AN EXPLORATORY BENEFIT-COST ANALYSIS
OF ENVIRONMENTAL CONTROLS ON
HYDROTHERMAL ENERGY

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SUMMARY

To discover how to effectively increase the rate and level of hydrothermal resource commercialization, the U.S. Department of Energy, Office of Hydrothermal Commercialization, initiated a study, using existing data, of the value of environmental benefits generated by environmental regulation of hydrothermal sites to compare these benefits with the estimated costs of regulation.

Primary objectives of the research were to 1) evaluate the environmental damages caused by unregulated hydrothermal resource development, 2) use existing environmental and economic data to estimate the dollar value of preventing expected environmental damages at two sites, and 3) compare the benefits and costs of preventing the damages.

The sites chosen for analyses were in the Imperial Valley at Heber and Niland, California. Reasons for this choice were 1) there is a high level of commercial interest in developing the Heber known geothermal resource area (KGRA) and the Salton Sea KGRA; 2) the potential for environmental damage is high; 3) existing data bases for these two sites are more comprehensive than at other sites.

The primary impacts analyzed were those related to hydrogen sulfide (H_2S) emissions and those related to disposal of spent hydrothermal brine. Environmental damages were found to be extremely site-specific and only roughly quantifiable with existing data. No quantifiable damages to crops or livestock could be found in the literature. Health effects on humans have been identified, but only at higher H_2S concentrations than are expected in the Imperial Valley. Therefore, health effects were not addressed in this study. In the Imperial Valley, the principal source of damage from hydrothermal airborne emissions appears to be an odor nuisance from H_2S . The range of maximum dollar damages caused by odor nuisance was estimated for development of 3000 MWe for the Imperial Valley. A willingness-to-pay approach was used, resulting in estimated range of odor damage of \$2,000 to \$12,400 per installed MWe (net present value). The net present value of abatement costs range from \$107,900 to \$152,100 per installed MWe of generating capacity.

The effects of brine on the environment are also site-specific. The severity of environmental damage depends upon the quantity and quality of the brine that would be produced from the wells, injected to maintain reservoir pressure in the absence of regulation, used to replace evaporation losses if required by regulation, and also, the quantity and quality of the receiving waters if surface discharge were permitted. For example, the Heber and Niland sites in the Imperial Valley are very different in these respects, so the effects of regulation are very different at the two sites. The primary sources of environmental damage from brine disposal in the Imperial Valley are inundation of Salton Sea shoreline caused by increases in the level of the sea due to discharged brine; land subsidence caused by brine removal; and damage to the Salton Sea sports fishery caused by salinity increases.

Imperial County requires 100 percent replacement of hydrothermal fluids by injection, primarily to reduce the chances of subsidence. At Heber, about 80 percent of the fluid would be voluntarily injected to recharge the reservoir. At Heber these regulations result in a lower level of the Salton Sea, which reduces the environmental damage caused by shoreline inundation and cropland subsidence. However, an offsetting environmental cost of regulation is increased salinity of the Salton Sea. At Niland, the reservoir recharges naturally, so no voluntary injection would occur. Regulation results in a lower level of the Salton Sea. At Niland, regulation causes a reduction in salinity.

The present value of estimated benefits of 100 percent fluid replacement regulations for 500 MWe at Heber ranges from -\$3,900 to +\$39,300 per installed MWe. A major source of the variability in benefits is the value of averted subsidence, which ranges from zero to \$12.8 million. The present value of total injection costs are estimated to be \$20.8 million or \$41,700 per installed MWe. Regulation thus shows a net cost. At Niland, the estimated benefits for 100 percent fluid replacement at 500 MWe range from \$32.6 to \$58.7 million, but costs are estimated at \$7,000 million. The present value of injection costs totally dominates the expected environmental benefits.

Regulation results in the early destruction of the Salton Sea sport fishery for 500 MWe of resource development at Heber, causing "benefits" of -\$8.9

million to -\$6.9 million. At Niland, regulation delays destruction of the fishery by four years, for a benefit of \$23 million to \$30 million. The costs of regulation are greater at Niland because the hydrothermal reservoir at that site is considered self-replenishing; consequently, regulation requires injection wells that would not be drilled or operated in the absence of regulation.

Although a considerable amount of environmental data is available on the Imperial Valley, it only permits very crude and limited estimates to be made of the benefits and costs of regulation. Based upon the analysis of quantifiable benefits and costs for the scenarios and sites examined, we conclude that the costs of regulating environmental damage are substantially greater than the benefits at Niland, but not at Heber. We found that the benefits and costs of regulation are extremely site-specific; therefore, they should be evaluated on a case by case basis. Results for one known hydrothermal resource area are not generalizable to other hydrothermal sites or for levels of development other than those investigated.

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FOREWORD

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

This research report is one of a series being prepared as part of the Department of Energy project entitled "Economic Valuation of Geothermal Environmental Impacts." The goal of this project is to provide information and support for program planning, research and marketing activities directed toward the commercialization of hydrothermal resources.

Pacific Northwest Laboratory (PNL) is conducting this research for the Department of Energy, Division of Resource Applications. Publications from this project include:

Wells, K. D., J. W. Currie, S. A. Weakley, and M. Y. Ballinger. 1980. The Cost of Meeting Geothermal Hydrogen Sulfide Emission Regulations. PNL-2802, Pacific Northwest Laboratory, Richland, WA 99352.

Wells, K. D., J. W. Currie, B. A. Price, and E. A. Rogers. 1980. The Cost of Meeting Geothermal Liquid Effluent Disposal Regulations. PNL-2991, Pacific Northwest Laboratory, Richland, WA 99352.

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

Scott, M. J., K. D. Wells, J. W. Currie, and M. J. King. October 1980. An Exploratory Benefit Cost Analysis of Environmental Controls on Hydrothermal Energy. PNL-3527, Pacific Northwest Laboratory, Richland, WA 99352.

J. W. Currie,
Project Manager

1.0 INTRODUCTION

This research was performed by Pacific Northwest Laboratory (PNL) for the Office of Hydrothermal Commercialization, U.S. Department of Energy. Information presented in this document is intended to aid DOE in the formulation of research, development and demonstration allocation decisions for hydrothermal resource commercialization. The major objective of this research is to evaluate and compare the cost of complying with environmental regulations in light of the expected value of the environmental damages prevented at a specific site.

This introduction briefly describes the background of the study, summarizes its objectives and presents the project outline.

BACKGROUND

The commercialization of hydrothermal resources is of primary importance to the Department of Energy (DOE). The rate of commercialization depends on many things, the most important of which is the cost of producing marketable energy from hydrothermal resources. Factors that increase the production costs can potentially impede hydrothermal resource commercialization. Environmental factors have the potential to be costly impediments.

Hydrothermal resource development is known to cause environmental changes in air, water and land resources at the development site. These changes may include damages to air, land and water resources. Individuals who are exposed to such damages may attach a relatively high dollar value to the lost environmental quality. These dollar values are referred to as "nonmarket costs" in this report, and more generally as "externalities" in economic literature.

Existence of nonmarket costs causes government to impose environmental regulations on resource developers in an effort to limit damages. These regulations can be a major and unnecessary barrier to the commercialization of hydrothermal resources. Clearly, when the standards are too stringent, developers will find the expected returns on hydrothermal resources to be too low relative to other investment alternatives of comparable risk. When standards are too lax, unnecessary damage may be done to the environment. To establish standards that are optimal from a resource development viewpoint, attempts

should be made to develop estimates of the schedule of compliance costs for preventing environmental damages and estimates of the value that society places on the prevention of such damages.

Recognizing this, DOE previously contracted with PNL to develop cost functions for H_2S emission abatement and for liquid effluent treatment and disposal. In that research, we demonstrated that abatement costs can be significant. For example, at Baca, New Mexico, the cost of abating H_2S emissions may increase the bus bar cost of electricity by over 20% (Wells et al. 1980, PNL-2802).

If the objective is to increase the rate and level of resource use, the relationships between damage values and damage prevention costs should be considered when environmental regulations are written. Merely stabilizing standards will not increase the growth rate of resource use if the standards promulgated are too stringent.

Because of the differing characteristics of hydrothermal resources and development sites, it appears that the selection of uniform (industry wide) standards could be less desirable than setting standards on a case by case basis. However, the absence of specific standards leaves developers uncertain about the possible level of future standards. This uncertainty could be a key factor in determining the rate of hydrothermal resource commercialization. Conversely, promulgation and/or stabilization of environmental regulations for hydrothermal resource development may reduce the perceived risks of regulatory uncertainty, and may thereby encourage commercialization. At this time it is not clear what the best regulatory strategy is in terms of encouraging commercialization.

OBJECTIVES

This project was exploratory in nature and, because of this, we used existing data and estimates from previous empirical research. The primary objectives of this study were to estimate and compare, for two hydrothermal sites,

- the nonmarket costs (a dollar measure of environmental damages) associated with unregulated resource commercialization,
- the costs of preventing environmental damages caused by hydrothermal resource commercialization.

The two sites chosen were Heber, in the Heber KGRA (known geothermal resource area) and Niland, in the Salton Sea KGRA, respectively. Both sites are located in the Imperial Valley, California. These sites were chosen because:

- the potential for environmental damage is high;
- existing data bases are more comprehensive than at other sites; and
- there is a high level of commercial interest in developing these sites.

This study will help answer the following questions:

- What data are required and available for the analysis to be performed?
- To what degree can we estimate nonmarket costs of commercial development of hydrothermal resources from existing data?
- To what extent do nonmarket costs differ between sites?
- To what degree do regulations create different benefits and costs across sites?
- What do the results suggest about the feasibility and usefulness of site specific regulations?

RESEARCH OUTLINE

To fulfill the objectives, the following research tasks were identified:

- Description of a reasonable development scenario for a site;
- Description of expected environmental damages in the presence and in the absence of environmental regulations;
- Calculation of the expected dollar value of damages;

- Estimation of the cost of preventing environmental damages;
- Comparison of the benefits of environmental protection with the costs of damage prevention.

Sections 2.0, 3.0 and 4.0 below present conclusions, recommendations, and suggestions for further investigations derived from this research. Section 5.0 introduces the theoretical structure and benefit-cost framework used in this report. Section 6.0 provides a description of the site and the development scenarios that the case study is built upon. Section 7.0 reviews each of the expected damages, their dollar values and prevention costs, and discusses the net benefits of environmental protection likely to be provided by existing standards. Appendices A through F provide supporting detail on the theoretical and computational aspects of the net benefits assessment presented in the case study in Sections 5.0, 6.0 and 7.0.

2.0 CONCLUSIONS

From this case study of two Imperial Valley hydrothermal sites, it is possible to draw the following conclusions:

- Techniques exist that may be used to estimate the dollar value of environmental damages (nonmarket costs) of hydrothermal resource development.
- These valuation techniques provide valid dollar estimates to the extent that reliable data are available that accurately describe expected environmental changes and the willingness of people to pay to avoid these damages.
- Environmental damages caused by hydrothermal resource development depend upon the characteristics of the resource and the site where development is undertaken. It is unwise to generalize from one site to another, even within a relatively small geographic area.

For the Imperial Valley, it can be concluded that:

- At least four environmental impacts are expected to have measurable dollar values:
 - Hydrogen sulfide odor nuisance
 - Subsidence
 - Shoreline inundation at the Salton Sea
 - Fisheries damages in the Salton Sea
- Hydrothermal resource development apparently will not damage crops at the levels of development currently being projected; however, boron, CO₂, and cooling tower salt drift have not been evaluated as potential impacts.
- The major source of hydrogen sulfide damages is the expected odor nuisance, which would be noticeable at full development with no abatement.

- Data on the effect of H_2S on human health indicate that with no regulation insignificant health damages are expected at the relatively low H_2S concentrations forecasted.
- A major source of uncertainty in the environmental damage estimates arose from subsidence damages to cropland. To obtain an estimate of the environment at risk, we assumed that in the worst case subsidence would render the land worthless for irrigated agriculture. This is an overestimate of the expected damages from subsidence at the site.
- No adequate data exist to estimate or measure the damages of, or potential for, induced seismicity.
- Brine disposal regulations governing surface disposal will result in environmental benefits from reduced inundation of Salton Sea shoreline; however, in some cases regulations have an associated cost of increasing the salinity of the sea. The direction and magnitude of this effect will depend on the total dissolved solids (TDS) content of the brine, the amount of brine that is handled, and the source from which outside makeup water can be taken.
- For H_2S odor nuisance the minimum cost of preventing the nuisance exceeded by several times the maximum estimated value of prevention (as measured by the willingness of individuals to pay to avoid the odor) for full development of the valley's resources.
- For subsidence, fisheries, and inundation damages, the minimum cost of preventing damages by brine injection was greater than the maximum value of preventing the damages for development scenarios at the Niland and Heber sites in all but one case. The difference between control costs and damages prevented increased dramatically with an increase in the level of development.

3.0 RECOMMENDATIONS

Because the total control costs were generally shown to be greater than the benefits of control:

- 1) Liquid waste disposal options other than 100% injection of spent brine should be allowed. Alternatively, lower levels of injection and other methods for mitigating salinity, subsidence, and inundation damage should be explored.
- 2) To require 100% abatement of potential H_2S emissions would be inefficient, although we assumed the most efficient abatement process. Therefore, a method of mitigating the potential nonmarket costs of the H_2S odor nuisance at a lower cost to society through new processes, less abatement, compensation procedures, damage fees or marketable emission rights should be considered.
- 3) The preliminary data we were able to obtain probably do not capture all the significant benefits and costs of preventing environmental damages. Additional data and analyses are needed to give a more comprehensive view of the environmental protection issue at those hydrothermal resource sites.

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4.0 FUTURE RESEARCH

The effects of air emissions and water related environmental damages differ greatly among the Imperial Valley KGRAs and for different levels of development. A comprehensive assessment of benefits and costs needs to be conducted for varying levels of hydrothermal resource commercialization in the Imperial Valley. To support a comprehensive benefit cost analysis, better technical and economic data are required. For KGRAs outside of the Imperial Valley, data are likely to be required for analysis. Data needs anticipated for benefit cost analyses of all KGRAs are summarized below.

TECHNICAL RESEARCH NEEDED:

- Relationship between hydrothermal fluid removal and subsidence.
- Relationship between subsidence and land productivity.
- Probability and expected value of damages caused by induced seismicity.

ECONOMIC RESEARCH NEEDED:

- Survey data on willingness of individuals to pay or accept compensation for exposures to an odor nuisance from H_2S ; for visual aesthetic changes; for changes in recreational opportunities; and for other nonmarket costs imposed on individuals near hydrothermal sites.
- Estimates of demand for environmental attributes of particular KGRAs by persons not located at the site who may wish to preserve their option of visiting the site in the future (option demand), or who benefit simply by knowing the environment at the site has been preserved (existence demand).
- Data on the cost of diking for protection of Salton Sea shoreline from surface releases of hydrothermal brines that cause inundation.
- Investigation of the alternative strategies available for efficiently preventing environmental damages and reducing their economic impact on the rate and level of hydrothermal resource commercialization:

- Alternative environmental protection standards, such as permitting the surface disposal of liquid wastes,
 - H₂S and liquid waste emission or effluent fees and taxes,
 - Marketable damage rights.
- Investigation of income distribution impacts for the alternative damage mitigation strategies analyzed above.

5.0 EVALUATION OF NONMARKET COSTS

INTRODUCTION

In this section we discuss the theory that economists use in measuring non-market costs of hydrothermal development and the information gaps that place limitations on our ability to develop empirically reliable measurements of non-market costs. The first part of the section begins with a description of the information needed to estimate nonmarket environmental costs. The economic theory of damage measurement and the application of benefit-cost analysis are then reviewed. The last part of this section discusses the selection of measurement techniques for geothermal sites in the Imperial Valley. This leads to Section 6, where we apply the measurement techniques and describe specific information gaps that prevent more complete measurement of the dollar value of environmental damages.

ECONOMIC THEORY OF ENVIRONMENTAL IMPACT

The conceptual framework an economist uses to estimate the dollar value of the environmental impacts contains three basic steps: first, identify how the development changes the environment; second, determine the degree of various physical environmental damages and benefits; third, translate the physical effects into dollar values using the guidelines of economic models. These values can then be incorporated in a benefit-cost analysis to compare the costs to society of preventing environmental damages with the costs of accepting these damages. Appendix A reviews the process of hydrothermal resource development and summarizes the characteristics of several known geothermal resource areas (KGRAs).

The process of estimating the benefits and costs of preventing environmental damages is depicted in Figure 5.1. The process consists of three steps:

- Identify the environmental interaction that is hypothesized to create environmental damages.
- Identify and estimate the physical damages expected from the interaction.

- Estimate the value of the environmental damages.

Three pieces of information are necessary to complete the first step in the analysis in Figure 5.1--the characteristics of the resource, the technology, and the environment. Even having fairly comprehensive information is no guarantee of the successful completion of this step, however. For example, consider the emission of H_2S from hydrothermal plants. Resource characteristics and development technology usually give us an estimate of the H_2S that is introduced into the environment. It is still difficult to specify the precise effect on the ambient atmospheric concentration of H_2S at various distances from the source, because of the variability in winds, mixing, other sources of emissions, topography, etc.

