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An Assessment of Geothermal Development in the Imperial Valley of California

Volume 2 - Environmental Control Technology

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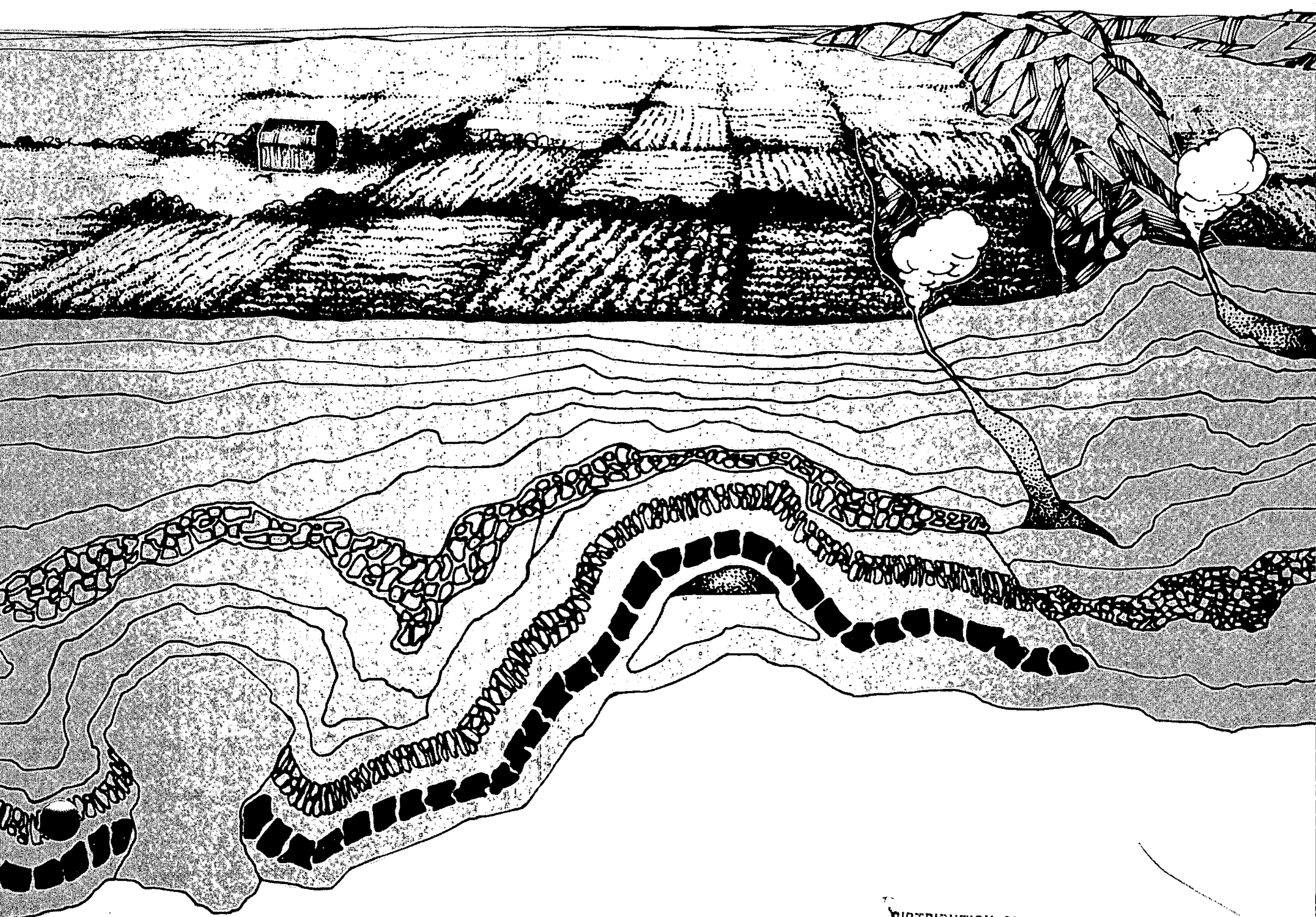

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An Assessment of Geothermal Development in the Imperial Valley of California

Volume 2 - Environmental Control Technology

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Washington, D.C. 20545

PREFACE

The Assistant Secretary for Environment of the Department of Energy (DOE) initiated the Imperial Valley Environmental Project (IVEP). The IVEP is a regional case study representing a program of surveys, field measurements and analyses aimed at characterizing existing environmental conditions in the Valley and assessing the potential impacts geothermal development could have on these conditions. This document is one of two comprising the final assessment report.

An Assessment of Geothermal Development in the Imperial Valley of California:

Volume I. Environment, Health and Socioeconomics

Volume II. Environmental Control Technology

The focus of Volume II is to identify environmental control requirements which are assumed either directly or indirectly in Volume I and to assess the efficacy and practicability of control options to meet those requirements. Sources of data include engineering state-of-the-art reports prepared by the Office of Environmental Compliance and Overview, Environmental and Safety Engineering Division* and other DOE Divisions, other engineering data and engineering judgment. It is anticipated that Volume II will establish a framework leading to the development and implementation of effective environmental control technologies for geothermal development in the Imperial Valley and in other liquid-dominated resource areas.

Douglas W. Boehm
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*Formerly Environmental Control Technology Division

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We express our appreciation to Lawrence Livermore National Laboratory staff scientists, especially D. Layton, D. Helm, K. Pimentel, P. Gudiksen, D. Ermak, R. Ireland, R. Quong, and J. Harrar for technical assistance and to L. Anspaugh and P. Phelps for their encouragement and guidance.

We also extend special thanks to Douglas Boehm of the Environmental Control Technology Division, Department of Energy for supporting our efforts in preparing this report.

CONTENTS

ABSTRACT

Environmental control technologies are essential elements to be included in the overall design of Imperial Valley geothermal power systems. This report assesses environmental controls applicable to abatement of hydrogen sulfide emissions, cooling tower drift, noise, liquid and solid wastes, and induced subsidence and seismicity.

Several currently available and emerging H_2S abatement technologies are applicable to power systems contemplated for the Imperial Valley. For optimum abatement of H_2S under a variety of plant operating conditions, removal of H_2S upstream of the steam turbine is recommended.

The environmental impact of cooling tower drift will be closely tied to the quality of cooling water supplies. Although significant technological progress has been achieved in reducing drift emissions, the efficiency of drift eliminators may be rapidly degraded if low quality water supplies are used.

Noise emission is not expected to be an important environmental issue in the Imperial Valley and strong community reaction is not anticipated. Conventional noise abatement procedures can be applied and no special research and development are needed.

Injection technology constitutes the primary and most essential environmental control and liquid waste disposal technology for Imperial Valley geothermal operations. Potentially large volumes of solid wastes may be generated requiring efficient methods for handling and hauling due to limited land availability for on-site, interim waste storage.

Subsurface injection of fluids is the primary control for managing induced subsidence. Careful maintenance of injection pressure is expected to control induced seismicity. Precise monitoring of surface elevations and the volumes of production and injection fluids are essential to provide useful data for making decisions regarding required subsidence and seismicity controls in the Imperial Valley.

INTRODUCTION

This report provides an assessment of environmental control technologies intended to mitigate anticipated environmental impacts resulting from geothermal development in the Imperial Valley of California. The assessment is based on energy production scenarios and predicted environmental impact levels described in Volume 1 of this report. Predictive assessments were undertaken because virtually no geothermal development has taken place in the Imperial Valley and there is very limited experience with the unique problems anticipated for the area.

In assessing environmental control technologies a systematic process is followed. The environmental concerns and their magnitudes are identified. Applicable environmental regulations and standards are weighed, and the control technology requirements are defined. Subsequently a survey and evaluation of control technologies are performed and the adequacy and cost effectiveness are determined. Findings and recommendations are presented regarding appropriateness of the technologies, possible gaps, and required research and development. Figure I-1 illustrates the process.

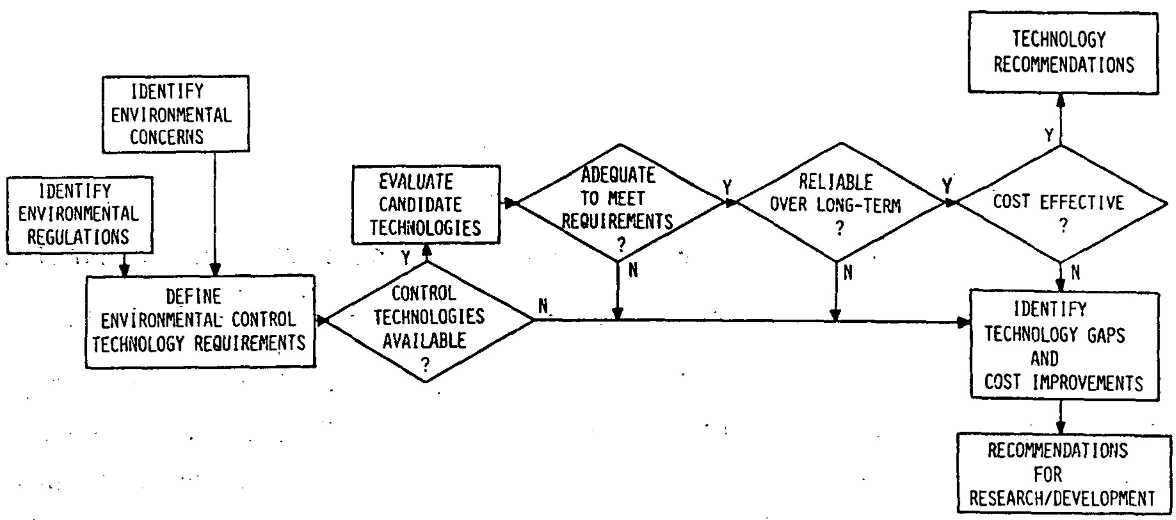

FIG. I1. Environmental control technology assessment process.

Most of the experience in utilization of geothermal resources for generating electricity in the United States has been gained at The Geysers area in Northern California. Many of the environmental concerns in the Imperial Valley are uniquely different from those encountered in The Geysers area because of the nature of the Imperial Valley resources, the characteristics and use of the land and the availability, quality, and allocation of water in the region. The following statements summarize some of the more important conditions influencing Imperial Valley geothermal energy system designs and the inherent environmental controls:

- Imperial Valley known geothermal resources are liquid-dominated.
- The Salton Sea and Brawley areas retain an estimated 60 percent of the total available geothermal energy in the known geothermal resources of the Imperial Valley.
- The Salton Sea and Brawley geothermal fluids contain total dissolved solids ranging from 80,000 to 200,000 mg/l.
- Relatively large volumes of cooling water are required for power plants utilizing liquid-dominated geothermal resources.
- Most of the high-quality water available to the Imperial Valley is allocated for use in agricultural irrigation.
- A large fraction of the land area in the Imperial Valley is dedicated to agriculture.
- Land surface integrity is essential for effective maintenance of agricultural activities.
- Land availability for geothermal power plant operations is limited.
- The Imperial Valley has a history of moderate seismic activity.

This report focuses attention on measures intended to mitigate impacts arising directly or indirectly from the nature of Imperial Valley geothermal resources and the conditions listed above. Specific technology assessments are presented for the mitigation of impacts due to hydrogen sulfide emissions, cooling tower drift, noise generation, liquid and solid waste, land subsidence, and induced seismicity. Regulatory policies and standards are reviewed and the requirements to meet the standards are presented. Currently available environmental control options and their applicability to the Imperial Valley environmental problems are described along with recent developments and outstanding needs. The assessments that are presented here are not complete because of the lack of practical experience with the types of resources and the conditions peculiar to the Imperial Valley. Existing technologies are not immediately or easily transferrable. Long-term effectiveness of certain proposed technologies is lacking and only limited capital, operating, and maintenance cost data are available.

HYDROGEN SULFIDE CONTROL TECHNOLOGIES

F. Stephens

INTRODUCTION

Background

The generation of electric power from geothermal resources can release a variety of gaseous substances into the atmosphere. Species such as CO_2, H_2S, and NH_3, are the most common and may be emitted in varying amounts. Hydrogen Sulfide (H_2S) is the principal gas of environmental concern because of its noxious odor. It is a pollutant common to both vapor-dominated and liquid-dominated resources.

Control of H_2S emissions from geothermal energy processes is necessary to minimize the odor nuisance and to avoid exceeding established ambient air quality standards. The control requirements depend on the allowable total H_2S emissions implied by these ambient standards. However, although emissions and ambient standards are related, any correlation between them must be a rough estimate until the geothermal industry develops improved operational and environmental control technology, adequate field measurements, and sophisticated modeling studies.

Local regulatory agencies have the authority to specify H_2S emissions and control levels for geothermal operations. Emission and control requirements for H_2S releases have been specified for The Geysers KGRA by the Northern Sonoma County Air Pollution Control District (NSAPCD) in California, and also by the State of California Air Resources Board (ARB) (Moyer, 1978). These requirements, specifying controls through 1986, become more stringent with time because increased power output will require increased total H_2S abatement. Similar emission and control requirements for the County of Imperial in Southern California have not been established.

Best Available Control Technology (BACT)

Any control technology must be researched, designed, developed, and then applied effectively to a particular plant process for several years before its applicability, efficiency, reliability, and costs can be evaluated. If the technology favorably meets these criteria, then it can be called the Best Available Control Technology (BACT) for that process. BACT does not imply that a proposed technique will provide effective H_2S emission abatement in geothermal applications simply because it is effective in some other industrial applications. The development of BACT for H_2S abatement in geothermal application will require a collaborative effort by participants from both government and industry. Since the technologies discussed in this section have never been applied commercially to Imperial Valley systems, none of them can be considered BACT at this time.

Technical Control Aspects

Hydrogen sulfide abatement techniques are new to electric power generation and must be viewed as experimental or developmental even though similar processes are used in the chemical and petroleum industries. Some of the information in this report relating to geothermal abatement technology has been obtained from experiences at the vapor-dominated resources of The Geysers in Northern California and can also be applied to liquid-dominated KGRA's. It is important that the developing geothermal sites in the Imperial Valley include adequate H_2S abatement technologies so that some of the environmental problems encountered at The Geysers can be avoided.

There are certain ancillary technical requirements necessary for an environmental control technology to be effective in the abatement of H_2S. These are listed below:

- The process should not create or add to the already existing corrosion problems associated with Imperial Valley resource fluids. Corrosive situations markedly increase maintenance costs and operational difficulties, not only to the abatement equipment, but also to the power plant.

- The abatement process should not cause excess reduced efficiencies in power conversion or other negative impacts such as excessive pressure or temperature reductions in the resource supply.

- The process chosen must be economical so that the economic penalties to the producer (and thus to the consumer) are not prohibitive.

- An abatement process should not increase hazards to plant workers or to the environment. Some processes require the use of hazardous chemicals such as H_2O_2 and concentrated NaOH. These materials must be transported to the plant site and in so doing increase the opportunities for dangerous spills. Storage of chemicals may also present a hazard. Processes that regenerate the needed chemicals are preferred to those that require a continuous new supply.

- Processes must minimize the production of excessive solids in injected fluids which can cause plugging of injection wells. These solids can also create a waste problem requiring transportation to dumpsites.

- Any process should not add to environmental problems because of chemicals used for abatement being emitted by cooling tower drift or from evaporation ponds.

THE IMPERIAL VALLEY GEOTHERMAL RESOURCES

Resource Characterization

Geothermal resources exist as vapor-dominated resources (steam), liquid-dominated resources (hot water/brine), and hot dry rocks. At the present time, the only power generation in the United States is taking place at The Geysers (a vapor-dominated resource) in Northern California. In the future, however, the major developments in geothermal power generation in the United States will most likely be on liquid-dominated resources such as those existing in the Imperial Valley.

In the Imperial Valley four known Geothermal Resource Areas (KGRA's) are in various stages of development for electric power generation. These are the Salton Sea, Brawley, Heber, and East Mesa KGRA's. Estimates of the total resource size have been made by Towse (1975), Renner et al. (1975) and Biehler & Lee (1975) estimating the total electric power production to be between 3000 and 5000 MW for a 30-year period (Towse, 1975; Nathenson & Muffler, 1975). Based on flashed-steam power plants, approximately 50 kg of brine from the Salton Sea and Brawley KGRA's are required per kilowatt of power compared with about 100 kg needed to produce the same amount of power from the Heber and East Mesa KGRA's. The difference is due to higher downhole fluid temperature. The Salton Sea KGRA, for example, averages 285°C while other KGRA's range from 180 to 200°C. With respect to total dissolved solids (TDS), Salton Sea resources contain about 200,000 ppm, but Heber TDS is about 20,000 ppm and East Mesa 2,000 ppm.

Geothermal reservoirs, both vapor- and liquid-dominated, are characterized by significant lack of uniformity, even within the same well field over distances as short as a few kilometers. The variability of geothermal fluids is illustrated in Table 1 by the range and average values of noncondensable gases found in several geothermal resources. These values represent the results from a limited number of samples taken from a few wells in each area. When actual power production in the Imperial Valley becomes significant (hundreds of MWe) and operational experience and additional data are accumulated, the source measurements may show significantly different H_2S concentrations.

TABLE 1. Ranges and average values of H_2S and other noncondensable gases found in geothermal fluids from wells in various KGRA's. Values are in mg/kg of fluid (ppmw).

	Geysers[a] (steam)		Salton Sea[b] (brine)		East Mesa[b] (brine)		Brawley[c] (brine)	Heber[d] (brine)	Baca[e] (brine)
	Range	Ave.	Range	Ave.	Range	Ave.	Ave.[f]	Ave.[f]	Ave.[f]
H_2S	5-1600	222	1.6-6.0	3.2	0.12-1.6	0.54	55.1	0.18	60.7
CO_2	290-30600	3260	1100-3800	1700	270-2300	1100	23500	34.6	8410.0
CH_4	13-1447	194	3.0-10	6.0	4.0-56	33	319	1.7	0.6
NH_3	9.4-1060	194	20-41	35	1.3-8.1	4.5	51	-	-

[a]Data from Giffin & McClure (1974). Average value measurements from 61 producing wells. 1972-74.

[b]Data from Ermak et al. (1979). Measurements from 2 or 3 wells.

[c]Data from Westec Services, Inc. (1979). Average from 2 wells: Veysey 2 and TOW 1. Data subject to sampling error. Values are probably closer to those found in Salton Sea brine.

[d]Data from Bechtel Corporation (1976); Howard (1979). Average of 2 wells

[e]Data from U. S. DOE, 1979. (Baca Ranch, Sandoval County, New Mexico)

[f]Meaningful range data not available.

The emission of H_2S from geothermal power plants depends on several factors: The H_2S content in the geothermal fluid, the chemical and physical properties of the fluid, and the efficiency of conversion and abatement technologies. The total emission from a given KGRA depends on the size of the individual power plants and the total number of power plants throughout the area of development. There is considerable uncertainty in all of these factors, especially with Imperial Valley's liquid-dominated systems which are only in the initial stages of development.

Geothermal Development for Nonelectric Uses

In general, the nonelectric uses of geothermal energy obtain their energy from liquid resource fluids that have an enthalpy (heat content) too low for efficient electric generation. These fluids usually have their heat energy extracted in a closed system by heat exchangers. The spent fluid is then injected into a nearby injection well (Fig. 1). In applications where the source fluid is "clean," it can be released into a river or

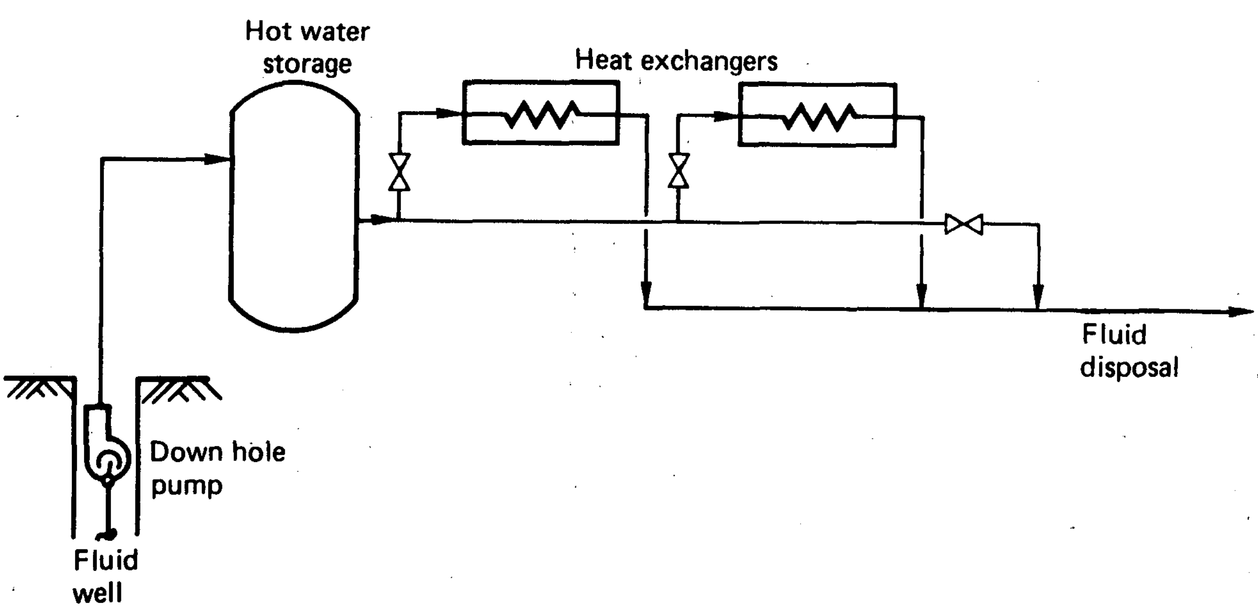

FIG. 1. Direct heating (closed system).

lake. In any case, most nonelectric uses do not result in the release of H_2S to the atmosphere. In one application, however, a water desalination plant was formerly planned by the Bureau of Reclamation for their East Mesa site. These plans have been cancelled because the capacity of the resource reservoir is inadequate to provide sufficient water for the project. If this project were carried out, H_2S could be released because the process involves the production of steam.

The Direct Use of Geothermal Energy Symposium sponsored by DOE on January 31 to February 3, 1978, in San Diego, California, indicated that there is considerable interest in the nonelectric uses of geothermal energy. Current applications include space heating, industrial process heating, crop drying, food processing, aquaculture, and greenhouse operations.

Geothermal Development for Electric Power

Except for The Geysers there is no other geothermal commercial electric power facility in the United States. A unit scheduled to come on-line this year (1979) is the Magmamax Binary 10 MW plant at the Imperial Valley East Mesa KGRA. The facility, owned by Imperial Magma Company, will use a binary cycle (hot water) process (Fig. 12).

Other efforts in the Imperial Valley are directed toward testing energy conversion equipment and various materials using actual geothermal fluids under field conditions.

Several geothermal facilities are proposed for electric power production in the near future. Forecasts for the period from 1979 to 1987 are assembled in Table 2. Several hundred megawatts of electric power production are projected. Estimates of electric power available from Imperial Valley geothermal sources by 1995 range from 500 to 8000 MW. The wide range reflects uncertainties in the size of the resource and the technological problems associated with utilization of brines from the Salton Sea KGRA. Other factors such as alternate power development and political decisions, may also affect development.

TABLE 2. Imperial Valley geothermal power projection to 1987 based on announced plans of utilities.[a]

Date on line	Utility	Developer	Location	MW	Cumulative total
1979	*SDG&E	Magma	E. Mesa	10[b]	10
1980	*SDG&E	RGI	E. Mesa	48[c]	58
	*SCE	Union	Brawley	10[c]	68
1982	*SCE	Chevron	Heber	50[c]	118
	*SDG&E	Magma/NAPCO	Salton Sea	50[c]	168
	*SDG&E	Chevron/EPRI	Heber	49[b]	217
	SCE	Mono/Union/ South Pac. Land Co.	Salton Sea	10	227
1983	SCE	Union	Brawley	100	327
	SDG&E	RGI/MAPCO	Westmoreland	48	375
1984	*DWR	CUI Venture	S. Brawley	55	430
	*DWR	McCulloch	E. Salton Sea	55 (Expanded)	485
	SDG&E	Magma	E. Mesa	50	525
	SCE	Union	Brawley	100	625
1985	SCE	Chevron	Heber	55	680
	SCE	Union	Brawley	100	780
1986	SDG&E	Chevron	Heber	100	880
	SCE	Chevron	Heber	100	980
	SCE	Union	Brawley	100	1080
1987	SCE	Mono/Union/ Southern Pac. Land Co.	Salton Sea	40 (Expanded)	1120

*A commitment has been made between utility and developer.

[a]California Energy Commission, February 1979.

[b]Binary conversion plant.

[c]Flashed steam conversion plant.

Development Scenarios from Modeling Techniques

To predict the impact of future power generation on the valley-wide air quality, atmospheric transport modeling techniques have been used. Recent reports studies by Ermak et al., 1979 and Gudiksen et al., 1979 at the Lawrence Livermore Laboratory (LLL) contain predictions of ambient air quality concentrations for H_2S and other gaseous emissions from projected geothermal development in the Imperial Valley. Scenarios based on 3000 MW, 2000 MW, 500 MW and 100 MW of power production have been considered. The main power level assessed in the studies is 3000 MW. The siting pattern for 30 power plants at this level of development is shown in Fig. 2, with isopleths of the predicted annual ground level concentrations plotted in Fig. 3. The levels are due solely to postulated geothermal sources and do not consider contributions from other sources.

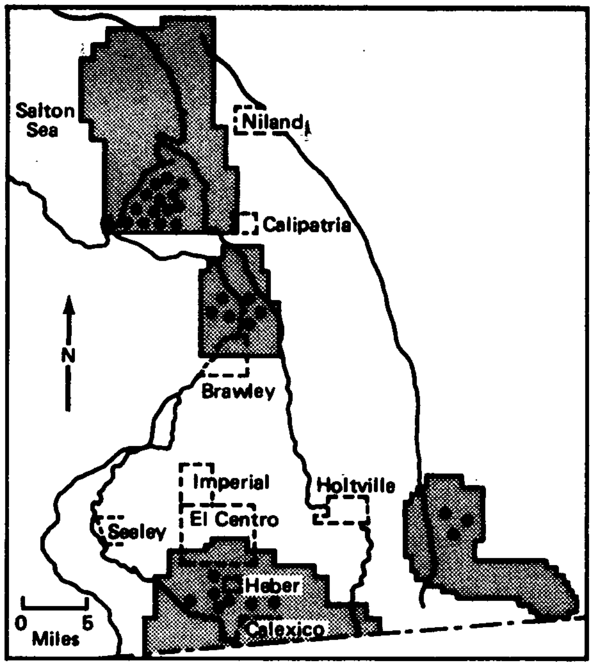

FIG. 2 Siting pattern for 30 power plant units by the year 2010 in the 3000 MW level medium-growth Scenario.

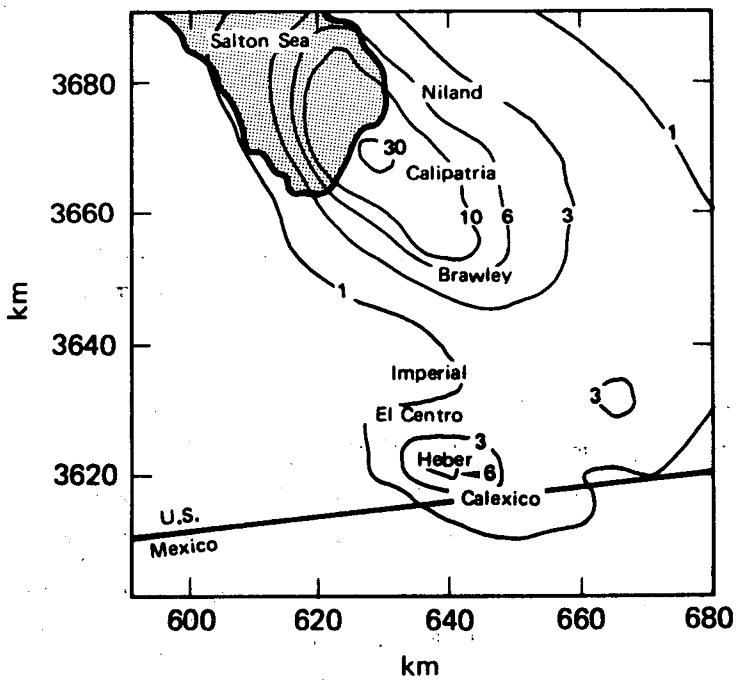

FIG. 3. Isopleth plot of the annual average ground level H_2S concentration in $\mu g/m^3$.

Conclusions from this study indicate that with no abatement:

- By the year 2010 at the 3000-MW level the California 1-h standard for H_2S (42 $\mu g/m^3$) would be violated at least 1% of the time over an area of approximately 1500 km^2 (about 1/3 of the valley area).
- The number of days when incidents of violations of the California standard would occur for selected cities would be

Calipatria	243	Holtville	14
Niland	73	Mexicali	2
Brawley	73	El Centro	0
Heber	14	Imperial	0

- For a single power plant the California 1-h H_2S standard would not be exceeded beyond 1 km when the emission rate is less than 0.8 g/s. This corresponds to an emission rate of 30 g/MWh. Rule 455(b) in the Northern Sonoma County Air Pollution Control District (where The Geysers is located) restricts emissions to 50 g/MWh by the year 1985.
- The entire valley - approximately 5000 km^2 - would experience levels in excess of 10 $\mu g/m^3$ (the average odor threshold) at least 1% of the time.

