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Updated Cost Estimates of Meeting Geothermal Hydrogen Sulfide Emission Regulations

K. D. Wells
J. W. Currie
S. A. Weakley
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August 1981

Prepared for the U.S. Department of Energy
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Pacific Northwest Laboratory
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FOREWORD

Development and commercialization of hydrothermal resources for electrical energy production is recognized as a complex political, environmental, and economic undertaking. Substantial uncertainty exists concerning the degree to which the economic climate, environmental changes, and political actions will influence development and ultimate commercialization.

This research report is one of a series being prepared as part of the Department of Energy's project entitled "Economic Valuation of Geothermal Environmental Impacts." The goal of this project is to provide information and support for program planning, research, and marketing activities directed toward the commercialization of hydrothermal resources. A primary objective of this work includes developing ways to identify, estimate, and mitigate the nonmarket cost impediments to the commercialization of hydrothermal resources.

Pacific Northwest Laboratory (PNL) is conducting this project for the Department of Energy, Office of Hydrothermal Commercialization, under Contract No. AE-30-03-02. Publications from this project include:

Wells, K. D. and J. W. Currie. 1979. "Impact of H₂S Emission Abatement on Geothermal Power Costs." Proceedings, Institute of Environmental Sciences, 25th Annual Technical Meeting. Seattle, Washington.

Wells, K. D., J. W. Currie, S. A. Weakley, and M. Y. Ballinger. 1980. The Cost of Meeting Geothermal Hydrogen Sulfide Emission Regulations. PNL-2802, Pacific Northwest Laboratory, Richland, Washington.

Scott, M. J., K. D. Wells, J. W. Currie and M. J. King. 1980. An Exploratory Benefit Cost Analysis of Environmental Controls on Hydrothermal Energy. PNL-3527, Pacific Northwest Laboratory, Richland, Washington.

Wells, K. D., J. W. Currie, B. A. Price and E. A. Rogers. 1981. The Cost of Meeting Geothermal Liquid Effluent Disposal Regulations. PNL-2991, Pacific Northwest Laboratory, Richland, Washington.

Wells, K. D., J. W. Currie, S. A. Weakley and M. Y. Ballinger. 1981. Updated Cost Estimates of Meeting Geothermal Hydrogen Sulfide Emission Regulations. PNL-3847, Pacific Northwest Laboratory, Richland, Washington.

J. W. Currie
Project Manager

SUMMARY

To discover how to effectively increase the rate and level of hydrothermal resource utilization, the U.S. Department of Energy, Office of Hydrothermal Commercialization, initiated a study of hydrogen sulfide emission control costs. Research was conducted by the staff of Pacific Northwest Laboratory, operated for the Department of Energy by Battelle Memorial Institute.

Hydrogen sulfide (H_2S) emissions from hydrothermal resources create an odor nuisance at development sites. The cost of preventing the odor nuisance may be large and may constitute a significant economic barrier to resource commercialization under existing environmental standards.

The primary objectives of this research were to develop H_2S abatement cost functions that may be used to estimate H_2S emission control costs and to prepare a case study of emission control costs at a specific known geothermal resource area (KGRA). H_2S abatement costs were hypothesized to depend on several variables, including H_2S concentrations, treatment process removal efficiencies, and environmental standards. Contacts with resource developers and utilities and literature reviews both indicated that H_2S concentrations may range from near zero to over 500 parts per million by weight (500 ppm_w) in the flashed-steam fraction of the fluid. Removal efficiencies ranged from 50 to 99% and environmental standards varied widely.

Regulations exist only at the state level of government, although the Environmental Protection Agency (EPA) has promulgated federal guidelines. Transition from an ambient concentration standard to an emission limitation was a regulatory trend identified that may solve the problem of estimating the H_2S abatement level required at a given site.

H_2S emission abatement processes considered feasible for airborne emission control included two upstream and two downstream treatment techniques. From literature describing the technical aspects of the processes, individual treatment cost functions were developed and then used in a case study to estimate the costs that may be encountered when controlling H_2S emissions at

one site. Treatment costs include estimates of certain fixed charges and overheads that normally apply to long-lived capital investment projects of similar nature.

A case study of H_2S emission control costs expected at the Valles Caldera KGRA in New Mexico was developed in this report. The resource has a relatively high H_2S concentration in the raw-flashed steam (250 to 500 ppm_w). Ambient environmental standards for H_2S are relatively stringent in this part of New Mexico (3 ppm_w), although a partial waiver may be granted for the Valles Caldera KGRA. For abatement levels up to 90% of potential H_2S emissions, the Stretford process appears to be the most cost-effective control system. Application of the process would cost an estimated minimum of 1.78 mills per kWh or \$1.3 million per year in January 1980 dollars for a 110 MWe plant.

To achieve higher levels of emission control, up to 97% abatement of potential H_2S emissions, the EIC process appears to be the most cost-effective system. As a substitute for the Stretford process it would achieve a maximum of 97% abatement at a cost of 3.55 mills per kWh, or \$2.6 million per year in January 1980 dollars for a 110 MWe plant.

The incremental cost of achieving the extra 8% control is 1.77 mills per kWh, a 100% increase. When the efficient allocation of society's scarce resources is considered, the value of the odor prevention benefits realized by the use of abatement systems must be weighed against the costs of those systems.

Currently, the value of preventing the H_2S odor nuisance at hydro-thermal resources is not known, but should be developed and used as the basis for assessing the net benefits of alternative levels of H_2S emission abatement to society.

ACKNOWLEDGMENTS

Pacific Northwest Laboratory would like to acknowledge the contributions of Garratt Sharp, Larry Krumland, and Carl Weinberg of Pacific Gas and Electric Company at the Geysers; Gerald Katz of the San Francisco DOE Operations Office; Joel Robertson of Union Oil Company, Los Angeles, California; William Dyer of the EIC Corporation, and John Wilson of Dow Chemical Company, Freeport, Texas. PNL researchers who participated in reviewing earlier drafts include Linda L. Fassbender and Clarence H. Bloomster. Word processing was coordinated by Ruth Keefe and Shari Loeber. Editing and proofreading was managed by Vicki Lee.

CONTENTS

FOREWARD	iii
SUMMARY	v
ACKNOWLEDGMENTS	vii
1.0 INTRODUCTION	1.1
2.0 CONCLUSIONS AND RECOMMENDATIONS	2.1
3.0 HYDROGEN SULFIDE EMISSIONS	3.1
4.0 HYDROGEN SULFIDE EMISSION REGULATIONS	4.1
FEDERAL REGULATIONS AND STANDARDS	4.1
STATE REGULATIONS AND STANDARDS	4.2
5.0 EMISSION CONTROL PROCESSES	5.1
EMISSION CONTROL TECHNOLOGY	5.1
UPSTREAM TREATMENT PROCESSES	5.4
Dow Process	5.4
EIC Process	5.6
DOWNSTREAM TREATMENT PROCESSES	5.9
Stretford Process	5.9
Iron Catalyst Process	5.15
COMPARATIVE PROCESS SUMMARY	5.17
6.0 CASE STUDY	6.1
SITE SELECTION CRITERIA	6.1
COST ESTIMATION	6.2
H ₂ S Abatement Costs	6.3
CASE STUDY SUMMARY	6.5
REFERENCES	R.1

APPENDIX A - RESERVOIR GEOCHEMISTRY SUMMARY	A.1
APPENDIX B - HYDROGEN SULFIDE CONTROL COST FUNCTIONS	B.1
APPENDIX C - H ₂ ABATEMENT COSTS	C.1
APPENDIX D - COST ESTIMATION METHODOLOGY	D.1

FIGURES

5.1	H ₂ S Treatment Process Locations	5.3
5.2	Dow H ₂ S Removal Process	5.5
5.3	EIC Hydrogen Sulfide Removal Process with Regeneration by Leaching	5.7
5.4	Modified System Cycle for Using Surface Condensers at The Geysers Power Plant	5.10
5.5	Typical Flow Diagram of Stretford Process at The Geysers	5.11
5.6	Mass Balance for 27 MWe Plant with Surface Condenser and Stretford Plant	5.14
5.7	Iron Catalyst H ₂ S Removal Process	5.16
6.1	Comparative H ₂ S Abatement Costs for Baca, New Mexico	6.4

TABLES

3.1	H ₂ S at The Geysers	3.2
4.1	State H ₂ S Standards for Hydrothermal Developments	4.2
5.1	H ₂ S Control Technology Summary	5.19
6.1	Baca, New Mexico Resource Description	6.2
A.1	Reservoir Geochemistry Summary	A.1
C.1	Hydrogen Sulfide Abatement Costs	C.1
D.1	Variables for Cost Estimation	D.4

1.0 INTRODUCTION

Geothermal resource development may lead to new or increased emissions of hydrogen sulfide (H_2S) and other environmental changes that will be subject to a range of regulation and control requirements. This research provides a means of estimating the cost of hydrogen sulfide (H_2S) emission control.

This study was designed to derive H_2S emission abatement cost functions and illustrate the cost of H_2S emission abatement at a hydrothermal site.

Four tasks were undertaken to achieve the study's objectives:

- document the release of H_2S associated with geothermal development
- review H_2S environmental standards
- develop functional relationships that may be used to estimate the most cost-effective available H_2S abatement process
- use the cost functions to generate abatement cost estimates for a specific site.

Section 2.0 presents the conclusions and recommendations derived from the research. Section 3.0 discusses the definition of the term "impacts" as used in this research and provides current estimates of the highest expected H_2S concentrations of in geothermal reservoirs. Regulations governing H_2S emissions are reviewed in Section 4.0, while Section 5.0 contains a review of H_2S control technology and a summary of the control cost functions. A case study is presented in Section 6.0 to illustrate H_2S abatement costs at the Baca KGRA in New Mexico.

Information presented in this document is intended to serve as an aid to the Department of Energy in research, development, and demonstration allocation decisions.

