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The Cost of Meeting Geothermal Liquid Effluent Disposal Regulations

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FOREWORD

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

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

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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 (DOE), Office of Hydrothermal Commercialization, initiated a study of geothermal liquid effluent treatment and disposal costs. The staff of Pacific Northwest Laboratory (PNL), operated for the Department of Energy by Battelle Memorial Institute, conducted both the technical and economic research. This report documents the research methodology and presents estimates of the cost of geothermal liquid-effluent treatment and disposal.

The primary objectives of the research included 1) developing generic treatment cost functions that could be used to estimate the costs that a private developer would incur when treating geothermal liquid effluents, and 2) using these cost functions to estimate liquid-waste-treatment costs at a geothermal site.

Liquid-waste-treatment processes were reviewed in detail in this research to develop cost functions for conventional and advanced water-treatment systems. Conventional wastewater-treatment systems consist of a series of processes that have been widely used in water-treatment plants for many years. These systems produce liquid effluents with a level of water quality that is sufficient for injection disposal and that is often suitable for other uses. Advanced treatment systems use processes that employ relatively new technology to provide a higher level of effluent water quality that is sufficient for nearly all disposal and reuse options.

A case study was conducted to estimate liquid-effluent-treatment costs for the Salton Sea hydrothermal resource at Niland, California. Liquid-waste-treatment and disposal costs were estimated from the cost functions developed in this report. All of the treatment costs include the expense of sludge disposal. Sludges are generated when the total dissolved solids (TDS) content of the geothermal liquid waste is reduced by the treatment processes.

At the Niland site in the Salton Sea Known Geothermal Resource Area (KGRA) the spent geothermal fluid may have a TDS content of 250,000 mg/l. Employing conventional water treatment and injection disposal was estimated to cost 161 mills per kWh, with 154 mills of the cost being attributable to sludge disposal. A system of conventional plus advanced-treatment processes may provide irrigation-quality effluent water (2,200 mg/l TDS) at a water-treatment cost of 234 mills per kWh. Sludge disposal costs (190 mills) are a significant fraction of the total treatment expenditures and currently present a barrier to the treatment of high-salinity fluids to provide irrigation quality water.

Not all hydrothermal resources face such high liquid-waste-treatment and disposal costs. Approximately 70% of the hydrothermal electrical generating potential that has been estimated to exist in the western United States occurs in resources with a TDS concentration below 7500 mg/l. For these resources, liquid-waste-treatment and disposal costs will be much lower than for the case study presented in this report.

In the Imperial Valley injection of spent geothermal fluids is the required liquid-waste disposal method. Injection is expected to reduce potential subsidence and may help maintain reservoir productivity for some hydrothermal resources. Estimates of the magnitude of the value of preventing geothermally induced subsidence damages should be developed and compared with the costs of liquid-waste treatment and disposal. This comparison can form the basis for assessing the net benefits to society of alternative levels of injection disposal at hydrothermal resource sites.

GLOSSARY OF TERMS

adsorption: The adhesion of a dissolved or discrete molecule of one compound (or element) onto a solid particle of another compound (or element). Silica (SiO_2) may be removed from wastewater by adsorption to magnesium hydroxide $\text{Mg}(\text{OH})_2$.

advanced treatment: Unit processes that employ (relatively) new technology to provide water of a quality higher than that typically required for domestic water use. Examples of advanced treatment processes include ion exchange, reverse osmosis, electrodialysis, and distillation. See also: conventional treatment.

agglomerate: To gather discrete particles together to allow their separation from water by settling or filtration. See also: coagulate; flocculate.

anion: An ion with a negative electric charge. See also: ion; cation.

blowdown: Discharge from a treatment system to control the concentration of dissolved or suspended solids.

cation: An ion with a positive electric charge. See also: ion; anion.

coagulate: To form a semisolid mass in a liquid through agglomeration of discrete particles. See also: agglomerate; flocculate.

colloids: Very small, discrete particles suspended in a liquid medium. Particles within the size range of 1 millimicron to 100 millimicrons are generally considered colloids. See also: suspended solids.

constituent: A particular element or compound of an effluent stream. See also: pollutant.

conventional treatment: Unit processes that have been in widespread use by domestic water treatment plants for many years. Examples of conventional treatment processes include rapid mixing, flocculation, sedimentation, and filtration. See also: advanced treatment; flocculate.

dissolved solids: Solids mixed with water in the form of discrete atoms or molecules. Dissolved solids usually (but not always) have an electric charge. See also: ion.

effluent: A stream of water exiting a unit process. See also: influent.

flocculate: The formation (by gentle mixing) of large, fluffy particles that are capable of settling. See also: agglomerate; coagulate.

hardness: A measurement of the scaling capacity of water. Hardness is caused by divalent metallic cations; calcium, magnesium, strontium, barium, iron, and manganese. See also: cation.

hydrothermal: Liquid- and steam-dominated geothermal resources.

influent: A stream of water entering a unit process or a plant. See also: effluent.

inorganic: Elements or compounds derived from mineral sources. Inorganic compounds generally do not contain carbon. See also: organic.

ion: An atom or molecule with an electric charge. See also: anion, cation.

nonmarket cost: In the case of geothermal resources, subsidence (that was caused by fluid extraction) that reduced the value of crop lands adjacent to the production islands places a nonmarket cost on certain members of society: the farmers. They are not compensated for the economic damages they have suffered from subsidence. The costs of the damage are not paid by the resource developers to the farmers. Hence, it is a nonmarket cost.

organic: A chemical compound containing carbon and usually derived from biological sources. See also: inorganic.

pollutant: Any alteration of the physical, thermal, chemical, biological, or radioactive properties of any water by man. See also: constituent.

precipitate: To cause a dissolved solid to become a suspended solid. See also: dissolved solid; suspended solid.

regulation: State or federal legislation that mandates 1) control of waterborne effluents, 2) establishment of specific wastewater standards, and 3) establishment of procedures to control wastewater effluents.

sludge: A liquid or semisolid mass with a high concentration of suspended solids. See also: suspended solids.

solubility: A measure of the ability of a constituent to dissolve in water. Species with high solubilities can exist in high concentrations of dissolved solids while species with very low solubilities exist mostly in the form of suspended solids. Parameters that affect the solubility of a species include temperature, pressure, and ionic concentration. See also: constituent, dissolved solids, ion, suspended solids.

standards: Specific qualitative or quantitative state or federally established criteria.

suspended solids: Compounds existing in water in their solid form (as opposed to dissolved) and capable of being separated by settling or filtration. See also: dissolved solid.

turbidity: A measure of the ability of light to pass through water. One turbidity unit has been arbitrarily defined to be the turbidity caused by one milligram per liter of suspended silica. See also: suspended solids.

weir: A structure that controls or measures the flow rate of water by allowing the water to overflow.

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1.0 INTRODUCTION

The liquid effluents resulting from hydrothermal resource development may create environmental impacts that give rise to significant nonmarket production costs. Regulations are being promulgated in an attempt to internalize these nonmarket production costs. The objective of this research is to provide a way to estimate the private cost of treating and disposing of these liquid effluents.

Several research tasks were undertaken to achieve the study objective:

- characterize liquid effluents
- review effluent control standards
- assess available wastewater treatment processes
- develop effluent treatment cost functions
- estimate effluent treatment costs in a case study.

Section 2.0 summarizes the conclusions and recommendations of the study. Section 3.0 presents background information on the characteristics of liquid wastes and the available disposal options. Regulations that may directly or indirectly influence liquid waste disposal are reviewed in Section 4.0. Section 5.0 provides an assessment of the available wastewater-treatment systems. A case study of expected liquid-waste-treatment and disposal costs is summarized in Section 6.0.

The information presented in this document is intended to aid the Department of Energy, Division of Resource Applications, in making research, development, and demonstration allocation decisions.

2.0 CONCLUSIONS AND RECOMMENDATIONS

Liquid waste treatment and disposal costs were hypothesized to be dependent on several variables, including the volume of liquid to be treated per unit time, the brine chemistry, the efficiency of the treatment processes, the characteristics of the resource and site, and the standards for liquid-effluent treatment and waste disposal. Increases in the liquid flow rate, the total dissolved solids (TDS) content, and the stringency of effluent regulations were hypothesized to increase treatment costs when all other factors were held constant. Literature reviews and contacts with both users and vendors of wastewater-treatment systems did not provide any information from which to develop explicit formulations of the functional relationships between effluent water quality (i.e. TDS) and total water-treatment costs. Both the capital and operating costs of wastewater-treatment systems were found to be expressed only as functions of liquid flow rates and treatment process TDS removal efficiency. Additional industry experience with hydrothermal brines may provide information on the impact of brine chemistry on treatment costs. The cost functions developed in this report are primarily sensitive to the liquid flow rate and the TDS removal efficiency.

A review of hydrothermal resource fluid characteristics, disposal options, effluent regulations, and the cost of effluent treatment processes indicate that the cost of meeting effluent regulations may significantly impact both the rate and level of resource commercialization. More specifically:

- Treatment systems are selected based on the given influent and required effluent water-quality criteria.
- Injection-quality effluent water can be obtained with conventional water-treatment systems (i.e. with rapid mixing, flocculation, sedimentation and filtration).

- The purification of effluent water for use in irrigated agriculture may require the use of an advanced wastewater treatment system in addition to conventional treatment processes at sites with relatively high TDS contents, (i.e. reverse osmosis, electrodialysis, ion exchange or distillation processes may have to be used).
- The cost of meeting liquid-effluent disposal regulations may be a significant fraction of the total private cost of developing a hydrothermal resource.
- The treatment costs are dominated by capital recovery charges and by sludge-disposal costs. Capital costs are determined primarily by the disposal flow rate to be treated.
- A case study of spent brine treatment costs at Niland, California, (Salton Sea KGRA) indicates that costs may range from 161 mills per kWh to 234 mills per kWh, depending on specific disposal standards.
- The capital cost functions in this report are not sensitive to TDS content. As a result, high-TDS resources may have higher treatment costs than estimated here.
- As effluent regulations become increasingly stringent (in terms of the required effluent water quality), the cost of compliance will also increase.
- Although only 30% of the hydrothermal resources with electrical generating potential have TDS concentrations in excess of 7500 mg/l, they are being actively commercialized. The developers of such resources may incur substantially higher wastewater treatment costs, depending on disposal regulations, than would be encountered at resources with lower temperatures and lower TDS contents.

After the cost of wastewater treatment and disposal at the Niland site was examined environmental regulations were determined to have a significant impact on the cost of hydrothermal energy. Additional investigations and reviews of existing data are recommended to more accurately estimate 1) the

removal efficiency of wastewater treatment processes, and 2) the cost of handling, transporting, and disposing of the sludges extracted by treatment processes.

A third recommendation of this study is that the value of the benefits realized by preventing environmental damages must be measured and compared with the estimated liquid-waste-treatment and disposal costs. From these benefit-cost comparisons, environmental standards that achieve the appropriate balance between society's valuation of the environment and society's valuation of geothermal energy can be established at each resource site.

3.0 LIQUID WASTES

This section discusses hydrothermal energy systems, energy conversion processes, the volume of liquid wastes expected from resource developments, fluid composition, and potential environmental damages caused by liquid waste disposal and summarizes technically feasible liquid waste disposal options.

3.1 ENERGY SYSTEMS

Because virtually all the known, economically exploitable hydrothermal resources in the United States are liquid-dominated KGRAs (Known Geothermal Resource Areas) this report focuses on developing liquid-waste-treatment cost estimates for liquid-dominated resources.^(a) Several of the better known systems are listed in Appendix A. Information in the literature indicates that subsurface temperatures will range from 323°C at Salton Sea to 152°C at Surprise Valley (Brook et al. 1979). Most systems, however, occur at temperatures below 230°C. High temperature is one of the primary factors a developer looks for in a geothermal area because it is indicative of large energy potential and low production costs. That is, energy can be recovered at a lower flow rate and subsequently lower private cost from such KGRAs (TRW 1975).

About 40% of the systems studied have low TDS concentrations (2,000 ppm_w or less) and may require little, if any, treatment of the brine before disposal (EPA 1978). The Salton Sea has a relatively high TDS concentration (250,000 ppm_w) and may require extensive liquid-waste treatment to prevent environmental damages. Other systems in the Imperial Valley may also share this problem.

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

(a) Of the 56 KGRAs identified in Geological Survey Circular 790 (Brook et al. 1979), all are hydrothermal and 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.

minimum potential that would be necessary to justify an electrical generating plant at a specific site. For example, representatives of the Electrical Power Research Institute (EPRI) have estimated that proven reserves of 200 MWe will be a commercial resource (TRW 1975). Lack of electrical potential was considered to be a major commercialization barrier for systems with a potential of less than 200 MWe for 30 years and includes 44% of the systems studied, although they may be good candidates for space-heating development. Of all of the high-temperature hydrothermal systems the Salton Sea has the highest estimated electrical potential (3,400 MWe for 30 years). It is interesting to note that estimated electrical potential is not entirely dependent upon resources temperature. For instance, Surprise Valley, the lowest temperature resource of the systems studied, has the fifth highest estimated electrical potential. Reservoir size, permeability, geochemistry and matrix structure, as well as temperature, influence recoverable reserves.

