

GROUNDWATER CHARACTERISTICS AND CORROSION PROBLEMS ASSOCIATED WITH THE USE OF GEOTHERMAL WATER IN KLAMATH FALLS, OREGON

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BACKGROUND

Klamath Falls, Oregon, is located on a Known Geothermal Resource Area (KGRA), and the residents have made use of the resource, principally in the form of hot water for space heating, at least since the turn of the century. The local use appears to be somewhat unique and is the most successful attempt at using geothermal hot water for space heating in the United States (Koenig, 1970 and 1973).

The shallow geothermal reservoir in Klamath Falls extends for at least 11 km in a northwest-southeast direction with a width of about 3 km. More than 400 wells ranging in depth from about 30 m up to 600 m, and obtaining or contacting water from 21 to 110°C, have been drilled into the reservoir. The system is not geologically homogeneous. Great variations in horizontal permeability and many vertical discontinuities exist because of stratigraphy and structure of the area. Basalt flows, eruptive centers, fluvial and lacustrine deposits, diatomite and pyroclastic materials alternate in the rock column. Normal faults with large throw (estimated up to 520 m) are spaced less than 1 km apart and appear to be the main avenue of vertical movement of hot fluids.

Since the turn of the century, geothermal well water has been piped through space heating systems in Klamath Falls. Even though the water in the area is unusually pure for geothermal (800 to 1200mg/l), it corroded and scaled plumbing systems of the area so that, in a relatively short time, the systems had to be repaired or replaced. In about 1930, the first downhole heat exchanger (DHE), locally known as a coil, was installed in a geothermal well. The heat exchanger coil consists of two strings of pipe connected at the bottom by a reverse bend. The temperature of the well water and the predicted heat load determine the length of the pipe required. Based on experience, local heating system contractors estimate approximately "one foot of coil per 1,500 Btu per hour" required (1.2×10^6 cal/m/hr). The coil pipes are connected to the supply and return of the distributing piping and the entire system filled with city water. Figure 1 illustrates a typical system. The heating coil is typically 51 mm in diameter and the domestic water coil is 19 mm in diameter. The "thermo-syphon" process (or gravity feed in standard hot water systems) circulates the water, picking up heat in the well and releasing the heat in the radiators. Circulation pumps are required in cooler wells or in larger systems to increase the flow rate. Thermo-syphon circulation will provide 20-35 kN/m² pressure difference in the supply and return lines to circulate 60 to 95 l/m with a 6 to 11°C temperature change.

Even though the local use is somewhat unique, only limited reporting and documentation has been made by others in the past (Peterson, 1967 and 1970). Based on the uniqueness of the utilization in the United States and the lack of specific information, an investigation was initiated and completed during the summer of 1974 (Culver, 1974). This investigation was an analysis and documentation of the hot water wells, heating systems and the economics of the utilizations. In the 1974

investigation, it was determined that the period of replacement for downhole heat exchangers varied from about 5 to 20 years in non-artesian waters. The average life of standard black iron pipe in the wells investigated was about 14 years. Artesian well downhole heat exchangers were found to have a replacement period of between 29 and 34 years. Failures in the downhole heat exchangers appeared to be due to corrosion at the air-water interface, or to electrolysis below the water line. Specific reasons for these failures (or on-failures, as in some artesian wells) were unable to be determined at that time, since it has been noted that a well with a replacement period of five years may be 100 m from a well with a replacement period of 15 to 20 years.

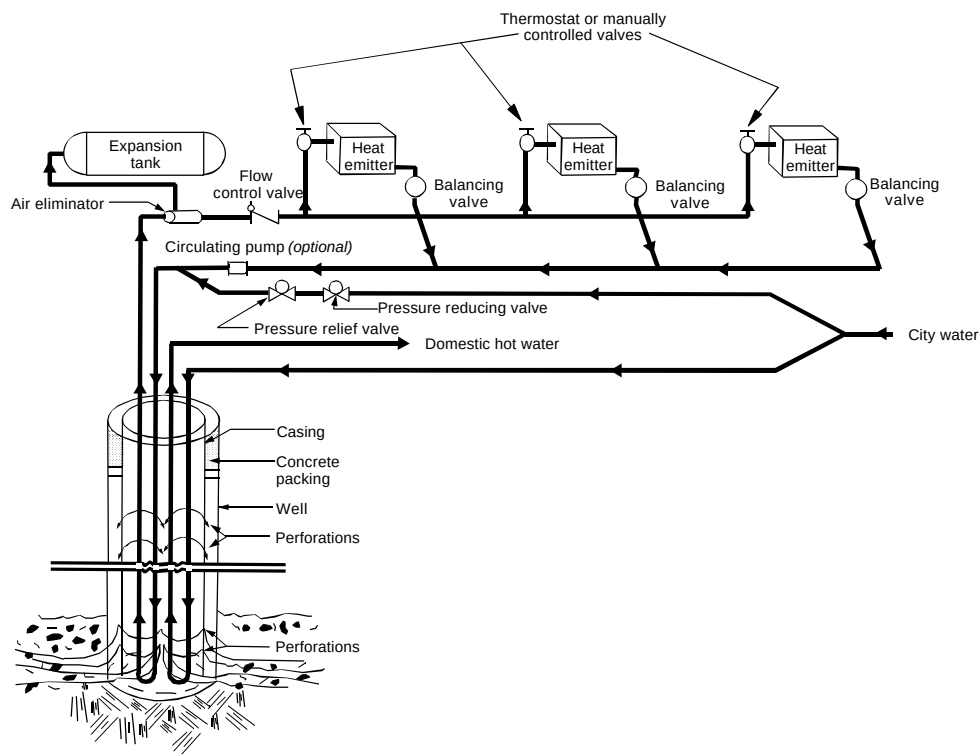


Figure 1. Typical Klamath Falls Hot Water Distribution System.

