Residential Heating Costs— A Comparison of Geothermal, Solar, and Conventional Resources

**Prepared for the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830**

**Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
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BATTELLE
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UNITED STATES DEPARTMENT OF ENERGY
Under Contract EY-76-C-06-1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy \$ ____*; Microfiche \$3.00

*Pages	NTIS Selling Price
001-025	\$4.00
026-050	\$4.50
051-075	\$5.25
076-100	\$6.00
101-125	\$6.50
126-150	\$7.25
151-175	\$8.00
176-200	\$9.00
201-225	\$9.25
226-250	\$9.50
251-275	\$10.75
276-300	\$11.00

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RESIDENTIAL HEATING COSTS-
A COMPARISON OF GEOTHERMAL, SOLAR AND
CONVENTIONAL RESOURCES

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August 1980

Prepared for
the U.S. Department of Energy
under Contract DE-AC06-79RLO 1830

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PROLOGUE

This report has undergone a broad review by several organizations in the geothermal and solar fields. We would like to thank the following reviewers, in particular, for their time, effort, and constructive comments: Richard Gilbert (Department of Energy/Policy, Planning & Analysis), Denis Hayes (Solar Energy Research Institute), Ray LaSala (Department of Energy/Resource Applications), Bernie Neenan (Solar Energy Research Institute), and Marshall Reed (U.S. Geological Survey). The purpose of this Prologue is to clarify and emphasize several important issues that were identified by the reviewers.

Our focus in this report is on evaluating energy alternatives. The report is intended to provide information with far-reaching implications for policy makers. It shows very graphically that the dramatic increases in conventional energy prices in 1979 have set the stage for geothermal and solar market penetration in the 1980's. It also depicts the promising areas where DOE could concentrate its efforts if it chooses to pursue a policy of commercialization of geothermal and solar energy. Equally important, it depicts areas and applications which are not promising for solar and geothermal energy.

We wish to emphasize the distinction between potential markets and actual markets. We identified large potential markets for geothermal and solar energy; this is a necessary first step in the definition of actual markets. For instance, we identified a potential market of about 7 quads for geothermal space heat, provided that productive geothermal resources could be found near large urban population centers. This does not imply that geothermal will capture 7 quads of the space heating market. It means that the maximum potential market penetration for geothermal space heat is 7 quads under the conditions of this analysis. If productive geothermal resources are not found and developed near the large cities in the East and the Midwest, then the actual geothermal market penetration will be much less than 7 quads.

Another issue raised by the reviewers concerns retrofit costs, since our reference cost analysis was based on new construction. Most conventional heating systems in the U.S. are forced-air, circulating-hot-water, or radiant-electric-resistance, all of which can be adapted to use geothermal energy. We feel that retrofit costs will be minimal (\$500 per house) for houses that currently have hot-water or forced-air heating systems. For houses that

require major modifications of existing heating systems, we estimate that retrofit costs will add about 20-30% to the costs of district heating presented in our report. The installed costs of geothermal and conventional heating systems are comparable for new installations. However, the costs of both retrofitting and new installations of geothermal systems may be partially defrayed through tax incentives, as in the National Energy Act.

High front-end costs of retrofitting could be a deterrent to many people. However, it may be possible for the district heating utility to pay for the retrofitting costs along with the distribution piping costs. The retrofitting costs could then be repaid over the system life by the consumers as part of their monthly bill payments. (There is precedent for this approach in some natural gas utility operating practices.)

Another issue concerns our assumptions regarding inflation, escalation, and interest rates. The general inflation rate (5%) and conventional fuel price escalation rates (7-10%) which we used appear to be too low in light of the drastic increases in fuel oil and natural gas prices and the unusually high rate of inflation during the past year. However, our objective was to make assumptions that would represent the most likely values for the financial parameters over the next 20 years. We do not feel that an inflation rate on the order of 18% would be representative of the long-term state of the economy, nor would extremely high fuel escalation rates be representative in the long term. We believe that the selected values for bond interest rate (8-8.5%) and return on equity (12-15%), in conjunction with the inflation rate, represent very reasonable "real" costs of capital. We believe that the selected conventional fuel price escalation rates relative to inflation, although appearing low in comparison with recent history, are conservative assumptions. More rapid escalation in these prices would make solar and geothermal energy much more competitive than our results already show.

Although we believe that the long-distance transmission of pressurized hot water will be economically feasible if it is done on a large scale, we are not advocating transmission of geothermal energy beyond 50 miles. For each of the Western cities in our study, we selected the nearest identified hydrothermal resource as a basis for comparison. In a few cases, the distance was over 50 miles. Since new geothermal resources may be discovered nearer to each site,

we determined geothermal heating costs as a function of distance using the temperature of the selected resource for reference purposes. Our objective was to systematically determine and illustrate the conditions (e.g., the transmission distance) under which geothermal energy is competitive with solar and conventional energy. One of our simplifying assumptions was that the terrain was flat. Obviously, in a more detailed analysis all site-specific factors, including the local terrain, must be taken into account.

In order to be competitive geothermal heating must, in general, be undertaken on a large scale. Economies-of-scale in heat transport and well drilling must be exploited. Implementing large-scale geothermal developments will probably require substantial incentives and inducements by the federal government, particularly in the resource definition phase. The time lags and the small scale of operations implied by a "business-as-usual" approach would probably discourage widespread geothermal development for district heating.

Geothermal resource availability is not now well established. However, the existence of a geothermal gradient is well established and such operating characteristics as well flow rate, well life, and disposal techniques have been documented in the literature on Iceland, New Zealand, Japan, Italy, Mexico, and El Salvador. The parameters which we used to represent the normal-gradient resources are representative of actual data from Iceland and France. We agree that the uncertainty about resource availability is a deterrent to geothermal development by the private sector, but this uncertainty can be reduced or eliminated through exploration and assessment activities. Our report is not intended to deal with the resolution of resource availability questions. These are separate issues requiring more detailed studies and actions. Our purpose is to estimate the maximum potential market penetration for geothermal district heating systems assuming that productive resources can be found. We believe that geothermal heating holds great promise and that a successful exploration program coupled with the elimination of institutional barriers will lead to a rapid expansion in large-scale geothermal district heating.

Solar energy will probably be more economic than geothermal energy for residential heating in most areas with low population densities such as suburbs, small towns, and rural areas. However, geothermal energy will probably be more economic than solar energy in most high-density urban areas

provided that geothermal resources are nearby. Meeting the goal of U.S. energy self-sufficiency will require the development of solar, geothermal, and other emerging energy technologies, each in its proper place. The goal cannot be met simply by installing solar systems in rural areas; big gains must be made in our cities. Therefore, we believe that increased emphasis should be placed on urban heating, and particularly on geothermal district heating.

August 21, 1980

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ACKNOWLEDGMENTS

The authors gratefully acknowledge the programming contributions of Harlan Huber and the assistance of Marcel Rouse in the background research. Also, we appreciate Barbara Eaton's cheerful typing and retyping of several versions of this report.

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ABSTRACT

The costs of residential heating throughout the United States using conventional, solar, and geothermal energy were determined under current and projected conditions. These costs are very sensitive to location -- being dependent on the local prices of conventional energy supplies, local solar insolation, climate, and the proximity and temperature of potential geothermal resources. The sharp price increases in imported fuels during 1979 and the planned decontrol of domestic oil and natural gas prices have set the stage for geothermal and solar market penetration in the 1980's.

1.0 SUMMARY

The competitive outlook for geothermal and solar heating changed dramatically during the past year. With continued price increases in imported oil and natural gas and the planned decontrol of domestic prices, geothermal and solar energy will become competitive for space heating throughout most of the country (Figure 1.1). Under these conditions, geothermal energy could competitively provide about 40% of the national demand for space heat and domestic hot water (about 7 quads based on 1980 demands). Nearly all of this geothermal energy use would be in high-population-density urban areas. Solar energy could competitively provide about 50% (about 9 quads) of the annual demand. Most of this solar energy use would be in suburban and rural areas. Conventional energy should remain competitive for about 30% (about 5 quads) of the annual demand. Conventional energy use would be concentrated in the South and as supplemental energy for solar/conventional systems. Geothermal, solar, and conventional energy would be equally competitive for about 20% of the annual demand, which is why the individual market shares add to 120%.

Under lower conventional fuel price assumptions, which appeared more likely prior to 1979, geothermal energy would competitively provide about 4% (0.6 quads) and solar would competitively provide about 10% (1.8 quads) of the annual demands (Figure 1.2). Conventional energy, of course, would continue to dominate the space heating market under these conditions. Although the percentage contributions of solar and geothermal in this case are low, the annual dollar volumes in equivalent energy sales would be huge -- on the order of \$18 billion for solar and \$6 billion for geothermal. In terms of equivalent barrels of oil saved annually, this would be 300 million barrels for solar and 100 million barrels for geothermal.

Geothermal district heating offers several practical advantages which could speed large-scale implementation. First, the technical feasibility is well established; it has been demonstrated over an extended period on a large scale in Europe and elsewhere. Second, geothermal heating should be well-accepted by a community; the quality of heating provided by hot water is high and air quality should be improved by replacing conventional fuels with geothermal energy. Third, financing should be no deterrent since the capital investment per dwelling for providing geothermal district heating is comparable in magnitude to that required for providing electrical service. Fourth, organizations exist which could be franchised to install and operate district heating systems; these are the investor-owned and municipal utility systems which now provide natural gas, electricity, and water.

URBAN DWELLINGS

SUBURBAN AND RURAL DWELLINGS

FIGURE 1.1. Expected Market Penetration for Solar and Geothermal Energy with Conventional Heating Costs at \$15/Million Btu of Space Heat Delivered (Includes Furnace Efficiency)

URBAN DWELLINGS

SUBURBAN AND RURAL DWELLINGS

FIGURE 1.2. Expected Market Penetration for Solar and Geothermal Energy with Conventional Heating Costs at \$10/Million Btu of Space Heat Delivered (Includes Furnace Efficiency)

The main impediments to widespread geothermal heating will probably be: (1) the timely demonstration that reliable, commercially-productive geothermal resources exist near enough to the market, and (2) the organization of heating districts which are both large enough and concentrated enough to be economically competitive. Although this study shows geothermal urban heating to be potentially competitive throughout the Northern 2/3 of the country, detailed studies will be required to determine commercial feasibility for the specific conditions at each location.

The comparative costs of residential heating throughout the United States using conventional, solar, and geothermal energy were determined under current and projected conditions. These costs are very sensitive to location -- being dependent on the local prices of conventional energy supplies, local solar insolation, climate, and the proximity and temperature of potential geothermal resources. The degree to which geothermal and solar heating become competitive with conventional energy will depend on future price trends and the reliability of conventional energy supplies. In the past, the abundance and low cost of fuel oil, natural gas, and electricity precluded the use of geothermal and solar energy for heating. Figures 1.1 and 1.2 graphically illustrate the increase in solar and geothermal market penetration resulting from an increase in conventional fuel prices. Our analysis indicates that:

1. Conventional and solar energy will probably be more economic than geothermal energy for residential heating in most areas with low population densities such as suburbs, small towns, and rural areas.
2. Geothermal energy will probably be more economic than solar and conventional energy in most high-density urban areas provided that geothermal resources are nearby. As an approximation, "nearby" means:
 - a. within 10 miles, if the resource is under 80°C,
 - b. within 30 miles, if the resource is between 80°C and 120°C, and
 - c. within 50 miles, if the resource is over 120°C.

Urban district heating from normal-gradient resources currently appears to be competitive in New England and in the North Central states. Under price de-control urban district heating from normal-gradient resources will probably be competitive throughout the entire Northern half of the country. The key to the successful application of the normal-gradient resource in district heating will be finding productive aquifers near major metropolitan areas.

Urban district heating from the higher-temperature hydrothermal resources in the West currently appears to be the most economic option for providing space heat in at least six locations. These are Reno, Nevada; Idaho Falls, Boise and Twin Falls, Idaho; Helena, Montana; and Klamath Falls, Oregon. Under price decontrol, urban district heating from other hydrothermal resources will probably be competitive throughout most of the West.

