**MITIGATION OF
HYDROGEN SULFIDE
EMISSIONS IN THE
GEYSERS KGRA**

**STAFF DRAFT
JULY 1981**

CALIFORNIA ENERGY COMMISSION

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EMISSIONS IN THE GEYSERS KGRA

July 1981

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ABSTRACT

Violations of the ambient air quality standard (AAQS) for hydrogen sulfide (H_2S) are currently being experienced in The Geysers KGRA and could significantly increase in the future. Attainment and maintenance of the H_2S AAQS is a potential constraint to optimum development of this resource. The availability of reliable H_2S controls and the development of a validated air dispersion model are critical to alleviating this constraint. The purpose of this report is to assess the performance capabilities for state-of-the-art controls, to identify potential cost-effective alternative controls, and to identify the California Energy Commission (CEC) staff's efforts to develop a validated air dispersion model.

Currently available controls (Stretford, Hydrogen Peroxide, and EIC) are capable of abating H_2S emissions from a proposed facility to five lbs/hr. Alternative controls, such as condensate stripping and condensate pH control, appear to be promising, cost-effective control options. The CEC staff is currently developing a validated air dispersion model for The Geysers KGRA. Work on this model will be completed in Fiscal Year 81/82. The CEC staff recommends investigation of retrofit control options for existing units, investigation of alternative control technologies, and dispersion analysis for optimum plant location in order to maximize the development potential of The Geysers KGRA.

MITIGATION OF HYDROGEN SULFIDE EMISSIONS
IN THE GEYSERS KGRA

Table of Contents

	<u>Page</u>
I. Introduction	1
II. Summary	3
III. Background Information	8
A. Air Quality Standards	8
B. History of H ₂ S Controls	11
IV. H ₂ S Control Technologies	18
A. State-of-the-Art Controls	20
B. Advanced Control Technologies	31
V. Analysis of Application of State-of-the-Art Control Technologies	39
A. Analysis of Power Plant Abatement System Performance Capabilities	39
B. Economics	52
VI. Application of Controls for Existing Facilities	57
A. Retrofit State-of-the-Art Controls	57
B. Economics of Retrofits	59
VII. Stacking Controls	65
VIII. Air Quality Analysis Plans for The Geysers KGRA	68
IX. Conclusion and Recommendations	70
X. References	72

LIST OF TABLES

	<u>Page</u>
1. Development of The Geysers Geothermal Resources Summary of Power Plant Emissions.	13
2. H ₂ S Abatement Method Summary	32
3. DWR Bottle Rock Abatement System Costs	53
4. Cost of Alternative Hydrogen Sulfide Abatement Processes	54

LIST OF FIGURES

	<u>Page</u>
1. The Geysers Development Area	12
2. Typical Geysers Power Plant Cycles	14
3. Typical Geysers Power Plant Cycles with Potential Locations for H ₂ S Treatment Systems	19
4. Typical Flow Diagram of a Stretford Process	21
5. Secondary H ₂ S Abatement with Hydrogen Peroxide	26
6. EIC Process, Process Flow Diagram	29
7. Secondary H ₂ S Abatement with Condensate Stripping	35
8. Secondary H ₂ S Abatement with pH Adjustment	37
9. Relationship Between g/GMWH Emission Rates and lbs/hr Emission Rates	43
10. Scenario #1 (EIC Alone) Performance Capabilities	44
11. Scenario #2 (Stretford Alone) Performance Capabilities	45
12. Scenario #3 (Stretford and Hydrogen Peroxide) Performance Capabilities	46
13. Scenario #4 (EIC, Stretford, and Hydrogen Peroxide Combination) Performance Capabilities	48
14. Performance Capability of Retrofit Scenario #5 Hydrogen Peroxide Alone	60
15. Performance Capabilities Retrofit Scenario #6 EIC and Hydrogen Peroxide	61
16. Performance Capabilities Retrofit Scenario #7 EIC Reprocessing	62
17. Performance Capabilities Retrofit Scenario #8 EIC Reprocessing and Hydrogen Peroxide	63

I. Introduction

The attainment and maintenance of the ambient air quality standard for hydrogen sulfide (H_2S) in The Geysers KGRA is a potential constraint for future full field geothermal development. The extent of this constraint is indeterminable at this time, because there is not a simple relationship between emissions and impacts. Many factors affect the attainment and maintenance of the ambient air quality standard for H_2S , and thus potentially constrain future development in The Geysers KGRA. The following are some of the more significant factors:

- A. H_2S emissions from existing geothermal power plants.
- B. H_2S emissions from well field development and operations, specifically steam stacking and drilling operations.
- C. H_2S emissions from future geothermal development.
- D. Location of existing and proposed geothermal development.
- E. The complex terrain of The Geysers KGRA.
- F. Local Meteorology.

In order to overcome this potential constraint to maximum development of the KGRA, it will be necessary to (1) accurately predict the H_2S cumulative impacts in the KGRA and (2) determine the performance capabilities and cost of available control technologies. To predict the H_2S cumulative impacts, a validated air dispersion model, accounting for the complex terrain and meteorology of the KGRA, must be developed. Various deployment and abatement scenarios can be examined using the air

dispersion model. Based upon the model analyses and the estimated capital, operational, and maintenance costs of the control technologies, an overall control strategy for the KGRA can be developed which will ensure attainment of the ambient air quality standard for H_2S and provide for maximum cost-effective development of the resource.

This report assesses the performance capabilities and costs of available control technologies for new and retrofit applications. In addition, the report discusses potential alternative controls which may improve the cost effectiveness of H_2S abatement in The Geysers KGRA. Finally, the report summarizes the CEC staff's efforts to develop a validated air dispersion model to be used to predict cumulative H_2S impacts at The Geysers KGRA.

II. Summary

This study consists of a survey of those hydrogen sulfide abatement systems that are commercially available for application at The Geysers. The study will also examine advanced abatement control systems. The main portion of the report deals with a general method of evaluating the performance of a system or combinations of systems. The results of specific analyses are graphically presented for those systems or combinations of systems that are commercially available. These systems are:

- A. Stretford process: This process uses a surface condenser and gas removal equipment to separate (partition) noncondensibles including H_2S from the condensate. The Stretford system then treats the H_2S entrained in the noncondensable gas stream. This process has a control efficiency of 99 percent plus for the H_2S which it receives. The expected range of partitioning efficiency is 65 percent to 80 percent (percentage of H_2S in noncondensibles).
- B. Hydrogen Peroxide process: This process provides treatment of H_2S contained in the liquid condensate and is usually used as a secondary control. A variation of this process is also used as the primary control on some of the existing units. This process has a control efficiency of 95 to 98 percent for the H_2S that it receives as a secondary control, and 90 to 95 percent as the primary control.
- C. EIC process: This process treats the steam for H_2S prior to its utilization by the power plant. Pilot-scale tests have been

conducted on PGandE Unit 7. The process has been approved for full-scale operation on the DWR Bottle Rock facility and PGandE Unit 7. The expected range of control efficiency of this process is 90 to 99 percent.

There are four basic control technology application scenarios. The selection of the appropriate scenario to apply to a proposed facility will depend on the emission limitation* to be applied to the facility, the inlet steam H₂S concentrations, and the expected H₂S partitioning efficiency. The four basic scenarios are as follows:

1. The EIC process alone;
2. The Stretford process alone;
3. The Stretford and Hydrogen Peroxide in combination; and
4. The EIC, Stretford, and Hydrogen Peroxide processes all in combination.

There are other possible combinations, such as EIC and Hydrogen Peroxide processes in combination. However, the operational and maintenance costs may be excessive.

Based upon information obtained during CEC regulatory cases, the Stretford/Hydrogen Peroxide combination (Scenario #3) and the EIC/Stretford/Hydrogen Peroxide combination (Scenario #4) are capable of controlling H₂S emission levels from proposed geothermal power plants to five pounds per hour, at least for the quality of steam and power plant

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*It can be expected that a five lbs/hr emission rate will be applied to most new facilities.

sizes proposed to date. The EIC process alone or the Stretford process alone would not likely be capable of controlling H₂S emissions to five lbs/hr, unless inlet H₂S concentrations were less than those normally experienced in the KGRA. Scenario #3 or #4 could reduce the H₂S emission levels from proposed geothermal power plants to even less than five lbs/hr if future assessments of H₂S impacts indicate such reductions are necessary. EIC, Stretford, or Hydrogen Peroxide, individually or in combination, are also potential retrofit candidates for existing geothermal power plants, which could emit more than five lbs/hr. However, the selection of these controls or possible alternative controls as potential retrofit candidates will depend on the economics, the need, potential control effectiveness, reliability, and site-specific conditions.

Although the Hydrogen Peroxide process is critical to attaining a five lbs/hr emission rate at this time, the high chemical costs associated with a high abatement efficiency dictate investigation of alternative control technologies. Alternative secondary abatement systems are currently being investigated by the utilities. The most promising are the Condensate Stripping process and Condensate pH Control process. These processes are not currently proven for use on geothermal power plants, although sufficient evidence may be developed in the near future for Application for Certification (AFC) approval.

