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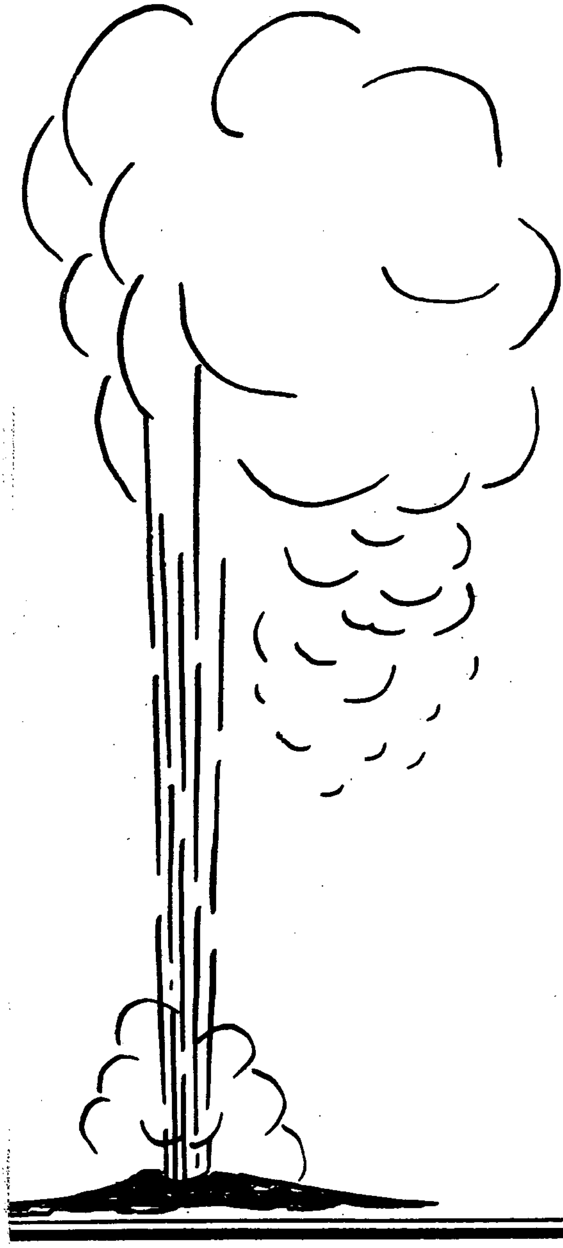
Final Report, October 6, 1975 - February 4, 1977



By

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Work Performed Under Contract No. EY-76-C-02-2797

The Dow Chemical Company
Texas Division
Freeport, Texas 77541

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
Division of Geothermal Energy

DISCLAIMER

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SUMMARY

A process for controlling hydrogen sulfide emissions and corrosivity in geothermal systems has been evaluated on a small laboratory pilot plant scale and shown to be technically feasible. The hydrogen sulfide was oxidized by oxygen injected directly into a 11.4-liter-(3-gallon)-per-minute flowing stream of simulated geothermal brine. The oxidation of the sulfide was complete at oxygen:sulfide mole ratios of 1.25:1 to 1.5:1, depending on temperature and total dissolved solids in the brine.

The reaction products were free sulfur, sulfite and sulfate. The ratio of these was dependent upon the oxygen:sulfide mole ratios; but, generally, more than 80% of the sulfide was converted to sulfate, approximately 10% to free sulfur and less than 10% to sulfite.

The reaction occurred too rapidly to measure in the apparatus designed. Reaction time was less than one minute at temperatures expected for geothermal waters. Thorough mixing using in-line mixers was used to achieve this rate.

Catalytic agents are believed to be necessary to achieve rapid reaction. However, addition of a known catalyst, iron and nickel ions, had no measurable effect on the reaction rate. Analysis of the lowest total dissolved solids (131 ppm)

solution used indicated 0.4 ppm iron in the water. On this basis, it is assumed that catalytic ions existed in all waters and that these same ions will exist in all geothermal waters. Therefore, it is proposed that no addition of catalysts will be necessary.

Further testing on actual geothermal waters will be necessary to assure the practical use of this process. However, it is presently proposed that oxygen would be injected in preference to air to avoid nitrogen introduction into the water. The injection would take place at the well--head to provide a less corrosive water in the pipelines of the gathering field.

Two conceptual designs are presented for the injection system. These differ by the manner of achieving the complete mixing of the gas with the water. One uses in-line mixers in parallel while the other proposes a packed tower with concurrent flow and a 30-second residence time. Estimated capital costs per well for the installed systems are $209,900 for the in-line mixer system and $362,250 for the packed tower. These costs may be reduced if further investigation reveals that other materials and procedures can be used in the process.

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I. INTRODUCTION

1. The Hydrogen Sulfide Problem in Geothermal Waters

Geothermal waters exist underground in primarily reducing conditions. Therefore, much of the natural sulfur content of these waters can occur in the sulfide form. Due to the difficulty of *in situ* sampling, valid sulfide analyses of the geothermal fluids are sparse and unreliable. However, it appears that most geothermal wells will contain appreciable amounts of sulfide, commonly in the form of hydrogen sulfide (H_2S). Most of the H_2S is carried along with the steam when flashing occurs and presents a corrosion problem as well as an environmental problem in the utilization of the steam for space heating or power production.

The total quantity of sulfide produced in this manner by a geothermal power plant may be quite large. For example, Kruger and Otte[1] have compared the H_2S content of various geothermal steams as shown in Table 1. Values as high as 17.2 mole percent of the total noncondensables are reported. In the case of the Geysers in California, a value of 3.0 mole percent is quoted. This calculates as 208 ppm H_2S in the steam. Axtmann[2] calculates total sulfur output at The Geysers (as of 1973) at 21 tons per day. The same calculation gave 55 daily tons of sulfur for the Cerro Prieto, Mexico plant. Li and Alzheimer[3] have compared the sulfur output at The Geysers with that of a coal-fired power

Table 1

Chemical Analyses of Noncondensable Gases in Geothermal Steam

Site	Noncondensable Gas Content of Total Discharge (wt. %)	Mole Percent H_2S
Hengill, Iceland	0.3	4.9
Hveragerdi, Iceland	0.1	17.2
Krysurik, Iceland	1.3	9.6
Wairakei, New Zealand	0.1 - 0.5	3.8
Waiotapu, New Zealand	0.07 - 0.2	7.8
Larderello, Italy	4.5	2.5
The Geysers, California	0.7	3.0

plant burning one percent sulfur coal and calculated the geothermal source to produce only one-fourth the sulfur release of the coal plant. However, the output is still quite large; and the noxious odor and toxicity of hydrogen sulfide compounds the problem.

The legal emission limit of hydrogen sulfide in California is 0.03 ppm. The Federal OSHA standard is 10 ppm average (20 ppm maximum) for an 8-hour exposure. These standards plus the corrosive nature of the sulfide on turbine blades and other equipment indicate the desirability of removing the H_2S where steam flashing is involved in the utilization of geothermal waters. In nonflashing systems;--for example, secondary fluid power cycles--the sulfide may not escape from the water and could be reinjected with only the corrosion problem being involved.

This project was undertaken to test the concept of oxidizing the sulfide to less noxious sulfur forms through the injection of oxygen into the water prior to flashing. This would preferably be done at or near the wellhead to minimize corrosivity in the collection lines.

2. Oxidative Properties of Hydrogen Sulfide

Previous experience in this laboratory indicated that direct oxidation of hydrogen sulfide to free sulfur and sulfate may be accomplished in hot geothermal-type brine by the injection of oxygen into the brine. Under a contract, No. 14-30-2936, with the Office of Saline Water, U.S. Department of the Interior, a simulated geothermal brine at 232°C (450°F) containing up to 100 ppm hydrogen sulfide was injected with oxygen just prior to flashing[4]. The oxygen, with approximately a 5-minute contact time in the flash system, effectively removed hydrogen sulfide below the odor threshold level in the steam condensate and by better than 90% in the wastewater.

Principal emphasis on solving the hydrogen sulfide problem has centered around removing the gas from steam. A process for accomplishing this removal has been developed at the laboratory scale by the EIC Corporation[5] and successfully field tested at the Geysers in California. The sulfide is removed by passing the steam through a copper sulfate ($CuSO_4$) tray-tower scrubber. The sulfide reacts to form copper sulfide (CuS) which is later regenerated to $CuSO_4$. Removal of 95% of the hydrogen sulfide is claimed. This appears to be a successful although costly process.

A gamut of sulfide sorbents have been investigated by Battelle[3]. These were intended to remove the sulfide from the steam by chemical or physical adsorption and included, primarily, metal oxides and organic amines in various forms. The most successful candidate was zinc oxide. Good removal was reported but regeneration of the spent sorbent proved to be difficult.

Direct oxidation of the sulfide by injection of oxygen in the steam has been tried with little success. This may be due to the absence of catalytic cations or it may be a kinetics problem in the gas-gas reaction. The presence of unreacted oxygen in the hot steam presents severe corrosion problems in turbines and steam-condensing systems.

The rate of oxidation of hydrogen sulfide at low levels in water has been shown to be a function of temperature and pH. Ostlund and Alexander[6] found the half-life of the sulfide in seawater at 25°C to be approximately 17 minutes. Werner[7] found the reaction of hydrogen sulfide and oxygen at room temperature and in the absence of catalysts to be much faster in solution than in the gas phase. Avrahami and Golding[8] found the aqueous reaction to be near first order with respect to sulfide ion and to increase in rate with temperature up to at least 55°C and with increasing pH. They proposed the following overall reaction scheme:

$$2HS^- + 3O_2 \rightarrow 2SO_3^{-2} + 2H^+$$

$$SO_3^{-2} + \tfrac{1}{2}O_2 \rightarrow SO_4^{-2}$$

$$SO_3^{-2} + HS^- + \tfrac{1}{2}O_2 \rightarrow S_2O_3^{-2} + OH^-$$

$$S_2O_3^{-2} + \tfrac{1}{2}O_2 \rightarrow SO_4^{-2} + S$$

In this sequence, the first reaction is the initial rate-determining step, the second and third steps are very rapid with the last step being slow. These studies indicate the likelihood of reasonable reaction rates between the sulfide and oxygen at the elevated temperatures of geothermal brines. The presence of a wide spectrum of metallic ions in the brines also provide the possibility of catalysts which may accelerate the reaction.

Thus it would appear from theoretical considerations and from the aforementioned experimental evidence that hydrogen sulfide may be effectively removed from geothermal brines by direct oxidation with oxygen. This could constitute an economical approach to the solution of an environmental problem. It should be noted that the presence of oxygen in the brine, even for a short time, may greatly accelerate corrosion problems on steel and copper alloys.

3. Technical Approach of this Program

The basic approach taken was to prepare simulated geothermal waters and test the oxidative process over a range of temperatures. The oxygen was injected in controlled quantities into a flowing stream of the hot brine. A reactor zone with a five minute residence time was provided with sampling points at one-minute intervals to follow the course of the reaction. Corrosivity of the waters was measured before and after the oxygen injection. The hot brine stream was disposed of through a 2-flash system to reduce temperature to 100°C, thence to the Dow wastewater treating system for release into the Brazos River via the Dow wastewater treatment plant.

4. Scope of Work

The technical program consisted of examining the reaction to determine the kinetics, end products, temperature dependence, catalytic requirements and optimum oxygen-sulfide ratios at various brine concentrations. The principal phases carried out were as follows:

- Determination of optimum oxygen-sulfide ratio to most effectively remove the H_2S while still avoiding the presence of free oxygen and the resulting excessive corrosivity.

- Establish temperature dependence of the reaction and estimate completion time at various temperatures at the optimum oxygen-sulfide ratio.

- Examine effects of dissolved solids content upon the kinetics and nature of the reaction with special emphasis on possible catalytic properties of heavy metal ions present in trace quantities in most geothermal fluids.

- Determine the effects of variables such as pH, ammonia, and sulfate ion on the reaction.

II. GENERAL DESCRIPTION OF PROCESS AND EQUIPMENT

1. Preparation of Simulated Geothermal Water

(a) The Pros and Cons of Simulated Water

The use of simulated water offers both advantages and disadvantages over actual geothermal well waters. The advantage is primarily the ability to change the nature of the water at will. Variables such as composition, pH, temperature and sulfide content may be introduced as desired within the limits of the system. A geothermal well source offers only very limited possibilities in this area since the basic composition can only be modified by addition or dilution, thus only increasing or decreasing the level of one or all components. The simulated water also offers an ease of short-term on-and-off operation not easily shared by a geothermal well flow.

The primary disadvantage of simulated water is the virtual impossibility of exact reproduction of any actual geothermal well source, especially in respect to trace components which could have important catalytic effects in H_2S oxidation. The question, "Will it work in the real world?", always remains and ultimately must be answered by going to a well with testing equipment. Simulation of geothermal water is also a complex problem in itself, giving rise to many chemical and operational complications. In spite of these disadvantages, simulation of the waters does offer an opportunity to gather data over a wide range of conditions and to establish the parameters of the oxidation process.

(b) Process for Preparing Simulated Geothermal Waters

The problems of mixing and heating a simulated geothermal brine are primarily physical in that many of the components are soluble only in the high-temperature, high-pressure state. Chief among these are silica and calcium carbonate or bicarbonate. The solution adopted to solve this problem was the preparation and deaeration of a base sodium chloride solution with certain nonscaling cations added, heating this base brine to temperature through a steam heat exchanger, injecting concentrated and deaerated solutions of the other desired components into the exit stream of the exchanger and mixing just downstream with in-line mixers. The resulting stream then represents a simulated flow from a geothermal well with the advantage of wide variations in composition and temperature.

The source of salt was "chlorine cell feed", a 26% sodium chloride brine from a salt dome solution mining process. This brine is treated to remove calcium and thus contains 1,200 to 1,800 ppm sulfate. A batch process utilizing barium chloride to precipitate the sulfate as barium sulfate was used to lower the sulfate levels to allow calcium addition without scaling in the heat exchanger. A typical composition of the Dow salt dome treated brine is given in Table 2.

This concentrated brine was diluted with Brazos River water or, in most runs, with Dow steam condensate. Chloride solutions of the desired cations such as calcium, iron, etc. were added to the base brine solution prior to deaeration.

Table 2

Composition of Dow Salt Dome Treated Brine

Gaseous and Cationic		Solid and Anionic	
Constituent	ppm	Constituent	ppm
CO_2	100	Cl	158,000
H_2S	1	Br	10 - 20
		I	1
Na	102,000	SO_4	1,200 - 1,800
K	350	HCO_3	100
Li	10		
Ca	3 - 6	SiO_2	0 - 10
Mg	0 - 1	H_3BO_4	0 - 10
Fe	1 - 3	TDS	260,000

The anions, prepared as concentrated solutions of the sodium salts were injected into the hot flowing brine stream. The primary anion solution contained 5% sodium silicate and 10% sodium bicarbonate. The sulfide was added as a separate solution of 18% sodium sulfide. Technical grade hydrochloric acid (HCl) was injected to adjust pH. All solutions were deaerated with nitrogen and stored under a nitrogen pad prior to injection.

(c) Equipment

A schematic diagram of the system for water preparation and hydrogen sulfide oxidation is shown in Figure 1. The item of special consideration is the reactor, R-1. The oxidation reaction was planned to take place in this reactor. The design is that of a five-pass, steam-jacketed reactor with one minute residence time in each pass and sample points between passes plus at the completion of the fifth pass. This provides for five sulfide analyses at one minute intervals to follow the course of the oxidation. Figure 2 is a photograph of the reactor showing the sampling valves and the connections between passes. Each pass consists of two concentric pipes, a 1.27-cm. (0.50-in.) O.D., 0.165-cm. (0.065-in.) wall thickness center tube inside a 5.08-cm. (2-in.) O.D. Schedule 40 blind-end outer pipe. The brine passes down the central tube and returns in the space between the two. The total path length is approximately 12.2 meters (40 ft.) with one minute residence time at the three gallon-

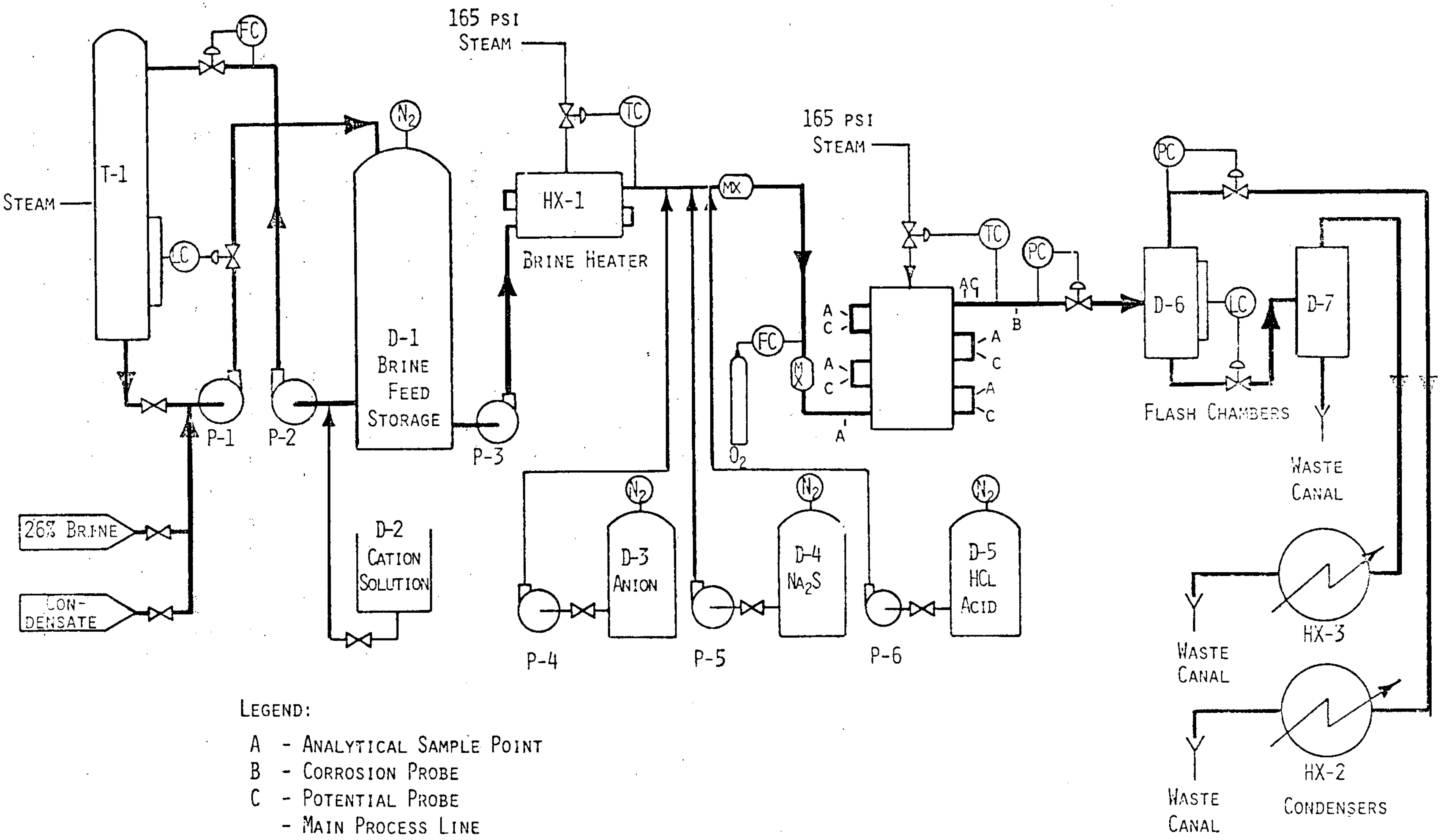

FIG. 1: HYDROGEN SULFIDE OXIDATION SYSTEM FLOW SHEET.