3. In most locations the optimum solar heating system will require a conventional energy backup system. The percent of energy supplied by solar at the optimum will vary from 40-100% depending on location. The economics of solar heating is independent of population density but does depend on the combination of solar insolation and annual heat demand at the location. Solar heating is least economic in the Pacific Northwest coastal regions.
4. Geothermal energy is most competitive when employed on a large scale to serve concentrated markets. The economics of geothermal district heating is very dependent on the size and density of heat demand, which are determined by population, population density, and climate. The economics is also dependent on the production and transmission costs of geothermal energy which, in turn, are related to the temperature, depth and production rate of the resource and the transmission distance. Because of sensitivity to distance, locating geothermal resources near to the demand is important. A high degree of participation within the heating district is also necessary for commercial success.
5. The economics of conventional residential heating depends primarily on the price and efficiency of utilization since the production, transmission, and distribution systems are well established. The economics of conventional heating is, to a large extent, independent of population density and climate.
6. Through price controls, regulations, and other market forces, conventional residential heating prices tend to be based on recovering the average costs of production rather than on marginal-cost pricing. That is, the higher costs of providing heat to new areas or from new conventional energy sources are "rolled in" with the production and distribution costs from existing sources. Average-cost pricing presents a significant barrier to market penetration by new energy sources which, in the absence of subsidies, must be priced on a marginal-cost basis since there is no existing production and distribution. However, with time the marginal costs of conventional fuels will predominate

and the new energy sources will become competitive.

7. Tax credits and other incentives which lower the cost of geothermal and solar relative to conventional energy can significantly increase the competitiveness of both geothermal and solar heating.
8. Although this report focuses on residential heating, commercial heating could be supplied by each of the energy sources at about the same or lower cost.

The following scenario best summarizes our outlook for residential heating in the United States:

Geothermal district heating systems will become economically feasible in most urban centers north of a line extending roughly from Los Angeles to Baltimore. West of the Rockies high-temperature ($>90^{\circ}\text{C}$) geothermal energy will predominate and will be transported up to 50 miles to the urban centers. East of the Rockies low-temperature ($60\text{--}90^{\circ}\text{C}$) geothermal energy will predominate and will be located within 10 miles of the urban centers. In the West the development of industrial process heating applications will aid the spread of residential heating applications. Also in the West scattered residential heating applications will develop in small towns located near geothermal resources and near the transmission lines to the urban centers.

Solar heating systems, with conventional heating backup, will become economically feasible throughout the country. The most economical applications will be in suburban and rural areas in the intermountain West and in the Great Plains region.

Conventional heating will continue to be most economic: (1) in most urban centers in the South (where annual heat demand is low), (2) in Northern urban centers which are too distant from geothermal resources, and (3) in suburban and rural areas in the Pacific Northwest coastal region and in other localized areas of low insolation throughout the country. Conventional energy will also supplement solar energy in most locations.

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2.0 INTRODUCTION

The purpose of this report is to evaluate the costs of residential heating throughout the United States and to determine which energy source is most economic at specific locations. In particular, we wanted to determine the conditions under which solar and geothermal heating were competitive with each other and with conventional energy sources. The heating options which we evaluated included fuel oil, natural gas, electric resistance heating, active solar, and geothermal district heating. Solar heating costs were evaluated both as the sole heating source and as the optimum (lowest cost) combined solar/conventional system.

In a previous study^(2.1) we had determined that geothermal district heating was competitive with conventional space heating in high-population-density urban areas. We also determined that geothermal energy could be transported economically up to 50 miles for district heating, if it was done on a large scale^(2.2).

For this study we updated the costs and conditions for geothermal district heating. We also analyzed the costs of residential heating with conventional energy sources and with solar energy using active solar systems. The solar heating systems studied included both 100% solar heating and the economic optimum combination of solar and conventional heating.

In the United States space heat is commonly provided by natural gas, fuel oil, and electricity. Early 1979 heating costs ranged from \$3-27/million Btu of heat delivered with the most common range being \$6-10/million Btu. These conventional energy heating costs are expected to increase at rates above the general inflation rate over the foreseeable future. During 1979 alone, fuel oil prices increased 80% and natural gas and electricity prices each increased by 30%. Currently, the marginal cost for providing space heat from new conventional energy supplies exceeds \$10/million Btu in most locations. Increases in conventional heating costs open up new opportunities for competitive geothermal and solar space heating.

Prior to the sharp increases in conventional heating costs during 1979, several hundred houses in Klamath Falls, Oregon and Boise, Idaho were being heated economically with geothermal energy from nearby, shallow geothermal resources. Now, with much higher conventional heating costs, geothermal space heating should become competitive at many other locations -- locations which may have deeper and more distant geothermal resources.

Abroad, geothermal energy is used for space heating in Iceland, Hungary, Italy, the Soviet Union, France, New Zealand, and Japan. The heat is usually distributed through district heating systems to apartment houses and individual residences. Most of the distribution to individual residences is currently confined to Iceland, where the colder climate makes this economically feasible. In Iceland geothermal energy provides heat for over 100,000 people at less than 1/2 the cost of oil heat. In the other locations the cost of geothermal heat is competitive with the cost of oil heat. Both France and Hungary have plans to expand geothermal space heating from under 10,000 residences at present to over 100,000 residences in 10 years or so.

Large district heating systems, using fossil energy, are common in Northern Europe, where the cold climate and concentrated populations make these systems more economic than dispersed individual heating systems. Large district heating systems have not been built in this country, but small systems that distribute steam are operating in forty Northern cities. However, conditions in our Northern cities are similar to those in Northern Europe. In fact, the density of energy demand is greater in many of our cities. With the recent increases in energy prices, large-scale district heating is probably now attractive in many U.S. locations.

There were 66,000 solar installations in the U.S. in 1977 according to estimates of the Solar Energy Industries Association^(2.3). The majority were water heaters only. About 5% of the installations were space and water heating systems and a very small fraction were combined space heating, air conditioning and water heating systems. There are currently over 300,000 solar systems operating in foreign countries such as India, Israel, Australia and Japan^(2.4). Unlike the United States, these countries did not have governmental policies favoring low conventional fuel prices. Consequently, solar technology became competitive with other fuels sooner. If the recent rate of increase in conventional heating prices in the United States continues and if the availability of conventional fuels becomes unreliable, then a more rapid shift toward solar energy may occur in the United States.

Other types of residential heating are also potentially attractive at various locations throughout the country. These include district heating based on fossil fuels, cogeneration, or waste heat, passive solar systems, reducing heating demand through better insulation and other conservation techniques, and heat pumps. However, these and other methods were outside the scope of this study since we were primarily

concerned with the potential of geothermal district heating systems and active solar heating systems to supply both space heat and domestic hot water in competition with conventional fuels.

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3.0 MODELS AND ASSUMPTIONS

This chapter describes the computer models used to calculate solar and geothermal heating costs and presents the assumptions upon which the costs are based.

3.1 SOLAR HEATING MODEL AND ASSUMPTIONS

Several solar heating models were assessed for their applicability to the project. Specific criteria were established as a basis for evaluating potential models. These criteria require that a model chosen for predicting solar heating costs:

1. Be capable of providing costs for a wide variety of locations;
2. Be based on state-of-the-art solar technology;
3. Be flexible to allow modification; and
4. Utilize life-cycle costing principles.

A model developed by Barley and Winn^(3.1) was selected on the basis of the above criteria. This model calculates directly, without iteration, the approximate collector area which minimizes the total life-cycle cost of a solar heating system. The Barley-Winn model is based on an empirical relationship between annual solar load fraction and relative collector area. This relationship was determined by correlating data generated by the Klein, Beckman and Duffie F-chart program^(3.2).

Before modification, the model provided the optimal collector area, the solar load fraction and the total life-cycle cost at a given heat load for a combination solar and conventional heating system. The model was modified to calculate a levelized heating cost in dollars per million Btu for five types of residences (see Appendix A). The five types of residences, which vary from single-family suburban houses to high-rise apartments, are representative of the range of dwelling types throughout the United States.

Calculated heating costs were based on the liquid heating system shown in Figure 3.1. Although the model can also be used to obtain costs for a solar air/rock storage system, information from solar component manufacturers and vendors indicates that the cost of the air heating system is significantly higher than the liquid heating system due to higher storage costs.

The collector loop in Figure 3.1 contains an anti-freeze solution and is isolated from the rest of the system by a liquid-liquid heat exchanger. A relief valve on the tank side of this heat exchanger is used to dump excess energy to the surround-

FIGURE 3.1. Schematic Diagram of Solar Liquid Heating System

ings. When needed, hot water is removed from the storage tank and circulated to the building load heat exchanger or the service hot water heat exchanger. Auxiliary energy is added whenever insufficient energy is transferred across the heat exchangers.

The model is based on flat-plate collectors because of their predominant use for space and domestic water heating. With simply-constructed flat-plate collectors permanently fixed in position, it is possible to produce heat at temperatures almost up to the boiling point of water^(3.3). A flat-plate collector is comprised basically of a radiation-absorbing flat plate beneath a transparent cover. The underside of the absorbing plate is insulated to reduce heat losses and water or air is circulated through the system to remove absorbed heat.

Solar system design values, based on vendor specifications and current literature^(3.3), used in the model are listed in Table 3.1.

TABLE 3.1. Flat-Plate Collector Design Parameters

<u>Parameter</u>	<u>Value</u>
$F_R \tau \alpha$	0.72
$F_R U_L$	5.50
F'_R / F_R	0.97

F_R = collector heat removal factor

F'_R = collector and heat exchanger heat removal factor

$\tau \alpha$ = collector transmittance - absorptance product

U_L = collector heat loss coefficient, $W \text{ } ^\circ C^{-1} m^{-2}$.

Solar system costs can be broken down into independent and collector-area dependent costs. Independent costs are independent of location for a given house. These costs include the costs of heat exchangers, pipes, pumps, valves and instruments. Collector-area dependent costs depend on geographic location. These costs include the cost of the solar collectors and the cost of the thermal storage tank.

The costs of solar heating systems were obtained from current vendor price estimates. Vendors' estimates for collector costs range from \$90/m² to \$280/m² installed. Storage tanks range from \$0.40/kg to \$0.75/kg. For this analysis we used mid-range values of \$183/m² and \$0.55/kg for the collectors and storage tank, respectively, for our reference assumptions. Estimates of the independent costs for different types of residences are listed in Table 3.2.

TABLE 3.2. Solar Equipment Costs

<u>Residence Type</u>	<u>Number of Dwelling Units</u>	<u>Independent Cost (\$/Unit)</u>
Suburban	1	5,000
High-Density, Single Family	1	4,500
Garden Apartments	60	175,000
Town or Row Houses	30	100,000
High-Rise Apartments	108	250,000

Equipment costs per dwelling unit for multi-family housing are generally lower than for single-family residences. Some economies-of-scale are realized with multiple dwellings because some solar heating equipment can be used in common. However, full realization of economy-of-scale benefits may be prevented by regional building codes. For example, current codes require that air supplies between individual apartments be kept separate. This necessitates a separate liquid-to-air heating coil for each apartment, rather than a central heat exchange system for the entire building. Also, if auxiliary energy were to be added at the hot water storage tank, each apartment would be required to have separate storage. This requirement arises from the National Energy Act, which requires individual metering of conventional fuels. The costs in Table 3.2 for multi-family units are based on: (1) individual heating coils and storage units for each apartment, and (2) some economy-of-scale benefits realized from sharing of other solar components.

The values for economic parameters used in this analysis are listed in Table 3.3. These values were recommended in a recent DOE report^(3.4). Parameters designated as private were used for the analysis of the suburban and high-density houses. Garden apartments, townhouses and high-rise apartments were treated as commercial ventures. Parameters designated as commercial apply to these residences. Undesignated parameters apply to both private and commercial residences.

Solar tax credit allowances were assumed to be ten percent of the system capital cost for commercial installations. A tax credit of 30% of the first \$2,000 of investment and 20% of the next \$8,000, for a maximum of \$2,200, as provided for in the National Energy Act, was assumed for privately-owned installations. Current bills pending in Congress may raise the commercial tax credit to 20% and the maximum tax credit for private installations to \$5,000.