Control Requirements

The amount of abatement of H_2S emissions required to avoid violations of the California standard (42 μg H_2S/m^3) is shown in Table 3. As previously discussed in Volume 1, Section 5, the source emission rate by modeling studies was predicted to be less than 0.8 g/s in order to prevent violations of the 1-h average concentration standard. To keep the peak concentrations (as opposed to 1-h average concentrations) below 42 $\mu g/m^3$ beyond 1 km from the source, the emission rate must be reduced by another order of magnitude, 0.08 g/s. These peak concentrations are very dependent on atmospheric stability and occur when the wind speed is low. In addition, the concentrations depend on the height and size of the source. For these reasons the percent abatement required for peak concentrations of H_2S are only approximations (Ermak et al., 1979).

TABLE 3. Control requirements for H_2S abatement.

	Percent Abatement Required[a]			
	Brawley/Salton Sea[b]		Heber/East Mesa[c]	
	1-h ave.conc	peak conc.	1-h ave.conc.	peak conc.
Single 100 MW Plant Development Model	82.0[b]	98.2[e]	47.0[d]	94.7[e]
Multiple 100 MW Development (3000 MW) Model	85.0[f]	-	16.0[g]	-

[a]Calculated from information by Ermak et al. (1979).

[b]Salton Sea/Brawley H_2S emissions = 4.4 g/s per 100 MW plant (3.2 ppmw H_2S and 50,000 kg/MWh fluid).

[c]Heber/East Mesa H_2S emissions = 1.5 g/s per 100 MW plant (0.54 ppmw H_2S and 100,000 kg/MWh fluid).

[d]Less than 0.8 g/s H_2S emissions per 100 MW plant to avoid violations of the 1-hr (42 $\mu g/m^3$) standard within a 1 km radius of the source.

[e]Less than 0.08 g/s H_2S emissions per 100 MW plant to avoid peak violations of the 42 $\mu g/m^3$ standard beyond 1 km from source.

[f]Less than 0.7 g/s H_2S emissions per 100 MW plant to avoid violations of the 1-hr. (42 $\mu g/m^3$) standard in the Salton Sea and Brawley areas.

[g]Less than 0.8 g/s H_2S emission per 100 MW plant to avoid violations of the 1-hr (42 $\mu g/m^3$) standard in Heber, Holtville, and Calexico.

It is important to emphasize that the controls on a single power plant should be sufficiently stringent to eliminate the possibility of violations of the H_2S standard when multiple plants are sited in the same region.

In volume 1, section 5 of this report, H_2S control requirements for the Imperial Valley were determined using a 3000 MW, multiple power plant, full-field development model. The model consisted of 30 power plants of which 20 were located in the Salton Sea-Brawley areas. A requirement analysis was made for H_2S controls based on predicted levels of H_2S at 22 independently located measurement sites throughout the valley (Figure 5-6, Volume 1). The analysis determined that 85% control of H_2S emissions would be needed for each power plant located in the Salton Sea-Brawley areas in order to reduce emissions to less than 0.7 g/s and thereby maintain ambient, ground level H_2S concentrations below the California, 1 hour, average standard of 42 $\mu g/m^3$. This level of control compares to the 82% requirement (Table 3) that was based on the single, 100 MW power plant model. Far less H_2S emission control, amounting to 16%, was calculated for the Heber-East Mesa areas based on the multiple plant model using measurement sites in Heber, Holtville, and Calexico. This calculated level, however, was lower than the required 47% control (Table 3) based on the single 100 MW power plant model and needed to prevent violations of the California standard within a 1 km radius of plant facilities.

Based on the above analysis, it can be concluded that individual power plants constructed in the Salton Sea-Brawley areas will require 85% control of H_2S emissions, reflecting the more stringent controls imposed by analysis of data from the 3000 MW, multiple plant model. This compares to 47% control of H_2S emissions for individual plants in the Heber-East Mesa areas based on the more stringent requirements imposed by data derived from the 100 MW single plant model.

HYDROGEN SULFIDE CONTROL PROCESSES

Discussion

A DOE report prepared by Stephens et al. (1980) on the state-of-the-art experience for environmental control of H_2S emissions is available. Most of the present research and experimental techniques are being developed for The Geysers. The greatest efforts are being directed at the abatement of H_2S emissions from the major release points; the condenser vent gas ejection systems and the cooling towers. In addition, pilot plant studies are being made on removing H_2S from the raw steam before it reaches the generating plant. Any successful abatement technologies developed at The Geysers should be directly applicable to H_2S removal from steam derived from liquid dominated resources.

The majority of the technologies used for the control of H_2S in other industrial processes, such as the desulfurization of coal gas are not suitable for geothermal application due to slow kinetics, high cost, or the chemical form of the sulfur waste product.

Methods of converting the energy contained in the geothermal fluid into electrical energy that utilize the direct transfer of heat from the resource fluid to a secondary fluid, such as isobutane or freon, generally do not release H_2S. This is because the fluid is simply cooled during the process and then injected into another well. These systems, however, have other problems, mainly the precipitation of dissolved solids (due to the cooling) which plug the injection well.

Most of the other energy conversion systems involve the production of steam (flash system) for use in the turbine generation of power. A schematic representation of such a system is shown in Fig. 4. The hydrogen sulfide control technology used for this type of system is one that treats a noncondensable gas stream. When the H_2S is removed in this manner from the noncondensable gas stream generated by the steam production unit, it is termed an upstream abatement process. If, however, the noncondensable gases are separated in the turbine condenser, and the H_2S is removed from the turbine off-gas stream, the removal is called a downstream abatement process.

Noncondensable Gas Separation

Regardless of whether the noncondensable gases are separated upstream or downstream, a major factor in the overall abatement of H_2S is how it partitions between the gas phase and the aqueous (condensate) phase. In addition to temperature, a significant factor in the distribution of the hydrogen sulfide is the pH of the condensate. This is shown in Table 4 where it can be seen that the lower the pH, the more the hydrogen sulfide partitions into the gas phase.

The type of turbine condenser is also important. More hydrogen sulfide remains in the gas phase (at the same pH) when surface condensers are used because the steam is condensed on tubes and is in contact with only the small amount of its own condensate. In a direct-contact condenser, however, the steam is condensed by contacting a spray of cooling tower water whose volume is about twenty times greater than the condensate. This large volume of water along with the more intimate contact provided by the spray increases the amount of noncondensable gases that can dissolve in the aqueous phase resulting in lower amounts of gases in the gas phase.

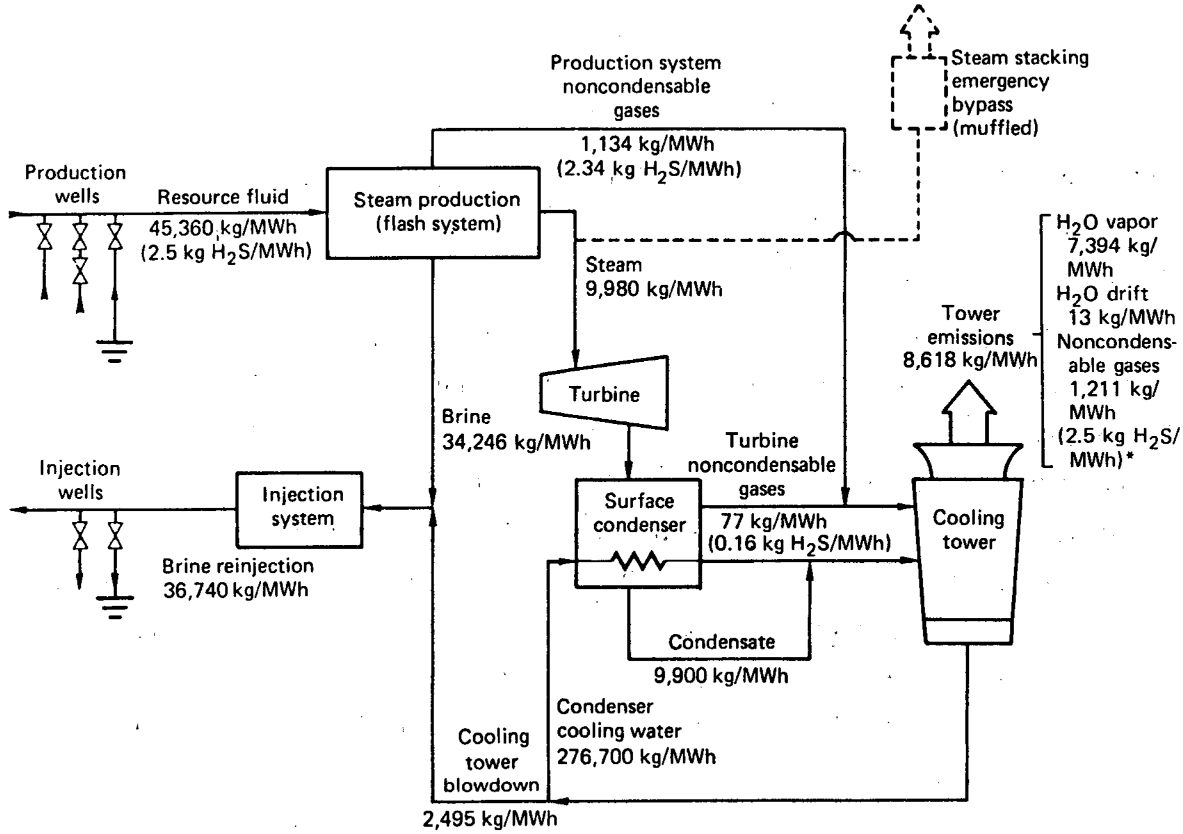

FIG. 4. Schematic of a power plant utilizing a liquid dominated resource to produce flashed steam. Source: Westec Services, Inc., (1979), p. 37.

*Assuming all gases emitted.

TABLE 4. Dependence of H_2S partitioning on pH and condenser.[a]

	% H_2S in gas phase			% H_2S in aqueous phase		
(pH, aqueous phase)	(6.5)	(7.0)	(7.5)	(6.5)	(7.0)	(7.5)
Surface condenser	93	89	79	7	11	21
Contact condenser	40	30	16	60	70	84

[a]Assuming 4000 ppmw noncondensable gases in steam (0.4%), the cubic feet of gas per pound of steam = 0.4/8 = 0.05. The values in the table were estimated from the curves in Fig. 5.

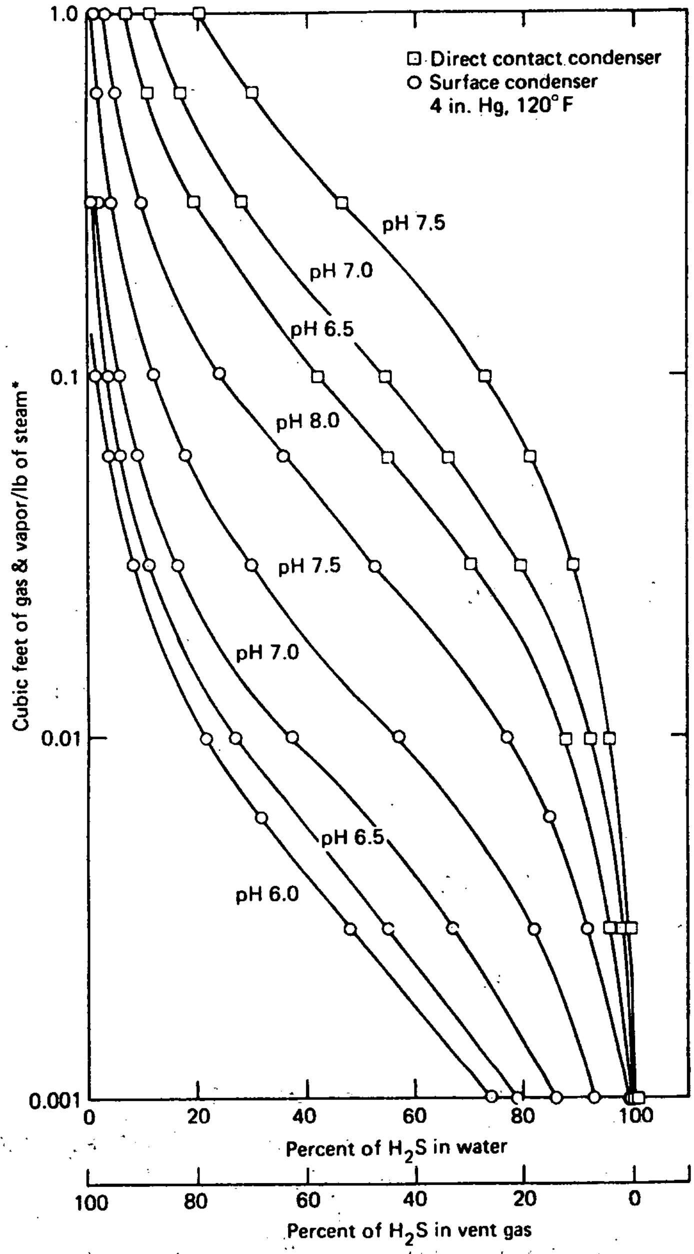

FIG. 5. Calculated H_2S distribution ratio in vent gas for direct contact and surface condensers. Source: Allen (1975).

*Cu ft/lb = (percent by wt noncondensable gas in steam)/8.

The pH of the aqueous phase also plays an important role in the partitioning of carbon dioxide, ammonia, and boric acid in the steam. A discussion of condensate chemistry in contact condensers and surface condensers has been detailed by Weres et al. (1977) Sections S11.6 and S11.7.

The Stretford Process

The Stretford process was originally designed for the removal of hydrogen sulfide from synthetic fuel gases. Many Stretford units are operating throughout the world for this purpose. The process is very effective; it removes more than 99 percent of the hydrogen sulfide that enters the system.

The first operational application of the Stretford process in the geothermal industry has been on Unit 15 at The Geysers for the downstream removal of the off-gas hydrogen sulfide. Recent tests confirm the performance of the Stretford process by removing at least 99 percent of the hydrogen sulfide that enters the unit. Initial tests indicated about 75-80 percent of the H_2S was being partitioned into the gas phase stream. Later findings by PG&E reveal that by shifting the pH to between 6.5 and 7 approximately 91% of the H_2S was partitioned. The latter improvement in partitioning could yield a total H_2S abatement of approximately 90%.

The Stretford process is also suitable for upstream abatement of H_2S on the off-gas stream of a flashed steam production unit. The off-gas is scrubbed with a solution containing sodium carbonate, sodium metavanadate, and anthraquinone disulfonic acid (ADA).

A flow diagram of the Stretford process is shown in Fig. 6. The gas stream is scrubbed in a countercurrent flow. The H_2S is dissolved forming bisulfide ion:

$$H_2S + CO_3^{-2} \rightarrow HS^- + HCO_3^-.$$

The bisulfide ion reacts with quinquivalent vanadium to form sulfur and quadravalent vanadium:

$$HS^- + V^{+5} \rightarrow S^o + V^{+4}.$$

The reduced vanadium is regenerated to the 5-valent state through a mechanism involving oxygen transfer by the ADA:

$$V^{+4} + ADA \rightarrow V^{+5} + \text{reduced ADA}$$

$$\text{reduced ADA} + O_2 \rightarrow ADA + H_2O$$

Air passed through the solution in the oxidizer tank not only oxidizes the ADA, but also brings the elemental sulfur to the surface as a froth. The sulfur froth is removed to a skim tank, separated, washed and melted to produce high quality sulfur.

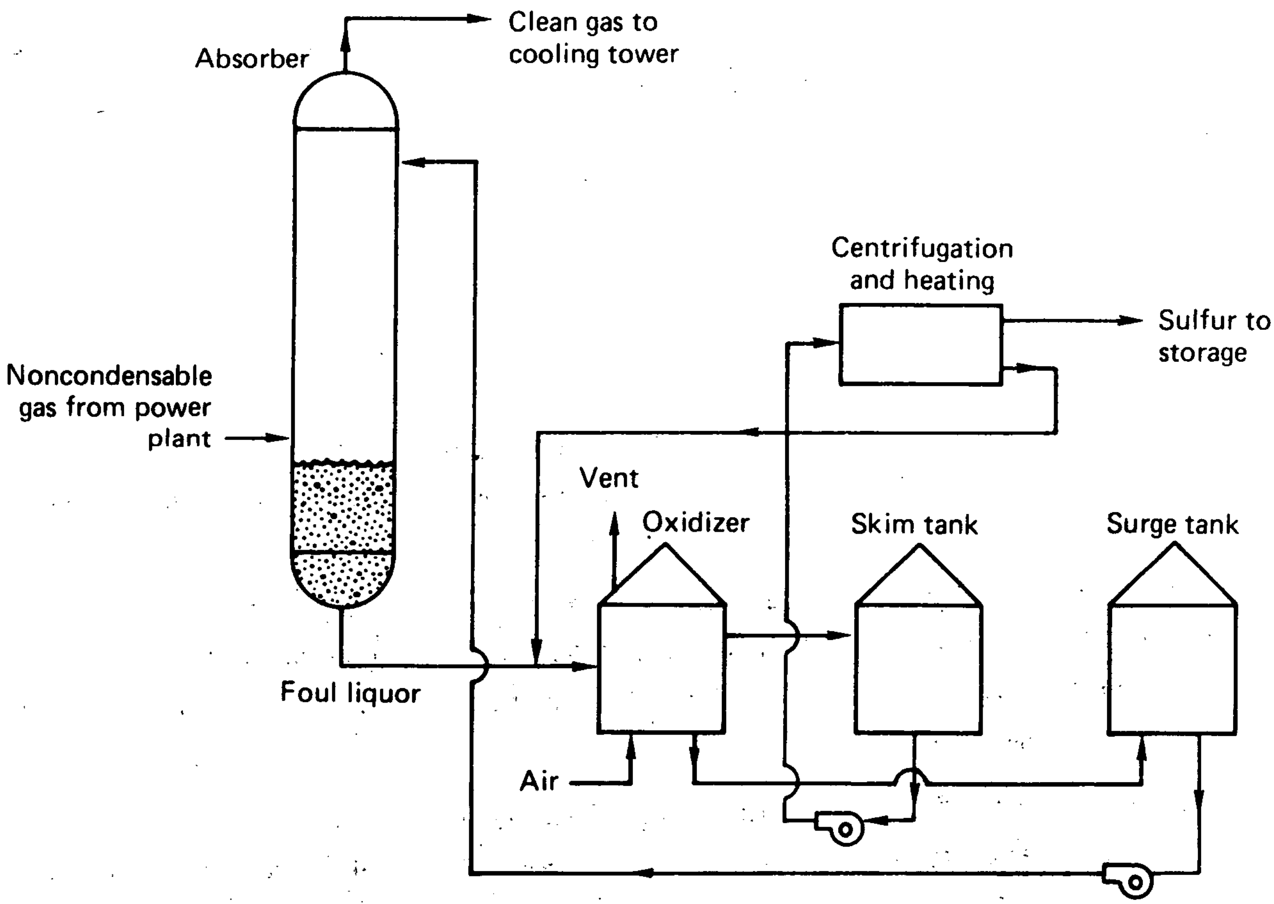

FIG. 6. Flow diagram of the Stretford process.

Brine Scrubbing Process

A simple and inexpensive method for removing H_2S from noncondensable gas streams was identified and initially tested by Quong et al. (1979). The method involves scrubbing the noncondensables with spent brine effluents which contain high concentrations of heavy metal ions such as Pb, Zn, and Fe. The H_2S is absorbed in the brine and reacts to form insoluble heavy metal sulfides which precipitate out and are removed prior to injection. The method is particularly applicable for use with Salton Sea and Brawley Geothermal Field brines which are known to contain high concentrations of heavy metal ions. At the Salton Sea Geothermal Field, the brines contain on the order of 65 ppm Pb, 280 ppm Zn, and 270 ppm Fe, far in excess of the stoichiometric quantity necessary to react with all the H_2S. The readsorption of H_2S in the spent brine is favorable because of the new equilibrium established between the gas and liquid at lower temperature and higher pH, the latter due to the evolution of CO_2 form the brine.

The precipitation of metal sulfides is also the H_2S eliminating step in the $CuSO_4$ (EIC) process. But unlike the EIC process, the use of spent effluents eliminates chemical feed costs, regeneration steps, and problems that may be associated with slurry pumping and recirculation.

A brief test at the Geothermal Loop Experimental Facility (GLEF) by Magma Geothermal and SDG&E using the reaction chamber of a 30 gpm EIMCO clarifier as the contactor indicated scrubbing efficiencies on the order of 97%. This adaptation of the process combines H_2S abatement with preinjection clarification with minimal added plant costs. There are also other potential beneficial effects such as increased clarifier efficiency and mineral recovery from the sludge.

In order to achieve high overall abatement of H_2S, a surface type steam condenser will be required to minimize the volume of liquid in contact with H_2S in the gas phase and thereby maximize the amount of gaseous H_2S to be ultimately scrubbed.

Partitioning of the H_2S in the surface condenser will be a factor in the overall abatement efficiency. The amount of H_2S retained in the brine and subsequently desorbed in the lower flash stages and evolved with the low pressure steam, may still pose a problem.

The EIC Copper Sulfate Process

Absorption of H_2S by scrubbing steam with aqueous copper sulfate ($CuSO_4$) solution is being investigated (EIC Corporation, 1977; Harvey, 1976), with funding from both DOE and PG&E. The process is undergoing exhaustive testing by PG&E and EIC on Unit 7 at The Geysers as an upstream abatement technology. The pilot plant is one-tenth scale (for a 55 MW plant) and processes 100,000 pounds of steam per hour. Copper sulfate is regenerated by the pressure-leaching method. The results have been encouraging. Recent tests, after about 350 hours of operation, have shown that 95 to 98 percent removal of the H_2S from the steam is feasible (Allen, 1979).

In the EIC process, the steam is contacted in a scrubber with a recirculating dilute solution of $CuSO_4$. Copper was selected because its sulfides are sufficiently insoluble, even at high temperature and acidity, to yield favorable equilibria and chemical kinetics. The initial chemical reaction taking place within the scrubber is approximately:

$$H_2S \text{ (in steam)} + CuSO_4 \text{ (aqueous)} \rightarrow CuS \text{ (ppt)} + H_2SO_4 \text{ (aqueous)}.$$

With extended residence time of the precipitated CuS, sulfur is formed by the following reaction:

$$2\ CuS \rightarrow Cu_2S + S$$

A simplified flow diagram of the EIC scrubbing process is shown in Fig. 7. The scrubber used is a simple tray-type tower, although Venturi scrubbers and packed towers have also been evaluated. The geothermal steam passes through the scrubber where H_2S and other pollutants (NH_3 and boron) are removed. The scrubber solution containing insoluble precipitates is partly recycled to the scrubber, the remainder being sent to the regeneration system. Ammonia is added to the scrubbing solution to maintain the pH within the range of 0.8 to 1.5 (EIC Corporation, 1977; Harvey, 1976; Irfan, 1975). The precipitate in the slurry recycle is a mixture of cuprous sulfide (chalcocite, Cu_2S), cupric sulfide (Covellite, CuS), and elemental sulfur. The cuprous sulfide fraction has a composition of from $Cu_{1.8}S$ to $Cu_{1.95}S$.

Two methods for regenerating $CuSO_4$ for recycle to the scrubber column can be used. Both are adaptations of methods used for production of copper metal from sulfide ores.

One is to use a "sulfating roast," which yields $CuSO_4$ and drives off sulfur dioxide, which would have to be recovered by absorption or conversion to sulfuric acid. The reactions are as follows:

$$CuS + 2O_2 \rightarrow CuSO_4$$

$$CuS + \frac{3}{2}O_2 \rightarrow CuO + SO_2$$

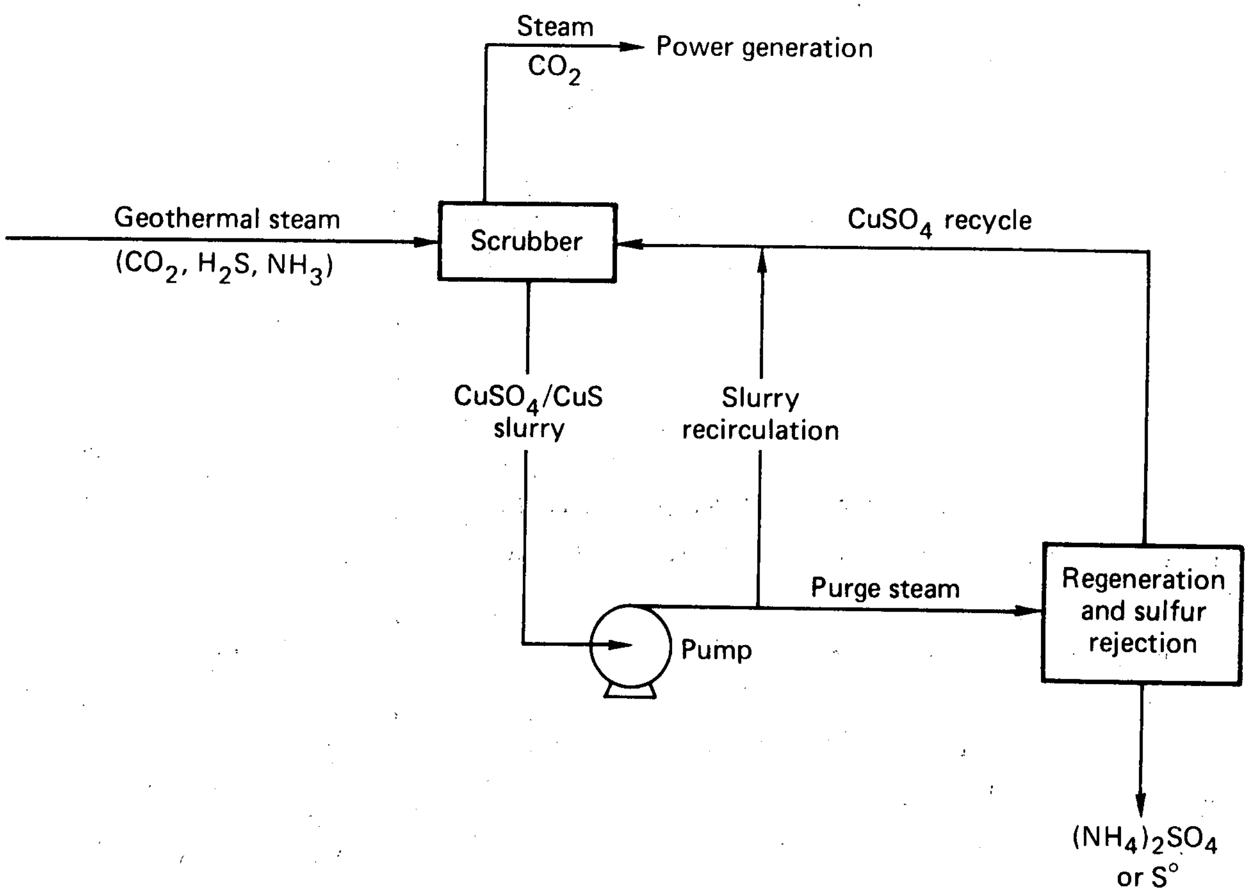

FIG. 7. Simplified flow chart of copper sulfate (EIC) emission control process.

The other method is acid pressure-leaching in which a slurry of copper sulfide in sulfuric acid solution is treated with air or oxygen under elevated pressure and temperature. Depending on the conditions used, the sulfide can be oxidized to elemental sulfur or oxidized to sulfate.

The possible reactions for $CuSO_4$ regeneration are:

$$CuS + 2O_2 \rightarrow Cu^{+2} + SO_4^{-2}$$

$$Cu_2S + \frac{5}{2}O_2 + 2H^+ \rightarrow 2Cu^{+2} + SO_4^{-2} + H_2O$$

The possible reactions for elemental sulfur formation are:

$$CuS + \frac{1}{2}O_2 + 2H^+ \rightarrow Cu^{+2} + S + H_2O$$

$$Cu_2S + O_2 + 4H^+ \rightarrow 2Cu^{+2} + 2H_2O + S$$

The kinetics of the regeneration process are better than that anticipated from laboratory experiments. If these optimistic results continue, plans for a full-scale plant at The Geysers may be scheduled.

One of the concerns of the EIC process has been the possible effects of $CuSO_4$ and elemental sulfur entrainment in the scrubbed steam. Analysis of the steam downstream of the pilot plant shows the presence of copper in amounts less than 1 ppm. It has been feared that even very small amounts will eventually cause significant plating of copper on the turbine blades and other parts of the power conversion equipment, leading to corrosion due to bimetallic coupling. Because of this, PG&E has not been returning the scrubbed steam to the turbine steam supply line. It is now thought, however, that copper entrained in the scrubbed steam will react with the residual hydrogen sulfide in the steam to form CuS particles and thus eliminate the plating and bimetallic corrosion problems. On considering this hypothesis, PG&E will soon begin returning the scrubbed steam to the turbine supply line. The amount of elemental sulfur in the scrubbed steam and its effect on the turbine have not been determined.