FIGURE 5.1. Process of Estimating the Benefits and Costs of Preventing Environmental Damages

Even when we know the average ambient concentration with some certainty, this does not guarantee we will be able to learn whether physical damages will occur, which is the second step in Figure 5.1. This is because exposures to high ambient concentrations of H_2S affect complex living organisms such as plants or people in the presence of many intervening factors, such as presence of other pollutants or the age and smoking habits of the population.

The third step in the process of estimating the benefits and costs of preventing environmental damages as shown in Figure 5.1 involves deriving estimates of the dollar value of the expected damages. This is often the most difficult step in the analysis simply because of a lack of reliable data. Frequently the primary reason is that the appropriate studies have not been done and comprehensive data bases are therefore not available. When this occurs, economists either search for more information or take the computations as far as the state of knowledge will let them go, and then compare estimates of the nonmarket costs with the costs of prevention. Such a tradeoff analysis has the advantage of pointing out where data gaps occur while at the same time forcing a comparison of the benefits and costs of environmental protection.

The starting point for the economic analysis of environmental damage (the third step of Figure 5.1), is a demand curve, shown in Figure 5.2 as Curve DE. The demand curve represents consumers' responses to changes in the prices of a commodity. It can be drawn either for individuals or for a group of consumers. The curve slopes downward because at lower and lower prices for x relative to all other goods, consumers would be willing to purchase greater and greater quantities of X ; e.g., when the price falls from P_0 to P_1 , the quantity desired increases from X_0 to X_1 in Figure 5.2.

Part of the increase in purchases X_0 to X_1 is due to the fact that the price of X relative to all other goods and services is lower and part is due to the fact that at the lower price, the consumers have left over real income available to purchase all goods--income they did not have available when the price of X was higher. If we can ignore this second effect because it is "small," then the demand curve also can be used to measure consumer welfare. If the price of X is P_0 per unit, the consumers will buy X_0 and pay P_0 for each unit taken. However, although they would be willing to pay no more than P_0 for the last (marginal) unit, they would still purchase some X if the

price were higher (say P^*), up to price D . Put another way, they would be willing to pay more than P_0 for all units of the good, up to the last one taken, when X_0 is purchased, rather than do without any X . Thus, the height of the aggregate demand curve out to the amount purchased measures the gross value to the consumers of each incremental unit of X taken, and when these values are all added together the total value of X_0 units of X is the area bounded by the points $ODAC$ in Figure 5.2.

This total value, whether computed for each consumer and then aggregated, or measured directly for a whole group of people, is the one we seek when trying to estimate the value of an environmental good X . Note that the price times the quantity taken (Area OP_0AC) understates the total value of X_0 to the consumers, because it represents only a portion of the total area under the demand curve.^(a)

FIGURE 5.2. Demand Curve

- (a) In much economic analysis, it is assumed that good X sells in a "workably competitive" market. If that is the case, the price of X reflects its unit cost of production and OP_0AC its total cost to produce. The net value or benefit to society is then P_0AD . However, in this analysis, we keep track of costs separately, so we use gross value on the benefit side of the calculations.

Environmental goods are different from the "typical" good X in two ways. First, they are usually not priced, even if they cost something to provide (e.g., keeping the air clean is not costless). In Figure 5.2, consumers of the environmental good would want X_2 of the environmental good X at zero price. This would not be efficient from society's viewpoint if it cost more than zero to provide. Second, unlike bread, for example, environmental goods can be consumed jointly by several people at one time. Thus, the value of the last unit of fresh air is not the price any individual would be willing to pay for it, as it would be with bread. It is the sum of the values all individuals would be willing to pay, but do not actually pay. This issue is the crux of the valuation problem: to determine the willingness of individuals to pay for the good.

MEASUREMENTS OF NONMARKET COSTS IN A BENEFIT-COST FRAMEWORK

Figures 5.3A and B demonstrate the use of the concepts discussed thus far in estimating the efficient level of environmental nonmarket costs.

Figure 5.3A depicts the aggregate demand curve of a group of consumers for a particular environmental good such as clean air or clean water, defined in terms of ambient quality (e.g., ppm H_2S). The lower the level of pollutants, the higher is the quality. Figure 5.3B translates this into a damage function for emissions as follows. As the level of emissions rises from Q_0 to Q_1 , the ambient quality of the environment falls from A_0 to A_1 . The lost total value of the consumer group identified by aggregate demand Curve DD' is $\hat{A} \hat{B} \hat{C} \hat{D}$ in Figure 5.3A, and is also reflected in the area $\hat{A} \hat{B} \hat{C} \hat{D}$ under damage Curve A in Figure 5.3B. Since several environmental goods with different demand curves (e.g., crop values, recreation, human health) may be affected simultaneously by the increase in emissions, we show an aggregate damage function Z in Figure 5.3B that is the sum of the damages to each segment of the environment that the emissions damage. The other curve in Figure 5.3B is the incremental treatment cost curve Y. As we proceed toward the left side of the figure, it becomes more and more costly to prevent emissions. This is either because hydrothermal environmental development is increasingly restricted, or because increased cleanup of emissions is required, or both. If we know precisely the

A.

B.

FIGURE 5.3. Nonmarket Costs of Environmental Damage and the Efficient Level of Damage

costs of cleanup and the nonmarket costs of environmental damage from emissions, the efficient level of emissions would be Q^* , where the incremental costs of damages prevented just equal the costs of preventing those damages.

However, although we sometimes know the control costs for differing levels of emissions, we seldom have enough information to translate changes in emissions into damages to environmental quality. Therefore, Curves Y and Z in Figure 5.3 are best thought of as uncertain zones that give a broad range of emission levels and damages (dotted rectangle in Figure 5.3) that are approximately efficient. Sometimes, as in this study, the best that can be done is to develop a range of estimates like $\hat{A} \hat{K} \hat{L} \hat{D}$ that can be compared to control costs like $\hat{A} \hat{F} \hat{G} \hat{D}$, to see if the required level of control on emissions is efficient.

DAMAGE VALUE ASSIGNMENT

Several methods are available for empirically estimating nonmarket costs. These are listed below and a brief review of each is presented in Appendix B.

- Substitution Approach,
- Travel Cost Method,
- Bidding Games,
- Expenditure Allocation, and
- Property Value Approach.

Because this study is an exploratory analysis, we relied on existing data and previous research to derive nonmarket costs. While previous research may have relied on any or all of the above methods, we have used the substitution approach. This approach was adopted because it enables the analyst to assign 1) the observed value of a market good or 2) the previously estimated value of a nonmarket good to an environmental good that has similar characteristics. As the two goods become near perfect substitutes their values will correlate closely, other things equal.

In the following section, background data are presented for a case study in the Imperial Valley that will be used in Section 7.0 to develop estimates of the expected dollar value of the benefits of preventing potential environmental damages.

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6.0 HYDROTHERMAL RESOURCE DEVELOPMENT IN THE IMPERIAL VALLEY

This section begins with a discussion of site selection criteria for the benefit-cost analysis. The chosen site, the Imperial Valley, is described and scenarios of potential energy developments are then outlined. Expected environmental damages are noted at the end of the section. This discussion is intended to provide background information for the case study of damage costs and prevention benefits that follows in Section 7.0.

SITE SELECTION CRITERIA

To focus the discussion of environmental impacts and to make possible a demonstration of the techniques for estimating the dollar value of environmental impact of hydrothermal development, we chose the Imperial Valley, California as a study area. There were several motives for this choice. In the first place, more is known about the environmental characteristics of the Imperial Valley than many other locations, thanks to the work of the Imperial Valley Environmental Project (IVEP), originally undertaken at Lawrence Livermore Laboratory for the Energy Research and Development Administration (Lawrence Livermore Laboratories 1980). Second, the valley contains commercial hydrothermal projects in an advanced state of planning and an existing demonstration project, all of which provide additional data and relevance to our calculations. Third, because the valley is a settled area with existing agricultural, residential, industrial-commercial, and recreation uses, we felt that it was likely that hydrothermal energy development in the valley would represent a maximum environmental impact case. In remote areas, impacts would more likely be limited to conflicts with recreation or wilderness land uses and aesthetics.

THE IMPERIAL VALLEY

The Imperial Valley is an irrigated agricultural area mainly contained in one county (Imperial), bordered by Mexico on the south, the Santa Rosa, Vallecito, and Coyote Mountains on the west, the Chocolate Mountains on the east, and the 30 mile-by-15 mile Salton Sea on the north. The Salton Sea is a

salty(a) lake that was created in 1905-07 when the Imperial Valley's irrigation diversion system failed and the Colorado River flooded a significant portion of the valley. The Salton Sea is about 228 feet below sea level and has no outlet; consequently, its level and salt content are mainly regulated by rainfall, irrigation runoff, and evaporation. The volume of the lake has increased in recent years due to accelerated use of irrigation water drawn from the Colorado River and increased rainfall. Although the lake level was stable enough during the 1960s to encourage the development of residential and recreation facilities, the lake level has risen about four feet since 1970, inundating several of these facilities (Lawrence Livermore Laboratories 1980). Salinity has remained stable since 1970 due to the lake's increased volume.

Irrigated agriculture is the principal use of land in the Imperial Valley. Some 450,000-475,000 acres of land in crops depend on nearly 3 million acre feet of irrigation water diverted from the Colorado River into the valley every year (Lawrence Livermore Laboratories 1980).^(b) The Imperial Irrigation District operates about 1650 miles of irrigation canals and laterals at intervals of one mile or less across the valley floor and 1,400 miles of drainage canals. Tile drainage systems installed about four to six feet below the surface of most of the valley's fields capture percolating irrigation water beneath the fields and divert it into the drainage canal system. While the inlet water from the Colorado River now averages about 838 mg/l TDS, irrigation water averages about 900-1000 mg/l and drain water is perhaps four times as saline as irrigation water (Lawrence Livermore Laboratories 1980). The balance of flows in the water supply and disposal system could be changed by the advent of large-scale hydrothermal development. Adverse effects could occur on irrigation water, drainage system water and Salton Sea water, depending upon the source of water used for cooling in the hydrothermal plants and the disposal option selected for hydrothermal brines.

(a) The lake's level of dissolved salts is approximately 39,000 ppm by weight, while sea water averages 35,000 ppm (VTN 1979).

(b) Of 4.5 million acre feet diverted by the All-American Canal every year, about 60 percent goes to the Imperial Irrigation District, 30 percent to the Coachella Valley, north of the Salton Sea, and 10 percent is lost through evaporation and percolation into groundwater formations. About 1.0-1.3 million acre feet per year reach the Salton Sea as return flow.

The Imperial Valley has a desert climate with rainfall averaging less than 3 inches per year. The average temperature is 55°F in January and 90°F in July. Average diurnal (daily) temperature variations are 20° to 30°F. Winds, which help determine the degree and direction of horizontal transport and dispersion of potential air pollutants, prevail from the west most of the year; in the summer there is a southeasterly component because of a thermal low pressure system over the valley (Lawrence Livermore Laboratories 1980). Calm conditions are present 9% of the time in the winter and 8% in the fall with light winds most of the rest of the time. Average wind speeds are 6 knots in the winter and 7 knots in the fall, with speeds below 3 knots prevailing 29 and 22 percent of the time, respectively during these seasons. Winter is also the time of year when the air is most stable, which prevents vertical dispersion of pollutants. During December, January, and February, the most stable class of conditions prevail about 52 percent of the time. Ordinarily, if the product of mixing height and wind speed falls below 6000 m²/sec, air dispersion capabilities are considered limited. On an annual basis, this product is 6000 to 11,000 m²/sec for the Salton Trough, which contains the Imperial Valley region. In the winter, however, the product is only 4400 to 5000 m²/sec (VTN 1979).

The valley has a current air quality problem with particulates and ozone. The particulate loading, which is probably heavily influenced by fugitive dust from agriculture, exceeded national and California 24-hour ambient standards between 37 and 55 times during 1977, depending on the site (VTN 1979). Ozone standards of 0.100 parts per million by volume (ppmv) are violated on occasion (2% of the time in June-July 1977). H₂S is not usually a problem because well over 90% of the H₂S hourly average concentration measurements taken in 1977 by Lawrence Livermore Laboratories fell below 0.005 ppm_v (the California standard is 0.030 ppmv) (EPA 1977). Current occasional violations may be a result of the application of agricultural chemicals. Sulfur dioxide is well within California standards. Thus, while the potential for air pollution exists in the valley, the evidence suggests that the current air quality situation is not especially serious. Noise levels are also generally low.

The bulk of the land in the Imperial Valley is zoned and used for agriculture and some commercial, light industrial, and residential uses. Recreational uses are mostly associated with camping, fishing, water-skiing and resort activities (such as golf) near the Salton Sea. Another group of activities, such as hunting, desert wildlife and flower observation and off-road vehicle use, take place in the desert surrounding the irrigated and near populated areas of the county. Proposed hydrothermal developments would most likely occur on land zoned for agricultural uses among fields used for grazing cattle, and growing alfalfa, lettuce, cotton, wheat, cantaloupe, and sugar beets (Lawrence Livermore Laboratories 1980) and would, therefore, be more likely to cause crop damage than interfere with recreation. Existing uses, especially agriculture and Salton Sea recreation, could be displaced or interrupted by hydrothermal development.

Two significant potential environmental problems related to land use are subsidence and induced seismicity. Like most other KGRAs, the major hydrothermal resources in the Imperial Valley are located in an area with active faults. The major faults in the area are the Holtville, Imperial, Brawley, Calipatria, and Sand Hills faults. Of these, the Imperial and Brawley faults are by far the most active. Of the twelve earthquakes of 6.0 or greater Richter magnitude that have occurred in the Salton Trough in this century, no less than four occurred on these two faults (Lawrence Livermore Laboratories 1980). The Imperial Valley also seems to be subsiding naturally with large local variations. The IVEP project and efforts of federal, state, and local agencies resulted in three separate measurements of elevation changes in the valley between 1972 and 1977. Maximum subsidence observed during the five year period was about 20 cm near the east edge of the Salton Sea, decreasing to about 7 cm near the south end of the valley (Lawrence Livermore Laboratories 1980). The chief concern with hydrothermal development in the Imperial Valley is that the extraction of large volumes of brine from hydrothermal reservoirs under the valley floor could accelerate these natural subsidence tendencies, leading to local surface deformation and slope reversal at the ground's surface.

POTENTIAL ENERGY DEVELOPMENT SCENARIOS

The Imperial Valley contains five known high-temperature (150°C -plus) KGRAs with an aggregate electrical potential of about 6760 MWe: Salton Sea, Westmorland, Brawley, Heber, and East Mesa (Muffler 1979). The approximate locations of these resources are shown in Figure 6.1. The future level of hydrothermal development in the valley is uncertain at this time because a number of regulatory, technical, and economic conditions will have to come together in a timely fashion to guarantee development. Among these are a commitment of California utilities to hydrothermal electric energy from this area rather than out-of-state purchases of electricity, and the building of high voltage transmission lines from the valley to the San Diego and Los Angeles areas (Lawrence Livermore Laboratories 1980). However, three development scenarios were constructed for Imperial Valley hydrothermal development to guide the Imperial Valley Environmental Project, and these give a broad idea of what level of development might take place.

The cases are presented in Figure 6.2, along with the projected cumulative production levels from all the hydrothermal units being planned by various developers, as reported by the California Energy Commission (CEC). The low growth case reflects technical, economic, or political constraints on development. It shows aggregate production of about 1000 MWe by the year 2010. The medium growth path attains 1000 MWe by 1991 and ultimately achieves generation of 3000 MWe in the year 2010, about half the total capacity of the resource. The difference between these cases is that Brawley, Heber, and East Mesa are fully exploited in the medium growth case and that technical problems with dissolved solids (corrosion and scaling) can be overcome to the extent that Salton Sea and Westmorland combined produce 1400 MWe. The high case requires 4000 MWe from Salton Sea and Westmorland areas and could only be achieved if additional hydrothermal resources are discovered and if all other conditions such as the economic feasibility of conversion processes, technological solutions to scaling and corrosion problems, demand for hydrothermal energy, and political climate are very favorable (Lawrence Livermore Laboratories 1980). The high level of hydrothermal development reported to the CEC in Figure 6.2 may reflect developer over-optimism regarding the pace of economic and technical events.

FIGURE 6.1. The Imperial Valley, California, and Its Known Geothermal Resource Areas (KGRAs)

Source: Based on Lawrence Livermore Laboratories 1980

FIGURE 6.2. Development Scenarios for Imperial Valley Hydro-thermal Resources (Based on Lawrence Livermore Laboratories 1980)

The specific scenarios of resource development to be considered in this document from an environmental benefit-cost standpoint is shown in Table 6.1

TABLE 6.1. Resource Development Levels by the year 2010

<u>Size of Facilities</u>	<u>Heber</u>	<u>Salton Sea (Niland)</u>	<u>Brawley</u>	<u>East Mesa</u>
100 MWe	50	50	0	0
100 MWe	500	500	0	0
3000 MWe	700	1400	600	300

For the 3000-MWe case, installations will be added each year in 100-MWe increments for 30 years, beginning in December of 1980 (Lawrence Livermore Laboratories 1980). For the 500 MWe cases we assumed that 50-MWe units would be installed at Heber and Niland annually until 1989 according to the schedule in Table 6.2:

TABLE 6.2. Resource Development Rates at Heber and Niland

<u>Year</u>	<u>Added (MWe)^(a)</u>	<u>Capacity^(a)</u>
1982	50	50
1983	50	100
1984	--	--
1985	--	--
1986	100	200
1987	150	350
1988	100	450
1989	50	500

(a) Capacity at each site.
Source: VTN 1979.