TABLE 3.3. Economic Parameters and Assumptions

Parameter	Reference Value
Annual rate of increase in operation expenses	0.05
Annual rate of increase in maintenance expenses	0.05
Annual insurance cost as a fraction of first cost	0.0
Operation expense as a fraction of first cost	0.0
Maintenance expense as a fraction of first cost	0.015
Annual discount rate	0.10
General inflation rate	0.05
Annual mortgage interest rate (private)	0.085
(commercial)	0.08
Property tax rate (private)	0.0
(commercial)	0.0
Income tax rate (private)	0.30
(commercial)	0.50
Period of mortgage (private)	30 years
(commercial)	25 years
Downpayment fraction of first cost (private)	0.20
(commercial)	0.30
Depreciation life (commercial)	20 years
Salvage value	0.0
Period of economic analysis	20 years

Current state property tax laws may discourage use of solar heating by adding 10 to 30 percent to the annualized costs; however, over 17 states had passed laws exempting solar installations from property taxes by the end of 1978^(3.8). The assumption of no property taxes is based on this trend toward exempting solar installations from property taxes and on DOE recommendations^(3.4) for economic parameters.

Current prices for electricity, fuel oil and natural gas, which are discussed in Chapter 5.0, were obtained from the literature^(3.5,3.6,3.7). Fuel prices are in 1979 dollars. In cases where fuel prices were not available in 1979 dollars, the available prices were updated to 1979 using the assumed escalation rates listed in Table 3.4, which were suggested by DOE^(3.4). Fuel prices used for the low price assumption are representative of early 1979 values. Since then, sharp price increases have been posted by OPEC and further large increases are planned. These OPEC actions, coupled with the planned decontrol of domestic oil and gas prices, are not consistent with the assumed escalation rates, which may be too low for valid comparisons. For example, prior to 1979 OPEC increases, fuel oil prices escalated an average of 7% per year; however, from January 1979 to 1980, fuel oil prices have increased 80%. For this reason we have adopted a second (higher-price) assumption for conventional fuel prices, which is more in line with the new conditions. The relative competitiveness of solar and geothermal energy will be assessed under both sets of assumptions. In determining the cost of space heat delivered by each fuel type, the efficiencies for fuel oil, natural gas and electric furnaces were assumed to be 55%, 60% and 90%, respectively.

TABLE 3.4. Annual Rate of Increase in Conventional Fuel Expense

<u>Fuel</u>	<u>Rate</u>
Electricity	7%
Fuel Oil	7%
Natural Gas	10%

The cost of the in-house equipment for the auxiliary heating part of a solar heating system is identical to that of the conventional system that would be used alone. Therefore, the in-house equipment cost has been omitted in the economic analysis of each of these systems. Cost items which are identical can be omitted

from a comparison without changing the outcome of the analysis because the relative difference remains unchanged.

3.2 GEOTHERMAL HEATING MODEL AND ASSUMPTIONS

A wide variation can be expected in the range of potential geothermal energy costs for district heating. The range of costs is determined by the characteristics of the resource, the characteristics of the demand, and the distance separating the resource and the demand. In this report we develop costs separately for each of the main parts of the production process. We then determine the costs for each part of the production process that are appropriate to a specific location. These costs are combined to determine the total cost for that location.

The four main parts of the production process for geothermal district heating are: production, transmission, distribution, and disposal. The costs for distribution depend on the size of the population, the population density, and the climate. Transmission costs are related primarily to distance, but the temperature of transmission, size of demand, and load factor are also important. Production costs depend primarily on well drilling costs, wellhead temperature, flow rate, and the load factor. Disposal costs vary primarily with the disposal method; consumptive use and surface disposal would incur only negligible costs; disposal by reinjection would incur higher costs which would vary with the same factors as the costs of production. In this study we assumed disposal by reinjection. The costs of disposal were then included in the costs of production.

The basis for geothermal energy costs 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 solar or conventional energy sources. Institutional and psychological barriers to substitution are outside the scope of this report.

The calculation of the unit cost of energy is based on life-cycle costing and discounted-cash-flow analysis. The GEOCITY model^(3.9) 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, \$/MBTU
 ny = useful life, years
 CAP = capital costs, \$ in year n
 EXP = annual operating expenses, \$/year
 TAX = annual taxes, \$/year
 PW = present worth factor
 ENERGY = annual energy production, MBTU/year
 n = year

The geothermal energy is assumed to be provided by firms having the capitalization and financial characteristics shown in Table 3.5. The firms might typically be a large oil company operating the reservoir and a large investor-owned utility operating the transmission and distribution system. The weighted after-tax cost of capital is 7.2% for the utility and 10.3% for the oil company. The equivalent annual fixed charge rate is about 15% for the utility and about 20% for the oil company. The large utility and large oil company are intermediate in the cost of capital among entities that might supply and distribute geothermal energy. These range from municipal utilities, with their low cost of capital, to small resource exploration firms which rely primarily on venture capital (Figure 3.2). Assumptions affecting taxes included expensing intangible drilling costs and accelerated (sum-of-the-years' digits) depreciation. All cost estimates are in January 1979 dollars.

TABLE 3.5. Financing and Tax Assumptions

	<u>Reservoir (%)</u>	<u>Transmission and Distribution System (%)</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
Investment Tax Credit	10	10
Percentage Depletion Allowance	15	--

FIGURE 3.2. Effect of Financing on Annual Costs

3.3 CALCULATION OF LEVELIZED HEATING COSTS

To provide for overall uniformity of results, levelized heating costs were calculated for conventional systems (electricity, fuel oil and natural gas) and for geothermal systems as well as for solar and optimal solar/conventional systems.

The levelized heating cost is obtained by dividing the annualized cost by the annual heat load as shown in the following equation:

$$\text{LEC} = \frac{\text{AW} \sum_{n=1,ny} \text{PW}_n \cdot (\text{C}_n/\text{FE}) \cdot \text{HL}}{\text{HL}}$$

where: LEC = levelized energy cost, \$/million Btu

AW = annual worth factor

PW = present worth factor

C = unit cost of energy, \$/million Btu

FE = furnace utilization efficiency

HL = annual heat load, million Btu/yr

n = year

ny = system life, years

The levelized heating cost represents a uniform stream of annual payments, the present value of which, over the life of the system, is equal to the present value of the life-cycle costs. To determine the present value of the life-cycle costs, the annual fuel demand is calculated by dividing the annual heat load by the product of the enthalpy (or heating value) of the fuel and the furnace efficiency. Annual heating costs are then determined by multiplying the annual fuel demand by the price. The cash flow represented by the annual heating costs is discounted by the present worth factor to obtain the present value of the life-cycle costs. The levelized heating cost is a representative average of the ever-increasing annual heating costs over the life of the system. Figure 3.3 illustrates a levelized heating cost in comparison with a typical escalating heating cost. On a present worth basis these two cash flow streams are equal.

The annual rate of increase in geothermal heating costs was assumed to be 2 percent, due to the capital intensiveness of geothermal district heating. Approximately 60 percent of the total cost of geothermal district heating is associated with the fixed initial capital investment, which is made during the construction

FIGURE 3.3. Comparison of Levelized Heating Cost With Escalating Heating Cost

CHAPTER 3.0 - REFERENCES

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period. The other 40 percent of the total cost is associated with the variable annual operating and maintenance costs, which escalate at the general rate of inflation (5 percent in this study). Thus, if the variable fraction comprises 40 percent of the total and if this fraction escalates at 5 percent, then the total cost will escalate at 2 percent.

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4.0 SOLAR HEATING COSTS

4.1 SUMMARY

The economics of solar heating is very dependent on the total annual heat load per residential unit and on the available solar insolation. The annual heat load depends on the climate (number of heating degree-days per year), the building heat loss coefficient, and the domestic hot water demand. The annual heat load is the sum of the annual building space heating demand and the hot water demand. In areas such as Southern Florida, where space heating requirements are low, it may be more economically feasible to use solar energy for hot water heating only.

In most locations solar heating systems will require a conventional energy back-up system: (1) because of local building codes or financial institution constraints, or (2) because the collector area required to supply the total load is uneconomically large. The percentage of energy supplied by solar (solar load fraction) in an optimal solar/conventional heating system will vary from 40-100% depending on location. In addition to climatic factors, the solar load fraction in an optimal system is very dependent on the price of the conventional fuel. An analysis of solar and solar/conventional levelized heating costs throughout the United States indicates that:

1. Sites with the greatest potential for solar heating are located primarily in the Rocky Mountain and Southwestern states.
2. The percentage of the total heat load that is provided by solar energy in an optimal solar/conventional system is highest in locations where conventional energy costs are highest and is lowest in locations where conventional energy costs are lowest.
3. The cost of heating large suburban houses is lower than the cost of heating small urban apartments for both all-solar and combined solar/conventional systems.
4. If conventional heating costs exceed \$15/million Btu of heat delivered, combinations of solar and conventional heating become competitive throughout most of the country.

4.2 INTRODUCTION

This section provides an economic assessment of the potential for active solar energy systems to supply space and hot water heat in the United States. The economics of solar heating is very location-dependent. Site-specific parameters which have the greatest impact on solar heating costs are the quantity of available solar energy, the heating degree-days, and the price of competing fuels, such as electricity, fuel oil or natural gas.

Figure 4.1 shows available solar energy in the United States in langleys (1 langley = 1 cal/cm^2). This represents the quantity of energy that falls on a horizontal surface, which is somewhat less than the amount that could be collected on a surface tilted to take advantage of the sun's position at various latitudes. As shown in the figure, more solar energy is available in the Southwestern United States than in other areas of the country.

The solar collector area needed to supply a given amount of energy is dependent on the number of annual heating degree-days. For a given amount of insolation, more collector area is required in a cold climate than in a warm climate to obtain the same solar load fraction. Therefore, the life-cycle cost of the system in the colder climate is larger. For example, Glasgow, Montana and Greenville-Spartanburg, North Carolina receive roughly the same annual solar insolation. However, almost 90% more collector area is needed in Glasgow to supply 100% of the heat load of a given house than is needed in Greenville-Spartanburg. The life-cycle cost of the Glasgow system is about 70% more than the life-cycle cost of the Greenville-Spartanburg system. When a levelized cost is calculated the heat load again is important. For two locations with equivalent solar life-cycle heating costs, the location in the colder climate will yield a lower levelized solar heating cost. For example, the life-cycle costs of 100% solar heating for suburban houses in Laramie, Wyoming and in Memphis, Tennessee are nearly equivalent. The suburban heat load in Memphis is about 60% lower than in Laramie, but the levelized cost is about 140% higher in Memphis. Figure 4.2 shows average annual heating degree-days ($^{\circ}\text{C-days/yr}$) across the United States. Heating requirements increase with latitude and with elevation.

The United States can be divided into nine climatic solar heating regions on the basis of heating degree-days and insolation, as was done in the TRW Phase 0 report^(4.1). These nine regions, shown in Figure 4.3, represent the possible combinations of three ranges of heating degree-days with three ranges of average solar in-

FIGURE 4.1. Average Annual Solar Radiation in Units of Langley's Per Day
(gram calories/centimeter²/day)

FIGURE 4.2. Average Annual Heating Degree Days (°C-Days/Yr)

solation. Figure 4.3 is actually a composite of Figures 4.1 and 4.2. High-heat-demand, high-insolation regions can be expected to be the most economic regions for solar heating for a given auxiliary fuel price and solar system price. Cities in Region 3 should have the lowest levelized solar heating costs. At a given level of solar insolation, areas with the highest heat demand will have the lowest levelized solar heating costs. That is, regions 3, 6 and 9 would have lower levelized heating costs than other regions within their range of insolation. For a given climate (heating degree-days), areas of highest insolation will have lowest levelized costs. Therefore, regions 1, 2 and 3 would show lower costs than other regions within their climatic category. Overall, region 3 can be expected to have the lowest levelized costs, followed by regions 2 and 6.

We analyzed solar and solar/conventional heating costs for 157 cities across the United States. These sites are indicated by the small dots in Figure 4.4. Levelized costs of solar and solar/conventional heating for these cities are tabulated in Chapter 7.0. Twenty-three cities, indicated by the circles in Figure 4.4, will be discussed in detail. Although costs were calculated for all five residence types shown in Appendix A, only the costs of heating the suburban house and the garden apartment are presented. The suburban house will represent high-heat-demand applications. The garden apartment will represent low-heat-demand applications.

