SURVEY AND PRELIMINARY EVALUATION OF
POTENTIAL GEOTHERMAL ENERGY APPLICATIONS
FOR RIVERSIDE, CALIFORNIA

by

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FOREWORD

The purpose of this study is to provide a preliminary assessment of the potential applications for geothermal energy in Riverside, California. This assessment includes both potential electrical and non-electrical applications. The assessment focuses on the following factors:

- (1) The location of nearby geothermal resources
- (2) Characteristics of these resources
- (3) Types of applications suited to each resource
- (4) Technical and economic feasibility of these applications
- (5) The potential impact on the energy demand of each application
- (6) Potential deterrents to the utilization of geothermal energy for the most promising applications

This study is part of a larger program for the development of an integrated alternative energy master plan for the California Region. The program is being conducted by Battelle-Columbus for the Department of Energy. Phase 1 of this program focuses on Riverside.

The master plan is concerned with the possible application of a wide variety of energy technologies which could reduce California's dependence on oil and natural gas and which could reduce pollution. Battelle-Northwest was requested to assess the potential role of geothermal energy in the master plan.

EXECUTIVE SUMMARY

Geothermal energy has a promising potential to supply electricity, space heating and cooling, and process heat to Riverside.

There are sufficient geothermal resources within 200 miles to supply the electrical requirements of Riverside for thousands of years. The technology for producing electricity from these resources is either in-hand or in-sight. Depending on the particular reservoir involved, this electricity can probably be generated at costs ranging from 1 to 3 times the cost of conventional electric power generation. Over this distance, the additional unit cost for energy transmission should be comparatively small.

The geothermal resource at nearby Arrowhead Hot Springs has the potential to supply space heating and cooling and process heat to Riverside for a hundred years. The technology for these non-electric uses is available. The cost of using geothermal energy for these applications is estimated at 1 to 2 times the cost of conventional fuels, depending on the population density of the service area.

Riverside is within a potentially valuable geothermal region. New geothermal resources may be discovered near Riverside in the future.

The most difficult problems in the possible use of geothermal energy in Riverside appear to be institutional difficulties in electric applications. The identified geothermal resources suitable for providing electricity for Riverside would require transmission services by private utilities, primarily Southern California Edison (SCE) which owns the lines serving Riverside. In addition, Riverside would permanently require emergency reserves and a continued supply of household electricity during development of a geothermal resource. Under existing conditions, the best provider of all of these is SCE. SCE presently supplies all Riverside's electricity and stands most to lose from Riverside's developing its own geothermal or other generating capacity. SCE has acted vigorously in the past to defend interests like those at stake here. While there have been some developments in antitrust law and in California statute that promise to make it easier for Riverside to deal with SCE in developing its own capacity, these are either of uncertain applicability to this case or are untested.

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SURVEY AND PRELIMINARY EVALUATION OF POTENTIAL GEOTHERMAL ENERGY APPLICATIONS FOR RIVERSIDE, CALIFORNIA

INTRODUCTION

Geothermal energy has the potential to meet many of Riverside's energy needs. In this report we will examine the technical, economic, legal, and environmental considerations involved in using geothermal energy to supply electricity, space heating and cooling, and process heat to Riverside. We will also examine the availability of nearby geothermal resources and the dependence of the various potential end uses on the characteristics and locations of the geothermal resources. We will formulate a plan for further evaluation or development of the most promising geothermal energy applications. The plan will propose actions designed to resolve existing constraints, risks, and uncertainties in a timely manner.

Geothermal energy, today, is a technically viable energy source for many American communities. Economics, the cost of production and distribution, is the main deterrent to its widespread use. Worldwide, geothermal energy already is used for electricity generation, space heating, domestic hot water, industrial process heat, greenhouse heating, refrigeration, by-product chemicals, fish rearing and balneology. Over 1000 MWe of geothermal electricity are generated in the U.S., El Salvador, Italy, New Zealand, Mexico, Japan, Iceland and the USSR. New installations are planned in many of these and other countries. In Iceland, municipal district heating systems use geothermal energy to heat the homes of more than 100,000 people. Less extensive geothermal district heating systems are located in France, Hungary, Japan, and the USSR. In the U.S., geothermal energy currently heats less than 1000 dwellings in Klamath Falls, Oregon and Boise, Idaho. Many countries have geothermal process heat installations, but combined the total energy currently supplied is small.

Rising energy prices and potential shortages of fossil fuels have spawned increased interest in geothermal energy for both electrical and non-electrical uses. In the past, both were severely limited in development by competition from low-priced alternatives. Now, with low-priced alternatives in short supply, geothermal energy may become economically competitive in many locations.

SURVEY OF GEOTHERMAL RESOURCES

We conducted a literature survey of the geothermal resources near Riverside and found eight resources within 200 miles that could be utilized to generate electricity. These eight resources contain an estimated electrical potential of 2749 MWe centuries (Table 1), which is enough to supply Riverside's electrical demands for over 2000 years. We also found over 20 hot springs within 50 miles of Riverside which might be suitable for non-electrical applications. However, of these resources, only Arrowhead Hot Springs has significant known potential; too little is known about the others.

TABLE 1. Electrical Potential of Geothermal Resources Within 200 Miles of Riverside, California^(a)

<u>Name</u>	<u>Subsurface Temperature, °C</u>	<u>Electrical Potential, MWe Centuries</u>
Coso	220	1360
Salton Sea	340	836
Heber	190	292
East Mesa	180	146
Brawley	200	100
Arrowhead	150	5
Border	160	5
Sespe	155	5
TOTAL		2749

(a) From USGS Circular 726

For potential electrical applications we included resources up to 200 miles away, although this is an arbitrary limit. Figure 1 shows the locations of all geothermal resources within 200 miles of Riverside with reservoir temperatures of 150°C or higher. These resources, which are described below, are considered promising for electrical generation. They include

FIGURE 1. Geothermal Resources Within 200 Miles of Riverside, California

Coso Hot Springs in Inyo County, Sespe Hot Springs in Ventura County, Arrowhead Hot Springs in San Bernardino County, and Brawley, Border, East Mesa, Heber and the Salton Sea KGRAs (Known Geothermal Resource Areas) in Imperial County. The characteristics of these eight resources are summarized in Table 2. In addition to these identified resources, the shaded areas on Figure 1 are "areas classified as being valuable prospectively for geothermal steam and associated geothermal resources."⁽¹⁾ These areas are shown on a new map prepared by the National Geophysical and Solar-Terrestrial Data Center in cooperation with the ERDA Division of Geothermal Energy and the USGS.

If the 200 mile limit is relaxed, many additional geothermal resources could be considered. For instance, it might be possible to obtain electric power from The Geysers, the large commercial geothermal resource 450 miles north of Riverside. Regional tie-lines for bulk power transfer already exist between Northern and Southern California.

For potential non-electrical applications we included resources up to 50 miles away. Geothermal energy is competitive for space and process heating out to distances of 50 miles from the wellhead when employed on a large scale to serve concentrated markets.⁽²⁾ The resources we considered for non-electrical uses include Arrowhead Hot Springs, Desert Hot Springs, and numerous thermal springs in the vicinity.

POTENTIAL RESOURCES FOR ELECTRICITY GENERATION

COSO

Coso Hot Springs is located in the Mojave Desert in east-central California, about 150 miles north of Riverside. About 80% of the 51,760-acre KGRA lies within the U.S. Naval Weapons Center at China Lake, which is closed to the general public.⁽³⁾ The Navy has announced plans to build a materials test facility and a 20-MWe power plant to utilize the geothermal energy.⁽⁴⁾ The Coso Hot Springs KGRA is estimated to contain an electrical potential of 1360 MWe centuries.⁽⁵⁾

TABLE 2. Geothermal Resources Within 200 Miles of Riverside, California^(a)

Name	Location			Subsurface Temperature, °C	Reservoir Assumptions		Total Dissolved Solids, PPM
	Latitude °N	Longitude °W	Miles From Riverside		Depth, km	Heat Content, 10 ¹⁸ Calories	
Coso	36° 03'	117° 47'	150	220	1.0	41	5,800
Salton Sea	33° 12'	115° 36'	115	340	1.0	21	120,000-250,000
Heber	32° 43'	115° 31.7'	130	190	1.0	11	14,000
East Mesa	32° 47'	115° 15'	145	180	1.0	5.5	2,400-25,000
Brawley	33° 01'	115° 31'	120	200	1.5	3	54,000
Arrowhead	34° 08.6'	117° 15.2'	15	150	1.5	0.2	*
Border	32° 44'	115° 07.6'	155	160	2.4	0.2	*
Sespe	34° 35.7'	118° 59.9'	105	155	1.5	0.2	*
TOTAL						82.1	

(a) From USGS Circular 726.

* No data available.

SALTON SEA

The Salton Sea KGRA is located at the southeastern end of the Salton Sea in the Imperial Valley. It contains 95,824 acres, 50% of which is underwater. More than 95% of the onshore land and about half of the off-shore land is privately controlled.⁽³⁾ All of the ongoing geothermal activities in the Salton Sea KGRA, such as the San Diego Gas and Electric Company's geothermal loop experimental facility at Niland, are onshore on private land. The electrical potential of the Salton Sea KGRA is estimated to be 836 MWe centuries.⁽⁵⁾

HEBER

The Heber KGRA is in the southern part of the Imperial Valley between El Centro, California and Mexicali, Mexico. The 58,568-acre KGRA is being developed by Chevron Oil Company, Magma Power Company, and New Albion Resources Company (a subsidiary of San Diego Gas and Electric Company).⁽⁶⁾ The Heber KGRA is estimated to contain 292 MWe centuries of electrical potential.⁽⁵⁾

EAST MESA

The 38,365-acre East Mesa KGRA is located in the southeastern part of the Imperial Valley very near the Mexican border. The area is being developed by the U.S. Bureau of Reclamation, Republic Geothermal, Inc., and Magma Energy.⁽³⁾ The electrical potential of the East Mesa KGRA is estimated to be 146 MWe centuries.⁽⁵⁾

BRAWLEY

The Brawley KGRA, which contains 28,885 acres, is in the southern part of the Imperial Valley about 20 miles north of Mexico. Several successful wells have been drilled in the area by Union Oil Company of California.⁽³⁾ The Brawley KGRA is estimated to have an electrical potential of 100 MWe centuries.⁽⁵⁾

ARROWHEAD, BORDER, AND SESPE

Little data is available on these three geothermal resources. The assumed heat content of each of these reservoirs is 0.2×10^{18} calories.⁽⁵⁾

The USGS estimated this heat content for systems with minimal surface evidence by assuming a subsurface area of 1.5 km^2 , a depth of 1.5 km, and a specific heat of $0.6 \text{ cal/cm}^3 - ^\circ\text{C}$. Under these assumptions, the estimated electrical potential is 5 MWe centuries for each of the three geothermal resources. As further geological, geochemical, and geophysical data become available, these resources may prove to hold a much greater potential.

FORD DRY LAKE

The 7,696-acre Ford Dry Lake KGRA is located 18 miles west of Blythe in Riverside County, about 140 miles from the City of Riverside. Ford Dry Lake is one of four dry lakes in the Chuckwalla Valley. The area was designated a KGRA only because overlapping geothermal lease applications were filed in the vicinity in 1974.⁽³⁾ According to the USGS, there is no evidence of the existence of any geothermal resource in the Ford Dry Lake KGRA.^(a)

POTENTIAL RESOURCES FOR NON-ELECTRICAL APPLICATIONS

The geothermal resources with reservoir temperatures below 150°C are not suitable for economic electric power generation, but some of them have potential for space and process heating. According to USGS Circular 726,⁽⁵⁾ there is only one geothermal resource above 90°C within 50 miles of Riverside. This resource, Arrowhead Hot Springs, is shown inside the 50-mile radius circle surrounding Riverside in Figure 1. However, a previous USGS paper⁽⁷⁾ shows about 20 lower-temperature thermal springs in the area; this paper lists only the surface temperature of the water. In order to assess the potential of these springs, more data are required on the subsurface temperature and the heat content of the reservoir. We tried to obtain additional information by telephone conversations with the USGS, the California Division of Oil and Gas, the Riverside County Planning Office, the University of California at Riverside, the California Energy Resources Conservation and Development Commission, and the California Institute of Technology's Jet Propulsion Laboratory. However, it appears that good resource assessment data on these lower-temperature nearby springs is not available. Figure 2 shows the locations of these springs.

(a) Discussion with Marshall Reed, USGS, Conservation Division, Menlo Park, CA, 9-14-77.