EXPECTED ENVIRONMENTAL DAMAGES

Hydrothermal resource development in the Imperial Valley of California has the potential to generate significant environmental damages. This section describes the types of damages expected to air, water and land resources in the region. Since most commercial interest is focused on the use of the dual flashed steam cycle in the Imperial Valley, this review focuses on the environmental damages that are associated with its use. Expected damages include:

- Visual impacts of cooling towers and steam plumes
- Noise
- Airborne emissions of noncondensable gases
- Liquid waste disposal related damages.

Each of these impacts is considered in the subsections that follow. Appendix C contains a brief description of the planned resource development at Heber.

Visual Impacts

Selection of mechanical draft towers over natural draft towers at the site will reduce the visual impacts of the physical structure but there will still be a vapor plume in existence. Because of the extremely low population density in the area and because of the often limited visibility due to particulates, the aggregate dollar value of consumers' willingness to pay to prevent the visible plume is expected to be small. This was coupled with the lack of data on willingness to pay to avoid plumes at hydrothermal plants and led us to decide not to evaluate visual impacts.

Noise

Creation of noise is not expected to constitute a significant nonmarket cost at the site for several reasons. First, the population density is so low that very few residents will be affected. Second, the noise levels created by the plant are expected to be approximately 56 dba at 1000 feet from the plant, which is well within OSHA and EPA standards (VTN 1979). There are private benefits that accrue to the utility from providing its own noise control (e.g., higher productivity at the site). Therefore, it is not possible to conclude that any expenditures for noise control represent environmental standards compliance costs that are imposed on the utility. Noise impacts will not be discussed further in this report.

Air Emissions

Figure 6.3 provides a detailed illustration of the effects of air emissions on the environment. We have identified four potential areas of damage from airborne emissions:

1. Crops
2. Human health
3. Aesthetics (Odor)
4. Livestock

These areas are discussed below.

Crops

Crops require carbon dioxide (CO_2) for photosynthesis. There are a number of compounds--including hydrogen sulfide (H_2S), boron, and salts--however, that in high concentrations will hinder the ability of plants to grow.

FIGURE 6.3. The Process of Environmental Changes Resulting From Hydrothermal Airborne Emissions

In the absence of increased CO_2 , the growth and development of crops would be adversely affected with exposure to hydrothermal gases. With high CO_2 concentrations, however, plant growth can actually be enhanced by hydrothermal airborne emissions. LLL (Lawrence Livermore Laboratories 1980) modified a crop growth simulation model (GROW) to show the effects of hydrothermal airborne emissions on sugar beets. This analysis assumed that the proportion of CO_2 to H_2S remained constant as H_2S concentrations increase. The result was that CO_2 produced more beneficial effects than H_2S destroyed up to emission rates of 0.3 ppmv of H_2S , ten times the California standard. Thus, there is some doubt that air emissions would cause damage to crops in the valley even with very high levels of hydrothermal development. The results of crop growth studies for Imperial Valley field crops indicate that combined H_2S and CO_2 emissions, even if unabated, would have no negative impact on crops (Lawrence Livermore Laboratories 1980).

Cooling towers are used to increase the operating efficiency of the steam turbines in hydrothermal power plants. A byproduct of the cooling tower is cooling tower drift, which contains salts. It may contain boron, depending upon the chemical characteristics of the cooling water and the hydrothermal brine. Levels of boron toxic to plants could occur in the drift if a large fraction of the boron in hydrothermal fluids is carried over in flashed steam. Boron released from cooling tower drift is the subject of ongoing research, and although we can assume that it hinders crop growth and development, we have no data to indicate the damages, if any, that would accompany boron emissions in the Imperial Valley.

Wind drift from cooling towers could deposit salts on land around the hydrothermal sites (Water Resources Council July 25, 1980), but the expected damages would depend on the crop variety, the source of the cooling water, the salt emission rate at each site and the likely damages caused by the salt deposition over time. In the absence of such data it is not possible to estimate the expected crop damages from cooling tower drift.

As discussed above, air emissions from hydrothermal production may have detrimental or beneficial effects on crop growth. To actually quantify the effects in dollar terms, however, we would have to know the exact relationship between changes in growth rates, quality, yield and changes in the value of the

crop. Unfortunately, we do not know of any research done in this area. For that reason we are unable to discuss crop damages of any type in the benefit cost estimates produced in later sections of this report.

Human Health

The effects of high concentrations of H_2S on human health are known to be severe. Concentrations of H_2S above 100 ppmv can cause death within 43 hours (EPA 1977), while loss of the ability to detect the presence of H_2S by smell occurs in the range of 0.067-0.67 ppmv. Its main effects on humans in low concentrations are eye and respiratory irritation, while high exposures can cause hemorrhaging (i.e., with exposures of 4-8 hours at concentrations of 200 ppmv and greater). The current California standard for H_2S is 0.03 ppmv, well below the toxic level. Ambient levels at the hydrothermal plants are expected to be well below the toxic level even in the absence of regulations (VTN 1979). As a result, health problems are not expected to arise. Therefore, potential damages to human health from airborne emissions will not be addressed further in this report.

Livestock

The final category of air emission damages one might consider is potential effects on livestock. Unfortunately, very little research has been done in this area. The livestock component of Imperial County's agricultural sector accounted for 28% of total output in 1978, and represents a major area where further research may be warranted. Since H_2S causes eye and respiratory irritation in humans, it does not seem unreasonable to assume that livestock are also adversely affected by H_2S emissions. For purposes of this study, we will assume that livestock react in a similar fashion, and that their productivity is not hampered by airborne emissions from hydrothermal facilities. For that reason, livestock damages will not be included in further discussions in this report.

Bees are important to crops simply because they provide the transportation of pollen necessary for commercial growth of seed cotton, cantaloupe, watermelons, and seed alfalfa. Fumigation studies on honey bees showed that their lifespan was significantly shortened when exposed to concentrations of H_2S of 0.1 ppmv and higher (Lawrence Livermore Laboratories 1980). Atmospheric dispersion modelling of the Imperial Valley airshed indicates that the expected

ambient levels of H_2S will be well below this threshold level. Given the likelihood that there will be no incidence of mortality and morbidity in the bee populations even in the absence of emissions standards, we have eliminated further references to bees in this report.

Odor

The potential for an odor nuisance caused by hydrogen sulfide emissions is more certain. Lawrence Livermore Laboratories used a diffusion model to estimate annual average ground level H_2S concentrations and the probability that the California ambient air quality standard of 42 micrograms per cubic meter (0.030 ppmv, one hour average) would be exceeded with hydrothermal development of 3000 MWe (Lawrence Livermore Laboratories 1980). The worst locations in the simulation were areas near Brawley and the Salton Sea KGRA, where violations of the standard for H_2S were projected to occur between 200 and 325 days out of the year. The violations would last for 3.3 to 5.7 hours per episode (Lawrence Livermore Laboratories 1980).

Panels of human subjects in a number of studies have shown that humans can detect H_2S at concentrations in the range of 0.003 to 0.009 ppmv for the 50th percentile of these panels, which is ten times lower than the California air quality standard of 0.030 ppmv for H_2S . Exposures to concentrations on the order of 0.100 ppmv have resulted in complaints such as headache, nausea, sinus congestion, abrupt awakening, and other deleterious health effects (Lawrence Livermore Laboratories 1980).

LLL (Lawrence Livermore Laboratories 1980) developed isopleths of H_2S concentrations for the full development (3000 MWe) case. We can estimate the odor exposures arising from H_2S , therefore, for the full development case. However, to estimate odor damages at specific sites, we would need isopleths for the 50 and 500 MWe cases, which are not currently available. Based on the isopleths for the 3000 MWe development level, it is clear that without regulation there will be an odor nuisance in the Imperial Valley in the year 2010. In the benefit cost analysis of section 7.0 we present estimates of exposure and of the dollar value of the odor nuisance caused by hydrogen sulfide emissions.

Damages Related to Liquid Waste Disposal

There are two alternatives for liquid waste disposal at hydrothermal sites: injection and surface release.^(a) Both options may have significant nonmarket costs associated with them, as shown in Figure 6.4, which provides a detailed illustration of the effects of alternative liquid waste disposal options on the environment. We have identified four potential areas of damage from these disposal options:

- 1) inundation
- 2) subsidence
- 3) seismicity
- 4) fisheries damages

These areas are discussed below.

Inundation

Since most of the Imperial Valley is below sea level, water entering the New and Alamo Rivers has no way to flow to the Gulf of California. The amount of irrigation return flow and precipitation has exceeded the amount of evaporation from the sea, thus, resulting in a net rise in the Salton Sea's level. The result has been inundation of private and federal land. An example of the seriousness of this problem is found at the town of Bombay Beach. The town was originally designed with eight north-south streets. The rising sea has inundated three of these streets. Dikes presently prevent the total inundation of the town.

Discharging hydrothermal brine into either the Salton Sea or its tributaries will increase the rate at which the sea level is rising. Withdrawing makeup water (water evaporated during the cooling process of power production) for injection from either the sea or its tributaries, will decrease the rate at which the sea level is rising. Because inundation has occurred in the past and because it has the potential to create large damages in the region, it will be explored further in Section 7.0 of this report.

(a) Because the Imperial Valley hydrothermal sites are located on highly valued agricultural lands, ponding and evaporation may not be a feasible surface disposal alternative. Ocean disposal is also not feasible due to the relatively high cost of transporting the spent brine to the ocean.

FIGURE 6.4. Water Related Impacts

Subsidence

Hydrothermal energy production entails extracting high temperature brine from a deep aquifer. As the brine is extracted the pressure drops in the reservoir. This results in compaction of the reservoir, which can be transmitted to the surface as subsidence, depending on the flexibility of the geological structures lying above the reservoir.

The Imperial Valley is an agricultural area and it requires large amounts of water. Water is diverted from the Colorado River to the valley through the All American Canal. The water is then transported to the fields by a system of gravity flow canals. Colorado River water has a relatively high TDS content, depositing salts on the fields if they are not properly drained. It was necessary in the Imperial Valley to lay a system of drainage tiles, buried 4-6 feet underground, to divert percolating irrigation water containing salt leached from the soil into agriculture drains that spill into the Salton Sea or its tributaries. At the Heber site, these drains deposit their contents in the New River approximately 45 miles from its destination in the Salton Sea. At the Niland site, they either drain directly into the Salton Sea or the Alamo River.

Because both canals and tile systems are designed for gravity flow, they are sensitive to changes in the slope of the land. Subsidence is therefore important because it can affect the lie of the land, i.e., disturb the canal, drain, and tile networks. The valley is presently subsiding naturally to the northeast, but it is a planar type of movement. The problems arise when subsidence occurs in localized areas, perhaps leaving some cultivated land without water and/or drainage. For these reasons a benefit cost evaluation of subsidence prevention will be presented in Section 7.0 of this report.

Seismicity

Significant seismic events may or may not be induced by the extraction or injection of hydrothermal fluids. Earthquakes have been linked to fluid injection unrelated to hydrothermal development at Rangely, Colorado and Rocky Mountain Arsenal, Colorado. Increased seismic activity at The Geysers has been linked to extraction of steam and injection of fluid. Most KGRAs, (including

the entire Imperial Valley and all of its KGRAs), occur in areas that are seismically active, which is why this issue is a cause of some concern (Lawrence Livermore Laboratories 1980). Damages from earthquakes in the valley have been significant in the past. Thus, induced seismicity constitutes an unknown but potentially serious risk of development. The problem is that there is presently no way to tell if pressurized injection will cause an increase in the number of damaging earthquakes. For this reason we will not pursue the seismicity issue further.

Sports Fishery

The Salton Sea supports three main sports fish: the Orangemouth Corvina, Bairdiella (gulf croaker), and Sargo. Lasker, Tenaza and Chamberlain (1972) have shown that Bairdiella and Sargo embryos cannot tolerate salinity above 40,000 ppm. Because Sargo and Bairdiella are the primary food for Orangemouth Corvina (Figure 6.5), it appears that at salinities greater than 40,000 ppm the life of the sports fishery will be in jeopardy because of its inability to maintain itself by natural reproduction.

If the salinity were to eventually exceed 40,000 ppm, two potential remedies would be to 1) create a strictly "put and take" fishery by introducing adult game fish or 2) introduce game fish which can successfully reproduce at the higher salinity. The first option would be relatively costly. With the second option, we have found no indication that a new species would be successful in the higher salinity waters.

Salton Sea salinity is projected to reach 40,000 ppm by 1990 (VTN 1979). The impact of hydrothermal development on the rate of increase in salinity will depend on the TDS content and the volume of the brine discharged to the sea, and on whether or not makeup water is being withdrawn from tributaries of the Salton Sea. Therefore the dollar value of potential damages to the sports fishery will be investigated in Section 7.0.

Summary of Expected Damages

Although the potential exists for airborne emissions to have deleterious impacts on crops, livestock and human health, there is considerable uncertainty surrounding the possibility of significant damages occurring. However, even

(SOURCE: WALKER, WHITNEY, AND CARPELAN (1961))

FIGURE 6.5. Salton Sea Food Chain

with 3000 MWe of hydrothermal resource on line by 2010 the probability appears to be fairly low. In a similar manner, airborne drift of salts and boron are not expected to cause measurable damages. Noise, visual aesthetic impacts, seismic activity and recreational land use disruptions are expected to be minor.

The only impacts that are believed to be potentially significant are subsidence, H_2S odor nuisance, damages to the Salton Sea sport fishery and inundation of land as the level of the Salton Sea rises. The benefits and costs of preventing these impacts are discussed in the following section.

7.0 IMPERIAL VALLEY ENVIRONMENTAL PROTECTION

BENEFIT-COST ASSESSMENT

In the previous section the expected environmental damages from hydrothermal resource commercialization in the Imperial Valley were reviewed. Of the potential impacts that could occur, the following are most likely to have a measurable and significant dollar value:

- Hydrogen sulfide odor nuisance
- Subsidence damages to irrigated agricultural land
- Inundation of land
- Sports fishery damages.

In the subsections below, a benefit-cost evaluation is presented for each of these impacts. The assessments present the individual scenarios within which the dollar damages and prevention costs were estimated. Where discounting was used to derive levelized annual costs and net present value estimates, a 5% real discount rate reflecting the opportunity cost of capital in the private sector was used to compute the net present value of the social benefits and costs of complying with environmental protection regulations. All benefit and cost estimates are in January 1980 dollars.

HYDROGEN SULFIDE ODOR NUISANCE

Hydrothermal resource development in the Imperial Valley will generate airborne emissions of hydrogen sulfide (H_2S) that may create an odor nuisance (the smell of rotting eggs) for residents and for visitors in the valley. Humans can detect the presence of H_2S by its noxious odor at concentrations of 0.003 ppmv (EPA 1977), which is one tenth of the state of California ambient standard of 0.03 ppmv (VTN 1979). Currently, developers of hydrothermal resources in the Imperial Valley will only have to meet this ambient criteria, and will not have to control emissions to prevent an odor nuisance. Although odor control is not currently required, we have selected the odor nuisance for benefit cost evaluation because it represents one area of virtually certain environmental damage that can be evaluated objectively to see if changing the level of protection to one which requires no damage is desirable from the standpoint of efficiency.

H_2S emissions can be controlled with scrubbing processes that oxidize the gas into elemental sulfur and water. The purpose of this section is to compare the dollar costs of H_2S emission abatement processes with the dollar benefits residents may realize through elimination of the odor nuisance. The subsections below present the framework of the preliminary benefit-cost assessment for H_2S abatement, including:

- the resource development scenario that leads to airborne emissions of H_2S
- the expected level of odor exposures for the resident population
- the willingness of individuals to pay to eliminate the odor nuisance (i.e., the dollar value of the odor nuisance)
- costs of H_2S emission abatement.

Resource Development Scenario for H_2 Odor Exposures

Since reliable odor exposure estimates were not available for other levels of development, the full development scenario of 3000 MWe in the valley was selected for analysis in this section of the report. The full development scenario will have a greater likelihood of generating an odor nuisance for the main population centers, while a single local development of 50 or 500 MWe may not. According to the scenario, the total of 3000 MWe will be generated within the four known geothermal resource areas as follows: 1400 MWe at Salton Sea; 600 MWe at Brawley; 700 MWe at Heber; and 300 MWe at East Mesa, as noted in Section 6.0, Table 6.2.