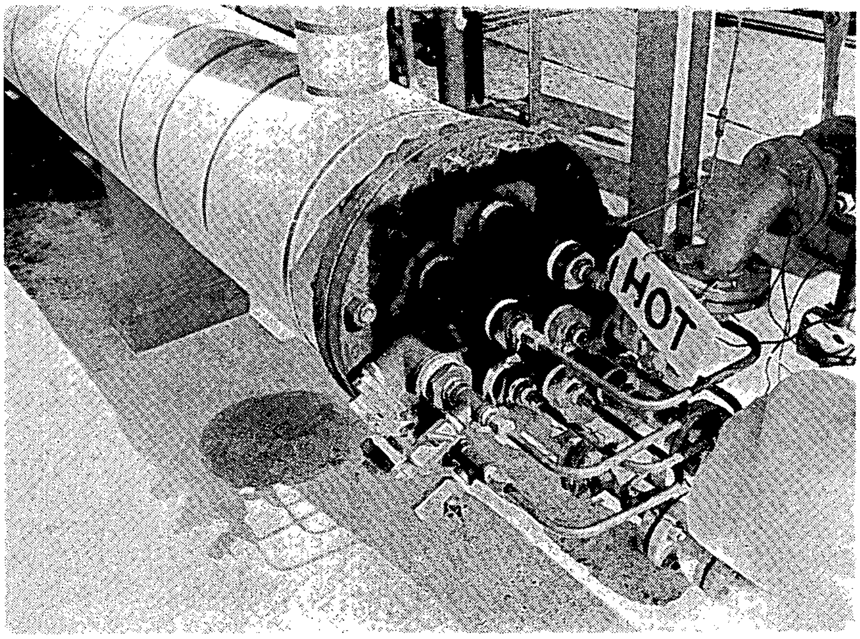

Fig. 2: Photograph of reactor, R-1, illustrating sampling values and crossovers between the five (5) passes.

per-minute flow rate. Both tubing and piping are Alloy 20 steel to avoid corrosion and contamination of the brines.

The other items prior to flash disposal shown in Figure 1 are of conventional design but constructed to avoid exposure of the brine to corrosive mild steel surfaces. All connecting piping is polytetrafluorocarbon-lined. The heat exchanger is constructed of titanium and is the lower vessel in Figure 3. The upper vessel is the condenser, HX-2, for the first flash chamber, D-2.

The brine flow into the heater, HX-1, is supplied by a 316 stainless steel, triple positive displacement pump, Model 431, manufactured by CAT Pump Corporation. The flow rate is modified by changing pump or motor pulleys. A pulsation dampener is included to provide a more uniform flow.

The anion solution, sodium sulfide solution and the HCl were injected with Model Milroyal D chemical injection pumps, P-3, P-5, and P-6. The pump chambers and the injection tubing are of Hastelloy®C or B to avoid corrosion and contamination.

Oxygen gas was metered into the flowing stream just prior to entry into the reactor. The metering system consists of a constant-differential flow controller upstream from a needle valve. The flow controller maintains a constant differential in the pressures across the needle valve, thus a constant gas flow. The magnitude of the flow is determined by adjusting the needle valve. Total flow is measured with a flow meter and displayed on a square-root gauge.

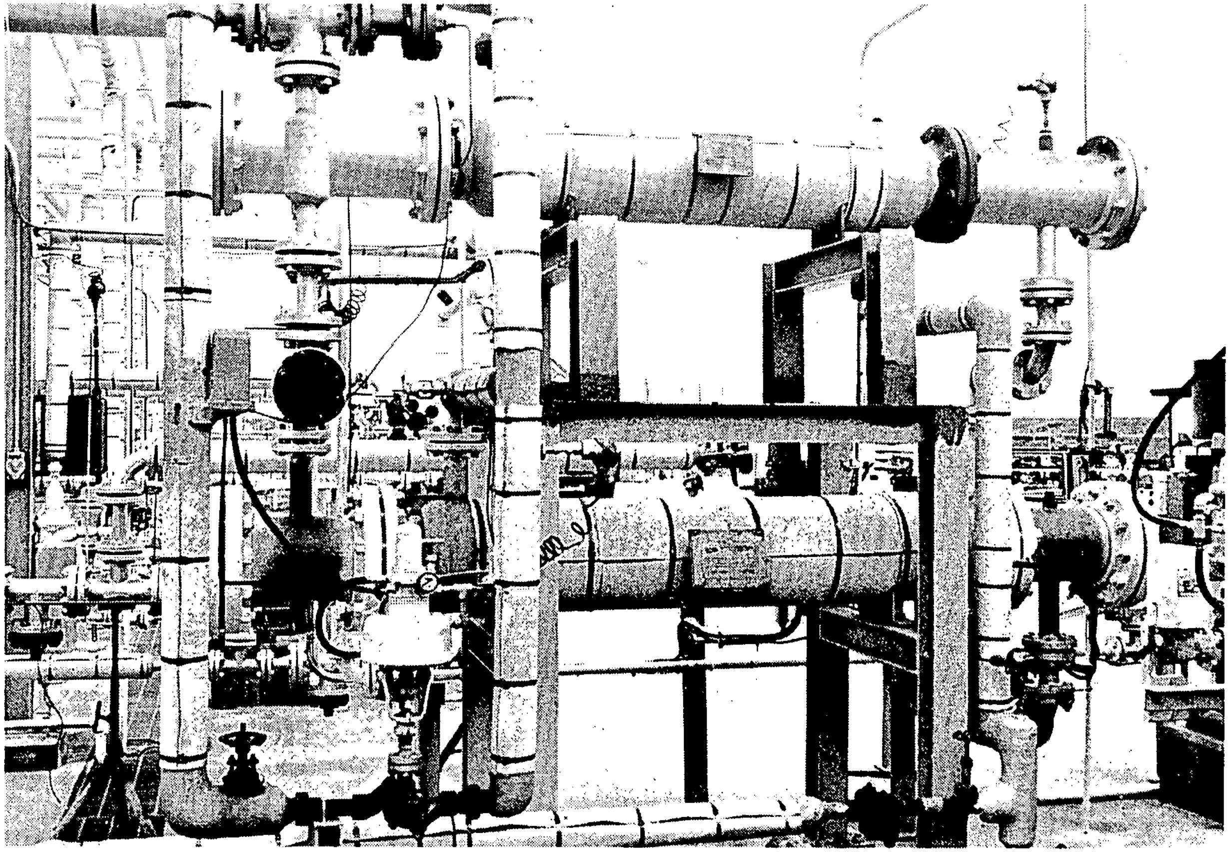

Fig. 3: View of titanium heat exchanger, HX-1, (lower vessel) and steam condenser, HX-2, (upper vessel).

Mixing of the anion, sulfide and acid solutions into the brine was accomplished by an in-line mixer. A similar mixer was installed just downstream of the oxygen injection point. These mixers are ISG (Interfacial Surface Generator) mixers of Dow design, manufactured by Charles Ross & Son Company of Hauppauge, New York. The ISG mixer consists of a series of stationary mixing elements enclosed in a pipe housing. Each unit has four passage holes at oblique angles. The ends of the elements are shaped such that adjacent elements form a tetrahedral chamber. A photograph of a disassembled mixer is shown in Figure 4.

The units used were of polytetrafluoroethylene, 5.08 cm. (2 in.) diameter with six units in each mixer. The number of layers emerging, L, can be calculated by the equation ($L = N(4)^E$) where N is the number of streams and E is the number of elements. Thus a two-layer stream through a six-element mixer results in 8192 emerging layers, giving effective mixing. Pressure drop across each mixer was calculated at 0.015 kg/cm^2 (0.22 psi). Operating pressure of the system is 14.06 kg/cm^2 (200 psi) with a pressure drop of approximately 3.52 kg/cm^2 (50 psi) across the entire system at an 11.4-liter-per-minute (3-gallon) flow rate.

Samples from the reactor sample points were taken into evacuated, 350 ml., polytetrafluorocarbon-lined, stainless steel bombs. The sample valves were Anderson, Greenwood and Company 316 stainless steel, Model M9, gauge valves. They

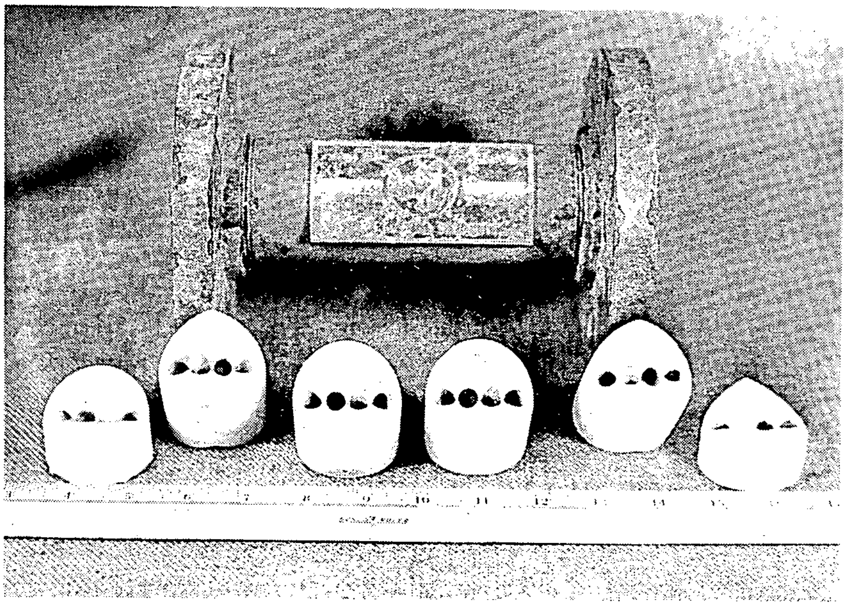

Fig. 4: IGS Static In-Line Mixer manufactured by Charles Ross and Son. Six (6) units illustrated divides a two (2) layer stream into 8192 layers.

have the advantage of low internal volume and a bleed valve to release internal pressure after closure.

An attempt was made to monitor the course of the reaction in reactor R-1 by measuring the oxidation potential of the brine. A silver-silver sulfide electrode and a tantalum reference electrode were installed at each of the five sample points. Potential differences between these electrode pairs were measured and recorded by a Bristol multipoint recording potentiometer. A photograph of the electrode assembly is shown in Figure 5.

Corrosion rates were determined by the polarization admittance instantaneous rate method. Three electrodes are used to give instantaneous corrosion rate readings. They are the reference, test, and auxiliary electrodes. Since corrosion is an electrochemical phenomenon, rates can be obtained by measuring electrochemical potentials, provided the measurement does not itself change that potential. The three electrode assembly as used by the Petrolite system accomplishes this measurement. Probes and the corrosion rate meter are supplied by the Petrolite Corporation, Petreco Division, Houston, Tex. The standard Petrolite equipment with mild steel electrodes was used to measure corrosivity of the reactor discharge stream. A photograph of the probe with electrodes in place is shown in Figure 6.

A modified ring configuration probe was constructed and tried in corrosion rate determination with the objective of

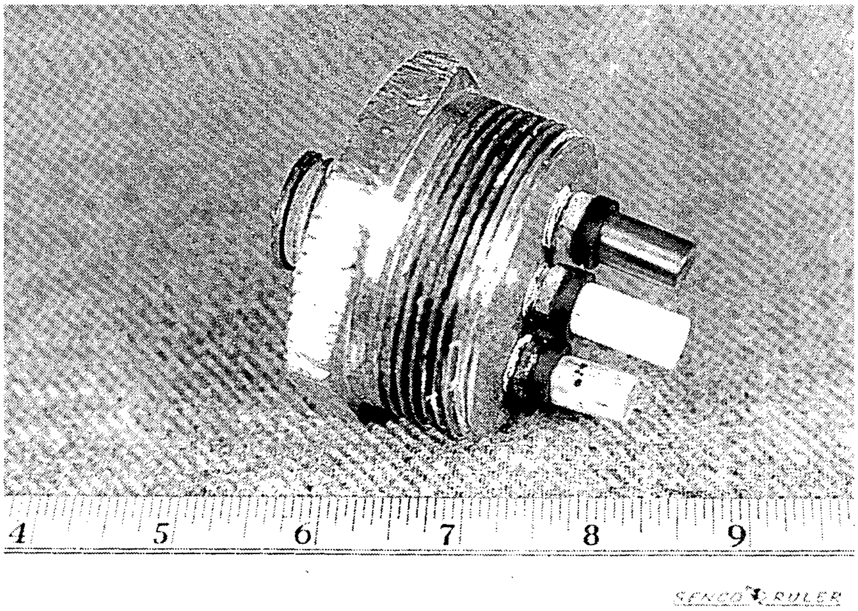

Fig. 5: Photograph of electrode assembly for oxidation potential measurements. Top electrode is tantalum reference and bottom is a silver-silver sulfide working electrode. Middle connection of the Standard Petrolite Holder is masked off with a Teflon plug.

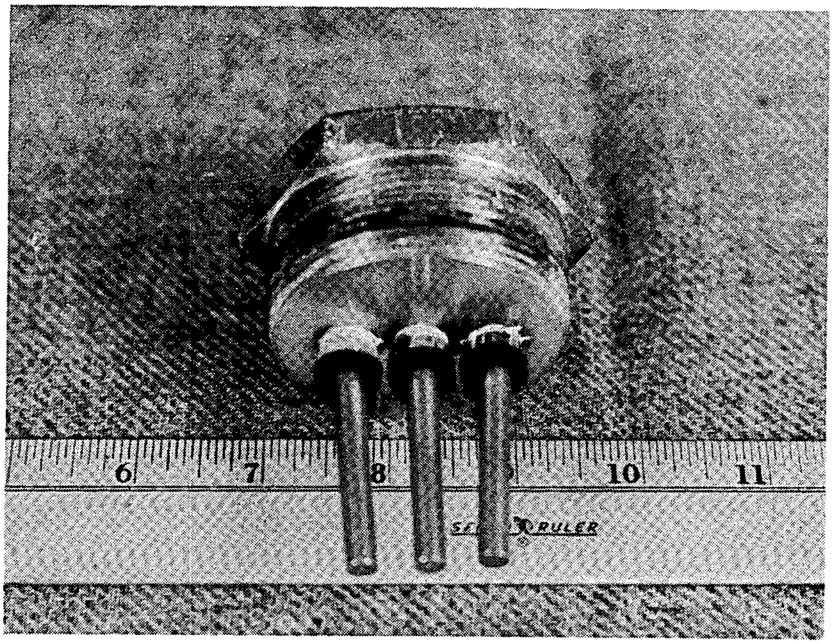

Fig. 6: Photograph of Standard Petrolite Corrosion Rate Probe with three (3) mild steel electrodes in place.

providing an uninterrupted flow path for the brine stream as compared to the Petrolite probes which protrude into the stream. This probe system consisted of three mild steel machined rings with the same internal diameter as the brine-containing pipe. These rings are the three electrodes and are separated by high temperature insulators of the same geometry. The entire assembly is pressed together between two flanges. Rate measurements are made in the usual manner, using the Petrolite instrument. Results compared favorably with those of the standard probes. However, temperature cycling gave enough expansion and contraction to cause excessive leakage around the rings and this approach was abandoned, primarily for safety reasons.

The remainder of the unit consists of a dual flash system for lowering the brine temperature prior to disposal. The first flash vessel, D-6, is pressure and level controlled to drop the temperature to 127°C (260°F). The liquid flow from this vessel enters the second flash chamber, D-7, which operates at atmospheric pressure. The steam from these chambers is condensed in heat exchangers, HX-2 and HX-3. The condensate flows into the Dow waste canal. The brine from D-7 is dumped into the waste canal.

III. EXPERIMENTAL PROCEDURES

Normal experimental procedures consisted of (1) preparation and deaeration of base brine solution, (2) circulation and heating of base brine, (3) adjustment of the injection of additive solutions, (4) injection of oxygen, (5) sampling procedures and analysis of samples and (6) corrosion monitoring. These steps are described in more detail in the following paragraphs.

1. Preparation and Deaeration of Base Brine Solution

A precalculated amount of 26% treated brine is added to the 10,000-gallon tank, D-1. This is diluted with steam condensate to the desired volume. Mixture and deaeration is achieved by circulating through the steam-stripping vacuum deaerator column. Typical final oxygen levels are 15-20 ppb (parts per billion) residual oxygen as determined by a modified Beckman Model 735 Dissolved Oxygen Analyzer and by oxygen analysis using the Winkler method.

Desired cations such as calcium, magnesium, iron, nickel, etc. are added to the solution from cation solution tank, D-2, prior to deaeration. Any ion which will not cause scaling in the heat exchanger, HX-1, may be added at this point. In the case of calcium addition, the sulfate from the treated brine was high enough to cause calcium sulfate scaling in the exchanger. This was avoided by pretreating the brine with barium chloride to partially precipitate the sulfate.

The operation of the deaerator consisted of pumping from D-1 into the top of the tower at a rate of 568 liters per minute (150 gpm) by way of a steam heat exchanger (not shown in Figure 1) which raises the solution temperature to 43°C (110°F). The tower is level controlled and operates with steam stripping at 5 cm. (2 in.) of mercury internal pressure.