4.3 COSTS OF TOTAL SOLAR HEATING

The cost of supplying space heat and sanitary hot water using only solar energy is calculated in the model by setting the solar load fraction to 100%. The model determines the collector area required for this load at each location. The total life-cycle cost of the system is then obtained by adding the collector-area-dependent costs to the independent costs. (The only collector-area-dependent costs are the cost of the collectors and the cost of the storage tanks. All other capital cost items are assumed to be independent of the collector area.)

Levelized solar heating costs are inversely proportional to the heat demand. The independent costs of a solar system comprise a greater percentage of the total system cost (1) in areas where the annual heating degree-days are low than in areas where the annual heating degree-days are high, and (2) for residences with low heat demands than for residences with high heat demands. When the independent costs are a significant portion of the total system cost, the levelized solar heating cost is

FIGURE 4.3. Regional Climatic Classification for Solar Heating

FIGURE 4.4. Sites for Which Solar Heating Costs were Evaluated

higher than when the independent costs are of lesser importance. This can be illustrated by comparing the levelized solar heating costs in Glasgow, Montana with those in Brownsville, Texas. Both cities have nearly equivalent annual solar insolation, but the number of heating degree-days for Glasgow is about 14 times that of Brownsville. Independent costs represent about 10% of the total system cost for heating a suburban house in Glasgow and about 35% of the total cost in Brownsville. Levelized heating costs are \$14/million Btu and \$21.76/million Btu in Glasgow and Brownsville, respectively. The heating demand per garden apartment unit is lower than the heating demand per suburban house, and the independent costs for the garden apartment constitute a higher percentage of the total cost than for the suburban house. This leads to a lower levelized solar heating cost for the suburban house than for the garden apartment.

Levelized solar heating costs are also inversely proportional to the solar insolation. That is, for two locations with nearly equivalent annual heating loads, the location which receives more solar insolation will have lower levelized heating costs. For example, a house in Madison, Wisconsin has an annual heat load approximately equivalent to the same house in Ely, Nevada; however, Ely receives almost twice the solar insolation per year as Madison. Levelized solar heating costs in Ely and Madison are \$9.51/million Btu and \$23.83/million Btu, respectively.

Levelized heating costs, calculated according to the methodology discussed in Chapter 3.0, are listed in Table 4.1 for suburban houses and garden apartments in several widely scattered locations. Later, in Table 7.1, we list the costs for all 157 locations.

TABLE 4.1. Levelized Costs for Total Solar Heating in Selected Cities
(\$/Million Btu)

<u>City</u>	<u>Suburban</u>	<u>Urban</u>
Seattle, WA	55.77	67.23
Medford, OR	36.93	44.25
Portland, OR	43.21	51.77
Fresno, CA	23.63	32.73
Sacramento, CA	23.44	31.82
San Francisco, CA	11.75	16.65
Riverside, CA	13.47	21.62
Boise, ID	22.39	26.66
Twin Falls, ID	22.25	26.19
Pocatello, ID	13.92	18.73
Salt Lake City, UT	20.61	24.53
Ely, NV	9.51	11.39
Reno, NV	10.29	12.76
Phoenix, AZ	15.26	25.91
Yuma, AZ	17.38	34.18
Great Falls, MT	15.78	18.36
Pueblo, CO	10.92	13.74
Albuquerque, NM	11.06	14.56
Little Rock, AR	25.21	33.13
Boston, MA	25.08	29.37
Baltimore, MD	24.15	29.58
Atlanta, GA	20.85	27.98

The sites with the greatest potential for solar heating are located predominately in the Rocky Mountain and Southwestern states. Figure 4.5 shows the calculated costs for solar heating a suburban house in 157 cities. Figure 4.6 shows the calculated costs for solar heating a garden apartment in the same cities. Note that the low-cost locations tend to coincide with climatic regions 2, 3, and 6 as previously shown on Figure 4.3.

Levelized solar residential heating costs tend to be lower in suburban and rural areas because the heat demand per unit dwelling is higher for these houses than for garden apartment units. An urban building with a high heat demand, such

FIGURE 4.5. Costs for Solar Heating a Typical Suburban House

FIGURE 4.6. Costs for Solar Heating A Typical Garden Apartment

as a commercial facility, would have lower solar heating costs than the urban apartment.

4.4 COSTS OF HEATING WITH OPTIMAL SOLAR/CONVENTIONAL SYSTEMS

The large collector areas required to provide all of the annual heat load will make 100% solar heating impractical at most locations, especially where the ratio of solar insolation to annual heat demand is low. In most locations a backup system using a conventional fuel to supply part of the heat load will be required due to constraints imposed by building codes or lending institutions or to the impractically large collector areas.

For each of the cities analyzed, a least-cost combination of solar with each of the conventional fuels addressed in Chapter 5.0 was calculated. The optimal collector area is calculated first by setting the partial derivative of the life-cycle costs of a combined system with respect to the partial of the area to zero. This area is then used to determine the percentage of the annual heat load supplied by solar energy and the percentage supplied by conventional fuel backup. The cost of the optimal system is then calculated as the sum of: (1) the solar system capital costs, (2) annual operation and maintenance costs, and (3) annual costs of the conventional fuel. This is shown graphically in Figure 4.7. This life-cycle cost is used to determine a levelized heating cost in \$/million Btu.

At the economic optimum, the solar collectors and storage tanks provide the fraction of energy which minimizes the total system cost. By definition this cost must be equal to or less than the cost of conventional heating. Table 4.2 presents optimal levelized heating costs for the suburban house and garden apartment. Levelized heating costs are listed, followed by the solar load fraction in parentheses. At several locations, even partial solar heating is uneconomic and the solar load fraction is zero. At these locations, the levelized heating cost in the table is actually the levelized cost of 100% conventional heating. In locations where the solar load fraction is one, conventional heating is unattractive.

In general, areas with the greatest potential for economic solar/conventional heating have the following location-dependent characteristics:

- high annual heat load,
- high ratio of solar insolation to annual heat load, and
- high conventional fuel cost.

FIGURE 4.7. Optimal Solar/Conventional System Cost As A Function of Collector Area

TABLE 4.2. Optimal System Levelized Heating Costs (\$/Million Btu) and Solar Load Fractions

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Seattle, WA	6.53(0)	6.52(0)	12.34(0)	12.34(0)	12.80(0)	12.80(0)
Medford, OR	15.68(.512)	17.52((0)	11.96(0)	11.96(0)	13.85(.460)	13.97(0)
Portland, OR	16.98(.456)	17.52(0)	11.96(0)	11.96(0)	13.97(0)	13.97(0)
Fresno, CA	18.14(.715)	23.50(.648)	11.96(0)	11.96(0)	7.70(0)	7.70(0)
Sacramento, CA	14.16(.566)	13.47(0)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
San Francisco, CA	11.75(1.00)	16.43(.927)	10.79(.804)	12.34(0)	7.70(0)	7.70(0)
Riverside, CA	13.47(1.00)	21.61(.986)	12.34(9)	12.34(0)	7.70(0)	7.70(0)
Boise, ID	13.76(.614)	15.82(.580)	12.44(.561)	13.94(0)	12.27(.553)	13.55(0)
Pocatello, ID	12.06(.708)	13.77(.676)	11.03(.650)	12.64(.619)	10.89(.642)	12.49(.611)
Twin Falls, ID	13.71(.611)	15.60(.579)	12.37(.557)	13.94(.524)	12.20(.549)	13.55(0)
Salt Lake City, UT	15.44(.714)	17.66(.679)	10.59(0)	10.59(0)	6.57(0)	6.57(0)
Ely, NV	9.20(.899)	10.81(.866)	9.02(.870)	10.58(.837)	7.68(.704)	9.03(.671)
Reno, NV	10.29(1.00)	12.75(.996)	9.65(.855)	11.67(.816)	8.23(.693)	9.20(0)
Phoenix, AZ	15.26(1.00)	25.81(.959)	11.68(0)	11.68(0)	11.00(0)	11.00(0)
Yuma, AZ	17.38(1.00)	31.09(0)	11.68(0)	11.68(0)	11.00(0)	11.00(0)
Great Falls, MT	12.58(.740)	14.20(.710)	9.63(.569)	10.56(0)	7.13(0)	7.13(0)
Pueblo, CO	10.57(.897)	12.99(.852)	9.13(.720)	10.49(0)	8.07(0)	8.07(0)
Albuquerque, NM	11.06(1.00)	14.56(1.00)	9.71(.756)	11.07(0)	8.52(0)	8.52(0)
Little Rock, AR	18.46(.672)	22.81(.612)	11.52(0)	11.52(0)	6.20(0)	6.20(0)
Boston, MA	19.80(.747)	22.24(.713)	12.48(.484)	12.60(0)	14.69(.571)	16.60(.537)
Baltimore, MD	18.99(.734)	22.13(.690)	12.19(0)	12.19(0)	13.37(0)	13.37(0)
Atlanta, GA	16.68(.718)	21.14(.654)	11.58(0)	11.58(0)	9.57(0)	9.57(0)

NOTE: Solar load fraction listed in parentheses

To obtain low levelized solar/conventional heating costs, it is important that the ratio of insolation to heat load be high and that the heat load itself be high.

Areas which receive a large amount of solar insolation but have a low annual heat demand, such as Florida, have a lower life-cycle system cost (in total dollars) than areas which receive a large amount of solar insolation but have a high annual heat demand, such as Lander, Wyoming. However, when these costs are distributed over the heat demand, the levelized solar heating costs (in \$/million Btu) in Florida are higher than those in Wyoming. The independent costs represent a greater percentage of the total cost in Florida than in Wyoming. Distributing these independent costs over a smaller annual heat load results in higher levelized costs.

Local fuel prices play an important role in determining the optimal solar load fraction. The portion of the load supplied by solar is greater if conventional fuel costs are high (see Table 5.1) and is smaller if fuel prices are low. For example, in Boston, Massachusetts the current (January 1980) unit costs of conventional heat as delivered by the furnace are: (1) electricity -- \$20.50/million Btu, (2) fuel oil -- \$11.43/million Btu, and (3) natural gas -- \$9.27/million Btu. As shown in Table 4.2, the solar load fraction for the suburban house in Boston is the greatest with electric backup (the most expensive conventional fuel) and is the least with natural gas (the least expensive conventional fuel). Figure 4.8 shows the effect of increasing fuel prices on the optimal solar collector area. As fuel prices increase at a given location, the optimal collector area increases and, therefore, the solar load fraction increases.

Under our low price assumption, fuel oil and natural gas prices are low with respect to recent and impending increases in the prices of these fuels. If, under decontrol, natural gas prices were to increase to a level competitive with fuel oil, the number of areas where solar could economically supply a portion of the load when used with these fuels would increase. For example, at a delivered fuel oil price of 75¢/gallon,* solar can supply 60% of the heat for a suburban house in Fresno, California, whereas at the early 1979 price of about 57¢/gallon it was uneconomic for solar to supply any of the heat. Table 4.3 shows heating costs and solar load fractions in 22 locations for solar/conventional systems when the conventional heating

*This is an initial fuel price which, with escalation, is equivalent to a levelized heating cost of \$15/million Btu as discussed elsewhere.