Drilling and casing costs reported in the literature are influenced by the type of rock overlying the reservoir. Due to the nature of natural-heat flow systems, most KGRAs are covered by hard, volcanic rock (TRW 1976). However, the Imperial Valley and Vale Hot Springs systems are overlaid by soft rock that is less costly to drill (Mitre 1978).

Site characteristics, like resource characteristics, will influence the private power costs, but in a less direct way. The primary characteristics affecting commercialization are topography, available transportation, climate, freshwater quality and availability, ownership and leasing cost, development status, state and local regulations, state and local attitude, available utilities and transmission lines, and seismic tendencies. Topography and available transportation influence the cost of transporting equipment over the terrain as well as the need for extra construction supports and leveling of the land. About one-fifth of the areas examined are located in mountainous areas and would require leveling of construction sites (Wapora 1978). The other four-fifths are located in relatively flat desert regions. Many of the sites are in isolated areas and would need improvement of old roads or construction of new roads for further development. The Imperial Valley sites are an exception in that they are in the middle of a very flat, highly developed agricultural area.

3.2 ENERGY CONVERSION PROCESSES

Several methods exist for extracting thermal energy from liquid-dominated geothermal reservoirs. Two of the proposed methods are being developed further by utilities, DOE, and electric utilities to meet specific end use and resource characteristic constraints. Both methods require a cooling system (e.g., towers or ponds) as part of the energy-conversion system.

Flashed Steam Cycle

This energy recovery technique takes advantage of the "flashing" or rapid vaporization process that occurs naturally in some hot water systems. As hot, pressurized hydrothermal fluid is withdrawn from the reservoir, approximately 20% by weight flashes to steam upon reaching the surface. The raw flashed steam is then used to drive turbines for electricity production. Remaining water may be disposed of by injection or surface drainage. Noncondensable gases^(a) are vented to the air or routed to the cooling tower. 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 of the heat energy (93% to 97%) must be either dissipated to the surface environment as reject heat or returned to the reservoir through the use of spent-fluid injection systems.

Binary Cycle

A heat exchange mechanism that maintains the hydrothermal fluids in a closed pressurized loop is known as a binary energy conversion process. Two process options have been introduced: 1) down hole heat exchange and 2) conventional surface heat exchange. With the down hole mechanism, fluids are not brought to the surface of the ground. With either mechanism the heat is exchanged with a second (binary) fluid such as freon, ammonia or isobutane, which have lower boiling points than the hydrothermal fluid. The vapor generated in the binary fluid is then used to drive the turbine. Once

(a) Gases that do not condense to liquids at standard temperatures and pressures (1 ATM, 0°C) are "noncondensable."

used, the binary fluid vapor is condensed to a liquid and recirculated through the heat exchanger in a closed system where it may be heated and used again. For several reasons this system appears to have advantages over the flashed-steam cycle for developing reservoirs having electricity potential and either high levels of total dissolved solids (TDS) or lower relative enthalpy (in Btu/lb of fluid):

1. Because the corrosive fluids do not come in direct contact with the turbines, blade pitting and wear is reduced.
2. While its efficiency is the same order of magnitude as the flashed-steam cycle, the binary cycle has a higher range of operating efficiency with respect to lower temperatures. For example, the binary cycle may require only two-thirds the volume of water required by the flashed-steam cycle at moderate temperatures to produce the same amount of electricity. Water handling costs would then be reduced.

Because downhole heat exchangers and two phase fluid pumps are needed for the binary cycle and have not yet been perfected, the flashed-steam cycle will be used throughout this report as a reference point for estimating treatment costs.

3.3 LIQUID WASTE VOLUMES AND COMPOSITION

As seen in Figure 3.1, the liquid effluent flow rate from a flashed-steam plant may range from less than 100,000 lb/hr/MWe to more than 300,000 lb/hr/MWe. The flow rate is inversely related to the resource temperature. As the temperature of the geothermal fluid increases, more electrical energy can be produced from a given flow rate. The main continuous liquid discharge from flashed-steam plants is the spent brine, which, depending on the temperature and pressure, comprises approximately 80% of the total fluid flow removed from the reservoir. Flashed-steam constitutes the remaining 20% of the fluid flow. The steam is piped to the power plant, as seen in Figure 3.2, for use in electrical generation. After passing through the turbine, the steam is condensed to a liquid and routed to the cooling system where approximately 85% evaporates. All the remaining liquid condensate overflows from the cooling tower basin and is then disposed of.

FIGURE 3.1. Flashed-Steam Cycle Fluid Requirements

In addition to these two continuous effluent flows (spent brine and cooling tower basin overflow), two intermittent streams of relatively minor volume exist. First, a periodic blowdown of the cooling water basin to remove sludge may be performed one or two times per year. Second, the hot well may overflow if more water accumulates in the hot well than is necessary for cooling purposes. However, large volumes of hot well overflow are rarely encountered in a properly designed cooling system.

Brines originate at depths of anywhere from a few hundred to a few thousand meters. At high temperatures and pressures, the brines reach a chemical equilibrium with the reservoir rock formations and attain a TDS content that ranges from a few hundred mg/l up to 350,000 mg/l. As the hot brine is brought to the surface for energy production: 1) the brine loses pressure and begins to cool, creating lower solubility products for the dissolved constituents; and 2) a fraction of the brine flashes to steam, further concentrating the

FIGURE 3.2. Flashed-Steam Cycle Mass Balance Illustration for The Geysers Unit 13(a)

(a) g = gas, l = liquid, aq = aqueous

Source: Fairfax and McCluer 1972; PG&E 1975; Walter et. al. 1975.

dissolved solids in the spent brine. As a result, many inorganic species precipitate from solution as insoluble suspended particulates.

Brines commonly contain the constituents listed in Table 3.1. These constituents may be either toxic or merely inert, but they are typically present in the brine in sufficient aggregate quantities to cause a host of environmental and technical problems. For the flashed-steam cycle, arsenic stays primarily (99%) in the brine, but the cooling tower sludges may also be an important repository for arsenic (Thompson et al. 1978). In the flashed brine, the concentration of arsenic may range from 0./28 mg/l to 10 mg/l (Robertson et al. 1978).

Boron releases are of major concern for agricultural reasons. Concentrations may vary from 0.13 mg/l to 340 mg/l in the flashed brine. At the Cerro Prieto power plant less than 0.2% goes to the plant in the steam phase (Robertson et al. 1978). Studies of boron at The Geysers are currently underway to evaluate its impact on flora at the site.

TABLE 3.1. Constituents of Geothermal Brines

<u>Constituent</u>	<u>Observed Amounts (mg/l)</u>	<u>Constituent</u>	<u>Observed Amounts (mg/l)</u>
Ammonia (NH ₃)	traces	Manganese (Mn)	6,500
Arsenic (As)	15	Mercury (Hg)	10
Barium (Ba)	2,000	Nickel (Ni)	1,000
Boron (B)	300	Potassium (K)	20,000
Calcium (Ca)	25,000	Radium (Ra)	traces
Carbonate (CO ₃)	50,000	Radon (Rn)	traces
Chlorine (Cl)	128,000	Silicon (Si)	1,000
Fluorine (F1)	20	Sodium (Na)	70,000
Iron (Fe)	4,500	Strontium (Sr)	4,500
Magnesium (Mg)	300	Zinc (Zn)	5,000

Source: Thompson et al. 1978; Bowen 1973; Axtman 1975; Swanberg and Wapora 1976.

The disposal of effluents containing high concentrations of dissolved salts or TDS is another problem that must be resolved in the development of liquid-dominated resources (Thompson et al. 1978). As the liquids in the brine are flashed to steam, the dissolved solids concentrate, become saturated and begin to precipitate out of solution. For calcium carbonate and silicates, this may occur at the point of flashing. Other species, however, may not saturate until a significant amount of cooling takes place. The primary anions involved include carbonates, chlorides, sulfides, silicates, and nitrates, while the principal cations are sodium, potassium, calcium, and magnesium (Defferding 1978). In a flashed-steam cycle, most of these dissolved salts remain in the spent brine, creating problems such as plugging in the injection well, pipeline scaling, and corrosion.

The main constituents that cause scaling and plugging are silica and silicates, calcium carbonate and metal sulfides, sulfates, oxides, hydroxides and carbonates (Shannon 1975). The corrosive nature of the effluent streams results from the interaction of several factors, including pH. Corrosion will increase with decreasing solution pH (Defferding 1978). Although the pH varies from 2.7 to 9.8 for subsurface brines, it clusters near 7 to 9. The other factors that influence the corrosion, scaling, and plugging rates are dissolved oxygen content, temperature, and salinity. The methods of controlling corrosion fall into two categories: 1) the removal or alteration of the brine constituents that cause corrosion, and 2) the development of corrosion resistant coatings for materials (Phillips et al. 1977). Estimates of the impacts of corrosion and scaling indicate that the problem may be relatively expensive to mitigate (Shannon 1975).

The TDS content ranges from 420 ppm to more than 250,000 ppm for geothermal brines from high-temperature systems with electrical generation potential, as shown in Appendix A. Figure 3.3 indicates that more than 30% of the MWec^(a) potential from high-temperature systems in the western United States will come from resources with a TDS concentration of 7500 mg/l or more.

(a) Megawatt electric centuries.

FIGURE 3.3. Distribution of Electrical Potential by TDS Concentration(a)

- (a) Cumulative sum of MWe potential versus TDS concentration for 35 identified high-temperature hydrothermal conversion systems in the western United States. Excludes The Geysers and Cove Fort/Sulphurdale.

Wastewater from sites with a 7500 mg/l or less TDS may require only minimal treatment for disposal. However, the Salton Sea KGRA is now being considered for utilization. It has a TDS content of approximately 250,000 mg/l and its liquid effluents may require substantial wastewater treatment before disposal.

3.4 POTENTIAL ENVIRONMENTAL DAMAGES

The flashed-steam system of heat exchange may create environmental changes and damages from several sources:

1. subsidence induced through fluid extraction
2. fluids released from the system for surface disposal or accidentally injected to freshwater aquifers
3. disruption of existing land use practices

4. microclimate changes caused by heat discharges
5. gases released from brines dumped at the wellhead; from jet gas ejectors designed to remove noncondensable gases from the flashed brine (steam) of power plant and from steam formed in the condensers and cooling towers (i.e. the cooling system).

All three major components of the environment are affected:

- air (chemistry and temperature of emissions, noise)
- water (chemistry and temperature of effluents)
- land (changes in productivity, visual change, access, use, etc.)

3.5 LIQUID WASTE DISPOSAL OPTIONS

Hydrothermal fluids and their residuals require final disposal whether or not they have had prior treatment. It is hypothesized that the "cleaner" the original fluids the lower will be the total costs of treatment and ultimate disposal if all other factors are held constant.

Several options are available to handle the liquid effluents and include injection, direct discharge to surface waters, ocean disposal, and evaporation ponding. Land spreading does not appear to be technically feasible and will not be discussed here (see Thompson et al. 1978 for a review of this topic). Reuse of the effluent water for agricultural, industrial, or domestic purposes will be contingent on water-treatment process efficiencies. Treatment processes will be needed for most disposal options. Solids requiring disposal will also result from most treatment systems.

Injection

Injection tests have been performed successfully world-wide at hydrothermal sites, including The Geysers, East Mesa, Niland, Heber, and Valles Caldera in the U.S. In determining the technical and economic feasibility of injection at a particular site, the following variables must be considered (Defferding 1978):

1. chemistry of fluids
2. pressure drawdown
3. subsidence
4. distance from the production system
5. depth
6. type of rock in the receiving formation
7. recharge mechanism and hydrology
8. formation permeability, porosity, and fracture pattern
9. treatment required, due to environmental or regulatory constraints.

Injection well locations should be selected after considering the potential of the system to perform several functions (Thompson et al. 1978):

1. mix with fresh groundwater
2. recharge the reservoir so that pressure can be maintained
3. prevent quenching; low-temperature effluents must not mix directly with production fluids
4. keep pumping requirements minimal
5. accept large flow volumes over long time periods.

A major environmental concern involves groundwater contamination. The failure of injection well casings is one potential cause of contamination of freshwater aquifers. Casing failures may be due to scale buildup, cement failure, plugging, and/or corrosion. Control and/or prevention of well casing failures may be achieved with conventional water-treatment processes, which can remove suspended constituents and some inorganic dissolved constituents (Sung et al. 1977). Specific treatments allow the liquid effluents to be injected into the subsurface formation without plugging, corrosion, and scaling. The specific treatment processes are discussed in Section 5.0.

Several areas should be investigated to determine the need for and amount of pretreatment required (Shannon 1975):

1. ambient reservoir pressure and temperature profiles

2. original fluid and heat source dominant flow mechanisms
 - a. recharged or closed
 - b. intergranular or fracture
3. reservoir matrix characteristics
 - a. areal extent
 - b. lithology
 - c. continuity and homogeneity
 - d. intergranular and fracture porosity and the resulting effective permeability
4. reservoir fluid characteristics
 - a. temperature and pressure
 - b. viscosity and density
 - c. composition and phase
 - d. chemistry and quality
5. waste fluid characteristics
 - a. volume and injection rate
 - b. temperature
 - c. composition
 - total solids content of fluid
 - dissolved gases
 - pH
 - microorganism content
 - d. reactivity potential
 - auto reactivity
 - corrosion of system components
 - reaction with reservoir rock and fluid constituents.