NUMBER	NAME OR LOCATION
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1	TYLERS BATH SPRINGS
2	ARROWHEAD HOT SPRINGS
3	IN DEEP CREEK CANYON, 16 MILES S.E. OF VICTORVILLE
4	IN DEEP CREEK CANYON, 16 MILES S.E. OF VICTORVILLE
5	NEAR BALDWIN LAKE, 40 MILES S.E. OF VICTORVILLE
6	HARLEM HOT SPRING
7	WATERMAN HOT SPRINGS
8	IN SANTA ANA CANYON, 12 MILES E.-N.E. OF SAN BERNARDINO
9	HIGHLAND SPRINGS
10	DESERT HOT SPRINGS
11	EDEN HOT SPRINGS
12	PILARES HOT SPRING
13	GILMAN HOT SPRINGS
14	SOBOBA HOT SPRINGS
15	WRENDEN HOT SPRINGS
16	ELSINORE HOT SPRINGS
17	MURRIETA HOT SPRINGS
18	DELUZ WARM SPRINGS
19	SAN JUAN CAPISTRANO HOT SPRINGS
20	GLEN IVY HOT SPRING
21	FAIRVIEW HOT SPRING

FIGURE 2. Thermal Springs Within 50 Miles of Riverside, California

ARROWHEAD

The geothermal resource nearest to Riverside is Arrowhead Hot Springs, about 15 miles north. The estimated temperature of this resource is 150°C, which makes it potentially useful for either electrical or non-electrical applications. As mentioned previously, the USGS assumed a heat content of 0.2×10^{18} calories for Arrowhead Hot Springs. This amount of heat is equivalent to about 100 years of natural gas consumption in Riverside.

DESERT HOT SPRINGS

The town of Desert Hot Springs is located at the northern end of the Coachella Valley in Riverside County, about 55 miles east of Riverside. Researchers at the California Institute of Technology's Jet Propulsion Laboratory are working on a project involving the utilization of nearby geothermal resources for non-electric purposes in Desert Hot Springs. The data they have collected is for shallow wells (less than 500 feet deep) and shows temperatures ranging from 88°F (31°C) to 212°F (100°C). (No deeper wells have been drilled in the Coachella Valley because the geothermal resource lies directly above the potable water aquifer, separated by non-permeable rock.^(a))

Although these temperatures are low, practical experience in several countries has shown them to be satisfactory for district heating, provided that the resource is very near the site of use. The Reykjavik municipal district heating system in Iceland uses 80°C water, the French use 70°C water, the Japanese use 40°C to 70°C water, and the Boise, Idaho district heating system uses 77°C water.⁽⁸⁾ However, in all these applications the geothermal resources are within 10 miles of the point of use. Thus if further resource assessment work identifies similar low temperature geothermal resources very near Riverside, there are distinct possibilities for utilization of the heat.

TECHNICAL FEASIBILITY OF ELECTRICITY GENERATION FROM GEOTHERMAL RESOURCES

The technical feasibility of generating electricity from dry-steam geothermal resources is well established. About 1000 MWe are currently

(a) Discussion with Yukio Nakamura, JPL, Energy Systems Section, 9-22-77.

produced worldwide from these resources. Unfortunately, there are no known dry-steam systems within 200 miles of Riverside. The nearest one is The Geysers in Northern California, about 450 miles away. The operating power plant capacity at The Geysers is 502 MWe with plans for expansion to 1500 MWe by 1985. The electrical potential of The Geysers is estimated at 477 MWe centuries, or 1590 MWe for 30 years.⁽⁵⁾ Thus except for distance, The Geysers has potential to supply Riverside's electricity needs.

All of the known geothermal resources within 200 miles of Riverside are liquid-dominated systems. Worldwide, about 300 MWe are produced currently from liquid-dominated systems. The two most promising methods of geothermal power generation from liquid-dominated systems are the flashed steam cycle and the binary cycle.^(9,10) In the flashed steam cycle the geothermal water is transported through an insulated pipeline to the power plant where it is flashed to produced steam. The steam is then expanded through a turbine as in conventional steam power plants. In the binary cycle heat is transferred from the geothermal water to the working fluid; the working fluid is then expanded through a turbine to produce electric power.

FLASHED STEAM PLANTS

In 1968 the Mexican Government started construction of a geothermal power plant at Cerro Prieto, about 19 miles south of Mexicali. Commercial operation of the 75-MWe flashed steam plant began in 1973. According to the Comision Federal de Electricidad, "Problems encountered have not been insurmountable. The operation of the plant is a great success."⁽¹¹⁾

As shown in Table 3, Mexico is not the only country with a flashed steam plant. Geothermal power production from liquid-dominated reservoirs began at Wairakei, New Zealand in 1958; at Otake, Japan in 1967; at Namafjall, Iceland in 1970; at Pauzhetka, USSR in 1967; and at Ahuachapan, El Salvador in 1975. Thus, flashed steam power plant technology has proven successful for high-temperature liquid-dominated geothermal resources.

TABLE 3. Flashed Steam Geothermal Power Plants
of the World

<u>Name</u>	<u>1975 Capacity, MWe</u>	<u>Year Operation Began</u>
Wairakei, New Zealand Kawerau, New Zealand Broadlands, New Zealand	193	1958
Hatchobaru, Japan		
Onuma, Japan		
Otake, Japan	13	1967
Cerro Prieto, Mexico	75	1973
Pathe, Mexico	3.5	1958
Namufjall, Iceland	3	1970
Pauzhetka, USSR	5	1967
Makhachkala, USSR	12	U.C.*
Ahuachapan, El Salvador	30	1975

* U.C. = under construction.

BINARY PLANTS

The only existing geothermal power plant using the binary cycle is the Paratunka power station (1 MWe) on the Kamchatka Peninsula in Russia. Evidently, the plant has been operating successfully since 1964, and the Russians have plans to build a similar 25-MWe plant nearby.⁽¹²⁾ Two new binary cycle plants are scheduled to start up in the Imperial Valley in the near future. San Diego Gas and Electric Company has a 45-MWe project underway at Heber and Republic Geothermal has a 10-MWe project at East Mesa. Also, the Japanese have a 1-MWe plant under construction at Otake. Thus, experience with the binary cycle has not yet been demonstrated on a large scale.

HYBRID PLANTS

A hybrid combination of the flashed steam cycle and the binary cycle is potentially most promising for electric power generation from the Salton Sea resource. The Salton Sea resource is a high-temperature, hypersaline liquid-dominated system with a high noncondensable gas content. Removing large volumes of noncondensable gases from the turbine exhaust condenser leads to low efficiency in the steam cycle. Excessive scaling rates are expected if the geothermal brine is sent directly through a heat exchanger in the binary cycle. Consequently, a hybrid flashed steam/binary cycle has been proposed to overcome these problems. No hybrid plants currently exist.

In 1976 the Bechtel Corporation completed a conceptual design for a 50-MWe geothermal power plant to be built at Niland, 4.5 miles east of the Salton Sea. The Bechtel design is a "multistage flash/binary process" using isopentane as the working fluid and requires the use of "current or in-sight state-of-the-art technology". The estimated total capital cost for the plant is \$37.1 million or \$742 per net kilowatt, in December 1975 dollars.⁽¹³⁾

ECONOMICS OF ELECTRICITY GENERATION FROM GEOTHERMAL RESOURCES

There are sufficient geothermal resources within 200 miles to supply the electrical requirements of Riverside for thousands of years. The technology for producing electricity from these resources is either in-hand or in-sight. Depending on the particular reservoir involved, this electricity can probably be generated at costs ranging from 1 to 3 times the cost of conventional electric power generation. Over this distance, the additional unit cost for energy transmission should be comparatively small.

Electricity is currently produced from only high quality geothermal resources throughout the world. High quality usually means dry steam or high-temperature liquid-dominated resources located near the surface. In the past, high quality also meant high productivity (at least 3 MWe electrical capacity) from each geothermal well. However, rapid escalation in energy costs plus advances in geothermal energy recovery technology make

lower quality geothermal resources more economically feasible. Thus, geothermal energy should become a much more important and widespread energy source for electricity production.

The most important factors affecting the economics of geothermal electricity production are the wellhead temperature, the well flow rate, and the cost of the wells.⁽¹⁴⁾ The capital cost of the power plant is significant, but not highly sensitive to these resource characteristics. The optimum geothermal plant size will be in the 50-100 MWe range; opportunities for achieving significant cost reductions in large plants through "economies of scale" are small. From this standpoint, geothermal power plants are ideal for integrated community energy systems.

Geothermal electricity production is capital intensive; over 75% of the generation costs are fixed costs related to capital investment. The steam and binary power cycles are closely competitive; the binary cycle appears better when the geothermal fluid temperature is below 200°C, and the flashed steam cycle appears better above this temperature.⁽¹⁴⁾ The breakeven temperature and comparative advantage of either cycle could vary over a wide range depending on the relative costs of the energy supply and power plant, the noncondensable gas content, scaling rates, and other factors.

However, because of the lack of experience with binary cycle power plants, there is considerable uncertainty in their capital and operating costs and in their performance. Improvements might be more rapid in the new binary cycle technology relative to the well-developed steam technology, and thus the binary cycle capital costs might become more competitive with time.

Technological advances are needed to reduce costs from marginal geothermal resources and thus stimulate geothermal energy development. Significant reduction in power costs would be achieved by reducing well drilling costs, stimulating well flow rates, reducing power plant capital costs, increasing power plant efficiency and utilization, and developing more effective exploration techniques for locating and assessing high quality resources. Programs for geothermal energy development in the Department of Energy are directed at these technology advances.

COST OF ELECTRICITY FROM GEOTHERMAL ENERGY

We estimated the cost of generating electric power from geothermal resources near Riverside using the GEOCOST model.⁽¹⁵⁾ The GEOCOST model is a techno-economic model which can simulate the production of electricity from any geothermal resource. Based on the subsurface temperature of the geothermal resources, we simulated a flashed steam cycle plant at Coso and binary cycle plants at Heber, East Mesa, Brawley, Arrowhead, Border, and Sespe. The steam cycle was modeled as a two-stage flash at the plant and the binary cycle was modeled with isobutane as the working fluid. For the Salton Sea resource we escalated the Bechtel cost estimate for the hybrid plant, discussed previously, by 7% to January 1977 dollars for purposes of comparison with the GEOCOST cost estimates for the other resources (Table 4). With the exception of the Salton Sea, the decrease in resource temperature results in an increase in the power plant capital cost. The binary plants become more expensive because the isobutane flow rate, and therefore the equipment sizes, must be greater with lower temperature geothermal fluids.

TABLE 4. Power Plant Capital Costs
(January 1977 Dollars)

<u>Name</u>	<u>Subsurface Temperature, °C</u>	<u>55 MWe Power Plant Total Capital Cost, (\$ Millions)</u>	<u>Capital Cost \$/kWe (Net)</u>
Salton Sea	340	39.7	794
Coso	220	20.4	389
Brawley	200	22.4	505
Heber	190	22.8	525
East Mesa	180	25.7	564
Border	160	30.4	669
Sespe	155	32.4	714
Arrowhead	150	33.4	740

Although the Salton Sea resource has the highest temperature of the eight resources, it also has the highest cost estimate. There are several reasons for this. The other seven resources are assumed to have non-corrosive, low-salinity fluids. The Bechtel cost estimate for the Salton

Sea resource is based on highly-corrosive, high-salinity brine. In addition, Bechtel's cost estimate includes safety factors and contingencies representative of a first-of-a-kind plant. A GEOCOST estimate is intended to be representative of an average plant cost for a standardized design rather than a safe cost for a first-of-a-kind plant. Placed on the same estimating basis, the Salton Sea plant would probably cost \$500-\$600/kWe (net).

The expected distribution of electricity generation costs is shown in Table 5. The total cost of geothermal power can be distributed into three categories: power plant capital costs, power plant operating costs, and energy supply costs. Nearly all the power plant costs are associated with the initial capital required to build it. Only a small percentage of the total is required to operate the plant, so uncertainties in operating costs would not have a significant impact on power costs. The energy supply cost is a significant part of the total and its significance grows as resource quality decreases.

Based on the cost of electricity generation (Table 5), the most promising geothermal resource for electricity generation for the City of Riverside is Coso Hot Springs. As stated previously, Coso is located about 150 miles north of Riverside on land owned by the U.S. Navy. The

TABLE 5. Distribution of Electricity Generation Costs
(Mills/kWh, January 1977 Dollars)

<u>Name</u>	<u>Temperature, °C</u>	<u>Power Plant</u>		<u>Cost of Energy Supply</u>	<u>Total Cost</u>
		<u>Capital Costs</u>	<u>Operating Expenses</u>		
Coso	220	10	0.4	18	28
Brawley	200	12	0.5	19	32
Heber	190	13	0.5	22	36
East Mesa	180	14	0.5	30	45
Border	160	16	0.6	35	52
Sespe	155	17	0.6	39	57
Arrowhead	150	18	0.6	44	63
Salton Sea*	340	13	1.0	20	34

* Estimate assumes standardized plant design and favorable resolution of scaling and corrosion problems.

Coso KGRA is estimated to have an electrical potential of 1360 MWe centuries, or about 4500 MWe for 30 years. The annual electricity consumption in Riverside during 1976 was 840,000,000 kWh. The Coso KGRA could potentially satisfy Riverside's electrical demands at this level for over 1000 years.

Over the long term, the Salton Sea resource may be the most promising. If the severe scaling and corrosion problems can be overcome at a reasonable cost, then power generation from this highest-temperature resource might become the lowest in cost. Several research programs are underway to reduce geothermal scaling and corrosion problems.