Another promising innovative technology would involve treatment of the steam by the EIC process, followed by reprocessing of the noncondensable gas stream by an EIC unit. Reprocessing would entail the routing of the noncondensable gas stream from a surface or direct contact condenser to

either the main EIC scrubbing tower or to a separate scrubbing tower, where the H_2S in the gas stream would be treated. To the CEC staff's knowledge, this modification of the EIC process is not currently being investigated. Although it might be prudent to first determine the long-term capabilities of the EIC process before major modifications to the process are made, this modification should at least undergo a paper study to determine its feasibility.

It is the objective of the CEC staff to develop a cumulative H_2S impact analysis of The Geysers KGRA, to develop abatement strategies for the existing units, and to prepare an overall development strategy for future geothermal expansion.

The CEC staff approach will be in two phases. During Fiscal Year 80/81 the staff will contract to develop a validated plume rise model for the geothermal cooling tower. In conjunction with the plume rise study, staff will also contract to measure the downwind dispersion of plumes from cooling towers. During Fiscal Year 81/82, the staff will contract to develop a validated air dispersion model for the complex terrain of The Geysers. The Geysers air dispersion model will be used to examine the cumulative H_2S impact and to examine various abatement strategies and siting options in order to maximize the development at The Geysers. The model should provide a useful tool to determine which areas are sensitive to H_2S emissions, and thus provide valuable data for development of an overall abatement strategy for The Geysers KGRA.

The key elements to improving the cost effectiveness of H_2S abatement in The Geysers are the development of the cumulative impact analysis and

development of advanced control technologies, such as innovative upstream controls, alternative secondary controls, and reprocessing of noncondensibles by the EIC process. In addition, reliability of the control technologies is key to maintaining the cost effectiveness of H₂S abatement and to ensure the attainment and maintenance of the ambient air quality standard for H₂S. Investigation into the reliability of control technologies and methods of improving the reliability is also recommended by staff. It is the CEC staff's recommendation that these elements be pursued.

III. Background Information

A. Air Quality Standards

During normal plant operations, hydrogen sulfide (H_2S) emissions from a geothermal power plant are governed by the California ambient air quality standards (AAQS) for H_2S as well as the Lake County or Northern Sonoma County Air Pollution Control Districts (LCAPCD and NSCAPCD) New Source Review regulations and specific district emissions limits for H_2S .

In theory, the APCDs' New Source Review (NSR) regulations limit H_2S emissions from a new plant to a level that will not prevent the attainment or interfere with the maintenance of the California AAQS for H_2S (0.03 ppm). This requires an assessment of the impacts of the proposed source on ambient air quality in combination with background H_2S levels.

The APCDs' NSR regulations in general would require that Best Available Control Technologies (BACT) must be applied to emission sources from the project if it is found that the project would interfere with attaining and maintaining the AAQS. The ARB and the NSCAPCO have determined that BACT can limit new geothermal plant emissions to five lbs H_2S per hour (ARB letter, Harmon Wong-Woo to William C. Walbridge, dated August 26, 1980).

The APCDs' NSR regulations on recent regulatory cases before the CEC have been the limiting factor for power plant H_2S emissions.

However, both NSCAPCD and LCAPCD have recently adopted new regulations, which would exempt a new facility from NSR review if the facility emitted no more than five lbs/hr H₂S per million pounds steam input to the facility.

District geothermal emission limitations in effect at the time of submittal of the AFC or mandated to be in effect when the project begins operation will define a specific emission limitation for H₂S, in grams per gross megawatt hour (g/GMWh). The emission limit for H₂S from new geothermal power plants, effective since January 1, 1980, is 100 g/GMWh of electricity generated (13.2 lbs/hr for a facility rate at 60 MW Gross).

Recently the emission limitations for both districts were modified as follows: effective July 1985 in NSCAPCD, and January 1, 1981 in LCAPCD, any new plants will be limited to 50 g/GMWh (6.6 lbs/hr for a facility rated at 60 MW gross). Emission limitations that would apply to existing facilities have also undergone modifications by NSCAPCD and LCAPCD. The standard for existing PGandE Units 1 -12 is effectively 200 g/GMWh, and 50 g/GMWh (effective June 1, 1985) for Units 14, 15, and 17 and NCPA #2 in NSCAPCD. In LCAPCD in 1990 (subject to a public hearing), existing units will be limited 50 g/GMWh.

The state H₂S Ambient Air Quality Standard is 0.03 ppm. The ARB, which sets and enforces state Ambient Air Quality Standards,

determined that ambient concentrations of H_2S which equal or exceed 25 ppb (0.025 ppm) constitute violations (ARB letter, Thomas Austin to Michael Tolmasoff, dated, April 2, 1980).

NSCAPCD reports that complaints about H_2S odor from The Geysers began in 1972 and concludes that an emission threshold was reached at that time. Emission data show an average annual H_2S emission rate of 482 lbs/hr in 1971, 919 lbs/hr in 1972, 750 lbs/hr in 1980, and a NSCAPCD projected emission rate of 699 lbs/hr in 1984. CEC staff projects an emission rate of 447 lbs/hr in 1985.

Complaints about H_2S odor had already occurred in Lake County prior to 1972. Winds transport H_2S emitted in Sonoma County across the Mayacmas ridgecrest into southern Lake County. Geothermal emissions affect local air quality to such a degree that the LCAPCD declares significant levels of contaminants are a public nuisance and may have possible health effects which are not understood at this time.

In 1979 and in 1980, significant reductions in the number of violations of the H_2S ambient air quality standard have occurred. However, the meteorological conditions in 1980 were unseasonable, and the number of violations might have been greater if meteorological conditions were more typical of the area. Because the H_2S ambient air quality standard will potentially be violated in the future, and new generating facilities will only tend to exacerbate the problem,

control of existing sources would be necessary to achieve the ambient air quality standard for H₂S now and to provide assurance of attainment of the standards in the future. The impact of air quality regulations on future geothermal development in The Geysers KGRA will depend on the availability and effectiveness of control technologies for both existing and new generating facilities.

B. History of H₂S Controls

Figure 1 shows the location of existing and proposed geothermal power plants in The Geysers KGRA. Table 1 shows existing and proposed geothermal power plant emissions, control technologies, proposed retrofit controls, inlet steam H₂S concentrations, and other plant details. The 1985 H₂S emission estimates are based upon the assumption that PGandE Units 1, 2, 7, 8, 9, and 10 will meet the NSCAPCD variance schedule and will emit no more than 200 g/GMWh. The alternative retrofit controls for the above PGandE units identified in Table 1 are based upon the alternatives identified in the NSCAPCD variance.

The typical power cycles of geothermal power plants are shown in Figure 2. The H₂S in the steam supply, after it is exhausted by the turbine, splits (partitions) off into both the gas stream and liquid stream. In the older PGandE plants, direct contact condensers (condensers where condensate and cooling water come into direct contact) are used for cooling. Due to the high rate of water flow through the condenser, more than 70 percent of the H₂S was absorbed into the cooling water-condensate mixture. Therefore, initial efforts to

SOURCE: USGS KELSEYVILLE, HEALDSBURG, MOUNT ST. HELENA,
AND LOWER LAKE QUADRANGLES

LEGEND

- EXISTING UNITS
- UNITS UNDER CONSTRUCTION
- ⊗ PROPOSED UNITS
- UNION LEASEHOLDS
- ..... McCULLOCH - GKI LEASEHOLDS
- - - SHELL LEASEHOLD
- - - - AMINOIL LEASEHOLDS
- OCCIDENTAL LEASEHOLD
- ⊘ THERMOGENICS LEASEHOLD

