REPORT OF OPERATIONS

UNITED STATES DEPARTMENT OF THE INTERIOR
BUREAU OF RECLAMATION
Montrose County, Colorado

Subsurface Project No. 60D5207

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Prepared By:

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1.0 INTRODUCTION

The United States Department of the Interior, Bureau of Reclamation (USBR) operates an Underground Injection Control (UIC) Class V brine injection well in Montrose County, Colorado. The well disposes of naturally occurring sodium chloride brine water that is recovered from the Paradox Valley along the Dolores River. The well operates under UIC Permit No. CO5108-00647, issued by the United States Environmental Protection Agency (USEPA), Region 7.

The USEPA requested certain testing be conducted on the well following a Magnitude 4.3 seismic event that occurred on May 27, 2000. A meeting was held in Denver, Colorado on October 24, 2000, to define the testing that would be carried out on the well during the next available shutdown period. It was agreed that the USBR would attempt to run a mechanical casing caliper survey and two differential temperature surveys to determine the condition of the bottom of the well, the depth to the top of the fill in the well, and the fluid distribution into the injection interval.

Subsurface Technology, Inc. (Subsurface) was contracted to provide engineering and project coordination for the performance of the tests. Subsurface created a work plan and prepared a Scope of Work and Potential Vendors List for the USBR to solicit services of a wireline logging company to run the test. Due to the necessity of logging the well under high-pressure wellbore conditions, it was agreed to conduct the test during a planned June 2001 shutdown period when ambient temperatures were well above freezing.

The USBR contracted Wood Group Logging Services (WGLS) of Houston, Texas, to provide the logging services and the testing was performed during the week of June 18, 2001. Injection of Paradox Valley Brine (PVB) into the well was discontinued on June 1, 2001, and the injection tubing was flushed with fresh water. By June 18, 2001, the shutin surface pressure had declined to 1908 pounds per square inch gauge (psig). The bottom-hole pressure at the top of the perforations (14,068 feet below kelly bushing or 14,036 feet below ground level) was calculated to be 7985 psig based on a freshwater gradient of 0.433 pounds per square inch (psi) per foot of depth below ground level.

2.0 DISCUSSION OF FIELD OPERATIONS

On the morning of June 18, 2001, WGLS arrived on site with their logging equipment and crew. Jim Bundy (Subsurface) was present to observe the logging operations and provide technical assistance to the USBR. Paul Osborne (USEPA) was present to witness the testing according to the requirements of the USEPA.

A meeting was conducted by Andy Nicholas (USBR) to: orient personnel, detail site safety procedures, and review the work plan. The top of the wellhead was checked for the presence of hydrogen sulfide gas with negative results. WGLS installed a 5-1/2-inch, 5000-psi working pressure, grease injector lubricator on top of the wellhead. A logging tool string was assembled to simulate the configuration of the multi-finger (SONDEX) caliper tools that were planned for the well.

The pressure from the injection tubing was equalized into the lubricator and the tools were lowered into the well at an approximate speed of 120 feet per minute. Because problems had been encountered in previous logging operations under high pressure, the tools were stopped at 1000-foot intervals from the surface to 12,000 feet and logged upward to measure line drag. From 12,000 feet to 14,000 feet, the line drag was measured on 500-foot intervals; then the line drag was checked at 14,080 feet (1120 pounds) and at 14,122 feet (1140 pounds). A casing collar locator log was run from 14,134 feet to 13,500 feet. The log was correlated to the Oilwell Perforators Temperature Survey dated August 16, 1993, and the Gearhart Pulse Echo Log dated November 26, 1988. WGLS log depths were adjusted to coincide with the Gearhart and Oilwell Perforators depths. The top of the fill in the well was located at 14,172 feet. The Upper Leadville perforations are between 14,068 feet and 14,173 feet, based on the Gearhart depths. The Middle and Lower Leadville perforations are believed to be covered with fill. The logging line was marked with tape at the drum for future reference and the tools were pulled from the well. The well was secured for the night.

On June 19, 2001, the lubricator was checked for hydrogen sulfide with negative results. The logging tools were removed from the lubricator and laid down. The tools were covered with a black, viscous, pasty material of unknown chemical composition. A SONDEX, 40-Arm, multi-finger, casing caliper tool was inserted in the tool string in place of the simulated tool. The caliper tools were run into the well to 14,070 feet, where a restriction or wellbore fill prevented the tool from returning to the depth reached on June 18, 2001. The caliper log was run from 14,070 feet to the surface. Upon retrieving the tools, one of the arms on the tool had been damaged. It was speculated that the damaged arm might have stopped the tools from descending through the perforated interval. The logging tools were packed with the same black material retrieved previously. A sample of the material was saved for analysis. Results of the analysis are discussed later in this report. The differential temperature tools were picked up and the well was secured for the night.

On June 20, 2001, the differential temperature tools were lowered into the well at approximately 120 feet per minute to a depth of 12,000 feet. The logging rate was slowed to 20 feet per minute below 12,000 feet to the top of the perforations. The tools stopped at a depth of 14,084 feet (corrected to the reference depth from Gearhart). The tools became stuck in the fill at that depth and were worked free. While working the tools free, the computer was still in the "logging-down" mode and the bottom 16 feet of the temperature survey were not recorded on the log. The temperatures were recorded manually and entered into the composite temperature spreadsheet. The deepest temperature recorded on the printed log was 132.2 degrees Fahrenheit at 14,068 feet. At 14,084 feet, the temperature was manually recorded at 121.1 degrees Fahrenheit.