The power cost for Brawley (32 mills/kWh) is only 14% higher than the power cost for Coso (28 mills/kWh); and the power cost for Heber (36 mills/kWh) is only 29% higher than the power cost for Coso. These differences are not significant in comparison with the uncertainties in the characteristics of the resources. The Brawley and Heber resources are also promising sources for electric power generation for Riverside. In fact, Heber might even be considered more promising, since it is scheduled to be in production by 1980.

For purposes of comparison, Table 6 shows electricity generation costs from other conventional sources of power. These costs are based on FEA estimates⁽¹⁶⁾ which we escalated by 11% (7% per year for 1.5 years) from July 1975 dollars to January 1977 dollars. Based on these data, geothermal electric power is expected to be 1 to 3 times as expensive as conventional power sources, depending on the particular reservoir involved.

TABLE 6. Baseload Electricity Generation Costs*
(Mills/kWh, January 1977 Dollars)

	<u>Nuclear</u>	<u>Coal</u>	<u>Oil Steam</u>
Capital	15	10	8
Fuel	2	11	23
Other	<u>3</u>	<u>2</u>	<u>2</u>
Total	20	23	33

* Assumes a delivered price of \$1.10 per million Btu for low sulfur coal and \$2.25 per million Btu for residual oil. Capital costs in 1975 dollars are \$550 per kW for nuclear, \$380 per kW for coal and \$310 per kW for oil. A fixed charge rate of 15 percent and a capacity factor of 0.7 were assumed.

ELECTRICITY TRANSMISSION COSTS

Cost ranges published by the Federal Power Commission⁽¹⁷⁾ for the cost of energy transmission vary from 0.3 to 0.9 mills/kWh/100 miles for voltages which vary from 700 kV to 200 kV. Thus, transmission costs from nearby geothermal resources to Riverside are expected to be minor.

METHODOLOGY

The GEOCOST computer program was developed to provide rapid and systematic calculations of the variation in geothermal power costs with important resource, power recovery, and economic factors. The computer program simulates the geothermal power production processes. Cost functions developed for GEOCOST calculate the capital costs and operating expenses for commercial power plants using the resource characteristics and power conversion technology specified for each simulation. These cost functions generate the cash flow requirements over the economic life specified for the simulation. Using discounted cash flow analyses, GEOCOST calculates the unit cost of energy for the specified input conditions. The unit cost of energy is the most appropriate common unit for comparing energy costs from alternative sources, either geothermal or nongeothermal. The GEOCOST computer program is described in more detail elsewhere.^(9,10,15,18,19)

Besides the unit cost of energy, the output from GEOCOST consists of the distribution of the components of the energy cost, including power plant and reservoir equipment costs and operating expenses. GEOCOST also calculates many other factors related to the design, performance, and operation of the power plant and reservoir, such as the number of wells required, fluid flow rates, thermodynamic conditions, internal electrical consumption and net plant output. Power costs are expressed as the "bus bar" generating cost of electricity and do not include electrical transmission and distribution costs. Costs are expressed in constant January 1977 dollars. Comparisons between GEOCOST estimates and other independently-developed estimates have shown consistent agreement.

ASSUMPTIONS

We selected the assumptions shown in Table 7 for our cost estimates. These economic and financial assumptions would be typical of a large oil company operating the reservoir and an investor-owned utility operating the power plant. The taxes are a composite, typical of the western states.

TABLE 7. Financing and Tax Assumptions

<u>Parameter</u>	<u>Reservoir (%)</u>	<u>Powerplant (%)</u>
Capitalization		
Debt	42	59
Equity	58	41
Bond Interest Rate	8	8
Return on Equity	15	12
Federal Income Tax Rate	48	48
State Income Tax Rate	7	7
Property Tax Rate	2.5	2.5
Royalty Payment	10	--
Revenue Tax Rate	--	4

All cases assume mechanical draft cooling towers and injection of the geothermal fluid. In all cases exploration costs were assumed to be constant and contribute the equivalent of 0.8 mills/KWh to the cost of power. Injection wells were assumed to be capable of handling twice the flow of the producing wells. All cases assume that dry wells will equal 20% of the producing wells, and will cost three-fourths of the cost of producing wells. All cases assume that 20% excess producing wells are required. Royalty payments are assumed to be 10% of the revenues of the reservoir. The assumed values for other important parameters are shown in Table 8.

TABLE 8. Assumed Values for Other Important Parameters

<u>Parameter</u>	<u>Value</u>
Power Plant Size, MWe	55
Drilling Cost per Producing Well, \$	400,000
Drilling Cost per Dry Well, \$	300,000
Drilling Cost per Injection Well, \$	350,000
Average Depth of Wells, Meters	2,000
Geothermal Fluid Flow Rate, lb/hr/well	400,000
Average Production Life of Wells, yrs	10
Power Plant Operating Life, yrs	30
Reservoir Well Spacing, acres	20

TECHNICAL FEASIBILITY OF NON-ELECTRICAL APPLICATIONS OF GEOTHERMAL ENERGY

Although current non-electric usage of geothermal energy in the U.S. is miniscule, a large potential demand exists. Geothermal energy could be used for space heating and cooling, industrial process heating, greenhouse heating, balneology, soil warming, and fish-rearing. However, we will consider only space heating and cooling and process heating applications for the City of Riverside.

SPACE HEATING

Residential and commercial space heating can be provided by using geothermal energy as the heat source in a district heating system. Geothermal space heating is technically feasible and thermodynamically efficient. Low quality geothermal energy is an excellent replacement for high quality fossil fuels or electricity for space heating purposes.

In district heating systems a network of insulated pipes distributes heat, using either hot water or steam, to commercial and residential customers from a central distribution point. European systems use hot water almost exclusively, while existing U.S. systems primarily use steam. In single-pipe, once-through distribution systems, fluid disposal is through a sewer system. In two-pipe systems, the fluid is recirculated, conserving the fluid and residual heat.

Geothermal district heating systems use hot water. Besides the distribution system, the geothermal system includes wells for hot water production and insulated pipes for fluid transmission between the wells and the central distribution point. Supplemental heating capacity is usually provided to handle peak demands, and storage tanks absorb flow fluctuations and provide limited reserve capacity. If the geothermal water is contaminated, heat exchangers may be used. If surface disposal of the water is not feasible, injection wells will be required.

A single-pipe distribution system is generally preferred when the geothermal energy is abundant and (1) the water is pure enough to be circulated through the distribution system and disposed of through a sewer system, or (2) the geothermal fluid is contaminated but sufficient fresh water is available for heat transfer, circulation, and disposal. Two-pipe, recirculating systems are preferred when the supplies of energy or potable water are the limiting factors of production.

The geothermal district heating systems in Iceland are mostly single-pipe systems, since the geothermal water is potable. The French geothermal district heating systems are mostly two-pipe systems; heat exchangers are used and the brine is injected. Future U.S. systems will probably be predominately two-pipe systems in the interest of both energy and water conservation.

SPACE COOLING

Residential and commercial space cooling (air conditioning) can be provided by using geothermal energy to power an absorption refrigeration system. In compression refrigeration machines, which are most common today, electricity is required to drive the compressor. An absorption refrigeration machine makes direct use of heat and does not consume electricity. This is accomplished by substituting a heat engine for the compressor.⁽²⁰⁾

Absorption cooling is not a new idea. Cooling by absorption of vapors was achieved by Faraday in 1824. Portable absorption-desorption units operated with kerosene fuel or natural gas have been on the market for over 40 years.⁽²¹⁾ With modifications, these units could be operated with geothermal energy.

In absorption cooling machines, cooling is accomplished through the vaporization of the refrigerant fluid; in the process heat is absorbed from the surroundings, thus cooling the room. Refrigerants are fluids which boil at low temperatures while at atmospheric pressure. The best fluids are fluorocarbons, lithium bromide/water solutions, and ammonia/water solutions.⁽²²⁾

According to Edward Wehlage,⁽²²⁾ consulting electrical and mechanical engineer for geothermal heat, "These (absorption refrigeration) units are all eminently practical. The requirements of a proposed design for installation made by the author in 1964 remain unchanged and the installation could begin today."

There is one absorption unit operating today at the Rotorua International Hotel in Rotorua, New Zealand. It is the only system designed for both space heating and cooling using geothermal resources. The system uses geothermal water at 150°C in a heat exchanger to heat fresh water to about 120°C. The 120°C water is used in radiators, tap water heaters, and to drive the absorption unit.⁽⁸⁾

INDUSTRIAL PROCESS HEAT

Under favorable economic conditions, geothermal energy could supply process heat to many industries. The substitution of geothermal energy for conventional energy in process heating involves replacing the conventional fuel supply and the plant furnace and boiler units with a delivery system for geothermal energy. The geothermal delivery system includes production wells, fluid transmission pipes, and heat exchangers, if required. The production wells and fluid transmission systems are similar to their counterparts for district heating applications.

If the mineral content of the geothermal fluid is high, heat will be transferred from the brine to purer process water. Depending on the location of the fresh water source, the heat exchanger can be located at the wellhead, at the plant site, at the disposal site, or at some other more favorably located site. If the geothermal fluid is sufficiently pure, it can be circulated through the plant, eliminating the need for the heat exchanger. Also, if pure enough, the geothermal fluid can be disposed of through the existing sewer system or perhaps used consumptively in the process, reducing or eliminating the need for fresh process water.

In applications in which the process heat is normally supplied by hot water, the in-plant circulation systems should be readily adaptable to geothermal energy and the incremental retrofitting cost for the geothermal system would be minimal.

Process heating applications differ from space heating in that (1) the fluid reject temperature is higher, and (2) climate has little or no direct impact on energy demand. However, the impact of seasonal variations in the production cycle may be significant. In some respects, process heating applications would tend to have economic advantages over district heating because the heat demand tends to be more concentrated and the average load factor tends to be higher. On the other hand, process heating would tend to have an economic disadvantage because the minimum temperature of utilization is higher and less of the potentially available energy is consumed. For district heating applications, the geothermal fluid in this study is rejected at 38°C. For process heating applications, the reject temperature in this study is 100°C. Actual reject temperatures may vary from these typical values depending on the characteristics of the specific application.

ECONOMICS OF NON-ELECTRICAL APPLICATIONS OF GEOTHERMAL ENERGY

The use of Arrowhead Hot Springs for geothermal district heating and cooling for the City of Riverside looks economically attractive for high-density urban areas. Based on the USGS estimate of the heat content at Arrowhead Hot Springs, this resource could potentially supply both Riverside's residential space heating and residential space cooling demands for over 100 years. The most promising area in which such a system could be instituted is the northeast section of the city, including the campus of the University of Riverside, the commercial "downtown" area to the west of the campus, and the industrial area to the north of the campus. According to the City of Riverside General Plan Map, there are also medium-high density residential areas in this section of the city. Space heating and cooling of residential and commercial buildings (including the campus) appears to be both technically and economically feasible in Riverside. Supplying industrial process heat in combination with space heating and cooling also appears attractive.

Geothermal energy is competitive for space and process heating applications over significant distances when employed on a large scale to serve concentrated markets. Under these conditions geothermal energy

from 90°C to 150°C hydrothermal resources should be economically competitive with conventional fuels for high-density urban district heating out to distances of 50 miles from the wellhead. From these same resources geothermal energy should be competitive for district heating in low-density urban and suburban areas out to 50 miles from most resources when conventional residential heating costs exceed \$8/million Btu. Resources in the 130°C to 150°C range should be competitive for process heating out to 30 miles from the wellhead.⁽²⁾

Production and distribution costs are particularly sensitive to well costs, well flow rate, resource temperature, distance separating demand and supply, population density, size of demand, and the system load factor. The supply of geothermal energy for district or process heating is capital intensive; over 75% of the production costs are fixed costs related to the initial capital investment.

Although no technology breakthroughs are required in the utilization of geothermal energy for these non-electric applications, technological advances are needed to reduce costs and increase the distances over which geothermal energy can be competitive. Significant cost reductions would be achieved by reducing well drilling costs, stimulating well flow rates, increasing productivity in pipeline construction, developing low cost pipeline materials, reducing fluid disposal costs and developing low cost energy storage capacity. Current research in these areas may lead to these cost reductions.

A wide variation can be expected in geothermal energy costs for district heating and process heating applications. The costs vary according to the characteristics of the resource, the characteristics of the demand and the distance separating the resource and the demand.

COST OF GEOTHERMAL SPACE HEATING

Our estimates of the cost of space heating for Riverside will be obtained using the GEOCITY⁽²³⁾ model. This model simulates geothermal district heating systems, including fluid production at the wellhead and its transmission to the district heating distribution center. GEOCITY designs and estimates the current costs of these systems. Process heating

applications are also simulated with the GEOCITY model as large point-source users. The economics of district heating and process heating applications are affected by many factors. With the GEOCITY model the impact of these factors on space heating costs can be analyzed rapidly in a systematic framework. Space heating costs are comprised of three components: energy production, fluid transmission, and distribution. These are analyzed separately below.