Most heat exchanger pipes are standard black iron pipe; although, a few are double strength near the top in deep wells to reduce stresses, or at the water line to provide longer corrosion resistance. Other materials have been tried for use at the water line, including brass and lead, and based on limited information these appeared to extend the life of the system. The most common, economical, and apparently effective method of reducing corrosion is to pour used motor oil or paraffin in the well. These materials either reduce evolved gases and water vapor, or provide a protective coating on the coil surface, or both. Several types of corrosion-resistant paints have been tried with questionable results.

Additional study of corrosion was performed during 1975 and 1976 funded by an ERDA grant through the Idaho National Engineering Laboratory. The details of this work are discussed in the following sections.

WELL WATER TEMPERATURE AND CHEMISTRY

Well water temperatures vary from 21°C at the top to over 110°C at the bottom. The low surface temperatures are generally caused by cold surface water cooling the surrounding formations. Rock

temperatures in drill holes have been measured as high as 127°C, but once water enters the hole, the temperature will drop to the 110°C range. Average water temperatures in the hot water area vary from 30°C to over 98°C.

The well water is generally characterized by high concentrations of sodium and low concentrations of potassium, having Na/K mass ratio of about 42 (atomic ratio of about 71). The water hardness of these samples is generally low and results principally from calcium ion. The total dissolved solids are approximately 1000 mg/l. on a mass basis, sulfate is the principal negative ion of these waters (approximately 500 mg/l). The alkalinity values indicate the major contributor to pH is bicarbonate ion and that these waters are highly susceptible to downward pH shifts. The silica concentrations typically is 70 to 90 mg SiO₂/l, which exists principally in these waters as bisilicate ion.

Wells which are adequate heat sources have a cation/anion pattern notably different from those wells which are not adequate heat sources. All of the adequate heat sources, while having notably different sampling temperatures, each share certain chemical composition patterns. Most notably in comparison between adequate and inadequate heat source chemical data are:

1. High cation concentrations of silica, sodium, and potassium in adequate heat source waters. Low cation concentration of calcium in adequate heat source waters.
2. High anion concentrations of the chloride ion in adequate heat source waters. Low anion concentrations of water hardness and total alkalinities (~ 40 mg, CaCO₃/l) in adequate heat source waters.

Water chemistry of geothermal wells varies as follows:

Table 1

<u>Variable</u>	<u>Units</u>	<u>Average</u>	<u>Standard Deviation</u>	<u>Typical Cold Water Well</u>
pH		8.08	0.337	7.30
Potassium	mg/l	4.80	1.11	2.0
Calcium	mg/l	21.8	8.48	55.0
Sodium	mg/l	201.0	47.7	10.8
Chloride	mg/l	49.1	7.95	6.8
Conductivity	µmhos/cm	1210.0	287.0	420.0
Silica	mg/l	91.3	21.4	45.8
Sulfate	mg/l	410.0	73.1	8.3
Water Hardness	mg/l	78.5	23.1	194.0
Dissolved Oxygen	mg/l	1.88	1.29	6.0
Magnesium	mg/l	0.20	0.34	13.7
Iron	mg/l	3.06	6.12	0.23
Boron	mg/l	0.78	0.10	0.16
Temperature	°C	72.6	2.47	25.0

Over 100 wells have been investigated in detail in the urban area as to water level, temperature profile and chemistry. In addition, a selected number of key wells have been measured periodically over several years to monitor changes in water level, temperature and chemistry. There are significant changes between summer and winter, as influenced by weather and use. During the winter months, when heat extraction is greatest, well temperatures will often increase by 2 to 20°C, and water levels may drop up to 3 m. the water level fluctuations are somewhat erratic, influenced by the great geological variations of the reservoir. By summer, the temperature and water level will return to that of the previous summer. This past fall, due to the lack of rainfall, water levels dropped more than usual. The artesian wells were affected greatest, causing some of them to stop flowing when the pressure head dropped below the casing top (the typical head above the casing top is only 0.3 to 0.7 m). The lack of artesian flow also caused the temperature of these wells to decrease by about 20°C as illustrated in Figure 2. The subsequent snow and rainfall this winter and spring have corrected this situation.