A discussion was held with Paul Osborne and Andy Nicholas to determine the path forward. Since the conditions in the wellbore prevented the logging tool from being run below the Leadville perforations, the benefit of the planned dynamic survey was questionable. The USEPA wanted to determine if the injection fluid was migrating both upward and downward from the Leadville Formation. The static temperature survey did not indicate any upward migration of injectate above the Leadville Formation. A dynamic survey would only reflect the temperature of the injectate inside the liner to the top of the perforations, and would provide no useable information regarding fluid migration downward. Considering the risk involved, the history of the well, and the lack of benefit of the dynamic survey, Paul Osborne agreed that the USEPA would waive the requirement for the dynamic temperature survey.

The logging tools were pulled from the well and WGLS began rigging down the logging equipment.

On June 21, 2001, a short injection test with the PVB mixture resumed, beginning at 115 gallons per minute (gpm). The initial pressure increased to approximately 2200 psig; then decreased to 1800 psig and began a gradual decline as the higher density brine displaced the fresh water in the injection tubing. WGLS completed rigging down and printing field copies of the logs. Field operations were completed.

3.0 DISCUSSION OF LOGGING RESULTS

The following sections discuss the logs that were run, historical references to similar logs, and interpretation of the results of the logs.

3.1 Determination of the Top of Fill or Maximum Attainable Depth

The first logging run, with the tools configured to simulate the multi-arm caliper tools, located the top of the fill in the wellbore at the base of the Upper Leadville perforations at a depth of 14,172 feet. The last recorded top of fill was at 14,604 feet by Oilwell Perforators on March 3, 1994, and the temperature tool was left in the well. This occurred on the third run of a temperature regression survey that began on March 1, 1994. The change in the top of the fill from March 1994 to June 2001 is 432 feet in seven years, or 61 feet per year.

Without the benefit of the data from the multi-arm casing caliper survey, there have been many speculations, hypotheses, and theories regarding the phenomena that have occurred in the wellbore. Some of those phenomena deserve discussion in this report. A brief history of the completion and subsequent workover operations is provided below to clarify the sequence of events that lead to the current conditions.

When the well was first completed, several zones were perforated and tested. The Precambrian was perforated from 15,489 feet to 15,827 feet and injection tested.

The Ignacio Formation was perforated from 15,376 feet to 15,386 feet and tested. The McCracken Formation was perforated from 14,651 feet to 14,719 feet and tested. Tests confirmed the information from the cores, drill cuttings, and electric logs that the zones were not capable of accepting significant quantities of fluid.

Clarence Harr (Project Geologist) concluded that the Leadville Formation from 14,066 feet to 14,352 feet was the "Prime Injection Zone". He also speculated that there may be potential for injection in the Ouray Formation and Upper Elbert Formation extending as deep as 14,504 feet. John DeWan (DeWan & Timko, Inc., January 27, 1988) stated that "...there are only two major zones showing any significant porosity: 14,095 feet to 14,155 feet with 3% average porosity and 14,230 feet to 14,268 feet with 4% average (porosity)". It was decided to perforate the entire interval. It was also decided to leave two intervals, of 30 feet each, **without perforations,** spaced evenly within the overall interval. These intervals were designed to provide a section of smooth internal surface in which to set isolation packers in the event that selective treatment of the injection interval became desirable. The location of the "blank" intervals have no geological nor reservoir significance, but were merely designed to facilitate future well stimulation. Prior to testing the interval and recovering fluid samples, a retrievable bridge plug with a diameter of 4.6 inches was successfully placed in the well at a depth of 14,564 feet (Fenix and Scisson final report, page 28) to isolate the zones that had been tested in the Lower Formations. At the conclusion of the testing, the bridge plug was not retrieved through the perforations and was left at 14,564 feet.

A Halliburton report dated August 30, 1990, provided the following information. On July 19, 1990, a pin-point-injection (PPI) packer, with a 4.55-inch diameter, was run into the well with the intent of isolating and stimulating the Lower portion of the Leadville/Ouray Formations. The packer stopped at 14,152 feet (near the bottom of the first set of perforations). When the packer was pulled out of the well, the drag blocks had been left in the hole. A 4.625-inch diameter mill was then run and would not pass the spot at 14,152 feet. A 4.25-inch mill was successfully run through the interval. It was speculated that the restriction was possible fill, scale, collapsed casing, or perforation burrs. The consensus at the time believed that "burrs" or slag-like protrusions inside the casing were created by the explosive jet charges. The burrs thus reduced the effective inside diameter of the casing sufficiently to prevent passage of the packer and tools. This was the first indication of any restriction to the inside diameter of the liner in the injection interval. A smaller diameter PPI packer set was then run and set in the Lower perforated interval. The treatment indicated that the fracture gradient in the Lower perforations was approximately 0.89 psi per foot and the injection rate was very low. At the conclusion of the acid stimulation, the bridge plug was pushed to 15,808 feet on August 9, 1990 and left in the well.

In 1994, another attempt was made to stimulate the Lower Leadville/Ouray perforations with isolation packers. A 4.500-inch diameter gauge ring was run into the well and could not be lowered past 14,138 feet. Attempts were made with 4.375-inch and 4.25-inch gauge rings without success. In retrospect:

- In 1988 a 4.6-inch packer was run through the perforations with no resistance.
- In 1990 a 4.55-inch PPI packer could not be run past 14,152 feet, but a 4.25-inch watermelon mill was run through the perforations.
- In 1994 a 4.25-inch tapered mill would not pass through 14,138 feet.
- The diameter restriction appears to be progressive.

With the history of the well in mind, the results of the multi-arm caliper survey become more reasonable.