Thermodynamics is the principal framework for the evaluation of these variables. However, due to the nature of hydrothermal brines, thermodynamic analysis has exhibited a very limited capacity to accurately predict scaling phenomenon under actual working conditions (Shannon 1975).

Land subsidence resulting from the withdrawal of fluids is among the most serious of the potential site-specific impacts of resource development that may be mitigated by injection of the spent brine. Throughout the United

States, both vertical and horizontal ground movements have occurred where oil and groundwater have been withdrawn. Hot water systems are expected to behave like petroleum reservoirs and exhibit subsidence unless subsurface pressures are maintained by fluid injection.

Significantly, the area of maximum subsidence has occurred outside of the production field, which means that subsidence could affect the property of adjacent landowners as much as, or more than, the immediate development area (EPA 1977). Subsidence was recorded seven miles outside the Cerro Prieto well field even before full-scale production and surface discharge began. Subsidence has also been noted within the well field at Wairakii, New Zealand (Axtman 1975). The Cerro Prieto well field, near the Imperial Valley in Southern California, is one of the most promising areas in the western U.S. However, the valley is tectonically active and may be subsiding naturally (EPA 1977). As a result, completely separating the impacts of natural subsidence from induced impacts may be difficult. Subsidence prevention programs are prone to several problems in the Imperial Valley:

- The initial withdrawal of fluids may cause irreversible collapse of some air spaces and pores in the underground formation.
- Dissolved solids may create technical problems with scale buildup and clogging of equipment and may lead to plugging of the underground formation that receives the spent fluids. Corrective measures designed to increase the fluid solubility coefficient appear likely to compound the problem (EPA 1977).
- Injection to the producing horizon may lower the heat content of the producing region.
- If the fluids are also used in the cooling towers, a reduction in the quantity of available injectable fluid will occur.
- Injection beyond the producing horizon may induce seismic activity in existing faults by providing either the triggering force or the lubrication needed to set off a quake.

Surface Disposal

The simplest method of spent brine disposal would be direct discharge to surface waters without treatment. This method requires only a conduit from the plant to the receiving waters. Thus, direct discharge would be simple in construction, would need no special equipment or materials and would have low operating costs and high reliability (Defferding 1978). However, the environmental effects could be severe. As previously noted, specific elements are often present in waste fluids in sufficient concentrations to be toxic to fish, wildlife, plant life, and humans (Thompson et al. 1978). Although any kind of water chemistry alterations may disturb both plant and animal life, surface disposal has been practiced at all of the major power plants, including Larderello, Wairakei, The Geysers, and Cerro Prieto. For flashed-steam plants such as Wairakei and Cerro Prieto, discharge lines flow directly into holding ponds for cooling and canals carry the overflow into the local drainage system. Maintenance is relatively simple and consists primarily of removing scale and precipitates that clog the canals.

For specific sites where either the nonmarket costs are low enough or the benefits are high enough, direct surface discharge may be environmentally, politically, and economically acceptable. The number of sites meeting this set of conditions is expected to be relatively small.

Ocean Disposal

Ocean disposal may only be a viable alternative for power plants with relatively close access to minimize transportation costs (Sung et al. 1977). The salinity of the ocean is about 35,000 mg/l TDS and any brine to be disposed of above that level must be treated (Thompson et al. 1978). Brine pretreatment may also be needed to control the level of toxic elements such as mercury and arsenic released to the ocean. Brines can be corrosive in nature, due to their high dissolved-gas content, pH, and other geochemical factors and may, therefore, have to be deaerated before cost-effective transfer to the ocean by pipeline is possible (Shannon 1975). The reduction of suspended solids, dissolved solids, and toxic chemicals to an acceptable level may require advanced treatment processes, depending on the TDS content of the

fluid, but the final water quality for ocean disposal may not need to be as free of contaminants as would be necessary for freshwater surface disposal.

Ponding

Evaporation ponds may be a cost-effective disposal technique for discharging wastes in areas where land costs are low and evaporation rates are high (Thompson et al. 1978). Manmade ponds will need to contain an impermeable barrier of either plastic or natural material at the sides and bottom to prevent contamination of underground aquifers or potable groundwater (Defferding 1978). Pond systems can be designed to separate and concentrate individual salts by using several unlined ponds in a series (Morrison et al. 1977). Ponding can also be used as an intermediate technique or as a backup system to aid in the precipitation of solids from the effluent streams.

Sludge Disposal

The precipitated solids collected in the treatment system or left in the bottom of an evaporation pond are another waste that requires disposal (Thompson et al. 1978). These solids can be disposed of in several ways including landfilling, mineral recovery, and ocean dumping. The method and site for the disposal of the solids will depend on whether they are classified as hazardous. Classification may vary from site to site and will serve to further limit the disposal options available. Sludge-disposal costs may be large if the solids content of the wastewater and the sludge-generation rate are high because transporting the solids to an offsite location could be very costly (Christensen and Wong 1978). Ideally, the production of marketable residues would eliminate the need for solid waste disposal sites for the geothermal industry. However, the production of marketable commodities from residual sludges has not been shown to be cost-effective for hydrothermal resources.

3.6 SUMMARY

Spent brine from hydrothermal resources will require disposal. The quantity of water will depend on the characteristics of the resource. The feasible means of disposal will depend on site characteristics, brine chemistry, and site-specific disposal requirements. In general, low-salinity fluids from

hydrothermal resources may be clean enough to discharge directly to surface waters after cooling. However, the majority of brines may either be too saline or toxic to discharge directly to fresh water without creating substantial environmental damages.

As a fluid disposal option, injection appears to be a practical and environmentally acceptable method. It not only solves the water disposal problem but may help minimize reservoir depletion and potential surface subsidence. Injection of relatively clean excess condensate has been practiced successfully for several years at The Geysers and at numerous other sites and is being tested at several sites in the Imperial Valley, California. The potential problems with injecting high-salinity fluids are system corrosion, scaling, and formation plugging. The solid residue disposal problems have not been completely resolved, and the production of marketable commodities from residual sludges has not been shown to be cost-effective for hydrothermal resources.

4.0 EFFLUENT REGULATIONS

The development of hydrothermal energy is subject to many effluent control laws that could potentially affect the economic feasibility of developing this energy source. The state and federal effluent regulations identified in this section may necessitate the development and use of effluent control processes, which would impose additional costs on the development of the resource.

The following sections describe the federal and state regulations and standards that govern the release of liquid effluents. The federal regulations will be addressed first, followed by a general overview of state regulations and standards for each of the following disposal options:

- disposal to surface water
- well injection (groundwater standards)
- surface ponding and storage
- ocean disposal.

Definitions of specific terms are found in the glossary.

4.1 DISPOSAL TO SURFACE WATER

Federal

The federal legislation applicable to effluent discharge to surface waters is the Federal Water Pollution Control Act (FWPCA) as amended by the Clean Water Act of 1977. The sections that pertain to liquid effluent discharge and that will be addressed are Sections 101, 303, 304, 307, and 402 of the FWPCA and Section 511 of the Clean Water Act (Thompson et al. 1978).

The FWPCA, in Section 101(a)(2), declares a national goal of eliminating the discharge of pollutants into navigable waters or waters of the United States by 1985. Also in this section, an interim goal that provides for the protection and propagation of fish, shellfish, and wildlife and for recreation in and on the water is established to achieve water quality (Federal Laws Index).

Section 303 calls for the establishment and maintenance of receiving water quality standards for both interstate and intrastate surface waters.

Table 4.1 lists several constituents federal water standards that appear to be applicable to hydrothermal liquid effluents. The numerical limits in the last two columns, receiving water and drinking water, apply to surface water discharges and depend on the use designation of a particular reach of surface water.

Section 402 establishes the National Pollution Discharge Elimination System (NPDES), which authorizes the issuance of discharge permits by the Environmental Protection Agency (EPA) or an EPA-approved state agency (Thompson et al. 1978). Sections 402(b) and 304(h)(2) contain provisions whereby the issuance authority may be delegated to a state that is able to satisfy various requirements. Of the 11 western states considered, Arizona, Idaho, New Mexico, and Utah do not participate in the NPDES system. Therefore, only the appropriate regional EPA office may issue permits for discharges to the surface waters of these states.

TABLE 4.1. Federal Water Quality Criteria (mg/l)(a)

	<u>Irrigation</u>	<u>Ocean Disposal</u>	<u>Receiving Water</u>	<u>Drinking Water</u>
Arsenic (As)	0.1	0.2	NA	0.05 ^(d)
Boron (B)	0.75	5.0	NA	1.0 ^(e)
Mercury (Hg)	1.0 ^(b)	0.001 ^(c)	0.0005	0.002 ^(d)
Total Dissolved Solids (TDS)	500 to 15,000	35,000	Background	500.0 ^(e)

NA - Not Available

(a) Criteria are presented for the most prevalent, likely to be encountered constituents only (EPA 1973, unless otherwise noted). Additional criteria are available for other brine constituents but have not been presented here for brevity.

(b) No criteria recommended for Hg in the EPA 1976, "Quality Criteria for Water."

(c) This value from EPA 1976 is for support of marine aquatic life and is more restrictive than the Footnote (a) value of 0.10 mg/l.

(d) National Interim Primary Drinking Water Regulations (40 CFR 142).

(e) U.S. Public Health Service (USPHS) Drinking Water Standards 1962.

The NPDES permits specify allowable constituents and concentrations and establish compliance schedules. The permit conditions are to be based on uniform effluent limitations determined by the EPA to be technologically achievable by each specific industry (Thompson et al. 1978). Waterborne effluent standards pertaining specifically to hydrothermal energy production have not yet been established. As the level of development increases and new hydrothermal technologies are demonstrated, industry-specific guidelines may be developed. In the interim, the effluent limitations prescribed by NPDES permits will be established on a case-by-case basis and will be tested using the state water quality standards that are applicable to the water receiving the discharge (Beeland 1978).

Section 307 of the FWPCA requires the EPA to establish another set of effluent limitations, known as pretreatment standards, for industries that discharge their effluents into municipal treatment systems rather than to a waterway. Limits are to be established for constituents that are not susceptible to sewage treatment or that would interfere with the operation of the treatment system (Thompson et al. 1978).

Section 511(c)(1) of the Clean Water Act subjects discharge permits, issued by the EPA for new effluent sources, to the environmental impact statement requirement established by the National Environmental Policy Act (NEPA) of 1969. Discharge permits issued by state agencies are exempt from this provision (Thompson et al. 1978). The potential impact of this section depends on whether hydrothermal facilities will be considered new sources. A new source is defined as one on which construction is started after EPA proposes applicable new source performance standards. In the absence of these standards, hydrothermal operations are not yet subject to federal regulations implementing this provision (Beeland 1978).

Sections 304(e) and 307(a) of the FWPCA are designed to control toxic effluents. Under these sections, the EPA is required to compile a list of toxic constituents and to establish effluent standards for each constituent. The toxic effluent standards or prohibitions required by the FWPCA are applicable to designated sources of pollution. Toxic effluent standards have not yet

been established for the geothermal industry by the EPA for use as guidelines by the state and federal agencies issuing NPDES permits. Section 307(a), as amended, allows the EPA to establish effluent standards more stringent than Best Available Technology (BAT) standards. The EPA has also been directed to specify the best management practices for industry to follow when using or storing toxic materials. These regulations will be implemented through the NPDES program (Beeland 1978).

State

Water quality standards, which are subject to periodic revision, have been established in compliance with Section 303 of the FWPCA by each state and approved by the EPA Administrator. These standards generally consist of three items (Thompson et al. 1978):

1. Designation of Use for particular reaches of water, including domestic, agricultural, fish and wildlife propagation, or a combination of these.
2. Effluent Limitations including chemical, physical, or biological limits for various constituents.
3. Antidegradation Policy stating that the deterioration of existing levels of water quality is prohibited.

In general, state regulations may impose restrictions on discharges beyond those required by federal law but may not be less restrictive (Thompson et al. 1978). The water-quality standards adopted by the 11 western states addressed in this report are not uniform and no state regulates all of the constituents. The majority of state water-quality standards are not applicable statewide but are applicable for designated state waters. Table 4.2 lists the constituents that are subject to state standards and indicates whether the standards apply statewide or only for particular reaches of water. As indicated in the table, most of the states have not established standards for all of these constituents.

TABLE 4.2. Effluent Constituents Limited by Water Quality Standards in Eleven Western States^(a)

	<u>Arsenic</u>	<u>Boron</u>	<u>Mercury</u>	<u>Total Dissolved Solids</u>
Arizona	d	d	d	
California	s		s	
Colorado				
Idaho				
Montana	d		d	
Nevada		d		d
New Mexico				d
Oregon	d	d		d
Utah	p			p
Washington				
Wyoming				

where d = Criteria for designated waters

s = Criteria applied statewide

p = Criteria conforming with Drinking Water Standards
(USPHS 1962)

Source: Beeland 1978.

(a) Limitations also exist for other constituents, but have been excluded due to either lower frequency of occurrence or due to lesser environmental importance, or both.

