TECHNICAL REPORT OF CONSTRUCTION

ON

Lake Meredith Salinity Control Project
New Mexico

July 26, 2000
JF0239

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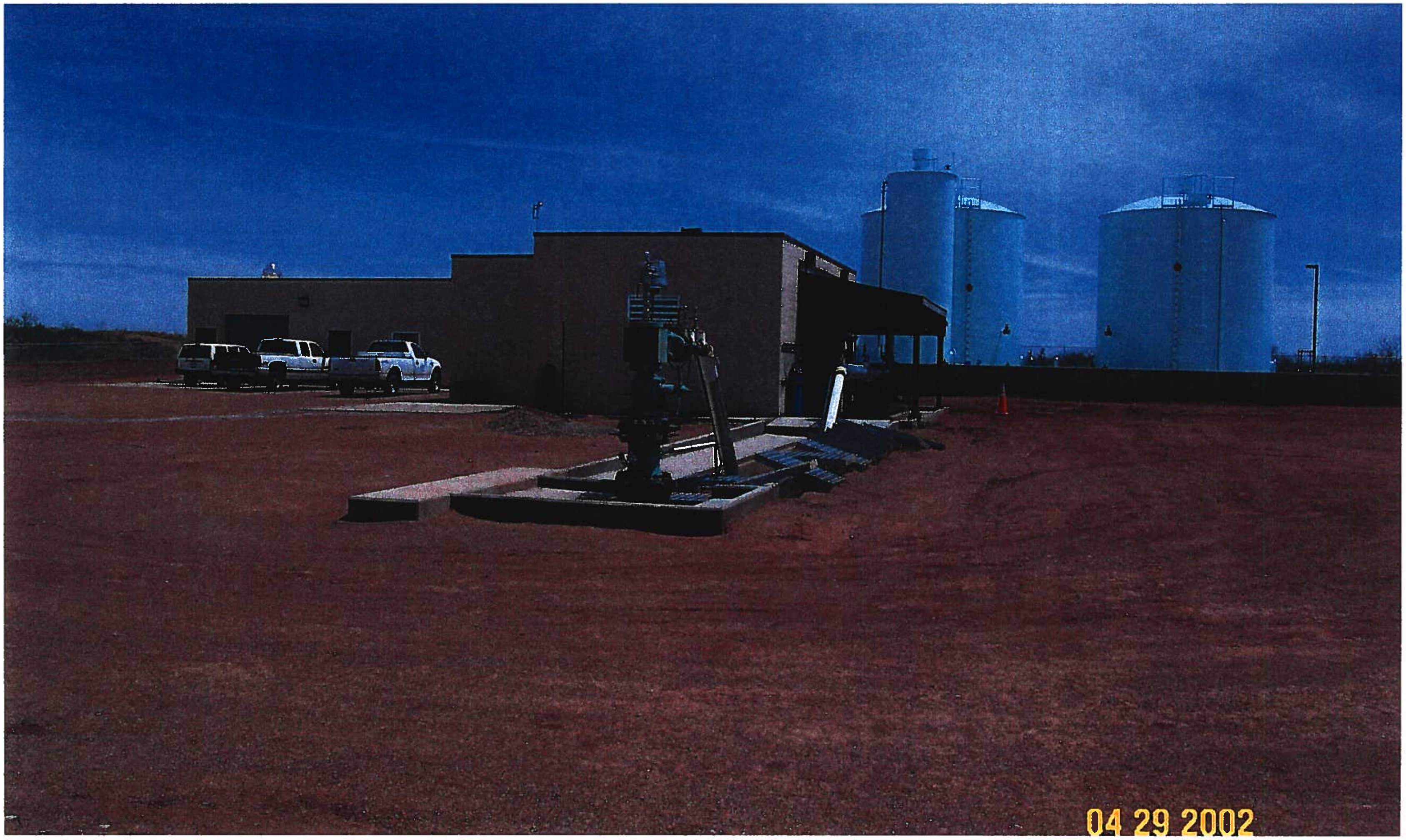

Lake Meredith Salinity Control Project – This view of the injection well facilities is to the northeast with injection well IW-1 in the middle foreground. The gratings have been removed from the discharge line (well chase) from the injection pump. CRMWA Corp. employees have added curbs to the well chase to prevent debris from entering. The injection pump and injection building are directly behind the injection well. The containment basin and storage tanks are to the right, and the office building is to the left. Photographed 4/29/02 by Dennis McDonough.

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CHRONOLOGY

June 1975	First drilling investigations began at site (DH-1 and 2).
1980	Feasibility Study for the Lake Meredith Salinity Control Project was authorized by Congress.
1983	Study Plan approved.
1985	Technical Report for Lake Meredith Salinity Control Project completed.
1986	Environmental Assessment / Finding of No Significant Impact (EA/FONSI) released.
October 1992	Congress passes Public Law 102-575 authorizing construction.
February 3 - March 6, 1996	Pilot hole is drilled near injection well site to obtain design information.
April 1995	Solicitation 1425-5-SI-60-07130 was issued by Reclamation with two-step bidding procedure for design and construction of Lake Meredith Salinity Control Project. The solicitation was canceled in August 1995 due to low bid exceeding available funding.
September 1995	Final Supplemental EA/FONSI issued to update the previous document.
December 1996	Class III Cultural Resource Inventory for the Lake Meredith Salinity Control Project Near Logan, Quay County, New Mexico issued.
April 1997	Value Engineering Study performed for Lake Meredith Salinity Control Project in Reclamation Technical Services Center, Denver, Colorado.
June 1997	Preconstruction surveying was performed by Reclamation survey crew from Farmington, New Mexico.
June 23, 1997	Public Information Meeting held at Village of Logan Community Center.
May 9, 1999	Request For Bids No. 17-0345-a through 17-0345-nn (40 bid requests) issued by TWO for Phase 1 construction of Injection Well IW-1 A pre-bid conference for Phase 1 bids held at the Logan, New Mexico City Hall at 9:00 AM. See Tables 4 and 5 for contract award information.
June 3, 1999	Phase 1 bid openings at Texas World Operations, Inc. headquarters in Houston, Texas.

July 19, 1999	Majority of Notices of Award issued for the 48 Phase 1 bid packages.
July 1999	Phase 1 construction began when CRMWA Corp. prepared access road, drilling pad, and reserve pits for drilling and construction of Injection Well IW-1. Akome, Inc., lined and fenced 3 sides of reserve pit. Weder Services set and cemented conductor casing, installed a Tinhorn cellar, and installed rat and mouse holes for IW-1.
July 20-21, 1999	Drill rig arrived at IW-1 site. Drilling for Phase 1 injection well began on July 21.
July 23, 1999	Installed and cemented 13-3/8 inch surface casing with bottom at 819.1 ft below the rotary kelly bushing (RKB).
July 25, 1999	Pressure tested the surface casing.
August 1-2, 1999	Installed and cemented 9-5/8 inch protection casing.
August 12, 1999	Obtained clearance from State of New Mexico Environment Department, Ground Water Quality Division, to drill vertical hole deeper than originally projected.
August 14, 1999	CRMWA Corp. authorizes drilling vertical hole ahead until encountering a zone with a lower drilling penetration rate.
August 15, 1999	Stopped drilling vertical hole after reaching a total depth (RKB) of 3800 ft.
August 15-16, 1999	Installed blank and pre-perforated 5-1/2 inch steel liner.
August 16-17, 1999	Cemented blank section of 5-1/2 inch steel liner. Considerable time was lost working on the TAM combo tool to assure engagement in the port collar prior to cementing the blank section. (TAM combo tools are drill string tools manufactured by TAM International; these tools are used to both inflate an external casing packer, and open and close a port collar in one trip into a well.)
August 19, 1999	Cemented blank 5-1/2 inch steel liner perforated in selected areas.
August 21, 1999	Injectivity fall-off testing performed on the vertical portion of the well.
August 23, 1999	Began milling window through the 9-5/8 inch protection casing for the lateral hole.
September 1, 1999	Stopped drilling lateral hole at a measured depth of 4078 ft after almost 100% loss of drill fluid return.

September 5, 1999	Installed 5-1/2 inch steel liner casing in lateral hole. As in the vertical hole, considerable time was lost working on TAM combo tool to assure engagement in the port collar prior to cementing the blank section.
September 6, 1999	Cement encountered in the lateral hole at measured depth of 3417 ft.
September 10, 1999	Holman Services mobilizes to site to begin plugging and abandonment of Pilot Hole.
September 11-12, 1999	Injectivity fall-off testing performed on the combined vertical and lateral holes.
September 12, 1999	The injection packer and polished bore receptacle were installed in the well.
September 14, 1999	Inhibited brine was installed in the annulus system and a preliminary annulus pressure test was conducted.
September 15, 1999	Pilot hole plugging completed by subcontractor.
October 6, 1999	The official mechanical integrity testing was performed in Injection Well IW-1, ending Phase 1 field construction.
May 2000	CRMWA issued Invitation to Bid for Phase 2 construction of Salinity Control Facilities.
May 15, 2000	Phase 2 pre-bid conference held at Logan, New Mexico.
June 23, 2000	Notice of Award issued to Garney Companies, Inc.
July 19, 2000	Preconstruction meeting is held at CRMWA Corp. construction trailer at injection well near Logan, New Mexico.
July 19, 2000	Standard Form of Agreement Between Owner and Contractor signed by CRMWA Corp. and Garney Companies, Inc.
August, 2000	Garney Site Administrator arrives at site.
August 31, 2000	Phase 2 Construction commenced when Couch Drilling Company (also known as Couch Drilling and Pump Service and Crouch Pump Service) began delivering equipment to site prior to starting to drill Production Well PW1-2.
November 8, 2000	Public Information Meeting is held at Village of Logan Community Center.
October 9, 2001	CRMWA Corp. issued letter to prime contractor declaring Phase 2 construction as substantially complete, commencing the 1-year warranty period on October 1, 2001. CRMWA Corp. retained some contract funds pending Final Completion.

GENERAL DESCRIPTION

Sanford Dam (Lake Meredith) was constructed in the 1960's as part of the U.S. Bureau of Reclamation (Reclamation) Canadian River Project. The reservoir serves as the principal source of water for 11 cities in the Texas Panhandle, including Amarillo, Lubbock, Tahoka, O'Donnell, Lamesa, Borger, Pampa, Levelland, Brownfield, Plainview, and Slaton. The Canadian River Municipal Water Authority (CRMWA) operates and maintains the dam and aqueduct. Shortly after Sanford Dam began impounding water, CRMWA discovered that a gradual decline in water quality was occurring because of increasingly high salt concentrations. Concentrations of sodium, chloride, sulfate, and total dissolved solids often exceeded the recommended standards for municipal water supplies. A gradual increase of these contaminants was expected to continue unless corrective action was undertaken. CRMWA asked for Reclamation assistance to identify the source(s) of the contamination and evaluate methods to control the salinity. In 1983, Congress authorized the Lake Meredith Salinity Control Project. Since then, numerous geological, geophysical, geochemical and groundwater testing and modeling studies were conducted to determine the source, location, concentration and quantity of saline water (brine). Based on extensive field and analytical work, a major source of concentrated brine from groundwater was identified along a 5.5-mile long stretch of the Canadian River near Logan, NM between Ute Dam and Revuelto Creek.

During low river flows, upward brine movement and evaporation concentrates salts at or near the channel surface. During high flows, these surface salt deposits (primarily sodium, chloride, and sulfate) are flushed downstream and into Lake Meredith. Lake Meredith has never spilled, so the only significant salt-removal mechanism is water withdrawn by CRMWA for municipal and industrial use.

Authorization

In October 1992, Congress passed Public Law 102-575 authorizing construction of the Lake Meredith Salinity Control Project in accordance with Federal Reclamation Laws (Act of June 17, 1902, 32 Stat. 388).

Funding

The authorizing legislation specified that Reclamation fund and be responsible for land acquisition and/or construction easements, design, and construction management. Reclamation cost for performing these functions was limited to 33 percent of the total project cost. The State of Texas provided 3 million dollars in funding. The member cities of CRMWA were responsible for the remaining funding, which was obtained via municipal bonds.

Location

Lake Meredith Salinity Control Project facilities are situated along a 4-mile stretch of the Canadian River just downstream of Ute Reservoir in eastern New Mexico. The injection well is located in Section 22, Township 13 North, Range 33 East, approximately 1-1/2 miles south of the Village of Logan. The well is in the SE/4 of the NE/4 of Section 22.

New Mexico East Zone Coordinates for the well location are N 1,580,125.78 ft and E 773,166.17 ft.

Purpose

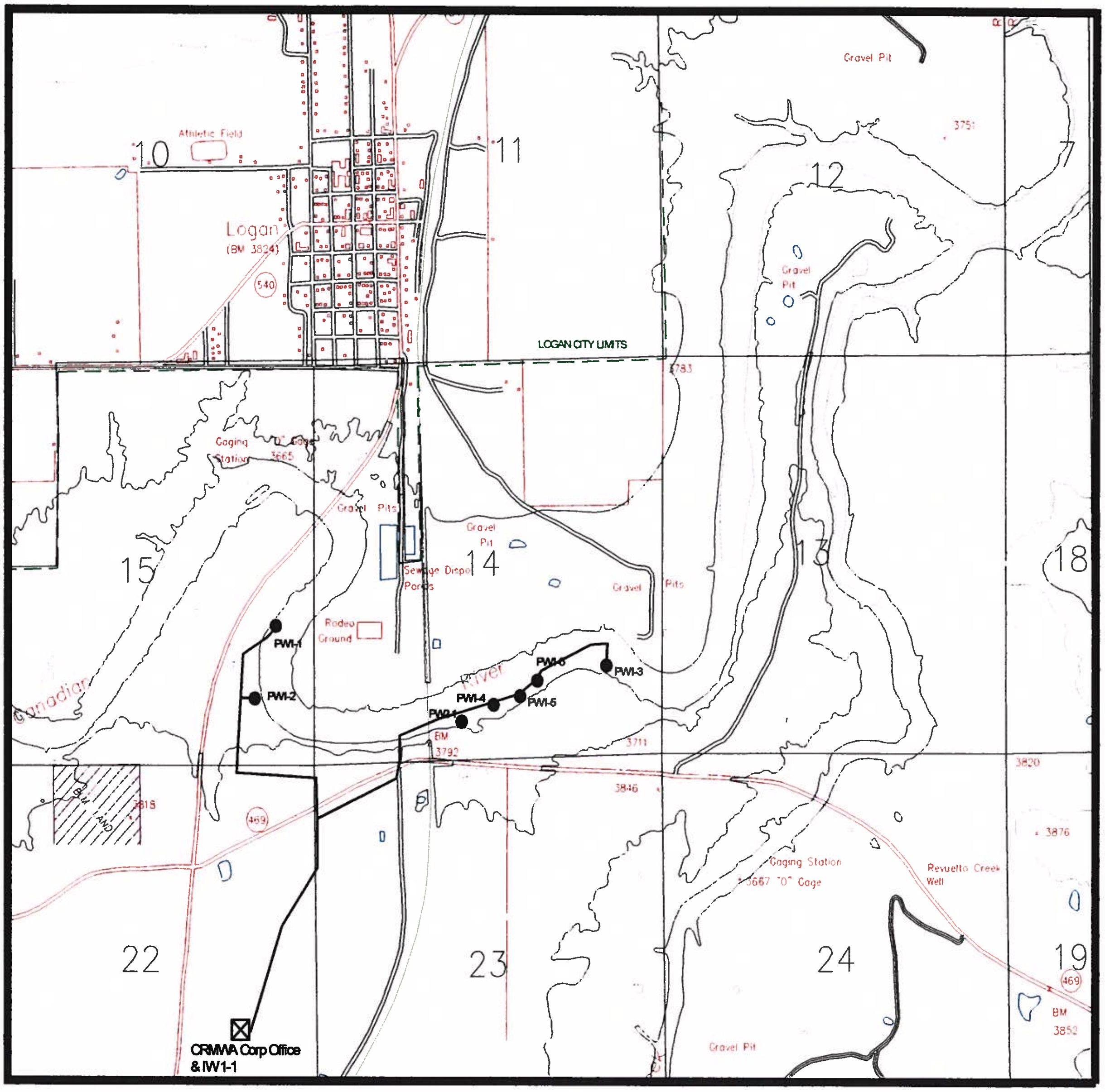
The purpose of this project is to decrease salt loading of Lake Meredith by reducing the influence of the brine aquifer on the Canadian River.

Description

The project presently consists of seven production wells, designated PW1-1 through PW1-6 and PW2-1, located along the Canadian River. East and west branch pipelines collect saline water extracted from the production wells and transport it to an injection facility located about ½ mile south of the river. One injection well, IW-1, has been completed at the injection facility. The saline water is filtered at the injection facility and then pumped into deep underlying marine formations. A Supervisory Control and Data Acquisition (SCADA) system provides automated operation, monitoring, and alarm capabilities at the injection facilities and CRMWA Headquarters in Sanford, Texas.

Location Map

A location map of the Lake Meredith Salinity Control Project area is shown below. The Village of Logan is about 1½ miles north of the injection well. The scale is about 1 inch equals ½ mile.



INVESTIGATIONS, STUDIES, AND TESTS

The need for salinity control of Lake Meredith by reducing brine entering the Canadian River upstream of the lake was recognized approximately 30 years ago. Since then, numerous geological, geophysical, geochemical and groundwater testing and modeling studies and tests were conducted to determine the source, location, concentration and quantity of brine that was entering the Canadian River. These studies were conducted by Reclamation, CRMWA, the State of Texas, or other entities such as Lee Wilson & Associates, Inc., a consulting firm under contract to CRMWA. Based on extensive field and analytical work, a major source of concentrated brine from groundwater was identified near Logan, NM between Ute Dam and Revuelto Creek.

Extensive geophysical work was also performed to determine the location of deep injection wells to dispose of the brine. A pilot hole located ½ mile south of the Canadian River was drilled to a depth of approximately 3200 feet. The pilot hole was constructed at the first of two injection well sites being considered at that time. Testing of the pilot hole suggested a design flow rate of significantly less than originally anticipated.

All of the above work including feasibility studies resulted in a preferred alternative, which became the basis for design. Flow rates to the injection wells were subsequently reduced in recognition of the pilot hole test results, discussion with regulatory agencies, and continuing hydraulic modeling. Other conceptual design goals are defined in the Statement of Work prepared by the Bureau of Reclamation. The most significant investigations and studies are summarized in Table 1. See the referenced reports on these investigations and studies for detailed information.

TABLE 1 – INVESTIGATIONS, STUDIES, AND TESTS

DATE OF INVESTIGATION OR REPORT	AGENCY OR COMPANY	INVESTIGATION OR STUDY
June-July 1975	Reclamation	Drill holes DH-1 and -2 completed to depths of 356 and 556 ft. Natural gamma log was obtained in DH-2.
1976	Reclamation	Report "Report on Electrical Resistivity and Seismic Refraction Surveys, Canadian River, Lake Meredith Salinity Study," dated 1976; issued to describe a limited geophysical investigations program completed north and south of the Canadian River near Logan.
September 1977 – March 1978	Reclamation	Test well TW-1 completed to depth of 358 ft. Observation wells POW-1, OW-2, OW-3, and OW-4 completed. Natural gamma logs were ran in all holes.
March 1979	Reclamation	Pumpout testing of TW-1 performed using POW-1, OW-2, OW-3, and OW-4 for drawdown observations.

TABLE 1 – INVESTIGATIONS, STUDIES, AND TESTS		
DATE OF INVESTIGATION OR REPORT	**AGENCY OR COMPANY**	**INVESTIGATION OR STUDY**
August-September 1983	Reclamation	Drill hole DH-3 cored to 569.5 ft. A natural gamma log was obtained.
January 9, 1984	Hydro Geo Chem, Inc.	Pictorial report titled "Geologic Study Related to Salt Pollution – Lake Meredith Salinity Study, Texas-New Mexico" issued. Report portrays geologic and groundwater conditions in the project area.
December 19, 1984	Hydro Geo Chem, Inc.	Report titled "Analysis of Geophysical Data to Examine the Feasibility of Deep-Well Injection of Brine Near Logan, New Mexico" issued. Report presents data from two deep seismic lines (one near north-south and one near east-west) completed south and east of the project area near Logan.
December 1984	Reclamation	Report titled "Lake Meredith Salinity Control Project – Hydrology/Hydrogeology Appendix, Canadian River – New Mexico-Texas" issued. This report documents the drilling of 12 shallow holes from 14.5 to 59.3 ft deep in alluvial deposits along the Canadian River. Also contains additional data on geology, surface and subsurface water quality, seismic and miscellaneous studies.
May 1, 1985	Hydro Geo Chem, Inc.	Report titled "Study and Analysis of Regional and Site Geology Related to Subsurface Salt Dissolution Source of Brine Contamination in Canadian River and Lake Meredith, New Mexico – Texas and Feasibility of Alleviation or Control" issued to present data on the geology, hydrology, geochemistry, and feasibility of saline control for the project.
June 1985	Reclamation	Report titled "Technical Report on the Lake Meredith Salinity Control Project, Canadian River, Texas-New Mexico" issued to summarize earlier investigations and develop preliminary cost estimates and plans for constructing a salinity control project.

TABLE 1 – INVESTIGATIONS, STUDIES, AND TESTS		
DATE OF INVESTIGATION OR REPORT	**AGENCY OR COMPANY**	**INVESTIGATION OR STUDY**
July 1992	Texas Bureau of Economic Geology	Report titled "Canadian River Salinity Sources, Ute Reservoir, New Mexico to Lake Meredith, Texas: Evaporite Dissolution Patterns and Results of February 1992 Water Quality Survey" issued to provide background information on geologic conditions, evaporite dissolution patterns, water chemistry, river conductivities, flows, and other data along the Canadian River downstream from Ute Dam.
July 1992	Parker, Smith and Cooper, Inc. in association with Lee Wilson and Associates, Inc.	Revised publications titled "Surface Water Notebook" and "Groundwater Notebook" with a separate Executive Summary issued to document available geologic, groundwater, and surface water information in the project area. The publications were revised April 1993.
April 1993	Texas Bureau of Economic Geology	Report titled "Electromagnetic Delineation of Saline Groundwater Plumes in Alluvium and Bedrock Along the Canadian River Between Ute Reservoir and Rana Canyon, New Mexico" issued to document an electromagnetic study.
October 1994	Reclamation	Report titled "Geophysical Investigations, Lake Meredith Salinity Study, New Mexico, Geophysical Progress Report, Well Log Analysis" issued.
August 1994	Reclamation	Revised report titled "Geologic Report on the Logan, New Mexico Area – Lake Meredith Salinity Study – Texas and New Mexico" dated August 1994 issued. Report documents geologic investigations conducted in the Logan, New Mexico, area between December 1993 and August 1994, including drilling and logging of test and observation wells, performing pump tests, geologic mapping, geophysical logging, and supplemented with information collected earlier. This document contains all available geologic logs for investigations through August 1994. (Revised January 1995.)

TABLE 1 – INVESTIGATIONS, STUDIES, AND TESTS		
DATE OF INVESTIGATION OR REPORT	**AGENCY OR COMPANY**	**INVESTIGATION OR STUDY**
January 1995	Reclamation	Report titled "Supplement No. 1 to the Geologic Report on the Logan, New Mexico Area - Lake Meredith Salinity Study – Texas and New Mexico," on drilling, geologic and geophysical logging, and testing of one test well (TW-4) and 3 observation wells (OW-7, OW-8, and OW-9) in November 1994.
January 1995	Reclamation	Report titled "Data and Analyses of TW-4 Aquifer Pumping Test and Water Quality Sampling Near Logan, New Mexico – Lake Meredith Salinity Study – Texas and New Mexico" issued for test well TW-4 testing performed in 1994.
February 1995	Reclamation	Report titled "Conceptual 3-D Groundwater Flow and Solute Transport Model for the Brine Aquifer near Logan, New Mexico – Lake Meredith Salinity Control Project – Texas and New Mexico" issued.
March 1996	RE/SPEC Inc.	Topical Report RSI-0692 titled "Drilling Report - Lake Meredith Salinity Control Project Pilot Hole" issued. This report describes drilling of pilot hole in February and March of 1996 to obtain drilling, geologic, and hydrologic information for future injection well(s).
March 1996	RE/SPEC Inc.	Topical Report RSI-0694 titled "Geologic Report – Lake Meredith Salinity Control Project Pilot Hole" issued. This report describes geology of pilot hole drilled to obtain drilling, geologic, and hydrologic information for future injection well(s).
May 1996	RE/SPEC Inc.	Topical Report RSI-0695 titled "Hydrologic Testing Report – Lake Meredith Salinity Control Project Pilot Hole" issued. This report describes hydrologic testing and analyses of test results from pilot hole drilled to obtain drilling, geologic, and hydrologic information for future injection well(s).
May 1997	Reclamation	Preconstruction design survey was performed by Farmington, NM survey crew.

Geologic Setting

This brief summary defines in general the stratigraphic nomenclature that provides the framework for interpretations of the lithology and stratigraphy of the Lake Meredith Salinity Control Project area. Much of this summary is derived from the Reclamation (preconstruction) geologic report [Taucher 1995] and the geologic report for the pilot hole [RE/SPEC, 1996].

Structural Setting

The project area is located generally north of the Tucumcari Basin and south of the Oldham Nose of the Sierra Grande uplift. The Tucumcari Basin is an extension of the Palo Duro Basin, which lies to the east-southeast in Texas. The uplift area to the north includes the Bravo Dome.

The uplifted areas are reported to have been active in Mississippian, Pennsylvanian, and Permian times and the Tucumcari Basin was probably best developed during late Pennsylvanian and early Permian times. Basement faulting may in part be controlling the structural elements described above. Basement faulting, in a variety of orientations and defined using a variety of techniques, has been described and compiled in the body of literature for this area (e.g., Foster et al. [1972]; Hydro Geo Chem, Inc. [1984a]; Broadhead and King [1988]). Each of the many structural contour constructions of the top of the Precambrian in this area includes a significant amount of relief.

Stratigraphic Setting

Sedimentary rocks ranging in age from Upper Pennsylvanian to Upper Triassic are present above the Precambrian basement. The upper surface of the Precambrian has been described as extensively eroded and widely variable in topographic relief. Stratigraphic names are not well defined in this area for all of the subsurface units but some correlations have been extended from adjacent areas.

The upper Pennsylvanian-lower Permian Sangre de Cristo Formation lies unconformably on the Precambrian surface. The Permian Abo Formation is reported to conformably overlie and possibly interfinger laterally with the Sangre de Cristo Formation. Both of these units are continental deposits and reported to contain red arkosic sandstone and brownish shale and siltstone derived from highlands to the northwest. In general, the Sangre de Cristo Formation is reported to include larger, more angular, less well-sorted particles and the Abo Formation includes finer-grained and more well-sorted clastic materials. Both contain arkosic materials with the lower unit containing relatively more and coarser arkosic material.

The Permian Yeso Formation conformably overlies the Abo Formation. This marine formation is reported to consist of sandstone, siltstone, shale, halite, and anhydrite. In the Palo Duro Basin, the Yeso-equivalent, Clear Fork Group, is divided into several discrete formations, the uppermost of which is the Glorietta Sandstone. The Glorietta is sometimes recognized separately, not a part of the Clear Fork Group, and sometimes as the lowermost unit of the conformably overlying San Andres Formation. The San Andres

Formation is reported to include interbedded sandstone, limestone, dolomite, halite, gypsum, and anhydrite.

The Permian marine Bernal Formation of the Artesia Group conformably overlies the San Andres Formation. The Bernal is reported to consist of red to salmon-colored shale, siltstone, fine-grained sandstone, anhydrite, salt, dolomite, and limestone. In the Palo Duro Basin, the Artesia Group is divided into a number of distinctive units. In the project area, only the name Bernal Formation has been used to describe the material above the San Andres Formation and below the unconformity that marks the top of the Permian sequence.

Above the erosional unconformity that marks the top of the Permian sequence is the Triassic Dockum Group of continental origin. Locally, the Dockum Group has been divided into a lower Santa Rosa Sandstone and an upper Chinle Formation, with the Santa Rosa further divided into a lower Tecovas Formation and an upper Trujillo Formation. The two lower Triassic units present, the Tecovas and Trujillo Formations, are reported to be clastic sediments that accumulated in deltaic and flood plain conditions. These sediments are comprised of lenticular sandstones and discontinuous shale units. The Chinle Formation is comprised primarily of variegated shale and siltstone.

Preconstruction Geologic Investigations

Most of the preconstruction geologic investigations focused on the Tecovas and Trujillo Formations and overlying alluvium in the Canadian River valley. The pilot hole was the only geologic investigation performed for the injection well.

Observation and Test Wells

Between 1975 and 1995, observation well and test well drilling and testing programs were performed to obtain geologic and hydrogeologic information in the vicinity of the seepage area between Ute Dam and Revuelto Creek. These investigations also included drill holes DH-1, DH-2, and DH-3. This information was collected to:

- Establish baseline water level and water quality data in project area.
- Determine salinity of groundwater in alluvium, Trujillo Formation, and underlying Tecovas Formation for consideration in determining locations of future extraction (production) wells in Trujillo and/or Tecovas Formations.
- Establish potential yield of future extraction (production) wells in Trujillo and/or Tecovas Formations.
- Provide data for estimating impact on river salinity of future extraction (production) wells in Trujillo and/or Tecovas Formations.
- Permit future periodic water sampling to determine impact of sustained operation of a salinity control project when/if constructed.

Descriptions of these investigation programs, regional and site geology, geologic and geophysical logs, drawings, test results, analyses of aquifer tests, photographs, and other information are included in the reports referenced above.

In September 1999, CRMWA Corporation, Inc. (CRMWA Corp.), a New Mexico corporate entity of CRMWA, issued an Invitation for Bids for the drilling and completion of 8 additional observation wells, designated OW-10, OW-11, OW-12, OW-13A, OW-13B, OW-14, OW-15, and OW-16. These wells were completed in the Trujillo and Tecovas Formations at selected locations to establish additional baseline water level and water quality data in project area prior to and during operation of the project. Geophysical logs were obtained in these wells. Geologic logs of these wells are included in the Appendices. In addition, CRMWA Corp. had several existing observation wells, drill holes, and test wells (that were no longer needed) plugged and abandoned. These wells were TW-1, OW-1, OW-2, and OW-3.

Pilot Hole

As the result of several investigations, by 1995 considerable geologic information was available for the production well system. With the exception of some geophysical work, no information existed regarding injection well site geology. Reclamation and CRMWA decided that the total construction cost of the project could be substantially reduced by providing potential bidders more geologic data by which to design and construct the injection well(s). Therefore, using an existing contract, Reclamation (the Great Plains Region) issued a work order to J.F. Sato and Associates (JFSA), Littleton, Colorado, for the drilling, geologic and geophysical logging, injection formation water sampling, and testing of a pilot hole to obtain injection well design information and verify if deep injection of produced brine water was environmentally and economically feasible. JFSA, with participation of Reclamation, issued a Request for Proposals for the pilot hole. After evaluation of the proposals by JFSA and Reclamation, JFSA awarded a separate subcontract for the pilot hole drilling and testing to RE/SPEC, Inc. of Rapid City, South Dakota. Drilling started on February 3, 1996, and was completed on March 6, 1996. The reports referenced in Table 1 contain the results and analyses of this work.

After the drilling and testing was completed, the pilot hole was left open for possible future formation water sampling or monitoring. It was plugged and abandoned during Phase 1 construction.

Geophysical Studies

Several geophysical studies and geophysical logging of drill holes, test wells, observation wells, and a pilot hole were performed in the project area. See the reports referenced in Table 1 for information on these studies.

PERMITS

Permits and agreements issued or implemented prior to and during construction of the project are summarized in Table 2.

TABLE 2 – PERMITS		
DATE ISSUED	**ISSUING/RESPONSIBLE AGENCY**	**PERMIT TITLE AND DESCRIPTION**
December 11, 1997	Department of the Army – Corps of Engineers, Albuquerque District	Section 404 of the Clean Water Act (33 CFR 330) Permit No. 12. (Reissued March 23, 2000)
1997	State of New Mexico - Environment Department-Surface Water Quality Bureau	Section 401 Water Quality Certification (Reissued March 28, 2000)
January 22, 1998	Bureau of Reclamation	Final Biological Assessment issued. (Consultation No. 2-22-95-I-127.)
February 25, 1998	State of New Mexico – Office of Cultural Affairs – Historic Preservation Division	Finding of no adverse effects to historic properties.
April 7, 1998	Union Pacific Railroad Company	Folder No. 1617-77 - Underground Pipeline Crossing Agreement. (Amended February 23, 2000, via e-mail from Union Pacific Railroad to eliminate requirement for encasement pipe.)
April 23, 1998	State of New Mexico – Highway and Transportation Department	Utility Permit Number 4-045-98 – Installation of 2-16 Inch Steel Casings Along State Road 469 between Mile Post 43 and 44.
October 26, 1998	State of New Mexico – Office of the State Engineer	Permit to Appropriate the Underground Waters of the State of New Mexico for Control of Pollution (Application for Extension of Time approved December 22, 1999.)
December 15, 1998	United States Environmental Protection Agency	Notice of Intent for Storm Water Discharges Associated with CONSTRUCTION ACTIVITY Under a National Pollutant Discharge Elimination System (NPDES) General Permit.

TABLE 2 – PERMITS		
DATE ISSUED	ISSUING/RESPONSIBLE AGENCY	PERMIT TITLE AND DESCRIPTION
December 16, 1998	State of New Mexico - Environment Department – Ground Water Quality Bureau	Discharge Plan DP-1054. Authorized injection well drilling, completion, and operation as a Class V Underground Injection Control (UIC) Special Drainage Well (5G30) constructed to Class 1 UIC standards. [Copy included in Appendix A]
November 28, 2000	State of New Mexico – Regulation and Licensing Department – Construction Industries Division – General Construction Bureau	Building Permit No. 202100.

DESIGN

Numerous alternatives methods of reducing salinity to Lake Meredith water users were considered, including the following:

- Reverse osmosis treatment
- Evaporation ponds
- A small dam downstream of the seepage areas to create backpressure on the saline seeps
- Pumping extracted brine to distant disposal sites

The References and Bibliography list reports and studies performed and the methods and results of pertinent tests and analyses. After CRMWA, their consulting firm (Lee Wilson & Associates, Santa Fe, New Mexico) and Reclamation studied these alternatives, the use of a production wells, a pipeline collection system, and one or two injection wells became the preferred method. Originally, the production wells were slated for installation with influence zones in the Tecovas Formation. Production test wells were drilled and tested to verify capability of reducing brine water flows to the Canadian River. However, because of these and other studies, the best location for the influence zone of the production wells was determined to be the lower portion of the Trujillo Formation.

In 1995, Reclamation issued Solicitation No. 1425-5-SI-60-07130. Work to be performed under this solicitation included:

- Developing a work plan, designs, and associated document
- Drilling, sampling, testing, and completion of two injection wells

- Drilling and completing 9 production wells and converting one existing well to a production well or drilling an extra production well in lieu of converting it
- Drilling and completing 6 or 7 observation wells
- Constructing/installing wellhead facilities, pipelines, roads, control systems, and associated features

The design, but not construction, of 15 additional production wells was also required. The solicitation required a two-step sealed bidding procedure. However, bids received exceeded the available funding for the project. Subsequently, the pilot hole was completed. After study and analyses of RE/SPEC drilling, geologic, and hydrology reports on pilot hole drilling and testing, Reclamation then issued a work order to JFSA to perform the conceptual and, subsequently, the final design. JFSA added Texas World Operations, Inc., of Houston, Texas, and The RMH Group, Inc., of Lakewood, Colorado as subcontractors for specialized portions of the work. Organizational information on these design firms is presented in Table 3 below.

TABLE 3 – DESIGN FIRMS

Company	Address And Telephone	Number of People Employed on Design	Key Personnel and Title
J.F. Sato and Associates, Inc.	5898 S. Rapp St. Littleton, CO 81120 (303) 797-1200	4	J.F. Sato, President Chris Pangburn, C.E. Jose Cornejo, P.E. George Cicoff, P.E.
Texas World Operations, Inc.	520 Post Oak Blvd. Suite 450 Houston, TX 77027 (713) 850-0003	4	Robert F. Whiteside, Jr., President William H. Armstrong, C.E. Thomas Michael Grant, Senior Geologist James Sandt, Senior Geologist
The RMH Group, Inc.	12600 W Colfax Ave. Suite A-400 Lakewood, CO 80215	1	Robert Anderson, P.E.

Conceptual design criteria included the following:

- Provide conceptual design for the injection well(s), production wells, pipelines to injection facility, injection facilities, and pipelines from injection facilities to injection well(s).

- The conceptual design would be used as the basis for the final designs. In developing the conceptual design, a major objective would be the ability to construct the conceived project at a total cost of no more than $6.6 million.
- Economical Operation and Maintenance (O&M) would be an important design criteria.
- Designs would consider that all water retrieved during dewatering or other work must be disposed in an environmentally acceptable and legal manner.
- The injection well(s) would be classified (Environmental Protection Agency classification standards) as Class V but constructed to Class I standards.
- Locations of the injection well(s) and production wells would be provided by Reclamation/CRMWA.
- Production wells would be drilled and completed to the base of the Trujillo Formation, with the influence zone confined to the Trujillo Formation.
- Conceptual designs would incorporate well and wellhead protection from vandalism, including damage from high-powered rifles. The structure would be adequate to provide safe and convenient access to maintain and replace the pump. Any wellheads in the Canadian River flood plain would be protected from flooding.
- All pipelines installed in the Canadian River valley floor would be buried a minimum of 4 feet below ground surface. In all other locations, pipelines would be buried a minimum of 3 feet below ground surface. Other than across the Canadian River valley floor, bedrock crops out or is near the ground surface at many locations. This bedrock may so hard it is not rippable.
- Well size, depth, casing size and material types would be determined.
- Recommendations on testing during drilling and development would be provided.
- Development criteria would be determined.
- Wellhead configuration design would be determined.
- A control and monitoring system criteria would be determined.

Final design criteria included the following:

- Reclamation would perform pre-design surveying.
- Reclamation would perform a transient analysis study of the pipeline system.
- Specification paragraphs and drawings for injection wells would be based on high angle wells drilled with a lateral (horizontal) displacement of 1500 ft or more.
- The injection tubing would be 5-1/2 inch fiberglass.
- Variable frequency drive motors would be included in the design of all production wells as a means of controlling well output and adjusting the response of the

system to obtain the most advantageous output of brine within the capacity of the injection well(s).

- Design would effectively address river scour damaging production wellheads and/or collection pipelines in the valley floor.
- Design would hydraulically integrate the collection, conveyance and disposal system into a cost effective project.
- Design and construction would not adversely impact cultural resources or the environment.
- Designers would develop alternative strategies for implementing project construction recognizing that only $6.6 million is available for construction including environmental mitigation, if required.

During the design process, it became apparent that numerous changes would be required in drilling, testing, and completion of the first injection well as the work proceeded. The many unknown factors regarding the drilling and completion of an injection well would probably result in excessively high price quotes for injection well construction. In addition, the number of injection wells required, injection pump selection and sizing, the number of production wells that could be utilized and/or constructed with funds available, and the extent of the pipeline collection system hinged on the results obtained during drilling, completion, and testing of the first injection well. Therefore, Reclamation, CRMWA, and JFSA decided several modifications to the traditional contract process would enhance the opportunity to construct the project within the budget constraints. CRMWA, working through CRMWA Corporation, Inc. (CRMWA Corp.), a subsidiary incorporated to perform work in New Mexico, would be the contracting agency for the construction. Construction would be divided into two phases. Phase 1 would consist of an access road to the injection facilities site; drilling, testing, completion, and mechanical integrity testing of the first injection well; and plugging and abandonment of the pilot hole.

Phase 2 construction would be implemented after completion of Phase 1. Construction of a second injection well, production wells, pipelines, and the injection facilities would be determined on Phase 1 injection well cost and test results from this well. Bid schedules would be configured to allow selection of groups of production wells to be constructed under the contract. Specifications would provide that individual production wells could be relocated to reflect conditions encountered during drilling of previous wells.

PHASE 1 CONSTRUCTION - Injection Well

CONTRACT ADMINISTRATION

Because of the numerous modifications required during drilling, testing, and completion of the injection well, after consultation with Reclamation and JFSA, CRMWA Corp. negotiated a professional services contract with Texas World Operations, Inc. (TWO) to provide injection well construction management. CRMWA awarded a contract to TWO for $288,000.00. The final cost for this contract was $ 362,961.97.

Summary of Bids

To prevent changes from having a ripple effect and to achieve other project savings, the work was originally split into 40 separate bid packages. Requests for bids were issued on May 9, 1999. Sealed bids were received at TWO offices, 520 Post Oak Blvd., Suite 450, Houston, TX 77027 until 2:00 P.M., June 3, 1999, after which bids were opened in the TWO Conference Room. TWO and CRMWA reviewed and analyzed all bids prior to award of purchase orders and service agreements by CRMWA Corp. Two of the original 40 bid packages were subsequently split, resulting in 42 separate purchase orders and service agreements. After receipt of bids and during construction, 6 additional purchase orders or service agreements were issued for materials or services that were not identified earlier. Bid package numbers, purchase order or service agreement numbers, bid package descriptions, dates of Notice of Award, engineer's estimates, contractor (low bidder) information, bid amount, and final cost are shown in Table 4. For the drilling contract, TWO used the International Association of Drilling Contractors "Drilling Bid Proposal and Daywork Drilling Contract – U.S." Under this standard drilling industry format, drilling bid packages did not indicate completion times or dates; only the approximate spud date (i.e., date drilling should begin) of July 6, 1999, was stipulated. (Note: this is a standard drilling industry practice, because there are too many unknown factors discovered during drilling, testing, and completion to specify a completion date.)

Injection well construction was completed on September 12, 1999, at the conclusion of the injectivity-falloff testing of the combined vertical and lateral hole. The last on-site work required under the bid packages was the mechanical integrity testing; this was performed on October 6, 1999.

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-a PO-989-104S	13-3/8 Inch and 9-5/8 Inch Casings and 5-1/2 Inch Liner NOA 7/12/99	$74,258.00	Trigon Tubulars, Inc. P.O. Box 56368 Houston, TX 77256-638	$68,278.82	$84,212.86
17-0345-b SA-989-105-02	5-1/2 Inch Fiberglass Injection Tubing NOA 7/19/99	75,521.00	Tubular Fiberglass Corp. 11811 Proctor Road Houston, TX 77038	71,851.60	76,021.81
17-0345-c SA-989-106-02	Tubular Inspections NOA 7/19/99	6,869.00	Phoenix Tubular Resources P.O. Box 1264 Channelview, TX 77530	6,230.61	6,208.00
17-0345-d SA-989-107-02	Liner Hanger, Seal Assembly, and Packer NOA 8/11/99	25,507.00	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	19,418.15	46,585.38
17-0345-e1 SA-989-108-02	Cementing Equipment NOA 7/19/99	25,616.00	TAM International 4620 Southerland Houston, TX 77092	29,866.00	91,932.60
17-0345-e2 PO-989-109-02	Cementing Equipment NOA 8/11/99	5,460.22	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	5,480.22	13,852.86
17-0345-f SA-989-110-02	Wellhead Equipment NOA 7/22/99	45,862.00	Cooper Cameron Corp. 13013 Northwest Freeway Houston, TX 77251-1212	41,819.65	41,732.02

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-g1 PO-989-111-02	Drilling Bits, Stabilizers, Shock Subs, Drilling Jars NOA 7/19/99	36,952.00	Halliburton/Security DBS 9950 Westpark Drive Houston, TX 77063-5153	30,480.87	27,173.46
17-0345-g2 PO-989-112-02	Drilling Bits NOA 7/19/99	18,044.00	Smith International, Inc. 2120 Maurice Odessa, TX 79760	18,044.00	12,500.21
17-0345-h DC-989-113-02	Drilling Contractor NOA 7/19/99	409,040.00	Norton Drilling Company 5211 Brownfield Highway Suite 230 Lubbock, TX 79407-3501	339,920.00	490,853.62
17-0345-i SA-989-114-2	Drilling, Fishing and Completion Tools NOA 8/11/99	15,000.00	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	11,106.25	75,361.68
17-0345-j SA-989-115-02	Conductor Pipe Installation NOA 7/12/99	4,250.00	Weder Services P.O. Box 1087 Woodward, OK 73802	4,250.00	7,950.00
17-0345-k SA-989-116-02	Cementing Services NOA 7/19/99	49,777.20	Halliburton Energy Services 9950 Westpark Drive Houston, TX 77063-5153	45,208.92	131,605.14
17-0345-l SA-989-117-02	Drilling Fluids NOA 7/19/99	78,000.00	Nova Mud, Inc. 419 Cain Street Hobbs, NM 88240	42,060.00	57,188.59

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-m SA-989-118-02	Directional Drilling Services NOA 7/23/99	22,720.00	Baker Hughes Inc. 3900 Essex Lane, Suite 1200 Houston, TX 77027-5177	17,840.00	29,152.50
17-0345-n SA-989-119-02	Directional Equipment Rental NOA 7/23/99	43,500.00	Baker Hughes Inc. 3900 Essex Lane, Suite 1200 Houston, TX 77027-5177	32,700.00	50,227.65
17-0345-o SA-989-120-02	Open Hole Logging NOA 8/2/99	13,600.00	Schlumberger Oilfield Services 200 Gillingham Lane Sugar Land, Texas	13,600.00	82,596.39
17-0345-p SA-989-121-02	Cased Hole Logging NOA 7/23/99	12,191.00	Baker Hughes Inc. 3900 Essex Lane, Suite 1200 Houston, TX 77027-5177	12,191.00	12,573.96
17-0345-q SA-989-122-02	Well Testing NOA 8/2/99	17,310.00	Schlumberger Oilfield Services 200 Gillingham Lane Sugar Land, Texas	14,990.00	65,729.43
17-0345-r SA-989-123-02	Coring Services NOA 7/19/99	21,342.00	Diamond Oil Well Drilling Co. P.O. Box 7415 Woodlands, TX 77387-7415	16,942.00	21,008.81
17-0345-s SA-989-124-02	Core Testing NOA 7/19/99	32,770.00	Reservoirs, Inc. 1151 Brittmore Road Houston, TX 77043	32,770.00	34,690.00
17-0345-t SA-989-125-02	Plugging and Abandonment of Pilot Hole NOA 7/19/99	18,975.00	Holman Services P.O. Box 2742 Pampa, TX 79066-2742	18,975.00	30,605.00

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-u PO-989-126-02	Completion Fluids NOA 7/99	655.00	Baroid Drilling Fluids P.O. Box 248 Liberal, KS 67901	653.00	662.14
17-0345-v PO-989-127-02	Formation Fluid Analysis NOA 7/19/99	15,000.00	ANA-LAB Corp. 4515 Sough Georgia, Suite 129 Amarillo, TX 79110	4,112.00	3,084.00
17-0345-w SA-989-128-02	Fluid Compatibility Analysis NOA 7/19/99	2,500.00	Omni Labs, Inc. 7200 Langtry Street Houston, TX 77040	2,500.00	2,500.00
17-0345-x SA-989-129-02	Formation Chemical Stimulation NOA 7/19/99	41,427.13	Halliburton Energy Services 9950 Westpark Drive Houston, TX 77063-5153	39,246.06	64,516.02
17-0345-y SA-989-130-02	Coiled Tubing and Nitrogen Services NOA 7/19/99	49,055.80	Halliburton Energy Services 9950 Westpark Drive Houston, TX 77063-5153	42,054.02	93,883.76
17-0345-z SA-989-131-02	Miscellaneous Pumping Services NOA 7/19/99	17,208.87	Halliburton Energy Services 9950 Westpark Drive Houston, TX 77063-5153	15,919.08	23,429.45
17-0345-aa SA-989-132-02	Vacuum Trucks and Fluid Hauling NOA 7/19/99	23,500.00	Key Energy P.O. Box 1286 Perryton, TX 79070	14,100.00	1,638.24
17-0345-bb ??-989-133-02	Trash Collection and Disposal	0	(No documentation available)	0	0

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-cc SA-989-134-02	Casing Tongs and Crews NOA 8/11/99	19,562.00	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	14,540.00	29,014.60
17-0345-dd PO-989-135-02	Fluid Storage Tanks NOA 7/19/99	11,800.00	Key Energy P.O. Box 1286 Perryton, TX 79070	6,280.00	22,051.36
17-0345-ee PO-989-136-02	Brine and Test Fluids NOA 7/7/99	13,200.00	G.P. Guinn, Inc. P.O. Box 934 Borger, TX 79008-0934	4,400.00	55,966.50
17-0345-ff PO-989-137-02	Fresh Water Supply (Hauling) NOA 7/7/99	15,000.00	G.P. Guinn, Inc. P.O. Box 934 Borger, TX 79008-0934	10,416.67	22,876.55
17-0345-gg SA-989-138-02	Mud Logging NOA 7/19/99	21,200.00	Technical Drilling Services 205 NW 132nd Street Oklahoma City, OK 73114-2305	15,990.00	22,568.63
17-0345-hh SA-989-139-02	Drillstem Test Tools and Service NOA 8/11/99	52,750.00	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	45,000.00	35,280.00
17-0345-ii PO-989-140-02	Filtration Equipment NOA 7/19/99	8,320.00	Key Energy P.O. Box 1286 Perryton, TX 79070	5,610.00	13,665.24

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-jj SA-989-141-02	Packer, Whipstock, Milling Tools and Services For Selective Reentry of Lateral Borehole NOA 8/11/99	67,228.00	Weatherford International, Inc. 1360 Post Oak Blvd. Suite 1000 Houston, TX 77056	57,245.00	78,153.10
17-0345-kk PO-989-142-02	Office Trailer, Water System and Sanitary Holding Tank NOA 7/19/99	3,500.00	Young's Manufactured Home Sales 4830 Seminole Highway Hobbs, NM 88240	2,999.00	4,408.00
17-0345-ll PO-989-143-02	Portable Restrooms NOA 7/19/99	1,680.00	Rocket Industries, Inc. 1000 East Brady Clovis, NM 88102	1,440.00	2,698.72
17-0345-mm PO-989-144-02	Miscellaneous Rental Equipment NOA 7/19/99	3,280.00	Prime Equipment Rental 6310 Canyon Drive Amarillo, TX 79109	2,343.00	6,444.93
17-0345-nn SA-989-145-02	Plugging and Abandonment of Test Well TW-1 and Observations Wells POW-1 (OW-1), OW-2, and OW-3 (Contract cancelled and work performed separately for CRMWA Corp. by local well drilling company.)	16,865.00	Lindsey Shelton Drilling and Pump	11,882.25	0
17-0345-oo	Mud Pit Liner NOA unknown	5,000.00	Akome, Inc.	2,717.10	2,717.10

TABLE 4 – PHASE 1 CONSTRUCTION SUMMARY OF BIDS AND CONTRACTS

BID PACKAGE/ CONTRACT	BID PACKAGE DESCRIPTION/ DATE OF NOTICE OF AWARD	TWO COST ESTIMATE	BIDDER	BID AMOUNT	FINAL COST
17-0345-pp PO-989-146-02	Welding Services NOA 7/19/99		Star Welding Service 802 North Main Lovington, NM 88260	2,000.00	1,161.88
17-0345-qq PO-989-147-02	Automated Drilling System 7/19/99	15,000.00	Wildcat Services PMB #232-8524 Hwy. 6 North Houston, TX 77095-2103	2,900.00	4,267.26
17-0345-rr PO-989-149-02	Furnish Centrifuge NOA 10/13/99		Oiltools, Inc. 19510 Oil Center Boulevard Houston, TX 77073	Unknown	7,963.65
Not Available	Solids Disposal			Unknown	0
PO-989-148-02	Liquids Disposal	15,000.00		Unknown	0
TOTALS:		$1,471,296.22		$1,198,370.27	$1,988,713.10

NOTES: PO = Purchase Order. SA = Service Agreement. DC = Drilling Contract. NOA = Notice of Award.

Contract Modifications

As described in the Design section, numerous changes were expected during injection well construction. TWO continually altered the drilling, testing, and completion as needed throughout construction to address the geologic conditions encountered. For most of the subcontracts (drilling contract, purchase orders or service agreements), some of the bid items were deleted, new bid items were added, and quantities changed to meet conditions encountered during construction. Changes that increased project cost were submitted by TWO to CRMWA Corp., the contracting agency, for approval and payment. Since completion times and dates were not specified, modifications during the execution of the contracts had no effect on completion dates. Some of the more significant modifications were made for the following:

- The vertical hole was drilled several hundred feet deeper due to changed geologic conditions (from the pilot hole) and drilling characteristics of the Precambrian basement (a rapid drilling penetration rate, which suggested different formation characteristics).
- Formation Micro Imager (a geophysical logging technique) technology was added to logging to obtain better injection formation information.
- The placement, cementing, and selected perforating of blank 5-1/2 inch steel liner casing in selected zones was added to control potentially unstable formations.
- More extensive well stimulation techniques were performed to enhance injection capability of the well.
- Far more brine and test fluids were needed than originally anticipated.
- The bid package for plugging and abandoning the pilot hole explicitly stated, "If the hole is not open to a depth of 2,570 feet, remedial action must be taken. The original borehole must be reamed out and cleared of obstructions to a minimum depth of 2,570 feet." However, the subcontractor protested that the cover letter to his bid did not describe, and therefore his bid did not include, reaming the hole. Therefore, this subcontractor received a lump sum increase of $10,000.00 for reaming the pilot hole to elevation 2570 prior to plugging.

Claims

No claims were filed against CRMWA Corp. by Phase 1 contractors.

CONSTRUCTION OPERATIONS

Site work began in early July 1999.

Clearing and Access Road

Assisted by a contract surveyor, CRMWA Corp. employees surveyed the access road and injection well. In July 1999, CRMWA employees prepared the access road and cleared and graded the drill pad before arrival of the drilling equipment. The following text in the Drilling and Testing, Construction Geology, Completion, and Mechanical Integrity

Testing sections is extracted, for the most part, from the Executive Summary of the Well Completion Report – Report Text [TWO, 2000]. For the complete text and references to figures, tables, and other information, see this separate referenced report.

Drilling and Testing

Drilling and Testing, Construction Geology, Completion, and Mechanical Integrity Testing sections are, for the most part, extracted from the Executive Summary of the Well Completion Report – Report Text [TWO, 2000]. For the complete text and references to figures, tables, and other information, see this separate referenced report.

Prior to arrival of the drill rig, Akome, Inc. lined and fenced 3 sides of the reserve pit. Weder Services set and cemented conductor casing, installed a Tinhorn cellar, and installed rat and mouse holes for IW-1. A TWO drilling supervisor and the Norton Drill Company drill rig arrived on side on July 20, 1999, and began rigging up that day. Because the previously placed pits and/or other preliminary work did not match the configuration of the drill rig, the injection well location was moved about 62.25 ft south and 7.38 ft east of the original location. Drilling commenced at the relocated position on July 21, 1999.

The drill rig used was Norton Drilling Company Rig No. 11. *(See Photographs 1 and 2.)* This rig has the following specifications:

- Depth rating of 12,000 ft with 4-1/2 inch drill pipe.
- 2 Caterpillar D-3406-TA 900 HP engines.
- 2 Gardner-Denver PZ-8w pumps with Caterpillar D-379-TA, 750 HP engines having maximum pressure of 1800 psi with 6-inch liners at 300 gpm, 2200 psi with 5-1/2 inch liners at 250 gpm.
- Gardner-Denver 17-1/2 inch rotary table with a capacity of 150 tons at 100 rpm, dead load 300 tons.
- Wilson mast, 131 ft, 344,000 lb. Hook load with 10 lines
- Drill pipe, 4-1/2 inch XH, 16.6 lb/ft, Grade E.
- Generators: No. 1 – 3306 DITA with Caterpillar SR-4 165 KW, No. 2 – 3306 DITA with Caterpillar SR-4 165 KW.

The CRMWA Corp. No. 1 injection well (TW-1) was drilled and completed during July, August, and September 1999. Mechanical integrity testing of the well was performed on October 6, 1999. The well was constructed according to the specifications contained in and referenced from Discharge Plan DP-1054, approved on December 16, 1998 by the Ground Water Quality Bureau of the State of New Mexico Environment Department. The well is a Class V Underground Injection Control (UIC) Special Drainage Well (5G30) constructed to Class 1 UIC standards. The well meets the construction standards specified in the Code of Federal Regulations (CFR), Title 40, Part 146.

The well was installed with a vertical segment drilled into the Precambrian basement to a measured depth of 3800 feet. The vertical segment was drilled several hundred feet into, instead of to the top, of the Precambrian basement because drilling penetration rate indicated the possibility of more permeable injection zone(s) within the basement rock. A sidetracked lateral segment was drilled laterally within the Permian Abo and Sangre de Cristo Formations to a measured depth of 4078 feet (3506 feet True Vertical Depth). Unless otherwise specified, all depths were measured from the rotary kelly bushing (RKB), 14.50 feet above ground level. Suites of open hole geophysical logs were run in all portions of the well.

Twenty-inch steel conductor pipe was set and cemented in place at a depth of 42 feet and 13-3/8 inch steel surface casing was set and cemented in place at 819 feet. *(See Photograph 3.)* A blowout preventer was installed after the surface casing was cemented. *(See Photograph 8.)* Protection casing consisted of 9-5/8 inch steel casing set and cemented at 2673 feet into the Abo Formation. *(See Photographs 4, 5, and 6.)* Casing pressure testing, cement bond logging, and temperature logging was performed on all cemented casing strings. *(See Photographs 9 and 10.)*

Steel 5-1/2 inch liner consisting of a 20 hole per foot pre-perforated lower section (3776 ft to 3247 ft) and a blank upper section (3224 ft to 2673 ft) was hung off in the protection casing, with an external casing packer and port collar between the segments. The blank upper section of the liner was cemented in place and selectively perforated with 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

A whipstock was set in the protection casing and a window was milled through the side of the 9-5/8 inch casing from 2515 feet to 2529 feet to begin the lateral portion of the well. The whipstock was oriented so that the lateral hole was directed on an azimuth of south 10 degrees west. The lateral hole was drilled to a depth of 4078 feet (3506 feet TVD) at a point approximately 1061 feet south and 185 feet west of the kickoff point from the vertical hole, along a lateral section 1077 feet in length. The lateral hole attained an inclination of approximately 78 degrees from the vertical. The lateral hole reached total depth within the lower member of the Sangre de Cristo Formation. This lateral segment was terminated at 4078 feet because several drilling breaks (areas of rapid drilling penetration) had occurred immediately above this depth, after which drill fluid losses increased to almost 100% by the time the lateral was at 4078 feet. See Table 5 below.

TABLE 5 - DRILLING BREAKS (SUDDEN ADVANCE IN DRILL STRING)

Date	Time	Lateral Bore Depth (Ft)	Comment
8/27	10 p.m.±	3060 to 3069	Penetration rates to 60 ft/hr.
8/27	10:15 p.m.±	3076 to 3090	Penetration rates to 60 ft/hr.
8/31	2:00 p.m.±	4697	4 ft break – first fluid losses in well reported 10 hrs later
9/1	10:00 p.m.±	4068	2 ft break
9/1	10:15 p.m.±	4074	2 ft break – drilling stopped 4 ft deeper (4078 ft) due to almost 100% loss of drill fluid return.

After drilling was stopped, the hole continued taking fluid at a rapid rate, estimated at over 8 barrels per minute. As in the vertical hole, TWO decided to install blank steel liner, cemented in place and then selectively perforated, to stabilize selected formations in the upper portion of the lateral hole. Steel 5-1/2 inch liner consisting of a 20 hole per foot pre-perforated lower section (4070 ft to 3419 ft measured depth) and a blank upper section (3397 to 2470 ft measured depth) was hung off in the protection casing of the vertical hole, with an external inflatable casing packer and port collar between the segments. *(An external inflatable casing packer and port collar for 9-5/8 inch casing are shown in Photograph 15.)* Personnel lost several hours attempting to assure engagement of the TAM combo tool in the port collar. *(See Photograph 16 for a TAM combo tool used in 9-5/8 inch casing.)* After the combo tool appeared to have latched in the port collar and the port collar was open, brine was pumped down the inner string with the rig pumps and circulation was established. Then the blank upper section of the liner was cemented in place. However, the drill string encountered resistance at 3417 ft after the cement had cured, and cement returns were noted at the surface.

Apparently, the cement injected through the port collar did not remain confined between the hole wall and the blank 5-1/2 inch steel liner above the casing packer. Although there are several possible reasons for this occurrence, the TAM Field Service Report Cover Sheet for September 1, 1999, FSJ#13420, contained in Appendix B of the Well Completion Report [TWO, 2000], indicates the external casing packer burst after inflation.

With the steel liner in place, cement could not be cleaned from inside the entire hole because the junction of a 2-3/8 inch x 4-1/2 inch drill pipe could not pass the liner hanger. Therefore, cement was cleaned from the hole only to a lateral distance of 3630 ft. After cleaning to 3630 ft, the drill string and selectively perforated with 8 or 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

After cementing, the hole was no longer taking significant fluid under gravity flow. A packer with a polished bore receptacle (PBR) was set in the 9-5/8 inch protection casing between 2446 ft and 2465 ft. An injection tubing string consisting of 5-1/2 inch fiberglass tubing and a seal assembly was landed in the PBR with the top of the seals at 2443.61 ft. The bottom of the tailpipe was at 2465.58 ft. A 3000-psi working pressure wellhead with bowl and seal assembly was installed to the top of the casing-tubing assembly.

Full cores were taken in the Yeso Formation (confining zone) and the Sangre de Cristo Formation (injection interval). A total of 150 feet of core was attempted and approximately 125 feet was recovered. *(See Photographs 10 through 14.)* The core material was subjected to extensive testing for porosity and permeability, petrographic, x-ray diffraction and scanning electron microscopy examinations. The recovered core was primarily siltstone, with high quartz content. Clay minerals in the injection interval contained a high proportion of illite and illite-smectite. These materials are generally sensitive to undersaturated fluids, and matrix swelling can be detrimental to injection by causing a reduction in permeability.

Samples of the core from the injection interval were subjected to flowthrough compatibility testing using fluid from the Trujillo Formation and local fresh water. No significant compatibility problems were noted, although there was a gradual degradation of permeability in most of the samples with continued injection.

Static fluid testing of Sangre de Cristo core samples indicated the formation to be sensitive to fresh water. Sodium chloride brine and ammonium chloride solution appeared to cause the least sample disaggregation of any of the fluids tested.

Mechanical properties of the injection interval were determined through acoustic velocity analysis performed on samples from cores. The fracture gradient in the injection interval was determined to be 0.7996 psi/ft. Based on this fracture gradient and the hydraulic gradient measured during well testing, the surface injection pressure that could cause fracturing at the weakest point of the injection interval is 924 psi. Injection pressure is limited to 850 psi by permit; therefore, injection operations will not initiate fracturing.