3.2 The SONDEX Multi-Arm Casing Caliper Survey

The hastelloy liner was manufactured by INCO Alloys {consistent with American Petroleum Institute (API) dimensional specifications} with a 5-1/2-inch outside diameter (20 lb/ft) and a 0.361-inch wall thickness. The resulting inside diameter is 4.778 inches nominal. API tolerances for wall thickness result in a "drift" or minimum diameter of 4.653 inches. The injection tubing was manufactured to 5-1/2-inch, 17 lb/ft, API dimensional specifications with a 4.892-inch inside diameter and 4.767-inch drift diameter. A magnetic marker was attached to the outside of the liner when it was installed. The marker was intended to create a magnetic response on a casing collar locator tool for permanent logging depth correlation in the non-ferrous hastelloy liner. The magnet is extremely strong, even after 14 years. At one point, the magnetic marker effected a spinner survey tool, making the tool useless for evaluating flow distribution in the perforated interval. Knowing that the marker had affected previous logging tools, the question was presented to WGLS. WGLS, in turn, contacted the manufacturer who stated that the magnet would not affect the SONDEX tool.

SONDEX
Multifinger Caliper

A picture of the SONDEX tool is shown to the right. The tool has a diameter of 2.75 inches and is centralized above and below the measuring arms. There are 40 arms, or fingers, that extend radially from the tool body and drag along the inner surface of the casing. The tool is calibrated with a series of known diameters as standard procedure prior to a survey. The tool is lowered into the well in the closed position. Depth correlation is made and the tool is opened. Each finger measures the radius from the center of the casing axis to the inner surface of the casing. Data are transmitted to the surface through the logging cable and recorded by a computer. The data are later processed for visual video presentation. The tool does not measure the outside diameter of the casing.

On June 19, 2001, WGLS ran their SONDEX tool into the well. The tool string set down on bottom at a depth of 14,070 feet (after correction to the referenced Gearhart depth). The bottom of the weight bar below the SONDEX tool was at 14,077 feet. When the tool was pulled from the well, inspection showed that Arm No. 17 had malfunctioned. It was postulated that the arm had opened prematurely and engaged the perforations, preventing the tool from being lowered through the perforations. The exact cause cannot be determined from available data, but it is known that the tool did not reach the depth that was reached during the simulated run. The inside diameter of the 5-1/2-inch hastelloy liner and injection tubing was recorded from 14,068 feet to the surface. As a result

The Ignacio Formation was perforated from 15,376 feet to 15,386 feet and tested. The McCracken Formation was perforated from 14,651 feet to 14,719 feet and tested. Tests confirmed the information from the cores, drill cuttings, and electric logs that the zones were not capable of accepting significant quantities of fluid.

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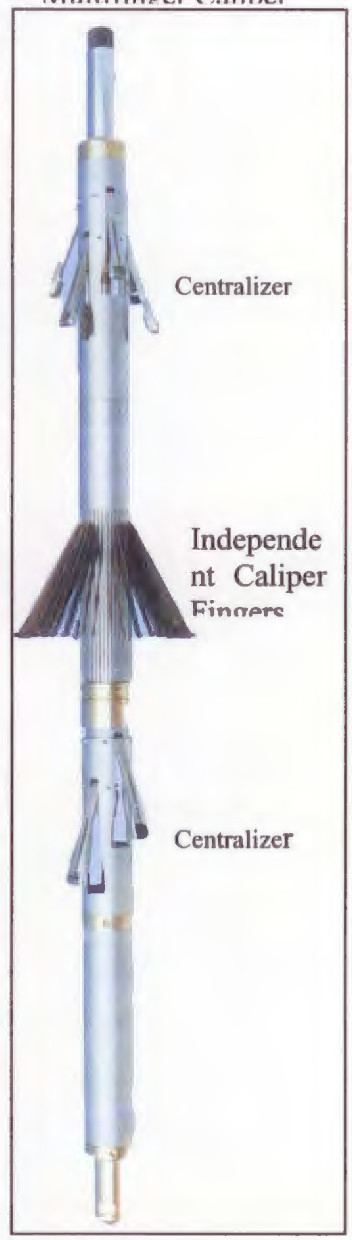