Odor Exposures

The hydrothermal resources in the Imperial Valley are expected to have H_2S concentrations in the raw flashed steam of at least 1.5 ppm_w (VTN 1979), and the concentration will be higher at specific sites within the valley. At the Salton Sea KGRA, for example, the concentration has been measured at 3.9 ppm_w (Gudiksen et al. 1977). These are very low concentrations relative to sites such as the Baca Ranch (Valles Caldera, New Mexico) and The Geysers, California, which have minimum observed H_2S concentrations of 200-290 ppm_w in the raw flashed steam.

Gudiksen (1977) calculated expected ambient air concentrations of H_2S for the valley assuming 3000 MWe of generating capacity were on line and that all H_2S removed from the reservoirs was emitted from the flashed steam cycle plants into the airshed. Expected exposure days were then calculated for the six major population centers in the valley: Calipatria, Heber, Niland, Westmorland, Calexico and Brawley. An exposure day is defined as at least one episode per 24-hour period during which the ambient H_2S concentration would exceed the state ambient air quality standard of 0.030 ppmv for one hour. Because humans can detect the presence of the gas at concentrations of 0.003 ppmv, which is one tenth of the state ambient standard, the number of exposure days listed in Table 7.1 is a very conservative estimate of the number of days when an odor nuisance will exist at a given town in the year 2010. For this reason, Gudiksen's calculations were used only in the minimum exposure calculation.

TABLE 7.1. Exposure Days for H_2S in the Imperial Valley(a)

<u>Town</u>	<u>Annual Exposure Days per capita^(b) in the Year 2010</u>	<u>Population in 1980</u>
Niland	108	1,158
Brawley	72	16,756
Calipatria	228	2,223
Westmorland	72	1,432
Heber	15	15,847
Calexico	12	2,436

(a) Forecasted by Gudikeson (1977), 3000 MWe total development.

(b) Day during which the ambient concentration exceeds the state standard for at least one hour in the year 2010.

The number of days per year that a given number of residents will be exposed to an H_2S odor nuisance was assumed to increase with each passing year until the year 2010, after which exposure was assumed constant. Specifically, we assumed (consistent with Livermore's medium development scenario

discussed in Section 6.0) that 100 MWe of generating capacity would be added each year from December 1980 to December 2010, until all 3000 MWe of capacity are on line. For example, in year n (where $n = 1$ through 30) the number of exposure days at Niland was assumed to be $(n/30) \times 108$. Total person days of exposure in year n was then calculated as the population in the town that year multiplied by the number of per capita exposure days for that year. Population was assumed to grow at a compound rate of 2% per year until the year 2010,^(a) thereby increasing the number of person days of odor nuisance experienced per year over time.

Dollar Value of the Odor Nuisance

Theoretically, an individual's valuation of an odor nuisance would be influenced not only by its intensity, duration and frequency, but also by the socioeconomic characteristics of the affected individual. Loehman et al. (1979) used a bidding game technique to calculate the willingness of individuals to pay to avoid an odor nuisance from sulfur dioxide (SO_2), which may be generated during combustion (e.g., coal-fired power plants) or as an intermediate compound in the oxidation of H_2S . Although the odor of SO_2 is not as objectionable as that of H_2S , we do not have estimates of individuals' willingness to pay to avoid an H_2S odor nuisance. For that reason we used the substitution approach, assuming that the unknown value of eliminating an odor nuisance caused by H_2S will be at least equal to the estimated value of eliminating a similar odor nuisance caused by SO_2 .

This is expected to provide an underestimate of the true willingness to pay to avoid the H_2S odor nuisance, which is a more foul odor, and should, therefore, command a higher damage value.

Loehman's "willingness to pay" measure (the "bid") was derived for Tampa, Florida residents. Analysis shows that changes in socioeconomic variables produce a statistically significant effect on the size of the bid; the median bid increases with income and with the percentage of the sample that is female. Assuming that the socioeconomic characteristics of the residents in

(a) This is slightly less than the county's recent growth rate of 2.5 percent (VTN 1979).

Tampa and in the Imperial Valley are not different enough to produce significantly different measures of the dollar value of the odor nuisance will permit the computation of a dollar value for elimination of the odor nuisance.

Two bid functions were used to calculate the expected value of eliminating the odor nuisance. These are referred to as the "low" and "high" bid functions in Table 7.2 below. The low bid function was developed on the assumption that the dollar value for any odor nuisance is likely to be greater than the dollar value of an odor nuisance that is less offensive. Because the odor of hydrogen sulfide is more offensive than the odor of sulfur dioxide, it was assumed that we could obtain a minimum estimate of willingness to pay (WTP) to avoid the H₂S odor nuisance by using the bid function (based on Loehman's work) for elimination of the SO₂ odor nuisance.

TABLE 7.2. Net Present Value of WTP Bids for H₂S Damage Prevention in the Imperial Valley (1980 Dollars)

	Bid Function Used	
	Low ^(a)	High ^(b)
365 days/yr of violation 2%/yr population growth until 2010 ^(c)	--	\$37,100,000
Minimum days/yr of violation 0% population growth	\$5,900,000	--
<hr/> (a) Bid = (1.87)(Exposure days/yr) ^{0.477} (b) Bid = (2.52)(Exposure days/yr) ^{0.505} (c) 1980 starting population of 39,852. Year 2010 population is maintained to the year 2040, the end of the planning horizon.		

The high bid function was simply set up to yield WTP bids for any given quantity of exposures to an odor nuisance that were approximately 50% greater than the bids provided by the use of the low bid function. We derived logarithmic bid functions of the form $Bid = AX^B$ from published bid estimates in the Loehman article for the minimum and maximum expected bids, where "Bid"

equals the willingness to pay to avoid "X" number of exposures, and A and B are constants determined by the socioeconomic characteristics of the individual.

These bid functions were combined with the expected number of person days of exposures each year for a 60-year time frame for each of the six sites to calculate the minimum and maximum expected aggregate bids.^(a) To calculate a minimum bid, we used the low bid function coupled with a zero population growth rate and exposure rates that represented the number of days per year that the ambient concentration of H_2S exceeded the state standard of 0.03 ppmv, a concentration level that is ten times the odor detection level.

The maximum WTP estimate was derived by assuming that the entire population was exposed to an odor nuisance 365 days per year over the entire 60-year period, that the population grew at a compound rate of 2% per year until 2010, and that the high bid function accurately reflected the WTP functions of the individuals located in the region.

Each year's bid was discounted at a 5% compound real rate of time preference, then summed for each site to derive the net present value of the willingness of individuals to pay to prevent the total odor damages over time. These are presented in Table 7.2.

Hydrogen sulfide emissions may be controlled with numerous processes. For example, simply passing the noncondensable gases (removed from the condenser) through the cooling towers will cause natural oxidation of anywhere from 10 to 40 percent of the H_2S loading that is present.

The abatement process (described in Appendix D) that was used to derive H_2S control cost estimates is the EIC upstream abatement system (Wells et al. 1980, PNL-2802). The system treats the raw flashed steam with chemicals that remove entrained hydrogen sulfide with a scrubbing column. This process

(a) The 60-year time frame was used because the last plant built in 2010 in the development scenario has at least a 30-year life. The benefits and costs of abatement were therefore estimated to the year 2040 to accommodate the projected economic life of the last plants built.

maintains the heat content and pressure (i.e., quality) of the turbine inlet steam and provides clean steam to the turbines. Reviews of the literature indicate that the process is among the most efficient and most cost effective systems available for H₂S control. Control costs were estimated on the basis of the steam flows from a 50-MWe plant operating at either Heber or Niland. The net present values of abatement costs were found to be approximately \$13,000,000 in 1980 dollars for each site, or approximately 2.4 mills per kWh. If the units were to be installed on 100-MWe generating stations, the net present value of abatement costs would be approximately 42% higher or \$18,450,000. The average net present value of abatement costs for a single plant is estimated to range between \$261,400 and \$365,800 per MWe.

Odor Nuisance Benefit Cost Comparison

Table 7.3 summarizes the net benefits and costs that would be realized if 97% control of H₂S emissions were required by regulations governing airborne emissions from hydrothermal facilities operating in the Imperial Valley. The estimated benefits accruing from the elimination of a potential odor nuisance over the 30-year period in the 3000 MWe development scenario for the Imperial

TABLE 7.3. Benefits and Costs of Odor Nuisance Abatement - Imperial Valley, California^(a)

	Low		High	
	Net Present Value	Dollars/MWe	Net Present Value	Dollars/MWe
Dollar Value of Odor Nuisance	\$ 5,900,000	\$ 2,000	\$ 37,100,000	\$ 12,400
Odor Prevention Costs	323,800,000	107,900 ^(a)	465,300,000	152,100 ^(a)
Net Benefits of Prevention	(\$317,900,000)	(\$105,900)	(\$428,200,000)	(\$139,700)

(a) Prevention cost = net present value divided by 3000 MWe.

Valley range from about \$6 million to approximately \$37 million in net present value, or \$2,000 to \$12,400 per MWe of generating capacity. Control of H_2S is very expensive relative to these benefits, with average abatement costs ranging from \$107,900 to \$152,100 in net present value for each MWe of added generating capacity. Clearly, requiring the virtual elimination of H_2S emissions would cost society a net of approximately \$100,000 to \$140,000 MWe of generating capacity, or more than 300 million dollars in net present value for the 3000 MWe development scenario.

The values reported as the minimum and maximum costs and benefits of odor nuisance elimination are believed to bound the ranges of actual benefits and costs. For the minimum benefit estimate the value is expected to be a minimum for several reasons:

- 1) The county's population understates the number of persons likely to be affected, since rural residents and visitors are excluded.
- 2) The dollar value per exposure was estimated for SO_2 not H_2S , and H_2S is a much more offensive odor.
- 3) The actual number of odor nuisance days may greatly exceed the number of days the ambient H_2S concentration violates the California ambient standard.

Likewise, the maximum benefit estimate is expected to provide an upper bound on the willingness of residents to pay to avoid odor nuisances for several reasons:

- 1) Actual emissions of H_2S could be as much as 10 to 40 percent less than the quantity forecasted if the noncondensable gases in the hydrothermal fluid are sent to the cooling tower for natural oxidation rather than being released directly to the atmosphere (through the gas ejectors on the condensers).
- 2) Sensitivity analyses indicate that the results are not sensitive to the selection of any population growth rate of less than 10 percent

(compounded annually) or to any positive discount rate. We found that the up front capital costs of the abatement systems exceeded the undiscounted benefits of eliminating of the odor nuisance in all cases.

WATER RELATED IMPACTS

There are two alternatives for liquid waste disposal at hydrothermal sites: injection and surface release. Both options may generate significant nonmarket costs. In the Imperial Valley, the nonmarket costs of hydrothermal energy production without injection include the potential:

- subsidence or uplift benefits or damages to surface facilities and land
- inundation or reclamation of land due to changes in the level of the Salton Sea
- fisheries benefits or costs due to salinity changes in the Salton Sea.

The subsections that follow describe:

- the resource development scenarios that are common to the generation of these damages.
- the expected level of subsidence, inundation and fisheries damages.
- the dollar values of these damages.
- the control costs that are common to all three damages.

Because injection of the liquid wastes is the way required by regulation to prevent these environmental damages at the sites selected, the costs of liquid waste disposal by injection are developed in one section below, following the development of estimates of the dollar damages for subsidence, fisheries and inundation.

Resource Development Scenarios Common to All Damages

The scenarios examined for water-related impacts are for a 50-MWe plant operating at Heber or Niland and a 500-MWe development at Heber or Niland for

regulated and unregulated cases. The unregulated producer at Heber must inject 80% of the brine extracted in order to assure recharge of the reservoir. The remaining 20% is either lost to evaporation or is discharged into agricultural drains (and hence the New River and Salton Sea). The Niland producer, however, would choose not to inject any brine, since the reservoir is naturally recharged by the Salton Sea. The brine not lost to evaporation will be discharged into the drain network (the Alamo River, the New River, and the Salton Sea). Imperial County requires injection of a fluid volume equal to 100% of the amount withdrawn by resource exploitation, unless a lower injection rate has been approved by the California Division of Oil and Gas (CDOG) (VTN 1979). CDOG has approved 80 percent injection for Niland while withholding formal approval of 80 percent for Heber until more experience with the reservoir has been obtained. The regulated case assumes the producer is required to inject 100% of all fluids withdrawn from the reservoir. The time that plants come on line will be important to our analysis. We will assume that the 50-MWe plants are beginning operation according to the schedule presented in section 6.0 of this report.

Subsidence

In this section the estimated dollar values of expected land subsidence are presented. The details of these cost estimates are developed in Appendix F from data presented in the literature for the Heber and Niland sites.

Quantification of the Environment at Risk

The amount of damage arising from subsidence will depend upon the amount of land affected and the amount that it subsides, which was estimated from a map of the area potentially subject to subsidence for a 500 MWe development at Heber with 85% injection (VTN 1979). For the 500 MWe resource development scenarios at Heber and Niland we assumed that the maximum amount of land subject to subsidence is proportional to the net fluid withdrawal rate as is determined by the level of development at the site, (the number of 50-MWe plants). For example, a 500 MWe development's area of potential subsidence in the unregulated case at Heber (with 80% injection) would be 2880 acres. Table 7.4 shows the estimate of acreage at risk for each case.

TABLE 7.4. Value of the Environment at Risk Due to Subsidence
(January 1980 dollars)

<u>Scenario</u>	<u>Maximum Dollar Values</u>	<u>Maximum Acreage Impacted</u>
50 MWe Heber	\$ 1,567,000 ^(a)	288
50 MWe Niland	1,105,000 ^(b)	406
500 MWe Heber	12,776,000 ^(a)	2880
500 MWe Niland	9,790,000 ^(b)	4060

(a) Assumes \$6000/acre.

(b) Assumes \$3000/acre.

Source: Table F.3 values have been rounded.

We do not have any estimates of the probability that alternative levels of subsidence will occur. If the analysis shows that even when considering the entire value of the land potentially subject to subsidence, we find that damage prevention costs still exceed the value of the environment at risk, then it is clear also that 100% subsidence prevention will not be a desirable policy to enforce.

Dollar Values of the Environment at Risk

The original approach was to use the full value of land as determined by the county assessor. Due to California Proposition 13, however, the full values were rolled back to 1975 prices, and then inflated by 2% to 1980, considerably less than market value. If a piece of land is sold, it is then reassessed at its new market value. Analysis of the tax records showed a high variance in land prices. Therefore, it was only possible to get a rough idea of land values from county assessor records. However, a local real estate firm (Century 21 in El Centro) in the Imperial Valley confirmed that the market value of agricultural land was approximately \$6,000 an acre at Heber while at Niland, where there are salinity problems with the irrigation water and a lack of adequate drainage, the agricultural land values were closer to \$3,000 per acre. Since the current market price of land reflects the net present value of all

services (e.g., the net value of all crops expected to be grown on it in future periods), the market value of the land will be used as the appropriate measure of property value.^(a)

Table 7.4 summarizes the maximum damages occurring from subsidence. These figures overstate the expected damages from subsidence, representing only the value of the environment at risk.

The maximum damages at Heber from a 50-MWe plant would be \$1,567,000 and for Niland \$1,105,000, if all the acreages potentially subject to subsidence at the two sites were made unproductive by subsidence damages. This is probably an overestimate of the expected level of damage at the two sites.

For the 500 MWe scenario the maximum net present value of damages at Heber would be \$12,776,000; assuming:

- subsidence occurs instantaneously with the initial operation of the plant,
- a 5% rate of discount,
- plants are added according to the scenario in Table 6.2.

More fluid is withdrawn because of zero injection at Niland; therefore, more land is affected. However, Heber is an area of highly valued land, while the market value of land at Niland is only \$3,000 an acre. The maximum damages at Niland under the 500 MWe scenario would therefore be considerably lower than at Heber and are estimated to be approximately \$9,790,000. The cost of preventing subsidence is presented in the section following inundation and fisheries damages below.

The Salton Sea

There are two liquid waste disposal options at each site in the Imperial Valley. At Heber, the spent liquid could be discharged to the New River or injected. At Niland, the options are discharging the liquids to the Salton Sea or injection.

(a) This omits any premium which may be paid for developed property which is more valuable than agricultural land. Almost all land affected is in agriculture.

The primary impacts will be changes in the rates at which the elevation, surface area and salinity of the Salton Sea are increasing. Hydrothermal development could alter these projections in different ways. For example, the discharge of large volumes of highly saline water into the sea could significantly increase the rates of change in these three parameters. A different result would occur if sea water were withdrawn for injection makeup. This would reduce the rate of increase in the three parameters. An increase in the rate at which the sea elevation is rising will create nonmarket costs either through:

- inundating surrounding lands,
- dike construction and maintenance, or
- other actions taken to prevent inundation.

In this section the estimated dollar values of expected environmental damages related to liquid waste disposal are calculated. Since these damages (fisheries and inundation) are created by two types of changes in the Salton Sea (level and salinity), expected changes in the Salton Sea are presented first, followed by discussions of the value of the sport fishery and of the land that may be inundated. These costs are developed from data presented in the literature for the Heber and Niland sites. Analyses were performed for the Heber and Niland sites for both the 50-MWe and 500-MWe scenarios. The Heber site is located near the New River approximately 30 miles south of the Salton Sea. Niland is located near the southeast portion of the Salton Sea.