Production Costs

Energy production costs at the wellhead are sensitive to wellhead temperature, well flow rate, and well cost (Figure 3). The horizontal axis in Figure 3 is a derived unit reflecting the ratio of well cost to well flow rate; energy production costs vary directly with this ratio. Well flow and well cost are interrelated and to some extent are controllable by the developer; i.e., economic tradeoffs exist between increasing production and increasing cost which the developer will seek to optimize. Costs decrease with increasing temperature as shown.

As stated previously, the geothermal resource nearest to Riverside is Arrowhead Hot Springs. Because of its proximity and its relatively high temperature, Arrowhead Hot Springs is the most promising geothermal resource for non-electrical applications in Riverside. The USGS has estimated the subsurface temperature at Arrowhead Hot Springs to be 150°C. They also estimated the depth to the top of the reservoir to be 1.5 km. Based on this depth and assuming the rock is of medium hardness, we estimate a cost of \$280,000 per well. Based on geothermal well flow rate data from the U.S., Mexico, and New Zealand, the average well flow rate from 8-inch bores in liquid-dominated reservoirs is 440,000 lb/hr (200,000 kg/hr). The ratio of well cost to this well flow rate is 1.4 and the energy production cost from Figure 3 is about 55¢ per million Btu. However, we should also include the cost of injection wells. If we assume each injection well has sufficient capacity to absorb the flow from 1.8 production wells, the appropriate well cost to use is $(\$280,000)(1 + 1/1.8) = \$436,000$. The ratio of this well cost to average well flow rate is now 2.2. Therefore, the estimated wellhead energy production cost for Arrowhead (from Figure 3) is about 75¢ per million Btu.

The system load factor has an enormous impact on the average cost of energy. The attainment of high system load factors will be important to the economic viability of geothermal energy in most applications. Energy production costs are inversely related to the load factor. The costs of production are predominately fixed costs. The principal variable cost will be the cost of energy consumption for pumping.

FIGURE 3. Effect of Fluid Temperature, Well Flow Rate and Well Cost on Production Costs

The load factor is determined by the climate and is not directly controllable by the geothermal energy supplier. For district heating applications in Riverside, the load factor on the distribution system will be about 30%. However, opportunities exist to increase the load factor on the geothermal production and transmission systems through the use of storage capacity and supplemental heat to meet peak demands.

If land subsidence appears to be a problem at Arrowhead, it might be necessary to inject the geothermal water into the reservoir after transferring the heat to a fresh water stream. There are a number of fresh water wells near the City of San Bernardino which provide the fresh water supply for the City of Riverside.^(a) The geothermal heat could be transferred to the water from these wells and then the hot fresh water could be transported to the distribution site in Riverside. After passing through the district heating system and giving up its heat, excess water could be disposed of in the existing sewer systems or used consumptively.

Transmission Costs

Flow rate and temperature have significant impacts on the cost of energy transmission (Figure 4). The flow rate refers to the peak demand, which is determined by the coincident end-use demands. Since pipe costs increase roughly linearly with diameter while capacity increases with the square of the diameter, economies of scale are achieved with increasing peak demand. Thus, a large market would tend to be served more economically than a small one.

The distance of fluid transmission will be a limiting factor for non-electric applications of geothermal energy. Transmission distances for existing geothermal applications are short, rarely exceeding 10 miles. The impact of distance on transmission costs is illustrated in Figure 5 for three fluid temperatures and pipeline capacities.

Based on the City of Riverside General Plan Map, Riverside will have a population of 362,000 by the year 1990. We estimate that about two-thirds of this population will be in low-density suburban areas and one-third will be in high-density urban areas. The peak fluid demand for this population will be about 21 million lb/hr for suburban areas. For high-density urban areas the peak demand will be about 4.3 million lb/hr. The total demand, 25.3 million lb/hr, is high enough to justify

(a) Discussion with David Sparks, Energy Information Coordinator, Riverside Public Utilities Department, 12/9/77.

FIGURE 4. Energy Transmission Costs

FIGURE 5. Energy Transmission Costs

at least a 48-inch transmission pipeline. From Figure 5, the energy transmission cost is about 45¢ per million Btu to pipe 150°C water from Arrowhead Hot Springs to Riverside, a distance of about 15 miles. The cost is only slightly higher if a 24 to 30-inch pipe is used to meet the urban demand only. Since Arrowhead is located in the San Bernardino Mountains, the geothermal fluid can be piped down the mountain under gravity flow; no pumping power will be necessary.

Distribution Costs

The costs of district heating are dependent on many factors related to climate, community characteristics, resource conditions, financing, system design, and construction. The district heating costs in this study refer to new construction unless otherwise stated; i.e., retrofitting costs and the added costs of construction in established areas are not included. The cost of the heating system within the building is not included.

Climate affects district heating costs through two factors—the minimum exterior temperature and the heating degree days. The minimum temperature establishes the peak-load heating requirements and thus determines the size and cost of the pipes. Lower exterior temperatures require more flow and larger pipes. Larger pipes increase the capital cost of the system. For economic reasons, district heating systems are usually designed to meet less than the peak demand. The peak heating requirements are then met with supplemental heat.

For this study we have assumed a municipal district heating system in which geothermal energy supplies 92% of the annual heat load demand. The remaining 8% of the demand is assumed to be met with supplemental heat costing \$6/million Btu. We have not included any geothermal energy storage capacity.

The number of heating degree days establishes the annual energy usage. In cold maritime climates, such as Iceland, the annual energy usage is high and relatively constant throughout the year. The average load factor on the Icelandic systems is about 50% of system capacity. In temperate climates, the average annual energy usage is less and the systems would

operate at lower capacity factors. Since district heating systems are very capital intensive, reductions in system capacity utilization, as reflected by degree days, lead directly to higher energy costs.

The total population of the district influences district heating costs in three ways. First, with increasing population, economies of scale are realized in the piping for the distribution network. Second, increasing population reduces costs associated with the investment in wells up to the point at which the maximum well flow is fully utilized. Third, with increasing population, economies of scale are realized in the transmission piping as discussed previously.

Population density is one of the most important factors affecting district heating costs. Increasing population density reduces district heating costs through reducing the average length of pipe run. With very high population densities, as in large multi-story apartment buildings, economies of scale are realized in the distribution system through the use of larger-diameter pipe. This cost advantage might be partially offset, however, by higher costs for heat distribution within the apartment building. Our cost estimates do not include costs of the heating systems within the buildings.

Researchers at Brookhaven National Laboratory have determined from case studies that \$8/square meter of floor area is the approximate cost of retrofitting a house for district heating.⁽²⁴⁾ We estimate 1,620 square feet of floor area for a typical single-family residence. Using these figures, the typical residence could be retrofitted for about \$1,200.

The City of Riverside has about 1100 heating °C days per year. For this climate, and assuming a 90°C fluid distribution temperature, the distribution costs for space heating are shown on Figure 6 as a function of population density. For suburban areas, the distribution cost ranges from \$4.50 to \$10 per million Btu. For high-density urban areas, the distribution cost ranges from \$2.30 to \$3 per million Btu. For construction in established areas, we estimate that the distribution costs would be 15 to 30% higher.

FIGURE 6. Energy Distribution Costs for Riverside

The total district heating costs, including production, transmission, and distribution, are summarized in Table 9. The total cost in urban areas ranges from \$3.50 to \$4.20 per million Btu, and the total cost in suburban areas ranges from \$5.70 to \$11.20 per million Btu. In the next section we will discuss comparative costs of conventional energy sources used for residential heating.

Opportunities exist for lowering the district heating costs by increasing the system load factor. This can be done by utilizing the district heating system for district cooling during the summer. It can also be done by supplying process heat for industrial demands. Both of these possibilities will be discussed later.

TABLE 9. District Heating Costs,
\$/Million Btu

	<u>Urban Areas</u>	<u>Suburban Areas</u>
Production	0.75	0.75
Transmission	0.45	0.45
Distribution	2.30 - 3.00	4.50 - 10.00
TOTAL	3.50 - 4.20	5.70 - 11.20

Arrowhead Hot Springs is not the only geothermal resource with potential for space heating applications in Riverside. For instance, one of the nearby lower-temperature thermal springs identified by Waring⁽⁷⁾ might be suitable. The French have a number of geothermal heating projects, mostly near Paris, which use heat pumps in conjunction with nearby low-temperature (50 to 80°C) geothermal resources.⁽²⁵⁾ These projects have demonstrated that it is definitely possible to utilize low temperature heat in district heating systems as long as the resource is very near the site of usage.

If a 90°C resource were found only one mile from Riverside, it would have space heating potential. The production costs would probably be higher than those quoted in Table 9 for Arrowhead (150°C resource) because the effective temperature range (ΔT) of utilization would be 60°C smaller (see Figures 3 and 4). However, if the transmission distance

were decreased from 15 miles to 1 mile, then the transmission costs would probably be lower even though the resource temperature was lower (see Figure 5). The distribution costs would be the same as shown in Table 9, because the fluid distribution temperature is 90°C in each case.

Comparative Costs of Conventional Energy Supplies

Space heating is commonly provided by natural gas, fuel oil, or electricity. Energy costs for residential heating are projected to increase in real dollars (Table 10), which will provide opportunities with time for the economic substitution of geothermal district heating. The energy costs include the energy utilization efficiency. The average energy utilization efficiencies for residential heating are: gas furnace, 69%; oil furnace, 66%; and electric furnace, 95%.⁽²⁶⁾ The residential electric heating costs reflect average prices in Riverside.

Comparison between Tables 9 and 10 shows that geothermal district heating is competitive now with heating oil and electricity in high-density urban areas. By 1985 geothermal should also be competitive with natural gas in urban areas. In suburban areas geothermal may be competitive by the year 2000.

TABLE 10. Energy Costs for Residential Heating
(In 1977 Dollars) (\$/MBtu of Space
Heat Delivered in Riverside)⁽²⁷⁾

	<u>1977</u>	<u>1985</u>	<u>2000</u>
Natural Gas	2.90	4.00	6.10
Heating Oil	4.15	4.55	6.05
Electric Furnace	10.25	13.40	17.90

(a) Includes utilization efficiency of fuel in the furnace.

COST OF GEOTHERMAL SPACE COOLING

The City of Riverside has about 735 cooling °C days per year. For this climate, and assuming a 90°C fluid distribution temperature, the distribution costs for space cooling are shown on Figure 6 as a function of population density. For suburban areas, the distribution cost ranges from \$9 to \$14 per million Btu. For high-density urban areas, the distribution cost ranges from \$3.10 to \$5 per million Btu.

The total district cooling costs are shown in Table 11. These costs should be compared with the costs of mechanical compression air conditioning, which uses electricity as the power source. Assuming an average coefficient of performance (Btu cooling/Btu input) of 2.0 for the compression cycle, the conventional energy costs for residential cooling are shown in Table 12. Comparison between Tables 11 and 12 shows that geothermal district cooling may be competitive by the year 2000 in urban areas, but it is far too expensive in suburban areas.

TABLE 11. District Cooling Costs,
\$/Million Btu

	<u>Urban Areas</u>	<u>Suburban Areas</u>
Production	2.25	2.25
Transmission	1.35	1.35
Distribution	3.10 - 5.00	9.00 - 14.00
TOTAL	6.70 - 8.60	12.60 - 17.60

TABLE 12. Energy Costs for Mechanical
Compression Air Conditioning
(In 1977 Dollars)(\$/MBtu of
Space Cooling Delivered in
Riverside)

<u>1977</u>	<u>1985</u>	<u>2000</u>
4.85	6.40	8.50

We have assumed that 50,000 Btu/hr of geothermal energy is required to deliver 3 tons (36,000 Btu/hr) of air conditioning using 90°C water,⁽²⁸⁾ which means that the absorption unit we modeled has a coefficient of performance of 0.72. We have also assumed that 1 ton of air conditioning is needed for every 600 ft² of floor area.

The production and transmission costs for district cooling (Table 11) are higher than the production and transmission costs for district heating (Table 9). There are several reasons for this difference in costs. First, the load factor on the cooling system is only 0.24 and the load factor on the heating system is 0.3. Production and transmission costs vary with the inverse of the load factor. Second, the ΔT of utilization for heating is about 30°C greater than the ΔT of utilization for cooling. Thus the geothermal fluid is used more efficiently for heating than for cooling, resulting in lower costs for the heating mode of operation. Third, the 0.72 coefficient of performance for the absorption cooling cycle means that each Btu of heat input results in only 0.72 Btu of cooling. This means that the cost per Btu utilized for cooling is greater than the cost per Btu supplied to the house by a factor of 1/0.72. The coefficient of performance for geothermal heating is assumed to be 1.

Distribution costs are strongly affected by climate; they vary inversely with the number of degree days. Since Riverside has 50% more heating degree days than cooling degree days, the heating distribution costs are lower than the cooling distribution costs.