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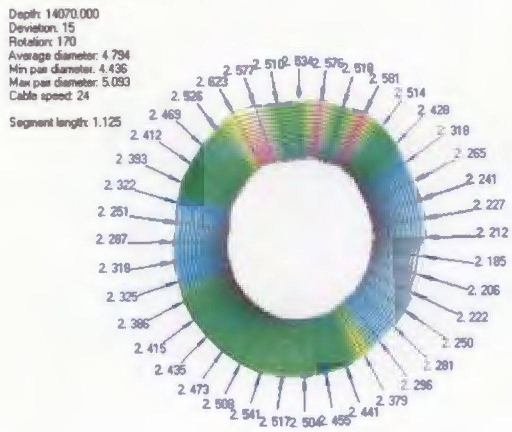
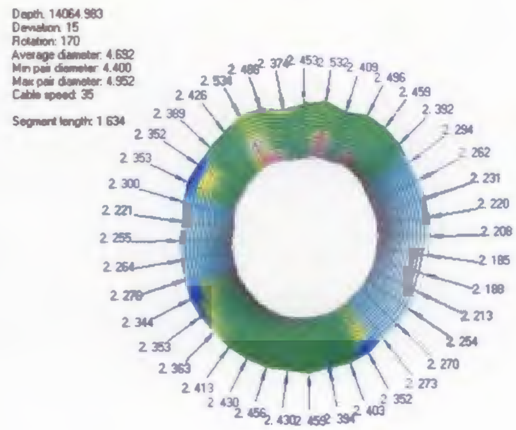
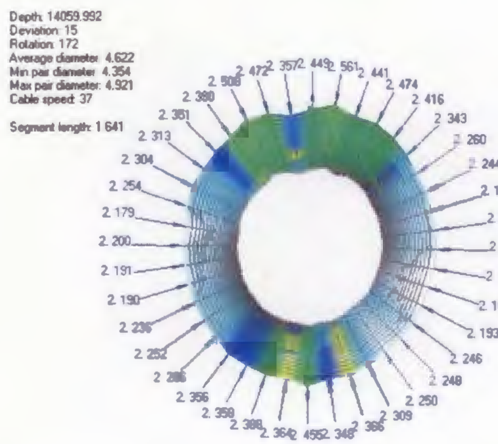
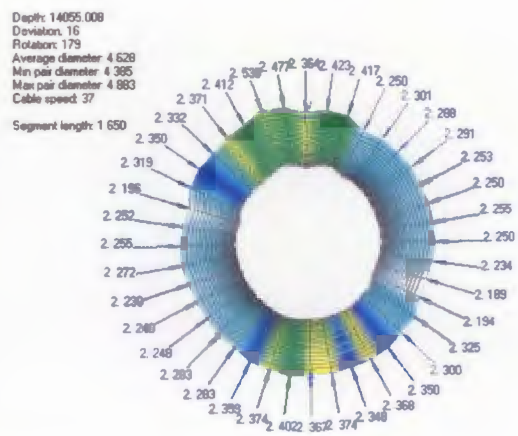
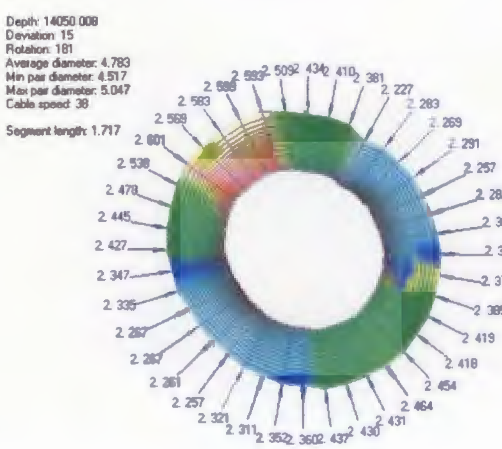
Cross-section prints from the processed caliper log from 14,070 feet to 14,045 feet are shown below.

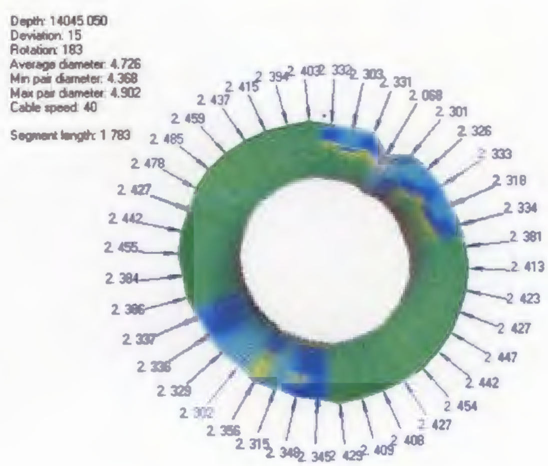






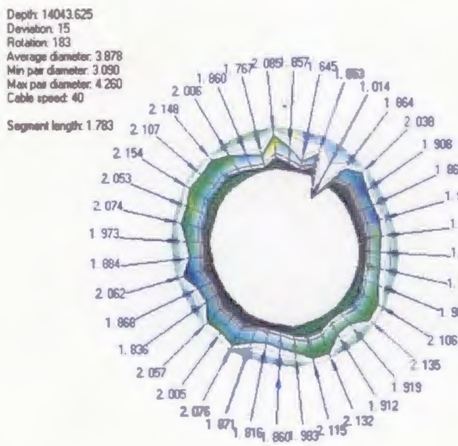


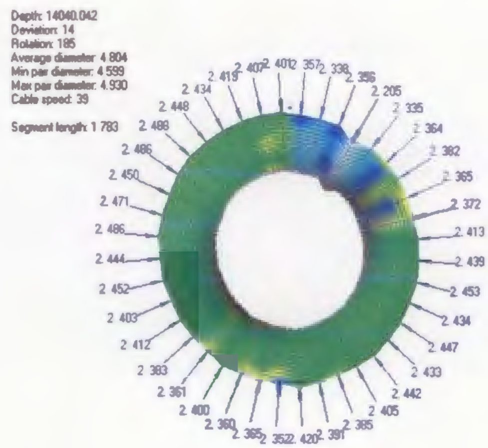


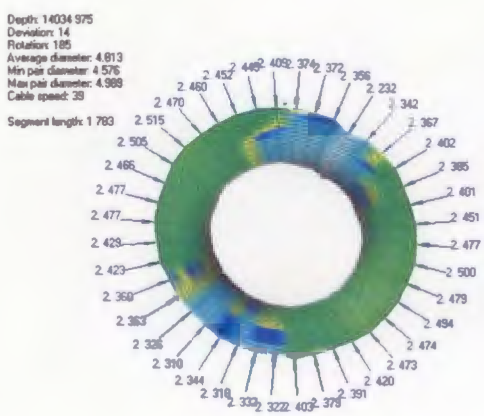


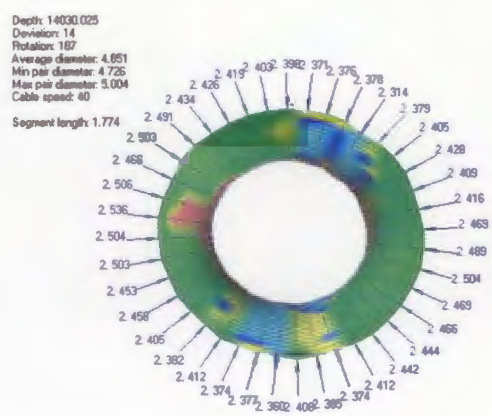
Beginning at 14,068 feet, a minimum internal diameter that is less than API drift diameter exists from 14,068 feet to 14,032 feet, 14,022 feet to 14,018 feet, and 14,012 feet to 14,001 feet. Generally there is an increase in the maximum internal diameter that corresponds to the above depths. This is indicative of oval or egg-shaped casing. Ovality is normally caused by partial collapse of the casing.