The antidegradation statement contained in most state regulations typically requires that, when surface water quality exceeds state criteria, it must be maintained at the higher quality. Also, if a water quality higher than that required by the existing standards can be achieved, it is to be attained by the best practicable treatment process and/or control of wastewater (Beeland 1978). That is, effluent treatment programs designed to attain constituent concentrations equivalent to ambient receiving water quality may not always be sufficient to achieve compliance with an NPDES discharge permit.

4.2 WELL INJECTION (GROUNDWATER STANDARDS)

Federal

Section 402 of the FWPCA encourages state efforts to control groundwater pollution but does not authorize direct federal control. The EPA regulations require that any state agency participating in the NPDES program should issue permits to control or prohibit all disposal of pollutants into wells. A recent court decision (Exxon vs. Train 1977) established that EPA regional offices have no authority under the NPDES program to impose conditions on well injection if no associated surface water discharge exists (Thompson et al. 1978).

According to the EPA, regulations governing the disposal of wastewater to subsurface freshwater aquifers under Part C of the Safe Drinking Water Act (SDWA) are not currently applicable to subsurface disposal of hydrothermal fluids. If and when injection regulations are promulgated at the federal level, pursuant to the SDWA, they most likely will include injection system design requirements and preoperational design approval. Regulations would probably prevent the injection of spent fluid contaminants into designated drinking water aquifers and would probably require injection to, or below, the producing reservoir where it is technologically and economically feasible (Beeland 1978). When returning the spent fluid to the producing reservoir is not economically feasible, such as may be the case with geopressured resources, injection to other aquifers may be allowed if the injected fluid does not degrade those aquifers for other existing or potential uses (EPA 1978). In some cases, the spent fluid may contain higher constituent concentrations than the fluid originally withdrawn. The EPA recommends that a concentration increase, caused by injected fluids, should be allowable to the reservoir if it does not interfere with other legitimate uses of the reservoir (Thompson et al. 1978).

State

None of the western states addressed in this study prohibit underground injection of wastes. However, most impose stringent disposal guidelines for wells and require issuance of permits, such as those of the NPDES system

(State Water Laws). Of these states, New Mexico is the only state that has quantitative groundwater standards for various constituents. None of the states considered specifically regulates the injection of hydrothermal brines.

4.3 SURFACE PONDING AND STORAGE

Federal

Restrictions on evaporation ponds and/or sludge impoundments may result from regulations developed under the Federal Resource Conservation and Recovery Act (RCRA). The RCRA provides for greater control of solid waste disposal. Solid wastes are defined as solid, liquid, and semisolid material and include such wastes as cooling tower sludge, sludges generated by air and/or water emission controls, drilling muds, and the sludge from spent-brine surface impoundments (Thompson et al. 1978).

Under Subtitle C of the RCRA, Section 3001 requires the EPA to determine substances that are to be designated hazardous based on toxicity, persistence, and other criteria developed for this purpose. Section 3002 requires that standards for record keeping, labeling, the use of containers, chemical analysis, the use of a system for tracking wastes, and submission of reports be developed to regulate generators of hazardous wastes. Wastes that may cause or contribute to adverse effects on human health or the environment when not properly controlled are considered potentially hazardous (Thompson et al. 1978). Although regulations have not been developed under any part of this act, drilling muds may be designated as hazardous in the future (Beeland 1978).

Section 3005 requires permits for hazardous waste disposal facilities and outlines conditions that must be met before permits are approved. A state may be granted the permit-issuance authority by the EPA Administrator. Also of importance is the provision in Section 6001 of RCRA that requires that federal, state, and local solid waste disposal laws be applied to federal facilities as they are to private entities. This regulation would include Department of Energy (DOE) demonstration and pilot plants (Thompson et al. 1978).

State

State regulations are primarily aimed at preventing the infiltration of effluents from surface impoundments and controlling runoff from impoundments to isolate both groundwater and surface water from possible contamination. California places specific restrictions on wastes discharged to land. Under these restrictions, brines and drilling muds are classified as Group I wastes that must be disposed of only at Class I disposal sites. Class I disposal sites are subject to waste discharge requirements that include limits on the type and quantity of material entering the site and the amount of material present or remaining on the site after the evaporation of liquids. Class I disposal sites must protect the quality of groundwater and surface water from wastes disposed of at the site and against hazards to public health and wildlife propagation (California Administrative Code 1977).

4.4 OCEAN DISPOSAL

Federal

The EPA states that ocean disposal may be acceptable when access is available and the brine will not significantly contaminate seawater and coastal zones. Ocean disposal will be regulated under Parts 220 through 229 Title 40 CFR in accordance with the Marine Protection, Research and Sanctuaries Act of 1972 and the FWPCA. In the most recent revision of the proposed ocean dumping regulations, all mention of ocean outfalls was eliminated and the regulations now apply only to dumping accomplished by vessel transport. As noted in the Federal Register, separate regulations covering ocean outfall are in preparation (Beeland 1978). Section 403 of the FWPCA states that ocean discharge criteria will be developed by the EPA Administrator. The second column of Table 4.1 shows the current federal water quality criteria for ocean disposal of some constituents commonly associated with hydrothermal brines. As with discharge to other surface waters, an NPDES discharge permit is required.

State

Of the three West Coast states, Washington and Oregon are the only ones with specific numerical effluent standards for marine and estuarine waters (State Water Laws). However, none of these standards apply to the constituents that may be present in hydrothermal liquid wastes.

4.5 SUMMARY

Waste disposal options may be affected by legislation at the federal level:

Surface Disposal - Federal Water Pollution Control Act (FWPCA) as amended by the Clean Water Act

Well Injection - Safe Drinking Water Act

Surface Ponding - Federal Resource Conservation and Recovery Act (RCRA)

Ocean Disposal - Marine Protection, Research and Sanctuaries Act.

Federal regulations require each state to establish receiving water quality standards and also require the EPA to establish effluent standards for specific sources. Under the FWPCA's discharge permit requirement, a state or the EPA will specify effluent limitations that must be met by a permit applicant for each case, based on the above-mentioned state and EPA standards. Because quantitative state standards are scarce and the EPA has not yet promulgated effluent standards specific to the geothermal industry, the discharge permit limitations are difficult to predict for a given site.

Although no regulations applicable to liquid waste treatment have yet been promulgated on the federal level, the EPA feels that injection to the reservoir appears to be the most environmentally acceptable disposal method for spent brine, cooling water blowdown, and excess condensates (Sung et al. 1977).

5.0 WASTEWATER TREATMENT SYSTEMS

Wastewater treatment systems were reviewed to derive functional relationships between treatment costs and wastewater flow rates. Ideally, the development of such wastewater treatment functions would enable quantity projection of treatment inputs (land, labor, capital) required to meet any given effluent water quality standard. Wastewater treatment cost estimates could then be derived for any given site simply by attaching site-specific prices to the functions. A literature review of wastewater treatment technology revealed that data on treatment cost functions were not readily available. Industry representatives were contacted in an effort to provide or generate data. Again, the data were either proprietary or simply not accessible with existing resources. Available literature and industry contacts provided data relating the total cost of a treatment system to its liquid flow rate and sludge generation rate. Flow rate in millions of gallons of liquid per day (MGD) was found to be the driving variable that determined both the capital and operating costs of wastewater treatment systems. Therefore, the cost of employing wastewater treatment processes to achieve a given standard of effluent water quality is reported primarily as a function of liquid flow rates and process TDS removal efficiencies. Where available, treatment costs were illustrated as a function of water quality to the extent that information allowed.

This section presents descriptions of the state-of-the-art wastewater treatment systems. Individual unit operations are presented first, and both conventional and advanced water-treatment processes are discussed. All of the estimated cost functions were placed in Appendix B to provide clarity and continuity in this section.

5.1 UNIT OPERATIONS

A wastewater-treatment system consists of a series of individual unit operations that perform complementary constituent-removal tasks. Each unit operation can be visualized as a pretreatment requirement for the succeeding unit operation. Therefore, the removal efficiency for each unit operation

depends on the efficient performance of each preceding unit operation. The failure of one operation may reduce the removal efficiency of all subsequent steps.

The unit operations described here fall into two categories: conventional and advanced. Conventional unit operations perform chemical precipitation, coagulation, and removal in a four-step system. These four unit operations are rapid mixing, flocculation, sedimentation, and filtration. The advanced unit operations include ion exchange, reverse osmosis, electrodialysis, and distillation.

Conventional Unit Operations

Wastewater treatment systems composed of rapid mixing, flocculation, sedimentation, and filtration have been in widespread use for many years in municipal and industrial applications. The most common wastewater treatment application is hardness removal with either aluminum sulfate (alum) or calcium hydroxide (lime). Often iron compounds (ferric chloride or ferrous sulfate) or polymers are added to enhance flocculation. Conventional systems are also useful for the removal of suspended solids and phosphate. Silica removal may be performed by adsorption if magnesium is present in the water.

Conventional treatment systems can remove more than 70% of the toxic elements, such as arsenic and mercury, from the water without chemical addition. With the addition of chemicals, more than 80% of these elements can be removed. Boron cannot be separated as effectively; only a 28% removal of boron can be achieved without chemical addition, but up to a 42% removal can be achieved with the addition of chemicals.

Chemical Addition

The first step in a conventional wastewater-treatment system is the addition of chemicals to facilitate the removal of specific constituents. Alum, polymers and iron compounds can be added in either liquid or solid form. Typically, they are stored dry and then slurried into a pumpable liquid and metered into solution. The addition of lime is slightly more complicated than the addition of other chemicals. Lime is typically stored dry in the form of calcium oxide, which is more stable and less expensive than calcium hydroxide.

Calcium oxide is mixed with water in a slaker, and calcium hydroxide is formed by the reaction. The lime is then metered into solution in the form of a paste that will easily dissolve.

Cost Factors. The capital costs of a chemical-handling system are dependent on several variables. Plant capacity is important because the amount of chemicals added to a given plant flow is directly proportional to the volume of flow. The influent water quality and the desired effluent quality are also important because the amount of dissolved solids that precipitate is dependent on the amount of chemicals added. The important water quality parameters include pH, hardness, and alkalinity. The type of chemicals handled also influences the capital cost of the handling system. The operating costs of chemical handling systems are dependent on chemical feed rates, power costs, labor costs, and maintenance costs. No information was available on the specific rate of chemical, energy, labor, and maintenance inputs required for geothermal liquid wastes. Costs functions are reported strictly as a function of flow rate in Appendix B.

Rapid Mixing, Flocculation, and Sedimentation (Solids Contact Reactors)

The unit operations of rapid mixing, flocculation, and sedimentation are typically performed in a single vessel called a solids contact reactor. A typical solids contact reactor is shown in Figure 5.1.

Rapid Mixing. The influent to the system is mixed with chemicals in the rapid-mix zone. In this zone, vigorous agitation assures intimate contact between the added chemicals and the impurities to be removed. The rapid-mix zone is typically designed for retention times of 30 seconds to two minutes. In this brief time, chemical reactions begin to occur and are continued in the flocculation zone.

Flocculation. The flocculation zone is where most of the chemical reactions occur. The dissolved solids react with added chemicals, and the resultant compounds are solid. The flocculation zone is typically designed for a retention time of 15 to 30 minutes. The water in this zone is gently agitated to promote good contact between chemicals without breaking up the newly formed floc.

FIGURE 5.1. Cross Section of a Typical Solids Contact Reactor

The newly formed solids are discrete particles that must be agglomerated to facilitate settling. Since the electrical charges on these colloids preclude coagulation, coagulant aids that work by neutralizing the electrical charges must be used to allow the particles to stick together. Iron compounds and polymers are used for this purpose.

Sedimentation. In the sedimentation zone, the floc is allowed to settle while the clear water overflows weirs. Upflow rates of 0.75 to 1.5 gallons per minute per square foot of surface are typical and provide retention times of one to two hours in the sedimentation zone.

The settled floc is collected at the bottom of the reactor and the sludge is drawn off. Much of the sludge is recycled to the flocculation zone to enhance coagulation. The reuse of the sludge is a very important attribute of solids contact reactors and may make them relatively attractive for use in conventional wastewater treatment systems. The rest of the sludge is blown down and must be disposed of.

Cost Factors. The capital cost of a solids contact reactor system is dependent on several parameters including flow rate, specific water composition, basin and system design, and water temperature. Obviously, the cost will increase with increasing plant flow rates. The nature of the sludge formed and the recycle rate depends on the amount and the nature of the impurities to be removed. The basins may be constructed of either steel or concrete and may either be above or below ground depending on the plant's flow scheme. With larger plants, a choice must be made between a single large reactor or multiple units.

Solids contact reactors usually operate at ambient temperature, and most published cost information concerns these plants. The elevated temperatures of hydrothermal brines could tend to increase or decrease the cost of the system. Reactors operating at very high temperatures (up to 200°F) would have to be insulated since failure to maintain near-constant temperatures could upset the system. Special bearings and corrosion inhibitors could also increase the capital costs. Conversely, high temperatures could also decrease costs because faster reaction rates could allow smaller units. The actual design, however, would have to be determined on a case-by-case basis with a pilot plant.