Injectivity fall-off testing was performed on the vertical portion of the well, and later on the combined vertical and lateral well segments. The vertical hole was tested with a packer set at 2630 feet in the 9-5/8 inch protection casing. A Halliburton pump truck was used to pump 9.1 pounds per gallon brine for the 8-hour injection period. Pressure and temperature were monitored and recorded at the surface. The spinner data indicated that all injected fluid was exiting the well through the three uppermost sets of perforations within the Abo Formation at 2734-2746 feet, 2766-2790 feet, and 2808-2820 feet. The gauges were set at 3200 feet after the spinner passes and the pressure were recorded for the remainder of the injection period and the entire falloff period at this depth.

Injectivity-falloff testing of the combined vertical and lateral hole was conducted on September 11-12, 1999 after completion of the lateral hole. The packer was set at 2469 feet (1 foot above the liner hanger packer in the 9-5/8 inch protection casing in the vertical hole). In this well configuration, there was a single joint of pre-perforated 5-1/2 inch liner immediately set above the lateral hole window in the 9-5/8 inch casing that allowed fluid access to the vertical wellbore. A Halliburton pump truck was used to pump 9.3 pounds per gallon brine for the 8-hour injection period. Pressure and temperature were monitored and recorded at the surface. The spinner data indicated that approximately 58% of the injected fluid was exiting the well through the vertical section, 34% through the perforations 2604-3375 feet in the lateral hole, and 8% through the pre-perforated liner below 3401 feet. The gauge was set at a measured depth of 3401 feet (true vertical depth of 3223 feet) feet after the spinner passes. The pressure was recorded for the remainder of the injection period and the entire falloff period at this depth.

The field injection results from both tests appear to be encouraging for long-term operation of the well. However, the analytical conclusions derived from the test data are somewhat less optimistic because the tests were not of sufficient length to achieve radial flow within the formation. The absence of radial flow reduces the accuracy and reliability of any simulation modeling. The current tests did not yield the mathematical predictions on the injection well capacity or longevity that were desired, but they definitely support injection at rates adequate to achieve the basic goals of the project.

Construction Geology

The injection well was installed approximately one-quarter mile southwest of the pilot hole that was drilled in 1996 to evaluate the injection potential of the area. The geological formations encountered in the injection well were very similar in depth, thickness and lithology to that noted in the pilot hole, with the exception of the lower Sangre de Cristo Formation - Precambrian interface. Underlying the mudstone and mudstone conglomerates of the upper Sangre de Cristo, a thick sequence of granite wash or grus was present in the injection well that was not described from the pilot hole. A total of 292 feet of this unit was drilled, followed by 58 feet of highly weathered Precambrian basement materials that overlaid a fractured igneous Precambrian basement formation. The injection well was drilled approximately 600 feet deeper than planned to fully penetrate the previously unknown geological units. The significant changes between the pilot hole and the injection well near the basement imply that there may be considerable relief present on the weathered Precambrian surface.

Based on the geological formations encountered, the injection and confining zones of the well are defined as follows:

Confining Zone: 1883 ft to 2421 ft, (lower Yeso formation)
Injection Zone: 2421 ft to 3800 ft

The injection zone is divided into the containment interval and injection interval. Only the injection interval directly receives injected fluids from the well.

Containment Interval: 2421 ft to 2500 ft (upper Abo Formation)
Injection Interval: 2 500 ft to 3800 ft (lower Abo, Sangre de Cristo, and Precambrian)

Dipmeter interpretation indicated that the structural dip, in geological formations where it could be determined, was generally to the south or southwest at very gentle rates of approximately one-half a degree.

Minor fracturing was present in the lower Abo and upper Sangre de Cristo. Fracturing was considerably more common in the granite wash and Precambrian sections of the well. The fractures had a predominate east-west strike and dipped toward the south. Many of the fractures were healed and do not contribute to the wells injection capacity.

Fracturing was not detected above the lower Abo Formation from geophysical logs, or in either of the two cores recovered from the Yeso formation (confining zone). The deeper fracturing that was noted in the injection zone is believed to be a minimal contributor to fluid movement due to mineral precipitation. Available data indicate that the integrity of the containment interval and the confining zone are intact, and these geological barriers will effectively isolate injected brine fluids from any potential underground source of drinking water (USDW).

Completion

(Note that, for the sake of clarity, some of the information in this section is duplicated in the Drilling and Testing section above.)

Twenty-inch steel conductor pipe was set at a depth of 42 feet and 13-3/8 inch steel surface casing was set at 819 feet. Protection casing consisted of 9-5/8 inch steel casing set and cemented at 2673 feet into the Abo Formation. Casing pressure testing, cement bond logging, and temperature logging were performed on all cemented casing strings.

[In the vertical hole] Steel 5-1/2 inch liner consisting of a 20 hole per foot pre-perforated lower section (3776 ft to 3247 ft) and a blank upper section (3224 ft to 2673 ft) was hung off in the protection casing, with an external casing packer and port collar between the segments. The blank upper section of the liner was cemented in place and selectively perforated with 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

[In the lateral hole] Steel 5-1/2 inch liner consisting of a 20 hole per foot pre-perforated lower section (4070 ft to 3419 ft measured depth) and a blank upper section (3397 ft to 2470 ft measured depth) was hung off in the protection casing of the vertical hole, with an external casing packer and port collar between the segments. The blank upper section of the liner was cemented in place and selectively perforated with 8 or 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

A packer with a polished bore receptacle (PBR) was set in the 9-5/8 inch protection casing between 2446 feet and 2465 feet. An injection tubing string consisting of 5-1/2 inch fiberglass tubing and a seal assembly was landed in the PBR with the top of the seals at 2443.61 feet. The bottom of the tailpipe was at 2465.58 feet. A 3000-psi working pressure wellhead with bowl and seal assembly was installed to the top of the casing-tubing assembly.

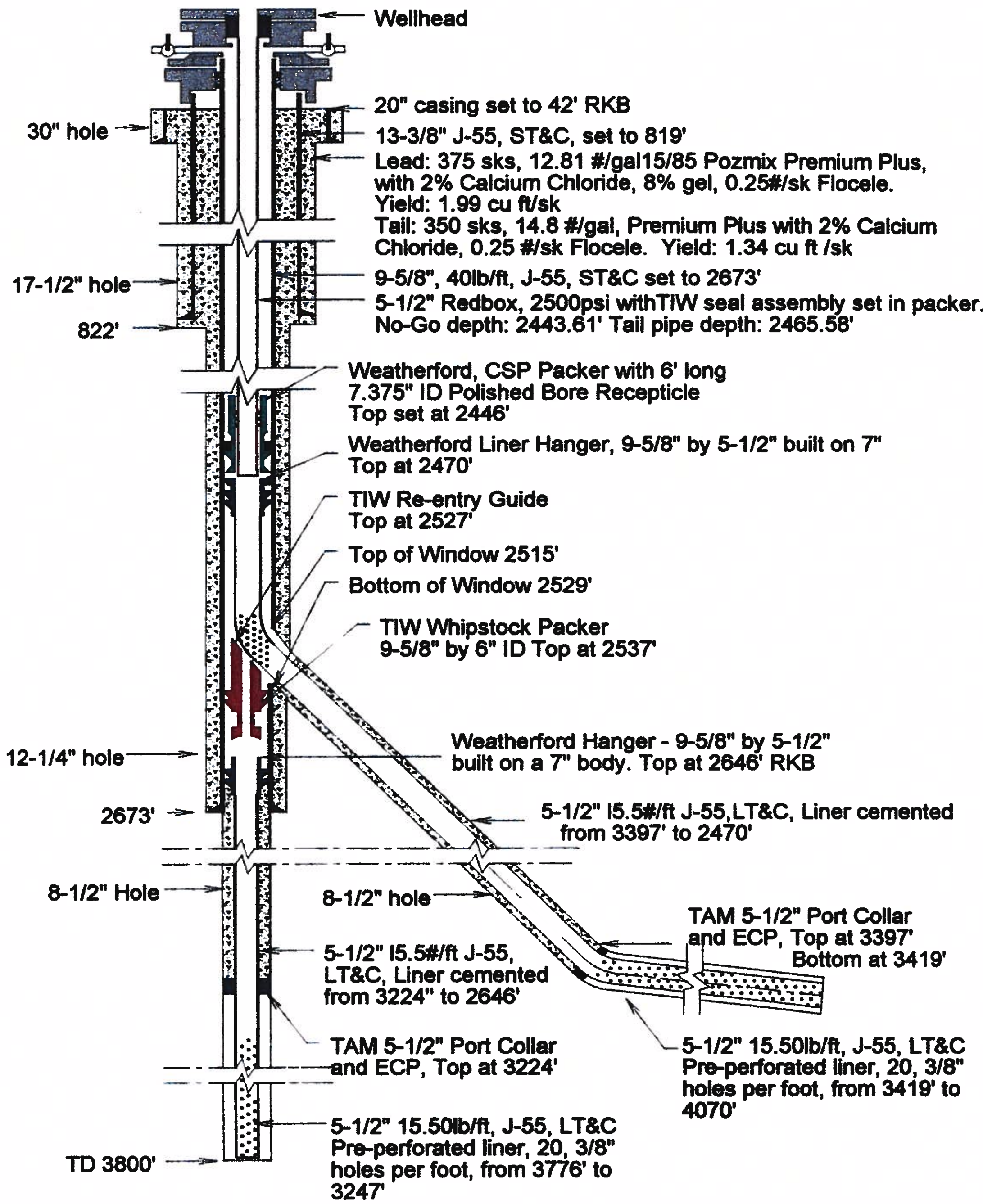
See Figure 1 below for a schematic of TW-1 and Figure 2 below for a surface and protection casing detail. See the separate full text of the TWO Well Completion Report – Report Text [TWO] for a full text of those sections extracted herein and for detailed Daily Operations Summary, Well Testing Summaries, and Laboratory Testing Results. Also included in this referenced document and its appendices are the following:

- Figures showing natural fracturing of formations, surface and casing pressure test results, rock-fluid compatibility (permeability versus pore volumes injected) and rock-fluid compatibility (permeability versus injection time).
- Tables showing whole core and core plug analysis summaries, summaries of acoustic velocity data, static rock-fluid compatibility test data for 2 samples, and pre and post rock-fluid compatibility test summary
- Construction schematics
- Casing, liner and injection tubing records
- Cementing records
- Casing pressure test records
- Directional surveys
- Stimulation (acidizing, jetting) records

- Drill stem test records
- Injectivity falloff test data and analyses – step rate pump test data for the vertical hole and the lateral hole
- Core analysis reports
- Fluid to fluid compatibility
- Formation fluid chemistry reports
- Mechanical integrity testing
- Major drilling activity summary
- Daily drilling reports
- Electric (geophysical) logs from installation and testing

Mechanical Integrity Testing

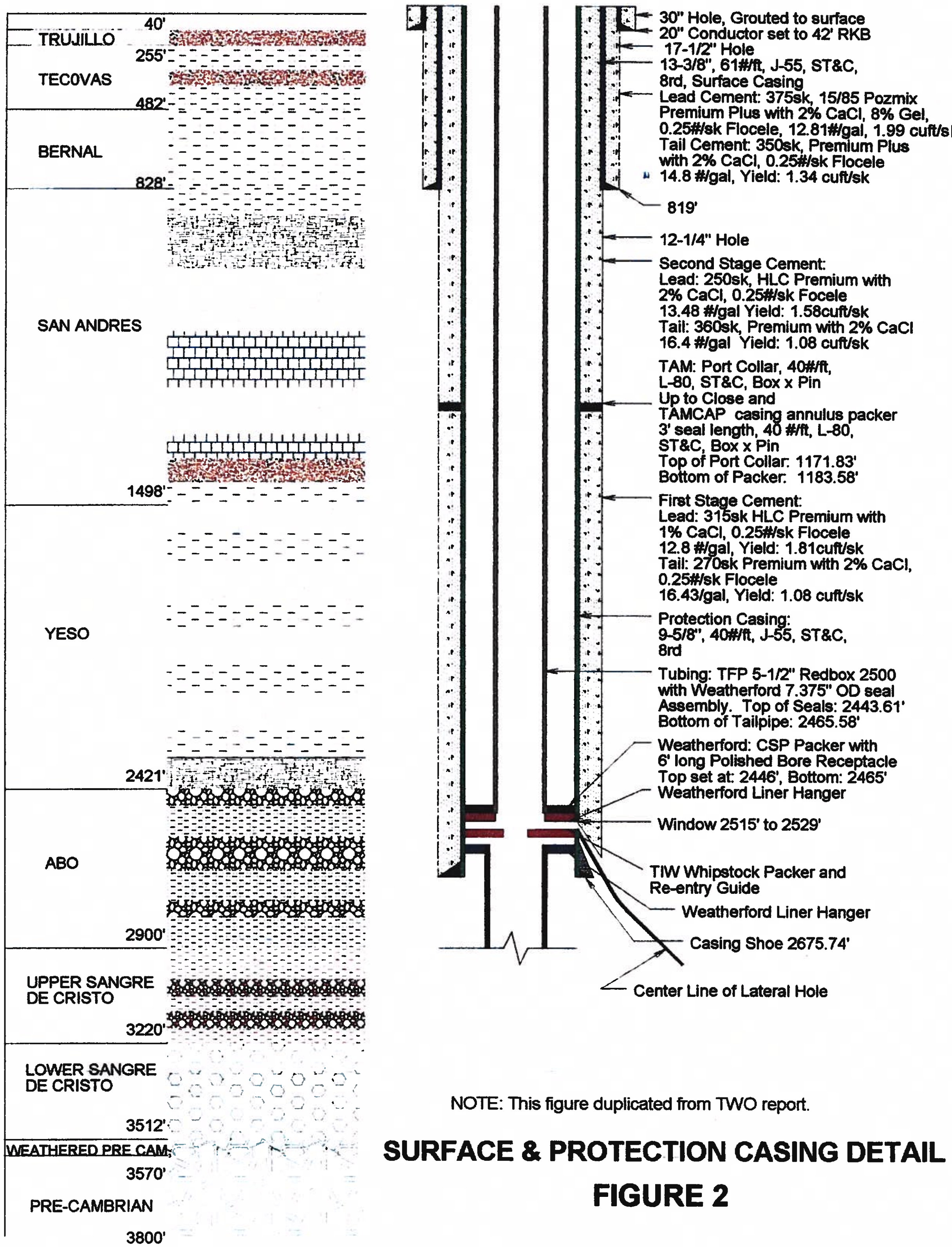
Following completion, mechanical integrity testing was performed on the well on October 6, 1999. An annulus pressure test, radioactive tracer survey and a temperature log were run. The results of the testing indicated that there was no significant leak in the well's casing, tubing, packer, or seals. Additionally, there was no evidence of upward fluid movement outside the well's protective casing that could endanger any underground sources of drinking water.



NOTE: This figure duplicated from TWO report.

TW-1 SCHEMATIC

FIGURE 1



SURFACE & PROTECTION CASING DETAIL

FIGURE 2

Plugging and Abandonment of the Pilot Hole

On September 10, 1999, Holman Services moved in and set up on the Pilot Hole to begin Plugging and Abandonment (P&A). They ran a tubing string in the hole and encountered an obstruction at 1250 ft. Holman then left the site. The crew returned to the site with additional equipment in the afternoon of September 13 and resumed work. They removed the tubing string from the hole. Using a drill string, they drilled and advanced the hole past the blockage. Several blocked areas were encountered, and they had to ream below about 1900 ft. On September 15, after reaming to 2593 ft, crew set the bottom of a tubing string at 2583 ft (2570 ft required by permit) and grouted as follows:

1. Pumped 70 sacks Class C cement mixed with water at 5.2 gallons water per sack of cement with 2% calcium chloride (accelerator) added. (About 83 ft^3.)
2. Pulled 1000 ft of tubing.
3. Pumped 70 sacks cement (same as above).
4. Pulled 1000 ft of tubing.
5. Circulated to surface using 32 sacks cement as above (about 38 ft^3) and pulled remaining tubing.
6. Topped hole with 8 sacks cement (about 9 ft^3) as above.

Grout was mixed by a jet pump (mud pump) with a cement hopper feed. A 1-pint sample of grout took an initial set in about 1 hour at surface temperature (about 70° F). The next day, the grout sample had excellent strength. Checked about 2 hours after topping out (6:30 p.m. on September 15), the grout surface had settled to about 60 ft below ground surface. The contractor topped this out before leaving the job. After topping out, a steel witness post was installed to mark the location.

The owner, Dennis Holman, completed and submitted the P&A forms to the State of New Mexico Environment Department.

Factors Affecting Contractor's Progress

Weather

Work was halted for a few hours during drilling due to lightening. On August 8, a heavy rain wetted the drawworks brake, making it impossible to control the weight on the drill bit; a few hours were lost when drilling was stopped, the kelly laid down, and the drill string worked up and down to dry the brakes.

Labor

There were no serious delays resulting from labor problems. The construction management firm, TWO, did an excellent job of coordinating the many subcontractors and incorporating changes without unnecessary delays in work progress.

Organization and Personnel

As described in the Contract Administration section, CRMWA Corp., incorporated in the State of New Mexico, was the contracting agency for all construction. For Phase 1 construction, TWO acted as construction manager for CRMWA Corp.

Contractor Forces

The construction management firm, TWO, is a environmental consulting and engineering firm offering services in a number of disciplines within the environmental, geological, and petroleum engineering fields. Their primary specialty is the subsurface disposal of liquid wastewaters via deep well injection. Excluding support staff in their Houston office, the staff working on this project consisted of the following individuals:

- Robert F. Whiteside, Principal Project Manager, Principal Field Supervisor, P.E.
- William H. Armstrong, General Manager, Sr. Management Field Supervisor, P.E.
- Mike Grant, Senior Geologist, Senior Field Supervisor
- Jim Sandt, Senior Geologist

TWO site staff usually consisted of one of managers and one of the geologists, with personnel rotating to and from their Houston office.

Subcontractors

See Table 4 above for a listing of the Phase 1 subcontractors. Staffing varied dramatically during the execution of the work. The drilling contractor had a drilling superintendent (tool pusher), 2 drillers, and 6 crew members on site. The drillers and crew members were split into 2 crews working 12 hour shifts 7 days per week. All personnel were rotated to provide leave from site work.

Other subcontractors would appear at the site when scheduled by TWO. In many cases, a subcontractor would arrive, perform their function, and leave within a few hours. During short intervals such as casing installation, cementing, and well stimulation, up to about 20 personnel were on site. During some activities, personnel were continually on site for 24 hours or more. Specific charts or listings of subcontractor personnel at the site on a chronological basis and wage information are not available.

Contract Administration Forces

CRMWA Corp. was the contracting agency for Lake Meredith Salinity Control Project Phase 1 construction. Staffing involved with this project consisted of the following:

- John E. Williams, General Manager
- Kent Satterwhite, Deputy General Manager (Project Supervisor – equivalent to Contracting Officer)
- Chad Pernell, P.E. (equivalent to Contracting Officer Technical Representative)
- Jerry Osborn, Operator/Inspector

- Ashby Lewis, Chemist

Mr. Osborn was at the site on a daily basis. Other individuals were on site as needed. Wage rates for these personnel are not available.

The Oklahoma-Texas Area Office was responsible for Reclamation activities associated with Phase 1 construction. Staff directly involved with construction included the following:

- Area Manager, Elizabeth Cordova-Harrison
- Project Director, Leon Esparza
- Construction Representative, Dennis McDonough

As previously described, Reclamation was to have been responsible for construction management. However, after determining that substantial savings could be realized, CRMWA Corp. became the contracting agency. Therefore, the role of Reclamation during construction was to coordinate various activities with regulating agencies, the design firm, J.F. Sato & Associates, Inc. (JFSA), and others, provide advice and support to CRMWA Corp., and verify compliance with the permits issued to Reclamation. Mr. McDonough was at Logan during most of the Phase 1 construction.

Safety

The Project Supervisor for CRMWA Corp. and TWO, their construction management company, were responsible for enforcement of safety requirements during the execution of the Phase 1 contracts.

Contractor Forces

Subcontractors held frequent toolbox safety meetings. In addition, prior to conducting relatively hazardous activities such as setting casing, perforating casing, or acid stimulation, the various subcontractors held mandatory safety meetings for all personnel on site. During these meetings, exact instructions and explicit cautions were given for employees involved in the various functions. The larger firms, such as Norton Drilling, Halliburton, Weatherford, and Schlumberger, demanded strict adherence to their excellent safety programs. Visitors and personnel not directly participating in the activity were not allowed in hazardous areas without supervision.

The TWO staff and their subcontractors had no lost time injury accidents during construction.

Contract Administration Forces

There were no lost time injury accidents involving CRMWA Corp. or Reclamation employees. Both CRMWA Corp. and Reclamation staff at the construction site attended all site safety meetings held by subcontractors.

PHASE 2 CONSTRUCTION – Production Wells, Pipelines, and Injection Well Facilities

CONTRACT ADMINISTRATION

CRMWA Corp. also served as the issuing agency for Phase 2 construction. However, because the work to be performed was more typical of the construction industry, CRMWA Corp. directly managed the construction activities.

Summary of Bids

The Phase 2 construction bid schedule was split into a Base Bid and Add Alternate Bids 2, 3, 4, 5, 6, and 7. The Base Bid schedule included the injection well facilities, pipelines, 5 valley production wells designated PW1-1, PW1-3, PW1-4, PW1-5, and PW1-6, and one plateau well designated PW1-2. Alternate Bids 2, 3, 4, 5, and 6 were for 5 additional valley production wells designated PW2-1, PW2-2, PW2-3, PW2-4, and PW2-5, respectively. Bid Alternate 7 was for the plugging and abandonment of 9 selected existing wells designated TW-1, OW-1 (POW-1), OW-3, OW-4, OW-7, OW-8, DH-1, DH-2, and DH-3.

Four addendums were issued by CRMWA Corp. prior to bid opening.

Addendum No. 1:

- The Access Road and related appurtenances such as culverts and concrete slope blankets were deleted from the contract, because this work was already performed by CRMWA Corp. staff prior to Phase 1 construction.
- The specifications for the bolted steel water storage tanks were replaced.
- A statement was added regarding furnishing of power during construction.

Addendum No. 2 changed the bid opening date from May 23, 2000 to June 14, 2000.

Addendum No. 3:

- Specifications for steel water storage tanks were changed to permit welded steel tanks with the same approximate dimensions as the specified bolted steel tanks. A requirement for coating all interior surfaces and painting all exterior surfaces of the welded tanks was added. Either bolted steel or welded steel tanks could be bid.
- Section 1.1 (Temporary Discharge and Other Permits) was replaced.
- Drawing 3a – East Profile was included to modify the East Branch pipeline profile and authorized plowing methods to install the pipe in the river bottom only.
- Directional boring methods to cross under the river and the AT&T cable were authorized.

- Notes under the production well vault detail on Electrical Drawing E1.9 were modified to state that one vault would be part of base bid and none as an alternate.
- The Item 16 Base Bid description of 5 Valley Production Vaults and Controls was replaced by a requirement for Production Wellheads (as shown on Drawing P1.1 of the Plans). This also applied to Item 1 of the Add Alternate Bids 2, 3, 4, 5, and 6.
- Site grading was stipulated as being performed by others, except for all structures, walkways, etc.
- The plugging and abandonment of wells, Items 43 through 54, were removed from the Base Bid and added as Add Alternate Bid 7.
- The Prevention of Water Pollution section was replaced.
- The previous bid schedule was replaced to reflect the changes incorporated above.

Addendum No. 4 deleted the "ground face" of the second sentence of Part A under I. 4200 UNIT MASONRY, Part 2 Products, 2.1 Masonry, A. The block units were specified to be regular medium weight CMU blocks as specified, not burnished blocks.

Bids were received by CRMWA Corp. at the Canadian River Municipal Water Authority headquarters 1 mile west of Sanford, Texas until 2:00 P.M., 2000, after which bids were opened. Only 2 bids were received. CRMWA Corp. reviewed and analyzed these bids prior to award. The low bidder was Garney Companies, Inc., 1331 NW Vivion Road, Kansas City, MO 64118. The high bidder was Versatile Construction Company, P.O. Box 336, Logan, NM 88426. Bids are summarized in Table 6 below.

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS

Item	Description	Quan-tity	Unit	Unit Prices			Contract Total Amount
				Engineer Estimate	High Bidder	Low Bidder	
	1. BASE BID						
1	Mobilization	1	LS		$350,000.00	$200,000.00	$200,000.00
2	Care and Diversion of River	1	LS		$100,000.00	$2,000.00	$2,000.00
3	Injection Well Facility	1	LS		$1,665,730.00	$1,500,000.00	$1,500,000.00
4	Access Road - DELETED FROM BID SCHEDULE	1	LS	----	----	----	----
5	Plateau 8" DR 17.0 Discharge Line	1598	LF		$30.89	$43.00	$68,714.00
6	Plateau 6" DR 17.0 Discharge Line	4042	LF		$70.14	$41.00	$165,722.00
7	Plateau 6" DR 15.5 Discharge Line	987	LF		$57.50	$42.00	$41,454.00
8	Valley 6" DR 15.5 Discharge Line	243	LF		$62.00	$54.00	$13,122.00
9	Valley 6" DR 13.5 Discharge Line	3555	LF		$117.97	$55.00	$195,525.00
10	Angle Drilled Discharge Line	1	LS		$45,000.00	$9,000.00	$9,000.00
11	East Branch Bore Under SH469	1	LS		$30,920.00	$54,000.00	$54,000.00
12	West Branch Bore Under SH469	1	LS		$45,865.00	$32,000.00	$32,000.00
13	Valley 4" DR 11.0 (PW to Mainline)	670	LF		$55.00	$51.00	$34,170.00
14	Plateau Vault	5	EA		$2,300.00	$5,000.00	$25,000.00
15	Valley Vault	2	EA		$9,750.00	$15,000.00	$30,000.00
16	Production Vault & Controls (5-Valley)	1	LS		N/A	$333,000.00	$333,000.00
17	Production Vault & Controls (1-Plateau)	1	LS		$9,400.00	$63,000.00	$63,000.00
18	Mobilization & Demobilization of Drilling Rig	1	LS		$50,000.00	$50,000.00	$50,000.00
19	Location Preparation - 5 Valley Wells	5	EA		$5,000.00	$4,250.00	$21,250.00
20	Location Preparation - 1 Plateau Well	1	EA		$5,000.00	$4,250.00	$4,250.00
21	Furnish & Install 16-inch Conductor Casing - 5 Valley Wells (total footage-all valley wells)	255	LF		$160.00	$144.00	$36,720.00
22	Furnish & Install 16-inch Casing-Head Flange - 5 Valley Wells	5	EA		1,000.00	$5,500.00	$27,500.00
23	Drill 10-inch Hole to 15 feet; Furnish, Install, & Cement 16-inch Conductor Casing - 1 Plateau Well	15	LF		$160.00	$277.00	$4,155.00
24	Furnish & Install 16-inch Casing-Head Flange - 1 Plateau Well	1	EA		$1,000.00	$5,500.00	$5,500.00
25	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth - 5 Valley Wells & 1 Plateau Well (total footage - all wells)	816	LF		$90.00	$50.00	$40,800.00
26	Furnish & Install 6-inch OD PVC Blank Pipe - Valley Wells & Plateau Well (total footage - all wells)	60	LF		$13.00	$10.00	$600.00

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)							
Item	Description	Quan-tity	Unit	Unit Prices			Contract Total Amount
				Engineer Estimate	High Bidder	Low Bidder	
27	Furnish & Install 6-inch OD PVC Screen - Valley Wells & Plateau Well (total footage - all wells)	300	LF		$15.00	$56.00	$16,800.00
28	Furnish & Install 8-inch OD PVC Riser - Valley Wells & Plateau Well	516	LF		$14.00	$11.00	$5,676.00
29	Furnish & Install Filter Pack - Valley Wells & Plateau Well (total cu. ft. - all wells)	396	CF		$40.00	$16.00	$6,336.00
30	Furnish & Install Bentonite Seal - Valley Wells & Plateau Well (total cu. ft. - all wells)	48	CF		$40.00	$74.00	$3,552.00
31	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC and 14-3/4-inch Hole and 16-inch Conductor Pipe - Valley Wells & Plateau Well (total cu. ft. - all wells)	368	CF		$40.00	$13.00	$4,784.00
32	Furnish Pump for Well Development - Develop Well - 5 Valley Wells & 1 Plateau Well (total hours)	48	HR		$100.00	$150.00	$7,200.00
33	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - 5 Valley Wells & 1 Plateau Well (total hours)	48	HR		$100.00	$150.00	$7,200.00
34	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well - 5 Valleys & 1 Plateau Well (total hours)	36	HR		$100.00	$150.00	$5,400.00
35	Laboratory Analysis of Formation Water from Each Well - 5 Valley Wells & 1 Plateau Well	6	EA		$500.00	$125.00	$750.00
36	Furnish Pump and Related Data Acquisition Equipment for Aquifer Testing - 5 Valley Wells & 1 Plateau Well (total hours)	324	HR		$125.00	$150.00	$48,600.00
37	Furnish and Install Fiberglass Production Tubing - 5 Valley Wells & 1 Plateau Well (total footage - all wells)	520	LF		$15.00	$70.00	$36,400.00
38	Furnish & Install Production Pump - 5 Valley Wells & 1 Plateau Well	6	EA		$9,072.00	$12,000.00	$72,000.00
39	Furnish & Install Wellhead - 5 Valley Wells & 1 Plateau Well	6	EA		$28,000.00	$5,000.00	$30,000.00
40	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable - 5 Valley Wells & 1 Plateau Well	6	EA		$3,162.00	$4,000.00	$24,000.00
41	Outlet Works and Vault	2	EA		$9,750.00	$15,000.00	$30,000.00
42	4" DR 11.0 to Outlet Works	30	LF		$62.00	$51.00	$1,530.00
	Total Base Bid			$3,199,905.44	$3,713,722.95	$3,257,710.00	$3,257,710.00

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)

Item	Description	Quan-tity	Unit	Unit Prices			Contract Total Amount
				Engineer Estimate	High Bidder	Low Bidder	
	2. ADD ALTERNATE PW2-1						
AA2-1	PW2-1, Production Vault & Controls	1	LS		32,050.00	$38,000.00	$38,000.00
AA2-2	4" DR 11.0 Pipe	850	LF		$62.00	$49.00	$41,650.00
AA2-3	6"x6"x4" Tee	1	EA		$250.00	$200.00	$200.00
AA2-4	Location Preparation	1	LS		$5,000.00	$4,250.00	$4,250.00
AA2-5	Furnish & Install 16-inch Conductor Casing	30	LF		$160.00	$144.00	$4,320.00
AA2-6	Furnish & Install 16-inch Casing-Head Flange	1	EA		$1,000.00	$5,500.00	$5,500.00
AA2-7	Furnish & Install Vaults	1	EA		$9,750.00	$5,000.00	$5,000.00
AA2-8	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth	112	LF		$90.00	$50.00	$5,600.00
AA2-9	Furnish & Install 6-inch OD PVC Blank Pipe	10	LF		$13.00	$10.00	$100.00
AA2-10	Furnish & Install 6-inch OD PVC Screen	48	LF		$15.00	$56.00	$2,688.00
AA2-11	Furnish & Install 8-inch OD PVC Riser	83	LF		$14.00	$11.00	$913.00
AA2-12	Furnish & Install Filter Pack	66	CF		$40.00	$16.00	$1,056.00
AA2-13	Furnish & Install Bentonite Seal	8	CF		$40.00	$6.00	$48.00
AA2-14	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC & 14-3/4-inch Hole & 16-inch Conductor Pipe	60	CF		$40.00	$13.00	$780.00
AA2-15	Furnish Pump for Well Development - Develop Well	8	HR		$100.00	$150.00	$1,200.00
AA2-16	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - Valley Wells	8	HR		$100.00	$150.00	$1,200.00
AA2-17	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well	6	HR		$100.00	$150.00	$900.00
AA2-18	Laboratory Analysis of Formation Water from Each Well	1	EA		$500.00	$125.00	$125.00
AA2-19	Furnish Pump & Related Data Acquisition Equipment for Aquifer Testing	54	HRS		$125.00	$150.00	$8,100.00
AA2-20	Furnish & Install Fiberglass Production Tubing	85	LF		$15.00	$70.00	$5,950.00
AA2-21	Furnish & Install Production Pump	1	EA		$9,072.00	$12,000.00	$12,000.00
AA2-22	Furnish & Install Wellhead	1	EA		$8,000.00	$5,000.00	$5,000.00
AA2-23	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable	1	EA		$3,162.00	$4,000.00	$4,000.00
AA2-24	Outlet Works & Vault per Drawing 3a of this addendum and the plans and specifications	1	EA		$9,750.00	$15,000.00	$15,000.00
AA2-25	Valley Vault per Drawing 3a of this addendum and the plans and specifications	1	EA		$9,750.00	$15,000.00	$15,000.00
	Total Add Alternate PW2-1			$197,143.47	$173,461.00	$178,580.00	$178,580.00

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)

Item	Description	Quan-tity	Unit	Unit Prices			Contract Total Amount
				Engineer Estimate	High Bidder	Low Bidder	
	3. ADD ALTERNATE PW2-2						
AA3-1	PW2-2 Production Vault & Controls	1	LS		$40,800.00		
AA3-2	4" DR 11.0 Pipe	700	LF		$62.00		
AA3-3	6" DR 11.0 Pipe	3149	LF		$62.00		
AA3-4	6"x6"x4" Tee	1	EA		$250.00		
AA3-5	Location Preparation	1	LS		$5,000.00		
AA3-6	Furnish & Install 16-inch Conductor Casing	30	LF		$160.00		
AA3-7	Furnish & Install 16-inch Casing-Head Flange	1	EA		$1,000.00		
AA3-8	Furnish & Install Vaults	1	EA		$9,700.00		
AA3-9	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth	112	LF		$90.00		
AA3-10	Furnish & Install 6-inch OD PVC Blank Pipe	10	LF		$13.00		
AA3-11	Furnish & Install 6-inch OD PVC Screen	48	LF		$15.00		
AA3-12	Furnish & Install 8-inch OD PVC Riser	83	LF		$14.00		
AA3-13	Furnish & Install Filter Pack	66	CF		$40.00		
AA3-14	Furnish & Install Bentonite Seal	8	CF		$40.00		
AA3-15	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC & 14-3/4-inch Hole & 16-inch Conductor Pipe	60	CF		$40.00		
AA3-16	Furnish Pump for Well Development - Develop Well	8	HR		$100.00		
AA3-17	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - Valley Wells	8	HR		$100.00		
AA3-18	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well	6	HR		$100.00		
AA3-19	Laboratory Analysis of Formation Water from Each Well	1	EA		$500.00		
AA3-20	Furnish Pump & Related Data Acquisition Equipment for Aquifer Testing	54	HR		$125.00		
AA3-21	Furnish & Install Fiberglass Production Tubing	85	LF		$15.00		
AA3-22	Furnish & Install Production Pump	1	EA		$9,072.00		
AA3-23	Furnish & Install Wellhead	1	EA		$8,000.00		
AA3-24	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable	1	EA		$3,162.00		
	Total Add Alternate PW2-2			$361,812.59	$348,599.00	----------------	---------------

CTION SUMMARY OF BIDS (Continued)

Item	Description	Quan-tity	Unit	Unit Prices: Engineer Estimate	Unit Prices: High Bidder	Unit Prices: Low Bidder	Contract Total Amount
	4. ADD ALTERNATE PW2-3						
AA4-1	PW2-3 Production Vault & Controls	1	LS		$40,800.00		
AA4-2	4" DR 11.0 Pipe	15	LF		$62.00		
AA4-3	6" DR 11.0 Pipe	858	LF		$62.00		
AA4-4	6"x6"x4" Tee	1	EA		$250.00		
AA4-5	Location Preparation	1	LS		$5,000.00		
AA4-6	Furnish & Install 16-inch Conductor Casing	30	LF		$160.00		
AA4-7	Furnish & Install 16-inch Casing-Head Flange	1	EA		$1,000.00		
AA4-8	Furnish & Install Vaults	1	EA		$9,750.00		
AA4-9	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth	112	LF		$90.00		
AA4-10	Furnish & Install 6-inch OD PVC Blank Pipe	10	LF		$13.00		
AA4-11	Furnish & Install 6-inch OD PVC Screen	48	LF		$15.00		
AA4-12	Furnish & Install 8-inch OD PVC Riser	83	LF		$14.00		
AA4-13	Furnish & Install Filter Pack	66	CF		$40.00		
AA4-14	Furnish & Install Bentonite Seal	8	CF		$40.00		
AA4-15	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC & 14-3/4-inch Hole & 16-inch Conductor Pipe	60	CF		$40.00		
AA4-16	Furnish Pump for Well Development - Develop Well	8	HR		$100.00		
AA4-17	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - Valley Wells	8	HR		$100.00		
AA4-18	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well	6	HR		$100.00		
AA4-19	Laboratory Analysis of Formation Water from Each Well	1	EA		$500.00		
AA4-20	Furnish Pump & Related Data Acquisition Equipment for Aquifer Testing	54	HR		$125.00		
AA4-21	Furnish & Install Fiberglass Production Tubing	85	LF		$15.00		
AA4-22	Furnish & Install Production Pump	1	EA		$9,072.00		
AA4-23	Furnish & Install Wellhead	1	EA		$8,000.00		
AA4-24	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable	1	EA		$3,162.00		
	Total Add Alternate PW2-3			$217,393.20	$164,137.00	------------------	------------------

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)

Item	Description	Quantity	Unit	Unit Prices: Engineer Estimate	Unit Prices: High Bidder	Unit Prices: Low Bidder	Contract Total Amount
	5. ADD ALTERNATE PW2-4						
AA5-1	PW2-4 Production Vault & Controls	1	LS		$32,050.00		
AA5-2	4" DR 11.0 Pipe	750	LF		$62.00		
AA5-3	6"x6"x4" Tee	1	EA		$250.00		
AA5-4	Location Preparation	1	LS		$5,000.00		
AA5-5	Furnish & Install 16-inch Conductor Casing	30	FT		$160.00		
AA5-6	Furnish & Install 16-inch Casing-Head Flange	1	EA		$1,000.00		
AA5-7	Furnish & Install Vaults	1	EA		$9,750.00		
AA5-8	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth	112	LF		$90.00		
AA5-9	Furnish & Install 6-inch OD PVC Blank Pipe	10	LF		$13.00		
AA5-10	Furnish & Install 6-inch OD PVC Screen	48	LF		$15.00		
AA5-11	Furnish & Install 8-inch OD PVC Riser	83	LF		$14.00		
AA5-12	Furnish & Install Filter Pack	66	CF		$40.00		
AA5-13	Furnish & Install Bentonite Seal	8	CF		$40.00		
AA5-14	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC & 14-3/4-inch Hole & 16-inch Conductor Pipe	60	CF		$40.00		
AA5-15	Furnish Pump for Well Development - Develop Well	8	HR		$100.00		
AA5-16	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - Valley Wells	8	HR		$100.00		
AA5-17	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well	6	HR		$100.00		
AA5-18	Laboratory Analysis of Formation Water from Each Well	1	EA		$500.00		
AA5-19	Furnish Pump & Related Data Acquisition Equipment for Aquifer Testing	54	HR		$125.00		
AA5-20	Furnish & Install Fiberglass Production Tubing	85	LF		$15.00		
AA5-21	Furnish & Install Production Pump	1	EA		$9,072.00		
AA5-22	Furnish & Install Wellhead	1	EA		$8,000.00		
AA5-23	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable	1	EA		$3,162.00		
	Total Add Alternte PW 2-4			-----------------	$147,761.00	-----------------	-----------------

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)

Item	Description	Quantity	Unit	Unit Prices: Engineer Estimate	Unit Prices: High Bidder	Unit Prices: Low Bidder	Contract Total Amount
	6. ADD ALTERNATE PW2-5						
1	PW2-5 Production Vault & Controls	1	LS		$32,050.00		
2	4" DR 11.0 Pipe	15	LF		$930.00		
3	6" DR 15.5 Pipe	1458	LF		$90,396.00		
4	6"x6"x4" Tee	1	EA		$250.00		
5	Location Preparation	1	LS		$5,000.00		
6	Furnish & Install 16-inch Conductor Casing	30	LF		$4,800.00		
7	Furnish & Install 16-inch Casing-Head Flange	1	EA		$1,000.00		
8	Furnish & Install Vaults	1	EA		$9,700.00		
9	Drill 6 Holes with Minimum 14-3/4-inch Diameter to Total Depth	112	LF		$10,080.00		
10	Furnish & Install 6-inch OD PVC Blank Pipe	10	LF		$130.00		
11	Furnish & Install 6-inch OD PVC Screen	48	LF		$720.00		
12	Furnish & Install 8-inch OD PVC Riser	83	LF		$1,162.00		
13	Furnish & Install Filter Pack	66	CF		$2,640.00		
14	Furnish & Install Bentonite Seal	8	CF		$320.00		
15	Furnish & Install Cement-Bentonite Grout Slurry Between 8-inch PVC & 14-3/4-inch Hole & 16-inch Conductor Pipe	60	CF		$2,400.00		
16	Furnish Pump for Well Development - Develop Well	8	HR		$800.00		
17	Furnish Pump for Well Productivity Testing - Run Production Test on Each Well - Valley Wells	8	HR		$800.00		
18	Furnish Pump for Formation Water Sampling. Collect Water Samples from Each Well	6	HR		$600.00		
19	Laboratory Analysis of Formation Water from Each Well	1	EA		$500.00		
20	Furnish Pump & Related Data Acquisition Equipment for Aquifer Testing	54	HR		$6,750.00		
21	Furnish & Install Fiberglass Production Tubing	85	LF		$1,275.00		
22	Furnish & Install Production Pump	1	EA.		$9,072.00		
23	Furnish & Install Wellhead	1	EA		$8,000.00		
24	Furnish & Install Electrical Tubing, Water Level Probe, & Instrumentation Cable	1	EA		$3,162.00		
	Total Add Alternate PW 2-5			$237,883.08	$192,537.00	----------------	----------------

TABLE 6 – PHASE 2 CONSTRUCTION SUMMARY OF BIDS (Continued)

Item	Description	Quantity	Unit	Unit Prices: Engineer Estimate	Unit Prices: High Bidder	Unit Prices: Low Bidder	Contract Total Amount
	6. ADD ALTERNATE PLUGGING & ABANDONMENT						
1	P&A TW #1 (including perforating)	1	LS		$8,940.00	$4,500.00	$4,500.00
2	P&A OW #1	1	LS		$2,976.00	$4,500.00	$4,500.00
3	P&A OW #2 (including perforating)	1	LS		$5,760.00	$4,500.00	$4,500.00
4	P&A OW #3	1	LS		$2,730.00	$4,500.00	$4,500.00
5	P&A OW #4	1	LS		$2,979.60	$4,500.00	$4,500.00
6	P&A OW #7	1	LS		$1,248.00	$4,500.00	$4,500.00
7	P&A OW #8	1	LS		$1,248.00	$4,500.00	$4,500.00
8	P&A DH #1	1	LS		$3,417.60	$4,500.00	$4,500.00
9	P&A DH #2	1	LS		$5,100.00	$4,500.00	$4,500.00
10	P&A DH #3	1	LS		$5,100.00	$4,500.00	$4,500.00
11	Pull/drill PVC string and bushing in OW #7 and OW #8	16	HR		$168.00	$150.00	$2,400.00
12	Redrill caved hole in DH #1 and DH #2	495	FT		$24.00	$50.00	$24,750.00
	Total Add Alternate Plugging & Abandonment			————	$54,067.20	$72,150.00	$72,150.00
	TOTAL BID/AWARD AMOUNT			$3,397,048.91	$3,941,251.15	$3,508,440.00	$3,508,440.00

Determination of the apparent low bidder was made by taking each bidder's base bid and adding as many of the additive bids (taken in the sequence listed) as available funds permitted. Garney did not enter bids amounts for Add Alternate Bids 3 through 6. However, the bids were high enough that CRMWA Corp. only had sufficient funding available to award the Base Bid and Add Alternates 2 and 7. Since the Garney Companies, Inc., bid was lower for the Base Bid and Add Alternates 2 and 7, Garney was the apparent low bidder.

Notice of Award was issued to Garney Companies, Inc. (Garney) on July 19, 2000. The date of receipt of Notice of Award is not available. On July 19, 2000, a Standard Form of Agreement between Owner and Contractor was signed by CRMWA Corp. and Garney. The Garney site administrator, Will Kennedy, arrived at the site during August 2000. Phase 2 construction began on August 31, 2000 with Couch Drilling Company, the production well drilling subcontractor, and mobilizing equipment to the site.

The Original Contract Time was 270 calendar days, resulting in a completion date of April 15, 2001. On October 1, 2001, CRMWA Corp. issued a letter to Garney declaring Phase 2 construction as substantially complete, thus commencing the 1-year warranty period. CRMWA Corp. retained some contract funds pending Final Completion. Final Completion was not declared as of May 1, 2002.

Contract Modifications

The following change orders were issued for Phase 2 Construction:

Change Order 001 dated August 30, 2000. This change order added 1 extra 8-inch centralizer on all production wells, except PW1-2, where 4 extra centralizers were added, per Contractor's Modification Request (CMR) 005. The change was made to help prevent deflection of the PVC riser casing as filter pack is installed in the wells. The cost increase was $1,375.00.

Change Order 002 dated September 25, 2000. This change order:

1. Added 3 one-inch electrical pipes in the 18-inch hole for the Angle Discharge Line per Request for Information (RFI) 005. The additional pipes were for possible future expansion of the production wells. The cost increase was $3,000.00.

2. Added a 40-mil HDPE liner under 3 tanks of the containment area (excluding the future tank foundation). The clay layer shown in the plans was replaced with 6-inches of clean sand under the tanks and crusher fines underneath the rest of the containment slab. The cost increase was $2,263.96.

3. Added bottom caps to the blank sump PVC at the bottom of each production well chamber per CMR 006. This change was made to prevent filter pack or formation materials from entering the well chamber. The cost increase was $252.00.

4. Replaced the 4-inch pipe in the leach field with 8 – 18-inch leach chambers per Proposed Contract Modification (PCM) 001. Replace the 1000-gallon septic tank in the plans with a 1000-gallon pre-fabricated septic tank as provided by Septco per Garney's letter of September 12, 2000; this change was made because the

State of New Mexico representative would only approve a prefabricated septic tank. This change reduced the cost by $1,750.00.

5. Substituted one air/vacuum valve and one combination air/vacuum valve in lieu of two air/vacuum valves per PCM 001 and Garney's letter of September 12, 2000. The cost increase was $420.00.
6. Added all labor and materials to contract to provide underground conduit to the electrical service transformer per CMR 009 and the plans and specifications. This change was made because the electric utility company would not run power to the transformer. The cost increase was $7,932.38.
7. Added a concrete cap to the top of the 4th (future) tank foundation. This was done to seal the tank foundation. The cost increase was $1,436.00.

<u>Change Order 003</u> dated November 7, 2000. This change order:

1. Substituted Matco-Norca butterfly valves for the 4-inch and 6-inch ball valves per CMR 018. This change was made because the butterfly valves were considered to operate better in sand-laden water. The cost increase was $2,216.20.
2. Moved Salinity Control Facilities 62.25 ft due south per PCM 002. As described above, this change was due to the injection well being drilled 62.25 ft south and 7.38 ft east of the design location. The cost increase was $903.00 plus any additional materials paid at the unit cost for each item bid.

<u>Change Order 004</u> dated November 20, 2000. This change order:

1. Added stand-by time for the Couch Drilling Company, resulting from delays required by CRMWA Corp. The Contractor was required to notify the Project Supervisor in advance that stand-by time would occur. At a rate of $115.00 per hour for 20 hours, the cost increase was $2,300.00.
2. Agreed to compensate Couch Drilling Company for extra drilling time, when requested by the Project Supervisor or one of his representatives, at the rate of $183.00 per hour for 10 hours. This cost increase was $1,830.00.

<u>Change Order 005</u> dated November 21, 2000. This change order:

1. Replaced the production well fiberglass tubing with CERTA LOK SCH 80 drop pipe in 10 ft lengths. This change resulted in a discount of $3.00 per ft for 605 ft for a total cost decrease of $1,815.00.
2. Added ¼-inch stainless steel cable (aircraft cable) to each production well to support the weight of the pump and motor in case of failure. There was no cost change for this item.

<u>Change Order 006</u> dated January 23, 2001. This change order:

1. Modified the outworks vault per CMR 024, with the exception of adding a flanged 90-degree elbow at the top and providing a cap for the elbow. This change was done to avoid the possibility of sand-laden groundwater back flowing into the pipeline system when the outlet works are used. This change also eliminated large volumes of alluvial sand, silt, and clay eroding into the river

when an outlet works release occurred. This resulted in a total cost decrease of $3,000.00.

2. Relocated and modified the lavatory, modified the shower, relocated the water heater, modified the toilet, and added handrails per CMR 021. This change order was issued to address Americans with Disabilities Act features of the injection well office bathroom, incorporating the changes recommended by JFSA, and reflecting modifications required by the State of New Mexico Construction Industries Department. The cost increase was $3,523.00.

3. Added a floor drain primer to the Shop/Office Building. (A floor drain primer is a device that, installed on the drain side of a toilet, assures water will remain in the P-trap.) This was done so the New Mexico state inspector would allow construction to continue. The cost increase was $466.25.

Change Order 007 dated February 23, 2001. This change order:

1. Added a Repeater to the SCADA system to achieve line-of-site between the injection site and the production wells as per CMR 020. Farmer's Electric was to furnish the pole and 120-volt electrical service. The cost increase was $3,543.70.

2. Compensated the Contractor for installation (and labor to install) of the conduit, wiring, etc. to connect the motor-operated valves at the tanks to the main PLC in the injection building, including upgrading the PVC conduit that runs from the junction box to the valves from ½-inch to ¾-inch. This change order was required because there was no drawing in the plans showing wiring or conduit to these valves. This change was administered on a Time & Materials basis with labor time at $65.00/hour for Subcontractor plus mark-up of 10% for General Contractor and 5.625% for Gross Receipts Tax; and cost of materials plus mark-up of 10% for Subcontractor, 10% for General Contractor and 5.625% for Gross Receipt Tax. The estimated time was 30 hours and the total estimated cost of materials was $1,000.00 for a total cost increase of $2,265.60 + $1,278.10 = $3,543.70.

3. Replaced the Allen-Bradley SCL 5/03 PLC in the injection building with the SCL 5/05, as well as add the Ethernet hub per CMR 026. This change provided greater speed and flexibility between the workstation and the PLC in the Injection Facility. The cost increase was $3,077.10.

Change Order 008 dated February 23, 2001. This change order:

1. Added a total of 9 days to the Contract Time (to 279 Calendar Days) due to weather delays per CMR 031, resulting in a new project deadline of April 24, 2001.

2. Added a light above the ceiling for servicing the air-handling unit as required by the State of New Mexico inspector, per CMR 032. The cost increase was $234.67.

3. Added 9 ¼-inch pipe taps on the three storage tanks and 1 3-inch threaded outlet on the 12,000 gallon tank per CMR 027, which were called for in response to RFI 023. The cost increase was $3,354.72.

Change Order 009 dated February 23, 2001. This change order:

1. Enlarged the concrete slab area and thickness of the concrete slab area outside the Office Building and the Injection Building per CMR 28-A. The cost increase was $2,450.01.
2. Added 2 6-inch PVC butterfly valves (to match others in containment area) and blind flanges per CMR 033. The cost increase was $904.36.
3. Added 2 pipe supports between the Containment Area and the Injection Building per CMR 034. The cost increase was $235.44.
4. Added 4 elbows and 2 pipe supports for the installation of the strainer. The cost increase was $855.90.
5. Modified the aquifer testing recovery time from 2 hours to 48 hours (addition of 46 hours per well) at an hourly rate of $23.91 plus gross receipts tax per CMR 039. Extended the contract 3 days for every well that an aquifer recovery test was performed for a total of 21 days (to 300 Calendar Days), resulting in a new project deadline of May 15, 2001. The cost increase was $8,158.94.

Change Order 010 dated February 23, 2001. This change order:

1. Added an annulus seal pot to the contract per CMR 038 (because the specifications did not include a design for an annulus seal pot). The cost increase was $11,975.60.
2. Added an additional drain and hand-operated vent in the containment area per CMR 041. The cost increase was $321.14.
3. Added flanged fittings to the wellhead per CMR 042. The specifications had required threaded fittings, but the specified flow meter and conductivity probe were only available in flanged ends. The cost increase was $1,165.58.00.
4. Compensated the Contractor per CMR 043 for 52 ft of conductor casing at $144 per ft due to decision to abandon and relocate production well PW1-6 per CMR 043. CRMWA Corp. did not pay any other incidentals associated with the re-drilling of PW1-6. This change order extended the Contract Time 15 days (to 315 Calendar Days), resulting in a new project deadline of May 30, 2001. The cost increase was $7,488.00.
5. Credited CRMWA Corp. for Contractor overcharge of pipe taps via CMR 027 (Change Order 008) per CMR 027R of ($1,501.87).
6. Added 1-inch insulation on all exterior piping and injection pump per CMR 049. The cost increase was $115,521.06.
7. Added heat trace tape on the process piping in the containment basin per CMR 047. The cost increase was $4,273.03.
8. Added heat trace tape on the process piping outside the containment basin per CMR 045. The cost increase was $1,995.37.
9. Added valve and pipe unistrut supports in exchange for the wooden sleepers called out in response to RFI 24 per CMR 050. The cost increase was $2,361.57.

10. Relocated the transformer to the east side of the office building per CMR 048 to comply with recommendation of the mechanical design firm, RMH Group. (Due to the weight of the transformer, the recommendation was to relocate the transformer from a wall mount in the Shop to outside the Shop/Office building).The cost increase was $305.81.
11. Added Sika caulking on the roof of the shell joint on the two 96,000-gallon tanks and one 12,000-gallon tank per CMR 046. The caulking was applied after the interior final coat on the shell and roof. The cost increase was $625.23.
12. Added metal buildings and slabs for to house the electric control panels for the production wells per CMR 052. The cost increase was $16,345.82.
13. Replaced the CPVC butterfly and check valves with PVC valves per CMR 030. The cost increase was $6,440.00.
14. Added galvanic anode cathodic protection system to the inside of the brine storage tanks per CMR 051. The cost increase was $2,437.08.
15. Added an I/O extension board to show motor speed for the injection pump motor and all production well pump motors per CMR 054, as recommended by the mechanical designer, RMH Group. The addition of the I/O extension board required reprogramming the injection well V.F.D. (variable frequency driver) and reprogramming the analog outputs on the production wells. The cost increase was $596.43.

Change Order 011 dated February 23, 2001. This change order:

1. Added the necessary components and wiring to soft start motors and all the VFD's to give the PLC (program logic controller) a permissive run signal in the Auto Mode, which also provides a fault input upon equipment failure. These items were not specified in the specifications manual. The cost increase was $280.42.
2. Added the required ground wire for the well pump for production well PW1-3 per CMR 056. The cost increase was $953.64.
3. Revised the contract price to reflect the actual time and materials involved to install the missing conduit and wiring per CMR 025 and Change Order 7 (Item 2). The cost decrease was ($517.27).

Change Order 012 dated February 23, 2001. This change order:

1. Added additional conduit, wire, and pull-boxes from the pad mount transformer to the production wells per CMR 029 and RMH Group response to RFI 21. The cost increase was $10,550.61.
2. CRMWA Corp. agreed to pay $1,800.00 of the $3,321.81 requested per CMR 037R for the seal pot trim materials. The cost increase was $1,800.00.
3. Added additional crusher fines around the concrete driveways per CMR 057. The cost increase was $681.85.

4. Added various appurtenances such as pressure gauges, ball valves, etc, for the Filter Units in the Injection Building per CMR 058. The cost increase was $461.17.
5. Replaced the 4-inch Endress Hauser flow meter with a Rosemount Magmeter to be installed on the fiberglass injection tubing per CMR 59 (modified). The cost increase was $3,729.68.
6. CRMWA Corp. agreed to pay for the 1-inch rigid PVC-coated conduit that could not be returned for credit per CMR 060. The cost increase was $6,883.18.
7. Added the vibration and pressure switch on the injection pump to the SCADA system per CMR 061 (modified). This change order extended the Contract Time 3 days and, combined with a letter from CRMWA Corp. to the Contractor extending the Contract Time to the end of July (to 380 Calendar Days), extended the project deadline to August 3, 2001. The cost increase was $1,465.28.
8. Added programming and equipment to integrate the actuated control valve to the system per CMR 062 on a Time and Materials basis. This change was required by the addition of the new modulated valve to be installed in place of the 4-inch motor operated valve already installed in the fiberglass discharge piping of the injection pump. This change order extended the Contract Time 7 days (to 387 Calendar Days), resulting in a new project deadline of August 10, 2001. The cost increase was $7,566.13.
9. Added the pressure transducer, programming, and materials for CMR 063 (modified). This change order extended the Contract Time 3 days (to 390 Calendar Days), resulting in a new project deadline of August 13, 2001. The cost increase was $2,907.40.

<u>Change Order 013</u> dated February 23, 2001. This change order:

1. Modified CRM 062 to reflect the actual time and materials for the additional programming and wiring for the Startup and Shutdown Sequence. This was required by the addition of the new modulated valve that Enterprise Construction installed in place of the 4-inch motor-operated valve already installed in the fiberglass discharge piping of the injection pump, per CMR 062R. This change order extended the Contract Time 21 days (to 411 days), resulting in a new project deadline of September 3, 2001.
2. Modified the contract to reflect the actual amount of control wiring to PW1-1 and PW1-2 per CMR 064 (modified). The const increase was $3,054.25.
3. Added the additional plumbing required for the annulus system per CMR 065. This included replacing the 2-inch valves on the injection wellhead, removing the drain at the bottom of the annulus tank, and reinstalling a tee, venting the annulus exhaust to the outside, installing an additional 4-inch high pressure gauge in the system, installing a manual valve bypass system, and adding the additional hoses for the nitrogen system. The cost increase was $3,051.78.

4. CRMWA Corp agreed to pay for 3 wellhead vents at $1500 per well, and for four that were already vented at $750 per well, per CMR 066 (modified). The cost increase was $8,741.72.
5. Removed the existing wire and conduit from the production well wellheads and replaced the connections with PVC LB's, then reinstalled the wire and conduit, on a Time and Material basis per CMR 067. This change order extended the Contract Time by 9 days (to 420 days), resulting in a new project deadline of September 12, 2001. The cost increase was $10,058.61.
6. Removed the existing pump in production well PW1-2, replacing it with a 4-inch, 7-1/2 HP pump per CMR 069. This change order extended the Contract Time by 5 days (to 425 days), resulting in a new project deadline of September 17, 2001. The cost increase was $8,699.37.
7. Relocated and reprogrammed the pressure transmitters to all the filter system for proper operation and provide automatic switchover per CMR 070. This change order extended the Contract Time by 2 days (to 427 days), resulting in a new project deadline of September 19, 2001. The cost increase was $8,699.37.

Change Order 014 dated February 23, 2001. This change order moved the filter pump, installed a 3-inch mechanically operated control valve and an air compressor, moved the eye wash station, modified the fiberglass piping, etc, per CMR 068R. The cost increase was $24,355.36.

<u>Change Order 015</u> dated February 23, 2001. This change order:

1. Modified the time and materials cost of CMR 067 in Change Order 013 to reflect the actual cost of $9,519.28 per CMR 067R. The cost decrease was ($539.33).
2. Added the web server software to the computer system per CMR 071. The cost increase was $2,243.71.

Claims

No claims were filed against CRMWA Corp. by the Phase 2 contractor or subcontractors.

CONSTRUCTION OPERATIONS

There were no corrections made to the Phase 2 specifications to accommodate the injection well having been moved 62.25 ft south and 7.38 ft east of the location shown in the specifications. Therefore, at startup of construction a field correction was made by moving all injection facilities 62.25 ft due south (no change in east direction) to accommodate the moved injection well. The discharge line from the injection well pump to the injection well was shortened by 7.38 ft. The access road, which was constructed by CRMWA Corp. before the injection well was relocated, remained at the original design location, except the beginning of the road was extended 62.25 ft south to accommodate the moved injection facilities. (New beginning point is at Station -62+25.)

Production Wells

Phase 2 construction commenced with the drilling subcontractor, Couch Drilling Company, mobilizing to site on August 31, 2000, and began setting up to drill the only plateau well, PW1-2. Couch used a 1300 Midway rotary drill rig mounted on a Ford 4 x 6 truck. As required by the environmental permits, the truck was cleaned prior to setting up on the first hole. In the following description of production well drilling, the wells are listed in ascending numerical order.

PW1-1

Drilling

Using a local subcontractor, Versatile Construction, Couch had a route cleared through the salt cedar to PW1-1 on October 11, 2000. *(See Photograph 18.)*

After drilling the first well (the plateau production well PW1-2, and believing the difficulty in developing the well and low yield could be related to using bentonite mud, Couch requested to drill bedrock in the remaining holes using air instead of bentonite mud. The Project Supervisor granted their request. Holes would continue to be advanced through surficial deposits using bentonite mud as the drilling media; after setting and grouting the conductor casing, the switch would be made to air drilling. This change was implemented with the second hole to be drilled, PW1-1.

Cuttings-laden saline water produced during air drilling would be discharged onto the river alluvium to filter out the cuttings. Because air drilling would produce significant quantities of saline water that would ultimately be discharged to the river, arrangements were made to use diluting flows from Ute Reservoir when air drilling was occurring.

On October 25, the Couch driller started drilling PW1-1 using a 22-inch diameter "hole-opener" bit and extremely heavy bentonite mud. Broken rock was encountered at 16 ft. The drilling was smoother but hard from 19 ft to 23 ft. After consultation with the Project Supervisor, the driller was directed to drill to 29 ft and, if he did not drill out of competent sandstone back into alluvial material, to install and grout the 16-inch steel conductor casing at that depth. The hole was advanced to 31.4 ft (because the driller made an error measuring the depth), with the hole appearing to remain in competent sandstone. The driller could only install the 16-inch conductor casing to 27.6 ft below ground surface. After grouting the casing, the excess above ground surface was cut off.

Couch did not drill November 4 through November 8 due to inclement weather and waiting for a starter replacement on their drill rig. They resumed drilling on November 9. Total depth was reached on November 14.

Construction Geology

This production well is in the Canadian River valley floor near the canyon wall, located on a slight knoll. River alluvium had been estimated in the specifications to be about 40 ft deep at this location, which is about 20 ft out from the talus slope of the south canyon wall. It was therefore considered very possible that a large (up to house size) boulder was being penetrated at this shallow depth. If the 16-inch conductor casing were to be installed and cemented in such a boulder and the hole subsequently penetrated through to more alluvium, the hole would have to be abandoned and re-drilled or the design of the well extensively altered. However, the rest of the hole continued to penetrate sedimentary

Four-wing stainless steel centralizers were placed at the following locations:
111 ft (top of blank casing at bottom of well screen)
85 ft (middle of third well screen)
59 ft (at bottom of 8-inch production casing)
20 ft (bottom of 8-inch production casing joint inside the 16-inch steel conductor casing)
Totals: 2 small and 2 large centralizers used

As on PW1-2, the crew spent considerable time struggling with a sand-locked tremie line. They were pouring the filter pack sand into the 55-gallon barrel (hopper) faster than the sand could flow down the tremie line. Another complication of pouring so fast without frequent probe checks is that the line would also sand-lock when they filled the annular area above the bottom of the tremie line. To clear the line, they would pull the barrel (thus wasting the surplus sand in the barrel), raise, and drop the tremie line a couple of feet while they poured water (about a cup full at a time) into the top of the tremie line.