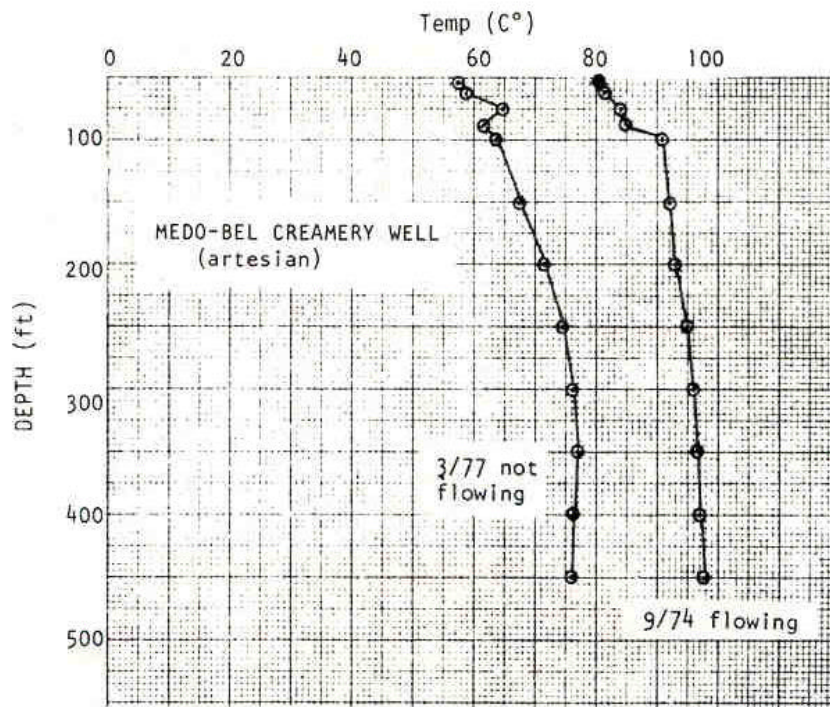


Figure 2, Well Temperature Profile

The Langelier Saturation Index (Langelier, 1936 and Sisson, 1973) was also determined for the wells where chemical analysis was available. This index describes the tendency of natural or conditional water to either deposit calcium carbonate or to dissolve calcium carbonate on the material with which the water is brought in contact (Mashiko, 1970). The saturation index is defined as the algebraic difference between actual measured pH of the water and the calculated pH at saturation with calcium carbonate:

$$\text{Saturation Index} = \text{pH} - \text{pH}_s$$

A positive index indicates the tendency to deposit calcium carbonate and a negative index the tendency to dissolve calcium carbonate. This in turn is related indirectly to scaling. With a negative index, no calcium carbonate is present to coat downhole heat exchanger pipes and well casing; thus, the greater the possibility for other forces to corrode the metals. Based on the 1974 study (Culver, 1974), there appears to be good correlation between this index and scaling.

WELL WATER CHEMISTRY AND SERVICE LIFE OF THE HEAT EXCHANGERS

Correlation on a geographic basis and with individual dissolved ions was attempted. An index of from 0 to 10 was developed as the corrosion indicator, based on service life which was often difficult to estimate. Low values were used for long heat exchanger life (0 for over 30 years between replacement) and high values for short replacement life (10 for under one year between replacement). A value of five was used for the average. In some cases, the service life or frequency of heat exchanger repair was not available for the particular well; however, based on experience and inspection of the heat exchangers, an estimate of their service life could be made. Multiple regression analysis was then applied to the data with the results shown in Table 2.

Geographic correlation of corrosion was attempted based on the 24 wells. A map of the results is shown in Figure 3. Based on this analysis, there does not appear to be a definite relationship between corrosion and any measurable field characteristics. The influence of variables such as casing depth, subsurface geology, stray electrical currents, etc., cannot be analyzed separately. Thus, the geographic correlation is not meaningful.

Table 2

<u>Variable</u>	<u>Mean</u>	<u>Units</u>	<u>Standard Deviation</u>	<u>Correlation with HE Service Index</u>	<u>Abr.</u>
Rating (service index)	4.42	--	2.47	--	R
Sampling temperature	72.6	°C	15.1	-0.383	ST
Maximum well temperature	81.5	°C	12.6	-0.369	MWt
Saturation index (well)	.249	—	.406	-0.338	SIW
Potassium	4.80	mg/l	1.11	0.306	K
Total water harness (CaCO ₃)	78.5	mg/l	23.1	0.287	TWH-1
Total water hardness (Ca)	31.5	mg/l	9.17	0.284	TWH-2
Total alkalinity	45.3	mg/l	22.8	0.253	TA
pH	8.08	--	.337	-0.240	pH
Calcium	21.8	mg/l	8.48	0.162	Ca
Sodium	201.0	mg/l	47.7	0.139	Na
Chloride	49.1	mg/l	7.95	0.110	Cl
Conductivity (x 10 ³)	1.21	µmho/cm	.287	0.104	EC
Silica	91.3	mg/l	21.4	0.098	SIL
Sulfate	410.0	mg/l	73.1	0.084	SO ₄
Saturation index (ambient)	-0.521	—	.351	-0.080	SIA

Minimum level of significance for n = 24 is 0.404.