The operating costs of a solids contact reactor are dependent on plant capacity, the amount of sludge formed, power costs, and labor costs. The most important variables seem to be plant capacity and sludge-generation rates. The cost data used to derive the functions in Appendix B for solids contact reactors are driven only by flow rate.

Filtration

Typically, the clarified effluent from a solids contact reactor is filtered. Filtration removes turbidity and the fine suspended solids that do not settle in the solids contact reactor. Figure 5.2 shows a typical gravity filter.

Filter Media. Several types of filter media are in widespread use. The oldest and most basic is a single medium, sand. As water flows through the porous bed of sand, particles impinge on the grains and collect in the space between. As particles are collected, the pores become plugged and increased pressure is required to maintain the flow rate. Periodically, the flow is stopped and the filter is backwashed to remove the accumulated solids. During the backwash cycle, water is pumped up through the bed at a rate fast enough to suspend the grains of sand but not fast enough to wash the sand over the backwash trough. At ambient temperatures, backwash rates of 12 to 15 gpm/ft² are typically used, but, due to the decreased viscosity of high-temperature water, a backwash rate as high as 25 gpm/ft² may be required. At the end of the backwash cycle, the sand settles; large grains first and smaller grains last, on top of the bed. Ideally, the largest particles should be on top of a gravity filter bed and the smallest on the bottom. In that situation large suspended solids would be removed at the top of the bed; medium-sized solids would be removed in the middle of the bed; and the smallest solids would be removed at the bottom of the bed. The entire bed would function as a filter. With the smallest grains on top, all suspended solids are removed in the first few inches. This causes rapid plugging and necessitates frequent backwashing. To overcome this problem, multimedia filters have been developed.

Multimedia filters have beds composed of two or more media of various densities and particle sizes. Dualmedia filters usually have a top layer of anthracite and a bottom layer of silica sand. A typical multimedia filter may

FIGURE 5.2. Gravity Filter Arrangement with Backwash Cleaning System

have a top layer of relatively large pieces of anthracite coal, a middle layer of silica sand, and a bottom layer of fine garnet sand. A mixed-media filter is a proprietary concept that provides the intermingling of various media. This concept most closely approximates the theoretical ideal of decreasing particle size with bed depth. Mixed-media filters often produce an effluent with a turbidity of less than one unit.

Cost Factors. The capital cost of a filter system is dependent on several variables. The plant capacity and the filter-loading rate are major influences on the size of the filter system. Water quality, however, can also influence system size. The type of filter medium selected also influences capital costs. In general, single-media sand is less expensive than dual or mixed-media. However, a trade-off exists between the capital investment and filter performance. The operating costs of filters are dependent on flow rate, the frequency of the backwash cycle, and power, labor, and maintenance costs. Plant layout can also affect operating costs since power requirements can be reduced if the filter influent or backwash influent can flow by gravity. Appendix B reports these costs as a function of flow rate only.

Sludge Disposal

The sludge discharged from a solids contact reactor may contain from 2% to 5% solids, depending on the chemicals added and the impurities removed. Concentrating the sludge to facilitate handling and disposal is usually desirable. The equipment that can be used to concentrate sludge includes gravity thickeners, vacuum filters, and centrifuges.

Gravity thickeners are large settling tanks. Solids in the sludge are allowed to settle while clear water overflows weirs. A sludge of up to 20% solids can be obtained. The volume of this sludge would be 25% of the volume of an influent sludge of 5% solids.

Sludge from a gravity thickener can be further reduced in volume by a vacuum filter, centrifuge, or an evaporation pond. Vacuum filters pull water through a porous medium that retains the solids. Centrifuges spin the sludge, forcing the dense solids outward. These systems typically produce cakes that are about 65% solids and that can then be disposed of in a landfill.

Cost Factors. The cost of handling sludge is dependent on the amount produced and the nature of the sludge. Plant capacity has only an indirect effect on sludge-handling costs; a small plant with a high-TDS influent and a high removal efficiency may produce more solid waste than a large plant with a low removal efficiency. Some solids separate from water more easily than others. For example, a heavy sludge such as calcium carbonate settles much more readily than a lighter sludge such as aluminum hydroxide.

The capital and operating costs of centrifuges are typically considerably greater than those for vacuum filters. However, depending on the specific plant, centrifuges may be more desirable than filters since vacuum filters generally require the addition of a polymer coagulant. The polymer may interfere with certain processes if the filtered water is to be recycled to the plant. In this case, centrifuges would warrant consideration.

Sludge disposal costs are a major part of the total costs of a conventional treatment system because of the distances between the plant and the disposal site, the cost of designing and monitoring the site, and the costs of the site itself. Often a sludge disposal site is miles from the treatment

site so a fleet of trucks and fulltime drivers must be employed. Because the sludge is a hazardous waste, disposal landfills must be properly designed and carefully monitored to prevent groundwater contamination. When land for waste disposal is readily available, thickened sludge may be disposed of in an evaporation pond. The cost of the pond is determined by its size and characteristics and its size depends on the volume of waste generated, evaporation at a given site, and the required lifetime of the pond. The pond's size will be relatively independent of the TDS content of the sludge because the yearly solids buildup due to evaporation may be small in comparison to the pond volume required to contain the annual holdover (amount of water left after evaporation). Ponds should be lined with impermeable membranes or clay to prevent seepage. These cost functions, reported in Appendix B, are sensitive to the rate of sludge generation, labor costs, and power costs.

Advanced Unit Operations

Advanced unit operations are used when conventional systems cannot meet the water quality desired and include ion exchange, reverse osmosis, electro-dialysis, and distillation.

Ion Exchange

An ion-exchange process removes undesirable ions from a waste stream and replaces them with other ions. This process is achieved as the water flows through a bed of special resins. Influent to ion-exchange systems typically require some pretreatment to remove suspended solids and to avoid fouling the resin bed. Styrene-based resins are capable of withstanding the high temperatures encountered with brine. The resin consists of a matrix of insoluble, infusible polymer. Specific ions attach to the matrix with reversible chemical reactions. When the resin has replaced all of its original ions with the undesirable ions from the waste water, it must be regenerated. This regeneration is accomplished by washing the resin with a strong solution of the original ion. Figure 5.3 shows the movement of the raw influent through the cation and anion units into the product and wastewater outfalls.

FIGURE 5.3. Typical Ion-Exchange System with Cation- and Anion-Exchange Columns and an Acid/Base Regeneration System

Many types of ion-exchange resins are commercially available. Each resin exhibits an order affinity for specific ions. When selecting a resin for a given application, the ions to be removed and all other ions present in the water must be carefully considered.

Examples of Ion-Exchange Processes. Perhaps the most common use of ion exchange is sodium zeolite softening. In this process, divalent metal ions (such as calcium and magnesium) are replaced with sodium and the resins are regenerated with highly concentrated solutions of sodium chloride.

Another common ion-exchange process replaces cations with hydrogen ions and anions with hydroxyl ions. Hydrogen ions and hydroxyl ions combine to form water. These resins are regenerated with strong solutions of sulfuric acid and sodium hydroxide, respectively. A fresh ion-exchange bed will remove virtually all of the specific ions that it is designed for. As the run pro-

gresses, the removal efficiency decreases. Overall removal efficiencies of 90% are not uncommon for toxic elements such as boron, mercury, and arsenic, as well as for total dissolved solids (Haugseth and Beitelshies 1974).

Cost Factors. The cost of an ion-exchange system depends on the wastewater flow rate and on the specific ions being removed. The capital cost is most dependent on the flow rate and the specific ions being removed. The largest fraction of the operating cost is the resin regenerant costs. The amount of regenerant required depends on plant capacity and the desired reduction of dissolved solids. The unit cost of regenerant is dependent on the specific ions being removed; sodium chloride regenerant is quite inexpensive while strong acids and bases are more costly. All the costs are reported in Appendix B as functions of removal efficiency and flow rate.

Reverse Osmosis

Osmotic pressure is the force that drives water through membranes from solutions of low dissolved-solid concentrations to solutions of higher concentrations. The magnitude of osmotic pressure is directly proportional to the difference in concentration between the two solutions. This natural phenomenon can be reversed by applying a pressure greater than the osmotic pressure to a highly concentrated solution. Reverse osmosis systems force water molecules through membranes that prevent the passage of dissolved solids. A reverse osmosis system is shown in Figure 5.4.

System Description. The influent to a reverse osmosis system is pressurized with high-pressure pumps. Because water that passes through the membrane loses its pressure in the process, the product water (or permeate) leaves the system near atmospheric pressure. Water that does not pass through the membrane becomes concentrated brine (or reject) and retains most of its pressure through the system. By passing the high-pressure reject through turbines, some of its energy can be recovered.

The percentage of water that becomes permeate depends on the applied pressure and the salinity. Usually, the recovery rate is constrained by the concentration of certain ions, such as calcium, magnesium, barium, strontium, carbonate, and sulfate. The concentration of these ions in the reject must

FIGURE 5.4. Representation of the Reverse Osmosis Unit Operation

not be allowed to exceed their solubility limits or damaging scale will form. Chemicals such as acids, polymers, or polyphosphate may be added to the feed to inhibit scale production and thus increase the recovery rate.

Salt rejection refers to the percentage of salt remaining in the reject. Rejection rates of 99% are not uncommon. Reverse osmosis systems are also highly efficient at removing suspended solids, although they are not designed to do so. Arsenic, boron, and mercury can also be removed effectively by reverse osmosis. Removal efficiencies of 60%, 85%, and 85%, respectively, can be achieved. Influent pretreatment is also required for reverse osmosis to prevent suspended solids from fouling the membranes (EPA 1978).

Two types of reverse osmosis systems are commercially available. Spiral-wound systems employ sheet membranes separated with spacers wound around a center tube from which the permeate flows. Hollow fine-fiber systems employ membrane fibers that are roughly the size of a human hair. Water passes the

wall of the fiber to a hollow center. The two schemes are quite competitive when treating brackish water, but, at higher salinities, the hollow fine fibers are more susceptible to compaction because of the high pressure.

Reverse osmosis membranes will not tolerate high temperatures. Manufacturers typically recommend operating temperatures of 85°F or less, which will restrict the use of reverse osmosis for treating geothermal water.

Cost Factors. The capital cost of a reverse osmosis system is most dependent on plant capacity. The operating costs depend on plant capacity as well as water quality. Because high-TDS influent water will require very high pressures to overcome osmotic pressure, power costs are quite important. Another major contributor to operating cost is membrane replacement. Typically, membranes must be replaced every three to five years. All costs are reported as functions of flow rate in Appendix B.

Electrodialysis

Electrodialysis is similar to reverse osmosis in that they are both membrane desalting systems, but the driving force for electrodialysis is an electrical field rather than pressure. Also, in electrodialysis the ions pass through the membrane rather than the water.

System Description. Two types of membranes are required for an electrodialysis system. One allows cations to pass but not anions, while the other allows anions through but rejects cations. The two types of membranes are separated with spacers and assembled into a stack. A stack is typically comprised of several hundred cell pairs. Stacks are placed in parallel rows to meet capacity requirements and may be placed in series to accommodate removal requirements (although a single stack may also contain multiple stages).* A typical electrodialysis stack is shown in Figure 5.5.

As water flows past the membranes, ions are attracted toward the electrode that is oppositely charged. An ion may pass through one membrane into the adjacent space, but it is blocked from going farther by an impermeable membrane. The flow in one spacer therefore becomes less concentrated while the flow in the adjacent spacers becomes more concentrated.

C represents cation permeable membranes
 A represents anion permeable membranes

FIGURE 5.5 Typical Electrodialysis Demineralization System

* One positively charged and one negatively charged electrode are on the end of each stack.

Two types of spacers are commercially available. A tortuous-path spacer forces water to wind around the face of the membrane, insuring contact for an ample period of time. A sheet-flow spacer allows the water to flow straight across the face of the membrane, but ripples in the spacer create turbulence, thus insuring thorough mixing and intimate contact between the ions and the membranes. The detention times of the water in the spacers range from 4 to 6 seconds for sheet flow and 10 to 20 seconds for tortuous-path spacers (Bechtel Corporation 1977).

Electrodialysis systems typically remove 30% of the ions from the feed water, including toxic elements such as arsenic and mercury. Boron, however can only be removed with a 10% efficiency by this process (EPA 1978). The

process is not effective for the removal of suspended solids of nonionic species such as silica. When a removal efficiency greater than 30% is desired, multistage systems are typically employed.

Cost Factors. The capital cost of an electrodialysis system is dependent on the number of membrane stacks required, which is in turn dependent on plant capacity and the desired removal efficiency. Operating costs are dependent on plant capacity, ionic strength, the temperature of the water, and the frequency of membrane replacement. These electrodialysis costs are reported in the literature strictly as a function of flow rate, as shown in Appendix B.

Distillation

Distillation systems separate water from dissolved solids by vaporizing a portion of the influent and condensing it as a mineral-free product. Dissolved solids remain in the nonvaporized water that leaves the system as a highly concentrated brine. Distillation systems are quite energy-intensive. About 1000 Btu is required to evaporate one pound of water.

System Description. Two basic distillation design systems are in use today: the multistage flash process and the vertical tube evaporation process (also called multieffect evaporation). The vapor compression process can be used in conjunction with either of the basic designs to improve efficiency. Schematics of these three systems are shown in Figures 5.6, 5.7, and 5.8.