We have specified a 90°C fluid distribution temperature for this study because Arkla data⁽²⁸⁾ is available on the coefficient of performance of units operating at this temperature. As discussed previously, there is an absorption cooling unit in New Zealand that utilizes 120°C water. The higher temperature would probably make the system more efficient; however, we don't know the C.O.P. at 120°C, so we can't model the New Zealand unit accurately.

The Arkla absorption chiller, which operates with a 90°C hot water inlet temperature and an 85°C outlet temperature, was designed for solar use. Nevertheless, it is technically feasible to use geothermal energy instead of solar as the heat source. By using a closed-loop system (between 85°C and 90°C) and exchanging this water with the 150°C geothermal fluid, the geothermal ΔT of utilization is increased from 5°C (i.e., 90°C - 85°C) up to 65°C (i.e., 150°C - 85°C). Also, the required geothermal flowrate is lower by an order of magnitude if this closed-loop heat exchange scheme is used.

COMBINED DISTRICT HEATING AND COOLING COSTS

The total costs for the combination of district heating and district cooling are lower than either the heating costs alone (Table 9) or the cooling costs alone (Table 11). This is because the system load factor is increased to 0.54 when the system is used for both heating and cooling. Since the heating demand is greater than the cooling demand, the system should be sized for the heating mode. However, the year-around use of the system, once it has been designed, will effectively spread the total capital cost over a larger quantity of geothermal energy, resulting in a lower cost per Btu.

The total costs for space heating and space cooling are shown in Table 13. For suburban areas, the total cost ranges from about \$4.80 to \$7.30/MBtu. For high-density urban areas, the total cost ranges from \$2.20 to \$2.70/MBtu. The conventional energy costs for the combination of space heating and cooling are shown in Table 14. We have assumed here that conventional heating is done with natural gas and conventional cooling is done with electricity. We used weighted averages of the costs based on the annual energy consumption for heating and cooling. The combination of geothermal space heating and space cooling in Riverside is competitive now with conventional fuels in high-density urban areas and may be competitive in suburban areas by the year 2000.

TABLE 13. Total Costs for Geothermal Space Heating and Cooling in Riverside (\$/Million Btu Utilized)

	<u>Urban Areas</u>	<u>Suburban Areas</u>
Production	0.50	0.50
Transmission	0.30	0.30
Distribution	1.40 - 1.90	4.00 - 6.50
TOTAL	<u>2.20 - 2.70</u>	<u>4.80 - 7.30</u>

TABLE 14. Conventional Energy Costs for Space Heating and Space Cooling in Riverside (\$/Million Btu Utilized)

<u>1977</u>	<u>1985</u>	<u>2000</u>
3.60	4.85	6.95

COST OF GEOTHERMAL PROCESS HEATING

In addition to the costs for production, transmission, and disposal for geothermal process heating applications, some retrofitting costs may be incurred. These might include heat exchangers and other equipment for converting the conventional system to geothermal energy. For processes in which water is normally used to carry heat, few or no retrofitting costs are anticipated. For other processes, such as drying with hot air, the use of geothermal energy may require adding water-to-air heat exchangers. The economic incentive for converting to geothermal energy will depend on both the cost of the energy supply and the in-plant retrofitting costs.

The process itself will have a significant impact on the costs of the geothermal energy supply through the size of the energy demand, the maximum temperature of utilization, the effective temperature range (ΔT) of utilization, and the impacts of seasonal factors and plant operating schedule on the load factor. These factors have already been treated for the production, transmission, and disposal costs.

For district heating applications, the geothermal fluid is rejected at 38°C. For process heating applications, the reject temperature is 100°C. The production and transmission costs increase as the minimum temperature of utilization increases because less of the available energy in the fluid is being utilized.

At this time, we don't have any data on industrial process heat demands or process water temperatures for the Riverside area. However, we can estimate the cost of geothermal process heating from previous general analyses.⁽²⁾

The minimum cost of using geothermal energy from Arrowhead Hot Springs to supply process heat to industries in Riverside is estimated to be between \$1.50 and \$2.00/MBtu. Thus, under favorable conditions, geothermal energy has the potential to be competitive with conventional fuels for process heating. These estimates include only the cost of delivering the geothermal energy to the plant site. They assume a load factor of 100% (i.e., a constant demand throughout the year) and a large demand in a concentrated area.

Process heating is currently provided by natural gas and fuel oil. However, the availability of these fuels, particularly natural gas, for industrial process heat is subject to curtailment. In the future, coal should provide the marginal cost competition for process heating. Combining the capital cost of a furnace and boiler with the mining and transportation costs and the combustion efficiency, process heat from coal should cost \$2 to \$3/MBtu in 1985 (in 1977 dollars).⁽²⁾ These costs are based on extrapolation of the current costs of coal production, transportation, and utilization. The underlying assumption is that coal supplies are abundant and, therefore, coal prices will be relatively insensitive to other energy prices and will be determined primarily by the costs of production.

METHODOLOGY AND ASSUMPTIONS

The basis for our geothermal energy cost analysis is the unit cost of energy which will recover all the costs of production - capital investment, operating expenses, taxes, and the specified rates of return on capital. This unit cost of energy can be directly compared with the costs for conventional energy sources. Our focus is on the economics of substituting geothermal energy, based on production costs, for conventional energy sources.

The calculation of the unit cost of energy is based on life-cycle costing and discounted-cash-flow analysis. The GEOCITY model is used for these calculations. The unit cost of energy is derived from the following expression:

$$C = \frac{\sum_{n=1,ny} PW_n \cdot (CAP_n + EXP_n + TAX_n)}{\sum_{n=1,ny} PW_n \cdot ENERGY_n}$$

where

- C = unit cost of energy
- ny = useful life, years
- CAP = capital cost
- EXP = annual operating expenses
- TAX = annual taxes
- PW = present worth factor
- ENERGY = annual energy production
- n = year

The geothermal energy is assumed to be provided by firms having the capitalization and financial characteristics shown in Table 15. The firms would typically be a large oil company operating the reservoir and a municipal utility operating the transmission and distribution system. Assumptions affecting taxes include expensing intangible drilling costs and accelerated (sum-of-the-years' digits) depreciation. All cost estimates are in 1977 dollars unless otherwise stated.

TABLE 15. Financing and Tax Assumptions

	Reservoir (%)	Transmission and Distribution System (%)
Capitalization		
Debt	42	100
Equity	58	0
Bond Interest Rate	8	6
Return on Equity	15	-
Federal Income Tax Rate	48	0
State Income Tax Rate	7	0
Property Tax Rate	2.5	0
Royalty Payment	10	-
Revenue Tax Rate	--	4

COMBINED APPLICATIONS
OF GEOTHERMAL RESOURCES WITH OTHER ENERGY RESOURCES

Although it would be technically feasible to combine geothermal energy with other energy resources, both for electricity generation and non-electric uses, combined applications, in general, appear to result in higher costs and, in some instances, less energy-efficient uses of the resources. Under some conditions, as explained later, a slight economic incentive might be achieved with a combined plant but, in general, each energy source would be most efficiently used in facilities designed for that resource. That is, for a specific application, if geothermal energy is the economic choice, then supplementing with an alternative energy source will probably lead to a more costly system. If the alternative energy source is the economic choice, supplementing with geothermal energy will probably lead to a more costly system. Further, the use of high-Btu fuels to supplement a geothermal system will generally be less efficient thermodynamically than their use separately in a more efficient, high-temperature plant. In principle, combined applications would require additional separate facilities to handle each energy source without increasing capacity; therefore, the utilization of capital tends to be inefficient. As shown previously, the initial capital investment costs are the major costs in geothermal energy utilization.

There might be a role for combined plants based on energy-supply reliability and lower-risk geothermal development criteria. An important constraint to geothermal energy development is the time required to drill wells and prove the energy supply. Currently, this requires prolonged well testing periods and methodical reservoir development prior to construction of the power plant. However, if the first plant at a geothermal reservoir was based on a combined energy supply, a larger plant, not entirely dependent on the geothermal energy, could be built sooner. This might accelerate initial and subsequent reservoir development and power plant construction. As the geothermal reservoir capacity was expanded, the supplemental energy source could be phased out and held in reserve to begin another cycle of power plant

expansion. An economic penalty would derive from the low utilization rate of the supplemental energy capacity.

The potential uses of geothermal energy in combined applications are similar for both electrical and non-electric uses: (1) geothermal could provide a reserve or backup capacity, (2) geothermal could provide supplemental energy, or (3) geothermal could provide the base energy source and be supplemented by the other energy source.

COMBINED SYSTEMS FOR ELECTRICAL APPLICATIONS

Reserve or Backup Systems

Geothermal energy is capable of supplying reserve or backup capacity. The technical, economic, and resource potential for generating electricity for Riverside from geothermal energy was shown in preceding sections to be promising. However, the nature of geothermal power generation is that the preponderance of costs are incurred with initial investment. Thus, once the capacity is in place, continuing costs are low, and there would be little incentive to allow the plant to be idle. Therefore, a stiff economic penalty, in the form of low productivity of capital, would be associated with installing a geothermal backup system.

Combined Plants

For purposes of discussion, we will assume combined geothermal-coal plants. The coal will serve as a surrogate fuel for other alternative energy sources such as methane generated from solid wastes, garbage incineration, a high-temperature solar furnace, etc.

We will consider two applications of combined coal-geothermal plants: (1) supplementing a modern coal plant with geothermal energy and (2) supplementing a geothermal power plant with coal (or other high-Btu fuel).

Modern Coal Plant

A schematic diagram of a modern coal plant is shown in Figure 7. These plants operate at a high heat rate of about 9,000 Btu/kW-hr, or about 38% thermal-to-electric conversion efficiency. The thermal energy

T_n = TURBINE EXTRACTION POINTS WHERE STEAM/CONDENSATE (OFF-BLADES) IS TAKEN TO HEAT FEED WATER

FIGURE 7. Power Cycle for Coal Plant

in geothermal fluids could provide energy to the feedwater heaters and could provide part or all of the energy to the economizers (preheaters).

In this plant, the enthalpy of the working fluid increases from 90 Btu/lb at the condenser outlet to 1,450 Btu/lb at the turbine inlets, an increase of 1,360 Btu/lb. If this increase is supplied entirely by coal, at a cost of \$1.00/million Btu, then the cost of the energy supply is 9 mills/kW-hr. The capital cost of the power plant and other operating costs would add about 10 mills/kW-hr (at 1977 prices), making the total cost of power about 19 mills/kW-hr.

If a high-enthalpy geothermal fluid, say 590 Btu/lb, is used for preheating, then about 500 Btu/lb (590 to 90) will be available for preheating. Thus geothermal could supply, in this instance, 37% of the thermal energy. If the plant could be redesigned to achieve the same heat rate, the coal consumption could be reduced by the same 37%. When geothermal energy costs less than coal, then the cost of energy would be reduced. If the total plant capital costs and operating costs were not increased by using geothermal, then the total power cost would be decreased. For instance, if the geothermal fluid were free, the maximum savings (again assuming coal at \$1/million Btu) would be 3.2 mills/kW-hr or about 15% of the total power cost. If the fluid cost the same as the coal, there would be no savings. If the fluid cost \$0.50/million Btu, a reasonable estimate, then the savings would be 1.6 mills/kW-hr or about 8%.

There are a lot of favorable "if" assumptions in the foregoing analysis which, if resolved unfavorably, could easily turn this small economic advantage into a disadvantage. Besides, a 590 Btu/lb geothermal fluid, which would have a temperature of about 600°F, would be economically competitive with coal in a geothermal plant by itself. Fluids of this temperature have high silica concentrations; this might lead to excessive scaling and inhibit their use in heat exchangers in a coal-fired plant.

The situation is less attractive for a low-enthalpy geothermal fluid. For a fluid with an enthalpy of 290 Btu/lb, only 200 Btu/lb would be available for preheating. Under the same assumptions as above, this

fluid could replace only 15% of the coal. The savings (assuming \$0.50/million Btu for the fluid) would be 0.7 mills/kW-hr or about 4% of the total power cost. This savings could be easily offset by increases in plant capital cost for the fluid-handling system or decreases in the efficiency of coal utilization.

In a study^(a) for the Energy Research and Development Administration, the City of Burbank reached similar conclusions. For three California sites, East Mesa, Coso, and Long Valley, a hybrid coal-geothermal plant would produce higher-cost electric power delivered in California than a coal-only plant located at Roosevelt Hot Springs, Utah. According to the study, a hybrid plant at Roosevelt, a high-enthalpy geothermal resource, would produce power at about a 10% savings over a coal-only plant located there. Whether there would be any savings over a coal-only plant located at a site more favorable for coal or a geothermal-only plant located at Roosevelt was not reported.

In summary, using geothermal fluid to supplement coal (or other high-Btu fuels) in a modern power plant could achieve up to a 35% reduction in coal consumption. On paper, a small economic advantage looks possible. However, this advantage, which is based on favorable assumptions, would diminish and probably disappear under actual conditions. Geothermal-only power plants, based on low-salinity and high-enthalpy fluids, would probably result in lower power costs than coal-only plants in most situations.