Below (left), the interval at 14,043 feet indicates severe narrowing in all radial directions. This corresponds with the depth of the magnetic marker. The severe narrowing is not recorded at 14,040 feet (below right). (Upon recovery of the



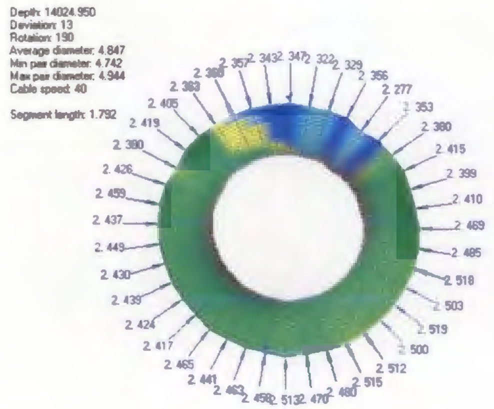


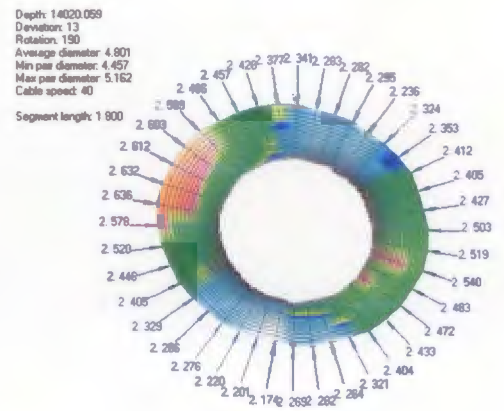


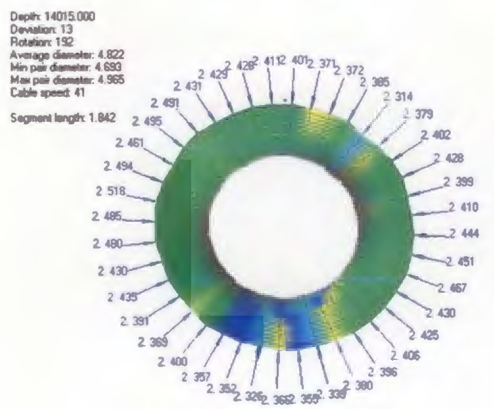


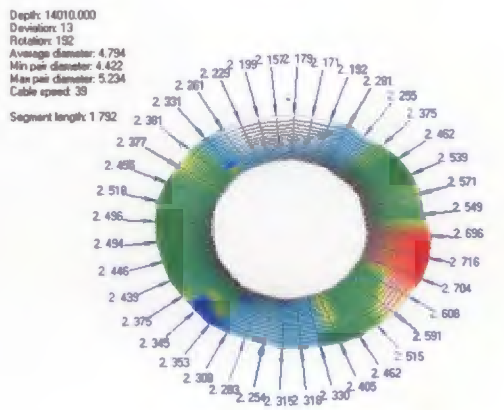
logging tool from the well, an attempt was made to determine if the magnetic marker had influenced the tool response from 14,043 feet to 14,045 feet. The tool was laid horizontally on the tool racks. The measuring arms were opened into the calibration sleeve and the tool placed in logging mode. A bar magnet (property of the USBR) was moved across the SONDEX tool above and below the measuring arms. There was a slight effect on the diameter response as the magnet was placed on the portion of the tool that contains the electronics. Further testing may be required in a more controlled environment.) It is possible that the magnetic marker effected the results within the interval from 14,038 feet to 14,048 feet.

An additional four cross sections are shown below. They are spaced on five-foot intervals from 14,025 feet to 14,010 feet. Some ovality is shown, but not to the magnitude indicated at 14,043 feet.



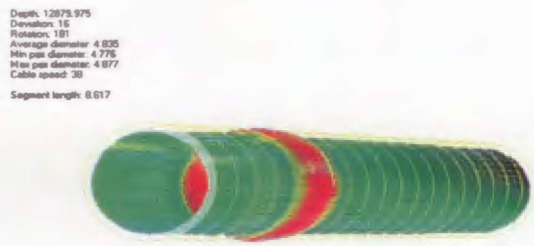






The interval between 14,000 feet and 13,940 feet indicate some minimal indications of ovality, but still remain well within tolerances. From 13,940 feet to the base of the liner hanger at 12,886 feet, the caliper survey shows signs of the well-documented problems INCO had with the manufacturing of the liner. The casing is still well within the allowable tolerances of the API.

The liner hanger, the polished bore receptacle, and the seal assembly are clearly shown between 12,886 feet and 12,869 feet, as expected. From 12,869 feet to the surface, the injection tubing is within tolerances.



The larger diameter of the seal assembly is apparent in the above-left picture and the diameter of the polished bore receptacle is shown in red in the above-right picture.