Using multiple regression techniques the equation using five variables gives:

$$R = 10.7 - 0.06462 (ST) + 1.347 (K) - 6.926 (EC) - 0.06017 (MWt) + 0.0156 (CL)$$

$$MCC = 0.6356$$

$$SEE = 2.152$$

and using nine variables gives:

$$R = 6.536 + 0.07075 (ST) + 0.5923 (K) - 4.164 (EC) - 0.06402 (MWt) + 0.411 (CL) - 0.3348 (SO_4) - 13.43 (SIW) + 12.84 (SIA) + 0.04106 (SIL)$$

$$MCC = 0.8271$$

$$SEE = 1.776$$

where,

MCC = Multiple correlation coefficient

SEE = standard error of estimate

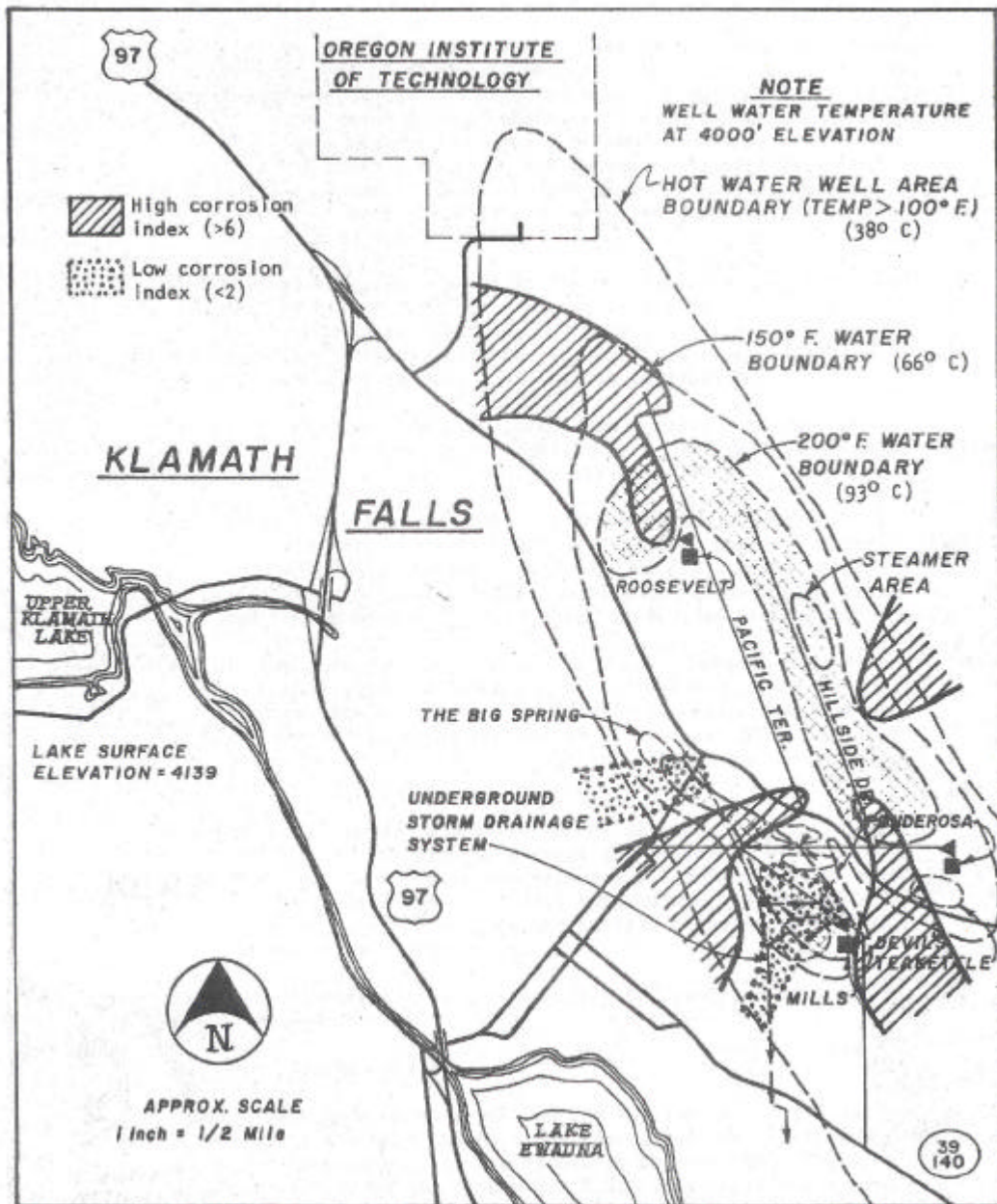


Figure 3. Geographic Distribution of Corrosion

FIELD INSPECTION AND OBSERVATION OF WELLS

During and since the summer of 1974, approximately 25 different wells have been inspected while maintenance and replacement of heat exchange pipes were being performed. Based on these observations and on discussions with homeowners, well drillers and local plumbers, the following conclusions and comments are of interest:

