696
20.3481	2928.443	100.767
20.3647	2928.448	100.762
20.3814	2928.372	100.786
20.3981	2928.386	100.884
20.4147	2928.427	100.951
20.4314	2928.425	100.932
20.4481	2928.445	100.906
20.4647	2928.447	100.890
20.4814	2928.455	100.868
20.4981	2928.458	100.866
20.5147	2928.423	100.948
20.5314	2928.378	101.047
20.5481	2928.387	101.150
20.5647	2928.411	101.190
20.5814	2928.412	101.225
20.5981	2928.430	101.227
20.6147	2928.453	101.227
20.6314	2928.445	101.193
20.6481	2928.455	101.155
20.6647	2928.474	101.145
20.6814	2928.451	101.089
20.6981	2928.469	101.031
20.7147	2928.479	101.028
20.7314	2928.442	101.070
20.7481	2928.409	101.094

Time	Pressure (Psia)	Temperature (°F)
20.7647	2928.421	101.166
20.7814	2928.409	101.206
20.7981	2928.396	101.211
20.8147	2928.423	101.248
20.8314	2928.436	101.264
20.8481	2928.411	101.267
20.8647	2928.445	101.339
20.8814	2928.432	101.365
20.8981	2928.431	101.331
20.9147	2928.475	101.317
20.9314	2928.462	101.344
20.9481	2928.406	101.410
20.9647	2928.394	101.541
20.9814	2928.377	101.618
20.9981	2928.382	101.620
21.0147	2928.434	101.607
21.0314	2928.464	101.599
21.0481	2928.405	101.633
21.0647	2928.406	101.716
21.0814	2928.413	101.750
21.0981	2928.408	101.769
21.1147	2928.407	101.846
21.1314	2928.456	101.883
21.1481	2928.432	101.947
21.1647	2928.410	101.994
21.1814	2928.412	102.047
21.1981	2928.428	102.066
21.2147	2928.430	102.045
21.2314	2928.479	102.013
21.2481	2928.459	101.976
21.2647	2928.455	101.952
21.2814	2928.440	101.939
21.2981	2928.431	101.933
21.3147	2928.433	101.952
21.3314	2928.447	101.973
21.3481	2928.403	101.973
21.3647	2928.380	102.016
21.3814	2928.395	102.098
21.3981	2928.385	102.148
21.4147	2928.388	102.172
21.4314	2928.418	102.220
21.4481	2928.425	102.241
21.4647	2928.452	102.222
21.4814	2928.446	102.201
21.4981	2928.476	102.193
21.5147	2928.366	102.233
21.5314	2928.406	102.381
21.5481	2928.385	102.456
21.5647	2928.377	102.538
21.5814	2928.384	102.585
21.5981	2928.454	102.596
21.6147	2928.431	102.570
21.6314	2928.407	102.577
21.6481	2928.463	102.628
21.6647	2928.431	102.609
21.6814	2928.415	102.577
21.6981	2928.430	102.617
21.7147	2928.393	102.652
21.7314	2928.393	102.699
21.7481	2928.421	102.816
21.7647	2928.403	102.927
21.7814	2928.376	103.033
21.7981	2928.347	103.186
21.8147	2928.350	103.345
21.8314	2928.334	103.432
21.8481	2928.428	103.501
21.8647	2928.449	103.496
21.8814	2928.434	103.469
21.8981	2928.433	103.451
21.9147	2928.445	103.406
21.9314	2928.454	103.358
21.9481	2928.450	103.361
21.9647	2928.449	103.395
21.9814	2928.397	103.430
21.9981	2928.426	103.504

Time	Pressure (Psia)	Temperature (°F)
22.0147	2928.415	103.541
22.0314	2928.435	103.536
22.0481	2928.441	103.530
22.0647	2928.461	103.485
22.0814	2928.449	103.443
22.0981	2928.446	103.419
22.1147	2928.447	103.525
22.1314	2928.375	103.610
22.1481	2928.393	103.673
22.1647	2928.393	103.734
22.1814	2928.421	103.795
22.1981	2928.425	103.758
22.2147	2928.440	103.744
22.2314	2928.438	103.713
22.2481	2928.442	103.702
22.2647	2928.470	103.697
22.2814	2928.416	103.660
22.2981	2928.415	103.747
22.3147	2928.374	103.784
22.3314	2928.364	103.840
22.3481	2928.420	103.921
22.3647	2928.430	103.932
22.3814	2928.391	103.948
22.3981	2928.397	104.035
22.4147	2928.374	104.122
22.4314	2928.354	104.212
22.4481	2928.354	104.304
22.4647	2928.411	104.326
22.4814	2928.453	104.289
22.4981	2928.419	104.194
22.5147	2928.449	104.141
22.5314	2928.446	104.091
22.5481	2928.409	104.104
22.5647	2928.360	104.101
22.5814	2928.426	104.101
22.5981	2928.395	104.056
22.6147	2909.964	104.386
22.6208	2889.494	104.885
22.7767	2051.202	105.796
22.7850	2051.117	105.415
22.7933	2051.041	105.040
22.8017	2050.997	104.721
22.8100	2050.933	104.415
22.8183	2050.896	104.159
22.8267	2050.861	103.927
22.8350	2050.813	103.697
22.8433	2050.780	103.506
22.8517	2050.720	103.313
22.8600	2050.720	103.171
22.8683	2050.680	103.020
22.8767	2050.665	102.893
22.8850	2050.661	102.792
22.8933	2050.630	102.670
22.8964	2050.609	102.628
23.1733	680.106	91.531
23.1817	680.042	91.124
23.1900	679.972	90.728
23.1983	679.937	90.408
23.2067	679.880	90.082
23.2150	679.814	89.786
23.2233	679.770	89.528
23.2317	679.731	89.291
23.2400	679.708	89.093
23.2483	679.678	88.902
23.2567	679.647	88.725
23.2650	679.740	88.570
23.2733	679.716	88.445
23.2817	679.704	88.316
23.2900	679.684	88.197
23.2983	679.667	88.093
23.3067	679.658	87.997
23.3150	679.623	87.886
23.3233	679.621	87.812
23.4244	85.500	85.570
23.4328	85.556	85.296

Time	Pressure (Psia)	Temperature (°F)
23.4411	85.526	85.027
23.4494	85.494	84.783
23.4578	85.449	84.560
23.4661	85.433	84.382
23.4744	85.419	84.217
23.4828	85.384	84.052
23.4911	85.372	83.906
23.4994	85.356	83.774
23.5078	85.333	83.651
23.5161	85.325	83.554
23.5244	85.316	83.458
23.5269	85.313	83.428
23.5283	85.301	83.398
23.5339	83.839	86.632
23.5353	82.457	86.807
23.5367	80.235	85.931
23.5381	79.278	86.640
23.5394	75.037	83.340
23.5408	73.573	83.398
23.5422	72.016	83.337
23.5436	70.467	83.296
23.5450	68.907	83.232
23.5464	67.458	83.307
23.5478	65.966	83.331
23.5492	64.377	83.243
23.5533	59.712	83.070
23.5561	56.716	83.097
23.5589	53.779	83.142
23.5603	52.276	83.144
23.5617	50.721	83.086
23.5644	47.538	82.902
23.5658	46.125	83.020
23.5672	44.639	83.053
23.5686	43.036	82.938
23.5756	35.452	82.935
23.5769	33.793	82.761
23.5797	30.942	82.979
23.5811	29.313	82.841
23.5825	27.830	82.885
23.5839	26.189	82.734
23.5853	24.766	82.841
23.5867	23.335	82.949
23.5881	21.688	82.789
23.5894	20.172	82.794
23.5908	18.675	82.814
23.5922	17.123	82.767
23.5936	15.603	82.759
23.5950	14.123	82.800
23.5964	14.123	82.808
23.5978	14.123	82.731
23.5992	14.123	82.819
23.5997	14.123.	82.818

APPENDIX 4.1.2-1

PANSYSTEM2 VERSION 2.5, WELL TEST ANALYSIS REPORT, WDW-1

ENVIROCORP
ENVIROCORP SERVICES AND TECHNOLOGY, INC.
HOUSTON, TX. · SOUTH BEND, IN.
BATON ROUGE, LA.

Envirocorp Services & Technology, Inc.

PanSystem Version 2.5

Well Test Analysis Report

Report File: WDW1.PAN

Analysis Date: 9/15/1998

Company	Navajo Refining Company
Location	Artesia, New Mexico
Well	WDW-1
Test Type	Injection/Falloff
Test Date	July 30 - 31, 1998
Gauge Type/Serial #	Eccossetex/009
Gauge Depth	7924 Feet
Injection Interval	7924 - 8115 Feet; 8220 - 8476 Feet
Completion Type	Perforated
Top of Fill	8997 Feet
Last Stabilization	New Completion
Analyst	LKM
Envirocorp Project No.	70A4614

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Reservoir Description

Fluid type : Water
Well orientation : Vertical
Number of wells : 1
Number of layers : 1

Layer Parameters Data

	Layer 1
Formation thickness	253.00 ft
Average formation porosity	0.10
Water saturation	0.00
Gas saturation	0.00
Formation compressibility	0.0000 psi-1
Total system compressibility	8.4000e-6 psi-1
Layer pressure	2925.3599 psia
Temperature	0.0000 deg F

Well Parameters Data

	WDW-1
Well radius	0.3696 ft
Distance from observation to active well	0.0000 ft
Wellbore storage coefficient	0.1038 bbl/psi
Well offset - x direction	0.00 ft
Well offset - y direction	0.00 ft

Fluid Parameters Data

	Layer 1
Oil gravity	0.0000 API
Gas gravity	0.0000 sp grav
Gas-oil ratio (produced)	0.0000 scf/STB
Water cut	0.0000
Water salinity	0.0000 ppm
Check Pressure	0.0000 psia
Check Temperature	0.0000 deg F
Gas-oil ratio (solution)	0.0000 scf/STB
Bubble-point pressure	0.0000 psia
Oil density	0.000 lb/ft3
Oil viscosity	0.000 cp
Oil formation volume factor	0.000 RB/STB

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Fluid Parameters Data (cont)

	Layer 1
Gas density	0.000 lb/ft3
Gas viscosity	0.0 cp
Gas formation volume factor	0.000 ft3/scf
Water density	0.000 lb/ft3
Water viscosity	0.530 cp
Water formation volume factor	1.000 RB/STB
Oil compressibility	0.0000 psi-1
Initial Gas compressibility	0.0000 psi-1
Water compressibility	0.0000 psi-1

Layer 1 Correlations

Not Used

Layer 1 Model Data

Layer 1 Model Type : Radial homogeneous

	Layer 1
Permeability	1130.00 md
Skin factor (Well 1)	30.1678

Rate Change Data

Time Hours	Pressure psia	Rate gpm
0.71330	2928.2310	0.0000
12.60750	3074.7930	-420.0000
12.64080	3011.3721	-200.0000
13.38939	3071.6079	-420.0000
22.59810	2928.3950	0.0000

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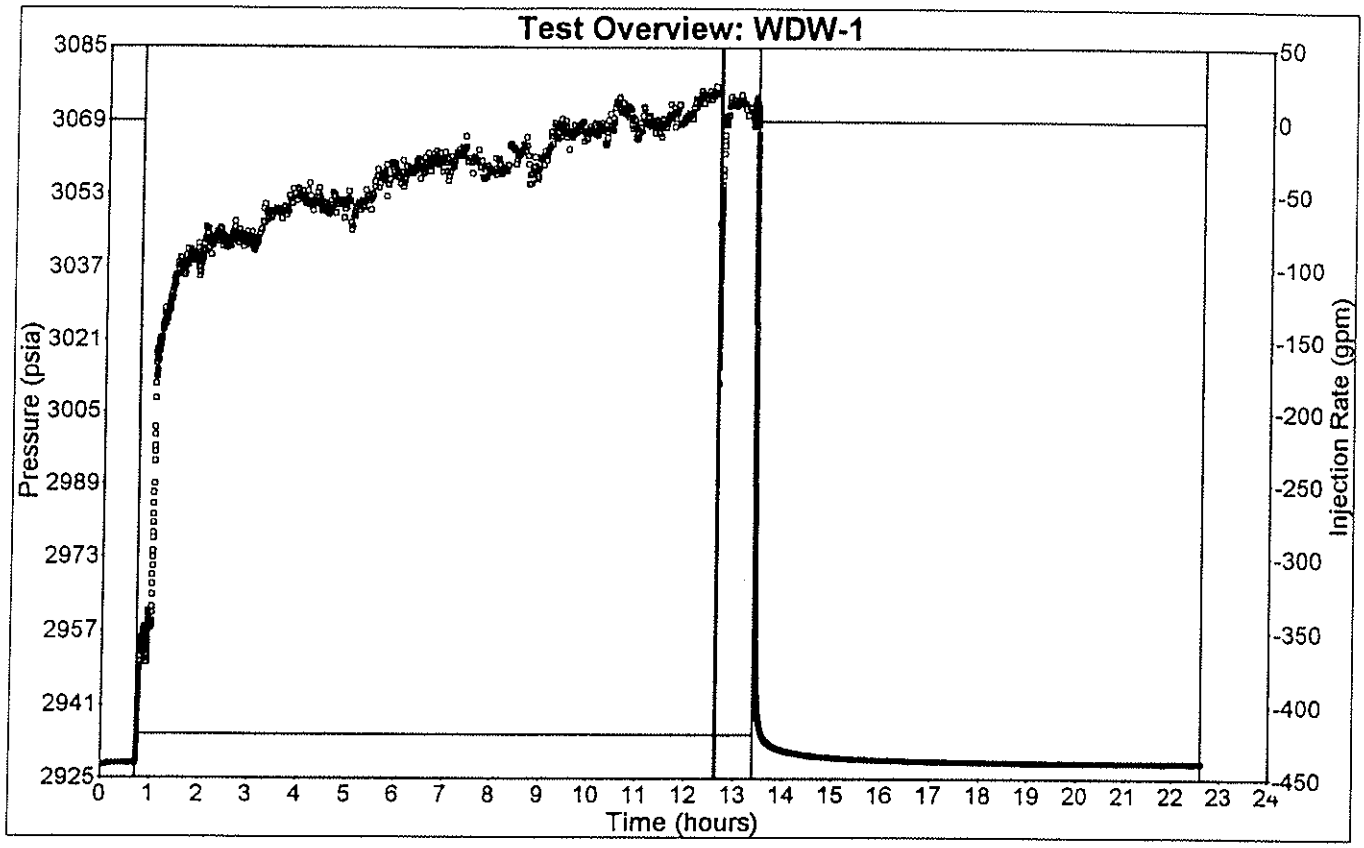

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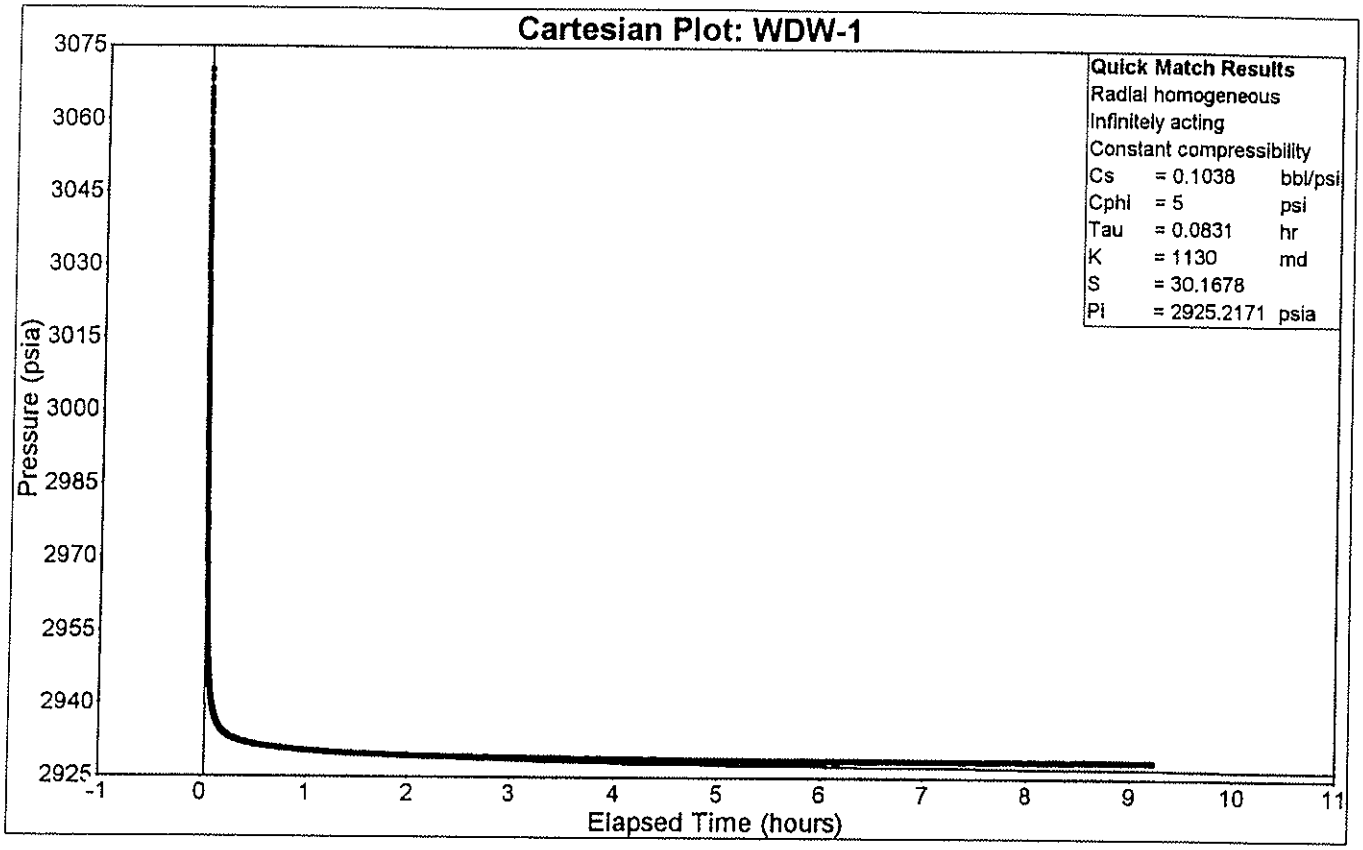

Cartesian Plot: WDW-1 Model Results
Radial homogeneous
Infinitely acting

	Value
Wellbore storage coefficient	0.1309 bbl/psi
Dimensionless wellbore storage	1035.9075

Cartesian Plot: WDW-1 Line Details
Line type : Wellbore storage
Slope : -4582.2
Intercept : 3071.68
Coefficient of Determination : 0.997527

Number of Intersections = 0

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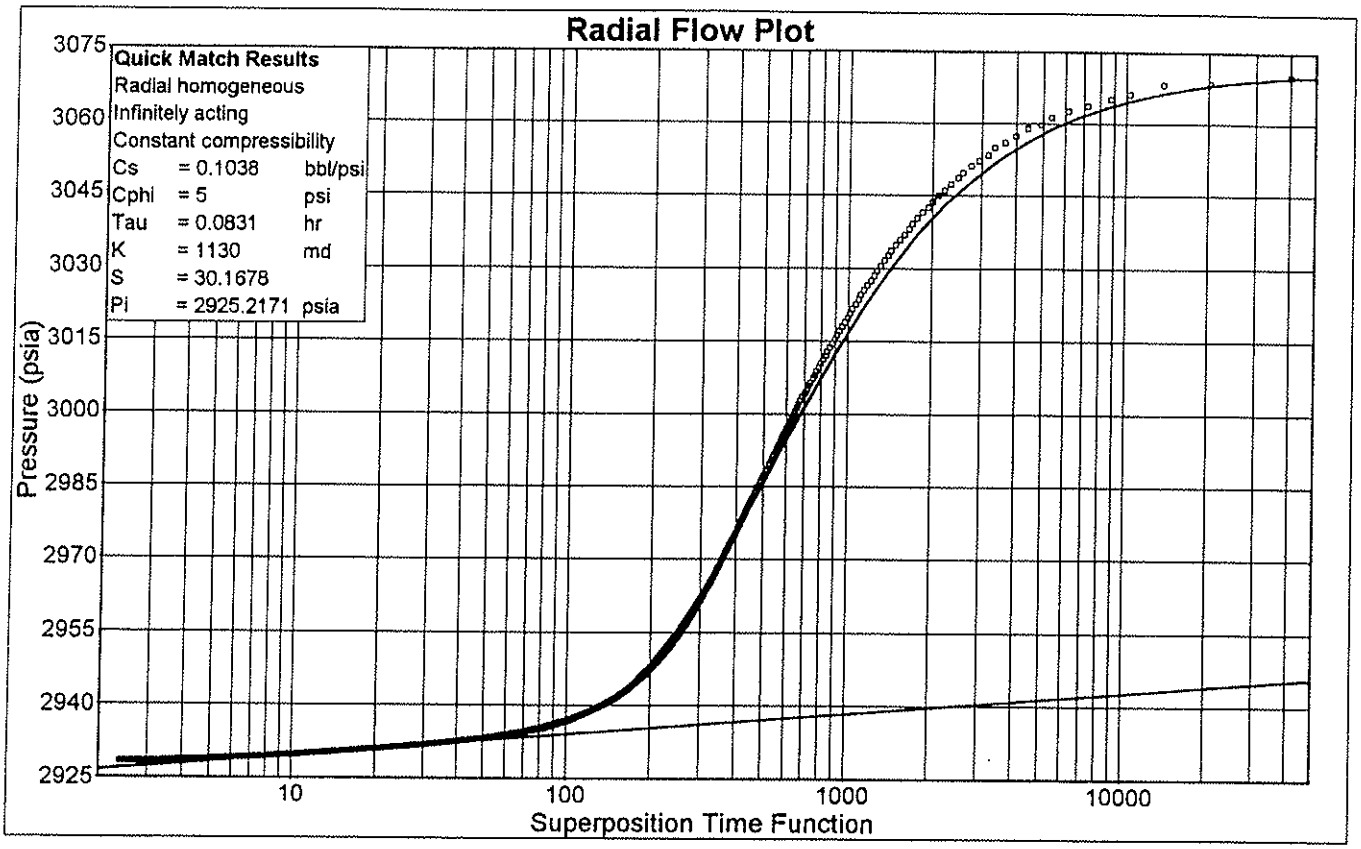

Radial Flow Plot Model Results
Radial homogeneous
Infinitely acting

	Value
Permeability	1125.5867 md
Permeability-thickness	2.8477e5 md.ft
Radius of investigation	4424.9595 ft
Flow efficiency	0.2247
dP skin (constant rate)	113.3868 psi
Skin factor	29.9633
Extrapolated pressure	2925.3599 psia

Radial Flow Plot Line Details
Line type : Radial flow
Slope : 4.35671
Intercept : 2925.36
Coefficient of Determination : 0.996956

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	Radial flow
Extrapolated pressure	2925.3599 psia
Pressure at dt = 1 hour	2930.2690 psia