2. Circulation and Heating of Base Brine

The prepared and deaerated base brine solution is stored under nitrogen pad in tank D-1. A run is normally initiated by pumping this brine through the system with the CAT positive displacement pump, P-3. The heat exchanger, HX-1, receives the discharge of P-3 and increases the brine temperature to the desired value. Maximum temperature is approximately 177°C (350°F). At this maximum temperature the system operates with a pump pressure of 10.5 kg/cm^2 (150 psi). Flow rates in the system are determined by the diameter ratio of the pump and motor pulleys of P-3. The calculated flow rates for the runs were 11.4 liters per minute (3 gpm) for most of the runs and 7.6 liters per minute (2 gpm) for a few later runs. Actual flow rates based on solution used over extended time periods indicated the calculated values to be within experimental error.

3. Adjustment of the Injection of Additive Solution

Once the base brine flow had been stabilized, injection of the desired anions, including sulfide was begun. The Milton Roy pumps are sized for maximum delivery rates and are adjustable for percent delivery. The actual values were checked by analyses of the brines and the pumps adjusted to give the desired quantities. The 37% hydrochloric acid was injected in the same manner as described for the anions. Samples were taken at several sample points to ensure that no deposition was occurring between the injection points and the exit from the reactor.

4. Injection of Oxygen

The oxygen was injected just prior to entry into the reactor, R-1. The source was medical grade cylinder oxygen. The flow was controlled by a needle valve and monitored by a flow indicator as previously described. The sulfide flow was calculated on the basis of solution flow rate and analysis of sulfide level in the solution. The oxygen addition rate was adjusted to provide the desired oxygen to sulfide mole ratio. The time interval between the oxygen injection and entry into the first pass of the reactor was 5 to 8 seconds, depending upon the solution flow rate.

5. Sampling Procedures and Analysis of Samples

The reactor, R-1, was a five-pass concentric tube design as stated previously. Residence time in each pass was one minute per pass at 11.4 liter per minute (3 gpm) flow rate. There were five analytical sample points, one after each pass. Five redox potential probes were located adjacent to the sample points after each pass with the purpose of measuring oxidation potential of the solution and correlating that potential with the sulfide residual found at those points.

Samples were taken through the sample valves into evacuated, 350-ml., polytetrafluoroethylene-lined bombs. It is recognized that flashing must occur in the initial stage of such a method. However, the final sample is believed to be equilibrated and to represent a true example of the solution. Over an extended period of time no solid residues appeared in the bombs, samples were reproducible and analyses were representative of known values.

The bombs filled almost instantly. The valves were immediately closed and the bomb drenched with cold water from a hose to cool the contents and stop, or at least greatly slow, the reaction. The sample was then taken to the laboratory and analyzed immediately for sulfide content.

The colorimetric methylene blue method was used for sulfide analysis with frequent checks by the Dow Central Analytical Laboratory using more sophisticated methods. Metal ions such as iron and nickel were determined, when desired, by atomic adsorption spectrophotometric methods; and calcium, by chelation titration. Silica was determined by the molybdate colorimetric procedure with Central Laboratory checks. Samples for complete analyses were submitted to the analytical laboratory.

6. Corrosion Monitoring

Corrosivity of the brines is of major importance. The sulfide itself is corrosive; thus its removal should lower the corrosivity of the solution. However, residual oxygen should be even more corrosive than the sulfide. Since geothermal brines are oxygen-free, the goal is the complete removel of the sulfide with no excess oxygen. Thus corrosion rate measurement is important and the corrosivity is an indication of the course and stoichiometry of the sulfide-oxygen reaction.

The Petrolite method as previously described was used to measure corrosion rates. The three pins or electrodes were of ASTM 1018 mild steel. The probe was the M-510 Standard Industrial Probe. With this system the instantaneous corrosion rate is displayed and recorded in mils per year (mpy) by a Petrolite Corrosion Rate Meter Model M-1000.

IV. EXPERIMENTAL RESULTS

1. General Comments

The reaction of hydrogen sulfide with oxygen was found to occur rapidly and completely, indicating this to be a viable method for removing the noxious gas from geothermal waters. The reaction was investigated over a range of temperatures, concentrations, and brine compositions. None of these variables exhibited sufficient influence on the course of the oxidation to detract from its practical use.

The apparatus, as previously noted, was designated to follow the reaction over a five-minute period. Unfortunately, this time span was too long, since completion was generally achieved within the first minute of contact time. This speed is encouraging on the practical side but prohibited meaningful kinetic studies.

Operation of the equipment proved to be troublesome. Many runs had to be made at higher than desirable pH due to failure of the acid pump to deliver. This was especially true in the earlier runs. Eventually the entire working portion of the pump was replaced. This improved the situation. Also, it was often necessary to run with conditions somewhat more or less than desired due to inflexibility of the system. In spite of the difficulties of the complex system, meaningful data was obtained. The details of the experimental results follow.

2. Oxidation Potential Probe Results

It was hoped to follow the course of the reaction by measuring the oxidation potential of the solution. Since the potential should change from reducing in the presence of sulfide to oxidizing in the case of free oxygen, this would appear to be a possible measure of the completeness of the reaction. Probes consisting of silver-silver sulfide working electrodes and a tantalum reference electrode were installed at each of the five sample points.

Data from these probes were quite erratic. Readings were taken on all the runs, and results may be noted in the run data sheets in Appendix A. A group of data points from the first pass or one-minute probe versus analyzed hydrogen sulfide values taken at the same time are plotted in Figure 7. Inspection of this plot indicates a trend toward lower potentials as sulfide levels decrease. However, results were not useful, thus sampling and chemical analysis had to be relied upon.

This method of determining sulfide removal should not be completely discounted. A control system would be necessary at an actual geothermal operation where oxygen injection is used to remove the sulfide. Oxidation potential would be a control measurement. More effort should be spent on a workable reference electrode, since the irreversibility of the tantalum was likely the reason for the inconsistent results in Figure 7. The "Wick" type electrode system using a standard reference electrode should be tried and could be expected to work.

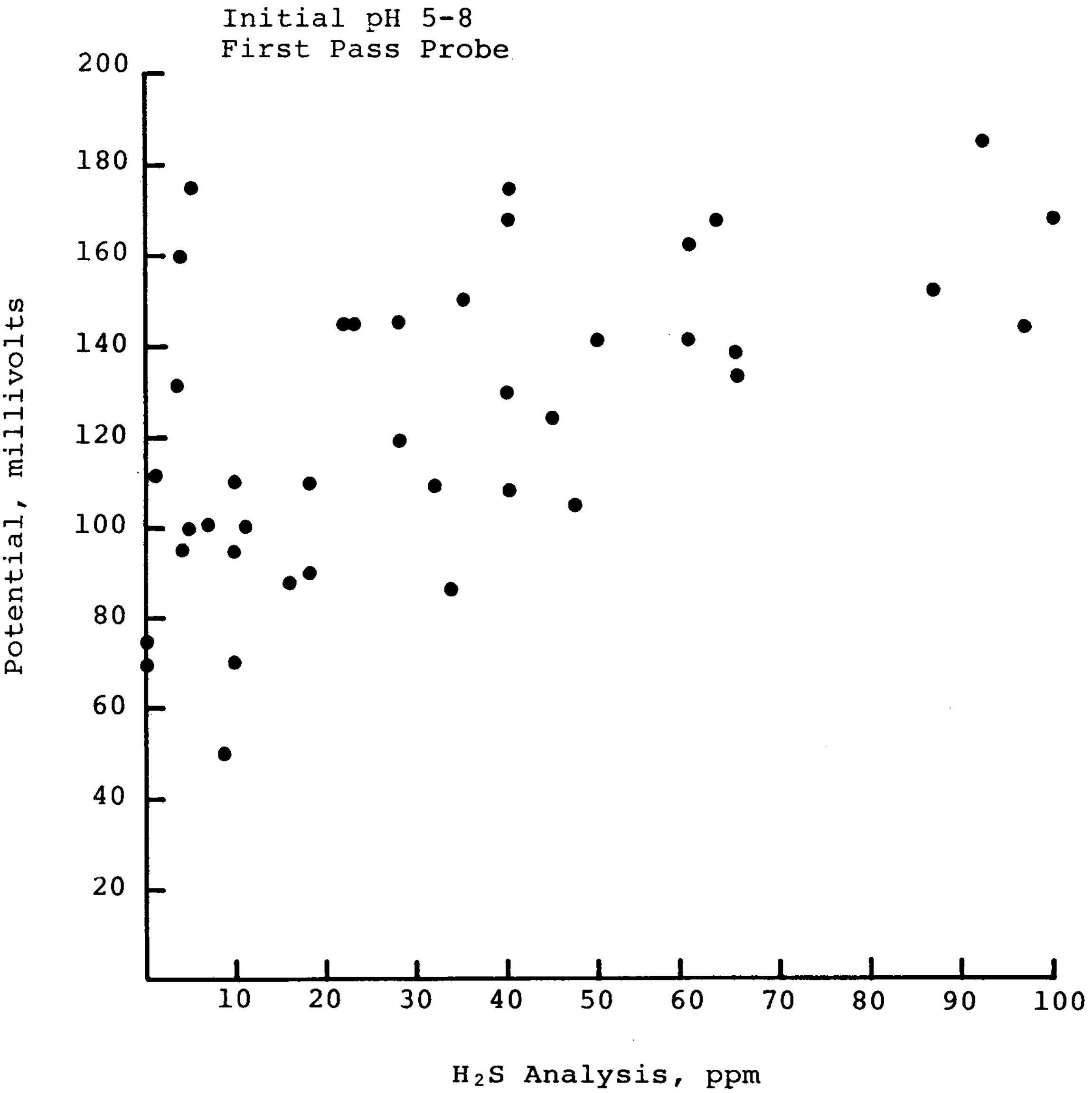

Fig. 7: Correlation of potential readings with hydrogen sulfide analysis.

An alternate approach to a control system would be corrosion measurements since instantaneous corrosion rates as measured in the runs always increased dramatically at the point of excess oxygen. Considerably more investigation would be required, however, since low corrosion rates are essential to avoid costly materials of construction.

3. Stoichiometry of the Oxidation Reaction

Several reactions and end products are possible in the reaction of sulfide with oxygen. These were discussed in Section I. The reaction:

$$2HS^- + 3O_2 \rightarrow 2SO_3^{-2} + 2H$$

gives a ratio of three moles of oxygen to two moles of sulfide or hydrogen sulfide. That ratio is the lowest oxygen level to give complete removal. The stoichiometry for maximum oxygen requirements would be 2:1 mole ratio or

$$H_2S + 2O_2 \rightarrow H_2SO_4$$

It would follow that 100% removal at some point between 1.5:1 and 2:1 oxygen:sulfide mole ratio could be expected since all possible reactions should occur simultaneously.

In actual experiments most runs showed complete sulfide oxidation at a 1.5:1 mole ratio. In these runs, the reaction was far toward completion (greater than 80%) at 1:1 mole ratio. Thus it would appear that some simpler reaction such as:

$$S^= + 1/2O_2 + H_2O \rightarrow S + 2OH \quad \text{(0.5:1 mole ratio)}$$

$$S^= + O_2 + H_2O \rightarrow H_2SO_3 \quad \text{(1:1 mole ratio)}$$

must occur.

An attempt was made to determine the end products of the oxidation at various oxygen-sulfide mole ratios. These results are shown in Table 3. More free sulfide formed at the lower (1:1 and 1.25:1) ratios. Less sulfate and more sulfite were also formed at these same lower levels as would be expected. At 1.5:1 mole ratio, sulfite was low; and most of the remainder was sulfate. The sulfide levels at the 1:1 and 1.25:1 mole ratios gave lower than expected residual sulfide values. However, these delayed analytical results checked well with sulfide analysis of the same samples made immediately after the sample was taken and are believed to be valid.

All applicable runs were examined for completeness of sulfide oxidation at the mole ratios of 0.5:1 to 2:1 used. The data are listed in Table 4. These runs include hydrogen sulfide levels from 23 to 205 ppm with the intent of evaluating any influence of sulfide level on the removal efficiency. Results from three selected sulfide levels are plotted in Figure 8. Inspection of the three curves indicate little difference in the oxidation at hydrogen sulfide starting values between 40 and 100 ppm.

A further examination of the influence of initial sulfide level is shown in Figure 9 where the percent removal at 1:1 mole ratio is plotted against initial level ranging from 20 to 140 ppm. The removal values generally ranged from 65 to 100% but initial sulfide level had no effect.

A plot of the entire scope of sulfide levels at 140 ppm and lower versus oxygen:hydrogen sulfide mole ratio is shown in Figure 10. Again the reaction appears to follow a similar pattern and approach completion at 1.5:1 mole ratio.

Table 3

Conversion of Sulfide to Sulfate, Sulfite, and Free Sulfur At Various Oxygen:Sulfide Mole Ratios

Oxygen:Sulfide Mole Ratio	Reaction Time (min)	Initial Sulfide (ppm)	Sulfate (%)	Sulfite (%)	Free Sulfur (%)	Residual Sulfide (%)
1:1	1	101	69.3	10.9	18.8	1.0
1:1	3	117	71.8	7.7	19.6	1.0
1:1	5	79	70.9	7.9	19.0	2.7
1.25:1	1	98	77.6	7.1	12.2	3.3
1.25:1	3	100	59.0	7.0	33.0	0.5
1.25:1	5	104	92.3	--	6.7	1.0
1.5:1	1	94	84.0	3.2	11.7	0.5
1.5:1	3	93	93.5	1.0	5.4	0.0
1.5:1	5	81	75.3	7.4	17.3	0.0

Table 4

Data Grouped by Oxygen:Hydrogen Sulfide Mole Ratio

Temperature 350°F

Run No.	Initial H_2S (ppm)	Initial pH	Mole Ratio $O_2:H_2S$	Final H_2S (ppm)	H_2S Removal (%)
8A	40	7.1	2:1	1	100
7	40	11.0	"	2	100
25B*	44	9.5	"	27	39
29B	49	9.0	"	1	100
20B	50	11.8	"	1	100
16A	55	7.1	"	0	100
24B**	63	6.5	"	0	100
10B	67	11.3	"	0	100
22B*	72	11.2	"	4	95
13A	23	8.1	1.5:1	0	100
27B	38	8.6	"	0	100
22A	40	8.5	"	0	100
20A	50	11.8	"	10	80
34C	50	8.7	"	2	95
33C	60	11.3	"	6	90
11B	65	8.3	"	1	100
17B	88	11.0	"	0	100
28	92	6.6	"	9	90
30B	97	9.1	"	1	99
35B	97	9.4	"	1	99
14B	97	7.7	"	0	100
36A	120	11.0	"	1	99
45D	107	8.4	"	0	100
48E	103	7.1	"	0	100
50D	93	6.2	"	0	100
51D	100	5.2	"	0	100
34B	40	8.7	1.25:1	8.5	83

Table 4

(Continued)

Run No.	Initial H_2S (ppm)	Initial pH	Mole Ratio $O_2:H_2S$	Final H_2S (ppm)	H_2S Removal (%)
32B	60	8.9	1.25:1	5	91
33B	60	11.3	"	8	88
38B	60	9.0	"	0	100
43C	83	8.3	"	1	99
31C	87	9.0	"	5	94
35C	97	9.4	"	10	90
40C	108	8.8	"	3	97
37C	100	9.0	"	1	99
39B	110	7.8	"	0	100
36B	120	11.0	"	12	90
45C	107	8.4	"	5	95
46C	112	7.9	"	8	93
47C	112	8.3	"	0	100
48D	103	7.1	"	0	100
50C	93	6.2	"	0	100
51C	100	5.2	"	12	88
12	20	9.3	1:1	2	90
13B	22	8.9	1:1	1	96
27C*	38	6.3	"	4	90
26**	40	8.6	"	7	82
3	40	11.1	"	0	100
23*	42	11.2	"	4	90
25C***	44	9.5	"	26	40
19	48	11.0	"	7	85
29A	49	9.0	"	11	79
18*	49	9.3	"	0	100
34A	50	8.7	"	16	68
6	52	9.5	"	1	98
16B	57	8.5	"	9	84

Table 4
(Continued)

Run No.	Initial H_2S (ppm)	Initial pH	Mole Ratio $O_2:H_2S$	Final H_2S (ppm)	H_2S Removal (%)
15	60	9.0	1:1	7	88
33A	60	11.3	"	14	77
9	60	10.2	"	11	82
24A	63	6.5	"	14	82
11A	65	7.5	"	5	92
10A	67	11.3	"	20	70
22A	72	11.2	"	18	75
43B	83	8.3	"	17	80
17A	88	11.0	"	12	86
14A	97	7.7	"	14	86
30A	97	8.6	"	10	90
35A	97	9.4	"	24	75
37D	100	9.0	"	11	89
40B	108	8.8	"	28	74
39A	110	7.8	"	8	93
44B	140	5.9	"	0	100
41	170	8.2	"	1	99
42A	205	7.9	"	0	100
45B	107	8.4	"	27	75
46B	112	7.9	"	22	80
47B	112	8.3	"	8	93
48C	103	7.1	"	3	97
49C	85	5.3	"	14	84
50B	93	6.2	"	9	90
51B	100	5.2	"	24	76
5	35	8.2	0.75:1	9	75
32A	60	8.9	"	25	58
38A	60	8.7	"	29	52
43A	83	8.3	"	48	43
31B	87	9.0	"	38	57

Table 4
(Continued)

Run No.	Initial H_2S (ppm)	Initial pH	Mole Ratio $O_2:H_2S$	Final H_2S (ppm)	H_2S Removal (%)
37B	100	9.0	0.75:1	32	68
37A	100	6.2	"	20	80
40A	108	8.8	"	28	74
44A	140	8.7	"	48	66
42B	205	7.9	"	9	96
45A	107	8.4	"	40	63
46A	112	7.9	"	51	53
47A	112	8.3	"	35	69
48B	103	7.1	"	24	77
49B	85	6.1	"	29	66
50A	93	6.2	"	30	68
51A	100	5.2	"	30	70
4	40	6.2	0.5:1	9	79
31A	87	9.0	"	50	42
48A	103	7.1	"	47	54