Multistage flash systems operate on the principle that water boils at lower temperatures under decreased pressures. The influent is heated and passed through several chambers or stages. The pressure in each chamber is lower than in the previous one. As the water enters a stage, part of it suddenly vaporizes or flashes. Flashing continues until the water and vapor are in thermodynamic equilibrium. Vapor is condensed onto coils through which cool influent water flows, preheating the feed water and thus recovering some energy.

Vertical tube evaporators operate on the same pressure/temperature equilibrium principle as the multistage flash system. The principal difference between the vertical tube evaporators and the multistage flash system is the location of vapor condensation and thus heat recovery. Vapor produced in

Source: Bureau of Reclamation 1972

FIGURE 5.6. Multistage Flash Distillation System

Source: Bureau of Reclamation 1972

FIGURE 5.7. Vertical Tube Evaporation System

FIGURE 5.8. Distillation System Employing Vapor Compression
(Bureau of Reclamation 1972)(a)

- (a) VC = Vapor Compression
VTE = Vertical Tube Evaporator
MSF = Multistage Flash

the first chamber or effect is condensed on the influent tubes to the second effect, and so on. Liquid remaining in the last effect is rejected as brine.

Vapor compression may be employed with either of the above systems to improve energy efficiency. As vapor is produced in a stage or an effect, it is collected and compressed. Some energy is required to drive the compressor, but the enthalpy of the vapor is increased significantly. When the vapor is condensed, the heat transfer efficiency is much higher than with low-enthalpy vapor.

Cost factors. The capital costs of a distillation system are most dependent on plant capacity. Multistage flash and vertical tube evaporation systems are, in general, competitively priced. Adding vapor compression to either system adds to capital costs, but this may be offset by reduced energy costs. The major operating cost is energy. Electric power is required to drive the pumps and steam is required for heat. Another operational cost is for scale- and corrosion-control chemicals. Chemical costs are dependent on water quality as well as plant capacity. All of the costs for distillation in the literature were reported as functions of flow rate. While this is known to be a misspecification of total costs, no alternative information could be found.

5.2 APPLICATIONS OF UNIT PROCESSES

For each proposed power plant, a detailed study will have to be performed to select treatment processes capable of attaining the desired 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 facilities.

Supersaturated Dissolved Solids Removal (SSDS)

As brine flashes and cools, the solubilities of certain dissolved solids decrease as their concentrations increase and the brine may become supersaturated. This condition is undesirable since supersaturated species eventually precipitate and may cause scaling or may plug injection aquifers.

Pilot studies at the Geothermal Loop Experimental Facility near Niland, California, indicate 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 5.9. 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.

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 a filter effluent can be provided with 1 mg/l suspended solids (Quong, Schoepflin, and Stout 1978), which is approximately one turbidity unit.

Based on the pilot-plant study, a system was designed and installed to handle spent brine from a 10-MWe plant at Niland. Cost estimates for handling the brine from a 55-MWe plant were also made. The treatment of brine in a solids contact reactor followed by gravity filtration was estimated to cost 11¢ per 1000 gallons, or 0.9 mills per kWh. Sludge handling, including thickening, dewatering, and disposal, was estimated to cost 8¢ per 1000 gallons, or 0.7 mills per kWh (Van Note, Featherstone and Pawlowski 1978). Due to the preliminary nature of the study, their report stressed that these estimates were accurate to an order of magnitude.

FIGURE 5.9. Typical Conventional Treatment System

Chemical Precipitation

The SSDS removal system described above will probably provide adequate treatment when the brine is to be disposed of by injection. When other disposal options are considered, certain dissolved solids would be chemically precipitated. The equipment used by a chemical precipitation system could be the same solids contact reactor and filters described above, except that chemical-feed systems would be added. At the East Mesa Test Site near Holtville, California, a chemical-precipitation system employing separate rapid-mix, flocculation, and settling tanks was built to remove silica, heavy metals, and bicarbonate. The performance of that pilot plant was quite poor (Bechtel Corporation 1977).

Some chemicals, such as lime and soda ash, will react with dissolved solids to form insoluble compounds. Other chemicals, such as iron salts and polymers, neutralize electrical charges on colloids and allow the particles to agglomerate. Although most experience with coagulants is with ambient-temperature water, pilot tests at Niland indicate that the elevated temperatures of hydrothermal brine do not alter the effectiveness of coagulants (Quong, Schoepflin, and Stout 1978). The industry has used chemicals such as lime and soda ash at high temperatures for many years.

Chemicals have been estimated to add between 0.2¢ and 0.5¢ to the cost of treating 1000 gallons of liquid effluents (Van Note, Featherstone and Pawlowski 1978). The actual chemical cost will depend on the specific dissolved solids to be removed and the desired effluent quality.

Ion Exchange

When certain specific ions must be removed from the brine, an ion-exchange system may be applicable. The ion-exchange systems would typically follow the chemical precipitation and filtration system described above and may precede another advanced system. When a desalination system is employed, the purpose of ion exchange is to reduce the concentration of specific ions to a point where saturation limits will not be exceeded when the ions are concentrated in the brine (Haugseth and Beitelshees 1974). As a final step in the water treatment system, ion exchange can be used to remove toxic metals from drinking water or to reduce the sodium-absorption ratio of irrigation water.

Desalination

In areas where water is extremely scarce, the reuse value of water may be high enough to justify a desalination system. A hypothetical treatment system employing desalination is shown in Figure 5.10.

Some type of effluent pretreatment would probably be required prior to desalination. In some cases, chemical addition for scale and corrosion control may be sufficient, while in other cases a conventional treatment system employing solids contact reactors and filters may be required. Ion exchange could be used if solubility limits of any compound would otherwise be exceeded in the brine from the desalting system. Feasibly the brine from the desalination system could be used to regenerate the ion-exchange resins.

At the East Mesa Test Facility near Holtville, California, the Bureau of Reclamation tested three desalination systems on hydrothermal brine (Bechtel Corporation 1977). Two distillation systems, a vertical tube evaporator and a multistage flash system, were operated on brine pretreated with corrosion inhibitors. Although some calcium carbonate scaling occurred, the distillation tests were successful. The concepts were found to be technically feasible and valuable design knowledge was obtained. A high-temperature electrodialysis system was also tested, but no conclusion could be reached due to the failure of the conventional pretreatment system and the abbreviated test program.

Presumably, desalting brine with reverse osmosis would be technically feasible, although no such tests have been identified. Such a system would have to cool the brine to 85°F prior to treatment.

The technical feasibility of a given process does not imply economic feasibility. To determine the economic feasibility of a desalting system, the value of the water, the cost of obtaining water from alternate sources, and the technical feasibility must all be considered. The purpose of the Bureau of Reclamation's investigation at East Mesa was to determine whether it was feasible to augment the flow of the Lower Colorado River by replacing irrigation water diverted into the All-American Canal with desalted brine. Further research on this possibility has been discontinued, due to the high cost of desalination, among other factors.

FIGURE 5.10. Hypothetical Treatment System Employing Conventional and Advanced Unit Operations

5.3 SUMMARY

At the beginning of this section, it was noted that ideally the control functions should be specified as physical production functions where possible. Prices could then be attached to each variable to relate the control costs to cost-driving variables. Literature searches and contacts with the industry have indicated that physical production function data are not available. As a result, the cost estimates reported in Appendix B are shown to be primarily sensitive to liquid-waste flow rates. Both conventional and advanced treatment process cost functions were derived; they will be used in the case study to estimate liquid waste treatment costs. Such cost estimates may understate the treatment cost by being relatively insensitive to the chemical composition of the liquid wastes.

Table 5.1 presents a summary of the wastewater treatment systems reviewed in this section. Conventional treatment processes can be used on any range of wastewater dissolved solids concentrations. Together, the sedimentation and filtration steps (SSDS removal) can remove 19% of the TDS as well as 28%, 78%, and 73% of the boron, arsenic, and mercury, respectively. All three of the steps listed under conventional treatment systems (SSDS removal enhanced by chemical precipitation) have combined removal efficiencies of 35% of the TDS, 42% of the boron, 96% of the arsenic, and 84% of the mercury.

The electrodialysis and ion-exchange processes have the most limited ranges of application. The wastewater to be treated should be less than 5000 ppm TDS to achieve TDS removal efficiencies of 30% to 40% for electrodialysis and 80% to 90% for ion exchange. At higher brine concentrations, these systems are not as effective. Reverse osmosis can be used with a wider range of brine concentrations (up to 50,000 ppm) and still obtain efficiencies of 85% to 95% for removal of TDS, mercury, and arsenic, and 60% to 80% for removal of boron. The distillation system can be applied to brines with concentrations of up to 300,000 ppm TDS. Few hydrothermal resources reach this concentration. For this process, the boron, arsenic, and mercury removal efficiencies are unknown.

TABLE 5.1. Treatment Systems Summary

Treatment System	Removal Efficiencies (%)				TDS Limit for System Application	Cost Variables
	TDS	Boron	Mercury	Arsenic		
Conventional:						
Sedimentation	10	10	10 to 30	10 to 30	no limit	volumetric flow rate
Filtration	10	20 to 40	70 to 80	79 to 95	no limit	volumetric flow rate TDS concentration labor cost power cost
Chemical Precipitation	20 to 40	20 to 40	40 to 60	80 to 98	1000 ppm TDS	volumetric flow rate chemical cost
SSDS Removal(a)	19	28	73	78	no limit	
SSDS Removal(a) enhanced by chemical precipitation	35	42	84	96	no limit	
Advanced:						
Electrodialysis	30 to 40 per stage	10	30 to 40	30 to 40	5000 ppm TDS	volumetric flow rate
Ion Exchange	80 to 90	80 to 90	80 to 90	80 to 90	5000 ppm TDS	volumetric flow rate change in TDS concentration
Reverse Osmosis	85 to 95	60 to 80	85 to 95	85 to 95	50,000 ppm TDS	volumetric flow rate
Distillation	99				300,000 ppm TDS	volumetric flow rate

(a) Supersaturated dissolved solids removal.

The MGD approach may underestimate the cost of environmental controls for the following reasons:

1. Removal efficiencies and operating inputs are expected to be somewhat sensitive to the inorganic nature of brines.
2. The impacts of variable concentrations of TDS and individual constituents such as divalent metal ions, which may generate scaling and corrosion problems, are difficult to predict.
3. The specific functional relationships have not been determined; thus, the cost functions used here are not sensitive to variations in TDS, but they are sensitive to the impact of sludge-disposal expenses.

6.0 CASE STUDY

A site-specific investigation of the costs of liquid-waste treatment and disposal is presented in this section. The previous sections of this report reviewed disposal options, regulations, and the control technology associated with the treatment of liquid wastes. This section is intended to illustrate the cost of liquid-effluent treatment at a specific site.

Site-selection criteria are discussed first in this section, followed by a description of the site and estimates of wastewater treatment costs.

6.1 SITE SELECTION CRITERIA

The site chosen for cost estimation should meet several criteria:

- have significant potential for energy recovery and utilization
- be known to contain the constituents under study for which reliable treatment cost estimates can be developed
- be of commercial interest, given the nature of the industry and the position of the site in the time path of development for the industry.

Many resources in the western United States meet these criteria, and based on its characteristics, the Niland Site in the Salton Sea KGRA in the Imperial Valley of California was selected for the case study.

Salton Sea- California

Recoverable energy in the Salton Sea KGRA represents approximately 16.2% of the potential electrical-generating capacity that can be derived from liquid-dominated, high-temperature hydrothermal convection systems (3400 of a total potential of 21,000 MWe for 30 years) (Brook et al. 1979). Imperial County, where the Salton Sea KGRA is located, has been the subject of active exploration and development for the past decade. Test wells have been drilled at the Niland site and also throughout the Salton Sea area. The Salton Sea field supplied brine to a 10-megawatt Geothermal Loop Experimental Facility

that was tested by San Diego Gas and Electric Company for the Department of Energy. Imperial Magma, a subsidiary of Magma Power Company, and New Albion Resources Company operated the field in what was probably the first on-line, high-temperature, high-salinity reservoir supporting a utility plant in this country (Nugent and Vich 1977).

Mr. Zajac of Magma Power Company in Los Angeles reports that the testing has been successfully completed and that the 10 MWe facility has been dismantled. He noted that one of the purposes of the experimental installation was to determine the level of water treatment required to achieve injectable liquid effluents.

In the test facility all spent fluids were passed through a solids contact reactor prior to injection disposal. Fluids withdrawn from test wells in the reservoir had TDS concentrations ranging from 200,000 ppm_w up to 240,000 ppm_w. Deeper production wells will have even higher TDS concentrations (e.g. 250,000 ppm_w). Following treatment in the solids contact reactors, Mr. Zajac reports that the liquid effluent had a TDS concentration of 35,000 ppm_w to 50,000 ppm_w, implying a TDS removal efficiency of approximately 80%.

The Salton Sea KGRA TDS concentration averages around 250,000 ppm_w and its subsurface temperature has been estimated to be approximately 323°C. The site is a satisfactory choice for an investigation of the cost of meeting wastewater effluent standards based on several factors: 1) the commercial interest in the site, 2) its larger-than-average estimated energy potential, 3) its relatively high concentration of TDS, and 4) its demonstrated ability to produce the large-volume flows necessary for power production.