Number of Intersections = 0

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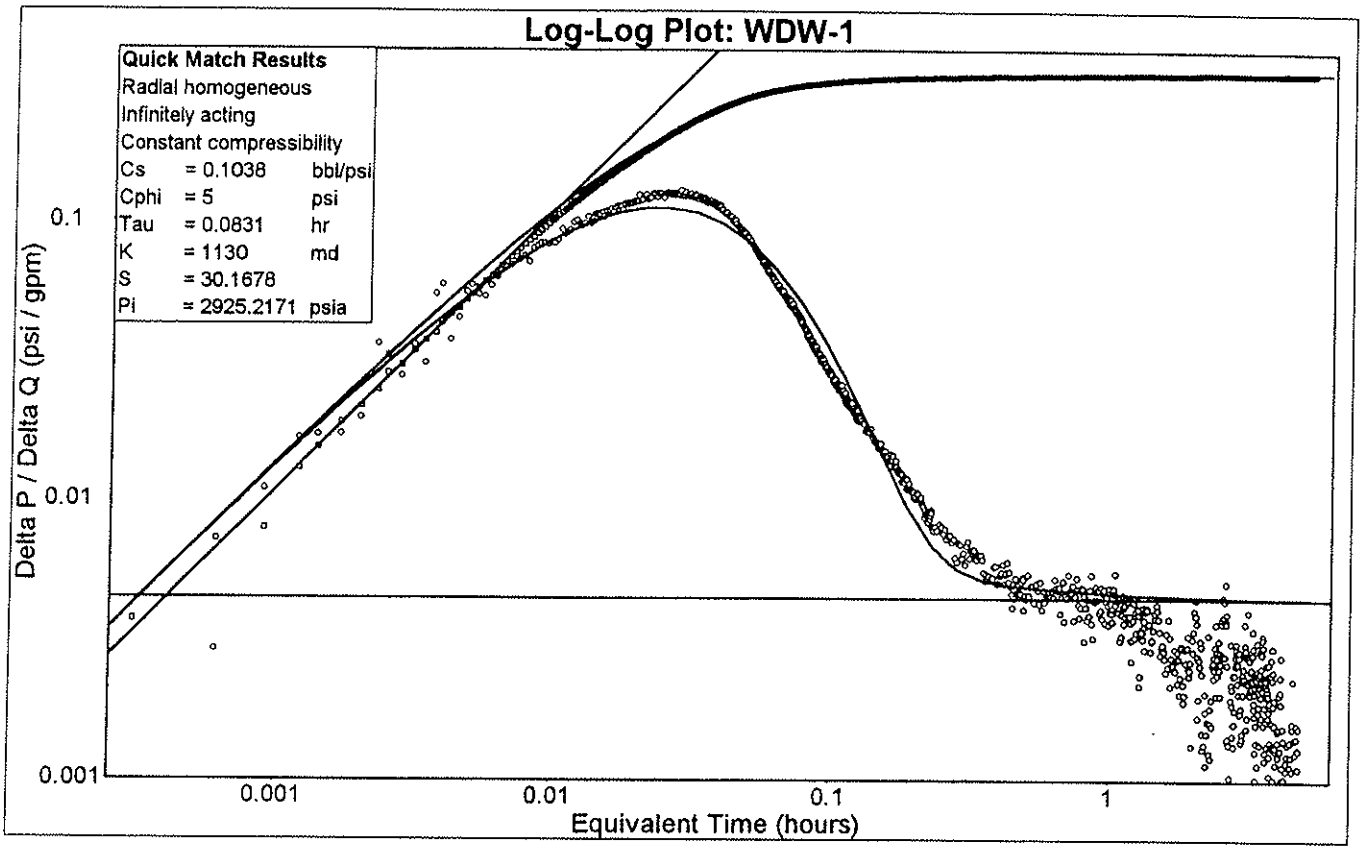

Log-Log Plot: WDW-1 Model Results
Radial homogeneous
Infinitely acting

	Value
Wellbore storage coefficient	0.1305 bbl/psi
Dimensionless wellbore storage	1032.4241
Permeability	1130.6444 md
Permeability-thickness	2.8605e5 md.ft
Skin factor	30.1285

Log-Log Plot: WDW-1 Line Details
Line type : Radial flow
Slope : 0
Intercept : 0.00448484
Coefficient of Determination : Not Used

Line type : Wellbore storage
Slope : 1
Intercept : 10.9468
Coefficient of Determination : Not Used

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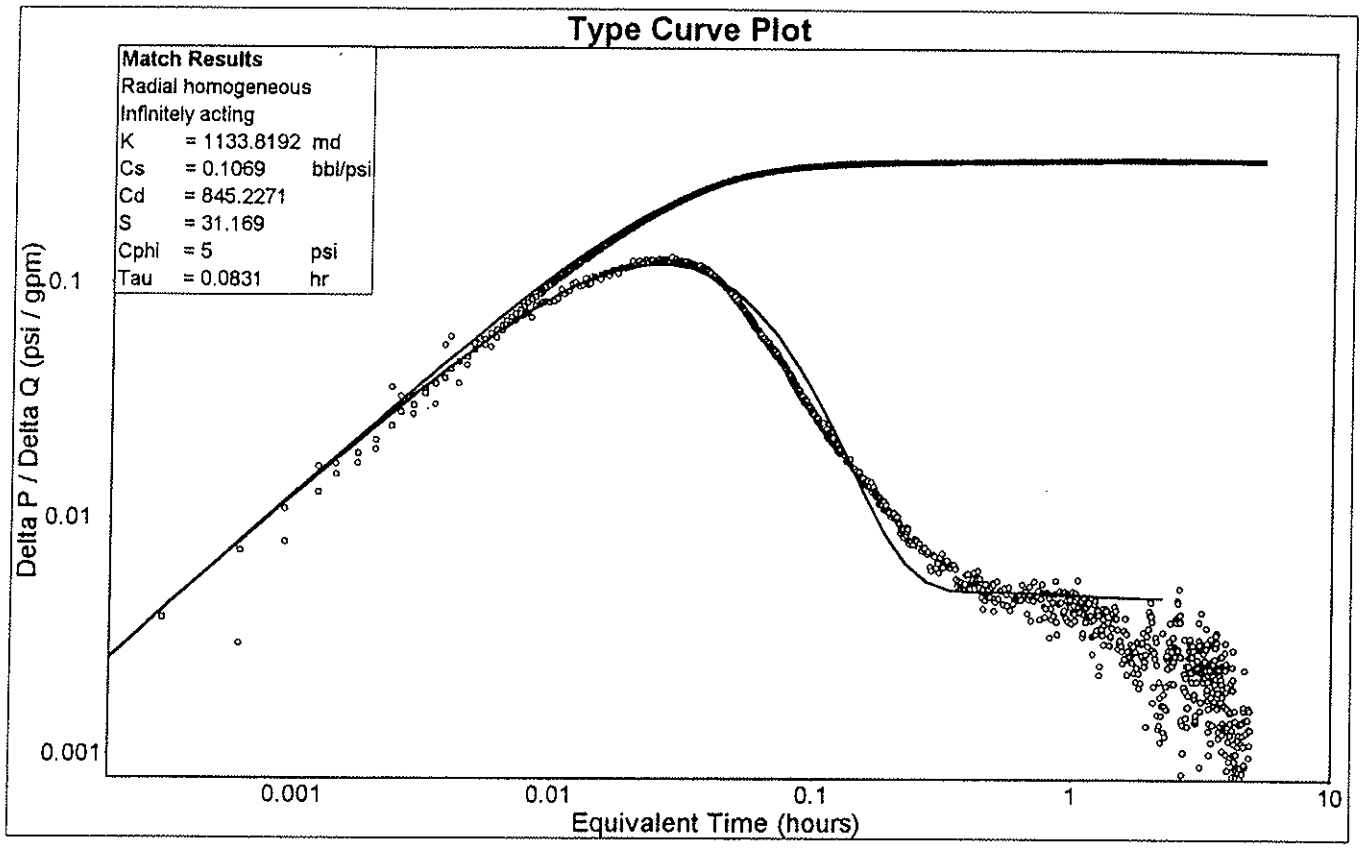
Number of Intersections = 0



Type Curve Plot Model Results
Radial homogeneous
Infinitely acting

	Value
Permeability	1133.8192 md
Wellbore storage coefficient	0.1069 bbl/psi
Dimensionless wellbore storage	845.2271
Skin factor	31.169

Type Curve Details
Stage 1 File Name : C:\pan25\typecurv\radhomog.tch
Axis Type : Td/Cd

	Stage 1
Match point - X	-3.1743
Match point - Y	3.5836
Curve Number	13.0000
Curve Value	1.0000e30

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APPENDIX H

WDW-2 CONSTRUCTION INFORMATION

SUBSURFACE

REENTRY AND COMPLETION REPORT
WASTE DISPOSAL WELL NO. 2

NAVAJO REFINING COMPANY
ARTESIA, NEW MEXICO

Subsurface Project No. 70A4955

July 1999

Prepared By:

SUBSURFACE TECHNOLOGY, INC.
Houston, Texas

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EXECUTIVE SUMMARY

Navajo Refining Company (Navajo) contracted Subsurface Technology, Inc. (Subsurface), formerly Envirocorp Services & Technology, Inc., to prepare an application for permit to reenter a producing Class II well and conduct injection testing within the Wolfcamp, Cisco, and Canyon Formations. The Application for Permit to Drill or Deepen was submitted to the Department of the Interior, Bureau of Land Management (BLM), on April 13, 1999. A permit modification was submitted to the State of New Mexico Oil Conservation Commission (OCD) in April 1999.

The BLM granted approval for the reentry and testing by letter, dated April 27, 1999. The OCD granted approval for the reentry and testing on the wellbore by letter dated May 3, 1999. In April 1999, Navajo contracted Subsurface to prepare a detailed engineering plan to reenter, test and complete The Eastland Oil Company, Chukka Federal No. 2.

Under contract with Navajo, Subsurface commenced field operations on May 5, 1999. The existing location was cleared and a pad was constructed for the drilling and completion rigs. Initially a completion rig was moved in and rigged up. The existing well pumping equipment was removed and the perforations from 1446 feet to 1462 feet were squeezed with cement. A 7-7/8 inch bit was lowered into the wellbore to drill and wash to 1922 feet. The 8-5/8 inch surface casing was successfully pressure tested to 660 psi prior to drilling out the cement plug across the shoe. A cement bond log confirmed continuous cement with good bond behind the 8-5/8 inch surface casing. The completion rig was released and moved off site.

The top 10 feet of the 8-5/8 inch casing was replaced before the installation of the blowout preventer assembly. A lined reserve pit was constructed for the containment of drill cuttings and fluids. A rotary drilling rig was moved in and rigged up. The BLM and the OCD were notified, and verbally approved the commencement of reentry operations on May 13, 1999. A 7-7/8 inch bit was lowered into the wellbore to drill out cement plugs within the 8-5/8 inch surface casing.

The 7-7/8 inch bit was lowered into the open-hole portion of the wellbore and cement plugs were drilled out to a total reentry depth of 8992 feet. A fracture identification log, 4-arm caliper, and gamma-ray log were conducted within the open-hole portion of the wellbore.

The 5-1/2 inch protection casing was installed with cement circulated through the annular space from bottom to the surface using a two-stage pump and plug method on May 19, 1999. Good returns were observed at the surface while cementing. The rotary drilling equipment was released and moved off site.

A completion rig and blowout preventers were moved in and rigged up on May 24, 1999. A 4-3/4 inch bit was lowered into the wellbore to clean out and pressure test the 5-1/2 inch protection casing. On May 25, 1999, the 5-1/2 inch casing was successfully pressure tested to 1514 pounds per square inch gauge (psig) above the differential valve tool at 5785 feet. On May 26, 1999, the 5-1/2 inch casing was successfully pressure tested to 1504 psig from surface to the plugged-back total depth of 8770 feet.

The wellbore was displaced with a clean brine fluid and a baseline temperature and casing inspection surveys were performed. A cement bond log was performed over the length of the 5-1/2 inch protection casing. The injection interval (Cisco/Canyon Formations) was perforated from 7826 feet to 8399 feet at two jet shots per foot. A sample of the formation fluid was obtained for analysis and the lower injection interval was stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter.

The injection interval (L. Wolfcamp/Cisco Formations) was perforated from 7570 feet to 7736 feet at two jet shots per foot. A retrievable bridge plug and packer were set to isolate the newly perforated interval. A sample of the formation fluid was obtained for analysis and the perforations were stimulated using 5000 gallons of 15% HCl acid and rock salt as a diverter. The packer and bridge plug were removed from the wellbore in preparation for the pressure buildup portion of the falloff test.

On June 4, 1999 and June 5, 1999, an injection pressure buildup and falloff test was conducted. Upon completion of the falloff test a differential temperature log was conducted

from surface to a total depth of 8736 feet. A radioactive tracer log was conducted and the results obtained from the survey confirmed external mechanical integrity of the wellbore.

A 3-1/2 inch outside diameter (OD) injection tubing and packer were installed in the well to 7528 feet. An extended annular pressure test was performed to confirm stabilization within the well system. On June 8, 1999, an annular pressure test was performed in accordance with the requirements of the OCD. The OCD witnessed the annular pressure test that successfully confirmed internal mechanical integrity at a pressure of 753 psig.

Upon conclusion of the annular pressure test, all equipment was rigged down and moved out.

1.0 INTRODUCTION

Navajo reentered, tested and completed The Eastland Oil Company, Chukka Federal No. 2 wellbore for injection of plant waste effluent. The name of the new waste disposal well will be designated as Navajo Refining Company Waste Disposal Well No. 2 (WDW-2). The wellbore is located in Section 12, T18S, R27E, Unit Letter E, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. A Well Location and Acreage Dedication Plat of the well location is shown on Figure 1.0-1. The construction and testing of this well were performed in compliance with the provisions of the New Mexico Water Quality Control Commission Regulations (NMWQCCR), dated November 15, 1996, Subpart V, Section Nos. 5204 and 5205, and the United States Environmental Protection Agency Code of Federal Regulations, 40 CFR 146.12, Subpart B.

Subsurface was contracted by Navajo to reenter and test WDW-2. The construction and testing of this Non-Commercial Class I Nonhazardous Waste Disposal Well were permitted by the Department of the Interior, Bureau of Land Management (BLM), and the New Mexico Energy, Minerals, and Natural Resources Department, OCD by letters dated May 3, 1999 (Appendix 1.0-1) and April 27, 1999 (Appendix 1.0-2). All work associated with WDW-2 was completed in accordance with the provisions specified in the permit approved by the BLM and OCD.

The work for WDW-2 was designated as Subsurface's Project No. 70A4955. This report summarizes all work performed on WDW-2 and includes the filing of the necessary documents.

2.0 SUMMARY OF DAILY OPERATIONS

The original wellbore was designated as the Amoco Production Company, Diamond Federal Gas Com. Well No. 1, installed July 18, 1973. The OCD Sundry Notices and Reports on Wells are presented in Appendix 2.0-1. The wellbore was constructed with a 13-3/8 inch OD conductor casing set at 40 feet and cemented to surface. An 11 inch hole was drilled to a depth of 1995 feet. Open-hole logs were conducted to include resistivity, spontaneous potential, porosity, and gamma ray, as presented in Exhibits 2.0-1 and 2.0-2. An 8-5/8 inch surface casing was set at 1995 feet and cemented to surface. A 7-7/8 inch hole was drilled to a depth of 10,372 feet to test potentially productive hydrocarbon zones. Subsequently, the wellbore was abandoned on August 31, 1973.

On August 29, 1985, Fred Pool Drilling Inc. submitted an Application for Permit to Drill or Deepen to the BLM. The wellbore was reentered to 1912 feet and completed as a producing oil well with perforations from 1446 feet to 1462 feet, as noted in the Sundry Notices and Reports on Wells (Appendix 2.0-2). The name of the wellbore was changed to the Chukka Federal Well No. 2. Figure 2.0-1 is the plugged-back wellbore schematic.

The Chukka Federal Well No. 2 continued to operate as a producing oil well from September 1985 to May 5, 1999. The Operator changed from Fred Pool Drilling, Inc. to The Eastland Oil Company prior to purchase by Navajo Refining Company in April 1999.

Navajo Refining Company submitted and received approval for the reentry, testing, and completion of the Chukka Federal Well No. 2 from the BLM on April 27, 1999.

On Monday, May 3, 1999, OCD approved the Application for Permit to Drill or Deepen Navajo Refining Company's (Navajo) WDW-2, formerly the Chukka Federal No. 2 operated by The Eastland Oil Company.

The reentry, testing, and completion operations for WDW-2 are presented in this section. Details of certain operations are referenced in the text and included as figures, exhibits, tables, and appendices.

Figure 2.0-2 is the current wellbore schematic for WDW-2. Table 2.0-I contains the detailed tubular program for WDW-2.

2.1 Cement Squeeze the Perforations

From May 5, 1999 to May 8, 1999, Navajo initiated field operations. The existing pumping equipment, rods, and tubing were removed from the wellbore. The perforations from 1446 feet to 1462 feet were squeezed using 100 sacks of Class 'H' cement. Approximately 50 sacks of cement were displaced into the perforated interval. The cement was allowed to cure and drilled out to a total depth of 1922 feet (1911 feet below ground level).

2.2 8-5/8 Inch Mechanical Integrity Testing

On Sunday, May 9, 1999, the 8-5/8 inch surface casing, set from 1955 feet (KB) to surface, was pressure tested for internal mechanical integrity between 1922 feet (KB) and 30 feet (KB) using a packer set at 30 feet. The 8-5/8 inch surface casing was pressure tested to 660 pounds per square inch (psi) and monitored at the surface for one hour. The fluid used for testing was a clean fresh water fluid. A pressure loss of 1 psi (0.15%) was observed during the first 30 minutes of the test. A pressure loss of 2 psi (0.30%) was observed during the last 30 minutes of the test. The results from the pressure test confirmed internal mechanical integrity of the 8-5/8 inch surface casing from 1922 feet (KB) to 30 feet (KB).

On Sunday, May 9, 1999, Halliburton Logging Services completed a Cement Bond Log and Microseismogram (same as a variable density log), CBL/MSG, survey within the 8-5/8 inch casing from a wireline total depth of 1919 feet (KB) to the surface (Exhibit 2.2-1). The results from the survey indicate a continuous column of cement from 1922 feet to surface with good bonding characteristics. The cement behind the 8-5/8 inch casing will provide an effective hydraulic seal to

prevent the movement of groundwater fluids into the underground source of drinking water with a base at 473 feet.

The workover rig was rigged down. A letter requesting regulatory approval for the surface casing pressure test and CBL/MSG log was submitted to the OCD for review and approval (Exhibit 2.2-2).

From Monday, May 10, 1999 to Tuesday, May 11, 1999, the 8-5/8 inch riser was replaced and the reserve pit was excavated.

2.3 Preparation of the Drillsite

On May 12, 1999, a 6 millimeter, high density, polyethylene liner was installed in the reserve pit. The rathole and mouseholes were installed in accordance with Patterson Rig 47 specifications.

2.4 Mobilization of the Drilling Equipment

On May 13, 1999, Patterson moved in and rigged up the drilling rig. A rental wellhead was installed and the blowout prevention equipment was installed and tested in accordance with The United States Department of the Interior, Bureau of Land Management, Onshore Order No. 2 Specifications (Appendix 2.5-1).

2.5 Reentry Operations

On May 14, 1999, a 7-7/8 inch bit was lowered into the 8-5/8 inch casing to drill out the 100-foot cement plug from 1922 feet to 2093 feet. The drillpipe was washed into the wellbore to 2898 feet. A deviation survey at 2898 feet indicated ¼-degree inclination. The wellbore was washed out to 3830 feet. A deviation survey at 3838 feet indicated ¼-degree inclination. The wellbore was washed and reamed to 4783 feet. A deviation survey at 4783 feet indicated ½-degree inclination. The wellbore was washed and reamed to 5082 feet.

On May 15, 1999, the cement plug at 5450 feet was tagged. The blowout prevention equipment was successfully tested in accordance with Section III(A) of

the Conditions for Approval attached to the Application for Permit to Drill or Deepen, approved April 27, 1999. The BLM was notified by letter of the blowout prevention equipment pressure test results on May 17, 1999 (Appendix 2.5-1). The wellbore was washed and reamed to 6106 feet. A deviation survey at 6106 feet indicated an inclination of 3/4 degree. The wellbore was washed and reamed to 6500 feet. The mud weight was increased to 8.7 pounds per gallon (ppg).

On May 16, 1999, the wellbore was washed and reamed to 6633 feet. A deviation survey at 6633 feet indicated an inclination of 1/2 degree. The wellbore was washed and reamed to 7269 feet and the mud weight was increased to 8.9 ppg. At 7500 feet, a small amount of gas was circulated out of the wellbore and the mud weight was increased to 9.1 ppg. The wellbore was washed reamed to 8100 feet. There was no indication of a cement plug from 7435 feet to 7534 feet.

On May 17, 1999, the wellbore was washed and reamed to total depth at 8992 feet. The wellbore was circulated clean and a short trip to 1900 feet did not indicate tight spots, bridges, or excessive drag on the drillpipe. The drillpipe, drill collars, and bit were removed from the hole.

On May 18, 1999, Halliburton Logging Services performed a 4-arm caliper survey from 8901 feet to 1800 feet (Exhibit 2.5-1), and a fracture identification survey from 8900 feet to 4000 feet (Exhibit 2.5-2). Cement volumes were calculated using the 4-arm caliper survey with 20% excess.

The bit, drill collars, and drillpipe were lowered into the hole to tag 30 feet of fill. The wellbore was circulated clean and the drillpipe was pulled out of the hole and laid down.

2.6 Installation of the Protection Casing

On May 19, 1999, 119 joints of 5-1/2 inch, 17 lb/ft, L-80, LTC, new, seamless, Range 3 protection casing were installed in WDW-2 (Table 2.6-I). The Mill Test Report from the manufacturer is included in Appendix 2.6-1. The packoff float shoe was set at 8869 feet, float collar at 8788 feet, and DV tool at 5792 feet. The

BLM was notified of the cementing operations. Halliburton cemented the first stage using 20 barrels of fresh water, 12 barrels of Super Flush, 20 barrels of water, and 575 sacks of modified Class 'H' cement (yield = 1.71 ft^3/sack at 13.0 ppg). The DV tool was opened and a total of 20 sacks of cement was displaced to the surface. A total of 18 hours was allotted to wait on cement to cure above 500 psi compressive strength.

On May 20, 1999, the second stage was successfully completed with 20 barrels of water, 12 barrels of Super Flush, 20 barrels of water, 300 sacks of Interfill 'C' (yield = 2.77 lb/sack at 11.7 ppg), and 695 sacks of modified 'H' cement (yield = 1.71 lb/sack at 13.0 ppg). The DV tool was closed with 3300 psi and a total of 150 sacks of cement was displaced to the reserve pit. Mr. J.D. Whitlock, representing the BLM, was on site and witnessed the second stage cementing operations. The cement was allowed to cure for 12 hours.