Volclay Gold Grout was mixed in a 55-gallon barrel and placed above the #60-mesh sand at the top of the filter pack. Four (4) bags were to be mixed and placed, but only about 3-2/3 bags could be pumped with the small centrifugal pump.

On November 16, Couch attempted to mix and place cement-bentonite grout. However, the mix tank they were trying to pump from was very large in diameter, and the grout was thick. Consequently, a vortex developed at the pump suction inlet and the drill rig mud pump sucked air. Couch decided to abandon the grouting for the day and mix grout in 55-gallon barrels in the future.

The drill crew had difficulty mixing cement-bentonite grout with 6.5 gallons water per sack of cement and 2% bentonite on November 17. After discussions with the site geologist and CRMWA Corp, it was decided that the cement-bentonite grout in future well completions would be mixed with 1% bentonite and 5.85 gallons of water per sack of cement.

On November 21, top of grout in PW1-1 at 36.8 ft below the top of the conductor casing. The well chamber was probed to total depth to verify that the grout had not migrated through the well screen or some discontinuity in the production casing. The well was open to total depth. Couch pumped 18 bags of cement grout on Tuesday, November 21. The next morning the grout surface was 30.25 ft below the top of the conductor casing. They placed another 10 bags on Wednesday, and about 1-1/2 hours later the grout surface was tagged at 29.4 ft below the top of casing, which is about a foot below the bottom of the casing. Another grout placement was subsequently made, after which the top of the cement-bentonite grout in the annular area between the 8-inch Sch. 80 PVC production casing and the 16-inch steel conductor casing was 26.7 ft below ground surface. Therefore, the top of the grout was higher than the bottom of conductor casing at 27.6 ft, and the crew was able to grout the rest of the annular area.

Development and Testing

Development information for PW1-1is not available. Results from a pump-out test (date of test unknown) are shown in Table 7.

TABLE 7 – Pumpout Test in PW1-1					
Date	**Time**	**Pressure**	**GPM**	**Meter Reading**	**Drawdown (ft)**
Unknown	3:39	98	108	3179	Unknown
Unknown	4:00	98	109	3204	Unknown
Unknown	4:30	99	108	3234	Unknown
Unknown	5:00	98	108	3268	Unknown
Unknown	5:30	98	109	3302	Unknown
Unknown	1:45	98	109	3842	Unknown
Unknown	8:15	99	109	4270	Unknown
Unknown	2:25	99	110	4661	Unknown
Unknown	8:19	98	109	5051	Unknown
Unknown	7:40	98	109	5788	Unknown

PW1-2

Drilling

Drilling started at PW1-2, the only plateau well to be constructed during Phase 2, the morning of September 1, 2000. However, at about 11 a.m., while drilling at 8 ft, the rotary table on the old Midway rig broke down. Couch shut down for several days while the rig was being repaired. The Couch driller was told to fix several small oil leaks on the drill rig truck to comply with environmental requirements. On September 11, Couch returned to the site, circulated the old drill mud out of the hole, and mixed new bentonite drill mud. They resumed drilling the next day, advancing the hole to 17 ft, and then reamed the hole to a 20-inch diameter. Twenty feet of 16-inch diameter steel conductor casing was set with 3 ft of stickup. Cement grout was placed from the bottom up using tremie lines between the casing O.D. and the hole wall.

After waiting for the grout to cure, on September 15 Couch prepared to begin drilling through the cemented casing, but the driller discovered the bit they had fabricated would not go through the steel casing. They shut down and left the site while waiting for a modified bit to be delivered. On September 18, Couch began drilling below bottom of casing (17 ft) using 14-3/4 inch tri-cone roller rock bit. Drilling was slow. On September 18, Couch brought a “hole-opener” bit, which consisted of a small tri-cone roller rock bit on bottom. There were three wings about a foot up from the bottom bit. Each wing had one roller bit designed to open or ream the hole. Couch believed this bit design would help maintain a straight hole. Progress was slow. Couch quit drilling on September 22 at a depth of 123 ft and did not return to resume drilling until October 3.

On October 5, Couch advanced the hole to a depth of 192 ft, where the site geologist (staff geologist with Lee Wilson & Associates) determined the hole had penetrated the top of Tecovas Formation shale.

The entire well was drilled using bentonite mud as the drilling fluid. All fluid was removed from the site after drilling was completed.

Construction Geology

In PW1-2, using rock bit cuttings, the site geologist picked the contact between the bottom of the surficial deposits and the top of the Trujillo Formation at about 10 ft. All measurements are from ground surface.) Tecovas Formation shale was encountered at 183 ft.

Completion

Immediately prior to completion, drill fluid was displaced from the hole using clean water injected through the drill string. The relatively shallow total depth, combined with considerable depth of the top of water surface, required modification of the original specified well completion. Therefore, the specified 10-ft blank pipe (sump) below the well screen was reduced to 5 ft, and the screen length of 50 ft was reduced to 40 ft. These changes were necessary to place the 6-inch diameter pump intake, which must be above the 6-inch diameter well screen, as low as `possible below the static water level, increasing available drawdown. Two samples of drill cuttings were sent to a materials laboratory for gradation analyses. Based on these sieve analyses, it was determined that 12-20 sand should be used for filter pack from the bottom of the influence zone to 10 ft above the bottom of the well screen, and 8-12 sand should be used above that point. In addition, Couch was directed to place 100 or 200 mesh sand on top of the bentonite seal to prevent grout intrusion. Couch stated they could not obtain the 8-12 sand until October 12. Couch also indicated 100-mesh sand was very difficult to obtain, so they obtained permission to use 60-mesh sand in lieu of specified 100-mesh for the fine sand on top of the filter pack.

On October 12, Couch began completion of PW1-1. Completion was very slow because:

- Couch had difficulty installing the Certa-Loc adapter between the 6-inch well screen and the 8-inch production casing. It was eventually discovered that snipping off the sharp end of the locking rod (which would not slide into the groove locking the adapter to the casing) cured the problem.
- In a hurry to get the filter pack and bentonite installed, the crew filled the tremie line with 8-12 filter pack. Considerable time was lost clearing the sand lock in the tremie line.
- The same problem occurred while installing the 60-mesh sand.
- The crew had problems mixing the high-solids bentonite slurry as they were trying to mix in a 55-gallon barrel using a mud gun. They had the barrel so full of water that there was no freeboard. The superintendent instructed them to dump part of the water; therefore, they mixed the bentonite too thick and the small centrifugal pump was not capable of pumping the grout.

Due to the above delays, the load of grout, which had been mixed at about 3:30 p.m., began to set in the transit mixer even though the driver had added water 2 or 3 times. The drilling superintendent finally directed the driver to dump the load. The crew later got the bentonite seal placed using the mud pump on the drill rig.

The following day, October 12, Couch placed the cement-bentonite grout in PW1-2. About 3¼ yd^3 were placed, and as the last of the grout was pumped, grout return was observed beginning to flow into the mud pit.

The following quantities and depths were noted during completion of PW1-1:

<u>PW1-2 Completion String</u>:

End cap and 6-inch sump =	5.1 ft
Well screen =	40.0 ft
Adapter =	0.65 ft
Production casing, 8-inch =	160.0 ft
Total string length =	205.75 ft

<u>PW1-2 Setting Depths</u>:

TD =	192 ft
Bottom of blank sump =	190 ft
Bottom of well screen (20 slot) =	185 ft
Top of well screen =	145 ft
Top of 12-20 filter pack =	168 ft (probed depth)
Top of 8-12 filter pack =	130 ft (probed depth)
Top of 12-20 sand (over 8-12) =	129 ft (estimated – 1 sack)
Top of 60-mesh fine sand =	127 ft (estimated – 2 sacks)
Top of bentonite grout =	122 ft (probed depth – mixed 4 bags, placed about 2)

Cement-bentonite grout to surface (shrinkage depth to top of grout at 7.5 ft 10/16/00)

When the completion string was inserted in hole, it would only go to 190 ft. This could have been due to either settlement of cuttings from drill mud in the hole as mud was displaced by water or material from the sidewall of the hole raveling to the bottom as completion string was placed.

<u>PW1-2 Quantities Used</u>:

12-20 sand from TD to 168 ft =	15 bags (100 lbs each)
8-12 sand from 168 ft to 130 ft =	22 bags (100 lbs each)
12-20 sand on top the 8-12 =	1 bag
#60-mesh sand on top the 12-20=	2 bags
Volclay Gold Grout =	4 bags (only about 2 bags were placed in hole)
Cement-bentonite grout =	3¼ yd^3 (contained 2% bentonite by weight of cement)

Volumes used filled a greater length of annular area than originally calculated. This could be attributed to either or a combination of the following:

- The hole diameter being a little less than 14-3/4 inches due to an undersized bit; however, the bit appeared to have maintained gauge.
- A fairly thick bentonite wall cake on the sidewall of the hole (that would not have been removed by the gentle action of mud displacement)

The bottom of the well screen was set at 185 ft, 2 ft into the shale. (There is 12-20 filter pack from TD up.)

Four-wing stainless steel centralizers were placed at the following locations:

185 ft (top of blank casing at bottom of well screen)
155 ft (well screen joint)
144 ft (at adapter between well screen and production casing)
124 ft (conductor casing joint)
104 ft (conductor casing joint)
64 ft (conductor casing joint)
44 ft (conductor casing joint)
14 ft (inside 16-inch steel conductor casing)

Development and Testing

Couch set up and began preliminary air development by airlifting on October 16. The first 1,900 gallons were hauled to the injection well pits. Subsequent water produced was ran through the portable mud pit baffles, then piped to a dry flood channel in the river flood plain. An additional 1.5 cfs was being released from Ute Dam to dilute the saline water. Three conductivity measurements of the produced water were made. Two, using two different instruments, were made at 4:20 p.m. with results of 63.12 milliSiemens (mS) and 61.68 mS. Measurement on another sample, made at 5:20 p.m., was 63.96 mS. The specifications require a minimum conductivity of 30 mS. The water was very turbid with clay (bentonite), but contained only a little very fine sand. On October 17, Couch finished development of PW1-2. Early in the day, when the air was shut off and the well allowed to recover, and then airlifting commenced again, water was considerably more turbid (translucent but not transparent) with only a slight amount of very fine sand. Later in morning, when airlifting was maintained at a constant rate, the water would be only a little turbid with almost no sand. Conductivity measurements made were:

- Conductivity at 10:30 a.m. = 69.2 mS (47,748 TDS*)
- Conductivity at 11:25 a.m. = 72.4 mS (49,956 TDS*)

On October 19, Couch brought in a small hydraulic pump service rig and set it up on PW1-2, installed a Reclamation 7-1/2 HP Berkley 6-inch submersible pump, hooked up and pumped the well for about 2 hours in preparation for a preliminary production test. The crew attempted to conduct a pumpout test on the following day, but the 6-inch pump could not be choked back enough to avoid drawing the water level below the pump intake.

The formation might not have been capable of greater yield, but the drill cuttings appeared to support higher yield. One theory was that the simple displacement of the bentonite drill mud left substantial wall cake on the hole. Another possibility was that the drilling fluid had not been properly maintained, and native mud had penetrated the formation, decreasing permeability. The filter pack was thick and relatively fine-graded. The slot width of the screen was narrow. The continuous wire-wrap PVC screen could not be subjected to jetting or agitation sufficiently violent to remove this wall cake through the filter pack and screen slots. Several options to increase the yield of this well were explored. Because of environmental constraints, permission could not be obtained to use a development aid (dispersant) to help remove any bentonite. Therefore, no further development was done and a shrouded 4-inch pump was recommended for permanent installation in this well.

A second pump-out test was performed on April 3 and 4, 2001, using a 4-inch pump. Results from this test are shown in Table 8.

TABLE 8 – Pumpout Test in PW1-2

Date	Time	Pressure	GPM	Meter Reading	Drawdown (ft)
4/3/01	20:00	32	28	006166	128.79
4/4/01	7:35	30	27	006351	132.25
4/4/01	12:00	30	27	006421	132.79
4/4/01	17:15	30	26	006503	132.42
4/8/01	13:30	31	25	007493	--------

PW1-3

Using a local subcontractor, Versatile Construction, Couch had an access trail constructed down the steep slope to PW1-3. Drilling commenced in February 2001. This well was completed on March 10, 2001.

Drilling

Drilling through the surficial deposits into the top of bedrock was done using bentonite mud as the drilling media. The hole was drilled to 56.5 ft using a 24-inch bit. The 16-inch conductor casing was set to 55.7 ft on February 26. As in PW1-1, drilling below the conductor casing was accomplished using air as the drilling media. A 6-inch pilot hole was drilled to 101 ft, and the hole was reamed to 14-3/4 inches before completion.

Construction Geology

Top of Trujillo Formation bedrock was encountered at 46 ft. Top of the Tecovas Formation was reported at 95 ft.

Completion

Completion of PW1-3 was done on March 9.

<u>PW1-3 Completion String</u>:

End cap and 6-inch sump =	5.0 ft
Well screen (20-slot) =	40.0 ft
Adapter =	0.5 ft
Production casing, 8-inch =	56.1 ft
Total string length =	101.6 ft
Stickup =	1.1 ft

PW1-3 Setting Depths:

TD =	100.6 ft
Bottom of 4-ft blank sump =	99.5 ft
Bottom of well screen (20 slot) =	95.5 ft
Top of well screen =	55.5 ft
Top of 12-20 filter pack =	45.0 ft (probed depth)
Top of bentonite pellets =	43.0 ft
Top of 60-mesh fine sand =	42.0 ft (probed depth)

PW1-3 Quantities Used:

12-20 sand 100.6 ft to 45.0 ft = 54 bags (all sand in 100-lb bags)
Bentonite pellets 45.0 to 43.0 ft = 3 buckets
#60-mesh sand 43.0 to 42.0 ft = 1 bag
Cement-bentonite grout = 25 bags (92.6-lb/bag Class C cement, mixed with 161 gallons of water, into which 23 lbs of bentonite had been pre-mixed)

Four-wing stainless steel centralizers were placed at the following locations:

99.5 ft (top of blank casing at bottom of well screen)
77.5 ft (midpoint of screen)
55 ft (just above 6-inch to 8-inch adapter)
35 ft
15 ft
Totals: 2 small and 3 large centralizers used

Development and Testing

Development records are not available. On May 20, 2001, a pump-out test was performed in PW1-3. Information from this test is shown in Table 9.

TABLE 9 – Pumpout Test in PW1-3

Date	Time	Pressure	GPM	Meter Reading	Drawdown (ft)
5/20/01	13:00	0			
5/20/01	14:00	0	62	014121	Unknown
5/20/01	19:30	0	63	014329	Unknown
5/20/01	21:00	0	63	014767	Unknown
5/21/01	7:13	0	63	015229	Unknown
5/21/01	12:55	0	63	015443	Unknown
5/21/00	13:00	0	0	015445	Unknown

PW1-4

Drilling

The Couch drill crew began drilling a 6-1/2 inch pilot hole at PW1-4 on January 2, 2001, advancing a pilot hole to 77 ft using a 6-1/2 inch bit. On January 3, they began reaming out the hole using a 22-inch hole-opener bit. However, while drilling at 55 ft on January 4, the bit broke off at the sub just above the bit. Couch could not fish the bit out of the open hole in the alluvium and had to plug and abandon this hole.

PW1-4 was relocated about 30 ft upstream (west) and 10 ft towards the river (north) of the original location. On January 24, the crew set the rig up and drilled to 40 ft using their 6-1/2 inch bit. The crew drilled the pilot holes to 61.5 ft on PW1-4 (relocated) on January 25. After drilling into the top of bedrock, they reamed the hole with a conventional 24-inch bit. (The drilling superintendent stated he would quit using the 22-inch "hole-opener" because he believes it is too susceptible to twisting off.) On February 2, the crew reamed the hole to 58.5 ft and began preparing to set and grout conductor casing.

After the loss of a well due to caving, CRMWA Corp. required changes in cement grouting procedures to help assure future installations of 16-inch conductor casings isolate the formation from the alluvium:

1. A Halliburton-type "wiper" plug was specified to push the cement to the bottom of the casing.
2. The casing was required to be hung in the well so that the cement would go out evenly around the bottom of the casing instead of through holes or slots cut in the side of the casing.
3. The quantity of cement placed below the plug should have sufficient excess to provide cement return to surface.

The Couch crew started installing conductor casing for PW1-4 (relocated) on February 3. They tagged the bottom of the hole at 58.3 ft before starting. The total length of casing at the site was 60.4 ft. Couch had problems welding bevel ends of pipe due to irregular cuts and lost significant time with mud pump problems. They mixed the first batch of 48 bags of cement plus 281 gallons water and injected that into the top of the casing string at 3:30 p.m. The crew spent until 7:30 p.m. trying to mix the second batch because many of the remaining bags of cement at the site were bad (old or exposed to moisture). The estimated unusable grout did not exceed the 20% excess provided in the batches. If the placement were halted until more cement could be obtained, the grout in the hole would set up and the hole would be lost. Therefore, the placement was allowed to continue. After pumping the second batch, the side port valve on the casing head was closed, the top port (above the casing plug) was opened, and the Halliburton-type casing plug was pumped with water to the bottom of the casing. Then the top port valve was closed, sealing in the casing plug. No cement return was noted during the grouting, a indication that the grout did not channel up through the heavy bentonite mud. However, the driller jacked the casing string up about 0.2 ft when the plug went to bottom. Apparently, the hydraulic pressure broke the axe handle "stop" and the plug protruded from the end of the casing to the bottom of the hole. The final depth of the bottom of the conductor casing was 57.5 ft.

The top of grout was probed in the annular area and inside the conductor casing as soon as the casing head was cut off the following morning. Mushy grout was probed at 13.5 ft in the annular area. Grout was probed at 38 ft inside the conductor casing. The top of the wooden cement plug should have been at 55.5 ft, and all the grout should have been below this plug.

The crew began drilling the grout out on January 6; it was soft until 53 ft. They had about 1 ft of harder grout, they encountered the wooden cement plug at 54 ft. The grout below the plug was hard. The 16 ft of soft grout on top the plug either leaked past the wooden cement plug or leaked through a poorly welded casing joint above the plug. When the wooden grout plug came part way out of the casing, it may have cocked to one side or the bottom wiper may have been damaged going back in. The column of heavy grout in the annular area may have forced grout past the damaged wiper. The annular area from 13.5 ft to 46 ft has a volume of about 40 ft^3. The inside of the conductor casing from 56 ft (about where the top of grout plug was originally) to 38 ft has a volume of 31 ft.

Enviro Log, Inc, of Edmond, OK, arrived the morning of February 6. After the crew drilled to 61.5 ft (4 ft below the bottom of the conductor casing), the Enviro Log operator did a cement bonding log, the first without a centralizer, the second with. He did not have or use the 2-receiver tool specified in Field Order 13, stating it was not possible to use such a tool in a well this shallow. He also claimed the log ran with the centralizer was not valid, because the centralizer was making the tool "drag" on the casing, especially near the bottom of the casing, and throwing the log off. (His logging truck vibrated as the tool was raised.) Apparently, it was dragging.

The bottom of the conductor casing (after "jacking") was at 57.5 ft. Because the open hole was not drilled quite far enough below the casing, the logging tool would only record to 57 ft, about 1/2 ft above the bottom of the casing. The log showed loss of bond above 46 ft. (The top of the Trujillo Formation was at 51 ft, so the log indicated cement bond extending 5 ft into the overlying alluvium.

The Couch crew advanced the 14-3/4 inch hole below the conductor casing from 102 ft to a total depth of 114.6 ft on February 13.

On February 14, Southwest Geophysical did a cement bonding log. After logging with a dual receiver tool and centralizers, the operator stated there was a good bond from bottom of casing at 57.5 ft to 54 ft, no bond from 54 to 49 ft, fair to good bond from 49 to 35 ft, and no bond above 35 ft. This operator commented that, in our wells, there was no advantage to using a dual receiver tool but centralizers were necessary to get a good log.

Construction Geology

The top of the Trujillo Formation was encountered at 51 ft. Tecovas Formation was reached at 107.5 ft, where drill returns and drilling characteristics indicated formation consisted of hard (firm) gray shale and fine-grained sandstone layers. Iron pyrite was also recovered. The maroon shale encountered in PW1-1was not penetrated.

Completion

PW1-4 (relocated) was completed on February 15. The following depths and measurements were obtained:

<u>PW1-4 Completion String</u>:

End cap and 6-inch sump =	6.2 ft
Well screen =	40.0 ft
Adapter =	0.50 ft
Production casing, 8-inch =	65.5 ft (below ground surface with 14.5 ft above gs)
Total string length =	112.2 ft (below gs)

<u>PW1-4 Setting Depths and Quantities Used</u>:

TD =	114.6 ft
Bottom of blank sump =	112.2 ft
Bottom of well screen (20 slot) =	106.0 ft
Top of well screen =	66.0 ft
Top of 12-20 filter pack =	62.2 ft (probed depth after 57 100-lb bags)
Top of bentonite pellets =	60.5 ft (probed depth after 3 5-gallon buckets)
Top of #60-mesh sand =	59.5 (assumed depth)

Cement-bentonite grout placed above #60-mesh sand

<u>Additional Probed Depths of 12-20 Sand While Filling Annular Area</u>:

Depth	Total Bags
86.0 ft	30
78.7 ft	40
72.0 ft	48
65.2 ft	54
63.1 ft	56
62.4 ft	56.7
62.2 ft	57

The lowest part of the hole took excessive sand. It is assumed this occurred in the shaly intervals below 106 ft due to caving or hole erosion while drilling. The volume of sand per foot of hole appeared to be consistent above this depth.

<u>Centralizers were installed as follows</u>:
Top of the blank sump at 105 ft
Middle of the screen at 85 ft
Just above the adapter between the screen and the 8-inch production casing at 65 ft
On the production casing at 42 ft
On the production casing at 24 ft

Tremie operation, especially the bentonite pellets, took much time, probably because there was set-up grout inside the tremie line. At 7:30 p.m., the crew left the site for the night to provide hydration time for the bentonite pellets.

The following day, one foot of #60 mesh fine sand were placed on top of the bentonite pellets (to 59.5 ft) and cement-bentonite grout was placed from 59.5 to the ground surface.

Development and Testing

Development records are not available. On March 13, 2001, a pump-out test was performed in PW1-4. However, the 6-inch pump could not be choked back enough to maintain flow without excessive drawdown. On April 12, a second pump-out test was performed using a 4-inch pump. Information from this test is shown in Table 10.

TABLE 10 – Pumpout Test in PW1-4

Date	Time	Pressure	GPM	Meter Reading	Drawdown (ft)
4/12/01	14:30	75	28	07569	Unknown
4/12/01	18:30	75	28	07636	Unknown
4/13/01	2:30	75	29	07768	Unknown
4/13/01	8:21	75	29	07866	Unknown
4/13/01	14:00	75	28	07960	Unknown
4/13/01	18:00	75	29	08027	Unknown
4/13/01	23:15	75	28	08114	Unknown
4/14/01	7:31	75	29	08253	Unknown
4/14/01	10:55	75	29	08312	Unknown
4/14/01	11:??	0	0	08312	Unknown

PW1-5

Drilling

Couch had fallen significantly behind in drilling progress. Therefore, they subcontracted with HydroGeologic of Albuquerque, New Mexico, to perform some of the remaining production well drilling. On January 18, 2001, HydroGeologic mobilized a Speedstar 30K top-head drive rotary rig mounted on a Ford F9000 4x6 truck, had the rig steam-cleaned, and prepared to move to the valley floor. Assisted by a bulldozer from Versatile Construction, the crew moved their drill rig to the staked location of PW1-5 and set up to drill.

On January 23, the HydroGeologic crew drilled from 0 to 30 ft. The drill bowl fell in the drill hole at that depth. They fished for it, but did not have it retrieved by quitting time. The crew left the job the next day to obtain a better fishing tool and returned the following afternoon.

The HydroGeologic crew drilled a pilot hole to 61 ft on January 25, encountering bedrock at about 51 ft. On January 31, the crew had a problem with the hole caving out from under the mud pit. They went after a temporary 24-inch casing to hold the upper hole open.

A new HydroGeologic crew arrived at PW1-5 on February 13. After starting to circulate and clean out the hole, they determined the washout below the 6-ft long 22-inch diameter temporary casing could not be controlled. The hole was only open to 40 ft, and they could not clean the hole to the bottom depth of 58 ft because of the danger of the hole collapsing under their rig. They decided to plug and abandon this hole and redrill at another location. A 5-ft cement grout plug was placed at the bottom of the open hole, the hole filled with gravel from the top of the grout to 8 ft below ground surface, then cement grout from 8 ft to 3 ft, and finally alluvial materials from 3 ft to the ground surface.

A new location was selected for the hole 35 ft to the west (upstream). However, the bulldozer could barely move the HydroGeologic Speedstar 30K drill rig through the alluvial sand. They finally managed to drag the rig to a point 50 ft upstream (west) of the original location. After discussions with the site geologist and CRMWA Corp. staff, this location was approved.

On February 21, 2001, the hole was reamed to 48 ft with a 22.5-inch bit. On March 14, the 16-inch conductor casing was set and grouted when the hole had been reamed to about 58 ft. A 14-3/4 inch hole was drilled to a total depth of 129.5 ft on March 21.

Construction Geology

Surficial deposits of alluvial sand, gravel, silt, and clay were penetrated in the upper portion of the hole. The top of the Trujillo Formation was encountered at 48 ft. The top of the Tecovas Formation was encountered at 122 ft.

Completion

Completion of PW1-5 relocated was done on March 22 and 23.

PW1-5 Completion String:

End cap and 6-inch sump =	5.0 ft
Well screen (20-slot) =	60.0 ft
Adapter =	0.5 ft
Production casing, 8-inch =	60.0 ft
Total string length =	125.5 ft
Stickup =	2.8 ft

PW1-5 Setting Depths:

TD =	129.5 ft (open to 123.2 ft at time of completion)
Bottom of 4-ft blank sump =	122.7 ft
Bottom of well screen (20 slot) =	117.7 ft
Top of well screen =	57.7 ft
Top of 12-20 filter pack =	48.0 ft
Top of bentonite pellets =	47.0 ft (approximate depth)
Top of 60-mesh fine sand =	46.3 ft

PW1-5 Quantities Used:
12-20 sand 123.2 ft to 48.0 ft = 70 bags (all sand in 100-lb bags)
Bentonite pellets 48.0 to 47.7 ft = 3 buckets
#60-mesh sand 47.7 to 46.7 ft = 1 bag
Cement-bentonite grout = 78 bags cement with (1 %?) bentonite added, mixed with 456 gallons of water

Four-wing stainless steel centralizers were placed at the following locations:

Six-inch:
121.7 ft
97.7 ft
77.7 ft

Eight-inch:
57.2 ft (at top of adapter)
27.2 ft
7.2 ft

Totals: 3 small and 3 large centralizers used

Development and Testing

Development records are not available. On March 31, 2001, a preliminary pump-out test was performed in PW1-5 using a 4-inch pump. On April 22 and 23, a longer pump-out test was run. Information from this test is shown in Table 11.

TABLE 11 – Pumpout Test in PW1-5

Date	Time	Pressure	GPM	Meter Reading	Drawdown (ft)
4/20/01	18:00	59-61	32	08437	Unknown
4/21/01	01:30	65-67	32	08579	Unknown
4/21/01	07:30	66-68	31	08692	Unknown
4/21/01	15:45	66-69	31	08847	Unknown
4/21/01	20:00	65-68	31	08927	Unknown
4/22/01	07:15	66-67	32	09141	Unknown
4/22/01	11:55	65-67	31	09229	Unknown
4/22/01	12:00			09231	Shutdown

PW1-6

The staked location of PW1-6 was at the edge of a gravel bar about 30 feet from the river. This well was relocated 15 ft south-southeast (directly away from the river) to place the well on a higher sandbar which lowered the possibility of drill fluid migration during drilling of the upper hole and made disposal of saline water produced during air drilling easier.

Drilling

The original location of PW1-6 was on a low gravel bar. This well was relocated about 15 ft further away from the river on an adjacent sand bar about a foot higher to provide better control of saline water disposal. PW1-6 was drilled to about 52 ft with a 22-inch bit. The driller indicated bedrock was encountered at 38 ft. Sixteen (16)-inch casing was installed to just above this depth. The grout was placed in the annular area using a grout plug (wooden plug with rubber wipers) to force the grout inside the casing down and out the annular area. It was calculated that 477 gallons grout would be required. Apparently, the crew had difficulty mixing the grout, so all the grout that could be mixed (390 gallons) was pumped. Good-looking returns of grout were observed at the surface. When the hole was re-entered, the plug was encountered at about 30 ft, followed by firm grout. The bottom 5 to 8 ft of cement drilled very fast, and below this were thick returns of grout and sand. The hole was abandoned.

PW1-6 was then relocated 37 ft upstream (west) of the revised drilling location, where the well was successfully drilled and completed. This well was drilled to a total depth of 115.5 ft. The bottom of the conductor was set and cemented at 59.8 ft.

Construction Geology

The top of the Trujillo Formation was encountered at 54.5 ft. The Tecovas Formation was encountered at 111 ft.

Completion

<u>PW1-6 Completion String</u>:

End cap and 6-inch sump =	5.0 ft
Well screen (20-slot) =	40.0 ft
Adapter =	0.5 ft
Production casing, 8-inch =	80 ft
Total string length =	125.5ft
Stickup =	10 ft (cut off later)

<u>PW1-6 Setting Depths</u>:

TD =	115.5 ft
Bottom of 4-ft blank sump =	115.5 ft
Bottom of well screen (20 slot) =	110.5 ft
Top of well screen =	70.5 ft
Top of 12-20 filter pack =	89 ft
Top of 8-12 filter pack =	60 ft
Top of bentonite pellets =	58 ft
Top of 60-mesh fine sand =	57 ft

<u>PW1-6 Quantities Used</u>:

12-20 sand 115.5 to 89 ft =	26 bags (all sand in 100-lb bags)
8-12 sand 89 to 60 ft =	32 bags
Bentonite pellets 45.0 to 43.0 ft =	3 buckets
#60-mesh sand 43.0 to 42.0 ft =	1 bags

Cement-bentonite grout = 34 bags cement, mixed with 224 gallons of water, into which 32 lbs of bentonite had been pre-mixed)

Four-wing stainless steel centralizers were placed at the following locations:
111 ft (top of blank casing at bottom of well screen)
90 ft
70 ft
50 ft
30 ft
10 ft
Totals: 2 small and 4 large centralizers used

Development and Testing

Development records are not available. A pump-out test was performed in PW1-6, but the date of the test is not available. Information from this test is shown in Table 12.

TABLE 12 – Pumpout Test in PW1-6

Date	Time	Pressure	GPM	Meter Reading	Drawdown (ft)
Day 1	15:53	2	68	011044	Unknown
Day 1	21:05	1-2	67	011244	Unknown
Day 2	06:30	2	67	011599	Unknown
Day 2	14:00	2	64	011889	Unknown
Day 2	21:30	2	65	012179	Unknown
Day 3	07:35	2	64	012576	Unknown

PW2-1

Drilling

Couch began moving their drill rig to PW2-1 on November 18. To eliminate the possible request to drill several feet into rock (to determine if it is truly bedrock), Couch decided to drill a pilot hole into bedrock using a 6-1/2 inch tri-cone roller rock bit, then reaming the hole with a larger bit. They encountered sandstone at 33.5 ft and advanced to 42.2 ft. The driller then reamed the hole to 42.2 ft using their 22-inch hole-opener bit. The drill crew installed 40.1 ft of casing with 1.9 ft of stickup above ground surface. They then grouted the annular area using tremie lines between the casing and the wall of the hole. However, the grout started coming up inside the casing. The crew shoveled sand into the inside of the casing in an unsuccessful attempt to keep the grout on the outside.

On Monday morning, December 4, top of grout was at about 14 ft below ground surface in the annular area. The crew then attempted to tremie additional grout in the annular area, but much of this grout came up along the tremie pipe instead of displacing the heavy bentonite mud that remained in the annular area.

After the grout had cured, the crew started drilling below the bottom of the 16-inch casing (38.2 ft) air drilling with a 6-1/2 inch bit and 5-7/8 inch drill collars. Couch used a non-traditional method of air drilling. The conductor casing diameter was very large (16-inches) and their drill pipe was only 2-3/8 inches. This results in a very large annular area between the drill pipe and the casing wall. The air compressor on their Midway 1300 drill rig could not produce a volume of air flow high enough to maintain uphole velocity required to carry cuttings out of the hole in the air flow. Therefore, Couch used air to airlift groundwater (and cuttings) in bursts (or "slugs" between large air bubbles").

The afternoon of December 7, the ground started caving under the drill rig. As soon as the caving was observed, the crew pulled the rig off the hole. Apparently, the hole pressured up and bridged to the alluvium above the Trujillo Formation sandstone surface (at 33.5 ft). The well was plugged and abandoned and re-drilled at another location about 65 ft north (towards the river).

After discussions between CRMWA Corp., Lee Wilson & Associates, and Reclamation staff, CRMWA Corp. told the Contractor and drilling subcontractor on December 11 that all conductor casing, including the replacement for PW2-1, would have to have some type of test, such as a cement bond log, that would verify the adequacy of the grout job. (This was to minimize the possibility of caving problems outside the casing in the future.) In lieu of this test, the casing could be driven to bedrock. Couch elected to have a cement bond log done on future wells.

At the relocated site, the crew drilled a pilot hole. Enviro Log, Inc, of Edmond, OK, arrived on January 5 to do cement bonding log in PW2-1 (relocated) and vertical plumbness logging of PW1-1 and PW1-2. The operator gave us a copy of his log plot. He was using a Bell bond tool and Robertson Geologging software developed in England. He said there was no bond from ground surface to 27 ft, a really good bond from 27 to about 42 ft, and "as not a good a bond but still okay (75% bond) " from 42 to 52 ft. This was as deep as he could log without the hole being drilled deeper.

CRMWA Corp., Reclamation, and Lee Wilson & Associates, Inc. staff did not accept the cement bond log for several reasons. The logging tool had not been centered in the hole. A log of the bottom of the casing was not obtained. There was dissatisfaction with the type of cement bonding log performed. PW2-1 (relocated) was then drilled to 71 ft to provide adequate room for the second cement bond log, which CRMWA Corp. required to demonstrate the conductor casing had been adequately cemented into the top of the bedrock. The second cement bond log varied significantly from the initial log, resulting in questions as to the accuracy of this logging tool/procedure. The second log indicated the cement bond in the bedrock was very marginal. Couch was asked not to proceed with drilling and completion until decisions were made as to whether to abandon this well or what conditions might be necessary to assure isolation of the influence zone from the alluvium. Without informing CRMWA Corp., Couch drilled to 101 ft before halting. On January 12, stipulations were provided by CRMWA Corp. to Couch as to conditions under which drilling and development could proceed. These stipulations were later provided in writing in Field Order 12.

Penetration rate in the sandstone was very slow. On January 18, drilling was stopped at 114.0 ft.

Construction Geology

Surficial deposits of alluvial sand, gravel, silt, and clay were penetrated in the upper portion hole. The top of the Trujillo Formation was encountered between 52 to 53 ft. Gray shale, interpreted by the site geologist to be the top of the Tecovas Formation, was encountered at 107.5 ft. Penetration rate was significantly faster in the shale. At 114 ft, the shale color became maroon.

Completion

Six conductivity measurements were made on saline water produced during air drilling from PW2-1 (relocated) on January 18, as the well was drilled from 101 ft to the top of the Tecovas Formation at 107.5 ft. The conductivities were high, ranging from 51.72 to 60.40 mS. (It should be noted, however, that conductivities could also be high in alluvial groundwater.) The site geologist examined cuttings from grab samples and did not see any evidence of alluvial materials. The bottom of the drill hole was sounded, and no materials were accumulating. It appeared the bedrock interval of the hole was isolated from the overlying alluvium by the cement-bentonite grout at the bottom of the conductor casing. Therefore, the conditions stated in Field Order 12 for verifying the integrity of the conductor casing seal were met and the decision was made to complete the hole.

To help ensure both hydraulic and mechanical isolation of the Trujillo Formation from the alluvium, it was decided to place 2 ft of cement-bentonite grout immediately below the bottom of the conductor casing.

Couch began completion of PW2-1 on January 20. Completion was as follows:

<u>PW2-1 Completion String</u>:

End cap and 6-inch sump =	3.0 ft
Well screen =	40.0 ft
Adapter =	0.65 ft
Production casing, 8-inch =	69.35 ft (below ground surface with 10.65 ft above gs)
Total string length =	113.0 ft (below gs)

<u>PW2-1 Setting Depths and Quantities Used</u>:

TD =	114 ft
Bottom of blank sump =	113 ft
Bottom of well screen (20 slot) =	110 ft
Top of well screen =	70 ft
Top of 8-12 filter pack =	106.5 ft (probed depth after 5.5 100-lb bags)
Top of 12-20 filter pack =	77.2 ft (probed depth after 59.5 50-lb bags)
Top of 16-30 sand =	64.3 ft (probed depth after 11 100-lb bags)
Top of bentonite pellets =	62.4 ft (probed depth after 3 5-gallon buckets)

<u>Centralizers were installed as follows</u>:

Top of the blank sump at 113 ft
Middle of the screen at 90 ft
Just above the adapter between the screen and the 8-inch production casing at 69 ft
On the production casing at 49 ft
On the production casing at 29 ft (inside the steel conductor casing)

Note: Ground Surface (gs)

The crew stopped for the night to allow the bentonite pellets to expand (hydrate).

On January 23, the crew tagged the top of the bentonite pellets at 62.5 ft. They placed 60-mesh sand from 62.5 to 61.5 ft. Then they mixed 42 bags of cement, 274 gallons of water, and 40 lbs of bentonite. This should have been an excess of about 10 percent. Grout was pumped through a tremie line until a full, thick grout return to the pit was achieved. There appeared to be 5 to 10 percent excess. After pulling the tremie line, the grout level fell to 1.4 ft below the top of the conductor casing. After about ½ hour, the level had dropped to 1.6 ft below ground surface. The top of (set-up) cement-bentonite grout was tagged at 4.7 ft on January 24. Therefore, there was 3.1 ft of bentonite-cement grout shrinkage.

Development and Testing

Development was done after completion of PW2-1 (relocated) by gently surging and airlifting. Couch installed a 4-inch test pump on February 8, 2001, and a pumpout test was performed. Readings made during this test are summarized in Table 13.

TABLE 13 – Pumpout Test in PW2-1 (Relocated)

Elapsed Time (mm:ss)	Water Level (ft below reference point)	Drawdown (ft)	Elapsed Time (mm:ss)	Water Level (ft below reference point)	Drawdown (ft)
0	1.9	0.0	8:00	36.8	34.9
0:10	4.0	2.1	9:00	37.5	35.6
0:25	9.9	8.0	10:00	37.9	36.0
0:50	19.2	17.3	15:00	39.5	37.6
1:15	21.7	19.8	20:00	41.1	39.2
1:25	23.4	21.5	25:00	41.8	39.9
1:55	26.0	24.1	30:00	42.4	40.5
2:20	28.0	26.1	45:00	43.3	41.4
2:35	28.6	26.7	60:00	43.8	41.9
3:05	30.7	28.8	75:00	44.0	42.1
3:35	31.8	29.9	90:00	44.15	44.25
3:55	32.6	30.7	105:00	44.25	42.35
4:15	33.1	31.2	120:00	44.35	42.45
5:00	34.0	32.1	150:00	44.40	42.5
6:00	35.3	33.4	180:00	44.44	42.54

TABLE 13 – Pumpout Test in PW2-1 (Relocated)					
Elapsed Time (mm:ss)	**Water Level (ft below reference point)**	**Drawdown (ft)**	**Elapsed Time (mm:ss)**	**Water Level (ft below reference point)**	**Drawdown (ft)**
7:00	36.1	34.2	240:00	44.49	42.59

The top of casing reference point for all readings was 1.7 ft above ground surface. The static was the 0:00 time (0.2 ft below ground surface).

Pump discharge was checked at 12, 33, 180, and 240 minutes; the rate was 75 gpm for all measurements.

Conductivity and temperature was measured from samples obtained during the pumpout test with the following results:

Elapsed Time (min)	Conductivity	Temperature (° C)
5?	48.8	15.8
22	49.4	15.9
33	49.4	15.7
62	49.6	15.8
180	49.9	15.7
250	50.2	16.3

Pipelines

On October 25, 2000, Lydick Engineers & Surveyors, Inc. surveyed the pipeline alignments. The following day, the Garney pipeline crew, composed of the pipeline superintendent and a heavy equipment operator, began clearing the pipeline alignment north from the injection well facilities and the West Branch pipeline alignment. *(See Photographs 22 and 23.)* The pipeline superintendent was directed to install erosion control on the steep portion of the cleared pipeline alignment running down the canyon wall to comply with the Stormwater Pollution Prevention Plan. He had his equipment operator place rock dams on the cleared slope.

Pipeline trench excavation began October 30 adjacent to the Injection Facilities and proceeding north towards Hwy. 469. Garney used a Cat Model 330B trackhoe, maintaining grade using laser surveying instrument. The specifications stated the Project Supervisor could waive the requirement for bedding material under the pipeline if he determined the excavated trench bottom would adequately support and not damage the HDPE pipeline. On November 2, the Project Supervisor eliminated the bedding requirement, but imposed strict criteria for removal of any oversize from the backfill, compacting with equipment in lifts, and placement of marker tape 1 ft above the pipe.

After excavating long sections of trench, Garney would remove any large rock fragments. In areas where the trench bottom was rough, bedding was placed. The HDPE conduit was then joined outside the trench by welding the trimmed ends. When a joint of pipe had been welded, the trackhoe would drag the assembled pipeline string forward prior to joining the next section. *(See Photographs 24 and 25.)* After the pipeline string was as long as the length of open trench, the trackhoe would be used to lower the assembled string into the trench, and then to backfill and compact the trench in lifts.

On November 6, the Garney pipeline crew began West Branch trench excavation on the north side of Hwy. 469. They excavated to expose the north end of the 16-inch casing that had been bored and jacked across the highway at a depth of 12.5 ft, about 7 ft lower than specified. Rather than have the boring contractor remobilize to the site and do another bore, Garney asked for and received permission from the Project Supervisor to modify the pipeline grade in this area. An air valve vault had to be moved to accommodate this change. Because the Garney trackhoe could not excavate deep enough to maintain a constant grade as they proceeded north up a high hill, Garney had to remove the top of the hill using a bulldozer with a ripper. They reconstructed the hill after the pipe was installed and covered.

Using only the Cat Model 330B trackhoe, the trackhoe operator managed to excavate the West Branch pipeline trench down the canyon wall with few problems.

Lydick Engineers & Surveyors, Inc. conducted several density tests to verify adequate compaction at some of the West Branch pipeline locations. *(See Photograph 26.)* The test results were all good.

Garney's pipeline crew started welding 6-inch HDPE along the canyon wall for the East Branch pipeline on January 19. *(See Photograph 30.)*

The Cat Model 330 Backhoe was also used for pipeline excavation and backfill in the Canadian River valley floor, which consisted primarily of alluvial sand with gravel, silt, and clay. On the West Branch pipeline, excavation from the modified upstream outlet works structure to PW1-1 downstream to the point the pipeline alignment begins ascending the canyon wall was accomplished without use of a trench box.

On the East Branch, the valley floor pipeline profile was substantially closer to river elevation, resulting in the pipeline being placed below the ground water surface. A steel trench box, approximately 20 ft long by 4½ to 5 ft high, was pulled along closely behind the trackhoe to place the 6-inch HDPE pipe as excavation progressed. A truck rim, welded to the front end of the trench box, pressed the HDPE pipe in into the alluvial material as the trench box was pulled along the top of the pipe.

After backfilling was completed by the trackhoe, a D-6 bulldozer compacted the backfill by equipment travel.

On the first day of East Branch pipeline excavation and installation in the valley floor, Garney placed pipe from the angle bore downstream to the AT&T fiber optic cable crossing. An AT&T representative was on site when the pipeline crossing of the fiber optic cable was accomplished. With AT&T and Project Superintendent approval, the pipe was placed above the fiber optic cable while maintaining the required 5-ft depth of burial. On the second day, pipeline installation proceeded to the first river crossing, and one vault was installed.

The first river crossing was completed and a vault was set on the third day. Silt fences were used to divert the river flow and prevent contamination while the river crossings were excavated and backfilled. The following day, pipeline construction was completed to the second river crossing (to Production Well PW1-3), where one of the two modified outlet structures was installed. Subsequent pipeline construction in the valley floor proceeded at a similar rate.

The permit to construct the pipeline under the Union Pacific Railroad bridge required an encasement pipe. Reclamation, CRMWA Corp, and JFSA did not believe the encasement pipe was necessary to protect the railroad bridge concrete piers, but the permit could not be obtained without this feature. However, the encasement pipe was not specified in the plans. Installing the unnecessary encasement pipe would have resulted in a contract cost increase. The Reclamation Construction Representative initiated contacts with the Union Pacific Railroad (UP), ultimately contacting a bridge engineer, George Meyer. Mr. Meyer stated the original pipeline crossing agreement had never gotten past their real estate department (an engineer had not seen it). Mr. Meyer indicated he would pull the agreement out of the file and see if they really needed the encasement pipe. By e-mail dated February 23, 2001, Mr. Meyer notified Reclamation the requirement for the encasement pipe was eliminated.

Dewatering

Because construction occurred during months the river was low, dewatering was not required during pipeline construction.

Highway Crossings

On October 2, 2000, DH Underground, Inc. arrived at the site with a John Deere 370 trackhoe. They excavated a test pit on the south side of Hwy. 469 at the locations of the directional bores for the two pipeline crossings. Sandstone was encountered at shallow depths. During the week of October 9, DH Underground, Inc. returned to the site, dug a trench on the south side of Hwy. 469 at the west road bore, and began setting up their horizontal boring equipment. A Plateau Telephone representative was present while they carefully excavated under a buried fiber optic cable. On October 11, they began boring under Hwy. 469. By the end of the day, they had jacked and bored about 40 ft of casing. *(See Photograph 31.)*

The boring contractor could not maintain the proper grade while boring and jacking the casing. Although they attempted to correct the grade, the bore ended on the north side of the highway several feet deeper than the plans specified. This was believed to be due to characteristics of the formation they were penetrating. On October 16, their auger string broke or separated in the highway bore casing. This occurred with the penetration distance at 140 ft. The Contractor contacted the State Highway Department and obtained permission to use a backhoe to dig down and free the auger head in the borrow ditch on the north side of the highway. DH Underground, Inc. finished the west Hwy. 469 bore on October 17. The following day they filled in the trench the boring machine had been set in and moved to the East Hwy. 469 bore, where they again set up on the south side of the highway. On October 19, DH Underground, Inc. completed the second bore under Hwy 469. They demobilized from the project on October 20.

Angle Bore

The "angle bore" or "angle discharge line" is located on the East Branch pipeline, with the inlet end at the junction of the Canadian River valley floor and the canyon wall and the outlet end on the plateau near the canyon rim. The specifications stated the Contractor could propose an alternative design of the drilled discharge line (angle bore), provided the design was prepared and sealed by a registered professional engineer and submitted for review and approval to the Contracting Office (Project Supervisor). Soon after construction started, Garney began exploring and proposing alternative methods for drilling and completing the angle bore. An alternative design was ultimately approved by the CRMWA Corp. General Manager and Project Supervisor. The low-pressure grout and silica sand slurry specified in the original design were eliminated. The approved design eliminated the galvanized steel sleeve, substituting DR-11 12-inch HDPE pipe suspended in bentonite-mud gel. The 6-inch DR-11 HDPE pipe was centered inside the 12-inch pipe using Ranger 2 non-metallic segmented (centering) spacers on 6-ft centers. One-inch electrical conduit was suspended in the angle bore through 1-inch conduit.

DH Drilling of Los Lunas, New Mexico drilled and installed the angle bore. Information on their drilling equipment and methods are not available.

Construction Geology

Trujillo Formation sandstone and/or siltstone was encountered in pipeline excavations, the highway crossing bores, and the angle bore. North of Hwy. 469, the formation material encountered was indurated. Using the Cat Model 330B trackhoe, much of the material excavated on the plateau north of Hwy. 469 was removed as bedrock up to several feet in size.

Injection Facilities

Containment Basin

Beginning on September 26 and finishing on September 29, 2000, RMB, Inc. of Logan, New Mexico, excavated the containment basin, using a grader and a loader. *(See Photograph 32.)*

RMB, Inc. began placing and compacting backfill around concrete storage tank foundations on October 31. On November 1, Garney was asked to see that cobbles were removed from the backfill material.

Concrete was placed in the sump pit walls of the containment basin on November 14. All concrete for the injection well facilities was supplied to the site by the local redi-mix company, Bruhn Redi-Mix of Logan, New Mexico.

Storage Tanks

On October 10, a Garney crew began forming, installing rebar, and placing concrete for storage tank concrete foundations in the containment basin. *(See Photograph 33.)*

The storage tank subcontractor (EBM - Edison Brown Minneapolis Tank Company) began assembling and welding steel storage tanks in the containment basin in December

2000. The "Run Tank," a small 12,405-gallon tank in the containment basin, was installed by EBM on January 19, 2001. *(See Photograph 39.)*

Office and Injection Buildings

Reynosa Construction, Inc., the subcontractor for the building construction, mobilized to the site on October 22, 2000. Excavation for building footings began on October 25. Newman Electric started working on the site electrical system on October 31.

When the forms were removed from the injection building footing, some honeycombing was noted. The contractor was directed to repair these areas and to provide more thorough vibration. *(See Photograph 40.)* On November 3, after the testing lab (Lydick Engineers & Surveyors) had pulled concrete samples for testing, the Reynosa foreman had the transit mix operator add water to a transit mixer. This increased a very usable 4-inch slump to 7 inches. The CRMWA Corp. inspector directed the operator to take the load back to the plant. The foreman objected strenuously, saying that if the concrete did not have air entrainment a 7-inch slump was fine. He was told it did and would continue to have air entrainment and that a 7-inch slump was not acceptable. He was informed that the slump should not exceed 5 inches. An occasional load with 6-inch slump would be acceptable, but any load with a 7-inch slump should always be rejected. The Reynosa foreman was then directed to vibrate the concrete.

The New Mexico building inspector and plumbing inspector visited the site on November 16. He informed CRMWA Corp. and Garney that there was no building permit or plumbing permit for the injection facilities building. The building inspector said that only a registered building contractor could obtain a building permit. Reynosa Construction was not registered as a building contractor in the state of New Mexico. Therefore, work on the facilities building was stopped. On November 17, the CRMWA Corp. inspector traveled to Santa Fe with the set of sealed drawings to obtain approvals from the State of New Mexico. Reynosa worked to get their building contractor's license activated. On November 28, the New Mexico sealed drawings and building permit were delivered to the construction site.

Concurrent with the waiting period for the building contractor to be licensed and the building permit to be delivered, JFSA was contacted to revise the building plans to comply with the 1998 Americans with Disabilities Act (ADA) provisions. (The plans had been developed prior to the current ADA standards being invoked.) On December 1, the final ADA revisions from JFSA were received at the site. Because the building contractor was not licensed, the Contractor did not claim the time required to make these revisions influenced the cost of the project.

Lydick Engineers & Surveyors, Inc. conducted several density tests to verify adequate compaction of the backfill in the injection well facilities building floor foundation. The test results were all good.

Bucola Masonry began laying CMU walls for the injection building in December 2000. However, they ceased working for several days in mid-January due the possibility of freezing temperatures damaging the mortar. They resumed laying masonry on January 20 as the temperatures were higher, and they completed masonry work the last week in

January. Reynosa Construction began working on the roofs for the buildings immediately thereafter.

Due to an error by the electrical subcontractor, the concrete transformer slab was not located as specified in the plans. Garney discussed this with the CRMWA Corp. Project Supervisor and received permission to leave the slab as placed. This required rerouting the discharge line from the run tank in the containment basin to the filter pump.

Mechanical and Treatment Equipment

C&E Mechanical, Inc. began work on mechanical installations in January 2001.

Injection Pump

The injection pump floor slab was placed in November 2000. The concrete had not been thoroughly leveled when the slab was place. Therefore, grout had to be installed under the injection pump. On January 23, 2001, the Garney crew formed and poured concrete for the floor of the injection pump discharge line chase and placed concrete in the chase walls on February 1.

SCADA System

Ener-Tech Automated Control Systems, Inc., of Albuquerque, New Mexico, was the Supervisory Control and Data Acquisition (SCADA) system subcontractor.

Miscellaneous

Electrical power service was installed for the project by Farmer's Electric Cooperative, who wheeled in overhead power from the south along Hwy. 54 to service the West Branch pipeline and the Injection Facilities; and from an existing power line east of the construction area to provide power to the East Branch pipeline.

Although the injection well was completed in Phase 1 construction, some additional work was performed in Phase 2. Two specified caisson holes were drilled adjacent to the well, rebar installed, and the holes were backfilled with concrete on November 15.

Construction Geology

Most foundation excavations for the injection facilities were confined to surficial deposits. The caisson holes were bored into the Trujillo Formation.

Quality Control

Eidson-Brown-Minneapolis Tank Company submitted reports of welder performance qualification testing for employees assembling the brine storage tanks.

Atomic Inspection Labs, Albuquerque, NM, performed an isotope radiography inspection of a brine storage tank on December 14, 2000. This company reported the welding inspected as acceptable.

On January 16, 2001, Panhandle N.D.T. & Inspection, Inc., Borger, Texas, performed a radiographic inspection of welds on a brine storage tank. The welding inspected was reported acceptable.

Results of density (compaction) tests performed by Lydick Engineers & Surveyors are tabulated in Table 14.

Lydick Engineers & Surveyors tested concrete placed during Phase 2 construction. All 28-day compressive strength tests exceeded the design strength of 4,000 psi. Results of these tests are summarized in Table 15. Two 4-inch by 8-inch concrete cores were taken from the south wall of the injection facilities office building on November 21, 2000. Compressive strength tests were performed at 15 and 28 days, with results of 2,947 and 4,010 psi, respectively.

TABLE 14 - Density (Compaction) Tests on Backfill Material					
Test Date	Test No.	Percent Compaction	Deviation from Optimum Moisture	Test Location	Required Density
				Buildings and Tanks:	
11/3/2000	1	96.3%	0.7%	South side tank	95%
11/3/2000	2	96.1%	3.8%	Inside tank area	95%
11/3/2000	3	97.1%	-0.9%	Inside tank northeast	95%
11/3/2000	4	100.1%	-1.1%	North of tanks	95%
11/3/2000	5	100.4%	-1.1%	Southwest tank-inside south	95%
11/3/2000	6	97.2%	-1.9%	Southwest tank-inside north	95%
12/7/2000	1	98.6%	-2.4%	Injection bldg. floor-filter room	95%
12/7/2000	2	97.8%	-0.9%	Injection bldg. floor-water supply	95%
12/7/2000	3	96.0%	1.9%	Office bldg.-shop area	95%
				Pipelines:	
11/3/2000	7	86.0%	-0.3%	Sta. 15+20 over springline	85%
11/3/2000	8	87.0%	3.1%	Sta. 10+00 over pipe	85%
11/3/2000	9	95.0%	2.6%	Sta. 6+25 over pipe	85%
11/3/2000	10	87.0%	2.8%	Sta. 2+50 over pipe	85%
12/1/2000	1	87.6%	2.9%	Sta. 205+00-top lift	85%
12/1/2000	2	88.9%	1.6%	Sta. 209+00-top lift	85%
12/1/2000	3	94.9%	-0.2%	Sta. 215+00-top lift	85%
12/7/2000	5	85.9%	-2.1%	Sta. 220+00-top lift	85%
12/7/2000	1	95.3%	3.6%	Sta. 205+00-pipe area	95%
12/7/2000	2	94.2%	2.2%	Sta. 210+00-pipe area	95%
12/7/2000	3	95.8%	1.9%	Sta. 215+00-pipe area	95%
12/7/2000	4	94.5%	2.3%	Sta. 220+00-pipe area	95%
12/12/2000	1	96.1%	1.7%	Sta. 225+00-pipe area	95%
12/12/2000	2	100.4%	-0.9%	Sta. 225+00-top	85%
12/12/2000	3	102.7%	-1.9%	Sta. 228+00-top	85%
12/12/2000	1	95.8%	-1.4%	Sta. 228+00-pipe area	95%
12/12/2000	2	96.1%	-0.5%	Sta. 232+40-pipe area	95%

TABLE 15 - Concrete Testing						
Specimen Marking	Date Sampled	Compressive Strength 7-Day (psi)	28-Day (psi)	Air Content (%)	Sump (inches)	Concrete Placement Location
1	10/10/2000	3,567		5.0%	—	Southwest tank footing
1			4,324			
1			4,279			
2	10/12/2000	3,092		3.5%	3.5	Southeast tank footing
2			4,382			
2			4,315			
3	10/12/2000	3,204		6.0%	4	Northwest tank footing
3			4,259			
3			4,200			
4	10/19/2000	3,409		4.3%	3.25	Southeast tank wall ring
4			4,231			
4			4,195			
5	10/19/2000	3,167		4.5%	3.5	Southeast tank wall ring
5			4,133			
5			4,195			
6	10/24/2000	2,782		—	—	Unknown
6			4,093			
6			4,122			
7	10/24/2000	3,023		—	—	Unknown
7			4,102			
7			4,195			
8	10/31/2000	3,203		5.2%	3	Footings
8			4,210			
8			4,185			
9	11/3/2000	2,613		7.0%	7	Unknown
9			4,010			
9			4,008			
	Average:	3,062	4,191	5.1%	4.0	

Plugging and Abandonment of Existing Wells

Ten observation (monitoring) wells were plugged and abandoned (P&A) during Phase 2 construction. These wells were designated DH-1, DH-2, DH-3, TW-1, OW-1 (POW1), OW-2, OW-3, OW-4, OW-7, and OW-8. The plugging and abandonment was performed in compliance with the specifications with some well-specific variations when agreed upon by representatives of Lee Wilson and Associates, Cough Drilling, HydroGeologic Services, and a representative of the New Mexico State Engineer's Office.

Couch Drilling was the subcontractor for this work. Couch performed P&A on DH-1, DH-2, OW-7, OW-8, and part of TW-1 using their Midway 1500 drill rig mounted on a Ford 4x6 truck. Only DH-1 and TW-1 were drilled out. For the remaining wells, the drill rig or service rig was used to lower/raise a plugging string. However, for OW-7 and OW-8, Couch manipulated the plugging string by hand. They used their Sullair 375 cfm, 100-psig compressor with a plugging/injection string to clean the holes by airlifting.

Couch subcontracted with HydroGeologic Services for the remaining P&A. HydroGeologic performed P&A in DH-3, OW-1, OW-2, OW-3, OW-4, and part of TW-1 using their SIMCO S8000 pump service rig mounted on a Ford F550 4x4 truck to lower/raise an injection string used to clean out the holes by airlifting and then inject cement-bentonite grout. HydroGeologic used Couch's Sullair compressor for airlifting. HydroGeologic's Wilden M-8 double diaphragm pump, driven by the compressor, was used to circulate and place grout. However, at DH-1 a McDonald Model 2 P5 HE, 2-inch, 75-psi centrifugal pump, powered by a Honda 5.5 HP gasoline engine, was used to mix and place the grout. See Table 7 for P&A depths and quantities.

A knife perforator was used in the well casings prior to injecting cement-bentonite grout.

The surface casing apparently collapsed in OW-1 while airlifting from 210 ft below ground level. When the airline recovered, they could only get to 16 ft and had to drill out the hole. HydroGeologic used the same service rig to lower and raise a plugging string.

On OW-2, the driller encountered steel in the well at 248 ft. They could not airlift deeper and could not get the knife perforator past 225 ft.

ON OW-3, with ten 21-ft joints of ½-inch airline pipe in the hole, the pipe sand-locked and parted 21 ft below ground surface.

Mr. Douglas Rappuhn, the site representative of the New Mexico State Engineer's Office, wrote a memorandum dated September 6, 2001, to the Director of the Water Resource Allocation Program (New Mexico Office of the State Engineer) stating that the ten monitoring wells administered in part by the Bureau of Reclamation, had been appropriately abandoned.

TABLE 16 - Plugging and Abandonment of Observation Wells										
WELL/ HOLE NO.	DATE	WATER (gallons)	BENTONITE (pounds)	CEMENT Type	CEMENT Sacks	YIELD (cu.ft.) Placement	YIELD (cu.ft.) Total	CALCULATED VOLUME (per specs)	PLUGGING DEPTH Top	PLUGGING DEPTH Bottom
DH-1	4/20/2001	140	25	Class C	13.5	25.3			10	250
	4/20/2001	140	25	Class C	14	25.5				
	4/20/2001	60	10	Class C	5.5	10.7	61.5	25.6		
	4/23/2001	Topped off with 1 sack of dry cement to 3' BGL							3	10
DH-2	5/9/2001	300	30	Class C	30	54.7			180	436
	5/10/2001	200	20	Class C	20	36.4	91.1	31.6	0	180
DH-3	3/14/2001	40	5	Class C	4	7.3	7.3	5.2	0	414
OW-1	3/14/2001	50	10	Class C	5	9.1	9.1	6.3	0	210
	3/14/2001	Topped off with 2.5 gallons of excess from OW-4								
OW-2	3/13/2001	110	25	Class C	9.5	19.3			7	248
	3/13/2001	110	25	Class C	9.5	19.3	38.6	55.5		
	3/14/2001	Topped off with one 5-gallon bucket (excess from OW-1)							0	7
OW-3	3/13/2001	50	10	Class C	5	9.1	9.1	8.3	1	210
OW-4	3/14/2001	30	5	Class C	2.5	5.2	5.2	8.7	0	194
OW-7	3/28/2001	80	6	Class C	8	14.6			32	104
	3/28/2001	80	8	Class C	8	14.6				
	3/29/2001	30	3	Class C	3	5.5	34.6	9.9	0	32
OW-8	3/28/2001	120	12	Class C	12	21.9			13	105
	3/29/2001	10	1	Class C	1	1.8	23.7	9.9	0	13
TW-1	4/23/2001	300	75	Class C	26	52.7			255	269
	4/23/2001	300	75	Class C	26	52.7				
	4/24/2001	325	75	Class C	30	58.0			168	255
	4/24/2001	300	75	Class C	25	52.2				
	4/25/2001	300	35	Type I-II	40	59.6			0	168
	4/25/2001	300	35	Type I-II	40	59.6				
	4/25/2001	180	25	Type I-II	24	35.7	370.6	277		

Factors Affecting Contractor's Progress

Weather

Winter storms delayed production well drilling for several days. Bucola Masonry postponed laying CMU masonry for several days in mid-January due the possibility of freezing temperatures damaging the mortar.

