Article from:

Proceedings of the Fifth Annual Geothermal Conference and Workshop, June 23-25, 1981, San Diego, California. Palo Alto, California: Electric Power Research Institute, 1981.

2461

UPSTREAM REBOILING FOR NONCONDENSABLE GAS REMOVAL

CONTRACT NO. RP1197-2

Glenn Coury and Robert A. Babione
Coury and Associates, Inc.
7625 West Fifth Ave.
Lakewood, Colorado 80226, 303-232-3823

I. Project Objectives and Results The objective of this project was to evaluate a heat exchanger process for removal of H_2S and other noncondensable gases from geothermal steam. The process was conceived by Coury and Associates, Inc. and has been developed and tested by both Coury and EPRI through this project and through other efforts by Coury. The heat exchanger process is shown schematically in Figure 1. Both the shellside and tubeside of the heat exchanger are at saturated conditions, with the tubeside at a pressure and temperature slightly lower than the shellside. This temperature difference causes heat transfer to occur so that saturated steam condenses in the shellside and saturated condensate evaporates in the tubeside. The incoming geothermal steam, directly from a well in the case of a vapor-dominated resource or from a vapor-liquid separator at hydrothermal locations, is almost completely condensed. The resulting condensate will dissolve some gases, but about 98 percent of the total noncondensable gases in the steam will remain in the vent gas stream. Over a typical range of geothermal steam compositions and process operating conditions, 90 to 99 percent of the H_2S will remain in the vent stream. The shellside condensate is transferred to the tubeside and is reevaporated as it circulates through the tubes. The total resulting tubeside vapor leaves the heat exchanger as clean steam.

In addition to achieving over 90 percent removal of H_2S and other noncondensable gases this process can operate at wellhead pressures and temperature and does not require any chemical additives to the main steam, thus making it suitable for operation upstream of a geothermal power plant turbine. Upstream removal of H_2S and other noncondensable gases has several advantages over processes which remove H_2S downstream of the turbine. These include: (1) the steam within the turbine is cleaner and less corrosive which should result in increased turbine reliability; (2) H_2S cannot get into the turbine condensate where it could require difficult liquid phase treatment to meet plant H_2S emissions requirements; (3) the removal of noncondensables ahead of the turbine reduces the steam requirements for the steam jet air ejectors which control the vacuum in the main condenser; (4) steam can be vented through the upstream unit, as a stacking operation when the power plant is not operating, thus avoiding the necessity to close down wells during such periods; and (5) the removal of gases from the condenser increases the power production in the turbine.

The project work included the testing of a small-scale, 150-ft^2 heat exchanger, similar to that shown in Figure 1. These tests were conducted with the cooperation of Pacific Gas and Electric Company at Unit 7 of The Geysers Power Plant, a dry steam geothermal resource north of San Francisco, California. The objectives of the test program were to: (1) demonstrate the capability of the process to remove at least 90 percent of the H_2S present in the incoming geothermal well steam; and (2) demonstrate the heat transfer performance of the falling-film vertical tube evaporator in a geothermal environment.

The test unit accumulated approximately 1000 hours of operating time with the following results:

- The measured H_2S removal rates were consistently better than 90 percent, with an average removal rate of 94 percent.
- At least 98 percent removal of the total noncondensable gases was indicated during the tests.
- Measured heat transfer rates were high enough to indicate acceptable economics for application of the process on a commercial scale. The average measured heat transfer coefficient was 576 Btu/(h·ft^2·°F) with indications that all measured values were conservative.
- The test unit demonstrated very simple and predictable operating characteristics during both steady state and transient conditions.

The project work also included studies for evaluating the cost and performance of various configurations and applications of the heat exchanger process. The results of these studies show the following:

- Alternative heat exchanger designs may improve heat transfer performance and reduce capital costs.
- The commercial-scale application of this

process would contribute about 4.4 mills/kWh to the electrical busbar cost of a typical 55-MW geothermal power plant.

- The effects of the steam pressure drop across the heat exchanger and steam consumption in the vent stream may be more than compensated for by beneficial effects on the total power plant system performance and on total net electric power production.

The final report for the project, Reference 1, presents a comprehensive discussion of the project work and results. In addition to the field test and studies mentioned above, the final report includes a complete preliminary design of a larger scale demonstration plant.

II. H_2S Removal

A. Predicted Removal Rates The removal of gases from geothermal steam is determined by how much of each gas dissolves in the liquid phase as the entering steam condenses. The amount of gas absorbed at equilibrium is controlled by three factors: (1) the partial pressure of the gas in the vapor phase; (2) the mass ratio of vapor to liquid in contact with each other; and (3) the pH of the liquid solution. The partial pressure of the gas depends on the amount of the gas present and the total pressure of the system. The mass ratio of vapor to liquid depends on the amount that is condensed; this ratio is a function of the vent rate, because more steam is condensed as less steam is vented. The pH of the liquid solution depends on the dissociation of the gases after they dissolve into the liquid phase. The amount of dissociation is determined by the appropriate equilibrium constants, which are a function of temperature, and by the concentration of the various gases in the steam. Thus, the major variables that affect gas removal are temperature, pressure, gas composition, and the percent of inlet steam vented.

If equilibrium is not achieved in the process, then removal is also dependent on the kinetic rates at which the various mass transfer steps occur. The question of equilibrium, or kinetics, has been evaluated resulting in the conclusion that the actual effect of kinetics will be insignificant with respect to the performance of the heat exchanger. This is discussed in more detail in the final report for this project (Reference 1).

A mathematical model was developed by Coury to predict the removal of H_2S and other gases from geothermal steam using the heat exchanger process. Figures 2 and 3 show the results of calculations using this model indicating better than 90 percent removal of H_2S for the wide ranges in H_2S, CO_2, and NH_3 concentrations that are expected to include most geothermal steams. Figure 2 represents a 98-percent condensing rate (2 percent vent rate) and Figure 3 shows a 90-percent condensing rate (10 percent vent rate). The inlet concentrations of H_2S and CO_2 covered in these figures range from 100 to 1000 ppm for H_2S and 3000 to 8000 ppm for CO_2. The inlet NH_3 concentration ranges from zero to 100 percent of the inlet H_2S concentrations. The pH values shown in the figures is dependent on the relative concentrations of the acid gases H_2S and CO_2 and the basic gas NH_3. As expected, the calculated H_2S removal increased with decreasing NH_3 concentrations, increasing CO_2 concentrations, and increasing vent rate. For conditions typical at The Geysers, as shown in Table 1, the model predicted better than 95 percent H_2S removal.