FIGURE 4.8. Effect of Conventional Fuel Cost on Optimal Solar Collector Area

TABLE 4.3. Optimal System Levelized Heating Costs (\$/Million Btu)
and Solar Load Fractions with Conventional Levelized
Costs of \$15/Million Btu

City	Suburban	Urban
Seattle, WA	15.00(0)	15.00(0)
Medford, OR	14.69(.485)	15.00(0)
Portland, OR	15.00(0)	15.00(0)
Fresno, CA	14.78(.604)	15.00(0)
Sacramento, CA	14.51(.603)	15.00(0)
San Francisco, CA	11.30(.876)	14.98(.807)
Riverside, CA	13.07(.883)	15.00(0)
Boise, ID	13.13(.589)	14.94(.555)
Pocatello, ID	11.57(.681)	13.23(.649)
Twin Falls, ID	13.07(.586)	14.91(.553)
Salt Lake City, UT	12.92(.608)	14.88(.573)
Ely, NV	9.00(.867)	10.56(.834)
Reno, NV	9.63(.853)	11.65(.814)
Phoenix, AZ	14.55(.846)	15.00(0)
Yuma, AZ	15.00(0)	15.00(0)
Great Falls, MT	11.50(.679)	13.01(.649)
Pueblo, CO	10.21(.845)	12.51(.800)
Albuquerque, NM	10.54(.865)	13.48(.811)
Little Rock, AR	15.00(0)	15.00(0)
Boston, MA	13.92(.542)	15.00(0)
Baltimore, MD	14.42(.561)	15.00(0)
Atlanta, GA	14.82(.628)	15.00(0)

NOTE: Solar load fraction in parentheses

cost is \$15/million Btu. Comparing these values with those for solar/fuel oil and solar/natural gas systems in Table 4.2 shows that an increase to \$15/million Btu in conventional heating costs would significantly increase the use of solar/conventional systems. This impact will be discussed in more detail in Chapter 7.0.

Areas where the optimal solar load fraction is zero are characterized predominately by low local conventional fuel prices. The amount of solar insolation available is also an important variable; however, the solar load fraction for the optimal system is more sensitive to fuel price than to insolation. With low-cost natural gas as the conventional backup fuel, few locations had solar load fractions above zero; those that did were characterized by relatively high solar insolation in relation to the heat demand. For suburban houses using the optimum solar/electric system, it is economic for solar to supply part of the load in all locations analyzed except cities in Washington State, where electricity prices are low. The potential impact of additional increases in fossil energy prices on the increased economic use of solar energy can be inferred from Table 4.2 by comparing the increased solar load fractions in the solar/electrical systems with the solar/natural gas systems.

In general, solar contributes a greater percentage of the heat load for the suburban house than for the garden apartment at the optimum. The levelized cost of heating the garden apartment with the solar/conventional system is higher than for the suburban house. This reflects the effect on the total cost of the capital costs that are independent of collector size. These costs are about the same for small as well as large residences; therefore, the cost is a fixed amount of dollars spread over smaller and smaller system outputs as house size (i.e., heat demand) is reduced. Higher levelized costs for the solar part of the solar/conventional system result in lower solar load fractions at the optimum.

4.5 SENSITIVITY ANALYSIS

A sensitivity analysis was performed to determine the effect of uncertainties and assumptions on the levelized heating costs. Uncertainty regarding costs for the solar systems arises principally because it is a relatively new technology. The following parameters were varied while holding all other base assumptions constant to determine their effects on heating costs:

- Discount Rate
- Tax Credit Allowance
- Income Tax Rate
- Fuel Escalation Rate
- Capital Costs for Solar Heating Systems
- General Inflation Rate

The effects of changes in these assumptions on solar heating costs are shown in Table 4.4. In general, levelized solar heating costs are reduced by increasing the discount rate, the income tax rate, or the tax credit allowance, or by decreasing the capital costs or the inflation rate. A more detailed discussion of the results of varying the parameters listed above follows.

4.5.1 Capital Costs for Solar Heating Systems

Solar heating costs are proportional to the independent and collector-dependent capital costs of the solar heating system.

Doubling solar system independent capital costs increases the levelized cost of heating the suburban house and the garden apartment by 15 to 40%, depending on location. Decreasing solar system independent capital costs to half of the base value reduces the levelized solar heating cost for the suburban house and the garden apartment from 10 to 25%.

Higher solar system independent capital costs shift the optimal solar/conventional system to greater dependence on the conventional fuel. The levelized cost of heating with the solar/conventional system increases as solar system independent capital costs are increased until the optimal cost occurs at the point at which the system is completely dependent on conventional fuel. The curves at the top of Figure 4.9 show the effect of varying solar independent capital costs. As the costs are increased, the optimal collector area shifts to the left, resulting in a lower solar load fraction.

Doubling collector-dependent costs increases the cost of heating the suburban house or the garden apartment by 60 to 100%. The magnitude of the change depends on the percentage of the initial capital cost that is collector-dependent. If collector-dependent costs comprise a small fraction of the total cost, as in areas of low insolation and low heat demand, the levelized cost of heating is less sensitive to changes in collector-dependent costs than it is in areas for which the dependent costs are a larger fraction of the total.

TABLE 4.4. Results of Sensitivity Analysis for 100% Solar Heating

Parameter	Base Value	New Value	% Change in Heating Cost-- Suburban	% Change in Heating Cost-- Urban
Discount Rate	10%	5%	+80%	+40%
	10%	15%	-36%	-20%
Income Tax Rate	30% (private)	20%	+25%	
	30% (private)	40%	-25%	
	50% (commercial)	40%		+20%
	50% (commercial)	60%		-20%
Solar System Independent Capital Costs	\$5,000 (suburban)	\$ 2,500	-10 to -25%	
	\$5,000 (suburban)	\$ 10,000	+15 to 40%	
	\$175,000 (urban)**	\$ 87,500		-10 to -25%
		\$250,000		+15 to 40%
Collector and Heat Storage Costs	\$183/M ²	\$91.50/M ²	-30 to -50%	-30 to -50%
	\$.55/kg	\$.275/kg		
	\$183/M ²	\$ 366/M ²	+60 to 100%	+60 to 100%
	\$.55/kg	\$ 1.10/kg		
Investment Tax Credit	30%/20%*(private)	0	+60%	
	30%/20%*(private)	50%	-60 to -65%	
	10% (commercial)	0		+25%
	10% (commercial)	50%		-5 to -10%
Inflation Rate	5%	0	-28%	-37%
	5%	10%	+31%	+36%

* 30% of the first \$2,000 and 20% of the next \$8,000.

** For 60 dwelling units.

FIGURE 4.9. Effect of Varying Solar System Independent and Collector-Dependent Costs on Optimal Solar/Conventional System Costs

Decreasing collector-dependent costs by 50% decreases levelized heating costs 30 to 50%. Again, the magnitude of the decrease is proportional to the fraction of the total cost that is collector-dependent.

Solar heating costs are more sensitive to changes in collector-dependent costs than to changes in independent costs. Therefore, solar market penetration would be increased more by a decrease in collector-dependent costs than a decrease in independent costs. The independent costs (pumps, pipes, valves, etc.) are not likely to experience decreases with time since they represent "old" technology. Collector-dependent costs (collectors and storage system) are more likely to decrease as more efficient mass production techniques and technological innovations become available. The effect of varying these costs is shown in the lower graph in Figure 4.9. Again, as costs are increased, the optimal collector area decreases, thereby lowering the solar load fraction of the optimal solar/conventional system.

4.5.2 Income Tax Rate

Solar heating costs are inversely proportional to the income tax rate. Increasing commercial and private income taxes to 60% and 40%, respectively, from the reference values of 50% and 30%, results in a 25% decrease in the levelized cost of solar heating a suburban house and a 20% decrease for solar heating the garden apartment. Decreasing commercial and private income tax rates to 40% and 20%, respectively, results in a 25% increase in levelized solar heating costs for the suburban house and a 20% cost increase for the garden apartment.

Conventional fuels supply a smaller percentage of the heat load in an optimal solar/conventional system as income taxes increase. An increase in the income tax rate decreases the cost of the solar part of the system while conventional fuel costs remain unchanged. As shown in Figure 4.10, an upward shift in taxes decreases total cost and increases the optimal collector area, thereby increasing the solar load fraction. Conversely, a downward shift in taxes decreases the optimal collector area and, therefore, the solar load fraction. Heating costs for the combined systems decrease with increasing income tax rate. The magnitude of this cost decrease is location-dependent.

4.5.3 Fuel Escalation Rate

The heating costs for conventional systems and for optimal solar/conventional systems are proportional to the fuel escalation rate. Changing the fuel escalation

FIGURE 4.10. Effect of Income Tax Rate on Optimal Solar/Conventional Costs

rate does not affect the cost for all-solar heating. Fuel escalation rates are derived from the expected real increase in the cost of fuel and the general inflation rate according to the following equation:

$$e = [(1 + \text{inflation}) \cdot (1 + \text{real})] - 1$$

Changes in the fuel escalation rate were assumed to be changes in the real portion with the inflationary component remaining constant.

Fuel escalation rates were increased to 15% from the base values of 7% for oil and electricity and 10% for natural gas. The optimal solar/conventional system becomes more dependent on solar as the fuel escalation rate is increased and the levelized heating cost becomes higher. The magnitude of the change in the levelized heating cost of the combined system resulting from a change in the fuel escalation rate varies with location. For example, when fuel escalation rates were increased to 15% from the 10% base value for natural gas, the levelized cost of solar/natural gas heating in Albuquerque, New Mexico increased 7%, whereas in Seattle, Washington the increase was 30%.

4.5.4 Discount Rate

Levelized heating costs are inversely proportional to the discount rate. A decrease in the discount rate from the base value of 10% to 5% results in an 80% increase in the levelized solar heating cost for the suburban house and a 40% increase for the garden apartment. Increasing the discount rate to 15% causes a 36% decrease in the levelized solar heating cost for the suburban house and a 20% decrease for the garden apartment. Solar heating costs for the suburban house are more sensitive to changes in the discount rate than are the costs of solar heating for the garden apartment because of the higher interest rate and larger balance remaining after the downpayment for the private owner.

Due to differences in financing schemes for private and commercial investors, the rate of increase in solar costs for the garden apartment is lower than the rate of increase for the suburban house when the discount rate is decreased. Relative to conventional fuel costs, solar system heating costs for the suburban house increase more as the discount rate is decreased. This shifts the optimal collector area and, therefore, the solar load fraction, to a lower value. Conversely, garden apartment heating costs increase at a slower rate relative to conventional costs as the dis-

count rate decreases. This causes the optimal collector area to shift to a higher value, leading to a higher solar load fraction. Therefore, decreasing the discount rate decreases the percentage of heat supplied by solar for the suburban house and increases the percentage of solar-supplied heat for the garden apartment. Conversely, increasing the discount rate increases the solar load fraction for the suburban house system and decreases the solar load fraction for the garden apartment. Again, this is due to differences in financing for the private and commercial sectors. In both cases, the total levelized heating cost of the optimal solar/conventional system is inversely proportional to the discount rate.

4.5.5 Investment Tax Credit

Solar heating costs are inversely proportional to the investment tax credit. If federal incentives to invest in solar heating equipment were eliminated, the cost of solar heating the suburban house could increase as much as 60% and the cost of solar heating the garden apartment could increase 25% above the reference values. Current bills pending in Congress could raise the tax credit allowance to 50% of outlays as much as \$10,000, for a maximum credit of \$5,000. Under this bill, increasing the tax credit allowance to 50% will decrease solar heating costs for the suburban house 60 to 65% and for the garden apartment, 5 to 10%; without the \$5,000 limitation, solar heating costs for the garden apartment would decrease 85 to 90%.

For the optimal solar/conventional systems, increasing the tax credit allowance to 50% increases the solar load fraction. The levelized cost of heating with the solar/conventional system decreases as tax credits are increased. Reducing the cost of the solar part of the solar/conventional system by increasing the investment tax credit increases the optimal collector area and, therefore, the solar load fraction.

Investment tax credits have a significant impact on the economics of solar heating. If the 50% tax credit allowance is approved by Congress, the private owner's incentive to invest in a solar heating system would be greatly enhanced. The number of locations at which solar and solar/conventional heating for the suburban house are most economic could be expected to greatly increase. An increase to 50% with the limit of \$5,000 would not greatly impact the commercial investor. The \$5,000 deduction, compared to the large capital investment for urban buildings, is of little significance.

4.5.6 General Inflation Rate

Levelized heating costs are proportional to the general inflation rate. Solar suburban heating costs are less sensitive to the general inflation rate than are solar garden apartment heating costs because of the larger downpayment required for the commercial owner.

In order to vary the general inflation rate, the nominal values of the interest rate, discount rate and fuel escalation rates must be adjusted. These nominal values include a component that reflects real costs as well as a component for inflation. When a zero inflation rate is assumed, levelized solar heating costs for the suburban house are decreased 28% and the garden apartment costs are decreased about 37% below base values. Doubling the base inflation rate to 10% increases the levelized solar heating costs for the suburban house about 31% and for the garden apartment about 36% above the base values.