On May 21, 1999, the blowout preventers were removed and the rig was released. A Larkin Type 'R' 5-1/2 inch by 3-1/2 inch wellhead was installed. Ready-mix cement was used to stabilize the 5-1/2 inch casing and the location was cleaned up in preparation of completion operations.

From May 22, 1999 to May 23, 1999, preparations were performed prior to completion activities.

2.7 Testing and Completion Operations

On May 24, 1999, Key Energy Services, Inc. moved in and rigged up a completion rig, pump, tank, power swivel, and 2-7/8 inch EUE 8rd work string. A 6 inch manual blowout preventer was installed for pressure control. A piece of pipe was lost in the hole during rig-up operations.

On May 25, 1999, the lost piece of pipe was successfully washed over and retrieved from the wellbore. A 4-3/4 inch outside diameter rock bit and six 3-1/2 inch drill collars were lowered into the wellbore on the 2-7/8 inch work string. The well system was pressurized to 1514 psig and monitored for testing. A loss of 17

psi per 30 minutes was observed (-1.15%) during the pressure test. The DV tool was drilled out.

On May 26, 1999, the bit was lowered into the well to wash and drill to a total plugged-back depth of 8770 feet (Table 2.7-I). The wellbore was circulated clean, pressurized to 1584 psig, and monitored for testing. A loss of 16 psi per 30 minutes was observed (-1.01%) during the pressure test (Figure 2.7-1).

On May 27, 1999, a bit and scraper were lowered into the wellbore to 8569 feet. A total of 500 gallons of 15% HCl inhibited acid preceded displacement of 250 barrels of 8.7 ppg clean brine water. Fluid returns were circulated to the reserve pit.

On May 28, 1999, a differential temperature survey was conducted within the 5-1/2 inch protection casing from surface to 8769 feet. The well system was pressurized to 1000 psig and a cement bond survey, concurrent with a casing inspection survey, was conducted from 8769 feet to 100 feet.

2.8 Perforating and Testing the Cisco/Canyon Formations

On May 29, 1999, the wellbore was perforated within the injection interval at two jet shots per foot, 120 degree phasing, using retrievable casing guns. The selected intervals were determined from the Compensated Neutron-Formation Density Log, dated August 27, 1973, as follows: 7826-34 feet, 7858-80 feet, 7886-7904 feet, 7916-36 feet, 7944-64 feet, 7990-8042 feet, 8096-8116 feet, 8191-8201 feet, 8304-8319 feet, 8395-99 feet. This interval has been designated Zone 1. The wellbore fluid level dropped during the perforating operations.

On May 30, 1999, Zone 1 was swab tested and a formation fluid sample was retrieved for analysis. The results from the laboratory analysis on the Zone 1 formation fluid sample are presented in Appendix 2.8-1.

On May 31, 1999, the injection interval from 7820 feet to 8392 feet (Zone 1) was stimulated with 5000 gallons of inhibited 15% HCl acid. A total of 2300 pounds of

salt was used as diverter during the stimulation operations. A final test rate indicated WDW-2 can accept an 8.7 ppg brine water at 7 bpm on a vacuum.

2.9 Perforating and Testing the L. Wolfcamp/Cisco Formations

On June 1, 1999, the wellbore was perforated within the injection interval at two jet shots per foot, 120-degree phasing, using retrievable casing guns. The selected intervals were determined from the Compensated Neutron-Formation Density Log, dated August 27, 1973, as follows: 7570 feet to 7620 feet and 7676 feet to 7736 feet. This interval has been designated Zone 2. The wellbore fluid level remained at approximately 1300 feet during the perforating operations. A complete record of the perforated intervals is presented in Table 2.9-I.

On June 2, 1999, Zone 2 was swab tested and a formation fluid sample was retrieved for analysis. The results from the laboratory analysis on the Zone 2 formation fluid sample are presented in Appendix 2.8-1.

On June 3, 1999, the injection interval from 7570 feet to 7736 feet (Zone 2) was stimulated with 5000 gallons of inhibited 15% HCl acid. A total of 2300 pounds of salt was used as a diverter during the stimulation operations. A final test rate indicated WDW-2 can accept an 8.7 ppg brine water at 7 barrels per minute (bpm) on a vacuum.

2.10 Injectivity Testing

On June 4, 1999, an electric wireline unit was moved in and rigged up with a digital quartz surface readout and memory backup pressure gauge. Both gauges were run into the well to a depth of 7570 feet. The initial bottom-hole pressure was 2843.86 pounds per square inch absolute (psia) at 124°F. Injection of an 8.7 ppg brine water was initiated at 10 bpm on a vacuum and continued for 12.75 hours. The final injection pressure was 2939 psia at 88°F. Injection of brine was discontinued and the bottom-hole pressure falloff was monitored at the surface.

On June 5, 1999, the pressure falloff was discontinued and the tools were removed from the wellbore while making gradient stops at 6000 feet, 4500 feet, 3000 feet, 1500 feet, and at the surface. A differential temperature survey was performed from the surface to a wireline total depth of 8736 feet (top of fill). A radioactive tracer survey confirmed external mechanical integrity of the 5-1/2 inch protection casing and provided an injection profile across the perforated intervals.

2.11 Installation of the Injection Tubing and Packer

On June 6,1999, a 5-1/2" x 3.5" Weatherford (Arrow) Model X-1 packer (Figure 2.11-1) was lowered into the wellbore on the 3-1/2 injection tubing (Table 2.11-I). The annulus was displaced with an 8.7 ppg corrosion inhibited brine water as packer fluid. The corrosion inhibitor was a Unichem TECHNI-HIB 370, as presented in the product information and Material Safety Data Sheets presented in Appendix 2.11-1. Mill test and inspection reports for the 3-1/2 inch injection tubing are presented in Appendix 2.11-2. The packer was set 7528 feet with 18,000 pounds of compression and the annulus was pressurized to 771 psig. The annular pressure was monitored for stabilization through June 7, 1999.

On June 8, 1999, an annulus pressure test was performed. The OCD elected to witness the test. The annulus was pressurized at 752 psig and monitored for 30 minutes. The final test pressure was 753 psig, an increase of 1 psi (0.13%), which is within the 10% allowed by the regulations. Upon the conclusion of the annulus pressure test the rig and ancillary equipment were rigged down and moved off site.

The installation of WDW-2 was completed on June 8, 1999. The wellhead was secured and the well remained shut in pending approval of the permit by the OCD.

2.12 Chronology of Field Activities

Appendix 2.12-1 is a Chronology of Field Activities from the Field Activity Reports.

3.0 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of WDW-2, required by NMWQCCR Subpart V, Section 5204(A) to (D) and Section 5205(A)(1)(a), included a casing inspection log of the 5-1/2 inch protection casing, pressure testing of the 5-1/2 inch protection casing, cement bond log of the 8-5/8 inch and 5-1/2 inch casings, a radioactive tracer survey, a differential temperature survey, and an annular pressure test. Results of these tests demonstrated that the well had internal and external mechanical integrity.

3.1 5-1/2 Inch Protection Casing Inspection Log

On May 28, 1999, Halliburton Logging Services conducted a casing inspection log from 8769 feet to the surface (Exhibit 3.1-1). A Circumferential Acoustic Scanning Tool was used to conduct the casing inspection survey. The data obtained from the survey may be used as a baseline for future comparison.

3.2 5-1/2 Inch Protection Casing Pressure Test

The protection casing was successfully pressure tested to 752 psig on June 8, 1999, for 30 minutes. A pressure gain of 1 psi was observed, as indicated on the pressure test chart shown on Figure 3.5-1.

3.3 Cement Bond Logging

A cement bond log was conducted within the 8-5/8 inch surface casing during the reentry operations from 1910 feet to the surface. Upon installation of the 5-1/2 inch protection casing, a cement bond log was conducted. A total of two strings of casing were successfully installed and cemented across the base of the underground source of drinking water (USDW).

3.3.1 8-5/8 inch Cement Bond Log

On May 9, 1999, a cement bond with variable density log was performed within the 9-5/8 protection casing from 1910 feet to the surface (Exhibit 2.2-1). The data obtained from the cement bond log confirmed a continuous column of cement with

good bonding characteristics behind the 8-5/8 protection casing from 1910 feet to 116 feet. The hydraulic coupling was lost above 116 feet and the tool would not respond. A letter of interpretation of the surface casing cement bond/variable density log is presented as Exhibit 2.2-2.

3.3.2 5-1/2 Inch Cement Bond Log

A cement bond with variable density log was conducted on the 5-1/2 inch protection casing on May 28, 1999 (Exhibit 3.3.2-1). As indicated on the log, a continuous column of cement extends from the base of the protection casing from a plugged-back depth of 8769 feet to the surface. Cement bonding was indicated to be sufficient for completion of the well. A letter of interpretation of the protection casing cement bond/variable density log is presented as Exhibit 3.3.2-2.

The adequacy of the cement above the top of the perforations was successfully confirmed in the subsequent radioactive tracer survey discussed in Section 3.4 and differential temperature survey discussed in section 3.6.

The results obtained from the cement bond and variable density logs conducted on the surface casing and the protection casing established that a continuous column of cement, with good compressive strength and cement bond, existed behind both casings. The installation of two casing strings across the base of the USDW, both of which demonstrate a continuous column of cement from surface to bottom, assures protection of the USDW.

3.4 Radioactive Tracer Survey

A radioactive tracer survey for WDW-2 was performed on June 5, 1999, following the reservoir evaluation testing operations and prior to the installation of the injection packer. The radioactive tracer survey consisted of running statistical checks, two baseline gamma ray surveys, and ejecting four slugs of radioactive material. Two (2) of the slug tests were stationary time-drive surveys and two were moving surveys. The radioactive tracer log, conducted June 5, 1999, is presented as Exhibit 3.4-1. An

injection profile analysis log is presented as Exhibit 3.4-2. All tests were conducted while injecting a nonhazardous brine water into the well.

The radioactive tracer tool was lowered into the well to tag the total depth at 8743 feet. A pre-survey baseline gamma ray log was conducted from 8743 feet to 7460 feet. A pre-survey statistical check was performed at 7550 feet (20 feet above the top perforation) for five minutes.

The moving surveys were conducted with the radioactive tracer tool initially positioned at 7460 feet (above the intended packer setting depth). The injection of a nonhazardous brine was initiated at a rate of 1/2 bpm. A slug of radioactive material was ejected and verified for intensity. The slug's downward movement was recorded by logging upward through the slug intermittently as it moved downward and dissipated into the perforated interval. This test was repeated at an injection rate of 1/2 bpm. The results obtained from the moving surveys determined that the ejected radioactive material was exiting into the permitted injection interval; therefore, mechanical integrity was confirmed between the intended packer setting depth and the top of the injection interval.

The injection of a nonhazardous brine was increased to 10 bpm. The radioactive tracer tool was positioned with the bottom detector at 7550 feet, which is 20 feet above the top of the top perforation, and a stationary time-drive survey was conducted. The tool remained stationary across the interval and the well was monitored for upward migration above 7550 feet for 15 minutes. This test was repeated and monitored for upward migration above 7550 feet for 15 minutes. No upward migration of radioactive material was observed during either survey.

A post-survey baseline gamma ray log was performed from 8727 feet to 7453 feet, with no residual radioactive material.

3.5 Annular Pressure Test

The official annular pressure test was conducted on June 8, 1999. The injection packer and tubing had been installed and the wellbore allowed to attain a thermal equilibrium.

A Barton circular chart recorder (Serial Number 0323), scaled from 0 psig to 1000 psig, was installed to monitor the annulus pressure. The OCD representative, Mr. Van Barton, was present to witness the annulus pressure test. At 0800 hours, the initial annulus pressure was 752 psig. At 0830 hours, the final annulus pressure was 753 psig. This represents a pressure gain of 1.00 psi in 30 minutes, which is within the limit of 10% in 15 minutes allowed by the OCD. An annulus pressure test chart is presented as Figure 3.5-1.

3.6 Differential Temperature Survey

A baseline differential temperature survey was performed on May 28, 1999 (Exhibit 3.6-1) following the cleanout of the 5-1/2 inch protection casing to 8770 feet. On June 5, 1999, a second differential temperature survey was performed following the reservoir evaluation testing, which included 12-hour injection of an 8.7 ppg brine water into the permitted injection interval (Exhibit 3.6-2).

As indicated on the May 28, 1999 baseline differential temperature log, the wellbore temperature increased steadily from 77.0 degrees at the surface to 154.0 degrees at 8769 feet. A temperature gradient of 0.01 degrees per foot was observed.

On June 5, 1999, a second differential temperature log was performed following the injection of brine water into the injection interval. A temperature gradient of .01 degrees per foot was observed from surface to the top perforation at 7570 feet. A significant cooling anomaly was observed within the perforated injection interval as temperatures cooled to 97.5 degrees. The data obtained from the differential temperature survey confirmed external mechanical integrity of the 5-1/2 inch protection casing and may be used for comparison during future surveys.

4.0 RESERVOIR EVALUATION

4.1 Bottom-Hole Pressure Testing

The bottom-hole pressure testing which was conducted on WDW-2, following the completion of the well, was designed to obtain the best estimate of permeability and transmissibility in the reservoir. The pressure testing on WDW-2 consisted of a static gradient survey and an injectivity/falloff test. Appendix 4.1-1 lists the time and pressure data recorded during the static gradient survey, injection period, and falloff period.

4.1.1 Static Gradient Survey and Bottom-Hole Pressure Analysis

On June 5, 1999, static gradient measurements were performed after conducting the injection/falloff test on WDW-2. Pressure data from the gradient stops made at the surface, 1500 feet, 3000 feet, 4500, 6000 feet, and 7570 feet are shown on Table 4.1.1-I. The gradient data are presented graphically as Figure 4.1.1-1. The static fluid gradient at 7570 feet was determined to be 0.429 psi per foot. The fluid level was at approximately 1292 feet.

4.1.2 Analysis of the Falloff Test

On June 4, 1999, a HP surface readout digital quartz pressure transducer with memory tool backup was positioned at 7570 feet in WDW-2 and allowed to stabilize for approximately 45 minutes. Injection into WDW-2 commenced at 0912 hours at an injection rate of 428.4 gallons per minute (gpm). WDW-2 was shut in at 2156 hours and the bottom-hole pressure and temperature were recorded for 7.2 hours.

The pressure data obtained during the falloff test were analyzed with the assistance of the commercially available pressure transient analysis software program "PanSystem2, Version 2.5". Appendix 4.1.2-1 contains the output from this software program. Figure 4.1.2-1 shows the pressure response recorded by the pressure tool from the time the tool was in place through the 7.2-hour shutin period. Figure 4.1.2-2 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure

derivative versus equivalent shutin time. The radial flow period is denoted on Figure 4.1.2-2.

The reservoir permeability was determined from the radial flow region of the superposition Horner plot (Figure 4.1.2-3). The radial flow regime begins at a Horner time of 16.9 and continues to 8.6. Figure 4.1.2-4 shows an expanded view of the superposition Horner plot. The slope of the radial flow period was determined to be 1.563604 psi per cycle.

An estimate of mobility-thickness, kh/μ, for the reservoir was determined from the following equation:

$$\frac{k\ h}{\mu} = 162.6\ \frac{q\ B}{m}$$

where,

kh/μ	=	mobility-thickness, md-ft/cp
q	=	flow rate, barrels per day
μ	=	viscosity, centipoise
B	=	formation volume factor, reservoir vol/surface vol
m	=	slope of semi-log straight line, psi/cycle

Using an injection rate of 428.4 gpm (14,688 barrels per day) and the information previously mentioned results in a mobility-thickness of 1,527,413 md-ft/cp:

$$\frac{k\ h}{\mu} = 162.6\ \frac{(14{,}688)(1.0)}{1.563604}$$

$$= 1{,}527{,}413\ \text{md-ft/cp}$$

Multiplying this value by the viscosity, μ, results in transmissibility, kh:

$$k\ h = \left(\frac{k\ h}{\mu} \right) \mu$$

$$= (1{,}527{,}413)\ (0.53)$$

$$= 809{,}529 \quad md\text{-}ft$$

And finally, permeability is determined by dividing transmissibility by the formation thickness. The formation thickness is 299 feet, which results in a permeability of 2707 md.

$$k = \frac{(k\ h)}{h}$$

$$= \frac{809{,}529}{299}$$

$$= 2707 \quad md$$

The skin factor was determined from the following equation:

$$s = 1.151 \left[\frac{p_{wf} - p_{1\,hr}}{m_1} - \log\left(\frac{k_p}{\phi\ \mu\ c_t\ r_w^2} \right) + 3.23 \right]$$

where,

s	=	formation skin damage at open perforations, dimensionless
1.151	=	constant
p_{wf}	=	flowing pressure immediately prior to shutin, psi
$p_{1\,hr}$	=	pressure determined by extrapolating the first radial flow semi-log line to a Δt of one hour, psi
m_1	=	slope of the first radial flow semi-log line, psi/cycle
k_p	=	permeability of the formation opposite the open perforations, md
ϕ	=	porosity of the injection interval, fraction

μ = viscosity of the fluid the pressure transient is traveling through, centipoise

c_t = total compressibility of the formation plus fluid, psi^{-1}

r_w = radius of the wellbore, feet

3.23 = constant

The final flowing pressure, p_{wf}, was 2939.42 psia. The pressure determined by extrapolating the radial flow semi-log line to a Δt of one hour, $p_{1\ hr}$, was 2846.23 psi. The porosity of the injection interval, ϕ, is 0.10 and the total compressibility, c_t, is 8.4×10^{-6} psi^{-1}. The wellbore radius, r_w, is 0.3281 feet. Using these values in addition to the previously determined parameters, m and k, results in a skin of 59.9:

$$s = 1.151 \left[\frac{2939.42 - 2846.23}{1.563604} - \log \left(\frac{2707}{(0.10)(0.53)(8.4 \times 10^{-6})(0.3281)^2} \right) + 3.23 \right]$$

$$= 59.9$$

The "Auto-Match" feature of PanSystem2 was used to improve upon the reservoir parameters. The final results of the auto-match are shown on Figures 4.1.2-5 through 4.1.2-7. These figures show the falloff data in cartesian, superposition Horner, and log-log formats with the simulated pressures overlaid.

SUBSURFACE

RE-ENTRY AND COMPLETION REPORT
WASTE DISPOSAL WELL NO. 3

NAVAJO REFINING COMPANY
Artesia, New Mexico

SUBSURFACE PROJECT NO. 70F5826

December 2006

PREPARED BY

SUBSURFACE CONSTRUCTION CORP.
6925 Portwest Dr., Suite 110
Houston, Texas77024

SUBSURFACE

February 5, 2006

Mr. Darrell Moore
Navajo Refining Company
P.O. Box 159
Artesia, NM 88211

RE: Re-Entry and Completion Report Waste Disposal Well No. 3;
Subsurface Project No. 70F5826

Dear Darrell:

Enclosed are four (4) copies of the above-referenced report. Four copies have been included for your records and for the State of New Mexico Energy Minerals and Natural Resources Department, Oil Conservation Division.

If you should have any questions, please feel free to contact me at (713) 880-4640.

Very truly yours,

Rusty L. Smith
Project Engineer, EIT

RLS/bl

Enclosures

Moore1_Ltr

Subsurface Construction Corp.
6925 Portwest Drive Suite 110 Houston TX 77024
713/880-4640 Fax 713/880-3248 1-800-535-4105

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EXECUTIVE SUMMARY

Navajo Refining Company (Navajo) contracted Subsurface Technology, Inc. (Subsurface), to prepare an Application for Permit and to Re-enter a Plugged and Abandoned (P&A) Oil and Gas Well. The Application for Permit to Drill or Re-enter and the Sundry Notices and Reports on Wells was submitted to the Department of the Interior, Bureau of Land Management (BLM), on June 29, 2006, and approved. The Application for Permit to Drill, Re-enter, Deepen, Plug Back, or add a Zone was submitted to the State of New Mexico Oil Conservation Commission (OCD) on June 29, 2006, and approved.

Subsurface prepared an engineering plan to re-enter the P&A' oil and gas well formally owned by Mewbourne Oil Company. The original well name was Caulk Bluff Federal No. 1 (API number 30-015-26575), and a Change of Operator application was submitted to the OCD on December 5, 2000, and approved under the well name of WDW-3. Under contract to Navajo, Subsurface commenced field operations on September 25, 2006. The existing location was cleared and prepared for re-entry operations. An earthen lined reserve pit was dug to catch returns. All depths, unless stated, are referenced to workover rig floor at six feet to seven feet above ground level. The rig floor was moved from six feet to seven feet after drilling out the cast iron bridge plugs.

A workover rig and reverse unit was placed on location and the existing wellhead was removed. The first cast iron bridge plug (CIBP) at 7010 feet was drilled and the perforated interval from 7050 feet to 7102 feet was squeezed off with neat cement and successfully pressured tested to six hundred eighty pounds per square inch gauge pressure (680 psig). The second and third CIBP at 7190 feet and 7279 feet was drilled. There appeared to be ten feet of cement on top of the third CIBP. The perforated interval from 7262 feet to 7278 feet and from 7304 feet to 7314 feet was squeezed with neat cement. The squeezed interval was pressure tested to 920 psig and would not hold. A second cement squeeze was performed across the perforated interval from 7262 feet to 7278 feet and from 7304 feet to 7314. The interval was pressured tested to 630 psig and continued to lose pressure at a rate of two pounds per square inch every thirty minutes (2 psi/30 min). The fourth CIBP at 7595 feet was drilled and at 7838 feet a cement plug was

encountered and drilled through. Cement was tagged twenty nine (29) feet above the top of the liner at 9022 feet. The hole was circulated clean and prepared for logging.

A Cement Bond Log (CBL), Variable Density Log (VDL), caliper log, and temperature survey were performed. The CBL/VDL showed that the top of the cement (TOC) behind the 7-inch casing was located 900 feet from the surface. The OCD was notified and approved the existing well condition. The casing was perforated from 7660 feet to 8450 feet and from 8540 feet to 8620 feet at 2-JSPF on sixty degree (60°) phasing.

A packer was set at 7546 feet with 2 7/8-inch PH-6 tubing, the well was swabbed back and samples of the formation fluid were recovered. It was estimated that two hundred twenty six barrels (226 bbls) of formation fluid was returned to the surface. A pressure test on the annulus between the 7-inch and 2-7/8-inch was performed at 660 psig with the annulus losing pressure at a rate of 8 psi/hr.

An injection test was performed on the well down the 2-7/8-inch tubing with the annulus open to the bottom of the well. The open annulus will allow for the calculation of the bottom hole pressure while pumping down the 2-7/8-inch tubing with out the influence of tubing friction pressure on the bottom hole calculations. The injection rates were from two barrels per minute (2 bpm) to ten barrels per minute (10 bpm). From the data collected during the injection test it appears that the well will be able to accept an injection rate up to 10 bpm at the permitted pressure of 1550 psig with 4-1/2-inch, 11.6 pound per foot (11.6 lb/ft) tubing in the wellbore.