B. Test Unit Results Figures 4 and 5 show plots of H_2S removal versus vent rate and ΔT as measured with the test unit at The Geysers. The measurements ranged from 98.1 percent to 87.3 percent (the one point lower than 90 percent), with an average of 94.0 percent and a standard deviation of 2.1 percent. Although no conclusive correlation is shown between the H_2S removal rate and ΔT (no direct correlation is expected based on theory), these figures do indicate that the H_2S removal rate is dependent on the vent rate, increasing as the vent rate is increased, as predicted by theory. As seen in Figure 4, however, the linear curve fit of the data gives values slightly less than theoretical values based on average conditions at The Geysers, with this difference in percent removal values ranging from about 1 at a vent rate of 1 percent to about 3 at a vent rate of 10 percent.

Most of the data represented in Figures 4 and 5 are from baseline tests with vent rates between 2 percent and 8 percent of the inlet steam flow rate and ΔT's across the heat exchanger of between 5°F and 9°F. During the baseline tests the inlet steam composition was not modified and was similar to that shown in Table 1. A few of the data points in Figures 4 and 5 represent special tests such as high vent rate tests and gas injection tests. As expected, the high vent rate tests typically showed high levels of H_2S removal. Table 2 shows the results of detailed analyses of H_2S and other noncondensable gases in the various flow streams for four gas injection test cases during which the inlet steam composition was modified by injecting H_2S and NH_3, and one baseline test case during this same general time period. With each of the five cases in Table 2, the measured H_2S removal rates are compared with the predicted removal rates for the measured inlet H_2S and NH_3, and CO_2 concentrations and the measured vent rates for each case. The measured percent H_2S removal values ranged from 2 to 5 less than the predicted percent removal values, as the ratio of

NH_3 to H_2S concentration in the inlet steam ranged from 0.2 to 2.0.

As can be seen from Table 2, the predicted removal rate for H_2S remained fairly constant during the injection tests, ranging from 95 percent to 98 percent, even though the NH_3 to H_2S ratio increased. This is because the absolute amount of H_2S decreased as this ratio increased, and the two effects almost balanced each other. The measured H_2S removal rates also remained essentially constant as would be expected, ranging from 92 percent to 95 percent. Although these values are all somewhat lower than the predicted values, they are still within the limits of the probable error band based on the accuracy of the analytical methods. The predictive model thus appears to be adequate, although the number of tests were limited. Most importantly, these tests demonstrated the high capability for H_2S removal over a wide range of steam composition.

An error analysis of the H_2S removal data indicates that the expected variations in measured values of percent H_2S removal range from 0.5 to 2 due to normal fluctuations of H_2S and NH_3 concentrations at The Geysers, and from 1 to 4 due to normal errors in the chemistry analyses. In accordance with these ranges of probable errors, error bands of ±1 and ±4 are indicated in Figure 4. As can be seen, most of the data points and the predicted values are inside the ±4 band.

Table 3 shows the predicted variations in H_2S removal rates due to variations in separate parameters including vent rate, inlet H_2S concentrations, and inlet NH_3 expected during the field test at The Geysers. Table 3 also shows the calculated effect on H_2S removal rate measurements due to estimated errors in the chemistry analysis techniques used during The Geysers tests.

III. Heat Transfer Performance

A. Predicted Performance Capital cost of the heat exchanger can be related almost completely to its size as defined by its surface area. The required surface area (A) is directly proportional to the heat load (Q), and inversely proportional to the heat transfer coefficient (U) and the temperature driving force (ΔT), as expressed below:

$$A = \frac{Q}{U\Delta T} \qquad (1)$$

For a given application, Q is essentially fixed by the amount of steam required to supply the turbine and ΔT is fixed by considering the allowable drop in steam pressure and temperature upstream of the turbine. The U value, however, is dependent on heat exchanger size and design.

The heat exchanger test unit at The Geysers and heat exchangers used in the cost models for the commercial scale cost estimates, presented in the following section, are vertical tube evaporators (VTE) as shown in Figure 1 with smooth tubes. Alternative heat exchanger designs with predicted improved heat transfer performance have been reviewed. These alternative designs are the VTE with doubly fluted tubes and the horizontal tube evaporator (HTE) with smooth tubes. Representative U values for these three design options have been estimated for this application by extrapolating data obtained in other applications, using a consistent theoretical approach, so that these U values can be used to compare heat transfer performance of these three options.

Doubly fluted tubes were developed by the desalination industry to increase the heat transfer coefficients over the smooth-tubes VTE unit. The tubes are fabricated with ridges both on the inside and outside tube surfaces. A number of different configurations are used, and a typical design is shown in Figure 6.

The major advantages of the doubly fluted tubes are that the condensing heat transfer coefficientis greatly improved. This is due to surface tension effects that cause most of the condensate to flow through the channels, leaving the ridge area with a very thin condensate layer that has a very low resistance to heat transfer.

In the HTE spray-film unit, the geothermal steam is introduced on the tubeside and condensate on the shellside. The condensate would be sprayed over the outside of the tubes, and the steam would condense within the tubes and flow out of the ends. Figure 7 shows an HTE configuration for the heat exchanger process.

The major advantage of the HTE is that the heat transfer coefficient is significantly improved over a smooth tube VTE design even while using smooth tubes in the horizontal unit. The primary gain is due to the improved condensing side coefficient, because of a reduced overall film thickness.

Table 4 shows the comparative estimated U values and surface area requirements for commercial applications of the three heat exchanger options discussed above. The test unit at The Geysers and the heat exchangers used in the commercial scale cost models discussed in the following section were VTE units, with smooth tubes. The estimated U value for this design option shown in Table 4 is 740 Btu/($h \cdot {}^\circ F \cdot ft^2$), while a conservative lower U value of 600 Btu/($h \cdot {}^\circ F \cdot ft^2$) was used in the commercial scale capital cost calculations discussed in the following section.

In Table 4 the comparison of data between VTE units with smooth tubes and those with fluted tubes indicates that there is very little difference in performance within the level of accuracy of this estimate. The anticipated improvement in the overall U value for fluted tubes was minimized by the high thermal conductivity of 304 SS which resulted in large tube wall resistances for the fluted tube. The same conclusions apply to titanium--another acceptable tube material for this application-- since its conductivity is about the same as that of 304 SS. The HTE smooth tube design appears to be significantly different in heat transfer performance when compared to VTE units. The required heat transfer area for an HTE unit is about two-thirds of that for the vertical tube exchangers.

The economic comparison depends on the unit cost per surface area of the three design options. With the understanding that the unit cost of fluted tubes will be somewhat higher than smooth tubes, it becomes obvious that the capital cost of the VTE with fluted tubes will probably not be lower than that of the VTE with smooth tubes. On the other hand, a significant capital cost savings is possible with the HTE because of the much less surface area required.