FIGURE 1.1-3

THE GEYSERS
DEVELOPMENT AREA

TABLE 1
DEVELOPMENT OF THE GEYSERS GEOTHERMAL RESOURCE
SUMMARY OF POWER PLANT EMISSIONS

Power Plant Unit	Commercial Operation Date	Steam Developer	Gross MW	MW Net	Steam Lbs/Hr Per Unit	Inlet H ₂ S ppmw	Lb/Hr	Abatement System*	Existing H ₂ S Emissions Lbs/Hr	1985 H ₂ S Emission Lbs/Hr **
PG&E 1	1960	Union	12.5	11	240,000	185	44	(e)(h)	44	5
PG&E 2	1963	Union	15.6	13	260,000	155	40	(e)(h)(i)	40	6
PG&E 3	1967	Union	27.5	27	510,000	445	227	(a)	12	12
PG&E 4	1968	Union	27.5	27	510,000	370	188.7	(a)	12	12
PG&E 5	1971	Union	55	53	910,000	280	255	(a)	24	24
PG&E 6	1971	Union	55	53	910,000	355	323	(a)	24	24
PG&E 7	1972	Union	55	53	910,000	210	191	(e)(f)	191	24
PG&E 8	1972	Union	55	53	910,000	125	114	(e)(f)(i)	114	24
PG&E 9	1973	Union	55	53	910,000	60	55	(e)(g)(i)	55	24
PG&E 10	1973	Union	55	53	910,000	65	59	(e)(g)(h)(i)	59	24
PG&E 11	1975	Union	110	106	1,810,000	330	597	(a)	49	49
PG&E 12	1978	Union	110	106	1,810,000	140	253	(a)	49	49
PG&E 15	1979	Thermogenics	62	55	1,160,000	320	429	(b)(c)	14	14
PG&E 13	5/80	Aminoil	139	135	2,650,000	45	119	(b)(c)	11	11
PG&E 14	9/80	Union	117.5	110	2,030,000	70	142	(b)	26	26
Wild Well							35		35	35
Existing Total			952	908			3,034		759	
NCPA 2	2/82, 9/82	Shell	55/55	53/53	1,000,000/1,000,000	70	70/70	(b)(c)		26
PG&E 17	12/82	Union	120	110	2,000,000	350	700	(b)(c)		26
PG&E 18	5/83	Union	120	110	2,000,000	65	130	(b)(c)		12
PG&E 16	11/83	Aminoil	120	110	2,060,000	70	144.2	(b)(c)		5
SMUDGEON #1	12/83	Aminoil	72	65	983,200	60-80	79	(b)(c)		5(8) ^{1/}
DWR Bottle Rock	6/84	McCulloch	62	55	1,071,000	450	482	(b)(c)(d)		5
Oxy Geo. Plant #1	5/84, 8/84	Occidental	88	80	1,300,000	90-30	156	(b)(c)		5(9.7) ^{1/ 2/}
DWR/So. Geysers	1986	Geothermal Kinetics	62	55	1,000,000	350	350	(b)(c)		(5) ^{2/}
NCPA 1	AFC Postponed	RFL	33/33	31/31	600,000/600,000	300	360	(b)(c)		(5) ^{2/}
Total			1772	1661			5578			747

- * (a) Iron Catalyst/NaOH/H₂O₂ (f) Possible Retrofit with EIC
 (b) Stretford (g) Possible Retrofit with Stretford
 (c) H₂O₂ + Catalyst (h) Possible Retrofit with Burner/Scrubber
 (d) EIC (i) Currently 50% Abatement only during adverse meteorological conditions.
 (e) Currently Uncontrolled

- Sources of information for data in the above tabulation:
 1. AFC and docketed information on cases processed at CEC.
 2. G.R.I.P.S. Commission, comprehensive air monitoring plan report CEC Contract 500-068 (8/9) 2/19/80.
 3. Geothermal development update bulletin - CEC Geothermal Office 3/80.
 4. ARB

**CEC Estimate Unit 1,2,7,8,9 and 10 at 200q/GMW, all other units at current or permit limitations.

^{1/}Emission limitation may be modified per DOC conditions.

^{2/}Estimated Emission Limitation, pending final Decision on project.

Direct Contact Condenser Configuration

Surface Condenser Configuration

FIGURE 2

TYPICAL GEYSERS POWER PLANT CYCLES

abate H_2S were through treatment of the cooling water-condensate mixture. The noncondensable gas stream was discharged directly to the cooling tower. Initial efforts to treat the mixture involved oxidation of H_2S with an iron catalyst. Later efforts included use of sodium hydroxide to increase the content of H_2S in the cooling water mixture and the addition of hydrogen peroxide to increase available oxygen for oxidation of the H_2S .

Although economics initially dictated treatment of the cooling water-condensate mixture, power plant reliability (i.e., problems with corrosion and clogging) and significant chemical costs resulted in a change in the abatement strategy. That change in abatement strategy was to alter the partitioning of H_2S in the condenser so that the majority of the H_2S would be contained in the noncondensable gas stream, where the H_2S could be abated easily. In order to increase the partitioning of H_2S into the noncondensable gas stream, a surface condenser (in this condenser, condensate and cooling water are not in contact; condensation occurs on the surface of tube bundles) replaced the direct contact condenser to minimize the amount of water available to absorb the H_2S , and therefore increase the partitioning of H_2S into the noncondensable gas stream. The Stretford process is being used by PGandE and proposed by the other applicants for geothermal plants to treat the H_2S in the noncondensable gas stream. This process is a proven process used in other industries, such as the petroleum industry. In order to be effective, the Stretford unit must receive a dry gas stream with temperature and pressure within its required operating limits.

Partitioning is a key factor in determining the performance of an abatement system, since a system can only treat what it receives. Prediction and control of partitioning is a complex process. Although the significant parameters that affect partitioning are known, there are insufficient data and experience to accurately predict partitioning. The factors that appear to be significant to the mechanism of partitioning are the chemical constituents of the steam and hydrogen ion index (pH) of the condensate, flow rates, pressure and temperature, the H₂S concentrations, and the design of the condenser.

The following is a summary of Dr. Oleh Weres of Lawrence Berkeley Laboratory, description of the factors influencing partitioning:*

- o The chemical composition of the noncondensable gases. The concentrations of H₂S, NH₃, and CO₂ are critical to partitioning. As the H₂S concentration increases, a greater percentage of H₂S will be partitioned into the noncondensable gases. As the ratio of NH₃/CO₂ increases, the condensate will become more basic, and more H₂S will dissolve in the condensate. The following data from power plants equipped with direct contact condensers illustrate this.

	H ₂ S (ppm)	NH ₃ (ppm)	CO ₂ (ppm)	NH ₃ /CO ₂	H ₂ S split (NC gas/ condensate) (%)
The Geysers	200	200	4,000	0.05	30/70
Cerro Prieto	2,000	100	12,000	0.008	70/30

*PGandE responses to LCAPCD data request Geysers Unit 16 case, Question #11, July 14, 1980.

- o The flow rates. At high steam flow rates, there will be less time for equilibrium, and more H_2S will be present in the noncondensable gases.
- o The condensate temperature and pressure. As the temperature increases, the solubility of H_2S decreases. As pressure increases, the solubility of H_2S increases.
- o The type of condenser and its design. In direct contact condensers used on Geysers Units 1 - 12, about 30 percent of the H_2S is in the noncondensate gas, and about 70 percent is dissolved in the condensate. Most of the H_2S is expected to remain in the noncondensable gas fraction from new units equipped with surface condensers. However, partitioning calculations can be highly misleading because they are so very dependent on condenser design and the physical chemistry of the constituents.

The previous discussion shows that a wide range of partitioning is possible. Partitioning will have an effect on the requirements for additional abatement equipment in order to meet air quality standards.

IV. H₂S Control Technologies

The scope of this section will be limited to those systems that are proven for commercial use or are potential candidates for use at The Geysers. Since technologies are rapidly changing, this study will probably have to be revised periodically to keep its usefulness up to date.

The H₂S abatement system types can be broken down into two major categories. These categories are based on where the system is to be installed (see Figure 3) and are as follows:

1. Upstream of the power plant (Location A).
2. Downstream of the power plant turbine (Location B on the noncondensibles gas stream and Location C on the condensate stream).

Systems upstream of the power plant will have to either abate the H₂S entrained in the flow, or H₂S will have to be separated from the steam and then treated. Systems downstream of the turbine will either abate the noncondensable stream or the condensate stream. When determining the abatement systems (either upstream or downstream or both) to be utilized for a given project, the steam composition, partitioning, and candidate abatement systems performance will be required to be evaluated in order to select the appropriate system or combination of systems.

Direct Contact Condenser Configuration

Surface Condenser Configuration

FIGURE 3
TYPICAL GEYSERS POWER PLANT CYCLES WITH
POTENTIAL LOCATIONS FOR H_2S TREATMENT SYSTEMS

A. State-of-the-Art Controls

1. Downstream Controls

a. Stretford Process

The Stretford process is a gas sweetening process in use in several industries, e.g., tail gas treatment for Claus sulfur plants. The Stretford process has proven to be reliable in these applications and has achieved 99 percent plus removal of H_2S .

The Stretford system is designed to operate on the off-gas stream from a surface condenser. The off-gas stream from a direct contact condenser contains too much water for the Stretford system to handle. This gaseous stream, containing H_2S and other noncondensibles, is scrubbed into the Stretford solution in a scrubbing tower. The solution oxidizes the H_2S to sulfur, which is floated away as a froth. An air sparger regenerates the oxygen carriers of the Stretford solution. The Stretford flow diagram is shown in Figure 4.

The constituents of the Stretford solution are sodium carbonate, sodium ammonium polyvanadate, and anthraquinone disulfonic acid (ADA). The hydrogen sulfide is scrubbed into the solution by the basic sodium carbonate, and the sulfide ion then reacts with the vanadium (V) to form elemental sulfur and vanadium ion (IV). The solution then

Figure 4: Typical Flow Diagram of a Stretford Process

SOURCE: Occidental Geothermal Power Plant #1

goes to an oxidizer tank where an air sparger reoxidizes the vanadium ion (IV) to vanadium (V). Anthraquinone disulfonic acid acts as an oxygen carrying medium.