Projected Level and Salinity Changes Without Geothermal Development

Projections for salinity and elevation levels assuming no hydrothermal development are given in Table 7.5. From 1980 to 2000 sea elevation is expected to rise by over four feet, resulting in a surface area increase (i.e., causing inundation) of over 13,000 acres. Salinity is projected to rise from approximately 38,000 ppm to 43,000 ppm, a 5,000 ppm increase, while surface area is projected to rise to 258,575 acres, with no hydrothermal development.

Projected Level and Salinity Changes with Geothermal Development

Table 7.6 summarizes the discharges and withdrawals that we project will occur with and without regulation. Between 10 and 20 percent of the well flow

TABLE 7.5. Salton Sea Elevation, Surface Area, and Salinity with No Hydrothermal Development^(a)

<u>Year</u>	<u>Elevation in Feet Below Mean Sea Level</u>	<u>Surface Area In Acres</u>	<u>Salinity In ppm</u>
1980	226.84	245,112	38,362
1990	223.88	254,130	40,033
2000	222.46	258,575	43,274

(a) From VTN 1979, Table IV-6, p. IV-37.

TABLE 7.6. Liquid Discharges and Withdrawals at Heber and Niland Sites

<u>Site</u>	<u>Regulated</u>	<u>Unregulated</u>
Heber	66 AF/yr/MWe 4657 ppm withdrawn from New River	60 AF/yr/MWe 20,000 ppm discharged to New River
Niland	34 AF/yr/MWe 38,492 ppm withdrawn from Salton Sea	144 AF/yr/MWe 250,000 ppm discharged to Salton Sea

rate is lost to evaporation in the conversion process, and with regulation this percentage is required for injection makeup. The amount of makeup at Heber is greater than that required at Niland by a factor of two. This is because Heber is a lower temperature resource (150°C-175°C) than Niland (320°C) and, therefore, requires about 3.55 times more volume of liquid per MWe.^(a) This, along with the different amounts that the developers at each site would voluntarily inject, explains the difference between the two sites without regulation.

(a) These figures are derived from the GEOCOST model runs used to derive abatement cost. See Appendix D.

The impact of regulation on Salton Sea surface elevation, area and salinity was calculated using the inputs from Table 7.6. The procedures and data base used are discussed in Appendix E. Each of these parameters were estimated for regulated and unregulated cases. The parameter estimates for the unregulated cases were subtracted from those representing regulated cases. The results are shown in Table 7.7. Although estimates were made by year from 1982 to 2020^(a) only those for the years 1990 and 2000 are shown for Heber and Niland and for 50-MWe and 500-MWe developments.

TABLE 7.7. Salton Sea Parameter Differences for Regulated and Unregulated Spent Liquid Disposal at Heber and Niland Sites

Capacity	Year	Surface Elevation Difference (feet)		Surface Area Difference (acres)		Salinity Difference (ppm)	
		Heber	Niland	Heber	Niland	Heber	Niland
50 MWe	1990	-0.11	-0.15	-330	-459	+55	-2030
	2000	-0.12	-0.17	-370	-522	+7	-4447
500 MWe	1990	-0.76	-0.97	-2349	-3310	+498	-11666
	2000	-1.17	-1.65	-3598	-5071	+216	-31171

Surface Area

In all cases (Table 7.7) regulation causes a decrease in the levels of surface elevation and area compared to the unregulated case. These differences are slightly larger at Niland than Heber because the difference between the amount of water withdrawn with regulation and the amount discharged without regulation is greatest at Niland. Referring to Table 7.6, we show that for Heber, 66 AF/yr per MWe are discharged under the regulated scenario, while for Niland the quantity is closer to 34 AF/yr per MWe. In the unregulated case, just the opposite situation prevails. Heber would discharge only 60 AF/yr per MWe while Niland would discharge approximately 144 AF/yr per MWe. Regulation

(a) Again, the time period was chosen so that the last plant built could have its full 30-year life.

of spent brine discharges at Heber and Niland would result in a lower level and smaller surface area of the Salton Sea than with no regulation.

Salinity

Regulation at Heber causes an increase in Salton Sea salinity (Table 7.7). This is because the water being withdrawn from the New River (regulation) would be of greater volume and lower TDS content than liquids that would be discharged to the New River (no regulation). Therefore, with regulation, less water with a higher TDS content would flow from the New River to the Salton Sea than with no regulation.

Niland presents an entirely different situation. Water withdrawn from the Salton Sea (regulation) would be four times less in volume and six times less saline than liquids that would be discharged to the Salton Sea (no regulation). Therefore, regulation would cause a lower level of salinity in the sea than would result with no regulation.

The impact of Heber and Niland development on the date when the salinity in the sea reaches 40,000 ppm is shown in Table 7.8. At Heber, with a 500-MWe development, regulation causes the sea to reach the critical 40,000 ppm level two years earlier than for the unregulated case. At Niland, regulation would delay the time required by the sea to reach the critical 40,000 ppm level by five years for a 50-MWe development and by six years for a 500-MWe development.

TABLE 7.8. Impact of Regulation on the Year Salton Sea Reaches 40,000 ppm for Heber and Niland Developments

<u>Site</u>	<u>No Development</u>	<u>50 MWe</u>		<u>500 MWe</u>	
		<u>Regulation</u>	<u>No Regulation</u>	<u>Regulation</u>	<u>No Regulation</u>
Heber	1990	1990	1990	1989	1991
Niland	1990	1991	1986	1991	1985

Inundation Dollar Damages

We have shown that regulation (required injection) will cause a decrease in the levels of surface elevation and area compared to the unregulated case.

Therefore, regulation will create a benefit, estimated either through the savings in diking costs or the value of land not inundated. Savings in diking costs represent a minimum value of damages prevented if dikes are constructed only when the value of damages prevented are greater than the costs of constructing and maintaining dikes. (This may not be the case.) In any event, we do not have sufficient information to estimate diking costs for the site. Therefore the present value of a reduced surface area was estimated as the value of land not inundated.^(a) These values are reported in Table 7.9, using a 5% discount rate.

TABLE 7.9. The Economic Value of Avoided Land Inundation From Regulating Spent Brine Discharges at Heber and Niland

<u>Site</u>	<u>Development Level</u>	<u>Present Value of Land Not Inundated^(a) When 1980 Market Value is</u>	
		<u>\$3,000/acre</u>	<u>\$6,000/acre</u>
Heber	50 MWe	\$ 861,000	\$ 1,721,000
	500 MWe	6,887,000	13,774,000
Niland	50 MWe	1,442,000	2,885,000
	500 MWe	9,707,000	19,415,000

(a) Inundation figures based on Table 7.7 and discussion on Page 51.

For the Heber site with 500 MWe of development, the benefits are estimated to be approximately \$6,887,000 to \$13,774,000, depending on the price of land. For Niland the benefits (inundation prevented) are estimated to be \$9,707,000 to \$19,415,000 for the 500 MWe level of development.

Fisheries Dollar Damages

Fisheries damages are assumed to occur when the salinity of the Salton Sea exceeds 40,000 ppm. We have shown that at Heber the time estimated for sea

(a) We ignore premiums that may be paid for developed shoreline property with structures. All of these areas are protected with dikes.

salinity to reach the critical salinity level of 40,000 ppm is reduced by regulation (cost), but at Niland it is increased (benefit). The next step is to determine the dollar values of these expected environmental changes.

To estimate the value of fishery damages we must have information on, or make assumptions about

- the effect of salinity on the fish population,
- the relationship between fish population and angler days, and
- the dollar value of an angler day.

There appears to be no available estimates of size of the Salton Sea fish population or how quickly angler success will decrease when the salinity reaches 40,000 ppm. Therefore, we have assumed a worst case; angler success falls to zero when the salinity reaches 40,000 ppm.

We can derive the value of the fishery to anglers from estimates of their willingness to pay (WTP) and willingness to accept (WTA) compensation for elimination of one day of fishing. These figures are collected by direct inquiry (e.g., bidding games) and reflect the value of the fishery to the individual when the property right to the fishery belongs to the individual (WTA) or to another entity (WTP). The WTP figures typically are lower than the WTA figures, but neither necessarily tells us the aggregate value of the fishery. This depends upon what substitute opportunities are specified in the direct inquiry, the demographics of the sample, strategic behavior, and a series of other factors (see Appendix B). We can determine only a range of value that fishermen place on the Salton Sea fishery by multiplying WTP and WTA by the number of angler days observed for the site during a year (the number of man days spent fishing at the Salton Sea).

Estimates of angler days of recreational activity at the Salton Sea have been made. These indicate that for the period from June, 1975 to June, 1976 74,780 angler days were recorded by researchers (Lawrence Livermore Laboratories 1980). These figures are now 5 years old, and no note was made as to whether the fishing activity was increasing, decreasing, or remaining constant. We will assume, in the absence of better information, that angler days remain constant across time.

Environmental Research (1974) estimated WTP and WTA figures for warm water fisheries to be \$38.14 and \$49.07 respectively, in 1973 dollars. When inflated

by the Consumer Price Index to 1980 values, WTP and WTA are \$73.40 and \$94.46 respectively. Unfortunately, this study did not allow for substitute fishing sites, so the values quoted above are probably overstated. However, our primary objective is to find the maximum damages, so these figures will be used. Our minimum estimate of the value of the fishery is given by multiplying WTP by the number of angler days for each year of reduced Salton Sea life, then discounting those figures to 1980 values at a 5% (real) discount rate. The maximum value is given by substituting WTA for WTP in the above procedure.

Table 7.10 gives the range of benefits, discounted to 1980 dollars, arising from liquid waste disposal regulation for the Salton Sea fishery. The Salton Sea would reach the 40,000 ppm critical value in 1990 if no development were to occur. Regulation in the 50 MWe scenario at Heber has no effect on this timing. Regulation in the 500 MWe scenario at Heber causes the salinity to reach the critical value in 1989, but the unregulated scenario extends the life to 1991. This cost of regulation is about \$7 million to \$9 million. Regulation at Niland will extend the life of the fishery. The regulatory benefits at Niland range from \$23 million to \$29.5 million.

TABLE 7.10. Fishing Benefits From Regulation

<u>Site</u>	<u>Development Level</u>	<u>Years Salton Sea Life Extended</u>	<u>Benefits As Measured By</u>	
			<u>WTP</u>	<u>WTA</u>
Heber	50 MWe	0	0	0
	500 MWe	(2)	(\$ 6,908,000)	(\$ 8,860,000)
Niland	50 MWe	5	18,619,000	23,962,000
	500 MWe	6	22,926,000	29,497,000

Control Costs for Subsidence, Inundation and Fisheries Damages

The private costs of injection disposal facing developers and utilities at hydrothermal sites include:

- life cycle costs of the injection wells and injection system
- life cycle costs of obtaining makeup water to replace evaporative losses and maintain reservoir productivity, and

- induced seismicity that creates damages to surface facilities needed for power production.

The incremental costs of damage prevention borne by the resource developer will be the increase in total disposal cost attributable to the additional 20% of injection capability required at Heber. At Niland, the incremental cost is the entire cost of adding 100% injection capacity.

Table 7.11 presents the net present value of the cost of achieving 100% injection disposal at Heber and Niland. Brine treatment and sludge disposal costs comprise most of the total disposal cost. Supporting calculations of these estimates of the costs of brine treatment are described in detail in Appendix D.

TABLE 7.11. Net Present Value of Damage Prevention Costs Through Injection

<u>Scenario</u>	<u>Present Value of Costs</u>
50 MWe Heber	\$ 2,670,000
50 MWe Niland	896,400,000
500 MWe Heber	20,840,000
500 MWe Niland	6,962,720,000

Summary of Water Related Benefits and Costs

The benefits of regulation (requiring injection of 100% of all brine extracted) are the subsidence damages avoided, the fisheries damages averted, and the value of avoided inundation of land. The (control) costs are the present value of the injection system expenses and sludge disposal fees. These costs and benefits are presented in Table 7.12. We have identified a range of possible net benefits. For subsidence, the minimum damage that could occur from failure to inject spent hydrothermal brines is zero, therefore, the minimum benefit column reflects this. Similarly, the minimum benefits reported for preventing land inundation are based on land valued at its lower market price, i.e., \$3,000 an acre. The minimum damages to the fishery are given by the WTP

TABLE 7.12. Benefits and Costs from Requiring Injection as a Means of Regulation

Site	Level of Development	Benefit Arising From	Minimum ^(a) Quantifiable Benefit	Maximum ^(a) Quantifiable Benefit	Control Cost ^(b)	Net Minimum Quantifiable Benefit	Net Maximum Quantifiable Benefit	Parameters ^(c) Varied
Heber	50 MWe	Averted Subsidence	0	\$ 1,567,000				A
		Averted Inundation of Land	\$ 861,000	\$ 1,721,000				B
		Averted Fisheries Damage	0	0				C
		Total	\$ 861,000	\$ 3,288,000	\$ 2,670,000	(\$ 1,809,000)	\$ 618,000	
	500 MWe	Averted Subsidence	0	\$12,776,000				A
		Averted Inundation of Land	\$ 6,887,000	\$13,774,000				B
		Averted Fisheries Damage	(\$8,860,000)	(\$ 6,908,000)				C
		Total	(\$1,973,000)	\$19,642,000	\$ 20,840,000	(\$ 22,813,000)	(\$ 1,198,000)	
	50 MWe	Averted Subsidence	0	\$ 1,105,000				A
		Averted Inundation of Land	\$ 1,442,000	\$ 2,885,000				B
		Averted Fisheries Damage	\$18,619,000	\$23,962,000				C
		Total	\$20,061,000	\$27,952,000	\$ 896,400,000	(\$ 876,339,000)	(\$ 868,448,000)	
Niland	500 MWe	Averted Subsidence	0	\$ 9,790,000				A
		Averted Inundation of Land	\$ 9,707,000	\$19,415,000				B
		Averted Fisheries Damage	\$22,926,000	\$29,497,000				C
		Total	\$32,633,000	\$58,702,000	\$6,962,720,000	(\$6,930,087,000)	(\$6,904,018,000)	

(a) Benefit estimates are biased upward. Subsidence is assumed to occur instantly each acre affected and drive land values to zero. Inundation costs may be larger than diking costs. Fishing value estimates assume destruction of all fishing opportunities rather than substitution of other fishing for that of the Salton Sea.

(b) Cost estimates are biased downward. Water treatment costs may be underestimated, particularly solid waste problems created by sludge disposal.

(c) Parameters varied between the minimum and maximum case.

A = land affected

B = price of land

C = price of fishing days

measure. The maximum benefits are given by using the maximum subsidence value, valuing potentially inundated land at \$6,000 per acre, and using the WTA measure for valuation of the fishery.

The net benefits are simply the difference between quantifiable benefits and control costs. The control costs greatly outweigh the damages avoided. This, in part, is due to the scenarios we have examined. The producer at Niland would not use injection disposal in the unregulated case, thus the costs of control at the 100% level of injection are equal to the entire costs of the injection system. At Heber we assumed the producer chooses to inject 80% of the spent brine to maintain the productivity of the resource, so the regulatory cost of 100% injection is only the additional 20% capacity he needs to add. In most cases, however, the costs of regulation far exceed the benefits of regulation. Generally speaking, the benefits do not justify 100 percent injection as a standard for brine disposal.

A possible interpretation of the results presented here is that the costs of controlling subsidence, preventing the inundation of land, and avoiding fisheries damage are so great that it would be more efficient to compensate individuals for their losses if such damages occurred, rather than to require costly control measures. This analysis has examined specialized scenarios, but due to information costs and gaps, we have not been able to estimate the efficient level of emissions. The analysis requires knowledge of benefit and cost functions rather than point estimates of the benefits and costs.

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APPENDIX A

HYDROTHERMAL RESOURCE DEVELOPMENT

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HYDROTHERMAL RESOURCE DEVELOPMENT

Hydrothermal energy is converted into electrical energy by extracting the heat present in hot water reservoirs or superheated rock deep in the earth and using this heat energy to expand gases through a turbine to drive an electrical generator. Environmental effects of this process result from the interaction of the characteristics of the resource itself, the energy conversion process employed and the characteristics of the local environment.

This section reviews hydrothermal energy systems, their development and utilization, the applicable energy conversion processes, and the resulting environmental changes that give rise to nonmarket costs. Nonmarket costs result in environmental regulations that may unnecessarily impede commercialization.

Resource Characteristics

Resource characteristics significantly influence the private cost of power from hydrothermal resources. These characteristics include physical features such as the surface and subsurface temperatures of the hydrothermal fluid, the total dissolved solids content of the brine, the type of overlaying rock and the estimated electrical energy potential.

Of the 56 high temperature (150⁰-plus) hydrothermal KGRAs identified in Geological Survey Circular 790 (Muffler 1979) 53 are liquid dominated. The potential of one vapor dominated system (The Geysers, California) is about half developed at 800 MW, and the other two, Mt. Lassen and Yellowstone, are in national parks, where development is prohibited. Since a large majority of the economically exploitable hydrothermal resources in the United States are liquid dominated KGRAs, this report is concerned with estimating the nonmarket costs of developing liquid dominated hydrothermal resources.