For optimal solar/conventional systems, the solar load fraction decreases as the inflation rate is increased.

4.6 INTERPRETATION OF RESULTS

Solar heating costs were based on current state-of-the-art technology and current cost data. Materials comprise about 30% of the installed cost of a solar system. The balance of the cost is labor in the manufacturing and installation phases^(4.2). System cost reductions should be forthcoming as mass production techniques become more prevalent, as solar heating systems become more packaged for ease of installation, and as improvements in technology and labor productivity occur. This should lead to more widespread applications of solar energy than our results would indicate.

Institutional barriers which may slow the growth of solar heating, as identified by SRI^(4.3), include:

- Requirement for conventional 100% capacity backup heating equipment by lending and code institutions. Unconventional, often less expensive, alternatives such as bottled gas or wood are not accepted as sole backup for solar space heating in most communities.
- Concern of utilities with excessive peak loads during long periods of inclement weather.

- Concern of residential construction industry with delays and excessive costs of a rapidly-changing technology, unperfected installation techniques, inadequate warranty protection, code and permit difficulties, and market acceptance of higher initial costs.

CHAPTER 4.0 - REFERENCES

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- 4.2 Richard H. Montgomery, "Solar Energy Systems and the Consumer", Solar Heating and Cooling. 1979 Buyer's Guide.
- 4.3 Marilyn Duffey-Armstrong and Joe E. Armstrong, Community Impediments to Implementation of Solar Energy. SRI International, June 1979.

5.0 CONVENTIONAL HEATING COSTS

5.1 SUMMARY

Conventional fuels are electricity, fuel oil and natural gas. In 1978, 97% of all new houses constructed in the United States used conventional fuels for space and hot water heating. Nationwide, 52% of new housing in 1978 used electricity, 37% used natural gas and 8% used fuel oil. On a regional basis, fuel oil dominated for heating new houses in Northeastern states, natural gas dominated in North Central and Western states, and electricity dominated in the South (Table 5.1). The choice of fuel at a given location depends on both its cost and availability.

The early 1979 conventional fuel prices, used as the low price assumption in this study, vary from a low of 17.4¢/therm of natural gas (\$1.74/million Btu) to a high of 8.3¢/kWh of electricity (\$24.33/million Btu). After furnace efficiencies, inflation, and fuel escalation rates are taken into account, levelized conventional heating costs range from \$6.20/million Btu to \$45.19/million Btu of heat delivered. The median levelized cost of conventional heating, based on these low-priced fuels, is \$10/million Btu for the cities analyzed. Under the reference price escalation assumptions, this median cost is the equivalent of a current unit price of 2¢/kWh of electricity, 48¢/gallon of fuel oil, or 28.2¢/therm of natural gas.

As of January 1980, the U.S. city average prices of conventional fuels were 92.9¢/gallon of fuel oil, 38.1¢/therm of natural gas, and 5.3¢/kWh of electricity^(5.2). These prices represent an 80% increase in fuel oil prices, a 28% increase in natural gas prices, and a 30% increase in electricity prices since the start of this study. In view of these recent sharp increases in conventional fuel prices, a levelized heating cost of \$15/million Btu is thought to be more representative of current prices.

Under conditions prevailing in 1979, natural gas provided the lowest cost heat in most locations. Under the reference price escalation assumptions, which appeared to be applicable in early 1979, natural gas continues to be the lowest cost fuel for heating in most locations over the next 20 years. However, with price decontrol, natural gas prices for heating will probably reach an equilibrium with oil. Considering the sharp increases in oil prices which occurred in 1979 and the further increases which are anticipated, natural gas prices will probably increase at a faster rate than the assumed escalation rate of ten percent per year. In fact, from January

TABLE 5.1 Characteristics of New Housing^(5.1)

<u>Region</u>	<u>Heating Fuel</u>	<u>Percent</u>
Northeast ^(a)	Gas	16
	Electricity	34
	Oil	43
	Other or None	8
North Central ^(b)	Gas	50
	Electricity	36
	Oil	11
	Other or None	4
South ^(c)	Gas	27
	Electricity	69
	Oil	3
	Other or None	2
West ^(d)	Gas	52
	Electricity	45
	Oil	-
	Other or None	3
Total U.S.	Gas	37
	Electricity	52
	Oil	8
	Other or None	3

(a) Maine, New Hampshire, Vermont, New York, Pennsylvania, Connecticut, Rhode Island, Massachusetts, New Jersey

(b) Ohio, Indiana, Illinois, Missouri, Iowa, Minnesota, North Dakota, Nebraska, Kansas, South Dakota

(c) West Virginia, Maryland, Delaware, Virginia, North Carolina, South Carolina, Georgia, Florida, Mississippi, Alabama, Tennessee, Kentucky, Arkansas, Louisiana, Oklahoma, Texas

(d) Montana, Wyoming, Colorado, New Mexico, Arizona, Utah, Idaho, Nevada, California, Oregon, Washington, Alaska, Hawaii

1979 to January 1980, the U.S. average natural gas price increased 30%.

This chapter discusses early 1979, current, and projected unit prices for conventional fuels. The calculated levelized heating costs of conventional fuels under the reference price escalation assumptions are also discussed.

5.2 UNIT FUEL PRICES

This section presents unit fuel prices under three scenarios: (1) early 1979 prices, (2) current prices, and (3) projected prices.

Local electricity prices were obtained from the Department of Energy publication Typical Electric Bills - January 1, 1978^(5.3). These prices were updated to 1979 dollars using an escalation rate of 7%. These electricity prices, which are representative of early 1979 values, range from a low of 1.2¢/kWh in Seattle, Washington to a high of 8.3¢/kWh in New York City. If electricity prices were to escalate seven percent annually, in 20 years electricity prices would range from 4.6¢/kWh to 32.1¢/kWh.

Data supplied by the U.S. Department of Labor^(5.4) indicate that electricity prices escalated at a much higher rate than seven percent through 1979. The average price of electricity as of January 1980 was 1.8¢/kWh in Seattle and 10.4¢/kWh in New York City. The U.S. city average cost was 5.3¢/kWh, which is about thirty percent above early 1979 prices.

Local delivered fuel oil prices were obtained from the American Gas Association publication Gas House Heating Survey^(5.4). The prices, which were reported in 1977 dollars, were updated to 1979 dollars using a fuel oil escalation rate of 7%. Early 1979 fuel oil prices ranged from 45¢/gallon in Jackson, Mississippi to 75¢/gallon in Las Vegas, Nevada. Twenty years from now fuel oil prices could range from \$1.74/gallon to \$2.90/gallon if escalated at the 7% rate.

However, since January 1979, fuel oil prices have increased as much as 80%. In January 1980 the average U.S. city price per gallon of heating oil was 92.9¢^(5.2).

Regional natural gas prices, as supplied to the residence, were reported in 1977 dollars in Gas Facts^(5.5), published by the American Gas Association. These prices were updated to 1979 dollars using an annual fuel escalation rate of 10%. Early 1979 natural gas prices ranged from a low of 17.4¢/therm in Arkansas to a high of 61.2¢/therm in Maine. Escalating natural gas prices at 10% would result in a

range of \$1.17/therm to \$4.11/therm in 20 years.

Natural gas prices as of January 1980 were 28% above the early 1979 prices. The U.S. city average price per therm of natural gas was 38.1¢ in January 1980^(5.2), whereas the average natural gas price under the low price assumption in the cities analyzed was about 28¢/therm.

Table 5.2 presents early 1979 conventional fuel prices for 22 cities. As shown in the table, prices for a given conventional fuel vary markedly with location. In general, for a given location electricity prices are highest and natural gas prices are lowest. Exceptions occur in the Pacific Northwest (Seattle, Washington) where low-cost hydroelectric power is available.

5.3 LEVELIZED CONVENTIONAL HEATING COSTS

Conventional heating costs depend primarily on the price of fuel as delivered and the utilization efficiency of the furnace. Conventional heating costs are largely independent of climate and population density.

Table 5.3 lists the levelized heating costs using conventional fuels for the 22 cities. (Levelized costs of conventional heating for all 157 sites are listed in Table 7.1.) Costs are in 1979 dollars. The costs are based on early 1979 prices and the reference price escalation assumptions. The lowest cost was for natural gas heating in Little Rock, Arkansas. For the 22 cities, the lowest fuel oil cost occurred in Great Falls, Montana and the lowest electricity cost occurred in Seattle, Washington. Under the reference conditions, the median levelized cost of conventional heating was found to be \$10/million Btu. This median levelized cost is equivalent to unit prices of 2¢/kWh of electricity, 48¢/gallon of fuel oil, or 28.2¢/therm of natural gas, based on the reference price escalation assumptions. In this study fuel escalation rates were assumed to be constant nationwide, whereas in reality they would vary with region and utility. In a more detailed analysis, separate escalation rates would be projected for each region and utility.

Uncertainty over energy prices clouds the projection of future conventional heating costs. When this study was initiated, the early 1979 price assumptions looked reasonable. However, during the course of the study events occurred which now make the early 1979 price assumptions appear too low. These events were the mid-1979 sharp increases in OPEC prices, the anticipated sharp increase in OPEC prices in 1980, the cut-off and uncertainty in Iranian oil supplies, and the planned

TABLE 5.2. Early 1979 Conventional Fuel Prices (\$/Million Btu Equivalent)

<u>City</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Seattle, WA	3.53	4.08	3.60
Medford, OR	9.48	3.96	3.92
Portland, OR	9.48	3.96	3.92
Fresno, CA	12.84	3.96	2.16
Sacramento, CA	7.29	4.08	2.16
San Francisco, CA	12.39	4.08	2.16
Riverside, CA	16.15	4.08	2.16
Boise, ID	9.28	4.61	3.81
Twin Falls, ID	9.28	4.61	3.81
Pocatello, ID	9.28	4.61	3.81
Salt Lake City, UT	12.48	3.50	1.85
Ely, NV	9.34	5.19	2.58
Reno, NV	15.38	5.19	2.58
Phoenix, AZ	17.66	3.86	3.09
Yuma, AZ	16.82	3.86	3.09
Great Falls, MT	10.44	3.49	2.00
Pueblo, CO	9.93	3.47	2.27
Albuquerque, NM	16.78	3.66	2.39
Little Rock, AR	12.48	3.81	1.74
Boston, MA	17.70	4.17	4.86
Baltimore, MD	15.62	4.03	3.76
Atlanta, GA	11.52	3.83	2.69

TABLE 5.3. Levelized Conventional Heating Costs (\$ Per Million Btu)

<u>City</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Seattle, WA	6.53	12.34	12.80
Medford, OR	17.52	11.96	13.97
Portland, OR	17.52	11.96	13.97
Fresno, CA	23.72	11.96	7.70
Sacramento, CA	13.47	12.34	7.70
San Francisco, CA	22.91	12.34	7.70
Riverside, CA	29.85	12.34	7.70
Boise, ID	17.15	13.94	13.55
Twin Falls, ID	17.15	13.94	13.55
Pocatello, ID	17.15	13.94	13.55
Salt Lake City, UT	23.06	10.59	6.57
Ely, NV	17.25	15.69	9.20
Reno, NV	28.42	15.69	9.20
Phoenix, AZ	32.63	11.68	11.01
Yuma, AZ	31.09	11.68	11.01
Great Falls, MT	19.30	10.56	7.13
Pueblo, CO	18.34	10.49	8.07
Albuquerque, NM	31.01	11.07	8.52
Little Rock, AR	23.06	11.52	6.20
Boston, MA	32.71	12.60	17.31
Baltimore, MD	28.87	12.19	13.37
Atlanta, GA	21.29	11.58	9.57

decontrol of oil and natural gas prices. Therefore, we adopted a second yardstick of conventional heating costs which may better reflect the new conditions; we call this the "\$15 price assumption". This yardstick simply assumes conventional heating will cost \$15/million Btu in each location. The use of both yardsticks permits a better assessment of the effect of conventional heating costs on the potential competitiveness of solar and geothermal energy.