2.0 CONCLUSIONS AND RECOMMENDATIONS

A review of H_2S emissions, environmental regulations, and the cost of H_2S emission abatement resulted in the following conclusions:

- H_2S gas is a potential emission from at least 25% of the identified high-temperature hydrothermal convection systems in the western United States.
- Regulatory compliance are costs positively related to the concentration of H_2S in the raw geothermal fluid, the fluid flow rate, and the abatement level achieved at the geothermal site.
- The magnitude of H_2S abatement costs will depend on the control level required to achieve regulatory compliance.
- For the Baca, New Mexico, case study: 1) the EIC H_2S removal process appears to be the most cost effective of the currently available abatement processes when high levels of emission control must be achieved. The process is expected to achieve 97% abatement of H_2S emissions. 2) H_2S abatement efforts may increase power costs for flashed-steam systems at the site by approximately 3.55 mills per kWh, in January 1980 dollars.
- Without an investigation of the incremental benefits of H_2S emission control, the most desirable emission abatement level for hydrothermal resources cannot be specified.

The results of this study indicate the need for additional research in the following areas:

- investigate the factors determining the value of reducing or eliminating the H_2S odor nuisance at geothermal sites
- estimate the net benefits and costs to society of alternative H_2S abatement levels at hydrothermal sites.

3.0 HYDROGEN SULFIDE EMISSIONS

Hydrothermal resource development will change the environment with three types of impacts: 1) airborne emissions, 2) waterborne emissions, and 3) land use impacts. This report deals specifically with hydrogen sulfide (H_2S) airborne emissions. A large body of literature that describes the sources of H_2S emissions has been developed but little has been done previously to develop functions for estimating abatement costs (Axtman 1975; Defferding et al. 1978; Futures Group 1975; Maritin et al. 1978; Midwest Research Institute 1978; Sung et al. 1977; EPA 1978; Wapora, Inc. 1976).

Unlike waterborne effluents and land impacts, the control processes for H_2S abatement are remarkably similar in design and application between liquid- and steam-dominated resources and conversion systems. Data from H_2S research at the Geysers are expected to be directly applicable to control situations that may arise on liquid-dominated resources, primarily because the conversion technology used on liquid-dominated systems may be the same as the technology used on vapor-dominated resources (flashed steam). The process flows and conditions may be sufficiently similar to allow the use of common control technology.

H_2S concentrations at hydrothermal resources vary a great deal, even among wells on the same site. At The Geysers recorded H_2S concentrations in the resource steam have varied between wells by a factor of ten, from approximately 50 ppm_w to well over 500 ppm_w.

August 1978 measurements of H_2S in geothermal steam at The Geysers were reported by Garratt Sharp of PG&E and are presented in Table 3.1. Concentrations of H_2S in the raw steam vary from 51 ppm_w at Unit 9 to 451 ppm_w at power-generating Unit 3. Liquid-dominated systems also exhibit considerable variability in H_2S concentrations. Information for the Baca, New Mexico, KGRA, chosen for evaluation as a case study in this report, indicates that H_2S concentration in the raw steam may vary from 290 ppm_w to over 560 ppm_w (Cosner 1977). The expected range of H_2S is illustrated in Appendix A along with currently available geochemical data for several

TABLE 3.1. H₂S at The Geysers

<u>Unit Number</u>	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>	<u>6</u>	<u>7</u>	<u>8</u>	<u>9</u>	<u>10</u>	<u>11</u>
H ₂ S ppm _w	272	163	451	390	329	372	373	113	51	66	338

additional high-temperature hydrothermal convection systems in the western United States. As many as 25% of the high-temperature KGRAs may have H₂S concentrations significantly greater than zero.

4.0 HYDROGEN SULFIDE EMISSION REGULATIONS

Hydrothermal resource development at KGRAs having significant H_2S concentrations will be subject to regulatory constraints at both the state and federal level. The following sections summarize several H_2S emission regulations and ambient standards at the state and federal levels.

FEDERAL REGULATIONS AND STANDARDS

The Clean Air Act of 1977 is the most significant federal regulation influencing airborne emissions of H_2S from hydrothermal resources. The Act describes the procedure to be used to establish emission limitations at the federal level. Numerical emission standards do not yet exist at the federal level for H_2S emissions. States may therefore establish their own individual standards without having to consider federal minimum ambient standards.

The procedure for establishing a federal minimum ambient standard for H_2S abatement requires the following steps:

- 1) scientific study of the effect that ambient H_2S concentrations have on human health and welfare
- 2) promulgation of a national primary standard (to protect human health) and a national secondary standard (to protect human welfare).

These standards may be either ambient standards, which are usually regarded as goals or targets to achieve, or they may be emission limitations, which are first calculated and then set at levels that will theoretically permit the ambient air quality standards to be achieved. Once an ambient standard (i.e. goal or target) is set at the federal level, the Clean Air Act requires the individual states to establish an emission standard that will enable the state to achieve the ambient standard. Emission limitation standards at the state level are therefore the regulatory device that resource developers will most likely have to deal with.

STATE REGULATIONS AND STANDARDS

Although no federal ambient standard exists for H_2S , some states have developed regulations governing H_2S emissions and ambient H_2S concentrations. This has been largely occurring in states such as California and New Mexico, which have hydrothermal resource developments that either create or have the potential to create an H_2S odor nuisance. The regulations are typically targeted to prevent or eliminate the odor nuisance, mainly by setting ambient standards at the odor detection threshold level for H_2S , which may vary in humans anywhere from 0.002 ppm_w up to 0.030 ppm_w (EPA 1977).

Four states have ambient air standards applicable to H_2S (California, Montana, New Mexico and Wyoming) and two have emission standards (Nevada and Texas). These states and the summarized standards are presented in Table 4.1 below.

TABLE 4.1. State H_2S Standards for Hydrothermal Developments

	<u>Ambient Standard</u>	<u>Emission Standard</u>
California	0.030 ppm _w as maximum;	175 grams per MW hr on 1 hour average new units from January 1, 1979
Montana	0.050 ppm _w ; 1/2 hour average not to be exceeded more than twice per year, and 0.030 ppm _w 1/2 hour average not to be exceeded more than twice per 5 consecutive days	
Nevada		10 lbs/hr
New Mexico	Range from 0.003 ppm _w to 0.100 ppm _w ; 1/2 hour average within certain regions.	
Texas	0.080 ppm _w ; 1/2 hour up to 0.120 ppm _w ; 1/2 hour depend- ing on down wind land use practices	
Wyoming	identical to Montana standard	

Source: EPA 1978.

The ambient standards range from 0.003 ppm_w in New Mexico, which has the most stringent of the state standards, to 0.120 ppm_w in Texas, which has the most lenient standards. Emission limitations range from 10 pounds per hour per installation in Nevada to 175 gm per MWh (~20 lb/hr for a 50 MWe facility) in California (Air Resources Board 1978).

Absolute emission regulations (e.g. ARB 175 gm/MWh) appear to offer an alternative to the problem facing developers and regulators in setting standards. Regulators have the dual goal of protecting the public health and welfare at a minimum cost to society. By setting absolute limitations, regulators will enable geothermal developers to identify the control processes required to achieve regulatory compliance. At the same time, the cost of monitoring ambient levels may be reduced for regulatory agencies.

5.0 EMISSION CONTROL PROCESSES

Hydrogen sulfide is the primary airborne emission resulting from geothermal resource development and presently existing in sufficient concentrations to require control. The techniques available for H_2S emissions control are summarized in this chapter. Abatement cost functions for these processes can be found in Appendix B.

EMISSION CONTROL TECHNOLOGY

Hydrogen sulfide occurs both in a gaseous form in geothermal steam and in a dissolved form in the steam condensate and raw geothermal fluids. Therefore, emission control processes may be applied to these gaseous or liquid streams within the facility.

Numerous processes exist or are being developed for control of H_2S emissions. Several have actually been demonstrated in conjunction with geothermal energy conversion systems. Much of the airborne emission control process development and operation has been conducted at The Geysers. Abatement processes developed there are expected to be directly transferrable to liquid hydrothermal geothermal resources.

Two basic types of treatment options exist: upstream treatment, which removes H_2S from the geothermal fluid before it passes through the turbine, and downstream treatment, which treats H_2S after it has passed through the turbine. Five such H_2S emission control techniques are being developed for potential application to geothermal plants:

Upstream Treatment

1. Dow Process
2. EIC Process

Downstream Treatment

3. Stretford Process
4. Peroxide Condensate Treatment Process
5. Iron Catalyst Process

These processes typically generate elemental sulfur precipitates that may be pure enough to be marketable. According to Garratt Sharp of PG&E, sulfur sludges from H_2S treatment processes at The Geysers have historically been disposed of in a solid-waste landfill. Final sludge disposal may also be accomplished by 1) settling in a sealed leak-proof evaporative basin, or 2) injection with other liquid wastes and cooling system waters into a sub-surface reservoir. Each treatment and disposal option has its own mix of benefits and costs that will vary between sites. Several of the techniques use regenerable catalysts. Each process would be applied at a different location within the power generation cycle. Some or all of the processes could be used in a complementary manner to achieve higher levels of emission control.

Figure 5.1 shows the location of each process in the power generation cycle. The Dow process is located on the fluid transport lines before the flashing unit. The EIC process is applied to the flashed-steam fraction only and immediately precedes the turbine. The Stretford process is applied downstream to the noncondensable gases released from the steam condensers. The Peroxide Condensate Treatment process is applied only to the fraction of the steam that condenses into the cooling system and is intended for use only with surface contact condensers. The Iron Catalyst process is applied downstream of the turbine on the entire liquid cooling system. Noncondensable gases are routed from the direct contact condenser to the cooling tower for scrubbing when the Iron Catalyst process is used.

The upstream or pretreatment processes are desirable because of their ability to 1) reduce turbine blade stress corrosion cracking and sulfide scaling caused by the presence of H_2S , and 2) reduce H_2S emissions during steam stacking.^(a) The downstream processes may achieve equivalent levels of abatement, but cannot reduce H_2S emissions during turbine outages.

Escape of gases during well and pipeline venting is not subject to the same control requirements as are continuous emissions. More efficient

(a) Steam stacking occurs when one turbine in a multi-turbine generating station is down for repairs and the steam is vented.

FIGURE 5.1. H₂S Treatment Process Locations

(a) Used only in conjunction with surface contact condensers and the Stretford Process.

collection and treatment systems may need to be developed further to control these emissions. Currently, the use of hydrogen peroxide (H_2O_2) in a manner similar to the Dow Process is the only process identified as technically feasible for controlling wellhead emissions (Martin et al. 1978; White et al. 1977).

For each available control technique the following data will be presented:

- system description
- removal efficiency
- control cost factors.