Table A.1 contains a summary of these data on resource attributes for 36 high temperature hydrothermal known geothermal resource areas (KGRAs) in the western United States, ranked by electrical potential by state.

TABLE A.1. Resource Characteristics of Selected Known Hydrothermal Resource Areas in the United States

<u>State and KGRA</u>	<u>Electrical Potential (MWe for 30 yrs)</u>	<u>Subsurface Temp ($^{\circ}\text{C}$)</u>	<u>Surface Temp ($^{\circ}\text{C}$)</u>	<u>Fluid TDS (ppm)</u>	<u>Overlaying Rock</u>
<u>ALASKA</u>					
Geyser Bight	136	208 ± 20	100	1,650	hard
<u>CALIFORNIA</u>					
Salton Sea(a)	3,400	323 ± 8	101	250,000	soft
Long Valley	2,100	227 ± 10	94	2,170	medium/hard
Westmorland ^(a)	1,710	217 ± 7	--	50,000- 350,000	soft
Surprise Valley	1,490	152 ± 12	97	1,500	medium/hard
Clear Lake	900	190 ± 9	83	low: a few thousand ppm	medium
Desert Peak	750	221 ± 5	--	7,500	hard volcanic
Coso	650	220 ± 11	95	6,410	medium/hard
Heber ^(a)	650	175 ± 5	--	14,000	soft
Brawley ^(a)	640	253 ± 10	--	53,750	soft
Stillwater	450	159 ± 8	96	4,865	hard
East Mesa ^(a)	360	182 ± 7	--	30,000	soft
Brady Hot Springs	157	155 ± 6	98	2,450	hard
Soda Lake	146	157 ± 5	90	3,660	hard
Beowave Hot Springs	127	229 ± 8	226	1,256	hard
Morgan Springs	116	217 ± 15	95	5,075	medium/hard
Kyle Hot Springs	97	159 ± 2	77	1,825	hard
Randsburg	84	172 ± 29	115	--	medium/hard
Leach Hot Springs	77	162 ± 3	96	790	hard
Sulfur Bank Mine	75	194 ± 6	75	5,510	medium
Sulfur Hot Springs	74	178 ± 3	93	781	hard
Humboldt	47	217 ± 16	--	--	hard
<u>HAWAII</u>					
Puna	251	275 ± 11	--	--	hard

TABLE A.1. (contd)

<u>State and KGRA</u>	<u>Electrical Potential (MWe for 30 yrs)</u>	<u>Subsurface Temp ($^{\circ}$C)</u>	<u>Surface Temp ($^{\circ}$C)</u>	<u>Fluid TDS (ppm)</u>	<u>Overlying Rock</u>
<u>IDAHO</u>					
Crane Creek	340	171 $\pm$ 10	92	960	medium/hard
<u>NEVADA</u>					
Steamboat Hot Springs	350	200 $\pm$ 5	96	2,500	medium/hard
Pinto Hot Springs	90	173 $\pm$ 8	93	1,270	hard
Baltazor Hot Springs	46	158 $\pm$ 3	80	880	hard
<u>NEW MEXICO</u>					
Valles Caldera	2,700	273 $\pm$ 8	87	7,500	hard
<u>OREGON</u>					
Vale Hot Springs	870	157 $\pm$ 2	73	1,270	soft
Newberry Caldera	740	230 $\pm$ 20	--	--	hard
Mickey Hot Springs	160	250 $\pm$ 10	73	1,913	hard
Hot Lake Area	91	191 $\pm$ 14	96	1,240	hard
Crumps Hot Springs	61	167 $\pm$ 9	78	1,245	hard
Alvord Hot Springs	49	181 $\pm$ 18	76	3,314	hard
<u>UTAH</u>					
Roosevelt Hot Springs	970	265 $\pm$ 8	88	7,000	medium/hard
Covefort- Sulphurdale	330	167 $\pm$ 6	--	(b)	medium/hard

(a) Denotes an Imperial Valley site.

(b) Probably the same as Roosevelt, believed to be the same resource.

Source: Muffler 1979.

The KGRAs listed in Table A.1 have relatively high subsurface temperatures and large estimated electrical energy potential, two factors that are believed to be important determinants of commercial potential. Sites of commercial interest to developers have subsurface temperatures ranging from around 150°C to 323°C (Muffler 1979).

The estimated electrical energy potential of a KGRA is calculated from the temperature and volume of each system and is one of the major incentives for commercial development. Utilities follow general guidelines as to the minimum potential that would be necessary to justify an electrical generating plant at a specific site. As an example, representatives of the Electrical Power Research Institute have estimated that proven reserves of 200 MWe anywhere will be a commercial resource (TRW 1975). Lack of electrical potential is considered to be a major problem for systems with a potential of less than 200 MWe for 30 years, although they may be good candidates for space heating development. Although electrical potential is correlated with high temperature, it is not entirely dependent upon it. For instance, Surprise Valley, the lowest temperature resource of the systems shown in Table A.1, has the fifth highest estimated electrical potential.^(a)

Energy Conversion Processes

Several methods exist for extracting thermal energy from liquid dominated hydrothermal reservoirs and converting it to electrical energy. Two of the systems include the flashed steam and binary cycles. Simplified process diagrams for these appear in Figure A.1.

Flashed Steam Cycle. This energy recovery technique takes advantage of a process that occurs naturally in some hot water systems. As hot, pressurized hydrothermal fluid is withdrawn from the reservoir, a portion (16% at Heber, 30% at Niland) flashes to steam under controlled conditions. The steam is captured, passed through separators, and is then used to drive turbines

(a) Reservoir size, permeability, geochemistry and matrix structure all influence recoverable reserves. Development costs are influenced by these factors and by the hardness of overlaying rock (which affects drilling costs), topography, land ownership patterns, proximity to roads and electrical transmission lines.

A. The Flashed Steam Process (Wellhead Separation)

B. The Binary Cycle Process

FIGURE A.1. Simplified Process Flow Diagrams of Major Hydrothermal Energy Extraction Options

for electricity production. Remaining water may be disposed of by injection, surface drainage, or evaporation. Noncondensable gases^(a) are vented to the air. Net energy efficiency is in the range of 3% to 7%, i.e., only 3% to 7% of the thermal energy is converted to electrical energy. The remainder (93% to 97%) is either dissipated to the surface environment or injected.

Binary Cycle. The binary cycle utilizes a heat exchange mechanism that maintains the hydrothermal fluids in a closed pressurized loop. Two options have been introduced: 1) down hole heat exchange and 2) conventional surface heat exchange. With the down hole mechanism, hydrothermal fluids are not brought to the surface of the ground. Instead, the hydrothermal heat is exchanged "down the drill hole" with a second (binary) fluid.

In the conventional binary cycle, hot water withdrawn under pressure from the reservoir is used at the surface to heat a second fluid (e.g., isobutane or Freon) having a lower boiling point than water. The binary fluid vapor is then used to drive the turbine. The spent vapor is condensed and recirculated through the heat exchanger in a closed system where it may be heated and used again. The binary system appears to have some advantages over the flashed steam cycle for developing reservoirs lower-temperature resources.

(a) Gases that do not condense at atmospheric pressure. They include carbon dioxide (CO_2), ammonia (NH_3), hydrogen sulfide (H_2S), nitrous oxides (NO_x), methane (CH_4), sulfur dioxide (SO_2), and others.

APPENDIX B

NONMARKET COST ESTIMATION TECHNIQUES

APPENDIX B

NONMARKET COST ESTIMATION TECHNIQUES

This presents a review in outline form of the major nonmarket cost estimation procedures available to the analyst. The reader may wish to go to the literature cited for a detailed and exacting treatment of each approach.

SUBSTITUTION APPROACH

The substitution approach involves identifying as close a substitute as possible to the environmental good in question and attributing the observed value of the substitute to the value of the environmental good. In order to effectively use this technique, the characteristics of each good that consumers demand need to be understood and measured. For those situations in which transactions data are available for the substitute, the accuracy of the method and its validity in application improve as the goods become more nearly perfect substitutes. For example, an estimate of the value of a trout population that may be killed by hydrothermal resource development in a watershed may be derived from:

- estimates of the price of trout purchased in a store for home consumption (probably not comparable goods, i.e., poor substitutes)
- the price of trout caught from "fee" fishing waters (a little better substitute good)
- the expenditures by a public agency to restock the watershed and/or maintain a trout population in a similar watershed
- the expenditures (e.g., travel costs) incurred by recreational users of a similar fishery (probably the best estimate of value attainable from the substitute goods method with the substitute goods that are listed here)

It is neither clear, a priori, which if any is the best or most appropriate substitute for use as a valuation proxy in any given situation, nor is

it clear how an estimate derived from the use of a particular substitute good may be biased. The validity and reliability of the results will depend on the degree to which the researcher has been able to select a substitute good that exhibits a high degree of value correlation with the environmental good in question (Freeman 1979).

The approach has considerable potential in an exploratory benefit-cost analysis where available secondary data and nonmarket prices from existing empirical studies are all that is available to the analyst.

TRAVEL COST APPROACH

The travel cost method developed by Hotelling, Clawson and Knetsch involves primary data collection and has been used primarily to estimate the value of recreation (Clawson 1959, Clawson and Knetsch 1966). Information on the number of visits to a recreation site and the cost of traveling to the site is used, under certain assumptions, to derive a demand curve for the entire recreation experience and for the recreation area itself. Travel costs traditionally include the out of pocket cost of traveling to the site plus the fixed cost increment of the passenger car used as transportation to the site, plus the value of the time spent in transit. However, it was recognized that the value of the recreation experience must include some measure of value at the recreation site. Therefore, both variable and fixed costs incurred at the recreation site have been included in recent studies.

Because detailed information is required on a wide variety of costs, questionnaires used to collect travel cost data are lengthy and complex. For example, individuals are requested to provide accurate information on date of purchase, cost and frequency of use of all equipment in their possession. This process can become burdensome for campers who are involved in boating or other activities that require a lot of equipment.

For valuing environmental quality changes that do not affect recreation use rates, this technique has little to offer. For example, people may be willing to pay to preserve a wilderness site even though they never intend to visit the site or to preserve their option to visit (existence or option

demand). Just knowing it is there is worth something to them. This value is not measured with the travel cost method.

Also, the method may produce overestimates of the benefits of environmental improvement by ignoring the changes that occur in the use of substitute recreational sites and opportunities by consumers. If one site loses while another gains users, it is incorrect to account for only the lost value of recreation at the first site. To do so would overstate the net cost of the environmental damages that caused a reduction in the use of the first site.

THE BIDDING GAME APPROACH

The bidding game technique is used to directly elicit individuals' valuations for goods and service. There are four types of questions that can be asked of individuals to obtain a theoretically correct measure of value for an environmental change.

Assuming you are entitled to your current level of environmental quality:

- How much would you be willing to pay for a specified improvement in environmental quality?
- How much would you be willing to accept in compensation for a specific reduction in environmental quality?

Assuming you are not entitled to your current level of environmental quality:

- How much would you be willing to pay to prevent a specific reduction in environmental quality?
- How much would you be willing to accept in compensation to forego a specific improvement in environmental quality?

The question that yields the theoretically correct measure of value depends on the assignment of rights to the environmental quality. In many situations these rights are ill-defined. For example, in assessing visual aesthetic impact, it is usually necessary to ask questions covering alternative assignments of rights (Adams et al. 1980). The resulting information places upper and lower bounds on the value of changes in visual aesthetics.

Bidding games may be administered by household, telephone, mail or group surveys. Elements of the survey instruments typically include a description of the problem being addressed, stimuli that represent the changes in environmental quality (photographs, verbal descriptions), the elicitation of bids, and other data, such as scaled attitude variables and socio-demographic characteristics.

Improved awareness of survey methods, coupled with the opportunity to control, to a large degree, the simultaneous collection of required data have resulted in a marked increase in studies using bidding games to estimate the public's value of a wide variety of environmental changes (Adams et al. 1980). Examples that are relevant to hydrothermal development include the valuation of changes in water quality, odors and visual aesthetics.

Bidding games are subject to several types of problems in application. For example, the process is hypothetical. People are asked to make instantaneous buy and sell decisions on goods and services they may never have thought about trading. Also, some people behave strategically. That is, they will intentionally understate or overstate their bid for a variety of reasons. These problems have been generally well researched and documented and most can be controlled or accounted for (Adams et al. 1980).

EXPENDITURE ALLOCATION APPROACH

The expenditure allocation method is a direct inquiry technique requiring primary data collection. The method differs from the bidding game technique in that individuals explicitly make trade-offs among goods and services. The method works as follows. Individuals are given a budget and are presented with two or three schedules on quantities and prices of goods and services they may purchase. They are asked to add to the list of goods and services and are told that one option would be that they could keep all or part of the budget allocated to them. They are then asked to allocate the total budget.

Analysis of data collected over a representative sample would produce what are called income compensated demand equations for all the goods and services used in the data collection process. Information from the demand equations will produce theoretically correct measures of value.

This approach has only recently surfaced in the literature and experience is limited (Hardie and Strand 1979). Although it is somewhat more complex than bidding games, we feel it has significant potential. This is because the process requires individuals to explicitly consider tradeoffs. Valuations of more than one type of environmental impact can be determined simultaneously for each individual.

PROPERTY VALUE APPROACH

The property value approach to estimating a non-market cost typically involves using information on the change in the price of property due to the nonmarket effect. This approach is based on the assumption that nonmarket costs will be fully reflected in property values. For the hydrothermal case this implies that malodorous gas emissions and other nonmarket effects cause property value changes that fully reflect the value of environmental change to society. In addition, the property value approach requires certain assumptions about the nature of the property value market. This approach typically uses secondary data, and has been used to estimate the benefits and costs of changes in air quality (Eckstein 1958, Howe 1971, Mishan 1976, Prest and Turvey 1965).

The basic advantage of this technique over some other approaches is that the expense of deriving a nonmarket cost estimate may be relatively low because the property value procedure requires only secondary data. The disadvantages of this approach for estimating hydrothermal nonmarket costs include: 1) the untenable nature of the required assumptions and 2) the difficulty associated with deriving valid estimates of the change in property values caused by hydrothermal developments. A hydrothermal plant may be on or surround public lands and privately owned land. It may be difficult to accurately assess property value changes on both types of land because they are either never or are only infrequently bought and sold in the marketplace. However, to the extent that the relevant price change can be estimated accurately, this approach may provide a low cost approximation of the nonmarket costs of a hydrothermal plant.

The information required to apply this approach to estimate nonmarket costs is: 1) the change in the price of property due to the hydrothermal emissions and 2) the stock of property affected. A nonmarket cost estimate is derived by summing the change in property values over all affected property.

The stock of property effected can be determined using engineering information on emission characteristics or by examining the property surrounding an existing plant. There are several ways to estimate the change in the price of property due to the plant emissions. Typically this has been done using economic theory, regression analysis and secondary data on property values. Regression analysis is used to determine the marginal affect of the attributes of property on property values. Attributes analyzed usually include house characteristics, such as square footage, if the property has a structure on it, and land characteristics, including air quality. This information is then regressed on the value of the property, as determined in the marketplace, to determine the marginal effect of the attributes on property values. Given the marginal effect of a change in air quality on property values and the marginal impact of the hydrothermal plant on air quality, it would then be possible to determine the average impact of the plant emissions on property values. The change in value estimate could, of course, be estimated in other ways. For example, expert opinion could be gathered on the property value impact of the plant emissions.

If the change in property value due to the plant emissions cannot be accurately determined, then information on the value of property damaged by the emissions will provide an upper estimate of the nonmarket costs. A worst possible case scenario is that the plant emissions will reduce the value of the effected property to zero. Thus, summing the value of all property effected by the emissions will provide an upper bound estimate of the nonmarket costs.

APPENDIX C

HEBER SITE DEVELOPMENT

APPENDIX C

HEBER SITE DEVELOPMENT

CONVERSION TECHNOLOGY

Heber site flashed steam energy conversion facilities are summarized in this section as an example of hydrothermal flashed steam technology. Flashed steam technology will probably be used at Niland, also, but specific operating conditions will differ. (Some of these differences appear in the Appendix D analysis.) The facilities under consideration by industry to be constructed and operated at Heber include the following (VTN 1979):

1. a series of hydrothermal power plants with a total capacity of up to 500 MWe;
2. the associated hydrothermal production and injection wells, and fluid transmission system;
3. a water treatment plant to provide makeup water for the hydrothermal power plants, water for purposes of injection into the hydrothermal reservoir, and associated injection wells; and
4. a contingency plan to provide a backup source of water in the event the proposed source becomes inadequate.

The project will be located near Heber, California, in Imperial County. The site is approximately 90 miles east of San Diego and is located within the 7320 acre zone that overlies the Heber hydrothermal anomaly. Currently, both Southern California Edison (SCE) and San Diego Gas and Electric Company (SDG&E) have plans to construct and operate hydrothermal facilities within two miles of the town of Heber, California. The proposed SDG&E power plant and associated production island are to be located approximately 1.5 miles south of Heber on an area of about 21 acres. The proposed SCE power plant and associated production island are to be located approximately one mile south of Heber on a 28-acre, wedge-shaped site.