Dow Oxygenation

The Dow oxygentation process is an upstream technology developed for the removal of H_2S from the resource liquid before flashing. Most of the experimental work (Wilson et al., 1977) has involved the treatment of simulated hot geothermal brine. The overall reaction which is believed to take place is as follows:

$$H_2S \text{ (aqueous)} + 2O_2 \text{ (gas)} \rightarrow H_2SO_4 \text{ (aqueous)}.$$

Lesser but significant amounts of sulfite and free sulfur are also formed by other reaction paths. Close to 90% H_2S abatement was achieved in the laboratory at pH 7 and 171°C at a 1.5 mole ratio of injected oxygen to H_2S. The oxygen is injected through a flow controller into a packed column.

Corrosion is a major problem if excess oxygen is injected. This requires very close monitoring and control of the oxygen injection system. A proposed design concept for the system is shown in Fig. 8.

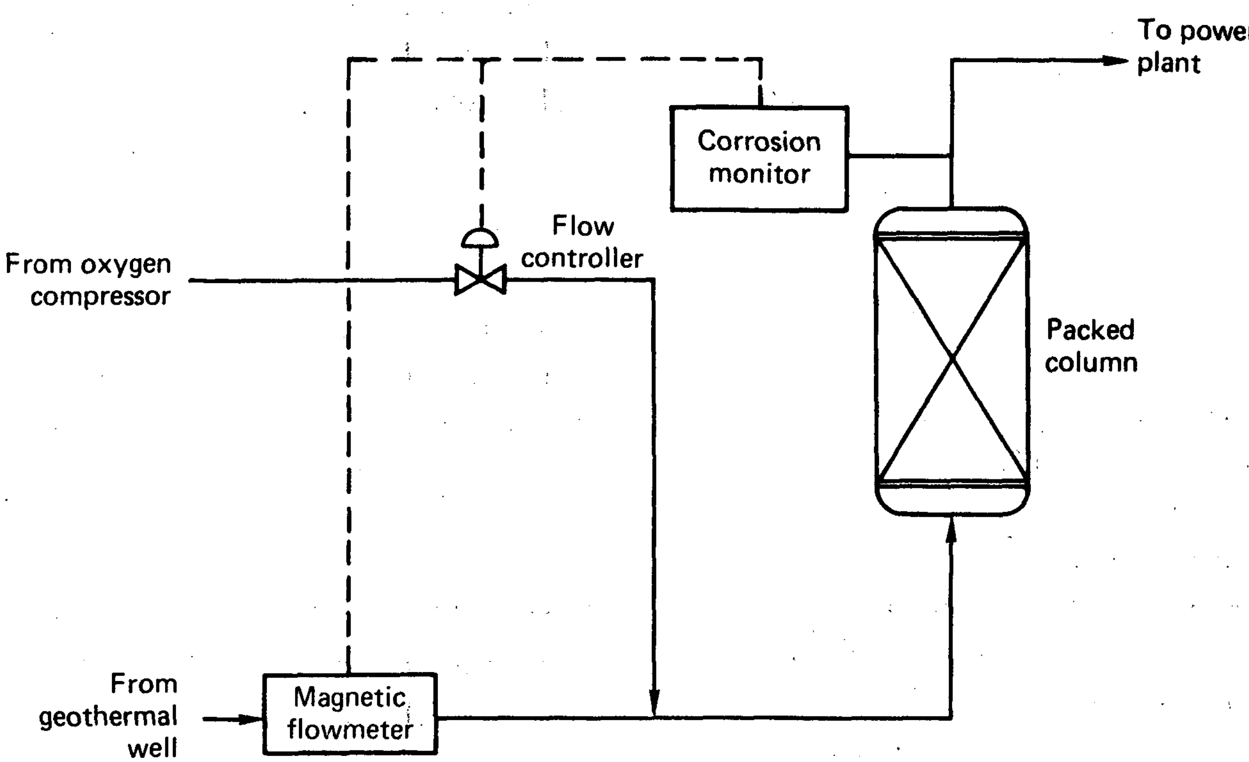

FIG. 8. Conceptual design of Dow oxygenation processing using a packed column (design case II).

Reaction times with all-liquid resource fluid is about 1 min. However, the reaction with vapor is too slow to be feasible with steam or two phase fluids. Two phases can be expected with high temperature liquid-dominated resources unless down-hole pumps are used to keep the fluid in an all-liquid state. The long term reliability of down-hole pumps is yet to be established. Because of these problems work on this process has been discontinued.

SRI Electrolytic Oxidation Process

SRI International, under Environmental Protection Agency (EPA) funding is studying a direct electrolytic oxidation procedure for the removal of H_2S from saline solutions. The present laboratory-scale experiments are being performed in a single stage process using solutions that contain from 1 to 30 ppmw H_2S with salinities of 16 g NaCl and 200 g NaCl/l (McKubre, 1980).

The oxidation reaction

$$HS^- \rightarrow S + H^+ + 2e$$

takes place at a flow-thru vitreous carbon anode with a porosity of 95%; at a temperature of 200^oC; and a pressure of 900 to 1000 psi. Early results indicate that better than 95% removal of H_2S can be achieved by the process. The system is precisely controllable, and the electrochemical aspects should be easy to scale-up. However, difficulties may be encountered with mechanical and physical scale-up.

UOP Catalytic Oxidation

UOP catalytic oxidation (Sulfox* process) utilizes a metal phthalocyanine compound supported by an activated carbon base to catalytically oxidize H_2S to sulfur, utilizing air as the oxidant.

The basic reaction may be written:

$$2H_2S + O_2 \rightarrow 2S + 2H_2O.$$

The oxidized sulfur products can vary considerably with the variations of reaction conditions. For example in an aqueous ammonical solution, the following oxidations to sulfur, thiosulfate, sulfite, and sulfate can occur:

*Registered trademark of UOP Incorporated

$$2NH_4SH + O_2 \rightarrow 2S + 2NH_4OH,$$

$$2NH_4SH + 2O_2 \rightarrow (NH_4)_2S_2O_3 + H_2O,$$

$$2NH_4SH + 3O_2 + 2NH_4OH \rightarrow 2(NH_4)_2SO_3 + 2H_2O,$$

$$NH_4SH + 2O_2 + NH_4OH \rightarrow (NH_4)_2SO_4 + H_2O.$$

This process was developed for use with hydrocarbon streams. A study has been recently funded by DOE to determine the applicability of this method to liquid- or vapor-dominated geothermal streams.

Any comments concerning the efficiency of this process must await the results of this study.

Steam Converters

Although not a true H_2S abatement process, steam converters have the capability of separating H_2S and other dissolved gases from steam. Abatement controls to remove H_2S from the separated gases would be required to supplement this process.

A schematic of a typical steam converter is shown in Fig. 9. The enthalpy of the geothermal steam fraction is transferred in a heat exchanger to a secondary stream of condensate. The steam loses part of its heat, condenses, and gases are removed in a gas stripping column. The condensate is then reflashed in the secondary coils of the heat exchanger. The basic principle of the steam converter is that when steam is condensed by removing heat, the resulting condensate is relatively free of dissolved gases which remain mostly in the gas phase. The heat from the condensing steam is used to reboil the clean condensate producing relatively clean steam. The condensing and reboiling processes are the two sides of the heat exchanger (converter).

A small steam converter, processing only several hundred pounds of steam per hour, is being tested, for "proof of concept" at The Geysers by PG&E and Coury Associates, Inc. (Lakewood, Colorado). Preliminary information, which is sparse at this time, indicates about 90% separation of hydrogen sulfide from the steam. Additional testing will probably reveal the extent of scaling, corrosion, heat loss and other operational problems.

The practical use of steam converters with steam produced from Imperial Valley liquid resources is not certain at this time because of the low enthalpy of the steam. Use of steam converters should not be ruled out however.

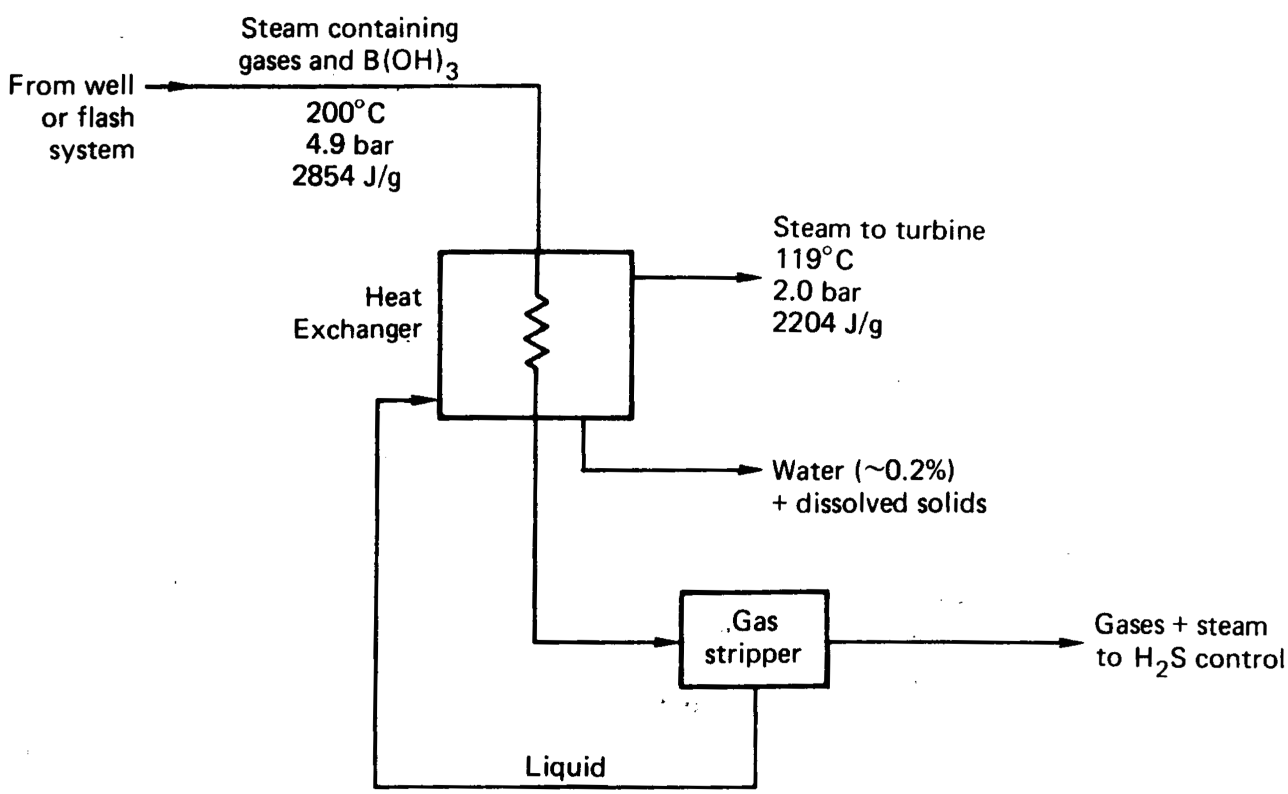

FIG. 9. Schematic of a typical steam converter unit (Weres et al., 1977)

Technical Comparison of H_2S Abatement Technologies

The candidate H_2S control systems for various process streams are compared in Table 5. All of them should be readily adaptable to Imperial Valley geothermal electric power systems. The reliability of these abatement technologies when used with the liquid resources of the Imperial Valley cannot be predicted with confidence. It is likely, however, that the Stretford, EIC, and brine scrubbing techniques will work well with the noncondensable gas streams.

Because nearly all of the abatement methods will produce a waste sludge by-product, this will probably be the only cross-media environmental impact of concern. If the brine scrubbing technique results in economically recoverable heavy metal compounds, then a benefit rather than a negative impact would result.

A judgement as to the best control technology for the Imperial Valley will have to await further research and testing under actual operating conditions.

TABLE 5. Comparison of candidate H_2S control systems for various process streams related to geothermal electric power development in the Imperial Valley.

PROCESS STREAM H_2S control system	Potential H_2S removal,%	Geothermal status[a]	Negative factors
NONCONDENSABLE GAS STREAMS			
Stretford	99+[b]	U	None
Brine Scrubbing	80 to 90	L	Unknown
EIC Copper Sulfate	98 to 99	P	Unknown
UOP Catalytic Oxidation	Unknown	L	Unknown
SINGLE-FLASH STEAM STREAMS			
EIC Copper Sulfate	98 to 99	P	Entrainment?
Steam Convertors[c]	90+	P	Heat loss
LIQUID RESOURCE STREAMS			
Dow Oxygenation	90 to 100	L	Corrosion
SRI Electrolytic Oxydation	>95	L	Unknown

[a]U - Used currently for geothermal H_2S abatement.
L - Laboratory or very small-scale field evaluation.
P - Pilot plant studies being conducted.

[b]Better than 99% applies to Stretford unit only. Overall abatement efficiency depends on partitioning (See text).

[c]Technology to apply this process to a full scale unit has been demonstrated by Resources, Conservation Company (RCC). Steam convertors separate noncondensable gases from the steam. They require H_2S abatement equipment for the noncondensable gas stream.

ENERGY CONVERSION TECHNOLOGIES

Several conversion technologies have been proposed to produce electricity from geothermal fluids. In general, these processes involve the use of a high enthalpy fluid to drive a turbine/generator. In a vapor dominated system such as The Geysers, geothermal steam is used directly in the turbine. Although there are no power plants now operating in the United States utilizing liquid dominated systems, processes are currently being developed. These include: flashed steam, flashed steam-binary cycle, hot water-binary cycle. Geothermal fluids may also be used as a direct source of heat for non-electrical applications such as space heating and process heating. Some of the processes for Imperial Valley resources under development for electrical power generation are discussed below.

Flashed Steam Power Generation

Liquid-dominated resources require flashing of the geothermal fluid to produce steam. Flashing is a process, illustrated in Fig. 10, whereby the superheated well fluid is allowed to boil at a pressure that is lower than its equilibrium subterranian pressure. The lower pressure also decreases the solubility of the gases dissolved in the liquid. The result is that the hot fluid is transformed into two phases, a liquid phase containing dissolved gases, and a vapor phase containing steam plus most of the non-condensable gases including hydrogen sulfide. The flash chamber also acts as a centrifugal separator to remove water and particulate matter from the steam. If the separator discharge liquid is hot enough, it can be flashed again in subsequent stages to produce additional steam. Once the steam is formed, it is then used for power generation by a turbine/ generator using either surface or direct-contact condensers. The spent liquid may be injected underground together with the cooling tower blowdown fluid.

For a single flash system the abatement of H_2S could be accomplished by an upstream technology that removes the gas from the whole steam stream. The EIC process is such a technology. The Stretford or brine scrubbing process could be used for downstream abatement.

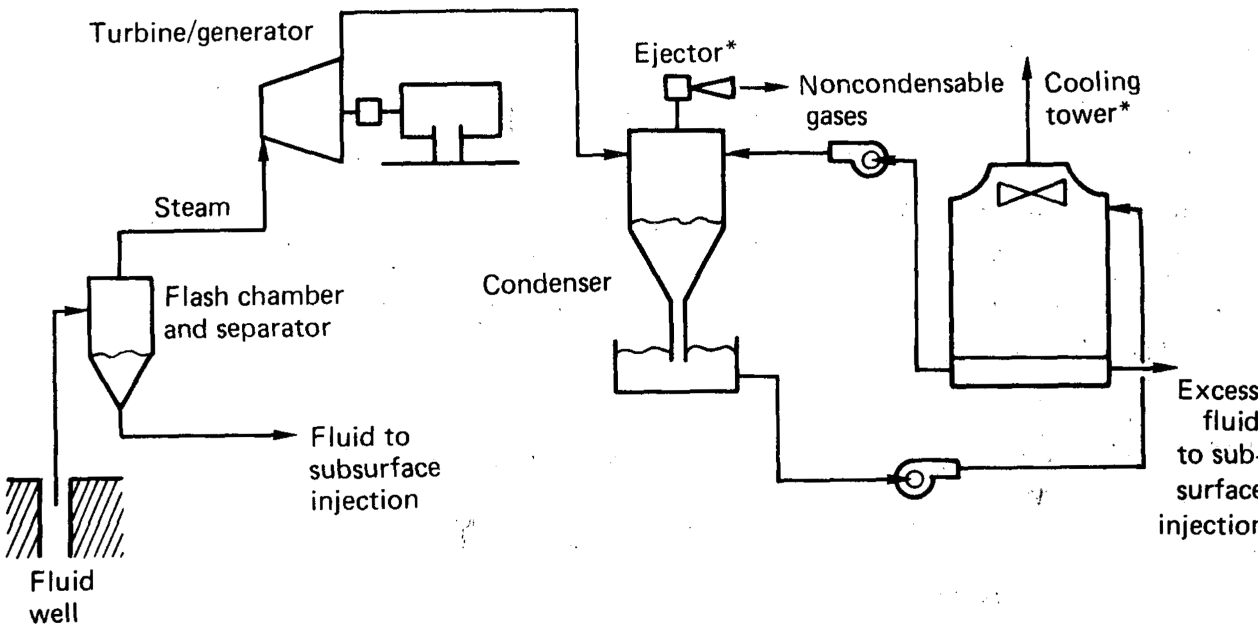

FIG. 10. Flashed steam process. Separator discharge liquid can be flashed again if its temperature is sufficiently high.

*Hydrogen sulfide release point.

Flashing Binary Cycle

This conversion process, shown in Fig. 11, uses steam from flashed geothermal brine as described in the previous paragraph. The steam thus produced is passed through heat exchangers, a boiler, and superheater, to vaporize a low boiling secondary fluid such as isobutane. The high-pressure secondary fluid is used to generate power by means of a turbine/generator unit as before. The secondary fluid (vapor) exhausted from the turbine is condensed and returned at high pressure to the heat exchanger. The spent steam from the heat exchangers is condensed and the noncondensable gases are removed. The steam condensate is then cooled in a cooling tower and recycled as a coolant for the barometric and working fluid condensers.

For this type of conversion system, H_2S could be abated upstream by the Dow oxygenation process, or downstream by one of the processes described earlier.

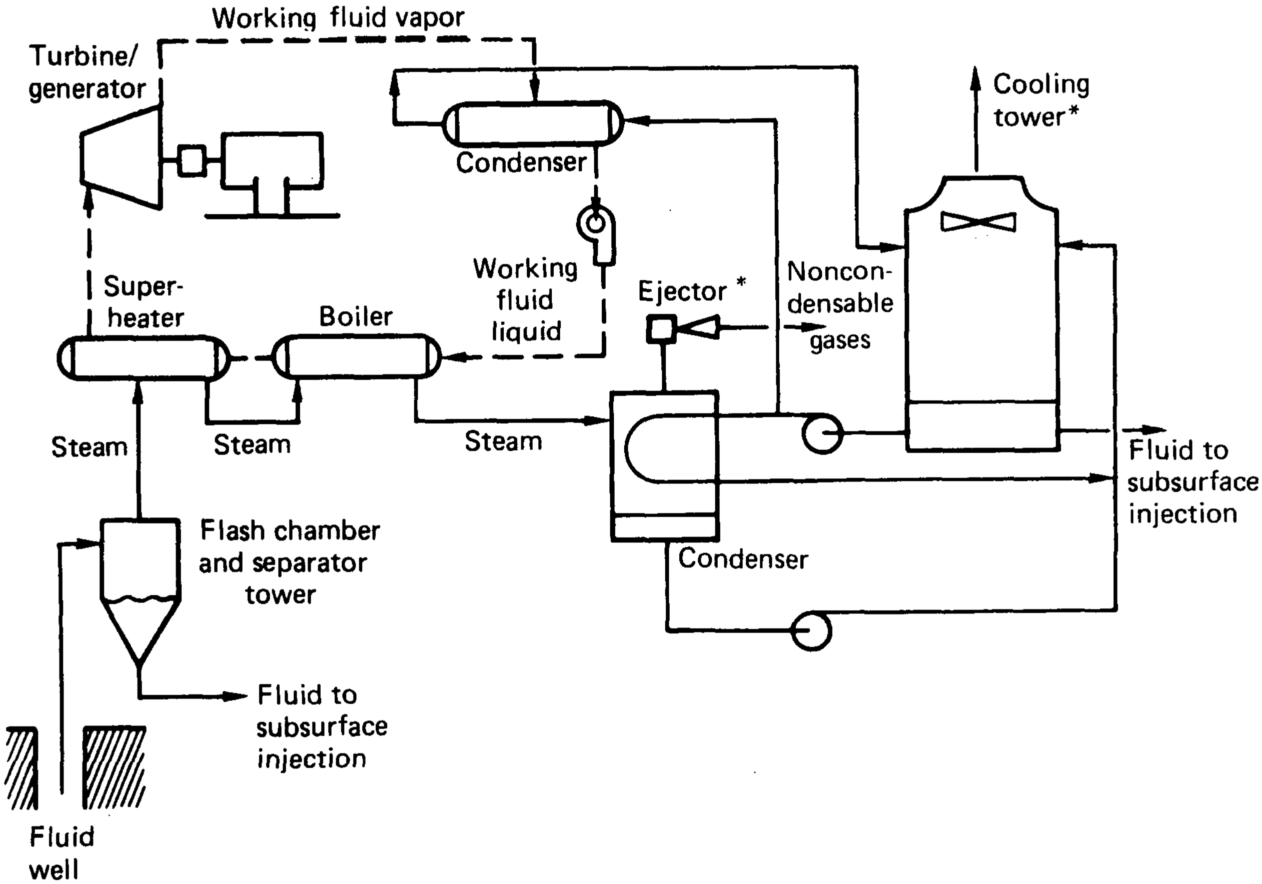

FIG. 11. Binary cycle (flashed steam) process. Flashed steam is used to heat a secondary fluid.

*Hydrogen sulfide release point.

Binary Cycle

This process is similar to the flashed binary cycle except that the hot geothermal fluid is used directly to vaporize the secondary fluid. The heat from the hot well fluid is transferred to the secondary fluid by countercurrent flow through a boiler and superheater. After expanding through the turbine, the secondary fluid is condensed with water from a cooling tower and pumped to the heat exchangers at a high pressure. The cooling water used in this process must be supplied by an outside source since no steam condensate is generated for cooling purposes. The entire spent geothermal fluid, including the H_2S, is injected underground. A schematic diagram is shown in Fig. 12.

It is generally believed that noncondensable gases are not emitted from binary cycle hot water systems because flashing is not required. If the

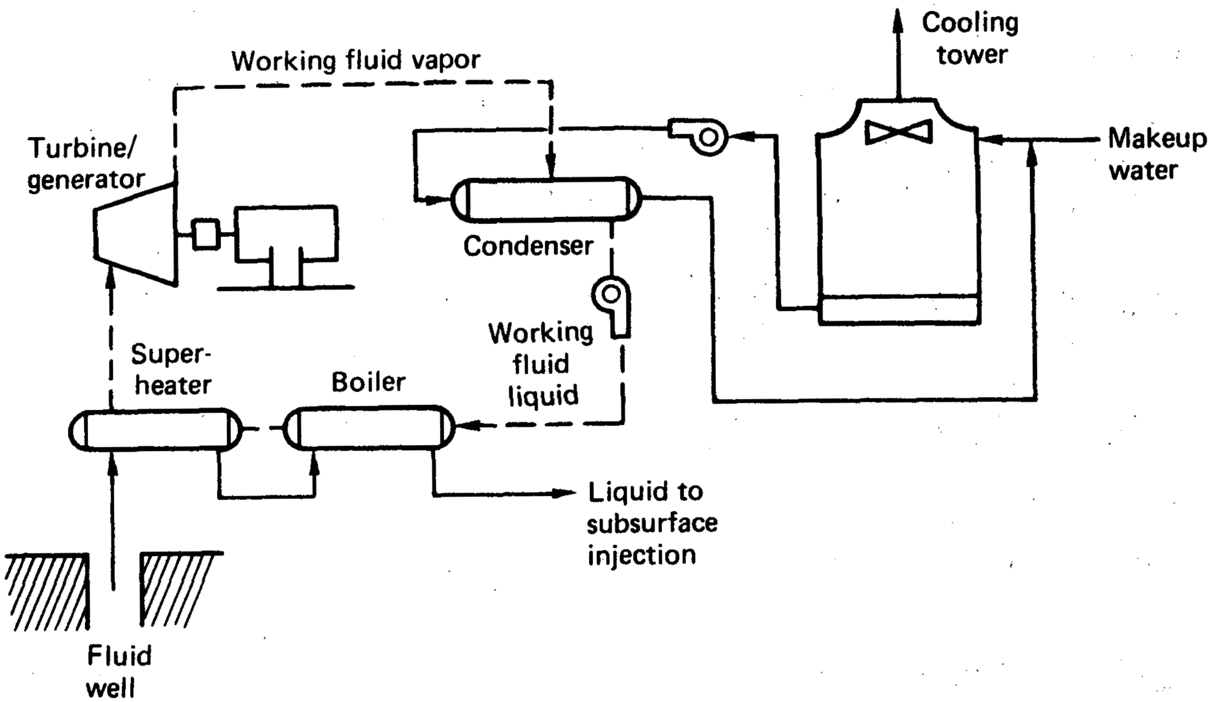

FIG. 12. Binary cycle (hot water) process. Hot water is used to heat a secondary fluid.

resource contains two phases or if gases separate after leaving the well, venting of the gas phase may be necessary to protect pumps from cavitation erosion. Some plants may require a treatment to separate the solids from the cooled spent brine to prevent plugging of the injection wells; this treatment could be another source of H_2S release. These types of H_2S releases may be controlled by the brine scrubbing system previously described.

CONCLUSIONS

Because the geothermal resources of the Imperial Valley are in the initial stages of development, the specific choices and applications of H_2S control technologies can only be estimated. However, some generalized remarks and conclusions can be made:

- The major H_2S emissions will emanate from release points in the geothermal power plants. H_2S emissions from other sources such as well-testing, well-venting and steam stacking are expected to be relatively less significant.

- Several H_2S abatement technologies are capable of reducing H_2S emissions to concentrations that meet the California ambient air standard. They have been used at the Geysers geothermal facilities or have been evaluated in laboratory or pilot plant tests. Additional experimentation and testing are necessary before their adaptability to proposed Imperial Valley power systems can be determined.

- The optimum location for H_2S separation and/or abatement is upstream of the steam turbine. In this way H_2S release during steam stacking incidents will be minimized.

- A single-flash steam producing facility may require an upstream abatement technology that is applied directly on the H_2S containing steam. The EIC copper sulfate process has been shown to be very efficient in this type of application. Whether the successful pilot plant performance at The Geysers will be as effective on steam produced from Imperial Valley resources remains to be seen.

- Steam production systems that separate the non-condensable gases from the steam can use H_2S abatement technologies on the off-gas stream. The Stretford process, brine scrubbing process, and probably the EIC copper sulfate process are applicable technologies.

- Direct treatment of the liquid resource to remove dissolved H_2S may be effective for all energy conversion technologies. Here, the Dow Oxygenation process appears feasible.

- Research now being carried out at SRI on the electrolytic reduction of H_2S in brine solutions may provide another technique for direct abatement in the liquid resource.

- The binary cycle (hot water process) is not expected to have large amounts of H_2S released. The relatively small amount of H_2S could be effectively abated using the brine scrubbing technique.

- Should downstream abatement be required, instead of - or in addition to - upstream abatement, the Stretford, EIC, or brine scrubbing process would be effective control technologies.

CONTROL TECHNOLOGIES FOR THE ABATEMENT OF COOLING TOWER DRIFT

C. R. Molenkamp

INTRODUCTION

One of the major elements of a geothermal power plant is a system for condensing and cooling the steam that exits from the turbine. The efficiency of the plant is determined primarily by the drop in temperature of the geothermal fluid as it passes through the turbine. For geothermal power plants, where the input conditions are controlled by the characteristics of the geothermal fluid, the temperature is lower than for fossil or nuclear plants. Therefore, the amount of water vapor passing through the turbine of a geothermal power plant with a thermal efficiency of 5-15% is 2-6 times larger than for an equivalent fossil or nuclear plant.

Most of the geothermal reservoirs in the United States with adequate temperatures to be used for production of electric power are located in the arid West where nearly all the available surface and ground water has been appropriated. Consequently the major available source of makeup water for a cooling system is the condensed geothermal steam. When this is used in a cooling tower, the dissolved salts and suspended particulates circulate in the cooling tower and are emitted with the water droplets that are blown out of the cooling tower, i.e. with the drift. Since these constituents can be toxic or harmful to receptors in the vicinity of the cooling tower, drift can be a significant environmental problem.

APPLICABLE STANDARDS

There are no emissions or air quality standards that apply directly to cooling tower drift from geothermal power plants. However, as part of the environmental review process, it is necessary to demonstrate that mitigation measures have been incorporated to guarantee that no significant impacts will occur.