Labor

There were no labor-related delays during Phase 2 construction.

Organization and Personnel

Contractor Forces

Garney Companies, Inc. constructed the pipelines, tank foundations, the chase to the injection well, the injection well caissons, and various other features.

The Garney Site Administrator, Will Kennedy, was present on site during most of the construction period. The Garney pipeline crew consisted of a superintendent and one equipment operator. While the foundation and chase work was being performed, Garney had up to about 6 additional employees on site. A detailed listing of contractor and subcontractor forces is not available.

List of Subcontractors

COMPANY	ADDRESS	SUBCONTRACT
Couch Drilling Company (also known as Couch Drilling and Pump Service and Crouch Pump Service)	P.O. Box 249 Cactus, TX 79013-0249	Drilling
D&H Drilling	Los Lunas, NM	Angle Boring
Eidson-Brown-Minneapolis Tank Company (EBM)	8301 Broadway Blvd. SE Albuquerque, NM 87105	Storage Tanks
Ener-Tech Automated Control Systems, Inc.	4730-D Pan American Freeway NE Albuquerque, NM	SCADA System
Enterprise Construction, Inc.	5827 S. Rapp Street Littleton, CO 80120	Mechanical & Piping
Hines Construction (also known as RMB, Inc.)	Logan, NM88426	Excavation & Backfill
HydroGeologic Services, Inc.	P8600 Beverly Hills NE Albuquerque, NM 87122	Drilling (subcontractor to Couch Drilling)
Newman Electric, Inc.	1517 S. Prince Clovis, NM 88101	Electrical

COMPANY	ADDRESS	SUBCONTRACT
Reynosa Construction, Inc.	3113 Line Avenue Amarillo, TX 79106	Buildings
Usrey's Enterprises	704 Martinez Street Logan NM 88426	PLC Buildings
Versatile Construction, Inc.	114 S. US Hwy. 54 Logan, NM 88426	Drill site preparation (subcontractor to Couch Drilling)
Bruhn Redi-Mix	Logan, NM	Concrete

Contract Administration Forces

CRMWA Corp. was the contracting agency for Lake Meredith Salinity Control Project. Staffing involved with Phase 2 construction consisted of the following:

- John E. Williams, General Manager
- Kent Satterwhite, Deputy General Manager (Project Supervisor – equivalent to Contracting Officer)
- Chad Pernell, P.E. (equivalent to Contracting Officer Technical Representative)
- Jerry Osborn, Operator/Inspector
- Ashby Lewis, Chemist

Mr. Osborn was at the site on a daily basis. Other individuals were on site as needed. Wage rates for these personnel are not available.

The Oklahoma-Texas Area Office was responsible for Reclamation activities associated with Phase 2 construction. Staff directly involved with construction included the following:

- Area Managers Elizabeth Cordova-Harrison and Larry Walkoviak
- Project Director, Leon Esparza
- Construction Representative, Dennis McDonough

As previously described, Reclamation was to have been responsible for construction management. However, after determining that substantial savings could be realized, CRMWA Corp. became the contracting agency. Therefore, the role of Reclamation during construction was to coordinate various activities with regulating agencies, the design firm, J.F. Sato & Associates, Inc. (JFSA), and others, provide advice and support to CRMWA Corp., and verify compliance with the permits issued to Reclamation. Mr. McDonough was at Logan during much of the Phase 2 construction until February 2001.

Safety

Contractor Forces

Many of the photographs in this document portray contractor personnel not wearing appropriate safety equipment or the occurrence of other unsafe acts. The reader should be aware that Reclamation had no direct control of contractor compliance with safety issues. The General Manager of CRMWA Corp. addressed safety at meetings with the contractor. Because of the General Manager's strong statements regarding enforcement of safety, contractor safety did improve substantially during the execution of Phase 2 construction.

One lost time accident occurred during Phase 2. Hydrogeologic, of Albuquerque, New Mexico, subcontracted to Couch to drill some of the production wells. This accident occurred n Sunday morning, January 21, 2000 at the site of PW1-5, where Hydrogeologic had just set up their drill rig on alluvial sand (a sand bar composed of fairly clean, loose sand).

Their driller penetrated a foot or two using air when the outriggers (rear leveling rams) on the back of the drill rig "gave way." (The shallow hole he drilled in the loose sand collapsed, when it did, the sand caved from under the leveling rams (outriggers), which had the drill rig suspended with all the rig tires off the ground, perhaps as high as a foot above the ground.) When the sand caved out from under the rear leveling rams, the back of the rig dropped. The driller was standing on the driller's platform, which folds up towards the front of the rig for transport. When the sand caved out from under the leveling rams, the back of the rig dropped, and the driller's platform came down on the front end of the steel mud pit. This caused the driller's platform to fold up, trapping and squeezing the driller's feet and lower legs.

He was driven to the hospital in Tucumcari, New Mexico. At the hospital, the staff checked his injuries, ran x-rays, and reported that he had no broken bones. They did give him medication for the pain. He was dismissed from the hospital at about 1:30 p.m. on January 21. He returned to the site on January 24. The amount of lost time is not known.

A Couch drill crew helper missed work on February 2 when he left the job to have his foot/ankle examined by doctor. He had hurt his ankle the day before when his foot slipped while carrying a small loading pump. He had pulled tendons. The doctor put his foot in a cast.

Contract Administration Forces

CRMWA Corp. was also the contracting agency for Phase 2 construction for the Lake Meredith Salinity Control Project. Staffing involved with this project consisted of the following:

- John E. Williams, General Manager
- Kent Satterwhite, Deputy General Manager (Project Supervisor – equivalent to Contracting Officer)
- Chad Pernell, P.E. (equivalent to Contracting Officer Technical Representative)

- Jerry Osborn, Operator/Inspector
- Ashby Lewis, Chemist

Mr. Osborn was at the site on a daily basis. Other individuals were on site as needed. Wage rates for these personnel are not available.

The Oklahoma-Texas Area Office continued to be responsible for Reclamation activities associated with the Lake Meredith Salinity Control Project. Staff directly involved with construction included the following:

- Project Director, Leon Esparza
- Construction Representative, Dennis McDonough (through January 2001)

As previously described, Reclamation was to have been responsible for construction management. However, after determining that substantial savings could be realized, CRMWA Corp. became the contracting agency. Therefore, the role of Reclamation during construction was to coordinate various activities with regulating agencies, the design firm, J.F. Sato & Associates, Inc., and others, provide advice and support to CRMWA Corp., and verify compliance with the permits issued to Reclamation. Mr. McDonough was at Logan during most of the Phase 1 construction.

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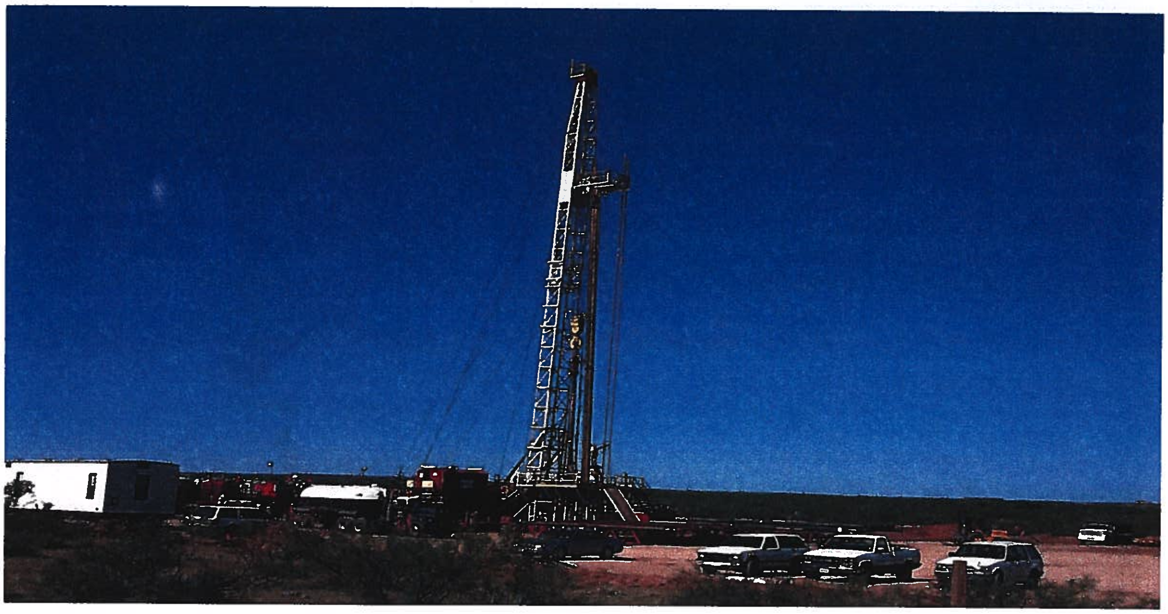
APPENDICES

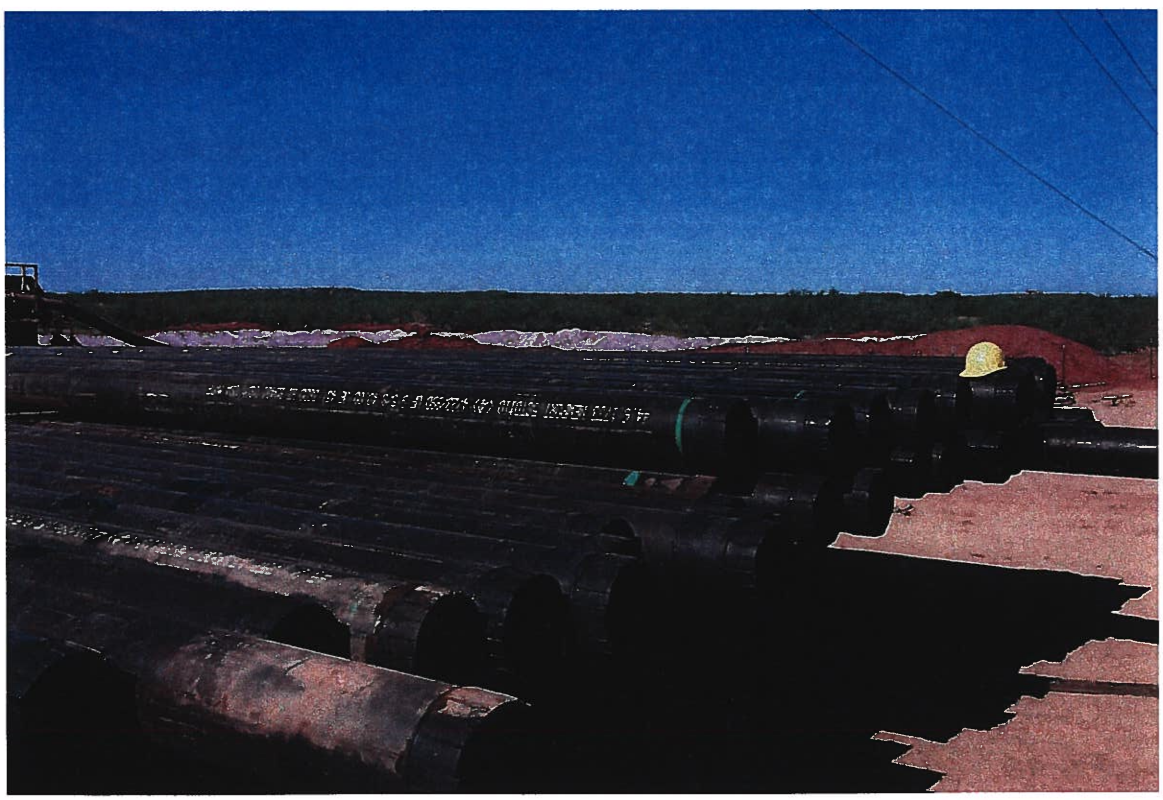
Appendix A – Photographs



Photograph 1 – Lake Meredith Salinity Control Project: Overview of Injection Well No. 1 drill site. The Halliburton cementing trucks are in the left middle ground. The Texas World Operations (TWO) office trailer is to extreme left. Photographed 7/23/1999 by Dennis McDonough.

Photograph 2 – Lake Meredith Salinity Control Project: Drilling fluid return is processed in a series of tanks, shakers, and centrifuges (desilters) on the backside of the Norton drill rig at Injection Well No. 1. Photographed 7/23/1999 by Dennis McDonough.

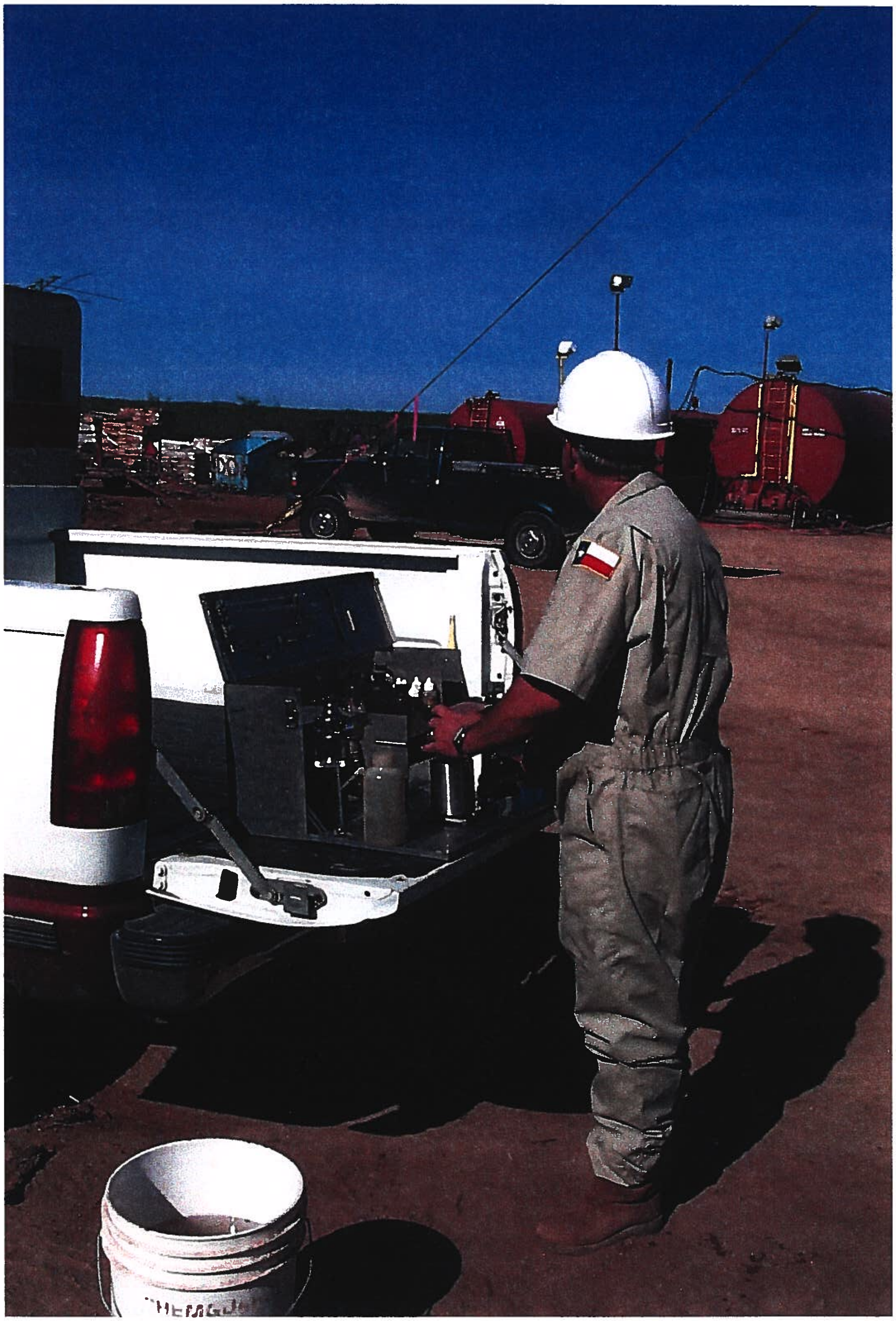
Photograph 3 - Lake Meredith Salinity Control Project: Excess cement return from annular area between the hole wall and the 13-3/8 inch surface casing at Injection Well No. 1 is discharging into the plastic film lined mud pit. Photographed 7/23/1999 by Dennis McDonough.



Photograph 4 - Lake Meredith Salinity Control Project: Steel protection (intermediate) casing, 9-5/8" O.D., has been tallied prior to installation at Injection Well No. 1. Photographed 7/23/1999 by Dennis McDonough.

Photograph 5 – Lake Meredith Salinity Control Project: The drill crew is removing excess 13-3/8" surface casing after cement has set 24 hours at Injection Well No. 1. Photographed 7/24/1999 by Dennis McDonough.

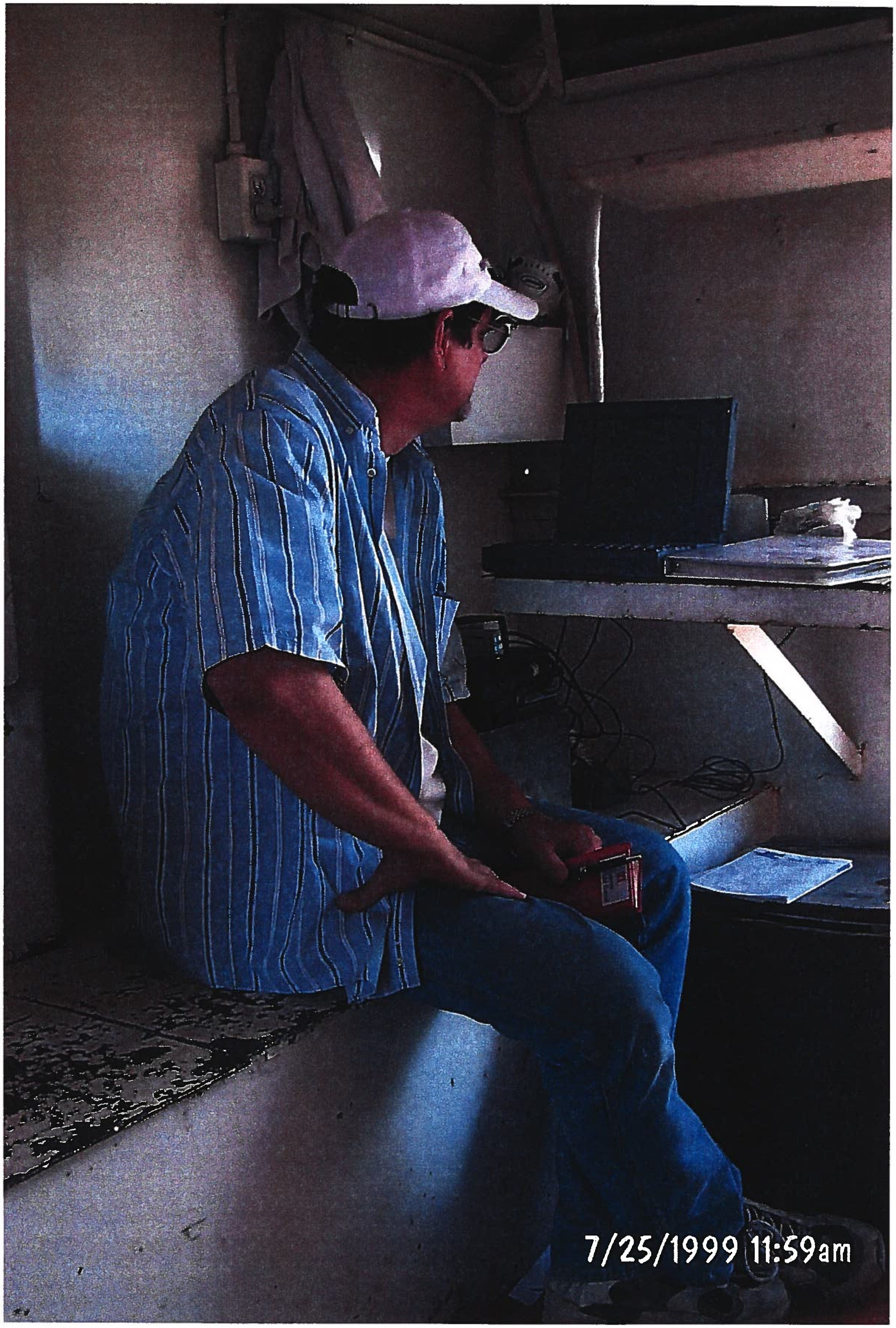
Photograph 6 – Lake Meredith Salinity Control Project: Welder is installing a Braden Head on 13-3/8" surface casing at Injection Well No. 1. The twenty-inch steel conductor casing has been cut off several feet below the Braden Head. Photographed 7/24/1999 by Dennis McDonough.



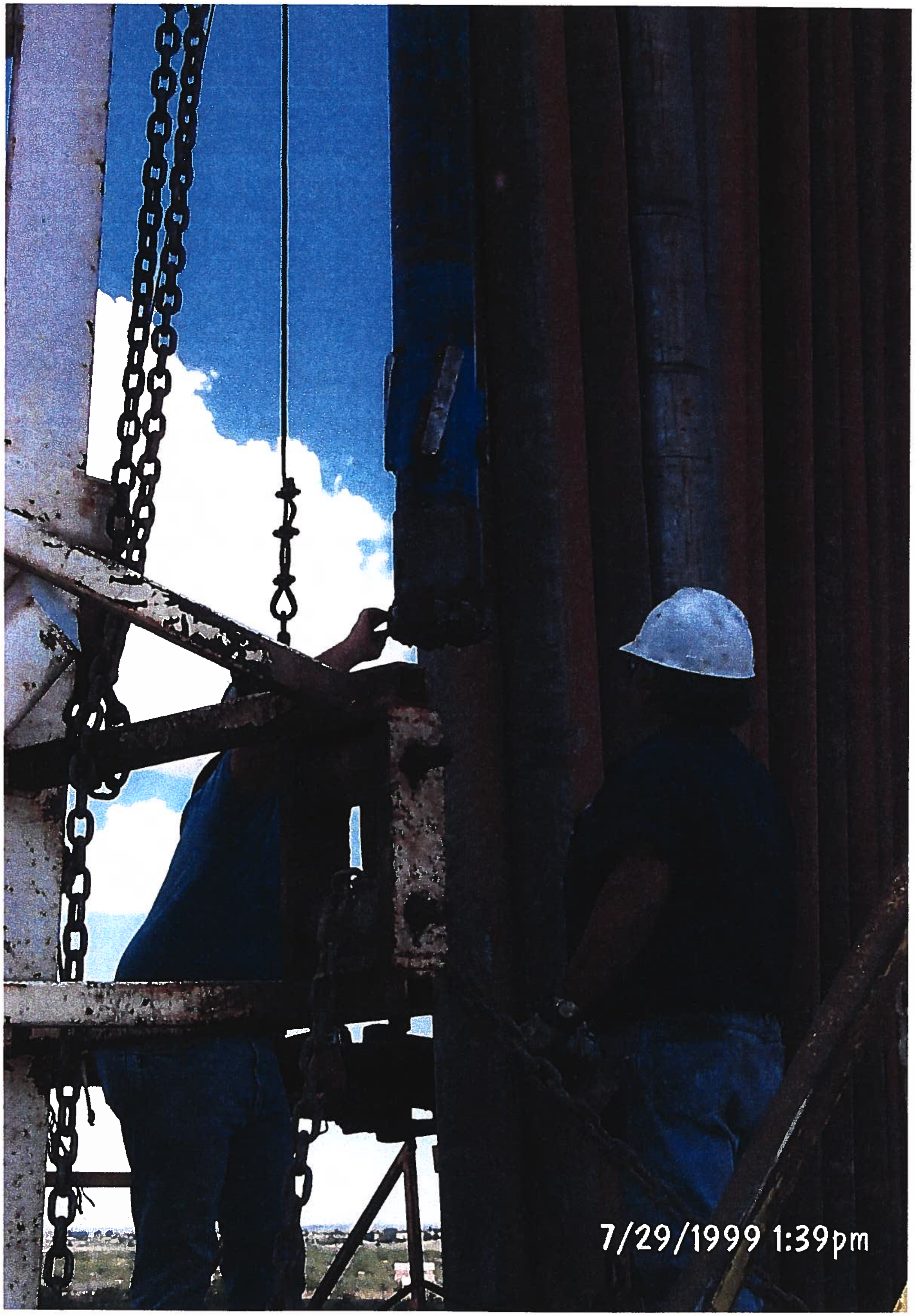
Photograph 7 – Lake Meredith Salinity Control Project: The mud engineer is testing drilling fluid during drilling of Injection Well No. 1. Photographed 7/24/1999 by Dennis McDonough.

Photograph 8 – Lake Meredith Salinity Control Project: The blowout preventer has been installed on top of the Braden Head at Injection Well No. 1. Photographed 7/24/1999 by Dennis McDonough.

Photograph 9 – Lake Meredith Salinity Control Project: Baker Hughes logging trucks are set up to do cement bond logging of surface casing at Injection Well No. 1. Photographed 7/25/1999 by Dennis McDonough.



Photograph 10 - Lake Meredith Salinity Control Project – Texas World Operations engineer is conducting pressure test of surface casing. Photographed 7/25/1999 by Dennis McDonough.



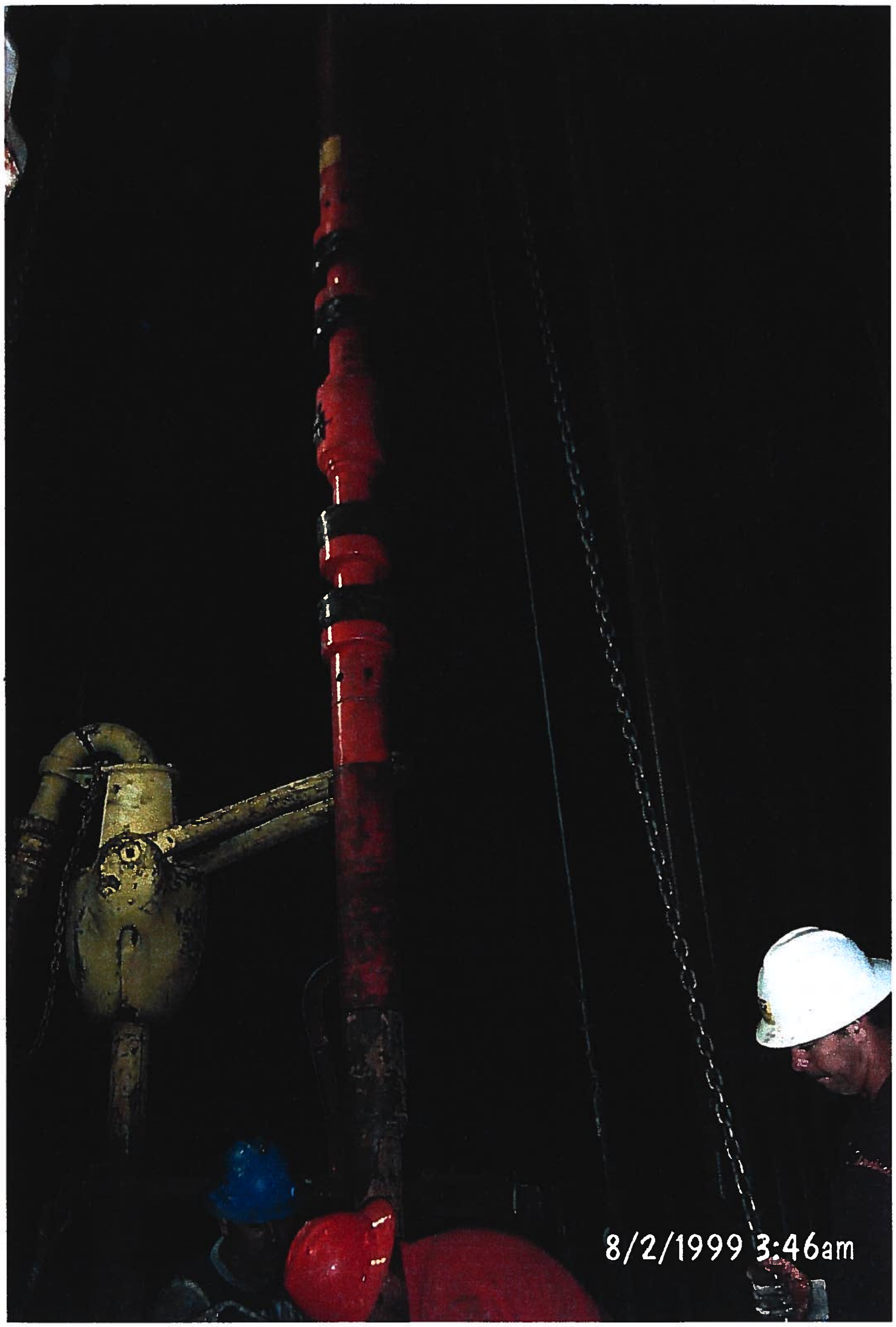
Photograph 11 – Lake Meredith Salinity Control Project: The driller is checking for core in the end of the core barrel on the core run from 2155 to 2185 ft in Injection Well No. 1. Photographed 7/29/1999 by Dennis McDonough.

Photograph 12 – Lake Meredith Salinity Control Project: The inner barrel with inner barrel shoe has been placed on the platform. The exposed bottom end of the core is from cored interval 2155 to 2185 ft in Injection Well No. 1. Core recovery in this 30 ft run was approximately 26.0 ft. Photographed 7/29/1999 by Dennis McDonough.

Photograph 13 - Lake Meredith Salinity Control Project: A subcontractor is cutting the inner barrel and core into sections. The core was from the 2155 to 2185 ft interval in Injection Well No. 1. Both ends of each barrel section are sealed, and the core is then transported to a core laboratory for testing. Photographed 7/29/1999 by Dennis McDonough.

Photograph 14– Lake Meredith Salinity Control Project – White crystals of halite (salt) appear in core removed from the bit and reaming shell. This core is from the bottom of the cored interval 2155 to 2185 ft in Injection Well No. 1. Photographed 7/29/1999 by Dennis McDonough.

Photograph 15 – Lake Meredith Salinity Control Project: An external casing packer (ECP) and port collar are being lowered into the injection well. Photographed 8/1/1999 by Dennis McDonough



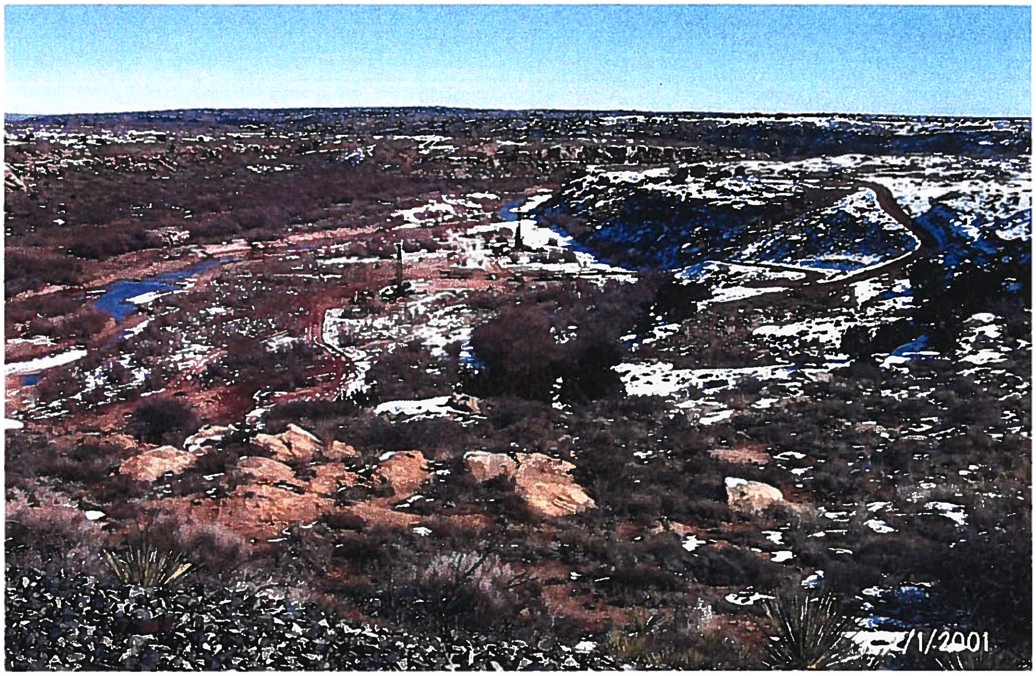
Photograph 16 – Lake Meredith Salinity Control Project: The TAM combo tool is being prepared for lowering into injection well. This tool is used to inflate the casing packer and then open and close the port collar. Photographed 8/2/1999 by Dennis McDonough.

Photograph 17 – Lake Meredith Salinity Control Project: A Halliburton crew is performing nitrogen back-flow (lift) to stimulate the injection well. Photographed 9/10/1999 by Dennis McDonough.

Photograph 18 – Lake Meredith Salinity Control Project – Couch Pump Service had a local subcontractor, Versatile Construction, clear a path through the salt cedars for access to production well PW1-1. This well is located below where trail ends just left of the lower center of the photograph. The Highway 54 bridge over the Canadian River is in the upper left corner of the photograph. Photographed 10/12/2000 by Dennis McDonough.

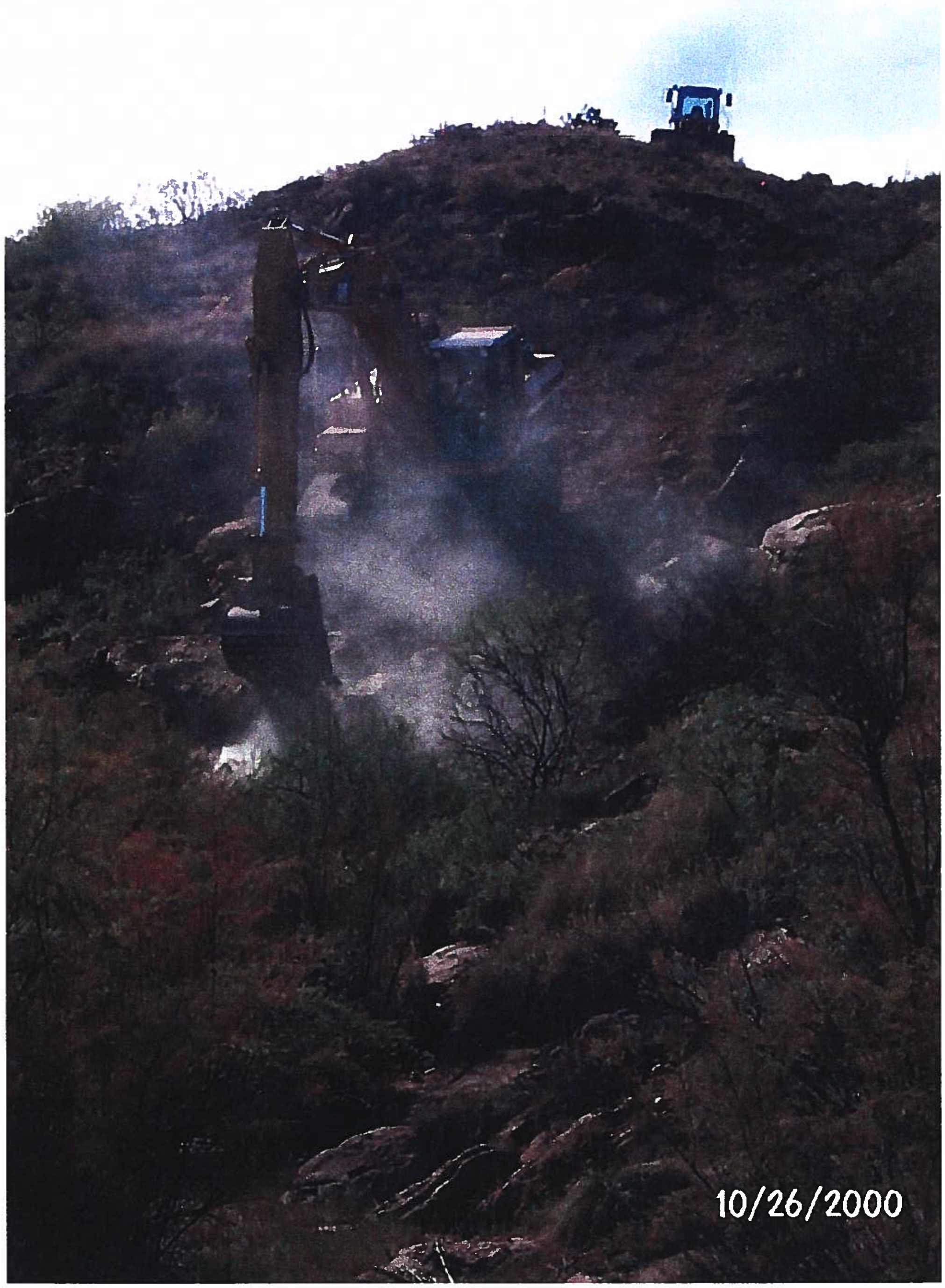
Photograph 19 – Lake Meredith Salinity Control Project: Couch Pump Service is backing their Midway 1300 drill rig onto a waterproof membrane at the site of PW1-1. Membranes and metal drip pans were used to prevent soil and water contamination from spills of fuel, oil, grease, or other chemicals. Photographed 10/19/2000 by Dennis McDonough.

Photograph 20 – Lake Meredith Salinity Control Project: Hydro-Geologic set up their Star 30K drill rig at PW1-5. The Star 30K uses 4-1/2 inch drill pipe. A plastic membrane has been placed under the rig and the separate trailer-mounted triplex mud pump (blue pump on white trailer to left of rig). A 10-inch down-the-hole hammer stands vertically behind the rig. Photographed 1/19/2001 by Dennis McDonough.



Photograph 21 – Lake Meredith Salinity Control Project: The Midway 1300 (closest to camera) and Star 30K drill rigs are set up on production wells PW1-4 and PW1-5 in the Canadian River valley. The view is to the east from the south abutment of the Union Pacific Railroad bridge. Photographed 2/1/2001 by Dennis McDonough.

Photograph 22 – Lake Meredith Salinity Control Project: The Cat 950F loader in background is clearing the West Branch pipeline alignment prior to trenching operations. View is to north on land owned by Mr. Romero. Cleared width is about 18 feet. Photographed 10/26/2000 by Dennis McDonough.



Photograph 23 – Lake Meredith Salinity Control Project: The Cat 330B trackhoe is breaking up sandstone ledges along West Branch pipeline alignment. The trackhoe cleared and smoothed the pipeline alignment to the Canadian River valley floor. The loader was used to clear the alignment on the plateau is in the background. Photographed 10/26/2000 by Dennis McDonough.

Photograph 24 – Lake Meredith Salinity Control Project: HDPE pipe sections are being welded near the containment basin. The trackhoe at the north end of the welded pipe is used to drag welded pipeline towards Hwy. 469. Photographed 11/1/2000 by Dennis McDonough.

Photograph 25 – Lake Meredith Salinity Control Project: A Garney employee is trimming and welding 8-inch diameter HDPE pipe. Photographed 11/1/2000 by Dennis McDonough.

Photograph 26 – Lake Meredith Salinity Control Project: A Lydick Engineering & Surveyors technician is checking density of backfill material along the West Branch pipeline. Photographed 11/30/2000 by Jerry Osborn.

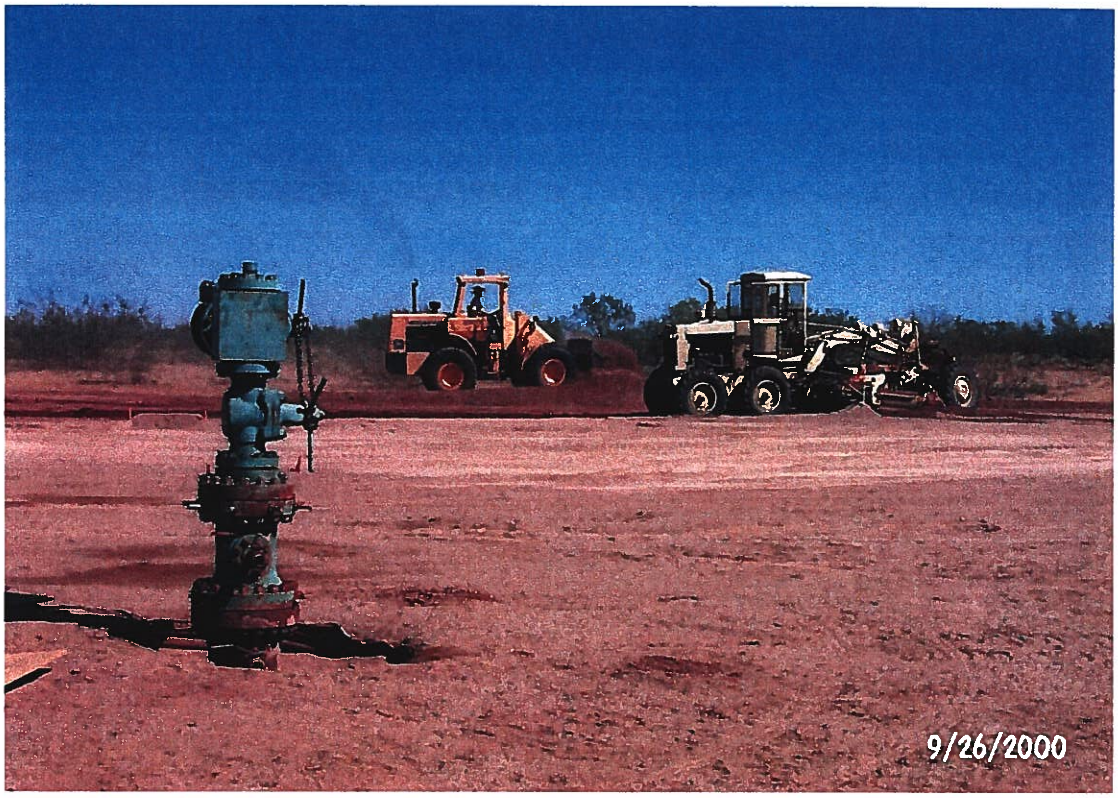
Photograph 27 – Lake Meredith Salinity Control Project: This valve vault is at Station 232+42.75 on the West Branch Pipeline. The vault is located at the top of plateau just before the pipeline drops off into the Canadian River valley floor. Photographed 12/11/2000 by Dennis McDonough.

Photograph 28 – Lake Meredith Salinity Control Project: Looking upstream towards the west, the staked East Branch Pipeline alignment ran from the middle foreground through the extreme upstream corner of the concrete bridge footing in the left middle of the photograph. The alignment was revised to run the pipeline centered and parallel between these two footings. Photographed 1/3/2001 by Dennis McDonough.

Photograph 29 – Lake Meredith Salinity Control Project: The Cat trackhoe has just finished excavating the West Branch Pipeline from plateau down the canyon wall to the Canadian River valley floor. Production Well PW1-1 is at extreme upper left. The trackhoe will travel back to plateau edge and begin laying bedding from the top down before the 6-inch diameter welded HDPE pipe is placed in the trench. Photographed 12/11/2000 by Dennis McDonough.

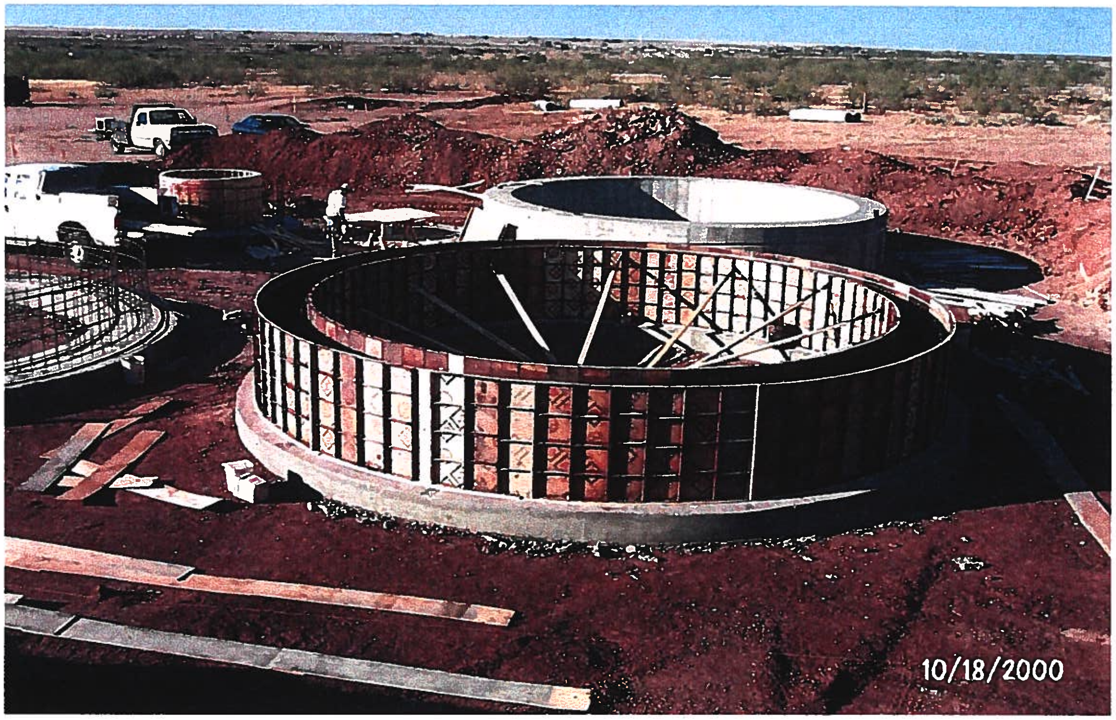
Photograph 30 – Lake Meredith Salinity Control Project: The Garney pipeline crew is welding 6-inch HDPE pipe for the East Branch Pipeline. View is to the west with the Union Pacific Railroad bridge over the Canadian River in the background. Photographed 1/19/2001 by Dennis McDonough.

Photograph 31 – Lake Meredith Salinity Control Project: DH Underground, Inc. is starting the horizontal bore under Hwy 469. As casing is jacked, it is steered by pivoting the section in foreground. A cutting head and auger system remove cuttings. Extra flight augers are at top of picture. The top of casing is only a few inches below a fiber optic cable. Photographed 10/11/2000 by Dennis McDonough.

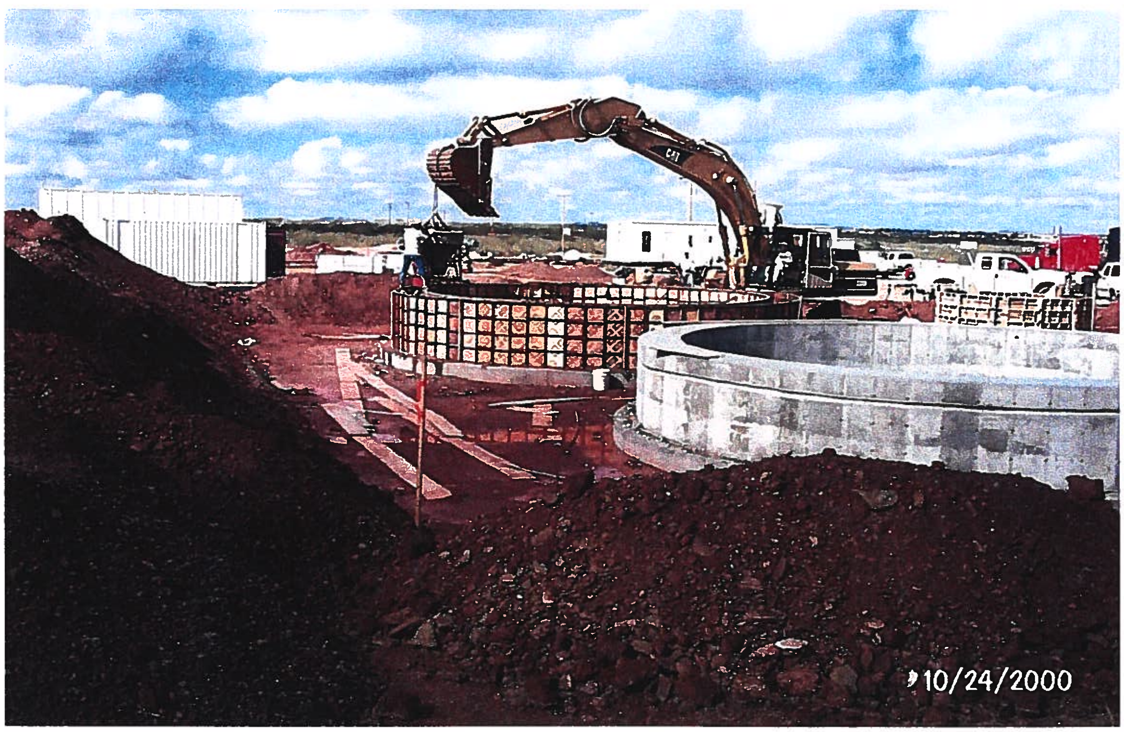


Photograph 32– Lake Meredith Salinity Control Project: RBM Incorporated is excavating the injection well facilities containment basin. The injection well Xmas Tree is in the foreground. Top of Xmas Tree has been rotated so the inlet now is to the east for future hookup to the injection pump discharge line. Photographed 9/26/2000 by Dennis McDonough.

Photograph 33 – Lake Meredith Salinity Control Project: A Garney Companies, Inc. crew is installing rebar for a storage tank foundation in the injection well facilities containment basin. Photographed 10/11/2000 by Dennis McDonough.

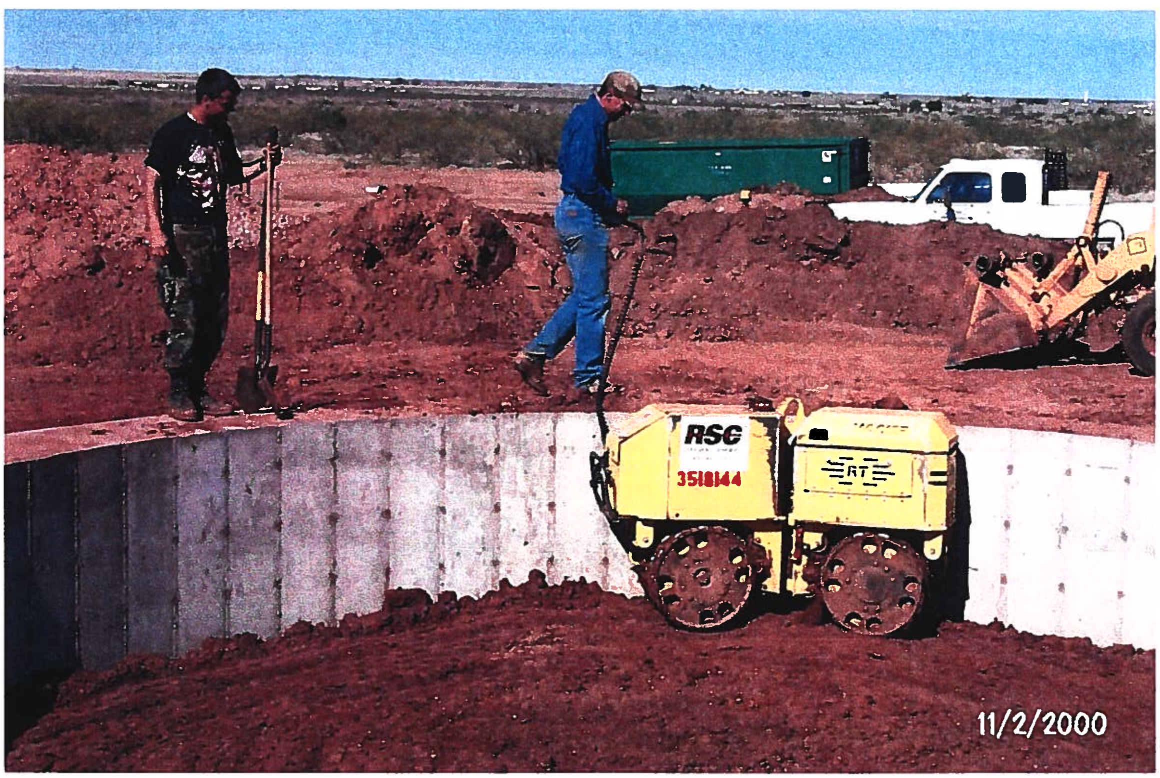


Photograph 34 – Lake Meredith Salinity Control Project: Garney Companies, Inc. employees are forming concrete for a storage tank foundation in the injection well facilities containment basin. Photographed 10/18/2000 by Dennis McDonough.



Photograph 35 – Lake Meredith Salinity Control Project: Concrete is being placed in a foundation wall for a brine water storage tank in the containment basin. Photographed 10/24/2000 by Dennis McDonough.

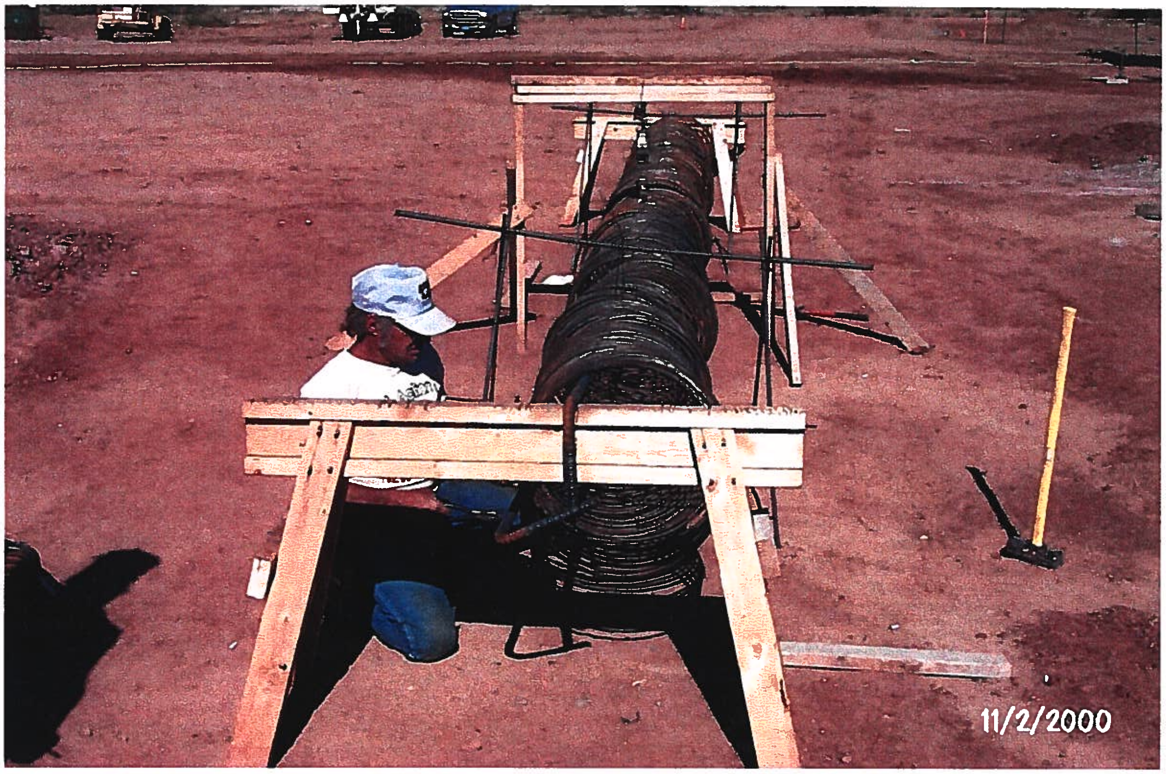
Photograph 36 - Lake Meredith Salinity Control Project: A remote-controlled compactor is being used to compact backfill inside the foundation of the future (no tank will be erected during Phase 2) tank foundation. A contract modification was to place a concrete cap over this backfilled foundation. Photographed 11/1/2000 by Dennis McDonough.



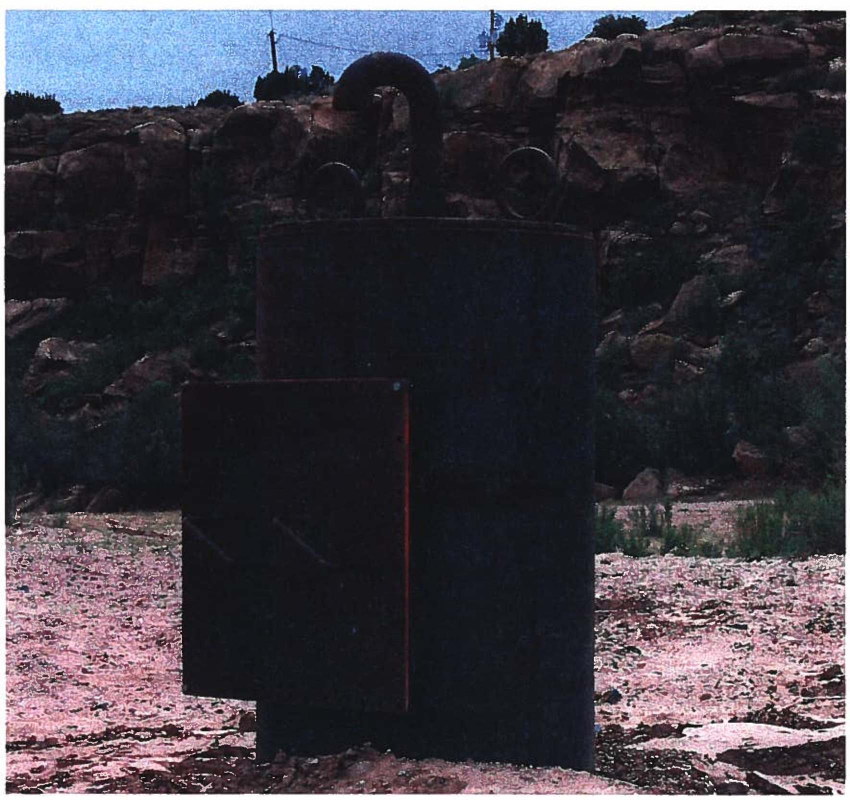
Photograph 37 – Lake Meredith Salinity Control Project: RBM Inc. operator is compacting backfill inside a foundation wall for a brine water storage tank. Photographed 11/2/2000 by Dennis McDonough.

Photograph 38 – Lake Meredith Salinity Control Project: RBM Inc. employee is compacting backfill in the containment basin outside a brine water storage tank foundation wall. Photographed 11/2/2000 by Dennis McDonough.

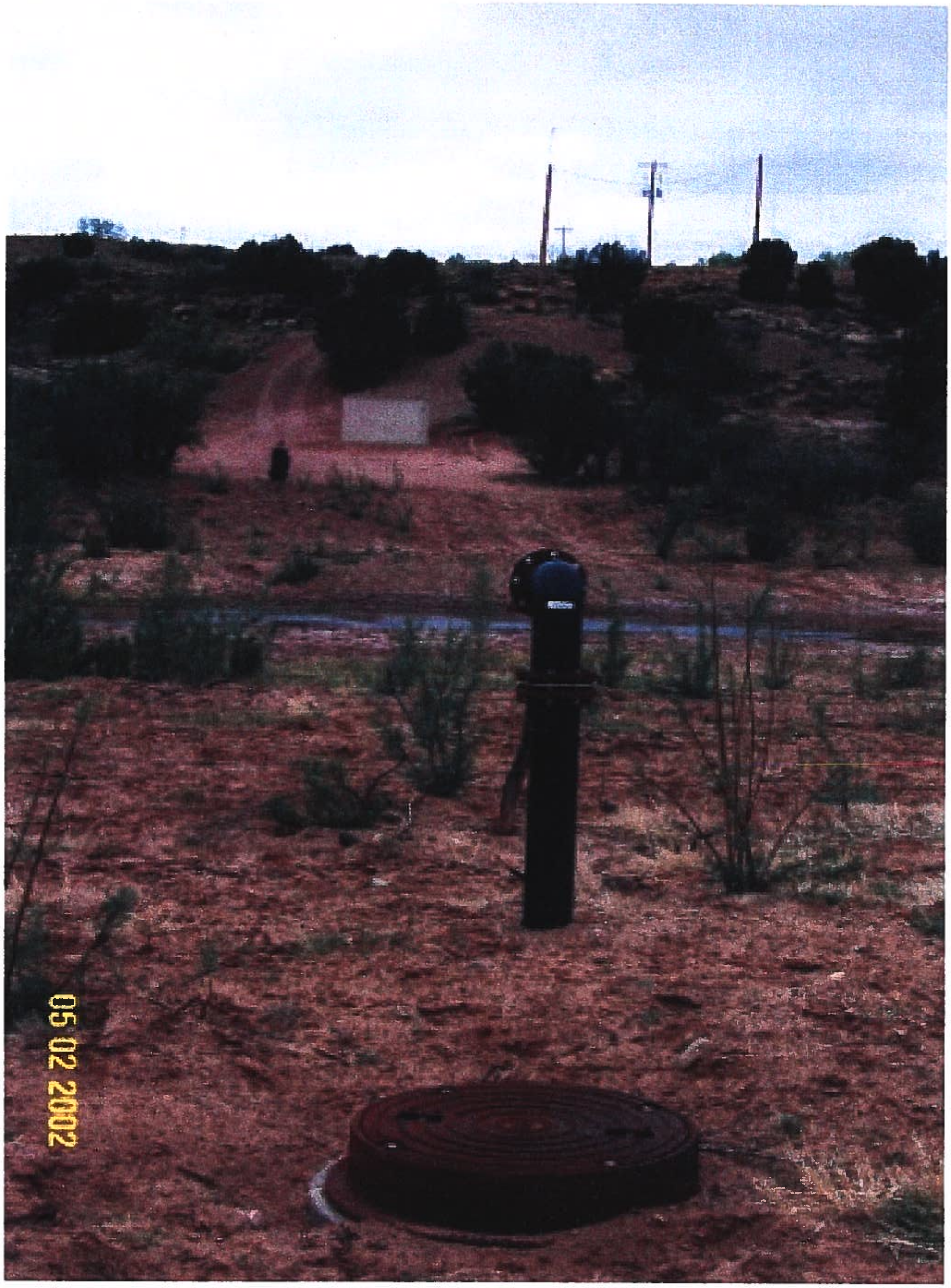
Photograph 39 – Lake Meredith Salinity Control Project: The 12,405 gallon "Run Tank" is being placed in the containment basin. The two 96,400 gallon brine storage tanks are to the right and left of the run tank. Erection of the masonry walls for the office building (left) and injection building (right) has been stopped due to cold temperatures. Photographed 1/19/2001 by Dennis McDonough.