At the request of the OCD, Subsurface went back into the wellbore with a retrievable bridge plug (RBP) to test the casing and isolate any leaks to within 1000 feet. The RBP was set at 7550 feet and the packer was set at 6985 feet to isolate the squeezed interval from 7050 feet to 7314 feet. The squeezed interval was pressure tested to 490 psig and the annulus to 632 psig. The squeezed interval was losing pressure at a rate of 6 psi/hr and the annulus was gaining pressure due to thermal affects. The RBP was moved up the wellbore to 1255 feet and casing pressure tested to 569 psig. The casing above 1255 feet was losing pressure at a rate of 2 psi/hr. The casing leaks were isolated to the squeezed interval from 7050 feet to 7314 feet and in the interval from surface to 1255 feet. The

OCD was called and approved the 300PSI sealing application to stop the casing leaks across the two intervals.

The 4-1/2-inch tubing was run into the wellbore and the Arrow X-1 packer was set at 7575.73 feet with 37,000 lbs of tension. Prior to running the 4-1/2-inch tubing a new Superior hanging spool was installed. Prior to setting the tubing packer, the annulus between the 4-1/2-inch tubing and the 7-inch casing was filled with inhibited brine, with the 300psi sealant across the squeezed perforations and across the upper section of the 7-inch casing. Once the packer was set and tubing hung off in the spool, a new Superior wellhead was installed and the P-seals were pressure tested to 3000 psig. After the wellhead was assembled the annulus was squeezed at 545 psig for four hours (4 hrs), as specified by the sealant manufacture representative on site. The annulus was then pressure tested to 480 psig overnight with no pressure loss. The workover rig was disassembled and moved off location with all associated equipment.

A 12-hr pump-in and falloff test was performed down the 4-1/2-inch tubing. To maintain a surface injection pressure that was below the permitted pressure of 1550 psi the injection rate was lowered to 9 bpm at the end of the pump-in procedure. The BHP gauge was placed at 8630 feet for 14 hrs to monitor BHP. When the gauge was pulled, five minute (5 min) gradient stops were made every 1000 feet with the first stop at 7000 feet. The equipment used to perform the falloff testing was moved off location to prepare for mechanical integrity testing (MIT).

The MIT consisted of an annulus pressure test and a radioactive tracer survey. The temperature survey was performed during the CBL/VDL logging event and will be used as a baseline for any future temperature surveys. The annulus pressure test was performed at 530 psia and lost 2.5 psi over a one-hour period, which was within the OCD requirements of five percent (5%) over a 30 minute time interval. The radioactive tracer survey showed no signs of fluid flow out of the permitted interval above 7650 feet. The OCD witnessed the annular pressure test and the first half of the radioactive tracer survey.

The annulus monitoring system will be installed and tested in March 2007. After the installation of the well annulus monitoring system, the well will be turned over to Navajo for injection.

1.0 INTRODUCTION

Navajo re-entered, tested, and completed WDW-3 for the injection of plant waste effluent. The well is located in Section 1, Township18 South, Range 27 East (S1-T18S-R27E) approximately 11.5 miles east-southeast of Artesia, New Mexico in Eddy County. A Well Location and Acreage Dedication plat of the well location is located in Appendix 2.0-2. The construction and testing of this well was performed in compliance with the provisions of the New Mexico Water Quality Control Commission Regulations (NMWOCCR) Subpart V, Section Nos. 5204 and 5205, New Mexico Oil Conservation Division Underground Injection Control (UIC) Program Manual, and the Environmental Protection Agency (EPA) Code of Federal Regulations 40 CFR 16.12, Subpart B.

Subsurface was contracted by Navajo to re-enter and test WDW-3. The construction and testing of this Non-Commercial Class I Nonhazardous Waste Disposal Well was permitted by the BLM and the OCD. All work associated with WDW-3 was completed in accordance with the provisions specified in the permit approved by the BLM and OCD.

The following report and contracted work on WDW-3 was designated as Subsurface Project No. 70F5826. The following report summarizes all work performed on the WDW-3 and includes the fillings of the necessary documents. The report is broken down into four parts Summary of Daily Activities, Mechanical Integrity Testing, Reservoir Evaluation, and Regulatory Compliance. For continuity this report is written in the same structure as the report completed on WDW-2. The well reentry procedure can be found in 1.0-1.

2.0 SUMMARY OF DAILY OPERATIONS

The reentry, testing, and completion operations for WDW-3 are presented in this section. Details of certain operations are referenced in the text and included as figures, exhibits, tables, and appendices. Appendix 2.0-1 contains a Chronology of Field Activities from the Field Activity Reports.

The original wellbore was designated as the Mewbourne Oil Company, Chalk Bluff Federal No. 1 (API No. 30-015-26575), installed March 7, 1991, as a producing oil & gas well. The wellbore was constructed with 13-3/8-inch, 54.5 lb/ft surface casing set to 400 feet in a 17-1/2-inch hole and was cemented to the surface. A 9-5/8-inch, 36 lb/ft intermediate casing was set at 2600 feet in a 12-1/4-inch hole and cemented to the surface. The 7-inch, 26 lb/ft and 29 lb/ft production casing was set at 9450 feet in an 8-3/4-inch hole and was cemented to 900 feet below ground level (GL). On March 7, 1991, the well was deepened to 10,119 feet and a 4-1/2-inch, 11.6 lb/ft liner was installed from 9051 feet to 10,119 feet and cemented in place with 175 sks of cement. The well was plugged and abandoned on August 14, 1995. The well was acquired by Navajo on November 27, 2000. The current well configuration is presented in Figure 2.0-1 and Table 2.0-1.

Navajo submitted the application to recomplete the well to both the BLM and the OCD on June 6, 2006, and received approval from the OCD on August 11, 2006, (Appendix 2.0-3 and Appendix 2.0-4). The Sundry Notices and Reports on New Wells notification was submitted to the BLM on June 6, 2006, (Appendix 2.0-5). The New Mexico Energy, Minerals and Natural Resources Department sent a letter of approval to discharge according to UIC-CLI-008-3 on June 23, 2004, which was later modified to raise the top of the injection interval from 7750 feet to 7650 feet (Appendix 2.0-6)

2.1 LOCATION CLEARING AND RIG MOBILIZATION

On September 27, 2006, Banta's roustabout crew arrived at the job site with two back holes and a three man crew. The location was cleared of all overgrowth and a thirty feet by thirty feet by five feet (30 ft x 30 ft x 5 ft) lined pit was dug to hold returns. An eight foot by seven foot by three foot (8 ft x 7 ft x 3 ft) cellar was dug around the wellhead in order to inspect the lower section of the wellhead for repairs. New valves and fittings were installed on the existing wellhead. Rig support equipment started to arrive at the job site.

On September 28, 2006, the roustabout crew framed in the cellar and the Basic workover rig arrived at the job site. The rig was spotted and the remaining support

equipment arrived at the job site. The derrick was erected and the rig crew repaired the sand line break and replaced the drilling line. The 2-7/8-inch work string was tallied at 9413.59 feet with a bottom hole assembly of 126.45 feet (See Table 2.1-1).

On September 29, 2006, the wellhead was inspected by a Superior Wellhead technician and was found to be an eleven inch, three thousand pound, by seven inch, five thousand pound (11^3 x 7^5) Cameron type spool. The Cameron type spool attached to the wellhead had been discontinued and Superior suggested that the spool be replaced. The remaining support equipment arrived at the job site and was rigged up for drilling. The annular blow out preventer (BOP) was attached up to the wellhead and the rig crew went into the wellbore with 2-7/8-inch, 7.9 lb/ft, PH-6 tubing, four 4-3/4-inch drill collars, 46.67 lb/ft, and a 6-1/8-inch Baker Hughes Rock bit. The rig crew tagged bottom at 7001 feet.

2.2 DRILLING OF CAST IRON BRIDGE PLUGS AND CEMENT SQUEEZING OF THE PERFORATIONS

On September 30, 2006, the sand line brake on the rig would not hold and operations were shut down until the brake was repaired. On October 1, 2006, first CIBP was drilled out with no show of cement or drilling mud. The second CIBP was tagged at 7190 feet. The well was circulated clean with brine water and an injection test was performed. The rig crew tripped out of the hole (TOOH) with the work string and tripped into the hole (TIH) with the work string excluding the bit and drill collars (open ended) to spot cement for squeeze operations.

On October 2, 2006, the first cement squeeze was executed across the perforations from 7050 feet to 7102 feet. Halliburton spotted eighty sacks (80 sks) of Premium Plus neat 14.8 ppg cement across the perforations. The rig crew pulled nine stands to get out of the cement and circulated out any excessive that was trapped in the work string. Halliburton was able to pump four barrels (4 bbls) of cement into the formation before reaching a squeeze pressure of 2000 psig. The well was shut-in over night with 680 psig left on the wellhead.

On October 3, 2006, the rig crew tagged cement at 6873 feet assuming the hole was full of cement to the CIBP. At 7190 feet there were 12.1 bbls of cement left in the wellbore. The total amount of cement spotted in the wellbore was 18.7 bbls leaving 6.6 bbls of cement either place in the formation or circulated out of the wellbore. It was estimated that 3.5 bbls were circulated out of the tubing during the clean out, leaving 3.1 bbls placed into the formation (Halliburton Report Appendix 2.1-1). The cement in the wellbore was drilled out to the top of CIBP at 7190 feet and the well was pressure tested to 578 psig. The well lost 123 psi over a thirteen and half hour period at 9.1 psi/hr (1.58%).

On October 4, 2006, the second CIBP was drilled out and the third CIBP was tagged at 7278.96 feet. It was estimated that there was 9 feet of cement on top of the third CIBP. The third CIBP was drilled out and the formation started to take fluid at a rate of 1.0 bpm to 1.25 bpm. It was estimated that during circulation 180 bbls of 8.7 ppg brine was lost to the formation. The fourth CIBP was tagged at 7591 feet. The hole was circulated clean to prepare for the second cement squeeze operation. A pump-in test was performed and the well would take fluid at a rate of 4.5 bpm at 710 psig. The rig crew TOOH with collars and bit and TIH open ended to spot cement for squeeze operations.

On October 5, 2006, the bottom of the work string was placed at 7321 feet. Halliburton pumped 100 sks of 14.8 ppg Premium Plus neat cement across the perforations. The rig crew pulled ten stands and Halliburton started to squeeze into the formation using a hesitation squeeze method. The cement was squeezed into the formation in seven stages 10 minutes apart with 1.5 bbls of cement pumped between each stage. After the first stage the wellhead pressure was 78 psig and after the seventh stage the wellhead pressure was 1973 psig. The well was shut-in with 1970 psig for 2 hours and then was bled off and an additional eight stands were pulled and the tubing was circulated to clear the tubing of any excessive cement (see Halliburton Report Appendix 2.1-2). The well was shut-in over night with 930 psig on the wellhead.

On October 6, 2006, the rig crew drilled through soft cement and tagged bottom at 7554 feet, which was 37 feet above the previous spot at 7591 feet. The well would

not hold pressure and squeeze perforation were taking fluid at 25 gpm with 920 psig on the wellhead. A second cement squeeze was required to seal off the perforations.

On October 7, 2006, Halliburton was not available to do the third squeeze job so Key Pumping Services was called and performed the third cement squeeze. Rig crew TOOH with collars and bit and TIH open ended (without collars and bit). The bottom of the work string was placed at 7290 feet. On October 8, 2006, Key Pumping Services placed 80 sks of 14.8 ppg Premium Plus neat cement across the perforations. The rig crew pulled eight stands of pipe and circulated the pipe free of excessive cement. Key Pumping Services pumped 6 bbls of cement into the formation at 750 psig. At a squeeze pressure of 1975 and additional 1.5 bbls was pumped into the formation. Key Pumping Service stopped pumping for 10 min to allow the pressure to fall then pumped another 1.5 bbls into the formation before the formation refused to take any addition fluid at 1940 psig (see Key's Report in Appendix 2.1-3). The well was shut-in for the night with 1830 psig on the wellhead.

On October 9, 2006, Rig crew tagged hard cement at 6981 feet and drilled hard cement to 7312 feet. The estimated amount of cement left in the pipe was 12.7 bbls out of a total of 18.8 bbls pumped with no sign of returned cement. The rig crew tagged bottom at 7559 feet and the wellbore was circulated clean. On October 10, 2006, the casing was pressure tested for twelve hours with a starting pressure 630 psig. At the end of the twelve hour period, the pressure was 568 psig. The wellhead pressure was recorded every thirty minutes and, after six hours the rate of pressure loss was maintaining 2 psi/ 30 minutes. The annulus valve between the 7-inch casing and the 9-5/8-inch casing was opened and contained pressure. A gauge was placed on the 7-inch by 9-5/8-inch annulus and monitored for 18 hours with no apparent increase in pressure (Table 2.1-2). The 7-inch by 9-5/8-inch annulus was initially bled off before the BOP was placed on the wellhead.

On October 11, 2006, rig crew drilled through the fourth CIBP at 7595 feet and while drilling though the plug the plug dropped to 7776 feet. At 7780 feet mud contaminated cement was encountered. At 7838 feet the rig crew had drilled though the cement plug and TIH to the top of the 4-1/2-inch liner (TOL). The rig crew

tagged bottom at 9022 feet 28 feet above the TOL. It appears that there is a 28 foot cement plug across the top of the liner at 9051 feet. The wellbore was circulated clean from 9022 feet to surface. On October 12, 2006 the rig crew TIH with a casing scraper and circulated the hole to prepare for logging. Wood Group Logging Services arrived at the job site and spotted equipment.

2.3 LOGGING AND PERFORATING THE INJECTION INTERVAL

On October 13, 2006, Wood Group ran a CBL/VDL log, temperature survey, and a caliper log. The CBL/VDL log showed top of cement behind the 7-inch casing at 900 feet below the ground level (Appendix 2.3-1). The temperature log showed no major anomalies throughout the wellbore (Appendix 2.3-2). The caliper log showed some minor ware in the casing wall below the top of the injection interval (Appendix 2.3-3).

The CBL/VDL log was difficult to evaluate due to the fast formation responses. It appears that there is cement behind the 7-inch casing from the packer at 7575 feet up to 1500 feet with areas that appear to have a micro annulus. Isolation from 1500 feet to 1000 feet is spotty with little or no cement. From 900 feet to the surface, the CBL and VDL show no cement behind the casing.

The temperature survey showed no anomalies in the temperature curve. The fluid level in the well was found at 296 feet. The static bottom hole temperature (BHT) at 7575 feet was 126° F, at 8140 feet the BHT was 132.5° F, and at 9020 feet the BHT was 142.6° F.

The caliper log showed 7-inch, 29 lb/ft casing and 7-inch, 26 lb/ft casing mixed throughout the casing string. A bad spot in the 7-inch casing string was discovered at 7604 feet. There appears to be some additional corrosion from 8662 feet to 8705 feet.

From October 14, 2006 through October 15, 2006, Wood Group perforated the intervals from 7660 feet to 8450 feet and from 8540 feet to 8620 feet. Perforating was done using a 40 foot steel hollow carrier gun that produced a 0.5-inch hole at

two shots per foot on 60° phasing. On the first day 12 perforating runs were made completing the interval from 8540 feet to 8620 feet and 400 feet of the interval from 8050 feet to 8450 feet. On the second day 10 perforating runs were made completing the interval from 7660 feet to 8050 feet. There were no misfires during both days and all perforating charges went off as planned.

2.4 FORMATION SAMPLE COLLECTION AND INJECTION TESTING OF THE WELL

On October 15, 2006, the well was swabbed back from 2400 feet to surface to collect formation samples. Four samples were collected at different volumes of returned fluid. The first sample was collected after twelve runs estimated volume at 151 bbls. The second sample was taken after fourteen runs estimated volume at 176 bbls. The third sample was taken after sixteen runs estimated volume at 201 bbls, and the fourth sample was taken after eighteen runs estimated volume of 226 bbls. Samples were delivered to the Navajo Refining Facility in Artesia, New Mexico. Between runs seven through nine hydrogen sulfide gas was encountered and all personnel not active in the swabbing process were moved off the location. The formation fluid sample lab results can be found in Appendix 2.4-1. A standard API water analysis of the formation water samples and brine water samples was completed by Texas Oil Tech Laboratories.

On October 18, 2006, Key Pumping services arrived at the job site to perform the injection test. Key Pumping services started the injection testing down 2-7/8-inch, PH-6 tubing. Key's pump truck broke down after pumping 80 bbls. Key Pumping services returned on October 19, 2006. The wellhead was shut-in with the bottom of the pipe left open ended. Pressure gauges were placed on the annulus and on the wellhead. Key Pumping services circulated the wellbore at 2 bpm and caught returns after 37 bbls. The test commenced starting at 2 bpm and increasing in 1 bpm increments to 10 bpm. Both the wellhead pressure and annulus pressure were monitored during the testing. The annulus pressure will allow for a calculation of the BHP with out the affect of the 2-7/8-inch pipe friction. The brine fluid weight that was pumped into the well was measured at 8.6 ppg.

Key pumping was able to reach 10 bpm for a short five minute period before the deck engine over heated and the pump shut down. The wellhead tubing pressure at 10 bpm was 5087 psig the annulus pressure was estimated at 660 psig. With a hydrostatic pressure of 3488.16 psi calculated to 7800 feet, the BHP is 4148 psi. The pressure gradient is 0.53 psi/ft, which is below the fracture gradient. According to the data collected from the annulus pressure gauge, it appears that it would be possible to pump into the well at 10 bpm and still stay below the fracture gradient and the permitted wellhead pressure of 1550 psig (Table 2.4-1).

2.5 FINDING AND REPAIRING CASING LEAKS

The State of New Mexico OCD requested that Navajo Refining try to find all the casing leaks to within 1000 feet. For two days from October 20, 2006 to October 22, 2006, a retrievable bridge plug (RBP) and packer were placed in the wellbore to isolate sections of the casing within 1000 foot intervals. The additional testing that was performed after each perforation cement squeeze revealed that there were two intervals that were suspect of casing leaks; the interval across the squeezed perforations and the interval from 1000 feet to surface.

The first suspected interval was across the squeezed perforations. The RBP was set at 7550 feet and the packer was set at 6985 feet. The isolated interval was pressure tested to 490 psig and the annulus between the 2-7/8-inch tubing to the packer was pressure tested to 632 psig. The pressure loss across the squeezed interval stabilized after two hours and was losing 6 psi/hr. The annulus gained pressure due to thermal affects and would not stabilize.

The next suspect interval in the casing was in the upper 1000 feet to surface interval. The RBP was set at 1255 feet and the entire casing interval form 1255 feet to surface was pressure tested to 570 psig. The pressure stabilized after two hours and maintained a pressure loss of 2 psi/hr over a twelve hour period. The two tested intervals accounted for the majority of the 7-inch casing leaks. The OCD was called and approved the pumping of a sealant treatment provided by 300 PSI, Inc. as a solution to sealing off the 7-inch casing leaks. The treatment would be pumped ahead of and be hind the inhibited packer fluid.

2.6 RUNNING THE 4 1/2-INCH 11.6 LB/FT TUBING AND SETTING THE PACKER

On October 23, 2006, Superior Wellhead replaced the existing Cameron spool with a new Superior Wellhead spool. The BOP was reseated and Allen's Casing Crews started into the hole with the Weatherford Arrow X-1 7-inch by 3-inch packer. The Packer would not go past 50 feet before getting hung up in the casing. The packer was pulled and examined, and it was discovered Weatherford had brought out the wrong packer. Kenco, out of Artesia, was called and they delivered a new Arrow X-1, 7-inch by 2-7/8-inch (Figure 2.6-1) packer to the location. The Weatherford packer was made with a 3-inch EUE thread and the Kenco packer had a 2-7/8-inch REG thread. As a result of the Weatherford cross over not threading up to Kenco's packer, Kenco had an integral cross over made and brought to the location.

On October 24, 2006, Allen's Casing crew started into the wellbore with 4-1/2-inch tubing and Arrow X-1 packer. The tubing was torqued to specifications at 1600 lbs. The bottom of the packer was set at 7575.73 feet with 37,000 lbs of tension on the packer. Before the packer was set the wellbore was circulated with approximately 240 bbls. 300PSI pumped 23.8 bbls of sealant followed by 95 bbls of 8.7 ppg inhibited brine (55 gals Baker Petrolite CRW 132 inhibitor fluid) and 14.29 bbls of sealant. At the end of the pumping the packer was set with 37,000 lbs of tension and the slips placed into the hanging spool. The BOP was removed and the wellhead installed.

2.7 INSTALLATION OF THE WELLHEAD

On October 25, 2006, the rig crew finished rigging up the wellhead. Superior arrived and pressure tested the P-seals to 3000 psig. The rig crew filled the annulus with 2.5 bbls of 8.7 ppg brine water and 300 psi applied 545 psig to the 4-1/2-inch by 7-inch annulus using nitrogen. The pressure was maintained for four hours. The pressure was bled off and the annulus was pressure tested to 490 psig with brine for one-hour and recorded on a circular chart (Appendix 2.7-1). The annulus was bled down and retested overnight to 480 psig with no pressure loss. From October 25,

2006 to October 28, 2006, the rig was demobilized and moved off location with all support equipment. Key Energy services started moving frac tanks onto the location for the pressure build up and falloff testing. The pipe tally for the 4-1/2-inch tubing can be found in Table 2.7-1. A schematic of the as-built wellhead can be located in Figure 2.7-1.

2.8 PRESSURE BUILD UP AND FALLOFF TESTING

On November 2, 2006, Key Energy services placed fourteen frac tanks on the location and were in the process of filling them. On November 3, 2006, Banta Roustabout service installed the pump-in flange on the wellhead. Six temperatures were taken at the mid-point in the frac tanks to determine the brine fluid temperature, so that the stress that would be applied to the packer, due to temperature changes in the wellbore could be calculated. The average water temperature of brine that would be used to perform the pump-in procedure portion of the pressure build up was 60.6° F. The shear pins in the packer were set at 80,000 lbs and the maximum amount of shear stress that would be applied to the packer was determined to be less than 60,000 lbs. All the brine located in the frac tanks were treated with biocide and the tanks were rolled with a Key vacuum truck.

On November 4, 2006, Petroplex Pumping service rigged up to the injection side of the wellhead and a Key Energy kill truck rigged up to the annulus side of the wellhead. The kill truck will maintain 700 psig on the annulus in order to help reduce tubing and packer stresses. Petroplex Pumping service started pumping at 3 bpm and after 28 bbls the well caught pressure at 162 psig. The rate was slowly increased to 10 bpm with a wellhead pressure of 1278 psig. The rate was maintained at 10 bpm until the wellhead pressure started to approach the 1400 psig mark and at that time the rate was decreased to 9 bpm at a wellhead pressure of 1170 psig. Based on strap measurements from the frac tanks it was estimated that 6700 bbls of 8.8 ppg brine were pumped into the well (Table 2.8-1 and Appendix 2.8-1).