B. Test Unit Results The measured U values are shown plotted with respect to vent rate and ΔT in Figure 8. These values ranged from 333 to 788 Btu/(h·ft^2·°F) with an average of 576 and a standard deviation of 85. As can be seen in Figure 8, correlations between the measured U values and the vent rate and ΔT can not be obviously shown from the field data. Intuitively, the U value would be expected to increase as either the vent rate or ΔT was increased due to a decrease in the noncondensable blanketing effect, either by purging the shellside of the heat exchanger or by increasing the turbulence on the shellside because of the higher flow rates associated with the higher ΔT.

Throughout the test program the measured U values were consistently lower than predicted values. In an attempt to explain these lower values, the test unit heat exchanger was chemically cleaned to determine if film or scale formation on the heat transfer surfaces was causing the lower measured U values. No conclusive difference could be seen after cleaning, thus implying that scaling was not a significant problem.

It is believed that a significant factor leading to the low measured U values was that the blanketing effect of noncondensable gases was relatively high because of the small size of the test unit; this will have a relatively much smaller influence on large units. However, the larger part of the discrepancy between measured and expected U values was due to leaks of condensate from the top of the tubesheet, through the tubesheet seal area, into the evaporator sump. These leaks were discovered towards the end of the test program,and were due to an inadequate seal design that has been corrected. Such leaks do not affect the performance of the unit in any way, but result in low measured values for U since this value is calculated on the basis of the amount of condensate transferred externally from shellside to tubeside. As the pressure difference from the shellside to the tubeside of the heat exchanger increased, as was the case during the test runs at high ΔT values, the leakage rate also increased, thus resulting in even lower measured U values. In reality, based on theory and on the results of most of the tests, it is believed that the actual U value was quite constant over the range of test conditions.

IV. Cost and Performance Estimates for Commercial Scale Units

A. Cost Estimates Figure 9 is an example of a commercial scale H_2S abatement system that would be appropriate at both a dry steam resource such as The Geysers and a liquid dominated resource where liquid is flashed to produce steam. This system consists of a two-stage heat exchanger process for removing H_2S and other noncondensables and a Stretford plant for disposal of the removed H_2S. Geothermal steam enters the first-stage heat exchanger unit and is separated into clean steam and a small vent gas stream. The clean steam is sent to the turbine and the vent gas goes to the second stage. Blowdown from and makeup to the first-stage sump are controlled to limit the buildup of various chemical species in the tubeside condensate.

In a manner similar to that of the first stage, the stream entering the second stage is also separated into clean steam and a vent stream. Clean steam from the second stage is used to supply the after-turbine condenser vacuum system and the Stretford process. Vent gas from the second-stage heat exchanger goes to the vent condenser. The second-stage sump also has provisions for blowdown and makeup.

The vent condenser cools the second-stage vent gas down to temperatures required for discharge to a Stretford unit, normally around 120°F. The condensate formed in the condenser is injected into disposal wells or discarded by some other means.

Table 5 presents a cost summary for a commercial scale system as shown in Figure 9, sized for a typical 55-MW geothermal power plant unit. The costs shown are based on 1979 dollars and the design bases for these costs are shown in Table 6. Table 7 summarizes the major equipment items included.

The capital cost for the heat exchanger process system is estimated at \$5.6 million. Based on vendor quotes, a 2.5-ton-per-day Stretford unit cost is \$2.6 million, giving a total abatement system cost of \$8.2 million. Total direct annual operating costs were $425,000 or 1.0 mill/kWh. With annualized capital charges of 18.5 percent, the total operating and capital costs are $1,945,000 or 4.4 mills/kWh.

The commercial cost estimates presented above are based on a Stretford unit being used for ultimate disposal of the removed H_2S. Under proper geologic conditions, however, one alternative to this approach is to reinject the high pressure H_2S-rich vent gas into an outlying geologic formation which has little or no interaction with the producing field. If this were done, the substantial capital and operating costs associated with the Stretford unit could be avoided.

B. Power Production Performance Effects

The heat exchanger process could result in a slight loss in power production because of the vented steam and the lower pressure of the steam which goes to the turbine. However, since the process removes all of the noncondensable gases ahead of the turbine, the demands of the steam jet air ejector system are reduced and enough clean steam can be obtained from the second-stage heat exchanger to drive the ejectors. The potential power which can be produced per unit of wellhead steam must take all of these factors into account.

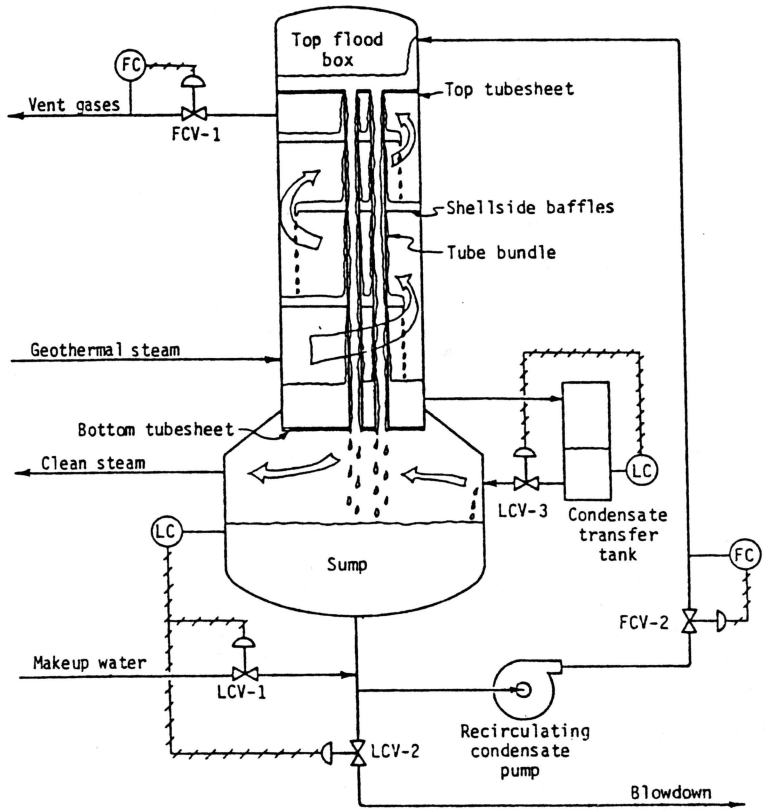
The amount and condition of the steam going to the turbine per mass unit of steam delivered to the heat exchanger process depend on the vent rate and ΔT of the first-stage exchanger. As the vent rate increases, the amount of steam available to the turbine decreases. As the ΔT increases, the temperature and pressure of the clean steam decreases so that less power can be derived per unit of steam. Calculations of theoretical power were done for various ΔT's and vent rates. The results are presented in Figure 10 which shows the relative power produced by the steam from the heat exchanger process versus using 350°F saturated wellhead steam directly. The figure is based on typical Geysers ratios of 95 percent of the wellhead steam going to the turbine and 5 percent going to the ejectors for the case without the heat exchanger process. If ejector requirements are different, then a different set of curves would apply. Calculations show that 2 percent going to the ejectors may be sufficient at The Geysers with the heat exchanger process upstream of the turbine. When the upstream pressure losses are considered, such as those caused by turbine throttle valves, the reduction in power output due to the heat exchanger process may be reduced. The selection of the vent rate, which depends on the steam composition and H_2S removal requirements, has a large effect on the relative power production. To summarize, the effect of the heat exchanger process on power production depends on the combined results of the design factors discussed above which will vary with each specific application. In certain situations the addition of the heat exchanger process could result in no net power loss at all and, in some special cases (low ΔT's and low vent rates), a net power increase might be conceivable.