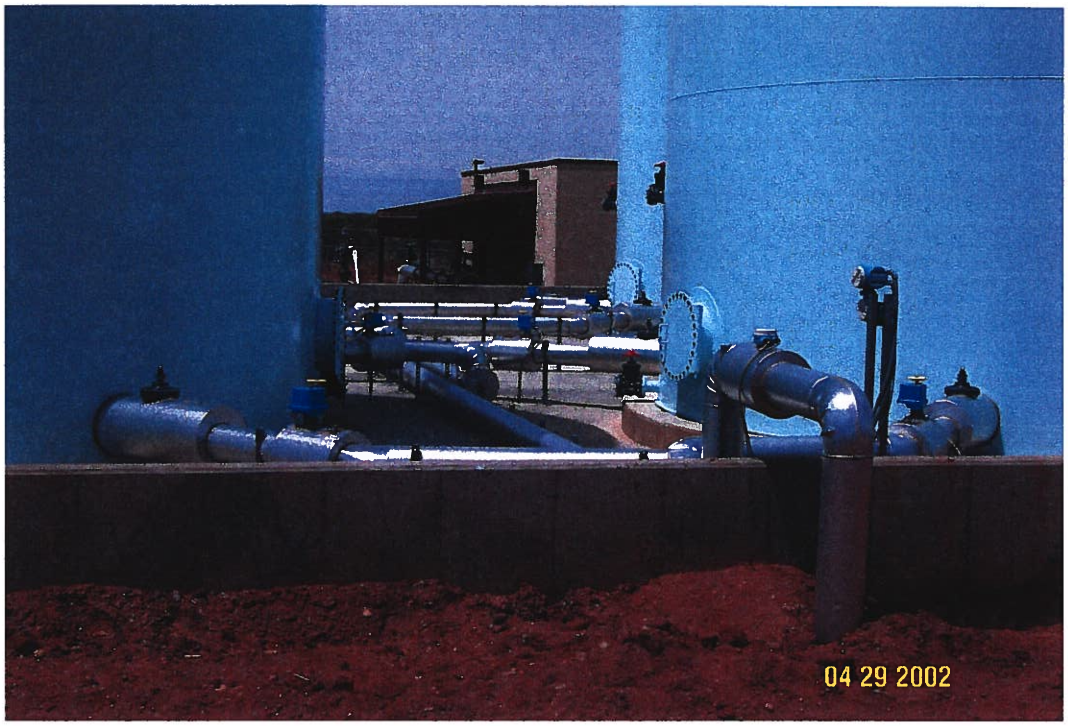
Photograph 41 – Lake Meredith Salinity Control Project: Reinforcement steel is being prepared for insertion in the two caisson holes adjacent to the injection well. Photographed 11/2/2000 by Dennis McDonough.



Photograph 42 – Lake Meredith Salinity Control Project: This production well has been completed in the Canadian River valley floor. Photographed 5/2/2002 by Dennis McDonough.

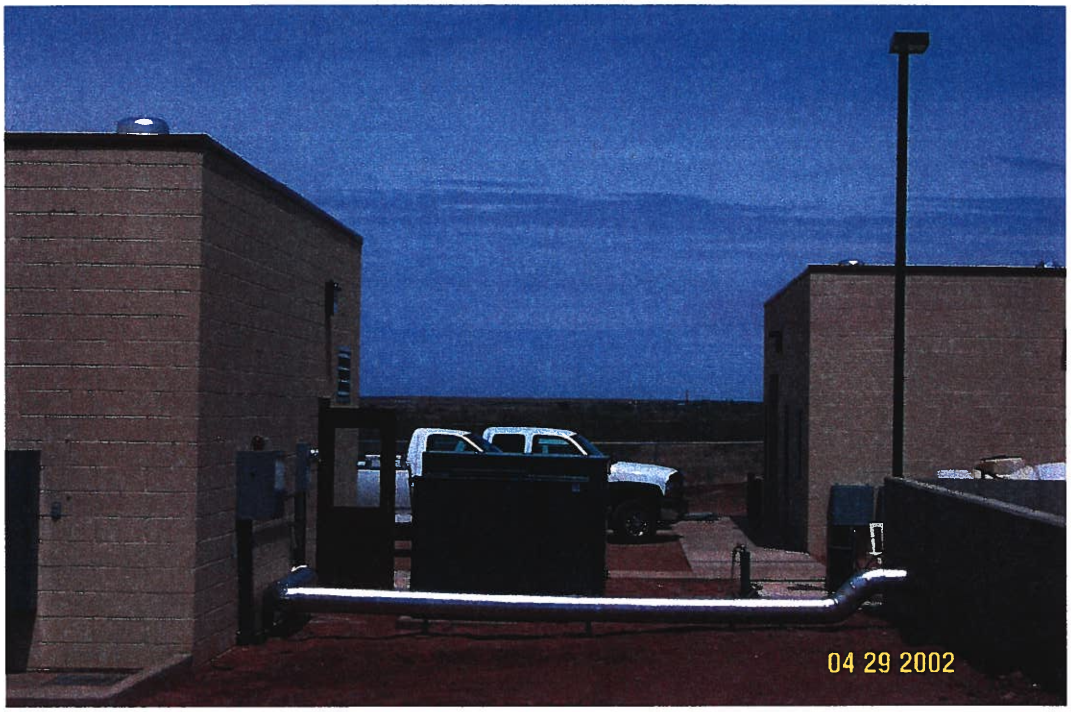


Photograph 43 - Lake Meredith Salinity Control Project - The East Branch Outlet Works Vault manhole is in the foreground. The capped flanged terminal end of the East Branch Pipeline is immediately behind the Outlet Works Vault manhole. A similar vault and flanged terminal end are located at the end of the West Branch Pipeline. (These vaults and terminal end pipe flange replaced the original outlet works structures in the specifications.) Production Well PW1-3 is immediately across the Canadian River. Behind and to the right of PW1-3 is a metal PLC building. A SCADA system antenna in mounted on top of the closest pole behind and to the right of the PLC building. The power line to the site runs south towards Hwy. 469. Photographed 5/2/2002 by Dennis McDonough.



Photograph 44 – Lake Meredith Salinity Control Project: Pipeline from production wells enters the containment structure and storage tanks. The injection building is in the background. Photographed 4/29/2002 by Dennis McDonough.

Photograph 45 - Lake Meredith Salinity Control Project: The containment basin sump is in the foreground with the 12,105-gallon run tank behind. A 96,400-gallon brine water storage tank is to the left. Photographed 4/29/2002 by Dennis McDonough.

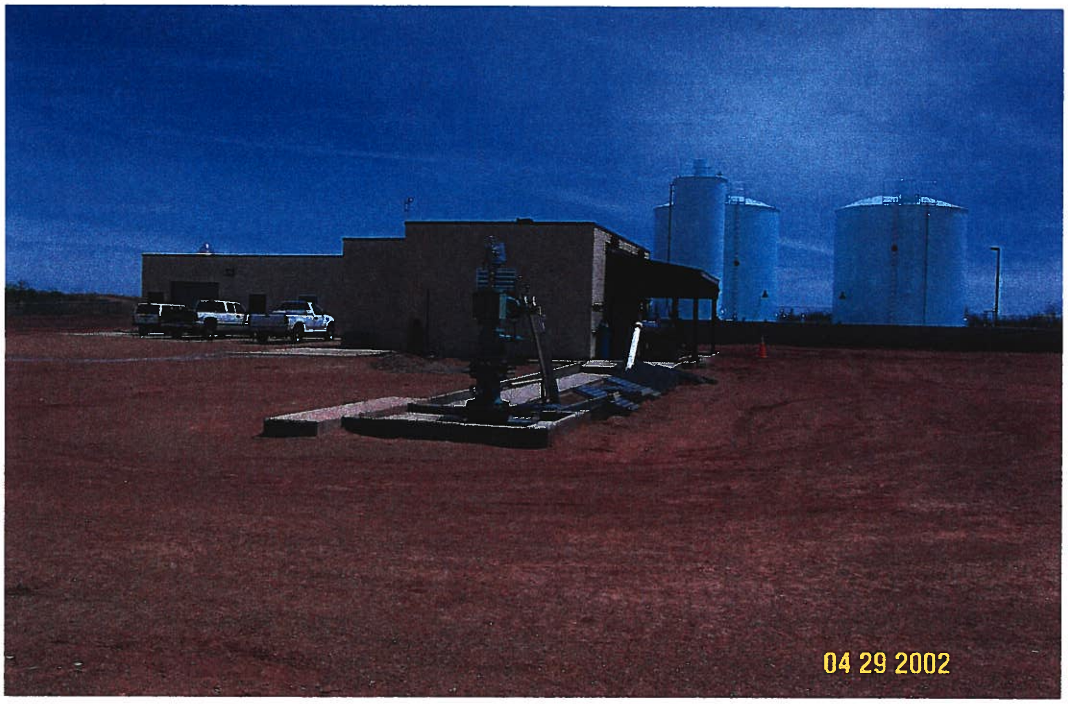


Photograph 46 – Lake Meredith Salinity Control Project: The brine tank discharge line exits the containment basin to the injection building. This discharge line was re-routed around the transformer. Photographed 4/29/2002 by Dennis McDonough.

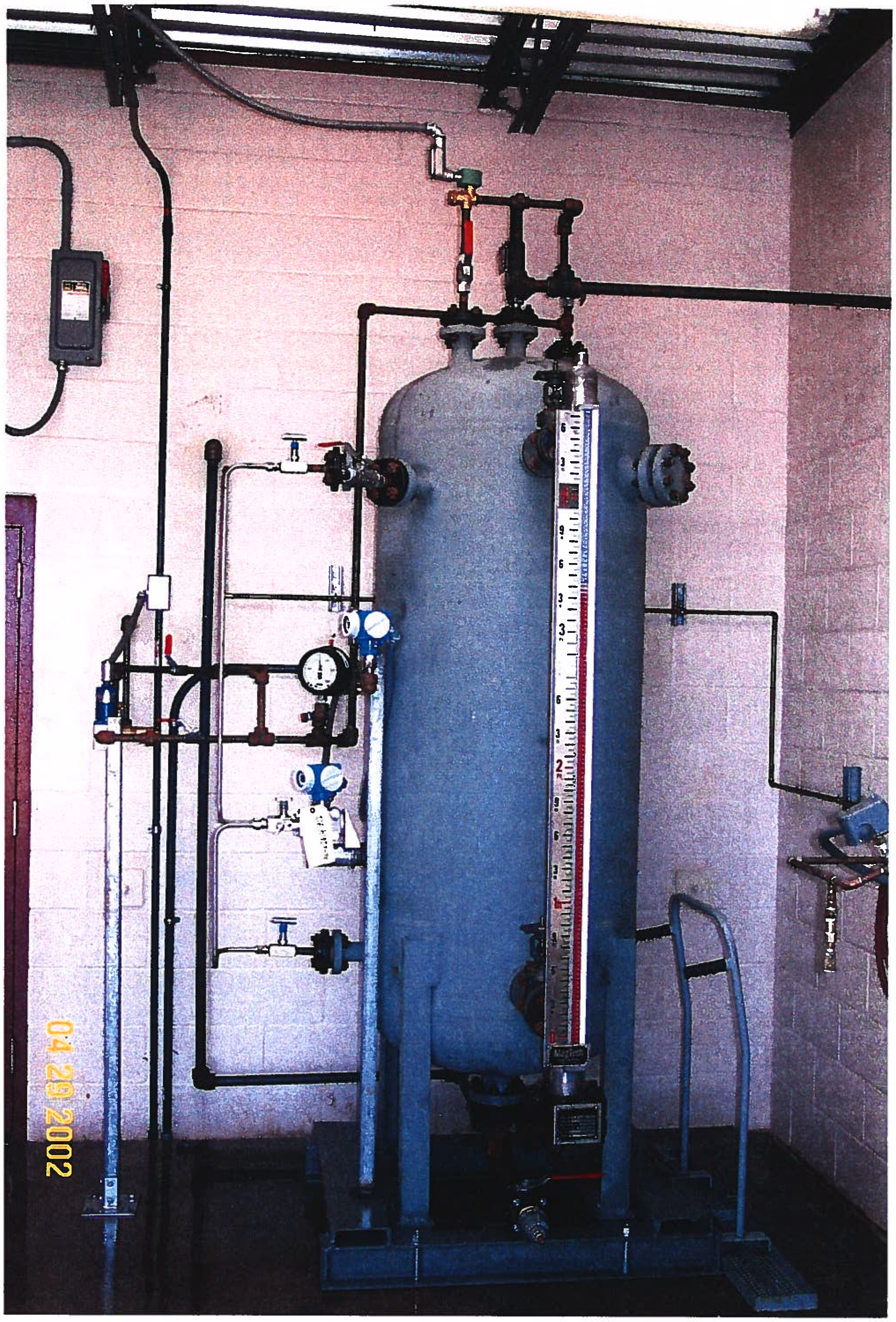
Photograph 47 – Lake Meredith Salinity Control Project: Brine water is piped from the storage tanks to the transfer pump and then to the cartridge filters to the right. Photographed 4/30/2002 by Dennis McDonough.

Photograph 48 – Lake Meredith Salinity Control Project – Brine water from the transfer pump is processed through this bank of cartridge filters. Photographed 4/30/2002 by Dennis McDonough.

Photograph 49 – Lake Meredith Salinity Control Project – Filtered brine water is pumped to the injection well by the injection pump at the right. The discharge line from the pump travels along the concrete lined well chase. Photographed 4/29/2002 by Dennis McDonough.



Photograph 50 – Lake Meredith Salinity Control Project: This view of the injection well facilities is to the northeast with injection well IW-1 in the middle foreground. CRMWA Corp. employees have added curbs to the well chase to prevent debris from entering. The gratings have been removed from the discharge line (well chase) from the injection pump. The injection pump and injection building are directly behind the injection well. The containment basin and storage tanks are to the right, and the office building is to the left. Photographed 4/29/2002 by Dennis McDonough.



Photograph 51 – Lake Meredith Salinity Control Project: The seal pot is mounted in the corner of the injection building. It supplies pressurized fluid to the annular area of the injection well. The seal pot was subjected to rigorous testing before shipment by the manufacturer. The blue nitrogen tanks in Photograph 49 are used to pressurize the fluid. Photographed 4/29/2002 by Dennis McDonough.

Appendix B – Injection Permit

State of New Mexico
ENVIRONMENT DEPARTMENT
Ground Water Quality Bureau
Harold Runnels Building
1190 St. Francis Drive, P.O. Box 26110
Santa Fe, New Mexico 87502
(505) 827-2918 phone
(505) 827-2965 fax

JUL 2002
J.F. Sato & Associates, Inc.

GARY E. JOHNSON
GOVERNOR

PETER MAGGIORE
Secretary

CERTIFIED MAIL - RETURN RECEIPT REQUESTED

DEC 21 1998
BUREAU OF RECLAMATION
AUSTIN, TEXAS

December 16, 1998

Ms. Elizabeth Cordova-Harrison, Area Manager
Bureau of Reclamation
Lake Meredith Salinity Control Project
300 East 8th Street, Room 801
Austin, Texas 78701-3225

RE: Discharge Plan Approval, DP-1054, Bureau of Reclamation - Lake Meredith Salinity Control Project

Dear Ms. Cordova-Harrison:

Pursuant to Water Quality Control Commission (WQCC) Regulation 3109, the discharge plan application for DP-1054, submitted by the Bureau of Reclamation for the discharge of 648,000 gallons per day of saline water removed from the leaking brine aquifer using deep-well injection into the underlying Sangre De Cristo Formation is hereby approved, subject to the conditions listed below. The facility is located downstream of the Ute Dam and Reservoir in New Mexico, approximately 35 miles west of the Texas-New Mexico state line in Section 22.2441, T13N, R33E, Quay County. In approving this discharge plan, the New Mexico Environment Department (NMED) has determined that the requirements of WQCC Regulation 3109.C have been met.

The approved Bureau of Reclamation - Lake Meredith Salinity Control Project disposal system is briefly described as follows:

Up to 648,000 gallons per day of saline ground water is intercepted and pumped from the lower portion of the Trujillo Formation using 6 to 11 production wells located in the Canadian River flood plain and at the top of the south canyon rim. The recovered saline water is piped from the production wells to the injection well facility and stored in a 12,105 gallon holding tank. The recovered saline water will be filtered to prevent formation plugging and injected into the Sangre de Cristo Formation using a Class V Underground Injection Control (UIC) Special Drainage Well (5G30) constructed in accordance with Class I UIC standards. Recovered saline water will be injected into the Sangre De Cristo Formation at an annulus pressure maintained at 150 pounds per square inch above the injection pressure using a compressed nitrogen pressurization system. Ground water in the Trujillo Formation below the project area ranges from approximately 100 to 150 feet below the ground surface and has a total dissolved solids concentration of approximately 50,000 milligrams per liter (mg/l) on the south side of the Canadian River, and approximately 500-1,000 mg/l on the north side of the Canadian River. Ground water in the Sangre de Cristo Formation is at a depth of approximately 3,500 - 4,000 feet and is believed to have a TDS concentration of greater than 10,000 mg/l.

The approved discharge plan consists of the materials submitted by the Bureau of Reclamation dated March 27 and 29, 1995, July 27 and 28, 1995, August 28, 1995, September 18, 1995, October 21, 1995, November 13, 1995, December 27, 1995, May 14, 1996, June 26, 1996, May 22 and 30, 1997, July 23, 1997, and April 15 and 22, 1998. The discharge shall be managed in accordance with the approved plan and is subject to the conditions listed below.

However, approval of this discharge plan does not relieve you of your responsibility to comply with the New Mexico Water Quality Act, WQCC Regulations, of any other applicable federal, state and/or local laws and regulations, such as zoning requirements and nuisance ordinances.

CONDITIONS FOR APPROVAL

This discharge plan approval is subject to the following conditions for the following reasons:

1. The Bureau of Reclamation shall submit to NMED logs from the installation and construction of the injection well as well as all mechanical integrity tests performed on the well for review and approval at least 60 days prior to operation.

   The reason for this condition is to demonstrate that the injection well is properly constructed prior to operation in accordance with WQCC Regulation 5205.

2. The Bureau of Reclamation shall perform a well stimulation test following completion of the well installation and prior to injection. Based on the results of the test, The Bureau of Reclamation shall provide to NMED for review and approval a proposed maximum allowable surface injection pressure which will prevent the initiation of fractures in the proposed disposal zone or the extension of any previously existing joints or natural fractures. The Bureau of Reclamation shall not exceed the approved maximum allowable surface injection pressure with the exception of during well stimulation. The results of the well stimulation shall be provided to NMED for review and approval within 60 days of testing.

The reason for this condition is to determine the maximum allowable surface injection pressure for the proposed well in accordance with WQCC Regulation 5206.B.1.

3. The Bureau of Reclamation shall notify NMED at least two weeks prior to injection of fluids into the injection well.

   The reason for this condition is to provide advance notification of discharge and in accordance with WQCC Regulation 3107.A.6.

4. The Bureau of Reclamation shall test all underground process/wastewater transfer piping to demonstrate mechanical integrity prior to discharge and the results shall be submitted to NMED. In addition, the Bureau of Reclamation shall demonstrate mechanical integrity of the distribution piping at least once every five years (prior to the expiration of the approved discharge plan). The Bureau of Reclamation shall propose to NMED the test method to be used, such as pressure testing or other testing which is acceptable to NMED.

   The Bureau of Reclamation shall demonstrate mechanical integrity of the injection well at least once every five years, however, if the tubing is pulled or the packer is reseated, the Bureau of Reclamation must conduct a mechanical integrity test prior to re-injection of fluids into the subsurface.

   The reason for this condition to demonstrate mechanical integrity of the wastewater distribution system in accordance with WQCC Regulations 3106.C.8, 3107.A.9, and 5204.B.3.

5. The Bureau of Reclamation shall augment its ground water monitoring plan (submitted to NMED on April 15, 1998) as follows:

   A. The following ground water monitor wells shall be monitored for the discharge plan: OW-5 A&B, OW-6 A,B,C, OW-9, OW-10, OW-11, OW-12, OW-13 A&B, OW-14, OW-15, OW-16, TW2, TW-3, TW-4. In addition, NMED shall be notified 2 weeks prior to the installation of the proposed monitor wells (OW-10 through OW-15). These monitor wells shall be installed prior to discharge to the injection well in the locations provided to NMED by the Bureau of Reclamation (Revised Attachment D - dated April 15, 1998). Construction logs of the proposed wells must be submitted to NMED within 60 days of well installation.

B. The seventeen monitor wells listed above shall be sampled and analyzed on a quarterly basis for the following parameters: Total dissolved solids (TDS), and conductivity for a minimum of two years. Once a relationship has been established between laboratory TDS and field conductivity, the Bureau of Reclamation may request that field conductivity measurements, using a conductivity meter calibrated against standard solutions may be used. In addition, the conductivity/TDS relationship and the meter must be checked with samples analyzed in the laboratory for conductivity and TDS from all compliance monitor wells at least once per year. The Bureau of Reclamation may request a reduction in sampling frequency and locations after two years if WQCC standards have not been exceeded.

C. Depth to water, measured to the nearest 100th of a foot shall be measured quarterly in all monitor wells (listed above) and the results shall be submitted to NMED in the quarterly report. A ground water contour map shall be constructed using the quarterly depth to water measurements and submitted to NMED.

6. The Bureau of Reclamation shall submit quarterly monitoring reports to NMED. All monitoring reports shall be signed by an authorized representative of the Bureau of Reclamation as defined in WQCC Regulation 5101.G. The monitoring reports shall be received by NMED Ground Water Pollution Prevention Section (GWPPS) no later than October 31, January 31, April 30, and July 31 of each year.

Monitoring reports shall include information listed in Condition #5A, B and C and Specific Requirement #15 below, and the following additional information:

A. Physical and chemical or other relevant characteristics of the injection fluid;

B. Monthly average, maximum and minium values for injection pressure, flow rate and volume, and annular pressure;

C. Any periodic test of mechanical integrity;

D. Any well work-over; and

E. Any changes within the area of review which may have the potential to impact subsurface conditions.

The reason for this condition is to provide a mechanism for monitoring and reporting, in accordance with WQCC Regulations 3107.5, 3107.A.6, 5101.G, 5207, and 5208.

7. In the event of a spill or if the injection well is suspected or found to be discharging brine solution into a zone other than the Sangre De Cristo Formation, the Bureau of Reclamation shall shut down the wastewater distribution system and the injection well, determine the quantity, extent and impact of the spill or discharge, and implement corrective action. Re-injection shall not be resumed until the equipment is operating properly. The Bureau of Reclamation shall inform GWPPS verbally within 24 hours of the spill or discharge event and shall provide written notification and a corrective action report as described in WQCC Regulation 1203.

   The Bureau of Reclamation shall take all steps necessary to ensure the brine solution enters only the Sangre De Cristo Formation (the proposed injection zone). The Bureau of Reclamation is not permitted to inject fluids into other formations or onto the ground surface.

   The reason for this condition is to provide a contingency plan to address spills or unpermitted discharges, in accordance with WQCC Regulation 1203.A, 3107.A.10, and 5208.A.

SPECIFIC REQUIREMENTS

The terms and conditions of this approval contain specific requirements which are summarized below.

1. Up to 648,000 gallons per day of saline ground water is intercepted and removed from the subsurface using 6 to 11 production wells located in the Canadian River flood plain and at the top of the south canyon rim. The saline water is piped from the productions wells to the injection well facility and stored in a 12,105 gallon holding tank. The recovered saline water will be filtered to prevent formation plugging and injected into the subsurface using a Class V Underground Injection Control (UIC) Special Drainage Well (5G30) constructed in accordance with Class I UIC standards.

2. Recovered saline water will be injected into the Sangre De Cristo Formation (an arkosic sandstone) at an annulus pressure maintained at 150 pounds per square inch above the injection pressure using a compressed nitrogen pressurization system controlled by a Photo Ionization Detector (PID) loop.

3. The Bureau of Reclamation will install six (6) to eleven (11) production wells along the Canadian River in the project area. All but one (1) of the production wells will

be located in the river flood plain, with the remaining well located at the top of the south canyon rim (as identified in Attachment D- General Plan for production well locations submitted to NMED April 22, 1998).

4. The Bureau of Reclamation will construct the brine solution pipeline system using high density polyethylene (HDPE) pipe. A 4-inch diameter pipeline will deliver brine solution from each production well to a 6-inch diameter collection pipeline. There will be two (2) collection pipelines, the "east branch" and the "west branch" which will collect and carry brine solution to the injection well facility. The total pipeline capacity is designed to be capable of flows up to 450 gpm.

5. The Bureau of Reclamation will notify NMED at least two weeks prior to commencement of injection well drilling, cementing and casing, well logging, mechanical integrity testing, and any well work over.

6. The Bureau of Reclamation will demonstrate mechanical integrity of the injection well prior to operation using the following methods:

   A. Inclination surveys will be run on the injection well during drilling of the 17 1/2-inch borehole approximately every 250 feet from the base of the conductor casing to total depth (TD) of the boring. During the drilling of the 12 1/4-inch borehole to about 2,650 feet, inclination surveys will be run approximately every 250 feet from TD to the base of the surface casing.

   B. Upon drilling into the top of the San Andres Formation, Spontaneous Potential (if any), Dual Induction, Natural Gamma Ray, 4-Arm Integrated Borehole Caliper (with gyroscopic telemetry) logs will be run from TD to the surface. After drilling to approximately 2,650 feet, Spontaneous Potential (if any), Dual Induction, Natural Gamma Ray, 4-Arm Integrated Borehole Caliper (with gyroscopic telemetry) logs will be run from TD to the base of the surface casing.

   C. Centralizers will be used on the surface casing set into the top of the San Andres Formation at the center shoe joint, center joint above the float collar, across collar on joint above the float collar, and across every other collar to the surface. In addition, centralizers will be used on the protection casing set to approximately 2,650 feet at the center shoe joint, center joint above the float collar, across collar on joint above the float collar, and across every other collar to the surface.

D. After geophysical logs are run, the protection casing will be pressure tested using a pressure of 1,000 psi for a minimum of thirty (30) minutes.

E. After drilling vertical and lateral portions of the injection well to TD (below the base of the protection casing) and installing 5 1/2-inch perforated liners and 5 1/2-inch injection tubing, the annular space between the 9 5/8-inch protection casing (set to approximately 2,650 feet) and the 5 1/2-inch injection tubing will be filled with a weighted brine solution containing a corrosion inhibitor (combination of an amine corrosion inhibitor and oxygen scavenger).

F. After initially installing the weighted brine solution, a preliminary annulus pressure test will be run on the injection well at a pressure of 1,000 psi for a minimum of thirty (30) minutes.

G. A baseline Temperature Survey will be conducted on the injection well from the surface to approximately 2,800 feet below the ground surface.

H. A Radioactive Tracer Survey will be conducted on the injection well.

7. The Bureau of Reclamation will test the formation water of the proposed injection zone during injection well construction to ensure that the injection of the brine solution will not result in plugging of the injection zone. In addition, if the TDS of ground water in the injection zone is determined to be less than 10,000 mg/l, the well will be drilled deeper or re-located.

8. The Bureau of Reclamation will monitor total production and compare it with total inflow to the injection facility using the supervisory, control, and data acquisition system (SCADA).

9. The Bureau of Reclamation will use a pump driven by a variable frequency motor capable of discharging 300 gpm at a head of up to 850 pounds per square inch (psi) to inject filtered water into the subsurface.

10. The Bureau of Reclamation SCADA will provide remote alarming via a modem.

11. The Bureau of Reclamation will install pumps with variable frequency motors and controllers capable of flows ranging from 30 to 90 gpm in each of the production wells. Each pump will generate enough head that no booster pumps will be necessary to transport the produced brine to the injection well facility.

12. The Bureau of Reclamation will utilize a vent solenoid will release any excess nitrogen to prevent over pressurization of the well annulus due to thermal expansion of the annulus fluid.

13. The Bureau of Reclamation will monitor and control each production well pump using remote telemetry units with communications to the injection well facility host computer and other necessary components to fully provide remote monitoring and operation of the production wells. The remote monitoring and control for the production wells will allow the following:

    A. Automatic start-up, shut-down, and adjustment of flow rate from individual production wells;

    B. Monitoring of flow rate, cumulative flow, drawdown, and conductivity; and

    C. Automatic alarming.

14. The Bureau of Reclamation will monitor and adjust flows from individual production wells to synchronize with the injection well pumping rate, the available storage capacity of the injection well facility, and to compensate for changes in the conductivity of the production well discharge water (as monitored by the continuous conductivity readings obtained from the remote telemetry system).

15. The Bureau of Reclamation will implement the following monitor plan to monitor system performance and shallow ground water quality in the vicinity of the Lake Meredith Salinity Control Project:

    A. Volume, annulus pressure, fluid pressure, and flow rate of saline water injected shall be monitored on a continuous basis;

    B. Discharge from each production well will be monitored on a continuous basis for conductivity;

    C. Manifold samples of fluids extracted from the production wells (fluids being injected) will be collected and analyzed quarterly for conductivity; and

    D. Daily volume pumped from each production well and the daily volume injected at the injection well.

    E. The SCADA will monitor the following injection well components: pressure differential across brine water filters, and water level in the storage tanks.

F. Manual measurements of gains or losses of annulus fluid pressure and the results will be monitored monthly and reported to NMED quarterly.

16. The Bureau of Reclamation will construct a containment system to capture spilled brine solution. The containment system will include the following components:

A. Concrete curbing around the entire perimeter of the injection well facility;

B. Concrete-lined trench under the pipeline from the injection pump to the injection well; and

C. Construction of a containment basin around the brine water storage tanks capable of containing the entire contents of the brine storage tanks in the event of a rupture. The containment basin will be constructed with concrete sides and bottom, with a 6-inch compacted clay blanket under the bottom of the basin.

17. The Bureau of Reclamation will install a pipeline leak detection system consisting of magnetic flow meters at each of the production wells and at the injection well facility. Total production will be monitored and compared with total inflow to the injection well facility by the SCADA. The SCADA will trigger a system alarm if discrepancies are detected, and the production well pumping will cease. The system will not be restarted until the problem has been identified and corrected. In addition, in an attempt to minimize pipeline maintenance problems the pipeline will be buried a minimum of 3 feet below grade outside the Canadian River flood plain, five feet below grade in the flood plain, and ten feet below grade under the river channel.

18. The Bureau of Reclamation will implement the following contingency plan in the event of a spill, discharge to an unauthorized zone (other than the injection zone), or if ground water standards are approached or exceed standards as a result of the discharge. In addition, the Bureau of Reclamation will notify NMED as outlined in Condition 8 (listed above) of any spill or unauthorized injection.

A. If conductivity increases significantly in ground water in any of the compliance monitoring wells, an immediate assessment will be conducted to determine if the project operations are the cause of the increase. If it is determined by NMED that project operations are increasing the conductivity of potable ground water, production and injection well pumping will be discontinued. Full-time injection will not be resumed until it can be shown that the increase in conductivity is not the result of the injection operation. The Bureau of Reclamation will abate any resulting ground water contamination in accordance with 3109.E and Subpart IV of the New Mexico WQCC Regulations.

B. If the SCADA system (Specific Requirement #7) triggers a system alarm, production well pumping will cease. The system will not be restarted until the problem is identified and corrected. In addition, the SCADA system will be set to alarm and shut off injection should there be a project malfunction such as a drop in annulus pressure in the injection well or rupture of a brine storage tank. Injection will not be resumed until the problem is corrected.

C. Spilled brine will be recovered in the containment system (Specific Requirement #16) and injected into the subsurface via the injection well.

19. The Bureau of Reclamation will not be required to provide Financial Assurance as defined in WQCC Regulation 5210.B.17 for the following reason:

The injection well will be constructed and operated in conjunction with the Lake Meredith Salinity Control Project, a project authorized by Congress under provisions of the Reclamation Projects Authorization and Adjustment Act of 1992, Public Law 102-575. The liabilities of the United States of America will be limited to those provided for in the Federal Tort Claim Laws. The remedies for the State of New Mexico will lie in the Federal Tort Claim laws and contractual obligations. Under contractual obligations, the remedies will be through appeal to the Interior Board of Contract Appeals (IBCA).

20. The Bureau of Reclamation will implement the following closure plan:

A. In the event any production or observation well becomes non-operational during the life of the project, the well will be plugged and abandoned in accordance with NMED Guidelines for Monitor Well Plugging and Abandonment. Any non-functioning wells will be replaced on an as needed basis and the location will be pre-approved by NMED prior to installation. If the project is terminated, all monitor wells a, and production wells will be plugged and abandoned in accordance with NMED guidelines for Monitor Well Plugging and Abandonment. The injection well will be plugged and abandoned in accordance with WQCC Regulation 5209.

GENERAL DISCHARGE PLAN REQUIREMENTS

In addition to any other requirements provided by law, approval of discharge plan, DP-1054, is subject to the following general requirements:

Monitoring and Reporting

Monitoring and reporting shall be as specified in the discharge plan and supplements thereto. These requirements are summarized on the attached sheet(s). Any inadvertent omissions from this summary of a discharge plan monitoring or reporting requirement shall not relieve you of responsibility for compliance with that requirement.

Record Keeping

1. The discharger shall maintain at the facility, a written record of ground water and wastewater quality analyses.

The following information shall be recorded and shall be made available to the NMED upon request.

a. The dates, exact place and times of sampling or field measurements.

b. The name and job title of the individuals who performed the sampling or measurements.

c. The dates the analyses were performed.

d. The name and job title of the individuals who performed the analyses.

e. The analytical techniques or methods used.

f. The results of such analyses, and

g. The results of any split sampling, spikes or repeat sampling.

2. The discharger shall maintain a written record of any spills, seeps, and/or leaks of effluent, leachate and/or process fluids not authorized by this discharge plan.

3. The discharger shall maintain a written record of the operation, maintenance and repair of facilities/equipment used to treat, store and/or dispose of wastewater; to measure flow rates; and/or

to monitor water quality. This will include repairs, replacement or calibration of any monitoring equipment and repairs or replacement of any equipment used in Bureau of Reclamation - Lake Meredith Salinity Control Project waste or wastewater treatment and disposal system.

4. The discharger shall maintain a written record of the amount of effluent discharged.

Inspection and Entry

In accordance with § 74-6-9.B & E NMSA 1978 and WQCC Regulation 3107.D., the discharger shall allow the Secretary or his authorized representative, upon the presentation of credentials, to:

1. Enter at regular business hours or at other reasonable times upon the discharger's premises or where records must be kept under the conditions of this discharge plan.

2. Inspect and copy, during regular business hours or at other reasonable times, any records required to be kept under the conditions of the discharge plan.

3. Inspect, at regular business hours or at other reasonable times, any facility, equipment (including monitoring and control equipment), practices or operations regulated or required under this discharge plan.

4. Sample or monitor, at reasonable times for the purpose of assuring discharge plan compliance or as otherwise authorized by the New Mexico Water Quality Act, any effluent at any location before or after discharge.

Duty to Provide Information

In accordance with § 74-6-9.B NMSA 1978 and WQCC Regulation 3107.D., the discharger shall furnish to the NMED, within a reasonable time, any relevant information which it may request to determine whether cause exists for modifying, terminating and/or renewing this discharge plan or to determine compliance with this plan. The discharger shall furnish to the NMED, upon request, copies of records required to be kept by this discharge plan.

Spills, Leaks and Other Unauthorized Discharges

This approval authorizes only those discharges specified in the discharge plan. Any unauthorized discharges violate WQCC Regulation 3104, and must be reported to the NMED and remediated as required by WQCC Regulation 1203. This requirement applies to all seeps, spills, and/or leaks discovered from the wastewater disposal system.

Retention of Records

The discharger shall retain records of all monitoring information, including all calibration and maintenance records, copies of all reports required by this discharge plan, and records of all data used to complete the application for this discharge plan, for a period of at least five years from the date of the sample collection, measurement, report or application. This period may be extended by request of the Secretary at any time.

Enforcement

Failure to grant the Secretary or his authorized representative access to the records required to be kept by this discharge plan or to allow an inspection of the discharge facilities or to the collection of samples is a violation of this discharge plan and the WQCC Regulations. Such violations as well as other violations of the discharge plan, may subject the discharger to a compliance order, a compliance order assessing a civil penalty or an action in district court pursuant to § 74-6-10 NMSA 1978, and/or modification or termination of this discharge plan pursuant to § 74-6-5.L NMSA 1978. Penalties assessed as part of a compliance order shall not exceed $15,000 per day for violations of the terms of this permit or the requirements of § 74-6-5 NMSA 1978, and shall not exceed $10,000 per day for violations of other sections of the Water Quality Act.

Modifications and/or Amendments

The discharger shall notify NMED, pursuant to WQCC Regs. 3107.C, of any modifications or additions to the Bureau of Reclamation - Lake Meredith Salinity Control Project's wastewater disposal system, including any increase in wastewater flow rate or wastewater storage and disposal management changes to the system as approved under this discharge plan. The discharger shall obtain NMED's approval, as a discharge plan modification, prior to any increase in the quantity or concentration of constituents in the leachate above those approved in this plan. Please note that WQCC Regs. 3109.E and F provide for possible future amendment of the plan.

Other Requirements

Please be advised that the approval of this plan does not relieve Bureau of Reclamation of liability should your operation result in actual pollution of surface or ground water which may be actionable under other laws and/or regulations.

RIGHT TO APPEAL

If the Bureau of Reclamation is dissatisfied with this action taken by NMED, the Bureau of Reclamation may file a petition for hearing before the WQCC. This petition shall be in writing to the Water Quality Control Commission within thirty (30) days of the receipt of this letter. Unless a timely request for hearing is made, the decision of the NMED shall be final.

TRANSFER OF DISCHARGE PLAN

Pursuant to WQCC Regulation 3111, prior to any transfer of ownership, the discharger shall provide the transferee a copy of the discharge plan, including a copy of this approval letter and shall document such to the NMED.

PERIOD OF APPROVAL

Pursuant to WQCC Regulation 3109.G.4., this discharge plan approval is for a period of five (5) years. This approval will expire on December 16, 2003, and you must submit an application for renewal at least 120 days before that date.

Sincerely,

Marcy Leavitt, Chief
Ground Water Quality Bureau

ML:VM

Enclosures: DP Summary

xc: Gary McCaslin, Dist. Manager, NMED Dist. 4
NMED Clovis Field Office
Mr. Leon E. Esparza, Project Director, OTAO, Bureau of Reclamation, 4149 Highline Blvd., Suite 200, Oklahoma City, OK 73108
Mr. John Williams, General Manager, Canadian River Municipal Water Authority, P.O. Box 99, Sanford, Texas 79078
Mr. Lee Wilson, Lee Wilson and Associates, P.O. 931, Santa Fe, New Mexico 87504

Appendix C – Complete text of WELL COMPLETION REPORT – TEXT – CRMWA CORP. – INJECTION WELL NO. 1 [TWO]

WELL COMPLETION REPORT

CRMWA CORP.
INJECTION WELL NO. 1

QUAY COUNTY, NEW MEXICO
Section 22 - Township 13N - Range 33E

PREPARED FOR
CRMWA CORP.

SANFORD, TEXAS

MAY 2000

Report Prepared By
Texas World Operations, Inc.
520 Post Oak Blvd., Suite 450
Houston, Texas 77027
713-850-0003

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LOG ID #	LOG DATE	LOGGED DEPTHS	LOGGER TD	DRILLER TD	TYPE LOG
1	07/22/1999	20 - 817	825	803	Platform Express- Array Induction, GR
2	07/22/1999	20 - 817	825	803	Formation Micro Imager, Inclinometry Downlog
3	07/25/1999	0 - 749	749	777	Cement Bond Log
4	07/26/1999	0 - 749	749	777	Temperature Log
5	07/31/1999	819 - 2675	2683	2681	Platform Express- Array Induction, GR
6	07/31/1999	819 - 2665	2683	2681	Platform Express- Comp Neutron, Three Detector D
7	07/31/1999	819 - 2681	2681	2681	Formation Micro Imager - GR
8	08/04/1999	0 - 2623	2623	2623	Cement Bond Log
9	08/04/1999	0 - 2623	2623	2623	Temperature Log
10	08/07/1999	2681 - 2907	2887	2907	Comp Neutron, 4-Arm Caliper, GR
11	08/10/1999	2678 - 3540	3548	3545	Platform Express- Array Induction, GR
12	08/10/1999	2400 - 3540	3548	3545	Platform Express- Comp Neutron, Three Detector D
13	08/10/1999	2678 - 3540	3548	3545	Formation Micro Imager - GR
14	08/15/1999	2678 - 3792	3800	3800	Platform Express- Array Induction, GR
15	08/15/1999	2678 - 3792	3800	3800	Platform Express- Comp Neutron, Three Detector D
16	08/15/1999	2710 - 3770	3800	3800	Elemental Capture Spectroscopy Tool - GR
17	08/15/1999	2710 - 3800	3800	3800	Formation Micro Imager - GR
18	08/15/1999	2722 - 3807			ECS ELAN Log Analysis
19	08/15/1999	2722 - 3807			ESC SpectroLith Elemental Analysis
20	08/15/1999	2722 - 3800			Calibrated and HILITE Images Log (from FMI Log)
21	08/15/1999	2722 - 3800			Borehole Image Interpretation
22	08/15/1999	819 - 3800			MSD Mean Square Dip (Pad to Pad Interval Correl
23	08/19/1999	NA	3774		Perforating Record
24	08/19/1999	2500 - 3774	3774	3775	Perforating Depth Control Log - GR / CCL
25	08/21/1999	1000 - 3700		3800	CCL / Pressure / Temp / Spinner Log
26	08/21/1999	NA			PL Advisor Using BorFlow
27	09/02/1999	2516 - 3666	3674	4078	Platform Express- Array Induction, GR
28	09/02/1999	2516 - 3656	3674	4078	Platform Express- Comp Neutron, Three Detector D
29	09/02/1999	2516 - 3630	3664	4078	Elemental Capture Spectroscopy Tool - GR
30	09/02/1999	2566 - 3664	3664	4078	Formation Micro Imager - GR
31	09/02/1999	2516 - 3666			ECS ELAN Log Analysis
32	09/02/1999	2572 - 3665			Calibrated and HILITE Images Log (from FMI Log)
33	09/09/1999	2400 - 3626	3630	4078	Gamma Ray / CCL Log (PDC)
34, 35, 36	Undated	Lateral Hole			MWD MD GR Logs at 1:240; 1:600; 1:1200 Scales
37, 38, 39	Undated	Lateral Hole			MWD TVD GR Logs at 1:240; 1:600; 1:1200 Scales
40	09/11/1999	2300-3400	---	4078	PSP - Injectivity Test
41	09/11/1999	NA			PL Advisor Using BorFlow
42	10/06/1999	Surface-3740	3740	3740	Temperature Log
43	10/06/1999	3650-Surface	3650	3650	Pump In Tracer
44	7/25 to 8/15	Vertical Hole			Mud Log
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1.0 EXECUTIVE SUMMARY

The CRMWA Corp. No. 1 injection well was drilled and completed during July, August and September, 1999. Mechanical integrity testing of the well was performed on October 6, 1999. The well was constructed according to the specifications contained in and referenced from Discharge Plan DP-1054, approved on December 16, 1998 by the Ground Water Quality Bureau of the State of New Mexico Environment Department. The well is a Class V Underground Injection Control (UIC) Special Drainage Well (5G30) constructed to Class 1 UIC standards. The well meets the construction standards specified in the Code of Federal Regulations (CFR), Title 40, Part 146.

The injection well is located in Quay County, New Mexico in Section 22, Township 13 North, Range 33 East, approximately 1-1/2 miles south of the Village of Logan. The well is in the SE/4 of the NE/4 of Section 22. New Mexico East Zone Coordinates for the well's location are 1,580,228.03 feet North and 773,158.79 feet East.

The well was installed with a vertical segment drilled into the Precambrian basement to a measured depth of 3800 feet, and a sidetracked lateral segment drilled laterally within the Permian Abo and Sangre de Cristo Formations to a measured depth of 4078 feet (3506 feet True Vertical Depth). Unless otherwise specified, all depths were measured from the rotary kelly bushing (RKB), 14.50 feet above ground level. Suites of open hole geophysical logs were run in all portions of the well.

Twenty inch steel conductor pipe was set at a depth of 42 feet and 13-3/8" steel surface casing was set at 819 feet. Protection casing consisted of 9-5/8" steel casing set and cemented at 2673 feet into the Abo Formation. Casing pressure testing, cement bond logging and temperature logging was performed on all cemented casing strings.

Steel 5-1/2" liner consisting of a 20 hole per foot pre-perforated lower section (3776' to 3247') and a blank upper section (3224' to 2673') was hung off in the protection casing, with an external casing packer and port collar between the segments. The blank upper section of the liner was cemented in place and selectively perforated with 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

A whipstock was set in the protection casing and a window was milled through the side of the 9-5/8" casing from 2515 feet to 2529 feet to begin the lateral portion of the well. The whipstock was oriented so that the lateral hole was directed on an azimuth of south 10 degrees west. The lateral hole was drilled to a depth of 4078 feet (3506 feet TVD) at a point approximately 1061 feet south and 185 feet west of the kick-off point from the vertical hole, along a lateral section 1077 feet in length. The lateral hole attained an inclination of approximately 78° from the vertical. The lateral hole reached total depth within the lower member of the Sangre de Cristo Formation.

Steel 5-1/2" liner consisting of a 20 hole per foot pre-perforated lower section (4070' to 3419' measured depth) and a blank upper section (3397' to 2470' measured depth) was hung off in the protection casing of the vertical hole, with an external casing packer and port collar between the segments. The blank upper section of the liner was cemented in place and selectively perforated with 8 or 4 shots per foot in zones that appeared to have the best porosity and permeability with the Abo and Sangre de Cristo Formations.

A packer with a polished bore receptacle (PBR) was set in the 9-5/8" protection casing between 2446 feet and 2465 feet. An injection tubing string consisting of 5-1/2" fiberglass tubing and a seal assembly was landed in the PBR with the top of the seals at 2443.61 feet. The bottom of the tailpipe was at 2465.58 feet. A 3000 psi working pressure wellhead with bowl and seal assembly was installed to the top of the casing-tubing assembly.

The injection well was installed approximately one-quarter mile southwest of the pilot hole that was drilled in 1996 to evaluate the injection potential of the area. The geological formations encountered in the injection well were very similar in depth, thickness and lithology to that noted in the pilot hole, with the exception of the lower Sangre de Cristo Formation - Precambrian interface. Underlying the mudstone and mudstone conglomerates of the upper Sangre de Cristo, a thick sequence of granite wash or grus was present in the injection well that was not described from the pilot hole. A total of 292 feet of this unit was drilled, followed by 58 feet of highly weathered Precambrian basement materials which overlaid a fractured igneous Precambrian basement formation. The injection well was drilled to a depth approximately 600 feet deeper than planned in order to fully penetrate the previously unknown geological units. The significant changes between the pilot hole and the injection well near the basement imply that there may be considerable relief present on the weathered Precambrian surface.

Based on the geological formations encountered, the injection and confining zones of the well are defined as follows:

Confining Zone:	1883' to 2421', (lower Yeso formation)
Injection Zone:	2421' to 3800'

The injection zone is divided in to the containment interval and injection interval. Only the injection interval directly receives injected fluids from the well.

Containment Interval:	2421' to 2500' (upper Abo Formation)
Injection Interval:	2500' to 3800' (lower Abo, Sangre de Cristo, and Precambrian)

Dipmeter interpretation indicated that the structural dip, in geological formations where it could be determined, was generally to the south or southwest at very gentle rates of approximately one-half a degree.

Minor fracturing was present in the lower Abo and upper Sangre de Cristo. Fracturing was considerably more common in the granite wash and Precambrian sections of the well. The fractures had a predominate east-west strike and dipped toward the south. Many of the fractures were healed and do not contribute to the wells injection capacity.

Fracturing was not detected above the lower Abo Formation from geophysical logs, or in either of the two cores recovered from the Yeso formation (confining zone). The deeper fracturing that was noted in the injection zone is believed to be a minimal contributor to fluid movement due to mineral precipitation. Available data indicate that the integrity of the containment interval and the confining zone are intact, and these geological barriers will effectively isolate injected brine fluids from any potential underground source of drinking water (USDW).

Full cores were taken in the Yeso Formation (confining zone) and the Sangre de Cristo Formation (injection interval). A total of 150 feet of core was attempted and approximately 125 feet was recovered. The core material was subjected to extensive testing for porosity and permeability, petrographic, x-ray diffraction and scanning electron microscopy examinations. The recovered core was primarily siltstone, with a high quartz content. Clay minerals in the injection interval contained a high proportion of illite and illite-smectite. These materials are generally sensitive to undersaturated fluids, and matrix swelling can be detrimental to injection by causing a reduction in permeability.

Samples of the core from the injection interval were subjected to flowthrough compatibility testing using fluid from the Trujillo Formation and local fresh water. No significant compatibility problems were noted, although there was a gradual degradation of permeability in most of the samples with continued injection.

Static fluid testing of Sangre de Cristo core samples indicated the formation to be sensitive to fresh water. Sodium chloride brine and ammonium chloride solution appeared to cause the least sample disaggregation of any of the fluids tested.

Mechanical properties of the injection interval were determined through acoustic velocity analysis performed on samples from cores. The fracture gradient in the injection interval was determined to be 0.7996 psi/ft. Based on this fracture gradient and the hydraulic gradient measured during well testing, the surface injection pressure that could cause fracturing at the weakest point of the injection interval is 924 psi. Injection pressure is limited to 850 psi by permit, therefore injection operations will not initiate fracturing.

Injectivity fall-off testing was performed on the vertical portion of the well, and later on the combined vertical and lateral well segments. The vertical hole was tested with a packer set at 2630 feet in the 9-5/8" protection casing. A Halliburton pump truck was used to pump 9.1 pounds per gallon brine for the 8 hour injection period. Pressure and temperature were monitored and recorded at the surface. The spinner data indicated that all injected fluid was exiting the well through the three uppermost sets of perforations within the Abo Formation at 2734-2746 feet, 2766-2790 feet, and 2808-2820 feet. The gauges were set at 3200 feet after the spinner passes and the pressure was recorded for the remainder of the injection period and the entire falloff period at this depth.

Injectivity-falloff testing of the combined vertical and lateral hole was conducted on September 11-12, 1999 after completion of the lateral hole. The packer was set at 2469 feet (1 foot above the liner hanger packer in the 9-5/8" protection casing in the vertical hole). In this well configuration, there was a single joint of pre-perforated 5-1/2" liner immediately set above the lateral hole window in the 9-5/8" casing that allowed fluid access to the vertical wellbore. A Halliburton pump truck was used to pump 9.3 pounds per gallon brine for the 8 hour injection period. Pressure and temperature were monitored and recorded at the surface. The spinner data indicated that approximately 58% of the injected fluid was exiting the well through the vertical section, 34% through the perforations 2604-3375 feet in the lateral hole, and 8% through the pre-perforated liner below 3401 feet. The gauge was set at a measured depth of 3401 feet (true vertical depth of 3223 feet) feet after the spinner passes. The pressure was recorded for the remainder of the injection period and the entire falloff period at this depth.

The field injection results from both tests appear to be encouraging for long term operation of the well. However, the analytical conclusions derived from the test data are somewhat less optimistic because the tests were not of sufficient length to achieve radial flow within the formation. The absence of radial flow reduces the accuracy and reliability of any simulation modeling.

The current tests did not yield the mathematical predictions on the injection well capacity or longevity that were desired, but they definitely support injection at rates adequate to achieve the basic goals of the project. A detailed discussion of the reservoir testing conducted on the well is included in Appendix H of this report.

Mechanical integrity testing was performed on the well following its completion. An annulus pressure test, radioactive tracer survey and a temperature log were run. The results of the testing indicated that there was no significant leak in the well's casing, tubing, packer or seals. Additionally, there was no evidence of upward fluid movement outside the well's protection casing that could endanger any underground sources of drinking water.

2.0 DAILY OPERATIONS SUMMARY

Note: Copies of the Texas World Operations, Inc. Daily Drilling and Completion Report are located in Appendix N of this report.

Prior to moving in the drilling rig and equipment, the drilling pad and reserve pits had been prepared by CWMWA Corp. personnel. The reserve pit was lined with a 10 mil thickness of EX liner by Akome, Inc., who also installed a four foot tall barbed wire fence on three sides of the pit. Conductor (20" OD carbon steel, 0.375' wall thickness) was set and cemented in 30" hole at 30', a 6' by 6' galvanized Tinhorn cellar, rat and mouse holes were installed by Weder Services.

7/20/99 Texas World Operations drilling supervisor arrived on site. Drilling rig on site. Spotted equipment and rigged up drilling rig and ancillary equipment. Polyethylene sheeting was laid down beneath the drilling rig and ancillary equipment to protect the ground surface from any run off or leakage of fuels, lubricants or drilling fluids.

7/21/99 Continued rigging up and spotting equipment. Mixed gel and lime mud in steel mud tanks. Began drilling with a 17-1/2" S3SJ4 bit with 8, 16, 16, 16 jets. Drilled ahead to 505' measured depth RKB. Periodic single shot inclination surveys were run during drilling operations. .

7/22/99 Drilled ahead to 822' measured depth. Rigged up Wildcat automatic driller while waiting on Schlumberger to arrive for running open hole electric logs. Ran Platform Express-Array Induction - Gamma Ray; Formation Micro Imager - Inclinometry Downlog from 817' to 20' Schlumberger measured depth. Rigged down and released Schlumberger logging equipment.

7/23/99 Rigged up Weatherford casing crew and began picking up float shoe and 13-3/8" 61 lb/ft J-55 STC casing. Ran casing to 819.1' (RKB) and circulated hole clean with 225 barrels of mud. Halliburton cementing crew and equipment arrived at the site and rigged up to cement. Held a safety meeting for all supervisory, rig, and Halliburton cementing personnel.

Dropped a lead wiper plug followed by 10 barrels of fresh water, 133 barrels of 12.8 lb/gal lead cement and 83.5 barrels of 14.8 lb/gal tail cement. Dropped an upper wiper plug and started displacement out of casing using water. Landed the wiper plug after pumping 123 barrels of fresh water. Checked the floats and found them to be OK. Shut down to wait on cement. Halliburton was rigged down and released from the site.

Cleaned mud pits and performed rig maintenance while waiting on cement to cure. Moved in a mobile storage tank (frac tank) for brine storage and began filling the tank with brine.

7/24/99 Cut off conductor pipe and surface casing. Mounted the bradenhead flange on the top of the surface casing. Began mixing salt gel and starch in the steel mud pits for use in drilling out of the surface casing. Tested the welds on the bradenhead flange to 850 psi. The welds held OK. Started to nipple up the BOPs while continuing to wait on the surface casing cement to cure.

7/25/99 Finished waiting on cement to cure (48 hours total). Baker Atlas arrived on site and rigged up to run temperature and cement bond logs through the surface casing. Baker Atlas ran a temperature log from 749' (tagged top of cement) to the surface. Ran a cement bond log from 749' to surface. Rigged down Baker Atlas.

Rigged up to pressure test the 13-3/8" surface casing. Pressured up on casing using rig mud pumps to 1243 psi (transducer gauge pressure). Repaired leaks in manifold. Started the casing pressure test at 1040.68 psi. Casing pressure declined to 1021.82 psi after 35 minutes. This change of 18.86 psi (1.8 percent) was acceptable.

Rigged up Technical Drilling Services, Inc. mud loggers in preparation of drilling out of the surface casing and making new hole. Drilled out the wiper plug and casing float shoe and began to drill new formation using a

12-1/4" Security S86CF bit with 11,12,12 jets. Drilled to 905'.

7/26/99 After reaching a depth of 915' the hole was circulated clean and the drilling assembly was pulled out of the hole to add a roller reamer and stabilizer to the bottom hole assembly. Tripped back in the hole and continued drilling to a depth to 1322'

7/27/99 Drilled and surveyed to 1982'. Hole inclination running 3/4 to 1 degree.

7/28/99 Drilled to first coring point at 2020' in the Yeso Formation. Circulated the hole clean, dropped a survey and pulled out of the hole to core. A service representative from DOWDCO was on site to oversee the coring operation. Picked up a 8-1/2" diamond core head, core barrel and jars and went in the hole to core. Stopped coring at 2029' due to pump problems. Switched over to pump #2 and continued coring to 2058.8'. Pulled out of the hole with the coring assembly and laid down the core barrel on the catwalk. There appeared to have been full recovery (30') of the cored interval. The aluminum core barrel was cut into 7-1/2' lengths, the barrel ends were sealed, and the core was prepared for transport to Reservoirs Inc. in Midland for analysis.

Tripped in the hole with rerun 12-1/4" Security S86CF bit and reamed the cored interval from 2020' to 2050'. Drilled new hole to 2106'.

7/29/99 Drilled ahead toward coring point #2 in the Yeso Formation. Mud log correlations indicated the well was running approximately 26' to 37' low on measured depth compared to the pilot hole. Drilled to 2155' and circulated hole clean, dropped a survey and pulled out of the hole to pick up coring bottom hole assembly.

Started in the hole to core using a CP43 8-1/2" x 4" core bit. Spaced out drill pipe and started coring the Yeso at 2155' for core #2. Cored with 10,000# WOB and 70 RPM on rotary. Stopped coring at 2185' after cutting 30' feet of core. Pulled out of the hole with core #2 and laid down the aluminum core barrel on the catwalk. The barrel was cut into 7-1/2' lengths and prepared for transport to Reservoirs Inc. The cored interval appeared to have been fully recovered.

Went in the hole and reamed the cored interval with a 12-1/4" bit. Drilled new formation to 2199' and lost 50 to 75 psi of pump pressure, indicating a possible washout in the drill string. Continued to drill ahead to 2212' while closely monitoring pump pressure. Pump pressure loss was now at 100 psi.

Started out of the hole looking for a washout in the drilling assembly. A washout was located in the first connection between 20 lb/ft drill pipe joints above the drill collars. Two joints of 20 lb/ft drill pipe were laid down. Replacement of the bad joints with 16.6 lb/ft drill pipe higher in the string after going back further into the hole was planned.

7/30/99 Ran back into the hole and resumed drilling and taking periodic inclination surveys. At 2407' the drilling rate had slowed significantly, and the bit was pulled out of the hole. The bit was found to be in good condition but was balled with soft gypsum. The jets in the bit were changed out to three 11/32" jets, and the bit was rerun. Drilling was continued to a depth of 2501'. Surveys indicated well inclination was approximately 3/4 of a degree.

7/31/99 Drilled and surveyed to 2681'. Circulated the hole clean and began to pull out of the hole standing drill pipe and collars back in the derrick. Rigged up Schlumberger to run open logs from 2681' to the base of the surface casing. Schlumberger ran a Platform Express - Array Induction - Gamma Ray (2675' to 819'); Platform Express - Compensated Neutron - Three Detector Density - Gamma Ray (2665' to 819'); Formation Micro Imager - Gamma Ray (2681' to 819'). The Formation Micro Imager was run in imaging mode for the lower 500' of the interval and in dipmeter mode for the remainder of the logged interval. The Formation Micro Imager tool data did not record properly and Schlumberger evaluated the computer problem.

8/1/99 The tool problems were resolved and the electric logging was completed. Rigged down Schlumberger.

Went in the well with a 12-1/4" bit and cleaned up the hole prior to running protection casing. Found 10' of fill on bottom and circulated it out of the hole. Worked bottom hole assembly up and down the bottom of the hole without rotating to make sure hole was free of any obstacles that might impede running casing. Hole was clean.

The kelly was stood back and the drill string pulled out of the hole. Laid down the 8" drill collars. Rigged up the Weatherford casing crew and equipment. A safety meeting was held for all personnel.

Started to pick up the 9-5/8", 40 lb/ft, J-55 casing to be used as the protection string. Changed out the BOP rams to 9-5/8" size and rigged up to circulate. Started running the casing in into the well, filling up the casing with water every fourth joint. Picked up and ran a TAM external casing packer and port collar, then continued running the 9-5/8" casing.

The hole volume was calculated to be 444.8 barrels, with 202.8 barrels in the casing (2676' x 0.0758 bbls/ft) and 242 barrels in the annular space (2681' x 0.0903 bbls/ft).

Installed a bowl in the rotary table and landed the casing about 2' above the rotary table. Bottom of float shoe is at 2673.21' below RKB. Rigged up to circulate down casing. Rigged down the casing crew and power swivel equipment.

8/2/99 Circulated drilling mud through the 9-5/8" casing using rig pumps prior to cementing. Pumped 667 barrels (1.5 well volumes). Broke circulation with mud and rigged up Halliburton to flush 95% of the casing volume with fresh water.

Held a safety meeting prior to having Halliburton perform any pumping. Planned to pump 190 barrels of fresh water with pressure not to exceed

500 psi. Began to displace the casing with fresh water at a rate of 2 BPM and had good returns to the surface. The pumping rate was increased to 6 BPM, then 8 BPM at a surface pressure of 270 psi. At 190 barrels pumped, the pump-in connection to the casing was rigged down.

A steel plate and slip bowl were installed on the top of the casing in preparation for going in the hole to perform an inner string cement job on the 9-5/8" casing. Began going in the hole with a stinger on the bottom of the drill pipe for the inner string cement job. Spaced out and picked up the TAM combo tool so that the tool would be one joint below the casing packer, and continued in the hole.

Tagged the port collar with the combo tool with joint #83 11 feet out above the rotary table. Added a 5.60' pup joint above joint #83. Landed the stinger in the float collar and rigged up Halliburton flow iron to pump cement into inner string.

A safety meeting for all site personnel was held prior to pumping cement. Halliburton tested their flow lines with water to 2000 psi, OK.

Pumped 10 barrels mud flush, 10 barrels fresh water, 10 barrels mud flush at 4.5 BPM.

Pumped Stage 1 lead cement, which consisted of 315 sacks of 35/65 Pozmix/Class H w/ 1%$CaCl_2$, 6% Bentonite and 0.25 lb/sack cellophane. Volume pumped was 98 barrels at 5.2 BPM and 120 psi average. Cement was 12.8 lb/gal, 1.81 ft^3/sack, 9.64 gal water/sack.

Pumped Stage 1 tail cement, which consisted of 270 sacks of 35/65 Pozmix/Class H w/ 1%$CaCl_2$, 6% Bentonite and 0.25 lb/sack cellophane. Volume pumped was 51 barrels at 3.5 BPM and 100 psi average. Cement was 16.4 lb/gal, 1.08 ft^3/sack, 4.32 gal water/sack.

Halliburton washed down their tanks and mixers to the rig pits. Dropped a wiper plug and displaced the drill pipe with 35.75 barrels of fresh water.

Landed the plug in the float collar and had a pump pressure increase from 550 to 1200 psi. There was no back pressure noted as the pump pressure was released form the float collar. Broke down the flow connections to move the inner string up inside the casing to start the second stage of the cement job. Pulled up out of the float collar and noted that the float equipment held OK. Laid down one joint of drill pipe and dropped an isolation ball.

Pulled up in the casing and positioned the combo tool across the inflation valves of the TAM inflatable casing packer. Slowly pressured up to open the inflate valve. The packer opened at 1320 psi and the pressure dropped to 580 psi. Increased the pressure to 1000 psi and waited for four minutes, then raised the pressure to 1550 psi to isolate the packer.