Geothermal Plants

If geothermal fluids are superheated with coal, then the coal would be used less efficiently than in a coal plant. (If the fluids are not heated to the same temperature and pressure as a modern coal plant, then the heat rates would be higher—the thermal conversion efficiency would be lower—than in a coal-only plant.) For example, at The Geysers, a geothermal steam plant, the heat rate is 21,000 Btu/kW-hr. Even heating the geothermal fluid to duplicate the conditions of a modern coal plant results in less efficiency because the heat in the return condensate is

(a) City of Burbank, Site Specific Analysis of Hybrid Geothermal-Fossil Power Plants, June 1977.

lost in a once-through plant. In addition, noncondensable gases and dissolved solids in the fluid could lead to other inefficiencies and higher costs.

Supplementing an expensive geothermal energy supply with energy from lower cost coal could decrease the cost of geothermal power, but probably not to the point of being competitive with the coal-only plant. In most instances, the greatest power production and lowest average cost would probably result from two separate plants—one coal and one geothermal. This same conclusion would probably apply, generically, to other combined applications.

COMBINED NON-ELECTRICAL APPLICATIONS

Combined systems for non-electric applications also do not appear promising from an economic standpoint, principally because of the capital-intensive nature of geothermal developments and capital-related economies of scale.

Reserve or Backup Systems

Geothermal energy is capable of supplying reserve energy or a backup system for non-electric applications. However, as with electrical uses, the preponderance of costs are incurred with the initial investment and the continuing costs are low. Thus, there would be no economic incentive to install and not use a geothermal backup system for non-electric applications.

Combined Systems

Combined systems for non-electrical uses would require separate facilities for the production and transmission of both energy forms. Two types of inefficiency might result from the combined application. First, if excess capacity is required in either system, the use of capital will be inefficient. Second, if the capacity for each energy source is decreased proportionately in size to avoid the foregoing problem, then diseconomies of scale will be encountered in both systems, again resulting in an inefficient use of capital. To illustrate the economies of scale in fluid transmission, the cost of a water transmission pipe varies approximately with the diameter to the first power, while the energy carrying capacity varies with the square of the diameter.

The economies of scale in developing the geothermal energy supply, although not large compared to those in transmission, also occur in well drilling and in maximizing the utilization of individual wells. Similar economies of scale also apply to the production and transmission of the nongeothermal energy source.

ENVIRONMENTAL, LEGAL, AND INSTITUTIONAL CONSTRAINTS

OVERVIEW

In order to understand environmental, legal, and institutional problems in using geothermal energy in Riverside, it is necessary to understand something of Riverside's energy supply. Riverside is a city of about 130,000, located some 60 miles east of Los Angeles. The city is within 50 miles of geothermal resources that are suitable for non-electric applications, most notably Arrowhead Hot Springs (which has water hot enough for space heating and marginally hot enough for electricity generation) and within range (200 miles) of a substantial number of geothermal resources suitable for the production of electricity.

Riverside has a municipal utility district which provides water and electricity. Its role is that of distributor of electricity; all of the city's electric power is currently purchased from Southern California Edison Company (SCE). Riverside's peak demand is almost 255 MWe. Riverside is the second largest of California's publicly-owned distribution systems. All of Riverside's natural gas is supplied by the Southern California Gas Company (SCG).

GENERAL LEGAL CONTEXT

Because Riverside is a publicly-owned utility, there are potential legal constraints on its actions that might not apply to a private utility. As a general matter, private corporations are free to engage in any lawful activity that is within the broad mandate of their corporate charters. Publicly-owned corporations are more limited in their powers, being able to do what is specifically designated by their corporate charters or directly authorized by state legislation.⁽²⁹⁾ It should be noted that municipal utilities in California already perform nearly all the activities that privately-owned ones do. The City of Burbank is directly involved with geothermal resource development. Two others, the Sacramento Municipal Utility District and the Northern California Power Agency, have also expressed strong interest in being active in developing the resource. Nonetheless, it is important to recognize at

the outset that the general legal framework by which municipalities and their public corporations are organized implies some limits on innovative activity.

Of course, there are some ways in which a municipal utility may find it easier to operate than a privately-owned one. For instance, publicly-owned utilities are not subject to the jurisdiction of the California Public Utilities Commission (CPUC) in the development of power plants and transmission of power. In addition, a municipality could use tax advantages for its bonds to finance energy facilities at lower rates than private corporations could. It is not within the scope of the present discussion to provide a detailed analysis along these lines. Rather, the purpose here is to raise the issue for a closer look at some appropriate time.

PUBLIC AND PRIVATE POWER

This is a general point of enormous importance. California has seen intense competition between private and publicly-owned power.^(30,31) Proposals to allow a city such as Riverside to begin generating its own electricity from geothermal or any other source are apt to meet spirited opposition both from the utilities such as Southern California Edison, whose markets would be placed in jeopardy, and from the larger community of privately-owned utilities and their supporters. This is not to argue that cooperation among the private and publicly-owned utilities in California is not possible. Indeed, some degree of it has been compelled as a result of antitrust considerations in licensing of nuclear plants. Nonetheless, it would be naive to expect that changes in the present balance between private and public generation would be unopposed.

ELECTRIC APPLICATIONS OF GEOTHERMAL ENERGY FOR RIVERSIDE

In general, the environmental, legal, and institutional constraints on the use of geothermal energy to produce electricity for Riverside depend upon two factors: (1) the arrangements by which the electricity is produced and (2) the location of the geothermal resources used. For example, one would anticipate relatively few problems if Riverside were somehow to start producing electricity from geothermal steam at The Geysers. The Geysers resource has already been well developed; both the technology for doing so and the regulatory framework for providing environmental protection, mitigating disputes, and other matters are tested. On the other hand,

development of a hot-water geothermal resource in a new area is apt to pose numerous problems. Since the most economically attractive sources of geothermal electricity for Riverside are relatively undeveloped hot-water resources at Coso Hot Springs, Brawley, and Heber, one should not expect smooth sailing with respect to environmental, regulatory, or institutional problems. Such problems are apt to be more difficult for early developers in an area because of uncertainty over environmental effects and because the regulatory apparatus is untried.

General Environmental Issues

For these three sites, and for hot-water sites in general, it would appear that the primary environmental concerns are (1) land use, (2) disposal of geothermal fluids, (3) other water pollution problems, and (4) subsidence or seismic activities.⁽³²⁾

Air quality concerns may not be as important an issue with the use of hot-water resources as they are for geothermal steam at The Geysers, since many hot-water systems are apt to be closed loops from extraction through reinjection of the geothermal fluids. Some systems may, however, involve air emissions problems, particularly with hydrogen sulfide (H_2S) gas. Land use activity problems are quite site specific. In general, there are no prohibitive barriers for using land for drilling geothermal wells or constructing electric power plants or related facilities using geothermal energy, although there may be compelling environmental reasons to deny such use at a given site.

Disposal of geothermal wastes, on the other hand, is apt to be a major problem anywhere in Southern California. The region is generally short of water, with a strong demand for water for agricultural purposes as well as for human use. It is very likely, therefore, that proposals to dispose of geothermal fluids will receive intense scrutiny from the appropriate regional Water Resources Control Board, which grants permits for activities which do or might affect the quality of surface water. Moreover, there is apt to be conflict over the provision of groundwater for power plant cooling and other purposes, should it be needed. There does not appear to be much unallocated water available in Southern California as a whole and, therefore, a power plant developer is likely

to be faced with the prospect of either buying an existing allocation or developing an alternative source of water.

Depending upon the geological characteristics of a given geothermal resource, there may be subsidence of the surface as geothermal fluids are pumped out. In Imperial County, where both the Brawley and Heber resources are located, surface subsidence could be a major problem because of disruption of irrigation networks and other facilities. The current preferred solution to subsidence problems from geothermal development in that area is to reinject the geothermal fluids into the reservoirs from which they came. This solution combines solutions to both the geothermal waste disposal and subsidence problems, while avoiding the need to use more valuable fluids (e.g., surface water) for the purpose of preventing subsidence.

It is too early to say with any confidence whether reinjection will prove successful generally, or in the geothermal resources most likely to be of interest to Riverside. There have been mixed results from reinjection tests at various hot-water geothermal sites: few problems at Heber, but some substantial ones at Brawley and other sites as the minerals in the fluid solidify and clog piping. To date, there is no firm evidence of subsidence in the Imperial Valley as a result of geothermal development, although it must be noted that activity there has been quite limited.

There may also be water allocation problems. Water may be necessary for power plant cooling or as an injection fluid to prevent subsidence. There is not much, if any, unallocated water in Southern California, therefore, it will be necessary to either purchase water or develop new wells to meet such needs. There is some possibility that unpotable well water in the Imperial Valley might be readily available for geothermal uses. However, it is likely that in any water-scarce area, concerns of other water users will lead to close regulatory scrutiny throughout the development process.

In the most probable case, that a geothermal developer would contract to supply hot water to a power plant which Riverside would construct and operate, many of these environmental problems would be for the developer

to resolve. It is also likely that by the time any Riverside plant were constructed, enough would be known about the characteristics of the specific resources that any environmental problems would have been resolved. There is already substantial activity at both Brawley and Heber and considerable interest in the Coso resource.

The Institutional Problem

The most intractable problem for the use of geothermal energy for the production of electricity for Riverside is that of getting the electricity to the city. With one possible exception, Arrowhead Hot Springs, the feasible resources are at considerable distance from Riverside itself. These distances may be too great to justify the construction of new transmission lines between the geothermal reservoirs, where the power must necessarily be produced, and Riverside. Moreover, building new lines, particularly in populated areas, is apt to be difficult because of environmental and other opposition. Then there needs to be some arrangement to carry Riverside's electricity over the existing power network.

None of the geothermal resources of most interest to Riverside is prohibitively far from existing transmission facilities.⁽³⁵⁾ Coso Hot Springs is within 20 miles of privately-owned 215 kV lines running north and south. The Brawley and Heber sites are close to lines in the Imperial Valley system owned by the Imperial Irrigation District. The problem is one of ownership of lines. Assuming there is excess capacity, there should be no particular problem in arranging for Riverside's power to be transmitted over publicly-owned lines. Arranging transmission over privately-owned lines is apt to be more difficult. The transmission lines within a feasible distance of Coso Hot Springs are privately held. The publicly-owned lines in the Imperial Valley get no nearer than Coachella, about 60 miles from Riverside. Moreover, transmission into Riverside itself is presently entirely controlled by SCE, which supplies the city with all of its electricity.

There are a number of reasons to expect privately-owned utilities, in this case SCE, to be reluctant to carry Riverside's power over their lines between generation site and the city. In general, the investor-owned utilities would prefer to use transmission lines to carry power

on which they are making full profits. Indeed, SCE has stated that it does not intend to become a common carrier with respect to transmission services.⁽³³⁾ Beyond this, increasing the number of sources from which power is fed into the system and differing the rates at which it is carried complicates load management.

Obviously, to these difficulties must be added the most important implication, at least to SCE, of Riverside's producing its own electricity: the loss of market. Currently, as noted above, SCE supplies all of Riverside's electricity. It would appear akin to adding insult to injury for Riverside to ask SCE to, on the one hand, forego its market and, on the other, provide the transmission services necessary for doing so.

There is the related problem of system reliability.⁽³⁰⁾ As noted above, Riverside's peak demand is 255 MWe. Riverside could supply its needs by building a single power plant of 255-megawatt capacity, most likely a fossil fuel or hydroelectric plant since geothermal units presently are much smaller. The problem with such a plan is that of providing backup power if the plant fails. In order to do so entirely on its own, Riverside would have to build a second 255-MWe plant. If Riverside supplies its needs with a number of power plants roughly on the 50-megawatt scale (a size which confers additional benefits since under 50 megawatts would escape regulation by the California Energy Resources Conservation and Development Commission), Riverside would need approximately six plants to provide system reliability; five to meet its 255-megawatt peak demand and an extra one of the same size to use in the event that one of the primary units went down. There is clearly an advantage in spreading capacity over a number of units. This advantage applies to system planning as well as reliability. For example, at a growth rate of 5% a year, Riverside will need an additional 12 MWe of capacity to meet next year's peak demand. These 12 megawatts are roughly one-fifth of a typical geothermal unit, but a much smaller fraction of such other generation alternatives as nuclear plants. For Riverside to attempt to provide capacity itself to meet all its own requirements, it is faced with either deferring needed additions until the demand has grown enough to justify them in economic terms, and thereby having to get by with inadequate capacity, or making investments in excess capacity in order to have the

supply in advance of anticipated demands. Even if Riverside were able to make efficient investments in a reliable set of generation facilities at Coso Hot Springs, Brawley or Heber, reliability problems would remain for transmission from the power plant to Riverside. As any New Yorker knows, reliability problems can result from transmission difficulties as well as from power plant failures. Hence even if Riverside had sufficient geothermal generation capability, it would have no protection against loss of power due to transmission failures.

The solution to these problems of reserve capacity, system planning and transmission reliability, and to such related ones as efficient uses of capacity, is in wide interconnections with other producers of electricity. Given the existing transmission network in California, there is really only one choice for Riverside: SCE, although there may be advantages in intertying with other systems as well.