In summary, the multi-arm caliper survey indicates moderate ovality exists in the hastelloy liner from approximately 50 feet above the base of the 9-5/8-inch diameter intermediate casing to the top of the perforations. The presence of the magnetic marker may have influenced the data from the SONDEX caliper tool in the area around the marker at 14,043 feet. It does not seem reasonable that the marker would influence the data recorded 40 feet away at 14,000 feet. The narrowing of the liner has been a progressive phenomenon dating back over 10 years, as discussed earlier in this report. It is Subsurface's conclusion that the hastelloy liner is partially collapsed through the Leadville perforated interval, but that it is probably not entirely closed.

4.0 DIFFERENTIAL TEMPERATURE SURVEY

The USEPA requested that a temperature regression survey be conducted during the testing to evaluate the potential migration of fluid out of the Leadville injection interval either upward or downward. It was intended that a static survey be conducted from 12,000 feet to the base of the perforations at 14,504 feet, followed by the injection of 23,000 gallons of fresh water and a dynamic survey to detect potential fluid movement below the perforated Leadville interval. Since it was not possible to run the logging tools to the bottom of the perforations, the dynamic survey was determined to be of little value, and consequently cancelled

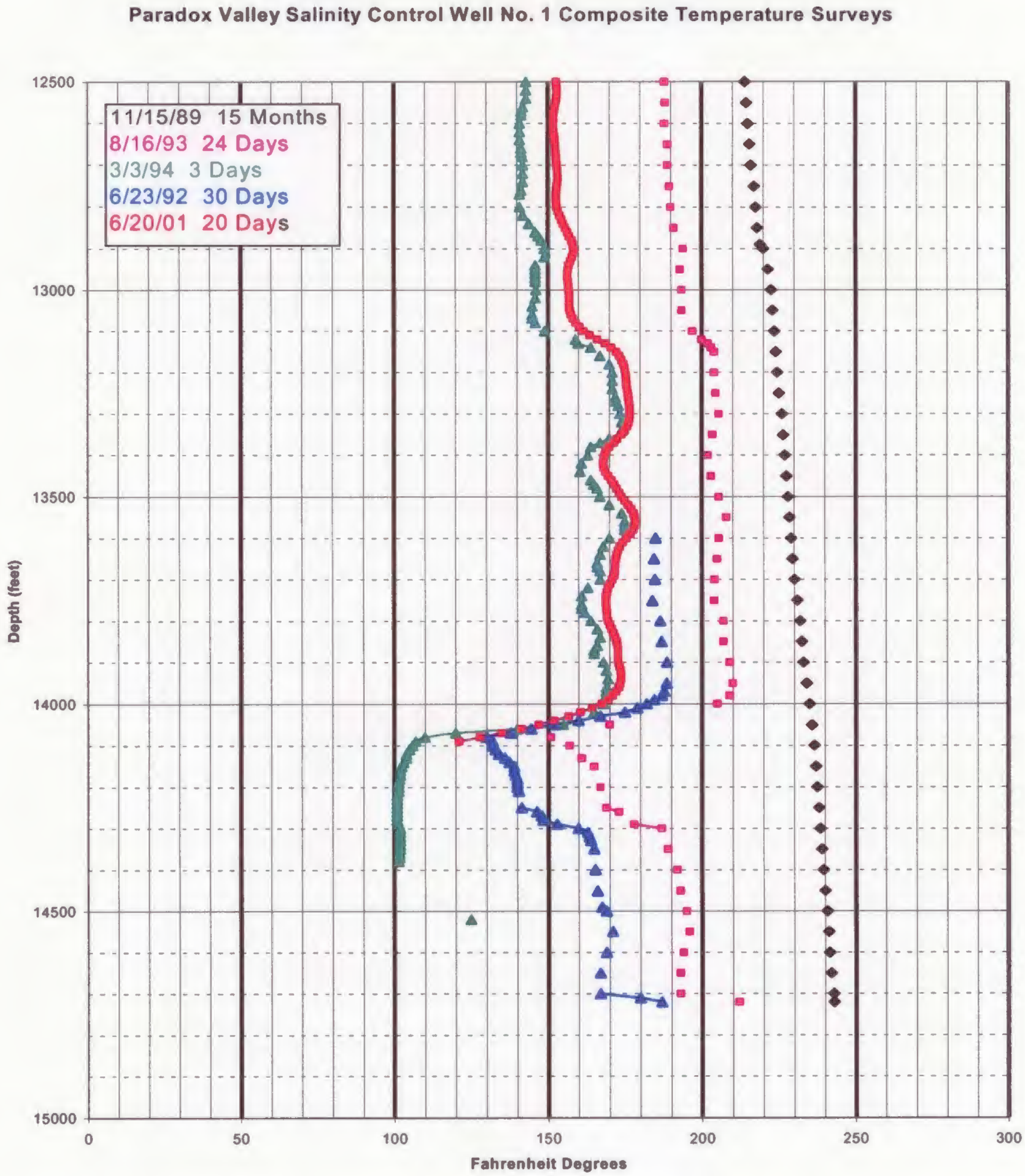
On June 20, 2001, WGLS ran their Differential Temperature Survey tools into the well. From the surface to 12,000 feet, the data were recorded at a downward logging speed of approximately 110 feet per minute. Logging speed was slowed to 20 feet per minute below 12,000 feet and stopped at 14,084 feet. The tool became stuck in the wellbore at 14,084 feet and was worked free; then pulled up to a depth of 14,068 feet. While attempting to work the tool free, the computer was left in the downward logging mode. After picking the tool up, the data on the log was lost below 14,068 feet. The data were, however, recorded manually. The final temperature recorded was 121.9°F at 14,084 feet, corrected to the Gearhart depth, which is 16 feet below the top of the perforations.