As of January 1980, U.S. city average unit prices of conventional fuels were 92.9¢/gallon of fuel oil, 38.1¢/therm of natural gas and 5.3¢/kWh of electricity^(5.2). Under our reference price escalation assumptions, these unit prices would result in levelized heating costs of \$19.08/million Btu for fuel oil, \$13.51/million Btu for natural gas and \$28.57/million Btu for electricity. Thus, conventional heating costs by the beginning of 1980 were more in line with the \$15 price assumption than with the early 1979 price assumption (which we refer to as the low price assumption).

5.4 SENSITIVITY ANALYSIS

Uncertainty arises in the levelized costs of conventional heating primarily because future supplies and prices of fossil fuels are unknown. The following parameters were varied to determine their effect on calculated heating costs:

- Discount Rate
- General Inflation Rate
- Fuel Escalation Rate

In general, levelized conventional fuel costs are reduced by increasing the discount rate or by decreasing either the fuel escalation rate or the general inflation rate. Table 5.4 summarizes the results of the sensitivity analysis. A more detailed discussion of the impact of changing these variables follows.

TABLE 5.4. Results of Sensitivity Analysis on Levelized Conventional Heating Costs

<u>Parameter</u>	<u>Reference Value</u>	<u>New Value</u>	<u>% Change Electricity</u>	<u>% Change Fuel Oil</u>	<u>% Change Natural Gas</u>
Discount Rate	10%	5%	+62%	+62%	+69%
	10%	15%	-33%	-33%	-35%
General Inflation Rate	5%	0%	-32%	-32%	-30%
	5%	10%	+30%	+30%	+28%
Fuel Escalation Rate	7% ^(a)	5%	-40%	-40%	
	10% ^(b)	5%			-53%
	7% ^(a)	15%	+102%	+102%	
	10% ^(b)	15%			+58%

a. for electricity and fuel oil

b. for natural gas

5.4.1 Discount Rate

Levelized conventional heating costs are inversely proportional to the discount rate. Levelized electricity and fuel oil heating costs are increased 62% and levelized natural gas costs are increased 69% when the reference discount rate is reduced to 5%. A decrease of 33% in levelized electricity and oil heating costs and a 35% decrease in natural gas heating costs occur when the discount rate is increased to 15%. The difference in the sensitivity of levelized natural gas heating costs to changes in the discount rate, as compared to electricity and fuel oil, occurs because of differences in the reference values of fuel escalation rates.

5.4.2 Fuel Escalation Rate

Levelized conventional heating costs are directly proportional to the fuel escalation rate. Increasing the fuel escalation rate to 15% increases levelized electricity and fuel oil costs 102%. Levelized natural gas heating costs are increased 58%. On the other hand, if fuel prices escalate at the general inflation rate only, levelized costs for electric and oil heating decrease 40% and natural gas heating costs decrease 53%.

There is a great deal of uncertainty in future prices of conventional fuels. Current rates of increase in fuels, especially fuel oil, indicate that our reference escalation assumptions were very conservative. Figure 5.1 shows the effect of fuel escalation on levelized fuel costs for a 30-year period of analysis. Fuel escalation rates below the discount rate (10%) show smaller changes in levelized cost than escalation rates above the discount rate. The levelized heating cost is obtained by dividing the levelized fuel cost by the furnace efficiency.

5.4.3 General Inflation Rate

Levelized conventional heating costs are directly proportional to the inflation rate. The impacts of a zero and 10% inflation rate are shown in Table 5.4. Electricity and fuel oil heating costs were decreased 32% and natural gas heating costs were decreased 30% with the zero inflation rate. Electricity and fuel oil heating costs increased 30% and natural gas heating costs increased 28% with the 10% inflation rate. Differences in sensitivity of these fuels to the inflation rate are due to differences in the real fuel escalation rates -- 2% for electricity and fuel oil and 5% for natural gas.

FIGURE 5.1. Effect of Fuel Escalation Rate on Levelized Fuel Cost

CHAPTER 5.0 - REFERENCES

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6.0 GEOHERMAL DISTRICT HEATING COSTS

6.1 SUMMARY

Geothermal district heating will probably be competitive in most high-density urban areas provided that geothermal resources are nearby. (Later in this report we will quantify the term "nearby" as a function of resource temperature.) The economics of geothermal district heating is very dependent on the density of heat demand per unit area which, in turn, is related to population density and climate. The economics is also dependent on the production and transmission costs of geothermal energy, which are related to the temperature, depth, and production rate of the resource and the transmission distance. Because of the sensitivity to distance, locating geothermal resources near to the demand is important.

The sensitivity of production costs to the important factors of production was determined. The most important factors are 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 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 district heating, 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.

Institutional deterrents to widespread geothermal district heating will probably be significant. Among these will be the acquisition of rights-of-way, the need to organize concentrated markets, and price competition from the conventional fuels based on average cost rather than marginal cost. Also, a high degree of participation within the heating district is necessary to the commercial success of a district heating system.

6.2 INTRODUCTION

This section provides an economic assessment of the potential for geothermal energy to supply space heat in the United States through district heating systems. The geothermal resources upon which this report is based are the high-temperature and intermediate-temperature hydrothermal reservoirs identified by the U.S. Geological Survey^(6.1). Estimates of the energy content, characteristics, and locations of the resources are derived from data in the USGS assessment (see Tables 6.1 and 6.2). We also evaluated the economics of using the normal-gradient resource (60°C) that may exist in the Atlantic Coastal Plain and elsewhere throughout the country.

There are Known Geothermal Resource Areas (KGRAs) and areas valuable prospectively for high-temperature and intermediate-temperature hydrothermal resources throughout the Western states^(6.2). Figure 6.1 shows that these resources are expected to lie within 50 miles of most of the major cities in the West. In a previous report^(6.3) we determined that the potential demand for district heating surrounding the hydrothermal reservoirs is large; over 10% of the U.S. population resides within 40 miles of the resources.

The normal-gradient geothermal resource underlies the rest of the United States, including areas in the Western states where high-temperature and intermediate-temperature resources are not found. Figure 6.2 shows the estimated average thermal gradients throughout the Central and Eastern states. Thermal gradients have been measured from about 30°C per kilometer in the East, to over 60°C per kilometer in the Gulf Coast region. The key to the successful application of the normal-gradient resource in district heating will be whether productive water-bearing aquifers can be located near major metropolitan areas.

Although the temperatures of the normal-gradient resources are low, practical experience in several countries has shown them to be satisfactory for district heating, provided that the resource is 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^(6.4). 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 near an urban area, the potential for utilization of the heat is favorable.

TABLE 6.1. High-Temperature Hydrothermal Reservoirs^(a)

Subsurface Temperature, °C	Reservoir Thickness, km	Heat Content, ^(b) 10 ¹⁸ Calories
275	2.0	20.780
275	1.5	1.914
265	2.0	7.643
255	1.5	5.256
230	2.0	1.123
230	1.5	6.450
225	2.0	18.634
220	2.0	5.973
220	1.5	6.928
215	2.0	1.075
215	1.5	16.441
205	2.0	1.553
200	2.7	3.440
190	2.0	1.329
190	1.5	10.081
180	2.0	4.243
180	1.5	1.699
175	2.0	7.406
175	1.5	1.027
170	2.0	4.874
165	1.5	6.422
160	2.5	7.000
160	1.5	1.885
155	2.5	3.751
155	2.0	11.349
		<u>158.276</u>

(a) Derived from data in USGS Circular 790, excluding National Parks, Alaska, The Geysers, and the Salton Sea.

(b) Above 15°C

TABLE 6.1. Continued

	Subsurface Temperature, °C	Reservoir Thickness, km	Heat Content, (a) 10 ¹⁸ Calories
Alaska	210	2.0	1.314
	165	2.0	0.320
	160	1.5	0.315
			<u>1.949</u>
The Geysers	237	2.0	23.885
The Salton Sea	325	2.0	23.168
National Parks ^(b)	265	2.5	296.169
	235	1.0	10.032
	225	1.3	1.099
			<u>307.300</u>

(a) Above 15°C

(b) Includes Yellowstone and Mt. Lassen National Parks, both of which are permanently withdrawn from exploitation; derived from data in USGS Circular 790.

TABLE 6.2. Intermediate-Temperature Hydrothermal Reservoirs^(a)

Subsurface Temperature, °C	Reservoir Thickness, km	Heat Content, (b) 10 ¹⁸ Calories
150	2.0	18.873
150	1.5	3.393
145	2.0	1.051
145	1.5	1.685
140	1.5	2.254
135	1.5	1.464
130	1.5	6.279
125	2.0	2.047
125	1.5	3.355
120	1.5	3.230
115	1.5	4.902
110	2.0	7.435
110	1.5	2.241
105	1.5	111.507
100	1.5	6.859
95	1.5	3.545
		<u>180.120</u>

(a) Derived from data in USGS Circular 790, excluding National Parks and Alaska.

(b) Above 15°C

TABLE 6.2. Continued

	Subsurface Temperature, °C	Reservoir Thickness, km	Heat Content, (a) 10 ¹⁸ Calories
Alaska	145	1.5	0.277
	140	1.5	0.803
	135	1.5	0.260
	130	1.5	1.232
	125	1.5	0.719
	120	1.5	0.222
	115	1.5	0.865
	110	1.5	0.201
	105	1.5	0.385
	100	1.5	0.184
	95	1.5	0.170
	90	1.5	0.327
			5.645
National Parks ^(b)	125	1.5	0.239

(a) Above 15°C

(b) Mount Rainier National Park, which has been permanently withdrawn from exploitation; derived from data in USGS Circular 790.

FIGURE 6.1. Areas Valuable Prospectively for High-Temperature and Intermediate-Temperature Hydrothermal Resources

ESTIMATED AVERAGE
THERMAL GRADIENT, $^{\circ}\text{C}/\text{km}$

30

35-40

60

FIGURE 6.2. Normal-Gradient Geothermal Resources

The geothermal reservoirs listed on the first pages of Tables 6.1 and 6.2 do not include the National Parks, Alaska, The Geysers, and the Salton Sea. The reason for this exclusion is to emphasize the special characteristics of these resources. The resources which are located in National Parks (Yellowstone, Mt. Lassen, and Mt. Rainier) have been permanently withdrawn from exploitation and will never be developed. The resources in Alaska were listed separately because the costs of geothermal development in Alaska are expected to be much higher than the costs in the lower 48 states. The Geysers is shown separately since it is the only known dry steam resource in the U.S.; and the Salton Sea is shown separately since its fluid chemistry is so much more hostile than the other hydrothermal resources.

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. Existing U.S. systems primarily use steam. Once-through distribution systems use a single pipe and fluid disposal is through a sewer system. In two-pipe systems, the fluid is recirculated, conserving the fluid and residual heat. Two-pipe systems cost approximately 20% more than single-pipe systems.

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. Submersible pumps are usually used to increase the flow from the wells. Other pumps are used to overcome head losses in the transmission and distribution pipes. Supplemental heating capacity is usually provided to handle peak demands. 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, reinjection wells will be required.

The geothermal district heating systems in Iceland are mostly single-pipe systems with fluid disposal to the ocean. The French geothermal district heating systems are mostly two-pipe systems; heat exchangers are used and the brine is reinjected. Since future U.S. systems will probably be predominately two-pipe systems, we based our economic analysis on a two-pipe system.

Geothermal district heating systems are capital intensive. The principal costs are initial investment costs for wells, pipes, pumps, meters, valves, and storage tanks. Operating expenses are low in comparison and consist of pumping power, sys-

tem maintenance and control, and meter reading.

Heat pumps may possibly be used to advantage in geothermal district heating systems. The French are experimenting with the use of large heat pumps. In the French experiments the heat pumps extract a greater amount of heat from the geothermal fluid, by lowering the reject temperature, than can be extracted through direct heating using only the sensible heat. The heat pumps are not used to increase the temperature of the fluid. The heat pumps do not decrease the heating costs, but they appear to substantially reduce: (2) either the geothermal fluid requirements, or (b) the amount of conventional fuels required to supplement the geothermal energy. However, since the heat pumps do not appear at this time to offer an economic advantage over direct radiant or convective heating, we did not include their potential application in this analysis.