Finally, even if Riverside could develop one or more geothermal resources sufficiently to supply all of its electric power, it is unlikely that it would be able to do so in a very short period of time. Development of The Geysers present production capability of 502 MWe took about 20 years. While the pace of development at The Geysers may have been particularly slow, development of a relatively unfamiliar hot-water geothermal resource would probably not proceed at a very rapid rate. During the period over which Riverside was developing its capability, therefore, it would have to continue to buy power elsewhere. The present supplier of this power is, of course, SCE and there is no reason to believe that Riverside would find it easy to develop a substitute source.

In any event then, it seems that Riverside will have a substantial need to cooperate with SCE should it decide to generate its own geothermal power. But this cooperation does not appear to be to SCE's advantage. As noted above, Riverside's generation of its own power robs SCE of a market. Riverside is a valuable customer to SCE; indeed it pays even more for wholesale electricity than some SCE industrial customers do. ⁽³⁰⁾

Not only does it appear to be contrary to SCE's best interest to cooperate with Riverside by providing transmission facilities or reserve sources of power or in other ways, but there are indications that SCE has in the past acted vigorously to protect its interests in these respects. In July 1963, SCE executed all requirements contracts with wholesale customers, such as Riverside, to prohibit the operation of any generating facilities parallel with SCE's own. Early in its contract, Riverside held discussions with SCE about some peak-sharing generation, but SCE opposed Riverside's development of generation.⁽³⁰⁾ SCE acted to prevent participation by another of its wholesalers, the City of Anaheim, in the Navajo coal-fired plant in Arizona by refusing to wheel power to Anaheim.⁽³⁰⁾ An SCE Vice President gave testimony before the Subcommittee on Energy and Power of the House Interstate and Foreign Commerce Committee on April 6, 1976, saying:

"... utilities have generally been concerned about the potential loss of base load, about the use of utility transmission facilities for wheeling, and about any idea that the utility system might be expected to provide backup to onsite generation without adequate compensation.

"... if a project is both technically and economically feasible, then the utility will itself give serious consideration to installing the generation.

"... concern was expressed about frequency control, the danger the proliferating small units might pose to system dispatching problems, and the need to be 'fully compensated' in standby service.

"... 'very large' customers with multiple plants in the utilities service territory may want to have wheeling and combined metering. This concept is not cost effective or practical for an electrical stability point of view. Additionally, the concept poses numerous liability problems in the event of transmission problems. The customer also may not be able to afford his fair share of the cost of wheeling as to the various interconnected utilities.⁽³⁰⁾

This statement was directed towards generation by industrial customers, nonetheless, it suggests that the utility retains its disposition towards preventing the development of small, or relatively small, generating capability by others within its service area.

There is some possibility of a remedy to this problem. The State of California has recently passed a law (California Public Utilities Code Sections 2801 - 2816, Chapter 915, Statutes of 1976, SB 77) that would allow a utility that chose to generate electricity from unconventional sources such as geothermal to petition the Public Utilities Commission for an Order of Interconnection to force the transmission line owner to provide wheeling services. This is an untested legal mechanism and it is difficult to say at this time how successful it would be in actual use. On the one hand, the threat of its use may provide bargaining power to Riverside and others in persuading the large utilities to deal voluntarily; on the other hand, legal challenges brought by SCE to any request for an Order of Interconnection may result in very long delays and, therefore, the cancellation of projects. It is also conceivable that the showings of fact required before an order might be granted are so difficult that in reality no one could ever present them.

Apart from this state statute, there are two possible federal solutions. First is the Otter Tail case,⁽³⁴⁾ which restricts the ability of privately-held utilities to deny transmission services to those who seek them by requiring good-faith bargaining. A potentially more important development results from antitrust disputes in the licensing of nuclear power plants. As a result of a dispute among SCE, the United States Department of Justice and municipal utilities in SCE's service area, SCE agreed in 1974 to permit participation by the municipals in future nuclear plants, to purchase and sell emergency bulk power and to transmit bulk power for other utilities.⁽³⁰⁾ The agreement seems to address most of the difficulties SCE had created in the past for utilities within its service area which, as Riverside would do with geothermal, sought to produce their own electricity.

Riverside and SCE have, as a result of the 1974 settlement, agreed to some degree of integrated operations. Hence Riverside would be given a credit of 80% for every kilowatt of capacity it develops against the costs of electricity it buys from SCE.^(a) The 20% that Riverside does not recover goes to transmission and reserve requirements.

However, it must be remembered that the SCE agreement came in the context of nuclear power plant licensing and was primarily directed towards enabling smaller utilities to participate in the ownership of such plants.

(a) Discussion with David Sparks, Energy Information Coordinator, Riverside Public Utilities Department, 12/12/77.

It is not clear that the wheeling, partial requirements, and reserves coordination provisions would apply to power produced by other means. Indeed the statement noted above about SCE not becoming a common carrier was made in the letter agreeing to nuclear plant participation. Moreover, the agreement itself provides SCE considerable protection:

"... SCE should not be obligated to enter into such an arrangement if (1) to do so would violate, or incapacitate it from performing any lawfully existing contracts it has with another party or (2) there is contemporaneously available to it a mutually exclusive competing or alternative arrangement with another party which affords it greater benefits." (30)

SCE retains considerable ability to take actions which would make it difficult for Riverside to begin producing its own power from geothermal resources. Presumably, it will be more difficult for Riverside to reach accommodation with SCE to the degree that Riverside desires to become self-sufficient. Self-sufficiency implies outright denial to SCE of a 255-MWe market; a single Riverside geothermal plant would deny only 20% of that market and could result in no absolute loss to SCE if calibrated to growth of the combined Riverside-SCE system as a whole.

In summary, it is very likely that Southern California Edison will view any attempt by Riverside to generate all or a substantial portion of its electricity by geothermal or other means as a threat to its own market position. This is obviously so with respect to the current load in Riverside and is apt to be a continued threat since Riverside might choose to compete with SCE for industrial users in the event that it was able to develop capacity. Riverside recently lost a major industrial customer to SCE because SCE's power rates to such customers were lower than those to Riverside. (30)

It is conceivable that SCE could produce electricity from geothermal energy for Riverside. SCE has been active in the Imperial Valley and other areas and contemplates adding 200 megawatts of geothermal capacity by 1990. (3) Only a slight escalation in these plans would match the capacity demands for Riverside as a whole. However, it does not make much sense to consider development of geothermal resources by SCE as directly providing geothermal energy to Riverside, since presumably the

electricity produced would be melded into the rest of SCE's 13,400-MWe capacity⁽³⁰⁾ and sold at the going rates.

Finally, SCE and Riverside could jointly participate in the development of geothermal electricity. Again, it is unlikely that such a partnership would avoid the difficulties implicit in Riverside's seeking to supply a very large portion of its own power. If, on the other hand, Riverside's participation is limited, there may be no problem.

NON-ELECTRIC APPLICATIONS OF GEOTHERMAL ENERGY FOR RIVERSIDE

It is technically and economically feasible for Riverside to obtain space heating and cooling from nearby geothermal resources. The most feasible resource is Arrowhead Hot Springs, some 15 miles away, in neighboring San Bernadino County. There would appear to be a number of difficulties in developing the resource at Arrowhead for space heating and cooling in Riverside.

One of these is an investment risk question. The normal model for geothermal resource development is for a field developer, typically an oil company, to acquire geothermal leases and arrange for exploration activities to prove the value of the resources. Then the developer negotiates with various utilities or other users to arrive at a long-term contract to purchase the geothermal energy. While this process is by no means as straightforward or easy as that involving oil and gas, it has been fairly well developed, at least at The Geysers, for electricity generation. Here, however, the ordinary model may be inappropriate. Riverside may be the only potential user of the Arrowhead Hot Springs geothermal resource. If such is the case, it is doubtful whether any developer would make the investment to prove up the resource without a strong indication that Riverside would purchase it. This strong indication may necessarily be so strong as to amount to Riverside playing the role of developer as well as user of the particular geothermal resource. In such an event, Riverside itself would be bearing a larger-than-usual share of the risks in the geothermal development enterprise. Moreover, these risks may be compounded, since Riverside is not experienced in geothermal field development.

There are also environmental issues involved. The development of Arrowhead Hot Springs for space heating and cooling would require the drilling of wells, installation of pipes connecting those wells, and construction of a pipeline leading some 15 miles through national forest land to Riverside itself. Once in Riverside, a distribution system to take the hot water to the ultimate users would need to be constructed.

There are land use questions involved in siting both the wells and the transmission facilities, although it is difficult to speculate on the environmental problems involved in these land use questions at this time. As a general matter, it would not appear that a transmission system through a national forest would be so obnoxious from an environmental point of view as to be a serious constraint on the resource development. It may, of course, be the case that a particular plan for such a transmission facility could be unacceptable, but such a judgment is impossible to make in advance of specific plans.

As with electrical application of geothermal energy, there are two potential environmental problems that can be identified now: waste disposal and subsidence. A solution to these problems, as with electricity production, may be to reinject into the geothermal formation. Since it would appear to be uneconomic to pipe the fluid back up the mountain, reinjection of the fluid at the reservoir would require a nearby potable water supply for heat transfer. If subsidence is not a problem, then it should be possible to reinject the fluid, if necessary, at a site near Riverside. It is not possible to say at this time that fluid reinjection would be necessary for the particular resource at Arrowhead Hot Springs.

The alternatives to reinjection are either to do nothing or to find some other fluid to pump into the formation. It is too soon to say whether doing nothing would be acceptable at Arrowhead, although alternative disposal of the geothermal fluid, unless it is potable, is very likely to create problems. It would appear that alternative injection fluids would be hard to come by. Surface appropriations are already over-allocated,^(a) and, therefore, finding water for injection purposes is apt to be difficult. In any event, it seems likely that a proposal to use groundwater to prevent subsidence is apt to be strongly resisted in any water-short area, particularly Southern California.

(a) Discussion with Dave Anderson, California Energy Resources Conservation and Development Commission, November 1977.

Finally, there is a possible institutional problem. Conversion to geothermal space heating and cooling will certainly require some form of backup or reserve heating and cooling capacity, especially during the early phases of the changeover. It would appear to be quite unreasonable, for example, to expect homeowners to convert to a sole dependence on geothermal heat, a very new and unproved system. Moreover, uncertainty over the extent and longevity of the resource at Arrowhead Hot Springs, the limited experience in dealing with geothermal in general, and the Arrowhead resource in particular, might make it prudent to retain a backup source of heating and cooling energy for a considerable time. There may be a problem in obtaining such a source. Southern California Gas, for instance, has expressed an unwillingness to provide backup for another primary source of energy beyond certain limits.⁽³⁰⁾ State Public Utility Commissions, by and large, have not required that privately-owned utilities provide such backup services. The possible difficulties in seeking electricity from SCE for such uses are discussed in the Electric Applications of Geothermal Energy for Riverside section above.

It is difficult to suggest remedies for this last problem at such an early stage. It may be that SCE and SCG will, in fact, be willing to provide supplementary services. It may also be the case that policy decisions by CPUC might be taken to compel them to do so in a reasonable way.

PLANS FOR DEVELOPING GEOTHERMAL ENERGY

If decisions are made to undertake further investigations or development of geothermal resources to meet all or part of Riverside's electrical or nonelectrical needs, then certain courses of action are desirable to overcome existing obstacles which might block geothermal development. Although it is premature to formulate detailed plans, the major issues which need to be resolved can be addressed. In this context, plans are described below for developing geothermal energy for both electrical and nonelectrical uses.

PLANS FOR ELECTRICAL APPLICATIONS

The plan for developing geothermal energy to meet electrical needs will depend primarily on the relative importance of timing, cost, and proximity criteria. The most promising geothermal resources for near-term electricity generation are Heber and East Mesa in the Imperial Valley. These resources are currently being developed and tested by several companies. The properties of the fluids and potential productivity of the reservoirs are comparatively well known. Electricity production from these resources could begin within five years. The most promising resources for low-cost electricity generation are the higher-temperature resources at the Salton Sea, Brawley, and Coso. Over the next few years, much more information from these sites should become available as a result of federal, state, local, and private resource assessment and development programs currently in progress. If scaling and corrosion problems can be overcome at reasonable cost, the Salton Sea resource could become competitive with conventional energy sources. Coso and Brawley also have the potential to become competitive with conventional energy sources. The only promising resource close to Riverside is Arrowhead Hot Springs. No work is currently underway at Arrowhead; much more data are required before power development could be undertaken at this site.^(a)

(a) In 1963 R. A. Rowan and Company drilled two geothermal exploration wells at Arrowhead. Evidently, they found 234°F water at a depth of 571 feet. Nothing more is known about the company or the wells at this time. (See Reference 36).