For comparison purposes, the survey is plotted on the Composite Temperature Surveys plot on the following page. There are five different temperature surveys plotted in the composite presentation. The first survey that was conducted was on November 15, 1989. The well had been drilled, cased, and cemented; then left dormant for 15 months, since August 29, 1987. Completion of the well was delayed while the hastelloy C-276 injection tubing was being manufactured.

The November 1989 survey is plotted in black and appears as the nearly linear curve on the plot. From 12.500 feet to 12,880 feet the gradient is linear at 11.4 degrees/1000 feet. At the top of the liner the temperature increases by two degrees and maintains a nearly linear gradient of 12.9 degrees/1000 feet from 12,900 feet to 13,750 feet. The gradient increases to 15.7degrees/1000 feet from 13,750 feet to 14,100 feet; then decreases to 10.5 degrees/1000 feet from 14,100 feet to 14,700 feet.

The maximum, recorded temperature at the base of the Leadville Formation was 240.7°F, after the well had been dormant for 15 months.

On June 23, 1992, another survey was run from 13,600 feet to 14,700 feet and is plotted with the blue triangle symbols. The well had been shut in for 30 days



following a total of 64 operating days, in four sessions, between July 11, 1991 and May 30, 1992. Cooling begins approximately 100 feet above the perforations and cools from 188.5°F at 13,950 feet to 130°F at 14,080 feet. The temperature increases to 140°F at the base of the top set of Leadville perforations; then increases to 160°F at the base of the second set of Leadville perforations. The temperature then increases slowly to 169°F at 14,500 feet, or the base of the Lower Leadville/Ouray perforations. The temperature continues to increase below the perforations to 171°F and decreases to 166°F through the McCracken perforations from 14,651 to 14,709. The temperature increases to 178°F in the next 20 feet below the perforations. It is interpreted that the majority of the injectate was entering the Upper Leadville perforations, with a lesser amount entering the Middle and Lower Leadville perforations, and a small amount entering the McCracken perforations. The maximum depth reached was 14,779 feet.

On August 16, 1993, another survey was run. Data are presented by magenta square symbols from 12,500 feet to 14,720 feet. The well had been on injection for 48 days between June 6, 1993 and July 24, 1993; then shut in for 24 days. It is notable that the temperature trend increases approximately 3°F at the top of the liner (12,880 feet); then increases approximately 8°F from 13,100 feet to 13,150 feet. This is near the top of the cement in the liner overlap. From 13,950 feet, the 1993 temperature profile is almost identical with the 1992 profile, except that the temperature is approximately 20°F warmer in 1993. The interval between 13,300 feet and 13,500 feet and the interval between 13,600 feet and 13,900 feet display a slight cooling trend of approximately 4°F, attributable to formation characteristics.

On March 3, 1994, another survey was run. Data are presented by green triangle symbols and is generally the coolest curve on the composite plot. The well had injected approximately 70 days in the period from October 3, 1993 to February 28, 1994. The well was shut in for a temperature regression survey and data were gathered on March 1, 2, and 3, 1994. On the final survey, the logging tool became stuck in the well and was subsequently lost. The similarity to the other temperature profiles is notable. The liner top, the cement top, and the cooling through the Leadville are consistent with previous surveys. The magnitude of the temperature changes is increased in all cases. The characteristic profile between 13,300 feet and 13,900 feet is again apparent, but with a larger temperature change then the previous surveys.

Until the current survey, no other surveys have been run since 1994. The well has injected over 800,000,000 gallon (approximately 2500 acre-feet) of dilute PVB. The current survey is presented as red, square symbols on the composite plot. The well had been shut in for 20 days. The temperature profile is almost a perfect overlay of the March 1994 survey.

The similarity of character of the individual temperature profiles in the composite survey plot shows that the injectate is entering the top of the Leadville Formation and is remaining confined below the top of the Leadville Formation within the radius of investigation of the temperature tool.

5.0 ANALYSIS OF RECOVERED SAMPLES

As mentioned earlier, a sample of the material recovered from the SONDEX caliper tool was collected for analysis. A second sample of similar material was collected from the intake manifold of the pumps at the brine injection facility. Both samples were shipped to Baker Petrolite for constituent analysis. A cursory examination of both materials was done on site the morning of June 21, 2000. No visible reaction was observed when either sample was exposed to alcohol or hydrogen peroxide (5%). Both samples were immersed in fresh water and PVB. Both samples sank to the bottom, indicating that the specific gravity of the material is greater than 1.18. It was concluded on site that there was probably not a high organic content in the material.

Baker Petrolite performed the testing at their Sugar Land, Texas facility. A copy of their analysis is attached as Attachment A. The samples were immersed in chloroform; then filtered. Nine percent (9%) of the downhole sample and 16% of the surface sample was insoluble in chloroform. The chloroform insoluble residue was dried and analyzed by X-ray fluorescence. Silicon (probably from clay) made up 2% to 3% of both bulk samples. The surface sample measured 7% iron and 5% sulfur (probably iron sulfide), but the downhole sample measured only 1% of each. Iron sulfide is insoluble in chloroform, and that percentage of iron sulfide would account for the difference in the insoluble percentage of the two samples.

The remaining solution was heated to remove the chloroform and the residue was examined by X-ray fluorescence. The result was nearly 100% elemental sulfur. The precipitate in the bottom of the well appears to be mostly sulfur. It was postulated verbally, by Baker Petrolite and others, that the sulfur is a result of the hydrogen sulfide in the brine and free oxygen, which probably comes from the dilution water. More verification of this reaction is being researched.