IMPERIAL VALLEY

The Imperial Valley is a very important and productive agricultural region; any potential adverse effects of drift deposition on this agriculture must be carefully evaluated and satisfactorily mitigated. The purpose of an assessment is to determine whether there are probable impacts, to estimate the possible effects, and to determine the level of control necessary to insure that the impacts are negligible. Such an assessment includes three main aspects:

- emission fluxes and characteristics,
- transport and deposition, and
- effects on receptors.

Mitigation measures available involve reducing the emission of drift.

The fluxes of specific pollutants and the emission characteristics depend mainly on the composition of the cooling water makeup and the design of the cooling system. Since these factors vary among individual power plants, it is necessary to evaluate each plant individually.

In the Imperial Valley there are two major sources of cooling water for geothermal plants, steam condensate and irrigation drainage water. Both of these sources contain high levels of dissolved and suspended substances, some of which could be detrimental to crops and vegetation. Colorado River water, used for irrigation in the Imperial Valley, is considered unavailable for cooling water.

Wet mechanical draft cooling towers are the most likely system to be used in the Imperial Valley. The processes taking place in such cooling towers are not well enough understood to predict the emission fluxes of specific substances. Measurements can be made with an accuracy estimated at 25%, but only after a cooling tower is operating. Determiniation of the important emission characteristics of drop size distribution, velocity and buoyancy can be measured, but they are subject to considerable variability and similar uncertainty.

Many models have been developed to simulate the plume rise, transport, and deposition of cooling tower drift for specified emission parameters and meteorology, but these models disagree widely with one another. Consequently, predictions based on a particular model include a large uncertainty, and the results are often viewed with considerable skepticism. Since none of these models has been validated by adequate comparison with measurements of drift deposition, there is no reliable basis for selecting one model over another. In addition the models that have been developed simulate drift deposition in a particular meteorological situation while most of the impacts occur as a result of continuing deposition and build-up of deposited material.

Even if we could predict the deposition rates over relevant time periods as a function of distance and direction from the cooling tower, there are very little data specifying the effects of deposited trace elements on receptor crops in the Imperial Valley. What little data that exist are widely scattered and not readily available. There are considerable data on effects of sea salt deposition on coastal vegetation, and that may provide some guidance for estimating effects, but even these data do not apply directly to the important crops grown in the Imperial Valley.

Mitigation techniques, based on interception of drift drops before they leave the cooling tower, can reduce the flux of drift from 1-2% of the cooling water flow rate for uncontrolled towers to 0.001%. This reduction may be sufficient to mitigate the possible impacts of drift deposition, but since the amount of water flowing through the cooling tower is very large (10^6 gallons per hour per cell and 8-10 cells per 50 MWe plant), the amount of material emitted with drift by continuously operating cooling towers can still be significant. Therefore, it will be necessary to examine the possible impacts for specific pollutants in greater detail. This need can only be met by measuring the emission characteristics of operating cooling towers equipped with state-of-the-art drift eliminators, validating appropriate models of drift deposition, and conducting research to determine the effects of deposited substances on sensitive Imperial Valley crops.

COOLING TOWER DESIGNS

There are a variety of cooling systems that have been used in the electric power industry. While all these methods could be used for geothermal power plants only a few are currently being considered as desirable. Robertson, (1978) has provided a recent review of the various cooling systems and evaluated their potential for application at geothermal power plants. He concludes that wet, mechanical-draft cooling towers will be used most widely. Because of the low thermal efficiency of geothermal plants, their cooling systems must dissipate 2-6 times as much waste heat as a comparably sized fossil or nuclear plant.

The various cooling systems in use today include

- Once-through cooling systems,
- Cooling ponds and lakes,
- Spray ponds and canals, and
- Cooling towers.

Because of lack of available water in areas where geothermal resources exist, once-through cooling will probably not be used in the geothermal industry. Cooling lakes or ponds are also not likely to be used because of the large land area required. This is especially true in the agricultural areas of the Imperial Valley. Spray ponds are a potential cooling method for geothermal power plants and are being used in the Imperial Valley for the 10 MWe Magma power plant at East Mesa. Since spray ponds use substantially more land area than cooling towers, their use in the Imperial Valley is probably limited to the East Mesa KGRA, and to relatively small power plants. Therefore, most power plants in the Imperial Valley will use some type of cooling tower.

The cooling towers used in the electric power industry can be divided into various types. The first division is between wet and dry cooling towers. Dry cooling towers work much as a car radiator with the fluid to be cooled contained in pipes. Such cooling towers are rather inefficient and expensive. They have been used only in special situations and for small power plants. They have no problem with drift since the fluid is entirely contained. Wet cooling towers allow the water to be directly exposed to the air and derive most of their cooling from evaporation. Nearly all electric power industry cooling towers are wet cooling towers, although there are a few combination wet and dry cooling towers, which will be discussed briefly later.

A second major division in cooling tower types is the method used to induce air flow through the tower. There are mechanical draft towers in which a large fan is used to draw air in and through the tower, and natural draft towers in which the air, heated as it passses into the tower at the base, rises because of its buoyancy and leaves the top of the cooling tower drawing more air in through the base.

The final major division in cooling tower types is the relative motion of air and water. In a cross-flow cooling tower the air and water move perpendicular to each other, usually with the air moving horizontally through the fill while the water drops are falling vertically. In a counter-flow cooling tower the water and air move in opposite directions with the air moving upward through the falling water drops. The four basic types of wet cooling towers are depicted in Figure 13.

Natural draft cooling towers are best suited to operate in conditions where temperatures are low, relative humidities high, and total cooling requirements very large. Because of their relative inefficiency in hot dry weather characteristic of most geothermal areas including the Imperial Valley and the relatively small size of geothermal power plants, they are expected to have very limited use in geothermal applications.

Wet mechanical-draft cross-flow cooling towers will be most widely used in geothermal power plants. At The Geysers this type of cooling tower is used exclusively. All development plans for the Imperial Valley, except the Magma plant at East Mesa, have this type of cooling tower in their designs. Consequently, we will consider techniques employed to control drift only for wet mechanical-draft cross-flow cooling towers; however the design of drift eliminators and their efficiencies are similar for all four basic types of wet cooling towers.

The typical geothermal cooling system for a 50 MWe plant consists of about 10 mechanical draft cross-flow cells arranged side by side in a long row. Each cell is constructed as shown in Figure 13a with air flowing in on two sides and being drawn out the top by a fan. The fans are about 7-8m in diameter and are driven by 150 kW motors. The air typically exits the stack at about 10 m/sec. Each cell is about 15m high, 20m wide and 25m across. The two sides of each cell are usually separated by a baffle to prevent air from blowing horizontally through the cell. Hot water flows into each side at the top and is broken up into drops by the fill material. The cooled

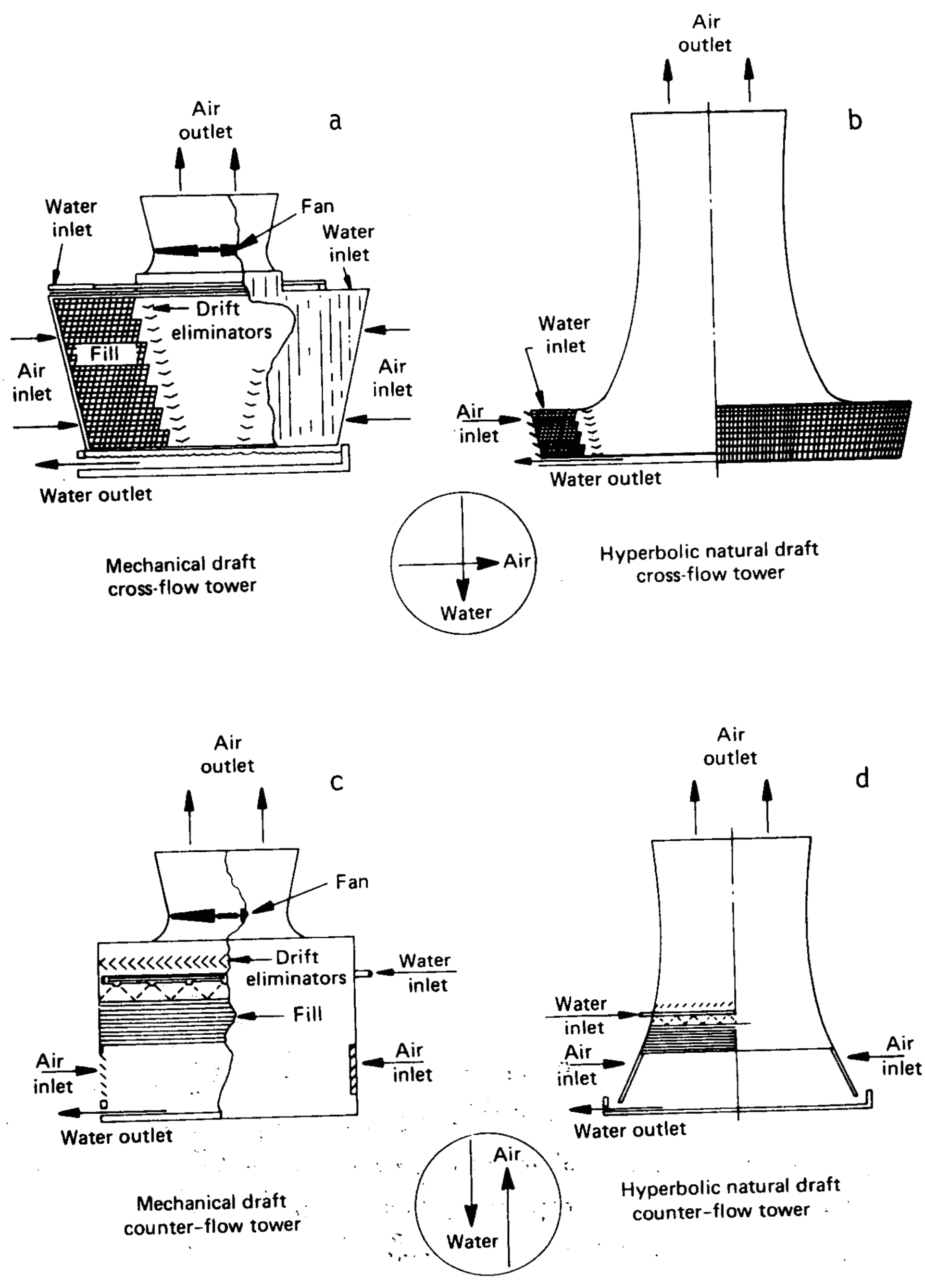

Fig. 13. Types of wet cooling towers (Holmberg and Kinney, 1973).

water is withdrawn by pumps at the base. Drift eliminators are usually placed in the air stream just downwind of the fill as shown in Fig. 13a. Each cell can cool about 1 m^3 sec^{-1} (15,000 gpm) of circulating water, depending on thermal efficiency, temperature drops desired, and wet bulb temperature.

In certain situations, particularly where fogging is a potential problem, wet-dry mechanical draft cross-flow cooling towers are being considered. A wet-dry cooling tower is a wet cooling tower with a dry cooling tower on top and is illustrated in Fig. 14. In these towers the hot water is pre-cooled in a dry section at the top of the tower before entering the fill material. Air that flows through the wet section becomes nearly saturated with water vapor. In the upper part of the cooling tower this nearly saturated air is mixed with air that has been heated inside the dry section so that the exhaust air is subsaturated. From a cooling tower drift perspective this mixing is important because drift drops from the wet section partially or totally evaporate.

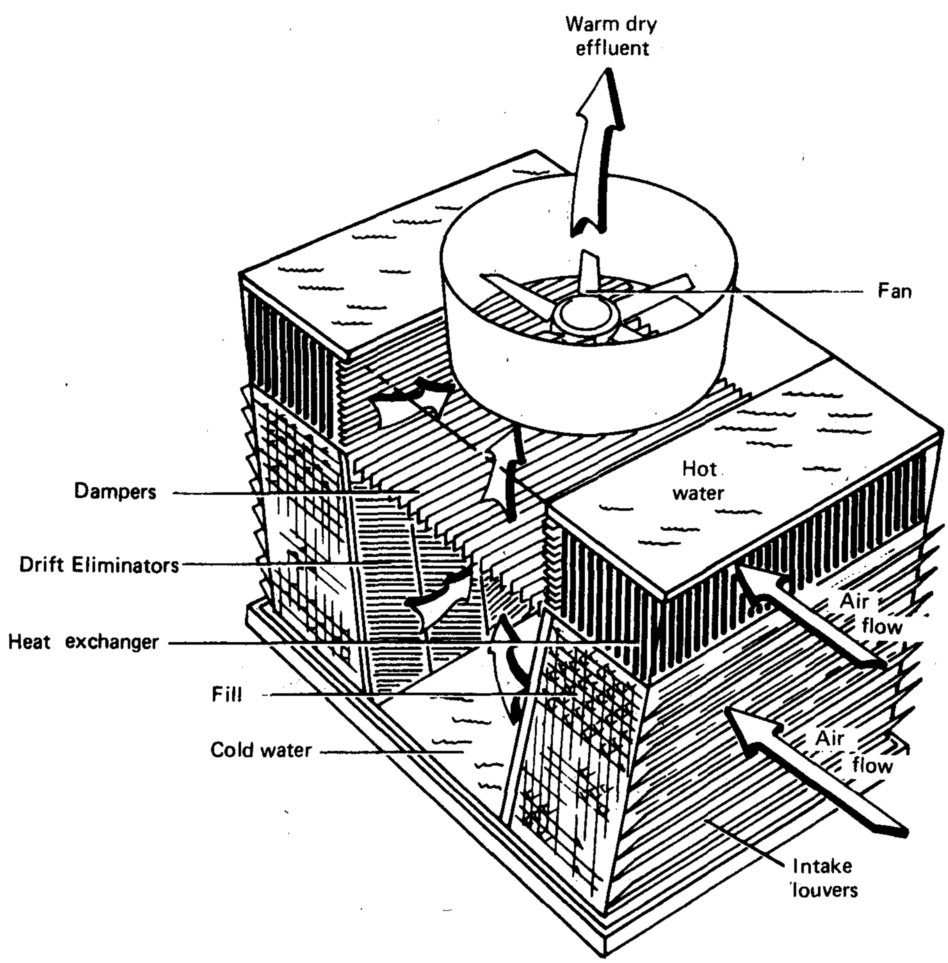

FIG. 14. Wet-dry cross-flow mechanical draft cooling tower cell (Reisman and Ovard, 1973).

DRIFT ELIMINATORS

As problems with deposition of cooling tower drift have emerged, a major effort has been made by cooling tower designers to eliminate drift efflux from cooling towers. Uncontrolled cooling towers have drift rates of 1-2% of the circulating water flow rate. Since this represents a significant rate of water loss and has unacceptable visual impacts, simple drift eliminators have been incorporated in cooling towers for many years. In a recent test by Wistrom and Ovard, (1973) these standard drift eliminators such as the Herringbone eliminator shown in Fig. 15a reduced the drift loss from 0.02% to 0.12% of the circulating water flow rate.

A variety of geometrical configurations have been used to improve the effectiveness of drift eliminators; the most common are the sinusoidal wave eliminator (Fig. 15b) or the "Hi-V" eliminator, which is V shaped rather than sinusoidal. The distance across these two eliminators in the direction of the air flow is typically about 10-15cm. The installation of a "Hi-V" eliminator in a typical cooling tower is illustrated in Fig. 16. Note that the channel of the V is sloped so that collected water is drained to the drift eliminator support beam and then down the beam to the cold water basin. More recently honeycomb material (Fig. 15c), oriented such that the air flow is deflected at the entrance, has been added to remove drops that passed through the upstream eliminators to improve the efficiency of drop collection. The latest innovation (Kinney, 1977) breaks the air stream into many small paths deflected at first upward and then laterally.

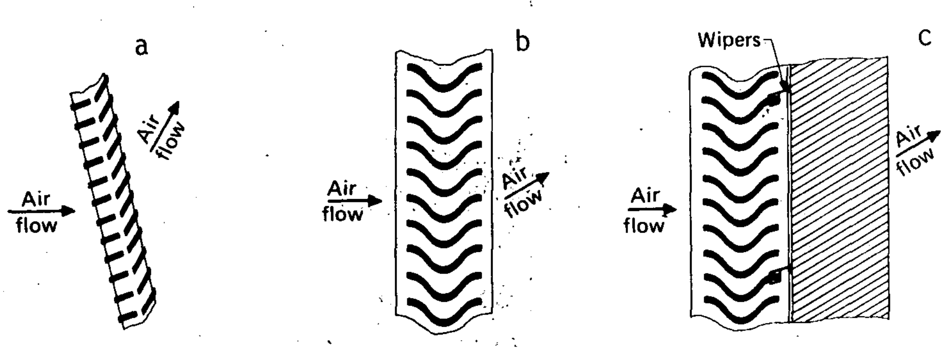

FIG. 15. Types of cooling tower drift eliminators (Holmberg, 1973).

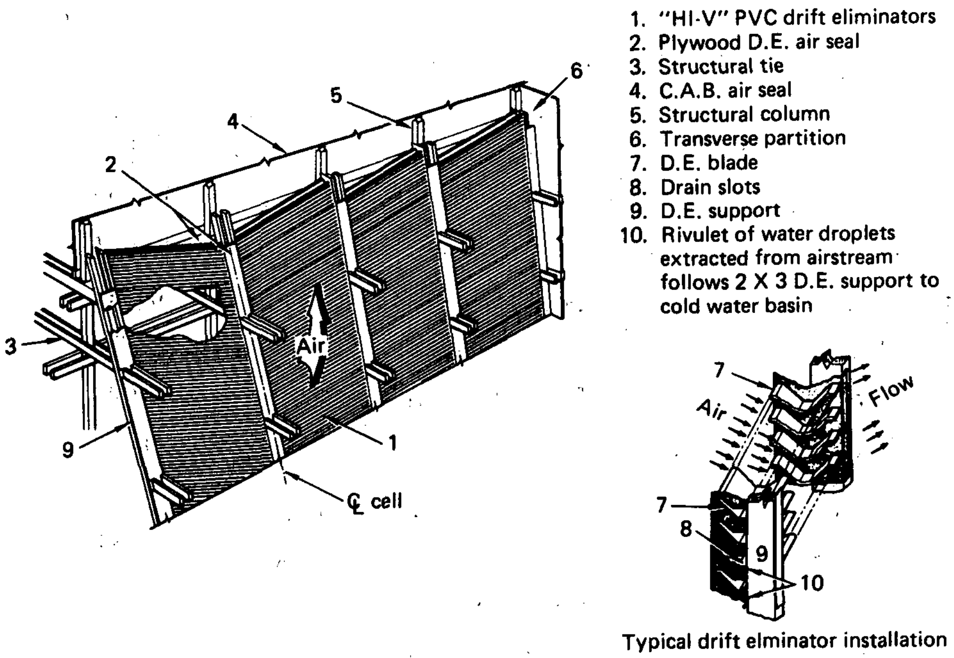

FIG. 16. Installation of "Hi-V" drift eliminator in cross-flow cooling tower (Reisman and Ovard, 1973).

The efficiency of the current drift eliminators available for geothermal cooling towers range from 0.001% - 0.004%. In tests of the "Hi-V" eliminator the drift rate was 0.001%-0.008% with a typical value of 0.004% (Wistrom and Ovard, 1973). The duplex eliminator employed on the Chalk Point cooling tower was guaranteed for a maximum drift rate of 0.002% (Holmburg, 1973). The new dual path eliminator (Kinney, 1977) is claimed to be about 4 times as efficient as the duplex eliminator.

Drift eliminator designs based on inertial impaction are most efficient at collecting large drops because of their greater inertia. This is fortuitous because the large drops carry most of the drift mass and are most likely to be deposited. Smaller drops have a high probability of evaporating completely before they fall to the ground, thereby leaving the emitted pollutants suspended in the atmosphere as particulates. The cut-off for minimum deposited size is 100-200 microns, but depends greatly on ambient atmospheric conditions. Most modern drift eliminators are very efficient at collecting drops larger than 100-200 microns.

An important effect that limits the design options for drift eliminators is restriction of air flow through a cooling tower; this tends to decrease the cooling efficiency of the system. As drift eliminators collect water, the air flow is further reduced, so it is important to provide for rapid drainage of the collected water to reduce the back pressure on the air flow.

For modern efficient drift eliminators there are two major ways that drops can escape the cooling tower, leaks or bypasses of the eliminators, and reentrainment of water drops from the eliminators. Leaks or bypasses occur around the edges and at joints in the eliminator support structure. Careful design can reduce this problem. If the water collected by the eliminators is not rapidly drained, it can be forced to the back of the eliminator and be reentrained into the air stream. These separated droplets are typically fairly large (>1000 microns) and are the major source of drift mass efflux for cooling towers equipped with modern drift eliminators. Separation of water drops from the drift eliminator support structure also contributes to this source of drift efflux.

A new cooling tower may be very efficient at removing drift, but the high dissolved and suspended particulate content of makeup water from geothermal condensate or agricultural drains leads to a build-up of residues on the drift eliminator surfaces. This can eventually clog the passages and plug the drainage routes. For geothermal plants that use the cooling tower as a pollutant scrubber, this residue build-up problem is greatly increased.

DRIFT EMISSION CHARACTERISTICS AND MEASUREMENT TECHNIQUES

The important characteristics of drift that have major impacts on deposition and possible detrimental effects are chemical composition, emission velocity and buoyancy, and size distribution. Each of these factors depends in part on the particular design and operating parameters of the geothermal power plant and cooling tower. Techniques have been developed to measure these characteristics, but the data generally are difficult to obtain and subject to some uncertainty. In this section we present the data available on these characteristics and how the characteristics depend on plant parameters, and we list the measurement techniques and their relative usefulness.

Chemical Composition of Cooling Tower Drift

For plants designed to use geothermal condensate for cooling tower makeup, data are available on the chemical composition of the geothermal fluid, but techniques to extrapolate these data into the chemical composition of drift are unavailable because knowledge of the transformations and partitioning that take place in the plant and cooling towers is incomplete. Consider, for example, the two-stage flashed-steam 50 MWe power plant proposed for Niland, California shown in Fig. 17. The geothermal fluid from the wells enters the plant at the flash tanks. Here a portion of the hot brine becomes steam and the rest remains as hot water which is injected into the geothermal reservoir. Each potential pollutant will be partitioned between these two streams depending on its own physical properties and the operating conditions of the flash units. The partitioning of the various pollutants at this point is not understood and adequate data will not be available until some of these units have been in operation. Most likely the particulate and dissolved materials will remain with the unflashed component, but significant quantities may find their way through the turbine and condenser and into the cooling tower. Most of the volatile and noncondensable

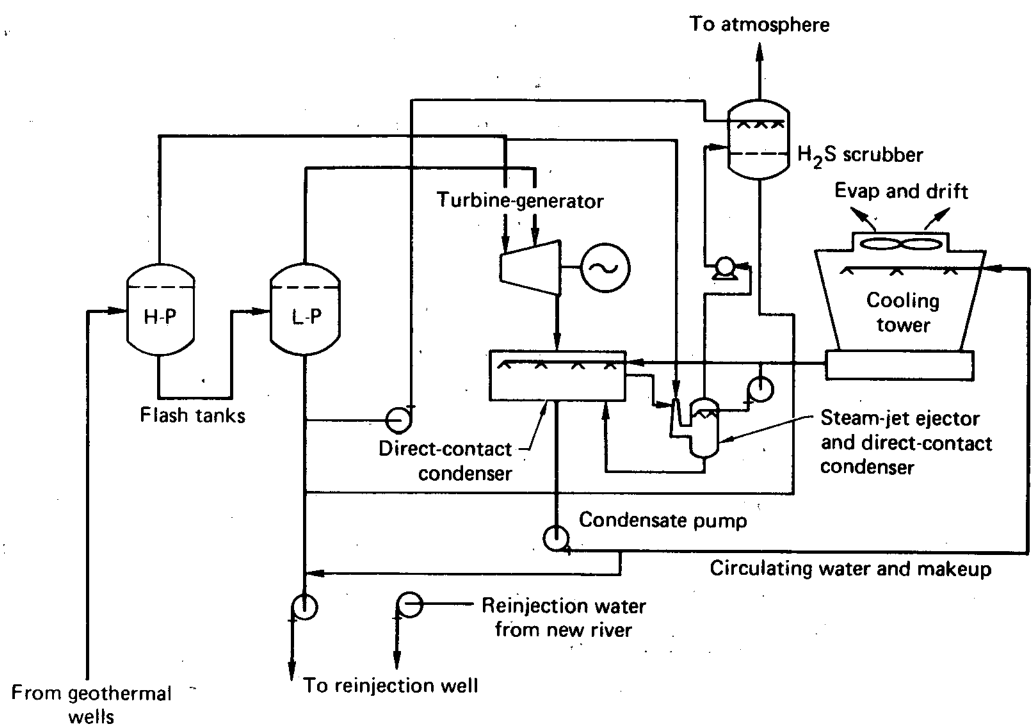

FIG. 17. Flow diagram for two-stage flashed-steam 50 MWe power plant proposed for Niland, California (Robertson, 1978).

substances will go with the flashed steam and either be released to the atmosphere through the H_2S scrubber or enter the cooling tower. Once in the cooling tower, the concentration of non-volatile pollutants will build up because of evaporation of water, although dissolved and particulate material will be constantly removed with the blowdown that is injected. The chemical composition of the cooling tower will probably come to an equilibrium, and it should be possible at that time to measure the amount of pollutants in the cooling tower and emitted as drift.

In the Imperial Valley, agricultural drain water is available for cooling tower makeup and is being considered in some power plant designs. An example is the multistage binary power cycle 50 MWe geothermal power plant proposed for Niland, California and shown in Fig. 18. In this case the circulating water for cooling is in a closed loop, and the makeup water composition has been measured. Based on mass balance considerations it is possible to estimate the mean composition of cooling tower drift drops. Measurement of the drift composition will be necessary to confirm these estimates.

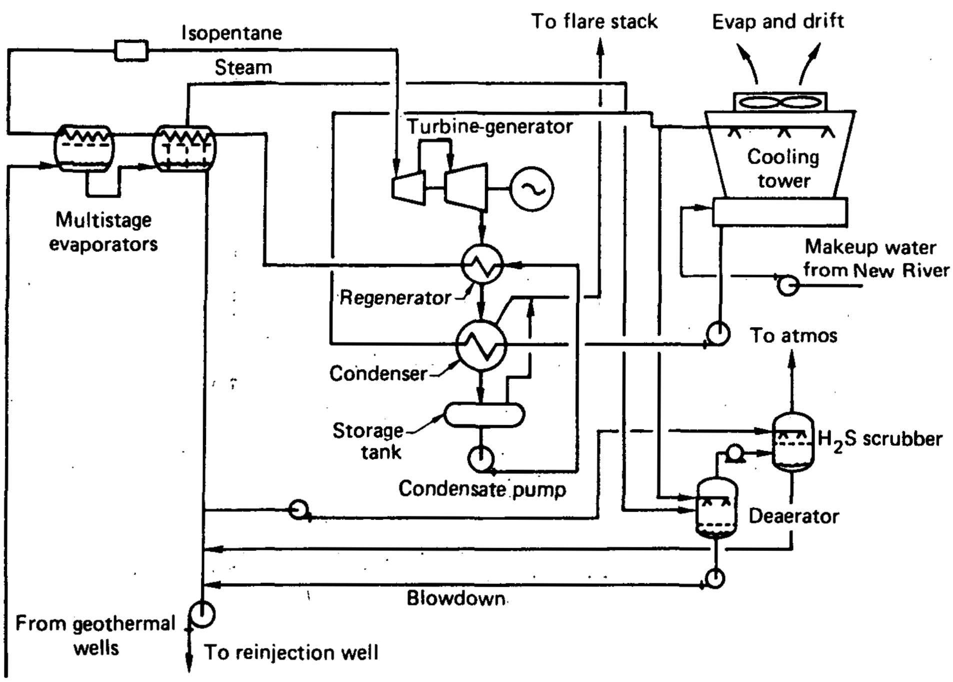

FIG. 18. Flow diagram for the multistage binary 50 MWe power plant proposed for Niland, California (Robertson, 1978).

Efflux Characteristics

The drift drops exiting the top of a cooling tower have an initial upward velocity and positive buoyancy which tends to accelerate them upward; therefore, the drops rise above the cooling tower and are transported downwind by the ambient airflow before falling to the ground.

These efflux conditions are part of the design criteria of the cooling tower and depend on ambient temperature and humidity. They can be adequately specified for a given design and meteorological conditions, although they are subject to considerable spatial and temporal inhomogeneity. Adequate techniques exist to measure the velocity and buoyancy of cooling tower efflux; an example is provided in Fig. 19.