Each process has a typical complement of fixed and variable costs. Using the cost functions presented in Appendix B for each process, a discounted cash flow methodology was used in a case study to estimate the levelized annual life cycle costs of H_2S abatement. These costs are tabulated in Appendix C and presented in the case study in Section 6.0. The discounted cash flow methodology is presented in Appendix D.

UPSTREAM TREATMENT PROCESSES

Dow Process

System Description

The Dow process, shown in Figure 5.2, is applicable to the treatment of H_2S dissolved in the brine of liquid-dominated resources. With this system aqueous or gaseous H_2S is oxidized at the wellhead by the injection of either oxygen (O_2) or H_2O_2 . H_2O_2 is pumped from storage, through a flow controller into the fluid lines, into the packed column and then to the corrosion monitor. The geothermal fluids are then sent to the turbogenerator for power production.

To assure complete reaction of H_2S with the oxidants, a packed-column reaction vessel is designed into the system. Initial evidence indicates that the packed-column system is more cost-effective than using in-line mixers (EPA 1978). Although the piping downstream of the column can be mild steel, the section upstream of the tower must be lined (e.g. with teflon) to resist the higher brine corrosivity associated with injection of oxidants. Bob Southard

FIGURE 5.2. Dow H₂S Removal Process (EPA 1978)

of Dow Chemical in Freeport, Texas, reports that using O₂ instead of H₂O₂ will allow the process to achieve 95% or higher scrubbing efficiency on H₂S in liquid streams. The process' removal efficiency falls dramatically when used on two-phase flow. John Wilson, also of the Dow Chemical, reports that removal efficiencies can be maintained in excess of 95% when either steam or two-phase flow is encountered by substituting H₂O₂ for O₂ as the oxidizing agent in the process. Until downhole pump technology is perfected, geothermal fluid flow will be predominantly two-phase flow. Mr. Southard indicated that substituting H₂O₂ for O₂ will achieve sufficient abatement of H₂S emissions (93% or more) on two-phase flow to warrant its consideration as the primary chemical input for the oxidation of H₂S by the Dow process.

Removal Efficiency

Numerous laboratory scale tests that attempted to duplicate geothermal conditions have been conducted. Removal efficiencies have ranged from 90 to 100% of total H₂S produced (Midwest Research Institute 1978; EPA 1978). For

purposes of this report, the H_2O_2 process will be evaluated assuming an average control efficiency of 96% under operating conditions. The oxygenation process will not be evaluated because of its limited applicability to the two-phase flow expected from liquid-dominated geothermal resources in the near future.

Control Cost Factors

Purchased equipment costs for the Dow process are primarily a function of brine flow rates. Size of piping and packed columns is determined by the fluid flow rate. Operating costs depend on actual H_2S flow rates. Waste disposal is assumed to be achieved by solid-waste landfilling. Values of the parameters used for cost estimation can be found in Appendix B.

EIC Process^(a)

System Description

The EIC system is being developed for the treatment of the steam fraction of the geothermal fluid flow ahead or upstream of the turbine. The system cannot treat H_2S dissolved in the brine in its aqueous state. Figure 5.3 illustrates the EIC process designed with regeneration of catalysts by leaching.

In the EIC process the flashed geothermal steam is first passed through a centrex separator that removes all large particles. The steam is then introduced to the H_2S scrubbing unit, shown in the upper left of Figure 5.3, where it passes through the scrubbing towers and exits again as cleaned steam. A scrubbing solution containing copper sulfate ($CuSO_4$) and ammonium sulfate $(NH_4)_2SO_4$ is used to precipitate sulfide solids from the raw steam into a purge slurry. Proper maintenance of the scrub solution pH helps ensure sufficient copper concentration to promote high removal efficiency. Following scrubbing, the steam passes through a water-washed demister for removal of any

(a) Bill Dyer of the EIC Corp. reports that his company's H_2S abatement process has been named the "CUPROSUL process." However, throughout this document it is referred to as the "EIC process".

FIGURE 5.3. EIC Hydrogen Sulfide Removal Process with Regeneration by Leaching (EPA 1978)(a)

(a) Arrows indicate direction of fluid flows.

residual scrub solution. The purge slurry is then separated into solid wastes and liquid wastes. The regenerated CuSO_4 solution is returned to the scrubbing towers for reuse.

At The Geysers the end product of the EIC process, ammonium sulfate, has been mixed with cooling tower water and injected underground during developmental testing (Sung et al. 1977). At sites where injection is either not permitted, not technically feasible, or less costly, the $(\text{NH}_4)_2\text{SO}_4$ may either be placed in solid-waste landfills or reclaimed for fertilizer manufacture.

Removal Efficiency

The EIC process was field-tested in December of 1976 at The Geysers' Unit 7. Efficiencies were generally over 97%. In addition to H_2S , almost 80% removal of ammonia (NH_3) and boric acid (H_3BO_3) was achieved. This removal rate is significant because EPA has identified these two effluents as toxic to fauna and flora, respectively, and high on the list of potentially regulated geothermal emissions (EPA 1978). According to a recent research report (EIC 1976), at least 97% of the H_2S , along with slightly lesser amounts of NH_3 , H_3BO_3 , rock dust, and other materials, are removed from the steam before it enters the turbine. Recent field tests at The Geysers demonstrated that H_2S removal efficiencies of 99.9% can be achieved with the process (Allen and Brown 1980). For this report 97% H_2S control is assumed to be achievable for continuous process operation.

Control Cost Factors

Because of its upstream benefits, this process appears very attractive, both in terms of removal efficiency and the cost-effectiveness of control. Purchased equipment costs are influenced both by steam flow rates (which size the scrubbing units) and by H_2S mass flow rates (which influence the materials handling capacity requirement). Operating costs are also sensitive to H_2S flow rates.

When H_2S abatement costs were estimated using only the EIC process, solid-waste landfilling was found to cost more than either the injection or fertilizer reclamation options. This conclusion was reached following discussions with Mr. William Dyer of the EIC corporation in Newton, Massachusetts. Mr. Dyer reported that reclamation will have zero net costs to the firm because revenue from the sale of the $(NH_4)_2SO_4$, which is assumed to be reclaimed, will cover all reclamation and disposal costs. Specific parameter values for the equation appear in Appendix B.

DOWNSTREAM TREATMENT PROCESSES

Stretford Process

System Description

The Stretford process is an offgas treatment system that may be used to scrub the noncondensable gas (NCG) stream passing through the NCG vent stack of geothermal power plants equipped with surface contact condensers. Figure 5.4 shows the Stretford unit in its typical placement in a flashed-steam system between the surface condensers and the cooling tower. Spent steam from the turbine is sent to the condensers, where noncondensable gases are vented to the Stretford unit for scrubbing. The condensate water is then routed to the cooling system before final disposal.

Surface condensers are expected to yield from 80 to 98% of the H_2S in the turbine exhaust steam to the Stretford unit, according to Larry Krumland of Pacific Gas and Electric. The rest of the H_2S will dissolve into the steam condensate and then be carried to the cooling tower for atmospheric release. Several variables, including pH, temperature, pressure and total NCG content of the steam, are believed to determine the split between gaseous and aqueous H_2S emission pathways.

Figure 5.5 shows the noncondensable gas stream from the surface condensers being scrubbed with an aqueous solution containing sodium carbonate, sodium ammonium polyvanadate, and anthraquinone disulfonic acid (ADA) (Midwest Research Institute 1978).^(a) The H_2S is oxidized in solution in the form of elemental sulfur prior to catalyst regeneration with air. Oxidized H_2S is skimmed, centrifuged and then heated to form pure molten sulfur. The sulfur may either be removed as a waste product or may be reclaimed for sale as high purity sulfur. Parsons (1975) reports that reclaiming the sulfur appears to be the most cost-effective disposal option for the process at The Geysers, if a market can be found for the sulfur (EPA 1978) at a net of \$25.00 per metric ton (MT) in January 1980 dollars.

(a) At The Geysers sodium hydroxide (NaOH) is being substituted for sodium carbonate (Na_2CO_3) in the treatment process.

FIGURE 5.4. Modified System Cycle for Using Surface Condensers at The Geysers Power Plant (Laszlo 1976)

FIGURE 5.5. Typical Flow Diagram of Stretford Process at The Geysers (Laszlo 1976)

Removal Efficiency

The Stretford process has historically been used in industrial applications. Currently between 50 and 60 industrial units are successfully operating in the United States in various gas treating applications (Martin et al. 1978). Contractors will guarantee up to 99% removal efficiencies of the H_2S passing through this unit. In addition, the Stretford unit can tolerate and recover rapidly from H_2S overloads that may result from normal well variability (Martin et al. 1978). Larry Krumland of PG&E reports that this characteristic was considered in selecting H_2S control technology for The Geysers.

When the Stretford process is used with surface condensers, net emission control may be as low as 79% of total H_2S emissions (0.99 removal efficiency x 0.80 condenser split), or as high as 99% under controlled conditions. Historically, direct contact condensers have been the type most commonly used in, or designed for, flashed-steam conversion systems. Compared to surface contact condensers the direct contact type exhibit higher heat transfer efficiencies and lower capital costs. Condenser selection will depend not only on reservoir temperature, but also on regulations and the relative prices of surface versus direct contact condensers.

Control Cost Factors

When the cost of employing surface condensers for the Stretford process is estimated only installation and use expenses (i.e., over and above direct contact condenser costs) are relevant. Purchased equipment costs for the Stretford process are driven not only by the incremental costs of surface condensers, but also by basic plant costs. Both costs are a function of H_2S , noncondensable gas and fluid flow rates, which may or may not be known with sufficient accuracy prior to plant design to be used. H_2S mass flow, and to a greater extent total noncondensable gas flow, should be used to size a Stretford unit, but these data are not always precisely known prior to the design of a power plant. Therefore, they may not influence the plant's actual cost, but will instead influence operating costs after installation. Operating costs hinge on chemical usage, sulfur sales, and electricity required for process operation. The specific values of the parameters used in this report for estimation are found in Appendix B.