1. Black iron (1010 steel) is the most common DHE and casing pipe material.
2. Both scaling and corrosion will occur on the outside of heat exchanger pipes in most wells. Thin deposits of iron sulfide have been noticed on the inside of heat exchanger pipes.
3. Corrosion is more extensive at and below the waterline.
4. In most cases, corrosion is minimal above the waterline (excluding the water fluctuation range).
5. All failures (corrosion producing leaks of DHEs were noted at or below the waterline, with the former being the greater percentage.
6. Wells with less than full depth casing have major and more frequent problems below the casing line.
7. Where heat exchanger and/or casing are in contact, deep crevice corrosion occurs. Some of this may be due to rubbing from expansion and contraction.
8. Extensive pinpoint pitting along the length of a pipe section or large localized pitting can occur in the same well.
9. In the hotter wells, corrosion can be extensive immediately above the waterline, either due to vapors and/or water level fluctuation. (Some feel that this may be more extensive than waterline corrosion; however, the reverse was true in the case of our corrosion test coupons—see the next section.)
10. Limited experience and data are available on the effectiveness of pipe of different material placed at the waterline. In many instances, the pipe was either misplaced above or below the waterline or the water level fluctuation (from 1 to 6 m) fell below or above the pipe, causing the adjacent pipes to corrode extensively. In general, metals such as copper and brass appear to be effective; however, the effect upon the adjacent casing is unknown, but is expected to be detrimental.
11. Limited experience and data are available in the effectiveness of oils and paraffin placed at the waterline to break the air-to-water interface and coat the pipes. They appear to extend DHE service life, but sufficient examples were not available to draw quantitative conclusions.
12. The variables effecting corrossions appear to be many and difficult to isolate as highly “corrosive” wells are randomly scattered throughout the “hot springs area.”

13. Stray electrical currents appear to be a major contributor to corrosion. This is especially true in cases where the home electrical system is grounded to the water pipes. This is in part verified by local power company experience and to one homeowner's detailed study (see recommendations).
14. Casing corrosion and scaling is almost impossible to determine. Very few failures are actually known, and only one that we know of has been pulled (in pieces). The life of the 6-mm thick casing appears to be at least 50 years. The older 3-mm thick casing had shorter life, based on discussion with well drillers.
15. Recent attempts to prevent corrosion include enclosing the DHE pipe in PVC pipe to disrupt the galvanic cell action. The higher well water temperature will deform the PVC pipe and the heat transfer is also reduced between the well water and the DHE, making the overall effectiveness of the treatment questionable.

PLACEMENT OF CORROSION TEST COUPONS IN SELECTED WELLS FOR LONG-TERM OBSERVATION

Six wells were selected to provide a cross-section of the corrosion problems in Klamath Falls. Test coupons were placed in each of these wells for a six-month period (November 29, 1976 to May 29, 1976).

Four sets of coupons were received from the International Nickel Company (INCO), each set consisting of a 270-mm rack of 56.8-mm diameter duplicate coupons including: iron, cast iron, copper, brass, aluminum and various stainless steels for a total of 11 separate coupons (each was duplicated). All coupon material supplied is commercially available in pipe. After testing, these coupons were returned to their laboratory for analysis and reporting. Three sets of these coupons were placed in one well—one set above the water in the well vapors, one set at the waterline, and one set completely submerged. The fourth set was placed in a second well.

We also constructed our own set of test coupons to be placed in the other wells. These consisted of Cor Ten and 1010 (black iron steel), brass, copper, aluminum and stainless steel. These were placed below the waterline with insulation strips between specimens and in some cases, with the coupons in contact with black iron. The latter was an attempt to simulate electrolysis between heat exchangers and casing, typically constructed of black iron.

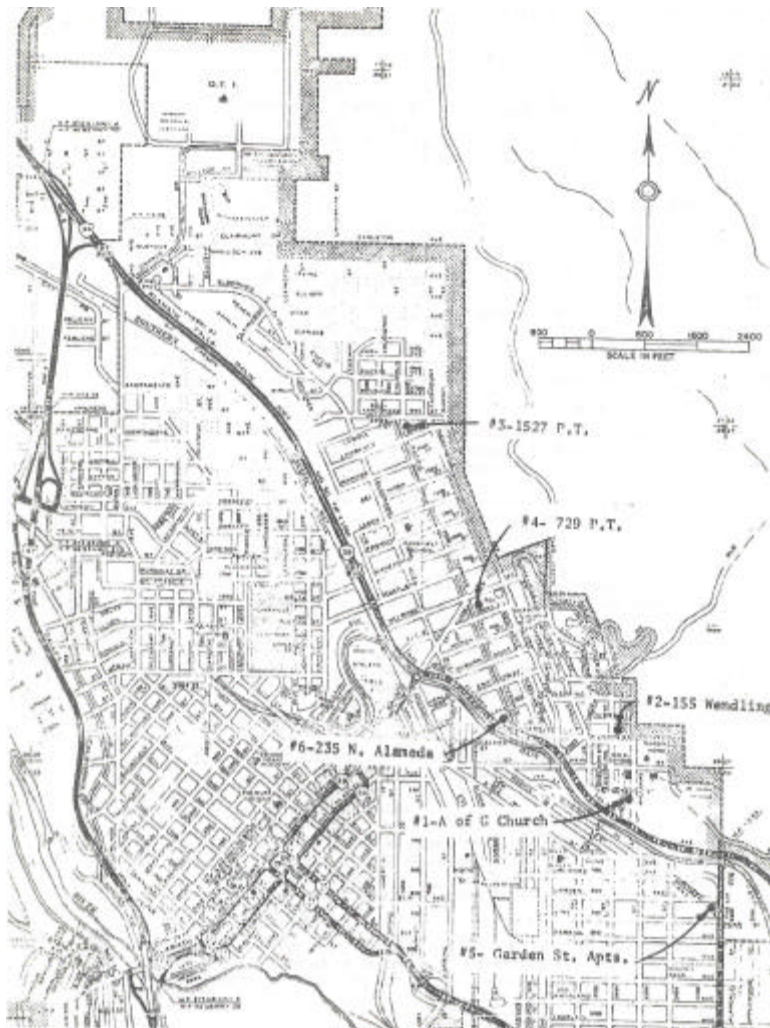
Brookhaven National Laboratory in New York through ERDA requested that we place polymer concrete specimens in these wells along with our coupons. These specimens, in stainless steel baskets, were all placed below the waterline. These samples were placed in the wells for varying periods of time (three months, six months and one year). A list of these wells and their characteristics is shown in Table 3. The map in Figure 4 shows the geographic location of each of the wells.