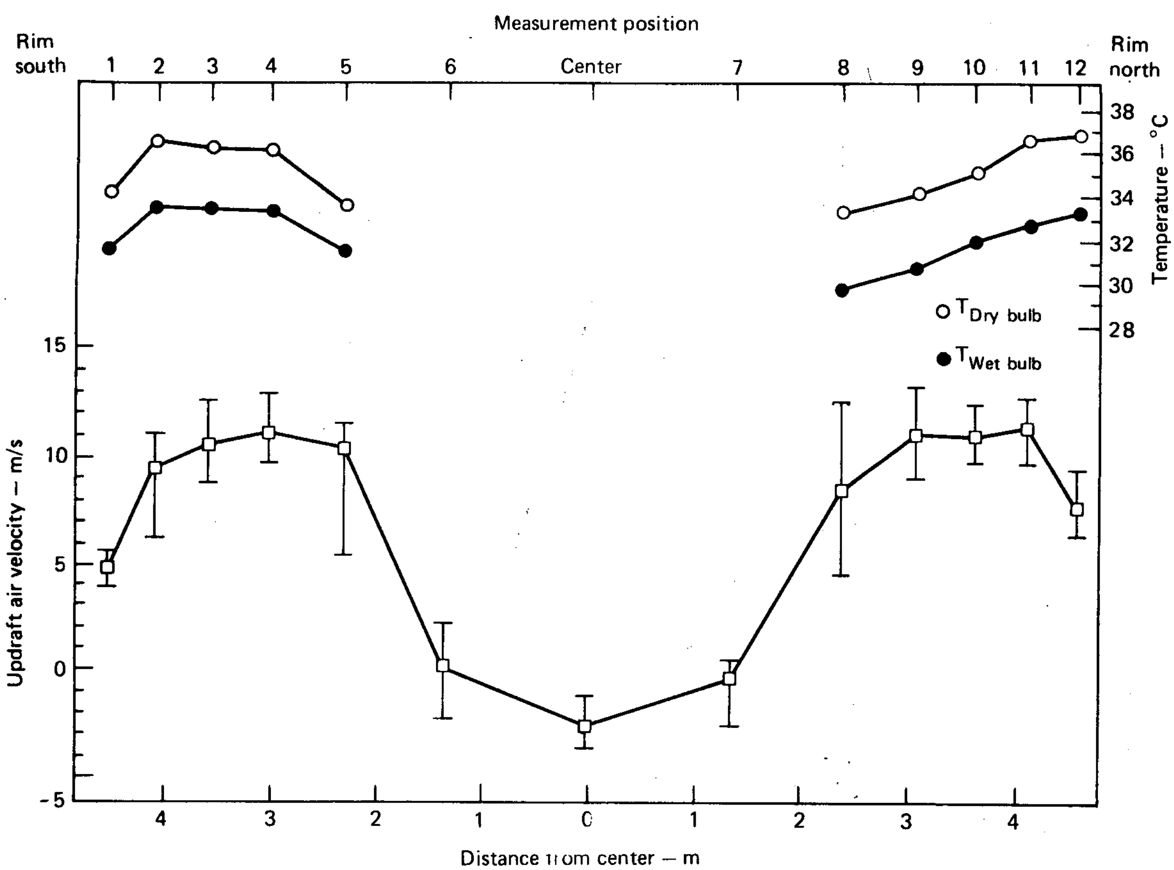

FIG. 19. Velocity and temperature profiles across the top of a cooling-tower fan stack for Unit 11 cooling-tower cell 6 (Rosen and Molenkamp, 1978).

Drift Drop Size Distribution and Mass Flux

The mass flux of water from a cooling tower is usually determined by integration of the drop size distribution with size. Drop size distributions and mass fluxes vary considerably among cooling towers and depend significantly on the effectiveness of the drift eliminators. An example of a drop size distribution measured at the top of the fan stack for a cooling tower with a drift rate of 0.001% of the circulating water rate, i.e. representative of the state-of-the-art in drift eliminators, is given in Fig. 20. Note that there is a relatively large percent by number of small drops and that a few very large drops are also observed. These small drops are presumably too

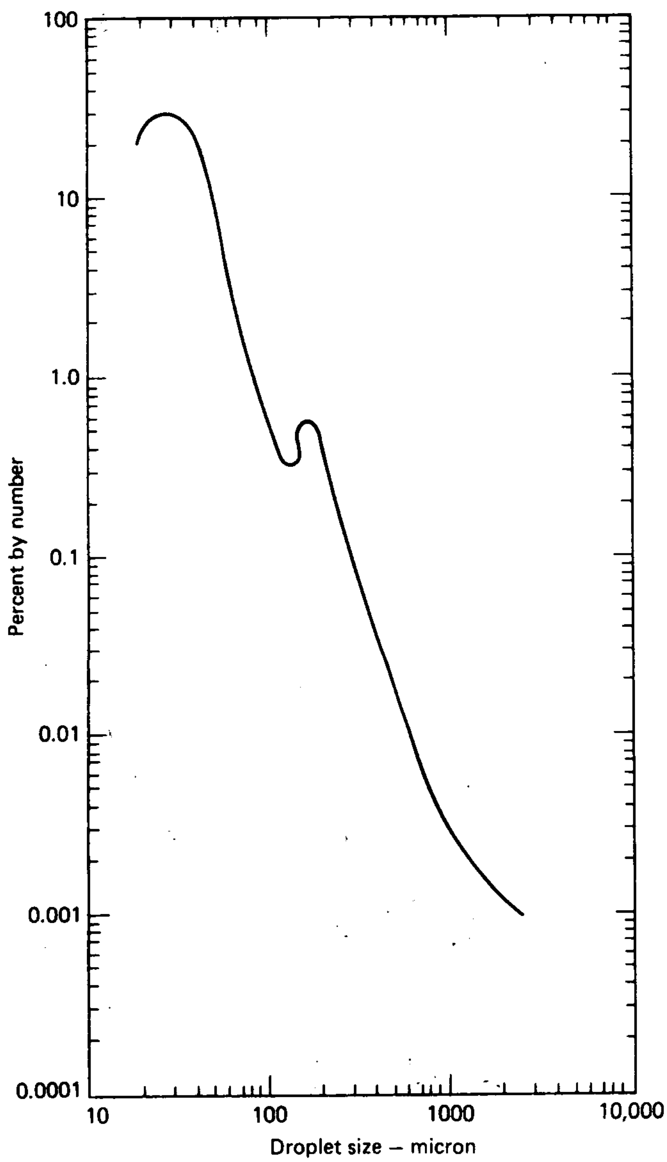

FIG. 20. Number of drift droplets as a function of droplet size (Wistrom and Ovard, 1973).

small to impact the drift eliminators, while the very large drops are considered to be "generated in the tower plenum area where impinging drift and vapor condensation accumulates on structural members (Wistrom and Ovard, 1973)." No particular significance is placed on the peak near 200 microns which may be peculiar to this set of observations. These data are replotted in a different form in Fig. 21 where they are compared to one of the operating cooling tower cells at The Geysers. The drift rate for The Geysers cooling tower is 0.02%-0.05%, i.e. about 20 to 50 times as large as the state-of-the-art drift eliminator equipped cooling tower. The actual numbers of drops at all sizes including the large sizes (>1000 microns) is larger for The Geysers tower. The percent of droplets at smaller sizes (100-1000 microns) is much larger for The Geysers cooling tower; it is these drops that are effectively removed by the advanced design drift eliminators. The measurements taken at The Geysers were made after the cooling tower had been in

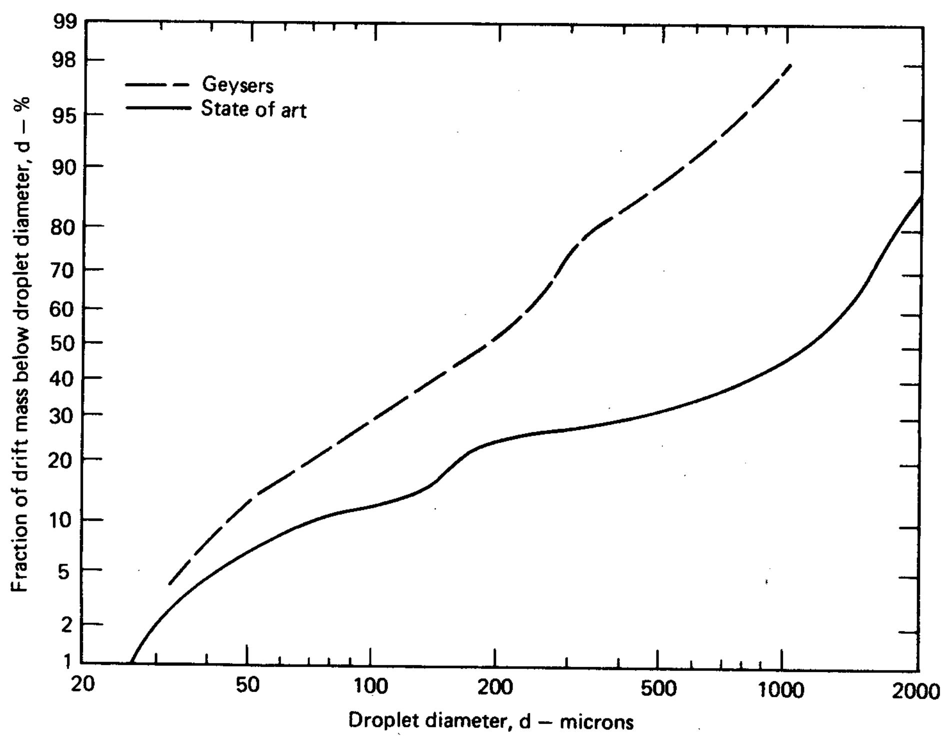

FIG. 21. Comparison between fraction of drift mass as a function of droplet size for a Geysers cooling tower cell and for a cooling tower equipped with state-of-the-art drift eliminators (Wistrom and Ovard, 1973; Rosen and Molenkamp, 1978).

operation for some time, and the efficiency of the drift eliminators initially installed had degraded with time. This unit at The Geysers is also equipped with the iron catalyst H_2S abatement system, and the cooling tower performance has been very adversely affected by the build-up of sludge. Note also that the mass median diameter for The Geysers cooling tower is about 200 microns while the mass median diameter for the state-of-the-art eliminator is over 1000 microns. If these largest drops are made up substantially of vapor condensed on structural members in the cooling tower, they would contain considerably lower pollutant concentrations than the mean cooling tower circulating water.

Measurement Techniques

The only reliable way to measure the mass flux and drop size distribution of cooling tower drift is in situ, i.e. by attaching various sensors and sample collectors to a boom extended across the fan stack. An excellent review of the measurement techniques and instrumentation available is given by McVehil, Heikes and Cole, (1975). They describe all of the instruments that have been used and their operating principles and assess their ease of use and accuracy. A summary of their evaluations is reproduced as Table 6.

The major conclusions of McVehil, Heikes and Cole, (1975) concerning measurement of drift residue flux and drop size distributions, which have not changed significantly in the intervening years, are

- Total mass flux of water and mineral constituents and drift drop size distributions can be measured with an accuracy of $\pm$ 25% or better.
- Such data can be obtained only with a great deal of effort using a variety of instruments and a significant amount of data analysis.
- There is no routine procedure available for measuring these parameters.
- Laser light scattering instruments show promise of providing a fairly reliable technique of monitoring cooling tower drift.
- Heated isokinetic sampling probes and cyclone separators provide an acceptable method of periodically verifying cooling tower drift performance.
- Cyclone separators have the potential of providing a means of obtaining drift mineral concentration as a function of drop size.

TABLE 6. Summary of drift and residue measurement methods.[a]

	Method or Instrument	Apparent Accuracy	Sampling	East of Use Data Reduction and Interpretation	Experience In Field Use	Cost
	Measurement of Total Drift Rate (D) or Drift Residue Flux (R)					
(R)	Isokinetic Sampling Tube	Very Good	Good	Good	Good	Moderate
(R)	Cyclone Separator	Good	Good	Good	Good	Moderate
(D)	Sensitive Paper	Fair	Good	Fair	Good	Moderate
(D)	Coated Slides	Fair	Fair-Good	Poor	Good	Moderate
(R)	Chemical Balance	Poor	Good	Good	Fair	Low
	Calorimetry (measures total water content, neither (D) nor (R)	Poor	Good	Fair	Unknown	Moderate
(D)	Optical Methods	Poor	Fair	Fair	Fair	Moderate /High
	Measurement of Drop-Size Distribution					
	Holography	Good	Poor	Poor	None	High
	Laser Scattering	Good	Good	Fair-Good	Very Good	Moderate /High
	Laser Imaging	Good	Good	Good	None	High
	Sensitive Paper	Good	Good	Fair	Good	Moderate
	Coated Slides	Good	Fair	Poor	Good	Moderate
	Measurement of Drift Residue (R) and Background (B)					
(R,B)	Single Strands	Very Good	Fair	Good	Fair	Low
(R,B)	APS(mesh)	Very Good	Good	Good	Good	Moderate
(R)	High-Volume Sampler	Fair-Good	Good	Good	Fair	Moderate
(R)	Deposition Pans	Good	Good	Fair	Good	Low

[a] McVehil, et al., 1975.

ATOMSPHERIC TRANSPORT, DEPOSITION, AND MODELING

Factors Affecting Transport and Deposition

A drift drop emitted into the atmosphere moves with the wind, while falling at its terminal velocity and evaporating if the air is subsaturated, until it either falls on a receptor or evaporates completely. As drops evaporate, their mineral concentrations increase because the dissolved substances remain in the drop. Pollutants dissolved in drops that evaporate completely do not contribute significantly to local drift deposition; they are transported away by the wind and ultimately are deposited by dry deposition or precipitation scavenging. Drift drops may collide and coalesce with one another, thereby changing the drop size distribution and making it artificial to talk about the fate of individual drops.

Drift parameters most important in affecting pollutant deposition are the drop size distribution, emission velocity and buoyancy, and the concentration of pollutant as a function of drop size if there is a significant variation. Properties of the ambient atmosphere with major influences are wind velocity, relative humidity, and turbulence.

Once drift material has been deposited on the ground or on plants, it can be further redistributed by wind, rain, irrigation, etc. This aspect is usually not considered in making estimates of drift deposition, but it may be important in assessing detrimental effects.

Types of Problems

Problems associated with drift deposition can be divided into two categories: short-term or episode impacts, and long-term build-up of damaging material. Nearly all drift deposition problems are due to long-term build-up. We draw this distinction to point out that the perspective taken in modeling is more relevant to short-term deposition than to long term build-up because models usually attempt to simulate what happens to emitted drops in particular representative atmospheric conditions. Assessment of long term build-up depends on properly combining simulations in many meteorological conditions to give the long term total deposition. Such an approach is very cumbersome with currently available models and represents a basic deficiency in cooling tower drift assessments.

Modeling

The usual technique for estimating the distribution pattern of deposited drift in the vicinity of a cooling tower is to calculate the transport of drift droplets with a numerical simulation model. Chen, (1977) has provided descriptions of the ten most widely used models and compared these models for a particular set of input data. The original reports are given by Refs. 26, 35, 48, 69, 72, 74, 75, 88, 90. Table 7 provides a summary of the basic features and differences of these models. The approach taken in each model is specified as ballistic, Gaussian, and K-theory.

The ballistic method assumes that drops follow trajectories through the atmosphere that have a horizontal component of the wind velocity and a vertical (downward) component given by the terminal velocity, which may or may not change depending on whether evaporation is considered. The ballistic trajectory is assumed to originate at the point where the drop emerges from the rising cooling tower plume. The purely ballistic models do not account for atmospheric turbulence.

The Gaussian method assumes that the motion of the drops is dominated by atmospheric diffusion with the Gaussian approximation used to represent the horizontal and vertical spread of a cloud of droplets of a given size. In order to account for the terminal velocity of large drops the centerline of the Gaussian profile is assumed to approach the ground at a rate equal to drop terminal velocity; such an approach is called a Ballistic-Gaussian method.

The K-theory method is similar to the Gaussian method but uses a different technique to specify the parameters governing turbulent diffusion.

The comparison of these models by Chen, (1977) provides an important insight into the state-of-the-art in cooling tower drift modeling. The input conditions specified for this comparison were chosen to be typical of a large natural draft cooling tower at Chalk Point, Maryland; however, the general conclusions are just as relevant to simulations of smaller mechanical draft cooling towers. Results from these simulations are given in Fig. 22a through 22c. It is immediately apparent that there are tremendous differences between the model predictions. Even such a simple parameter as maximum

Table 7. Summary and model characteristics for ground-deposition-rate prediction.[a]

Investigator	Method	Atmospheric Turbulent Diffusion	Plume Rise Formula	Breakaway Point	Evaporation
Hosler et al. May, 1972	Ballistic	No	Ns[b]	Drop fall velocity exceeds updraft	Three categories: no evaporation, saturated solution, and dry particles
Roffman and Grimble Jan, 1973	K-theory	Yes, constant K assumed	Briggs	Maximum plume rise	Same as Hosler et al.
Wistrom and Ovard Jan, 1973	Ballistic - large drops; Gaussian - small drops	Yes, PG[c]	Ns[b]	Tower top	Yes
Slinn Mar, 1974	Ballistic - large drops; Gaussian - small drops	Yes, PG[c]	Briggs	Tower top - large drops; Max plume rise - drops	No
Laskowski Mar, 1974	Ballistic - Gaussian	Yes, PG[c]	Briggs or Slawson and Csanady	Drop fall distance exceeds plume radius	Yes
Israel and Overcamp Mar, 1974	Gaussian	Yes, BNL[d] or PG[c]	Briggs or Slawson and Csanady	Drop fall velocity exceeds updraft	Same as Hosler et al.
Hanna Mar, 1974	Ballistic - large drops; Gaussian - samll drops	Yes, PG[c]	Briggs	Drop fall distance exceeds plume radius	Yes
Wolf Mar, 1974	Ballistic	No	Briggs	Nsb	Yes
Tsai and Johnson Apr, 1974	Ballistic	Ns[b]	Extension of Morton, Taylor, and Turner Models[f]	Fall velocity exceeds updraft	Yes
ORFAD[g] Jan, 1975	Ballistic	No	Briggs	Ns[b]	Same as Hosler, et al.
Rao, et al.	Ballistic - Gaussian	Yes	Extension of Morton, Taylor, and Turner models[f]	Ns[b]	Empirical formula

[a] Chen, 1977.
[b] No specification is given in the model.
[c] Pasquill-Gifford stability class.
[d] Brookhaven National Laboratory stability class.
[e] Wolf's model is not reviewed in this report.
[f] B. R. Morton, G. Taylor, and J. S. Turner, "Turbulent Gravitational Convection from Maintained and Instantaneous Sources," proc. Roy. Soc. (London, Ser. A 234: 1956 1-23.
[g] Oak Ridge Fog and Deposition model.
[h] Effects of downwash and washout are accounted for only by Laskowski.

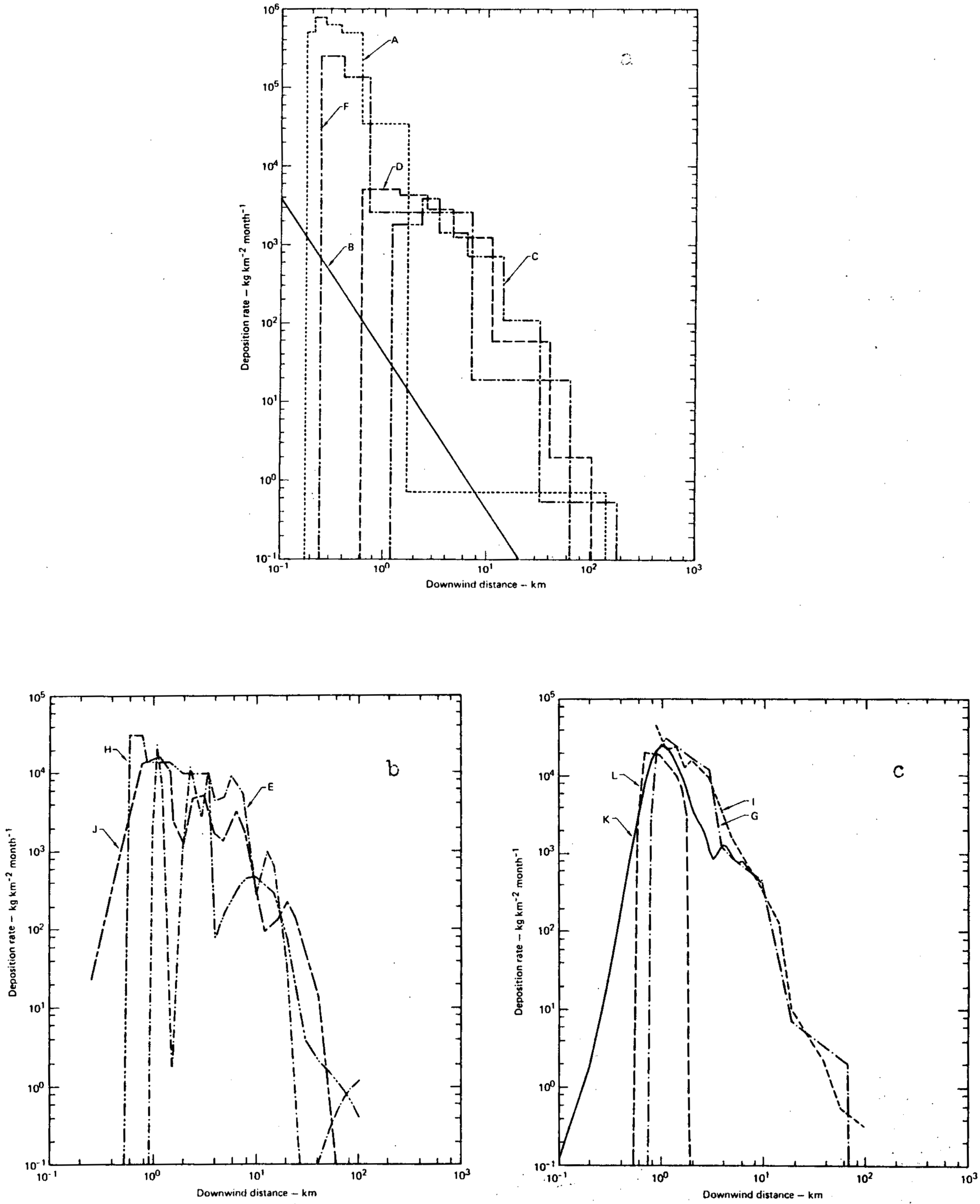

FIG. 22. Model comparison using the input data given in Table 7. The predicted deposition rate is plotted as a function of downwind distance. The correspondence between curves and specific models is not given in Chen, (1977) from which the figure is reproduced.

deposition rate varies by 2-3 orders of magnitude. While the wide dispersion in results can be explained on the basis of model assumptions, it is largely a matter of personal preference which model one would use for a particular cooling tower drift study. Estimates of impacts using one of these models could be tremendously different from estimates based on another model.

An ability to simulate the deposition of cooling tower drift with numerical models and provide adequately reliable results does not exist.

Measurement

The method for determining whether a simulation model of cooling tower drift is reliable is to validate the model with comprehensive sets of measurements. These sets must include data on drift deposition rate at various locations downwind of a cooling tower and corresponding measurements of emission characteristics and meteorological data for winds, vertical temperature and moisture structure, and turbulence. Collection of adequate data sets is a major research project involving measurements of many variables under a variety of conditions. There are none currently available that can be used to validate models.

Measurement of the drift deposition rate of pollutants is very difficult; it is accomplished by collecting drops and particles and analyzing the collected material chemically or by atomic absorption spectroscopy. Four devices have been used including, high volume samplers, airborne particulate samplers, deposition pans, and sensitive papers. They are described and compared by McVehil, Heikes, and Cole, (1975).

EFFECTS OF POLLUTANTS

To the very important question of how much deposition of a given substance can be tolerated by various receptors before damage occurs, there are few answers, particularly for the potential pollutants from geothermal power plant cooling towers.

Salt

Because of the early problems associated with drift deposition of sea salt as well as deposition of salt on crops and vegetation near the oceans or by irrigation with slightly saline water, there is much more information available for sea salt than for any other pollutant. There has not been a review or summary of such data, and the information is widely dispersed.

Available data on the salt tolerance of crops and vegetation should be collected and reviewed for use in environmental analyses of cooling tower impacts for all energy technologies.

The water available for use in cooling towers in the Imperial Valley is moderately to extremely saline; therefore deposition of salt is clearly a major issue. Some specific information on natural vegetation in southeastern California which is relevant to the Imperial Valley is given in Table 8. This available data is in very general terms and is of only marginal adequacy.

Table 8. Salt tolerance of some Colorado desert shrubs.[a]

Species	Conductivity (mmhos/cm)					
	0.20	6.92	12.47	17.81	21.68	25.82
Ambrosia dumosa	1	2	4	5	5	5
Larrea divaricata	1	2	4	5	5	5
Lycium andersonii	1	5	5	5	5	5

1 = Normal growth and color.
2 = Visible inhibition without color change.
3 = Reduced growth with color change (applied to Mojave Desert species only).
4 = Serious damage but alive after nine months.
5 = Dead within first three months.

Source: Wallace, A., and E. Romney. 1972. Radioecology and ecophysiology of desert plants at the Nevada Test Site. TID-25954. U.S. AEC.

[a] Rao, et al., 1975.

Other Substances

Boron has already proven to be an issue for the geothermal industry at The Geysers power plant by damaging trees in the vicinity of several cooling towers. Data on the sensitivity of these trees to boron or the deposition amounts they have experienced is not yet available. Boron in soil is known to damage many plants even when present in quite low concentrations. Collection of the available data and evaluation of research needs regarding this substance are needed.

Many other substances are detrimental to plants of various types at rather low concentrations. In order to assess their effects, data on receptor sensitivities need to be collected and made readily available.

CONCLUSIONS

We have reviewed the state-of-the-art for reducing drift emissions and techniques available for assessing the environmental impacts of deposited drift. The major conclusions are the following:

- Mechanical-draft cross-flow cooling towers can be built with a maximum quaranteed drift loss of less than 0.001% of the circulating water flow rate.
- The efficiency of the drift eliminators in geothermal power plant cooling towers can be rapidly degraded by using relatively low quality makeup water from geothermal condensate or agricultural drains and by using the cooling tower as a reaction vessel for removal of pollutants.
- The drift mass flux, mineral mass flux, drift drop size distribution, distribution, and drift exit velocity and buoyancy can be measured with an accuracy of about $\pm$ 25%.
- The chemical composition of cooling tower drift when the circulating water is made up from geothermal condensate cannot be adequately predicted.
- Predictions of drift transport and deposition by the available models differ from one another by orders of magnitude.
- No adequate data sets exist to validate drift deposition models or test their assumptions.
- Data have been obtained on the effects of sea salt deposition on some receptors, but these data have not been collected and made conveniently available.
- Data for all other emitted materials are inadequate to specify damage thresholds.

Significant progress has been made in reducing drift emissions, but gaps in knowledge and lack of data on transport, deposition, and receptor sensitivity prevent a determination of what an acceptable rate of drift emission might be and whether further reductions in drift emissions are required.

NOISE CONTROL TECHNOLOGIES

P. Leitner*

INTRODUCTION

Background

Noise from geothermal industry operations in Imperial Valley is of concern because of potential adverse effects on:

- The occupational health and safety of workers.
- The public health and welfare in nearby communities.
- The behavior and well-being of native wildlife in refuges and critical habitat areas.

Experience gained at The Geysers project in Northern California is worthwhile in evaluating environmental control needs for the Imperial Valley. Noise, chiefly due to large-scale venting of steam, was raised as an issue by residents of communities near the Geysers project. However, recent improvements in noise control technology and operating procedures have provided significant mitigation of impacts (Whitescarver, 1978). While the frequency of venting has been reduced and certain types of effective muffling devices have been developed, there is still no currently available control technology to abate the noise from wellhead venting operations (Leitner, 1979).

Because of the history of noise problems at The Geysers, it is important to evaluate the requirements for noise control technology in the development and utilization of the liquid-dominated geothermal resources of the Imperial Valley. To do this, it is necessary to take account of:

- Applicable noise regulations and standards.
- Existing ambient noise conditions.
- Emissions characteristics of geothermal noise sources.

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Noise Regulations and Standards

Noise emissions from geothermal industry sources in the Imperial Valley are subject to regulations and guidelines promulgated by a number of government agencies. These regulations pertain both to the assurance of occupational health and to the protection of local communities from excessive noise exposure.

Occupational Health Regulations. The U.S. Department of Labor regulates occupational exposure to noise under provisions of the Occupational Safety and Health Act of 1970. Each state may establish its own occupational safety and health program, including measures to protect workers against the effects of noise exposure, provided that it is as effective as that of the federal government. In order to contribute to the conservation of workers' hearing, the California Occupational Safety and Health Act (CAL-OSHA) sets standards for noise exposure comparable to those of the federal regulations. Table 9 shows the current allowable daily exposure without the use of personal hearing protection devices.