Two hours prior to ending the pumping procedure, Schlumberger Slickline service lowered a bottom-hole pressure gauge into the well at 8630 feet. While lowering

the tool, the rate was decreased to 5 bpm in order to get the tool passed through the upper section of the wellbore. At 9:00 PM pumping was stopped with the BHP tool at 8630 feet, and the well was closed in with 50 psig on the annulus and no pressure on the wellhead. On November 5, 2006, at 10:20 a.m. Schlumberger Slickline service started out of the hole, with the BHP gauge taking gradient stops every 1000 feet, starting at 7000 feet. Once the BHP tool was out of the wellbore the annulus was bled down and the well shut-in (Appendix 4.1-2). All but one frac tank were removed from the location.

2.9 LOCATION CLEANUP AND STATE REQUIRED TESTING

On November 13, 2006, Banta Roustabout service cleared the location of debris, hauled off trash, filled in cellar with pea gravel, removed diesel contaminated soil around the location, and leveled the location. The well cuttings and contaminated soils were placed in the reserve pit. The returned solids that remain in the reserve pit will have to be profiled prior to disposal and cannot be disposed of under the oil field exemption. The cuttings and returned solids that remain in the reserve pit will be hauled off once the profile of the material is complete.

On November 14, 2006, Wood Group was unable to rig up to the wellhead due to high winds and the OCD delayed testing until November 15, 2006.

On November 15, 2006, Wood Group logging services, Petroplex Pumping services, and OCD inspectors arrived at the job site. Wood Group Logging services performed an annulus pressure test, and radioactive tracer survey. Petroplex Pumping services provided pumps for the annulus pressure test and the chase down portion of the radioactive tracer survey.

The 4-1/2-inch by 7-inch annulus was pressure tested to 530 psia over a one-hour period and lost 1.99 psi. This represents a 0.37% pressure loss which is well within the OCD requirement of 5% for 30 minutes at a minimum pressure of 300 psig. The annulus pressure test was witnessed by the OCD representatives. The radioactive tracer test was run without any sign of radioactive material being pumped out of the injection interval. The first part of the radioactive tracer survey was witnessed by

the OCD representatives (Appendix 2.8-1, Attachment 2.8-1, Table 2.8-1, Figure 2.8-1). At the end of the job the annulus was again pressure tested to 300 psig and held pressure for 1-1/2-hrs before being bled off.

3.0 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of WDW-3, required by New Mexico Water Quality Control Commission Regulations (NMWQCCR) Subpart V, Section 5204 (A) to (D) and Section 5205(A)(1)(a), included a casing caliper inspection on the 7-inch protective casing, pressure testing of the 7-inch protective casing, CBL/VDL of the 7-inch casing, a radioactive tracer survey, a differential temperature survey, and an annulus pressure test. Results of these tests demonstrated that the well had internal and external mechanical integrity.

3.1 CALIPER CASING INSPECTION LOG

On October 13, 2006, Wood Group Logging services ran a caliper log to determine the condition of the existing casing wall thickness and to check for anomalies (Appendix 2.2-3). Overall the 7-inch protective casing looked good. The caliper log revealed that there was 26 lb/ft and 29 lb/ft casing in the wellbore. There was one anomaly found that occurred at 7604 feet, which appeared to be a gouge in the casing wall. The upper section of the 7-inch casing string appeared to be in better condition than the lower section. There appeared to be some corrosion and scale build up in a section of the casing just above and below the 8700 feet. The data obtained from the caliper log may be used as a baseline for future comparisons.

3.2 CEMENT BOND LOGGING

On October 13, 2006, Wood Group Logging services ran a CBL/VDL log (Exhibit 2.2-1). The CBL/VDL revealed cement had not been circulated to the surface behind the 7-inch protective casing, as was indicated in the state records. The TOC behind the 7-inch protective casing was located at 900 feet and the cement bond quality was poor down to 1200 feet. There were indications on the log that a micro annulus may be present below the 1200 foot interval. The intervals above the

injection interval from 2662 feet to 2160 feet, from 4876 feet to 5372 feet, and from 6750 feet to 7600 feet indicated that there was good bonding between the 7-inch casing and the cement to isolate the injection interval. The OCD was called and they approved the existing wellbore for injection and did not request that any additional cement be placed behind the 7-inch casing (Attachment 3.2-1).

3.3 CASING PRESSURE TESTING

After performing each perforation squeeze, the wellbore was drilled out and the casing was pressure tested. The casing pressure test that was performed across the squeezed interval from 7050 feet to 7102 feet had a loss rate of 9.1 psi/hr with a starting pressure of 580 psig. The pressure was run for 13.5 hours with the final reading at 455 psig.

The second perforation squeeze was over the perforated interval from 7262 feet to 7278 feet and 7304 feet to 7314 feet. The second cement squeeze would not hold pressure. A third cement squeeze was performed across the interval and the casing was pressure tested to 630 psig for a period of 12 hours. The final casing pressure was 568 psig with a average pressure loss of 2 psi/hr.

The OCD was notified of the pressure losses on the casing pressure test and requested that Navajo attempt to isolate the leakoff in the casing to within 500 feet to 1000 feet. A 2-7/8-inch by 7-inch packer and an RBP were run into the wellbore to isolate the squeezed interval. The RBP was set at 7550 feet and the packer was set at 6985 feet. The annulus between the 2-7/8-inch work string and the 7-inch protective casing was pressure tested to 632 psig and appeared to gain pressure due to a thermal heating effect in the wellbore. The tubing was pressure tested to 490 psig with a loss rate of 6 psi/hr down the 2-7/8-inch tubing.

The 7-inch protection casing interval from 900 feet to the surface did not appear to have cement behind it, therefore, it was necessary to determine if that interval mechanically sound. The RPB was set at the shallowest point possible at 1255 feet and the casing was pressure tested to 570 psig. Over a 13 hour period the wellhead pressure dropped to 540 psig with a loss rate of 2 psi/hr.

The request by the OCD was completed. The intervals across the squeezed perforations and the interval from 1255 feet to surface both showed signs of a casing leak. The leak-off rate across both intervals was small and within the regulator requirements of 5%. Again the OCD was contacted and they requested that Navajo attempt to seal off the leaks. A casing sealant was pumped with the inhibited brine down the 4-1/2-inch by 7-inch annulus before setting the 2-7/8-inch by 7-inch Arrow X-1 injection packer. The sealant treatment was performed by 300PSI Inc. and approved by the OCD (Attachment 3.2-1). The packer was set and the sealant was squeezed. An annulus pressure test was recorded with the initial annulus pressure at 490 psig, after one-hour the annulus pressure maintained 490 psig, there was no measurable loss over the one-hour period. A copy of the chart is in Appendix 2.7-1.

3.4 ANNULUS PRESSURE TEST

The State of New Mexico required an annulus pressure test which was performed on November 15, 2006, in conjunction with a radioactive survey. The well was allowed to sit idle for 10 days to attain a thermal equilibrium in the wellbore prior to running the annulus pressure test. Wood Group Logging service monitored the annulus pressure and Petroplex Pumping Service provided the pressure pumping equipment. The OCD representatives were present to witness the annular pressure test.

The annulus was pressurized using a high pressure, low volume triplex pump isolated from the pressure source. The official annular pressure test began at 11:32:30 AM at a pressure of 530.94 psia. The tubing pressure was 0 psi. After one-hour, the pressure decreased to 528.95 psia. This represents a loss of 1.99 psi, or 0.37%, which complies with the OCD allowable of 5% per 30-minute test period at a minimum test pressure of 300 psi. The annulus pressure test data are presented as Table 2.9-1. The pressure gauge calibration certificate is presented as Appendix 3.4-1.

3.5 RADIOACTIVE TRACER SURVEY

A radioactive tracer survey was performed on the WDW-3 on November 15, 2006, following the annulus pressure test. The first part of the radioactive tracer survey was witnessed by the OCD representatives. The radioactive tracer survey consisted of running two statistical checks, two baseline gamma ray surveys, and injecting four slugs of radioactive material. Two (2) of the slugs were injected during the time-drive surveys and two were injected during the moving surveys. All tests were conducted while injecting nonhazardous brine water into the well. Wood Group Logging service performed the logging services and Petroplex Pumping service provided the pumping equipment.

The radioactive tracer tool was lowered to a total depth of 9,020 feet and a pre-survey baseline log was then run from 9,020 feet to 7,350 feet. Five-minute statistical surveys were conducted at 7,550 feet and at 7,640 feet.

The injection rate was set at 102 gallons per minute (gpm) and a slug of radioactive iodine was ejected at 7,375 feet. A total of seven passes were made during the first moving survey, until the slug dissipated into the permitted injection interval from 7,650 feet to 8,830 feet.

The radioactive tracer tool was repositioned at 7,375 feet and a second slug of radioactive iodine was ejected. The injection rate was 102 gpm. A total of five passes were made during the second moving survey, until the slug dissipated into the permitted injection interval from 7,650 feet to 8,894 feet.

The first stationary time-drive survey was performed with the lower detector at 7,640 feet with an injection rate of 102 gpm. A slug of radioactive iodine was ejected and monitored on time drive for 15 minutes.

The second stationary time-drive survey was performed with the lower detector at 7,640 feet. The injection of brine water was maintained at 102 gpm. A 2-second slug of radioactive iodine was ejected and monitored on time-drive for 15 minutes.

No upward fluid movement was observed during the two chase downs or the two time-drive surveys. There does not appear to be any upward movement of fluid out of the injection interval from 7,650 feet to 8,884 feet.

Injection into WDW-3 was terminated and a post-survey gamma ray log was run from 9,016 to 7,342 feet. The initial and post-survey gamma ray logs were comparable.

The radioactive tracer log is presented as Appendix 2.9-1. The corresponding letter of interpretation of the radioactive tracer log, dated November 27, 2006, by Wood Group is presented as Appendix 3.5-1.

3.6 DIFFERENTIAL TEMPERATURE SURVEY

A baseline differential temperature survey was performed on October 13, 2006, (Exhibit 2.2-2) after the CBL/VDL logging run. The baseline differential temperature survey will be used to evaluate future temperature surveys to confirm mechanical integrity of the well. No anomalies were observed during the differential temperature survey.

The temperature log was run from 9020 feet to the surface. The fluid level in the wellbore was at 296 feet with 8.6 ppg brine water in the wellbore. The wellbore temperature at 560 feet was 68.1° F, at 1000 feet the wellbore was temperature 74.6° F, at 7650 feet the temperature was 127° F, at 8850 feet the temperature was 140.2 ° F, and at 9020 feet the temperature was 142.9° F. The gradient from 7650 feet to 9020 feet was 1.16° F / 100 ft.

4.0 RESERVOIR EVALUATION

The bottom-hole pressure testing, which was conducted on the WDW-3 following the completion of the well, was designed to obtain the best estimate of the permeability and mobility-thickness in the reservoir. The pressure testing consisted of an injection falloff test and a gradient survey. Petroplex Pumping Service

provided the pumping equipment for the injection period of the testing and Schlumberger Slickline Services provided the BHP equipment.

The calculated value for the skin does not appear to correspond with the pump-in surface pressure values or the injection test valves. It is possible that the offset wells, WDW-1 and WDW-2, influenced the bottom hole pressure response of the bottom hole pressure gauge during the pressure falloff test. Historically, the calculation for the permeability appears to be in the range that was anticipated from previous falloff testing conducted on WDW-1 and WDW-2. WDW-1 and WDW-2 are completed in the same zone of interest.

Due to the proximity of WDW-3 to both the WDW-1 and the WDW-2 and the procedure used by Navajo for injecting into the wells, consideration needs to be given to monitoring the bottom hole pressure in the two offset wells while performing a fallout test the target well. This should allow for a better understanding of the pressure behavior in the reservoir.

4.1 PRESSURE FALLOFF TEST

Petroplex Pumping Services rigged up on WDW-3 on November 4, 2006. Injection into WDW-3 was initiated at 0919 hours at an injection rate of 126 gpm. The injection rate was gradually increased to 420 gpm. At 1800 hours, Schlumberger rigged up and the injection rate was decreased to 210 gpm in order to run the bottom-hole pressure gauges into the well. The tandem memory gauges were positioned at 8,630 feet below ground level and the injection rate was increased to 378 gpm.

At 2100 hours, the injection pumps began to lose suction and WDW-3 was subsequently shut in. The final injection rate was 189 gpm with a final injection pressure at 8,630 feet of 4,577.59 psia.

The pressure falloff test was terminated after 13.57 hours with a final shut-in pressure of 3,804.87 psia. Gradient stops were made at 1000-foot intervals while removing the pressure gauges from the well.

The pressure data obtained from the falloff test were analyzed with the assistance of the commercially available PanSystem pressure transient analysis software. The PanSystem output for the falloff analysis has been included as Appendix 4.1-1 and includes the input reservoir parameters used in the reservoir analysis. The pressure and temperature data recorded during the pressure falloff testing are included as Appendix 4.1-2.

Figure 4.1-1 shows the pressure response recorded by the bottom-hole pressure gauge from the time the tool was in place through the 13.57-hour shut in period. Figure 4.1-2 is a cartesian plot of the pressure falloff data. The superposition time function was used to account for the rate changes during the pressure build up portion of the testing. Figure 4.1-3 is a log-log diagnostic plot of the falloff data, showing change in pressure and pressure derivative versus equivalent shut in time.

The reservoir permeability was determined from the radial flow region of the superposition Horner plot, Figure 4.1-4. The radial flow regime occurs between Horner times of 486 and 196. Figure 4.1-5 shows an expanded view of the radial flow regime. The slope of the radial flow period was determined to be 0.473785 psi/cycle.

An estimate of mobility-thickness, kh/μ, for the reservoir was determined to be 2,223,895 md-ft/cp from the following equation:

$$\frac{kh}{\mu} = 162.6\frac{qB}{m}$$

where,

kh/μ	=	formation mobility-thickness, millidarcy-feet/centipoise
q	=	rate prior to shut in (6,480 bbl/day)
B	=	formation volume factor (1.0 reservoir bbl/surface bbl)
m	=	slope of the infinite acting radial flow period (0.473785 psi/cycle)

Substituting,

$$\frac{kh}{\mu} = 162.6\,\frac{(6,480)(1.0)}{0.473785}$$
$$= 2,223,895 \text{ md–ft/cp}$$

The permeability-thickness, kh, was determined to be 1,601,204 md-ft by multiplying the mobility-thickness by 0.72 centipoise, the viscosity of the reservoir fluid (μ res).

$$kh = \left(\frac{kh}{\mu}\right)\mu_{res}$$
$$= (2,223,895)(0.72)$$
$$= 1,601,204 \text{ md–ft}$$

The average reservoir permeability was determined to be 1,840 md using the total perforated interval thickness of 870 feet:

$$k = \frac{(kh)}{h}$$
$$= \frac{1,601,204}{870}$$
$$= 1,840 \text{ md}$$

4.2 STATIC GRADIENT SURVEY

On November 5, 2006, the pressure gauges were removed from WDW-3. Static gradient stops were made at 8,630 feet, 7,000 feet, 6,000 feet, 5,000 feet, 4,000 feet, 3,000 feet, 2,000 feet, 1,000 feet, and at the surface. The bottom-hole pressure and temperature after 13.57 hours of shut in at 8,630 feet were 3,804.87 psia and 135.88° F, respectively. The static fluid level was determined to be at 420 feet.

A summary of the static gradient survey results is provided in Table 4.2-1 and are graphically depicted in Figure 4.2-1.

5.0 Regulatory Compliance

The construction of WDW-3 was performed in accordance with the regulatory considerations and standards specified in the approved modification to the Discharge Plan UIC-CLI-008-3 Dated June 23, 2004; the OCD Permit, Dated June 29, 2006; the BLM Sundry Notices and Reports on Wells Dated June 29, 2006; NMWQCCR, Subpart V, Section Nos. 5204 and 5205; and the United States Environmental Protection Agency 40 CFR 146.12.

5.1 Siting

Navajo re-entered, tested, and completed a plugged and abandoned wellbore located in Section 1, T18S, R27E, Unit Letter N, approximately 11 miles east-southeast of Artesia, in Eddy County, New Mexico. The modification to Discharge Plan UIC-CLI-008-3 includes provisions for the location, depth of the injection interval, and specific reentry and completion requirements. The Navajo WDW-3 will inject plant effluent into a the Cisco and Brushy Canyon formations, which are beneath the lowermost formation contained within one quarter of a mile of the wellbore, with ground water having 10,000 mg/l total dissolved solids or less. A plat of the Navajo WDW-3 well location is shown in Appendix 2.0-2.

5.2 Casing Cementing

The existing casing and wellbore configuration was used and the only modifications to the wellbore were the removal of four existing CIBP's in the original wellbore configuration and the squeeze cementing of existing perforations. Table 2.0-1 and Figure 2.0-1 contain a detailed description of the current wellbore configuration.

5.3 Tubing and Packer

The Installation of the tubing and packer were in accordance with NMWQCCR Subpart V, Section 5205(B)(3).

The WDW-3 injection tubing is a 4-1/2-inch, 11.6 lb/ft, J-55, LTC 8rd connection, carbon steel pipe. The injection tubing was connected into the Arrow X-1, 2-7/8-inch by 7-inch packer via an integral 2-7/8-inch by 4-1/2-inch crossover. The packer was set with 37,000 lbs of tension in a competent area of the 7-inch casing with the bottom of the packer at 7575 feet, which is approximately 85 feet above the upper most perforation. The tubing was designed and selected based on its ability to withstand the chemical affect of the injectorate and its burst pressure, collapse pressure, and tensile stresses, which may be experienced during the operational life of the well. Table 2.0-1 is a detailed tubular list of the existing pipe and the installed pipe. Figure 5.3-1 is a schematic of the Kenco packer system, and Table 2.6-1 is an inspection tally of the tubing that was used. All the injection tubing that was placed in the well was inspected and threads cleaned prior to installation.

5.4 Directional Surveys

Deviation checks were obtained prior to re-entering WDW-3 and were based on prior deviation surveys obtained from state records, which were in accordance with NMWQCCR Subpart V, Section 5205 (A)(4)(a). Attachment 5.4-1 contains the deviation surveys that were obtained from the State of New Mexico record archives submitted to the OCD.

5.5 Logging Program

The logging program for WDW-3 was completed in accordance with the regulations specified in NMQCCR Subpart V, Section 5205(A)(4)(b).

Type of Log	Type of Hole Logged	Interval Logged (ft)	Document Reference
Dual Induction Laterolog	Open Hole	2595 – 9448	Appendix 5.5-1
Spectral Density Dual Spaced Neutron Log	Open Hole	0 – 9448	Appendix 5.5-2
Cement Bond Log (CBL/VDL)	Cased Hole	0 – 9020	Appendix 2.2-1
Temperature Log	Cased Hole	0 – 9020	Appendix 2.2-2
Casing Inspection Caliper Log	Cased Hole	0 – 9000	Appendix 2.2-3
Radioactive Tracer Survey	Cased Hole	7375 - 9008	Appendix 2.9-1

5.6 MECHANICAL INTEGRITY TESTING

The demonstration of the mechanical integrity of the WDW-3, required by NMWQCCR Subpart V, Section 5204 (A) to (D) and Section 5202 (A)(1)(a), is discussed in detail in Section 3.0 of this report. The associated logs and interpretation of the results obtained from the mechanical tests are also included in Section 3.0 of this report.

5.7 PHYSICAL AND CHEMICAL CHARACTERISTICS OF THE FORMATION FLUIDS

In accordance with NMWQCCR Subpart V, Section 5202(A)(3)(h), an analysis describing the physical and chemical characteristics of the formation fluids, extracted from the Cisco and Upper Canyon Formation, is presented as Appendix 2.3-1.

The well materials used to construct WDW-3 were compatible with fluids which the material may be expected to come into contact. Well material would be deemed to have compatibility as long as the materials used in the construction of the well meet or exceed standards developed for such materials by the American Petroleum

Institute (API), The American Society for Testing Materials (ASTM), or comparable standards acceptable to the NMWQCCR.

5.8 REGULATORY WITNESSING

In accordance with NMWQCCR Subpart V, Section 5205(A)(5), notification prior to commencement of the reentry, cementing and casing, well logging, and mechanical integrity testing was communicated with the BLM, Carlsbad, New Mexico and the OCD, Artesia, New Mexico offices. The BLM and the OCD had an opportunity to witness all installations, logging, and testing as required in the Application for Permit to Drill, Re-enter, Deepen, Plugback, or Add a Zone and in NMWQCCR Section 5205(A)(5).

6.0 FUTURE TEST RECOMMENDATIONS

As stated earlier, due to the proximity of WDW-3 to both the WDW-1 and the WDW-2 and the procedure used by Navajo for injecting into the wells, consideration needs to be given to monitoring the bottom hole pressure in the two offset wells while performing a fallout test in the target well (WDW-3). This should allow for a better understanding of the pressure behavior in the reservoir. This may further enhance reservoir pressure forecast and increase Navajo's ability to proactively respond to reservoir and wellbore conditions.

A proposed procedure for falloff testing on the three injection wells, consist of placing BHP gauges in each well prior to starting injection into WDW-3. The injection period would consist of maintaining a constant injection rate into WDW-3 for a period 24 hours. At the end of the 24-hour injection period, shut-in WDW-3 and shift the waste injection stream to WDW-1. This would be in line with the current Navajo injection procedures. Continue injection into WDW-1 for 12 hours, and then shift the injection stream to WDW-2 for a period of 12 hours. At the end of the 12 hour injection period in WDW-2 shut down injection operations and remove the BHP tools from each wellbore. Once the BHP gauges have been removed from the wells, return to normal injection operations.

APPENDIX 2.0-1

CHRONOLOGY OF FIELD ACTIVITIES

CHRONOLOGY OF FIELD ACTIVITIES

Tuesday, July 25, 2006

Rusty Smith, with Subsurface Construction, Inc. traveled to Artesia, New Mexico and met with David Alvarado, District Manager of Basic Energy, to inspect the two rigs that they will have available on August 7th. Only one rig was available; the other could not be released. The Cooper 500 with a 250K lb derrick was the rig that was inspected. The rig was well maintained, has no pipe racks, work string, and no power swivel. The rig is used mainly for workover operations. Inspected the well site where the workover rig unit will be located. Well site needs to be scraped clean and the barbed wire fence, which surrounds the area where the old tank used to be, needs to be removed. The wellhead needs some work. Pictures of the Basic rig and well location were taken.

Wednesday, July 26, 2006

Rusty Smith left Artesia, New Mexico and traveled to Farmington, New Mexico. The rig and well location inspection summary were completed and e-mailed to Subsurface personnel for review. Included in the inspection summary were photos of the rig and location.

Wednesday, August 30, 2006

Subsurface personnel traveled to Artesia, New Mexico to meet with David Alvarado, District Manager of Basic Energy, to develop a location layout for equipment and assist Joe Konicki. Talked with Julian Carrillo, the rig tool pusher, because David Alvarado was on vacation, and he informed Subsurface that the rig was no longer available because Yates Energy had changed its position and would not release it. Set up meetings with Darrel Moore and the new Project Engineer at the Navajo plant to discuss the current job situation and introduce Joe Konicki. Joe and I talked with Key Energy about the possibility of acquiring a rig.