Plan for Development of Near-Term Electrical Generating Capacity

If timing is the most important criterion, Riverside should seek to secure geothermal resources at Heber or East Mesa. This would involve striking agreements with one or more of the resource companies currently active at these sites. If the agreement was to purchase the energy supply, then much of the risk of development and environmental control would be borne by the resource company. In addition, agreements would have to be reached with Southern California Edison (SCE) on construction and operation of the power plant, the transmission of the electricity to Riverside, and the provision of reserve power. If these agreements can be reached in a reasonable time, say within two years, then it might be possible to have a small power plant in operation within 5 or 6 years and to have sufficient geothermal capacity at these sites to supply all of Riverside's needs within 10 to 12 years. The latter schedule requires overlapping construction of the additional power plants. The cost of generating power produced under this plan is expected to cost about the same as power produced from new oil-fired plants or about 1-1/2 to 2 times the cost of power produced from conventional nuclear or coal plants.

Needed Actions

The most important constraint upon Riverside's development of geothermal energy for the production of electricity in the short run appears to be institutional: the need to reach some accommodation with SCE. Southern California Edison currently supplies the city all its electricity. Development of independence in electricity generation from geothermal (or any other source) is a threat to SCE's market. Moreover, such development is apt to take a considerable time, during which Riverside will need SCE's cooperation for transmission, backup power, some portion of the normal load, and other services. The first and most important step for Riverside, therefore, is to explore the possibilities for cooperation with SCE.

The current agreement between Riverside and SCE provides at least a model for the arrangements that might be necessary if Riverside chooses to develop geothermal resources. This agreement, it should be noted, rose from an antitrust dispute in connection with nuclear power plant licensing;

its provisions may, therefore, not apply to all possible geothermal developments. At any rate, close scrutiny of the Riverside-SCE agreement regarding Riverside's ability to develop its own generating capacity and the kinds of cooperation which SCE is bound to provide is an early necessity.

Shortcomings in the existing arrangement might be overcome through further negotiations. Of course, to the degree that Riverside's development plans pose a threat to SCE, such negotiations are apt to fail. There is, thus, a need to explore other possibilities. Some of these may be application of current California law; for instance, use of the statutory provisions which allow the California Public Utilities Commission to issue Orders of Interconnection to compel wheeling. There are possible federal legal remedies as well. One is the Otter Tail decision's requirement of good-faith negotiations by utilities such as SCE. Also, antitrust provisions in nuclear licensing might apply. Riverside might, for instance, intervene in a future SCE nuclear licensing proceeding to demand that SCE be compelled to cooperate with Riverside's development of geothermal resources as a condition of its own nuclear development. There are also political remedies. Riverside might join other publicly-owned utilities in seeking legislation to enhance their ability to develop their own generating capacity, whether geothermal or other, and, at the same time, assure cooperation from privately-owned utilities as they do so.

The foregoing actions are meant as examples and offered on the assumptions that the current Riverside-SCE agreement will not easily allow Riverside to develop substantial geothermal capacity on its own and that SCE will oppose such attempts. It may, of course, happen that neither assumption holds. A crucial factor is likely to be the amount of capacity Riverside desires. In other words, if Riverside seeks energy independence, it is more likely to encounter resistance from SCE than if it merely seeks to produce a small portion of its electricity. A major issue which Riverside must resolve, therefore, is the amount of power it wants to produce on its own. Once that decision is made, it will be possible to evaluate SCE's disposition and undertake appropriate action on the institutional front.

It may even happen that SCE might choose to aid Riverside's development of capacity. This would appear to be most likely in joint developments. SCE could find Riverside a useful source for capital and risk-sharing and, therefore, encourage its participation in power plant construction. Such ventures may be geothermal; although the most probable ones are nuclear or large coal plants. A joint venture, whether with SCE or another party, would relieve Riverside of some of the burdens of geothermal field and power plant management, a set of burdens that Riverside might do well to avoid since it has no experience with any form of electricity generation. However, surrendering operational control to a more-experienced partner, such as SCE, may dilute the energy independence associated with developing an integrated community energy system.

The questions of how much capacity to develop, whether to do so alone or in conjunction with SCE, and what steps are needed to implement such decisions are the most important matters for Riverside to address. Environmental problems and remaining legal or institutional constraints can be addressed later.

Generic solutions to the environmental problems of fluid disposal and subsidence/seismicity are apt to be reached before Riverside acts. If so, Riverside's problem will be to make tentative site selections, evaluate the likely fluid disposal, subsidence prevention and other environmental problems at those sites, evaluate possible solutions to the problems and then go forward with final site selection.

If Riverside chooses to proceed with geothermal development, the general sequence of actions would be as follows. For near-term power development, Riverside most likely should seek to purchase a supply of energy from a geothermal field operator rather than becoming a field developer and operator in its own right. Then would come design and construction of a power plant, most likely without any review of the California Energy Resources Conservation and Development Commission and, simultaneously, negotiation of arrangements to transmit Riverside's power from the geothermal field to the city. It is premature to attempt to provide further detail at this time. The immediate issues have to do with whether to attempt to produce geothermal electricity and how and where. Once these issues are addressed, questions of financing, site selection, plant construction, transmission and others will arise, but detailed plans for resolving these questions can be deferred until the immediate issues are resolved.

Plan for Development of Low-Cost Electrical Generating Capacity

If cost is the most important criterion, Riverside should await further information on the characteristics and prospects for the Salton Sea, Brawley, and Coso resources. These resources have the potential to generate electricity at costs which are competitive with nuclear or coal plants. Over the next five years, definitive information about these resources should become available which will resolve current uncertainties surrounding their technical and economic viability. In addition, technical developments during this period, may improve the competitiveness of the Heber and East Mesa resources. Under this plan, the earliest geothermal capacity would be on line in 8 to 10 years with about 15 years required to construct sufficient capacity to meet all of Riverside's needs.

This longer schedule allows more time to resolve the same institutional constraints which were discussed under the near-term development plan. This longer timeframe would also provide Riverside a realistic opportunity to assume the role of the geothermal developer. If the developer role is selected, Riverside should seek to acquire leases or lease options as soon as possible, since the prices and availability of such leases should be strongly affected by the expected favorable determination of commercial viability of the higher-temperature resources.

Plan for Developing Close-Proximity Electrical Generating Capacity

If proximity is the most important criterion, then Riverside should begin exploration and assessment of Arrowhead Hot Springs - 15 miles distant - or undertake systematic exploration and/or wildcatting for other resources nearby. As stated previously, Riverside is within an area potentially valuable for geothermal resources, and numerous thermal springs lie in the vicinity. The Arrowhead resource is assessed by the USGS at 150°C with an assigned minimum energy content. However, little is known about this resource and much additional information is required before the design and construction of a power plant could begin with confidence. Even so, if the temperature of this resource is 150°C, as assessed, the cost of generating electricity from Arrowhead is likely to be 2 to 3 times the cost of generating electricity

from conventional resources. Similarly, for wildcatting to be successful in substantially reducing this cost penalty, a higher-temperature, shallow geothermal resource would have to be located. At least 10 years would elapse before it would become feasible to produce power at Arrowhead or from another nearby, as yet unlocated, resource.

This longer schedule also allows more time to resolve the institutional constraints previously discussed. Work under this plan would begin with exploration and assessment activities and the acquisition of leases. Decisions to undertake development of the geothermal reservoir and construction of a power plant would depend on the success of the resource exploration and assessment program.

PLAN FOR NONELECTRIC APPLICATIONS

Arrowhead Hot Springs is the most promising resource for nonelectric applications, but, again, too little is known of the resource to proceed with development. This resource, however, is much more promising for nonelectric uses than for electricity generation. Little technical innovation will be required to utilize the resource for nonelectric uses, and further, it is expected that geothermal energy will be competitive with conventional energy sources for district heating and cooling and perhaps process heat. Riverside, under this plan, should begin exploration and assessment work at Arrowhead or undertake systematic exploration and/or wildcatting for other geothermal resources nearby. The chances of successful wildcatting are much greater for nonelectric uses than for electric because lower temperature resources can be used efficiently and because of the greater sensitivity of fluid transmission costs to distance.

Since work under this plan would begin with resource exploration and assessment, at least 10 years would be required before widespread nonelectric uses of geothermal energy in Riverside would be feasible. Nonelectric uses face similar institutional and environmental constraints as electrical uses; resolution of these institutional issues should be undertaken concurrently with the resource exploration and assessment program.

The constraints on nonelectric applications may be considerably less severe. While Southern California Gas (SCG) may feel the same concern with loss of market as SCE, the probability of opposition to Riverside's developing its own resources to replace natural gas may be lower. Loss of the Riverside market may, for example, not particularly bother SCG if natural gas is in short supply. On the other hand, loss of market and provisions to amortize the existing gas distribution system may be major issues. Gas could be plentiful but expensive as, for instance, with imported LNG or coal gasification; this could result in strong opposition to Riverside's quest for independence. Such opposition is, however, less likely to be effective, since Riverside is not itself in the gas business and is, therefore, not dependent upon gas company cooperation in order to serve its own customers, as contrasted with the case with SCE.

Before proceeding to construct a geothermal municipal heating system, Riverside should establish the adequacy of the geothermal resource for this purpose and confirm the economic feasibility of space heating or cooling with that resource. Economic feasibility of a municipal geothermal system will depend upon a large concentrated market and high levels of participation by all potential customers. Several means are available for constructing and operating such a geothermal system. Two possibilities include the establishment of a municipal department to provide this service and the creation of a special district for this purpose.

Under California law the legislative body of a municipality may "acquire, own, construct, maintain, and operate . . . works for . . . heat" ⁽³⁷⁾ In addition, "for the purpose of constructing, equipping, using, maintaining, or operating any facility, the city may lease or acquire by purchase, condemnation, or otherwise and hold and use any land, rights-of-way, water, water rights, quarry, gravel bed, other mineral deposits, or other necessary property, within or without the city or the county where the city is located." ⁽³⁸⁾ Under these provisions, Riverside's legislative body could establish the mechanism for setting up a geothermal district heating system.

Another approach for constructing a geothermal district heating system is to establish a special district for this purpose. Special districts are governments of limited jurisdiction created for a specific purpose. Although a municipality can acquire facilities outside of its boundaries, it has limited authority to establish a unified geothermal system that

extends substantially beyond its borders. A special district, however, can be established which has boundaries that are contiguous with the optimal geothermal system. A special district is established by a vote of the people within the boundaries of the proposed district.

"A district may acquire, construct, own, operate, control, or use, within or without, or partly within or partly without, the district, works or parts of works for supplying the inhabitants of the district and public agencies therein, or some of them, with ... heat"(39)

Special districts are governed by an elected board and the board may finance special district enterprises in a number of ways.

"The board may, in its discretion, finance any special district enterprise, the interest on and retirement of any bonded indebtedness therefore, and provide for the maintenance and operation thereof entirely by the levy and collection of taxes upon the property within the special district for which the enterprise is constructed or operated, or by rates and charges imposed upon the users of the facilities of the enterprise, or by both taxes, rates, and charges, apportionment of expenses among public agencies served, or any combination of the foregoing."(40)

Accordingly, there appears to be adequate statutory authority for a municipality or a special district to construct and operate a geothermal district heating system. Further, ample authority appears to be present for the purpose of adequately financing the construction and operation of such a system. As a practical matter, such a step is likely to be taken only if those proposed to be served by the system desire such service and approve the issuance of bonds and the levying of service charges or assessments to pay for the system. The financial burden to Riverside citizens might be lessened by creative and aggressive seeking of funds for system construction from both state and federal governments. Additional legal problems may exist with respect to the termination of an existing natural gas distribution franchise. If the local natural gas distribution company is a private firm, then depending upon franchise conditions, the City may be required to make a payment for premature franchise termination and it would be required to pay compensation in order to acquire either by purchase or eminent domain all or part of the natural gas distribution pipelines in the ground.

It appears that Riverside, with voter consent, can construct and operate a geothermal heating system pursuant to existing statutory requirements. As a practical matter, however, such voter consensus may be difficult to obtain if costs are regarded as excessive, or if electric or natural gas utilities choose to vigorously oppose the creation of such a system.

Another possibility which might lessen the financial burden to Riverside citizens would be for the City to finance the retrofitting of individual homes for geothermal district heating and cooling. Since gas companies can lease gas furnaces and other gas appliances to their customers, Riverside may be able to lease radiators and absorption cooling units to its customers. This scheme would allow amortization of the individual pieces of equipment over the life of the district heating system and would eliminate the large initial capital outlays which homeowners would otherwise have to make.

Once the economic and financing questions are settled, Riverside must make decisions about environmental and other problems in the use of the Arrowhead Hot Springs resource. As with electrical applications, there is little point in Riverside's acting in advance of generic solutions to such problems as fluid disposal and subsidence. Assuming such problems can be solved, Riverside will have to obtain permission to build fluid transmission facilities through national forest land to get from the hot springs to the city. While there appears to be no insurmountable barrier on this score, such permission is likely to take time to obtain.

Finally, of course, Riverside needs to bargain with the holders of geothermal rights at Arrowhead to make arrangements for resource development and the provision of hot water. Again, as with electricity, Riverside may wish to purchase the energy supply and avoid direct involvement in field development or operation. Similar considerations would also apply if other nearby geothermal resources were located and developed.

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