All six wells had detailed temperature profiles, static water level determination and chemistry determined on a periodic basis during the corrosion testing.

An attempt was made to measure free gases just above the waterline in each well. As best can be determined (using Drager tubes), less than 2 mg/l H₂S and less than 100 mg/l CO₂ gases are present.

Table 3. Corrosion Test Well Characteristics

<u>Location</u>	<u>Depth</u>	<u>Temp. Range</u>	<u>Depth to Water</u>	<u>Casing Diameter</u>	<u>Casing Depth</u>	<u>Downhole Heat Exchanger</u>	<u>Estimated Corrosion Level</u>
1. Assembly of God Church 235 South Laguna	108.3 m	66-89°C	12.5 m	305 mm	110.7 m	No	High
2. Chad Carroll 155 Wendling	98.2	93-99°C	27.8	203	Full?	No	Medium
3. Warren Wiley 1527 Pacific Terrace	72.9	24-47°C	16.8	203	Full?	No	Low
4. Donald Crane 729 Pacific Terrace	60.4	68-77°C	34.2	305	9.2	Yes	Low
5. Garden St. Apartments 2538/2560 Garden St.	155.6	31-66°C	8.9	305	Full?	Yes (Pumped)	High
6. Raymond Thexton 235 North Alameda	83.0	48-71°C	5.8	203	9.2	Yes (Pumped)	High

**Figure 4. Corrosion Test Wells Locations**

Carbon dioxide is the chief cause of acidity and low pH values in groundwaters. It is readily soluble in water and forms carbonic acid. CO₂ concentrations in excess of 20 ppm are generally considered sufficient to cause severe corrosion on steel- and copper-based alloys. A high pH indicates concentrations of CO₂ must be very low, thus causing minimal corrosion. For this reason, it is estimated that the CO₂ contents are low.

In general, the results from the testing can be summarized as follows (based on observations by INCO):

1. Exposures of specimens below the water surface and the vapor above the water surface are not particularly aggressive except to steel and aluminum
2. The average corrosion rates of steel and aluminum are not particularly high for these two well placements, but localized corrosion and crevice corrosion should be considered in view of any equipment placed in wells.
3. The exposure at the waterline is much more aggressive than above or below the water surface, as illustrated by one well (Assembly of God Church):

Table 4. Loss in Mils/yr

<u>Metal</u>	<u>Above Waterline</u>	<u>Waterline</u>	<u>Below Waterline</u>
Brass	0.1	0.7	0.2
Copper	0.1	0.8	0.2
Aluminum	0.3	1.4	0.4
1010 Steel	0.7	9.3	0.5
Cor Ten Steel	1.5	11.7	0.3
Cast Iron	2.7	12.6	1.0
304 Stainless	0.0	0.3	0.0

4. The water line corrosion is probably the result of oxygen concentration cells and deposits from evaporation.
5. With steel well casing, copper and aluminum heat exchangers should be avoided. Copper will accelerate the corrosion of steel. Steel will accelerate the corrosion of aluminum.
6. Stainless steel alloys perform well with steel.

Examples of loss rates for the various metals based on coupons placed below the waterline are as follows:

Table 5. Loss in Mils/yr

Metal	Wells*					
	#1	#2	#3	#4	#5	#6
Brass	0.08	0.12	0.77	0.01	0.01	0.02
Copper	0.09	0.13	0.46	0.02	0.02	1.08
Aluminum	0.12	0.99	4.00	0.20	0.12	0.02
1010 Steel	0.17	0.10	2.54	0.75	0.26	0.29
Cor Ten Steel	0.18	1.13	2.32	0.66	0.11	1.02
Cast Iron	—	—	--	0.71	0.22	2.63
304 Stainless	0.00	0.00	0.01	0.01	0.00	0.01
Temperature (°C)	71	65	27	65	75	42

Correlation analysis was used to compare the corrosion rates of the various coupons with that of water chemistry. A summary of the results is shown in Table 6. The following observations can be made:

1. Brass, aluminum, and 101 steel corrosion rates had high correlation with well water chemistry.
2. Cor Ten corrosion rate had moderate correlation with well water chemistry.
3. 304 stainless steel and copper corrosion rates had no significant correlation with well water chemistry.
4. The ions having the highest correlation with corrosion rate were sodium (Na), water hardness (WH), chloride (Cl), sulfate (SO₄), and pH (PH).