Varying the ΔT affects both the heat transfer area and power production. For example, reducing ΔT increases the heat exchanger area required but also increases power production. As a result, ΔT must be optimized by balancing capital cost against power production. Figure 11 shows the effect of changing ΔT on capital costs for a 55-MW system. The base case used in Figure 11 is the commercial scale cost estimate previously discussed. A 0.6 power law dependence based on surface area is adopted based on normal process industry scale-up cost estimating techniques.

Changes in the heat transfer coefficient also affect the heat transfer area. Different designs such as fluted tubes or a horizontal tube spray film exchanger, as discussed earlier, could provide higher heat transfer coefficients. The cost estimate developed was based on a 600 Btu/(h·ft^2·°F). This is considered a conservative estimate based on pilot plant data. Problems with leakage in the pilot plant exchanger likely have caused calculated values of the heat transfer coefficient to be low. For this reason, Figure 11 includes capital cost comparisons for design heat transfer values of both 600 and 1000 Btu/(h·ft^2·°F). Knowing the cost of power, load factor, equipment design life, and interest rate, the heat exchanger could be designed to run at whatever ΔT gives the lowest combination of capital and operating costs.

V. References

1. Glenn Coury and R. A. Babione (1981), "A Heat Exchanger Process for the Removal of H_2S Gas from Geothermal Steam--Final Report," Prepared for Electric Power Research Institute, Palo Alto, California, March 1981.



FC - Flow controller

LC - Level controller

FCV - Flow control valve

LCV - Level control valve

Figure 1. Heat Exchanger Process Vertical Tube Evaporator With Baffled Shellside Configuration.