The Stretford process is currently in use at PGandE's Geysers Unit 15 (first full-scale test of surface condensers and Stretford). The partitioning efficiency achieved on Unit 15 is approximately 65 percent (i.e., 65 percent of the H_2S is contained in the noncondensable gas stream) as compared to the 80 - 90 percent predicted. The overall abatement efficiency of the Stretford system, including partitioning, is approximately 65 percent. The cause of the low partitioning efficiency may be related to the pH of the steam. Other Geysers units' steam may not be as basic (high pH) as Unit 15, and condenser modifications may improve the partitioning efficiency on those units. PGandE Unit 13, for example, has achieved an 80 - 89 percent partitioning efficiency. PGandE Unit 14 has achieved partitioning efficiency of the order of 80 - 90 percent. Design modifications of the condenser or acidic addition to the condensate might improve the partitioning efficiency. Secondary abatement can be utilized to control H_2S remaining in the condensate. PGandE Unit 15 has been retrofitted with a Hydrogen Peroxide secondary abatement system, capable of removing 92 percent of the H_2S in the condensate, in order to meet the NSCAPCD emission limitations. The Stretford/Hydrogen Peroxide system is controlling emissions to approximately 14 lb/hr.

The older Geysers units which utilize the direct contact condensers would require retrofitting with surface condensers in order to effectively utilize the Stretford process. The surface condenser would increase the H_2S in the noncondensable gas stream and provide a dry noncondensable gas stream to the Stretford system. Therefore, utilization of Stretford is not considered desirable if more cost-effective methods are available (see Section VI on retrofit controls).

The reliability of the Stretford process is expected to be relatively good, based upon past experience in the petroleum industry. PGandE has indicated that they have experienced problems with sulfur clogging some lines. This problem can be overcome by redesigning the sulfur lines. If sufficient redundancy is provided for critical components, the Stretford process should obtain an availability factor in excess of 90 percent. Approximately 3 percent of the nonavailable hours would be due to forced outages.

b. Hydrogen Peroxide Secondary Process

When the Stretford process is inadequate to meet emission limitations due to low partitioning efficiency, a secondary abatement system is needed to treat the condensate. The primary method of secondary abatement being considered at this time is the Hydrogen Peroxide/Catalyst process.

Other secondary abatement candidates are condensate stripping and condensate pH control. These latter processes are not currently demonstrated for The Geysers, although they have been proposed as alternative controls for the SMUDGE #1 and Oxy Geothermal plant #1 facilities, (see Advanced Control Technology section for discussion of these controls).

The Hydrogen Peroxide process can remove 95 - 98 percent of the H_2S remaining in the condensate after the noncondensable gases have been removed in the surface condenser and sent to the Stretford unit. The combined removal efficiency of the Stretford process and Hydrogen Peroxide secondary abatement process would be 95 percent plus.

Hydrogen peroxide (H_2O_2) oxidizes the H_2S in the condensate. In order to increase the rate of reaction between H_2S and the H_2O_2 , a ferrous catalyst such as $FeSO_4$ may be injected into the condensate. The addition of 1 ppm of ferrous catalyst will increase the reaction rate by a factor of approximately 12. Since this iron will also react with H_2S and oxygen to form suspended solids, a chelating agent such as hydroxyacetic acid (HAA) may be mixed with the $FeSO_4$ to keep the iron in suspension.

A Hydrogen Peroxide process may also include a caustic and acid injection system to control the condensate pH. This

pH control system would be designed to promote the formation of soluble sulfur compounds from the reaction of H_2S with H_2O_2 and to reduce corrosion and scaling in the circulating water system. The caustic would be injected into the condensate along with the hydrogen peroxide in order to maintain an alkaline environment favorable for the production of soluble sulfur compounds from H_2S and H_2O_2 . The acid would be added to the condensate after the H_2S was oxidized to reduce the pH to between 6.5 and 8.0.

A flow diagram for a Hydrogen Peroxide condensate treatment process using an $FeSO_4$ /HAA catalyst with a pH control system is shown in Figure 5. PGandE, at a recent workshop on NSCAPCD proposed rule changes, indicated that they are experiencing corrosion effects on stainless steel screens located downstream of the Hydrogen Peroxide process on Unit 15. The extent and cause of the corrosion is not certain at this time, although PGandE attributes the corrosion to the chelating agent. Possible solutions to the problem, if it proves to be significant, could be to reduce the amount of chelating agent and ferrous catalyst being injected and increase the reaction time by increasing the length of piping or by installing a holding tank.

Other than the corrosion problem discussed above, there appears to be little that can go wrong with the Hydrogen Peroxide process that cannot be mitigated. The major

Figure 5

Source: Occidental Geothermal Power Plant #1 AFC

Secondary H_2S Abatement
With Hydrogen Peroxide

components of the process are pumps, valves, pipes, and storage tanks. If sufficient redundancy is provided for the critical components (i.e., pumps and valves), the availability of the Hydrogen Peroxide process should be high. Because the control efficiency of the process is directly related to the input rate of hydrogen peroxide, and the inlet H_2S concentration can vary over a wide range in a short time, control of the input rate of hydrogen peroxide is critical to maintaining the control efficiency. Currently there are not adequate H_2S condensate monitoring devices to provide automatic control of the input rate of hydrogen peroxide. PGandE and other utilities are currently pursuing development of continuous H_2S condensate monitors, primarily for compliance purposes. However, when adequate monitors are developed, they can be used to provide the necessary feedback to control the hydrogen peroxide input rates, thus improving the reliability of the control process.

2. Upstream Controls

a. EIC Process

PGandE and DOE are sponsoring a pilot test of the EIC process at Geysers Unit 7 (a 100,000 lb/hr test). Preliminary data would indicate a control efficiency of approximately 90 percent, peaking as high as 99 percent. A full disclosure of the results of the Unit 7 test is available

in the Final Report, May 1980, by F.C. Brown, EIC Corp., prepared under PGandE contract 5-36-78 and DOE contract FC03-78ET27181. DWR has committed to utilizing EIC on the Bottle Rock facility to compensate for the high concentrations of H_2S from the Bottle Rock steam field and to reduce emissions during unit outages. PGandE will retrofit the EIC system on their Unit 7 and possibly on their Unit 8 (see Table 1).

This process, developed by the EIC Corporation, is based on scrubbing H_2S from geothermal steam with a solution of metal ($CuSO_4$) salts. Upstream of the turbine, the incoming steam will encounter a solution of $CuSO_4$ in a scrubbing tower. The H_2S in the steam will react with the $CuSO_4$ to form CuS and Cu_2S precipitate. Ammonia, boric acid, and rock dust are also scrubbed into the reagent solution. The scrubbing solution is recirculated and a purge stream is withdrawn from it and separated into a clear liquid fraction and a portion of concentrated copper sulfide solids. The clear liquid purge carries the reaction products and is discarded by reinjection into the geothermal reservoir. The concentrated copper sulfide slurry is regenerated by reoxidizing the copper sulfide solids to copper sulfate, which in turn is recycled to the scrubbing step. A simplified flow chart is shown in Figure 6.

EIC PROCESS

PROCESS FLOW DIAGRAM

SOURCE: DWR Bottle Rock supplemental filing of April 18, 1981

Figure 6

The system may be conveniently described as consisting of three modules: (1) a scrubbing module, (2) liquid-solid separation/regeneration module, and (3) a service module.

The first module consists of a system for the continuous removal of hydrogen sulfide from geothermal steam. Here fresh scrub solution is transferred from the scrubbing solution tank by pump to the scrubbing tower. Hydrogen sulfide is removed from the steam in the scrubbing tower by counter-current contact with scrubbing fluid. The second module, a liquid-solid separation/regeneration system, consists of a decanter or filter to separate the purge stream into a clear liquid stream and a slurry of copper sulfide solids; a system to neutralize the clear liquid stream and recover any copper before reinjection or disposal; and a regeneration reactor to reconstitute the precipitate slurry into CuSO_4 . The CuSO_4 is then returned to the make-up tank and, ultimately, to the recirculating solution.

The third module, a service module, will consist of a copper sulfate make-up tank, surge or balance tanks, chemical storage and metering equipment, process water system, and other miscellaneous equipment.

There are many uncertainties related to the operation of the EIC process. Chief among these uncertainties are the reliability of the process, the potential long-term operational problems (e.g., sulfur may be carried over in the steam to the turbine where it might deposit on the

turbine blades), the potential long-term process problems (e.g., the regeneration of the CuSO_4 may not be as effective as originally thought), and the long-term control efficiency may not achieve expected levels. These uncertainties will not be resolved until the EIC process has undergone full-scale long-term operation. Until the uncertainties are resolved, these uncertainties must be weighed against the potential for the process before a decision can be made to apply the process on a project. In the DWR Bottle Rock case the CEC staff found these uncertainties acceptable.