TABLE 9. Standards for occupational noise exposure.[a]

Total Exposure Time Per Day, Hours	Sound Pressure Level, dBA
8	90
6	92
4	95
3	97
2	100
1-1/2	102
1	105
1/2	110
1/4 or less	115

a. Source: CAL-OSHA, Title 8, California Adminstrative Code, Sections 5095-5099.

<u>Community Noise Regulations.</u> The only federal regulation that applies specifically to geothermal noise emissions is found in the U.S. Geological Survey (1975) Geothermal Resources Operational Order No. 4. This document states that geothermal-related activities on federal leases shall not exceed a noise level of 65 dBA[1] at the lease boundary or at 1/2 mi (800 m), whichever is greater.

The U.S. Environmental Protection Agency (1974) has identified environmental noise levels that appear to protect against community annoyance and activity interference. An outdoor ambient day-night average sound level (L_{dn})[2] of 55 dBA or less has been proposed as a criterion for residential areas, schools, and hospitals. This criterion is useful as a guideline for judging the acceptability of noise intrusion, but does not represent a federal standard.

Regulatory authority over community noise is delegated to local governmental jurisdictions by the State of California. A Noise Element must be included in all city and county General Plans in order to provide a basis for achieving an acceptable noise environment. The Imperial County Noise Element sets standards and limits in terms of various types of criteria (Imperial County Planning Department, 1974). It includes the U.S. Department of Housing and Urban Development noise criteria for new residential construction sites (Table 10).

In addition, Imperial County has established noise criteria specifically for geothermal development activities (Imperial County Department of Public Works, 1977). These criteria set octave-band limits and compliance is judged by measurements made at the boundary of the project area. Two classes of drilling and production noise standards are established; the

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1 dBA = A-weighted sound level. The sound level in decibels measured using a sound level meter with a weighting network (filter) approximating the frequency sensitivity of the human ear.

2 L_{dn} = Day-night sound level. The A-weighted sound level for a 24-hour period that is equivalent in total energy to an actual time-varying sound level; a 10-decibel penalty is added to nighttime sounds (10 pm-7 am).

TABLE 10. U.S. Department of Housing and Urban Development external noise exposure standards for new construction sites.[a]

Imperial County Noise Element Category	U. S. DHUD Category	General External Exposure Standard (dBA)
Critical	Unacceptable	Exceeds 80 dBA 60 minutes/24 hrs Exceeds 75 dBA 8 hours/24 hrs
Concern	Normally Unacceptable	Exceeds 65 dBA 8 hours/24 hrs Load repetitive sounds on site
Caution	Normally Acceptable	Does not exceed 65 dBA more than 8 hours/24 hrs
Allowable	Clearly Acceptable	Does not exceed 45 dBA more than 30 minutes/24 hrs

[a] Source: U.S. Department of Housing and Urban Development (1971).

County Planning Commission determines the standards that apply to a specific geothermal development project. The Class I standard corresponds to an overall A-weighted sound pressure level (SPL) of 76 db and applies to areas remote from sensitive receptors. The Class II standard is considerably more stringent; it is subdivided by land use category, with progressively lower limits applied to industrial, commercial, dense residential, normal residential, and open space uses.

IMPERIAL VALLEY

Ambient Noise Levels

Current ambient noise conditions in the Imperial Valley are quite variable, depending on the particular location and the existing land use.

General urban noise levels (approximately 50-60 dBA) are undoubtedly characteristic of towns and cities within the valley, while significantly higher sound levels may be expected in the vicinity of industrial facilities. An extensive highway network carries large volumes of autos and truck traffic throughout the region; traffic noise is audible in many parts of the valley. Other important transportation noise sources are railroads and aircraft. Heavy farm machinery and crop-dusting aircraft result in higher ambient noise levels throughout the extensive agricultural lands. Mechanized farming operations are commonly conducted at night, as well as during daylight hours.

Several ambient noise surveys have been carried out recently in the Imperial Valley to provide a baseline for the assessment of noise impacts from geothermal development.

Ambient noise levels were measured at several locations in the northern Imperial Valley (Brawley and Salton Sea KGRAs) as part of the IVEP investigations (Nyholm and Anspaugh, 1977; Leitner, unpublished data, 1979). These measurements were made in open-space areas used for agriculture and wildlife habitat. At some locations no man-made noise sources were audible, while at others distant aircraft, vehicular traffic, or farm machinery contributed to the measured noise levels. Most values were below 40 dBA, although about one-third (9 out of 26) ranged from 41 to 50 dBA (Table 11). These ambient levels are probably typical of the less-

TABLE 11. Ambient noise measurements in open-space areas of Imperial Valley.[a]

Location	Range in Sound Pressure Level (dBA)	Number of Measurements
Imperial Wildlife Management Area		
Wister Unit	27 - 50	8
Finney-Ramer Unit	29 - 49	8
Salton Sea National Wildlife Refuge		
Headquarters Unit	38 - 44	6
South Unit	33 - 37	4

[a]Sources: Nyholm and Anspaugh, 1977; Leitner, unpublished data, 1979.

intensively used lands both within the Imperial Valley and on the desert mesas to the west and east.

Another study, conducted in an agricultural area two miles (3.2 km) north of the City of Brawley municipal boundary, resulted in measurements of ambient noise levels for representative time periods during the day, evening, and night (WESTEC Services, Inc., 1979). Equivalent sound levels (L_{eq})[1] were 52 dBA (day), 35 dBA (evening), and 44 dBA (night) (Table 12). The minimum and maximum values varied widely during each sampling period: 37 to 77 dBA during the day, 25 to 65 dBA in the evening, and 24 to 75 dBA at night. Day-night average sound level (L_{dn}) was calculated at 52 dBA. Noise sources present in the area were farm machinery and highway traffic. These data are consistent with those reported for the Heber KGRA, where ambient sound levels (L_{dn}) ranged from 50 to 65 dBA (VTN Consolidated, Inc., 1978). Although these L_{dn} values are relatively high for an agricultural area, they are probably representative of much of the Imperial Valley where transportation, industrial, and urban noise sources intrude.

Ambient noise levels in parts of The Geysers-Calistoga KGRA where geothermal development has not yet taken place appear to range from 30 to 50 dBA (Pacific Gas & Electric Company, 1977; California Department of Water Resources, 1978). These levels are comparable to those measured in agricultural and open space areas of the Imperial Valley in the absence of obvious human activity. However, much of the Imperial Valley is presently subject to higher levels of continuous or intrusive noise as a result of the presence of numerous urban centers, heavy surface and air traffic, and industrial and agricultural development. Because noise sources comparable to those accompanying geothermal development are already a part of the existing environment, strong community resistance due to noise impacts would not be expected.

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1 L_{eq} = Equivalent sound level. The A-weighted sound level that is equivalent in total energy to an actual time-varying sound level.

TABLE 12. Ambient noise levels (dBA) in the vicinity of the North Brawley Ten Megawatt Geothermal Demonstration Facility.[a]

Date	Time	L_{90}[b]	L_{50}[c]	L_{max}/L_{min}[d,e]	L_{eq}
May 17, 1978	1915-2215 hours	30	34	65/25	35
May 17-18, 1978	2215-0615 hours	28	37	75/24	44
May 18, 1978	1240-1340 hours	39	43	77/37	52

a. Source: Westec Services, Inc. (1979)

b. L_{90} = 90% sound level. The A-weighted sound level equalled or exceeded 90% of the time.

c. L_{50} = 50% sound level. The A-weighted sound level equalled or exceeded 50% of the time.

d. L_{max} = Maximum A-weighted sound level.

e. L_{min} = Minimum A-Weighted sound level.

Geothermal Noise Sources

Well Field Exploration and Development. Three distinct operations are usually conducted at any given well location.

- Drill site preparation.
- Well drilling.
- Well testing.

Drill site preparation involves such operations as grading, compacting, and surfacing the well pad and access road, as well as excavation of a reserve pit or sump. Noise emissions from the heavy power equipment required will be in the range 85-95 dBA at 50 ft (15 m).

Attenuation with distance will result in sound pressure levels of 50-60 dBA at 1/2 mi (800 m). Construction activities will be confined to daylight hours.

Drilling will go on around the clock for four to six weeks per well. In the Imperial Valley, it is carried out with a rotary rig using mud as the circulating medium. Large diesel engines are the dominant noise sources at a drill site. A maximum sound pressure level of 85 dBA is expected at 50 ft (15 m). At 1/2 mi (800 m) from the drill site noise levels should be in the range 45-55 dBA.

Geothermal wells are normally flowed to a sump for a short time to clean out drilling mud and cuttings. If steam is allowed to flash to atmosphere at the outlet of the discharge pipe, well cleanout can be relatively noisy, 80-85 dBA. However, if the discharge pipe is submerged, noise will be greatly reduced. Flow testing to determine well production characteristics may be conducted for days or weeks. In this case, fluid will be pumped from a production well, steam separated and vented to atmosphere, and the residual water injected at another well. Major noise sources are the diesel engines driving the various pumps. Sound pressure levels of 80-90 dBA occur at 50 ft (15 m), with levels at 1/2 mi (800 m) in the range 45-55 dBA.

Construction of Power Plant and Related Facilities. Construction of a power plant with its associated pipelines and transmission lines will require considerable site preparation, including excavation and grading work. The dominant noise sources will be large pieces of diesel-powered earthmoving equipment such as bulldozers, graders, front-loaders, and heavy trucks. During the erection of buildings, transmission towers, and other facilities and the installation of pipelines and equipment, a number of noise sources will be operating in a given project area: cranes, concrete mixers, pumps, generators, and compressors. The range of noise emissions is very similar to that expected during drill site preparation, a maximum of 85-95 dBA at 50 ft (15 m) and 50-60 dBA at 1/2 mi (800 m).

Operation of Power Plant. The major noise sources associated with a geothermal power plant are the turbine/generator and the cooling tower. Noise emissions will vary somewhat depending on the generating capacity of the plant and the size of the cooling tower. Although sound levels may be as high as 90-95 dBA in close proximity to the turbine/generator unit, total plant noise emissions are in the range 75-85 dBA at 50-100 ft (15-30 m). Overall plant noise at 1/2 mi (800 m) will be attenuated to 40-45 dBA.

TABLE 13. Sound pressure levels expected to be associated with the various phases of geothermal energy development in Imperial Valley.

Development Phase	Expected Range of SPL (dBA) 50 ft (15 m)	1/2 mi (800 m)
Drill Site Preparation	85-95	50-60
Well Drilling	75-85	45-55
Well Testing	80-90	45-55
Construction of Power Plant	85-95	50-60
Operation of Power Plant	75-85	40-45

Summary of Geothermal Noise Sources. The sound pressure levels (SPL) that will be associated with various phases of geothermal development in the Imperial Valley are summarized in Table 13. Steam venting will not be a significant source of noise here, since geothermal wells in a liquid-dominated reservoir can usually be completely shut-in when their production is not required. As a result, maximum SPL at geothermal facilities will be much lower than at the Geysers, where levels as high as 125 dBA have been measured from large-scale steam venting operations.

In the Imperial Valley, the loudest noise sources will be heavy trucks and earth-moving equipment used primarily in the preparation of sites for wells, power plants, and other facilities. This equipment will normally operate during daytime only and will be on-site temporarily for construction phases. When power plants are in operation, the noise levels at 1/2 mi (800 m) are not expected to exceed 45 dBA.

Control Requirements

The need for improved noise control technology in Imperial Valley can be assessed by comparing expected noise emission levels from geothermal industry sources with applicable regulations and standards. In general, it appears that most geothermal projects will be able to meet existing regulations without making any changes in the equipment and operating procedures in use today. Compliance will have to be demonstrated for each project on a site-specific basis, but even in those cases where noisy operations will be conducted close to a sensitive receptor there are a number of readily available mitigation measures that can be used. Thus, there seems to be no requirement for the development of new and more effective noise controls.

Occupational Health Regulations. Because of relatively moderate levels of noise emissions, the geothermal industry in Imperial Valley should have no difficulty in meeting both federal and state occupational noise exposure standards with existing control technology. Workers can be required to wear personal hearing protection devices in particularly noisy situations where exposure standards may be exceeded.

Community Noise Regulations. Noise emissions from geothermal projects in Imperial Valley should meet all applicable community noise regulations with currently available control technology.

Although the relatively moderate noise source levels will help to ensure compliance, Imperial County policy in siting geothermal facilities will also be an important factor. This policy would place buffer zones between noise sources such as well pads and power plants and sensitive receptors (Imperial County Department of Public Works, 1977; Imperial County Planning Department, 1973). Siting criteria include:

- Power plant operations are not to be located in wildlife refuges and critical habitat areas.
- Power plant operations are to be sited in accordance with the Imperial County Current Zoning Plan and the Ultimate Land Use Plan--mainly in agricultural, industrial, and recreational zones.
- Power plant operations are to be excluded from buffer zones surrounding the following facilities.

Facility	Buffer Distance
Hospital	(1.0 mi) 1.6 km
School	(0.5 mi) 0.8 km
Municipal boundary	(0.5 mi) 0.8 km

These buffer zones will allow considerable noise attenuation with distance; a separation of 1/2 mi (800 m) between noise source and receptor should result in a reduction in SPL of 35 to 40 dBA (Bush, 1977). Thus, even in the absence of improved control technology, noise from the loudest geothermal sources should not exceed 60 dBA at 1/2 mi (800 m).

Thus, it will be entirely feasible for the geothermal industry to meet both the U.S. Geological Survey standard of 65 dBA at 1/2 mi (800 m) and the U.S. Department of Housing and Urban Development criteria for "Normally Acceptable" residential site conditions. Well drilling, because it is an around the clock operation, may slightly exceed the U.S. Environmental Protection Agency community noise criterion of L_{dn} equal to or below 55 dBA, but all other industry activities will definitely be in conformance. The Imperial County Class II noise limits for residential land uses may present difficulties, but only in those cases where the boundary of the project area is close to residential receptors.

It should also be noted that the medium growth-rate siting pattern for 30 power plants presented earlier in the text (Fig. 2) appears to be consistent with the Imperial County siting criteria.

AVAILABLE NOISE CONTROL TECHNOLOGIES

In a few cases, particularly in close proximity to residential areas, standard equipment and procedures may not be adequate to achieve compliance with noise regulations. A number of currently available noise control techniques may be used to mitigate potential impacts.

Well Field Exploration and Development

During drill site preparation and well drilling, all large internal combustion engines can be fitted with the most effective commercial mufflers to reduce exhaust noise. This will usually reduce noise emission levels up to 5 decibels and is the only effective treatment for mobile sources.

Noise radiated from stationary engines used on the drill site can be attenuated by the use of acoustic barriers or enclosures. If necessary, the drill rig can be completely enclosed. These measures are routinely used in drilling for oil and gas at urban locations. Because of the effort and expense involved, they are unlikely to be employed in Imperial Valley unless a drill site must be located within 1/4 mi (400 m) of a sensitive receptor.

Well cleanout noise can be reduced greatly by submerged discharge of the geothermal fluid instead of direct venting to atmosphere. This technique has been used with good success in the liquid-dominated geothermal resource area at Roosevelt Hot Springs, Utah.

During extended flow tests, engines and pumps can be muffled and enclosed as described above. The noise from separated steam vented to atmosphere can be silenced through a rock muffler or commercial blowoff muffler. Both devices have been used at The Geysers; the rock muffler is more effective at reducing noise emissions and requires less maintenance (Leitner, 1978; Whitescarver, 1978). In the Imperial Valley, however, commercial blowoff mufflers might be more appropriate because the separated steam contains few particulates that could damage such units, because of lower cost, and because they could be readily moved to new locations as needed.

Construction of Power Plants and Related Facilities

The most effective commercial exhaust mufflers can be used on large pieces of earthmoving and materials-handling equipment. If necessary, acoustic barriers can be erected to shield nearby receptor sites from excessive noise exposure.

Operation of Power Plants

A number of control measures are available to reduce noise emissions during operation of a power plant and related facilities.

The turbine/generator unit can be enclosed by an acoustic barrier or located inside a building. These measures should achieve at least 5 to 10 decibels of noise attenuation.

Noise from the venting of non-condensible gases can be largely eliminated by covering the steam jet ejector with sound-absorbent lagging. This has been practiced routinely at The Geysers generating units with excellent effect.

Any steam-venting noise associated with start-up or shut-down of power plants in the Imperial Valley can be controlled with commercial blowoff silencers.

Because of its size, the cooling tower will be the major source of noise at any distance from the power plant complex. A standard approach to control of noise from mechanical draft cooling towers is to install fans with a low noise emissions rating or variable-speed fans that can be set to run more slowly and quietly at night and in cool weather. This has not been necessary at the Geysers, but it is a routine procedure at industrial cooling towers in urban locations.

CONCLUSIONS

- Noise emisssions from geothermal industry sources will not be an important environmental issue in the Imperial Valley. The operation of geothermal well fields in a liquid-dominated resource area of this type does not require venting large amounts of superheated steam to atmosphere. At The Geysers, sound pressure levels accompanying steam venting to atmosphere at the wellhead may reach 125 dBA at 50 ft (15 m). In contrast, the loudest geothermal industry noise sources in the Imperial Valley KGRAs will be large diesel engines (ca. 95 dBA at 50 ft).

- Strong community reaction to geothermal noise is not expected in the Imperial Valley. Ambient noise levels are somewhat higher than in undeveloped areas of The Geysers-Calistoga KGRA. Furthermore, noise sources of the kinds that will accompany geothermal development in the Imperial Valley are already an accepted part of the local environment.

- Siting restrictions will provide effective buffer zones between geothermal operations and sensitive receptors.

- No special research and development effort is needed in the area of noise control technology for Imperial Valley geothermal projects. It will be possible to successfully meet all current regulations and standards with available noise control devices and procedures.

LIQUID AND SOLID WASTE CONTROL TECHNOLOGIES

W. Morris and G. Armantrout

INTRODUCTION

Background

Liquid and solid waste sources and their impact on the environment were presented in Volume 1, Section 7 of this report. The wastes were identified and the quantities estimated based upon projections of an intermediate geothermal power growth rate over 30 years (Ermak, 1977). Potentially large quantities of wastes can accumulate based on these projections and their handling and disposal are critical to preserving the quality of the Imperial Valley environment and its agricultural industry as well as facilitating the growth and sustenance of geothermal power production.

Governmental regulations and guidelines have played a significant role in the development of technologies intended to control the handling and disposal of geothermal wastes. Many of the techniques and methods being used by the geothermal industry are taken from those utilized in oil and gas production facilities. Although the conditions and problems faced by geothermal developers are often similar to those of the oil and gas industry, there are at the same time significant differences that require geothermal developers to modify or develop new technologies.

Other factors that affect geothermal liquid and solid waste control technologies are: the changing, more restrictive government regulations, limited water and land-use options in the Imperial Valley, and the extraordinary solids content of Imperial Valley geothermal brines.

Regulations

Disposal of geothermal liquid and solid wastes is regulated by county, state, and federal laws. Regulatory control and jurisdiction over geothermal operations in the Imperial Valley is not easily defined; however, there appears to be reasonable uniformity between California State and

Federal standards. The subject of regulations is complex and a full delineation is not practical here. Jurisdiction is not uniform and oftentimes not clear and permits are required by numerous agencies. Therefore, we discuss only the principal regulatory agencies involved and the laws that bear upon the disposal of liquid and solid wastes.

The disposal of geothermal effluent is currently defined by the geothermal element of the Imperial County Code (Imperial County, 1977). The code requires full injection of fluids withdrawn from geothermal resources. Well injection technology is regulated by standards and technical criteria administered by the Division of Oil and Gas of the California Department of Conservation (CAC, 1976) and by the Underground Injection Control program requirements (USEPA, 1979) proposed by EPA under the Federal Safe Drinking Water Act. The act requires EPA to set forth minimum requirements to safeguard underground drinking water sources from contamination as a result of injection.

Disposal of geothermal effluents to surface waters is regulated in the Imperial Valley by the Colorado River Regional Water Quality Control Board and the California State Water Resources Control Board (CSWRCB). Regulation is established by the Porter-Cologne Water Quality Control Act of 1976 (CSWRCB, 1978). This act is closely associated with and meets the approval of the Federal Water Pollution Control Act requiring dischargers to obtain permits that define the limitations on effluents allowed to be discharged. The permit system is known as the National Pollution Discharge Elimination System (NPDES).

Solid wastes and their disposal to land in California are regulated by guidelines established by the CSWRCB, (1977). At the federal level the Resource Conservation and Recovery Act of 1976 (RCRA) will play a major role in the disposition of wastes. RCRA requires EPA to provide standards that can be used to define hazardous wastes and to issue regulations and guidelines for their storage, treatment and disposal (USEPA, 1980). RCRA places the responsibility for identifying and controlling hazardous wastes upon the waste generator.

Table 14 lists some important examples of regulated maximum levels for contaminants in different media.

TABLE 14. MAXIMUM LEVELS OF CONTAMINANTS TO WATER SUPPLIES

Medium Affected	Contaminant	Maximum Level mg/l	Standards
Public Water Supplies	Arsenic	0.05	National Interim Primary Drinking Water Standards - EPA, under the Safe Drinking Water Act of 1974.
	Barium	1.00	
	Cadmium	0.010	
	Chromium	0.05	
	Fluoride	1.4-2.4[a]	
	Lead	0.05	
	Mercury	0.002	
	Nitrate	10.00	
	Selenium	0.01	
	Silver	0.05	
Surface Water (River or Stream) Imperial Valley.	TDS[b]	4000	Colorado River Regional Water Quality Control Board - Water Quality Control Plan.
Extract from Solid Waste[c]	Arsenic	5.0	Hazardous Waste and Consolidated Permit Regulations, U.S.E.P.A, Under the Resource Conservation and and Recovery Act (USEPA, 1980).
	Barium	100.0	
	Cadmium	1.0	
	Chromium	5.0	
	Lead	5.0	
	Mercury	0.2	
	Selenium	1.0	
	Silver	5.0	

a) Fluoride level varies with maximum daily temperature of air; 1.4 mg/l at 90.5^{O}F, 2.4 mg/l at 53.7^{O}F and below.

b) Total Dissolved Solids, annual average.

c) A representative sample of solid waste exhibits toxicity if the extract derived from the recommended extraction procedure contains levels of the contaminants equal to or greater than the concentrations listed.

LIQUID AND SOLID WASTE SOURCES

There are a variety of liquid and solid wastes associated with geothermal power plant operations in the Imperial Valley. They have been described in detail in Volume 1, Section 7 of this report and are summarized in Table 15. Spent geothermal brine constitutes the largest volume of waste generated in geothermal power plant operations. Other liquid wastes include: cooling tower blow-down fluid, accidentally discharged brine, and accidentally spilled process chemicals such as NaOH and H_2O_2 used in H_2S abatement process units. These liquid wastes, for the most part, are expected to be disposed by subsurface injection. It is also quite likely that some may be disposed along with solid wastes after intermediate processing. The major fraction of the liquid waste, that is spent geothermal brine, is not defined as accumulated waste because

TABLE 15. LIQUID AND SOLID WASTES FROM GEOTHERMAL OPERATIONS

	Liquid Waste Generated		Solid Waste Accumulated	
Operation	Type	Amount	Type	Amount
Well Drilling[b]			Drilling Mud, Well Cuttings	8.6×10^{5}[a]
Well Clean-out			Dried Brine, Wellbore Debris	9×10^{5}[a]
Well Flow Test	Brine[c]	9.6×10^{4} m^3 per Well for a 30 day test.		
Energy Production	Spent Brine[c]	2.5×10^{7} m^3 per Year for one 100 MW Plant	Separated Solids from Preinjection Treatment	1.5×10^{6}[d]
			Scale from Process Lines, Separators, etc.	1.8×10^{5}[d,e]
Cooling Tower Operations	Blowdown Fluid	2.5×10^{6} m^3 per Year for one 100 MW Plant	Solids from Ponding and Evaporation of Blowdown Fluid.	1.3×10^{7}[a]
			Solids Separated by Pretreatment of Makeup Water.	5×10^{5}[a]
H_2S Abatement			By Product Ammonium Sulfate	1×10^{5}[a]

Notes

a) Cubic meters accumulated over 30 years at an annual growth rate of 100 MW.

b) Estimated 50-70 wells per year required to maintain 100 MW per year growth rate.

c) Brine expected to be injected after treatment to remove precipitated solids.

d) Calculation for Salton Sea and Brawley areas; 50 MW per year growth rate, 25 years.

e) Value represents estimate of maximum level and does not take into consideration possible scale prevention through the addition of acids or chemical inhibitors.

f) Assuming blowdown fluid is ponded and evaporated (alternative to injection). Calculation assumes 20,000 mg/l solids in blowdown fluid (5 cycles) and blowdown rate of 1.9×10^{4} m^3 per MW-year.

g) Waste by-product from EIC H_2S abatement process used as an example.

it is expected to be injected back underground. Solid wastes on the other hand are accumulated and are usually in the form of cuttings, mud, sludges, or caked partially dried materials. The solid waste sources include: well drilling and wellbore cleanout debris, separated solids from spent brine and cooling water treatment operations, solids from H_2S abatement, geothermal scale, and a variety of wastes from evaporation ponds and treatment facilities.

Although the waste sources have been identified and the amounts estimated, more specific data on the compositions of the wastes are lacking especially with regard to constituents that may be considered hazardous. These data must be obtained for the various types of wastes in order to classify them in accordance with regulatory criteria and to determine the appropriate treatment, handling, and disposal methods.

LIQUID AND SOLID WASTE CONTROL TECHNOLOGY

The environmental controls required to cope with liquid and solid wastes ultimately involve disposal technology. However, one should not overlook the fact that preventive and containment control measures are also required along with intermediate storage facilities for the treatment and temporary retention of wastes.

Figure 23 illustrates principal and subordinate geothermal development and production activities, identifies types of wastes generated and traces probable and improbable alternative routes leading to final disposal.

Preventive and Containment Controls.

Preventive and containment measures not only provide safe conditions for well drilling and power production operations, but also attempt to minimize the chances for discharging unmanageable quantities of waste. Blowout protection equipment installed prior to well drilling operations is an example of such technology. The implacement of berms under pipelines and at other stategic locations throughout the plant site serve to contain and direct the flow of accidental spills resulting from pipeline or tank ruptures.

Intermediate Waste Storage.

Intermediate storage operations for liquid and solid waste include the use of reserve pits for the collection of debris from well-drilling operations. The operations also include utilization of ponds and lagoons for the collection of limited quantities of brines from well testing and pre-production activities, accidental spills, effluent discharges from cooling water treatment steps, and from cooling tower blowdown operations. Due to limited availability of land in the Imperial Valley, it is expected that lagooning and ponding will be confined to relatively small areas requiring attentive maintenance and clean-out to insure adequate receiving volume. Regulations will also require the utilization of good berming techniques and the installation of impermeable liners of natural materials such as bentonite clay or synthetic materials such as polyvinyl or butyl rubber sheeting. Also associated with intermediate storage technology is the use of heavy equipment and trucks for day-to-day maintenance and periodic removal of waste material.

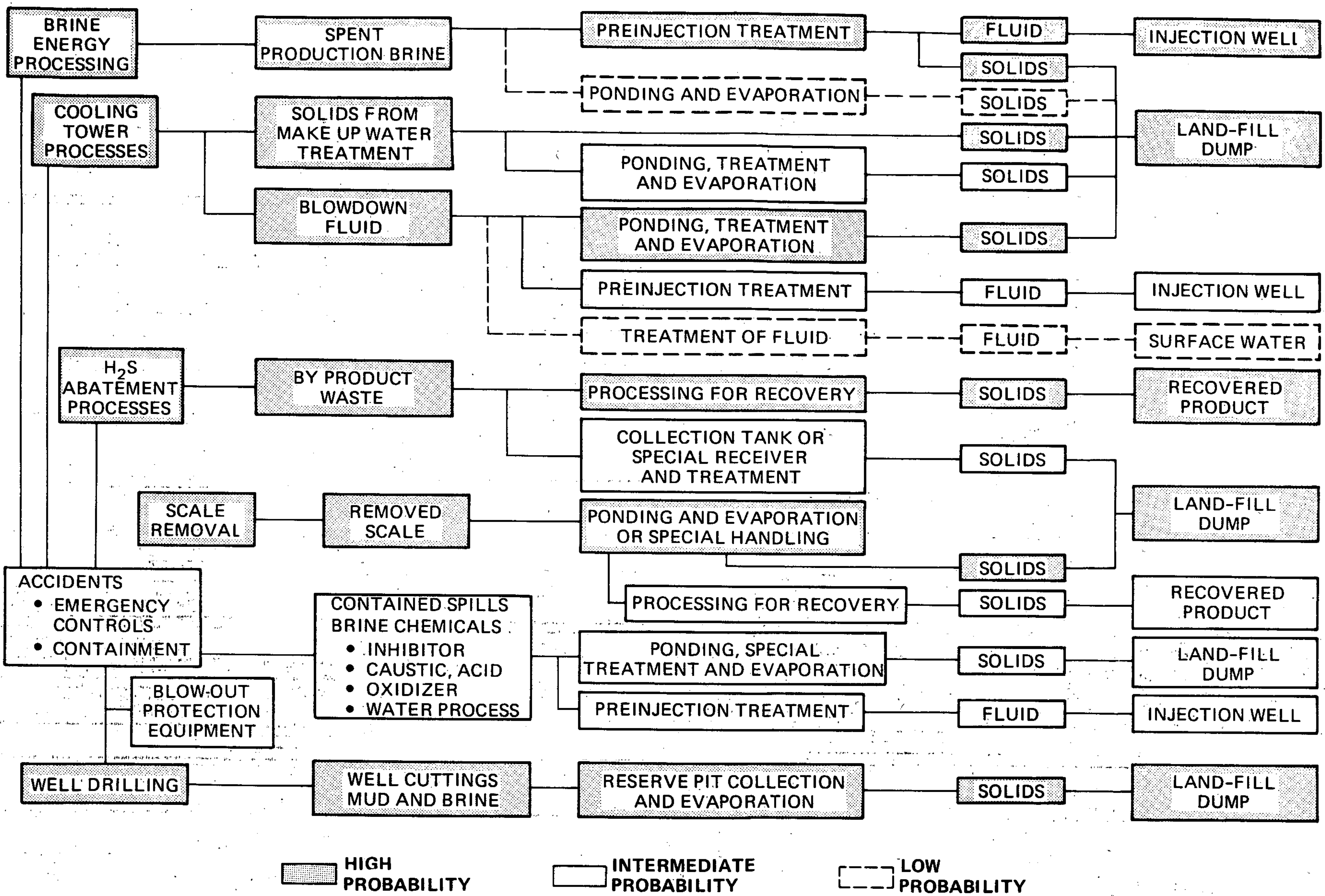

FIG. 23. Routes leading to final disposal of geothermal liquid and solid wastes.