Sub-System Description: Hydrogen Peroxide

Although the Stretford process has a very high removal efficiency on the gas fraction delivered by surface condensers, it is unable to control cooling tower emissions. The process cannot control these emissions because surface condensers may allow from 2-20% of the gaseous H_2S in the flashed steam to dissolve into the steam that condenses inside the surface condensers of the

cooling system. The condensate is then pumped to the cooling tower before it evaporates, is injected or returns to the condensers. Upon reaching the cooling tower, this H_2S may be emitted to the atmosphere. Figure 5.6 presents a simplified mass balance diagram of a steam driven geothermal generating unit found at The Geysers and fitted with a surface condenser and a Stretford plant. In that illustration, approximately 4% of the total H_2S loading in a raw fluid is shown to be escaping from the cooling towers through evaporation of the steam condensate. To abate such cooling tower H_2S emissions following Stretford treatment of the noncondensable gases, a system designed to use H_2O_2 to oxidize H_2S from the steam condensate has been investigated (White et al. 1977).

The peroxide process in theory converts most of the H_2S to elemental sulfur by combining the reactants in a 1:1 mole ratio (White et al. 1977). Using the condensate pump as a mixer, the H_2O_2 is added directly to the condensate line. The condensate transfer line itself may serve as a reactor and if additional retention time is required a holding tank may be constructed. Equipment required includes storage tanks for the H_2O_2 , an injection metering pump to control the H_2O_2 addition rate, and (probably) a holding tank in the condensate transfer line. Because the sulfur must be removed from the condensate as it precipitates, a filtration system may be required. That system comprises most of the capital cost of the peroxide system. The peroxide system should be able to be fitted with relative ease into an existing geothermal plant that was not originally equipped for condensate treatment, so its incremental costs can be viewed as independent of the control costs for the Stretford plant that may be used in conjunction (White et al. 1977).

Removal Efficiency

The control level achieved depends on a fairly complex mix of condensate H_2S concentrations, temperature, mole ratios of reactants, and the presence of catalysts (such as PG&E's iron catalyst) (White et al. 1977). Removal of H_2S from geothermal power plants when the Stretford and Peroxide systems are combined is expected to approach 99% under optimal operating conditions.

FIGURE 5.6. Mass Balance for 27 MWe Plant with Surface Condenser and Stretford Plant (Fairfax and McCluer 1972)

All flows are kg/hr. Entering H₂S concentration is 623 ppm_w. Ninety-five percent H₂S control achieved with 1% of entering H₂S emitted from Stretford Plant and 4% from cooling tower.

Control Cost Factors

Purchased equipment costs are expected to vary as a function of sulfur flow rates; however, no information on the impact of H_2S concentrations holding the steam flow rate constant is available. Operating expenses will be directly proportional to the quantity of H_2O_2 required for oxidizing the H_2S present in the steam condensate. As noted by Stanford Research Institute (SRI), the condenser H_2S split becomes a cost-determining factor at this point (White et. al. 1977). Estimates of specific parameters used for cost estimation in this report can be found in Appendix B.

Iron Catalyst Process

System Description

The natural H_2S oxidation that occurs in the cooling system of geothermal power plants can be increased by adding a metal catalyst. For use at The Geysers, Pacific Gas and Electric Company (PG&E) has developed an iron catalyst system that has been permanently installed on Units 3, 4, 5, 6 and 11, according to Garratt Sharp of PG&E. The system is also used intermittently on Units 2, 8, 9 and 10. In Figure 5.7 an iron catalyst is added to the circulating cooling waters to oxidize dissolved H_2S to elemental sulfur that first precipitates out as a sludge and is then filtered for removal. H_2S in the condensate from the direct contact condensers, as well as all the noncondensable gases captured by the condenser jet gas ejectors, is scrubbed by the system in the cooling tower. The system has several problems, including precipitation of sludges and increased corrosion. EPA (1978) has stated that corrosion problems are so severe that condenser life may be shortened from 30 years to only 7 years.

Removal Efficiency

Initially, PG&E researchers hoped that the 90% efficiency the process exhibited during initial tests would be characteristic of the process. Garratt Sharp of PG&E reports, however, that the process has been a disappointment in two respects. First, actual experience indicates that the process has an effective removal efficiency of only 50%. The Iron Catalyst process was initially field-tested on Unit 1, which has relatively low H_2S

FIGURE 5.7. Iron Catalyst H₂S Removal Process (EPA 1978)

content. Sufficient oxygen was available in the cooling tower to oxidize 90% of the H_2S that was present. However, when the control process was introduced to other production units that had significantly higher concentrations of H_2S in the raw steam at The Geysers, Mr. Sharp reports that the cooling towers were unable to adequately oxygenate the cooling waters to achieve anything more than approximately 50% control. Experiments are under way to use caustic soda and H_2O_2 to improve process removal efficiency.

Mechanical difficulties also affect the process' performance. Solids and sludges stick to the cooling tower nozzles and heat exchangers. Plugging is common and troublesome, and corrosion is still a problem.

Cleaning, maintenance and lost electric production are the biggest costs resulting from these two problem areas. Sludge disposal, which presents a problem, is currently being landfilled for final disposal.

Control Cost Factors

Purchased equipment costs for the Iron Catalyst (Ferrox, Ferrifloc, Dry-Box, etc.) process are primarily a function of the steam flow rate for a geothermal facility. In the literature operating costs are reported to be directly related to H_2S concentrations and the steam flow rates. Cooling tower cleaning, maintenance, and sludge disposal are all related to mass flows of H_2S and removal efficiencies. The specific values adopted for this report and used in cost estimations are found in Appendix B.

COMPARATIVE PROCESS SUMMARY

Processes have been developed to control H_2S emissions from geothermal power plants and have been field-tested with varying degrees of success. State-of-the-art control technology is probably best represented by the EIC and Stretford processes, which are being installed on generating units at The Geysers. The processes can achieve an overall level of H_2S control of up to 99%.

Both the Iron Catalyst (downstream) and Dow (upstream) processes tentatively have been judged to be not as cost-effective as the Stretford process

in achieving H_2S abatement. The Iron Catalyst process has both removal efficiency and solid waste disposal problems, while the Dow Peroxide process is very cost sensitive to both H_2S concentrations and brine flow rates.

Future state-of-the-art technology seems to center on application of the capital-intensive upstream EIC process. The process is relatively complex and requires a high degree of technical competence to design, install and operate effectively, but it has several advantages (EIC 1978; EPA 1978):

- provides clean steam to turbines, allowing optimal material selection for peak turbine efficiency
- abates H_2S emissions even during unit outages
- reduces boron and ammonia emissions along with H_2S emissions
- regenerates the process catalysts, thus minimizing chemical consumption and solid waste disposal problems
- achieves high levels of total removal efficiency--up to 99% of potential emissions.

Table 5.1 summarizes the H_2S emission abatement processes reviewed here and tabulates the removal efficiencies and operating cost variables for each system. Cost estimates are presented in the case study that follows.

TABLE 5.1. H₂S Control Technology Summary

<u>Process</u>	<u>Application</u>	<u>Control Range</u>	<u>Inputs</u>	<u>Capital</u>	<u>Operating</u>
EIC	Upstream - Steam Ahead of Turbines	95-99	Regenerable Copper Catalyst	Steam and H ₂ S Flow Rates	H ₂ S Flow Rate, Sludge or Liquid Disposal
Stretford	Downstream - Noncondensable Gases	80-98	Regenerable Catalysts	H ₂ S Flow Rate	H ₂ S Flow Rate, Sulfur Sales
Peroxide	Downstream - Condensate Treatment	up to 10.0	Chemical Reagent	Steam and H ₂ S Flow Rates	H ₂ S Flow Rate, Sludge Disposal
Stretford and Peroxide	Downstream	up to 99.0	Chemicals	H ₂ S Flow Rate	H ₂ S Flow Rate, Residual Disposal
Dow	Upstream - Two Phase Flow	up to 96.0	Chemical Reagents	H ₂ S Flow Rate, Fluid Flow Rate	H ₂ S Flow Rate, Sludge Disposal
Iron Catalyst	Downstream - Circulating Cooling Waters	up to 50.0	Chemical Reagents	H ₂ S Flow Rate	H ₂ S Flow Rate, Sludge Removal
	Peroxide Addition	up to	Chemical 90.0	H ₂ S Flow Reagents	H ₂ S Flow Rate

6.0 CASE STUDY

A site specific investigation of the costs of H₂S emission control is presented in this section. Site selection criteria are presented first, followed by a description of the chosen site and estimates of abatement costs.

SITE SELECTION CRITERIA

A site chosen for evaluating the costs of meeting environmental standards should exhibit several characteristics:

- The site should have significant development potential for energy recovery and utilization.
- The resource should be known to contain the emissions under study to enable development of reliable control cost estimates.
- Commercial interest in the site should exist.

Many resources meeting the above criteria exist in the western United States. The resource chosen for cost estimation in this report was the Valles Caldera KGRA in New Mexico. The site represents approximately 13% of the potential electrical generation capacity that may be obtainable from liquid-dominated, high-temperature, hydrothermal convection systems (2700 MWe of 21,000 MWe for 30 years) (Brook et al. 1978).

Two developers have entered a joint venture at the site, which is located on the Baca Ranch. Resource exploitation will be performed by Union Oil Company, while the Public Service Company of New Mexico will handle power distribution. A 50 MWe flashed-steam plant has been selected as the most cost-effective energy conversion facility for the site. Power is expected to be on line in 1982 (Energy User News July 17, 1978). Injection has been selected for liquid-waste disposal. The resource has a total dissolved solids concentration of 7500 ppm_w, with a H₂S concentration ranging from 290 to well over 500 ppm_w in the raw steam, as noted in Appendix A. The site's subsurface temperature has been estimated at 273°C (Brook et al. 1978).

The site appears to be a satisfactory choice for investigating H₂S emission control costs, based on several factors: 1) the commercial interest in the site; 2) its larger-than-average estimated energy potential; 3) its relatively high H₂S loading; 4) its demonstrated ability to produce the large volume flows necessary for power production; and 5) the region's ability to accept injected fluids. Table 6.1 summarizes the pertinent KGRA data for the Baca Ranch.

TABLE 6.1. Baca, New Mexico Resource Description

Site:	Valles Caldera KGRA, New Mexico
Temperature:	273°C
Hydrogen Sulfide Concentration:	290 to 550 ppm _w in the raw steam
Expected Well Flow Rate (Assumed):	500,000 lb/hr per well
Total Dissolved Solids Concentration:	7,500 ppm _w
Liquid Waste Disposal:	Injection

Because the TDS content is relatively moderate, injection should be practiced with minimal, if any, liquid-waste pretreatment. The site's relatively high H₂S concentration is expected to require a high degree of abatement to prevent significant deterioration of ambient air quality in this recreational region (Roberts 1976).