B. Advanced Control Technologies

The Energy Commission consultant report "Assessment of H_2S Control Technologies for Geothermal Power Plants" (Report #P300-80-004; February 1980) discusses various control systems. Table 2 summarizes the various systems covered in the report.

See the above report for an in-depth analysis of the Coury, Dow Oxygenation, and Burner-Scrubber processes. The Burner-Scrubber process has had significant problems in early testing at PGandE Unit 4. However, the process is currently being planned for retrofit on PGandE Units 1 & 2. The Coury process is being investigated by the steam suppliers for stacking control, but it appears that energy penalties may be high.

In a DOE report released in April 1980 "Analysis of Hypochlorite Process for Removal of Hydrogen Sulfide from Geothermal Gases," a comparative study on a hypothetical 10 MW plant was conducted. The

TABLE 2. H₂S ABATEMENT METHOD SUMMARY

Name of Control System	Status of System	Type of Geothermal Reservoir and Combination Possibilities for Abatement	Points of Application	Abatement System Reliability and Effect on Powerplant Reliability	Abatement Efficiency	
					Individual Process	Plant Overall
Iron catalyst	In use at 5 units at Geysers until December 1978	Dry steam, liquid, combination with Stretford	In circulating water-cooling tower	Up to 15 % loss in capacity factor for plant	40 - 70% (can be higher for low H ₂ S steam)	40 - 70%
Peroxide combination	In use at 5 units at Geysers since January 1979	Dry steam, liquid, combination with Stretford	In circulating water-cooling tower	Similar loss in capacity factor expected as for iron catalyst system	93 - 99%	93 - 99%
Stretford system	Startup June 1979 Unit 15 at the Geysers	Dry steam, combination with iron catalyst, peroxide	Off-gases after the condenser	Sulfur line cooling during outages lessens availability. No effect on plant reliability	99%+	95 - 99%
EIC	100,000 lbs/hr test beginning summer 1979 at Geysers	Dry steam	Upstream of powerplant	Continually available, even during outages -- process reliability unproven, plant effects untested	80 - 98%	80 - 98%
Coury process	Test Facility installed at Geysers	Dry, maybe liquid. Only separates H ₂ S from steam, must be used in combination with Stretford, or burner-scrubber	Upstream of turbine	Continually available even during outages -- process reliability unproven	92 - 98%	92 - 98%
Dow oxygenation	Laboratory tests completed	Single-phase liquid flow, two-phase flow, treatment of condensate	Upstream of turbine or condenser	Continually available even during outages, process reliability unproven	60 - 90%	60 - 90%
Burner-Scrubber	Pilot scale tests completed	Dry steam	Off-gases after condenser	Poor flammability of gases at some units decreased reliability of burner	20 - 75%	15 - 51%

Source: CEC Report, "Assessment of H₂S Control Technologies for Geothermal Power Plants", February 1980.

study investigated three gas stream treating abatement units, utilizing gas compositions from various locations, including The Geysers KGRA. The three abatement units studied were "Hypochlorite Process," "LO-CAT Process," and the "Stretford Process."

The Sodium Hypochlorite process and the LO-CAT process treat gas streams as does the Stretford process. The processes were determined to be competitive in removal efficiency, more economical, and appear to be less complex in design than the Stretford process. These processes have been used in other industries, but have not been used in a geothermal application.

SMUD on its SMUDGE #1 project and Occidental Petroleum on its Occidental Geothermal Plant #1 are investigating two alternatives to the Hydrogen Peroxide abatement process to treat condensate--the Condensate Stripping process and the Condensate pH Control process.

The Condensate Stripping process (with an inert gas) has been successfully used to remove H_2S dissolved in water in the petroleum industry. The H_2S removal efficiency of the Condensate Stripping process is expected to be in excess of 85 percent. This is based on a computer model used in a report entitled "A New Correlation of NH_3 , CO_2 , and H_2S Volatility, Data from Aqueous Sour Water Systems," published in the American Petroleum Institute Publication No. 955, 1978. The Condensate Stripping process is an alternative proposal which would boost the partitioning efficiency obtained in the surface condenser. Additional H_2S liberated from the condensate would be treated by the Stretford process.

The stripping process takes place in a tower where the condensate is pumped into the top of the tower, and a stripping gas is fed into the bottom of the tower. This gas then flows up and out of the top of the tower while the condensate flows down the tower. During this process, H_2S is stripped out of the condensate. The gas stream containing the H_2S is then routed to the Stretford unit for treatment. A flow diagram of the process is shown in Figure 7.

The stripping process is a proven process in the refining industry. However, design work will be required to make the process adaptable to geothermal application.

The Condensate pH Control has been suggested by PGandE in the past and is being investigated by various utilities. This control has not yet been utilized for geothermal applications. Theoretically, this control will increase partitioning efficiency of H_2S in the condenser housing. SMUD has indicated that there is little supporting data available to allow design calculations for this process. PGandE has used caustic soda ($NaOH$) in conjunction with H_2O_2 in some of their existing plants where direct contact condensers are used instead of surface condensers. PGandE is conducting investigations into Condensate pH Control, using direct injection of ammonia into the condenser. SMUD's approach is to utilize the abundant CO_2 in the noncondensable gas stream to produce carbonic acid (H_2CO_3). This reaction takes place in a CO_2 absorption tower. The carbonic acid is then recycled back to the condenser where it is sprayed into the condenser neck to cause both a desorbing of H_2S already in the soluble form of ammonium bisulfide and the lowering

Source: Occidental Geothermal Power Plant #1

Figure 7
Secondary H₂S Abatement
With Condensate Stripping

of pH to prevent more H_2S from becoming dissolved in the condensate (i.e., increase partitioning). A flow diagram of the process is shown in Figure 8.

Since the SMUD process uses a natural source of chemical (CO_2), it appears to be more economical than the PGandE method. The performance of a Condensate pH Control process is uncertain until test data is available.

In July 1980, SMUD contracted with the Colorado School of Mines Research Institute for bench-scale laboratory studies of Condensate pH Control process. Although the studies are still in progress, SMUD reports (letter October 21, 1980) that the preliminary results appear promising. The SMUDGE0 #1 facility was certified on the basis of using the Hydrogen Peroxide process; however, under the terms of the NSCAPCD Determination of Compliance, SMUD may modify the proposed abatement process with CEC and NSCAPCD approval.

Reprocessing of the noncondensable gas stream by the EIC process appears feasible, based on a cursory review of the technology. Reprocessing would entail the routing of the noncondensable gas stream from a surface or direct contact condenser to the main EIC scrubbing tower or to a separate tower where the H_2S in the stream would be treated. To the CEC staff's knowledge, this modification of the EIC process is not currently being investigated. The advantage of such a modification would be reduced capital cost, as no Stretford unit would be required to treat the noncondensable gas

Source: Occidental Geothermal Power Plant #1

Figure 8
Secondary H₂S Abatement With
pH Adjustment

stream. Some of the major uncertainties of the modification are whether the temperature or chemical composition of the noncondensable gas stream will be favorable for abatement by the EIC process and whether the injection of the noncondensable gas stream into the main EIC scrubbing tower will affect the performance of the process. These potential problems could be resolved by reheating the noncondensable gas stream. Although the performance capabilities of this modification are shown in Section VI, "Application of Controls for Existing Facilities," this control is also potentially applicable for new facilities.

Innovative upstream controls, such as the Coury and the Dow Oxygenation processes, merit further investigation. Based on recent communications with the steam developers, a number of other upstream controls are currently being investigated. These controls are advantageous because they can provide abatement for power plant emissions and steam stacking emissions.

V. Analysis of Application of State-of-the-Art Control Technologies

A. Analysis of Power Plant Abatement System Performance Capabilities

There are four basic control technology application scenarios. The selection of the appropriate scenario to apply to a proposed facility will depend on the emission limitation* to be applied to the facility, the inlet steam H_2S concentrations, and the expected H_2S partitioning efficiency. See Figure 3 for the location of the abatement system. The four basic scenarios are as follows:

1. The EIC process alone (location A);
2. The Stretford process alone (location B);
3. The Stretford and Hydrogen Peroxide processes combination (location B & C); and
4. The EIC, Stretford, and Hydrogen Peroxide processes combination (location A, B & C).

There are other control application scenarios such as the Hydrogen Peroxide process alone or in combination with the EIC process, and the combination of the Stretford and EIC processes. However, the capital or operational and maintenance cost of these scenarios would be excessive for new applications. If used at all, they would generally be applied as retrofit technologies.

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*It can be expected that the emission limitations to be applied to most new facilities will be five lbs/hr.