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* 250°F

** 207°F

*** 160°F

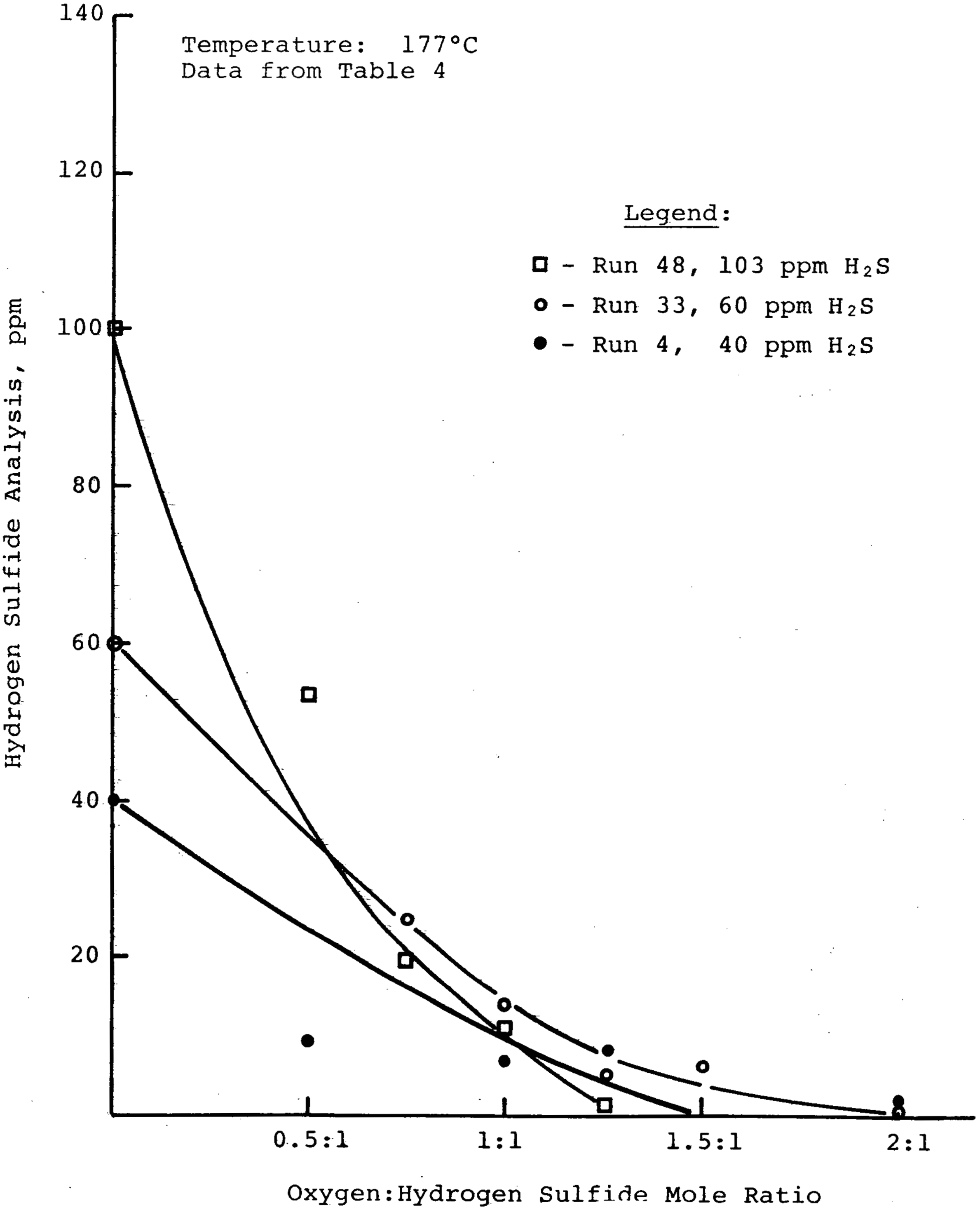


Fig. 8: Hydrogen sulfide concentration as a function of oxygen mole ratio added, selected hydrogen sulfide levels.

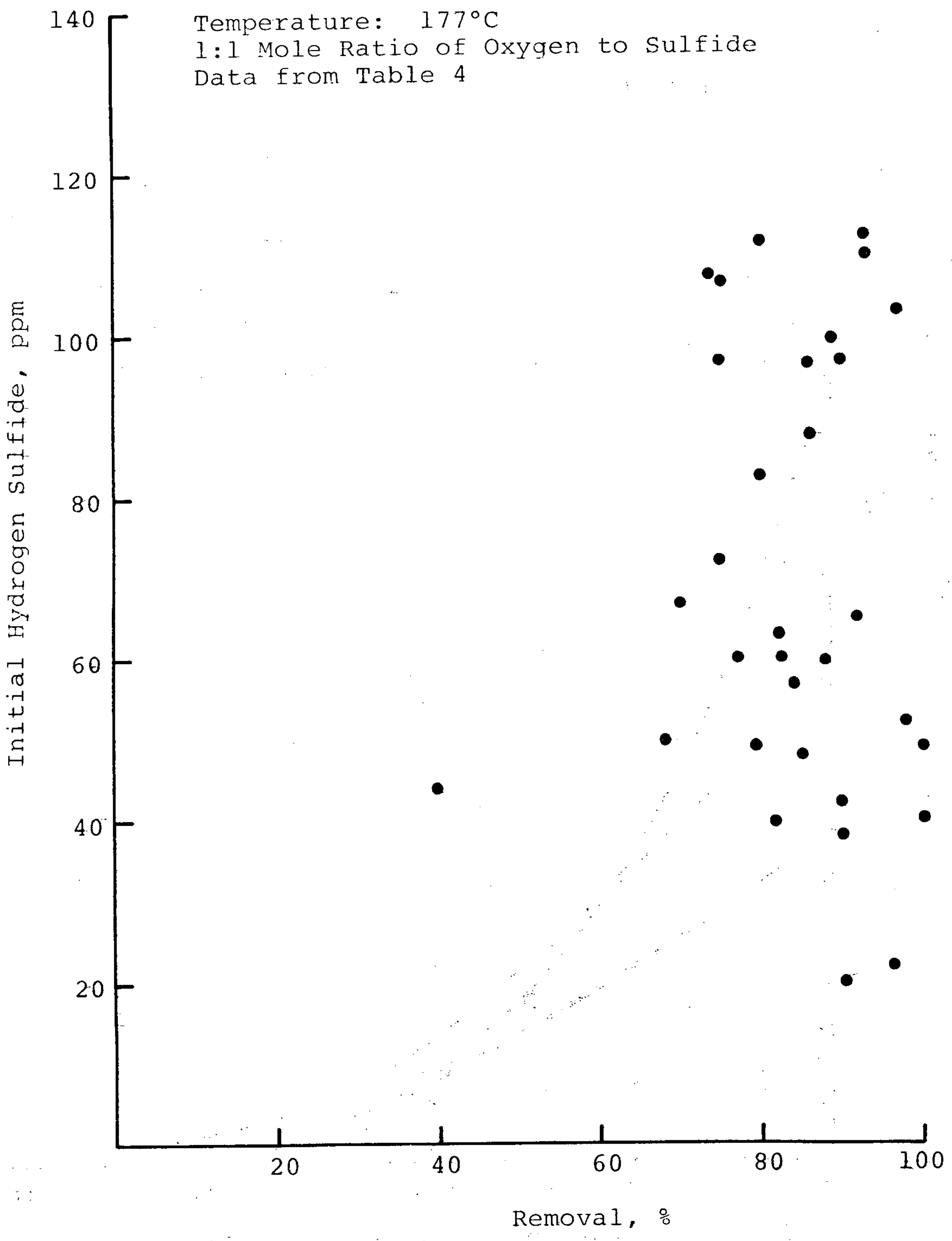


Fig. 9: Percent removal of hydrogen sulfide as a function of initial sulfide concentration.

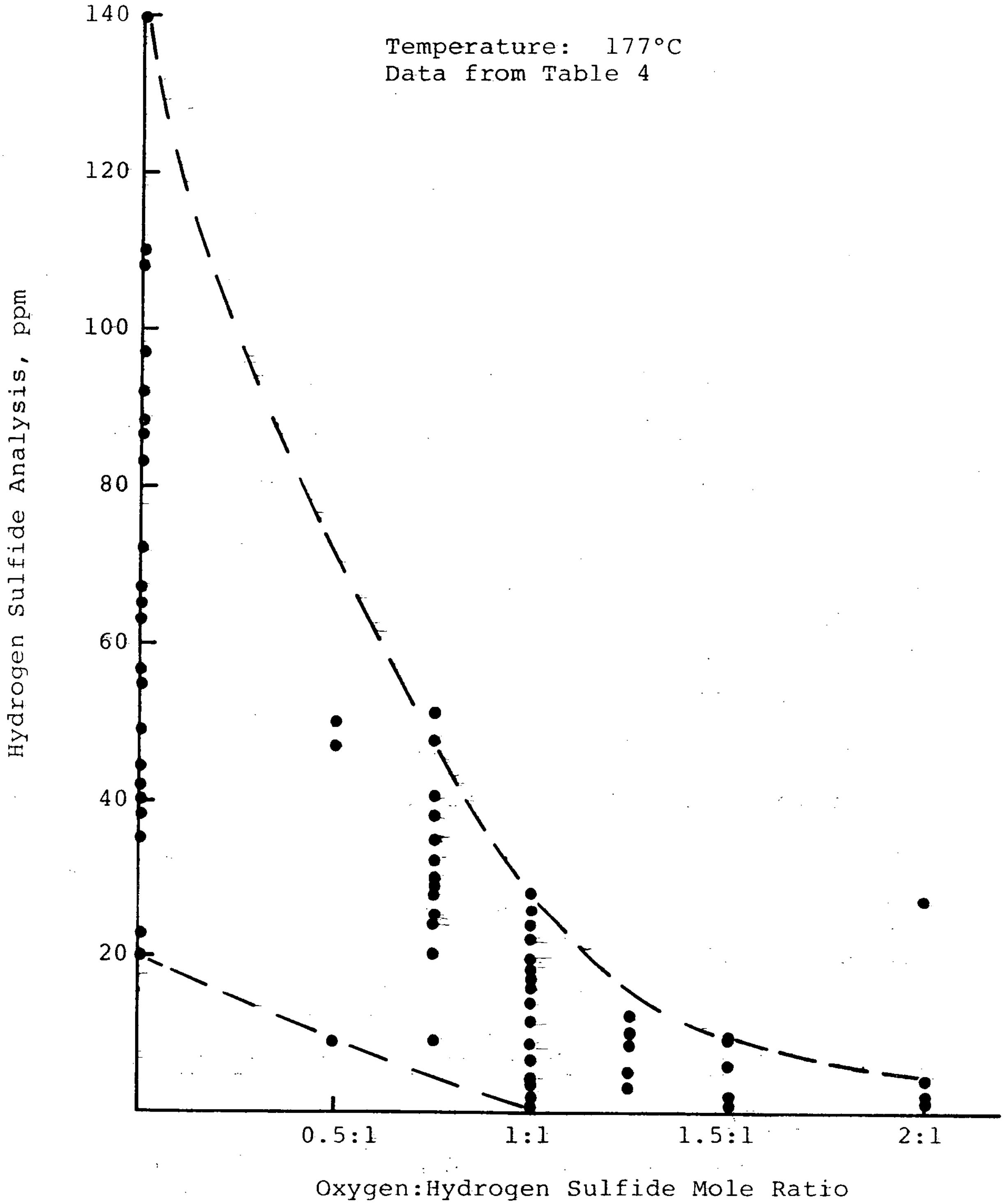


Fig. 10: Hydrogen sulfide concentration as a function of oxygen, mole ratio added.

4. Temperature Dependence of the Reaction

Temperature would be expected to influence the reaction rate but to have little or no effect upon the stoichiometry. Runs were made at the maximum obtainable temperature of 177°C down to a lowest level of 71°C on the assumption that this would be the lowest level of interest in geothermal water useage. The results of three selected runs are shown in Table 5 and plotted in Figure 11.

The values indicate that at a 1:1 mole ratio the reaction at 121°C still proceeds to completion in less than one minute. However, the percent sulfide removed is somewhat less (75% versus 86%) at the lower temperature. At 71°C, the reaction becomes slow enough to obtain some degree of measurement, taking four minutes to reach completion. The percent removal also falls to 61%.

These data would indicate no temperature dependence problem for most geothermal waters. The variation in sulfide removal at the 1:1 mole ratio is evidence that several different reaction paths are possible and that these reactions are temperature dependent.

5. Dependence of the Reaction on Initial pH of the Geothermal Water

Some variation of pH is to be expected between different geothermal waters. The oxidation rate of sulfide in water is reported to be accelerated by higher pH values. Runs were made to examine this effect. As previously noted, some

Table 5

Hydrogen Sulfide Removal at Various Temperatures

			pH				% Hydrogen Sulfide Removed with Contact Time				
Run No.	Salinity, TDS	Temp., °C	Initial	Final	O_2:H_2S Mole Ratio	Initial H_2S (ppm)	1 min.	2 min.	3 min.	4 min.	5 min.
29A	30,000	177	9.2	9.0	1:1	49	87.6	87.6	71.6	71.6	87.6
22A	32,000	121	11.2	11.0	1:1	72	75.0	75.0	76.4	73.6	73.6
25A	31,000	71	9.5	11.0	1:1	44	9.1	18.2	50.0	61.4	61.4

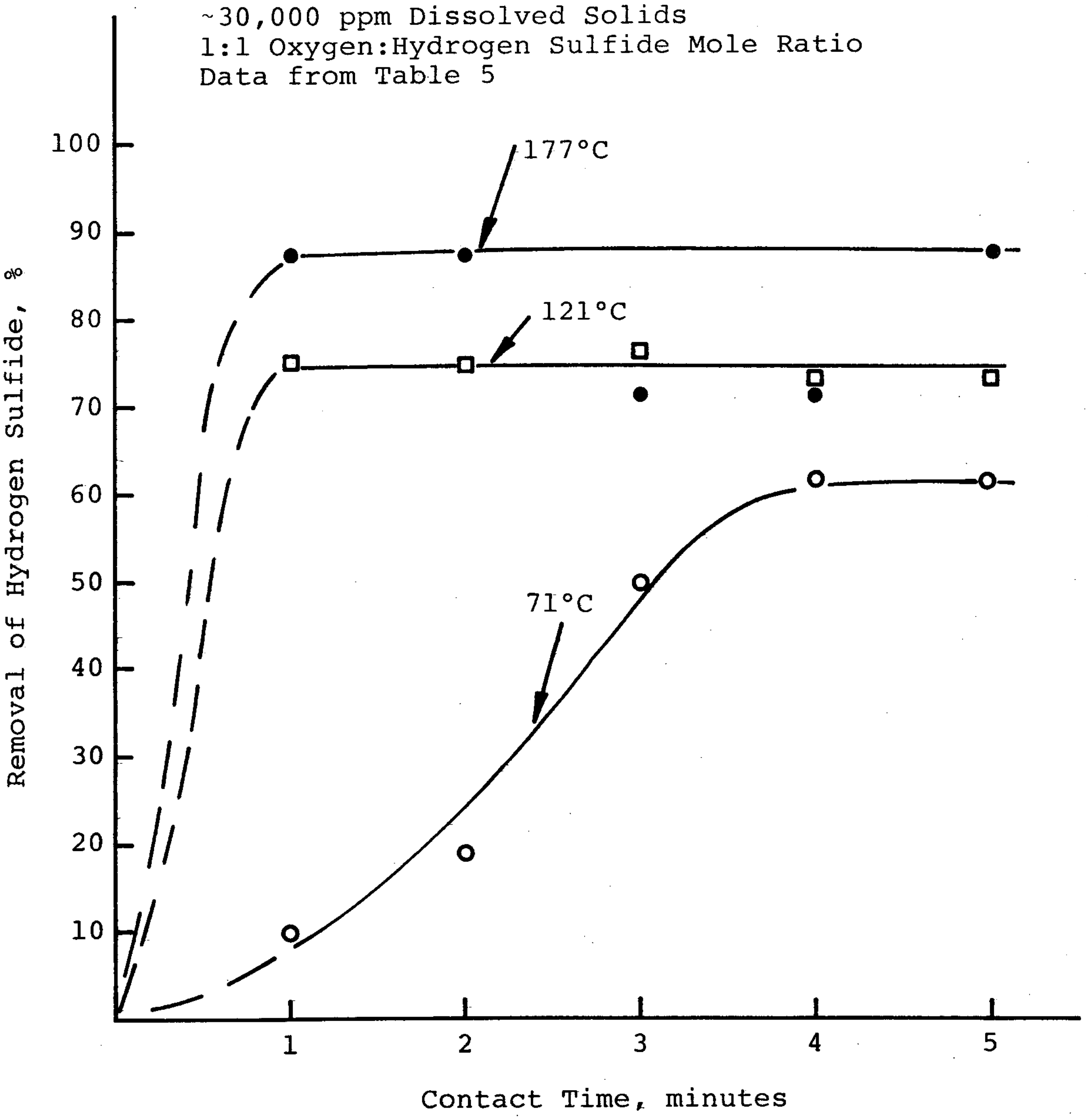


Fig. 11: Hydrogen sulfide removal as a function of temperature.

pH values were higher than intended due to acid pump failures. The resulting range of pH for the runs was 5.2 to 11.3. The sulfide levels ranged from 22 to 103 ppm.