As currently envisioned by SCE and SDG&E, the project will consist of seven to ten power plants of 50 to 100 MW each that will produce 500 MW of electrical energy. The numbers and types of power plants for total development have not been finalized. Two of the 50-MW plants may utilize the binary cycle and the remainder would utilize the dual flash cycle (VTN 1979).

The following section describes the dual flash cycle and the expected fluid flow rates and fluid emissions the power plants will generate.

Dual Flashed Steam Cycle

A 50-MWe dual flash steam cycle plant will be used as the basis for estimating environmental damages in this report. Increments in the size of total resource development will be in units of 50 MWe (gross), the least common denominator. VTN (1979) reports that fluid requirements increase linearly with increasing plant size, thus, a 500-MWe facility will require about ten times as much hydrothermal fluid as would a 50-MWe installation.

A 50-MWe dual flash cycle power plant for the Heber site consists of the following basic components:

- the phase separation system (liquid and steam separator),
- turbine-generator,
- condenser,
- noncondensable gas removal system, and
- cooling tower.

Initially, hydrothermal fluid at about 360°F (182°C) will be conveyed from the production island to the steam separators. As the hydrothermal fluid enters the separators the pressure will be dropped causing the fluid to flash to steam. The liquid fraction will then be cascaded to a second-stage separator where its pressure will be further decreased and the fluid will flash again. Additional steam will be produced at this point. The liquid remaining after the second-stage flash will be injected into the reservoir (6.89 million lb/hr) (VTN 1979, p. II-31). The higher pressure steam from the first-stage separator will be admitted to the turbine throttle and the low pressure steam will enter at an auxiliary port for use in the lower pressure portion of the turbine. The turbine will drive a generator that will produce 55 MW of power.

About 10 MW will be used for internal plant pumps, cooling tower fans and hydrothermal fluid pumps. The remaining power, about 45 MW, will be transformed to a higher voltage for distribution to the grid (VTN 1979).

Exhaust steam will be condensed in a surface condenser, using water that was cooled by evaporation in the mechanical draft cooling tower. Condensed exhaust steam (condensate) will collect in the bottom of the condenser and will be used to replace the water lost from the cooling tower by evaporation and drift. The amount of condensate produced will be 1,220,000 lb/hr (554,000 kg/hr). The rate at which water is lost from the cooling tower will vary with atmospheric conditions, but will average about 935,000 lb/hr (425,000 kg/hr) (VTN 1979). Any excess condensate not utilized in the power plant operation will be combined with the spent fluid from the second-stage separator and injected into the hydrothermal reservoir. The noncondensable gases in the hydrothermal fluid and the air that normally leaks into the surface condenser will be removed by the steam ejector system for distribution to the cooling tower. These gases are then released to the atmosphere with the cooling tower plumes. These gases are listed in Table C.1. A tabulation of the characteristics of flash cycle power plants is shown in Table C.2.

To provide makeup water to replace that lost by evaporation, water will be removed from the New River, treated and injected into the hydrothermal reservoir or used for cooling tower makeup. The average rate of injection of river water will be equal to the average rate of evaporation from the power plant cooling towers, resulting in no net withdrawal of fluid from the reservoir. This quantity of water amounts to 2,500 acre feet per year per 50-MWe plant.^(a) For 500 MWe the total water needed would be 25,000 acre feet. The developers have obtained permits for up to 50,000 acre feet of water from the New River per year. A water treatment plant is required to clean up this makeup water prior to its use in the cooling towers or prior to its injection into the hydrothermal reservoir.

The water treatment plant to be utilized is still in a preliminary design stage, and pilot studies are being conducted. As currently planned, the water

(a) The PNL GEOCOST model runs used in Appendices D and E estimate required makeup water at 3300 AF/yr per 50 MW net electric output, for somewhat different assumptions.

TABLE C.1. Analysis of Noncondensable Gases in Heber Hydrothermal Fluid

<u>Component</u>	<u>Mole Percent</u>
Air ^(a)	2.45
Hydrogen (H ₂)	1.57
Nitrogen (N ₂)	28.30
Carbon Dioxide ^(b) (CO ₂)	58.96
Methane (CH ₄)	8.19
Ethane (C ₂ H ₆)	0.11
Propane (C ₃ H ₈)	0.01
Butane, Pentane, Hexane	tr.
Heptane (C ₇ H ₁₆)	0.01
Hydrogen Sulfide (H ₂ S)	<u>0.40</u>
	100.00

Calculated Molecular Weight: 36.1043

Weight Fraction of Total Flow^(c)

Noncondensibles: 48.37 ppm

Hydrogen Sulfide: 0.18 ppm

(a) Contamination from flashing process.

(b) Percentage depends on operating pressure of flash vessel.

(c) Determined from average gas flow readings of 3 ft³/hr at average water flow of 6,250 lb/hr.

Source: VTN 1979.

treatment plant will be of modular design, with one module having sufficient treatment capacity to satisfy the makeup requirements for one power plant. Conceptually, the treatment plant is similar in design to a conventional municipal drinking water treatment plant. Water will be diverted from the New River via diversion works equipped with a screen to keep fish out. The water will be routed to a primary settler, to remove the larger solids. Flocculating agents will then be added, and most of the remaining suspended solids will be removed

TABLE C.2. Dual Flash Steam Cycle at Heber

Working fluid	Steam
Generator output	55 MW
Auxiliary power use	10 MW
Net power output	45 MW
Hydrothermal fluid usage	8.1 million lb/hr
Number of production wells	9 to 15
Number of injection wells	7 to 11
Cooling tower evaporation	0.90 million lb/hr
Cooling tower makeup source	Condensate
Cooling tower makeup rate	0.93 million lb/hr
Cooling tower drift rate	12.8 gpm
Drift solids content	50-250 ppm
Solids emission rate	0.3-1.8 lb/hr
H ₂ S path	Fluid-steam cooling tower
H ₂ S emission rate	1.44 lb/hr (14.5 gm/MWhr)
H ₂ S emission point	Cooling tower
Site area (including well sites)	25 acres

Source: VTN 1979.

in a clarifier. The water is then pumped through a dual media filter, treated with chlorine or other biocide and finally deaerated before injection into the reservoir. The solids removed from the water will be digested in aerobic digestors, dewatered and dried for ultimate disposal in a county-approved landfill adjacent to the water treatment facilities (VTN 1979).

As part of a separate contingency plan, up to 20,000 acre-feet/year of water could be diverted from the New River at another location to supply the requirements of these facilities if, for some reason, not all of the needs can be met at the planned site. Under any conditions, the maximum annual diversion of water would be 50,000 acre-feet. In any event all the water required for cooling makeup and injection makeup will be taken from the New River.

APPENDIX D

THE COST OF PREVENTING ENVIRONMENTAL DAMAGES

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This appendix presents estimates of the cost of H_2S and liquid waste treatment for sites in the Imperial Valley. H_2S abatement cost estimates are presented first, followed by a section discussing liquid waste treatment and disposal costs.

HYDROGEN SULFIDE EMISSION CONTROL COSTS

In the absence of airborne emission regulations the developers would be likely to provide sufficient H_2S abatement at hydrothermal sites to eliminate any obvious short-term health hazards that tended to reduce labor productivity. Eliminating an odor nuisance would probably not be profitable for the firm. Table D.1 presents estimates of the costs of H_2S abatement at Heber and Niland for a 55-MWe generating station (about 50 MWe net) using the EIC upstream treatment process. From the table it can be seen that the incremental costs of H_2S abatement that a developer would face at Heber when attempting to eliminate the odor nuisance would be approximately $\$0.84 \times 10^6$ per year, or 2.40 mills per kWh, for the expected H_2S emission rate of 1.83 lbs per hour. At Niland, where the H_2S concentration is only slightly higher than at Heber, H_2S abatement costs will be approximately the same. Ninety-seven percent removal of H_2S was assumed to be necessary at Niland and Heber to eliminate the possibility of an odor nuisance at the plant boundary.

LIQUID WASTE DISPOSAL COSTS

There are two alternatives for liquid waste disposal at hydrothermal sites: injection and surface release.^(a) Both options may have significant private and nonmarket costs associated with them.

(a) Because the Imperial Valley hydrothermal sites are located on extremely valuable agricultural lands, ponding and evaporation is not a feasible surface disposal alternative. Ocean disposal is also not feasible due to the relatively high cost of transporting the spent brine to the ocean.

TABLE D.1. H₂S Abatement Costs(a)

	<u>Heber</u>	<u>Niland</u>
Expected H ₂ S Concentration in Raw Flashed Steam	1.15 ppm _w	3.59 ppm _w
Expected Steam Flow	1.59 x 10 ⁶ lbs/hr	0.86 x 10 ⁶ lbs/hr
Expected H ₂ S Flow/hr	1.83 lbs/hr	3.09 lbs/hr
Purchased Equipment Costs (\$10 ⁶)	2.4	2.4
Total Capital Investment @ 3.25 x P.E. (\$10 ⁶)	7.80	7.80
Levelized Annual Fixed Costs (\$10 ⁶)	0.48	0.48
Annual Variable Costs (\$10 ⁶)	0.36	0.37
Levelized Total Annual Cost (\$10 ⁶)	0.84	0.85
Mills/kWh	2.40	2.33
Net Present Value of Costs ^(b) (\$10 ⁶)	12.91	13.07

(a) 55 MWe dual flashed steam cycle, 80% capacity factor. EIC upstream abatement process. 97% removal efficiency. All costs are in January 1980 dollars. See Wells et al., PNL-2802 for abatement process description and cost estimation methodology.

$$(b) \text{ NPV} = \frac{\text{Annual Costs}}{\frac{i}{(1+i)^n - 1}} + i$$

where n = 30 years and i = 5% real discount rate.

The private costs of deciding to use surface disposal rather than injection include the:

- loss of reservoir pressures and well productivity caused by not replacing withdrawn hydrothermal brine
- subsidence damages to surface facilities needed for power production
- life cycle costs of the surface disposal system.

In the absence of environmental regulations governing surface disposal, developers would compare its private costs and benefits to those of alternatives such as injection and select the least costly alternative. In the event that surface disposal was selected, the private costs borne by the developer would include those listed above.

The private costs of injection disposal facing developers and utilities at hydrothermal sites include:

- life cycle costs of the injection wells and injection system
- life cycle costs of obtaining makeup water to replace evaporative losses and maintain reservoir productivity, and
- induced seismicity that creates damages to surface facilities needed for power production.

In the absence of environmental regulations the developer would select the least costly liquid waste injection option for the site after considering the expected value and benefit-cost variance for each alternative. From the private cost standpoint, it appears that injection of at least 80 percent of the spent hydrothermal liquids (brines) withdrawn from the reservoir will be sufficient to maintain well flow rates over the life of the resource. The 80% injection rate for Heber is expected to be the economic optimum from the resource developers' point of view.

At Niland the reservoir has been reported as recharging naturally from the Salton Sea. Thus, the expected optimal level of injection for that resource may be zero, from a private cost standpoint. For both sites Imperial County

requires 100% fluid replacement unless the California Division of Oil and Gas (DOG) approves a lower fluid replacement rate. DOG has approved 80 percent for Niland while withholding formal approval of 80 percent for Heber until more experience with the reservoir has been obtained. Assuming that the expected value of the private costs of subsidence and seismicity damages are near zero, Table D.2 below presents estimates of the costs of liquid waste injection at Heber and Niland for a 50-MWe generating station for the 80% and 100% fluid replacement cases.

From Table D.2, it can be seen that the incremental cost of 100% injection disposal over the 80% case per 50-MWe plant at Heber is estimated to be \$300,000 per year. At Niland, the marginal cost is estimated to be \$59,270,000 per year. In both cases sludge disposal costs comprise most of the total disposal cost. For this reason the cost of brine treatment is described in detail in the following section.

BRINE TREATMENT COSTS AT HEBER AND NILAND

Before hydrothermal fluids may be disposed of by injection, the super-saturated dissolved solids (SSDS) and suspended solids must be removed from the spent brine to prevent plugging of the injection formation. The system of SSDS removal outlined here is based on a review of a series of pilot studies at the Hydrothermal Loop Experimental Facility near Niland. These studies indicated that silica and metal salts can be reduced below their solubility limits without the addition of chemicals. One study showed that silica will reach saturation levels in 2 to 3 hours when 90°C brine is collected and held in open containers without agitation (Quong, Schoepflin, and Stout 1978).

In an effort to reduce treatment time, another study was conducted using a solids contact reactor followed by dual-media gravity filters (Van Note, Featherstone, and Pawlowski 1978). A schematic of this system is shown in Figure D.1. In this system, supersaturated silica and heavy metals are precipitated in the flocculation zone of the reactor. Sludge is recirculated at rates between 10 and 15 times the influent rate to provide seed nuclei onto which dissolved solids can adsorb. A solids concentration of 2.5% in the flocculation zone and a reaction time of 17 minutes provides a nonsaturated effluent.

TABLE D.2. Brine Injection Disposal Costs at Heber and Niland(a)

	Hydrothermal Sites Spent Brine Injection Rate			
	Heber		Niland	
	80%	100%	0%	100%
Injection System:				
Disposal Volume (10 ⁶ lb/hr) ^(b)	7.97	9.96	0	2.81
Number of Wells ^(c)	10	10	0	4
Total Cost/Yr (\$10 ⁶)	2.01	2.14	0	0.96
Mills/kWh ^(b)	5.73	6.10	0	2.62
Brine Treatment Prior To Injection Disposal: ^(b)				
Total Cost/Yr (\$10 ⁶)	12.77	12.94	0	58.31
Mills/kWh	37.69	38.34	0	160.00
Total of Injection and Brine Treatment Costs/Yr (\$10 ⁶):	14.78	15.08	0	59.27
Net Present Value of Costs (\$10 ⁶): ^(d)	196.20	198.87	0	896.40
Marginal Injection Costs:(e)				
\$/acre foot/yr		415.24		6,540.00
mills/kWh		7.33		160.00
cents/1000 gals		127.76		2,012.00
Net Present Value (\$10 ⁶): ^(f)		2.67		896.40

(a) 55-MWe dual flashed steam plant, 50-MWe net, 80% capacity factor, 30-year life. All costs are in January 1980 dollars.

(b) From Table D.3.

(c) Estimated by GEOCOST (Bloomster 1975).

$$(d) \text{ NPV} = \frac{\text{Annual Costs}}{\frac{i}{(1+i)^n - 1}} + i$$

where n = 30 years and i = 5% real discount rate.

(e) Computed by dividing the change in levelized total annual costs (\$10⁶) by the change in the quantity of treated water to be returned to the reservoir, or, by the fixed electrical output. It is actually the average of the marginal costs for the change in question.

(f) Difference between the net present values of the costs of 80% and 100% injection rates at Heber; difference between costs at 0% and 100% at Niland.

FIGURE D.1. Cross Section of Typical Solids Contact Reactor

At the Niland site, dissolved silica in 200°F brine is reduced from 293 to 172 ppm, but the effectiveness of this system is not limited by the influent concentration; by adjusting the solids concentration in the reaction zone and the reaction time, supersaturated solutions of any concentration may be reduced to their solubility limits. The turbidity of the reactor effluent is around 15 units and is further reduced by the dual-media filters (Van Note, Featherstone, and Pawlowski 1978). Tests with a precoat filter indicate that it is feasible to provide a filter effluent with 1 mg/l suspended solids (Quong, Schoepflin, and Stout 1978). This is approximately one turbidity unit.

Costs for hydrothermal liquid waste disposal at Heber were calculated from cost functions developed by Wells et al. (PNL-2991) using a discounted cash flow procedure. The wastewater treatment plants are modular in design to handle the liquid effluent from a 50-MWe dual flashed steam plant. They can be replicated for each additional 50-MWe plant brought on line. The cost of treating the liquid effluent prior to injection for the first 50-MWe installation is assumed to be identical to and independent of the cost for any additional treatment plants. However, it should be noted that for each proposed hydrothermal plant, a detailed study will have to be performed to select treatment processes capable of attaining the desired level of effluent quality. Each study would typically include a review of state-of-the-art technology and jar tests on the specific brine in question. Pilot-plant testing will probably be employed by the first generation of hydrothermal power plants.

Table D.3 shows the derivation of the liquid waste treatment costs and the reference assumptions for the Heber and Niland sites. From Table D.3 it can be seen that requiring 100 percent liquid waste replacement in the Niland and Heber reservoirs is a relatively expensive undertaking for the resource developer. The expenses increase the expected cost of power by 7.3 mills/kWh at Heber and 160 mills/kWh at Niland. From the standpoint of society it is important to evaluate these costs in light of the net benefits they will generate. The text of this report attempts to assess the net benefits of these and other environmental damage mitigation efforts in light of the value of the environmental damages that will be prevented.