The emission rate of a proposed facility utilizing one of the above four scenarios or the application of one of the potential retrofit scenarios can be calculated as follows:

$$W = M \times (1 - E_A) \times [(1 - E_B) \times P + (1 - E_C) \times (1 - P)] \text{ (Equation \#1)}$$

where:

M = inlet H₂S flow rate in lbs/hr.

Inlet H₂S flow rate in lbs/hr can be calculated from H₂S concentrations in parts per million by weight (ppmw) by the following equation:

$$M \text{ (lbs/hr)} = C \text{ (ppmw)} \times 10^{-6} \times \text{Inlet Steam Flow (lbs/hr)} \\ \text{(Equation \#2).}$$

E_A = control efficiency (in percent) of EIC process or control at location A.

E_B = control efficiency (in percent) of Stretford process or control at location B.

E_C = control efficiency (in percent) of Hydrogen Peroxide process or control at location C.

P = partitioning efficiency, i.e., percent of H₂S in the noncondensable gas stream.

W = the emission rate in lbs/hr.

For example, assume a facility is proposed utilizing the Stretford and Hydrogen Peroxide combination (scenario #3), the inlet H₂S

concentration (M) is 200 lbs/hr, the control efficiencies of the Stretford and Hydrogen Peroxide process are 99 percent (E_B) and 95 percent (E_C), respectively, and the partitioning efficiency (P) is 65 percent. The emission rate from such a facility would be calculated as follows:

$$W = 200 \frac{\text{lbs}}{\text{hr}} \times (1 - 0) \times [(1 - .99) \times (.65) + (1 - .95) \times (1 - .65)] = 4.8$$

Note: The E_A is zero because no upstream control was proposed.

Based upon recent cases before the CEC and the ARB/NSCAPCD BACT determination, this facility would likely meet the regulatory requirements depending on project-specific impact analysis. If the inlet H_2S flow rate were 100 lbs/hr, the emission rate of the facility would be 2.4 lbs/hr. In this case, if the facility's emission limitation were 5 lbs/hr, the chemical feed of the Hydrogen Peroxide process could be reduced (i.e., reduce the Hydrogen Peroxide control efficiency to 88 percent), and the facility could still meet the emission limitation.

If the inlet H_2S flow rate were 400 lbs/hr, the emission rate would be 9.6 lbs/hr. In this case, the control efficiency of the hydrogen peroxide secondary abatement process would need to be increased or a third control technology would need to be incorporated in order to meet a five lbs/hr emission limitation.

In the following pages, graphical analyses of the performance capabilities of the above control scenarios (1, 2, 3, and 4) are illustrated. These graphical analyses are based upon Equation #1 above.

Figure 9 shows the relationship between the g/GMWh emission rates and the corresponding emission rate in lbs/hr. For example, if the emission rate were 50 g/GMWh, the corresponding emission rate for a 60 gross MW facility would be 6.6 lbs/hr.

Figure 10 shows the performance capability of Scenario #1 (EIC alone) based upon the expected EIC range of control efficiencies. For example, if the inlet H₂S concentrations were 160 lbs/hr and the EIC control efficiency (E_A) were 96 percent, the emission rate (W) would be 6.4 lbs/hr.

Figure 11 shows the performance capabilities for Scenario #2 (Stretford alone). The Stretford control efficiency (E_B) is set at 99 percent; the emission rate varies based upon the partitioning efficiency (P). For example, if the inlet H₂S concentration (M) were 70 lbs/hr and the partitioning efficiency (P) were 90 percent, the emission rate (W) would be 7.6 lbs/hr.

Figure 12 shows the performance capabilities for Scenario #3 (Stretford and Hydrogen Peroxide processes combination). The Stretford control efficiency (E_B) is set at 99 percent, and the Hydrogen Peroxide control efficiency (E_C) is set at 95 percent. The emission rate varies based upon the partitioning efficiency (P). For example, if the inlet H₂S concentration (M) were 250 lbs/hr and the

FIGURE 9

RELATIONSHIP BETWEEN g/GMWH EMISSION
RATES AND lbs/hr EMISSION RATES

Stretford Efficiency $E_B=99\%$
 H_2O_2 , Efficiency $E_C=95\%$

Figure 12
Scenario #3 (Stretford and
Hydrogen Peroxide)
Performance Capabilities

Partitioning Efficiency

partitioning efficiency (P) were 75 percent, the emission rate would be 5 lbs/hr.

Figure 13 shows the performance capabilities of Scenario #4 (EIC, Stretford and Hydrogen Peroxide processes combination). The EIC control efficiency (E_A) is set at 90 percent, Stretford control efficiency (E_B) is set at 99 percent, and Hydrogen Peroxide control efficiency (E_C) is set at 95 percent. The emission rate varies based upon the partitioning efficiency (P). For example, if the inlet H_2S concentration (M) were 300 lbs/hr and the partitioning efficiency (P) were 65 percent, the emission rate would be .72 lbs/hr. If the emission limitation for such a facility were 5 lbs/hr, the control efficiency of the Hydrogen Peroxide process could be reduced to approximately 55 percent by reducing chemical inputs, and thus meet the emission limitation.

For the Condensate Stripping and Condensate pH Control alternatives, Equation #1 would need to be modified. The control efficiency (E_C) at location C would be equal to zero, as any H_2S remaining in the condensate after application of these controls would be released unabated. The partitioning term in Equation #1 would be modified to include the partitioning efficiencies resulting from application of these alternatives. For the Condensate Stripping process, the partitioning efficiency would be modified as follows:

$$P^* = P + (E_S) \times (1 - P) \quad (\text{Equation \#3})$$

where:

Figure 13
Scenario #4 (EIC, Stretford, and
Hydrogen Peroxide Combination)
Performance Capabilities

48
W - PLANT H_2S EMISSIONS - LB/HR

EIC Efficiency $E_A = 90\%$
Stretford Efficiency $E_B = 99\%$
 H_2O_2 Efficiency $E_C = 95\%$

M - INCOMING H_2S IN STEAM SUPPLY - LB/HR

P = partitioning efficiency without control (same as in Equation #1).

E_S = efficiency of the stripping process.

P* = Total partitioning efficiency with control.

(P* would be substituted in Equation #1 for P in order to obtain the emission rate utilizing the control.)

For the condensate pH control, E_{pH} (efficiency of pH control) would be substituted in Equation #3 for E_S to obtain P*. Equation #1 would be modified as follows for either control alternative:

$$W = M \times (1 - E_A) \times [(1 - E_B) \times (P^*) + (1 - P^*)] \text{ (Equation \#1*)}$$

No graphical representations of Equation #1* will be provided, as E_S and E_{pH} have not been defined at this time.

The graphical representations on the preceding pages are for those H₂S abatement systems scenarios that the CEC staff believes to be the most viable for new geothermal power plant proposals. The graphs are intended to enable the user to make a quick estimate of emissions that can be expected under various conditions. The range of evaluation in the makeup of the graphs reflect those ranges of H₂S concentrations and emission limitations that have been encountered in the certification process of geothermal plants. Analysis of the graphical representations provides the following conclusions on application of the scenarios:

1. EIC process alone--If the control efficiency of EIC does not exceed 90 percent, this scenario will not be capable of meeting a 5 lbs/hr emission rate if inlet H_2S concentrations are greater than 50 lbs/hr. However, if the control efficiency is approximately 99 percent, the scenario could abate to 5 lbs/hr with inlet H_2S concentrations as high as 500 lbs/hr. This scenario appears promising if high control efficiencies are obtained, since it can provide control during both emergency plant shutdown and normal operation. It is, however, the least proven of the three types of systems approved during the CEC certification process. Application of this scenario on facilities with inlet H_2S concentration greater than 50 lbs/hr will depend on the ability of the process to reach the high end of the expect range of efficiency.
2. Stretford process alone--This scenario could not meet a five lbs/hr emission rate based upon the normally experienced inlet H_2S concentrations, even if partitioning efficiency is high.
3. Stretford/Hydrogen Peroxide processes combination--This combination will be the standard system for meeting a five lbs/hr emission limitation. If the partitioning efficiency (P) achieved is as high as 80 percent and the Hydrogen Peroxide process efficiency (E_C) is 95 percent, this scenario would be capable of abating inlet concentrations as high as 275 lbs/hr to 5 lbs/hr. If E_C is increased to 98 percent by the addition of more hydrogen peroxide, an inlet concentration of 370 lbs/hr could be abated to 5 lbs/hr.

This scenario may not be the most desirable downstream of plant treatment because of the economics associated with the secondary Hydrogen Peroxide/catalyst abatement system (see Economics section). However, this scenario will be used because the technology is the only proven system available.

4. EIC, Stretford, and Hydrogen Peroxide processes combination--
This system is proposed for the DWR Bottle Rock project due to high H_2S inlet concentrations and permit emission limitation. Control efficiencies obtainable with this scenario are generally greater than current laws would require. If P and E_C were 80 percent and 95 percent respectively, inlet concentrations as high as 2,800 lbs/hr (greater than any concentrations found at The Geysers) could be abated to 5 lbs/hr.