Environmental Regulations

Imperial County, California, requires that all fluids withdrawn from a geothermal reservoir for power production be replaced with an equal volume of fluid. The intention is to keep the extremely slow rate of natural subsidence in the valley from accelerating and destroying portions of the valleys'

irrigated agricultural acreage. The developers of the Niland Site at the Salton Sea KGRA had received permission from the California Division of Oil and Gas (CDOG) to inject only 80% of the brine volume withdrawn from their resource development projects (Imperial County October 1979). The reason for this partial (i.e. 20%) waiver is that the Salton Sea KGRA reservoir is believed to be fully compacted and not subject to subsidence at the Niland site.

In addition, the reservoir is believed to recharge naturally from the Salton Sea. Thus, from the developers' standpoint, the most profitable procedure for exploiting the resource is to a) use surface disposal of the spent brine by dumping it into the Salton Sea and b) allow the reservoir to recharge itself. However, the 80% injection level was designed to encourage initial testing and verification of the resource; it was not intended as a long-run operating policy for injection at the Niland site. The estimated cost of meeting liquid-effluent disposal regulations for the Niland Site will therefore consist of the expenses incurred when complying with the requirement for injection disposal of 100% of the spent brine. Because the brine has a relatively high TDS content, it will require treatment prior to injection to prevent scaling and plugging of the receiving formation.

6.2 COST ESTIMATION

The cost of meeting liquid effluent disposal regulations is divided into two sections below. The first section deals with the costs of treating and then injecting fluids withdrawn from the hydrothermal reservoir. The second section below presents the cost of treating the spent brine with advanced processes for eventual use as irrigation water.

For both cases the cost of water treatment was estimated from the process cost functions presented in Appendix B. All costs are expressed in January 1980 dollars. The liquid-waste flow rate from a 55 MWe (gross) dual flash steam cycle facility with a 30-year life and 80% capacity factor was estimated to be 8.236 million gallons daily (MGD) at the Niland site.

The Cost of 100% Fluid Replacement

Table 6.1 summarizes the costs of treating and injecting 100% of the spent brine at the Niland site. These cost estimates are presented in detail in Appendix C on Table C.1 and the cost estimation methodology is explained in Appendix D.

TABLE 6.1. Brine Treatment and Injection Costs for 100% Replacement (January 1980 Dollars)^(a)

	<u>Levelized Total Cost (\$10⁶)</u>	<u>Mills per Kwh</u>	<u>Cents per 1000 gals</u>	<u>\$/Acre Foot</u>
Fixed Costs	1.000	2.75	33.95	110.35
Variable Costs	1.743	4.80	59.18	192.33
Sludge Disposal ^(b)	55.900	153.45	1897.87	6168.32
Total	58.643	161.00	1991.0	6471.0

(a) From Table C.1 in Appendix C.

(b) The removal efficiency for the treatment series is assumed to be 80% for SSDS removal. Quality of the injected water is 50,000 mg/liter.

In terms of net present value, the 30-year stream of levelized total annual costs, when discounted at a 10% real rate, is equal to \$553,000,000.

The Cost of Brine Treatment for Irrigation Use

Table 6.2 summarizes the estimated costs of obtaining irrigation water from the spent brine at the Niland site. Although regulations do not require the reuse of spent brines at the Niland site, the possibility exists that such a policy may be imposed if injection is not selected as a disposal option. The table indicates that this can be a very costly decision to impose on the firm exploiting high TDS resources. Reuse of the Niland brine for irrigation water requires the use of distillation preceded by chemical precipitation and the conventional treatment series. Distillation is the only advanced treatment process suitable for Niland because the TDS content of the brine exceeds the tolerance limits for the other advanced processes discussed in Section 5.0.

TABLE 6.2. Brine Treatment Costs to Produce Irrigation Water from Niland Brines (January 1980 Dollars)^(a)

	<u>Levelized Total Cost (\$10⁶)</u>	<u>Mills per Kwh</u>	<u>Cents per 1000 gals</u>	<u>\$/Acre Foot</u>
Fixed Costs	8.120	22.28	275.7	896.10
Variable Costs	7.887	21.64	267.8	870.35
Sludge Disposal ^(b)	69.175	189.83	2348.5	7633.55
Total	85.182	233.75	2892.0	9400.0

(a) From Table C.2 in Appendix C.

(b) Distillation removal efficiency of 99% leading to production of large volumes of sludges.

The costs of distillation were calculated assuming a 99% removal efficiency (refers to the percent reduction in TDS achieved by the given treatment process) and a water recovery rate of 75% (refers to the percent of the liquid waste stream that has been purified). For the distillation process, calculations were made for full-stream treatment to provide irrigation water.

For purposes of this study, it was assumed that no net revenues would be generated from the sale or disposal of the product water. It may be argued that in water scarce areas where hydrothermal resources are typically located, the product water could easily be sold to either agricultural or industrial users. However, the analysis required to calculate and substantiate a market clearing price for the water would involve expenditures of research resources beyond those deemed appropriate.

The levelized life-cycle cost of the advanced treatment is estimated to be 234 mills per kWh for irrigation water. These costs are heavily dominated by sludge disposal costs. The net present value of levelized total annual costs discounted at 10% for irrigation water is approximately \$803,000,000. The product water would have to sell for over \$9000 per acre foot to retrieve these expenses. Neil Crow of Lawrence Livermore Laboratories reports that even drinking water in the Imperial Valley sells for the equivalent of only

\$75.00 per acre foot, which is well below the price required to recapture the full costs of using liquid wastes for an irrigation water source.

The most important expense in the conventional treatment system cost function is the cost of sludge disposal. The value used as a reference (\$25 per ton including \$5 for transportation and \$20 for landfill fee) is based on the assumption that an onsite landfill either already exists or can be developed within five miles of the site. If the landfill fee is higher or if the sludge must be transported 100 miles or more, sludge-disposal costs may be \$90 per metric ton or more.

6.3 SUMMARY

This section presented the estimated cost of treating liquid wastes to meet effluent quality levels for injection disposal and irrigation use. The treatment costs at the site ranged from 161 mills per kWh for wastewater treatment and injection disposal, up to 234 mills per kWh for irrigation-quality effluent water. Depending on where the injection disposal standards are ultimately set (i.e. from zero to 100% fluid replacement), the cost of meeting liquid effluent disposal regulations could be a significant impediment to the rapid commercialization of the Niland site.

As noted in previous sections, the resources that are most attractive to the private developer (high temperature), may also have high-TDS contents and high liquid-waste disposal costs. The results of this case study indicate that when the costs of liquid waste disposal are included, such resources may be more expensive to develop than resources with lower temperatures and TDS contents. These cost differences are primarily due to regulations requiring injection disposal that leads to higher sludge-generation rates and sludge disposal costs for high-TDS resources. Lack of data on the impact of TDS-induced corrosion and scaling costs on wastewater-treatment systems indicates that the cost estimates developed here may understate the treatment costs for high-TDS resources such as the Salton Sea KGRA.

7.0 IMPLICATIONS FOR COMMERCIALIZATION

Regulations governing liquid-waste disposal in the Imperial Valley are a potentially major impediment to hydrothermal commercialization. Treatment and disposal costs will range from near zero (with no regulation of surface discharge) to more than 230 mills per kWh (for advanced treatment systems). This cost range points to the need for both environmental policy makers and regulators to be aware of the magnitude of the benefits and costs of complying with alternative environmental standards.

Specific disposal requirements such as "Injection Only" could impose social costs in the form of net benefits foregone. For example, the reuse of liquids in specific irrigation and/or recreation applications may be justified where it is the least-cost disposal option for the developer and where regional demands for water are relatively high. Regulations that prevent reuse eliminate such alternatives. In the Imperial Valley, Imperial County requires 100% injection of spent fluids, yet the Pleistocene structure of the reservoir is equivalent to portions of that of Los Angeles and is not subject to significant subsidence (VTN 1979). Thus, in this water short region, liquid-waste treatment and reuse or partial surface disposal directly to the Salton Sea may be the best use of the fluids.

Because of different site characteristics, the selection of uniform (industry-wide) disposal standards could be less desirable than setting disposal standards on a case-by-case basis. However, the absence of specific standards leaves developers uncertain about possible future disposal standards. This uncertainty could be a key factor in determining the rate of resource commercialization. Uncertainty may be incorporated into the private decision analysis using risk-adjusted discount rates. The net effect of adding risk premiums to discount rates is to reduce estimates of the present value of the profitability of developing a given resource. Promulgation and/or stabilization of environmental standards for resource development may reduce the perceived risks and may thereby encourage commercialization.

Merely stabilizing the standards will not increase the resource utilization growth rate, however, if the standards ultimately promulgated are either too stringent or too lax in terms of their effectiveness of internalizing the environmental damages caused by liquid-waste disposal. Clearly, when the standards are too stringent, developers will find the expected returns on their investments to be too low, relative to alternative investments of comparable risk. When standards are too lax, potentially adverse impacts on commercialization may develop through the intervention of environmentalists, who may be sensitive to the absence of environmental considerations in the planning, construction and operating stages of resource development.

To establish standards that are optimal from a resource commercialization standpoint and thereby ensure both near- and long-term resource utilization, attempts should be made to not only develop estimates of the schedule of compliance costs for preventing environmental damages but also to estimate the value society places on the prevention of such damages.

If the objective is to increase the rate and level of hydrothermal energy utilization, then, given the relationships between water treatment costs and environmental standards, the effluent regulations should be written so that the present value of the incremental compliance costs that are incurred does not exceed the present value of the incremental environmental damages that are prevented.

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APPENDIX A

RESERVOIR GEOCHEMISTRY SUMMARY

TABLE A.1. Reservoir Geochemistry Summary

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

TABLE A.1. Reservoir Geochemistry Summary (contd)

Reservoir	Soluble Heavy Metals ppm		Temperature (Subsurface) °C	Constituents				Spec. Cond.
	Hg (Vapors)	AS		SiO ₂	Na	Cl	pH	
R1. Geyser Bright			208	303	441	569	7.5	
R2. Hot Springs Cove			164	88	603	1,126	5.9	
R3. The Geysers	(0.02)	(0.05)	237					
R4. Surprise Valley			152	200	343	223	8.91	
R5. Morgan Springs			217	233	1,398	2,430	--	
R6. Sulfur Bank Mine	1.5		194	203	1,723	900	2.7	7,880
R7. Calistoga			144	139	212	255	9.0	
R8. Skagg's Hot Springs	0.98 g/l		113	124	945	54	7.2	3,690
R9. Long Valley Caldera	0.10 g/l	2.2 mg	227	340	552	842	9.2	1,920
R10. Coso Hot Springs			220	458	1,630	3,040	8.5	
R11. Salton Sea			323	316	10,800	15,300	8.11	
R12. Brawley			253					
R13. Heber			175					
R14. East Mesa			182					
R15. Big Creek Hot Springs			162	150	220	29	7.5	
R16. Sharkey Hot Springs			114	91	270	51	7.4	
R17. Weiser Area			130	140	140	56	9.3	
R18. Crane Creek			171	180	290	300	7.1	
R19. Baltizor Hot Springs	0.001	0.07	158	160	180	48	8.0	947
R20. Pinto Hot Springs	0.004	0.08	173	150	330	160	7.1	
R21. Great Boiling (Gerlatch) Springs			178	172	1,460	2,200	7.62	6,350
R22. Sulfur Hot Springs	0.0015		178	75	103	0	7.8	652
R23. Beowawe Hot Springs	0.0017	0.05	229	534	257	70	9.8	1,490
R24. Leach Hot Springs	0.0006	0.01	162	198	193	33	8.8	811
R25. Stillwater Area			159	170	1,480	2,200	7.57	6,910
R26. Soda Lake	0.0005		157	160	1,000	1,500	7.90	5,110
R27. Brady Hot Springs			155	279	774	968	7.3	
R28. Steamboat Springs			200	353	2,047	1,345	9.3	3,340
R29. Valles Caldera			273					
R30. Mickey Hot Springs	0.0001	0.01	205	200	550	240	8.05	
R31. Alvord Hot Springs	0.0001	0.04	181	184	960	780	8.1	
R32. Hot Lake	0.0004	0.01	191	190	500	300	9.21	688
R33. Vale Hot Springs			157	130	310	360	7.47	1,530
R34. Neal Hot Springs	0.0001	0.02	188	180	190	120	7.32	1,010
R35. Lakeview			150	146	280	170	8.4	
R36. Crumps Spring	0.0004	0.46	167	180	293	263	8.7	1,490
R37. Roosevelt (McKean) H.S.			265	313	2,500	4,240		
R38. Cove Fort-Sulphurdale			167					

- (a) MWe Potential = Megawatts of electrical generating potential for 30 years as determined by USGS (Brook et al. 1979).
- (b) Approximation of TDS = (SiO₂ + Na + Cl) x 1.25.
- (c) Estimated linearly from TDS = 250 + 0.67 x (Specific Conductance), where 250 roughly corresponds to the specific conductance of water and 0.67 indicates that the ions are 50% monovalent (such as Na⁺ and Cl⁻) and 50% divalent (from silicates). Overestimation is expected for a few resources, but generally the results are retained as lower range TDS predictions.
- (d) Parts per million in the raw steam by weight.