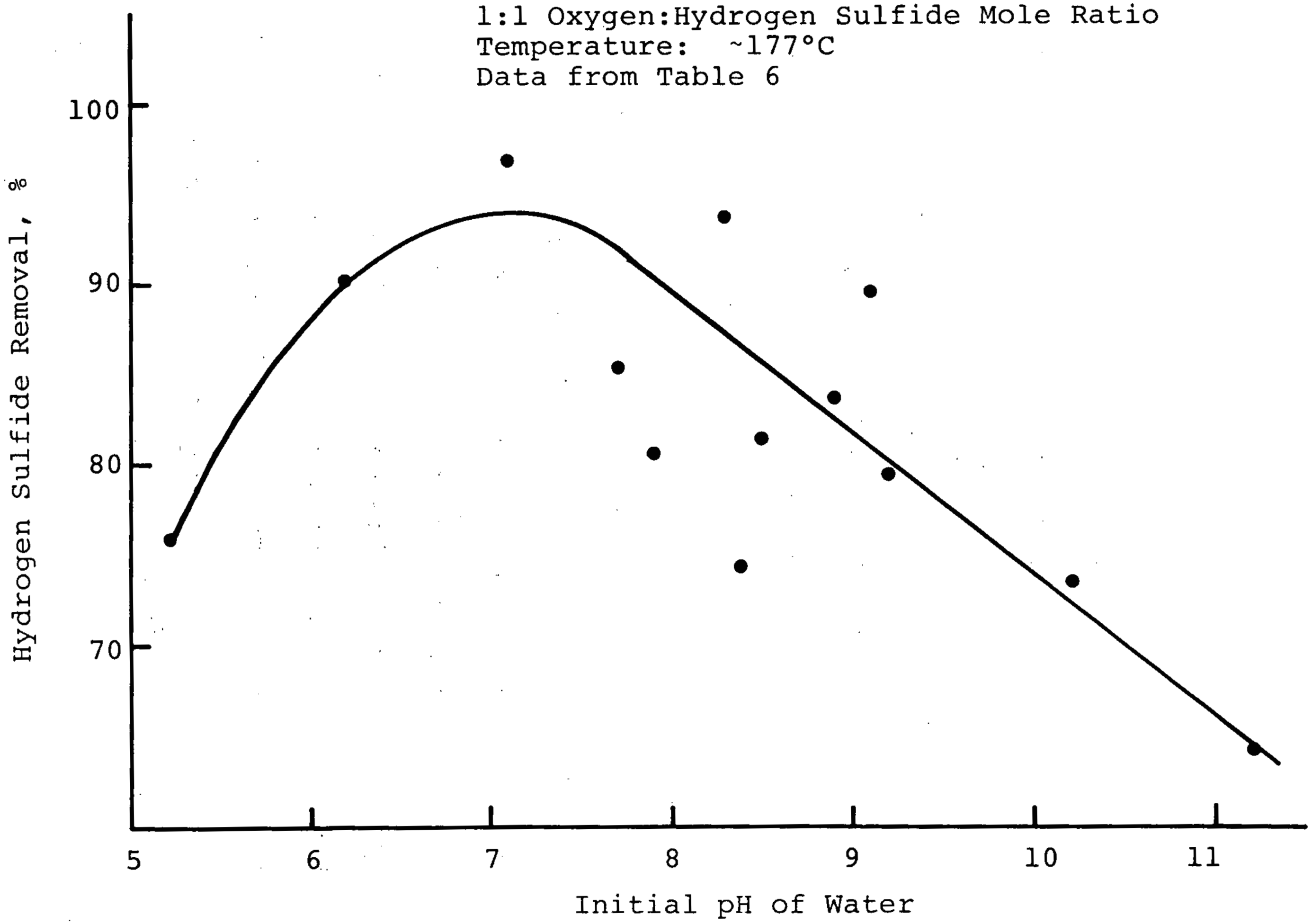
The data from these runs are tabulated in Table 6. The mole ratio of oxygen used was 1:1 since the removal was essentially complete at 1.5:1 at all pH levels. Figure 12 is a plot of percent removal at 1:1 mole ratio and various pH levels. This plot does indicate a pH dependence. The reaction removes the highest percent of the hydrogen sulfide at near neutral or pH 7. Both higher and lower pH results in somewhat less complete removal. There was quite a scatter of data points and this conclusion may be subject to some question. However, the difference is only from 75% to 95% removal and addition of stoichiometric amounts of oxygen gives complete removal at all pH values.

It is notable that oxidation of the sulfide reduced the pH in almost all runs. The presence of carbonate and silicate tended to buffer the solution so the drop in pH was less noticeable at the low sulfide levels. However, at 50 ppm to 100 ppm hydrogen sulfide, complete oxidation resulted in a drop of as much as two pH units. This was especially true in the near neutral pH area of 6 to 8 where part or all of the carbonate is in the bicarbonate form. This decrease in pH was apparently due to the formation of sulfuric acid through the oxidation of sulfide to sulfate.

Table 6

Hydrogen Sulfide Removal at Various Brine pH Levels

Run No.	Salinity, TDS	Temp., °C	pH		O_2:H_2S Mole Ratio	Hydrogen Sulfide Analysis with Contact Time, ppm						
			Initial	Final		Initial	1 min.	2 min.	3 min.	4 min.	5 min.	% Removal
9	31,000	177	10.2	9.0	1:1	60	12	13	17	15	16	73.3
16A	30,000	177	11.3	11.2	1:1	67	22	22	24	22	24	64.2
29A	30,000	177	9.1	9.0	1:1	49	11	11	9	9	11	79.6
30A	30,000	175	9.1	8.7	1:1	97	11	11	10	9	10	89.7
14A	30,000	176	7.7	6.0	1:1	97	18	17	16	16	16	85.5
16B	30,000	177	8.5	6.0	1:1	57	11	11	12	13	11	81.7
13B	30,000	178	8.9	5.2	1:1	22	4	4	4	4	3	86.4
48A	31,000	177	7.1	5.8	1:1	103	3	3	3	4	3	97.1
45B	40,000	176	8.4	6.5	1:1	107	30	--	29	--	27	74.8
46B	40,000	176	7.9	6.5	1:1	112	18	--	21	--	22	81.3
47B	28,000	176	8.3	6.2	1:1	112	6	--	7	--	8	93.8
50B	31,000	176	6.2	5.7	1:1	93	8	8	9	8	10	90.3
51B	31,000	176	5.2	2.3	1:1	100	22	23	24	--	24	76.0



1:1 Oxygen:Hydrogen Sulfide Mole Ratio
Temperature: ~177°C
Data from Table 6

Fig. 12: Hydrogen sulfide removal as a function of brine pH.

6. Effect of Dissolved Solids and Addition of Catalytic Agents

Influence of total dissolved solids was studied on the assumption that trace metals which might catalyze the reaction were very likely present in the salt dome brine used as the source of salt. The span of concentrations ranged from 131 ppm to 112,000 ppm TDS (total dissolved solids). The data for these runs are tabulated in Table 7.

Curves of percent removal versus oxygen:sulfide mole ratio for four TDS levels are shown in Figure 13. The data are again somewhat scattered; but there is a definite indication that, other factors remaining constant, the reaction proceeds further toward completion as the TDS increases. The analyzed composition of the 131-TDS water is given in Table 8.

The question of composition could be best answered by examination of reaction rates at various TDS levels. However, the reactions occurred too rapidly in all cases for the sampling system to gather this data. It does appear that some catalytic agents were present. Since multivalent cations are known to catalyze the oxidation of sulfide ion cations, it would be expected that geothermal waters would contain in situ catalysts to support the reaction.

Runs were made with added known catalyst. Run number 15 contained 10 ppm added ferric ion in the form of ferric chloride of which less than 1 ppm actually carried through to the sample point. Runs number 47A, B, and C contained

Table 7

Hydrogen Sulfide Removal at Various Dissolved Solid Levels

Run No.	Salinity, TDS	Temp., 0°C	pH Initial	pH Final	O_2:H_2S Mole Ratio	Initial H_2S (ppm)	% Removal
31A	30,000	177	9.0	--	0.5:1	87	42.5
30A	30,000	175	9.1	8.7	1:1	97	89.7
30B	30,000	175	9.1	8.6	1.5:1	97	100
31C	30,000	177	9.0	8.9	1.25:1	87	91.9
35A	131	177	9.4	7.4	1:1	97	75.3
35C	131	177	9.4	6.9	1.25:1	97	89.7
35B	131	177	9.4	4.7	1.5:1	97	100
37A	52,000	176	6.2	4.0	0.75:1	100	84
37D	52,000	177	9.0	8.3	1:1	100	88
37C	52,000	176	9.0	6.1	1.25:1	100	100
43A	66,000	177	8.3	--	0.75:1	83	44.6
44A	66,000	177	8.7	--	0.75:1	140	63.6
43B	66,000	177	8.3	--	1:1	83	80.8
44B	66,000	177	8.7	--	1:1	140	100
43C	66,000	177	8.3	--	1.25:1	83	100
39A	84,000	177	8.8	7.8	1:1	110	95.5
39B	84,000	177	8.8	--	1.25:1	110	100
40A	112,000	177	8.8	--	0.75:1	108	73.1
40B	112,000	177	8.8	--	1:1	108	86.1
40C	112,000	177	8.8	--	1.25:1	108	100

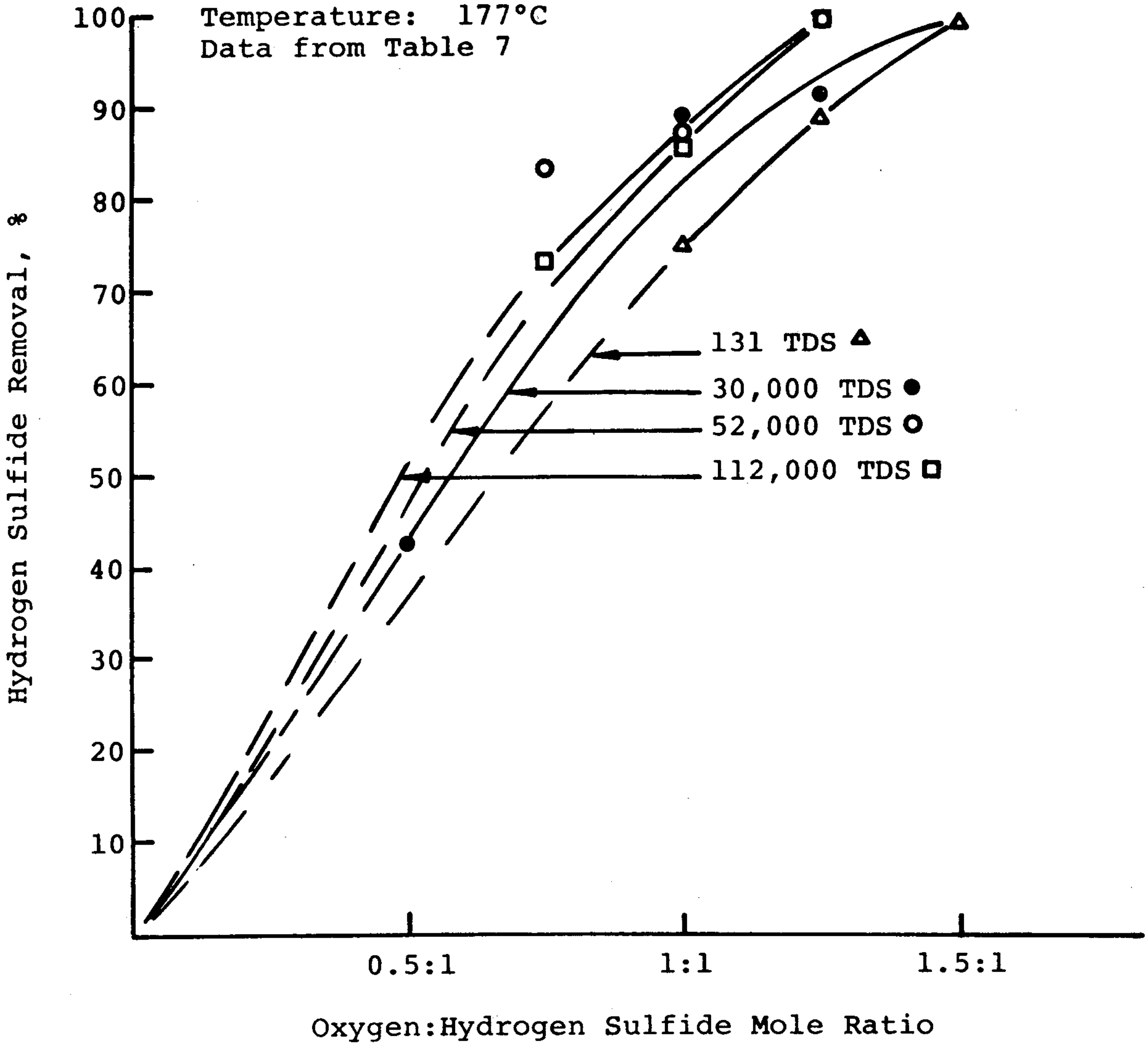


Fig. 13: Hydrogen sulfide removal at various dissolved solids levels and oxygen:hydrogen sulfide mole ratios.

Table 8

Complete Analysis of 131 ppm Water Used in Runs 33 through 36

	Water from Blank Runs 9-10-76	
Nickel (Ni), ppm	<0.1	0.03 est.
Iron (Fe), ppm	0.4	
Copper (Cu), ppm	<0.1	0.04 est.
Chromium (Cr), ppm	<0.1	0.02 est.
Calcium (Ca), 00m	0.4	
Magnesium (Mg), ppm	0.8	
Carbonates (CO_3), ppm	3.4	
Sodium (Na), ppm	42	
Potassium (K), ppm	0.2	
Sulfates (SO_4), ppm	2.0	
Silica (SiO_2), ppm	1.2	
Chlorides (Cl), ppm	62	
TOTAL SOLIDS, ppm	131	

10 ppm each of added nickel ion in the form of nickelous chloride. However, by analysis of samples, only 1 ppm nickel actually carried through the entire system. Results of these runs showed no truly identifiable difference from runs without additives. The nickel runs did reach 100% removal at 1:1 mole ratio but some noncatalytic runs showed the same result. It is believed that no catalyst addition will be required.

Ammonia is a common component of geothermal waters. Runs 45A, B, C, and D plus Runs 46A, B, and C were made with 55 ppm ammonia added. Results of these runs were normal, indicating no oxygen demand from the ammonia and no interference in the sulfide reaction.

7. Results of Corrosion Measurements

Corrosivity, as previously noted, was measured by the Petrolite Instantaneous Corrosion Rate method. The rates are those for mild steel. This method has the disadvantage that some period of time is desirable to condition the steel electrodes in the solution being tested. Generally, the runs were of four to six hours' duration. This is a short time in terms of electrode conditioning. Many of the early runs gave erratic corrosion rates for this reason. In later runs, after run No. 30, care was taken to use freshly prepared electrodes; and it is believed that these results are reliable.

Corrosion appeared to be a function of three factors:

a. pH
b. Sulfide
c. Oxygen

At high sulfide levels and relatively high (8 or above) pH, corrosion rates were of the order of 20 to 40 mils per year (mpy). As oxygen was added, the sulfide level fell and corrosivity decreased. At the point of complete sulfide removal, excess oxygen began to be present and corrosivity increased dramatically, often to as high as 200 mpy at 2:1 mole ratio. A typical curve of corrosivity variation with oxygen addition is shown in Figure 14.

As previously noted, pH levels below 7 will increase corrosion rates of mild steel. For waters poorly buffered with carbonates, silicates, or borates, the decrease in pH as the sulfide is oxidized to sulfate may reverse the downward trend in corrosion rates. In these cases, the curve in Figure 14 would not go through a minimum but could show a continuous increase in corrosion with the dramatic increase as free oxygen becomes available. This type of water would be the exception, however. For normal geothermal fluids, the removal of hydrogen sulfide by this oxidation method should actually result in lower corrosion rates, provided careful control is maintained to avoid excess oxygen.

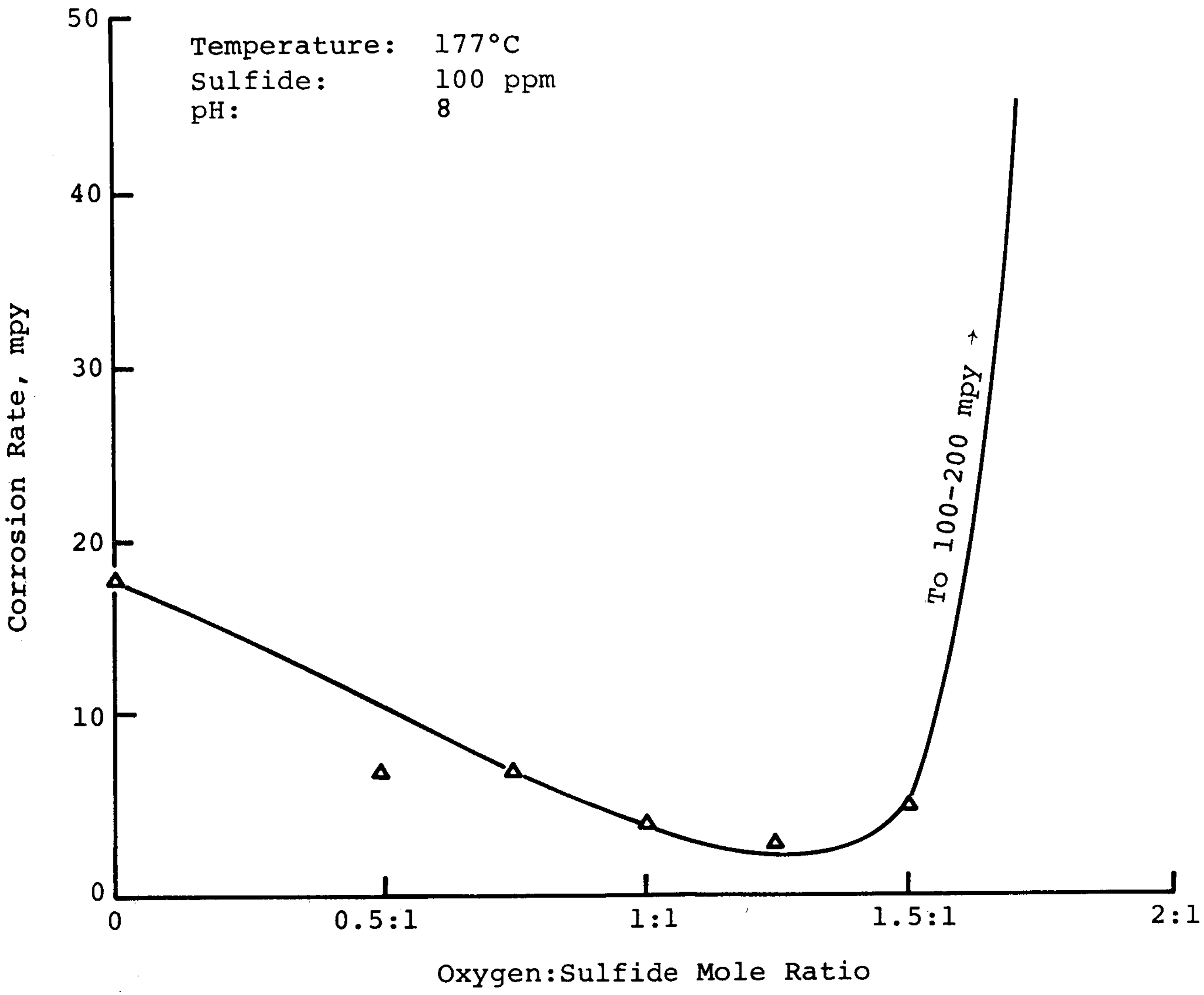


Fig. 14: Corrosion rate change with hydrogen sulfide oxidation.

V. CONCLUSIONS

The injection of oxygen into a hydrogen-sulfide-containing stream of hot simulated geothermal water does rapidly and completely oxidize the sulfide. The products of this oxidation are primarily sulfate ion with small amounts (10% to 25%) of free sulfur and even smaller quantities of sulfite ion. The ratio of the three products varies with temperature and oxygen:sulfide mole ratio. Higher oxygen ratios lead to higher sulfate as would be expected.