Final Disposal Techniques.

The disposal of geothermal wastes at various sites throughout the world includes: subsurface injection, discharge into surface waters and disposal to land usually preceded by intermediate storage as described above. A fourth method, mineral recovery, should also be considered as an alternative to waste disposal. It is conceivable that all four methods will be used to dispose of wastes generated by geothermal operations in the Imperial Valley. However, the method selected will depend upon the type of waste, its composition and quantity, and its effect on the environment. Other factors entering into the choice include: the long-term reliability of the disposal method, its convenience and cost effectiveness, and public policies and laws regulating the activity. Disposal of geothermal liquid waste is a critical problem for the geothermal industry in the Imperial Valley. Most of the technical working experience resides in resource areas other than the Imperial Valley where the geology, hydrology, land use, and legal and environmental requirements may be different. Studies of disposal options conducted by other investigators can be helpful in assessing the Imperial Valley problem. The Battelle Pacific Northwest Laboratories evaluation of geothermal liquid waste disposal techniques (Defferding, 1980) provides valuable information on criteria that are useful in evaluating appropriate site-specific technologies. Table 16 taken from the Battelle report summarizes in matrix form the available disposal options and evaluation criteria. Choice of waste disposal options for the Imperial Valley will undoubtedly consider technical, legal, and environmental criteria but will focus particularly on actions affecting high quality water and prime land traditionally used for agricultural purposes. Thorough evaluation of these criteria will form the basis for defining waste handling and disposal systems design requirements.

Injection Technology.

Injection technology was developed by the oil industry to enhance oil production and control land subsidence. As a disposal method it has

	TECHNICAL ASPECTS							LEGAL ASPECTS				ENVIRONMENTAL AND SAFETY ASPECTS								
Disposal Method	Experience with method	Equipment	Importance of geology and underground hydrology	Interaction with processes	Useful by-products	Reliability	Cost	Geothermal laws	Environmental laws	Water rights laws	Land use laws	Occupational Safety	Water pollution	Air pollution	Noise pollution	Toxic substance disposal	Solid waste disposal	Induced seismicity	Land subsidence	Comments
Direct Release to Surface Waters	In use (a)	Readily available	Minimal	Very low	No	High	Low	Yes	Yes	Yes	Minimal	Excellent	Moderate	Yes	Yes	No	No	No	Potential	Low cost, good potential for low-temp., direct-heat applications
Treatment and Release to Surface Water	Minimal	Special materials may be needed	Minimal	Moderate (1)	Possibly	Moderate	Moderate	Yes	Yes	Yes	Minimal	Good	Low	Yes	Low	Potential	Yes	No	Potential	Cost of treatment must be kept low
Closed-cycle Ponding	In use (b)	Special materials (pond Liners) needed	Minimal	Very low	Possibly	High	Low (3)	Yes	Yes	Yes	Yes	Good	Low potential	Yes	Yes (5)	Potential	Some	No	Potential	Needs reliable liners and low-cost land in arid regions
Consumptive Secondary Use	Experimental	Readily available	Minimal	Significant (1)	Yes	High	Low	Yes	Yes	Yes	Yes	Good	No	Low potential	Low	No	No	No	Potential	Shows potential for medium- to low-temperature waters
Injection into Producing Horizon	In use (c)	Special Equipment (pumps) needed	High	Significant (1)	Possibly	Moderate (2)	Moderate (4)	Yes	Yes	No	No	Good	Moderate potential	Low	Low	No	Low	Low potential	Low	Very popular, but potentially has some problems
Injection into Nonproducing Horizon	Experimental	Special equipment (pumps) needed	High	Significant (1)	Possibly	Moderate	Moderate (4)	Yes	Yes	No	No	Good	Moderate potential	Low	Low	No	Low	Low potential	Potential	Used primarily where producing zones are highly fractured
Treatment and Injection	Experimental	Special materials may be needed	Moderate (1)	Significant	Possibly	Moderate to high	Moderate	Yes	Yes	No	No	Good	Low	Yes	Low	Potential	Yes	Low potential	Low	Solid disposal may be a big problem

(a) Wairakei, New Zealand; Ahuachapan, El Salvador; Iceland; Klamath Falls, Oregon
(b) Cerro Prieto, Mexico
(c) Ahuachapan, El Salvador and Larderello, Italy

(1) Temporary backup systems needed
(2) Has shown moderate reliability except in highly permeable zones
(3) Depends on liner and land costs
(4) Depends on permeability of receiving zone (lower permeability increases cost)
(5) Good designs reduce noise output

TABLE 16. Evaluation of geothermal liquid waste disposal techniques.

distinct advantages over the alternative methods noted earlier. It exerts a relatively minimal land-surface environmental impact and, if operated and maintained properly, does not affect surface and underground water supplies. As well as reducing the potential for land subsidence, it also recharges the producing geothermal source and conserves the heat energy of the source.

Injection simply involves the return of spent geothermal fluid to the producing aquifer through an injection well having a configuration similar to that of a production well. The spent fluid flows through a slotted liner which provides access to the formation while maintaining the integrity of the well borehole. Fluid may be injected either by gravity flow or under pressure at rates dependent upon permeability of the formation.

The locations of the injection wells in a producing field are very important because much of the fluid is transported in the geothermal aquifer through cracks and fissures caused by geological activity. These channels can rapidly transport cooler injection well fluids into the region of the producing well causing reduction in the enthalpy. To minimize well fluid interactions, it is recommended that a minimum well separation of 150 meters be maintained and that well density not exceed 1 well per 280 acres.

Formation permeability and chemical compatibility appear to be the most significant factors affecting injection well performance. The odds are that injection of geothermal fluid back into the aquifer from which it was withdrawn will meet with a favorable degree of success. However, it has been found that, upon reduction of fluid temperature and pressure during the energy conversion process, constituents that were barely soluble at higher down-hole conditions are now precipitated. This phenomenon is most prevalent for the high-solids content brines of the Salton Sea KGRA in the Imperial Valley. Injection technology requires separation of these precipitated and suspended solids in order to avoid formation plugging. Methodology to accomplish this is only now being developed. The reactor-clarifier process developed by Envirotech Corporation is an example. It has been tested at the Geothermal Loop Experimental Facility at the Salton Sea KGRA with relatively good results being demonstrated.

Discharge into Surface Waters.

Disposal of liquid waste into surface waters is a very simple and relatively inexpensive technology. However, it is very unlikely that geothermal wastes generated by Imperial Valley power plants will be disposed in this manner. The Imperial County full injection policy virtually rules out alternatives. In addition the high-solids content of brines, 10,000-250,000 mg/L, far exceeds the minimum standard of 4000 mg/l in effluents permitted for discharge to surface waters.

Disposal to Land.

Disposal of geothermal wastes to a land-fill dump site will without doubt be used as one of the options for Imperial Valley geothermal operations. The technology to be implemented must meet standards set by the CSWRCB and the Colorado River Regional Water Quality Control Board. Relatively conventional equipment for handling and hauling solid wastes and preparing the land-fill dump site are utilized in the disposal technology. The more significant problems with regard to Imperial Valley operations focus around the selection of an environmentally appropriate and adequate dump site that can be utilized cost-effectively by the geothermal industry. These problems and the steps taken to solve them were discussed in Volume 1, Section 7.

Other factors may be brought to bear on land-fill disposal technology as a result of RCRA and the guidelines for hazardous wastes proposed by EPA. It is reasonably certain that final regulations will require stricter control and maintenance of dump sites, fuller characterization of the wastes being discarded, and more precise monitoring of the land-fill facility to determine its impact on the immediate environment.

Mineral Recovery.

The recovery of minerals from geothermal wastes may have a mitigating influence on the overall solid waste disposal problem if recovery processes can be proved cost effective. Mineral recovery appears to be most viable for those processes that utilize hot spent geothermal brine as raw material rather than dried wastes such as evaporated salts, muds or well cutting debris. Several hypothetical chemical processes that exploit hot brine have been described by Wahl, (1977). He makes some interesting assessments of the market value of recovered minerals, the utilization and value of hot brine for process heat, and the relative value of electrical energy production.

Practical endeavors to utilize hot brine for process heat and to recover minerals have met with both success and failure. It should be emphasized, therefore, that much development work will be required before a determination can be made regarding the merits of mineral recovery and whether it can be cost-effective.

Current Imperial County policy requires injection of all fluids withdrawn from geothermal resources. To comply with this policy and to avoid large accumulations of waste, much of the technological emphasis to date has been placed upon development and optimization of injection techniques. If injection technology does not prove fully adequate then development of alternative procedures such as mineral recovery will demand more study as a means of alleviating the accumulation of large quantities of solid waste requiring disposal.

Although there are perceived recoverable and marketable minerals contained in the precipitates and scale of geothermal brines, no on-going research and development for their recovery are underway. Of the various categories of waste identified in this report only one, solid waste from H_2S abatement, shows promise for mineral recovery in the near future. Recovery of minerals from other geothermal wastes will require extensive economic and technological study before its mitigating effect can be determined.

DISPOSAL OF WELL-DRILLING AND WELL-TESTING WASTES

The principal wastes associated with well drilling and testing are drilling muds, formation cuttings and geothermal brine. The composition and amounts of these wastes are described in Section 7 of Volume 1 and are listed in Table 15. Most of the solid wastes from well drilling are accumulated in a reserve pit adjacent to the well. Some geothermal brine will also be discharged to the pit, but for the most part this latter waste originating from well flow testing operations will be reinjected.

In order to insure that the environment is not adversely affected by liquid and solid wastes from well drilling operations it is incumbent upon the well drilling contractor to adhere to regulations requiring appropriate well casings and blowout protection equipment. The regulations for Imperial Valley are set by the California Division of Oil and Gas. Construction of the reserve pit, assurance of its impermeability, and the handling, hauling and disposal of wastes from the pit should be carried out according to standards defined by the CSWRCB.

DISPOSAL OF SPENT GEOTHERMAL BRINE

Spent geothermal brine constitutes the most abundant type of waste associated with geothermal operations in the Imperial Valley. This is a consequence of the high solids content of the brine and the relatively large fluid flow-rate required for the generation of power (Ermak, 1977). In Table 1 we have not entered spent brine as an accumulated liquid waste because it is assumed that spent brine will be disposed of continuously by sub-surface injection technology operating as an integral part of the energy production process. Thus the accumulated waste associated with spent brine will be composed of suspended and precipitated solids separated prior to injection. It is expected that this solid waste will be disposed either to a land fill dump site according to regulations established by CSWRCB or will be processed for recoverable minerals.

At the present time the geothermal element of Imperial County policy mandates full injection of all fluids withdrawn for geothermal operations. The imposition of this policy is intended primarily to minimize the potential for subsidence and its possible adverse impact on agricultural drainage systems and irrigation structures. Notwithstanding the existence of the Imperial County full injection policy, there does not appear to be any more reasonable or effective disposal alternative. Inability to carry out or achieve injection of spent geothermal fluids will impose severe economic demands on geothermal operations as well as serious land-use and environmental requirements. The magnitude of the problem can be demonstrated if we consider the alternative disposal method consisting of ponding, separation of the solids by sedimentation and evaporation of water, followed by disposal of the solids to land. For a 100 MW plant operating in the Salton Sea KGRA, the ponding requirements alone exceed 1600 Hectares (4000 Acres). Ponding acreage of this size will be required to accommodate brine discharging at 2700 metric tons per hour. The calculation assumes that water will evaporate at a rate of 150 centimeters per year to maintain the pond at a constant fluid level. If the brine waste were concentrated to a density of 1590 kg per cubic meter, then disposal residue would accumulate at an approximate rate of 4.3×10^4 cubic meters or 70,000 metric tons per day. Clearly this imposes prohibitive requirements in terms of needed land and solid waste handling facilities.

Discharge of spent geothermal brine to surface waters does not appear to be a viable alternative to injection either. The total dissolved solids content of Imperial Valley brines ranges in concentration from 10,000 mg/l to 250,000 mg/l, well beyond the limit of 4000 mg/l for effluents that are permitted to be discharged to surface waters under state and regional regulations.

In view of these circumstances, it should be emphasized that injection technology constitutes the primary and most essential environmental control technology for Imperial Valley geothermal developments. The technology is intended not only to control possible subsidence but more importantly to minimize an extraordinary waste accumulation problem. Assured, effective injection technology for spent geothermal fluid is not a full reality at this time. Spent geothermal brines, because of suspended and dissolved solids have a tendancy to plug the injection well and only recently have successful experiments been carried out to alleviate the problem (Van Note et al., 1978). Work continues on efforts to understand the problem and perfect the technology. It is not unreasonable to conclude that geothermal development in the Imperial Valley very much depends upon success of the development of brine injection technology.

DISPOSAL OF COOLING TOWER WASTE

Cooling tower waste consists primarily of blowdown water containing salts that have been concentrated as a result of evaporation of water from the cooling tower. This waste can be handled either as a liquid or a solid. The more convenient procedure is to handle it as a liquid effluent and, if possible, discharge it to a surface water drainage system or inject it underground. There are serious environmental constraints that preempt discharge of blowdown to a surface water drainage system because of state and regional regulations prohibiting discharge of effluents exceeding 4000 mg/l total dissolved solids. Cooling tower blowdown is expected to surpass this level by as much as a factor of two. This expectation is based upon Layton's study of potential cooling water supplies (Layton, 1978) indicating that water usage and policy constraints will force cooling towers to utilize relatively impure water supplies.

Subsurface injection of blowdown water appears to be a viable disposal alternative. However, since the fluid may contain suspended solids capable of plugging the injection well or the immediately adjacent geologic formation, preinjection treatment to remove solids may be necessary. Chemical treatment prior to injection may also be necessary to prevent possible subsurface precipitation of calcium and barium sulfates that may form as a result of mixing high sulfate containing blowdown water with calcium or barium-rich subsurface geological materials. Because of these potential difficulties, it is not unreasonable to anticipate that cooling tower blowdown operations may require the handling and disposal of solid wastes.

The disposal of cooling tower blowdown as a solid waste will be a stepwise process requiring ponding, evaporation, residue handling, hauling and disposal in a landfill dump-site. The accumulation of solid wastes that can occur if this option is exercised are described in Section 7 of

Volume 1. For example, if agricultural drainage water is used as the cooling tower water supply, solid wastes from blowdown accumulate to a level nearing 1.3×10^7 cubic meters over a period of 30 years assuming a power growth-rate of 100 MW per year. The problem is alleviated to some extent if higher quality water such as mixed steam condensate and agricultural water is supplied to the cooling tower.

The cost of facilities and services to implement solid waste disposal technology for cooling tower blowdown is significant. The major required facilities are evaporation ponds, landfill dump sites and operating equipment. Services include maintenance and administration of the ponds, dump sites and access roads, and support services for loading, hauling, unloading and disposition of the waste material.

CONTROL AND DISPOSAL OF GEOTHERMAL SCALE

Scale is rapidly deposited on surfaces exposed to geothermal brines as a consequence of evaporative concentration and cooling of the depressurized hypersaline brine. The problem is especially evident at facilities in the Salton Sea KGRA and is expected to persist in spite of efforts to alleviate it by dissolution (Deutscher et al., 1980) or the addition of organic additives (Harrar et al., 1980).

Physical methods such as hydroblasting described in Volume 1 are expected to be used to remove scale from pipelines, separators and other critical locations in geothermal plants. The amount of scale shown in Table 15 is a preliminary estimate based upon experimental scaling rate studies. The actual amounts that will require disposal will depend upon the total solids content of the production brine, the chemical additives used to inhibit scaling and the effectiveness of the physical removal processes.

Although the amount of scale requiring disposal may not be large, the composition may present an environmental problem because of the relatively high concentrations (percent levels) of metals such as Fe, Pb, Mn, and Cu (Deutscher et al., 1980 and Harrar et al., 1980). Special handling, accounting, and disposal of scale may be required if it is determined to be hazardous under the regulations set forth by EPA under RCRA. Alternatively mineral recovery methods for the extraction of Pb, Mn and other metals may be worth pursuing if it is determined that cost-effective processes are possible.

DISPOSAL OF WASTES FROM H_2S ABATEMENT SYSTEMS

Significant accumulations of solid waste from H_2S abatement systems are not expected in Imperial Valley power plant operations. As stated in Volume 1, the more promising H_2S abatement systems such as the EIC and the Stretford processes generate sulfur and ammonium sulfate waste products respectively. Both products are useful, potentially marketable substances; however, some chemical treatment may be necessary to improve their quality. A detailed study will be required to determine the costs and benefits of such by-product recovery relative to the more conventional control technology involving waste accumulation, handling, hauling and disposal.

CONTAINMENT AND DISPOSAL OF ACCIDENTAL DISCHARGES AND SPILLS

Potentially significant discharges and spills can occur as the result of accidents such as well blowout, breaks in a brine transmission line or rupture of a process chemical storage tank. Control technology to minimize the effects of such events include blowout protection equipment, alarms, automatic shut-off values, and containment measures such as site grading and berm construction to direct and confine spills in specially prepared areas. These control measures should be designed in such a way that personnel and the environment are safeguarded and that access to critical production control areas is maintained. Disposal of accidentally discharged fluids may be accomplished by injection provided compatibility with the well is maintained. Alternatively ponding, treatment, and evaporation methods may be used followed by disposal to a landfill dump site.

CONCLUSIONS

- Design and development of environmental control technologies for the handling and disposal of liquid and solid wastes must be approached as a systems problem. Critical components of the system include: the geothermal power plant design, injection facilities for handling spent geothermal fluids, cooling water sources, cooling tower facilities for make-up water pretreatment and blowdown disposal, and land availability for intermediate waste treatment facilities and approved land-fill dump-sites.
- Specific data on the composition of geothermal wastes are lacking. These data are needed in order to classify the wastes in accordance with regulatory criteria and to determine appropriate treatment, handling and disposal.
- Injection technology constitutes the primary and most essential waste disposal technology for Imperial Valley geothernal operations. Methodology for separating solids prior to injection of spent geothermal fluids must be perfected.
- Disposal of geothermal solid wastes to land will be required as a consequence of geothermal operations in the Imperial Valley. The current technology for handling, transportation, disposal and monitoring will be significantly affected by new regulations under RCRA.
- Due to limited availability of land in the Imperial Valley for use in intermediate waste storage facilities (ponds, sumps, etc), control technology systems designs should consider efficient waste clean-out, handling, and transportation techniques.
- Spill prevention and containment measures should be considered in the overall design of waste handling and disposal facilities.
- Disposal of geothermal wastes to surface waters is very unlikely in the Imperial Valley due to the nature of the wastes and the policies protecting surface waters and land integrity.
- Recovery of marketable minerals from geothermal wastes is a viable option. More thorough cost-effectiveness studies and marketing projections are needed.

CONTROL TECHNOLOGIES FOR INDUCED SUBSIDENCE AND SEISMICITY

N. Crow

INTRODUCTION

Land subsidence and induced seismicity have been identified as potential adverse environmental effects that may result from geothermal power production operations in the Imperial Valley. Concerns regarding these effects have been prompted by reports of environmentally damaging incidents within the United States and in other areas of the world where large-scale fluid withdrawal and injection have taken place.

Interest in subsidence and seismicity in the Imperial Valley is relatively high because of the potential impact on the extensive irrigation and drainage systems in the Valley and the possibility that the already natural seismic activity in the area may be increased. Injection technology as used by the oil and gas industry has long been recognized as an effective means for controlling subsidence resulting from large-scale fluid withdrawal from subsurface reservoirs. Imperial County has instituted regulatory measures to insure that all fluids withdrawn for power production will be returned to the reservoir. This measure is intended to control subsidence, protect surface irrigation and drainage systems, and to aid in conserving the geothermal resource. Unfortunately there is evidence that fluid injection, while directed toward controlling subsidence, may generate a potential adversary impact exhibited as induced seismicity. It is this adversary relationship that requires the simultaneous assessment of control technologies for induced subsidence and seismicity.

INDUCED SUBSIDENCE

Subsidence in the Imperial Valley

The Imperial Valley is characterized by a flat, gently-sloping floor averaging 1 m/km (5 ft/mi) in slope northwestward towards the Salton Sea. An intricate gravity-flow irrigation system supplies water for large-scale agriculture in the Valley. The system includes canals to deliver water to the fields, tile drains in the fields to move saline water out of the root zone to the drainage system, and ditches to convey water to the natural drainage of the Valley. All are designed with carefully-controlled and regularly maintained gradients that are susceptible to damage by subsidence.

Other facilities of the Valley that are potentially sensitive to subsidence include industrial and residential buildings and roads. However, these structures are not considered to be as sensitive as the irrigation canals and tile drain systems.

Relatively substantial natural subsidence has been documented for the Imperial Valley and there is evidence of localized variations (Lofgren, 1978; Crow and Kasameyer, 1978; Elders, 1975). Regional tectonic forces are deemed to be the cause, and the local variations have been related to differential movements on the faults. The natural subsidence that has occurred is not known to have caused damage to land or structures in the valley. However, concerns have been raised regarding the nature and magnitude of subsidence that may occur when large-scale geothermal energy production gets underway.

Mechanics of Subsidence

This discussion is concerned primarily with possible subsidence induced by compaction of deep subsurface reservoirs as a consequence of fluid withdrawal. It is limited to conditions believed to be present at most locations in the Imperial Valley where the reservoirs are located in sedimentary rocks that have primary intergranular porosity supplemented by some connecting fractures.

Subsidence is caused by the response of the overburden to compaction of the reservoir rocks. Production of fluid from the reservoir system of fluid and rock disturbs its state, causing a drop in reservoir pressure. The resulting stresses cause the system to lose volume, and the weight of the overburden causes the system to compact. The structure, thickness, and composition of overburden will control the amount of compaction that propagates vertically and horizontally. Two kinds of compaction can occur. Recoverable compaction, essentially an elastic response, takes place when the rigid grains of the reservoir rock are rearranged into a more dense packing. Nonrecoverable compaction is largely caused by plastic deformation of the rock when the fluid is "squeezed" out of the highly-porous, uncompacted muds that may be found in lenses within the reservoir and in the adjacent aquitards. Once the porosity has been destroyed by the "squeezing", it cannot be restored by injection of fluid to the reservoir. Recoverable compaction occurs at a lower pore pressure than that required by nonrecoverable compaction when fluid is forced out of the plastic muds.

Compaction is a function of pressure drop in the reservoir and compressibility of the reservoir rock/fluid system defined as volume of rock yielded per unit pressure drop. The latter is an important required parameter for the calculation of compaction, but a value representative of the rock medium involved is difficult to determine by laboratory or simulation tests.

Subsidence above a compacting reservoir is a more complex process than the compaction itself, primarily because of the heterogeneous layers that make up the overburden. The properties of these layers are very difficult to measure, and it is also difficult to construct a mathematical model that will approximate them.

Two kinds of subsidence bowls are known to form above compacting reservoirs. The most common kind are shallow bowls fairly large in area relative to the size of the reservoir. Experience reveals that the depth of these bowls is a few feet and they have small slopes (Poland and Davis, 1969). The second kind of subsidence bowl is relatively rare and is small in area relative to the size of the reservoir. It is deep, has steep slopes, and is more likely to have significant environmental effects if it occurs in the Imperial Valley.

Legal and Regulatory Control of Subsidence

Legal Actions. Several legal actions involving damages due to subsidence have taken place. Three of the more important cases were related to large-scale fluid withdrawal from oil reservoirs and are described in detail by Poland and Davis (1969). Although the actions demonstrate early recognition of subsidence caused damage, and damage payments were made, no legal precedents were established and no regulatory criteria evolved from the actions. Equally important is the fact that possibly useful technical and geological details concerning the incidents were not released. All of these results stem from the out-of-court nature of the settlements in the three cases.

Regulatory Control. The California Division of Oil and Gas (DOG) exercises regulatory control over geothermal wells. Although the Division has jurisdiction over potential damages due to subsidence, they have focused attention primarily on safety rules and regulations intended to prevent damage by blowouts or other well equipment failures during well construction.

In recent years, county governments in California have assumed regulatory authority in the matter of subsidence. Erickson (1976) of Chevron Resources describes a case study involving Los Angeles County authorities and the operators of the Beverly Hills East oil field. There was serious concern about the potential for subsidence-induced damage to a nearby residential area. An extensive precision elevation survey network was developed to make periodic measurements permitting identification of the subsidence related to oil and gas production, shallow ground water extraction, and natural tectonic movement. The amount (about 0.04 ft/yr) and kind of subsidence related to oil and gas production were judged acceptable by the county authorities, and production of oil from the field continued successfully.

In the Imperial Valley, county authorities asserted jurisdiction over potential geothermal development several years ago. In its "Terms, Conditions, and Standards" (1971), the county requires periodic surveying of geothermal wellhead elevations. The surveys are required to be tied to nearby regional precision leveling network points. This network, the Imperial Valley Subsidence Detection Network, is described in Volume 1 of this report. The county also exercises authority in geothermal operations through its full injection policy requiring that all withdrawn fluids be injected back to the reservoir.

Subsidence Control Requirements

When reservoir fluid is withdrawn, subsidence can occur as a consequence of compaction of reservoir rocks caused by pressure drop in the reservoir and compressibility of the reservoir rock/fluid system.

Injection of fluid can be used to restore reservoir pressure. If the pressure is maintained below or slightly in excess of the threshold of nonrecoverable compaction, then compaction can be minimized.

Although subsidence is a complex process as stated earlier in this volume and in Volume 1, it is evident that a well-managed injection program accompanied by monitoring of the volumes of geothermal fluids withdrawn and injected constitutes the basis for an effective technology to control induced subsidence. There is abundant evidence from oil and gas field experience to confirm the reasonableness of this approach. For example, destructive subsidence at the Wilmington oil field in Long Beach, California was stopped very quickly, and even reversed locally by injection (Poland and Davis, 1969). Perhaps even more impressive is the lack of damaging subsidence in the eastward extension of this field where injection was initiated early in the production history. Reservoir pressure drop has been controlled, and no significant subsidence has occurred (Erickson, 1979). Unfortunately, this experience has not yet been formally documented. That it has happened is not in doubt; the locality is sensitive to subsidence and is carefully observed by public officials.

Table 17 presents data from 5 documented case histories where subsidence measurements were made. Fluid injection was carried out in only two of the cases and both show lower values for total subsidence and slope. At the Beverly Hills East oil field in Los Angeles, California, the data were used to demonstrate that oil production was not causing subsidence sufficient to disrupt facilities in the high-density residential and commercial district overlaying the field. The data convinced Los Angeles authorities, and production was allowed to continue. At Groningen, in the Netherlands, the gas field in part underlies "new lands" reclaimed from the ocean at great expense, and the government was not eager to see them reinundated. Schoonbeek (1976) states that the careful monitoring and reiterated predictions of ultimate compaction gave indications that no significant damage would occur.

Although the oil and gas industry has experienced reasonable success in abating subsidence by injection, it does not necessarily follow that the

Table 17. Subsidence data from documented cases.