Thursday, August 31, 2006

Rusty Smith measured the current WAMS units on Disposal Well No. 1 and Disposal Well No. 2 and acquired photos of Well No. 1 WAMS and the current well configuration. The well location inspection summary was completed. All photos, drawings, and the inspection summary were e-mailed to Subsurface personnel for review. Rusty Smith and Joe Konicki. left Artesia, New Mexico for Houston, Texas.

Monday, September 25, 2006

Rusty Smith traveled to Artesia, New Mexico to prepare the location for the reentry project on WDW–3, formally owned by Mewbourne Oil Company and known as Chalk Bluff Federal No. 1. The sundry notice to the BLM for the transfer of ownership was submitted on May 5, 2003. The OCD Change of Operator Notice was submitted on October 5, 2000.

Tuesday, September 26, 2006

Subsurface personnel called Knight Oil Tools & Rental and spoke with Francisco about work string and pipe. He wanted to know what type of crossovers, bit sub, safety clamp, and elevators would be needed. Spoke with Basic and they did not have any handling tools for the PH6 tubing and would need elevators and a safety valve. Knight said that they would provide elevators and a safety valve with the work string. Talked with Allen, of Key Fishing Tools, and he said that they would provide all the crossovers and bit subs. Basic was in agreement with the supplied tools.

Banta Oilfield Services will arrive tomorrow to clear the location and dig 30 foot x 30 foot x 3 foot pit. Key Energy Services will deliver tanks tomorrow and start filling them up. Portable toilets will arrive tomorrow from Sani-Tech Rentals. Young's Mobile Homes will deliver a small office trailer on Thursday. Knight Oil Tools will provide

work string, elevators, and the safety valve to be delivered September 27, 2006. Key Fishing Tools and Rental will provide reverse unit, subs, collars, bit, BOP (Allen), which are scheduled to arrive on Thursday, after noon. The rig is also scheduled to arrive on Thursday. Steve L., with Halliburton, has been notified and will need 48 hours notice. Contacted Aztec Rental about a fork lift and they will send account information to the office to be filled out by Subsurface's accountant. Once the account is approved, they will deliver a fork lift on September 27, 2006.

Wednesday, September 27, 2006

Subsurface personnel arrived at the job site at 7:00 a.m. MST. Banta's roustabout crew called and said that were having problems finding the location. Therefore, I met them at the ATOKA compressor station and led them to the location. Banta arrived with two backhoes and proceeded to clear the location of over growth and remove all fencing. Key Energy arrived at the job site with three frac tanks, two sets of pipe racks, catwalk, and Knight Oil Tools arrived with 150 joints of 2-7/8-inch PH-6 tubing. Knight Oil Tools will not charge for the pipe until the remaining 148 joints pipe and tools are delivered. Aztec Rental arrived on the job site with an extended boom fork lift. Julian, with Basic, called and said that they should be able to move onto the location by noon tomorrow.

The roustabout crew dug a 30 feet x 30 feet x 5 feet lined pit, cleared the location of over growth, removed the barbed wire fence, and dug out cell. The roustabout crew will return tomorrow to frame in the cellar. Key will start filling the frac tanks tomorrow and Knight Oil Tools will deliver the remaining pipe and handling tools. Subsurface left the jobsite at 6:30 p.m.

Thursday, September 28, 2006

Subsurface personnel arrived at the location at 7:20 a.m. MST. The roustabout crew arrived at 8:00 a.m. The roustabout crew completed the cellar. The Basic rig crew arrived on the location at 12:30 p.m. with a mechanic to repair the sand line brake. The

rig crew raised the derrick and replaced the drilling line. Rig mats had to be placed under the derrick for support. The rig mats were acquired from G&L Tools a division of Basic Energy Services. The rig crew completed repairs on the rig and left the location at 7:20 p.m. Key finished loading the frac tanks with water and brine. Key delivered the reverse unit and open top flow back tank, and the reverse unit operator will arrive tomorrow with BOP, collars, and handling tools.

Knight had problems getting the remaining work string delivered before nightfall. Knight will have the remaining pipe delivered in the morning. Young's delivered a 10 foot x 30 foot office trailer and Aztec delivered a light plant to the location. Superior Wellhead was notified and will have a man on the job site in the morning to inspect the hanger and wellhead before installing the BOP. The 150 joints of 2-7/8-inch PH-6 tubing were tallied at 4691.06 ft. Subsurface left the location at 7:45 p.m.

Friday, September 29, 2006

Subsurface personnel arrived on the jobsite at 6:45 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. Subsurface and Basic crews spotted catwalk & pipe racks. The last load of pipe from Knight Tools arrived at the location with handling tools. The rig crew moved pipe and off-loaded pipe onto the pipe racks. The BOP from Key Energy arrived at the job site and was flanged up to the wellhead. The Superior wellhead technician arrived at the job and inspected the tubing hanger spool and found it to be 11_3 x 7_5 Cameron hanger and profile. The Superior wellhead technician suggested that the tubing hanger spool be replaced as the Cameron spool has been discontinued and is hard to find parts for. Key Energy's reverse unit operator arrived at the job site with 3-1/2-inch collars and handling tools.

The reverse unit (pump & tank) were rigged up to the wellhead. Portable toilets arrived at the job site. The rig crew tallied the top layer of PH-6 tubing, drill collars, bit, and started into the hole with the BHA at 1:30 p.m. The first plug was tagged at 7001 feet, at

7:10 p.m. The rig crew pulled a single joint of tubing from the wellbore, the well was shut in, and operations were shut down for the night.

Saturday, September 30, 2006

Subsurface personnel arrived on the jobsite at 7:20 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. Basic rig crew and Key's reverse unit operator rigged up the swivel. At 10:30 a.m., Basic could not get the brake to hold on the sand line. Operations were shut down until Basic could repair the brake on the sand line and the reverse unit operator was put on stand by. Basic estimated that it will take all day to repair the brake. Basic finished repairing the brake at 7:00 p.m. Drilling operations will commence Sunday morning. Halliburton was notified to be ready to perform a perforation squeeze job on Monday. Pipe tally was checked and verified at 297 joints of 2-7/8-inch tubing for a total footage of 9413.59 feet, including the BHA at 126.45 feet. The well was shut in and operations were shut down for the night.

Sunday, October 1, 2006

Subsurface personnel arrived on the job site at 7:20 a.m. MST. Basic rig crew arrived on location at 7:30 a.m. At 8:00 a.m. Key's reverse unit operator started to drill out CIBP after circulating bottoms up (40 bbls) and there did not appear to be any cement on top of the plug. Current ROP is about 1 ft/hr while circulating returns to pit. The reverse unit operator will change over to tank once fluid cleans up. The returns appear to contain trace amounts of oil with no mud. RPM on the swivel is at 50 with a pump pressure between 250 psi to 300 psi with brine water. Drilled through plug at 9:45 a.m. and circulated hole clean. Rig crew started back into hole to tag second plug. Tagged second plug at 7190 feet, rig crew hooked up swivel to circulate hole and perform an injection test. The injection test revealed the following: 1 bpm at 300 psi, 1.5 bpm at 550 psi, and 2 bpm at 980 psi. After the pump-in test, the falloff went from ISIP of 950 psi to 200 psi in 22 minutes. Key Energy Service removed 250 bbls of water from earthen pit.

Rig crew tripped out of hole (TOOH) with pipe to prepare for cement squeeze job. Rig crew tripped in hole (TIH) open ended with tubing to spot cement for squeeze job, with bottom of the tubing at 7101.49 feet. Contacted Halliburton and ordered 80 sks of cement (cmt) for squeeze job into upper perforations.

Monday, October 2, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Halliburton was on the jobsite waiting on cement to arrive. Cement arrived at the location at 7:30 a.m. Halliburton rigged up their cement pump while waiting on a crossover for the PH-6 tubing. Halliburton did not bring a crossover to the PH-6 thread to 8rd, so Key Fishing Tools had one delivered.

Cement squeeze went well at 2000 psi squeeze pressure. Pressured up to 2001 psi. After 10 minutes, pressure fell to 1950 psi and re-pressured to 2007 psi. After one hour, pressure dropped to 1990 psi with 2.2 bbls, released pressure and recovered about 2 bbls. Re-pressured well to 2001 psi and held for 5 minutes at 1990 psi. The ring gasket began to leak around BOP. Halliburton released pressure and recovered 1.9 bbls. Halliburton rigged down and the rig crew TOOH with tubing. Hole remained full while tripping pipe. Rig crew tightened BOP flange head bolts. Key reverse unit operator pressured up well to 680 psi, with no apparent leaks, and the well was shut-in over night, while waiting on cement (WOC).

Tuesday, October 3, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TIH with the collars and bit. Rig crew tagged cement at 6873 feet on joint No. 215 plus 20 feet. Assuming hole is full of cement to CIBP at 7190 feet, there are 12.1 bbls of cement in the hole and 6.6 bbls of cement were circulated out and/or squeezed into the formation. It was estimated that 3.5 bbls were circulated out leaving 3.1 bbls of cement having been squeezed into the near wellbore. Rig crew drilled out cement and

circulated hole clean at 4:00 p.m. The well was shut-in to prepare for a pressure test on the squeeze perforation for 12 hours at 500 psi.

Started 500 psi pressure test at 4:30 p.m. Pressured up well to 590 psi and after one hour pressure fell to 530 psi. Re-pressured well to 580 psi and after one hour pressure was at 578 psi. At 5:30 p.m. well was at 578 psi and holding. Shut down operations overnight.

Wednesday, October 4, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. At 7:00 a.m., the pressure on the well was 455 psi. The well lost 123 psi over 13.5 hour, for a 9.1 psi/hr (1.58%/hr) loss. Rig crew rigged up swivel and continued to drill out CIBPs at 7190 feet and (estimated third plug depth) at 7294 feet. While drilling through the second plug at 7190 feet metal cuttings were being retrieved across screen. Third CIBP was found at 7278.96 and it was estimated that there was 9 feet of cement on top of both plugs, which places the second plug at 7199 feet and third plug at 7287 feet. At 12:25 p.m., rig crew commenced drilling through third plug. At 3:00 p.m., driller punched through the third plug. The formation started taking fluid at a rate of 1.0 to 1.25 bpm while pumping, lost 180 bbls of 8.7 ppg brine water to the formation.

Rig crew TIH and tagged the forth CIBP at 7591 feet then pulled up 20 feet and reversed circulated the wellbore clean. The reverse unit operator completed the pump in test for the perforations from 7262 feet to 7278 feet and from 7304 feet to 7314 feet. The maximum rate was 4.5 bpm (max that the pump could deliver) at 710 psi with no pressure build up. The ISIP was about 580 psi and fell to 170 psi in 9 minutes. At 4:45 p.m., rig crew TOOH with collars and bit. Halliburton will be out tomorrow afternoon with 100 sks of Class C cement to squeeze off perforations. At 7:30 pm, the rig crew was out of the hole with the collars. The well was shutin and operations were shut down.

Thursday, October 5, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m. and TIH open ended, placing the bottom of the work string at 7321 feet; 7 feet below the bottom perf at 7314 feet. Key filled fresh water and salt water tanks while we waited for a Halliburton pump truck to arrive. Halliburton arrived on the location at 11:30 a.m. At 12:44 p.m. Lines were pressure tested to 3000 psi. Halliburton broke circulation and caught returns with 6.3 bbls pumped. At 12:52 p.m., Halliburton started mixing cement and pumped 23.5 bbls of cement, followed by 35.5 bbls of fresh water. Rig crew pulled 10 stands (630 feet) and Halliburton started to squeeze the cement into the formation. The squeeze was performed in 7 stages, each 10 minutes apart, pumping approximately 1 to 1.5 bbls per stage.

After the first stage the wellhead pressure was 78 psi. After the 7th and last stage, the wellhead pressure had increased to 1973 psi. A total of 9 bbls were pumped during the squeeze job. The well was shut-in with 1970 psi on the wellhead. Subsurface allowed the well to remain shut-in for an additional 2 hours, after which the wellhead pressure was bled off and 8 stands (500 feet) of pipe were TOOH to insure that no cement remained around the pipe. The well was pressured up to 930 psi and shut-in overnight to WOC.

Friday, October 6, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with work string. The wellhead pressure this morning, after 14 hours, was 850 psi. With a loss of 80 psi over a 14-hour period after the squeeze or 5.7 psi/hr. At 10:00 a.m., rig crew TIH with work string, collars, and a new bit. At 12:30 p.m., rig crew tagged soft cement at 7052 feet and quickly drilled through the cement. At 7092 feet, hard cement was encountered. Rig crew drilled through cement to 7338 feet and tagged bottom at 7554 feet (previous tag 7591 feet). Well would not hold pressure during test and reverse unit operator was able to pump into the well at ~20 to 25

gpm at 920 psi. A second cement squeeze on the second set of perforations will be required. Well was shut in over night.

Saturday, October 7, 2006

Subsurface personnel arrived at the location at 7:20 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with work string, collars, and bit. A new Key reverse unit operator arrived at the location. Halliburton was called to confirm a third cement squeeze job. Halliburton informed Subsurface that they would not have a pump truck available until Wednesday. Key Pumping service was contacted and retained to provide the service on Sunday afternoon. Due to unavailability of cement pumping services to do the third cement squeeze, the estimated schedule has been pushed back 2 days.

At 10:50 AM the rig crew had collars and bit out of the hole and TIH with open ended work string to just above the bottom set of perforations at 7314'. The open ended work string was placed at 7290 feet, 24 feet above the bottom set of perforations (1 bbl of casing volume). The well was shut-in while waiting on a cement pump truck to arrive.

Sunday, October 8, 2006

Subsurface personnel arrived at the location at 10:10 a.m. MST. Rig crew arrived at 10:20 a.m. Key Pressure Pumping Services arrived at the location at 10:30 a.m. Key pumping crew rigged up pump and bulk truck. The mix water for the cement squeeze in the frac tank was contaminated with brine water and a load of city water was called in for mix water. At 2:00 p.m., fresh mixed water arrived on location. Key pumping pressure tested lines to 2500 psi and then circulated 12 bbls to fill the wellbore with fluid. At 3:04 p.m., Key started mixing cement and pumped 10 bbls of FW ahead followed by 18.5 bbls of 14.8 ppg cement. The cement was displaced with 35.5 bbls of FW. Rig crew TOOH with 8 stands (500 feet) and the well was reversed circulated with 40 bbls of FW. At 4:03 p.m., Key pumping started to squeeze the well with an initial rate of 0.5 bpm at

750 psi. After 6 bbls the rate was decreased to 0.3 bpm at 1890 psi. After 7.5 bbls at 1975 psi pumping was stopped to allow the pressure to fall.

At the end of 10 minutes, the wellhead pressure had fallen to 1063 psi and pumping was resumed. An additional 1.5 bbls was pumped before the pressure reached 1940 psi. The wellhead pressure fell to 1914 psi after 20 minutes and did not appear to fall any further. The well was shut-in and Key rigged down their pumps. After one hour, the wellhead pressure had fallen to 1860 psi. At 6:00 p.m., the well was shut-in for the night with 1830 psi on the wellhead to WOC.

Monday, October 9, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and TOOH with open ended work string. Rig crew TIH with work string, collars, and bit to drill out cement. The wellhead pressure this morning after the 80 sk cement squeeze job was 1825 psi. Reverse unit operator tagged cement at 6981 feet and found hard cement at about 7003 feet. At 4:43 p.m., driller broke through the cement at 7312 feet. The estimated cement plug length left in casing was 331 feet or 12.7 bbls out of 18.8 bbls of cement. Driller tagged bottom at 7559 feet, rig crew pulled up off bottom approximately 20 feet, and the reverse unit operator circulated the wellbore. The well was shut-in and pressure tested to 610 psi at 6:45 p.m. for a 12-hour test.

Tuesday, October 10, 2006

Subsurface arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. Wellhead pressure at the end of 13 hours was 480 psig, down from 610 psig; a pressure loss of 130 psi over the 13-hour period. The decision was made by Subsurface personnel to retest the casing after the squeeze for an additional 12 hours. At 8:03 a.m., the wellhead pressure was increased to 630 psig and monitored every thirty minutes. At 9:30 a.m., the 7-inch x 9-5/8-inch annulus valve was opened to see if it had any effect on the casing pressure. Casing pressure fell slightly faster from 2 psi/30 minutes to 5 psi/30

minutes. Once the annulus casing valve was closed, the pressure loss maintained a 2 psi/30 min loss.

When the casing valve was first opened it smelled like natural gas. The annulus casing valve was closed and a pressure gauge placed on the annulus and monitored. At 2:03 p.m., the wellhead pressure was falling at a rate of 2 psi/30 minutes with less than 5 psi on the casing annulus. At 5:03 p.m., wellhead pressure was maintaining a falloff rate of 2 psi/30 minutes. At 8:03 p.m., after 12 hours, the wellhead pressure was 568 psig.

Wednesday, October 11, 2006

Subsurface arrived at the location at 7:00 a.m. MST. The wellhead pressure was 523 psig. At 7:03 a.m., maintaining a 2 psi/30-minute pressure loss. Rig crew arrived at 7:30 a.m. and rigged up swivel and broke circulation. At 8:00 a.m., reverse unit operator tagged bottom and started to drill out plug at a circulation rate of 2 bpm, with 500 psi of pressure. At 9:30 a.m., reverse unit operator tagged the top of the plug at 7595 feet and started to drill through the plug. While drilling out the plug, the plug dropped to 7776 feet and, reverse unit operator continued to drill out the plug. Reverse unit operator drilled 2 feet through the plug and tagged mud contaminated cement at 7780 feet. Continued to drill through the cement.

At 2:00 p.m., reverse unit operator drilled through cement plug at 7838 feet, then circulated for 30 minutes before the rig crew TIH to tag the top of the liner (TOL). The well was taking fluid at a rate of about 1/2 bpm once the cement plug was drilled through. Rig crew tagged cement on TOL at 9022 feet and broke circulation. At 3:30 p.m., the reverse unit operator commenced circulating the hole clean to 9022 feet. Reverse unit operator circulated 347 bbls of 8.6 ppg brine water. At 5:30 p.m., the rig crew started TOOH with work string, bit, and collars. Tomorrow, the rig crew will TIH with casing scraper to prepare the well for logging operations.

Thursday, October 12, 2006

Subsurface arrived on location at 7:00 a.m. MST. Wood Group logging crew was at the job site spotting equipment. Rig crew arrived at the location at 7:30 a.m. and continued to TOOH with work string, collars, and bit. At 10:00 a.m., rig crew TIH with casing scraper to 9022 feet. At 12:30 p.m., rig crew TOOH with casing scraper. At 3:30 p.m., Wood Group Wireline Services rigged up to the wellhead to run the CBL/VDL into the wellbore. At 4:30 p.m., the well was shut-in for the night.

Friday, October 13, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:10 a.m. Rig crew arrived at the location at 7:30 a.m. and Wood Group started into the wellbore with CBL/VDL logging tool. Fikes Truck Lines arrived at the location with 4-1/2-inch, 11.6 lb/ft, J-55, LTC tubing, from C&R Industries, and the rig crew unloaded 174 joints of tubing. Wood Group completed CBL/VDL logging and ran into the wellbore with the temperature logging tool. The temperature log was completed at 3:00 p.m. with no anomalies. At 3:15 p.m., Wood Group ran the caliper logging tool into the wellbore. The CBL/VDL log showed that the TOC was located at 900 feet with good to fair bonding to 9020 feet. The VDL indicated that cement was placed into the squeezed perforations.

At 6:40 p.m., Wood Group was out of the wellbore with the caliper log and there did not appear to be any major anomalies in the 7-inch casing from 9020 feet to surface. The well was shut-in for the night and Wood Group will be back tomorrow to perforate. The time needed to perforate well was estimated to be two days.

Saturday, October 14, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:00 a.m. Rig crew arrived at the location at 7:30 a.m. and Wood Group started into the wellbore with a 40 foot perforating gun. Basic provided two men to assist Wood Group as needed with the rig. Wood Group made 12 perforating runs, completing the interval from 8540 feet to 8620 feet and 400 feet of the interval from 8050 feet to 8450 feet. Wood Group will complete the remaining 390 feet tomorrow from 7660 feet to 8050 feet. The well was shutin for the night.

Sunday, October 15, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Wood Group logging crew arrived at the job site at 7:00 a.m. Rig crew arrived at the location at 7:20 a.m. and Wood Group started into the wellbore with a 40 foot perforating gun. Basic provided two men to assist Wood Group as needed with the rig. Wood Group made 10 perforating runs, completing the interval from 7660 feet to 8050 feet. A total of 22 perforating runs were made and there were no misfires during any of the runs. All the retrieved hollow steel carrier guns shot 2-JSPF on a 60° phasing. The two man rig crew assisted Wood Group with rigging down the logging equipment. The well was shutin for the night.

Monday, October 16, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and started to lay down collars. Kenco packer and operator arrived at the job site at 8:30 a.m.. Kenco did not have the proper x-over for the PH-6 to 8rd and had to wait for a cross-over before the rig crew could run the packer. Cross-over arrived at the location and the rig crew TIH with the 7-inch x 2-7/8-inch packer. Packer was set at 7546 feet and the rig crew started to swab back the well. The first formation fluid sample was taken after 12 runs to 2400 feet (estimated 151 bbls), the second sample was taken

after 14 runs (estimated 176 bbls), the third sample taken after 16 runs (estimated 201 bbls), and fourth sample was taken after 18 runs (estimated 226 bbls). Had H_2S gas present between runs 7 through 9 (estimated at 88 and 113 bbls). Well was shutin over night.

Tuesday, October 17, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m. Rig crew loaded collar and swivel onto Key's trailers. While waiting on Key's pump truck to arrive, reverse unit operator pressured up on 2.875-inch x 7-inch annulus with packer set at 7546 feet to perform an annulus pressure test. Initial pressure was 660 psi at 8:15 a.m. After 2 hours the pressure loss started to stabilize at about 4 psi/30 minutes. At 12:30 p.m., Key Pressure Pumping was called to verify that a pump truck was coming. Apparently there was a mix-up by the dispatcher and the pump was sent to another job. Key informed Subsurface that they will have a pump on the jobsite tomorrow afternoon.

At 1:30 p.m., the wind had picked up to a point that the rig crew could not TOOH with the packer and pipe. Therefore, the annulus pressure test will be continued for the remainder of the day. Rig crew worked on rig until 3:30 p.m. and then shut-in the well for the night. Subsurface monitored pressure until 6:30 p.m.

Wednesday, October 18, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:20 a.m.. Reverse unit operator arrived at 7:30 a.m. Subsurface delivered field copies of the logs to Navajo Refining and contacted Darrel Moore. Rusty Smith informed Darrel of the need to contact the State of New Mexico for approval to use the well, even though cement did not come all the way to the surface around the 7-inch x 9-5/8-inch casing annulus (900 feet from the surface). Darrel approved Subsurface's request to

contact the appropriate state officials for approval and to take necessary steps as the State of New Mexico directs.