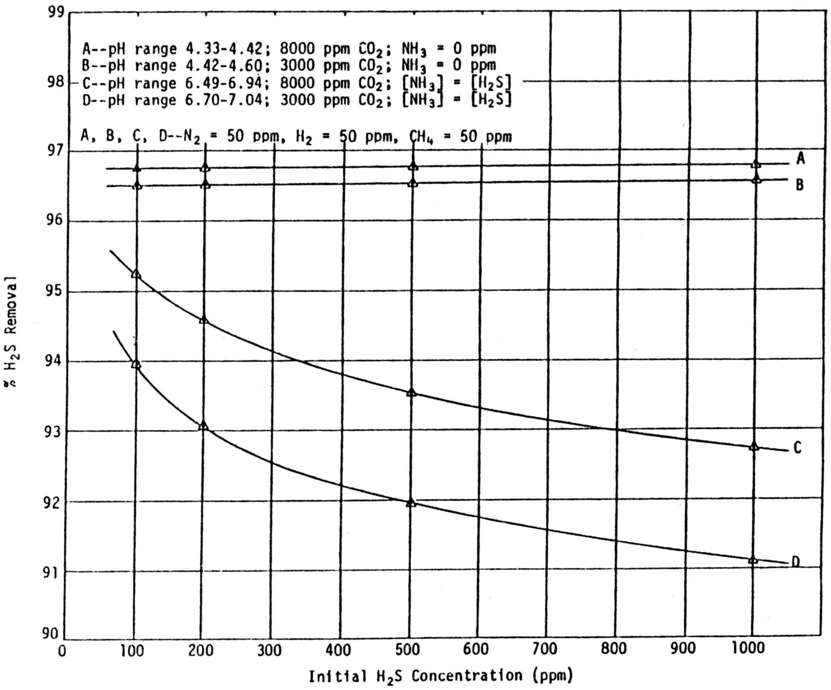


Figure 2. Predicted H_2S Removal at 98% Condensation

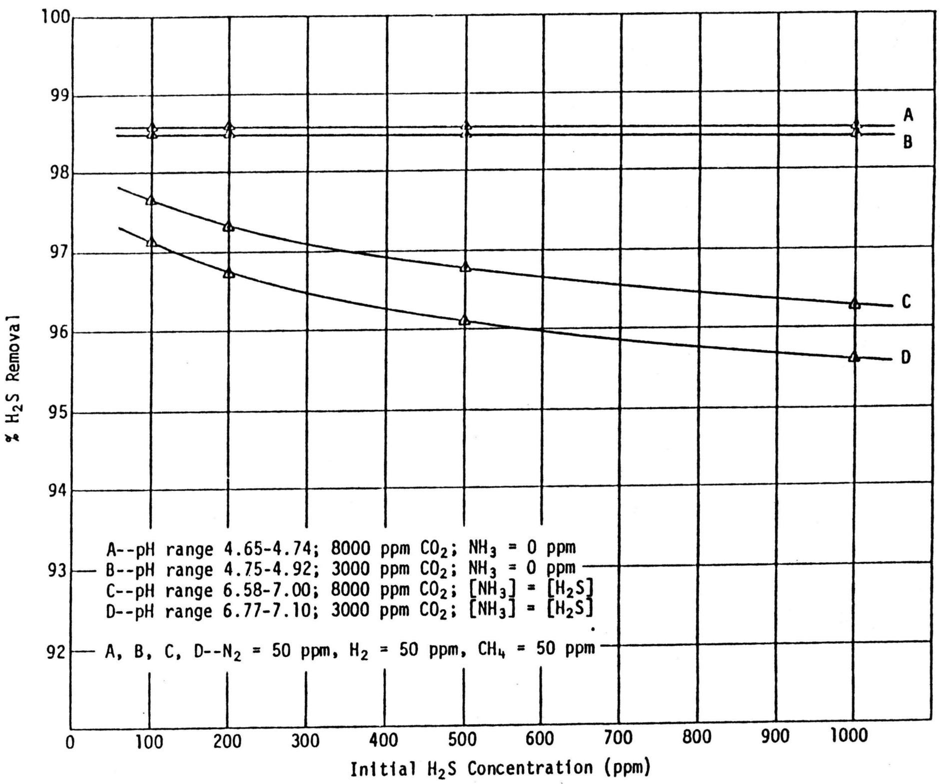


Figure 3. Predicted H_2S Removal at 90% Condensation

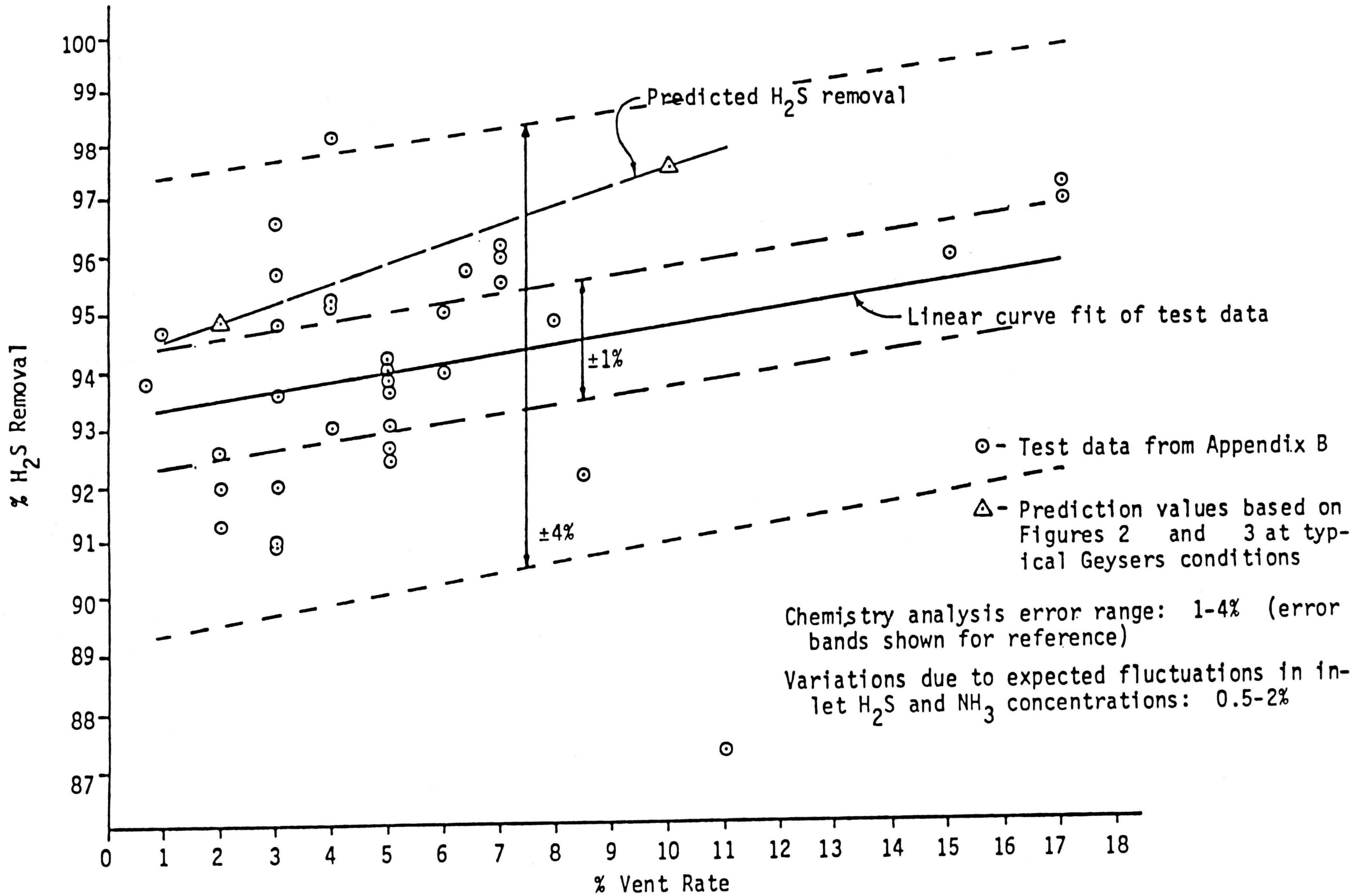


Figure 4. Test Unit Performance: H_2S Removal Versus Vent Rate

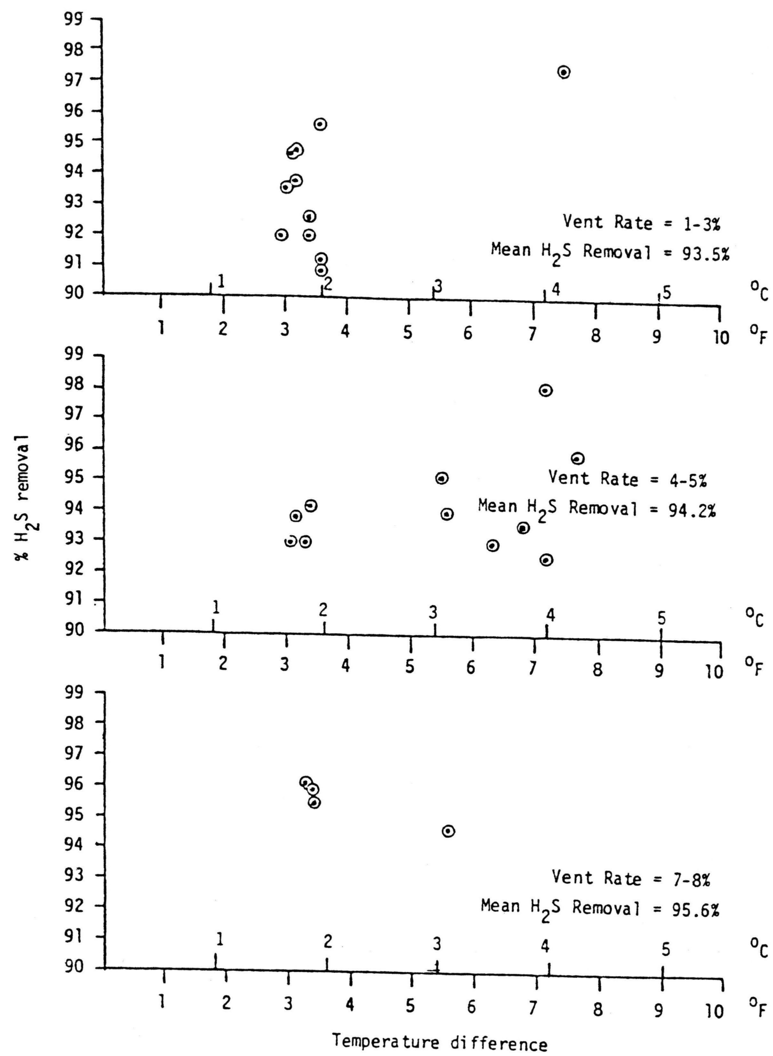