The reaction goes rapidly, being complete within one minute or less at temperatures above 100°C and oxygen:sulfide ratios of 1.25:1 to 1.5:1. This reaction rate was achieved with thorough mixing and turbulent flow. Reaction kinetics were independent of initial sulfide levels up to 205 ppm.

The reaction rate was not appreciably altered by the addition of ferric iron or nickel ions. Increasing total dissolved solids in the simulated brine appeared to promote completeness of the oxidation at lower oxygen ratios. Traces (less than one ppm) of catalytic metallic ions in the brine apparently catalyze the reaction. Natural geothermal fluids would be expected to contain these cations.

Corrosivity to mild steel increased as initial sulfide level increased. Oxidation of the sulfide generally lowered the corrosivity up to the point where removal was 90 to 100% complete. Further oxygen addition gave increasing corrosion rates becoming grossly excessive at the point of excess oxygen or beyond the 1.5:1 oxygen:sulfide ratio.

The oxidation of the sulfide produces sulfate as the principal product. This sulfate, as sulfuric acid, lowers the pH. In waters poorly buffered by weak anions, such as carbonate and silicate, this decrease in pH could be sufficient to produce acidic corrosion, reversing the decrease due to sulfide removal and actually resulting in an increase in corrosivity at the point of complete sulfide removal. However, it is believed that such waters would not be typical of geothermal fluids.

The injection of oxygen appears to be a viable method of eliminating the hydrogen sulfide problem in flowing geothermal waters. Further investigation in actual geothermal brines and in two-phase steam-water mixtures appears justified.

VI. PROCESS DESIGN AND COST ESTIMATE

1. Process Conditions

Based on the data from the three gpm pilot plant, a process applicable to a 1000-gpm well was designed and a preliminary cost estimate completed. The conditions used for calculation were:

a. 1000 gpm flow
b. 350°F
c. 150 psi pressure
d. One-phase (liquid)
e. 40 ppm H_2S
f. 1.25:1.0 oxygen:hydrogen sulfide mole ratio

It was assumed that the process unit would be located at or near the well head with the purpose of providing a less corrosive fluid to the field collection piping. Automatic operation was provided with the measured corrosion rate being the controlling signal for the addition of oxygen.

2. Process Design

The results of three gpm pilot plant indicate that thorough contact between the oxygen and the brine is necessary to achieve rapid, complete oxidation. This was accomplished in the small pilot plant by the use of Ross Engineering Co. ISG mixers.

The largest standard available size IGS mixer has a six-inch inside diameter. Thus when considering this type of contacting system for the 1000 gpm flow, the pressure drop across the mixer becomes significant. Alterations in the mixing design are necessary to decrease the pressure drop. This is accomplished by using 10 mixers in parallel and resulting 100 gpm through each mixer. With this system, the pressure drop is limited to a much more realistic 3 to 6 psig.

Designing a full-flow system in this way has disadvantages. The mixers are expensive and require extensive duplication of the instrumentation. This is to insure that each mixer is removing the sulfide. Another disadvantage to this system is the large surface area involved in splitting the one stream into 10 streams. This is a potential site for excessive heat loss or scaling. This particular design is the basis for Case I in the cost estimate (Table 9) and is shown in Figure 15.

In describing the major pieces of equipment used in this process, it is evident that there is a great deal of instrumentation in this particular system. There are 10 magnetic flowmeters to measure the flow of the liquid. This provides a signal to the flow controller in the geothermal brine stream, to insure that each of the streams are getting equal amounts of brine, and to the flow controller on the oxygen line to control the amount of oxygen added to the brine stream. The source of oxygen is a cryogenic oxygen tank which feeds an oxygen compressor, which then pressures the oxygen stream up into the brine. After the

Table 9

Capital Cost Summary

	Case I	Case II
Equipment	$ 42,600	$ 67,400
Piping	67,000	18,900
Instruments	114,000	21,750
Cryogenic O_2	5,200	5,200
Electrical	2,700	1,800
Painting	1,250	950
Insulation	5,500	5,500
Compressor	40,000	40,000
TOTAL JOB COST	$278,250	$161,500
Engineering (15%)	42,000	24,200
Contingencies (15%)	42,000	24,200
PROJECT INSTALLED COST	$362,250	$209,900

Notes:

1. Compressor cost includes cooling requirement, labor and foundations.

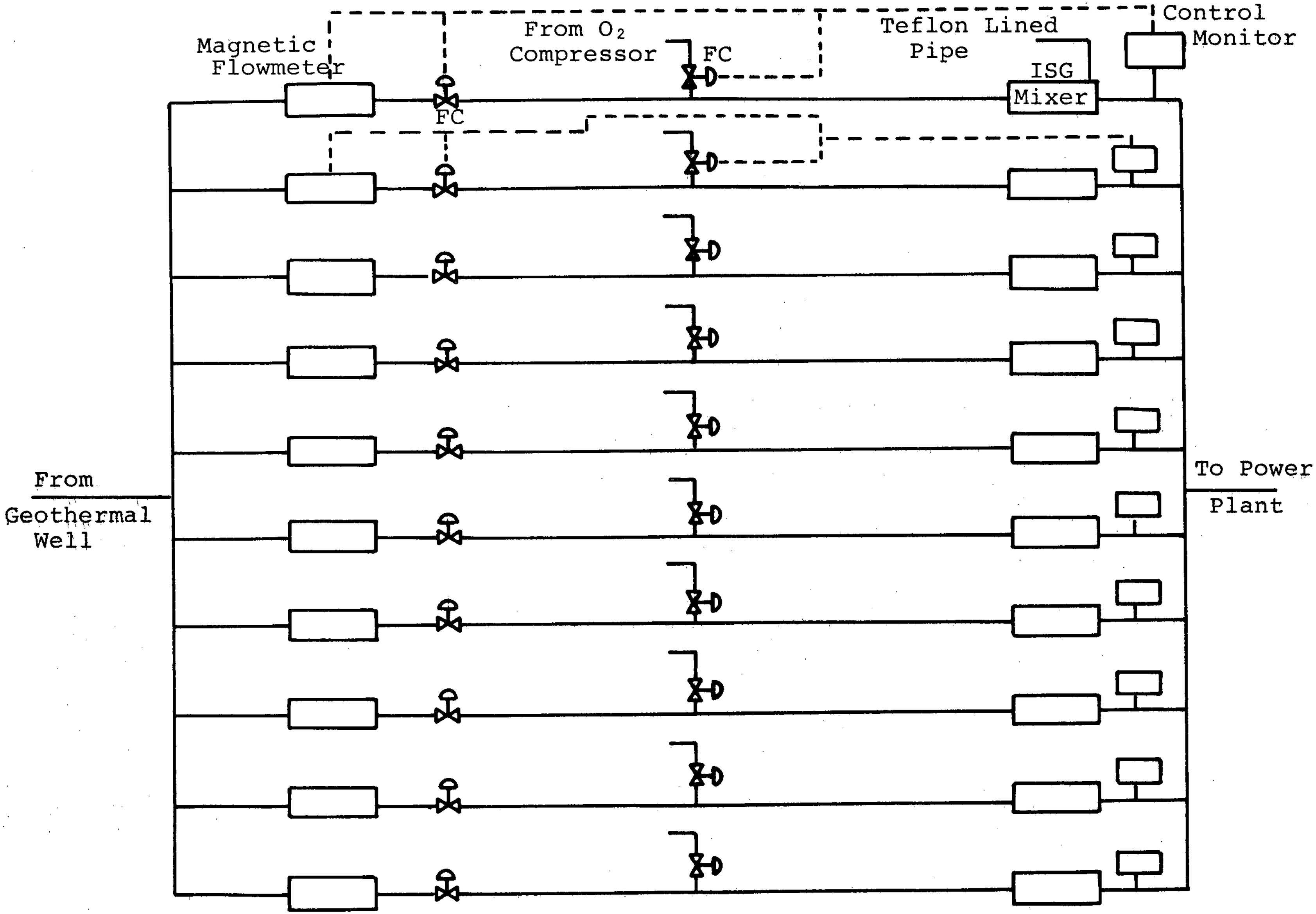


Figure 15: Case I flowsheet IGS mixing.

injection of the oxygen, the brine and oxygen mixture then passes into the Ross Engineering Co. teflon, 6-element ISG mixers. Up to this point, the system is all teflon-lined pipe to reduce any corrosion problems that might occur. From the mixers on, the piping is mild steel due to the removal of the sulfide and assumed lower corrosion rate. Immediately after each mixer is a Petrolite Corrosion Rate Monitor that gives an instantaneous corrosion rate and sends a signal to the oxygen flow controller. By combining the two signals at the oxygen controller, the one from the magnetic flowmeter and the corrosion monitor, it is possible to accurately control the oxygen addition. Finally, the ten separate streams are combined by the use of a header system into one stream, and the brine is carried on to the power plant.

An alternative system that could be utilized is one making use of a cocurrent packed column to give contact between the oxygen and the brine. This system does not have the disadvantage of the duplicity in the instrumentation. It does have a disadvantage in materials of construction. Due to the presence of free oxygen (until it reacts with the sulfide in the brine), the corrosion problem is greatly enhanced. This increase in corrosivity requires a vessel of a corrosion resistant alloy such as Carpenter 20. This increases the cost of the packed column. This system is the basis for Case II in the cost estimate (Table 9) and is shown in Figure 16.

The flowsheet of this system is much simpler than that of Case I. The total flow from the geothermal well goes through

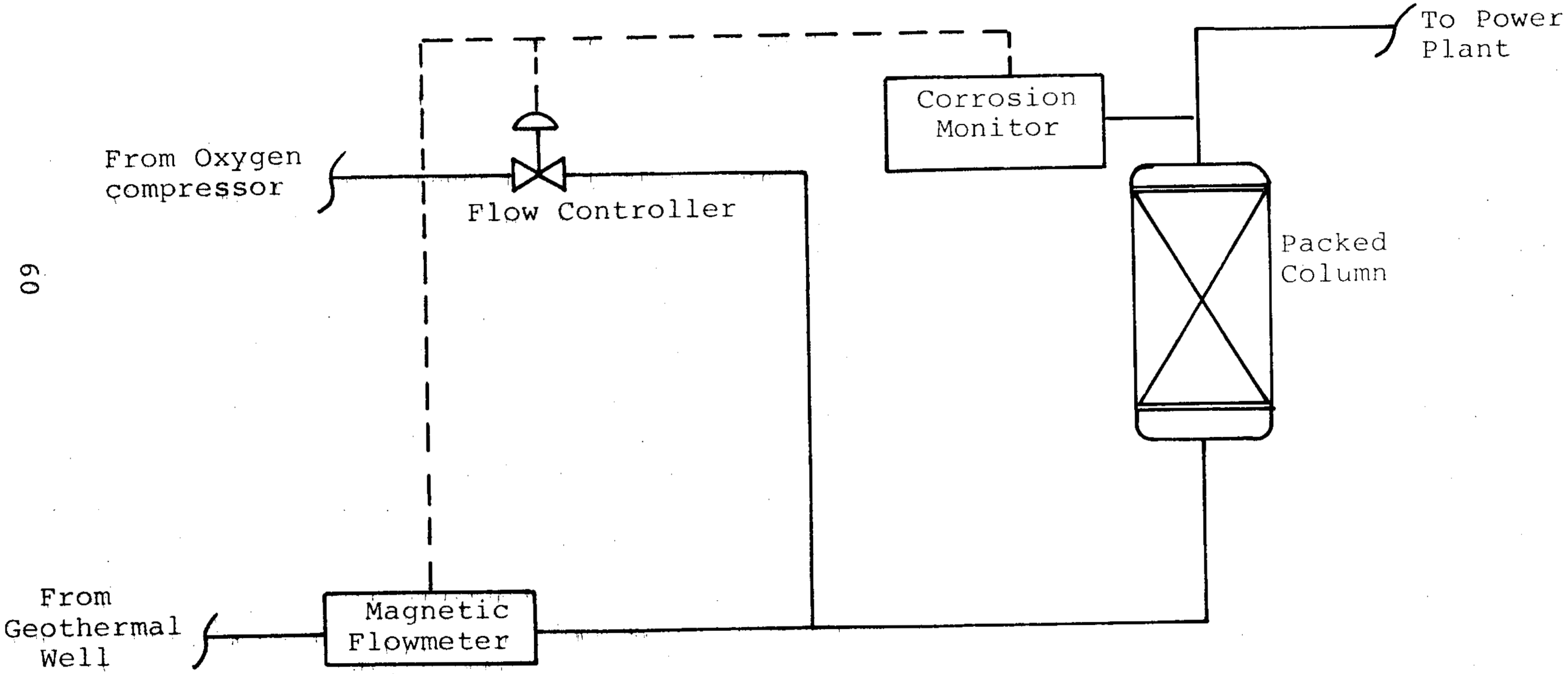


Figure 16: Case III flowsheet.

the magnetic flowmeter. This flowmeter sends a signal to the flow controller on the oxygen line. The oxygen source in this case is the same as the source in Case I. A cryogenic oxygen supply tank to an oxygen compressor is the equipment used in supplying the oxygen. After the oxygen is injected, the brine stream then goes to a Carpenter 20 column packed with teflon pall rings. This tank is designed to give a small pressure drop (less than 5 psi) and a holdup time of 30 seconds. All of the piping up to this column is teflon-lined pipe; while after the column, the piping is mild steel. Immediately after the column is a Petrolite Corrosion Monitor which gives an instantaneous corrosion rate and sends a signal to the oxygen flow controller so that excess oxygen is not added to the system At this point, the water would then be ready for use in the power plant.

3. Cost Estimates

The capital cost for building each of these two proposed systems is given in Table 9. This is an estimate of the capital cost to build this system for each operating well that flows 1000 gallons per minute. The costs were estimated on the construction of the equipment in the Imperial Valley in California.

A more detailed cost analysis is not called for at this time since further work must be done to test the feasibility of the packed column system. Also the possibility of using air instead of oxygen should be investigated. Finally, more testing is called for on actual geothermal brine which would probably flow in the two-phase flow regime.

These cost estimates indicate considerable expense for such a simple concept. Much of this cost is instrumentation. Further work should be done on simpler control systems. Also, a lined column might work in most waters. This would be more economical than the Alloy 20 suggested. The use of this method would, of course, be dependent upon the severity of the H_2S problem.

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APPENDIX

RUN DATA SHEETS

PLANT DATA SHEET GEOTHERMAL TEST UNIT

RUNS ① THROUGH ⑦

RUN NO. DATE	REACTOR TEMP °F	INITIAL CORROSION RATE MPY	CORROSION RATE BEFORE O_2 INJ MPY	CORROSION RATE AFTER O_2 INJ MPY	pH	T.D.S. PPM	O_2:H_2S MOLE RATIO	O_2 FLOW RATE SCFM	INITIAL H_2S CONC PPM	FIRST PASS H_2S CONC PPM	FIRST PASS pH	FIRST PASS POTENTIAL MV	SECOND PASS H_2S CONC PPM	SECOND PASS pH	SECOND PASS POTENTIAL MV	THIRD PASS H_2S CONC PPM	THIRD PASS pH	THIRD PASS POTENTIAL MV	FOURTH PASS H_2S CONC PPM	FOURTH PASS pH	FOURTH PASS POTENTIAL MV	FIFTH PASS H_2S CONC PPM	FIFTH PASS pH	FIFTH PASS POTENTIAL MV
① 4/2/76	315	.6	–	–	–	31,000	–	–	–	–	–	-10	–	–	-100	–	–	-160	–	–	-100	–	–	–
River Water Ca 45ppm, SO_4-22ppm ①																								
② 4/29/76	342	–	6.5	2.5	11.3	29,000	–	–	40	32	11.3	-30			-10			+160			+10	30	11.3	–
Condensate Ca 7ppm, SO_4-20ppm ②																								
③ 5/3/76	348	–	–	40	11.1	29,000	1:1	.95	40.	5	10.85	250	3.8	10.85	100	2.5	10.95	180	1.8	11.0	130	1.3	11.1	–
Condensate ③																								
④ 5/18/76	353	–	18	45	6.2	30,000	–	–	40	–	–	108	–	–	95	–	–	122	–	–	-5	–	–	–
Condensate	353	–	18	45	3.5	3000	.5:1	.475	40	10	3.2	70	11	3.7	190	11	3.4	185	12	3.5	-5	10	3.4	–
④																								
⑤ 5/19/76 ⑤	352	–	–	700	8.2	30,000	–	–	35	–	–	150	–	–	140	–	–	140			-5	–	–	–
	352	–	–	700	5.4	39000	.75:1	1.73	35	11	9.8	100	10	9.7	55	11	9.6	85	18	9.6	-5	12	9.75	–
Note: After Reading drop in pH After O_2 increased HCl flow																								
⑥ 5/21/76 ⑥	348	–	–	–	9.5	30,000	–	–	52	–	–	150	–	–	110	–	–	115	–	–	130	–	–	100
	349	–	–	1.55	6.4	30,000	1:1	.95	52	5	6.5	110	5	6.5	80	4	6.3	80	4	6.3	75	5	6.3	55
⑦ 6/4/76 ⑦	352	–	52	–	11.0	31,000	–	–	40	–	–	168	–	–	130	–	–	138	–	–	131	–	–	150
Ca-6.4 PPM SO_4-1600PPM	352	–	–	35	10.9	31,000	2:1	1.95	40	5.5	10.9	150	5	10.9	30	6	10.9	105	6.5	10.9	115	6.5	11.0	120
Notes: Could not get HCl injection																								