At 10:30 a.m., the reverse unit operator pressured up the annulus between the tubing and the 7-inch casing to 700 psig for the injection test and left the location. Key Pumping Service arrived at the job site at 3:30 p.m. and started pumping down the 2-7/8-inch tubing at 4:20 p.m. with produced water in the wellbore and 650 psi on the annulus. The initial rate was 2.2 bpm (inline flow meter) at 300 psig on the tubing. After 43 bbls the pressure stabilized at 150 psi, with a total of 50 bbls pumped. The rate was increased to 4.1 bpm with an initial pressure of 830 psi. After 20 bbls, the tubing pressure stabilized at 900 psi. The pump broke down with a total of 80 bbls pumped (tubing volume 43 bbls). The ISIP was about 630 psi. Rig crew shut-in the well for the night and Key Pumping will return tomorrow morning to complete the job. (Note: pump wire harness fell into the drive shaft ripping it apart along with some hydraulic hoses)

Thursday, October 19, 2006

Subsurface personnel arrived at the location at 7:30 a.m. MST. Rig crew arrived at 9:00 a.m. Reverse unit operator arrived at 8:00 a.m.. At 9:00 a.m., Key pumping supervisor called and said that they were 45 minutes out and were given directions to the location. Subsurface released the down hole packer and will monitor both the backside and tubing pressure during the pump-in testing.

Key Pumping circulated the wellbore at 2 bpm to fill the wellbore with fluid & caught returns after 37 bbls. At 2 bpm tubing pressure (Pt) was 183 psig and backside pressure (Pa) was 28 psig. At 3 bpm, Pt was 638 psig & Pa was 148 psig. At 4 bpm, Pt was 1132 psig & Pa was 250 psig. At 5 bpm, Pt was 1678 psig & Pa was 320 psig. At 6 bpm, Pt was 2343 psig & Pa was 408 psig. At 7bpm, Pt was 3108 psig & Pa was 518 psig. At 8 bpm, Pt was 3748 psig and Pa was 535 and at 9 bpm, Pt was 4522 psig Pa was 590 psig. Key was able to reach 10 bpm but the engine over heated and was shut down. The Pt was 5087 psig at shut down and no Pa was recorded but estimated at 660 psig. Well went on

a vacuum once pumping had stopped. The best estimate for ISIP 230 psig total volume of brine water pumped was 280 bbls.

Rig crew started out of the wellbore with the packer and went back into the hole with RBP and packer to test casing below squeezed perforations. We first tested across squeezed perforations and then the annulus above the perforation. RBP was set at 7550 feet packer was set above the RBP and RBP was pressure tested for leaks and packer was released. At 6:00 p.m., 640 psig was left on the annulus with the well shut-in overnight.

Friday, October 20, 2006

Subsurface personnel arrived at the location at 6:45 a.m. MST. At 7:00 a.m., the wellhead had 770 psig from 640 psig over 13 hours, a net pressure build of 130 psi. Rig crew arrived at 7:20 a.m. Subsurface and Navajo Refining received approval from the State of New Mexico after they reviewed the revised procedure and CBL/VDL log to complete the well for injection without additional cementing. The State of New Mexico requested that we try to find the leak in the casing within 500 feet to 1000 feet of the leak. Rig crew pulled 8 stands and one joint of pipe and the packer was set at 6985 feet to isolate the cement squeezed perforated interval. The squeeze interval was initially pressure tested to 490 psig and the annulus was initially pressure tested to 632 psig. The pressure test ran for 5 hours and appeared to stabilize after 2 hours.

After 2 hours, the squeezed interval was losing 6 psi/hr while the annulus was gaining about 0.75 psi/hr due to thermal effects. The final pressure for the squeezed interval was 458 psig and the final pressure for the annulus was 640 psi. At 2:30 p.m., the rig crew picked up the RBP and TOOH to 1255 feet where the RBP was reset. At 5:30 p.m., the casing was pressure tested from surface to 1255 feet with an initial pressure of 570 psig. At 6:00 p.m., the well was shut-in over night with 569 psig on the casing.

Saturday, October 21, 2006

Subsurface personnel arrived at the location at 6:45 a.m. MST. At 7:00 a.m., the wellhead had 540 psig from 569 psig over a 13 hour period, a net pressure loss of 29 psi at a rate of 2 psi/hr with the RBP set at 1255 feet (48 bbl). Rig crew arrived at 7:30 a.m. Continued to monitor pressure to verify loss rate. At 7:30 a.m., pressure was 539 psig and at 8:00 a.m. pressure was 538 psi. Packer hand released RPB and rig crew TOOH with packer and RBP. Charlie's Services inspected the 4-1/2-inch tubing. Rig crew TIH and TOOH with work string and started laying down the work string as they came out of the hole. Charlie's inspection crew found two bad joints of 4-1/2-inch tubing as marked on their tally. Rig crew finished laying down the work string and loaded 4-1/2-inch tubing onto the pipe rack. Well was shut-in for the night.

Sunday, October 22, 2006

Pipe, location, and rig personnel are ready for casing crew. Wellhead, packer, and annulus fluid to arrive on Monday.

Monday, October 23, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew arrived at 7:30 a.m. and replaced the old Cameron 7-1/16-inch 5M x 11-inch 3M spool with a new Superior 7-1/16-inch 5M x 11-inch 3M spool. P-seals were pressure tested for 15 minutes to 3000 psi with no leakoff. BOP was reseated on the new spool to run the casing into the wellbore. At 12:00 p.m., casing crew started into the wellbore with packer and 4-1/2-inch tubing. Packer would not go past the 50-foot mark therefore, packer was pulled out of the hole and inspected.

Weatherford had brought to location, a packer for 7", 24 lb/foot casing. The casing in the wellbore was 7 inches, 29 lb/ft casing. Weather had to go back to Hobbs, New Mexico to

pick up the correct packer. Kenco was called, and they had an Arrow X-1 Packer in the shop. Kenco delivered a new 7-inch Arrow X-1 packer to the job site but brought out the wrong size cross-over. At 4:15 p.m., Weatherford brought out a rebuilt 29 lb/ft packer to replace the 24 lb/ft packer that was originally brought out to location. Kenco will have a cross-over on the job site in the morning and Weatherford was sent back to Hobbs. Kenco will install the packer. The well was shut in for the night.

Tuesday, October 24, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Rig crew and casing crew arrived at 7:30 a.m. The crews started running casing at 8:00 a.m. There were no problems getting Kenco's new Arrow Packer into the wellbore. Kenco also used an integral cross over rather than a sedge and casing collar for a cross. At 2:30 p.m., casing crew ran 7567 feet of casing into the hole and each joint was torqued to specifications at 1600 lbs. The wellbore was circulated full of fluid (240 bbls), then 300 PSI pumped 23.8 bbls of squeeze chemical. The reverse unit operator pumped 95 bbls of inhibited brine water followed by 14.29 bbls of squeeze chemical, leaving 7.23 bbls of brine in the bottom of the annulus. The weight of the brine circulated and the inhibited brine in the annulus was 8.7 ppg. The weight of the squeeze chemical was 10.2 ppg.

At 5:30 p.m., the bottom of the Arrow packer was set at 7575.73 feet with 37K lb in tension within 7 minutes after we stopped pumping with the well taking fluid at ~0.5 bpm. The length of the packer was 7.2 feet and the length of the cross over was 0.54 feet. Casing slips were set in the spool and the BOP was removed and a rough cut made on the casing. Once all equipment was removed from the area the 4-1/2-inch tubing was dressed off and the wellhead installed. At 7:00 p.m., the well was shut-in for the night.

Wednesday, October 25, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Superior Wellhead arrived at the job site at 7:20 a.m. and pressure tested the P-seals to 3000 psig. Rig crew

and casing crew arrived at 7:30 a.m. Rig crew started mobilizing the rig. The reverse unit operator pumped the annulus full with 2.5 bbls. At 10:00 a.m. 300 PSI arrived at the job site and performed a 545 psi squeeze for 4 hours with no pressure loss. At 3:00 p.m., an annulus pressure test was performed and recorded for one hour by 300 PSI, at a pressure of 490 psig on the chart. At 4:00 p.m., the annulus pressure test showed no pressure loss over the hour. Left 480 psig on the annulus (at 4:30 p.m.) overnight to watch for pressure leaks. At 6:00 p.m., annulus was maintaining 480 psig. Well was shut-in for the night.

Thursday, October 26, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. At 7:00 a.m., EL Farmer trucking was at the job site waiting on someone to load the 2-7/8-inch, PH-6 tubing onto the truck. At 7:15 a.m., Subsurface started loading tubing onto the EL Farmer truck. At 7:30 a.m., Renco Equipment arrived at the job site with a fork lift and completed loading up truck. The first truck picked up slips, stabbing tool, safety valve, and 150 joints of pipe. At 8:00 a.m., annulus was maintaining 480 psig and showed no signs of pressure loss over the 14-hour period. The second truck arrived at 8:05 p.m. and was loaded with 147 joints of pipe. At 8:30 a.m., two Key Fishing Tool trucks arrived at the job site to pick up pump, open top tank, pipe racks, BOP, and catwalk. Key Energy delivered 4 frac tanks to the job site and started to fill the tanks with fresh water and brine. At 4:30 p.m., G&L Tool Rental picked up rig mat boards. At 5:30 p.m., annulus was maintaining 480 psig and showed no signs of pressure loss over the 23.5-hour period. Well was shut-in for the night.

Friday, October 27, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Key will not have all 14 frac tanks spotted and filled by this Saturday therefore the pressure build up/falloff test will have to be postponed until Saturday, November 4th, due to the availability of pump trucks to perform the pressure build up portion of the test.

Trailer and light plant will remain on the job site for another week, as we will need the light plant for the 12 hours of pumping. At 10:00 a.m., Medina's Hot Shot service arrived at the job site and delivered a flange, ring gasket, and bolts from Superior Wellhead to cover the injection line valve. At 3:00 p.m., Key delivered one frac tank to the job site and repaired a leak around the bottom valve on one of the tanks that was delivered yesterday.

Saturday, October 28, 2006

Rusty Smith traveled to Houston and will return on Thursday, November 2, 2006 to oversee the pressure build up and falloff test.

Thursday, November 2, 2006

Rusty Smith traveled to Artesia, New, Mexico and arrived at the jobsite at 2:30 p.m. MST. Key had 14 frac tanks on the site and should have them filled by tomorrow afternoon. Tried to find a 1-13/16-inch hammer wrench for flange bolts and could not find any in Artesia. Contacted Banta to install side flange for pump-in test, Banta will have hammer wrenches for flange. Subsurface acquired fuel containers for light plant. Key will roll frac tanks tomorrow.

Friday, November 3, 2006

Subsurface personnel arrived at the location at 7:30 a.m. MST. Banta Roustabout Service arrived at the location at 8:15 a.m. and installed the injection side flange. Six temperatures were taken at midpoint in the frac tanks to determine the current water temperatures. The shear pin in the packer was set at 80K lbs, which is well above the stress being applied due to temperature changes. Petroplex treated all tanks with biocide and Key came out and rolled the tanks with a vacuum truck.

Alex, with Schlumberger Slickline, was on notice for tomorrow at 3:00 p.m. MST. After rolling the tanks, the average water temperature in the tanks was 60.6° F. Key left the job site at 5:30 p.m.

Saturday, November 4, 2006

Subsurface personnel arrived at the location at 6:20 a.m. MST. Petroplex Pumping Service arrived at the location at 7:10 a.m. and started to rig up their pumps. Key's kill truck arrived at 7:12 a.m. and rigged up to the annulus to hold pressure on the annulus. At 9:15 a.m., treating lines were pressure tested to 4400 psi. Started pumping at 9:19 a.m. at 3 bpm to fill hole and after 28 bbls we caught pressure with 162 psig on the wellhead and 535 psig on the annulus. At 9:42 a.m., with 50 bbls into the well, the rate was increased to 5 bpm at 385 psig and 463 psig on the annulus. At 9:55 a.m., the rate was 5 bpm with 525 psig on the wellhead and 118 bbls pumped. At 10:00 a.m., the second pump was brought on line and the first pump was taken out of service due to a leaking hydraulic hole. At 10:10 a.m., the rate was 5 bpm at 531 psig and 493 psig on the annulus. At 10:15 a.m., the rate was increased to 6.8 bpm at 700 psig on the wellhead with 215 bbls pumped. At 10:45 a.m., the rate was increased to 10 bpm at 1200 psig and 542 psig on the annulus with 438 bbls pumped. At 10:55 a.m., the rate was 10 bpm at 1220 psig with 532 bbls pumped and 730 psig on the annulus. At 1105 a.m., the rate was being maintained at 10 bpm at 1278 psig with 673 bbls pumped.

Petroplex is sending out another pump to the location. The backup Petroplex pump arrived at 12:10 p.m. and the crew rigged up two additional pumps in the treating line for backup. At 1:00 p.m., the rate was 10 bpm at 1185 psig with 1785 bbls pumped, annulus pressure was 775 psig. At 2:30 p.m., the rate was 10 bpm at 1387 psig with 713 psig on the annulus, 2307 bbls pumped. At 3:30 p.m., the rate was lowered to 9 bpm at 1209 psig with 725 psig on the annulus, 3028 bbls pumped. At 5:30 p.m., the rate was 9 bpm at 1171 psig with 719 psig on the annulus. At 6:00 p.m., Schlumberger arrived at the job site and rigged up the slickline unit. At 7:17 p.m., the rate was lowered to 5 bpm to allow the BHP memory tool into the wellbore. At 7:30 a.m., the rate was increased to 5 bpm at

344 psig. At 7:41 p.m., the rate was increased to 9 bpm at 1104 psig. At 9:00 p.m., the pumps started to lose suction pressure and the pumping job was ended (est. 6700 bbls). Well was closed in with 50 psig on the annulus and no pressure on the wellhead. Petroplex rigged down and left location at 11:00 p.m.

Sunday, November 5, 2006

Subsurface personnel arrived at the location at 8:30 a.m. MST, with 800 psig on the annulus. Schlumberger slickline crew arrived at the location at 10:20 a.m. and started out of the hole with memory tool at 8630 feet (10:35 a.m.), taking gradient stops every 1000 feet for 5 minutes. The length of the tool was 27 feet with the top of the tool placed at 8630 feet. First stop was at 7000 feet at 10:40 a.m.. At 12:35 p.m., Schlumberger completed the rig down process and left location at 1:00 p.m. The office trailer was cleaned out and disconnected from the light plant. The light plant was rigged down and made ready for pickup. The well annulus was bled down and left open and the wellhead shut-in. Schlumberger left their 4-1/2-inch 8rd EUE x 2-7/8-inch female 8rd tubing swedge in the top of the wellhead.

Monday, November 6, 2006

Subsurface personnel traveled to Houston and will return on Monday, November 13, 2006, to oversee the temperature survey, radioactive tracer survey, and annulus pressure test. Called Young's to pickup office trailer, Sani-Tech to pick up portable toilets, and Aztec to pickup light plant. Larry at Key was notified to leave one frac tank on location and pickup the remaining frac tanks. Banta was notified for waste removal of pit and location cleanup for the week of November 13th.

Sunday, November 12, 2006

Rusty Smith traveled to Artesia, New Mexico, and arrived at the job site at 5:00 p.m. MST. Key Energy emptied the frac tank bottoms and the tanks are ready to be

disconnected and picked up. Aztec and Sani-Tech still have not removed the equipment from the location. The equipment was taken off rental on November 6, 2006.

Monday, November 13, 2006

Subsurface arrived at the location at 7:30 a.m. MST. Banta roustabout service arrived at the job site at 8:15 a.m. to remove well cutting and clear location of debris, fill in cellar with gravel, and haul off trash. Navajo refining requires that that all produced cuttings and debris contained in the pit be profiled prior to disposal (cannot be disposed under oil field exemption). Key started to remove frac tanks from the location. The OCD pushed back the annulus pressure test, and radioactive tracer survey one day to November 15th. Wood Group Logging services will arrive tomorrow afternoon for testing on the 15th. Petroplex Pumping will provide a pump truck for the radioactive tracer test.

Tuesday, November 14, 2006

Subsurface personnel arrived at the location at 8:30 a.m. MST. Wayne, with the OCD, was emailed at 5:00 p.m. MST November 13, 2006, informing the OCD of the annulus pressure test and radioactive tracer survey set for November 15, 2006. Included in the email were directions to the well and a short testing procedure. Wood Group and Petroplex were contacted to verify the job for tomorrow. Key has filled one frac tank with one load of brine and three loads of fresh water to chase down the radioactive slug. Wind gusted up to 50 mph and Key could not haul any more frac tanks for the day, in accordance with DOT regulations. Because of the high wind speed Wood Group will rig up tomorrow. OCD called and said that they will arrive at 10:00 a.m. tomorrow morning.

Wednesday, November 15, 2006

Subsurface personnel arrived at the location at 7:00 a.m. MST. Petroplex was on location. At 7:50 a.m., Petroplex hooked up to the frac tank and started to circulate the tank and will circulate for +2 hours. Wood Group started to rig up at 8:30 a.m. and

completed the rig up at 10:00 a.m. OCD representatives arrived at the location to witness the annulus pressure test. The annulus was pressure tested to 530 psia and over a one hour period and lost 2.5 psi. According to the OCD, the well passed the annulus pressure test.

The radioactive survey was started and during the 5-minute check, the upper gamma ray sensor malfunctioned and the sensor had to be pulled and replaced. Once the sensor was replaced, the remainder of the survey went as planned and there did not appear to be any radioactive material above the packer or being pumped out of the injection interval.

There were some undocumented perforations below 8600 feet that were taking fluid. During the first chase down, additional RA material was released as a result of the well being on a vacuum. At the end of the job the annulus was pressure tested to 300 psig and held pressure for 1.5 hours and was then bled off and left open. Wood Group rigged down at 8:30 p.m.

Thursday, November 16, 2006

Subsurface personnel called Key to release frac tank and went to location to check well and sign invoices from Basic and G&L Tools in Artesia, NM. Subsurface personnel travel to Houston, Texas.

Subsurface personnel will return to Artesia in ± one month to install WAMS. Subsurface is waiting on the unit to be built.

APPENDIX I
CALCULATION OF PERMEABILITY
FROM DST NO. 5
MEWBOURNE OIL COMPANY, CHALK BLUFF 31, STATE NO. 1

The permeability of the interval tested is calculated to be 597 md, as follows from test data in Attachment VIII-9:

$$k = 162 \frac{qB\mu}{mh}$$

where:

- k = permeaibility, md
- q = production rate (bbl/day)
- B = formation volume factor, (reservoir bbl)/(stock tank bbl)
- μ = viscosity, centipoise (cp)
- m = slope of Horner plot, psi/cycle
- h = reservoir thickness, feet

The production rate, q, is calculated from the total volume of fluid, 78.7 bbl, produced during DST No. 5, which lasted for 90 minutes (the sum of lengths of the first and second flow periods). Using these values, q is equal to 1259 bbl/day. The formation volume factor, B, is assumed to be 1. The viscosity, μ, of reservoir brine with 25,000 ppm chlorides (approximately 2% salinity) at a bottom-hole temperature of 130°F is 0.53 cp, taken from the charge in Attachment VI-7. The slope of the Horner plot, m, is taken form the Horner plot for the second flow period of DST no. 5, or 5.348 psi/cycle (page 22 of Attachment VIII-9). The reservoir thickness, h, is the thickness of the interval tested during DST No. 5, or 34 feet (7851 feet – 7817 feet). Substituting these values into the equation above gives:

$$k = 162 \frac{(1259)(1)(0.53)}{(34)(5.348)}$$

$$= 597 \text{ md}$$

INJECTED FLUID MONITORING PLAN

NAVAJO REFINING COMPANY, L.L.C.
ARTESIA, NEW MEXICO

SUBSURFACE PROJECT NO. 60A6781

SUBMITTED
JUNE 2012

SUBSURFACE TECHNOLOGY, INC.
HOUSTON, TEXAS

SUBSURFACE

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1.0 INTRODUCTION

This injected fluid monitoring plan (plan) has been prepared per the requirements of 20.6.2.5207B NMAC. This plan allows for consistent characterization of the injected fluids that are being injected into the three nonhazardous waste injection wells operated by Navajo Refining Company, L.L.C. (Navajo) at their refinery in Artesia, New Mexico. The plan shall be updated as necessary to remain accurate and the analysis remains representative of the fluids being injected into the three nonhazardous waste injection wells.

2.0 INJECTED FLUID DESCRIPTION

The fluid injected into all three Navajo injection wells is comprised of exempt and nonexempt nonhazardous oilfield waste that is generated in the refining process. Waste waters from process units, cooling towers, boilers, streams from water purification units, desalting units, recovered and treated ground water, and general waste waters, all waters will be blended to form the injected fluid into the injection wells.

3.0 INJECTED FLUID CHARACTERIZATION SAMPLING PROGRAM

The following sampling program shall be used to collect a representative sample of the injected fluid for chemical analysis to demonstrate the consistency of the fluid composition.

3.1 Sampling Frequency

The injected fluid shall be sampled on a quarterly basis unless a change in the injected fluid composition occurs as a result of operating changes at the Navajo refinery. If the injected fluid composition does change, a representative sample of the waste stream shall be collected at that time and reported to OCD.

3.2 Sampling Location

A representative sample of the injected fluid shall be obtained from the discharge side of the wastewater transfer pump that sends wastewater to the wellheads. The sample port is located at the refinery's wastewater treatment unit.

3.3 Sample Collection Equipment

The fluid samples shall be collected directly from the sample port on the wastewater transfer line into appropriately prepared sample containers required for specific analyses.

3.4 Sample Containers

The injected fluid sample shall be collected in new and previously unused sample containers as provided by the off-site commercial laboratory performing the analyses.

3.5 Sampling Methodology

The injected fluid sample shall be poured directly into the new and previously unused sample containers provided by the off-site commercial laboratory performing the analyses.

3.6 Sample Preservation

EPA and/or ASTM sampling protocols shall be used, including provisions for preserving samples when required. Sampling personnel shall verify that appropriate preservatives are present in sample containers if required by analytical protocol.

3.7 Field Measurements

Field measurements of pH, specific conductance, and temperature shall be recorded on a representative sample of the injected fluid during each quarterly monitoring event.

3.8 Sampling Personnel

Navajo environmental staff or qualified contractor sampling personnel shall be responsible for collecting the injected fluid samples in accordance with the procedures presented in this plan.

4.0 FIELD DOCUMENTATION

The following procedures shall be implemented to properly document each injected fluid characterization sampling event as described in Section 3.0.

4.1 Water Sampling Log

A water sampling log shall be completed at the time the sample is collected. The type of information to be recorded on the water sampling log includes, but is not limited to, the following:

- Date and time of sampling
- Weather conditions
- Sampling location
- Sampling method
- Sample identification
- Field measurements
- Laboratory analyses
- Sampling personnel

4.2 Sample Container Label

Each laboratory provided sample container shall have a label adhered to the outside of the container providing pertinent information identifying the sample,

location and time the sample was collected, analytical parameters, preservatives, and sampler identification.