TABLE D.3. Hydrothermal Brine Treatment Costs(a)

	Hydrothermal Sites Spent Brine Injection Rate			
	Heber ^(b)		Niland ^(c)	
	80%	100%	0%	100%
Liquid Waste to be Returned to Reservoir:				
Millions of gallons daily (MGD)	23.37	29.21	0	8.24
10 ⁶ pounds per hour	8.13	10.16	0	2.86
System Design Volume:(d)				
MGD	30.38	37.97	0	10.70
10 ⁶ lb/hr	10.57	13.21	0	3.72
Average pounds of Dry Solids removed per Day (10 ⁶):(e)	2.67	2.67	0	13.48
Tons per Year Removed(e)	443,175	443,175	0	2,236,000
Purchased Equipment Costs (\$10 ⁶):(f)				
Solids Contact Reactors	1.73	2.01	0	0.87
Dual Media Filters	1.85	2.14	0	0.93
Gravity Thickeners	0.78	0.78	0	1.37
Vacuum Filters	0.07	0.07	0	0.17
Total Purchased Equipment Costs (\$10 ⁶):	4.43	5.00	0	3.33
Total Capital Investment (\$10 ⁶) (@2 x Purchased Equipment):	8.86	9.99	0	6.67
Levelized Annual Fixed Costs (\$10 ⁶) @ 0.3 x Purchased Equipment):	0.89	1.00	0	0.67
Annual Variable Costs (\$10 ⁶):				
Solids Contact Reactors	0.23	0.26	0	0.14
Dual Media Filters	0.20	0.24	0	0.11

TABLE D.3. (contd)

	Hydrothermal Sites Spent Brine Injection Rate			
	Heber ^(b)		Niland ^(c)	
	80%	100%	0%	100%
Gravity Thickeners	0.08	0.08	0	0.62
Vacuum Filters	0.28	0.28	0	0.87
Subtotal	0.80	0.86	0	1.74
Sludge Disposal ^(g)	11.08	11.08	0	55.90
Total Annual Variable Costs (\$10 ⁶):	11.88	11.94	0	57.64
Levelized Total Annual Costs (\$10 ⁶):	12.77	12.94	0	58.31
Treatment Volumes and Costs: ^(h)				
Pounds of fluid per Year (10 ¹⁰):	6.98	8.73	--	2.46
Acre Feet per Year	25,721	32,152	--	9,063
kWh per Year (10 ⁶):	350.4	350.4	--	364.4
10 ⁶ Gallons per Year:	8,359	10,449	--	2,946
\$/acre foot	496.30	402.40	--	6,434.00
mills/kWh ⁽ⁱ⁾	36.40	36.90	--	160.00
cents/1000 gal	152.70	123.80	--	1,980.00
Net Present Value of Treatment Costs (\$10 ⁶): ^(j)	196.20	198.87	--	896.40
Marginal Treatment Costs: ^(k)				
\$/acre foot		415.24		6,540.00
mills/kWh		7.33		160.00
cents/1000 gal		127.76		3,012.00
Net present value (\$10 ⁶): ^(l)		2.67		896.40

TABLE D.3. (contd)

- (a) All costs are in January 1980 dollars for a 50-MWe dual flashed steam plant. Treatment consists solely of supersaturated dissolved solids removal. Conventional water treatment to remove supersaturated dissolved solids: rapid mixing, chemical precipitation, flocculation, sedimentation and filtration using solids contact reactors. See Wells et al. (PNL-2991) for system description and cost estimation methodology.
- (b) Resource 15,000 ppm_w TDS.
- (c) Resource 250,000 ppm_w TDS.
- (d) System designed 30% larger than brine volume to handle internal backflushing operations.
- (e) Assumes 80% TDS removal efficiency for entire treatment system.
- (f) Calculated from Wells et al. (PNL-2991).
- (g) Sludge disposal cost of \$25.00 per metric ton (2200 lb) of dry solids. Dewatered sludges are assumed to be zero percent water by weight.
- (h) One acre foot = 43,560 ft³ = 2.714 x 10⁶ lb of fluid = 325,000 gal.
- (i) 45 MWe (net) x 8760 hr/yr x 0.80 capacity factor x 1000 kWe/MWe = 3.1536 x 10⁸ kWh/yr.
- (j)
$$NPV = \frac{\text{Annual Costs}}{\frac{i}{(1+i)^n - 1}} + i$$
- where n = 30 years and i = 5% real discount rate.
- (k) Computed by dividing the change in levelized total annual costs by the change in the quantity of treated water to be returned to the reservoir, or, by the fixed electrical output. It is actually the average of the marginal costs for the change in question.
- (l) Difference between the net present values of the costs of 80% and 100% injection rates.

APPENDIX E

PROCEDURE USED IN DERIVING ESTIMATES OF ENVIRONMENTAL
CHANGE ON THE SALTON SEA FROM HYDROTHERMAL DEVELOPMENT
AT HEBER AND NILAND

APPENDIX E

PROCEDURE USED IN DERIVING ESTIMATES OF ENVIRONMENTAL CHANGE ON THE SALTON SEA FROM HYDROTHERMAL DEVELOPMENT AT HEBER AND NILAND

The problem was to determine how the surface elevation, area and salinity of the Salton Sea would change under the different development scenarios. Two sites were evaluated, Heber and Niland, assuming both 50 MWe and 500 MWe developments at each site.

The data used was from three sources. Estimates of the TDS content of the hydrothermal liquids were from Wells et al 1980 (PNL 2991). All other data were from the EIR at the Heber site (VTN 1979).

The available data was as follows:

Heber and Niland Sites

- well flow rate
- salinity content
- evaporation losses during conversion to electricity.

New River

- average annual flow near Heber
- average annual salinity near Heber

Salton Sea

- projections from 1977 to the year 2010 of elevation, area, and salinity with 1) no hydrothermal development and 2) 500-MWe development at Heber.
- average annual evaporation between 1952 and 1978
- average length, width and depth of sea in 1982 with no development.

For our problem there are four different actions which can impact the sea. At Heber, water is either withdrawn from or discharged to the New River

approximately 30 miles upstream from the sea. At Niland, water is either withdrawn from or discharged to the Salton Sea.

For water which would be discharged to the New River or Salton Sea we answered the question "what is the quality and quantity of this water in future time periods?" At any future time period of interest we then mixed the discharge water with the Salton Sea to determine the change in elevation, area and salinity.

For water which would be withdrawn from the New River or Salton Sea we answered the following question "if this water had not been withdrawn what would have been its quantity and quality in future time periods?" For any future time period of interest we deleted the withdrawn water from the Salton Sea base projections to determine the change in elevation, area and salinity.

In deriving these estimates no computer model was used. A simple mass balance algorithm was constructed for a hand calculator. Following is an example of the procedure for the Heber site with regulation.

For a 50-MWe development the total flow rate from all production wells is 10.16×10^6 lb/hr and evaporation losses are expected to be 1.28×10^6 lb/hr. Regulations require that 100% of the volume withdrawn must be injected, so makeup water equivalent to evaporation must be diverted from the New River. This is equivalent to approximately 3300 AF/yr beginning in 1982. It was assumed that losses on any parcel of water withdrawn would have been 20% per year. Thus, if the 3300 AF were not withdrawn in 1982, it would have evaporated to 2640 AF in 1983, 2112 AF in 1984, etc., until by the year 2000 there would be scarcely 50 AF remaining from the original 3300 AF. At the same time that the volume of this water parcel were shrinking the TDS concentration would be increasing to maintain the following relationship

$$\text{Volume}_t \times \text{Concentration}_t = \text{Volume}_{t+h} \times \text{Concentration}_{t+h} \quad (\text{E.1})$$

Note that other 3300 AF parcels would be withdrawn in succeeding years. Thus, it was necessary to keep track of the volumes and TDS content of all these parcels over time. The problem takes on additional complexity when the

500-MWe development is considered because the volumes of withdrawals increases from 3300 AF in 1982 to a maximum of 33,000 AF in 1989, remaining at this level over the life of the project.

For the 500-MWe development at Heber, the total volume of New River withdrawals to 1990 would be 178,740 AF at a TDS concentration of 4,657 ppm. If this volume had not been withdrawn between 1982 and 1990 it would become reduced in size but with an increased concentration. By 1990 the volume would be 101,780 AF. The concentration can be found from Equation A.1 as follows:

$$\begin{aligned} 178,740 \text{ AF} \times 4,657 \text{ ppm} &= 101,780 \text{ AF} \times C \\ C &= 8,178 \text{ ppm} \end{aligned}$$

To determine the change in sea elevation and area, the 101,780 AF must be subtracted from the sea volume which would exist in 1990 with no hydrothermal development. To aid in this calculation we used data on the relationship between sea elevation and area (VTN 1979) to develop the following coefficient:

$$K = \frac{3075 \text{ acre change in surface area}}{1 \text{ foot change in sea level elevation}} \quad (\text{E.2})$$

Knowing the surface area in 1990 with no development, the problem then becomes straightforward.

$$\frac{101,780 \text{ AF}}{254,300 \text{ acres}} = 0.40 \text{ ft change} \times \frac{3075 \text{ acres change}}{1 \text{ ft change}} = 1,231 \text{ acres}$$

Therefore, withdrawals to serve a 500-MWe development at Heber result in a change in the elevation and surface area in 1990 of 0.40 feet and 1,231 acres respectively.

The impact on salinity can be found using the following relationship:

$$\frac{V_1 C_1 - V_2 C_2}{V_1 - V_2} = C_3 \quad (\text{E.3})$$

V_2 and C_2 are the volume (101,780 AF) and concentration (8,178 ppm) of the water which was withdrawn between 1982 and 1990 which would have existed in 1990 if the water had not been withdrawn. V_1 and C_1 are the volume and concentration of the sea in 1990 with no development. We begin with a rough estimate of the average sea volume in 1982. This is given by the VTN (1979) as 30 miles by 13 miles by 30 feet. In acre-feet this becomes

$$30 \text{ miles} \times 13 \text{ miles} \times \frac{5,280^2 \text{ ft}^2}{1 \text{ mi}^2} \times \frac{1 \text{ acre}}{43,560 \text{ ft}^2} \times 30 \text{ feet} = 7.488 \times 10^6 \text{ AF}$$

The volume in 1990 can be found by determining the change in volume from 1982 to 1990 without development (VTN 1979) and adding it to the volume in 1982.

	<u>Area in Acres Without Development</u>	<u>Elevation in Feet Below Mean Sea Level</u>
1990	254,130	223.88
1982	$\frac{247,458}{6,672}$	$\frac{226.06}{2.18}$

$$6,672 \text{ acres} \times 2.18 \text{ feet} = 14,544 \text{ AF}$$

$$\text{Volume} = 7.488 \times 10^6 + 14,544 = 7.50 \times 10^6 \text{ AF in 1990.}$$

Salton Sea salinity in 1990 can be estimated as Equation E.3 as follows:

$$\frac{(7.5 \times 10^6 \text{ AF} \times 40,033 \text{ ppm}) - (101,780 \text{ AF} \times 8,178 \text{ ppm})}{7.5 \times 10^6 \text{ AF} - 101,780 \text{ AF}} = 40,471 \text{ ppm}$$

This procedure was repeated for each site, with and without regulation, and for the dates 1990 and 2000.

APPENDIX F

CALCULATIONS FOR SUBSIDENCE IMPACT

APPENDIX F

CALCULATIONS FOR SUBSIDENCE IMPACT

We begin with the documented estimate that with 500 MWe developed at Heber and 85% replacement of geothermal fluids withdrawn, about 2160 acres will be subjected to subsidence and a net 14.94 lb/hr of fluid per hour will be withdrawn (VTN 1979). This basic estimate is then extended to other development conditions, assuming

- land subject to subsidence is proportional to net fluid withdrawal rate during each year for the geothermal site
- subsidence occurs in the first year during which the land is subjected during subsidence risk.

For example, consider the Heber site in 1989. The net fluid withdrawal rate with the 80 percent injection assumed to occur voluntarily is:

$$1.99 \times 10^6 \text{ lb/hr/50 MWe} \times \frac{500 \text{ MWe}}{50 \text{ MWe}} = 19.90 \text{ lb/hr.}$$

The acres at risk are then

$$2160 \text{ acres (500 MWe, 85\% injection)} \times \frac{19.90 \text{ lb/hr}}{14.94 \text{ lb/hr}} = 2877 \text{ acres, or about 2880 acres,}$$

reported in Table F.1. The difference in acres at risk between 1989 and 1988 is then 288 acres, which is the land area newly exposed to subsidence risk. Table F.2 is prepared in the same fashion.

Table F.3 is based on the newly exposed acreage. The land is assumed to be driven to zero value by subsidence in the year it is first exposed to subsidence risk. For Heber in 1989 with 500 MWe and 80 percent injection, at \$6000 per acre, damages in 1989 are

$$(\$6,000-0) \times 288 \text{ acres} = \$1,728,000$$

The present value of 1989 damages, viewed from 1980, is:

$$\$1,728,000 / (1 + 0.05)^9 = \$1,113,884.$$

The sum of these discounted impacts is the estimated total net present value of subsidence damages.

TABLE F.1. Acres at Risk From Subsidence

	<u>Cumulative MWe</u>	<u>Heber, 80 Percent Injection, 500 MWe</u>		
		<u>Net Rate of Brine Removal (10^6 lb/hr) ^(a)</u>	<u>Acres at Risk ^(b)</u>	<u>Incremental Acres at Risk</u>
1982	50	1.99	288 ^(c)	288
1983	100	3.98	576	288
1984	100	3.98	576	0
1985	100	3.98	576	0
1986	200	7.96	1152	576
1987	350	13.93	2016	864
1988	450	17.91	2592	576
1989	500	19.90	2880	288
1990- 2000	500	19.90	2880	0

(a) Heber site net rate of brine removal for 500 MWe with 0 percent reinjection is 99.60×10^6 lb/hr. For 50 MWe with 80 percent reinjection, it is 1.99×10^6 lb/hr. See Appendix D.

(b) Acreage at risk is scaled from the acreage at risk at Heber with 500 MWe of development and 85 percent reinjection. The scale factor is a fraction, the numerator of which is the estimated net withdrawal rate at Heber in a given year, and the denominator is the rate at 500 MWe with 85 percent injection - 14.94×10^6 lb/hr. Base acreage is 2160 acres (VTN 1979).

(c) Lawrence Livermore Laboratories (1980) computes an area of 1 to 2 km² as the area of severe to moderate subsidence with 50 MWe and 30 years of production: 250 to 500 acres. This is similar to our result.

TABLE F.2. Acres at Risk From Subsidence

	Cumulative MWe	Niland, Zero Percent Injection, 500 MWe		
		Net Rate of Brine Removal (10^6 lb/hr) ^(a)	Acres at Risk ^(b)	Incremental Acres at Risk
1982	50	1.43	406	406
1983	100	2.86	812	406
1984	100	2.86	812	0
1985	100	2.86	812	0
1986	200	5.72	1624	812
1987	350	10.01	2842	1218
1988	450	12.87	3654	812
1989	500	14.30	4060	812
1990- 2000	500	14.30	4060	0

(a) Niland site rate of brine removal with 0 percent reinjection for 50 MWe is 2.81×10^6 lb/hr. See Appendix D.

(b) Scaled from Heber net rate of withdrawal at 500 MWe, 85 percent reinjection: 14.94×10^6 lb/hr. Base acreage is 2160 acres. Answer rounded to nearest full acre.

TABLE F.3. Computation of Potential Dollar Damages From Subsidence

	Incremental Acres at Risk	Heber						Niland					
		500 MW, 80% Injection			50 MW, 80% Injection			500 MW, 0% Injection			50 MW, 0% Injection		
		Damages at \$6000/Acre	Present Value of Damages at 5%	Acres	Damages at \$6000/Acre	Present Value of Damages at 5%	Acres	Damages at \$3000/Acre	Present Value of Damages at 5%	Acres	Damages at \$3000/Acre	Present Value of Damages at 5%	
1980	0	0	0	0	0	0	0	0	0	0	0	0	
1981	0	0	0	0	0	0	0	0	0	0	0	0	
1982	288	1,728,000	1,567,347	288	1,728,000	1,567,347	406	1,218,000	1,104,726	406	1,218,000	1,104,726	
1983	288	1,728,000	1,492,711	0	0	0	406	1,218,000	1,052,108	0	0	0	
1984	0	0	0	0	0	0	0	0	0	0	0	0	
1985	0	0	0	0	0	0	0	0	0	0	0	0	
1986	576	3,456,000	2,578,920	0	0	0	812	2,436,000	1,817,743	0	0	0	
1987	864	5,184,000	3,684,172	0	0	0	1218	3,654,000	2,596,898	0	0	0	
1988	576	3,456,000	2,339,157	0	0	0	812	2,436,000	1,648,685	0	0	0	
1989	288	1,728,000	1,113,884	0	0	0	812	2,136,000	1,570,245	0	0	0	
1990	0	0	0	0	0	0	0	0	0	0	0	0	
Total	2880	\$17,280,000	\$12,776,192	288	\$1,728,000	\$1,567,347	4060	\$13,398,000	\$9,790,405	406	\$1,218,000	\$1,104,726	

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