Figure 5. Test Unit Performance: H_2S Removal Versus Temperature Difference

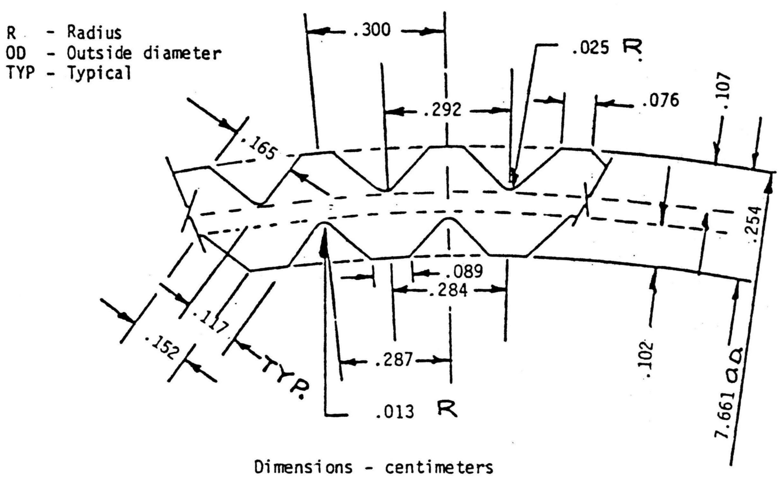


Figure 6. Cross Section of a Doubly Fluted Heat Exchanger Tube

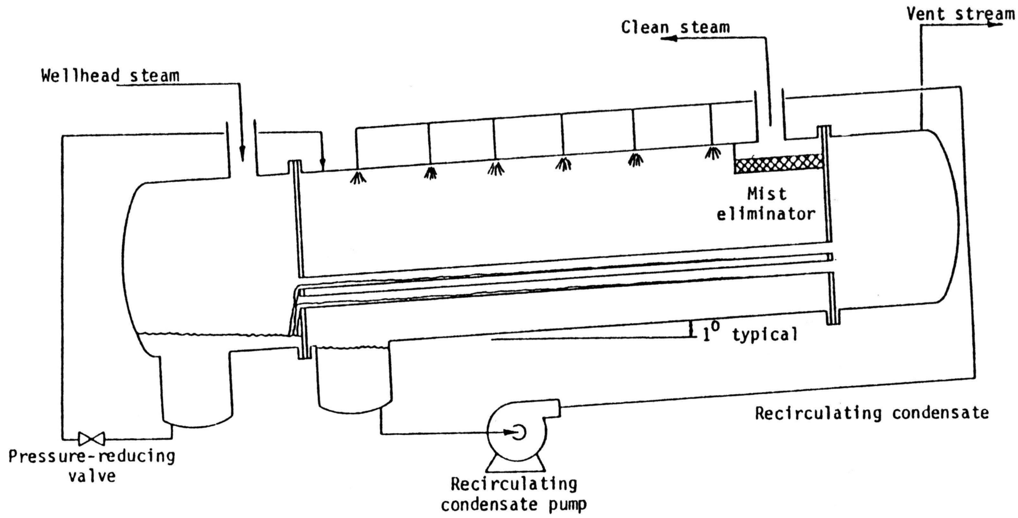


Figure 7. Horizontal Tube Evaporator Configuration

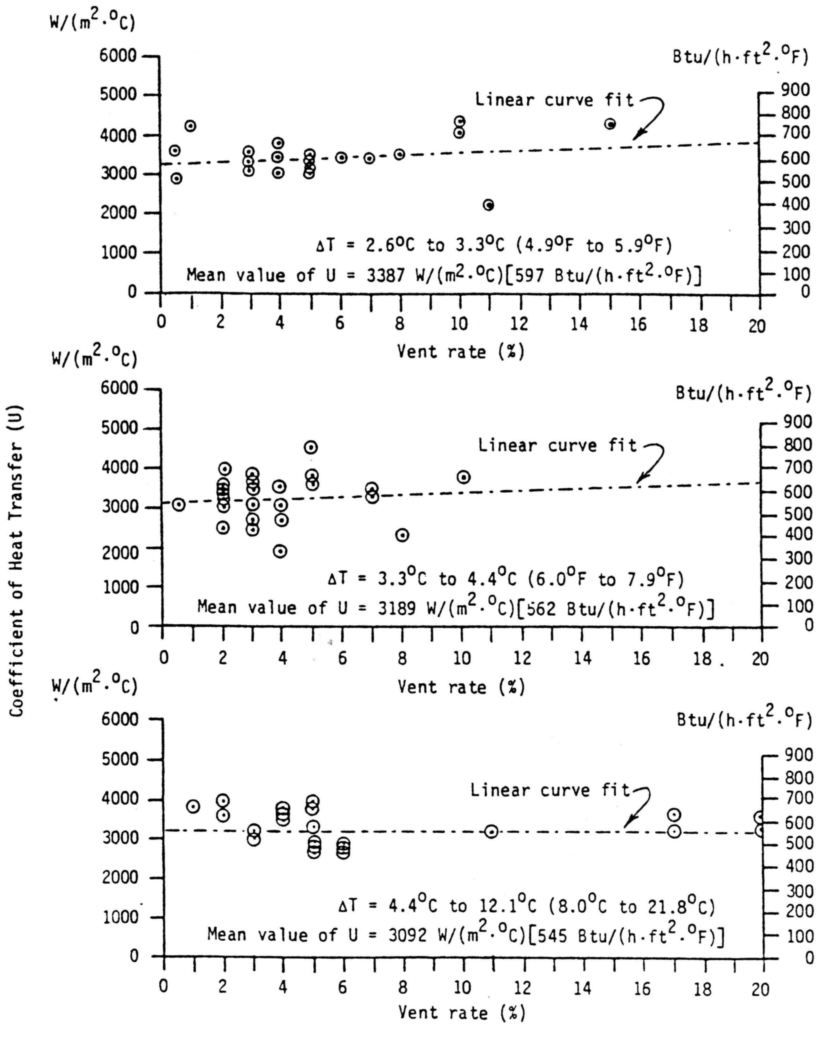