Based upon the ARB/NSCAPCD determination of BACT and the experience of recent regulatory cases (DWR Bottle Rock, SMUDGE #1, and PGandE Unit 16), it is likely that any proposed facility in The Geysers KGRA will be required to emit no more than 5 lbs/hr H_2S . Either Scenario #3 or #4 could meet this emission limitation, depending on the specifics of the project (i.e., inlet steam constituents and partitioning). It is also likely that either Scenario #3 or #4 could meet a more stringent emission limitation if the worst case air quality analysis dictates. The current control technologies are adequate to meet the existing regulations, although research into alternative technologies may provide more economically advantageous

controls, such as condensate stripping and condensate pH control.

B. Economics

Geothermal energy is an attractive alternative energy source, primarily because it displaces oil and because of its relative cost compared to other energy sources. The cost of geothermal power in 1980 was approximately 25 mills/kWh compared to 53 mills/kWh for conventional oil/gas power plants. The costs of geothermal power have increased in recent years, as have other sources of energy. The cost of geothermal power has increased primarily due to inflation, higher steam costs and because of application of environmental mitigations, such as H₂S controls. The costs of H₂S controls depend not only on the emission limitation applied to the facility, but also on the inlet H₂S concentrations and the size of the facility.

The abatement system cost estimates for the 55 MW DWR Bottle Rock facility (design 643 lbs/hr inlet H₂S, 65 percent partitioning) are shown in Table 3.

Table 4 shows the costs of abatement systems for a 110 MW facility based upon the inlet steam conditions of PGandE Unit 7 (382 lbs/hr inlet H₂S; partitioning assumed the same as Unit 15, 65 percent). This table was obtained from the ARB report "Suggested Control Measures for the Control of Hydrogen Sulfide Emissions From Geothermal Operations at The Geysers Known Geothermal Resources Area," April 22, 1981.

TABLE 3
DWR BOTTLE ROCK ABATEMENT SYSTEM COSTS^{1/}

System	Capital Cost \$10 ⁶	Capital Cost \$1KW	Chemical Cost ^{4/} \$10 ⁶ /Year	Operational and Maintenance Cost \$10 ⁶ /Year	Operational and Maintenance Cost Mills/KWh ^{6/}
Turbine Bypass	0.46	8.4	-	-	-
Stretford ^{2/} (99% Abatement Eff.)	5.0	91	0.7	0.2	2.3
EIC (90% Abate- ment Eff.)	5.5 ^{7/}	100	0.3	0.2	1.3
Hydrogen Peroxide (95% Abatement Eff.)	1.5	27	1.7	.025	4.5
Solids Removal ^{3/}	13.5	245	-	-	-

^{1/} DWR Bottle Rock is a 55 MW net facility, cost estimates were based upon 600 ppmw inlet H₂S concentrations.

^{2/} The costs include the estimated cost of a surface condenser over a direct contact condenser. Stretford unit sized for 643 lbs/hr H₂S inlet steam, 65% partitioning is assumed.

^{3/} Solids Removal system may be required for Hydrogen peroxide system, however best information at this time indicates it would not be required.

^{4/} Chemical costs are based upon the assumption all abatement systems are operating at their maximum potential, however if EIC obtains 90% control, chemical cost for Stretford and the emission limitation of 5 lbs/hr could be met at the inlet H₂S concentration of 600 ppmw.

^{5/} Assumes treatment of 35% of total H₂S flow entering plant; 65% of the H₂S goes to the Stretford system.

^{6/} Based on 7000 hours of operation per year.

^{7/} Costs are preliminary estimates provided during the course of the DWR Bottle Rock AFC proceedings.

TABLE 4
COST OF ALTERNATIVE
HYDROGEN SULFIDE ABATEMENT PROCESSES^{1/}

<u>System</u>	<u>Capital Cost \$10⁶</u>	<u>Capital Cost \$/kw</u>	<u>Operational and Maintenance Cost \$10⁶/Year</u>	<u>Operational and Maintenance Cost mill/kwh^{3/}</u>
Iron-Caustic Peroxide (90-95% Abate. Eff)	7.0	64	3.5	4.5
Stretford ^{2/} (99% Abatement Eff.)	8.0	73	0.6	0.8
Stretford and Hydrogen Peroxide ^{4/} (95% Abatement Eff.)	9.0	82	1.6	2.1
EIC Process (90% Abatement Eff.)	10.2	93	0.9	1.2

1/ Based on a 110 MW Facility with PGandE Unit 7 inlet conditions, 382 lbs/hr H₂S input.

2/ The costs include the estimated cost of a surface condenser over a direct contact condenser. Stretford unit sized for 382 lbs/hr H₂S inlet steam, 65% partitioning is assumed.

3/ Based on 7000 hours of operation per year.

4/ Based on 65/35 partitioning split in the condenser. To obtain Hydrogen Peroxide costs subtract Stretford costs.

If the operating and maintenance (O&M) cost of the Stretford and Hydrogen Peroxide processes are compared in Tables 3 and 4, it can be seen that the O&M costs are approximately proportional to the H₂S to be treated. For example, the Stretford O&M and chemical costs for Bottle Rock inlet conditions and for Unit 7 inlet conditions are 246 mils/lbs H₂S treated and 276 mils/lbs H₂S treated, respectively. The Hydrogen Peroxide O&M costs for Bottle Rock conditions and for Unit 7 conditions are 862 mils/lbs H₂S treated and 854 mils/lbs H₂S treated, respectively.

The values shown in Tables 3 and 4 would indicate that the O&M costs of the EIC process are proportional to the MW size of the facilities. Since the EIC system has not been demonstrated on a full-scale test, the values shown are preliminary and scaling factors may not have been incorporated in the O&M cost estimates.

With the exception of the Hydrogen Peroxide process, the capital costs are not proportional to H₂S inlet conditions. Because the sizing of the Stretford and EIC systems would be proportional to the stream to be treated (i.e., noncondensable gas and steam flow rate), the capital costs are proportional to the MW size of the facility. The sizing of the Hydrogen Peroxide process would be proportional to the amount of H₂S to be treated, because the sizing of equipment would be based on the requirements of chemical input to complete the reactions.

The O&M costs for the Bottle Rock facility shown in Table 3 may be overestimated; the O&M cost for the Stretford and Hydrogen Peroxide

processes assume that the EIC process is not operating. If the EIC system obtained 90 percent control, the O&M cost of the Stretford and Hydrogen Peroxide process would be reduced by 90 percent and the 5 lbs/hr emission limitation would still be met. The O&M costs on Table 3 also assume that the systems are operating at their maximum potential efficiency. The Hydrogen Peroxide process need only obtain 80 percent control (partitioning efficiency, 65 percent; EIC, 90 percent control; and Stretford, 99 percent) in order to meet the 5 lbs/hr emission limitation. The O&M costs for the Hydrogen Peroxide process, therefore, could be reduced by an additional 15 percent corresponding to their reduced control efficiency (80 percent vs. 95 percent). The total O&M cost under these conditions would be 8.5 percent of the amount shown in Table 3. Based upon the above discussion, the total O&M costs for Bottle Rock are approximately 1.46×10^6 /yr.

Although the O&M costs for Bottle Rock are lower than the O&M cost for a 110 MW facility with PGandE Unit 7 inlet conditions utilizing the Stretford/hydrogen peroxide combination scenario, the capital costs for Bottle Rock are nearly double those of a 110 MW facility on dollars per kilowatt basis.

VI. Application of Controls For Existing Facilities

A. Retrofit State-of-the-Art Controls

Control of existing units presents a different problem than new units. The existing units, in general, were constructed without H₂S controls. The majority of these units have since been retrofitted with the Hydrogen Peroxide Caustic abatement system with an overall control efficiency of approximately 90 percent (see Table 1 for emission rates and abatement systems). Capacity factors of these units have fallen as a result of applying this control (see Section III.B of this report). Because these units (1 - 12) are fitted with direct contact condensers, retrofit with the Stretford system is not economically practicable. The EIC system appears promising for retrofit, depending on further design and performance data. PGandE will utilize the EIC system on Unit 7 and, depending on the results, may utilize the system on Unit 8.

Some of the most important factors which will dictate how or whether an existing unit should be retrofitted are as follows:

1. Existing and future emission limitations applicable to existing units;
2. Need for retrofit (i.e., facility is resulting in or contributing to a significant impact, or the impact is restraining future geothermal development);

3. Site constraints (i.e., availability of land for construction of additional abatement facilities);
4. Facility constraints (i.e., space limitations and facility design--direct contact condensers);
5. Feasibility of applying controls and control efficiencies;
6. Economics (including loss of capacity during unit outage for retrofit).