In 1992, Envirocorp Services & Technology, Inc. (the predecessor of Subsurface) performed a sample recovery project on the well. The well was flushed with fresh water and allowed to stabilize; then backflowed to recover samples. The recovered samples did not contain any solids or residue. The well was then flushed with PVB and allowed to stabilize for two weeks. Samples were recovered with a bailer on .092-inch stainless steel wireline. Samples wiped from the wireline and recovered from the bailer were described as a "greenish colored, runny material". Core Laboratories analyzed two of the samples and reported sulfur content of 2700 and 2860 parts per million (by weight) and 14% to 18% solids, respectively. There was a high organic content in each of the samples that was attributed to diesel fuel from the annulus of the well. The theory that solids of specific gravity greater than 1.0, but less than 1.2, existed in the wellbore was verified. The diesel fuel has since been removed from the system.

6.0 CONCLUSIONS

Several conclusions can be drawn from the data acquired in June 2001, and historical events that have occurred since 1988. These conclusions are:

- The restriction in the perforations that has not allowed full diameter tools to pass through the perforations has been attributed to "perforation burrs". In reality, a Halliburton bridge plug, with a 4.60-inch diameter, was lowered through the perforated interval with no resistance after the well was perforated. The restriction was not discovered until after the high-rate acid stimulation on the Leadville perforations. Subsequent tools of progressively smaller diameter were run through the perforations; however, the last known inside diameter in the perforations was less than 4.25 inches. The magnitude of the restriction in the liner has been progressive, indicating that the liner has partially deformed over the years.

- The SONDEX casing caliper appears to verify that the hastelloy liner is partially deformed, but not entirely collapsed. The deformation may be a result of the multitude of seismic events (fractures) that may be impressing extreme stress on the liner along one primary horizontal axis.

- The liner has slowly filled with solid material that has always been described as sticky, waxy, or slimy. The recent analysis of the material indicates it to be sulfur. An analysis in 1992 also indicated the solid material to be sulfur. It appears that sulfur has been precipitating in the well during the entire life of the injection. The top of the fill was located at 14,070 feet, which is 432 feet higher than the last recorded top of fill in 1994.

- The Upper Leadville Formation, and associated fracture system, is the primary reservoir. Fill has covered the Middle Leadville, Lower Leadville, and Upper Ouray perforations. It could be said that the fill in the wellbore is preventing fluid from entering these perforations. More likely, the fill occurred because the Lower perforations were not taking fluid and the stagnation of the injectate allowed solids to settle to bottom. This conclusion is reached because: (1) three attempts have been made to stimulate the lower perforations with no lasting success; (2) data gathered and evaluated during the installation of the well indicated the Upper Leadville Formation would have the best chance of receiving fluid; and (3) the original evaluation and research, before the well was drilled, indicated the upper portion of the Mississippian to be the best target zone, with lower zones as potential receptors.

- The injection of over 800,000,000 gallons of water has increased the bottom-hole pressure in the reservoir by approximately 1900 psi. This is estimated by comparing the first injection pressure falloff with the shutin pressure in June 2001. After the first injection period in July 1991, the wellbore was filled with fresh water. The shutin pressure declined to 0 psi in 21 days. The shutin surface pressure on June 20, 2001, was 1908 psi, 19 days after the well was flushed with fresh water and shut in.

- Injected fluid is not migrating upward above the Leadville Formation. This is verified by the comparison of the current temperature survey with previous temperature surveys.

- The temperature in the reservoir, for some distance from the well, has been reduced by injection. The temperature in the Upper Leadville was 121°F after 19 days of thermal recovery. This constitutes a super-cooled buffer zone, some distance from the well, which will prevent the creation of conditions favorable to calcium sulfate precipitation.

- Upon completion of the testing, the well was placed in service and continues to function as it has in the past. Although the temperature tools only reached 16 feet into the perforations, the well does not appear to be damaged or plugged by solids.

7.0 RECOMMENDATIONS

Subsurface recommends, once again, that the USBR re-visit the calcium sulfate question and reconsider the continued dilution of the PVB with Dolores river water. The disadvantages of continued dilution are listed below:

- The precipitation of the sulfur may be attributable to free oxygen associated with the river water used for dilution.
- At a 230 gpm rate, 30% of the water (69 gpm) comes from the river. This reduces the flow of water to the Lower Colorado River Basin by 111.4 acre-feet per year.
- Effective salt disposal at 161 gpm of PVB is approximately 80,000 tons per year. If dilution water were replaced by PVB, the additional 69 gpm would increase annual tonnage by approximately 34,000 tons. This would return the annual tonnage to within 6000 tons of the old disposal rate at 345 gpm, while sustaining the reduced frequency of seismic events.
- Reduction of near-wellbore fracturing events, resulting from the reduction of injection rate in May 2000, may reduce the stresses tending to collapse the liner. Without dilution, the higher salt disposal rate could be maintained.

- The effective ultimate capacity of the reservoir and life of the well will be decreased by 30% because of dilution.
- Surface injection pressure is elevated by approximately 330 psi with the 30% dilution.
- Hydraulic horsepower required for injection is greater by 44 hp with dilution.
- Expense and manpower to operate the freshwater treatment plant would be reduced if dilution were eliminated.
- The salinity of the river, at the north side of the valley, is increased proportionately to the loss of the fresh water being injected.

Having gained the knowledge that logging tools can be safely run to a depth near the top of the Leadville perforations, Subsurface recommends that the USBR consider running the downhole, fiber-optic, video camera that was suggested during the October 2000 meeting. The camera may verify the ovality detected by the SONDEX caliper and clarify the question of the magnetic marker's influence on the SONDEX readings.

Subsurface recommends that surface pressures be continuously recorded during the next planned shutdown so that a pressure transient analysis can be performed using the pressure falloff data.

USBR should consider updating the SWIFT 486 computer simulation with rate and pressure data available through June 2001.