Figure 8. Test Unit Performance: Coefficient of Heat Transfer Versus Vent Rate

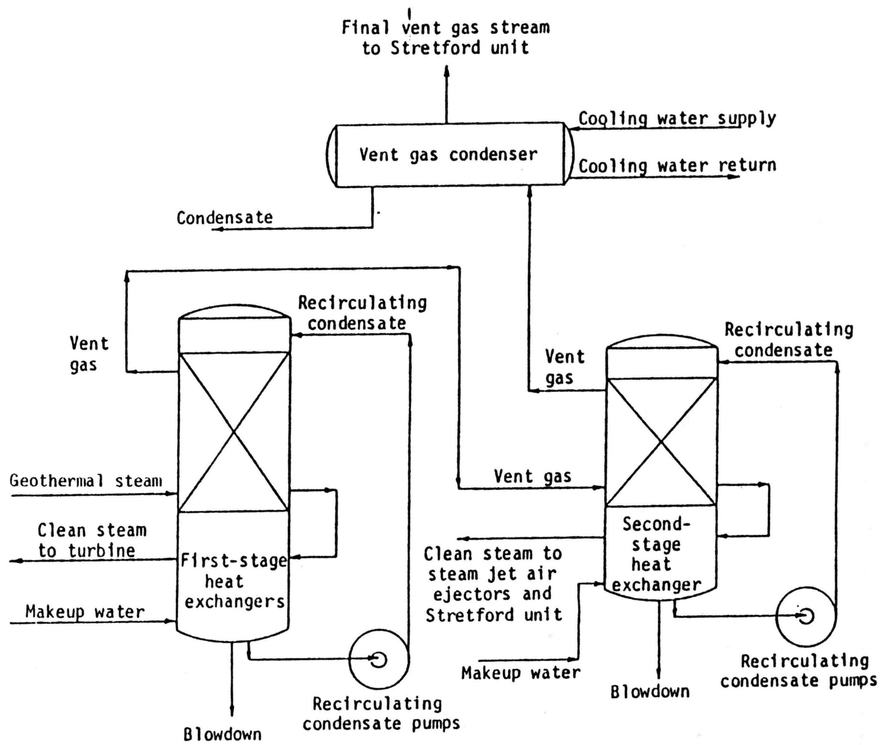


Figure 9. Process Flow Diagram, Commercial-Scale Heat Exchanger Process H_2S Abatement System

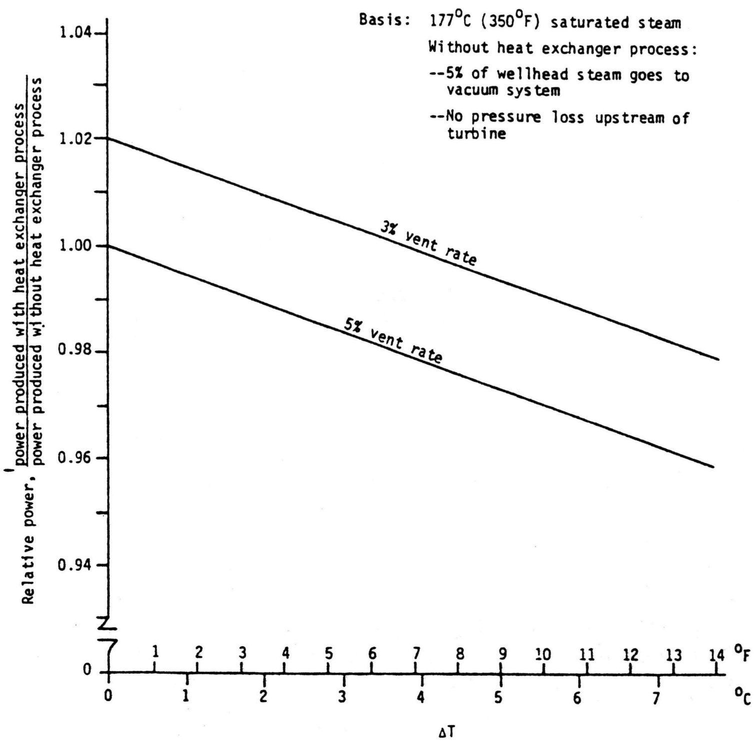


Figure 10. Comparison of Power Production Using Heat Exchanger Process as a Function of ΔT and Vent Rate