In addition to the four control scenarios discussed in Section V of this report, the following are also potential retrofit scenarios:

5. Hydrogen Peroxide caustic process alone;
6. EIC and Hydrogen Peroxide processes combination;
7. EIC process with reprocessing of noncondensable gas stream by EIC process; and
8. EIC and Hydrogen Peroxide processes combination with reprocessing of noncondensable gas stream by EIC.

Scenarios 7 and 8 involve technologies which have not been demonstrated or, to the CEC staff's knowledge, investigated. However, based upon the CEC staff's cursory review of the technology, they appear promising (see Section IV.B).

The efficiency of the above retrofit scenarios would be calculated from Equation #1 (see Section V of this report). For Scenarios 7 & 8, the efficiency of EIC (E_A) would replace the efficiency of the

Stretford process (E_B) in Equation #1. The performance capabilities for retrofit Scenarios 5 through 8 are shown in Figures 14, 15, 16, and 17, respectively.

Because of the potential costs and the potential effects on the reliability of these units, further investigation of control technologies for existing units on a case-by-case basis would be warranted. This would also help in developing an overall H_2S control strategy for The Geysers KGRA.

B. Economics of Retrofits

The capital and operating and maintenance costs discussed in Section V.B. of this report are accurate for the abatement system equipment and hardware necessary for retrofit application. However, the costs in Section V.B. do not include the secondary costs resulting from application of these abatement systems on existing units. For example, if the Stretford process were applied to a unit with a direct contact condenser (units 1 through 12), additional costs would be incurred from refitting the facility with a surface condenser, loss to generation during the facility retrofit (perhaps as much as 9 months), and engineering redesign. Engineering and refitting costs are unique for each unit and should be determined on a unit by unit basis. In addition, the unit sites are also unique. In some cases space may be a prime criterion in determining what retrofit control would be appropriate. Criteria such as space limitations, facility design constraints, down time, costs, and effects on reliability must be examined in addition to the

W - PLANT H_2S EMISSIONS - LB/HR

W - PLANT H_2S EMISSIONS - LB/HR

performance capabilities in order to make a rational choice between the retrofit controls.

A very simplistic analysis would indicate that the EIC process is the most cost-effective control for retrofit. If a facility were retrofitted with the EIC process, the facility could continue to operate while the EIC plant was built. Only a relatively short down period would be required while the necessary steam transmission line connections were made. Since no major facility modifications would be required, the capital cost of this retrofit alternative would be less than other alternatives.

VII. Stacking Controls

Historically, whenever a power plant outage occurred (scheduled or forced), the total steam flow for the unit was released (stacked) directly to the atmosphere unabated. The total flow was stacked until the decision was made that the outage would be long term. For scheduled outages, this decision was made immediately. In the case of forced outages, the decision was generally made within four hours of the outage. The wells were shut in gradually and individually to approximately 1 percent of their total flow in order to avoid damage to the well casing. Because stacking emissions are unabated, the potential impact is significant.

Unit interties are currently being used to mitigate stacking. For those units which are adjacent to each other (such as unit 5 & 6, 7 & 8, and 9 & 10), steam can be transferred from one unit to the other. Steam production from each unit's well field would also be reduced.

There are three types of stacking controls currently being planned. These controls are:

1. EIC process;
2. Turbine bypass; and
3. Automatic well control valves, including unit interties.

The EIC process has previously been discussed in Section V of this report. Because the process is upstream of the plant, it can abate during plant outages.

The purpose of the turbine bypass system is to reroute the steam around the turbine to the condenser, during unit outages, in order that the downstream abatement processes can treat the H_2S in the steam. The turbine bypass system can also be used during unit startups. The turbine bypass system can operate from zero to full load reduction. During turbine bypass operation the heat load on the condenser will increase, and the evaporation rate in the cooling tower will increase. In order to mitigate this effect, the circulating water flow rate and the number of operating cooling towers cells can be reduced to reduce evaporation losses. The cooling tower will operate at a higher temperature than normal under such conditions.

During operation of the turbine bypass system, supplemental electrical power will be required to maintain operation of the H_2S abatement systems. This power can be supplied from on-site standby generators, reduced operation of the main turbine to meet in-house needs, or off-site power supplies.

The turbine bypass system has not yet been used for geothermal operations. However, initial data indicates that the turbine bypass should operate reliably (i.e., available greater than 99 percent of the time). The effect of the turbine bypass system on partitioning is unknown, although it is expected to be negligible. The effectiveness of the control will depend heavily on the availability of the downstream abatement systems (i.e., Stretford and Hydrogen Peroxide secondary abatement system).

Automatic well control valves may have effects on well casings, although no firm data are available. This system, when combined with unit interties, may be effective in reducing stacking occurrences.

VIII. Air Quality Analysis Plans for The Geysers KGRA

The development of a cumulative impact analysis is critical to the development of an overall H₂S abatement strategy and the attainment and maintenance of the ambient air quality standard for H₂S. Without such an analysis, the application of any abatement strategy would be purely a guess.

In the SMUDGE #1 case, the SAI Geysers Hybrid air dispersion model was utilized to estimate the cumulative impacts at Anderson Springs. The results of that analysis showed an estimated background H₂S concentration of 24 ppb in 1984 when SMUDGE #1 comes on line. Because of the uncertainties in the model and the lack of validation of the model, it was concluded that the estimated H₂S concentration was sufficiently close to the 25 ppb criteria of ARB (see Section III.A. Air Quality Standards) that a violation was likely to exist when SMUDGE #1 comes on line. The results of the analysis also showed, although tentative, that some of the existing units contributed a greater proportion to the impact than indicated by their respective emission rates.

It is the goal of the CEC staff to perform a cumulative impact analysis of The Geysers KGRA, not only to develop an abatement strategy for the existing units but also to prepare a development strategy for future geothermal expansion (i.e., site screening and abatement strategy). The first step in the analysis is to develop a validated air dispersion model.

The CEC staff approach will be in two steps. During Fiscal Year 80/81 the staff will contract to develop a validated plume rise model for

predicting the behavior of releases from geothermal cooling towers. The staff's approach will be to utilize tracers released from existing cooling towers to accurately measure plume rise and pollutant dispersion downwind. These measurements will be utilized to perfect a plume rise model.

During Fiscal Year 81/82, the staff will contract to develop a validated air dispersion model for the complex terrain of The Geysers. The dispersion data obtained during the Fiscal Year 80/81 study will be used to perfect an existing dispersion models suitable for use in the KGRA. These models will be used in concert with the plume rise model developed in Fiscal Year 80/81 to carry out a cumulative impact assessment of The Geysers KGRA.

IX. Conclusion and Recommendations

The state-of-the-art control technologies are capable of abating H₂S emissions from proposed facilities to five lbs/hr, or even less if necessary. However, the cost of abatement for facilities which would be located in areas of the KGRA with high H₂S concentrations in the steam may be significant. Although the costs would not exceed conventional generation costs, the development of such areas with high H₂S concentrations may not be the most cost-effective strategy for achieving the maximum development potential for The Geysers KGRA. Abatement costs for plants in areas with relatively clean (low H₂S concentration) steam would be less, and for this reason, such clean steam areas should be utilized first if otherwise acceptable.

The standard control scenario for new facilities is the Stretford and Hydrogen Peroxide combination. Although the Hydrogen Peroxide process is critical for this scenario to meet a five lbs/hr emission rate, alternative secondary controls such as Condensate Stripping and Condensate pH Control may be demonstrated in the near future and should improve the economics of H₂S abatement. The Stretford/Hydrogen Peroxide combination is not the most desirable control scenario for retrofit application because of the potentially high capital cost of the retrofit. The EIC process shows promise as a retrofit scenario because of the ease of application and the cost of abatement. The EIC process also shows promise as the primary control for new facilities, if the process is proven capable of high abatement efficiencies (i.e., 98 percent to 99 percent). However, currently EIC is expected to have a control

efficiency in the range of 90 percent to 99 percent, and the lower end of the range is insufficient to meet a 5 lbs/hr emission rate without additional control technology. A possible improvement to the EIC process would be the reprocessing of the noncondensable gas stream in conjunction with normal operation of the EIC process. This innovation could greatly improve the performance capabilities of the EIC process even at the lower end of the expected range of efficiencies. However, this innovation is not currently being investigated.

There are many uncertainties related to a strategy for achieving maximum development potential for The Geysers KGRA. Chief among these are the feasibility and cost effectiveness of retrofit technologies, reliability of control technologies, the cost effectiveness of future siting, and the cumulative impacts of development. The staff recommends pursuing the following elements in order to ensure optimum development potential of The Geysers KGRA:

1. Assess the mitigation of cumulative impacts for the KGRA;
2. Investigate the feasibility and cost effectiveness of the control options for retrofit of existing units;
3. Investigate potential cost-effective alternative H₂S controls;
4. Investigate the reliability and methods of improving reliability of control technologies; and
5. Develop siting guidelines and criteria for future geothermal expansion which ensure optimum cost-effective KGRA development.

X. References

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