4.3 Chain-of-Custody Form

A chain-of-custody form shall be completed and accompany each shipment of samples to the off-site commercial laboratory. Each transfer of sample custody shall be signed by both parties on the chain-of-custody form.

4.4 Custody Seal

A custody seal shall be affixed over the opening of the ice chest used to store and transport samples to the receiving laboratory. The laboratory shall note in their Check-In Form that the seal is properly attached and has not been broken.

4.5 Field Equipment Calibration Log

Calibration and maintenance of field equipment (pH, specific conductance, turbidity, and temperature meters) shall be in compliance with the manufacturers' recommended calibration or maintenance procedures. Field logs shall be completed in the field to properly document all calibration and maintenance activities to field equipment.

5.0 QUALITY ASSURANCE/QUALITY CONTROL

A trip blank will be prepared during each waste stream characterization sampling event as described in Section 3.0.

6.0 SAMPLE CUSTODY AND TRANSPORT

Injected fluid characterization samples shall be maintained in the custody of the sampling personnel until the samples are transported to the laboratory or transferred to a representative of the receiving laboratory. Upon transfer of custody, the chain-of-custody record shall be completed and signed by the sampling personnel. The signed chain-of-custody record shall be placed in a plastic bag inside the shipment cooler containing the properly labeled injected fluid

samples. A signed and dated custody seal shall be placed over the lid of the opening of the sample cooler to indicate if the cooler has been opened during delivery prior to receipt by the laboratory.

The chain-of-custody record shall be signed and returned by the laboratory no later than the date the analytical results are available. If the samples are delivered in person by the sampling personnel or picked up by a laboratory employee, the chain-of-custody record shall be signed by the laboratory representative immediately upon relinquishment of the samples by the sampling personnel. One of the copies shall be maintained by the sampling personnel and the remaining copies kept with the samples.

7.0 WASTE STREAM ANALYTICAL PROGRAM

The following describes the injected fluid characterization analytical program.

7.1 Laboratory Requirements

The laboratory performing the analytical services for this project shall be an accredited laboratory. The laboratory shall possess a quality control/ quality assurance (QA/QC) manual prepared in accordance with the requirements of the NELAC certification program. A current copy of the plan shall be sent by the laboratory to the project manager in charge. When the manual is updated by the laboratory the updated version of the manual shall be sent to the project manager. The previously issued copy of the manual must be archived by the project manager to insure traceability of the data generated using the applicable QA/QC manual.

Navajo is currently utilizing ALS Environmental, a commercial laboratory located in Houston, Texas. ALS is a NELAC accredited laboratory.

7.2 Analytical Parameters and Methods

The injected fluid samples are analyzed for the following listing of parameters that are representative of the injected fluid:

- VOC (EPA Method 8260)
- SVOC (EPA Method 8270)
- Total Metals (EPA Method 6020/7000)
- RCI
- Chloride
- Sulfate
- Alkalinity
- TDS
- pH
- Conductivity

The parameter listing shall be updated as necessary to remain accurate and the waste analysis remains representative of the injected fluid being injected.

8.0 REPORTING

The laboratory performing the injected fluid characterization analyses shall generate a report of the analytical results. These analytical results shall be compiled with the field measurement results and tabularized. The results of each waste stream characterization sampling event, including tabularization of analytical results, copies of laboratory reports, and copies of water sampling logs, shall be provided to OCD within 90 days following each sampling episode. The report shall document any obvious fluctuations in the injected fluid composition.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-1)

Final Testing Program

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

Mechanical Integrity Testing

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

Pressure Falloff Testing

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

1. Prepare the well and location for plugging. Remove the well monitoring equipment and wellhead injection piping.

2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

3. Move in and rig up the frac tanks and pump for the pressure falloff test. Fill frac tanks with 2,000 barrels of brine.

4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

5. Commence injecting 2,000 barrels of brine at a constant rate. The brine will be compatible with the injection zone reservoir fluid, as determined by compatibility testing. Record the pressure buildup. Cease pumping and record the pressure

falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

6. Rig down the wireline unit.

7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.

8. Remove the wellhead and install the BOP equipment and stripper head.

9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.

10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,004 feet. Rig down the wireline unit.

11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.

12. Run in the well with the work string and sting into the cement retainer at 9,004 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.

13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,004 feet to the surface.

14. Cut casing strings ±3 feet below ground level.

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the OCD.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-2)

Final Testing Program

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

Mechanical Integrity Testing

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

Pressure Falloff Testing

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

1. Prepare the well and location for plugging. Remove the well monitoring equipment and wellhead injection piping.

2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

3. Move in and rig up the frac tanks and pump for the pressure falloff test. Fill frac tanks with 2,000 barrels of brine.

4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

5. Commence injecting 2,000 barrels of brine at a constant rate. The brine will be compatible with the injection zone reservoir fluid, as determined by compatibility testing. Record the pressure buildup. Cease pumping and record the pressure

falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

6. Rig down the wireline unit.

7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.

8. Remove the wellhead and install the BOP equipment and stripper head.

9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.

10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,004 feet. Rig down the wireline unit.

11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.

12. Run in the well with the work string and sting into the cement retainer at 9,004 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.

13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,004 feet to the surface.

14. Cut casing strings ±3 feet below ground level.

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the OCD.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

APPENDIX K

INJECTION WELL CLOSURE PLAN
HOLLYFRONTIER NAVAJO REFINING LLC
(WDW-3)

Final Testing Program

After ceasing injection in the well and prior to commencing physical closure procedures of the injection well, a pressure falloff test will be conducted in order to determine if the transient pressure data have conformed with predicted values within the injection interval. The brine injected for the falloff test will be nonhazardous and will also act as a buffer between the injectate and the well. Appropriate mechanical integrity testing shall also be conducted to ensure the integrity of the long casing string and cement that will remain in the ground after closure. Notify the OCD of mechanical integrity and pressure falloff testing procedures of the long casing string and cement that will remain.

Mechanical Integrity Testing

An annular pressure test and radioactive tracer survey will be conducted prior to removing the injection tubing and packer. Subsequent to tubing and packer removal, a casing inspection and a cement bond/variable density log will be conducted from total depth to the surface.

Pressure Falloff Testing

A wireline unit with pressure control equipment will be rigged up to run in the hole with a surface recording bottom-hole pressure transducer with temperature capabilities to position the transducer at the top of the injection interval. The transducer will be stabilized prior to injecting brine.

Two thousand barrels of brine will be injected at a constant rate. The brine will be compatible with the injection zone reservoir fluid as determined by compatibility testing. The pressure buildup will be recorded. After pumping is ceased, the pressure falloff will be recorded for a minimum of 24 hours after shut in. The pressure derivative curve to will be monitored confirm the test has investigated beyond the wellbore storage effect.

Regulatory Notification

Navajo will notify OCD at least 60 days before commencing plugging and abandonment procedures on any waste disposal well.

Plug and Abandonment Procedures

The balance plug method will be employed to plug and abandon this well. This technique involves displacing the cement through a work string which has been run into the casing. The cement slurry is pumped down the work string and up the annulus to a calculated height which would balance the cement inside and outside the work string. The work string is then slowly pulled out of the cement leaving a solid, uniform plug.

Heavy drilling mud is placed between the cement plugs. This mud establishes a hydrostatic gradient that will exceed the static bottom-hole pressure at the time of plugging and any anticipated pressures which would result from future injection activity in these particular formations.

Finally, after all cement plugs are set, the well casings will be cut off 3 feet below grade and capped by welding a ½ inch steel plate to the outermost casing string.

The plugging and abandonment procedures for a typical well are described as follows:

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2. Notify the OCD of the MIT schedule. Conduct an annulus pressure test and a radioactive tracer survey to satisfy OCD mechanical integrity requirements.

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4. Rig up the wireline unit with pressure control equipment. Run into the hole with a surface recording bottom-hole pressure transducer with temperature capabilities and position the transducer at the top of the perforated injection interval. Allow the transducer to stabilize prior to injecting brine.

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falloff. Measure the pressure falloff for a minimum of 24 hours after shut in. Monitor the pressure derivative curve to confirm the test has investigated beyond the wellbore storage effect.

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7. Move in and rig up the well service unit with BOP equipment and a 2 7/8 inch work string.

8. Remove the wellhead and install the BOP equipment and stripper head.

9. Unseat the seal assembly from the packer and displace the annular fluid by flushing with 200 bbls of brine. Trip out of the hole laying down the 4 ½ -inch injection tubing.

10. Rig up the wireline unit and run a casing inspection log and a cement bond/variable density log from total depth to the surface. Pick up and run a wireline set cement retainer at 9,022 feet. Rig down the wireline unit.

11. Rig up cement service equipment. Cement shall be Class "A" (or comparable), weighing 15.6 pounds/gallon. Pressure test the surface lines as required.

12. Run in the well with the work string and sting into the cement retainer at 9,022 feet. Establish a pump-in rate into the injection perforations and pump 100 sx of Class “A” cement below the retainer. Pull out of the retainer and spot sufficient Class "A" (or comparable) cement slurry to develop a 100-foot plug above the cement retainer. Pull the tubing up above the top of cement and reverse out excess cement. Catch a sample of cement to check curing time and compressive strength. Allow the cement to set overnight (8-hour minimum) before tagging top of plug to confirm proper setup and location. Pressure test the plug to the pressure recommended by the OCD.

13. Set a balanced cement plug using Class “A” cement from the top of cement at approximately 9,022 feet to the surface.

14. Cut casing strings ±3 feet below ground level.

15. Weld a ½ inch steel plate across the 13-3/8-inch casing. Inscribe on plate, in a permanent manner, the following information: (1) operator name, (2) closure date, and (3) UIC permit number.

16. Release all equipment and clean up the location.

17. Submit closure data to the TCEQ.

Once closure operations are complete and the well is officially plugged and abandoned, a closure report certifying that the well or wells were closed in accordance with applicable requirements, will be submitted to the OCD within 30 days. The report will include any newly constructed or discovered wells or information, including proposed well data, within the area of review. When plugging and abandonment is complete, Navajo will submit certification to the OCD that the injection well has been closed in accordance with applicable OCD regulations.

Form ___WQCC-1____
Adopted 5-24-2011

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO. **_____6186996**
OCD PERMIT **___UICI-008-1**
AMOUNT OF BOND **___$95,000.00**
COUNTY **__Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, (~~an individual~~ **if dba must read Example: John Doe dba ABC Services**) (~~a general partnership~~) (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

_____WDW-1_____API No. 30-015-27592 , located___660___feet from the
(**Name of Well**)
____South_____ (~~North~~/**South**) line and _____2,310_____feet from the _____East_____ (**East**/~~West~~) line

of Section___31_____ Township_____17_____ (~~North~~) (**South**), Range_____28_____ (**East**) (~~West~~),

NMPM, and Latitude 32°47'6.77"N_ Longitude 104°12'50.22"W_ County _____Eddy_____, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-1 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

_____	_____
PRINCIPAL	**SURETY**
_____	_____
Address	**Address**
By_____	_____
Signature	**Attorney-in-Fact**
_____	
Title	
If PRINCIPAL is a corporation, affix Corporate seal here	**Corporate surety affix Corporate seal here**

DRAFT

Form WQCC-1

ACKNOWLEDGMENT FORM FOR INDIVIDUAL

(If dba, must read – Example: John Doe dba Well Services)

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____ day of _____20_____

by_____.
(Name of Individual)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR PARTNERSHIP, CORPORATION, OR LIMITED LIABILITY COMPANY

STATE OF_____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on _____day of _____20____by_____
(Name of Person Signing Instrument)

as _____of_____
(**Capacity, e.g., partner, president, manager, member**) (**Name of partnership, corporation or limited liability company**)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR CORPORATE SURETY

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____day of _____, 20____,

by_____, as Attorney-in-Fact for _____
(Name of Attorney-in-Fact) (Name of Corporate Surety)

_____
Notary Public

SEAL

_____
My Commission Expires

<u>Corporate Surety attach Power of Attorney</u>

APPROVED BY:

OIL CONSERVATION DIVISION OF NEW MEXICO

By_____

Date_____

DRAFT

Form ___WQCC-1____
Adopted 5-24-2011

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO. **_____6187002**
OCD PERMIT **___UICI-008-2**
AMOUNT OF BOND **___$95,000.00**
COUNTY **__Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, ~~(an individual **if dba must read Example: John Doe dba ABC Services**) (a general partnership)~~ (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

WDW-2 (**Name of Well**) API No. 30-015- 20894 , located 1980 feet from the North (**North**/~~South~~) line and 660 feet from the West (~~East~~/**West**) line of Section 12 Township 18 (~~North~~) (**South**), Range 27 (**East**) (~~West~~), NMPM, and Latitude 32°45'49.32"N Longitude 104°14'18.59"W County Eddy, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-2 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

_____	_____
PRINCIPAL	**SURETY**
_____	_____
Address	**Address**
By_____	_____
Signature	**Attorney-in-Fact**
_____	
Title	
If PRINCIPAL is a corporation, affix Corporate seal here	**Corporate surety affix Corporate seal here**

DRAFT

Form WQCC-1

ACKNOWLEDGMENT FORM FOR INDIVIDUAL

(If dba, must read – Example: John Doe dba Well Services)

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____ day of _____20_____

by_____.
(Name of Individual)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR PARTNERSHIP, CORPORATION, OR LIMITED LIABILITY COMPANY

STATE OF_____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on _____day of _____20____by_____
(Name of Person Signing Instrument)

as _____of_____
(**Capacity, e.g., partner, president, manager, member**) (**Name of partnership, corporation or limited liability company**)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR CORPORATE SURETY

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____day of _____, 20____,

by_____, as Attorney-in-Fact for _____
(Name of Attorney-in-Fact) (Name of Corporate Surety)

_____
Notary Public

SEAL

_____
My Commission Expires

<u>Corporate Surety attach Power of Attorney</u>

APPROVED BY:

OIL CONSERVATION DIVISION OF NEW MEXICO

By_____

Date_____

DRAFT

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION (OCD)
WATER QUALITY CONTROL COMMISSION (WQCC) OCD DISCHARGE PERMIT BOND

BOND NO. **6186995**
OCD PERMIT **UICI-008-3**
AMOUNT OF BOND **$95,000.00**
COUNTY **Eddy County**

File with the Oil Conservation Division, 1220 South St. Francis Drive, Santa Fe, NM 87505

KNOW ALL MEN BY THESE PRESENTS:

That Navajo Refining Company, ~~(an individual **if dba must read Example: John Doe dba ABC Services**) (a general partnership)~~ (a corporation), (limited liability company) (limited partnership) organized in the State of New Mexico, and authorized to do business in the State of New Mexico, as PRINCIPAL, and Safeco Insurance Company of America, a corporation organized and existing under the laws of the State of Delaware and authorized to do business in the State of New Mexico, as SURETY, are firmly bound unto the State of New Mexico, for the use and benefit of the Oil Conservation Division of the Energy, Minerals and Natural Resources Department (or successor agency) (the DIVISION), pursuant to 20.6.2.5210.B(17) NMAC, 20.6.2.5006 NMAC, and 20.6.2.3107.A(11) NMAC, in the sum of $95,000.00, for the payment of which the PRINCIPAL and SURETY hereby bind themselves, their successors and assigns, jointly and severally, firmly by these presents.

The conditions of this obligation are such that:

WHEREAS, the PRINCIPAL does or may own or operate a "Facility" (identified by location only below) and/or one or more wells (identified by location(s) below) for the injection of fresh and non-fresh water, remediation fluids (i.e., Class I (NH) Disposal Well or Class V Pump & Treat Injection Well), oilfield exempt, non-exempt and/or geothermal produced fluid waste(s) into the subsurface for use in connection with oil, gas and/or geothermal activities, which well is classified as a Division Underground Injection Control Class I, III or V Injection Well pursuant to the 20.6.2.5002 et seq. NMAC, the identification and location(s) of said well(s) being:

WDW-3 (**Name of Well**) API No. 30-015- -26575 , located 790 feet from the South (~~North~~/**South**) line and 2250 feet from the West (~~East~~/**West**) line of Section 1 Township 18 (~~North~~) (**South**), Range 27 (**East**) (~~West~~), NMPM, and Latitude 32°46'16.51"N Longitude 104°13'59.80"W County Eddy, New Mexico.

NOW, THEREFORE, if the PRINCIPAL and SURETY or either of them, or their successors or assigns or any of them, shall: (a) cause said well(s) to be properly plugged and abandoned when no longer productive or useful for other beneficial purpose in accordance with the WQCC rules and/or orders of the DIVISION; and (b) take all measures necessary, as required by the DIVISION by OCD Permit No. UICI-008-3 pursuant to 20.6.2 and 20.6.4 NMAC, as such rules now exist or may hereafter be amended, to prevent contamination of ground water having 10,000 milligrams per liter (mg/l) or less concentration of total dissolved solids (TDS), including, but not limited to, surface and ground water restoration if applicable, and post-operational monitoring.

THEN AND IN THAT EVENT, this obligation shall be null and void; otherwise and in default of complete compliance with any and all of said obligations, the same shall remain in full force and effect.

_____ **PRINCIPAL**	_____ **SURETY**
_____ **Address**	_____ **Address**
By_____ **Signature**	_____ **Attorney-in-Fact**
_____ **Title**	
If PRINCIPAL is a corporation, affix Corporate seal here	**Corporate surety affix Corporate seal here**

DRAFT

ACKNOWLEDGMENT FORM FOR INDIVIDUAL
(If dba, must read – Example: John Doe dba Well Services)

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____ day of _____20_____

by_____.
(Name of Individual)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR PARTNERSHIP, CORPORATION, OR LIMITED LIABILITY COMPANY

STATE OF_____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on _____day of _____20____by_____
(Name of Person Signing Instrument)

as _____of_____
(**Capacity, e.g., partner, president, manager, member**) (**Name of partnership, corporation or limited liability company**)

_____
Notary Public

SEAL

_____
My Commission Expires

ACKNOWLEDGMENT FORM FOR CORPORATE SURETY

STATE OF _____)
ss.
COUNTY OF_____)

This instrument was acknowledged before me on this _____day of _____, 20____,

by_____, as Attorney-in-Fact for _____
(Name of Attorney-in-Fact) (Name of Corporate Surety)

_____
Notary Public

SEAL

_____
My Commission Expires

<u>Corporate Surety attach Power of Attorney</u>

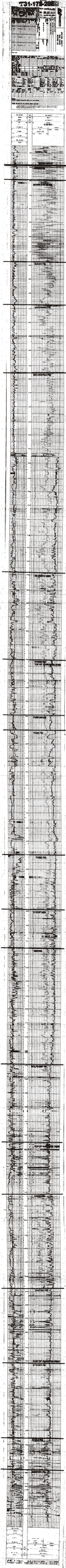
APPROVED BY:

OIL CONSERVATION DIVISION OF NEW MEXICO

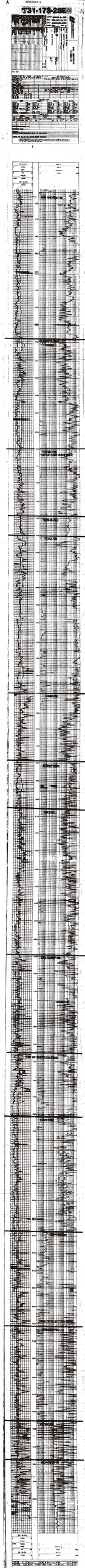
By_____

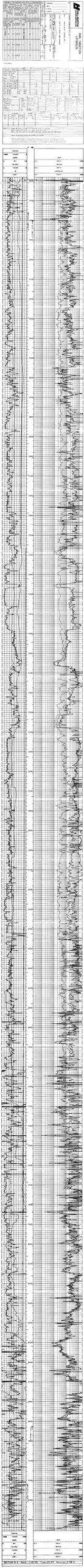
Date_____

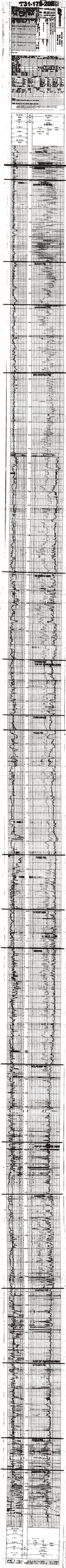
DRAFT



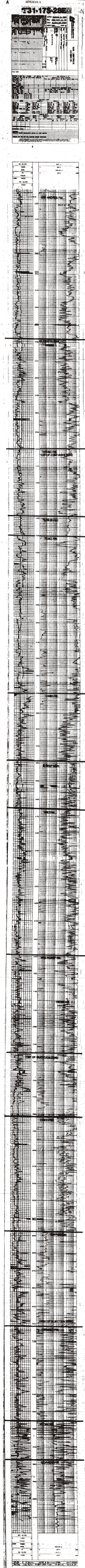
APÉNDICE A

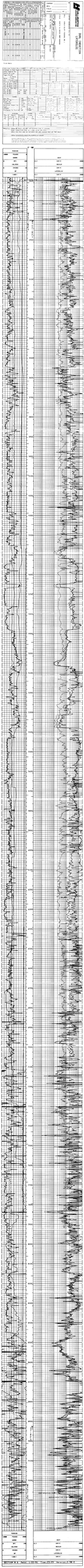



SCHLUMBERGER
COMPENSATED NEUTRON LITHO-DENSITY
CASED HOLE
COMPANY
WELL
FIELD
COUNTY
STATE
LOCATION
Other Services
Permanent Datum
Elev.: K.B.
D.F.
G.L.
Log Measured From
Drilling Measured From
Date
Run No.
Depth-Driller
Depth-Logger
Bottom Logged Interval
Top Logged Interval
Type Fluid in Hole
Salinity, PPM Cl
Density
Level
Max. Rec. Temp. Deg. F
Equip. No. Location
Recorded By
Witnessed By
Run No.
Tool Type
Tool No.
Density Source
Source Strength
Detector Spacing
Neutron Source
Source Strength
Detector Spacing
Mud Type
Density
Viscosity
Fluid Loss
Resistivity
Temperature
Mud Cake
Resistivity
Temperature
Time Since Circ.
Time Since Log



APÉNDICE A




SCHLUMBERGER
COMPENSATED NEUTRON LITHO-DENSITY
CASED HOLE
COMPANY
WELL
FIELD
COUNTY
STATE
LOCATION
Other Services
Permanent Datum
Elev.: K.B.
D.F.
G.L.
Log Measured From
Drilling Measured From
Date
Run No.
Depth-Driller
Depth-Logger
Bottom Logged Interval
Top Logged Interval
Type Fluid in Hole
Salinity, PPM Cl
Density
Level
Max. Rec. Temp. Deg. F
Equip. No. Location
Recorded By
Witnessed By
Run No.
Tool Type
Tool No.
Density Source
Source Strength
Detector Spacing
Neutron Source
Source Strength
Detector Spacing
Mud Type
Density
Viscosity
Fluid Loss
Resistivity
Temperature
Mud Cake
Resistivity
Temperature
Time Since Circ.
Time Since Log