Table 6. Corrosion Correlation

Material/ Chemistry	Na	K	WH	Cl	SO₄	SO₂	EC	Ca	pH	O₂	Sampling Temp.
304 Stainless											
Brass	-.96	-.84	.94	-.95	-.96		-.93	.88	.98	.91	
Copper											
Aluminum	-.92		.94	-.91	-.89		-.86	.92	.94	.93	
Low-Carbon Steel 1010	-.94		.97	-.94	-.94	-.86	-.92	.85	.94		
Low-Carbon Alloy Steel											
Cor Ten	-.8		.82		-.87				.94		-.84

Blanks indicate no significance.

Minimum significance level for N = 6 is 0.811.

*See Table 3 for details of well locations.

FIELD TESTING OF INDUCED CURRENT IN TEST SPECIMENS

Stray electrical currents (both AC and DC) were felt to be a significant cause of corrosion in heat exchanger pipes. In addition to that caused by power lines and other electrical equipment in the vicinity of the well, the older requirement of grounding a home electrical system to the cold water pipes was felt to be a major contributor to this problem. This has in part been verified by discussion with the local power company.

Professor Jerry Newcomb, a member of the OIT faculty, studied this problem in detail due to the high replacement rate of his own heat exchangers (replacement rate of every two to three years). The local power company suggested that his well and heat exchangers were acting as the ground (or sacrificial electrode) for the entire neighborhood. This was especially distressing, as his neighbor's wells did not exhibit this high corrosion rate and frequent heat exchanger replacement. During the summer of 1975, he replaced his heat exchanger pipes and made several modifications of the system. Most important were the placement of electrical isolation junctions in the pipe, the attachment of a sacrificial electrode and covering in the pipe with special insulating tape. The report of his work is summarized in (Newcomb, 1976).

A preliminary experiment with electrical currents was attempted in September of 1975. Three 3-mm diameter black iron wires were suspended at the waterline in the hot water well at 155 Wendling. These wires were approximately 45 mm long, and were insulated from each other and the well casing by plastic triangles. A power source was connected to two the wires: 3.2 volts AC and -1.0 volts DC; the third wire had no current.

These wires were left for a six-week period and then removed. During this time, the wire with the AC current had completely corroded through; the -DC wire had acted as a cathode and had extensive deposits of carbonate attached. The non-current wire had oxidized slightly, mainly at the water line.

Based on this experience, a more detailed and precise experiment was undertaken. Four wires similar to those used in the original experiment were each encased in CPVC pipe to electrically insulate each wire. The four CPVC pipes had numerous holes drilled through them to allow the circulation of water when suspended in the wells. Three of the four wires were connected to a power source (AC, -DC, and +DC). Each wire was weighed to the nearest milligram before the experiment. The four wires were then suspended at the waterline in three of the six corrosion test wells (those without heat exchangers) to get a range of temperature and chemistry exposure. Since failure of the wire was not desired, they were suspended for only a three-day period. We attempted to maintain the same voltage in each well, but due to chemistry and temperature differences, this was impossible within the time and equipment constraints. In all cases, the DC+ wire had the greatest weight loss (6.6 to 9.0 percent), the DC- wire the greatest weight gain (1.7 to 7.6 percent), and the AC results were variable (0.4 percent gain to 1.4 percent loss). The non-current wire was slightly pitted at the waterline.

It can be concluded from these results that, both AC and DC+ voltages contribute to corrosion, depending upon the magnitude of the voltages. The DC- resulted in scaling with large deposits of calcium carbonate. Since both AC and DC voltages have been measured on heat exchangers in wells, corrosion (electrolysis) must occur and is probably the significant cause of failures. This probably also accounts for the randomness of corrosion in the urban area.

LABORATORY TESTING OF CORROSION SPECIMENS

Test coupons of 1010 steel and copper were suspended in geothermal water from the OIT wells to measure various corrosion rates. Three separate experiments were performed:

1. A single 1010 steel coupon in water;
2. A 1010 steel coupon in contact with a copper coupon; and
3. Two separated 1010 steel coupons with a low-voltage DC current between them.

Galvanic cell (anode–cathode cell) action occurs when dissimilar metals such as copper and 1010 steel are coupled or where concentration cells exist in crevices. Chlorides and other dissolved minerals increase the electrical conductivity of the water so that the flow of corrosion currents will be facilitated. Under acid conditions, the chloride ions are capable of penetrating and breaking down otherwise protective films (pitting) and are corrosion accelerators for most metals.

The results indicated that the 1010 steel coupon in contact with copper had the highest corrosion rate (26,00 MPY), the one with the current between them next (21.73 and 16.59 MPY), and the single 1010 steel coupon the lowest rate (18.75 MPY). Additional details are documented in Section 8 of Appendix F.