PLANT DATA SHEET GEOTHERMAL TEST UNIT

RUNS 8A THROUGH 11-B

RUN No. DATE	REACTOR TEMP °F	INITIAL CORROSION RATE MPY	CORROSION RATE BEFORE O_2 INJ MPY	CORROSION RATE AFTER O_2 INJ MPY	pH	T.D.S. PPM	O_2:H_2S MOLE RATIO	O_2 FLOW RATE SCFH	INITIAL H_2S CONC PPM	FIRST PASS			SECOND PASS			THIRD PASS			FOURTH PASS			FIFTH PASS		
										H_2S CONC PPM	pH	POTENTIAL MV	H_2S CONC PPM	pH	POTENTIAL MV	H_2S CONC PPM	pH	POTENTIAL MV	H_2S CONC PPM	pH	POTENTIAL MV	H_2S CONC PPM	pH	POTENTIAL MV
8-A 6-7-76	352	—	95	—	7.1	31,000	—	—	40	—	—	130	—	—	-30	—	—	120	—	—	118	—	—	80
	352	—	—	135	5.7	31,000	2:1	1.95	40	5	7.9	175	5	8.3	+80	5	8.4	+112	4	8.7	+98	4	8.7	113
							pass 2 - bad reading																	
FOR RUN 8-B JUST INCREASED O_2 FLOW																								
8-B 6-7-76	352	—	—	800	8.4	31,000	3:1	2.85	40	5	8.4	-40	3	8.0	+20	3	7.7	-45	4	7.4	-10	3	8.0	-35
	352	—	—	—	—	31,000	—	—	33	—	—	155	—	—	150	—	—	155	—	—	145	—	—	125
NOTE SULFIDE LEVEL DID NOT COME BACK UP TO 40																								
9 6-10-76	348	—	4	—	10.2	31,000	—	—	60	—	—	152	—	—	103	—	—	153	—	—	100	—	—	135
	346	—	—	5	10.2	31,000	1:1	1.42	60 Avg. 77.5	12	9	135	13	8.6	65	17	9.0	110	15	8.1	90	16	8.9	115
	348	—	2	—	10.3	31,000	—	—	95	—	—	152	—	—	85	—	—	150	—	—	120	—	—	133
NOTE INCREASED SULFIDE LEVEL AFTER STOPPING O_2 INJ																								
10-A 6-17-76	351	—	1.5	—	11.3	30,000	—	—	67	—	—	145	—	—	107	—	—	140	—	—	135	—	—	143
	351	—	—	.5	11.2	30,000	1:1	1.58	67	22	11.2	115	22	11.2	64	24	11.2	102	22	11.2	140	24	11.2	127
10-B 6-17-76	351	—	—	.5	11.2	30000	1:1	1.58	67	22	11.2	115	22	11.2	64	21	11.2	102	22	11.2	140	24	11.2	127
	350	—	—	4	11.0	30,000	2:1	3.16	67	4	11.0	115	3.5	11.0	80	4	11.0	65	4	11.0	92	40	10.9	78
11-A 6-18-76	352	—	11	—	7.5	30,000	—	—	65	—	—	138	—	—	136	—	—	131	—	—	145	—	—	140
11A	352	—	—	46	6.0	30,000	1:1	1.54	65	7	6.2	100	9	6.1	85	9	6.0	76	10	6.0	83	8	6.0	80
11-B 11B	351	—	9	—	8.3	30,000	—	—	65	—	—	135	—	—	122	—	—	125	—	—	130	—	—	130
	351	-	—	9	7.0	30,000	1.5:1	2.3	65	4	6.8	95	4	7.0	80	4	6.9	75	4	7.2	75	4	7.6	85

8310 1-60

DOW PLANT DATA SHEET

GEOTHERMAL TEST UNIT

Run No. Date	Reactor Temp °F	Corrosion Rate MPY	Corrosion Rate Before O₂ Inj MPY	Corrosion Rate After O₂ Inj MPY	pH	T.D.S. PPM	O₂:H₂S Mole Ratio	O₂ Flow Rate SCFH	Initial H₂S Conc PPM	First Pass H₂S Conc PPM	First Pass pH	First Pass Potential MV	Second Pass H₂S Conc PPM	Second Pass pH	Second Pass Potential MV	Third Pass H₂S Conc PPM	Third Pass pH	Third Pass Potential MV	Fourth Pass H₂S Conc PPM	Fourth Pass pH	Fourth Pass Potential MV	Fifth Pass H₂S Conc PPM	Fifth Pass pH	Fifth Pass Potential MV
12 6-22-76	350	—	10	—	9.45	30,000	—	—	20	—	—	—	—	—	122	—	—	137	—	—	143	—	—	142
12	352	—	—	10	9.3	30,000	1:1	47	20	4	9.4	115	4	9.4	92	5	9.3	99	5	9.3	95	5	9.2	115
13-A 6-23-76	353	—	1.9	—	8.1	39,000	—	—	23	—	—	145	—	—	125	—	—	130	—	—	120	—	—	122
	354	—	—	1.5	5.0	30,000	1.5:1	.71	23	.5	6.0	100	.4	5.4	140	.4	5.0	80	.4	4.7	115	.4	4.5	80
13-B 6-23-76	359	—	1.5	—	8.9	30,000	—	—	22	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	353	—	—	35	5.2	30,000	1:1	.47	22	.4	6.1	160	.4	5.3	82	.4	5.2	70	.4	5.2	110	.3	5.2	40
14-A 6-24-76	348	—	4	—	7.7	30,000	—	—	97	—	—	142	—	—	140	—	—	135	—	—	102	—	—	134
	348	—	—	4.1	6.0	30,000	1:1	2.34	97	18	6.1	90	17	6.1	85	17	6.0	80	16	5.9	48	16	6.0	82
14-B 6-24-76	348	—	—	4.1	6.0	30,000	1:1	2.34	97	18	6.1	90	17	6.1	85	17	6.0	80	16	5.9	48	16	6.0	82
	349	—	—	5.0	5.4	30,000	1.5:1	3.51	97	4	5.6	210	4	5.5	192	3.5	5.4	80	4	5.4	46	3.5	5.6	68
15 6-29-76	350	—	2.5	—	9.0	30,000	—	—	60	—	—	75	—	—	68	—	—	72	—	—	117	—	—	72
	351	—	—	25	8.7	30,000	1:1	1.4	60	10	8.8	88	10	8.7	59	11	8.7	65	9	8.7	15	9	8.7	78

NOTE: FEED BRINE 12 PPM FE - NOTICED LOT OF DARK PPT

* C

6310 1-60

PLANT DATA SHEET GEOTHERMAL TEST UNIT

RUNS 16-A - 19

Run Number	Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass			Second Pass			Third Pass			Fourth Pass			Fifth Pass		
											H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV
16A	7-1-76	351	—	6	—	7.1	30,000	—	—	55	—	—	86	—	—	64	—	—	55	—	—	18	—	—	72
		353	—	—	10	4.7	30,000	2:1	2.8	55	3.5	5.0	78	3.0	4.7	70	3.5	4.6	80	3.5	4.7	101	3.0	4.9	108
		* POTENTIALS VERY ERRATIC																							
16B	7-1-76	351	—	—	8	6.0	30,000	1:1	1.4	55	11	5.9	80	11	5.8	90	12	6.0	91	13	6.7	21	11	6.2	80
		352	—	8	—	8.5	30,000	—	—	5.7	—	—	88	—	—	108	—	—	95	—	—	0	—	—	78
17A	7-2-76	354	—	1.5	—	11.0	30,000	—	—	88	—	—	97	—	—	102	—	—	70	—	—	—	—	—	90
		354	—	—	2.5	10.8	30,000	1:1	2.0	88	15	10.8	87	17	10.8	75	15	10.8	50	15	10.8	—	16	10.5	60
*POTENTIAL PROBE NO 4 LOST DUE TO LEAKAGE INTO CONNECTOR																									
17B	7-2-76	354	—	—	5.0	10.5	30,000	1.5:1	3.1	88	4	10.5	200	4	10.5	65	4	10.5	35	4	10.5	—	4	10.5	35
		* POTENTIAL #1 VERY ERRATIC																							
18	7/7/76	256	—	32	—	9.3	30,000	—	—	49	—	—	125	—	—	111	—	—	102	—	—	155	—	—	125
		256	—	—	40	9.1	30,000	1:1	1.1	49	3.5	7.3	131	3.5	9.2	108	3.5	9.1	130	3.5	9.1	30	3.5	9.2	140
19	7/19/76	352	—	2	—	11.0	32,000	—	—	48	—	—	158	—	—	120	—	—	151	—	—	150	—	—	91
		352	—	—	2	10.7	32,000	1:1	1.1	48	7	10.7	163	7	10.7	105	9	10.7	147	9	10.7	152	5	10.6	112
	*	The RUN WAS FIRST IN USING REAGENT BLANK FOR SULFIDE ANALYSIS ALSO ANALYSIS VERIFIED AT CENTRAL LAB																							

8310 1-60

DOW PLANT DATA SHEET · GEOTHERMAL TEST UNIT

RUNS 20A THRU 23

Run Number	Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass			Second Pass			Third Pass			Fourth Pass			Fifth Pass		
											H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV
20A	7/21/76	351	—	10	—	11.8	32,000	—	—	50	—	—	155	—	—	80	—	—	155	—	—	140	—	—	140
		350	—	—	3	11.5	32,000	1.5:1	1.76	50	10	11.5	—	11	11.5	—	10	11.5	—	11	11.4	—	7	11.3	—
20B	7/21/76	350	—	—	3	11.1	32,000	2:1	2.40	50	1.5	11.1	180	2.1	11.1	95	0.8	11.2	120	0.8	11.1	95	1.2	11.1	100
21	7/22/76	350	—	15	—	11.0	32,000	—	—	105	—	—	140	—	—	112	—	—	125	—	—	122	—	—	118
		350	—	—	28	10.8	32,000	1.5:1	3.74	105	3.7	10.0	110	51	10.8	50	49	10.8	72	55	11.0	58	28	11.0	45
22A	7/27/76	252	—	4	—	11.2	32,000	—	—	72	—	—	142	—	—	120	—	—	150	—	—	132	—	—	134
		251	—	—	10	11.0	32,000	1:1	1.7	72	18	11.1	240	18	11.0	120	17	11.0	128	19	11.0	80	19	11.0	100
22B	7/27/76	251	—	—	280	10.9	32,000	2:1	3.4	72	9	10.9	90	4	10.9	35	3	10.9	50	1	10.9	10	1	10.9	-20
23	7/28/76	256	—	40	—	11.2	32,000	—	—	42	—	—	162	—	—	150	—	—	152	—	—	150	—	—	143
		256	—	—	20-100	10.8	32,000	1:1	.95	42	8	11.0	230	6	10.9	250	3	10.8	190	2	10.8	190	2	10.9	180

* POTENTIALS VERY ERRATIC

PLANT DATA SHEET GEOTHERMAL TEST UNIT

Runs 24A Trough 27C

Run Number / Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O₂ inj. MPY	Corrosion Rate after O₂ inj. MPY	pH	T.D.S. ppm	O₂:H₂S Mole Ratio	O₂ Flow Rate SCFH	Initial H₂S concentration ppm	First Pass H₂S conc. ppm / pH	First Pass Potential MV	Second Pass H₂S conc. ppm / pH	Second Pass Potential MV	Third Pass H₂S conc. ppm / pH	Third Pass Potential MV	Fourth Pass H₂S conc. ppm / pH	Fourth Pass Potential MV	Fifth Pass H₂S conc. ppm / pH	Fifth Pass Potential MV
24A 8/1/–	254	—	40	—	6.5	31,000	—	—	63	— / —	168	— / —	150	— / —	165	— / —	161	— / —	160
	255	—	—	22	7.8	31,000	1:1	1.51	63	12 / 7.8	[illegible] 240	16 / 8.3	160	14 / 7.8	175	14 / 7.4	160	16 / 7.4	135
24b	255	—	—	22	7.9	31,000	1:1	1.51	63	13 / [illegible]	+240	[illegible]	+160	14 / [illegible]	+17.5	14 / [illegible]	+160	16 / [illegible]	+135
8/?/76	255	—	—	140	10.6	31,000	2:1	3.02	63	9 / 10.4	+50	4 / 10.5	-120	1 / 10.6	-95	1 / 10.6	-70	.5 / 10.6	-90
	↓ LOST	HCl	INJECTION																
25A	160	—	.1	—	9.5	31,000	—	—	44	— / —	180	— / —	190	— / —	158	— / —	195	— / —	144
8/9/76	160	—	—	7	11.0	31,000	1:1	1.02	44	40 / 10.9	55	36 / 11.0	430	22 / 11.0	150	17 / 10.9	310	17 / 11.0	220
25B	160	—	—	7	11.0	31,000	1:1	1.02	44	40 / 10.9	55	36 / 11.0	430	[illegible] / 11.0	150	17 / 10.9	310	17 / 11.0	230
8/9/76	159	—	—	—	11.0	31,000	2:1	2.09	44	43 / 11.0	265	37 / 11.0	370	24 / 10.9	245	17 / 10.9	250	17 / 10.9	220
26	207	—	12	—	9.5	31,000	—	—	40	— / —	205	— / —	170	— / —	185	— / —	194	— / —	162
8/10/76	205	—	—	16	8.6	31,000	1:1	.96	40	11 / 8.8	120 → 200	10 / 8.6	280	5 / 8.5	240	3 / 8.6	230	4 / 8.8	190
27A 8/11/76	206	—	15	—	8.8	31,000	—	—	40	— / —	168	— / —	160	— / —	190	— / —	181	— / —	174
	202	—	—	124	6.5	31,000	1.5:1	1.44	40	0 / 6.5	70	0 / 7.0	170	0 / 6.5	5	— / —	155	— / —	100
27B 8/11/76	257	—	18	—	8.6	31,000	—	—	38	— / —	184	— / —	163	— / —	180	— / —	165	— / —	162
	258	—	—	170	5.9	31,000	1.5:1	1.44	38	0 / 5.9	30	— / —	150	— / —	70	— / —	69	0 / 5.9	78
27C 8/11/76	258	—	—	170	5.9	31,000	1.5:1	1.44	38	0 / 5.9	30	— / —	150	— / —	70	— / —	69	0 / 5.9	78
	252	—	—	140	6.2	31,000	1:1	.96	28	4 / 6.2	168	4 / 6.5	142	4 / 6.2	145	4 / 6.3	138	4 / 6.5	130

6310 1-60

DOW PLANT DATA SHEET GEOTHERMAL TEST UNIT

28 - 30B

Run Number Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass H_2S conc. ppm / pH	First Pass Potential MV	Second Pass H_2S conc. ppm / pH	Second Pass Potential MV	Third Pass H_2S conc. ppm / pH	Third Pass Potential MV	Fourth Pass H_2S conc. ppm / pH	Fourth Pass Potential MV	Fifth Pass H_2S conc. ppm / pH	Fifth Pass Potential MV
28	257	—	40	—	6.6	31,000	—	—	92	— / —	185	— / —	179	— / —	181	— / —	179	— / —	180
8-12-76	258	—	—	180	4.4	31,000	1.5:1	3.24	92	18 / 5.0	110	10 / 4.6	170	8 / 4.4	142	5 / 3.9	185	3 / 3.8	184
29A 8-18-76	350	—	28	—	9.2	30,000	—	—	49	— / —	159	— / —	145	— / —	148	— / —	132	— / —	137
375 ppm SiO₂	349	—	—	19	9.0	30,000	1:1	1.08	49	11 / 8.9	172	11 / 9.2	78	9 / 9.0	92	11 / 9.0	84	11 / 9.0	97
29B 8-18-76	349	-	-	19	9.0	30,000	1:1	1.08	49	11 / 8.9	172	11 / 9.2	78	9 / 9.0	92	11 / 9.0	84	11 / 9.0	97
375 ppm SiO₂	349	—	—	23	9.0	30,000	1.5:1	1.62	49	4 / 9.1	75	1.0 / 9.0	120	1.0 / 9.0	140	0.5 / 9.0	86	0.5 / 9.0	88
30A 8-19-76	346	—	22	—	9.1	30,000	—	—	97	— / —	164	— / —	155	— / —	152	— / —	143	— / —	142
375 ppm SiO₂	346	—	—	15	8.7	30,000	1:1	2.3	97	11 / 8.7	165	11 / 8.6	103	10 / 8.6	90	9 / 8.7	75	10 / 8.7	81
30B 8-19-76	346	—	—	15	8.7	30,000	1:1	2.3	97	11 / 8.7	165	11 / 8.6	103	10 / 8.6	90	9 / 8.7	75	10 / 8.7	81
375 ppm SiO₂	346	—	—	60	8.6	30,000	1.5:1	3.5	97	4 / 8.9	-93	1 / 8.6	-25	.5 / 8.6	-72	.2 / 8.6	-20	.1 / 8.6	-20

PLANT DATA SHEET GEOTHERMAL TEST UNIT

RUNS 31A THROUGH 33C

Run Number / Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass H_2S conc. ppm	First Pass pH	First Pass Potential MV	Second Pass H_2S conc. ppm	Second Pass pH	Second Pass Potential MV	Third Pass H_2S conc. ppm	Third Pass pH	Third Pass Potential MV	Fourth Pass H_2S conc. ppm	Fourth Pass pH	Fourth Pass Potential MV	Fifth Pass H_2S conc. ppm	Fifth Pass pH	Fifth Pass Potential MV
31A 9/2/76	350	+	18	—	9.0	30,000	—	—	87	—	—	152	—	—	145	—	—	90	—	—	158	—	—	200
	349	—	—	7	8.1	30,000	.5:1	1.05	87	47.5	7.9	105	50	8.1	100	—	—	50	52	8.7	130	52	8.9	180
SILICA LEVEL 15 PPM																								
31B 9/2/76	350	—	18	—	9.0	30,000	—	—	87	—	—	152	—	—	145	—	—	90	—	—	158	—	—	200
	350	—	—	7	8.3	30,000	.75:1	1.58	87	34	7.8	88	38	8.3	78	—	—	205	40	8.5	128	39	8.7	169
31C 9/2/76	350	—	18	—	9.0	30,000	—	—	87	—	—	152	—	—	145	—	—	90	—	—	158	—	—	200
	350	—	—	3	8.2	30,000	1.25:1	2.64	87	0	7.7	75	6	8.2	78	—	—	70	5	8.4	112	7	8.9	168
32A 9/3/76	352	—	11	—	8.9	30,000	—	—	60	—	—	142	—	—	140	—	—	182	—	—	169	—	—	185
SiO_2 - 15ppm	351	—	—	.6	8.9	30,000	.75:1	1.08	60	23	8.9	146	23	8.8	122	—		189	—		145	25	8.9	161
32B 9/3/76	352	—	11	—	8.9	30,000	—	—	60	—	—	142	—	—	140	—	—	182	—	—	169	—	—	185
	350	—	—	3	8.9	30,000	1.25:1	1.8	60	12	8.8	130	6	8.4	152	5	8.9	135	—	—	130	4	8.9	152
33A 9/8/76	352	—	20	—	11.3	131	—	—	60	—	—	130	—	—	112	—	—	318	—	—	103	—	—	101
NO chem	353	—	—	4	10.5	131	1:1	1.44	60	14	10.5	120	15	10.5	123	—	—	302	—	—	90	14	10.5	90
33B 9/8/76	352	—	20	—	11.3	131	—	—	60	—	—	130	—	—	112	—	—	318	—	—	103	—	—	101
	353	—	—	36	10.3	131	1.25:1	1.8	60	9	10.3	160	6	10.2	113	—	—	310	—	—	89	7	10.5	80
33C 9/8/76	352	—	20	—	11.3	131	—	—	60	—	—	130	—	—	112	—	—	318	—	—	103	—	—	101
	353	—	—	48	10.6	131	1.5:1	2.16	60	[illegible]	10.8	150	6	10.6	105			290			90	5	10.6	92