The inner string was pulled up to the port collar and latched in. The port collar was opened and an increase in pressure of 90 psi was noted. Water was circulated through the port collar to clean out the excess cement from the first cementing stage. Cement was noted at the surface at approximately 60 barrels pumped. A total of approximately 45 barrels of cement and cement cut water were circulated out of the annulus.

Preparations were made for pumping stage two of the cementing job. Pumped 10 barrels mud flush, 10 barrels fresh water, 10 barrels mud flush with good returns to the surface.

Pumped Stage 2 lead cement, which consisted of 250 sacks of 35/65 Pozmix/Class H w/ 1%$CaCl_2$, 6% Bentonite and 0.25 lb/sack cellophane. Volume pumped was 68 barrels at 5.0 BPM and 170 psi average. Cement was 13.4 lb/gal, 1.58 ft^3/sack, 7.90 gal water/sack.

Pumped Stage 2 tail cement, which consisted of 360 sacks of 35/65 Pozmix/Class H w/ 1%$CaCl_2$. Volume pumped was 68 barrels at 5.0 BPM and 225 psi average. Cement was 16.4 lb/gal, 1.07 ft^3/sack, 4.33 gal water/sack.

Had good cement returns to the surface after 54 barrels were pumped. A total of approximately 36 barrels were circulated out of the well. Halliburton cleaned out their tanks and pumps and displaced the drill pipe with 16.3 barrels of fresh water.

Picked up with 25,000 lbs over the string weight and closed the port collar. No back flow or pressure was noted, therefore the port collar was properly closed. The cementing head and Halliburton flow iron were broken off from the casing. The port collar was then rotated out of the port collar. Laid down the cementing equipment an started pulling out of the hole with the drill pipe. Laid down the combo tools and crossovers. The combo tool and the last two stands of drill pipe were full of cement cut with water.

Set up the rig floor to land the casing slips and cut off the 9-5/8" casing. The BOP stack was picked up and the Cameron field service representative worked the casing slips into the bradenhead around the 9-5/8" casing. The casing was cut off, with 13.52' section of the top joint removed. The top of the casing was dressed to a final grade.

The well "B" section, 13-5/8" 3000 lb bottom flange x 11" 3000 lb top flange, was installed. The secondary seal over the top of the 9-5/8" casing was energized and the space between the secondary seal and the hanger was filled with packing. The bell nipple was modified by the welded for the changed made to the BOP stack. The welder and the Cameron representative were released.

A 13-5/8" 3000 lb x 11" 3000 lb double studded adaptor and 6" drill collars were delivered to the site. The 8" drill collars were loaded out. Redressing of the double studded adaptor was begun.

8/3/99 Various rig service was performed while waiting on cement to cure. Installed the double studded adaptor above the wellhead "B" section. Nippled up the BOP stack. Changed out the 9-5/8" pipe rams for blind rams in the lower stage of the BOP stack. Calipered new 6" drill collars.

Loaded out the 12-1/4" rental tolls and unloaded the 8-1/2" string reamer in preparation of drilling out of the 9-5/8" casing.

8/4/99 Continued performing rig service while waiting on cement to cure. A Baker Atlas wireline unit arrived and rigged up to run cased hole logs in the 9-5/8" casing. Ran a temperature log with collar locator (from surface to tagging depth of 2623') and a Cement Bond Log with variable density and a gamma ray and casing collar locator from 2623' to the surface. A repeat section was run from 2623' up to 2334'. Rigged down the Baker Atlas equipment and prepared to run a casing pressure test on the 9-5/8" casing.

A Sensotec Model z/1262-01 (0-2000 psi range) pressure transducer was installed to the casing and the rig pumps were used to pressure up on the casing. It was necessary to bleed the pressure off the casing in order to repair leaks in the standpipe valve. Pressured up again on the casing in stages to 500 psi, then 900 psi, then 1100+ psi and began monitoring the casing pressure. The casing pressure changed from 1095.74 psi to 1080.96 psi in thirty (30) minutes). The 14.78 psi pressure loss over a thirty minute period represents a change of 1.3%. The test was acceptable.

An 8-1/2" Security Type ERA33 bit, Serial No. 715829, with three 11/32" jets was picked up, along with 29 6" drill collars and 27 joints of drill pipe. Tripped out of the hole laying down the 27 joints of drill pipe. The pipe remaining in the derrick was strapped and 54 joints were run in the hole above the bit and drill collars to drill out cement and the float equipment. Cement was tagged at 2629' and drilling commenced. Began drilling apparent new formation at 2683' by geolograph as opposed to the 2681'depth measured upon finishing the protection hole.

Drilled to 2758' and circulated the hole clean. Pulled out of the hole to change the bottom hole assembly. A reamer and stabilizer were added to the drill string, the bit was circulated back to bottom and drilling was resumed.

Tight hole was encountered when making a connection at 2865'. A possible packoff was suspected around the reamer or stabilizer. Reamed hole clean, moving up and down with approximately 5000 to 6000 lbs off string weight. Resumed drilling ahead.

Tight hole again on connection at 2896'. Pulled up and laid down two joints and reamed the interval up and down several times. Resumed drilling at 2896'.

Drilled to the first drill stem test point at 2907'. Circulated and conditioned the hole for the test dropped an inclination survey before pulling out of the hole.

8/6/99 Finished pulling out of the hole and laid down the 8-1/2" stabilizer and reamer. Inclination survey result from 2886' was 3/4 degree. Picked up Weatherford drill stem test tools consisting of a 9-5/8" compression packer, three memory gauges, a valve assembly and a fluid chamber. The memory gauges were pre-set to record data every one minute.

The drill stem test tools were run into the hole on drill collars and drill pipe. The drill collars and pipe were run filled of air. The packer was set in the 9-5/8" casing with the bottom of the element at 2611'. (The lower portion of the Abo formation from the protection casing setting point at 2673' to 2907' was open for testing.)

The drill stem test valve was opened by rotating the drill pipe 12 turns. A weak blow into a five gallon bucket was noted, changing to a strong blow within approximately five minutes, then stabilizing at a moderate blow.

Following a 30 minute flow period, the drill stem test valve was closed by rotating the drill pipe 12 additional turns. Following a one hour shut-in period the valve was again opened and a weak to moderate blow to a five gallon bucket of water was maintained.

With the test tool valve remaining open, 1-1/2" MT tubing was rigged up to run into the well for use in airlifting fluid to the surface for sampling. The approximate well volume open below the packer consisted of 23.13 barrels. This volume was made up of 231' of open 8-1/2" hole (16.2 barrels) and 65' of 9-5/8" 40 lb/ft casing (4.93 barrels). In order to recover a representative fluid sample, it was desirable to purge the well of three times the hole volume (3 x 21.13 barrels = 63.39 barrels).

With the 1-1/2' tubing at 605' inside the drill pipe air flow from a Weatherford rental compressor was initiated at 900 SCFM and 100 psi. No back pressure was notes, indicating that the fluid level was deeper than 605'. The compressor was shut down and the tubing was run in the well to a depth of 1200'.

Flow from the compressor was again commenced, with 250 psi back pressure on the tubing. A blow of mud and air was recovered at the surface. The fluid level was estimated to have been at 800'. Fluid flow rate to the gas buster was estimated at 5 GPM. Recovered a total of 4 barrels of fluid (mud) by the time the well blew down (approximately 30 minutes).

The compressor was shut down and the 1-1/2" tubing was run into the drill pipe to a depth of 1650' (approximately 50 feet above the top of the drill collars). The compressor was turned on at 350 psi. No return to the surface was noted and the compressor pressure was reduced to 300 psi. Still no returns were noted at the surface. Lowering the air pressure to 240 psi, then 220 psi produced no results at the surface. The compressor was shut down and the tubing was moved up to a depth of 1450'.

With the tubing at 1450' the compressor was brought on line slowly to a pressure of 350 psi. Began getting good air returns to surface with a pressure of 375 psi on the compressor. A good slug of fluid (mud) followed by a continuous flow of fluid and air began to reach the surface one minute later. The flow was steady but slow, with the rate estimated at 5 GPM. Flow began slowing down after recovering 3 additional barrels of mud (7 barrels total now recovered).

The compressor was shut down and the tubing lowered to 1650'. The compressor was started at 375 psi and 900 SCFM rate. Good air returns followed by fluid in slugs reached the surface. A total of 10 barrels of mud had now been recovered.

Continued to air lift from 1650' and began to take periodic readings of pH, conductivity and temperature for the recovered fluids. The recovered fluid began to change from drilling mud to a light mixture of muddy water.

Following one hour of continuous air lifting, cycling the compressor on and off was tried in order to see if a higher overall rate of production could be reached. This production by slugs did not appear to be successful and the well was put back on continuous air lift. Flow rate was averaging 2.25 to 2.5 GPM as measured into a 5 gallon bucket.

The fluid recovery rate continued to slow down, reaching about 2 GPM. The air flow from the compressor was cut to about 600 SCFM by opening a bleed off valve at the surface. Due to the configuration of the compressor, a lower rate of air flow could not be introduced to the well. The measured fluid recovery was relatively steady at a rate 2.18 GPM. The recovered fluid was still very muddy in appearance.

A 5 gallon sample of the recovered fluid was collected at the gas buster for possible laboratory analysis. A total of 29 (approximately 1.4 times the hole volume) barrels had been produced from the well at this time. This sample was actually planned as a back up in case a cleaner formation fluid sample from the lowermost portions of the drill stem was not recovered.

The air compressor was shut down following collection of the fluid sample and the 1-1/2" tubing was removed from the well. The packer was kept open during removal of the air lifting tubing so that additional formation fluid would continue to flow in the drill stem.

The fluid propertied as measured at the surface during the air lifting from the Abo were as follows:

Time	Volume Recovered (Barrels)	pH	Conductivity (mS)	Temperature (Deg C)
1640	12.0	7.86	129.9	24
1723	14.5	7.61	170.4	24
1748	16.0	7.53	176.8	23
1822	18.0	7.51	180.8	23
1923	21.0	7.73	182.1	24
1944	23.5	7.53	184.9	22
2030	25.5	7.50	191.3	22
2110	27.0	7.55	195.1	23
2145	29.0	7.54	197.4	21
2230	31.5	7.40	197.7	22
2300	33.0	7.43	197.3	21

The fluid recovered prior to 12 barrels was drilling mud.

A total of approximately 34 barrels (1428 gallons) was recovered at the surface from the Abo during the drill stem test over a period of approximately 10 hours. This volume was approximately 1.6 times the volume contained in the open hole and casing below the packer. Three well volumes of fluid could not be obtained in a reasonable period of time and the tested interval appeared to possess relatively low permeability.

8/7/99 Finished pulling out of the hole with the 1-1/2" M airlift tubing. The drill stem test packer was closed and a period of one hour was allowed for pressure build up. Following the pressure build up period the packer was released and the DST tools were removed form the well. The bottom 13 stands of drill pipe were found to contain fluid recovered from the testing. This volume represents an additional 17 barrels of fluid that came from the Abo Formation. (Total recovered would therefore be 51 barrels.)

A fluid sample for laboratory analysis was collected from the lowermost joint of drill pipe, and should have represented the cleanest fluid recovered from the Abo Formation. An additional 5 gallons of fluid was recovered from the drill pipe for use in later compatibility testing.

The DST tools were rigged down and Schlumberger was rigged up to run a correlation log consisting of a gamma ray, compensated neutron and a caliper log from TD up to the protection casing at 2676'. Following an examination of the logs the structural correlation of the well with the pilot hole was still uncertain, and the possibility existed that the well had faulted into the Sangre de Cristo Formation. After consultation with CRMWA personnel, a decision was made to take a 30' foot core beginning at the present TD of 2907' to see if conglomerate was recovered.

Schlumberger was rigged down and a 8-1/2" x 4" coring head, core barrel with aluminum sleeve, jars and bottom hole assembly were picked up. The coring assembly was washed down from 2862' to TD at 2907' and cutting of Core #3 was commenced. Cored to 2937' and broke off core pulling with 15,000 lbs over string weight. Pulled out of the hole with Core #3 and laid the core sleeve on the catwalk. The aluminum core sleeve was cut into sections, capped and marked with depth identification prior to shipment to Reservoirs Inc for analysis. A full 30' foot interval of core was recovered and no conglomerate was visible at the exposed ends of the core. Dense mudstone appeared to predominate, indicating that the well had not faulted into the conglomerate portion of the Sangre de Cristo Formation.

A used 8-1/2" bit was picked up and run back in the hole to ream the cored interval back to bottom to 2937'.

8/8/99 Began drilling new formation at 2938'. Penetration rate was up to 30' per hour. Drilled to 3002' and circulated hole clean in preparation of coring. Dropped an inclination survey and pulled out of the hole. Laid down the drilling bit, reamer and stabilizer, and picked up the 8-1/2" coring head core barrel with aluminum sleeve and jars. Started in the hole to cut Core #4 (Sangre de Cristo Formation). Washed down from 2960' to 3002', picked up two pup joints (22'). Had a minor gas show (50 units total gas) upon circulating bottoms up. Also had a sheen of oil in the opossum belly.

Cored from 3002' to 3033'. Pulled out of the hole and laid down the core sleeve on the catwalk. The core was cut, capped and marked for transport to the lab for analysis.

Recovery was approximately 24.8'. The bottom 4" of the visible core was conglomerate and the 6" to 8" above that was loose conglomerate and gravel sized pieces of mudstone. The sleeve cut at 3023.5' revealed mudstone. The cut at 2016 was also mudstone, with few gravel sized clasts. Drilling breaks during coring at 3008' to 3022' and from 3016' to 3020 feet were possible the intervals of the core that were washed out, and could have been very loose conglomerates.

The coring assembly was redressed to go back in the hole and take an additional core (Core #5, Sangre de Cristo). Went back in the hole and tagged bottom at 3033'. Resumed coring at 3033' with 5000# WOB, 55 RPM and 400 psi pump pressure. The first 10' of core cut very fast (0.5 to 1.5 min/ft), then 1' slower (5 min/ft), then 4' very fast, then the penetration rate dropped off for the next 4'. The 20th foot cored took 20 minutes to cut. The WOB was increased to 10,000#, then 12,000# and the pump pressure was raised to 500 psi. A significant amount of metal filings began to appear in the cuttings returns.

A heavy rain wetted the brakes on the draw works making it impossible to control the WOB. Coring was broken of, the kelly was laid down and the drill string wad worked up and down the hole for 1 hour to dry the rig brakes. The rain stopped, the brakes dried and the core head was run back to bottom to resume coring.

8/9/99 Coring at 3058.5'. Progress was very slow, now with 14,000# WOB and pump pressure at 600 psi. At a depth of 3061' a total of 26 feet had been cored, and the last one foot required 70 minutes to cut. No additional headway was being made and it was thought the bit could be dulled or the barrel full of debris. An attempt was made to break off the core but no break was noted. The coring assembly was pulled out of the hole and the core sleeve laid out on the catwalk. The bit was found to have been balled up with clay and the cutting surfaces and fluid channels were blocked.

Approximately 12' of core was recovered out of the 26.5' cored. The base of the core was mudstone with green clasts. The sleeve cut 7.5' above the base was a mudstone conglomerate with green clasts. The top of the recovered interval was red mudstone that split irregularly along green lined parting planes. The mudstone appeared to be easily liquified by the addition of fresh water.

The bottom hole assembly with an 8-1/2" bit (re-run bit #3, an ERA33 Serial No. 715829), reamer and stabilizer was picked up and run in the hole to ream out the cored interval and drill ahead toward the basement.

Drilled and surveyed to 3348'. The cuttings from approximately 2170' down had been showing characteristics of a fresh igneous-metamorphic terrain. Very fresh fractures grain boundaries, increasing heavy minerals, highly angular cuttings and multiple combined mineralogies (ie quartz-feldspar-heavy minerals not dis-aggregated) had become apparent. The drilling penetration rate remained high, at from less than 1 minute to two minutes per foot. Drilling was continued, looking for a penetration rate decrease that might indicate competent basement rock.

8/10/99 Drilled and surveyed to 3510'. The penetration rate had slowed slightly (to 2 ft/min) since 3505'. Cuttings indicated less quartz content and increasing amounts of red to brown shaly appearing material with significant heavy mineral content.

At 3545' drilling was halted and the hole was circulated clean. The bit was pulled up into the protection casing on a short trip, then run back to bottom to check for fill. No fill was encountered and bottom was tagged at

3545'. An inclination survey was dropped and the drill string was pulled out of the hole to run electric logs.

Rigged up Schlumberger and ran the following suite of logs:
Platform Express - Array Induction, Gamma Ray (2678' - 3792').
Platform Express - Compensated Neutron, Three Detector Density, with Gamma Ray (2400' - 3540').
Formation Micro Imager, Gamma Ray (2678' - 3545').

Weatherford began to rig up DST tools to test the Sangre de Cristo interval. Ran in the hole with DST tool and attempted to set an inflatable packer with the top of the element at 2917' in the 8-1/2" open hole.

8/11/99 Removed the slips from the table and attempted to set the packer with the rig pumps. The ball was sheared out of the packer before the packer set due to the pump pressure increasing too rapidly. Pulled out of the hole with the DST tools to redress the packer.

The packer was redressed, the gauge clocks were reset and a new ball loaded. Started back in the hole to set the packer with the top of the element at 2917.39'. Filled the annulus with mud and set packer by pressuring up on the packer to 1000 psi with the rig pumps. Picked up on the packer to 4000# to 6000# over string weight and found the packer to be sliding in the hole. The packer inflation pressure was increased to 1250 psi. The pressure was bled off and the packer appeared to be set properly.

Pressured up to 1800 psi to shear the ball and seat. Attempted to set down weight on the packer and found it to be moving freely in the hole. The Weatherford field service representative felt that the packer element had failed.

Started to pull out of the hole with the packer and it began dragging significantly. Were not able to work the packer free. Rigged up to pump down the tubing and attempted to pump in with 800 psi. Not able to pump. The packer was worked up the hole with approximately 42,000# over string weight. Pulled the packer about 8' up the hole and it became stuck. Pulled up to 130,000# over string weight and the packer would not move up, or down. The packer had been moved up hole a total of 20' from the setting position.

The annulus was filled with mud, all of the string weight was set down on the packer, the pipe rams were closed on the drill pipe and pressure was applied to the backside with the rig pumps. Pressured up the annulus to 250 psi, then 350 psi then 450 psi. The pressure was bled off but the packer did not move.

Pulled up with 5000# over string weight and rotated 7 turns to the right to obtain travel in the packer mandrel. Pulled up with string weight and the packer pulled free. The packer was worked up and down and appeared to be totally free. The packer was pulled up inside the 9-5/8" casing and an attempt was made to pump down the drill pipe.

Pulled the DST tools out of the well and laid them down for examination. The packer element was in good condition except for the wear caused by dragging it in the hole while partially inflated.

Picked up a bit and bottom hole assembly to go in the hole for a clean out trip. Approximately 10' of fill was found on bottom and was circulated out of the well from 3545'. Pulled out of the hole with the drill string and DST tools with a mechanical packer. Started in the hole with the DST tools on drill pipe and rigged up to set the packer in the open hole.

The packer was set in the protection casing, with the top of the element at 2613.03'. The bottom hole pressure was recorded for 20 minutes. The DST tool was opened and a strong air blow was noted at the surface in approximately 30 seconds. A good blow was noted throughout the 30 minute open period, although there was some decrease noticed during the last 10 minutes. The DST tool was shut in and 1.5" MT tubing was prepared to be run into the hole for air lifting.

8/12/99 Ran in the hole with 47 joints of the 1.5" air lift tubing to a depth of 1407' and rigged up lines to air lift. Opened the DST tool and started air at 250 psi discharge pressure. Had good returns of air and mud to the surface in three minutes. After 68 minutes of air lifting 22 barrels of fluid had been recovered. Air lifting was shut down to move the tubing deeper into the well.

The 1.5" air lift tubing was run in the hole to 2015' and air lifting was resumed. An additional 18 barrels of fluid (40 bbls total) were recovered in 21 minutes. Air lifting was continued at discharge pressure of 325 to 350 psi and the recovery rate was monitored. A total of 63 barrels had been recovered when the radiator fan on the compressor blew out and cut the hydraulic hose, shutting down the compressor.

While arrangements for an alternate compressor were being made, Mr. Joe Marcoline of the New Mexico Environment Department's Ground Water Quality Division was contacted by Texas World's Bill Armstrong about the possibility of drilling the well deeper than originally projected. Mr. Marcoline had previously received a fax advising him of this possibility, since the stratigraphy encountered in the well to that point had not exactly matched the pre-drilling projections. Mr. Marcoline stated that the Department did not object to drilling deeper than planned, into the Precambrian. Mr. Dennis McDonough of the US Bureau of Reclamation and Mr. Jerry Osborne of the CRMWA also participated in the phone call from the well site.

A replacement compressor arrived at the well site and was rigged up to air lift. Air lifting was resumed with the tubing at 2015'. The stripper head was leaking at a rate of approximately 3 to 5 GPM, but air lifting was continued. After producing a total of 166 barrels, air lifting was shut down to replace the pack-off rubber and run an additional 13 joints of 1.5" tubing into the well. This placed the bottom of the tubing at a depth of 2408'. Air lifting was resumed until a total of 279 barrels of fluid had been recovered at the surface. A tabulation of this sequence of air lifting is as follows:

Time	Cumulative (Barrels)	Fluid Weight (lbs/gallon)	Tubing Depth
0236	0	na	1407'
0300	13	na	1407'
0344	22	na	1407'
0504	40	na	2015'
0517	50	na	2015'
0527	55	na	2015'
0537	60	9.0	2015'
0542	63	na	2015'
0542	Compressor down, waiting on a replacement unit		
1550	Resumed air lifting with new compressor		
1604	86	9.1	2015'
1708	116	9.1	2015'
1745	130	na	2015'
1812	140	9.3	2015'
1917	166	9.3	2015'
1917	Shut down to replace rubber, go in hole with tubing to 2408'		
2040	Resume air lift		
2118	193	9.3	2408'
2126	197	na	2408'
2231	230	na	2408'
2331	260	9.3	2408'
8/13/99 0010	279	na	2408'

During the air lifting fluid conductivity, pH and temperature had also been measured periodically. The results of these measurements were as follows:

Time (24hr)	Cumulative (Barrels)	Fluid Wt. (lbs/gal)	Conduct. (mS/cm)	pH (Units)	Temp. (Deg. F)
1604	86	9.1	163.8	7.54	75.0
1705	115	9.1	184.1	7.19	73.1
1820	143	9.3	194.9	7.15	73.1
2205	217	9.3+	256	7.09	74.9

2301	244	9.3	258	7.09	74.1
2331	262	9.3	257	7.10	73.9
0007	277	9.3	256	7.06	73.6

Shut down the air lifting after producing a total of 279 barrels from the open interval 2673' to TD at 3545', bled down the air pressure and broke down the air lifting connections. Pulled out of the hole with the 1.5" tubing and rigged down the stripper head.

The packer was released from inside the casing and the drill pipe and DST tools were started out of the hole. Two pup joints and a single joint of drill pipe were laid down and remainder of the drill pipe was stood back in the derrick. Samples of the fluid from the DST were collected for future analysis and use in core testing. The DST tools were broken out and laid down.

Went in the hole with a 8-1/2" bit and bottom hole assembly. Began taking weight at 3049' to 3090'. The kelly was picked up and the hole was reamed to a depth of 3545'. Additional mud volume was mixed and the hole was circulated clean prior to pulling out of the hole with the drill string.

An open hole set of DST tools with an inflatable packer was picked up and run into the hole. The packer was set with 1100 psi with the top of the element at a depth of 3173'. Checked the packer setting by setting down with 4000 lbs and pulling up with 2000 lbs over string weight. The packer appeared to be set properly.

The bottom plug of the packer was sheared out with 1500 psi, and the pressure dropped to 400 psi and bled off slowly. The 1.5" tubing was run in the hole to a depth of 2408' and the stripper head and air lines were rigged up. Began to air lift. Had an initial high rate of flow to surface from unloading the drill pipe volume. The rate then dropped off.

Jetting the interval 3173' (packer) to TD at 3545' with the air lift tubing at

2408' resulted in the following recovery:

	Time	Cumulative (Barrels)	Fluid Weight (lbs/gallon)
	2328	Had good returns to the surface	
	2339	28	9.1
	2350	30	9.1
8/14/99	0013	32	9.1
	0057	38.5	na
	0127	42.5	na
	0257	53.5	na
	0357	60	9.1
	0457	67	na
	0557	73	9.1
	0731	83	9.1

The compressor was shut down and the DST isolation valve was shut. The 1.5" air lift tubing was pulled out of the hole and the compressor was released from service. The open hole packer was deflated.

Mr. John Williams of the CRMWA was contacted by Bill Armstrong of Texas World concerning drilling deeper. It was agreed to drill ahead further until a zone with a lower drilling penetration rate was reached.

Pulled out of the hole with the DST string and collected fluid samples from the lower portion of the drill pipe. The drill pipe was found to be full of drilling mud. Upon laying down the DST tools the isolation valve was found to have been plugged with solids.

A 8-1/2" bit and bottom hole assembly was picked up and run in the hole. The kelly was picked up and the hole was cleaned out to TD at 3545', including removal of 20' of fill.

Drilling new formation was begun at 3545'. Drilled ahead with 38,000 lbs WOB and a 320 GPM pump rate at 1350 psi.

8/15/99 Drilled and surveyed to a depth of 3800'. The hole was circulated clean and the drill string was pulled out of the hole in order to run electric logs.

Schlumberger rigged up and ran the following open hole logs:
Platform Express - Array Induction, Gamma Ray (3792' - 2678')
Platform Express - Compensated Neutron, Three Detector Density, Gamma Ray (3792' - 2678')
Elemental Capture Spectroscopy Tool, Gamma Ray (3770' - 2710')
Formation Micro Imager (3800' - 2710')

(From this suite of open hole logs, additional computed logs were later prepared, including: ECS Elan Log Analysis; ECS Spectrolith Elemental Analysis; MSD Mean Square Dip Log; Calibrated and HILITE Images Log; Borehole Image Interpretation; MSD Interpretation.)

Schlumberger was rigged down and the Weatherford casing crew rigged up. The running of 5-1/2" liner, TAM external casing packer and port collar was begun.

8/16/99 The 2-3/8" innerstring with a 5-1/2" TAM combo tool for cementing were rigged up. Nineteen joints of 2-3/8" innerstring were run attempting to locate and latch the port collar with the combo tool. The combo tool would not properly engage the port collar. The combo tool would pull free with 3000 to 4000 lbs, and bounce through the port collar with very little drag on most passes.

The innerstring and combo tool was pulled out of the hole and the edges of the dogs (latches) on the combo tool were ground. The combo tool was run back in the hole on the innerstring and several unsuccessful attempts to latch into the port collar were made.

The innerstring and combo tool were pulled out of the hole and the 19 joints of the 2-3/8" EUE innerstring were laid down. Pulled out of the hole with, and laid down, 14 joints of blank 5-1/2" 15.50 lb/ft, J-55, LT&C liner.

The TAM port collar was laid down and inspected. No problems were noted. TAM sent replacement equipment to the site.

The replacement TAM port collar was installed in the 5-1/2" liner string and tested at the surface with the old combo tool. The tools would not latch successfully. The latch assembly of the port collar was replaced, but the combo tool and port collar still would not latch.

A 1/8" steel spacer was installed under each dog of the combo tool but the tool would not then go into the liner. One spacer was removed, and the combo tool successfully latched into the port collar. The 1/8" spacer was removed from the single dog and 1/16" spacers were inserted under both dogs of the combo tool. The tools then latched successfully during testing.

The running of the 5-1/2" liner was resumed with each joint being torqued to the optimum level of 2390 ft-lbs. The liner consisted of the following:

1	5-1/2" blank guide shoe
13 jts	5-1/2", 15.50 lb/ft. J-55, LT&C perforated liner
1	5-1/2", TAM XCAP Inflatable packer, 9.9' element
1	5-1/2" TAM Port Collar
1	5-1/2", 15.50 lb/ft J-55, LT&C pup joint
14 jts	5-1/2", 15.50 lb/ft, J-55, LT&C blank liner
1	Weatherford 9-5/8" x 5-1/2" liner hanger, built on 7" mandrel

Began running the 2-3/8" innerstring to cement the liner. The liner hanger was picked up and installed in the string. Began strapping and running drill pipe to set and cement the liner. The liner hanger was set with the top at 2646' and the bottom of the liner at 3775.95'. The setting tool was rotated out of the liner hanger. The combo tool was latched into the port collar and the opening and closing of the port collar was tested several times.

Circulating lines were rigged up and circulation with mud was established through the bypass on the TAM port collar at 4.4 BPM. Circulation with the rig pump was stopped and Halliburton was rigged up to inflate the TAM external casing packer (ECP).

The ball was dropped to isolate the bypass in the TAM combo tool. Halliburton tested their lines to 4100 psi. The innerstring was set to inflate position for the ECP and pressurization was initiated to inflate the packer element. The pressure was increased in stages; 264 psi, 420 psi, 750 psi without seeing any pressure bleed off. The pressure was increased to 930 psi. The innerstring was lowered 2 feet. Still no pressure bleed off was observed. The pressure was increased to 1100 psi, then manually bled off. The ECP was pressurized again, to 1500 psi, and there was no indication of the inflation ports opening. The pressure was manually bled off.

A review of the Halliburton pump truck pressure charts indicated a breakover at 700 psi that was not noticed on the digital readouts. An evaluation of the pressure data indicated that the ECP had initially inflated during the circulation through the bypass of the combo tool. It was decided to continue with the cementing procedure. The Weatherford casing crew was released.

The port collar was opened and circulation established using the rig pumps. Halliburton began mixing and blending cement.

8/17/99 A safety meeting was held for all personnel on site to discuss the planned cementing operations and pertinent safety issues. Halliburton finished mixing cement for the job and circulation was switched from the rig pumps to the Halliburton pump truck.

Pumped 5 bbls of fresh water at 2 BPM. Pumped 20 bbls of superflush at 4 BPM. Pumped 5 bbls of fresh water ahead of the cement. Pumped 52.9 bbls (250 sacks) of cement at 3.6 BPM. Cement consisted of 50/50 Pozmix with 0.25% CFR-3, 2% gel, 2 gal/sk Latex 2000, 0.2 gal/sk stabilizer, 0.03 gal/sk D-Air2, 0.03 gal/sk D-Air3. Yield was 1.19 cu ft/sk at

14.5 lbs/gal.

The cement was displaced with 3.5 bbls of fresh water and 36.5 bbls of mud. The port collar was closed and an attempt to shear the ball in the combo tool was made by pressurizing to 3500 psi. The ball would not shear. The pumps were shut down, Halliburton lines were rigged down and the drill string was started out of the hole. The liner setting tool was laid down and all the 2-3/8" innerstring and the TAM combo tool was pulled out of the hole and laid down. Began waiting on the cement to cure while performing rig maintenance and repair operations. A review of log and coring data was performed to pick intervals for perforating in the blank 5-1/2" liner.

8/18/99 The mud system was dumped and the mud pits and equipment were cleaned while waiting on the cement from the liner installation to cure.

Following 30 hours of waiting on cement to cure, a 4-3/4" speed bit, crossover sub, 17 joints of 2-3/8" tubing, crossovers and 4-1/2" drill pipe were picked up and run in the hole. A bridge was tagged at 2623' and reamed out. The hole was cleaned out to 2782' where the liner was found to be clean. The drill string was run in the hole to 3198' where another bridge was tagged, and subsequently reamed to 3272', where the liner was clean. Alternately ran in the hole and washed spotty cement to 3775' where bottom was tagged. Circulated the hole clean using 8.7 lb/gal brine.

Jetted 300 barrels from the mud tanks, topped off with fresh water and circulated around to obtain 8.5 lb/gal fluid in the tanks.

8/19/99 Circulated the hole until the brine in and out stabilized at 8.6 lb/gal. Circulation was halted and the pipe rams were closed on the 4-1/2" drill pipe. The rig pumps were engaged to test the lower interval of the liner containing perforated pipe (below 3241'). The pressure as measured at the rig floor pump pressure gauge increased to approximately 550 psi and the pumps were stopped. The pressure decreased very slowly from 550 psi to 450 psi, over a period of nine minutes. The pressure was bled off the well, the pipe rams were opened and the drill pipe was pulled out of the hole to the 2-3/8" tubing. Drill collars were run in the hole above the 2-3/8" tubing and a belly board was rigged up to run the 2-3/8" tubing.

The drill collars and 2-3/8" tubing were removed form the well and a Schlumberger logging unit was rigged up in preparation of perforating. A gamma-ray and casing collar locator log was run for correlation purposes and Hi-efficiency 4" casing perforating guns were picked up and run in the hole. The following intervals were jet perforated with 4 shots per foot:

2734-2746
2766-2790
2808-2820
2840-2850
3000-3008
3020-3026
3034-3044
3046-3054
3066-3074
3116-3122
3170-3174

The perforating guns were removed from the well and Schlumberger was rigged down. The pipe rams were changed out from 5-1/2" to 4-1/2".

A Weatherford 9-5/8" test packer was run in the hole on 4-1/2" drill pipe and set at 2630'. A Halliburton coiled tubing unit and a nitrogen unit were rigged up to jet the well and a safety meeting to discuss the jetting operation and related safety issues was held for all site personnel.

The coiled tubing was started in the hole and nitrogen flow was begun at 300 SCFM. The jetting operation progressed as follows:

Time	CT Depth	N_2 Rate	Total Returns

		(Feet)	(SCFM)	(Barrels)	
	2200	1550	300	27	
	2242	3775	200	54	Rate increasing dramatically
	2350	3775	200	79	
		Switched to frac tank for gauging fluid return volumes			
8/20/99		Began working tubing up and down over 5-1/2" liner interval			
	0001	3200	175	123	
	0020	2700	175	132	
	0120	2900	175	142	
		Return flow rate declines sharply with tubing above 2900'			
	0310	3700	175	158	
	0420	3200	225	190	
	0535	3400	275	213	
	0635	3450	275	259	
	0745	3400	275	280	
	1030	3400	275	360	

The nitrogen unit was shut down. A total of 164,500 SCFM of nitrogen had been pumped.

A safety meet was conducted prior to commencing the pumping of 12,000 gallons of 15% HCL Iron acid. Began pumping acid through coiled tubing and steadily increased the rate and pressure. Stabilized the injection rate at approximately 1.67 bbls/min at 240 to 280 psi on the formation and approximately 4500 psi on the coiled tubing.

Finished pumping the acid and switched to 10 lb/gal brine to flush the well. A total of 200 barrels of brine was pumped. The pressure was bled off the coiled tubing and the formation. Halliburton was rigged down and brine volume was mixed prior to commencing injectivity fall-off testing.

A replacement Halliburton pump truck arrived on the location and was rigged up to pump brine from a series of frac tanks for the injectivity fall-off testing. A Schlumberger wireline unit arrived on the location and was rigged up to run bottom hole pressure, temperature, spinner tools and a gamma ray tool into the well.

8/21/99 The Schlumberger bottom hole tools were run into the well and the fluid level was tagged at a depth of 690'. A pressure gradient stop was made at 1000' (181.6 psi). The bottom hole tools set down at approximately 1100' and the wireline backlashed on the drum. The line was untangled, rewound on the reel, and running in the hole was resumed. Another gradient stop was made at 2004' (717.76 psi). The wireline tools kept hanging up while running in the hole, and would not go past 2250'.

A gamma ray correlation strip was run that indicated the correlation was off by approximately 54'. Tag depth was actually approximately 2300'. The wireline was flagged and pulled out of the hole to check the tools. The spinner looked OK and all minimum IDs of the drill string and rental tools were checked. Minimum ID was found to be 2.75", and all logging tools should have been able to pass through this size hole.

A 2.125" OD weight bar was installed on the wireline and run in the hole to 2700' with no problem. The weight bar was removed from the well and added to the bottom of the pressure/ temperature / spinner tool assembly. The tools were run in the hole and set at a depth of 3200'. Bottom hole data recording was begun.

Pumping into the well was commenced at a rate of 2 BPM. The spinner was run for two up and two down passes in the well. It appeared that all flow was exiting the liner through the top three sets of perforations. The tool was again set a 3200' to record pressure data.

Conducted the injection portion of the test at a rate of 2.1 BPM for a total of 8 hours and a total of 966 barrels of brine had been pumped. Pumping was shut down at 1700 hours and the fall-off portion of the testing was commenced.

The final weight of the injected fluid was 9.05 lb/gal, final injection bottom hole pressure was approximately 1602 psi, and surface pressure was 79 psi. Fall-off pressure data was generally as follows:

	Time	Pressure (psia)	Temperature (Deg F)
	2000	1478.2	93.4
	2107	1455.6	93.6
	2202	1437.6	93.7
	2300	1421.1	93.9
8/22/99	0002	1406.1	94.0
	0100	1394.7	94.1
	0200	1383.6	94.2
	0300	1373.7	94.1
	0410	1363.9	94.1
	0501	1357.6	94.2
	0600	1351.1	94.3
	0700	1344.4	94.3
	0900	1334.2	94.3

Fall-off testing was stopped, the data was saved, and preparations were made to run additional spinner surveys at higher injectivity rates. Pumping was commenced at 4 BPM and raised in increments to 5, 6, 7 and 8 BPM at a maximum of 530 psi surface pressure. Pumping was then shut down and fall-off pressure was recorded for a period of 20 minutes.

The test tools were started out of the hole making gradient stops every 1000 feet. Key energy and Halliburton equipment and personnel were rigged down. The test packer was released from within the casing and the drill pipe and packer were removed from the well.

A gauge ring was run in the well while the whipstock packer setting tools (for milling the window in the casing to commence the lateral hole portion of the well) were assembled. The whipstock packer and setting tools were run in the hole and set with the top of the whipstock packer at 2537', as correlated to the bond log on the 9-5/8" casing.

The whipstock orientation tools were picked up and run in the hole and stung into the packer. A Baker-Hughes gyro tool was run in the hole on Weatherford wireline. The whipstock key was set to an azimuth of 191 degrees and drill collars, drill pipe and the orientation tools were pulled out of the hole and laid down.

8/23/99 The whipstock and make up tools were picked up, connections tightened and the orientation checked and reset. The whipstock and a starter mill were run in the hole on drill collars and drill pipe. Tagged up 19.5' in on the kelly but had no positive indication of latch-in. No overpull was observed during several attempts to latch. The drill string was rotated and lowered down, tagging at the same depth.

The drill string was pulled out of the hole to verify the status of the whipstock assembly, and a retrieving hook was run in the hole to check the whipstock latch. After latching into the whipstock, a 5000 lb overpull indicated that the whipstock was properly latched. The retrieving hook was released and pulled out of the hole.

A mill was picked up and run into the hole. Following tag-up, milling of the window through the 9-5/8" casing was commenced. Milled to 2520'.

8/24/99 Continued milling, using one starter mill and two watermelon mills, to a depth of 2537', which included approximately 8' of new formation outside the window. (Window is from 2517' to 2529'.) A carbide test bag was dropped to determine the circulation lag time while continuing to work a watermelon mill up and down through the window to smooth the edges. Lag time was determined to be 19 minutes. Pulled out of the hole with the milling assembly and laid it down. Baker directional tools were picked up.

8/25/99 The Baker directional tools were started in the hole. The bottom hole assembly consisted of the following:

Item	Length (ft)
Bit - SmithF47HFS with 3 13/32" jets	1.5

Mud motor - D625SS	22.93
DMWD Orientation Sub	2.47
Monel Collar	28.03
MWD Flow Sub	1.64
Monel Collar	29.24
Total Length	85.81

Ran into the hole with the bottom hole assembly and rigged up to run a gyro survey to verify the correct orientation of the tools. The gyro survey was performed and the tools pulled out of the hole. The drilling bottom hole assembly was lined up in the proper orientation and drilling was commenced on time control at 3 ft/hr. Drilling continued ahead slowly as the mud motor showed a tendency to stall in the sticky formation materials. Drilled ahead to 2562' taking periodic gyro surveys to verify the hole direction.

The MWD (measurement while drilling) tools were run into the hole on wireline and stung into the bottom hole assembly. The MWD tools were released from the wireline and an attempt to calibrate the gamma ray tool in the MWD assembly indicated a communications problem. The communication cables were changed out and good contact between the surface instrumentation and the MWD tools was established.

8/26/99 The rotary table was locked out and pump pressure was brought up slowly to begin drilling ahead at 2562'. Drilled ahead on time drilling followed by use of the Wildcat Autodriller under pump differential to 2751', where a survey was run.

The hole was circulated clean and the bottom hole assembly was pulled out of the hole. The motor angle adjustment was changed and the assembly run back in the hole followed by 5 stands of 6-1/2" drill collars and 12 stands of 4-1/2" drill pipe.

Drilling was resumed using the mud motor on pump differential. A connection was made and an inclination survey taken at 2771'. Drilling was resumed and rotation of the drill string from the surface was begun.

8/27/99 Drilled and surveyed ahead while rotating and using the mud motor. The rig generator motor blew a seal and all power was lost until the No. 2 generator was started. The drill string was picked up off bottom and the hole circulated. The MWD tools were recalibrated following the power loss. Drilling and surveying ahead was resumed.

At 2833' the surveys indicated that the hole inclination was decreasing while the drill string was being rotated. The angle was at 40.6 degrees instead of the planned 45 degrees. Drilling was continued using only the mud motor in an attempt to build the hole angle back to the planned 45 degrees.

At 2848' the mud motor began stalling and drill string rotation at 45 RPMs with 20,000 lbs WOB was resumed. The penetration rate while rotating was approximately 30 to 40 ft/hr.

At 2865' drilling continued using only the mud motor again, while attempting to build up the hole angle. Drilling continued to 3115' using only the mud motor while adjusting the weight on bit and pump pressures to obtain an optimum penetration rate. Survey results indicated the hole to have approximately a 39.2 degree inclination and an azimuth of 189.2 degrees. Good drilling breaks were encountered at 3060', 3069' and 3076' to 3090'. Penetration rates were up to 60 ft/hr.

8/28/99 Drilled ahead with the mud motor to 3146'. The hole inclination was averaging 40 degrees and the azimuth was 190 degrees. Difficulty was encountered getting the MWD tools to initiate following connections, possibly due to low pump pressures. It was decided that following future connections drilling would be restarted using a 330 GPM pump rate until the tool was known to be functioning, and then the rate would be reduced to approximately 250 GPM.

Drilled and surveyed ahead to 3523' alternately rotating the drill string and drilling with the mud motor only. Surveys indicated the hole to have an inclination between 40 and 42 degrees with an azimuth between 190 and 194 degrees through this portion of the well.

The hole inclination and the rate of angle build that had been found possible with the 1.25 degree bent sub in the bottom hole assembly indicated that the directional target objectives for the well would not be met without changing the sub for one with a greater angle building potential.

8/29/99 The hole was circulated clean and the bottom hole assembly removed from the well for replacement with a 1.75 degree bent sub. The rig's drilling line was slipped and cut, then the modified bottom hole assembly was run into the hole.

The drill string became stuck in the hole while running back to bottom. The drill string would not move up or down and could not be rotated. Circulation was possible with 1600 psi pump pressure. The call was put out for a wireline unit with back-off tools, but the equipment would not arrive at the well site for six to seven hours. Waited on back-off tools while continuing to circulate and reduce mud weight from 9.4 to 9.1 lbs/gal.

Circulation was stopped and the kelly broken off when the wireline unit and fisherman arrived at the site. The drill string was now free to partially rotate, and could be moved down to the top of the monel collars. The wireline unit was rigged up and the MWD tolls were pulled out of the drill string. The wireline was rigged for running a string shot charge, which was run in the hole to a point opposite a connection at 2413' and detonated, with two left turns of torque being applied to the drill string. The drill string was pulled up 5' and found to be free. The wireline was pulled out of the hole and the wireline unit was rigged down. The drill pipe and drill collars down to the point of the shot were pulled from the well.

Fishing tool (bumpers, jars and accelerators) were picked up and started in the hole.

8/30/99 The fishing tool assembly was run into the hole to 2413' and the fish was tagged. The fishing tools were screwed into the fish and circulation was established. The fish was worked free with the bumpers and the string was worked up and down while circulating to clean up the hole. The hole was reamed down three joints while rotating and circulating to a depth of 3063'. The hole was still sticky, so the interval from 2802' to 2926' was reamed. The drill string was started out of the hole.

Twenty-nine joints of drill pipe were laid down from the string and derrick. The drill collars were stood back in the derrick and the fishing tools were laid down. New mud motor with a 1.75 degree bent sub and orientation bit were picked up and run into the hole. Drilling jars were inserted in the drill string. While running in the hole at 3173' 20,000 to 25,000 pounds of weight were taken by the hole. The kelly was picked up and the hole was circulated, reamed and rotated toward bottom. The drill string took 10,000 pounds of weight periodically to continue toward bottom. The drill string was continued past 3290' rotating and circulating toward bottom.

8/31/99 The drill string was continued on toward the bottom by rotating and circulating. Approximately 25,000 to 30,000 pounds of weight was required to move past ledges when not rotating.

The original drilled depth of 3523' was reached, and the last joint was reamed to bottom twice. A survey from the bottom of the hole indicated an inclination of 42.4 degrees and an azimuth of 194.2 degrees. The bit face was oriented and drilling of new hole was commenced by use of the mud motor with 35,000 pounds WOB and 1250 psi pump pressure.

Drilling with the mud motor was continued to 3864' while the inclination was built up toward a target of 75 degrees. Surveys indicated the following hole orientations:

Survey Depth	TVD	INC.	AZM

3512	3305.7	43.1	193.4
3759	3436.1	73.7	183.3
3789	3444.2	75.1	183.2
3821	3452.1	76.2	183.7

9/1/99 Drilling ahead at 3895' with an inclination of 77.1 degrees at an azimuth of 183.4 degrees. The tool face was adjusted downward to stop the increase in inclination angle. The well is beginning to take fluid at a rate of approximately 10 barrels per hour. Some fluid had also been lost on the previous day. Prior to this, no significant amount of fluid had been lost to the well.

Mud pump pressure began dropping (100-150 psi pressure loss) and it appeared that the sleeves in the pump were worn. Circulation was switched to the alternate mud pump and the pressure stabilized at 1250 to 1300 psi.

Drilling ahead was continued with the rate of mud loss to the hole relatively constant at 10 to 15 barrels per hour.

Nearly total returns of the drilling fluid was lost while drilling at 4078' measured depth. A total of approximately 200 barrels of mud was lost from the steel mud pits and the mud pump lost suction due to the low fluid level in the tank. It was decided to halt drilling and start completion operations for the well.

A final survey at 4035' MD indicated a TVD of 3497.1', inclination of 77.7 degrees and azimuth of 186.0 degrees. A projection to the bit depth of 4078' MD yielded a TVD of 3506.3', inclination of 77.5 degrees and an azimuth of 186.2 degrees.

The drill string was started out of the hole in preparation for running electric logs. The hole was still taking fluid at a rapid rate, estimated at 8+ BPM.

9/2/99 The MWD tools were pulled out of the hole and laid down. The 5-1/2" liner was laid out and arranged in preparation for use. A Schlumberger wireline logging unit arrived on site and was rigged up to run electric logs. Logs in the lateral hole consisted of the following:

Platform Express - Array Induction, Gamma Ray (3666' - 2516')
Platform Express - Compensated Neutron, Three Detector Density, Gamma Ray (3656' - 2516')
Elemental Capture Spectroscopy Tool, Gamma Ray (3630' - 2516')
Formation Micro Imager (3664' - 2566')

(From this suite of open hole logs, additional computed logs were later prepared, including: ECS Elan Log Analysis and Calibrated and HILITE Images Log.)

Schlumberger was rigged down and tools to pull the whipstock from the hole were rigged up and run in the hole. The whipstock was latched and pulled upward with 25,000 pounds of force over the string weight. The whipstock was pulled upward in the well with the well swabbing. Pulling the whipstock across the ECP and port collar in the 9-5/8" casing required 50,000 pounds of overpull. The well stopped swabbing following this occurrence and the whipstock pulled up more freely. The whipstock was removed from the well and laid down.

9/3/99 The work string was run in the hole to knock out the plug closing off the vertical portion of the hole below the whipstock packer. The plug was knocked out with 20,000 pounds of downward force and the work string and knock-out tool was pulled out of the hole.

The re-entry guide was picked up and oriented and started in the hole on the work string. The re-entry guide would not set. This was probably due to a portion of the rubber swab cup from the debris sub of the whipstock having been ripped off during whipstock retrieval and falling downhole into the packer opening. The work string was pulled out of the hole but the re-entry guide was left in the well.

A watermelon mill was picked up and run into the hole to see if the re-entry guide may have set sufficiently to allow passage into the lateral hole. The mill would not go through the window in the casing and was pulled out of the hole while fishing tools were transported to the site.

When the fishing tool arrived, an overshot was made up and run into the hole to latch onto the re-entry guide. The first attempt to latch the fish failed and the overshot slid past the re-entry guide and out into the lateral hole. The kelly was picked up and the overshot was rotated over the top of the fish. Pulling upward with 20,000 pounds over the string weight implied that the re-entry guide was caught in the overshot.

9/4/99 Pumping down the work string was initiated at 500 psi to check if the vertical hole was open to injection through the packer and re-entry guide. Pumping was conducted in surges, ultimately bringing the pressure up to 1500 psi. Flow to the vertical hole appeared to be restricted, probably due to the whipstock swab cup rubber.

The work string was set down on the fish with 7000 pounds, then picked up to 20,000, then 30,000 pounds. The guide shoe sheared out of the packer and was started out of the hole. Upon recovery at the surface the re-entry guide was removed from the overshot.

The end of a 3-1/2" drill pipe sub was dressed as a stinger to be used in pushing the lost rubber through the packer. The stinger was run into the hole and pushed through the packer with a minor bump, and set down on the packer with 8000 pounds. Pumping through the packer was initiated with minimal pressure, indicating that the packer was clear and the vertical hole was open to injection. The stinger was pulled out of the hole.

The re-entry tool was redressed and run back in the hole. The re-entry guide was set at 2527' by setting down on the packer with 7,000 pounds, pulling up with 10,000 pounds, setting down again, pulling up with 15,000 pounds, setting down and shearing off the setting tool by rotating ½ turn right and pulling out of the hole with the setting tool.

A bit was picked up and run in the hole to the top of the re-entry guide. The guide was tagged and the bit slid out into the lateral hole. Ran in the lateral hole and hit a tight spot 13 joints off bottom. The kelly was picked up and the hole was circulated, washed and reamed to total depth to insure that it was as clean as possible for running the liner. The hole was sticky when pulling the work string upward but seemed clean when moving downward. The work string was pulled out of the hole in preparation for running liner in the lateral hole.

9/5/99 A Weatherford casing crew and equipment was rigged up to run the 5-1/2" liner. The liner was made up by adding one stabilizer to each connection of the pre-perforated liner while the blank liner had two spiral stabilizers per joint. A TAM ECP and port collar were installed in the liner string between the perforated and the blank liner sections. The combo tool's latch and release mechanism was tested with the port collar in the rotary table prior to running, and seemed to function OK. The 5-1/2' liner was run in the hole and hung off in the slips from the rotary table. The casing crew was rigged down.

An innerstring of 2-3/8" pipe was made up with a ball catcher, choke sub and combo tool and run into the hole. The latch in the combo tool was found to be pulling free with only 3000 to 5000 pounds. The innerstring was pulled out of the hole to check the springs in the latch mechanism. Stronger springs were added to the combo tool and it was run back into the hole.

The combo tool still would only hold approximately 3000 to 5000 pounds weight before releasing from the port collar. It was decided to make up the liner hanger and run in the hole. The liner was landed and the hanger was set at 2470'. The setting tool was backed off the hanger.

The port collar was opened and circulation was established. Then the port collar was closed. The ECP was set. The combo tool was pulled up to the port collar, but the collar would not open. The combo tool was pulled out of the hole to check the latch mechanism. The dogs on the combo tool appeared to be OK, but shims were added under the springs and the tool was re-run.

Following several attempts, the combo tool appeared to have latched in the port collar and the port collar was open. Brine was pumped down the inner string with the rig pumps and circulation was established after approximately 15 minutes. Halliburton was rigged up to cement and a safety meeting was held.

The cementing job for the liner was commenced. The job consisted of the following: 5 bbls water; 10 bbls superflush; 3 bbls water; 54.5 bbls 14.5 lb/gal cement with latex additive and defoamers; displaced with 38.5 bbls of water. The cement consisted of: 250 sacks of 50/50 Pox Premium plus 2 gals/sack Stabilizer 434B, 0.25% CFR3, 0.03 gals/sack D-Air2 and 0.03 gals/sack of D-Air3.

The port collar was closed and the ball was sheared with 8000 psi and the innerstring was started out of the hole.

9/6/99 Finished pulling out of the hole with the innerstring and laid down the string and combo tools. Waited on cement to cure.

Ran a 3-1/2" mill in the hole on 2-3/8" pipe and 4-1/2" drill pipe to 2 stands past the liner hanger to check for and/or clean out cement. Encountered resistance at 3417' that required 300 to 6000 pounds of force to overcome. It was possible to wash down with 1800 psi pump pressure. Good cement returns were noted at the surface. Stopped washing cement at 3608', circulated the hole clean and pulled out of the hole since the junction of the 2-3/8" x 4-1/2" drill pipe would not pass below the liner hanger due to diameter restrictions.

Schlumberger was rigged up and the bottom of the cleaned out hole was tagged at 3630'. A gamma ray background log and a casing collar strip were run in preparation of perforating the blank liner in the lateral hole.

The intervals planned for perforation were to be perforated with 8 shots per foot which would require double shooting each interval, and were as follows:

2604-2610
2616-2623
2625-2635
2650-2655
2678-2683
2731-2735
2739-2743
2762-2795
2803-2807
2817-2822
2827-2831
2838-2843
2849-2857
2862-2872
2902-2907
2959-2965
3007-3017
3026-3032
3074-3092
3104-3109
3116-3121
3125-3134
3157-3161
3302-3318
3322-3330
3367-3375

Perforating was begun from the bottom of the proposed intervals and worked upward toward the top intervals.

9/7/99 Perforating in the lateral hole continued all day and evening. Two Schlumberger perforating crews worked on a rotating shift basis.

9/8/99 Perforating gun run No. 35 that was intended to perforate the interval 2773' - 2784' would not go down the liner past 2719'. Several attempts to move past this depth were not successful. Upon removal from the well the perforating gun showed scrape marks near the middle of the barrel.

Gun No. 35 was set aside and gun No. 36 which was intended to double shoot the same interval was picked up and run into the hole. This gun also would not go past 2719'. A pull of 400 to 600 pounds was required to break loose the gun from its resting spot in the casing after it set down each time.

Schlumberger was rigged down and the perforating equipment moved aside so that drill pipe could be run into the hole to clean the deeper portions of the liner of cement, and move out any other obstructions from the well bore.

A string of 2-7/8" drill pipe had been ordered out previously, and was now moved to the pipe rack for use in the clean out. The 2-3/8" pipe was run into the hole then pulled out laying down. The 2-7/8" pipe was tallied and picked up. A 4-3/4" tri-cone speed bit was picked up and run into the hole on the 2-7/8" drill pipe followed by 4-1/2" drill pipe. No obstructions were noted while running the drill string into the hole past 2719'.

Soft cement was tagged at 3228' and washing down was begun. The inside of the liner was washed down to 4070', which was the depth of the guide shoe at the base of the 5-1/2" liner in the lateral hole. The guide shoe was drilled out and the hole washed to the original total depth of 4078'. An attempt to drill some additional new hole was not successful.

The hole was circulated clean and the drill string started out of the hole. The Schlumberger perforating crews and equipment stood by to resume perforating in the lateral liner. The 12' long perforating guns that would not go into the well on the previous day had now been cut back to an overall length of 11.5'.

9/9/99 The drill string was removed from the well and Schlumberger rigged up to resume perforating. Perforating gun No. 35 again would not go down the well past 2719', even in its shortened configuration. This gun was pulled out of the hole and a 7' long gun intended for a shallower zone of perforations was run into the hole . This gun made it through the 2719' depth point with no problem.

The planned intervals for running the remaining pre-loaded perforating guns were rearranged to enable most of the guns to be utilized while perforating almost all of the originally proposed intervals. One 11' long gun would be left unused. The **actual perforated intervals in the lateral liner ended up as follows:**

2604-2610
2614-2625
2625-2636
2650-2655
2678-2683
2731-2735
2749-2743
2762-2780 **
2784-2795
2803-2807
2817-2822
2827-2831
2838-2843
2849-2857
2862-2872
2902-2907

2959-2965
3007-3017
3026-3032
3074-3092
3104-3109
3116-3121
3125-3134
3157-3161
3302-3318
3322-3330
3367-3375

** All perforated intervals are shot with 8 shots per foot (intervals were double shot), **EXCEPT** for a portion of the **Lateral Hole** overall interval from 2762 - 2780'. As follows:

2762 - 2768	4 shots per foot
2772 - 2773	4 shots per foot
2778 - 2780	4 shots per foot

Schlumberger was rigged down and an Arrowset packer was picked up and run into the hole on 4-1/2" drill pipe. The packer was set at 2464' in the 9-5/8" casing.

A Halliburton coiled tubing unit, nitrogen pumper and nitrogen transports were rigged up to jet the liner in the lateral hole. The coiled tubing would not go down the well past 2466', approximately at the liner hanger for the 5-1/2' liner going out the lateral hole. The hole was jetted with nitrogen from 2465' within the 4-1/2" drill pipe for ninety minutes, and approximately 90 barrels of fluid was recovered at the surface.

The coiled tubing was removed from the well and the bottom few feet of the tubing were bent slightly to attempt to allow it to pass out into the lateral hole. The coiled tubing still would not go down past 2466' with several attempts.

The coiled tubing was again removed from the well and a site manufactured "stinger" made from a section of 2-3/8" pipe was added to the end of the tubing. The coiled tubing with the stinger attachment was run into the hole and successfully made it past the 2466' level on the first attempt. With the coiled tubing at a depth of 2495' nitrogen flow was started at a rate of 200 SCFM. Return flow was directed through a gas buster and then into frac tanks for gauging and storage.

9/10/00 Jetting of the well continued at 200 SCFM and with the coiled tubing at 2495'. Good fluid returns were obtained at the surface. The tubing was lowered to 4070' and nitrogen rate raised to 400 SCFM. Periodic readings of the pH, conductivity and temperature of the produced fluids were initiated and jar samples of the fluid were collected. At 400 SCFM the injection pressure was 1140 psi on the coiled tubing and the well head pressure of the return flow was 303 psi.

The nitrogen flow was cut back to 300 SCFM to reduce the amount of blowoff from the gas buster. The coiled tubing injection pressure was 1102 psi and the well head return pressure was 271 psi. The well was making an average of 1.7 BPM. A total of 279 barrels of fluid had been produced from the well. At a cumulative volume of 465 barrels produced the fluid had become clear, with minimal visible suspended solids content.

After 10 hours of jetting, 797 barrels of fluid had been produced, for an average rate of 1.33 BPM. Samples of the produced fluids were collected for laboratory analysis.

The results of measurements taken during the jetting were as follows:

Cumulative (Barrels)	Conduct. (mS/cm)	pH (Units)	Temp. (Deg. F)
90	186.1	7.35	20
127	186.9	7.58	21
180	193.7	7.67	21
279	194.2	7.25	20

355	196.6	7.03	21
425	197.6	7.17	21
465	200+	7.11	22
680	246	7.08	22
720	248	6.91	19
797	247	6.85	24

Nitrogen lifting was suspended after a total of 12.5 hours of jetting. A total of 293,000 SCFM of nitrogen had been utilized for the jetting. Sixty barrels of 9.3 lb/gal filtered brine was pumped down the coiled tubing to flush the nitrogen. Sixteen barrels of 20% HCL was then pumped to fill the pre-perforated portion of the liner.

The coiled tubing was pulled out of the hole and the packer was released and pulled out of the hole. A 5-1/2" Arrow packer was picked up and run into the hole. The packer was set in the 5-1/2" liner inside the ECP. With the element between 3408' and 3415' with 16,000 pounds.

Filtered brine was pumped down the annulus but the hole could not be filled up since it was taking fluid at a rate in excess of 8 BPM.

A pre-acidization safety meeting was held and Halliburton tested its flow lines to 4000 psi with brine.

The acid job was started pumping into the pre-perforated portion of the liner below the Arrow packer while pumping brine down the annulus at 5 BPM as a diverter to retain the acid in the lateral hole. The acid stages were:

500 gallons (12 barrels) brine
1328 gallons (31.6 barrels) 20% HCL
2000 gallons (47.61 barrels) 3% HF+17%HCL
2000 gallons (47.61 barrels) 20% HCL
5000 gallons (119 barrels) 9.3 lb/gal brine

Nitrogen was added to the acid flow to increase the downhole flow rates to as much as 12 BPM.

The packer was pulled loose and moved 1 joint up hole. The well began flowing at the surface on the annulus side. The pipe rams were closed and the well was allowed to flow to the reserve pit through the choke. Halliburton pumped 40 barrels of brine down the drill pipe while the well continued to flow to the pits through the choke. The rig pumps were used to pump brine down the annulus side, and the well was dead. The pipe rams were opened and the drill pipe and 5-1/2" packer were started out of the hole.

9/11/99 While pulling out of the hole with the drill pipe and packer the well began kicking through the drill pipe and the annulus. Brine with entrained nitrogen were blowing 15 feet to 20 feet above the rotary table. The pipe rams were closed on the 4-1/2" drill pipe and 9.3 lb/gal brine was pumped down the drill pipe and annulus. The well was dead. Stopped pumping brine and observed the well for approximately 90 minutes for signs of flow or pressure. Well dead.

It was decided to complete the acid job of the lateral liner with the packer and drill pipe already in the well. The 5-1/2" packer was run back down hole and set at 2550' in a blank liner section of the lateral hole.

A safety meeting was held and an acid job was begun on the liner section that had been perforated by Schlumberger. The acid job consisted of:

4500 gallons (107.14 barrels) 20% HCL
4500 gallons (107.14 barrels) 3% HF+17%HCL
5000 gallons (119 barrels) 20% HCL
5000 gallons (119 barrels) 9.3 lb/gal brine

No nitrogen was added to the acid flow with these stages of acidization.

Halliburton was rigged down and the hole was allowed to stabilize while

10 lb/gal brine was filtered to fill the hole. The 5-1/2" packer was pulled loose and removed form the well.

A 9-5/8" packer was picked up and run into the hole on drill pipe and set 1' above the top of the liner hanger for the lateral hole liner. Schlumberger was rigged up and a pressure / temperature / spinner assembly was picked up and run into the well on wireline to 3600' for injectivity fall-off testing. An up and down spinner survey was run without any pumping occurring, then the tools were set at 3400.7' (3223' TVD) and allowed to stabilize for five minutes. The bottom hole pressure was 1352 psi, bottom hole temperature was 93.4 degrees F.