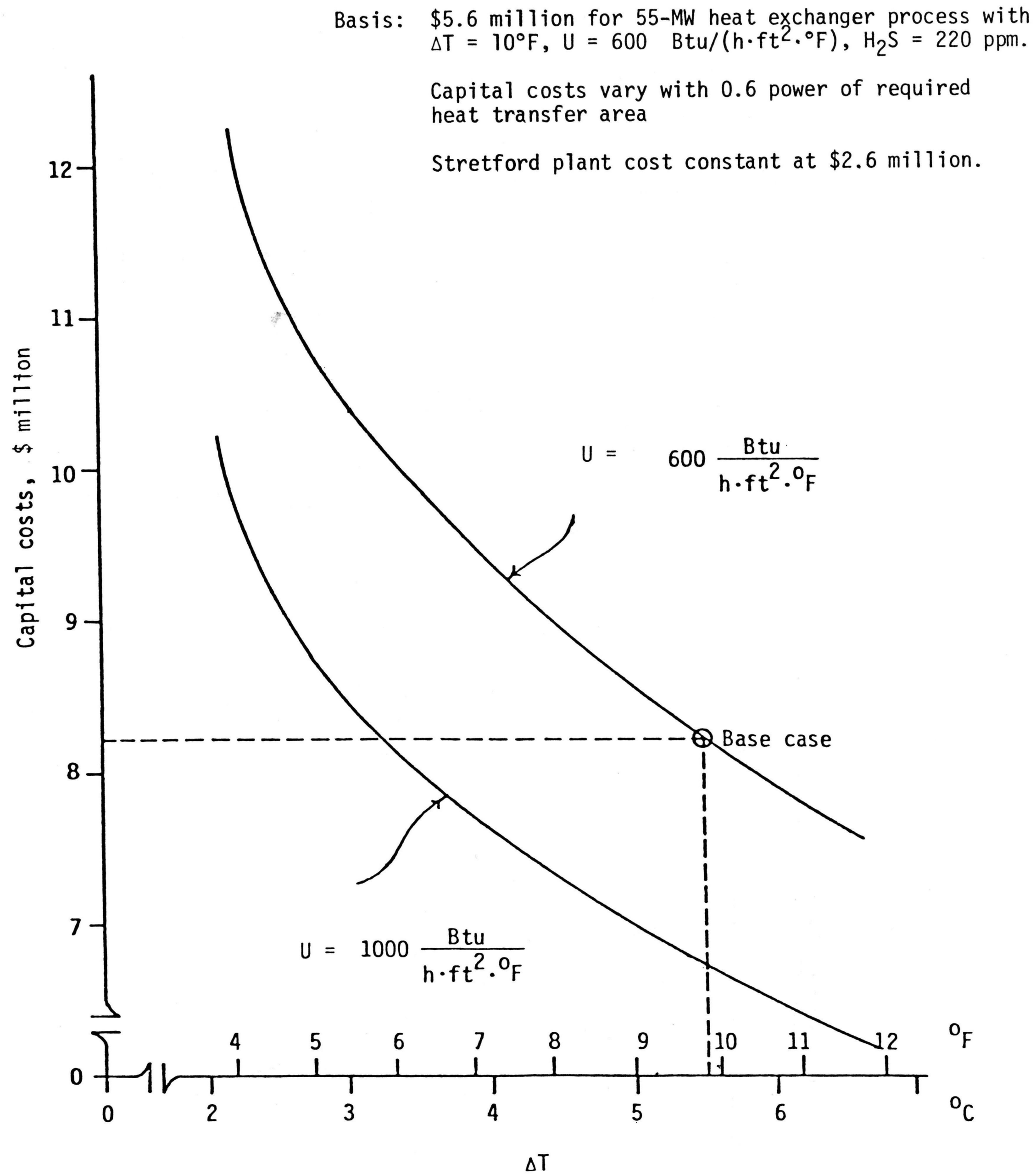


Figure 11. Comparison of Heat Exchanger Process Capital Costs as a Function of Temperature Difference (ΔT) and Heat Transfer Coefficient (U) in First-Stage Heat Exchanger

TABLE 1

STEAM COMPOSITIONS AT THE GEYSERS GEOTHERMAL FIELD

Component	Average Concentration (ppm)	Range (ppm)
CO_2	3000	300 - 6000
H_2S	220	70 - 570
NH_3	100	10 - 330*
CH_4	200	
H_2	50	
N_2	50	
B	20	
Total	3640	

*Total concentration of NH_3 ranges from about 50% to about 100% of the H_2S concentration for a particular set of conditions.

TABLE 2

H_2S REMOVAL VS. INLET H_2S AND NH_3 CONCENTRATIONS

TEST DATE	1/18/80	1/22/80	1/23/80	1/24/80	1/25/80
INLET H_2S (PPM)	722*	801*	317	380*	310
INLET NH_3 (PPM)	171	173	632*	228*	120
INLET CO_2 (PPM)	4,410	4,040	3,093	4,022	3,991
INLET RATIO OF NH_3:H_2S	0.24	0.22	1.99	0.60	0.39
CLEAN STEAM H_2S (PPM)	55	46	23	19	18
CLEAN STEAM NH_3 (PPM)	173	115	254	155	89
% VENT	5	6	5	6	5
ΔT (^oF)	11	10	11	9	10
H_2S REMOVAL (%)	92	94	93	95	94
NH_3 REMOVAL (%)	0	34	60	32	26
PREDICTED H_2S REMOVAL (%)	97	98	95	97	97

* CONCENTRATIONS INCREASED ARTIFICIALLY BY GAS INJECTION

TABLE 3

COMPARISON OF EFFECTS ON MEASURED H_2S REMOVAL VALUES

Process Parameter or Analysis Error	Process Parameter Range or Error Assumptions	Predicted Variation of Measured H_2S Removal Values	Reference
Vent rate	2-10% of inlet flow rate	∿ ±3 to 4%	Figures 2 and 3
Inlet H_2S concentration	150-350 ppm	∿ ±0.5 to 1%	Figures 2 and 3
Inlet NH_3 concentration	50-100% of inlet H_2S concentration	∿ ±1 to 2%	Figures 2 and 3
Chemistry analysis error	*	∿ ±1 to 4%	*

* The chemistry analysis errors are assumed to be ±5% for the inlet steam H_2S concentrations and ±5 ppm for the clean steam H_2S concentrations. This is based on communications with PG&E personnel who are familiar with these techniques and also on the standard deviation of the measured concentrations. A detailed discussion is presented in Reference 1.

TABLE 4

COMPARISON OF PREDICTED HEAT EXCHANGER HEAT TRANSFER PERFORMANCE

		Overall Heat Transfer Coefficient-U	Total Heat Surface Area-A
Unit	Tubes	$Btu/(h \cdot ft^2 \cdot {}^oF)$	Ft^2
VTE	Smooth	740	120,000
VTE	Fluted	780	110,000
HTE	Smooth	1100	80,000

1. Tubes - 304 stainless steel - 2 in. OD x 0.049 in. wall thickness
2. $\Delta T = 10^oF$
3. $Q^* = 871 \times 10^6$ Btu/h

---

*Based in flow requirements of 1.1×10^6 lb/h of 350^oF saturated steam for a typical 55-MW geothermal power plant unit.

TABLE 5

H_2S ABATEMENT SYSTEM COST SUMMARY IN 1979 DOLLARS

Capital Investment:	
Heat exchangers	\$2,900,000
Pumps	100,000
Piping, valves, controls, insulation	900,000
Major equipment cost	3,900,000
Construction @ 20% of major equipment cost	780,000
Subtotal	\$4,680,000
Engineering and fees @ 20%	940,000
Total capital cost -- heat exchanger process	5,620,000
Stretford unit	2,600,000
Total capital cost H_2S abatement system	\$8,220,000
Annual Cost of Investment:	\$1,520,000
Annual Operating Costs:	
Power @ 4.5¢/kWh	\$ 53,000
Operating and maintenance (heat exchanger process)	112,000
Operating and maintenance (Stretford unit)	260,000
Total	\$ 425,000
Operating costs (mills/kWh)	1.0
Total annual capital and operating costs	\$1,945,000
Total annual capital and operating costs (mills/kWh)	4.4

TABLE 6

BASES FOR H_2S ABATEMENT COST SUMMARY

Generating Capacity Basis -- 55 MW

Supply Steam to First Stage H.X. - 1.1×10^6 lb/h, 350^oF saturated, 220 ppm H_2S

Overall H_2S Removal -- 95 percent

On-line Time -- 8000 hours per year

Process H.X. Design -- VTE smooth tube

Process H.X. Materials of Construction -- 304 S/S

First-Stage H.X. U Value -- 600 Btu/($h \cdot ft^2 \cdot {}^oF$)

First-Stage H.X. Condensing Rate -- 95 percent

Second-Stage H.X. Condensing Rate -- 50 percent

Vent Gas Condenser Temperature -- 120^oF

Stretford Unit Production -- 2.5 tons of sulfur per day

Annualized Capital Costs -- 18.5 percent of total plant cost

H_2S Removal Process O&M Costs -- 2 percent of removal plant cost

H_2S Disposal Process O&M Costs -- 10 percent of disposal plant cost

TABLE 7

REMOVAL PROCESS PLANT MAJOR EQUIPMENT LIST

First-Stage Heat Exchangers	-- 3	33 percent units
Second-Stage Heat Exchanger	-- 1	100 percent unit
Vent Gas Condenser	-- 1	100 percent unit
First-Stage Circulation Pumps	-- 4	33 percent units
Second-Stage Circulation Pumps	-- 2	100 percent units