6310 1-60

PLANT DATA SHEET GEOTHERMAL TEST UNIT

RUNS 34A THROUGH 36B

Run Number	Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O₂ inj. MPY	Corrosion Rate after O₂ inj. MPY	pH	T.D.S. ppm	O₂:H₂S Mole Ratio	O₂ Flow Rate SCFH	Initial H₂S concentration ppm	First Pass		Second Pass		Third Pass		Fourth Pass		Fifth Pass	
											H₂S conc. ppm / pH	Potential MV	H₂S conc. ppm / pH	Potential MV	H₂S conc. ppm / pH	Potential MV	H₂S conc. ppm / pH	Potential MV	H₂S conc. ppm / pH	Potential MV
34A	9-9-7	349	—	12	—	8.7	131	—	—	50	—	142		120	— / —	225	— / —	102	— / —	109
		350	—	—	46	7.0	131	1:1	1.2	50	16 / 7.7	88	17 / 7.0	80	— / —	210	— / —	91	13 / 7.0	95
34B	9-9-7	349	—	12	—	8.7	131	—	—	50	— / —	142	— / —	120	— / —	225	— / —	102	— / —	109
		349	—	—	50	6.7	131	1.25:1	1.5	50	10 / 6.9	95	8 / 6.7	88	— / —	150	— / —	92	8 / 6.5	100
34C	9-9-7	349	—	12	—	8.7	131	—	—	50	— / —	142	— / —	120	— / —	225	— / —	102	— / —	109
		347	—	—	58	5.2	131	1.5:1	1.8	50	2 / 5.7	129	2 / 5.7	118		165		120	2 / 5.4	112
35A	9-10-7	352	—	35	—	9.4	131	—	—	97	— / —	150	— / —	142	— / —	170	— / —	138	— / —	135
		353	—	—	58	7.4	131	1:1	2.34	97	24 / 7.4	75	24 / 7.4	77	— / —	155	— / —	80	24 / 7.2	95
35B	9-10-7	352	—	35	—	9.4	131	—	—	97	— / —	150	— / —	142	— / —	170	— / —	138	— / —	135
		354	—	—	68	4.7	131	1.5:1	3.51	97	0.9 / 4.6	170	— / —	125	— / —	92	— / —	138	1.3 / 4.9	
35C	9-10-7	352	—	35	—	9.4	131	—	—	97	— / —	150	— / —	142	— / —	170	— / —	132	— / —	135
		353	—	—	50	6.9	131	1.25:1	2.93	97	9 / 6.9	80	11 / 6.9	75		200		82	10 / 7.0	95
36A	9-10-7	348	—	30	—	11.0	131	—	—	120	— / —	160	— / —	149	— / —	X		153		142
		350	—	—	20	10.4	131	1.5:1	4.32	120	2 / 10.3	35	1 / 10.4	60	— / —	X	— / —	90	1 / 10.4	72
36B	9-10-7	348	—	30	—	11.0	131	—	—	120	— / —	160	— / —	149	— / —	X	— / —	153	— / —	142
		350	—	—	40	10.6	131	1.25:1	3.6	120	11 / 10.6	152	12 / 10.6	80		X		102	12 / 10.2	92

8310 1-60

DOW PLANT DATA SHEET GEOTHERMAL TEST UNIT

Run Number / Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	$O_2:H_2S$ Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass H_2S conc. ppm / pH	First Pass Potential MV	Second Pass H_2S conc. ppm / pH	Second Pass Potential MV	Third Pass H_2S conc. ppm / pH	Third Pass Potential MV	Fourth Pass H_2S conc. ppm / pH	Fourth Pass Potential MV	Fifth Pass H_2S conc. ppm / pH	Fifth Pass Potential MV
37A 9-15-7	349	—	160	—	6.2	52,000	—	—	100		112	— / —	85		X		85	— / —	125
	342	—	—	250	4.0	52,000	.75:1	1.8	100	27 / [illegible]	152	19 / [illegible]	153		X		180	16 / 4.0	183
	* Lost		[illegible]	↓	[illegible]	[illegible]	INJECTION												
37B 9-15-7	343	—	20	—	9.0	52,000	—	—	100	— / —	168	— / —	152	— / —	X	— / —	155	— / —	145
	349	—	—	26	7.5	52,000	.75:1	1.8	100	32 / 7.5	110	[illegible]	73		X		108	31 / [illegible]	93
37C	348	—	20	—	9.0	52,000	—	—	100	— / —	169		152	— / —	X	— / —	155	— / —	145
	350	—	—	20	6.1	52,000	1.25:1	3.0	100	1 / [illegible]	112	.4 / 6.[illegible]	80	— / —	X	— / —	93	1 / 6.5	104
37D 9-15-7	348	—	20	—	9.0	52,000	—	—	100	— / —	168	— / —	152	— / —	X	— / —	155	— / —	145
	350	—	—	15	8.3	52,000	1:1	2.4	100	15 / 8.2	110	17 / 8.3	83	— / —	X	— / —	95	17 / 8.2	89
38A 9-16-7	350	—	60	—	9.0	52,000	—	—	60	— / —	163	— / —	140	— / —	X	— / —	150	— / —	141
	351	—	—	100	8.7	52,000	.75:1	1.08	60	22 / 8.7	120	[illegible]	75	— / —	X	— / —	108	23 / 8.6	97
38B 9-16	350	—	60	—	9.0	52,000	—	—	60	— / —	163	— / —	140	— / —	X	— / —	150	— / —	141
	350	—	—	240	4.8	[illegible]	1.25:1	1.8	60	.7 / 4.8	-10	[illegible]	75		X	— / —	-30	.1 / 4.[illegible]	-15
↓ Lower Flow Rate 2.43 GPM																			
39A 11-24-76	250	—	—	—	8.8	84,000	—	—	110	— / —	—	— / —	—	— / —	—	— / —	—	— / —	—
	350	—	—	—	7.8	84,000	1:1	2.0	110	9 / 7.6	—	8 / 7.8	—	— / —	—	— / —	—	5.0 / 7.9	—
39B 11-24-76	350	—	—	—	8.8	84,000	—	—	110	— / —	—	— / —	—	— / —	—	— / —	—	— / —	—
	350	—	—	—	7.9	84,000	1.25:1	2.5	110	0.4 / 7.8	—	0.3 / 7.9	—	— / —	—	— / —	—	0.2 / 7.8	—

8310 1-80

PLANT DATA SHEET GEOTHERMAL TEST UNIT

Run Number	Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass			Second Pass			Third Pass			Fourth Pass			Fifth Pass		
											H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV
40A	12-2-76	350	—	2.5	—	8.8	112,000	—	—	107.5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	3.0	8.5	112,000	.75:1	1.5	127.5	26	8.5	—	—	—	—	23	8.5	—	—	—	—	29	8.6	—
40B	12-2-76	350	—	2.5	—	8.8	112,000	—	—	107.5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	3.0	8.4	112,000	1:1	2.0	107.5	14	8.4	—	—	—	—	14	8.4	—	—	—	—	15	8.4	—
40C	12-2-76	350	—	2.5	—	8.8	112,000	—	—	107.5	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	3.0	8.4	112,000	1.25:1	2.5	107.5	3.0	8.4	—	—		—	3.0	8.4	—	—	—	—	4.0	8.4	—
41	12-3-76	350	—	21	—	—	112,000	—		170	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	—	8.2	112,000	1:1	3.0	170	0.5	8.5	—	—	—	—	0.5	8.2	—	—	—	—	1.0	8.1	—
42A	12-28-76	350	—	18	—	8.8	66,000	—	—	205	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	430	5.2	66,000	1:1	4.1	205	1.0	5.5	—	—	—	—	0.2	5.2	—	—	—	—	0.2	5.2	—
42B	12-28-76	350	—	18	—	8.8	66,000	—	—	205	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	40	6.4	66,000	.75:1	3.1	205	80	6.5	—	—	—	—	9.0	6.4	—	—	—	—	10	6.4	—
43A	12-29-76	350	—	26	—	8.3	66,000	—	—	83	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
		350	—	—	19	8.2	66,000	.75:1	1.24	83	81	8.3	—	—	—	—	46	8.1	—	—	—	—	46	8.2	—

6310 1-60

DOW PLANT DATA SHEET GEOTHERMAL TEST UNIT

Run Number / Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	$O_2:H_2S$ Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass			Second Pass			Third Pass			Fourth Pass			Fifth Pass		
										H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV
43B 12-29-76	350	—	26	—	8.3	66,000	—	—	83	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	18	8.3	66,000	1:1	1.67	83	15	8.3	—	—	—	—	21	8.5	—	—	—	—	16	8.5	—
43C 12-29-76	350	—	26	—	8.3	66,000	—	—	83	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	400	7.9	66,000	1.25:1	2.11	83	0.8	7.9	—	—	—	—	1.5	8.0	—	—	—	—	0.7	7.2	—
44A 12-30-76	350	—	8	—	8.6	66,000	—	—	140	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	19	7.1	66,000	.75:1	2.11	140	44	6.8	—	—	—	—	49	7.1	—	—	—	—	51	7.2	—
44B 12-30-76	350	—	8	—	8.6	66,000	—	—	140	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	90	5.9	66,000	1:1	2.81	140	0.2	5.9	—	—	—	—	0.4	5.9	—	—	—	—	0.4	6.0	—
45A 1-26-77	350	—	22	—	8.4	40,000	—	—	107	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NH_3 – 55ppm	350	—	—	40	6.4	40,000	.75:1	1.54	107	44	6.4	—	—	—	—	43	6.4	—	—	—	—	40	6.4	—
Ca^{++} – 120.2ppm																								
45B 1-26-77	350	—	22	—	3.4	40,000	—	—	107	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NH_3 - 55ppm	350	—	—	45	6.5	40,000	1:1	2.05	107	30	6.4	—	—	—	—	29	6.5	—	—	—	—	27	6.55	—
Ca^{++} – 120.2ppm																								
45C 1-26-77	350	—	22	—	8.4	40,000	—	—	107	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NH_3 - 55ppm	350	—	—	50	5.1	40,000	1.25:1	2.56	107	65	5.0	—	—	—	—	8.3	5.1	—	—	—	—	7.5	5.25	—
Ca^{++} -120.2 ppm																								
45D 1-26-77	350	—	22	—	8.4	40,000	—	—	107	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
NH_3 55ppm	350	—	—	130	3.0	40,000	1.5:1	3.08	107	0.2	3.3	—	—	—	—	—	—	—	—	—	—	0.2	3.0	—

Ca^{++} 120.2ppm

8310 1-80

PLANT DATA SHEET GEOTHERMAL TEST UNIT

Run Number Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	O_2:H_2S Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass			Second Pass			Third Pass			Fourth Pass			Fifth Pass		
										H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV	H_2S conc. ppm	pH	Potential MV
(46A) 1-27-77	350	–	17	–	7.85	40000	–	–	112	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NH_3-549ppm	350	–	–	42	7.2	40,000	.75:1	1.62	112	52	7.2	–	–	–	–	55	7.5	–	–	–	–	51	7.3	–
SiO_2=350ppm, [illegible]																								
(46B) 1-27-77	350	–	17	-	7.85	40,000	–	–	112.	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NH_3-54.9ppm	350	–	–	45	6.8	40,000	1:1	2.16	112	18	6.7	–	–	–	–	21	6.8	–	–	–	–	22	[illegible]	–
SiO_2-350 Cr 130.2																								
(46C) 1-27-77	350	–	17	–	7.85	40,000	–	–	112	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
NH_3-54.9 ppm	350	–	–	40	6.5	49,000	1.25:1	2.7	112	6.0	6.4	–	–	–	–	11	6.55	–	–	–	–	8.0	6.5	–
SiO_2-350 Cr^+ [illegible]																								
(47A) 1-2-77	350	–	24	–	8.3	28,000	–	–	112.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ni-10ppm, Cr^+ [illegible]	350		–	22	7.2	28,000	.75:1	1.62	112.5	33	7.2	–	–	–	–	34	7.2	–	–	–	–	35	7.3	–
(47B) 2-2-77	350	–	24	–	8.3	28,000	–	–	112.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ni-10ppm	350	–	–	68	6.2	28,000	1:1	2.16	112.5	6.0	6.1	–	–	–	–	7.0	6.2	–	–	–	–	5.0	6.4	–
Cr^+-58ppm																								
(47C) 2-2-77	350	–	24	–	8.3	28,000	–	–	112.5	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Ni-10ppm Cr^+-58ppm	350	–	–	60	6.2	28,000	1.25:1	2.7	112.5	0.0	5.7	–	–	–	–	4.0	5.8	–	–	–	–	0.0	5.8	–
(48A) 2-15-77	350	–	24	–	7.1	31,000	–	–	103	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Cr^+ 44ppm	350	–	–	60	6.6	31,000	.5:1	1.58	103	43	6.6	–	46	6.6	–	47	6.6	–	47	6.6	–	47	6.5	–
3836ppm																								
(48B) 2-15-77	350	–	24	–	7.1	31,000	–	–	103	–	–	–	–	–	–	–	–	–	–	–	–	–	–	–
Cr- 44ppm	350	–	–	54	6.2	31,000	.75:1	2.37																
3836ppm																								

6310 1-80

PLANT DATA SHEET GEOTHERMAL TEST UNIT

Run Number Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	$O_2:H_2S$ Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass H_2S conc. ppm	First Pass pH	First Pass Potential MV	Second Pass H_2S conc. ppm	Second Pass pH	Second Pass Potential MV	Third Pass H_2S conc. ppm	Third Pass pH	Third Pass Potential MV	Fourth Pass H_2S conc. ppm	Fourth Pass pH	Fourth Pass Potential MV	Fif Pas H_2S conc. ppm	Fif Pas pH
48C 2-17-77	350	—	24 -	—	7.3	31,000	—	—	103	—	—	—	—	—	—	—	—	—	—	—	—	—	—
O_2 60 ppm	350	—	—	64	5.8	31,000	1:1	3.16	103	2.5	5.5	—	3.2	5.8	—	3.1	5.8	—	3.5	5.8	—	3.3	5.8
3.83 GPM																							
48D 2-17-77	350	—	24	—	7.3	31,000	—	—	103	—	—	—	—	—	—	—	—	—	—	—	—	—	—
O_2 - 90 ppm	350	—	—	110	5.6	31,000	1.25:1	3.95	103	0	5.6	—	—	—	—	0	5.6	—	—	—	—	0	5.6
3.83 GPM																							
48E 2-17-77	350	—	24	—	7.3	31,000	—	—	103	—	—	—	—	—	—	—	—	—	—	—	—	—	—
O_2# 66 ppm	350	—	—	—	5.6	31,000	1.5:1	4.74	103	0	5.6	—	—	—	—	0	5.6	—	—	—	—	0	5.6
3.83 GPM																							
49A 2-22-77	350	—	60	—	6.1	31,000	—	—	85	—	—	—	—	—	—	—	—	—	—	—	—	—	—
O_2# 44 ppm	350	—	—	76	5.9	31,000	.5:1	1.24	85	45	5.85	—	50	5.9	—	48	5.9	—	49	5.9	—	50	5.9
3.83 GPM																							
49B 2-22-77	350	—	60	—	6.1	31,000	—	—	85	—	—	—	—	—	—	—	—	—	—	—	—	—	—
O_2# 44 ppm	350	—	—	62	5.6	31,000	.75:1	1.86	85	24	5.5		28	5.6		29	5.6		29	5.6		29	5.6
3.83 GPM																							
CHANGED BACK TO 2.43 GPM PULLEY																							
50A 2-24-77	356	—	60	—	6.2	31,000	—	—	93	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	76	5.8	31,000	.75:1	1.4	93	32	5.8	—	30	5.8	—	28	5.75	—	30	5.8	—	30	5.8
50B 2-24-77	350	—	60	—	6.2	31,000	—	—	93	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	85	5.7	31,000	1:1	1.84	93	8	5.65	—	8	5.7	—	9	5.7	—	8	5.7	—	10	5.7
50C 2-24-77	350	—	60	—	6.2	31,000	—	—	93	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	104	4.8	31,000	1.25:1	2.30	93	0	4.9	—	—	—	—	0	4.8	—	—	—	—	0	4.8

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PLANT DATA SHEET · GEOTHERMAL TEST UNIT

Run Number Date	Reactor Temperature °F	Corrosion Rate MPY	Corrosion Rate before O_2 inj. MPY	Corrosion Rate after O_2 inj. MPY	pH	T.D.S. ppm	$O_2:H_2S$ Mole Ratio	O_2 Flow Rate SCFH	Initial H_2S concentration ppm	First Pass H_2S conc. ppm	First Pass pH	First Pass Potential MV	Second Pass H_2S conc. ppm	Second Pass pH	Second Pass Potential MV	Third Pass H_2S conc. ppm	Third Pass pH	Third Pass Potential MV	Fourth Pass H_2S conc. ppm	Fourth Pass pH	Fourth Pass Potential MV	Fifth Pass H_2S conc. ppm	Fifth Pass pH	Fifth Pass Potential MV
50D 2-24-77	350	—	60	—	6.2	31,000	—	—	23	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	124	4.8	31,000	1.5:1	2.75	93	0	4.2	—	—	—	—	0	4.8	—	—	—	—	0	4.7	—
51A 2-25-77	350	—	101	—	5.15	31,000	—	—	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	186	2.7	31,000	.75:1	1.46	100	27	2.7	—	28	2.7	—	28	2.45	—	29	2.7	—	30	2.7	—
51B 2-25-77	350	—	101	—	5.15	31,000	—	—	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	195	2.3	31,000	1:1	1.94	100	22	2.3	—	23	2.3	—	24	2.3	—	—	—	—	24	2.3	—
51C 2-25-77	350	—	101	—	5.15	31,000	—	—	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	190	2.15	31,000	1.25:1	2.43	100	10	2.2	—	12	2.2	—	12	2.1	—	12	2.15	—	12	2.1	—
51D 2-25-77	350	—	101	—	5.15	31,000	—	—	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	200	2.05	31,000	1.5:1	2.91	100	1.0	2.0	—	1.0	2.1	—	0.0	2.0	—	0.0	2.0	—	0.0	2.1	—
51E 2-25-77	350	—	101	—	5.15	31,000	—	—	100	—	—	—	—	—	—	—	—	—	—	—	—	—	—	—
	350	—	—	225	2.0	31,000	2:1	3.88	100	0.0	2.1	—	—	—	—	0.0	2.0	—	—	—	—	0.0	1.9	—