Pumping was initiated at 8 BPM. Pumping continued for 8 hours at an average rate of 8.1 BPM. The final bottom hole pumping pressure was approximately 1611 psi. A total of 161,998 gallons (3833.3 barrels) of brine was pumped. The well was shut-in for observation of pressure and temperature.

9/12/99 The observation of fall-off pressure and temperature was continued for a total of 16 hours. Final bottom hole pressure was 1314 psi.

A short higher rate pumping test was performed for approximately 25 minutes, pumping at rates of 10 BPM and 10.76 BPM. A spinner survey was performed.

Halliburton and Schlumberger were rigged down. The drill pipe and packer were pulled out of the hole and laid down. The injection packer and polished bore receptacle (PBR) were picked up and run into the hole. CSPH 7" 23# x 9-5/6", 40#, 10' sleeve.

9/13/99 The injection packer and PBR were continued into the hole. The packer was set down on the liner hanger at 2570', and then picked up 5'. The packer was set with the bottom of at 2465' and the top at 2446'. The packer was released from the work string.

The well was rigged to test the packer seal by filling the hole with 9.3 lb/gal brine, closing the pipe rams and pumping into the well to 1150 psi with the rig pumps. The pressure held OK for 15 minutes and was then bled off the well and the BOPs were opened.

The drill pipe and drill collars were started out of the hole and laid down. The 2-7/8" drill pipe was run into the hole and subsequently pulled out laying down. The casing crew and equipment were rigged up.

The 5-1/2" fiberglass injection tubing was moved to the pipe racks, tallied and made ready for running. The lower seal assembly, tubing and upper seals were spaced out and run into the well. Brine at 9 lbs/gal was mixed with 1% Baroid corrosion inhibitor and pumped to fill the annulus. Pressure was applied to the annulus and surface leaks were repaired.

9/14/99 Leaks in the annulus system were repaired and the annulus filled with inhibited brine. A preliminary annulus pressure test was conducted and the annulus pressure dropped from 1012.96 psi to 1009.0 psi over a 30 minute time period. The test was good.

The BOPs were nippled down and the wellhead valves were mounted. The annular seals were tested at 2800 psi. The test was satisfactory. Rigging down of the drilling rig and ancillary equipment was begun.

Note: The official mechanical integrity testing (temperature logging, radioactive tracer logging and annulus pressure testing was scheduled for 0800 on Wednesday October 6, 1999. The New Mexico Environment Department, CRMWA Corp. and the US Bureau of Reclamation were notified of and concurred with the test schedule. Halliburton and Baker Hughes were notified of and scheduled for the performance of the testing.

3.0 GEOLOGICAL DATA SUMMARY

3.1 GENERAL

CRMWA CORP. Injection Well No. 1 was installed approximately one-quarter mile to the southwest of the pilot hole which had been drilled in February of 1996 to evaluate the local stratigraphy and the potential for salt water disposal by deep well injection. The stratigraphy of Injection Well No.1 was expected to be very similar to that of the pilot hole. Injection well installation proved this assumption to be true, except in the lowermost portions of the Sangre de Cristo Formation and the Precambrian basement where strata not seen in the pilot hole were encountered. A thick sequence of "granite wash" or grus-like material was penetrated above an igneous-metamorphic basement.

The injection well was drilled to a greater depth (by approximately 600 feet) than originally planned in order to penetrate more of the basal Paleozoic / uppermost Precambrian materials that were identified in the well. The documentation for the installation of the pilot hole referenced previous regional geological studies that indicated that the surface of the Precambrian was extensively eroded and widely variable in topographic relief. The stratigraphic differences between the pilot hole and Injection Well No. 1 may be evidence of significant stratigraphic variation over relatively short distances near the boundary of the Precambrian - Paleozoic interface.

The subsurface formations penetrated by the injection well were evaluated utilizing a variety of tools, including:.

1) A mud logging crew from Technical Drilling Services, Inc. was on site from the time the well drilled out from under the surface casing until drilling was completed. Cutting samples were collected and examined to total depth in both the vertical and lateral portions of the well. Drilling penetration rate, drilling parameters, formation lithology, natural gas chromatography, CO_2 and H_2S concentration was recorded. The log of this data is included in Appendix O.

2) Geophysical logs were run in every portion of the well. The suite of

Schlumberger open hole geophysical logs run in the well included Array Induction, Gamma Ray, Three Detector Density, Compensated Neutron, Formation MicroImager and Elemental Capture Spectroscopy Tool. Calculated logs prepared from analysis of the open hole suite included: ECS ELAN Log Analysis, MSD Mean Square Dip Log, Borehole Image Interpretation Logs and Calibrated and HILITE Images logs. The open hole interval from approximately 3666' to 4078' measured depth in the lateral hole was only logged with a gamma ray instrument associated with the Measurement While Drilling (MWD) tool array, due to the severe hole inclination of 61° to 78° below that point. Copies of geophysical logs are included in Appendix O of this report.

3) Whole cores were taken from the Yeso and the Sangre de Cristo Formation during the well installation. The whole cores were subjected to the following studies: megascopic examination, full analysis for porosity, permeability (to air) and bulk density determination. Selected plug samples from the cores were analyzed for horizontal and vertical permeability to brine, porosity, petrographic analysis via thin section, X-Ray diffraction analysis, scanning electron microscopy, mechanical properties analysis (for fracture gradient calculation) and flow through compatibility testing. The results of these analyses are discussed in Section 5 of this report while the full results of the analyses are reproduced in Appendix I.

3.2 STRUCTURE

3.2.1 FORMATION TOP RELATIONSHIPS

The injection well was expected to encounter geological conditions similar to those previously found in the pilot hole. This was the case for the most part. Geophysical log correlations between the two wells were generally good, with the following exceptions. The log correlations for the tops of the Trujillo and the Tecovas formations were subjective due to the stratigraphic variation present within the units. Additionally, the contact between the base of the Abo and the top of the Sangre de Cristo Formation appears to be transitional, and no sharp dividing criteria is discernable from geophysical logs.

The structural relationship of the subsurface formations encountered in the

GEOLOGICAL UNIT	INJECTION WELL NO. 1 (Reference Elev. =3834.5')* Measured	Sea Level	PILOT HOLE (Reference Elev. =3800.7')** Measured	Sea Level	Injection Well Relationship to the Pilot Hole
Trujillo	40	3794.5	39	3761.7	32.8 feet high
Tecovas	255	3579.5	254	3546.7	32.8 feet high
Bernal	482	3352.5	472	3328.7	23.8 feet high
San Andres	828	3006.5	804	2996.7	9.8 feet high
Yeso	1498	2336.5	1462	2338.7	2.2 feet low
Abo	2421	1413.5	2383	1417.7	4.2 feet low
Sangre de Cristo	2900	934.5	2864	936.7	2.2 feet low
Granite Wash or Grus	3220	614.5	not present	not present	
Weathered PC Basement ?	3512	322.5	not present	not present	
PC Basement ?	3570	264.5	3135	665.7	401.2 feet low
Well Total Depth	3800	34.5	3232	568.7	

* The injection well reference elevation was the drilling rig's kelly bushing, which was 14.50 feet above the ground level of 3820 feet.

** The pilot hole reference elevation was the top of the 4-1/2" casing at 3800.7 feet above sea level.

injection well (vertical hole) is compared to that of the pilot hole in the following table.

The injection well ran slightly high structurally (relative to sea level) to the pilot hole in the upper half of the interval penetrated, then ran slightly low in the lower formations. As was previously noted, log correlations in the Trujillo, Tecovas, lower Abo and Sangre de Cristo formations were subjective due to significant stratigraphic changes occurring within those intervals.

The lateral hole portion of the well was completely contained within the Abo, Sangre de Cristo and Granite Wash or grus intervals. The boundary of the Abo and Sangre de Cristo was picked at 2894' TVD in the lateral hole while the Sangre de Cristo - Granite Wash interface was picked at 3210' TVD, approximately 6 feet and 10' structurally high to the vertical hole, respectively.

3.2.2 STRUCTURAL DIP

A Schlumberger Formation Micro Imager was run in the vertical hole portion of the injection well from approximately 850' to a total depth of 3800'. Only portions of this logging were performed in "imaging mode" (approximately 2700' to 3800'), but the entire interval was logged using the "dipmeter mode" for the determination of structural dip rates and orientations. Structural dip and related comments for particular intervals are as follows:

Interval	Dip Direction	Magnitude
830' to 2900'	South	½ Degree
2900'	NA	Possible Unconformity
2900' to 3220'	South-Southwest	½ Degree
3360' to 3380'	NA	Possible Fault
3400'	NA	Possible Fault
3200' to 3800'	Could not be determined with any certainty	

Generally, structural dip was interpreted as south and south-westerly at approximately ½ degree. Dip rate and direction in the Granite Wash and Basement portions of the well could not be determined due to the lack of consistent marker horizons to correlate. This was reported by Schlumberger as being a common occurrence in these lithologies. A copy of the MSD Mean Square Dip log, with interpretation, is located in Appendix O of this report.

3.2.3 FRACTURING AND FAULTING

Schlumberger's Formation Micro Imager tool was utilized to identify faults and fractures within the stratigraphic section from the lower Abo through the Precambrian basement. Fracturing was minimal within the Abo and Sangre de Cristo Formations, but was relatively common in the Granite Wash and Basement sections.

Only two definite fractures were identified within the interval from 2722' to 3220' in the vertical hole (Abo and Sangre de Cristo formations). One of these fractures had a nearly north south strike and dipped to the east at 82 degrees. The other fracture had a strike at nearly right angles to the first, and dipped 68 degrees to the south. Fracturing in these formations does not appear to present much potential for the acceptance of injected brine. Figure 3-1 presents the orientation and dip information for fracturing in the Abo and Sangre de Cristo sections that were subjected to analysis.

Fractures were more common in the Granite Wash section, and in the interval from 3220' to 3568'. The dominate fracture strike direction was N85W - S85E. The fracture plane dips ranged from 35 to 82 degrees toward the south. The average dip rate was approximately 67 degrees. Hydraulic fracture aperture were widest in the interval from 3450' to 3500' and were developed to a somewhat lesser degree in the interval from 3350' to 3570'. A conjugate set of fractures exhibited a strike of N50E - S50W and dipped to the southeast at an average rate of approximately 65 degrees. Figure 3-2 presents the orientation and dip information for fracturing in the Granite Wash section of the vertical hole.

The dominate fracture strike in the Precambrian basement section from approximately 3568' to 3800' was NW - SE. A secondary fracture set had a N - S strike and a tertiary fracture set had a NE - SW strike. The fracture dip direction was primarily toward the south and west at angles from 48 to 83 degrees, with an average dip of approximately 68 degrees. The hydraulic apertures of most of the fractures in the basement section were less than the 0.08 mm width that is commonly assumed to be necessary to accept fluid. Figure 3-3 presents the orientation and dip information for fracturing in the Precambrian basement section of the vertical hole.

Two possible faults were identified from the Formation Micro Imager within the Granite Wash section of the well. The shallower fault was at approximately 3365' with a strike of N82W - S82E, and exhibited a fault plane dip of 41 degrees at an azimuth of 188 degrees. The second fault was at approximately 3405' with a strike of N79W - S79E, and exhibited a fault plane dip of 59 degrees at an azimuth of 161 degrees. These possible faults are about 150 feet above the Precambrian basement. No independent verification of the existence of these faults was possible due to the lack of any correlable intervals in other nearby wells. The possible faulting matched up well with the dominate fracture orientation within the Granite Wash section.

A copy of the log containing the Borehole Image Interpretation made from the Formation Micro Imager tool is located in Appendix O of this report.

3.3 STRATIGRAPHY

3.3.1 FORMATION THICKNESSES

Since the structural tops of the formations encountered in the injection well were similar to those of the pilot hole, it naturally follows that the overall thicknesses of the corresponding formations would be similar. The thickness of the formations penetrated in the injection well compared to those of the pilot hole showed relatively little variation, and are indicated in the following table:

GEOLOGICAL UNIT	INJECTION WELL (ft)	PILOT HOLE (ft)
Trujillo	215	215
Tecovas	227	218
Bernal	346	332
San Andres	670	658
Yeso	923	921
Abo	479	481
Sangre de Cristo	320	271
Granite Wash or Grus	292	Not present ?
Weathered Basement	58	Not present ?

3.3.2 FORMATION LITHOLOGY CHARACTERISTICS

3.3.2.1 TRIASSIC FORMATIONS

Sample logging (mud logging) for the injection well began at a depth of approximately 824 feet. This depth is within the Permian aged San Andres Formation. Geological units above 824 feet were not sampled or described in the injection well. These unsampled units include the Triassic aged Trujillo, Tecovas and Bernal Formations. The lithology of these formations is assumed to be similar to that described from the pilot hole.

The Trujillo Formation was described as a light grey sandstone, predominately fine grained but with occasional coarser materials present. The gamma ray log through the Trujillo in the injection well indicated the unit to be composed of massive low level radioactivity intervals (probably sands and silts) from 50 to 100 feet thick separated by relatively thin zones of higher natural radioactivity (shale zones) from 3 to 10 feet thick.

The Tecovas Formation was described from the pilot hole as a siltstone to mudstone, reddish in color in the upper portions, changing downward to a fine grained sandstone in the lower portion of the formation. The gamma ray log of the injection well showed massive zones with low radioactivity levels, indicating a low clay content throughout. Thin shaley beds were minimal. Additionally, the induction log through the Tecovas showed markedly lower resistivity than in the overlying Trujillo Tecovas, and separation of the various induction resistivity curves within most of the Tecovas indicated the possible presence of greater permeability than in the Trujillo.

The Bernal formation of the pilot hole was reported to be a reddish mudstone and siltstone with minor gypsum and anhydrite present. The gamma ray log of the injection well shows the Bernal to be predominately shale with minor silty or sandy intervals. Approximately 20 percent of the unit may be classified as siltstone with the remainder being shale. Tracking of the induction resistivity curves through most of the Bernal indicate minimal permeability is present, except for a silty zone in the lowermost 30 feet of the formation that does exhibit some possible permeability.

3.3.2.2 PERMIAN FORMATIONS

SAN ANDRES

The sample log from the injection well indicated the San Andres Formation to be 670 feet thick. The formation consisted of alternating anhydrite, halite, limestone, mudstone and sandstone units. Anhydrite dominated the upper portion of the formation with halite and limestone becoming more common in the middle two thirds of the formation. The lower 100 feet of the unit was composed of sandstone and halite.

YESO

The Yeso Formation was 923 feet thick in the injection well. Cuttings samples indicated that this formation was composed of inter bedded halite, mudstone and anhydrite, with relatively minor amounts of sandstone and limestone. The upper 400 feet of the formation was mainly halite and mudstone inter bedded in nearly equal proportions. The 300 feet toward the middle of the formation showed an increase in anhydrite levels, but was predominately mudstone with subordinate levels of halite interbeds. Approximately the lowermost 230 feet of the formation was dominated by halite inter bedded with secondary volumes of mudstone. An increasing amount of siltstone and sandstone was present in this lower part of the unit, as was a detectable increase in anhydrite and limestone. This lower 230 feet of the formation appeared to consist of thinner interbeds and rapidly alternating lithology. The basal 20 feet of the Yeso consisted of an extremely hard and consistent anhydrite bed that yielded some of the slowest rates of drilling penetration encountered in the injection well.

ABO

The Abo Formation was 479 feet thick in the injection well and was composed principally of mudstone, with secondary amounts of siltstone and sand according to the sample log. Schlumberger's Elemental Capture Spectroscopy (ECS) tool and Formation Micro Imager (FMI) was run over approximately the lower third of the Abo and on to total depth of 3800' in the Precambrian basement. The ECS is capable of determining the proportion of a rocks lithology that is composed of principal rock forming materials. The ECS analysis indicated the Abo to be composed of an average of approximately 55% quartz, 25% clay minerals, 5% calcite and 15% void space. The ECS can not determine exact rock makeup, only its component parts. Therefore, the high quartz content could be in the form of pebble, sand, silt or clay sized particles.

The FMI tool images the borehole walls using eight resistivity measuring pads. The resulting images, when processed, can yield a "picture" of the hole wall that is an indicator of lithology, and also bedding, fracturing and faulting.

The Abo contained relatively few mudstone "conglomerate" zones as had been described from the pilot hole. The formation was primarily mudstone red beds.

SANGRE de CRISTO

The Sangre de Cristo Formation consisted of two major members as encountered in the injection well. The upper member was a mudstone and mudstone "conglomerate" zone, and the lower member was a granite wash or grus zone. The lower member had not been noted in the pilot hole only one-quarter of a mile to the east.

SANGRE de CRISTO - Upper Member

The upper mudstone and "conglomerate" member was 320 feet thick. Cuttings samples indicated that this zone was somewhat more sandy than the overlying Abo Formation and contained approximately 100 feet of the mudstone conglomerate that had been described from the pilot hole. The conglomerate contained clasts of mudstone, but the clasts were contained in a mudstone matrix. The lower one-half of the upper member contained more mudstone and also more of what was described as a quartz wash. ECS analysis of the upper member indicated that its mineralogic composition was actually very similar to the Abo in the upper half, but the lower half contained a higher clay mineral content, at the expense of the quartz content.

Gamma ray logs in the basal 100 feet of the upper member show a marked increase in natural background radiation. This indicates an increasing proportion of radioactive minerals.

FMI interpretation indicated that the channel deposits of mudstone conglomerate present within the Sangre de Cristo demonstrated a predominate north-south orientation. Transport direction along these channels, as indicated by paleocurrent cross bedding, was toward the south. There was an indication that the thalweg of some of these channels was in a southwesterly direction. Figure 3-4 presents a composite plot of the channel orientation and thalweg direction for the lower Abo formation and the upper member of the Sangre de Cristo Formation. Some of the clasts filling the paleochannels imaged by the FMI were in excess of 6 inches in diameter.

SANGRE de CRISTO - Lower Member

The lower member of the Sangre de Cristo consisted of a granite wash or grus zone that was 292 feet thick. Grus is the geological term for an accumulation of angular, coarse grained fragments resulting from the granular disintegration of crystalline rocks, especially granite, in an arid or semiarid environment. This member had not been described from the pilot hole. This material consisted of an extremely high proportion of coarse to very coarse quartz fragments, frequently associated with pink to light tan colored feldspar fragments in multi-grain aggregates. Heavy minerals consisting of micas and opaques were present, and sometimes joined to the quartz-feldspar grain aggregates. Cuttings boundaries were extremely angular.

The granite wash interval of the lower Sangre de Cristo member was marked by a sharp lithologic change noted by the ESC tool. The quartz - clay mineral matrix of the upper member changes to high silica felsic rock (60%) - high iron mafic rock (25%) mixture, with about 5% heavy minerals and calcite in the lower member. The FMI indicates the member materials to be relatively coarse grained and uniform in size.

Gamma ray logs throughout the lower member of the formation indicate extremely high background radiation levels. The log is on the backup scale for the entire interval. Induction resistivity logs through the wash section show a higher and more consistent resistivity (about 10 ohm-meters) than in the upper member. Density and compensated neutron logs through the wash also are quite consistent in their readings, and indicate lower porosities than are present in the upper member.

3.3.2.3 PRECAMBRIAN FORMATIONS

WEATHERED PRECAMBRIAN

A lithologic section 58 feet thick is present below the granite wash interval that exhibits a lower gamma ray count, a more variable resistivity, lower rock density and higher neutron porosity readings. The ECS tool indicated a change to a higher iron rich mafic rock type (60%) at the expense of silica rich felsic rock (25%). The FMI showed a change to a less granular, partially stratified material showing evidence of considerable fracturing and possible dissolution along channels. This zone is considered to be highly weathered, but in place Precambrian basement material.

BASEMENT

At a measured depth of 3570 feet the vertical hole encountered a rock type with a low gamma ray count, a high but variable bulk density (up to 3.0 gm/cc), and variable induction log resistivity. The ECS tool indicated that the proportion of iron rich mafic rock types increased to approximately 75%. The FMI tool indicated massive, highly resistive formation material with some closed fractures. This material is interpreted to be non-weathered mafic basement. Approximately 230 feet of this material was penetrated in the vertical hole of the injection well.

3.3.2.4 FORMATIONS OF THE LATERAL HOLE

The well was sidetracked toward the south-southwest from a point in the upper portion of the Abo Formation, and remained within the Abo and Sangre de Cristo Formations for the extent of its penetration. The lateral hole reached a total depth near the base of the lower member (Granite Wash) of the Sangre de Cristo. The lithologies penetrated in the lateral hole were very similar to those encountered and described in the vertical portion of the well. The bottom hole location for the lateral part of the hole was approximately 1076 feet to the south-southwest of the well's surface location.

3.4 POROSITY AND PERMEABILITY

Geophysical logs for the determination of formation porosity were run from the base of the surface casing to total depth in the vertical hole and from the sidetrack point to approximately 3656' measured depth in the lateral portion of the hole. The logs consisted of combination density-neutron tools. Porosity logs could not be run in the lowermost 422' of the lateral due to the severity of the hole inclination (over 70 degrees). Computer processing of the geophysical log suites was also performed over selected portions of the vertical and lateral holes. These computed logs calculated an estimated permeability value. Copies of the geophysical logs run in the well and the computed logs that were subsequently prepared are located in Appendix O of this report.

Whole cores were collected from the Yeso and Sangre de Cristo Formations. These cores were subjected to analysis for porosity and permeability. Permeability to air was determined for flow in the horizontal and vertical directions through full core analysis. Plugs were cut from the full cores and vertical and horizontal permeability to sodium chloride brine was also investigated. The full results of the porosity and permeability testing that was performed on the core materials is included in Appendix I of this report.

Selected samples from the Sangre de Cristo Formation were subjected to flow through testing using fluid recovered from the Trujillo Formation, which will ultimately be injected into the well, and local fresh water from the Village of Logan. The fluids were filtered to multiple controlled levels as flow through testing progressed in order to evaluate the effects of filtering on injection zone permeability behavior. The plugs were analyzed before and after flow through testing to determine what changes may have occurred. Pre and post flow through testing consisted of evaluations of porosity, permeability (air and liquid) , bulk density, thin section petrography and electron microscopy examination. The results of this testing are discussed in Section 5 of this report and will not be further addressed here. Complete results of the flow through testing are found in Appendix I of this report.

3.4.1 POROSITY FROM GEOPHYSICAL LOGS

SAN ANDRES FORMATION

The San Andres Formation is primarily composed of anhydrite and halite intervals generally assumed to be of extremely low porosity. Log derived porosity data in these lithologies is not reliable. A few relatively thin limestone and sandstone intervals are present in the formation, which comprise a total of approximately 150 feet (18%) of the formation's thickness. These units have calculated porosities that range from 4% to 24%, with the average being approximately 13%.

YESO FORMATION

The Yeso Formation is primarily composed of halite (low porosity) and mudstone-siltstone with minor amounts of anhydrite and sandstone. The formation is a chaotically interbedded and mixed blend of these lithologies. Formation intervals composed of clay or halite free silt, sand or limestone are absent. Log derived porosities are relatively meaningless in this type of mixed lithology formation. The tools read total porosity in the mudstone and siltstone intervals, rather than effective porosity. Log derived total raw porosity values in the mudstone-siltstone intervals typically range from 15% to 25%, but this porosity is not effectively interconnected. When shale correction factors are applied to this data the effective porosity is reduced to the range of 3% to 6%.

ABO FORMATION

The Abo Formation is primarily composed of redbeds of mudstone and siltstone, with minor intervals of mudstone conglomerate. Geophysical logs have the same problem with porosity determination here as in the Yeso Formation. There are however some thin zones within the Abo that appear to composed of relatively clay free quartz rich silt or fine sand. Within these this zones porosity determination is more reliable. In a few of the most clay free siltstone intervals, porosity reaches as much as 20% to 25%. More typically the porosity of even the "cleaner" thin silt zones is between 15% and 20% from log calculations.

SANGRE de CRISTO FORMATION

The upper member of the Sangre de Cristo Formation is very similar in composition to the Abo Formation. A slight increase in the volume of mudstone conglomerates is present. Since these "conglomerates" are actually composed of mudstone clasts encased in a mudstone matrix, the overall conglomerate is lithologically still basically just a mudstone. There appears to be no particular enhancement of porosity in these intervals. A few of the cleanest silt zones (each only 2 to 3 feet thick) have porosities in the 20% to 25% range. The majority of the cleaner intervals have porosity between 15% and 20%, and are very similar to the clean intervals within the Abo.

The lower member of the Sangre de Cristo Formation is composed of the granite wash lithology. This lithology is very uniform over the entire interval present, and porosity ranges from 11% to 17% with an average of about 14%. The effectiveness of this porosity appears to be low since flow profiling indicated minimal acceptance of injected fluids.

PRECAMBRIAN

Log data inferred from the Precambrian may be subject to considerable error since the geophysical logging tools are designed and calibrated to function in sedimentary rock types.

The weathered Precambrian interval (58 feet thick) displayed very high porosities, generally over 20%. This may be the result of the solutioning effects apparent from the FMI logs. However, this porosity does not seem to be effectively connected since minimal fluid entered the zone during injectivity profiling.

The Precambrian basement unit, composed of iron rich mafic rock materials demonstrated a more variable porosity range, and at lower overall values than that found in the granite wash unit. Porosity ranged from 2% to 18%, with an overall average of about 8%. Once again, this porosity does not appear to be effective.

3.4.2 POROSITY AND PERMEABILITY FROM CORES

WHOLE CORE ANALYSIS

Porosity and permeability to air, grain density and additional factors were determined through whole core analysis performed on every other foot (where physically possible) of the core recovered from the Yeso and Sangre de Cristo formations. The Yeso is designated as the confining zone for the injection well and the Sangre de Cristo is a portion of the injection zone.

Permeability to air was performed with flow in both a horizontal direction and a vertical direction. The full core segments were analyzed by rotating the core in the holders to determine the maximum horizontal permeability direction and then taking another horizontal permeability reading at right angles to the maximum direction.

A summary of the porosity, air permeability and grain density data obtained from whole core analysis is presented in Table 3-1. Complete data from the core analysis is contained in Appendix I of this report.

PLUG ANALYSIS

Plugs were drilled from the whole cores at an interval of every other foot (where possible) and tested for porosity, permeability to sodium chloride brine and other factors. The plugs from the Yeso were all cut vertically and tested for vertical permeability. Plugs taken in the Sangre de Cristo were cut so that a horizontal and vertical permeability were obtained approximately every other foot. A summary of the porosity, brine permeability and materials density data obtained from plug analysis is presented in Table 3-2. Complete data from the core analysis is contained in Appendix I of this report.

3.5 PETROGRAPHY

To determine the lithology, texture, cementing properties and mineral composition, selected samples representing various lithologies recovered in the cores from the Yeso and Sangre de Cristo formations were subjected to analysis by thin section, x-ray diffraction and scanning electron microscopy. The results of these analyses are summarized in Section 5 of this report. Complete results of the testing are included in Appendix I.

FIGURE 3-1
NATURAL FRACTURING
SANGRE de CRISTO FORMATION (Upper Member)

CRMWA Corporation
CRMWA #1
Quay County, New Mexico

Natural Fracture Strike - 2722' To 3220'

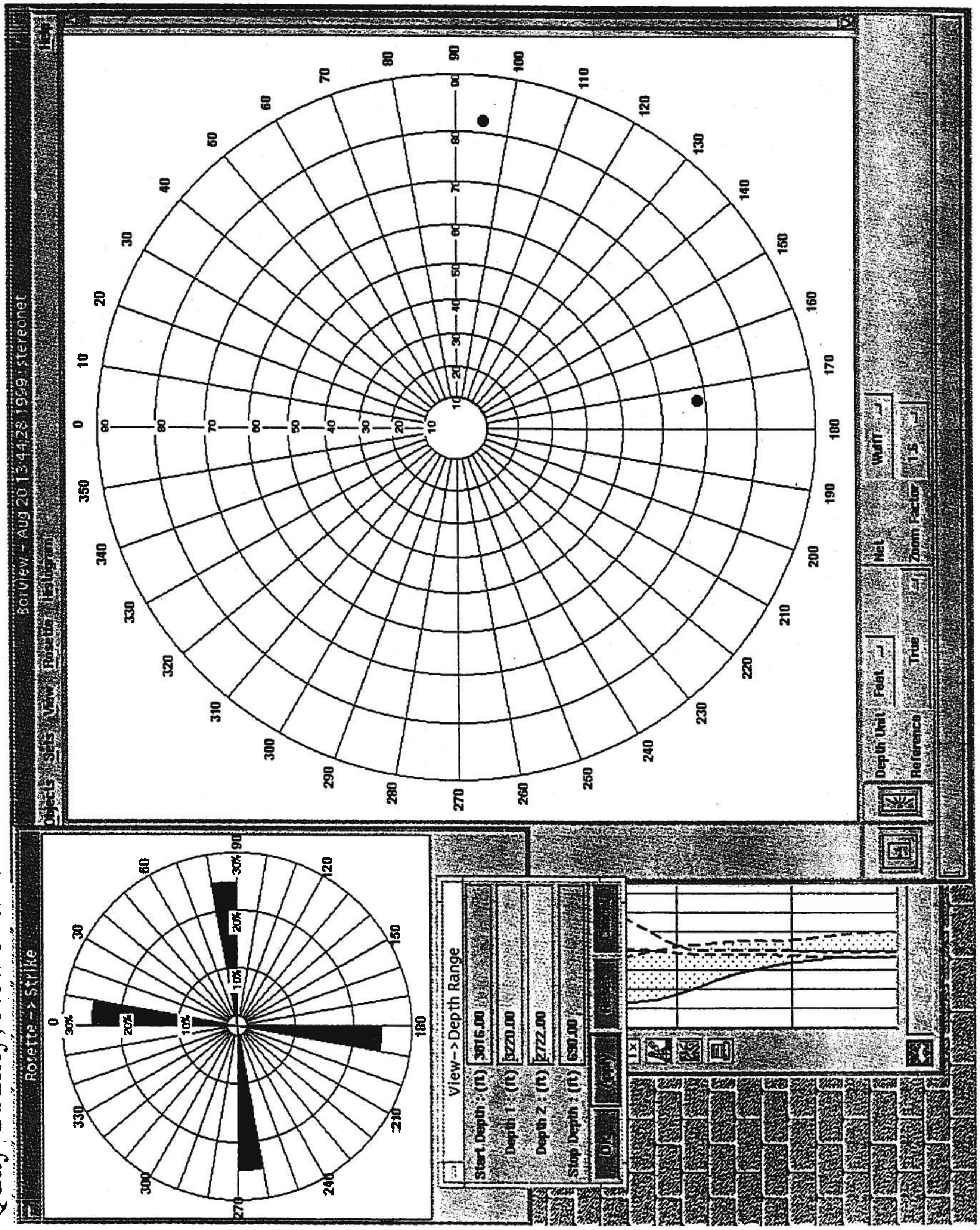


FIGURE 3-2
NATURAL FRACTURING
SANGRE de CRISTO FORMATION (Lower Member)

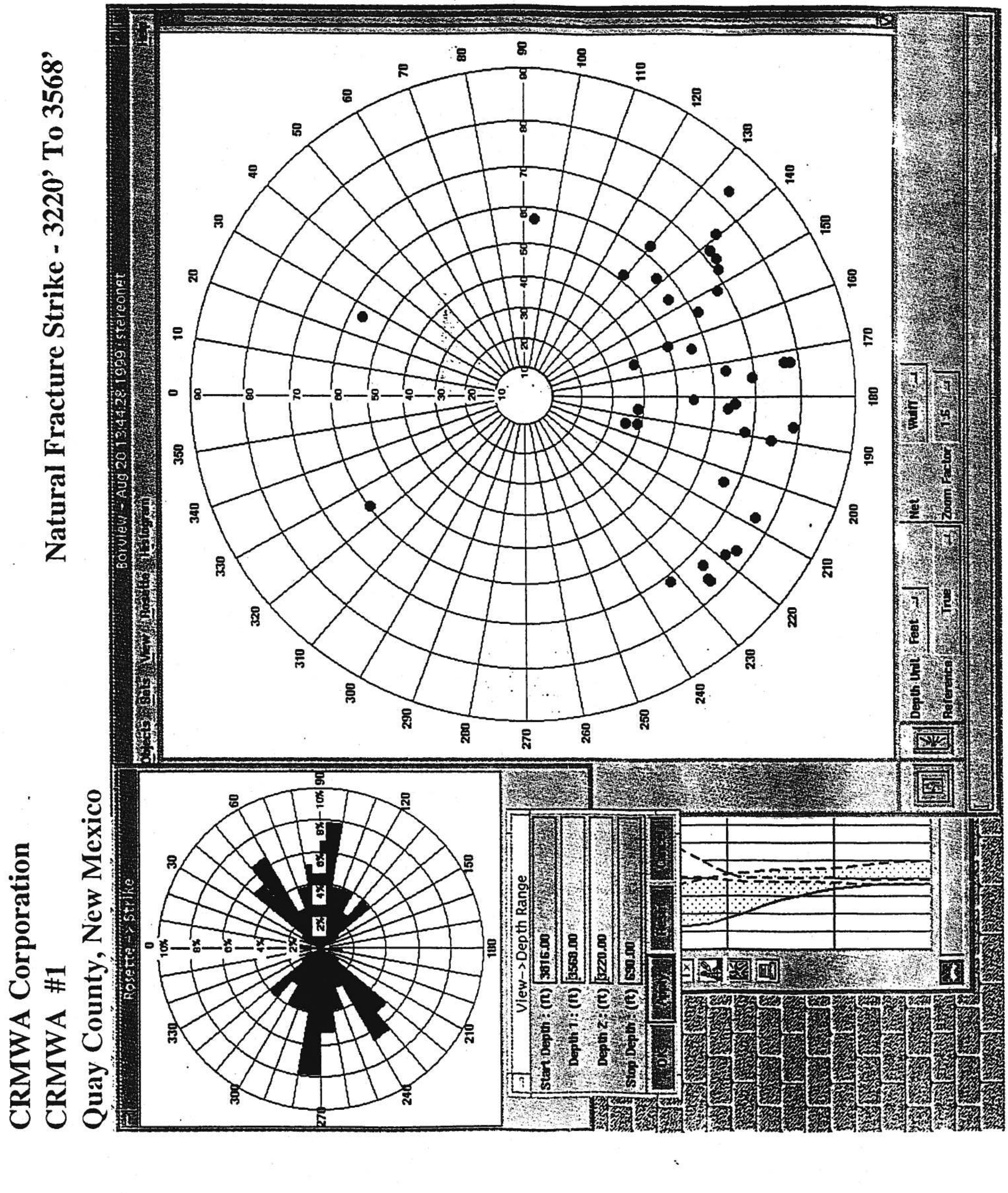
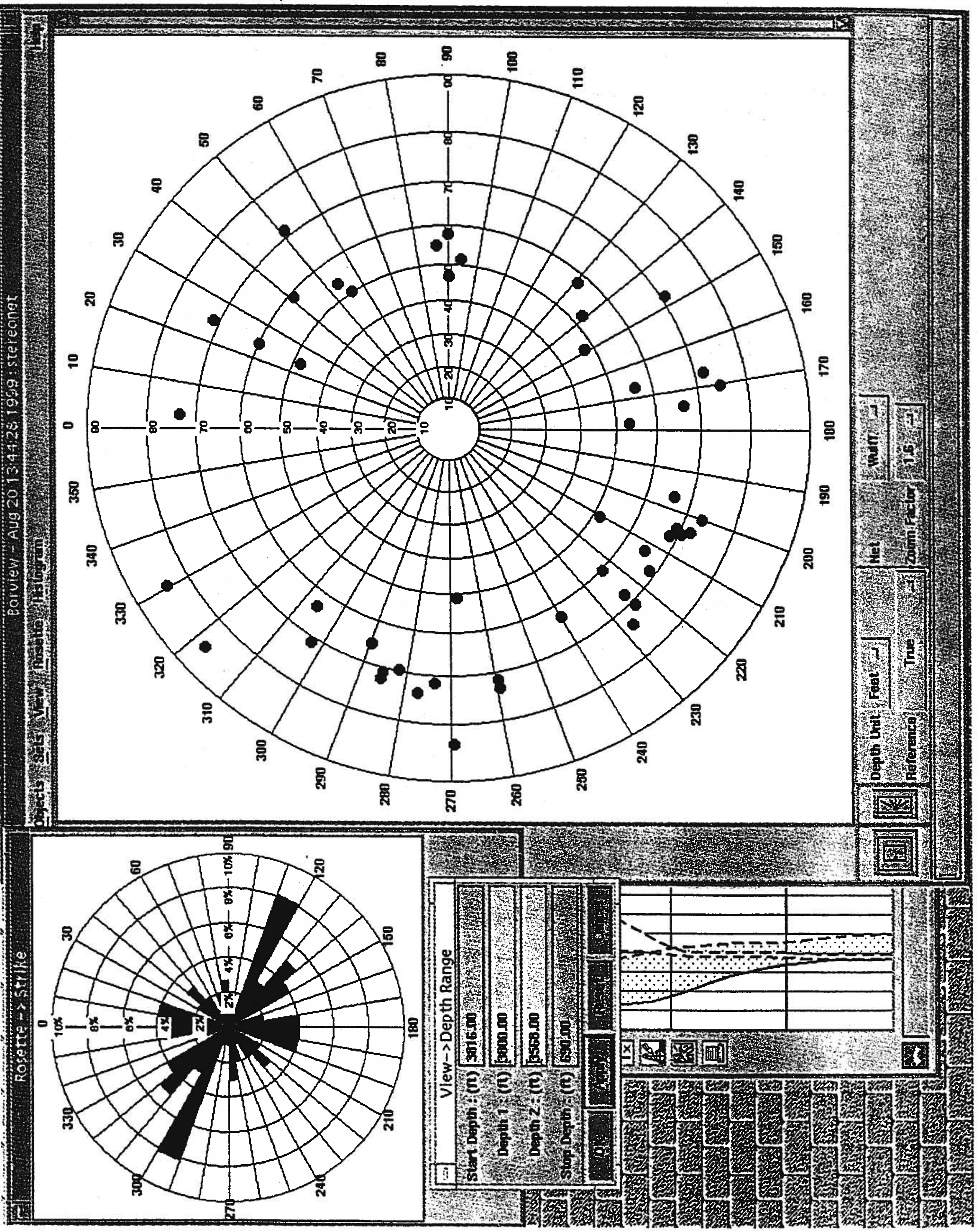


FIGURE 3-3
NATURAL FRACTURING
PRECAMBRIAN BASEMENT

Natural Fracture Strike - 3568' To 3800'



CRMWA Corporation
CRMWA #1
Quay County, New Mexico

FIGURE 3-4
CHANNEL TRENDS
SANGRE de CRISTO FORMATION (Upper Member)

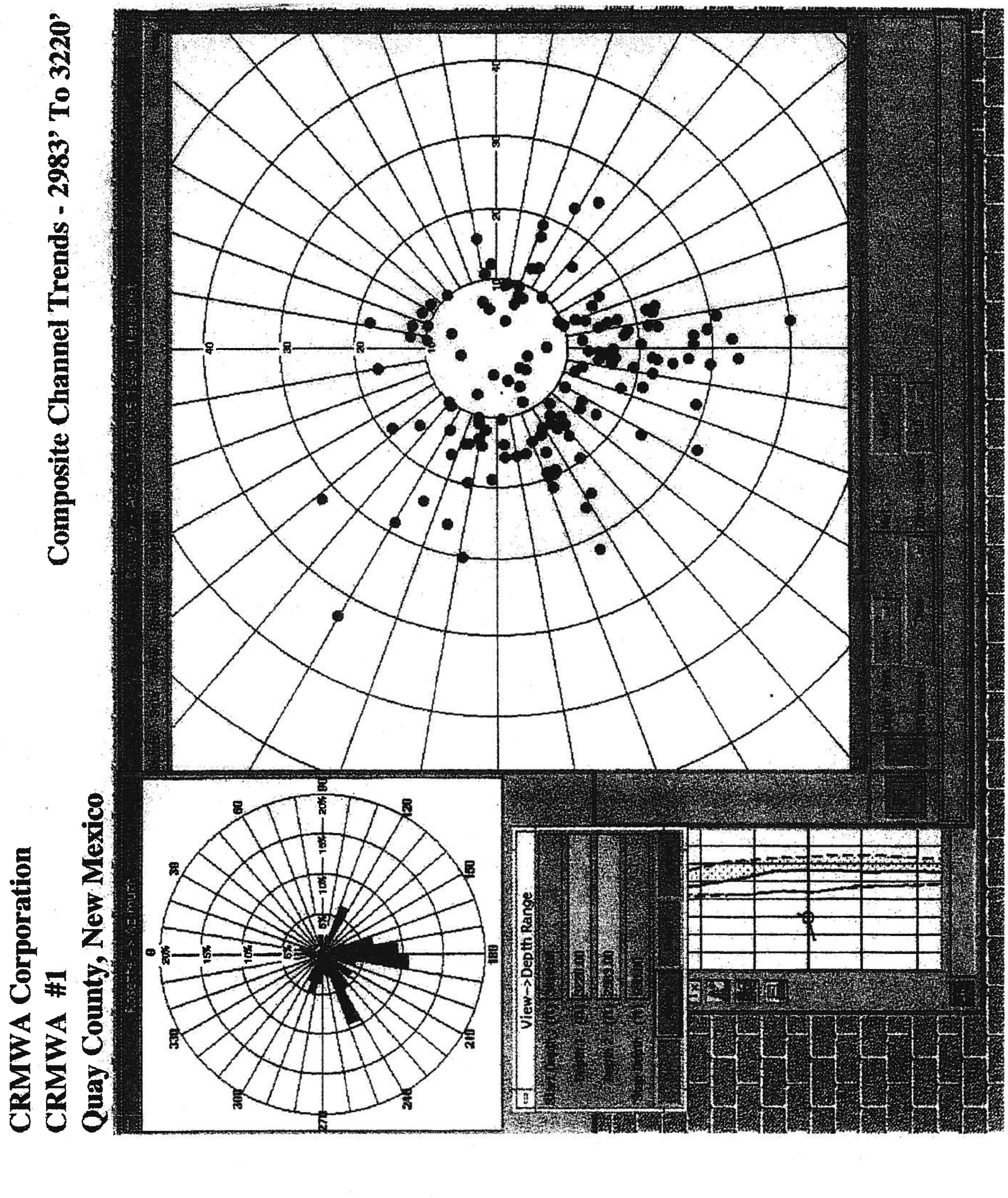


TABLE 3-1

WHOLE CORE ANALYSIS SUMMARY

YESO FORMATION CORES (NO. 1 and NO. 2)

CORE NO.	SAMPLE DEPTH	PERMEABILITY (To Air, in md) K Max	K @ 90	K Vert	POROSITY (%)	GRAIN DENSITY (gm/cc)
1	2020 - 2021	TBFA	TBFA	TBFA	13.1	2.55
1	2022 - 2023	TBFA	TBFA	2.45	10.8	2.57
1	2024 - 2025	1.51	1.22	0.27	2.8	2.28
1	2027 - 2028	TBFA	TBFA	TBFA	13.7	2.56
1	2029 - 2030	55.93	16.98	1.93	5.2	2.37
1	2031 - 2032	27.13	17.64	5.54	8.8	2.43
1	2034 - 2035	7.71	7.42	3.65	7.5	2.42
1	2036 - 2037	1.15	0.82	1.05	4.2	2.48
1	2038 - 2039	1.19	1.12	0.72	2.8	2.49
1	2040 - 2041	2.32	1.66	0.44	3.6	2.44
1	2042 - 2043	8.55	4.32	0.50	4.3	2.39
1	2044 - 2045	14.00	7.15	3.02	8.3	2.46
1	2046 - 2047	TBFA	TBFA	TBFA	5.1	2.67
1	2048 - 2049	1.11	1.08	0.11	2.2	2.25
2	2155 - 2156	15.19	14.15	6.48	8.9	2.53
2	2157 - 2158	10.83	2.14	0.25	5.5	2.51
2	2159 - 2160	8.58	8.26	0.14	7.1	2.56
2	2161 - 2162	0.65	0.64	0.16	4.8	2.46
2	2163 - 2164	1.22	1.11	0.22	7.1	2.53
2	2165 - 2166	TBFA	TBFA	78.25	7.7	2.61
2	2167 - 2168	0.40	0.35	0.19	0.9	2.47
2	2169 - 2170	62.73	51.94	0.72	11.2	2.57
2	2171 - 2172	44.91	41.18	0.86	12.5	2.62
2	2173 - 2174	TBFA	TBFA	79.94	8.1	2.64
2	2175 - 2176	TBFA	TBFA	26.75	8.8	2.49
2	2177 - 2178	5.47	3.39	0.31	5.1	2.41
2	2179 - 2180	0.38	0.32	0.10	1.9	2.29
	Average	**13.55**	**9.14**	**8.92**	**6.74**	**2.48**

TBFA = Too Broken For Analysis

TABLE 3-1
WHOLE CORE ANALYSIS SUMMARY
SANGRE de CRISTO FORMATION CORES (NO. 3, 4, and 5)

CORE NO.	SAMPLE DEPTH	PERMEABILITY (To Air, in md) K Max	K @ 90	K Vert	POROSITY (%)	GRAIN DENSITY (gm/cc)
3	2907 - 2908	1.49	1.03	0.22	12.4	2.66
3	2909 - 2910	16.61	9.99	0.77	11.5	2.67
3	2911 - 2912	0.63	0.59	0.12	10.3	2.71
3	2913 - 2914	6.56	1.83	0.55	10.9	2.70
3	2915 - 2916	1.53	1.47	0.29	14.5	2.67
3	2917 - 2918	12.15	1.89	0.19	14.7	2.68
3	2919 - 2920	4.48	2.95	0.57	15.4	2.68
3	2921 - 2922	6.54	3.02	0.21	13.6	2.67
3	2923 - 2924	21.97	9.99	5.09	11.5	2.72
3	2925 - 2926	0.56	0.46	0.08	12.3	2.67
3	2927 - 2928	1.14	0.95	0.18	13.7	2.66
3	2929 - 2930	3.37	3.36	0.48	15.8	2.66
3	2931 - 2932	7.04	6.55	0.16	15.5	2.66
3	2933 - 2934	2.61	2.38	0.19	14.2	2.66
3	2935 - 2936	0.25	0.24	0.05	4.5	2.74
4	3002 - 3003	34.51	20.12	2.93	10	2.67
4	3003 - 3005	14.52	12.11	79.49	9.5	2.69
4	3006 - 3007	153.96	143.53	171.40	21.2	2.59
4	3008 - 3009	44.92	43.22	1.26	15	2.65
4	3010 - 3011	4.27	2.91	0.78	6.8	2.71
4	3013 - 3014	11.16	11.09	1.74	8.3	2.72
4	3014 - 3015	15.06	7.59	0.18	6.3	2.68
4	3016 - 3017	17.28	5.93	0.28	9.1	2.71
4	3018 - 3019	18.11	9.49	0.20	8.6	2.73
4	3020 - 3021	38.92	3.16	0.89	8.6	2.75
4	3022 - 3023	6.73	3.11	1.90	7.6	2.68
4	3024 - 3025 *	59.40	58.97	28.49	10.4	2.61
5	3034 - 3035 *	1003.86	997.23	1428.39	19.6	2.62
5	3036 - 3037	48.02	47.69	4.31	8.6	2.69
5	3038 - 3039	TBFA	TBFA	TBFA	12	2.64
5	3042 - 3043	TBFA	TBFA	TBFA	TBFA	TBFA
5	3043 - 3044	TBFA	TBFA	TBFA	TBFA	TBFA
5	3044 - 3045	TBFA	TBFA	TBFA	TBFA	TBFA
	Average	**53.71**	**48.72**	**59.70**	**11.35**	**2.59**

TBFA = Too Broken For Analysis
* = The core segment was broken. Data may be unreliable.

TABLE 3-2
PLUG ANALYSIS SUMMARY
YESO FORMATION CORES (NO. 1 and NO. 2)

Note: All plugs for the Yeso were drilled vertically

Sample	Depth (ft)	Permeability to Brine (md)		Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 317V	2021.0	0.529	√	33.2	2.70	1.80
E 318V	2023.5	0.997		35.2	2.69	1.74
E 416V	2029.5	3.57		N/A	N/A	N/A
E 417V	2031.8	0.184		31.1	2.62	1.81
E 319V	2032.8	*		*	*	*
E 320V	2035.9	< 0.001	√	16.7	2.61	2.17
E 397V	2037.0	58.4	√	39.8	2.62	1.58
E 398V	2038.7	79.8		26.6	2.57	1.89
E 418V	2039.2	0.051		9.4	2.47	2.24
E 399V	2041.6	*		*	*	*
E 400V	2043.3	0.200		15.3	2.52	2.13
E 401V	2045.1	0.003		24.8	2.68	2.02
E 402V	2049.0	0.001		31.5	2.80	1.92
E 403V	2155.9	1.06		31.1	2.62	1.81
E 404V	2158.2	0.790		29.5	2.65	1.87
E 405V	2160.2	< 0.001		17.5	2.58	2.13
E 406V	2162.0	< 0.001		8.7	2.56	2.34
E 407V	2164.2	< 0.001		11.6	2.58	2.28
E 408V	2165.9	0.012		30.4	2.75	1.91
E 409V	2168.0	< 0.001		5.1	2.48	2.35
E 410V	2170.3	< 0.001		12.3	2.72	2.39
E 411V	2172.3	0.001		26.4	2.66	1.96
E 412V	2174.4	< 0.001		22.7	2.82	2.18
E 413V	2176.5	< 0.001	√	10.3	2.52	2.26
E 414V	2178.4	< 0.001	√	15.7	2.40	2.02
E 415V	2180.0	< 0.001		2.8	2.28	2.22

* Denotes sample contained large amounts of halite which dissolved when sample was saturated with brine. Brine permeability determination could not be performed.

√ Denotes sample was tested with 150,000 ppm sodium chloride brine. All others were tested with a saturated sodium chloride brine.

TABLE 3-2
PLUG ANALYSIS SUMMARY
SANGRE de CRISTO FORMATION (CORE NO. 3)

Note: Plugs for the Sangre de Cristo were drilled both horizontally and vertically (V)

Sample	Depth (ft)	Permeability to Brine (md)	Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 451	2907.1	< 0.001	15.5	2.77	2.34
E 452V	2907.2	< 0.001	13.0	2.74	2.38
E 453	2909.8	< 0.001	8.1	2.80	2.57
E 454V	2909.9	< 0.001	8.6	2.82	2.58
E 455V	2911.2	< 0.001	11.0	2.69	2.39
E 456	2911.5	0.002	15.3	2.76	2.34
E 457V	2913.2	< 0.001	14.1	2.80	2.41
E 458	2913.5	0.007	14.7	2.73	2.33
E 459	2913.8	0.008	17.5	2.73	2.25
E 460V	2915.9	< 0.001	18.0	2.70	2.21
E 461V	2917.5	< 0.001	15.3	2.73	2.31
E 462	2917.8	0.003	18.1	2.72	2.23
E 463	2919.2	0.440	19.7	2.72	2.18
E 464V	2919.5	0.002	17.4	2.70	2.23
E 465V	2921.7	< 0.001	15.6	2.74	2.31
E 466	2921.8	0.002	16.8	2.76	2.30
E 467V	2923.2	< 0.001	16.9	2.74	2.28
E 468	2923.6	< 0.001	14.8	2.82	2.40
E 469V	2925.3	< 0.001	15.3	2.75	2.33
E 470	2925.7	0.044	19.2	2.75	2.22
E 471	2927.2	0.003	16.6	2.72	2.27
E 472	2927.4	0.009	16.6	2.74	2.29
E 473	2929.3	0.639	17.0	2.46	2.04
E 474V	2929.6	0.002	18.0	2.74	2.25
E 475V	2931.2	< 0.001	14.1	2.80	2.41
E 476	2931.3	0.147	18.3	2.74	2.24
E 477	2933.2	< 0.001	14.5	2.76	2.36
E 478V	2933.6	< 0.001	17.0	2.70	2.24
E 479V	2935.7	< 0.001	5.9	2.82	2.65
E 480	2935.8	< 0.001	4.5	2.84	2.71

TABLE 3-2
PLUG ANALYSIS SUMMARY
SANGRE de CRISTO FORMATION (CORE NO. 4)

Note: Plugs for the Sangre de Cristo were drilled both horizontally and vertically (V)

Sample	Depth (ft)	Permeability to Brine (md)	Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 481	3003.1	< 0.001	14.8	2.74	2.33
E 482V	3003.2	< 0.001	14.4	2.69	2.30
E 483	3005.5	< 0.001	11.4	2.74	2.43
E 484V	3005.7	< 0.001	12.4	2.69	2.36
E 485	3007.6	9.67	22.1	2.65	2.06
E 486V	3007.8	0.002	20.0	2.64	2.11
E 487V	3009.6	< 0.001	7.5	2.72	2.52
E 488	3009.9	< 0.001	9.8	2.69	2.43
E 489V	3011.1	< 0.001	10.5	2.73	2.44
E 490	3011.3	< 0.001	10.3	2.72	2.44
E 491V	3013.1	0.770-29.3 *	9.5	2.64	2.39
E 492	3013.3	953	14.4	2.63	2.25
E 493	3015.4	< 0.001	7.7	2.77	2.56
E 494V	3015.6	< 0.001	14.1	2.73	2.35
E 495	3017.3	< 0.001	11.3	2.79	2.47
E 496V	3017.5	< 0.001	15.1	2.76	2.34
E 497	3019.7	< 0.001	14.6	2.75	2.35
E 498V	3019.8	< 0.001	14.1	2.73	2.35
E 499V	3021.7	< 0.001	6.8	2.64	2.46
E 506	3021.8	< 0.001	11.3	2.69	2.39

* Denotes there was a continual pressure decrease during brine injection, possibly caused by dissolution of the rock matrix. Initial perm. to brine was 0.770 md increasing to 29.3 md at the end of the test.

TABLE 3-2

PLUG ANALYSIS SUMMARY

SANGRE de CRISTO FORMATION (CORE NO. 5)

Note: Plugs for the Sangre de Cristo were drilled both horizontally and vertically (V)

Sample	Depth (ft)	Permeability to Brine (md)	Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 545	3023.4	< 0.001	5.9	2.66	2.50
E 546V	3023.8	< 0.001	8.3	2.62	2.40
E 547	3025.0	. 0.004	12.0	2.61	2.30
E 548V	3025.3	0.019	13.7	2.63	2.27
E 549	3033.2	2.65	11.5	2.59	2.29
E 550V	3033.7	168	22.2	2.61	2.03
E 551V	3035.0	139	22.8	2.58	1.99
E 552	3035.6	412	19.7	2.63	2.11
E 553V	3036.9	< 0.001	9.7	2.67	2.41
E 554	3037.1	< 0.001	6.4	2.68	2.51
E 555V	3025.6	40.9	19.1	2.58	2.09

TABLE 3-1
WHOLE CORE ANALYSIS SUMMARY
YESO FORMATION CORES (NO. 1 and NO. 2)

CORE NO.	SAMPLE DEPTH	PERMEABILITY (To Air, in md) K Max	K @ 90	K Vert	POROSITY (%)	GRAIN DENSITY (gm/cc)
1	2020 - 2021	TBFA	TBFA	TBFA	13.1	2.55
1	2022 - 2023	TBFA	TBFA	2.45	10.8	2.57
1	2024 - 2025	1.51	1.22	0.27	2.8	2.28
1	2027 - 2028	TBFA	TBFA	TBFA	13.7	2.56
1	2029 - 2030	55.93	16.98	1.93	5.2	2.37
1	2031 - 2032	27.13	17.64	5.54	8.8	2.43
1	2034 - 2035	7.71	7.42	3.65	7.5	2.42
1	2036 - 2037	1.15	0.82	1.05	4.2	2.48
1	2038 - 2039	1.19	1.12	0.72	2.8	2.49
1	2040 - 2041	2.32	1.66	0.44	3.6	2.44
1	2042 - 2043	8.55	4.32	0.50	4.3	2.39
1	2044 - 2045	14.00	7.15	3.02	8.3	2.46
1	2046 - 2047	TBFA	TBFA	TBFA	5.1	2.67
1	2048 - 2049	1.11	1.08	0.11	2.2	2.25
2	2155 - 2156	15.19	14.15	6.48	8.9	2.53
2	2157 - 2158	10.83	2.14	0.25	5.5	2.51
2	2159 - 2160	8.58	8.26	0.14	7.1	2.56
2	2161 - 2162	0.65	0.64	0.16	4.8	2.46
2	2163 - 2164	1.22	1.11	0.22	7.1	2.53
2	2165 - 2166	TBFA	TBFA	78.25	7.7	2.61
2	2167 - 2168	0.40	0.35	0.19	0.9	2.47
2	2169 - 2170	62.73	51.94	0.72	11.2	2.57
2	2171 - 2172	44.91	41.18	0.86	12.5	2.62
2	2173 - 2174	TBFA	TBFA	79.94	8.1	2.64
2	2175 - 2176	TBFA	TBFA	26.75	8.8	2.49
2	2177 - 2178	5.47	3.39	0.31	5.1	2.41
2	2179 - 2180	0.38	0.32	0.10	1.9	2.29
	Average	**13.55**	**9.14**	**8.92**	**6.74**	**2.48**

TBFA = Too Broken For Analysis

4.0 WELL TESTING SUMMARIES

This section briefly describes testing that was performed during the installation of the injection well and summarizes the results. For detailed information and data the reader is referred to specific appendices of this report that contain the complete results.

4.1 CASING PRESSURE TESTS

Casing pressure tests were conducted on the injection well's surface casing and long string protection casing following the setting and cementing of each string. This pressure testing was performed to verify the integrity of the casing string and connecting joints. A Sensotec Model Z/1262-01 (0-2000 psi range) pressure transducer was attached to the well head to monitor both of the casing tests. The signal from the transducer was recorded on a laptop computer.

4.1.1 SURFACE CASING

Surface casing consisting of 13-3/8" 61 lb/ft J-55 STC pipe had been run and cemented in place at a depth of 819.1 feet. The pressure test was performed on July 25, 1999 after the cement had cured for in excess of 48 hours, and a temperature and cement bond log had been run. The casing was pressurized using the rig mud pumps. Several small leaks at the well head connections were located and repaired, and the casing pressure test was begun at 1040.68 psig. The casing pressure declined to 1021.82 psig after 35 minutes. This change of 18.86 psi (1.8 percent) represented an acceptable pressure test, and met the criteria of having less than a 5% change in 30 minutes.

Figure 4-1 shows a plot of the pressure data. Tabular information on the pressure test is in Appendix D.

4.1.2 PROTECTION CASING

The protection casing string consisted of 9-5/8", 40 lb/ft, J-55 pipe run and cemented at a depth of 2673.21 feet. The pressure test was performed on August 4, 1999 after allowing the cement to cure, and performing a temperature and cement bond logging. The casing was pressurized using the rig mud pumps. It was necessary to bleed the pressure off the casing in order to repair leaks in the standpipe valve. The casing was then pressurized again in stages to approximately 500 psig, then 900 psig, then 1100 psig. The casing pressure changed from 1095.74 psi to 1080.96 psi in a thirty (30) minute time period. The 14.78 psi pressure loss over a thirty minute period represents a change of 1.3%. This demonstrated an acceptable pressure test, and met the criteria of having less than a 5% change in 30 minutes.

Figure 4-2 shows a plot of the pressure data. Tabular information on the pressure test is in Appendix D.

4.2 CORING DATA

Whole cores were recovered from the Yeso Formation and the Sangre de Cristo Formation. Two 30 foot cores were attempted in the Yeso and three 30 foot cores were attempted in the Sangre de Cristo. The depths and recoveries are listed below.

Core No.	Formation	Depths Cored	Recovery
1	Yeso	2020' - 2050'	30'
2	Yeso	2155' - 2185'	27' +/-
3	Sangre de Cristo	2907' - 2937'	30'
4	Sangre de Cristo	3002' - 3033'	25' +/-
5	Sangre de Cristo	3033' - 3061'	13' +/-
Totals		**149' +/-**	**125' +/-**

The penetration rate while cutting Core No. 5 dropped off to essentially zero, and the last 2' of the intended 30' interval was not cut. The bit was found to have been balled up with clay and the cutting surfaces were blinded off.

The recovered core material was subjected to a variety of tests to determine petrophysical properties . These tests and procedures included the following:

Analysis Requested	Cored Zone	Frequency of Testing
Core gamma ray logging	All cores	All recovered core
Full diameter core analysis to air - establish porosity, permeability to air (@K max and 90°)	All cores	Analysis performed on every other foot recovered

Analysis Requested	Cored Zone	Frequency of Testing
Slabbing core (2/3 - 1/3) and megascopic description	All cores	All recovered core
Vertical permeability (to 0.001 md) using 150,000 ppm NaCl brine or saturated brine as required and plugs cut from core. Includes a porosity determination.	Yeso cores	Every other foot
Vertical permeability (to 0.01 md) using 50,000 ppm NaCl brine and plugs cut from core. Includes a porosity determination.	Sangre de Cristo cores	Every other foot
Horizontal permeability (to 0.01 md) using 50,000 ppm NaCl brine and plugs cut from core. Includes a porosity determination.	Sangre de Cristo cores	Every other foot
X-Ray diffraction analysis, matrix and clays.	Sangre de Cristo cores	Samples selected from distinct lithologies
Scanning electron microscopy. At least two photographs per sample, with a discussion.	Sangre de Cristo cores	Samples selected from distinct lithologies.
Thin section preparation and petrographic examination, including a point count, photographs and discussion..	Yeso and Sangre de Cristo cores	Samples selected from distinct lithologies.
Mechanical properties and acoustic velocity analysis. Including shear and compressional wave velocities, Poission's Ratio, Young's Modulus, bulk and shear modulus.	Sangre de Cristo cores	Four samples.

In addition to this testing, core plug samples were selected from the Sangre de Cristo Formation for use in flow through testing using reservoir fluid from the Trujillo Formation and fresh water supplied from the Village of Logan. Petrophysical parameters for each plug were determined prior to the flowthrough testing, and re-evaluated following the flow through to determine what changes occurred within the sample.

Pre and post flow through tests on each selected plug included:

1) porosity
2) permeability (to air, and Trujillo fluid filtered to 0.45 µm absolute)
3) pore volume calculation
4) bulk density calculation
5) thin section preparation and examination
6) SEM evaluation

During the testing, fluid flow rates, cumulative flow volumes and the differential pressure across the sample plugs were monitored continuously. From this data the permeability of each sample was determined.

The testing consisted of conducting flow through testing at ambient reservoir conditions for a period of either 56 hours, or until 280 total pore volumes of fluid had passed through each sample. A series of Trujillo fluids each filtered to a different extent, as described below, constituted the test fluid.

The batches of Trujillo fluid utilized in the testing were filtered in the laboratory to the following degrees, and introduced to the plug samples in the following order:

1) 0.45 µm absolute
2) 2 µm absolute
3) 5 µm absolute
4) 10 µm absolute
5) 20 µm absolute
6) 40 µm absolute
7) total unfiltered Trujillo water

Each batch of fluid was injected through the test plug until at least 40 pore volumes had been injected, then introduction of the next (lesser filtered) batch of fluid was begun. If an individual fluid batch did not have 40 pore volumes pass through the sample within a period of 8 hours, injection of that batch was suspended and the next fluid batch was introduced. The testing of a sample was suspended if the permeability dropped to less than 0.01 md.