COST ESTIMATION

Emission control costs at the Baca site were estimated from the cost functions in Appendix B. Power generation costs and steam flow rates were derived from the PNL GEOCOST model. All assumptions regarding reservoir parameters used to model the Baca site for this case study are given in the summary of the GEOCOST model (Bloomster 1975). Injection expenses for disposal of spent fluids have been included in the power generation cost estimates, which are expressed in January 1980 dollars.

H₂S Abatement Costs

With the Stretford and EIC processes, varying the fraction of the H₂S laden fluid being scrubbed was assumed to achieve the control level shown on the horizontal axis in Figure 6.1. The relation is given as:

$$\text{Percentage Control Achieved} = \text{Fluid Fraction Scrubbed} \times \text{Removal Efficiency.}$$

Producers are assumed to achieve only the minimum abatement level required to comply with effluent limitations, unless incentives exist to achieve higher levels. One such incentive may be a reduction in the damage that corrosive H₂S can cause. By using upstream treatment processes, such benefits may be realized. The value of such potential benefits was not estimated in this study, however.

Only EIC, Stretford and peroxide condensate treatment process cost estimates are presented here. The iron oxide process has been found to be both inefficient and very costly and the Dow process is simply too costly to be practical. The Stretford and EIC processes represent the most cost-effective systems available.

Although calculating the expected abatement level that a process will achieve for a given set of conditions is relatively simple, accurately estimating the percentage control required for a given site to meet an ambient standard (e.g., 30 ppb_w) is much more difficult. The minimum level of emission control that will be sufficient to achieve compliance with any given ambient air quality standards at the Baca site, or at any other KGRA, is not known precisely.

Figure 6.1 presents H₂S abatement costs for each of the individual processes at the Baca site. The costs were developed from the cost estimates in Table C.1 of Appendix C.

Abatement costs were estimated using an assumed H₂S concentration of 250 ppm_w in the raw flashed steam. Using this concentration provides a conservative estimate of the minimum abatement costs most likely to be encountered

FIGURE 6.1. Comparative H_2S Abatement Costs for Baca, New Mexico
(Appendix C, Table C.1)(a)

(a) 250 ppm_w H_2S , 110 MWe plant, 273°C downhole, 2,400,090 lb of steam/hr

at the site, since measured concentrations average 290 ppm_w and have been known to exceed 500 ppm_w. The 97% abatement level represents the state-of-the-art limits in H₂S emissions control. Higher abatement levels can only be achieved by adding additional units of the same processes in series. The costs of redundant scrubbing systems are virtually identical to the costs of the first treatment units in a series because the replicated units in the processes evaluated in this report are so heavily capital-intensive. Capital costs are more sensitive to steam flow rates and volumes of fluids handled than to H₂S concentrations.

At control levels of 97%, Figure 6.1 indicates that the Stretford-Peroxide combination treatment system will most likely increase power production costs by approximately 4.6 mills per kWh. The EIC process is less expensive for high levels of H₂S control, probably for all levels in excess of 90% control. The Stretford system is most cost effective up to the 89% control level.

In terms of net present value, the cost of achieving 97% emission control over the project's 30-year expected economic life is approximately \$39,300,000, based on a real (inflation free) discount rate of 5%. This is \$19,610,000 greater than the net present value of the cost of achieving 89% emission control. To achieve economic and regulatory efficiency, the environmental benefits gained by the higher level of control must be worth at least the incremental cost of control (\$19,610,000).

If the value of the benefits of preventing the additional odor nuisance (caused by allowing 89% control instead of requiring 97% control) do not equal or exceed the costs of preventing the extra nuisance, then clearly the regulations should not require 97% abatement. Empirical investigations are required to establish whether the maximum technically feasible abatement level (97%) is also the socially optimal level of environmental protection.

CASE STUDY SUMMARY

Baca, New Mexico, was selected as an appropriate geothermal site for a case study of the cost of H₂S abatement. The resource, undergoing commercial

development, has an H_2S concentration greater than 290 ppm_w in the raw steam and will be subject to emission regulations. To meet a 97% abatement standard, abatement costs for a flashed steam facility were found to increase total power costs by 3.55 mills per kWh, a minimum estimate for this standard because it is based on the assumption that H_2S concentrations will average 250 ppm_w in the raw steam.

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APPENDIX A

RESERVOIR GEOCHEMISTRY SUMMARY

APPENDIX A

RESERVOIR GEOCHEMISTRY SUMMARYTABLE A.1. Reservoir Geochemistry Summary

Reservoir	State	MWe Potential (a)	Total Dissolved Solids (ppm)	Noncondensable Gases in ppm (d)	
				H ₂ S	Boron
R1. Geyser Bright	Alaska	136	1,650 ^(b)		
R2. Hot Springs Cove		27	2,160 ^(b)		
R3. The Geysers	California	1610	--	220.0	
R4. Surprise Valley		1490	1,500		
R5. Morgan Springs		116	5,075 ^(b)		
R6. Sulfur Bank Mine		75	5,510 ^(c)	30.0	3,417.0
R7. Calistoga		62	760 ^(b)	42.0	
R8. Skagg's Hot Springs		23	2,895 ^(c)		97
R9. Long Valley Caldera		2,100	2,170 ^(b)	100.0	
R10. Coso Hot Springs		650	6,410 ^(b)		
R11. Salton Sea		3,400	250,000		
R12. Brawley		640	53,750		
R13. Heber		650	15,000		
R14. East Mesa		360	30,000		
R15. Big Creek Hot Springs	Idaho	26	500 ^(b)		
R16. Sharkey Hot Springs		23	515 ^(b)		
R17. Weiser Area		35	420 ^(b)		
R18. Crane Creek		340	960 ^(b)		
R19. Baltizor Hot Springs	Nevada	46	880 ^(c)		2.9
R20. Pinto Hot Springs		90	1,270 ^(c)		7.5
R21. Great Boiling (Gerlatch) Springs		32	5,331 ^(c)	<0.5	9.9
R22. Sulfur Hot Springs		74	781		
R23. Beowawe Hot Springs		127	1,256	11.0	2.5
R24. Leach Hot Springs		77	790 ^(c)		1.2
R25. Stillwater Area		450	4,865 ^(c)		15.0
R26. Soda Lake		146	3,660		5.7
R27. Brady Hot Springs		157	2,450		
R28. Steamboat Springs		350	2,500	11.0	47.0
R29. Valles Caldera	New Mexico	2,700	7,500	290.0	
R30. Mickey Hot Springs	Oregon	160	1,913 ^(c)		10.5
R31. Alvord Hot Springs		49	3,315 ^(c)		30.0
R32. Hot Lake		91	1,240		16.6
R33. Vale Hot Springs		870	1,270 ^(c)		9.4
R34. Neal Hot Springs		36	925 ^(c)		4.1
R35. Lakeview		140	835 ^(c)		
R36. Crumps Spring		61	1,245 ^(c)	30.0	13.6
R37. Roosevelt (McKean) H.S.	Utah	970	7,000		
R38. Cove Fort-Sulphurdale		330			
TOTAL		18,719			

TABLE A.1. Reservoir Geochemistry Summary (contd)

Reservoir	Soluble Heavy Metals ppm		Temperature (Subsurface) °C	Constituents				Spec. Cond.
	Hg (Vapors)	AS		S ₂ O ₂	Na	Cl	pH	
R1. Geyser Bight			208	303	441	569	7.5	
R2. Hot Springs Cove			164	88	603	1,126	5.9	
R3. The Geysers	(.02)	(.05)	237					
R4. Surprise Valley			152	200	343	223	8.91	
R5. Morgan Springs			217	233	1,398	2,430	--	
R6. Sulfur Bank Mine	1.5		194	203	1,723	900	2.7	7,880
R7. Calistoga			144	139	212	255	9.0	
R8. Skagg's Hot Springs	.98µg/l		113	124	945	54	7.2	3,690
R9. Long Valley Caldera	.10µg/l	2.2 mg	227	340	552	842	9.2	1,920
R10. Coso Hot Springs			220	458	1,630	3,040	8.5	
R11. Salton Sea			323	316	10,800	15,300	8.11	
R12. Brawley			253					
R13. Heber			175					
R14. East Mesa			182					
R15. Big Creek Hot Springs			162	150	220	29	7.5	
R16. Sharkey Hot Springs			114	91	270	51	7.4	
R17. Weiser Area			130	140	140	56	9.3	
R18. Crane Creek			171	180	290	300	7.1	
R19. Baltizor Hot Springs	.001	.07	158	160	180	48	8.0	947
R20. Pinto Hot Springs	.004	.08	173	150	330	160	7.1	
R21. Great Boiling (Gerlatch) Springs			178	172	1,460	2,200	7.62	6,350
R22. Sulfur Hot Springs	.0015		178	75	103	0	7.8	652
R23. Beowawe Hot Springs	.0017	.05	229	534	257	70	9.8	1,490
R24. Leach Hot Springs	.0006	<.01	162	198	193	33	8.8	811
R25. Stillwater Area			159	170	1,480	2,200	7.57	6,910
R26. Soda Lake			157	160	1,000	1,500	7.90	5,110
R27. Brady Hot Springs			155	279	774	968	7.3	
R28. Steamboat Springs			200	353	2,047	1,345	9.3	3.34
OR29. Valles Caldera			273					
R30. Mickey Hot Springs	.0001	.01	205	200	550	240	8.05	
R31. Alvord Hot Springs	.0001	.04	181	184	960	780	8.1	
R32. Hot Lake	.0004	.01	191	190	500	300	9.21	688
R33. Vale Hot Springs			157	130	310	360	7.47	1,530
R34. Neal Hot Springs	.0001	.02	188	180	190	120	7.32	1,010
R35. Lakeview			150	146	280	170	8.4	
R36. Crumps Spring	.0004	.46	167	180	293	263	8.7	1,490
R37. Roosevelt (McKean) H.S.			265	313	2,500	4,240		
R38. Cove Fort-Sulphurdale			167					

- (a) MWe Potential = Megawatts of electrical generating potential for 30 years as determined by USGS (Brook et al.).
- (b) Approximation of TDS = (S₂O₂ + Na + Cl) x 1.25.
- (c) Estimated linearly from TDS = 250 + 0.67 x (Specific Conductance), where 250 roughly corresponds to the specific conductance of water and 0.67 indicates the ions are 50% monovalent (such as Na⁺ and Cl⁻) and 50% divalent (from silicates). Over estimation is expected for a few resources, but generally the results are retained as lower range TDS predictions.
- (d) Parts per million in the raw steam by weight.