Name	Total Subsidence	Steepest slope	Source
Wilmington, CA (unabated)	8.2 m (27 ft)	2 m/km (10.6 ft/mi)	Poland and Davis (1969)
Goose Creek, TX (unabated)		0.6 m/km (3.2 ft/mi)	Poland and Davis (1969)
Signal Hill, CA (unabated)	0.6 m (2 ft)	0.3 m/km (1.6 ft/mi)	Poland and Davis (1969)
Beverly Hills East, CA[a] (injection)	0.25 m (0.8 ft)	0.17 m/km (0.9 ft/mi)	Erickson (1976)
Groningen, Nederlands (injection)	0.2 m	0.02 m/km (0.11 ft/mi)	Schoonbeek (1976)

(a) Erickson reports rate of 0.01 m/y (0.04 ft/yr); subsidence for a 20-yr period was calculated.

geothermal industry will experience equal success. There is some uncertainty because, unlike oil and gas injection wells which are located relatively close to production wells, geothermal injection wells will probably be located as much as 1 mile from the production wells. This siting arrangement is deemed necessary in order to preserve the high temperature of the fluids produced by the geothermal reservoir.

Subsidence Monitoring Requirements

An effective subsidence control program in the Imperial Valley will require a well-designed and implemented monitoring program. Monitoring data can be used both for predictive modeling and for control purposes in an injection program. There are well-developed techniques that use data collected by monitoring systems to make relatively accurate predictions of ultimate subsidence and a number of models that are satisfactory for predicting compaction and subsidence (Poland and Davis, 1969; Erickson, 1976; Schoonbeek, 1976). Available monitoring data are used in the models to form consensus predictions and periodically the new data from the monitoring systems are used to update the predictions. As experience is gained and more data become available for the models the predictions will become increasingly more accurate. The techniques can also be used to predict the results of changes to be made in a subsidence control program, such as changing the amount of fluid injected.

A well-designed monitoring system should include the following records and measurements: a running record of surface elevation changes, fluid production and injection volumes, reservoir pressures versus time, and if possible, direct compaction measurements.

Elevation Change Monitoring. An extensive subsidence detection network was established in the Imperial Valley in 1971. Land surface elevation surveys were performed during the winters of 1971-72, 1973-74 and 1976-77, and another survey is being negotiated for 1980-81. More descriptive details of the network and the results of the surveys are given in Volume 1. To date the surveys have provided valuable baseline data on the magnitude of substantial natural movement in the Valley. Periodic surveys performed at 2 year intervals after geothermal energy production begins would provide additionally valuable data revealing the extent of subsidence due to production activities.

Fluid Production and Pressure Records. Data on the volumes of fluid withdrawn and injected into a reservoir, and the pressure changes associated with them, are collected routinely by the California Division of Oil and Gas. This information can be useful in a monitoring and subsidence control program; however, it is often considered proprietary because it can be used to calculate energy reserves. Therefore, DOG handles the information on a confidential basis. It would be valuable if DOG or their contractor could interpret the data and make the results available to individuals responsible for subsidence control programs. Thus, the effectiveness of the control programs could be evaluated and appropriate modifications could be made.

Measurements of Compaction. Casing collar logs and gamma ray-neutron logs, run on wire lines into the well, are everyday techniques that can be used to measure compaction. They provide useful information even though the absolute depth measurements are good only to about 1-3 feet as a consequence of wire line stretch and variations between different wires.

Relative measurements are more accurate, ranging from 0.5-1 foot. More precise measurements are quite difficult, although they have been made in the highly sensitive situations at Long Beach, California and at Groningen in the Netherlands. The costs of such measurements are high, and unless the subsidence potential as measured by the detection network is quite high, these special techniques are probably not justified. Compaction can sometimes be determined by means other than measurement. For example, one unmistakable indication of substantial compaction of the reservoir is damage to the well casing. Reservoir compaction of 1-2 meters (3-6 feet) will usually cause buckling of the well casing near the reservoir. If the cement bond is not strong, it will break and the casing may protrude from the ground.

Predictions of Subsidence

In the Imperial Valley, where subsidence can cause significant environmental problems, there is an understandable interest in pre-production prediction. Unfortunately, such predictions are highly uncertain, especially in the Imperial Valley where there are very few data about the behavior of reservoirs. At present, the only data available about the Imperial Valley reservoirs are short-term, pressure-drawdown tests and a few laboratory measurements of compressibility of the rock/fluid system in the subsurface. As explained in Volume 1, the laboratory measurements can yield low compressibility values. In addition the core samples used in the laboratory measurements are only an infinitesimal fraction of the heterogeneous reservoir rock, and the rock is only part of the fluid/rock subsurface system. Laboratory measurements have differed from compressibilities derived from reservoir behavior by two or three orders of magnitude.

Because of this lack of Imperial Valley data, modeling and prediction must depend on extrapolation of information from other areas, and this brings about the uncertainty. It is not likely that pre-production predictions will give actual amounts of subsidence and thus they are not appropriate for regulatory decisions. Rather, the information can be used to predict the approximate degree of subsidence, and whether worst case subsidence will be damaging. In Volume 1, Layton and Crow describe an appropriate use of modeling to predict pressure declines, aquifer compaction and associated subsidence. The study is based upon a hypothetical reference reservoir having characteristics similar to those existing in the Imperial Valley. The results indicate that substantial damage is likely only if worst-case subsidence were to occur.

Assessment of Subsidence at Proposed Geothermal Sites in the Imperial Valley.

Vertical elevation changes in the Imperial Valley between 1971-1977 have been documented by Reese (1977) and interpreted by Lofgren (1978). Annual rates of downward motion are about 2 cm/yr in the south end of the Valley, increasing to 4 cm/yr and more in the north end. If these rates are extrapolated over the 60-year history (1920-1980) of the developed irrigation system, the calculation indicates that subsidence varies from 1.2 m (4 ft) in the south end to more than 2.4 m (8 ft) in the north end. There has been no perceived damage to the irrigation system as a result of these vertical motions (Pierson, 1979). Possible reasons are: the low rate of movement and very small changes in slope (0.03-0.99 m/km--0.2-0.5 ft/mi).

Although vertical changes have apparently not affected the irrigation system, substantial gradient change could conceivably cause damage to agricultural land surfaces that must retain proper gradient to insure efficient, gravity-flow application and drainage of water. In order to assess the impact of slope changes due to subsidence in the Imperial Valley it is necessary to analyze each of the potential geothermal power production sites with regard to the localized topography, water distribution system layouts and technology, and the sensitivity of other structures.

Site-Specific Analyses

Heber At the Heber geothermal field, the land surface slope varies between 1.6 m/km (8.8 ft/mi) and 1 m/km (5 ft/mi), slightly steeper than the average for the Valley. Many of the northward-flowing relatively steep canals in this area have drop structures to lower the velocity of the flowing water. The canals are not very sensitive to changes in slope of a few tenths of a meter per kilometer (about a foot per mile) over a 20-year period.

The Central Main Canal, however, has an east to west reach across the geothermal field at a slope of about 0.4 m/km (2.2 ft/mi). This slope was scaled from the Heber 7.5 min. quadrangle topographic sheet (1957). If a slope change of about 0.2 m/km (1 ft/mi) were to take place in a subsidence bowl along the canal over a period of 20 years, the gradient on the west side of the bowl would be decreased by one-half. While this is a substantial change, it is not at all clear that it would cause significant damage to the canal. The reach of the canal immediately upstream of the flattened gradient would have a complementary increase in gradient. Would the extra hydraulic head compensate in part for the decrease downstream? Only a detailed engineering study can answer the question adequately. There are a number of factors and facilities involved including, for example, a control gate structure 3.2 km (2 mi) upstream of the Heber area which imparts extra hydraulic head to the water passing through the low gradient section. Engineering considerations include: sufficiency of the head to handle flow through the flattened portion and changes in structure that may be required to restore the necessary head, for example increases in canal cross-section and depth. Finally, it is not clear how potential induced subsidence would interact with the expected natural subsidence of approximately 0.4 m (1.3 ft) over the 20-yr period.

Because the Central Main Canal is unlined, repairs to it are relatively simple. Changing the vertical profile, widening the cross-section, and raising the dikes are quite straightforward. Adjustment of head gates may be a little more complicated, but well within standard engineering practice. There was a recent dramatic example of the feasibility of repairs to the Imperial Valley irrigation canals. Serious damage to the All American Canal near Holtville was caused by the major earthquake of October 15, 1979. The damage, sufficient to put this main canal out of service, was repaired so that it could be used within two days (Real et al., 1979).

Since Heber lies within the geothermal field, it is appropriate to assess the sensitivity of structures in the community to induced subsidence. The effects of slope changes of 0.6 m/km (3 ft./mi) and 2 m/km (10 ft/mi) were determined in relation to a 30 m (100 ft) long building oriented in the direction of the slope. The slope change of 0.6 m/km represents actual subsidence experienced at Goose Creek, Texas (Table 17).

If such a slope change due to induced subsidence were to occur in the Heber area it would adversely affect the flow of water in the Central Main Canal but would merely lower one end of a 30 m building by approximately 1.5 cm (0.6 in.). This alteration is well within the tolerances of conventional building construction practice and is not significant. On the other hand a slope change of 2 m/km would not only impact water flow in the Central Main Canal, but also cause some building damage as well. A slope change of 2 m/km represents a level of subsidence close to the worst case prediction of Layton and Crow (Volume 1) in their subsidence model using 85% injection. It is also the actual amount of subsidence experienced at the Wilmington oil field (Table 17) where no injection took place. There is no reason to expect that this degree of subsidence will occur as a result of geothermal operations in the Imperial Valley.

Salton Sea Geothermal Field. This field lies along the margin of the Salton Sea near the mouth of the Alamo River, with new development extending southward towards the mouth of the New River.

At the present time, the Salton Sea is flooding agricultural lands near the south end of the Sea as well as residential developments on the northest and southwest shores. This flooding has been caused by unusually heavy rainfall in the last several years, larger-than-normal quantities of agricultural drain water inflow, and the natural subsidence of this part of the basin (Lofgren, 1978). A system of levees has been constructed to preserve high-value lands, including some of the better agricultural land and geothermal facilities. Similar levees have been constructed farther north on the east and west shores of the Sea to protect resort and residential areas not within the area influenced by geothermal production activities. The major effect of any induced subsidence at the Salton Sea geothermal field would be to lower the freeboard on the already-constructed levees. This can be offset by increasing the height of the levees.

North Brawley. This area is relatively insensitive to subsidence because of its position relative to the New and Alamo Rivers and the configuration of the local irrigation system. The field lies near the New River, close to the axis of the Valley. Main irrigation supply canals run northerly, well to the sides of the geothermal field while local water is supplied by east-west canals. Slope changes due to subsidence are expected to produce only slight changes in the gradient of these structures with relatively minor impact. Also it is expected that the New River has sufficient flow to cause erosion that will quickly adjust the stream bed to possible slow-changing slopes resulting from subsidence.

East Mesa. The East Mesa geothermal field lies outside the irrigated portion of the Valley. There is a substantial quantity of intermediate quality (1500 mg/l TDS) ground water that could be used for irrigation of salt-tolerant crops but present Federal policy precludes development. The land surface is flat to gently rolling, covered by a 1-2 m (3-6 ft) layer of windblown sand. With the exception of a 320-acre orange grove located west of the central part of the geothermal field, the land is undeveloped desert, primarily under the jurisdiction of the Bureau of Land Management. The orange grove is irrigated by surface water, pump-lifted from the East Highline Canal adjoining it to the west. Any subsidence would lower the east edge of the field and would tend to reduce the lift. In general, it appears that land use in the East Mesa area is insensitive to induced subsidence.

INDUCED SEISMICITY

Natural Seismicity in the Imperial Valley

The fault systems of the Imperial Valley are very active, with an extremely high level of seismic activity as well as vertical and horizontal crustal displacement measured in meters during this century. Activity occurs in swarms of hundreds of sporadically-occurring earthquakes, separated by periods of less intense activity. In recent years, some of these swarms have included as many as several hundred earthquakes larger than Richter magnitude 3.0--about the threshold of perception--with several approaching Richter magnitude 5.0 (Hill et al., 1975; Johnson and Hadley, 1976; Fuis and Schnapp, 1977; and Johnson, 1979). In addition to the swarms of earthquakes there are also major mainshock-aftershock sequences. More than 12 major earthquakes (Richter magnitude greater than 6) have occurred in the Salton Trough during this century (Elders, 1975). The most recent major earthquake occurred October 15, 1979 on the Imperial fault near Holtville.

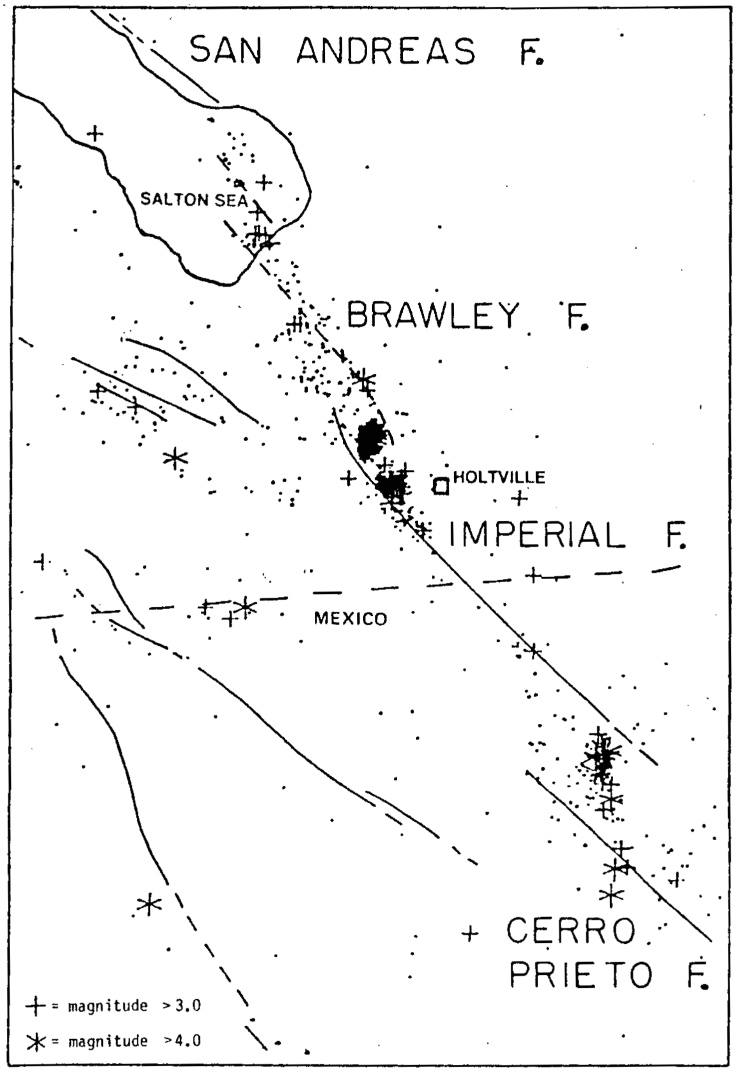

FIG. 24. Major fault structures in the Imperial Valley of California (Johnson, 1979).

The Imperial and Brawley fault zones, which trend northwesterly from the Mexican border near Holtville past the city of Brawley to Obsidian Butte at the south edge of the Salton Sea, are by far the most active fault zones in the Imperial Valley (See Fig. 24). No less than five of the major earthquakes in this century have occurred on these faults. The major earthquake on October 15, 1979 had its epicenter on the Imperial fault to the south of Holtville. It was followed by a series of large aftershocks that migrated progressively northwestward along the Imperial fault as far as Mesquite Lake. These fault zones are part of the San Andreas system, and show right-lateral strike-slip motion--the block to the west of the fault moves northwest relative to the block on the east of the fault.

There is also evidence of large vertical movements. For example, in recent geological time, a 10 m (30 ft) scarp has formed along the Imperial fault on the west side of the Mesquite Lake Basin. The recent earthquakes resulted in continued vertical movement in this area; the author and others have observed a fresh scarplet 15-20 cm (6-9 in) high at the foot of the major scarp after the earthquakes of October and November, 1979.

Reviews of the seismic data by Hill et al. (1975), Johnson and Hadley (1976), Fuis and Schnapp (1978), and Johnson (1979) reveal the following seismic characteristics for the region:

- A linear, northwest-trending alignment of many earthquake epicenters, corresponding to the traces of the Imperial and Brawley fault zones,
- A more-diffuse pattern of seismicity in the remainder of the Valley, although earthquakes still tend to occur near the traces of the known faults,
- A low level of seismicity to the east of the Imperial and Brawley faults except in the Salton Buttes area, where earthquakes occur on small fault strands _en echelon_ with the Brawley fault to its east,
- Focal depths between 5 and 14 kms, and
- The presence of spreading centers between the adjacent ends of eastward-stepping fault systems, for example at Mesquite Lake and at the south end of the Salton Sea.

Spreading centers are significant because they are believed to be the source of geothermal heat that is found in the geothermal resource areas in the Imperial Valley. This leads to the conclusion that the geothermal resource areas and the system of faults in the Imperial Valley are generically related, and that geothermal resource areas are likely to have higher natural seismicity than other areas in the Valley.

Potential for Induced Seismicity

Injection. There is concern that injection of geothermal fluids into reservoirs may enhance seismic activity in the Imperial Valley. The concern originates from two incidents in Colorado linking high-pressure subsurface injection with seismic activity. The incidents are rare and contrast to injection practices used widely to increase oil and gas reservoir productivity. No documented evidence of induced seismicity has been found with regard to this latter practice and with other waste water disposal techniques using injection. Probably a major factor for the absence of significant seismic activity is the control of injection pressures by state regulations. Although the ways in which the regulations are stated differ, the effect is to limit downhole injection pressures below 0.8 psi/ft depth, to avoid reservoir rock fracture.

Other Potential Causes of Induced Seismicity. There is also some concern that withdrawal of fluids from geothermal reservoirs may induce seismic activity. This concern is based on the possibility that disturbance of the present state of pore pressure or thermal regime in the subsurface will result in the release of seismic strain or, stated in other terms, that the system is on a hair-trigger and small disturbances might release it. Pilot-scale withdrawal and injection of fluids at several of the fields in the Imperial Valley have taken place, and the seismic monitoring system has not recorded any such activity; the threshold level of the system is Richter magnitude 2. In other seismically-active areas, such as the Los Angeles and Ventura basins of Southern California, there is no evidence of any significant seismic activity related to oil and gas production. Quite simply, we cannot evaluate the risk in the Imperial Valley before full-scale production begins, but the experience elsewhere suggests that the risk may be low.

At The Geysers steam field, the evidence interpreted by Marks et al. (1978) indicates that production has resulted in an increase in microseismicity (events ranging from Richter magnitude of approximately 2 to less than magnitude 1.5). Marks et al. relate the increase to the fact that production areas are experiencing pressure drop and possibly cooling. The cause of the increase is not known, but there is speculation that partial closing of the fracture systems resulting from pressure drops as well as cooling may be responsible. The rocks and steam reservoir system at The Geysers, a system of connecting fractures in impermeable metamorphic basement rocks, is very different from the water-dominated reservoirs in sediments at the Imperial Valley geothermal areas. Extrapolation from one to the other cannot be justified. Again, there are so few data regarding the Imperial Valley that the potential for induced seismicity from this cause cannot be evaluated before full-scale production begins.

Induced Seismicity Experience

The seismic events linked to subsurface injection at Rangely, Colorado and Rocky Mountain Arsenal near Denver are clearly unusual. The data presented in Table 18 illustrate the point (Healey et al., 1968; Raleigh et al., 1975). The pressures required to fracture the rocks in the reservoirs were unusually low, and were substantially exceeded by the injection pressure. Thus for a long period the fluid was forced into fracture and fault planes in the rock body, lubricating them and reducing the forces holding them in place. Also, fluid was forced into the interstices of the rock itself, increasing the pore pressure. Both processes reduced the rigidity of the rock. It is believed that the reservoir rock was under substantial seismic stress, and when it was weakened, yielded. This caused the earthquakes.

There are two other points worth noting. The earthquakes ceased when injection stopped and, at Rangely, an injection threshold pressure was demonstrated (Raleigh et al. 1975). Earthquakes occurred at pressures above the threshold and ceased below it. Raleigh et al. (1975) speculate that injection could be used to trigger earthquakes at relatively low stress levels, thus avoiding buildup of seismic stress to levels at which large, damaging earthquakes might occur.

Table 18. Data on injection at Rangely and Denver Rocky Mountain Arsenal[a]

Data	Rangely	Denver
Reservoir Formation	Sandstone	Granite
Depth to injection zone	6,200 ft (1,884m)	12,000 ft (3,648m)
Average porosity of reservoir	12%	(Fractured)
Average permeability of reservoir	1 millidarcy	(Fractured)
Original reservoir pressure	2,465 psi	2,900 psi
Maximum pore pressure due to injection	4,205 psi	5,640 psi
Least stress for initiating fractures	3,725 psi	5,200 psi
Maximum magnitude of earthquakes	3.1	5.3
Focal depth of earthquakes	6,550 to 11,500 ft (1,991 to 3,496 m)	14,750 to 18,000 ft (4,484 to 5,472 m)

[a]Healey et al., 1968; Raleigh et al. 1975.

Induced Seismicity Control Strategy for the Imperial Valley

If the injection pressures used in Imperial Valley geothermal operations are kept below levels that will fracture the reservoir rock the risk of inducing significant seismic activity will be minimized. Short-term excursions above the fracture pressure are not expected to cause a problem in cases where relatively small volumes are being injected before the threshold pressure is known. On the other hand injection of large quantities of fluid at pressures that will fracture the rock increases the risk of inducing seismic activity as fluid is forced into fractures opened by the high pressure.

To date there is very little experience with the injection of fluids into Imperial Valley geothermal reservoirs. Relatively small volumes of fluid have been disposed of by injection technology at several sites but most of the experience is not documented. However, there are indications that injection can be carried out successfully at well head pressures of 200-300 psi. This corresponds to an incremental pressure exerted at the formation face of a few tens of psi or less. Higher well-head pressure levels reaching 300 psi were required to inject fluid at the Magmamax 3 well in the Salton Sea resource area. Ultimately the injection operations ceased and it was determined that the well bore was plugged by precipitated solids in the fluid being injected.

Lack of extensive injection experience in the Imperial Valley resource areas gives rise to uncertainties regarding induced seismicity, its magnitude, whether it can be detected in relation to natural seismic activity, and the kinds of control that may be needed to control it. It is imperative, therefore, that an extensive seismic monitoring program be maintained in the Valley as a means of resolving some of these questions and formulating an effective control strategy.

Assessment of Induced Seismicity in the Imperial Valley

Sensitivity to Seismicity. How can we assess the significance of earthquakes? Small earthquakes cannot be felt; the generally-recognized threshold of perception is a Richter magnitude of 2.5-3. It seems clear that smaller earthquakes are not environmentally significant, because they cannot be felt and cause no damage. At the other end of the range, the threshold of damaging earthquakes is in the vicinity of Richter magnitude 4. Earthquakes with larger magnitudes are likely to be considered environmentally significant, with the degree of significance increasing with the amount of damage.

Between the unperceived earthquakes and damaging earthquakes is a gray area, where earthquakes are felt, but do no damage. In a region without seismic activity, earthquakes in this range are likely to be widely noticed by the public. In the Imperial Valley, where natural earthquakes of this magnitude are commonplace, a few added induced earthquakes that are felt but that do no damage are not likely to be considered environmentally significant.

Natural and Induced Earthquakes. Analysis of data from the USGS seismic network indicates that natural earthquakes in the Imperial Valley do not occur in a regular sequence, but rather as sporadic swarms of many earthquakes separated by periods of relative inactivity. This distribution of earthquakes is not uncommon, and can be described by use of a Poisson distribution (Crow and Kasameyer, 1978). This determination illustrates the value of baseline data before geothermal production begins. The natural distribution is similar to what might be expected from any potential induced activity resulting from geothermal production. Thus we know that sporadic earthquake events near a geothermal area are not necessarily production-related changes.

Most of the earthquakes detected by the USGS regional seismic network, those with Richter magnitude greater than about 2, occur at focal depths greater than about 5 km, probably in the basement rock beneath the sedimentary fill of the Imperial Valley. However, a brief microseismic study by Gilpin (1978) at the Salton Sea geothermal field determined that small earthquakes, most less than Richter magnitude 1.5, occur at a rate of about 2 to 3 per day. These events were at shallow focal depths, in the range of 1-3 km. Such a pattern of microseismicity is common at geothermal areas, and in fact is used as a prospecting tool.

Distinguishing Between Natural and Induced Earthquakes. It will be a difficult problem to distinguish between natural and induced earthquakes in the Imperial Valley. The high natural level of fairly large earthquakes occurring near geothermal resource areas, and the probable microseismicity at shallow levels near the geothermal reservoirs indicate that any induced activity will probably appear as an increase in existing activity, rather than a new phenomenon.

Assessment of Seismic Monitoring in the Imperial Valley

In the Imperial Valley the most important monitoring system is the regional seismographic network maintained by the U. S. Geological Survey. The network records events with Richter magnitude greater than about 2.0 and monitors most of the important areas except Heber. Originally, the USGS maintained a station there but seismic noise caused by passing heavy trucks and other activity made the data useless and the USGS removed the station. Later Chevron Resources, the operator at Heber geothermal field, drilled an emplacement hole and tested seismometers emplaced at 15 m (50 ft) and 250 m (500 ft). Results were satisfactory, and the station was maintained for about a year (Erickson, 1977). Erickson indicated that Chevron would be responsive to a request to use this hole for emplacement of a seismometer in the regional network. The station at Heber would provide important data both before and during production at this site.

Microseismicity data for the various geothermal sites in the Imperial Valley are incomplete. The work of Gilpin (1978) at the Salton Sea field indicates there is much natural activity there very similar to the kind that might be expected as a result of injection. Microseismicity data for other geothermal sites in the Imperial Valley have not been obtained or have not yet been interpreted. It is essential, therefore, that short-term surveys be carried out in these areas before production begins in order to evaluate seismic activity in the future.

CONCLUSIONS

Induced Subsidence

- At the present time, before production begins, only estimates of the potential magnitude and environmental significance of induced subsidence can be made. They are based on a small amount of data from the Imperial Valley and extrapolations from experience in oil and gas fields where deep reservoirs have been subjected to large-scale fluid withdrawal and injection. The estimates are not considered to be reliable enough for regulatory decision-making.

- It is probable, except in unusual cases, that injection of waste fluid back to the reservoir can control induced subsidence within acceptable limits. If subsidence substantial enough to cause damage does occur even with injection, damage will be minimal and repair will be effective in nearly all cases. In the worst case, if uncontrollable subsidence occurs, causing irreparable damage, then halting production will terminate subsidence.

- It will not be possible to make accurate predictions of the magnitude and kind of subsidence that will occur at specific reservoirs in the Imperial Valley until various fluid volume and pressure data related to withdrawn and injected geothermal fluids have been collected for some time. As data collection proceeds from monitoring systems established in the production areas, the predictions will become more reliable and the significance of induced subsidence can be determined.

- The carefully graded irrigation system in the Imperial Valley is insensitive to natural subsidence that has occurred over a long period of time. Some flooding of agricultural lands adjacent to the Salton Sea has taken place as a result of unusually large inflows of water and natural subsidence. Levees have been installed as an effective mitigating measure.

- Although vertical changes due to subsidence have not affected the irrigation system in the Imperial Valley, subsidence-induced slope changes resulting in gradient alterations may affect gravity-flow irrigation and drainage.

Induced Seismicity

- The risk of induced seismicity related to subsurface fluid injection is probably low if injection pressure is kept low enough to avoid fracturing of the reservoir rock. A more quantitative prediction must await the gathering of data during production so that any increase in presently-documented seismicity can be judged correctly.
- Another risk of induced seismicity is the possibility of seismic strain release resulting from changes in the fluid pressure regime in the subsurface. The small amount of data from pilot-scale injection in the Imperial Valley indicates that no related strain release has occurred. Similar findings have come from other locations in the U.S. where large-scale production and injection have taken place. Although the probability of seismicity cannot be evaluated from changes in fluid pressure, the evidence suggests that it may be low.
- Induced earthquakes that can be felt, but do not cause damage (Richter magnitude 3-4) are unlikely to be considered significant in the Imperial Valley where natural earthquakes of such magnitude are commonplace.

Environmental Control Techniques

- Injection of spent fluid back to the reservoir is the primary environmental control technique to manage induced subsidence. Supplemental measures include repairs of damaged facilities. If irreparable, significant damage is occurring as a result of otherwise uncontrollable subsidence, terminating production will stop subsidence.
- Maintaining fluid injection pressures below levels at which fracturing of the reservoir rock occurs has been shown to control seismicity resulting from fluid injection.

Monitoring Systems

- Monitoring systems are essential to collect the necessary data to evaluate the potential significance of any induced subsidence caused by geothermal production. The data required are:
  --Precise amounts of surface elevation change; these can be provided by periodic precision leveling at intervals of about 2 years.
  --Running records of fluid volumes produced and injected, records of reservoir pressure behavior over time, and direct measurements of subsurface compaction in cases where there is an actual measured risk of potentially significant subsidence. These records can be maintained in confidence by regulatory agencies.
- Because any induced seismicity related to injection is likely to resemble some kinds of natural seismicity, it is necessary to continue using the present seismic monitoring system up to and during production. The data collected will allow evaluation of any increases in the amounts of seismicity in the vicinity of geothermal facilities.

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