Additional flow through core testing was performed on Sangre de Cristo plugs using fresh water from the well site (from the Village of Logan water supply). The testing procedures were similar to the tests performed with Trujillo formation fluids, except the fresh water was not filtered to varying degrees. Plugs were flow through tested with fresh water for a total of 56 hours, or until 280 pore volumes of fluid were forced through the plug. Pre and post flow through testing and monitoring were the same as for the Trujillo fluid samples.

Basic data concerning core porosity and permeability was presented in Section 3.4 of this report. Additional petrophysical results of the core testing are summarized in report Section 5.1, while the detailed laboratory report in included in Appendix I. Flow through testing results are summarized in Section 5.3 and detailed laboratory results are in Appendix I.

Several small samples of core materials from the Sangre de Cristo were subjected to static compatibility testing by immersing the samples in various fluids to monitor the amount of dis-aggregation that occurred in the samples. This testing was performed after it became evident during drilling that the Sangre de Cristo was sensitive to some under saturated fluids. The results of this testing resulted in a change in the well's completion method from that originally planned. The results of this testing is summarized in Section 5.2 of this report, and the full laboratory results are included in Appendix I.

4.3 DRILL STEM TESTING

Several intervals of open hole in the vertical portion of the well were subjected to drill stem testing (DST) during well installation to determine the capacity of the interval to give up fluid to the well. Three DSTs were successful in producing significant amounts of fluid from the targeted interval, and provided pressure data from downhole memory gauges. Two DST's were not successful due to problems with setting the packer and sealing off a specific interval of the hole.

All tests were performed using a mechanically set packer, on 4-1/2" drill pipe. Downhole pressure gauges were run as a part of the DST tool string. The test string was run in the hole completely dry in order to cause the maximum possible differential pressures inward from the formation when the test tool was open. To produce fluid to the surface, 1.5" tubing was run into the well inside the 4-1/2" drill pipe and air lifting was performed using a truck mounted rental compressor. All fluids produced to the surface were run through a skid mounted gas buster and directed into an 80 barrel capacity gauging tank, then subsequently pumped in larger frac tanks.

The three intervals that were successfully tested were as follows:

Open Interval	Formation(s) Open	Fluid Recovered
2673' - 2907'	Abo	51 barrels
2673' - 3545'	Abo & Sangre de Cristo (Upr. & Lwr.)	279 barrels
3173' - 3545'	Sangre de Cristo (Lwr.)	83 barrels

Tabular pressure data and pressure plots from the vertical hole DSTs are located in Appendix G.

Fluid samples for laboratory analysis were collected from the DSTs of the Abo and the Abo-Sangre de Cristo intervals. Fluid analysis is summarized in Section 5.5 of this report and the full analytical reports are reproduced in Appendix K.

4.4 INJECTIVITY-FALLOFF TESTING

Injectivity-falloff tests were performed on two occasions during the installation of the injection well. The first was performed following the nitrogen jetting and acid stimulation of the vertical hole. Following the completion and stimulation of the lateral portion of the well, a second test was performed that evaluated the combined hydraulic properties of both the vertical and lateral sections of the well.

4.4.1 VERTICAL HOLE

The injectivity-falloff testing of the vertical hole was conducted on August 21-22, 1999 after the 5-1/2" liner was set, cemented, and perforated. The test was conducted with a mechanical set packer on 4-1/2" drill pipe. The packer was set at 2,630 feet in the 9-5/8" protection casing. A Halliburton pump truck was used to pump 9.1 pounds per gallon brine for the 8 hour injection period.

A Schlumberger-Lee production logging string was run into the wellbore. The logging string included a gamma ray tool, casing collar locator, spinner tool, and a high resolution pressure and temperature gauge. Pressure and temperature were monitored and recorded at the surface.

The spinner data indicated that all injected fluid was exiting the well through the three uppermost sets of perforations within the Abo Formation at 2,734-2,746 feet, 2,766-2,790 feet, and 2,808-2,820 feet.

The gauge was set at 3,200 feet after the spinner passes and the pressure was recorded for the remainder of the injection period and the entire falloff period at this depth. A analysis of the injectivity-falloff test of the vertical hole is included in Appendix H.

4.4.2 COMBINED VERTICAL AND LATERAL HOLE

The injectivity-falloff testing of the combined vertical and lateral hole was conducted on September 11-12, 1999 after completion of the lateral hole. A 5-1/2" liner was set, cemented, and perforated to finalize the completion. The test was conducted with a mechanical set packer on 4-1/2" drill pipe. The packer was set at 2,469 feet (1 foot above the liner hanger packer in the 9-5/8" protection casing in the vertical hole). In this well configuration, there is a single joint of pre-perforated 5-1/2" liner immediately set above the lateral hole window in the 9-5/8" casing that allows fluid access to the vertical wellbore. A Halliburton pump truck was used to pump 9.3 pounds per gallon brine for the 8 hour injection period.

A Schlumberger-Lee production logging string was run into the wellbore. The logging string included a gamma ray too, casing collar locator, spinner tool, and a high resolution pressure and temperature gauge. Pressure and temperature were monitored and recorded at the surface.

The spinner data indicated that approximately 58% of the injected fluid was exiting the well through the vertical section, 34% through the perforations 2,604-3,375 feet in the lateral hole, and 8% through the pre-perforated liner below 3,401 feet.

The gauge was set at a measured depth of 3,401 feet (true vertical depth of 3,223 feet) feet after the spinner passes. The pressure was recorded for the remainder of the injection period and the entire falloff period at this depth. An analysis of the injectivity-falloff test of the combined vertical and lateral hole is included in Appendix H.

4.5 MECHANICAL INTEGRITY TESTING

CRMWA Corp. (CRMWA) conducted the required annual mechanical integrity testing (MIT) on the well October 6, 1999. The testing was conducted in compliance with the State of New Mexico Water Quality Control Commission Regulations and the specific requirements of the approved Discharge Plan (DP-1054) from the State of New Mexico Environment Department. The MIT consisted of an annulus pressure test, temperature log, and a radioactive tracer survey.

ANNULUS PRESSURE TEST

An annulus pressure test was conducted on the well on October 6, 1999. A 0 to 2,000 psi calibrated Sensotec Model Z/1262-01ZG pressure transducer was rigged up to the annulus of the well. A Halliburton pump truck was rigged up to pressurize the annulus to ± 1,040 psi. The annulus was blocked in from the pump truck and the annulus pressure test was started at 0855 hours with an initial pressure of 1,032.1 psi.

The annulus pressure was monitored and recorded on the Texas World's computer recording unit for 62 minutes. After 62 minutes, the annulus pressure had decreased 24.2 psi (2.3 psi pressure change). The annulus pressure test was supervised by Bob Whiteside of Texas World and witnessed by Kurt Vollbrecht of the New Mexico Environment Department.

The annulus pressure test verified the mechanical integrity of the wellhead, injection tubing, injection tubing seal assembly, and the long string casing. A Class 1 Well Integrity Test Affidavit, a copy of the annulus pressure test data, and graph of the annulus pressure test data versus time is included in Appendix L.

TEMPERATURE LOGGING

A Temperature log was run on the well on October 6, 1999 to fulfill the requirements of the approved discharge plan. The well had been shut-in since the well was completed on September 13, 1999.

A wireline unit with pressure control equipment was moved in and rigged up on the wellhead. The temperature tool with a casing collar detector was run into the well. The temperature log was run from the surface to 3,740 feet at an average logging speed of 30 feet per minute. The fluid level was tagged at a depth of 749 feet. The average geothermal gradient measured from 749 feet to 2,800 feet was 0.78°F per 100 feet of depth.

This temperature survey will serve as a baseline for comparison with future temperatures surveys after the well is operational. The temperature log demonstrated there was no fluid movement into an underground source of drinking water through vertical channels adjacent to the injection wellbore. A copy of the temperature log is included in Appendix 0 (log No. 42).

RADIOACTIVE TRACER SURVEY

A radioactive tracer tool, consisting of an ejector, two detectors and a CCL was picked up and run into the well (see the Radioactive Tracer Logging Sequence Chart for tool configuration). A correlation strip was run and the depth counter corrected. A baseline gamma pass was run from 3,650 to 1,600 feet. Five-minute statistical checks of the background gamma counts were recorded at 2,421 feet and 2,429 feet.

Injection of 9. 3 brine water was started to the well at 84 gpm using the Halliburton pump truck. The tracer tool was positioned at 1,900 feet and the recorder was set in time-drive mode to check for a slug of Iodine-131 lost uphole. The tool was held stationary at 1,900 feet and the slug was recorded passing the detectors after 11 minutes. A series of six overlapping log passes were made following the slug down within the injection tubing, through the packer and seal assembly and into the permitted injection interval.

A second slug of Iodine-131 was ejected at 1,900 feet while injection was held constant at 168 gpm. One logging pass was run from 2,200 to 1,900 feet and only a very weak slug was recorded. The run was aborted.

A third slug of Iodine-131 was ejected at 2,200 feet while injection was held constant at 168 gpm. A series of four overlapping log passes were made following the slug down within the injection tubing, through the packer and seal assembly and into the permitted injection interval. No indication of any upward fluid movement was observed during the moving surveys.

Two stationary surveys were then run while injection of 9.3 ppg brine was maintained at a constant rate of 168 gpm. A slug of tracer material was ejected at 1,900 feet. The logging tool was immediately run down the hole and set with the lower detector at 2,440 feet (4 feet above the uppermost seals in the polished bore receptacle). The slug was verified passing both detectors. A recording of the background radioactivity was made for 20 minutes after the passage of the slug. No upward movement was observed over the duration of the stationary test.

The stationary survey was repeated according to the same procedure and at the same injection rate. A slug of tracer material was ejected at 1,900 feet. The logging tool was immediately run down the hole and set with the lower detector at 2,440 feet (4 feet above the uppermost seals in the polished bore receptacle). The slug was verified passing both detectors. A recording of the background radioactivity was made for 20 minutes after the passage of the slug. No upward movement was observed over the duration of the stationary test.

A final baseline gamma pass was run from 3,650 to 1,600 feet. The final base pass was compared with initial base. No anomalous reading were observed. The logging tools were removed from the well. A copy of the Radioactive Tracer Survey is included in Appendix O (log No. 43).

The Radioactive Tracer Survey demonstrated the integrity of the bottom-hole cement (above the window in the 9-5/8 inch protection casing at 2,515 feet. No radioactive material was observed moving upward behind the protection casing, nor was there any indication of fluid exiting the injection tubing above the seal assembly. All injected fluid was shown to be exiting the wellbore through the perforations into the permitted injection interval.

CRMWA CORP. - INJECTION WELL NO. 1
CASING PRESSURE TEST ON 13-3/8" SURFACE CASING

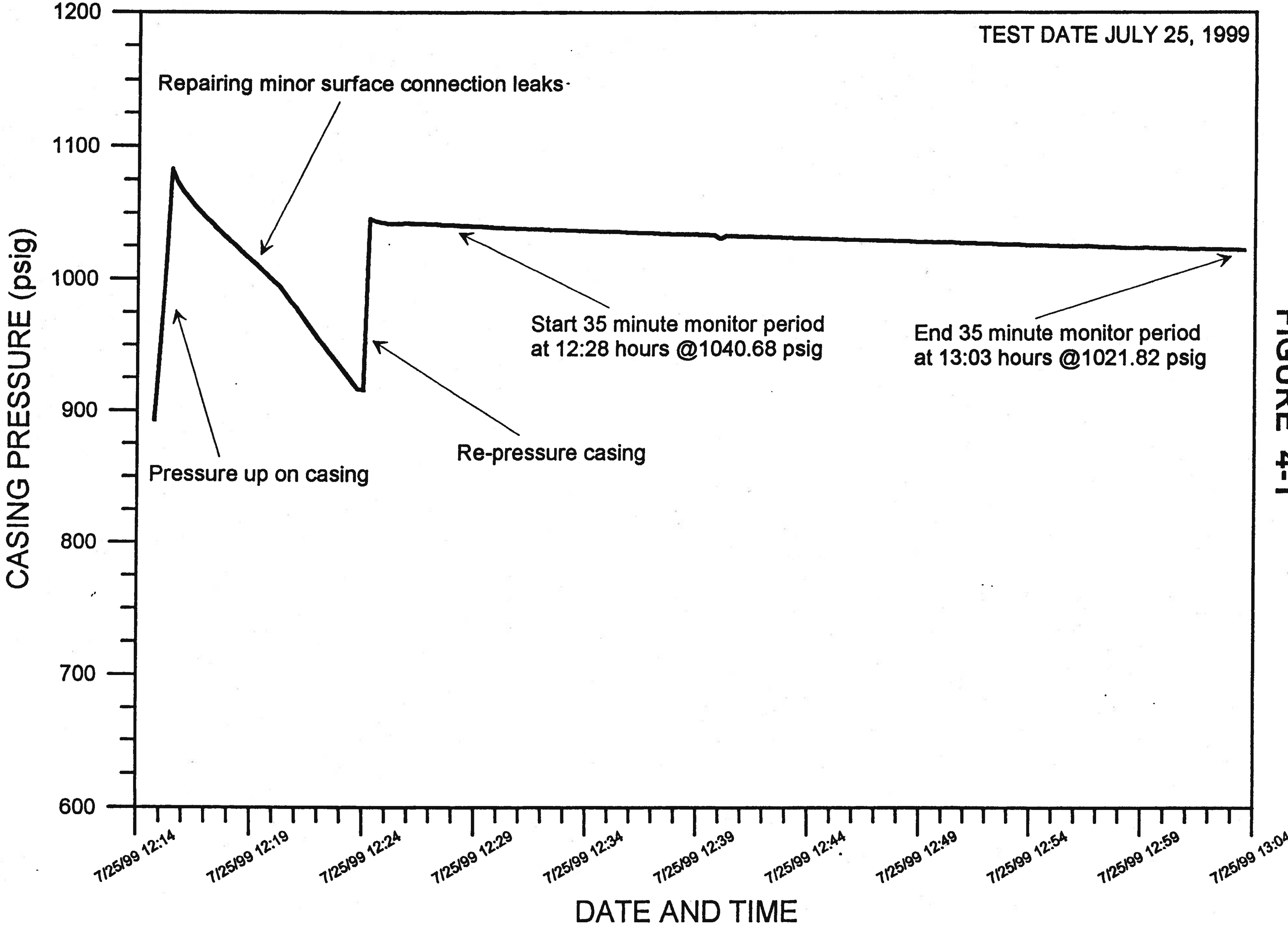


FIGURE 4-1

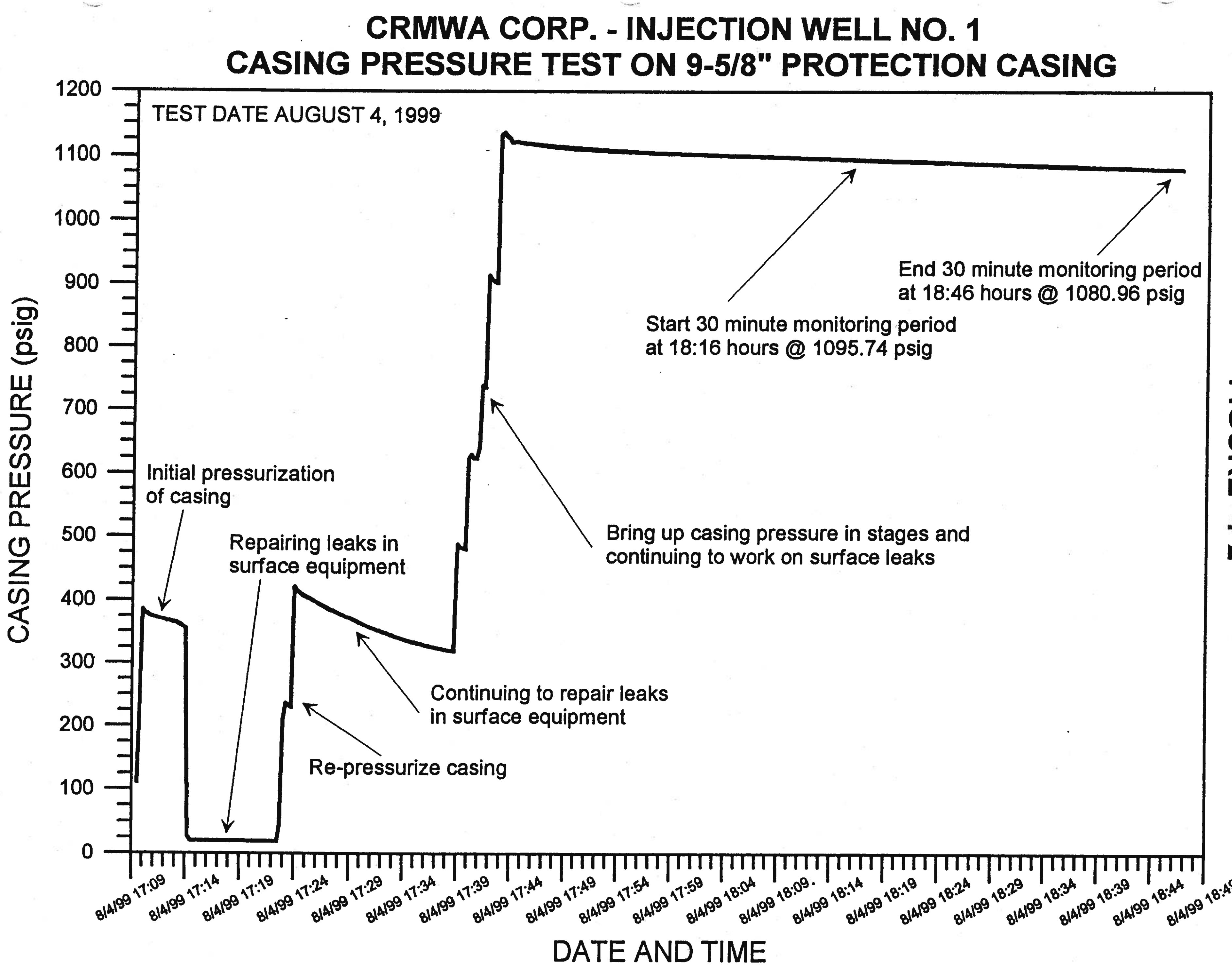

CRMWA CORP. - INJECTION WELL NO. 1
CASING PRESSURE TEST ON 9-5/8" PROTECTION CASING
TEST DATE AUGUST 4, 1999
CASING PRESSURE (psig)
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
DATE AND TIME
8/4/99 17:09
8/4/99 17:14
8/4/99 17:19
8/4/99 17:24
8/4/99 17:29
8/4/99 17:34
8/4/99 17:39
8/4/99 17:44
8/4/99 17:49
8/4/99 17:54
8/4/99 17:59
8/4/99 18:04
8/4/99 18:09
8/4/99 18:14
8/4/99 18:19
8/4/99 18:24
8/4/99 18:29
8/4/99 18:34
8/4/99 18:39
8/4/99 18:44
8/4/99 18:49
Initial pressurization of casing
Repairing leaks in surface equipment
Re-pressurize casing
Continuing to repair leaks in surface equipment
Bring up casing pressure in stages and continuing to work on surface leaks
Start 30 minute monitoring period at 18:16 hours @ 1095.74 psig
End 30 minute monitoring period at 18:46 hours @ 1080.96 psig

FIGURE 4-2

5.0 LABORATORY TESTING RESULTS

5.1 CORE TESTING

Whole cores were recovered from the Yeso Formation (within the confining zone) and the Sangre de Cristo Formation (within the injection zone). Two 30 foot cores were attempted in the Yeso and three 30 foot cores were attempted in the Sangre de Cristo. The depths and recoveries are listed below.

Core No.	Formation	Depths Cored	Recovery
1	Yeso	2020' - 2050'	30'
2	Yeso	2155' - 2185'	27' +/-
3	Sangre de Cristo	2907' - 2937'	30'
4	Sangre de Cristo	3002' - 3033'	25' +/-
5	Sangre de Cristo	3033' - 3061'	13' +/-
Totals		**149' +/-**	**125' +/-**

This section summarizes data from the core analysis. Complete results of the testing are contained in Appendix I of the this report.

5.1.1 CONFINING ZONE TESTS

The confining zone is a part of a geological formation, a formation, or a group of formations between the injection zone and an underground source of drinking water (USDW) or freshwater aquifer that acts as a barrier to the movement of fluids upward and out of the injection zone. The confining zone for the CRMWA CORP No. 1 injection well is the lower portion of the Yeso Formation between measured depths of 1883' to 2421'.

5.1.1.1 LITHOLOGY

The Yeso Formation in general consists of interbedded salt, mudstones , silts, intermixed salt and mud, and contains minor amounts of sand and anhydrite. The lower half of the formation contains a higher proportion of mudstone than does the upper half. Within the lower portions of the formation that make up the confining zone, the upper half of the confining zone is predominately mudstone and the lower half of the confining zone contains more salt and anhydrite. The two cores that were taken in the confining zone were within predominately a mudstone interval of the Yeso.

Physical examination of the cores indicated the recovered materials were mostly redbeds (mudstone and silt with thin chaotically bedded salt intervals intermixed). Thin sections were prepared from representative lithologies of the recovered core for the determination of petrographic properties. The petrographic data from the laboratory report (Appendix I) is partially reproduced below.

Texture

The three analyzed samples are poorly to moderately well sorted, coarse siltstones (0.047-0.055 mm). The samples are slightly to moderately compacted. The presence of detrital matrix has inhibited grain compaction. However, point and long grain contacts were observed in the sample from 2038.7 feet, which has the lowest matrix content (13.0%). Grains in these samples are typically subangular to subrounded.

Framework Grain Mineralogy

Quartz (14.5-40.0%, by point count) is the principal framework grain constituent in these siltstones, followed by less common feldspars and lithic fragments. Plagioclase (3.0-6.5%) is more abundant than potassium feldspar (1.5-4.0%). Lithic grains consist mostly of argillaceous rock fragments (0-4.5%), with fewer quartzose sedimentary rock fragments (0-2.5%), muscovite (0-1.5%) and chert (01.0%) grains.

Pore-Filling Constituents

Halite (2.0-18.5%) is the principal pore-filling constituent in these samples. Authigenic clay (0-7.5%), is less common. Anhydrite (0.5-4.0%) and dolomite (1.0-2.0%) cements are present in patches. Additional clay material of uncertain origin (0-4.0%) was also observed. The mode of occurrence of the clay material (detrital or authigenic) is ambiguous.

Detrital matrix (13.0-68.5%) is abundant in the Yeso Formation samples. The matrix is comprised of silty clay material which typically displays a mottled (perhaps altered, desiccated, or reworked by soil generating processes) texture and a reddish-brown color that is indicative of oxidation. These features suggest a pedogenic origin for the samples.

Pore System Properties

Only traces of visible pore space were observed by point count; in comparison, measured porosity values for the same samples range from 5.2 (whole core) to 26.6%. Micropores associated with detrital matrix are, by far, the most abundant pore type. This explains the large variation between visible and measured porosity. However, despite their contribution to total porosity, micropores do not contribute to effective porosity.

The complete results of the petrographic analysis are located in Appendix I of this report. Point count data and photomicrographs of the examined samples are included.

5.1.1.2 POROSITY AND PERMEABILITY

Porosity in whole core samples from the Yeso averaged 6.74%. Porosity from 23 plugs drilled from the core averaged 21.2 %.

Horizontal permeability to air in Yeso whole cores averaged 13.55 md in the maximized orientation with an average permeability at right angles to the maximum of 9.14 md.

Retardation of vertical fluid movement is critical in the confining zone in order to keep injected fluids from migrating upward into a USDW. Therefore, vertically oriented permeability measurements are more significant in this zone than horizontal measurements.

Vertical permeability to air averaged 8.92 md arithmetically. However, in a layered system, flow across the layers is more typically represented by the harmonic average since low permeability layers tend to retard flow through the entire system. The harmonic average for vertical air permeability was 0.373 md.

Twenty-six plugs were cut vertically from the whole core of the Yeso for the determination of porosity and permeability to NaCl brine. Twenty-four of the plugs provided usable data. Porosity averaged 21.2%. Vertical permeability ranged from less than 0.001 md to 79.8 md. The averages for vertical permeability to brine were 6.067 md and 0.0019 md (arithmetic and harmonic, respectively). True average vertical brine permeabilities are actually lower than those calculated since 10 of the 24 permeability values were 'less than' 0.001 md, and 0.001 was used in the calculation.

Yeso porosity and permeability data was previously summarized in Section 3.4 and Tables 3-1 and 3-2.

5.1.2 INJECTION ZONE TESTS

The injection zone is a geological formation, group of formations or part of a formation that receives fluid through a well. The injection zone may be further subdivided into the injection interval and the containment interval. The injection interval is that lower portion of the injection zone into which fluid is directly emplaced (through a well's perforations, for example). The containment interval is the upper segment of the injection zone that acts to hold injected fluids in the formations below it. The containment interval is allowed to have injectate within it, but the fluid is not directly emplaced there.

The injection zone for the CRMWA CORP. No. 1 well is the Abo and Sangre de Cristo Formations between 2421' and 3800', measured depth. The containment interval is between 2421' and 2500', and the injection interval is between 2500' and 3800', as measured in the vertical hole.

Three cores taken in the injection zone were all within the Sangre de Cristo Formation.

5.1.2.1 LITHOLOGY

The Sangre de Cristo is generally described as primarily a mudstone containing mudstone conglomerate channels and thin sandy intervals. The three cores that were taken in the injection zone were within predominately mudstone interval of the Sangre de Cristo, with minor amounts of mudstone conglomerate recovered. Thin sections were prepared from representative lithologies of the recovered core for the determination of petrographic properties. Additionally, scanning electron microscopy (SEM) and x-ray diffraction analysis were performed on selected samples. The petrographic and mineralogic data summary is in part reproduced below. The full analytical report is in Appendix I.

Texture

The eleven petrographic samples are very poorly to moderately sorted, coarse siltstones to conglomeratic coarse sandstones (0.037-0.997 mm). Grain compaction ranges from minimal to moderate. Detrital matrix has greatly inhibited grain compaction in several samples; point and long grain contacts were observed primarily in the samples with low matrix content. Grains in these samples are angular to subrounded.

Framework Grain Mineralogy

Quartz (18.5-35.5%, by point count) is the primary framework grain constituent, with fewer feldspars and rock fragments. Potassium feldspar (3.0-23.0%) is more abundant than plagiociase (3.0-14.0%). Lithic grains consist mostly of plutonic rock fragments (0-1 3.5%), with fewer unidentified grains (0-7.0%), argillaceous rock fragments (0-3.0%), chert (0-1.0%) and volcanic rock fragments (0-0.5%).

Pore-Filling Constituents

Sangre de Cristo Formation samples contain a wide variety of pore-filling constituents. Grain-coating and pore-filling authigenic clays (0-10.5%), halite cement (0-7.0%;), quartz overgrowths (0-5.5%) and pyrite cement (0-5.5%) are relatively common in varying proportions within the sample suite. Additional clay material (0-5.5%) was also noted, but the mode of occurrence (detrital or authigenic) could not be determined. Patches of dolomite (0-3.0%) and anhydrite (0-3.0%) cements are present, but not common. Feldspar overgrowths (0-1.5%) and siderite (0-1.0%) are rare.

Overall, the clay mineral fraction is small (2.0-4.0%, by weight), based on XRD analysis. Relative percentages of clay minerals, also obtained through XRD analysis, indicate that illite (21.0-97.0%) is the most abundant clay mineral, followed by mixed-layer illite/smectite (0-77.0%) and chlorite (0-53.0%). The total clay detected through XRD analysis occurs in both detrital (matrix) and authigenic (cement) modes, as well as in granular form (argillaceous rock fragments).

Detrital matrix (0-59.5%) is present in the Sangre de Cristo Formation samples in widely varying proportions. The matrix is comprised of silty clay, and is typically reddish-brown in color, suggesting oxidizing conditions.

Pore System Properties

Total visible porosity ranges from 0 to 22.5% by point count, in comparison with a measured porosity range of 9.8-25.4% for the same samples. The large variations between measured porosity and visible porosity in the sample suite are attributed to micropores associated with detrital matrix, authigenic clay cements and argillaceous rock fragments. SEM analysis confirms the presence of micropores.

Intergranular pores (0-19.0% are the most common type of visible pore in this sample suite. Secondary, leached-grain pores (0-3.5%) are much less abundant, and are most often associated with the dissolution of feldspars and plutonic rock fragments. Grain compaction and cementation have significantly reduced the size and interconnectivity of the intergranular pores in these samples. Micropores contribute greatly to total porosity, and are associated with detrital matrix, authigenic clay cements, and argillaceous rock fragments. However, despite their contribution to total porosity, the micropores do not contribute to effective porosity.

5.1.2.2 POROSITY AND PERMEABILITY

Porosity in whole core samples from the Sangre de Cristo averaged 11.35%. Porosity measured in 61 plugs drilled from the cores averaged 13.95 %.

In the injection zone, horizontal permeability is considered to be a more significant factor than vertical permeability. This is due to the injected fluids tendency to move laterally away from the point of injection.

Horizontal permeability to air in Sangre de Cristo whole cores averaged 53.71 md in the maximized orientation with an average permeability at right angles to the maximum of 48.72 md. Vertical permeability to air arithmetically averaged 59.70 md while the harmonic average was 0.28 md.

Permeability to NaCl brine measured from 31 horizontally oriented plugs was 44.47 md (arithmetic average). Permeability to NaCl brine measured from 30 vertically oriented plugs was 11.62 md and 0.0013 md (arithmetic and harmonic averages, respectively). True average vertical brine permeabilities are actually lower than those calculated since 22 of the 30 permeability values were 'less than' 0.001 md, and 0.001 was used in the calculation.

Sangre de Cristo formation porosity and permeability data was previously summarized in Section 3.4 and Tables 3-1 and 3-2. Full data is contained in the analytical report in Appendix I.

5.1.2.3 MECHANICAL PROPERTIES

Acoustic velocity tests were conducted on four Sangre de Cristo Formation samples in order to determine compressional and shear wave velocities, Poisson's Ratio, and dynamic elastic moduli at net confining pressures of 1000 psi and 1600 psi. Table 5-1 is a reproduction of the data table from Appendix I and summarizes all the information collected.

Net confining stress is lithostatic pressure (due to the weight of rock above a given point) minus hydrostatic pressure (due to the weight of water above the equivalent point). Net confining stress at the top of the injection interval (2500 foot depth) is approximately 1600 psi, calculated as follows. Lithostatic pressure (1.02 psi/ft gradient established in the pilot hole) - hydrostatic pressure (0.38 psi/ft gradient established from testing the injection well) x 2500 foot depth = 1600 psi. Therefore, the data collected at the 1600 psi net confining stress is most appropriate to the situation at the top of the injection interval.

The pressure required to hydraulically fracture a formation can be estimated from the following formula:

$$P_t = (P_{ob} - P_r)\,(v/(1-v)) + P_r \qquad \text{where:}$$

P_t = fracture treating pressure gradient, psi/ft

P_{ob} = overburden pressure gradient, psi/ft (1.02)

P_r = reservoir pressure gradient, psi/ft (0.38)

v = Poisson's Ratio (0.396, average of Table 5-1 values at 1600 psi net stress)

Substituting into the equation yields:

$$P_t = (1.02 - 0.38)\ (0.396/(1-0.396) + 0.38 = 0.7996 \text{ psi/ft}$$

The maximum allowable surface injection pressure that will not cause fracturing of the injection interval may be calculated with the following formula:

$$SIP_{max} = BHP_{max} - P_h + P_f \qquad \text{where:}$$

SIP_{max} = maximum allowable surface injection pressure, psi
BHP_{max} = maximum allowable bottom hole pressure, psi
P_h = hydrostatic pressure of the injectate fluid, psi
P_f = friction loss in the tubing, psi

The maximum allowable bottom hole pressure is the fracture gradient (0.7996 psi/ft) multiplied by the depth (2500 ft), or 1999 psi.

The hydrostatic head of the injectate column is calculated by multiplying the fluid specific gravity by the fresh water gradient and the depth. Assuming a maximum specific gravity for the Trujillo injectate of 1.03 gm/cc (equivalent to approximately 50,000 mg/l NaCl solution) yields a hydrostatic pressure of 1115 psi (1.03 x 0.433 psi/ft x 2500 ft).

Friction loss in 5-1/2" fiberglass injection tubing at 2500 feet is estimated to be 44 psi.

The maximum allowable surface injection pressure that will not cause fracturing at the top of the injection interval (the point least resistant to fracturing) is therefore calculated to be 924 psi:

$$SIP_{max} = 1999 \text{ psi} - 1115 \text{ psi} + 44 \text{ psi} = 924 \text{ psi}$$

At greater depths within the injection interval a higher surface injection pressure would be required to cause fracturing. For example, for a depth of 3500 feet the surface injection pressure required to initiate fracturing would be approximately 1298 psi .

The well's permitted maximum surface injection pressure is 850 psi. This is 74 psi below the pressure that could initiate hydraulic fracturing in even the most susceptible portion of the injection interval.

5.2 STATIC CORE MATERIAL VS FLUIDS TESTING

During the well installation concerns were raised about the sensitivity of the injection zone formation materials to possible completion fluids, and the long term stability of the injection zone during future injection operations. Cuttings samples from the Abo and Sangre de Cristo (but especially the Abo) were observed to readily become disaggregated at the surface when placed in contact with fresh water. The plan for completing the well called for a factory perforated liner to be set in the open hole, and not cemented in place. It was feared that the observed formation disaggregation would have an adverse impact on the uncemented liner perforations.

Two formation samples were taken from cores of the Sangre de Cristo (no Abo samples were available) and tested with a variety of possible completion fluids to determine the sensitivity of the rock materials to each fluid. A wedge of the formation material was immersed in seven (7) different fluids and the resultant disaggregation was observed and recorded in set time intervals (start of test, 1 hour, 16 hours).

Table 5-2 and Table 5-3 are reproduced here from the core testing analytical report (Appendix I). These tables indicate that NaCl brine (which was ultimately used for injectivity fall-off testing) and ammonium chloride caused the least sample disaggregation. The samples were most sensitive to fresh water, Bio 31 (a synthetic potassium chloride substitute), and calcium chloride.

As a result of the observed disaggregation, the well's completion procedure was revised to include cementing the liners in place through the Abo and upper Sangre de Cristo formations. Selective perforating of zones that appeared to have better porosity and permeability was then performed. The lower Sangre de Cristo and Precambrian section was completed using the originally planned method with a pre-perforated liner, not cemented in place.

Complete results of the testing and photographs of the samples taken during the testing are included in Appendix I.

5.3 FLOW THROUGH TESTS OF SANGRE DE CRISTO

Thin section petrography and SEM analyses were performed on seven (7) Sangre de Cristo Formation samples both before and after rock-fluid compatibility testing. A summary of the petrographic data collected before and after rock-fluid compatibility testing are presented in Table 5-4, which is reproduced from Appendix I. Thin section and SEM photomicrographs of the samples, taken before and after flow through testing, tabular and graphical displays of the testing results are located in Appendix I. Additional detail of the petrographic changes documented during the flowthrough testing is also found in the appendix.

Rock-fluid compatibility testing seems to have had the greatest influence on pore filling constituents. Thin section analysis reveals that slight to moderate pore dilation may have occurred in some samples. The pore dilation probably results from the dissolution of halite and anhydrite cements during testing. In addition, SEM analysis indicates that authigenic illite cements in some samples appear to be degraded following RFC analysis, in comparison with the well-developed, fibrous and sheet-like crystals that were observed in the same samples prior to testing. This is probably the result of cation exchange, illite mobilization and/or dissolution caused by the reaction of illite with under saturated brines containing monovalent cations during flowthrough testing.

The reductions in permeability noted in most of the plug samples is typical of that normally observed in flowthrough tests. It is not abnormal, nor does it indicate any significant compatibility problem between the Trujillo fluid and the sample plugs.

5.3.1 TRUJILLO FORMATION WATER

Rock-fluid compatibility testing was conducted using Trujillo Formation fluid (filtered to varying degrees) for five (5) samples, while unfiltered fresh water was used for two (2) samples. The majority of the samples that underwent analyses displayed a consistent and gradual decrease in permeability to brine (relative to initial brine permeability) as the degree of brine filtration decreased. This is probably due to a combination of: 1) pore clogging by particulate matter derived from test brines and 2) pore clogging by illite, which was caused by the reaction of illite with under saturated test brines containing monovalent cations.

One sample showed an increase in brine permeability relative to initial brine permeability, followed by a gradual decrease. This increase in brine permeability is thought to be the result of halite and anhydrite dissolution at the initiation of the test (with highly filtered test brine). The subsequent decrease in brine permeability probably reflects the pore clogging mechanisms that were previously discussed.

Figures 5-1 and 5-2 are presented here as typical of the trend for results from the flowthrough compatibility testing. Additional tabular and graphical data on all of the tests is found in Appendix I.

Most of the tests indicated an initial drop in permeability when highly filtered (0.45 um) Trujillo water was introduced to the sample. The permeability then typically leveled out or continued to slowly drop as different stages of filtered fluid were introduced. Generally, fluid filtered to the 10 um level flowed through the sample plugs with minimal permeability degradation. An inspection of all the data indicates that there appears to be no reason to filter the injectate stream to a greater degree than 10 um prior to injection. Additional pre-treatment of the injectate stream prior to injection is not warranted at this time.

5.3.2 LOGAN FRESH WATER

Unfiltered fresh water was found to have the smallest effect on brine permeability; brine permeability decreased only 2.5% (relative to initial brine permeability) during the course of the test. This contrasts sharply with the average total decrease in brine permeability for samples tested with filtered Trujillo Formation fluid, which was calculated to be 46.5% (relative to initial brine permeability).

These results appear somewhat anomalous since fresh water caused the greatest disaggregation of samples during the static compatibility tests. This particular sample had a relatively high initial permeability (1370 md to brine). The high initial permeability may have had an effect on the constant permeability during the flow test. The test of a second sample to be tested with fresh water was terminated when an extremely low initial permeability was determined. A replacement plug should have been substituted for testing, but due to an oversight, this was not done. Therefore, there is no other permeability data for flowing fresh water through the Sangre de Cristo.

5.4 FLUID VS FLUID COMPATIBILITY TESTING

The effect of potential chemical reactions resulting from the mixing of injected fluid with connate formation fluids and lithic materials of the injection zone must be evaluated prior to the initiation of injection. The injection capacity of a well may be greatly reduced, or injection may even be precluded by reactions occurring within the pore spaces or along grain boundaries within the formation receiving the injected fluids. Identification of possible incompatibility problems prior to the commencement of injection operations enable treatment options to be evaluated, and reduce the possibility of well failure due to injection zone permeability plugging.

This fluid to fluid portion of the compatibility testing was designed to identify any reactions which may damage the well's injection performance as a result of scaling, precipitation, emulsions, etc. Testing utilized connate fluid from the Trujillo Formation (shallow, salt contaminated aquifer), and connate fluids from the Sangre de Cristo and Abo Formations (the disposal zone). Trujillo reservoir fluid was recovered from an existing test well at the project site. Connate fluids from the Sangre de Cristo and Abo were recovered during installation and testing of the injection well through DSTs and jetting the well with nitrogen.

The fresh water supply that was used during the drilling and installation of the well was tested for compatibility with the natural formation fluids from the production and disposal zones. This fresh water may be needed as a possible buffer between the native injection zone fluids and the injected fluids originating from the shallower Trujillo Formation.

The testing consisted of water bath mixing tests for fluid to fluid compatibility evaluation. The proportions of the fluids being evaluated were varied and subjected to a range of likely subsurface temperatures. The mixes were observed at specified time intervals for sign of precipitate or scale formation.

The following fluid combinations were analyzed for compatibility:

Mix No. 1 - Trujillo brine vs Abo connate water

Mix No. 2 - Trujillo brine vs Sangre de Cristo connate water
Mix No. 3 - Trujillo brine vs Site fresh water
Mix No. 4 - Site fresh water vs Abo connate water
Mix No. 5 - Site fresh water vs Sangre de Cristo connate water

Compatibility testing for each of the above fluid combinations was performed at each of the following binary mix proportions:

Fluid # 1 (%)	-	Fluid # 2 (%)
0	-	100 (control)
10	-	90
25	-	75
50	-	50
75	-	25
90	-	10
100	-	0 (control)

The above fluid combinations at the specified mix proportions for each combination were tested for compatibility at three different constant temperatures in water baths. The test batch temperatures were 75 °F, 100 °F and 125 °F

Total fluid volume for each mixed sample was 250 ml, and the containers utilized were constructed of clear glass. Visual observations were made and documented for each batch at the following times during the testing: before placing into the bath, 1 hour, 6 hours, 24 hours, 48 hours, 72 hours and 96 hours. Additionally, turbidity measurements of each sample were taken using a turbidity meter at the beginning and end of the testing.

None of the fluid combinations at any of the three test temperatures showed any evidence of incompatibility. The yellow and orange colors that were noted in fluid combinations containing Abo formation water were due to the presence of dissolved solids in the original Abo fluid samples. This coloration is not due to any reaction with other fluids that occurred during the testing. Complete results of the testing, including tabular data and photographic documentation of the samples is included in Appendix J of this report.

5.5 FORMATION FLUID CHEMICAL ANALYSIS

Fluid samples from the injection zone are required for characterization of the reservoirs into which fluid will be injected. Compatibility problems between injected liquids and native reservoir fluids can lead to long term injectivity problems that have the potential to decrease or completely eliminate the capacity of the reservoir to accept injectate. Should compatibility issues arise, the availability of analytical data for the native pre-injection reservoir fluids is advantageous in developing stimulation or pre-treatment methods to improve or alleviate the situation.

Three separate fluid samples were collected for chemical analysis during the installation of the well. The Abo Formation alone, and then the combined Abo - Sangre de Cristo Formations were sampled in the vertical hole during air lifting associated with drill stem tests. The open hole sections and perforated sections of the combined vertical hole and lateral hole were sampled during nitrogen jetting of the well following perforating the lateral liner. This last sample was a commingled fluid from all the open intervals of the injection zone.

For quality control purposes, a set of samples consisting of a sample, a duplicate sample and a field blank was collected from each sampling point. All of the fluid samples were analyzed for the same suite of chemical and physical properties. The results of the chemical analyses are summarized in the following sections while the complete laboratory analytical reports are included in Appendix K.

The laboratory control numbers that were assigned to the samples were as follows:

Sampled Interval	Sample	Duplicate	Blank
Abo	417301	417302	417303
Abo & Sangre de Cristo	418053	418052	418051
Entire Injection Interval	420862	420864	420863

5.5.1 ABO (Vertical Hole)

This sample was recovered from drill pipe at the base of the DST test string and consists of fluid recovered from the Abo Formation at depths between 2673' (the base of protection casing) and 2907' (well depth at the time). This zone gave up fluid at a relatively slow rate. A total of approximately 51 barrels (2142 gallons) of fluid had been purged from the test interval prior to collection the sample.

Results for the sample and duplicate sample were as follows:

Parameter	Sample	Duplicate
pH (field data)	7.52	7.50
Conductivity (field data, in uS)	252,000	252,000
TDS (mg/L)	180,000	183,000
Specific Gravity	1.1225	1.1217
Chloride (mg/l)	96,600	87,300
Total Alkalinity (as $CaCO_3$ in mg/l)	46	42
Ammonia Nitrogen (mg/l)	3.92	3.84
Total Calcium (mg/l)	2290	2620
Total Iron (mg/l)	12.5	12.5
Total Magnesium (mg/l)	561	623
Total Phosphorus (ug/l)	ND	ND
Total Potassium (mg/l)	487	569
Total Sodium (mg/l)	62,200	74,400
Total Sulfur (mg/l)	1570	1750
Total Arsenic (ug/l)	214	ND
Total Barium (ug/l)	266	215
Total Cadmium (ug/l)	ND	ND
Total Chromium (ug/l)	ND	15.8
Total Copper (ug/l)	3600	10,500
Total Lead (ug/l)	ND	ND
Total Manganese (ug/l)	1220	1180
Total Nickel (ug/l)	ND	39.7
Total Selenium (ug/l)	237	95.6
Total Silver (ug/l)	ND	ND
Total Zinc (ug/l)	705	973
Total Mercury (ug/l)	ND	ND
Nitrate-Nitrogen (mg/l)	ND	ND
Sulfate (mg/l)	5130	4040
TOC (mg/l)	368	367

There were detections for several parameters in the field blank, however all the blank detections were at levels less than 10% of that found in the sample or duplicate, and should have no effect on the sampling results.

5.5.2 ABO AND SANGRE de CRISTO (Vertical Hole)

This sample was recovered from drill pipe at the base of the DST test string and consists of fluid recovered from the Abo Formation and the Sangre de Cristo at depths between 2673' (the base of protection casing) and 3545' (well depth at the time). This interval included the lower part of the Abo and the entire Sangre de Cristo Formation (mudstone-conglomerate and wash portion) and approximately 33' of the weathered Precambrian basement.

The zone gave up fluid at a faster rate than the previous DST. A total of approximately 279 barrels (11,718 gallons) of fluid had been purged from the test interval prior to collection the sample.

Results for the sample and duplicate sample were as follows:

Parameter	Sample	Duplicate
pH (field data)	7.4	7.4
Conductivity (field data, in uS)	266,000	266,000
TDS (mg/L)	188,000	188,000
Specific Gravity	1.1220	1.1213
Chloride (mg/l)	94,400	93,000
Total Alkalinity (as $CaCO_3$ in mg/l)	76	76
Ammonia Nitrogen (mg/l)	17.0	25.0
Total Calcium (mg/l)	3170	2680
Total Iron (mg/l)	128	28.4
Total Magnesium (mg/l)	721	631
Total Phosphorus (ug/l)	1630	1970
Total Potassium (mg/l)	563	678
Total Sodium (mg/l)	63,600	63,200
Total Sulfur (mg/l)	1480	1380
Total Arsenic (ug/l)	17.0	ND
Total Barium (ug/l)	540	202

Total Cadmium (ug/l)	ND	ND
Total Chromium (ug/l)	258	70.7
Total Copper (ug/l)	6840	6550
Total Lead (ug/l)	348	302
Total Manganese (ug/l)	2910	2720
Total Nickel (ug/l)	142	62.3
Total Selenium (ug/l)	152	244
Total Silver (ug/l)	ND	ND
Total Zinc (ug/l)	1240	1280
Total Mercury (ug/l)	ND	ND
Nitrate-Nitrogen (mg/l)	ND	ND
Sulfate (mg/l)	4160	3980
TOC (mg/l)	480	465

There was one significant detection in the field blank that has an effect on the sample result reliability. Ammonia-Nitrogen was detected at 8.15 mg/l in the blank. This represents 48% and 33% of the concentrations reported from the sample and duplicate, respectively. The sample and duplicate results for this parameter must therefore be discounted. Other detects in the blank were at levels less than 10% of that in the sample or duplicate.

5.5.3 ENTIRE INJECTION INTERVAL (Vertical and Horizontal Holes Open)

This sample came from the entire open injection interval in both the vertical and horizontal portions of the hole. The sample consisted of commingled fluids from the Abo, Sangre de Cristo and Precambrian. The sample was collected from the gas buster at the surface during the final nitrogen jetting of the well, following perforation of the liner in the lateral hole and prior to acididization and performance of an injectivity-falloff test.

The open intervals gave up fluids relatively easily. A total of approximately 797 barrels (33,474 gallons) of fluid had been purged from the test interval prior to collection the sample.

Results for the sample and duplicate sample were as follows:

Parameter	Sample	Duplicate
pH (field data)	6.85	6.82
Conductivity (field data, in uS)	248,000	246,000
TDS (mg/L)	187,000	189,000
Specific Gravity	1.117	1.119
Chloride (mg/l)	97,000	98,100
Total Alkalinity (as $CaCO_3$ in mg/l)	230	230
Ammonia Nitrogen (mg/l)	4.14	4.31
Total Calcium (mg/l)	2910	2510
Total Iron (mg/l)	52.5	46.4
Total Magnesium (mg/l)	484	432
Total Phosphorus (ug/l)	ND	ND
Total Potassium (mg/l)	676	594
Total Sodium (mg/l)	63,800	58,100
Total Sulfur (mg/l)	1050	1030
Total Arsenic (ug/l)	ND	ND
Total Barium (ug/l)	385	369
Total Cadmium (ug/l)	ND	ND
Total Chromium (ug/l)	36.7	29.9
Total Copper (ug/l)	164	156
Total Lead (ug/l)	197	171
Total Manganese (ug/l)	8850	7840
Total Nickel (ug/l)	126	116
Total Selenium (ug/l)	101	96.6
Total Silver (ug/l)	ND	ND
Total Zinc (ug/l)	6840	6040
Total Mercury (ug/l)	ND	ND
Nitrate-Nitrogen (mg/l)	ND	ND
Sulfate (mg/l)	3020	3040
TOC (mg/l)	74.1	49.4

There was one significant detection in the field blank that has an effect on the sample result reliability. Arsenic was detected at 1.7 ug/l in the blank while it was reported as non-detected in the sample and duplicate. However, the Minimum Analytical Limit (MAL) in the blank was 1 ug/l while it was 10.0 ug/l for the sample and duplicate due to dilution. Therefore, this detection does not require any discounting of the arsenic sampling results, considering the applicable MALs. Other detects in the blank were at levels less than 10% of that in the sample or duplicate.

FIGURE 5-1

**ROCK-FLUID COMPATIBILITY
WITH TRUJILLO INJECTION WATER**

**T.W.O. CRMWA Corporation
Special Drainage Well 5G30
Sangre De Cristo Formation
Quay County, New Mexico**

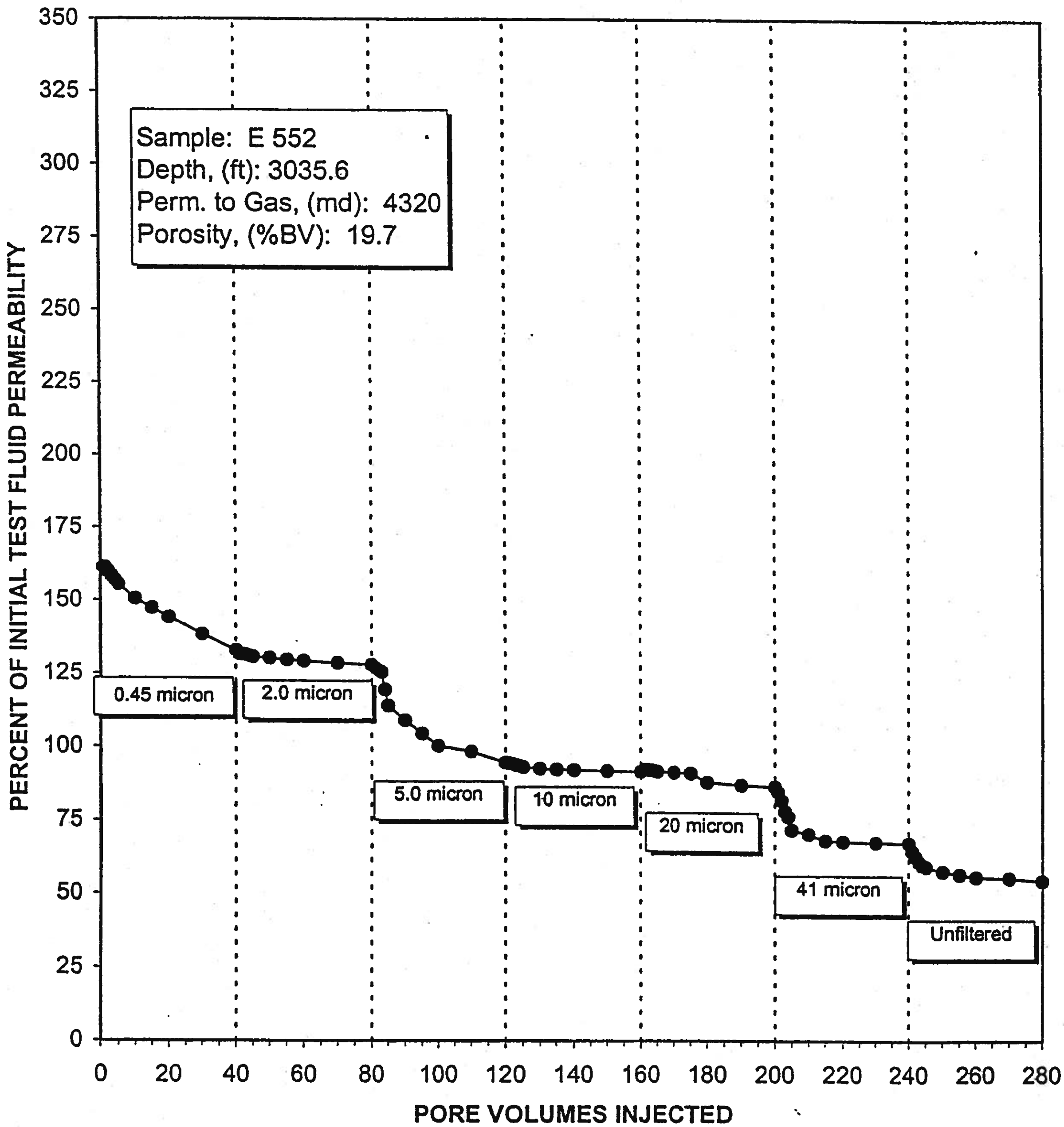


FIGURE 5-2

ROCK-FLUID COMPATIBILITY WITH TRUJILLO INJECTION WATER

T.W.O. CRMWA Corporation
Special Drainage Well 5G30
Sangre De Cristo Formation
Quay County, New Mexico

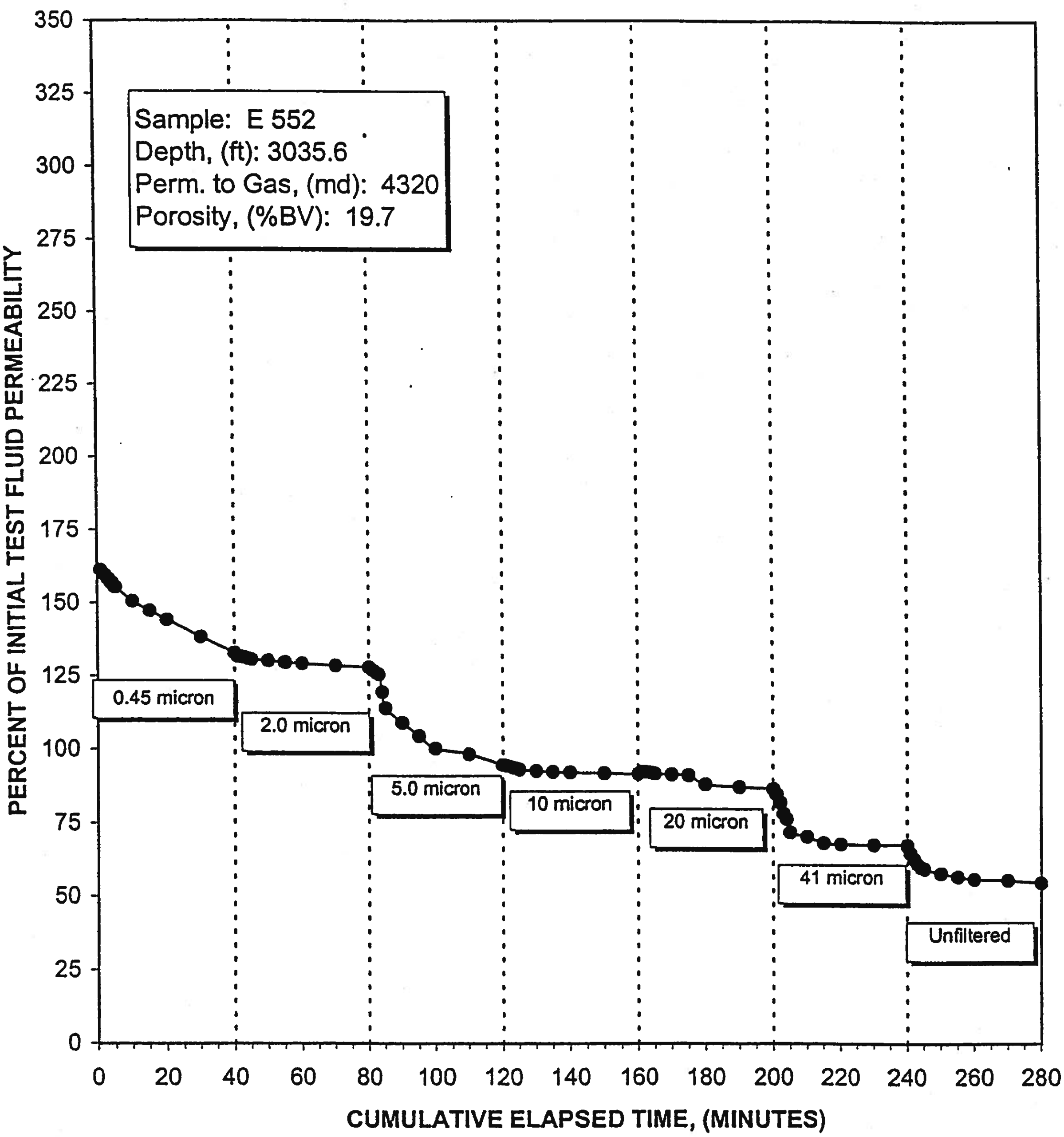


TABLE 5-1

SUMMARY OF ACOUSTIC VELOCITY AND DYNAMIC ELASTIC MODULI AT CONFINING PRESSURE

T.W.O. CRMWA Corporation
Special Drainage Well 5G30
Sangre De Cristo Formation
Quay County, New Mexico

				Confining	Velocity, ft/sec			Dynamic Elastic Moduli (dynes/cm^2 x 10^{11})		
Sample	Depth (ft)	Perm. to Gas (md)	Porosity (%BV)	Pressure (psig)	Compressional (P) Wave	Shear (S) Wave	Poisson's Ratio	Shear	Young's	Bulk
E 748V	2912.7	1.61	15.8	1000	9408	3768	0.404	0.352	0.988	1.724
E 749V	2932.5	0.302	14.6	1000	12463	5449	0.382	0.747	2.064	2.911
E 750V	3013.2	17.3	8.2	1000	14003	5217	0.419	0.667	1.894	3.916
E 751V	3023.6	5.19	11.1	1000	13615	6333	0.362	0.997	2.716	3.279
	minimum	0.302	8.2	1000	9408	3768	0.362	0.352	0.988	1.724
	maximum	17.3	15.8	1000	14003	6333	0.419	0.997	2.716	3.916
	average	6.101	12.4	1000	12372	5192	0.392	0.691	1.916	2.958
E 748V	2912.7	1.61	15.8	1600	9508	3965	0.395	0.389	1.086	1.721
E 749V	2932.5	0.302	14.6	1600	13093	5512	0.392	0.764	2.127	3.293
E 750V	3013.2	17.3	8.2	1600	14460	5571	0.413	0.761	2.149	4.110
E 751V	3023.6	5.19	11.1	1600	14731	6447	0.382	1.033	2.855	4.017
	minimum	0.302	8.2	1600	9508	3965	0.382	0.389	1.086	1.721
	maximum	17.3	15.8	1600	14731	6447	0.413	1.033	2.855	4.110
	average	6.101	12.4	1600	12948	5374	0.396	0.737	2.054	3.285

TABLE 5-1

TABLE 5-2

STATIC ROCK-FLUID COMPATIBILITY TEST

T.W.O. CRMWA Corporation
Special Drainage Well 5G30
Sangre De Cristo Formation
Quay County, New Mexico

Sample Depth: 2931.8 feet

Condition

Start of Test

Fluid	Reaction
2% CaCl	Slight red discoloration
9PPG NaCl	Little reaction; faint red discoloration
5% NH_4Cl	No reaction
2% KCl	Faint red discoloration; slight disaggregation
4% KCl	Faint red discoloration
Fresh Water	Faint red discoloration
2% Bio 31	Faint red discoloration, traces of effervescence
4% Bio 31	Faint red discoloration; minor disaggregation; traces of effervescence

1 Hour

Fluid	Reaction
2% CaCl	Minor discoloration; moderate disaggregation
9PPG NaCl	Minor discoloration; moderate disaggregation
5% NH_4Cl	Minor discoloration; moderate disaggregation
2% KCl	Minor discoloration; moderate disaggregation
4% KCl	Minor discoloration; moderate disaggregation
Fresh Water	Moderate discoloration; moderate disaggregation
2% Bio 31	Minor discoloration; minor disaggregation
4% Bio 31	Minor discoloration; minor disaggregation

16 Hours

Fluid	Reaction
2% CaCl	Minor discoloration; minor disaggregation
9PPG NaCl	Minor discoloration; minor to moderate disaggregation
5% NH_4Cl	Minor discoloration; minor to moderate disaggregation
2% KCl	Minor discoloration; minor to moderate disaggregation
4% KCl	Minor discoloration; minor to moderate disaggregation
Fresh Water	Moderate to extensive discoloration; moderate disaggregation
2% Bio 31	Minor discoloration; minor disaggregation
4% Bio 31	Minor discoloration; minor disaggregation

TABLE 5-4

PRE AND POST ROCK-FLUID COMPATIBILITY
BASIC ROCK PROPERTIES SUMMARY

T.W.O. CRMWA Corporation
Special Drainage Well 5G30
Sangre de Cristo Formation
Quay County, New Mexico

Pre Rock-Fluid Compatibility

Sample	Depth (ft)	Permeability to Gas (md)	Permeability to 0.45 Micron Filtered Trujillo Injection Brine	Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 463	2919.2	3.85	0.545	19.7	2.72	2.18
E 745	3002.4	19.2	0.0009 *	12.3	2.69	2.36
E 746	3006.5	1230	33.0	25.4	2.61	1.95
E 485	3007.6	275	104	22.1	2.65	2.06
E 492	3013.3	2270	1350 *	14.4	2.63	2.25
E 747	3024.3	692	14.4	19.7	2.62	2.10
E 552	3035.6	4320	2770	19.7	2.63	2.11

Post Rock-Fluid Compatibility

Sample	Depth (ft)	Permeability to Gas (md)	Permeability to 0.45 Micron Filtered Trujillo Injection Brine	Porosity (%BV)	Grain Density (g/cc)	Bulk Density (g/cc)
E 463	2919.2	3.65	0.949	18.7	2.66	2.16
E 745	3002.4	0.435	N/A	11.3	2.70	2.39
E 746	3006.5	170	24.6	21.8	2.58	2.02
E 485	3007.6	195	147	21.3	2.61	2.05
E 492	3013.3	2210	N/A	13.4	2.62	2.27
E 747	3024.3	58.5	11.1	16.8	2.60	2.16
E 552	3035.6	2530	1190	18.7	2.59	2.10

* Denotes permeability to 180,000 ppm NaCl brine.