APPENDIX B

HYDROGEN SULFIDE CONTROL COST FUNCTIONS

APPENDIX B

HYDROGEN SULFIDE CONTROL COST FUNCTIONS

CONTROL COSTS - DOW PROCESS

Initial estimates indicate that the Dow Process will probably be the most expensive of the four primary H_2S treatment processes considered to be technically feasible. A discussion of control costs is broken into capital and operating cost components in the following sections.

Purchased Equipment

Preliminary cost estimates of the oxygenation process developed by the Dow Chemical Company have been reviewed and evaluated by numerous authors in the literature (EPA 1978; Midwest Research Institute 1978; Sung, et al. 1977). Based on these reviews and on information provided to PNL by John Wilson and Bob Southard of the Dow Chemical Company, a purchased equipment cost function has been developed below.

The equipment required for the packed column design includes the packed tower, the oxidant supply system, instrumentation, piping, and flow meters. Costs are expected to vary exponentially with changes in brine flow rates, independent of H_2S concentrations.

Operating Costs

Operating costs are sensitive to H_2S flow rates. Mass balance calculations indicate a residual solid waste may be generated as a result of this process, requiring disposal (EPA 1978). For each mole of H_2S oxidized, one mole of elemental sulfur is assumed to be generated and require disposal. Disposal is assumed to be achieved by solid-waste landfilling @ \$25.00 per ton in 1980 dollars (EPA 1978). Electricity requirements are assumed to be independent of the H_2O_2 use rate.

EQUATION B.1. Dow Process Cost Functions

$$PE_{1980} = IB \times (BA/BB)^X + (NT/WF \times BA \times TC)$$

$$AOC_{1980} = (PH_2S \times CF) \times [(MR \times MW1 \times MW2 \times PC \times SR) + (C1 \times SRE \times C2 \times DC)]$$

Variables:

AOC_{1980} = Annual Operating Cost in January 1980 dollars

BA = Brine Flow Rate in the Proposed Facility (lb/hr)

BB = Brine Flow Rate in the Design Facility (5×10^6 lb/hr)

C1 = Constant (32 lb S/34 lb H_2S)

C2 = Constant (1 Metric Ton S/2205 lb S)

CF = Capacity Factor (0.8)

DC = Disposal Cost (25.00/MT Sulfur)

IB = Purchased Equipment Cost in the Design Facility (\$2,400,000)

MR = Mole Ratio (3 Moles H_2O_2 /1 Mole H_2S)

MW1 = Mole Weight (34 lb H_2O_2 /1 Mole H_2O_2)

MW2 = Mole Weight (1 Mole H_2S /34 lb/ H_2S)

NT = Number of H_2O_2 Tanks Needed (1 Tank)

PC = Peroxide Cost (\$19.00/100 lb H_2O_2 , 35% Solution)

PE_{1980} = Purchased Equipment cost in 1980 dollars

PH_2S = H_2S Flow Rate Through Facility (lb/yr)

SR = Solution Ratio (100 lb H_2O_2 Solution/35 lb H_2O_2)

SRE = System Removal Efficiency (.96)

TC = Tank Cost (\$13,750/tank)

WF = Brine Flow Rate (500,000 lb/hr)

X = Equipment Sizing Factor (0.85)

CONTROL COSTS - EIC

Several cost estimates are available for the EIC process. The process is undergoing testing and demonstration at The Geysers because of its very high removal efficiency and its upstream treatment benefits.

Purchased Equipment

Previous cost estimates from EIC have been reviewed and evaluated by numerous authors in the literature (EPA 1978; Midwest Research Institute 1978; Sung 1977). However, a current cost estimate from EIC for a 110 MWe sized H_2S treatment design was used as the basis for cost estimates in this report. Based on the literature reviews and on the estimates provided to PNL by EIC, a purchased equipment cost function has been developed below. Equipment required includes scrubbers, reactors, tankage, pumps and agitators, heat exchangers, and liquid-solid separation facilities. The steam flow rate will size the steam scrubbers.

Operating Costs

Estimates of operating costs have been prepared by EIC for specific conditions at The Geysers (EIC Corporation 1978). Process costs are sensitive to H_2S flow rates and can be expressed both in terms of capital investment and mass flow rates.

EQUATION B.2. EIC Process H_2S Abatement Cost Functions

$$PE_{1980} = P1 \times IB \times (SA/SB) + P2 \times IB \times (HA/HB)^X$$

$$AOC_{1980} = (LU \times LC) + (THR \times CF) \times [(ER \times EC) + (WR1 \times OC) + (WR2 \times AC) + (WR3 \times CC) + (WR4 \times HC) + (RR \times RC)] + MR \times PE_{1980}$$

Variables:

- AC = NH_3 Cost (\$190 MT NH_3)
- AOC_{1980} = Annual Operating Cost in January 1980 dollars
- CC = $CuSO_4$ Cost (\$.815/lb $CuSO_4$)
- CF = Capacity Factor (0.80)
- EC = Electricity Cost (\$0.043/kWh)
- ER = Electricity Ratio (1210 kWh/MT H_2S)
- HA = H_2S Concentration in the Proposed Facility (ppm_w)
- HB = H_2S Concentration in the Design Facility (240 ppm_w)

HC = H_2SO_4 Cost (\$0.030/lb H_2SO_4)
 IB = Purchased Equipment Cost in the Design Facility (\$4,500,000)
 LC = Labor Cost (\$16.80/Manhour)
 LU = Labor Units (8320 Manhours/yr)
 MR = Maintenance Rate (0.065)
 OC = O_2 Cost (\$90/MT O_2)
 P1 = Percent of Represented by Scrubbers (0.75)
 P2 = Percent of Purchased Equipment Determined by H_2S Concentration (0.25)
 PE₁₉₈₀ = Purchased Equipment Cost in 1980 Dollars
 RC = Resin Cost (\$115.00/ft³ Resin)
 RR = Resin Ratio (0.0686 ft³ Resin/MT H_2S)
 SA = MWe (gross) of the Proposed Facility
 SB = MWe (gross) of Design Facility (110)
 THR = H_2S Flow Rate Through Facility at 100% of Rated Capacity (MT/yr)
 WR1 = Weight Ratio of O_2 (1.025 MT O_2 /MT H_2S)
 WR2 = Weight Ratio of NH_3 (0.25 MT NH_3 /MT H_2S)
 WR3 = Weight Ratio of CuSO_4 (17.6 lb CuSO_4 /MT H_2S)
 WR4 = Weight Ratio of H_2SO_4 (68.6 lb H_2SO_4 /MT H_2S)
 X = Equipment Sizing Factor (0.60)

CONTROL COSTS-STRETTFORD

Because of the Stretford's wide acceptance as an H_2S control process, relatively reliable cost estimates are available for it.

Purchased Equipment

Larry Krumland of PG&E reports that the additional cost of substituting a surface condenser for a direct contact condenser at The Geysers is expected to be approximately \$1.1 million. Each Stretford unit will cost approximately \$3.8 million, bringing the total purchased equipment cost in (January 1980 dollars) for a surface condenser and Stretford plant to \$4.9 million. These plants are designed to handle the 3000 standard cubic feet per minute (scfm)

noncondensable gas flow of the 110 MWe generating units described earlier. H₂S design treatment capacity of 600 lb/hr corresponds to an expected H₂S concentration maximum of 300 ppm_w. These costs represent the base case from which functional extrapolations will be made. The \$4.9 million estimate includes direct engineering, material, and labor, but not general overheads, general engineering, administrative expenses, construction interest, or ad valorem construction taxes, all of which might add 20 to 30% in a typical installation at The Geysers. Based on literature reviews and on information provided by Mr. Krumland at PG&E and Mr. Alex Ingles of the R. M. Parsons Company, a purchased equipment cost function has been developed. Equipment required includes not only the surface condensers mentioned earlier, but also an oxidizer tank, skim tank, surge tank, centrifugation and heating units, and the associated instrumentation.

Operating Costs

Estimates of operating costs for a Stretford system have been prepared by several sources (Bowen 1973; Mariner 1974; Mariner 1976). Operating costs are directly related to H₂S flow rates in a linear relationship.

EQUATION B.3. Stretford Process Cost Functions

$$PE_{1980} = IB \times (SDA/SDB)^X$$

$$AOC_{1980} = (LC \times LU) + (THR \times CS \times CF) \times [(ER \times EC) + (WR1 \times AC) + (WR2 \times VC) + (WR3 \times NC) - (SR \times SRE \times SC)]$$

Variables:

AC = ADA Cost (\$5.25/lb ADA)

AOC₁₉₈₀ = Annual Operating Cost in January 1980 dollars

CF = Capacity Factor (0.80)

CS = Condenser H₂S Split (0.90)

EC = Electricity Cost (\$0.043/kWh)

ER = Electricity Ratio (380 kWh/MT H₂S)

IB = Purchased Equipment Cost in the Design Facility (\$2,250,000)
 LC = Labor Costs (\$16.80/Manhour).
 LU = Labor Units (4000 Manhours/yr)
 NC = Na_2CO_3 Cost (\$0.075/lb Na_2CO_3)
 PE₁₉₈₀ = Purchased Equipment Cost in 1980 Dollars
 SC = Sulfur Credit (\$500/MT Sulfur)
 SR = Sulfur Ratio (32 MT Sulfur/34 MT H_2S)
 SDA = MT Sulfur to be Disposed of in Proposed Facility (MT/day)
 SDB = MT Sulfur to be Disposed of in Design Facility (5.5 MT Sulfur/day)
 SRE = System Removal Efficiency (0.99)
 THR = H_2S Flow Rate Through Turbine at 100% of Capacity (MT/yr)
 VC = Vanadium Cost (\$500/lb Vanadium)
 WR1 = Weight Ratio of ADA (0.52 lbs ADA/ MT H_2S)
 WR2 = Weight Ratio of Vanadium (0.52 lbs Vanadium/ MT H_2S)
 WR3 = Weight Ratio of Na_2CO_3 (65.1 lbs Na_2CO_3 /MT H_2S)
 X = Capital Sizing Factor (0.5)

CONTROL COSTS - PEROXIDE PROCESS

The estimated costs of treating condensate that contains H_2S from surface condensers have been developed by SRI for a specific unit at The Geysers.