CONCLUSIONS AND RECOMMENDATIONS

A. Present Practice

Corrosion has occurred in downhole heat exchangers in Klamath Falls, requiring periodic replacement. The replacement period for the standard black iron pipe varies from five to 20 years, with 14 being the average. Based on a 1974-study, the average replacement cost was \$560. Corrosion has occurred in the form of localized pitting, causing leaks in the pipe as well as generalized surface corrosion (iron oxide and sulfide) and scaling (carbonate). The greatest occurrence of corrosion is at the waterline, with corrosion below the waterline being the next most severe location. In partially cased wells, the corrosion below the casing level may be more severe.

Present practice to reduce corrosion of the downhole heat exchanger is to place various pipe metals at the waterline such as copper, lead or high-strength steel. In addition, used oil or paraffin is poured down wells to break the air-water interface and to coat the pipes at the waterline. Based on limited information, these methods appear successful.

B. Present Study

This study attempted to isolate the specific causes of corrosion of downhole heat exchangers. There appeared to be some geographic distribution of high corrosion and low corrosion areas within the Klamath Falls urban area; however, no specific reasons were attributed to these distributions. It is felt that too many variables control this distribution which could not be measured or isolated (casing depth, subsurface geology, touching of heat exchanger pipes, stray electrical currents, etc.).

The Langelier Saturation Index, based on pH, was found to be successful in predicting scaling or corrosion in the 1974 study. The current study found less correlation with corrosion, mainly due to

the difficulty of estimating the actual service life of the downhole heat exchangers. It is felt that this index has an excellent potential for predicting scaling and the possibility of corrosion and more data should be gathered to verify or disprove this as accurate information data gathered during maintenance.

Well water chemistry was also studied in relation to service life. No specific elements or ions were found to have significant correlation with corrosion life, again probably due to the difficulty of estimating service life. Well temperatures appeared to have the best correlation, with high temperature related to longer service life.

Using various metal coupons placed in wells gave more precise data relating to corrosion vs. chemistry. Sodium, water hardness (CaCO_3), chloride, sulfate, and pH had significant correlation with corrosion (measured in mils of loss per year). Electrical conductivity, calcium, and dissolved oxygen have a less significant correlation with corrosion. Water hardness, calcium, pH, and oxygen had positive correlation with corrosion loss (i.e., the higher the concentration, the greater the corrosion), while the remaining items had negative correlation. Calcium and water hardness are also related to the Langelier Saturation Index, thus in part verifying the latter's importance.

Analysis of black iron results (low carbon 1010 steel) showed that water hardness had the highest correlation with corrosion, with sodium, chloride, sulfate, electrical conductivity, and pH following close behind.

Various other metal coupons were also exposed in hot water wells for a six-month period. In all cases, the highest corrosion rate (in mils of loss per year) was at the waterline. Cast iron, Cor Ten steel and 1010 steel had the highest corrosion rates of the metals tested. Aluminum had some corrosion, with brass and copper being slightly less. Stainless steel had the lowest or no corrosion loss. The relative corrosion loss of aluminum, brass and copper did vary and in several cases, aluminum had the highest loss of any material due to pitting.

Copper or aluminum should be avoided in wells with casing as copper will accelerate the corrosion of steel (well casing) and steel will accelerate the corrosion of aluminum. Stainless steel would be the best solution to the corrosion problem; however, the high initial cost probably precludes its use as it is about five times the cost of black iron. The use of protective coatings on pipes was not investigated in this study; however, they appear to have merit and should be studied in more detail as to cost, temperature susceptibility, heat transfer efficiency, etc.

Electrolytic corrosion has been suspected of being a major source of corrosion, as has been observed by power and pipeline companies with underground (wet) installations. Work in the field indicated that there were stray electrical potentials and currents (both AC and DC) in heat exchanger pipes and casings of local wells. These varied up to one volt AC and DC with 100 and 300 millivolts being common, and up to 100 milliamps with 5 to 30 milliamps being common. These stray electrical currents were probably due to power lines in the vicinity and to the practice of grounding residential electrical circuits to the cold water pipes.

Experimental work with electrical currents indicated that AC and DC+ currents gave high corrosion rates, with DC- accumulating carbonate deposits. The amount of corrosion and the relative importance of AC or DC+ depends upon the magnitude of the power source and the characteristics and chemistry of the well. AC currents produce a skin effect, causing flows only on the surface of the heat exchangers. These current flows will disperse at the waterline, thus causing corrosion and

pitting. Clamps and joints at the surface are probably poor conductors due to rust, thus “bleeding off” any current flow. Connections and threads on the heat exchanger pipes may disrupt circuit flow, and this may be the reason why some wells do not have high corrosion rates.

In summary, the following conclusions can be made for geothermal well water in Klamath Falls:

1. The Langelier Saturation Index is probably a good indication of corrosion or scaling potential of a well.
2. Dissolved sodium, water hardness, chloride, sulfate, and pH have a significant correlation with corrosion potential.
3. Mild steel and cast iron have low resistance to corrosion.
4. Stainless steel has the highest resistance to corrosion.
5. Copper, brass and aluminum should not be used in heat exchanger pipes due to adverse reactions with steel well casings.
6. Stray electrical currents causing electrolytic corrosion appear to be the most significant cause of corrosion.
7. Based on historical observations:
 - a. Corrosion below casing depth appears to be greater than in full depth cased wells.
 - b. Oil and paraffin at the waterline appear to reduce corrosion.

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