APPENDIX B

WASTEWATER TREATMENT SYSTEM COST FUNCTIONS

APPENDIX B

WASTEWATER TREATMENT SYSTEM COST FUNCTIONS

The following cost functions were used to estimate the cost of treating effluents in the case study presented in Section 6.0. Presumably, land would be available on the existing geothermal power plant site, and therefore site preparation costs (e.g. roads) would be included in the cost of the power plant. Fixed charges such as taxes, insurance, installation, time-related expenses and contingencies are added to purchased equipment cost estimates by the method described in Appendix D.

Note that these are order of magnitude estimates. The estimates are not as accurate as would be expected from a site-specific detailed analysis performed by architectural engineers. As noted in Section 5.0, numerous variables are recognized to affect the cost of a treatment system; however, the literature reports cost functions only in terms of flow rate because it is the most dominant equipment cost-determining variable. As a result, an unknown amount of accuracy is lost when estimating the cost of liquid-waste treatment when TDS concentrations vary widely among specific sites.

CONVENTIONAL TREATMENT SYSTEMS

The cost functions for conventional treatment systems, which include chemical handling, solids contact reactors and filters, were derived from published cost curves (Chen, Takenaka and Miele 1975). The cost functions were updated from July 1972 to January 1979 using the EPA's sewage treatment plant cost index and from January 1979 to January 1980 at 10%. The power cost is assumed to be 40 mills/kWh and the fully burdened labor cost is assumed to be \$14/man/hr.

Chemical Addition Cost Functions

- Polymer storage and feed systems:
Total purchased equipment = $\$19,900 \times \text{MGD}^{0.68}$
- Alum or iron compound storage and feed systems:
Total purchased equipment = $\$22,300 \times \text{MGD}^{0.73}$
- Lime storage, slaking, and feed systems:
Total purchased equipment = $\$36,400 \times \text{MGD}^{0.68}$
- Annual operation and maintenance of any of the above systems (not including chemicals):
O&M costs = $\$31,500 \times \text{MGD}^{0.36}$

Solids Contact Reactor Cost Functions

- Assuming an upflow rate of 1 gpm/ft^2 :
Total purchased equipment = $\$220,000 \times (0.75 \times \text{MGD})^{0.66}$
- Annual operation and maintenance cost:
O&M costs = $\$51,700 \times (0.75 \times \text{MGD})^{0.48}$

Dual Media Gravity Filter Cost Functions

- Assuming a loading rate of 4 gpm/ft^2 :
Total purchased equipment = $\$602,000 \times (0.18 \times \text{MGD})^{0.66}$
- Annual operation and maintenance cost:
O&M costs = $\$70,400 \times (0.18 \times \text{MGD})^{0.63}$

SLUDGE HANDLING

The cost functions for sludge-handling systems were derived from Culp, Wesner, and Culp (1977).

Gravity Thickener Cost Functions

- Total purchased equipment = $\$10^{(0.35 \times \log(\text{PD}) + 3.64)}$
where PD = pounds per day of dry solids

- Annual operating and maintenance costs:

$$\text{O\&M costs} = \$0.281 (\text{PD})^{0.75} + \$1.12 (\text{PC}) (\text{PD})^{0.84} + \$1.78 (\text{LC}) (\text{PD})^{0.01}$$

where PC = power cost in \$/kWh = \$0.04/Kwh

LC = labor cost in fully burdened \$/yr = \$30,000

Vacuum Filter Cost Functions

- Total purchased equipment = $\$10^{(0.52 \times \log (\text{PD}) + 1.52)}$
- Annual operation and maintenance costs:
 $\text{O\&M costs} = \$8.71 (\text{PD})^{0.70} + \$0.07 (\text{PC})(\text{PD})^{0.83} + \$0.02 (\text{LC})(\text{PD})^{0.67}$
 where C = \$15.00 per hour.

Sludge Disposal

Sludge disposal costs were updated from Sung et al. (1977).

- Sludge disposal costs = \$25 per ton of dry solids.

These costs include \$5 per ton transportation costs and \$20 per ton landfill costs. Sludge disposal costs are the greatest contributors to the total cost of a conventional treatment system because this sludge is considered a hazardous waste. If the sludge can be disposed of onsite, substantial cost savings may be achieved.

ADVANCED TREATMENT SYSTEMS

The cost functions for advanced treatment systems, which include ion exchange, reverse osmosis, electrodialysis, and distillation, were derived from curves in Bureau of Reclamation (1972). Equipment cost functions were updated from July 1971 to January 1979 using Engineering News Record's building cost index and from January 1979 to January 1980 at 10%. Operating and maintenance costs were updated using the Bureau of Labor Statistics cost index for public utilities. Cost information was also reviewed from several other sources and generally concurred quite closely with the cost functions listed below. The equipment cost functions include engineering costs. The power cost functions assume a power cost of 40 mills per kWh.

Ion-Exchange Cost Functions

- Total purchased equipment = $\$1,520,000 (\text{TDS} \times \text{MGD} \times 10^{-3})^{0.70}$
where TDS = reduction in dissolved solids in mg/l
- Annual operation and maintenance cost:
Labor cost = $\$67,200 \times \text{MGD}^{0.45}$
Power cost = $\$16,500 \times \text{MGD}^{0.87}$
Regenerant cost = $\$160,600 \times \text{MGD}$

Reverse Osmosis Cost Functions

- Total purchased equipment = $\$1,056,000 \times \text{MGD}^{0.86}$
- Annual operation and maintenance costs:
Labor cost = $\$67,200 \times \text{MGD}^{0.45}$
Power cost = $\$241,000 \times \text{MGD}$
Membrane replacement = $\$88,000 \times \text{MGD}$

Electrodialysis Cost Functions

- Assuming stack capacity of 0.10 MGD:
Total purchased equipment = $\$242,000 \times (10 \times \text{MGD})^{0.68}$
- Annual operation and maintenance costs:
Labor cost = $\$67,200 \times \text{MGD}^{0.45}$
Power cost = $\$321,200 \times \text{MGD}$
Membrane replacement = $\$18,700 \times \text{MGD}$

Distillation Cost Functions

- Total purchased equipment = $\$4,600,000 \times \text{MGD}^{0.77}$
- Annual operation and maintenance costs:
Labor cost = $\$258,500 \times \text{MGD}^{0.47}$
Energy cost = $\$726,000 \times \text{MGD}^{0.95}$

APPENDIX C

WASTEWATER TREATMENT COSTS

**TABLE C.1. Conventional Brine Treatment and Injection
Disposal Costs at Niland (January 1980 dollars)**

	SSDS Removal To Enable Injection(a)
Injection System:(b)	
System design volume (MGD):(c)	10.701
Disposal Volume (10 ⁶ lbs/hr)	2.865
(acre feet/yr)	9063.0
(MGD)	8.236
Pounds of solids removed per day (10 ⁶)(d)	13.477
Number of wells	4
Total Cost/yr (\$10 ⁶ s/b exponent)	0.960
Mills/Kwh	2.62
Brine Treatment Expenses for Conventional Treatment(e)	
Purchased Equipment (\$10 ⁶)	
Solids contact reactors	0.870
Dual media filters	0.928
Gravity thickeners	1.366
Vacuum filters	0.169
Total Purchased Equipment (\$10 ⁶)	3.333
Total Capital Investment @2XP.E.	6.666
Levelized Annual Fixed Costs (\$10 ⁶)	1.000
Annual Variable Costs, (\$10 ⁶)	
Solids contact reactors:	0.141
Dual media filters	0.106
Gravity thickeners	0.623
Vacuum filters	0.873
Subtotal	1.743
Sludge disposal @ \$25.00/metric Ton(d)	55.900
Total Annual Variable Costs (\$10 ⁶)	57.643
Levelized Total Annual Treatment Costs (\$10 ⁶ s/b exponent)	58.643
\$/acre foot(f)	6471
mills/Kwh(g)	161
cents/1000 gallons	1991
Net present value of treatment and disposal costs (\$10 ⁶)	552.82

- (a) SSDS = supersaturated dissolved solids removal
 (b) System design and flows calculated by GEOCOST algorithm (Bloomster 1975).
 (c) Design volume is set at 130% of disposal volume to allow for flow
 variation overtime and for backflushing operations.
 (d) Pounds of dry solids removed per day (average) =

$$\left[\frac{250,000 \text{ lbs TDS}}{1,000,000 \text{ lbs fluid}} \times \frac{2,865,000 \text{ lbs fluid}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{yr}} \right. \\
\left. \times 80\% \text{ capacity factor} \times 80\% \text{ removal efficiency} + \right. \\
\left. \frac{250,000 \text{ lbs TDS}}{1,000,000 \text{ lbs fluid}} \times \frac{2,865,000 \text{ lbs fluid}}{\text{hr}} \times \frac{8760 \text{ hr}}{\text{yr}} \right. \\
\left. \times 18\% \text{ downtime with treatment} \times 80\% \text{ removal efficiency} \right] \times \\
\frac{1 \text{ year}}{365 \text{ days}} = 13,477,000 \text{ lbs/day} = 2,236,000 \text{ metric tons/yr}$$

- (e) Calculated from equations in Appendix B.
 (f) One acre foot = 43,560 ft³ = 2,714,000 lbs of fluid
 = 325,000 gallons.
 (g) Total annual Kwh production = 364,416,000.
 (h) 10% real, after tax, weighted-average cost of debt and equity capital for
 30-year stream of expenses.

TABLE C.2. Advanced Brine Treatment and Disposal Costs at Niland (January 1980 dollars)

Treatment System:(a)	
System Design Volume (MGD)(b)	10.701
Disposal Volume (10 ⁶ lbs/hr)(c)	2.865
(acre feet/yr)	9063.0
(MGD)	8.236
Solids removed(d)	
16,680,000 lbs/day or 2,767,000 MT/yr	
Brine Treatment Expenses(e)	
Purchased Equipment (\$10 ⁶)	
Solids contact reactors	\$0.870
Dual media filters	0.928
Gravity thickeners	1.366
Vacuum filters	0.169
Chemical precipitation(f)	0.408
Distillation	23.327
Total Purchased Equipment	27.068
Total Capital Investment @2xP.E.	54.136
Levelized Annual Fixed Costs (\$10 ⁶)	8.120
Annual Variable Costs (\$10 ⁶)	
Solids contact reactors	0.141
Dual media filters	0.106
Gravity thickeners	0.623
Vacuum filters	0.873
Chemical precipitation	0.067
Distillation	6.077
Sludge disposal	69.175
Total Annual Variable Costs (\$10 ⁶)	77.062
Levelized Total Annual Treatment and Disposal Costs (\$10 ⁶)	85.182
Treatment and Disposal Costs(g)	
\$ per acre foot	9400.0
mills per kWh:(h)	233.75
cents per 1000 gals	2892.0
Net Present Value of Treatment and Disposal Costs (\$10 ⁶)(i)	803.00

- (a) System produces effluent of 1500 ppm_w TDS for use as irrigation water.
 (b) System design volume is set at 130% of disposal volume to allow for flow variation over time and for backflushing operations.
 (c) System flows calculated by GEOCOST (Bloomster 1975).
 (d) Dry solids removed:

$$\text{Pounds per day} = \frac{.99 \text{ removal efficiency}}{.80 \text{ removal efficiency}} (13,477,000) = 16,680,000$$

$$\text{Metric Tons per year} = \frac{.99}{.80} (2,236,000) = 2,767,000$$

 (e) Calculated from equations in Appendix B.
 (f) Consists of systems to add alum polymer flocculants and lime.
 (g) One acre foot = 435,560 ft³ = 2,714,000 lbs fluid
 = 325,000 gallons.
 (h) 364,416,000 Kwh annual production.
 (i) 10% real, after tax, weighted-average cost of debt and equity capital for 30-year stream of expenses.

APPENDIX D

COST ESTIMATION METHODOLOGY

APPENDIX D

COST ESTIMATION METHODOLOGY

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

THE CAPITAL BUDGETING MODEL

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

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

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

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

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

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

Cost-Determining Variables

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

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

Financial Variables

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

The Cost Algorithm

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

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

TABLE D.1. Variables for Cost Estimation

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

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

1. Calculate purchased equipment cost estimates from the control cost functions developed in this report. Purchased equipment costs are stated in January 1980 dollars as: PE_{1980}

2. Calculate the direct and indirect capital investment overheads to PE_{1980} :

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

$$CI = .4 DCI = .14 PE_{1980}$$

3. Calculate the contingency overhead to PE_{1980} : $CCI = 0.30 (ICI + DCI) = .15 PE_{1980}$

4. Estimate the contractors' fees:

$$CF = 0.10 (DCI + ICI + CCI) = 0.06 PE_{1980}$$

5. Calculate interest during construction:

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

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

$$= .27 PE_{1980}$$

6. Calculate total capital investment in January 1980 dollars

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

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

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

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

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

Capital Recovery Factor: 10.6%

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

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

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

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

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

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

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

INVESTMENT CLIMATE

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

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

Regulated Utilities

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

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

Income Tax Factors

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

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

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

Risk and Inflation Factors

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

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

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

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

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

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

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