Purchased Equipment

A purchased equipment cost function was developed from SRI estimates of filtration and pipeline reactor costs. No information that relates these costs to variations in the H_2S concentration in the condensate is available. Based on experience with other abatement cost functions, costs are expected to depend on the steam flow rates.

Operating Costs

Total operating costs are dominated by the high cost of H_2O_2 . Power requirements are expected to be insignificant.

EQUATION B.4. Peroxide Process Cost Functions

$$PE_{1980} = IBF \times (SA/SB)^X + IBP \times (SA/SB)$$

$$AOC_{1980} = (LC \times LU) + (PH_2S \times CS \times CF) \times [(WR1 \times HC \times SR) + (SRE \times MWR \times C1 \times DC)]$$

Variables:

AOC_{1980} = Annual Operating Cost in January 1980 Dollars

CF = Capacity Factor (0.80)

CS = Condensate H_2S Split $\left(\frac{0.10 \text{ lbs } H_2S \text{ Condensate}}{1.00 \text{ lbs } H_2S \text{ Steam}} \right)$

C1 = Constant (1 MT/2205 lbs)

DC = Disposal Cost (25.00/MT Sulfur)

HC = H_2O_2 Cost (\$16.50/100 lbs H_2O_2 35% Solution)

IBF = Purchased Equipment Cost in Design Filtration Unit (\$230,000)

IBP = Purchased Equipment Cost in Design Pipeline System (46,000)

LC = Labor Cost (\$16.80/Manhour)

LU = Labor Units (2112 Manhours/yr)

MT = Metric Tons

MWR = Molecular Weight Ratio (32 lbs S/34 lbs H_2S)

PE_{1980} = Purchased Equipment Cost in 1980 dollars

PH_2S = Total H_2S Flow Rate Through Turbine at Full Capacity (lb/yr)

SA = Steam Flow Rate in Proposed Facility (lb/yr)

SB = Steam Flow Rate in Design Facility (1×10^6 lb/yr)

SR = Solution Ratio (100 lb H_2O_2 Solution/35 lbs H_2O_2)

SRE = System Removal Efficiency (0.99)

WR1 = Weight Ratio of H_2O_2 (1 lb H_2O_2 /lb H_2S)

X = Equipment Sizing Factor (0.40)

y = Equipment Sizing Factor (0.20)

CONTROL COSTS - IRON CATALYST PROCESS

Available cost estimates for the Iron Catalyst system come from PG&E at The Geysers in California where the process was developed and installed. By design it is a mechanically and chemically simple system.

Purchased Equipment

The following relationships have been estimated by EPA to explain the purchased equipment cost of the system (Bowen 1973):

- (1) Cost of the proposed unit is a function of the cooling water flow rate.
- (2) Cooling water flow rate is a function of the steam flow rate.
- (3) Therefore, the steam flow rate is an acceptable cost modeling variable.
- (4) Purchased equipment costs are assumed to be independent of the H_2S concentration, given the existing need for control.

Operating Costs

Several sources have prepared estimates of operating costs for the basic Iron Catalyst process (Parsons 1975; Mariner 1974a). No cost estimates are available for the peroxide modified system. Technical relationships have also not yet been worked out for the modified process, so all costs below are for the basic unmodified system. Operation and maintenance costs were assumed to be linearly dependent on two factors (Bowen 1973):

- (1) steam flow rate, with H_2S concentration constant
- (2) H_2S concentration, with steam flow rate constant.

EQUATION B.5. Iron Oxide Process Cost Functions

$$PE_{1980} = IB \times (SA/SB)^X + [CC + (CI/SA)]$$

$$AOC_{1980} = (LC \times LU) + (PS \times CF \times ER \times EC) + (PH_2S \times CF) \times [(WR1 \times NC) \\ (WR2 \times SC) + (WR3 \times FC) + (CF \times PH_2S \times SRE \times DC)]$$

Variables:

AOC₁₉₈₀ = Annual Operating Cost in January 1980 Dollars

CC = Condenser Cost (\$230,000)

CF = Capacity Factor (0.80)

CI = Constant = $\$6.5 \times 10^{-4}$ /lb/hr

DC = Disposal Cost (\$25,00/MT)

EC = Electricity Cost (\$0.043/kWh)

ER = Electricity Ratio (1×10^{-4} kWh/lb Steam)

FC = FeSO₄ Cost (\$0.03/lb FeSO₄)

IB = Purchased Equipment Cost in Design Facility (\$3,010,000)

LC = Labor Costs (\$16.80/Manhour)

LU = Labor Units (4000 Manhours/yr)

NC = NaOH Cost (\$0.105/lb NaOH)

PE₁₉₈₀ = Purchased Equipment Cost in 1980 Dollars)

PH₂S = Total H₂S Flow Rate from Wells (lbs/yr)

PS = Steam Flow Rate from Wells (lbs/yr)

SA = Steam Flow in Proposed Facility (lb/hr)

SB = Steam Flow in Design Facility (2×10^6 lb/hr)

SC = Na₂CO₃ Cost (\$0.53/lb Na₂CO₃)

SRE = System Removal Efficiency (0.50)

WR1 = Weight Ratio of NaOH (0.006 lb NaOH/lb H₂S)

WR2 = Weight Ratio of Na₂CO₃ (0.43 lb Na₂CO₃/lb H₂S)

WR3 = Weight Ratio of FeSO₄ (0.40 lb FeSO₄/lb H₂S)

X = Sizing Factor (0.60)

APPENDIX C

H₂S ABATEMENT COSTS

APPENDIX C

H₂S ABATEMENT COSTS

TABLE C.1. Hydrogen Sulfide Abatement Costs(a)

Process	Control Level					
	50%		80%		97%	
	<u>\$/yr</u>	<u>Mills/kWh</u>	<u>\$/yr</u>	<u>Mills/kWh</u>	<u>\$/yr</u>	<u>Mills/kWh</u>
Stretford & Peroxide	\$972,000	1.35	\$1,281,000	1.78	\$3,303,000	4.59
EIC	\$1,608,000	2.23	\$2,393,000	3.32	\$2,554,000	3.55

(a) All Costs are in January 1980 dollars.
Annual output of 7.2×10^8 kWh.

APPENDIX D

COST ESTIMATION METHODOLOGY

APPENDIX D

COST ESTIMATION METHODOLOGY

The cost of meeting geothermal environmental standards is determined by several factors including, but not limited to, the capital and operating costs associated with employing environmental control technology (ECT). This report focuses strictly on the expenditures directly attributable to the use of ECT.^(a) A discounted cash-flow capital-budgeting methodology is presented in this appendix to describe the procedure used to estimate the costs of employing geothermal environmental control technology.

THE CAPITAL BUDGETING MODEL

A discounted cash-flow framework that expresses the life-cycle costs of employing ECT in terms of levelized costs per kWh has been selected for use in this report. Selection of a discounted cash-flow methodology is in accord with economic theory, with practice in both public and private utilities, and with current DOE and EPRI methodologies (Colborn and Cronin July 1979).

The procedure calculates the impact that the use of environmental control processes may have on the busbar cost of producing electricity from a utility-owned geothermal electric system. This approach is applicable to both publicly and privately owned utilities. Busbar cost represents the minimum price per kWh that will produce revenues equal to the sum of energy-production costs and environmental-control-system-related costs. This equality is expressed in present value terms; the real discount rate used reflects the real after-tax

-
- (a) Additional costs that are imposed by the existence of environmental regulations include, for example, the expense of maintaining a legal staff to comply with and interpret, lobby, and testify on new, existing, and/or proposed standards. Although the magnitude of indirect regulatory costs may be significant, the quantification of such costs is beyond the scope of this immediate research effort.

cost of capital to the firm. Data are needed on variables that describe the output capabilities and capital cost of the treatment systems, the real cash flows required for system operation and maintenance, and the financial structure and tax environment of the utility. The analysis will identify the most cost-effective liquid-waste-treatment system for geothermal applications. The cost-estimation procedures adopted here require neither computer software nor expertise in financial management for their successful use.

The basic approach requires the user to develop an estimate of those costs incurred by a utility as the result of purchasing, installing, and operating a given abatement system. These costs are expressed in real (inflation-adjusted) dollars on a yearly basis. The total annual costs are then divided by the expected yearly energy output of the specific geothermal plant. The result is an estimate of the change in the busbar cost of energy from the system that is attributable to operating the environmental control technology. If the system were to produce exactly its expected net energy output and if that output were "sold" at a price equal to the sum of the estimated production costs and environmental control system costs, the resultant revenues would exactly recover the full costs of the system over its lifetime. The full cost includes compensation to creditors and investors for the real (inflation-free) opportunity cost of their committed funds.

Use of the cost estimation procedure requires definition of specific cost-determining variables and selection of accurate price and quantity coefficients for those variables. Second, a simple algorithm is required to compute costs per kWh. Finally, the cost estimates need to be interpreted and analyzed to draw meaningful conclusions from the results of the procedure. The factors influencing the results are discussed in the subsection dealing with the investment climate.

Cost-Determining Variables

Experience dictates that the most accurate and useful characterization of the flow of funds (revenues and expenditures) associated with long-lived capital investment projects consists of classifying cash flows as either fixed or variable. With environmental control technology, the focus is on minimizing

the cost of meeting environmental standards. Therefore, the discussion will deal mainly with fixed and variable costs. Fixed costs include both initial capital investments in land, plant, operating equipment, and interim capital replacements. In addition, any periodically recurring expenditures that may best be approximated as a fraction of the initial capital investment, such as property taxes and insurance fees, may also be categorized as fixed costs. Variable costs include the annual expenditures for fuel, maintenance, and labor inputs to the production process. Any revenues generated during a given operating period (e.g. through the sale of reclaimed emissions or effluents) would be treated as variable but positive cash flows.

Financial Variables

A technical (engineering-oriented) investigation of the environmental control process is required to estimate the particular physical conditions that will prevail during operation of the environmental control processes at a specific site. These physical conditions, coupled with environmental standards, make possible the estimation of the least-costly combination of fixed and variable production factors required by the treatment process to meet the given standards. From these estimates and from market prices, projections of the required capital investment (fixed costs) and required annual operating expenditures (variable costs) may be generated for the geothermal facility. Table D.1 presents a description of the financial variables used in the estimation procedure and their values assumed for purposes of this report. Note that a weighted average real after-tax cost of capital (WACC) of 10% has been assumed for purposes of computing the cost of using the environmental control processes.

The Cost Algorithm

Using the appropriate variables, as defined in Table D.1, the Levelized Total Annual Cost in January 1980 dollars of employing environmental control technology may be expressed symbolically as:

$$\text{LTAC} \frac{\text{mills}}{\text{kWh}} (\$1980) = \frac{\text{LAFC} + \text{LAOC} (\$1980)}{\text{kWh/yr}}$$

TABLE D.1. Variables for Cost Estimation

Symbol	Description	Assumed Value
PE _{RY}	Cost of Purchased Equipment in Reference Year	As given in the literature
LAFC	Levelized Annual Fixed Costs	
LAOC	Levelized Annual Operating Costs	Endogenously determined
LTAC	Levelized Total Annual Cost	LAFC + LAOC
N	System Lifetime	30 years
B	Construction Period	3 years
CI _{xxxx}	Capital Investment. Subscripts will indicate in which years' dollars the estimate is denominated.	Endogenously determined = DCI + ICI + CCI + IDC + CF
DCI	Direct Capital Investment	Purchased equipment at cost (PE _{RY}) plus installation @ 35% (PE)
ICI	Indirect Capital Investment	Engineering @ 20% DCI Construction O/H @ 20% DCI
CCI	Contingency Capital Investment	Engineering and construction overheads @ 30% (DCI + ICI)
CF	Contractors' Fees	10% (CCI + DCI + ICI)
IDC	Interest During Construction Factor	Estimated by the following equation, which assumed a linear investment expenditure pattern: $= 0.16 = 1 - \left(\frac{1+d}{1} \right)^B \frac{\left(\frac{1}{1+d} \right)^B - 1}{B \ln \frac{1}{1+d}}$
d	Real Discount Rate	Real WACC after taxes: $d = K_d \frac{D}{D+E} + K_e \frac{E}{D+E} = 10\%$
FCR	Real Fixed Charge Rate	Derived as the sum of insurance, local tax, administrative, maintenance, and capital recovery factor rates = 15% Depreciation Tax Shield @ - 1.6% CI Insurance @ 1% CI Local Taxes @ 2% CI Maintenance and Repairs @ 2% CI Administration @ 1% CI
CRF	Capital Recovery Factor	$\frac{d}{(1+d)^N - 1} + d = 10.6$
PF	Geothermal Plant Capacity Factor	80%

Intermediate stages in the procedure are outlined below in a series of thirteen steps:

1. Calculate purchased equipment cost estimates from the control cost functions developed in this report. Purchased equipment costs are stated in January 1980 dollars as: PE_{1980}
2. Calculate the direct and indirect capital investment overheads to PE_{1980} :

$$DCI = .35 PE_{1980}$$

$$CI = .4 DCI = .14 PE_{1980}$$
3. Calculate the contingency overhead to PE_{1980} : $CCI = 0.30 (ICI + DCI) = .15 PE_{1980}$
4. Estimate the contractors' fees:

$$CF = 0.10 (DCI + ICI + CCI) = 0.06 PE_{1980}$$
5. Calculate interest during construction:

$$IDC = .16 PE_{1980} + CCI + DCI + ICI + CF$$

$$= .16 PE_{1980} + PE_{1980} (.35 + .14 + .15 + .06)$$

$$= .27 PE_{1980}$$
6. Calculate total capital investment in January 1980 dollars

$$CI_{1980} = PE_{1980} + CCI + DCI + ICI + IDC + CF$$

$$= PE_{1980} + PE_{1980} (.35 + .14 + .15 + .06 + .27)$$

$$= 1.97 PE_{1980} = 2.0 PE_{1980}$$

This excludes installation, which may add approximately 125% of PE to CI_{1980} .

7. Estimate the Real Annual Fixed Capital Charges (AFC) applied to CI_{1985} using Real (Fixed Charge Rate) FCR:

Capital Recovery Factor: 10.6%

Depreciation Tax Shield	1.6%
Insurance	1.0%
Local Property or	
Revenue Taxes	2%
Maintenance & Repairs	2%
Administrative Overhead	<u>0.2%</u>
Fixed Charge Rate	15.00%

$$LAFC_{1980} = 0.15 \times CI_{1980} = 0.15 \times (2.0 PE_{1980}) = 0.30 PE_{1980}$$

8. Obtain an estimate of the annual operating costs (AOC) in 1980 dollars, as given by the cost functions for individual treatment processes.
9. If relative capital and operating costs are assumed not to change, then the present value of a 30-year stream of operating costs using the 10% WACC is equal to the levelized present value of the future operating costs using the real WACC in a capital recovery factor. Thus, the AOC_{1980} estimate may be used directly as the $LAOC_{1980}$.
10. Add the annual operating costs (in 1980 dollars) to the levelized annual fixed charges (in 1980 dollars) to find the levelized total annual cost $LTAC_{1980}$. Convert to mills/yr (1980) by multiplying by 10^3 .
11. Using the plant capacity factor, compute the expected annual net kWh production (kWh/yr).
12. Compute the cost of using the environmental control technology per unit of energy: $LTAC_{1980}/kWh$ per year. Note that installation may add approximately 125% of PE to bring $LAFC_{1980}$ up to $0.50 PE_{1980}$. When the given values are used, this entire procedure simplifies to:

$$1) LAFC_{1980} = PE_{1980} \times 2.0 \times .15 = 0.30 PE_{1980}$$

$$2) AOC_{1980} = LAOC_{1980} \text{ (from cost functions)}$$

$$3) \frac{\text{mills}}{kWh_{1980}} = LAFC_{1980} + LAOC_{1980} \frac{10^3 \text{ mills}}{\$} \times \frac{1 \text{ yr}}{kWh \text{ production}}$$

Note that the payback period for the purchased equipment is approximately three years, based on the results of steps 7.

INVESTMENT CLIMATE

The commercialization of geothermal resources requires at least two distinct corporate entities: a resource developer to provide geothermal steam to

the power plant, and a (regulated) utility that uses the steam to generate electricity. Discussion here will focus on the utility as the main entity of interest and the implications of that selection for the cost of employing environmental control technology (ECT).

Regulated Utilities

The utility is emphasized in this report because their WACC is the relevant discount rate for the capital budgeting analyses of ECT. The geothermal resource developer who performs the functions of well field exploration and fluid/steam transmission facility siting is not expected to employ the type of ECT that is investigated here and that will be required during the facility's operating phase. Instead, the developer will only provide the geothermal fluid to the production facility (generating unit) and, thereby, avoid the possibility of becoming regulated as a public utility. Such regulation could place a ceiling on the allowable rate of return. Because that ceiling might be below the developer's weighted average cost of capital, the developer would be prevented from earning a rate of return on well-field exploration and development activities sufficient to compensate for the higher risks involved. As a result, the potential to profitably undertake ventures would be reduced or eliminated.

The utility rate structure is, therefore, relevant to an evaluation of capital budgeting for geothermal ECT. Rates are set at a level sufficient to recover invested capital plus the utilities' opportunity cost of that capital as represented by the utilities' real after-tax WACC. Determinants of the real, after-tax WACC used in the costing methodology include the income tax, inflation, and risk factors present in the utilities' environment.

Income Tax Factors

Accelerated depreciation in excess of either the sum of the years' digits or double declining balance (SYD or DDB) is not allowed on pollution control equipment on geothermal facilities put into operation after January 1, 1976. The maximum allowable IRS tax life for electric-generating facilities is 22.5 years; therefore, this report's use of a 30-year economic life and

straight-line depreciation (SLD) with no tax preference item allowance may actually overstate the present value of the after-tax cash outflows attributable to capital recovery for ECT systems.^(a)

Investment tax credits (ITC) are allowed on geothermal capital investments and presumably would also be allowed on ECT. In this report the ITC has not been included in the analysis. This exclusion has the effect of overstating the life-cycle costs of capital-intensive ECT relative to operating cost-intensive processes. Income (revenue) generated by the utility is expected to be taxed at a marginal rate of 46%, providing a tax shield on debt interest expense only.^(b) Depending on relative weights of debt and equity in the firm's capitalization, these tax effects will influence the discount rate of the regulated utility.

Risk and Inflation Factors

In addition to the influence of income tax factors, both industry risk and expected price-level changes may be significant determinants of the real, after-tax WACC facing a utility. With respect to geothermal risk factors, the premium attached to the real riskless rate of return available in short-term government securities (T-Bills) will be determined by the following items:

- system reliability
- temperature and flow rate declines over time
- changing environmental regulations
- rapid technological advances in ECT systems.

These items are meant to represent the nondiversifiable risks associated with capital investments in ECT for geothermal resources (i.e., the marginal or incremental risks that characterize investments in geothermal facilities as opposed to less risky investments in T-Bills).

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- (a) The magnitude of overestimation is not expected to be significant relative to the uncertainty surrounding price estimates for the purchased equipment.
- (b) The cost of equity to the firm is equal to the rate of return demanded by investors. No tax deduction is available to the firm for their equity costs. From the firm's standpoint, both the before- and after-tax cost of equity capital is the same.

A risk premium would be attached to discount rates only if the investment in geothermal facilities influences the firms' expected marginal cost of capital (in that case, the WACC is an inappropriate hurdle rate or decision criterion and the marginal cost of capital is used in its place). Because this report assumes that investments by a utility in geothermal facilities will not change the marginal cost of capital, a risk-adjusted real after-tax WACC was used as the theoretically appropriate accept/reject investment criterion.

The final source of impact on the appropriate WACC, which is used in discounting future cash flows, arises from expected changes in the general price level (inflation). In this study the inflation premium has been eliminated from the analysis. All cash flows and discount rates reflect real (constant) January 1980 dollars. Relative price changes for factors and products are assumed to be negligible; thus, the discount rate "d" is applicable to all future cash flows.

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