Although we limited the scope of this analysis to space heating, the high-temperature geothermal resources can also provide process heat. Combined applications of space heating with process heating offer the potential to lower both space heating and process heating costs: (1) through economies of scale, particularly in fluid transmission, and (2) through achieving a higher system load factor. The latter, of course, would be most effective if the space heating and process heating demands were contraseasonal.

6.3 FLUID PRODUCTION AND DISPOSAL COSTS

Fluid production costs are primarily related to the cost of the producing wells, the well flow rate, the temperature, the well life, and the average annual load factor. The last four factors determine the energy production rate. Our cost analyses cover the expected range of values for these major factors of production (Table 6.3).

TABLE 6.3. Key Fluid Production Parameters

<u>Parameter</u>	<u>Expected Range</u>
Temperature	60 - 275°C
Flow Rate	110,000 - 440,000 lb/hr
Well Cost	\$400,000 - \$1,000,000
Well Life	10 - 50 years
Load Factor	10 - 100%

The costs for geothermal energy production derive mainly from the initial cost of the producing wells. Operating expenses, including well redrilling, maintenance, and pumping costs, will usually be small in proportion to the initial cost. Only when well lifetimes are extremely short will production costs be significantly affected by continuing costs; i.e., the costs for replacement wells. Our cost estimates include a gathering system to bring the flow from several wells to a central point.

6.3.1 Load Factor

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, because the costs of production are predominately fixed costs. The principal variable cost will be the cost of energy consumption for pumping. Although the load factor is determined by the end use, it is controllable to some extent by the geothermal energy supplier through the increased use of storage and supplemental heat.

6.3.2 Well Productivity and Well Cost

Energy production costs are sensitive to temperature, well flow rate, and well cost (Figure 6.3). The horizontal axis in Figure 6.3 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. Temperature, a property of the resource, is not subject to the control of the developer, except to the extent that a thermal gradient is exploited.

Well costs are mainly a function of depth. Geothermal wells currently cost on the order of \$300,000/km (\$100/ft). The depth to the convective hydrothermal reservoirs in the West is estimated to be 1 to 1.5 km in most instances. In the East, the depth to "useful" normal-gradient resources ($>60^{\circ}\text{C}$) will be 1.5 to 2 km. The well drilling costs to reach normal-gradient resources will probably be lower than the costs for hydrothermal resources because the normal-gradient resources will occur in geologic basins similar to oil and natural gas. Oil and gas wells typically cost \$150,000/km for depths of about 1.5 to 2 km. Drilling costs to reach normal-gradient resources in areas where the estimated average thermal gradient is 60°C/

FIGURE 6.3. Energy Production Costs

km (Gulf Coast region) will be about half the costs on the East Coast, where the thermal gradient is only about 30°C/km.

Although some existing geothermal wells have had flow rates near 1,000,000 lb/hr, the median flow rates are much less. Most geothermal wells for district heating will be pumped to obtain high flow rates. Our production cost estimates contain a provision to cover downhole pump capital and O&M costs and pumping power consumption. Table 6.4 shows our assumptions regarding downhole pumps.

TABLE 6.4. Downhole Pump Characteristics

Flow Rate	880 GPM (440,000 lb/hr)
Depth	500 feet
Life	7 years
Horsepower	220 HP
Efficiency	60%
Capital Cost	\$60,000
Annual O&M	15% of capital cost
Electricity Cost	
Western U.S.	\$18,000/year (30 mills/kWh)
Eastern U.S.	\$24,000/year (40 mills/kWh)

Based on these assumptions, downhole pump costs range from about 10¢/MBTU for 150°C geothermal resources to about 65¢/MBTU for 60°C resources, under private financing conditions. These costs are included in Figure 6.3.

Our assumption of downhole pump placement depth of 500 feet reflects information in the literature regarding downhole pump operation in Iceland and one of the authors' personal experience in Paris. In Iceland, the average depth of the newest wells (completed between 1970 and 1975) is 5,300 feet and the average drawdown is only about 100 feet. At this depth, the pumps are producing an average flow rate of 370,000 lb/hr, at an average temperature of 84°C. The maximum flow rate achieved was 640,000 lb/hr^(6.5). At Creil in the Paris Basin, downhole pumps are placed at a depth of 100 meters (about 300 feet). The artesian flow from the wells is about 300 GPM (150,000 lb/hr). The pumps are expected to increase the flow to 600 GPM (300,000 lb/hr).

Energy production costs are inversely related to well flow rate. At a constant temperature, the energy production from a well is proportional to the flow rate. Only the energy production costs are affected by the well flow rate; the costs for fluid transmission and distribution will not be affected.

6.3.3 Well Life

Energy production costs decrease with increasing well life. Based on past experience, economic lifetimes should exceed 10 years and may exceed 30 years. Thus, well life should have little impact on energy production costs. Geothermal wells in Iceland and New Zealand have produced from 20 to 30 years. Well life can be controlled somewhat through varying the production rates and well spacing and through well stimulation practices.

6.3.4 Disposal Costs

Disposal costs could range from negligible to in excess of the costs of fluid production. If the geothermal fluid is very pure, surface disposal or consumptive uses would entail low or nil costs. However, if deep reinjection were required, the cost of the reinjection wells could equal or exceed the cost of the production wells. The cost of disposal by reinjection depends on the same factors as the costs of fluid production. In this sense, Figure 6.3 may also be used to estimate disposal costs by reinjection, which would be additive.

6.4 FLUID TRANSMISSION COSTS

Fluid transmission costs are primarily related to the distance between the user and the well. In addition, the peak demand, the average annual load factor, and the temperature of the fluid also affect the costs. The expected range of values for these factors is shown in Table 6.5. Other factors, which are site-dependent, will not be addressed in this study; these include the terrain, cost of right-of-way, and whether pipe burial is required. The costs in this section refer to transmission costs only; the costs of energy production are not included.

TABLE 6.5. Key Transmission System Parameters

<u>Parameter</u>	<u>Expected Range</u>
Temperature	60-150°C
Pipe Diameter	12-48 in.
Distance	1-50 miles
Load Factor	10-100%

Flow rate and temperature have significant impacts on the cost of energy transmission (Figure 6.4). The flow rate refers to the peak demand. The peak demand 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, significant economies of scale are achieved with large pipes. Thus, a large market would tend to be served more economically than a small one.

Transmission costs decrease with increasing temperature because the energy content of each pound of fluid delivered increases with temperature. At a constant pipeline capacity, transmission costs decrease linearly with temperature. At a constant energy demand, transmission costs decrease nonlinearly with temperature because the relationships between pipeline diameter, cost and capacity are nonlinear as discussed above.

As with fluid production costs, the load factor also has a significant impact on transmission costs. The costs for fluid transmission derive mainly from the initial investment in the pipeline. Operating expenses, including pumping and maintenance, will usually be small. Since the principal transmission costs are fixed costs, high load factors contribute significantly to lowering the unit energy costs.

Our cost estimates are based on insulated steel pipe, which is conventionally used in these temperature ranges. New developments in pipe technology, e.g., plastic-lined, reinforced concrete, asbestos-cement, and fiberglass-epoxy, hold promise for reducing transmission costs, especially for lower-temperature water. A large program for testing new pipe designs is in progress at the Studsvik Research Center in Sweden. It is reported that "Even when limiting temperatures to 100°C, the newer pipes are calculated to give lower costs than steel pipelines of conventional design." (6.6).

FIGURE 6.4. Energy Transmission Costs

The distance of fluid transmission will be a limiting factor for geothermal district heating. Transmission distances for existing geothermal applications are short, rarely exceeding 15 km. Although oil and natural gas can be economically piped over thousands of miles, the economic limitation for geothermal fluids will probably be less than 100 miles because of the low energy content of the fluid. For instance, fuel oil contains on the order of 100 times more energy per unit volume than hot water.

6.5 DISTRICT HEATING DISTRIBUTION COSTS

The costs of district heating are dependent on many factors related to climate, community characteristics, resource conditions, financing, system design, and construction. We will examine distribution costs over the range of values (Table 6.6) expected for many of these factors. The costs in this section refer to the district heating distribution system only; transmission and production costs are not included. The district heating costs in this report refer to new construction unless otherwise stated.

TABLE 6.6 Key District Heating Parameters

<u>Parameter</u>	<u>Expected Range</u>
Fluid Temperature	60 - 150°C
Size (population)	1,000 - 50,000
Climate (heating degree-days)	1,000 - 8,000
Minimum Design Temperature	-45°C - 0°C
Population Density	2,000 - 30,000/km ²

6.5.1 Climate

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.

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 load 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 (Figure 6.5).

6.5.2 Community Characteristics

6.5.2.1 Population

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. Pipe weight and cost increase nearly linearly with diameter, while flow capacity increases with the square of the diameter. A minimum district size of 1,000 dwelling units will probably be required for economic feasibility. Second, increasing population reduces costs associated with the investment in wells up to the point at which the maximum well flow is fully utilized. This population, or multiples of this population, tend to yield local minimum cost points. Third, with increasing population, economies of scale are realized in the transmission piping as discussed previously.

6.5.2.2 Population Density

Population density is one of the most important factors affecting district heating costs, as previously shown in Figure 6.5. Increasing population density reduces district heating costs through reducing the average length of pipe run. With very high population densities, resulting from large multi-story apartment buildings, economies of scale are realized in the distribution system through the use of larger diameter pipe.

6.5.3 Distribution Temperature

Energy distribution costs are also related to the temperature of distribution. Figure 6.6 is almost identical to Figure 6.5; the only difference is that in Figure 6.6 the fluid is distributed at 60°C rather than at 90°C. Figure 6.6 is the appropriate figure to use to estimate distribution costs for the normal-gradient resources on the East Coast. Distribution at 60°C is about 10-20% more expensive than distribution at 90°C.

ENERGY DISTRIBUTION COSTS

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FIGURE 6.5. Energy Distribution Costs

FIGURE 6.6. Energy Distribution Costs

6.5.4 New Construction

District heating will be more economically attractive for new housing developments than for established areas. Routing of the water distribution lines will be more direct and construction less impeded than in established areas, leading to lower costs. The initial installed costs for both hot water heating systems and conventional heating systems within homes and commercial buildings are expected, on the average, to be nearly equal. District heating systems and conventional heating systems then should compete for new construction projects on the basis of projected energy supply costs and reliability.

6.5.5 Established Areas

The cost of installing district heating systems in established residential and commercial areas will generally be higher than in new developments. Trenching costs will be higher because existing streets and sidewalks must be dug up and replaced. Indirect routing of district heating lines around existing sewer and water lines will also increase installation costs. Based on limited data from Iceland, construction costs for district heating systems in established areas will be 10 to 30% higher than costs in new areas.

The retrofitting cost for replacing existing heating systems in residential and commercial buildings with hot water heating systems will be a deterrent to district heating in many established areas. Retrofitting is estimated to cost \$500 to \$2,000 per dwelling unit. The lower part of the cost range would apply to the conversion of an existing forced air or hot water system.

6.5.6 The Load Duration Curve

In the preceding sections the costs for energy production, transmission, distribution, and disposal were treated separately. The total cost for district heating is the sum of these four costs. These costs have similar characteristics. They are capital intensive. Fixed costs dominate. Variable costs are relatively low. The system load factor has an enormous impact on the average cost of energy.

The utilization of energy storage capacity and supplemental energy to meet peak demands provides an opportunity for system optimization. The average load factor for the distribution system is equal to the area under the load duration curve divided by the maximum potential energy distribution for the year. The geothermal energy costs related to production and transmission might be reduced by designing the

geothermal transmission and production capacity to meet less than the peak demand. In this way the load factor on the geothermal transmission and production systems can be substantially increased. The excess demand would then be met from energy storage and supplemental heat. For instance, if the average annual load factor is 33% for a system, the number of producing wells required could potentially be cut by a factor of 3 through the use of adequate storage capacity. Such large storage capacity might be provided economically by shallow, natural aquifers. Through classic system optimization techniques, a minimum-cost system could be designed which employs the optimal geothermal, storage, and supplemental heating capacities.

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

6.6 SENSITIVITY TO SELECTED ASSUMPTIONS

6.6.1 Municipal Financing

Although we assumed private financing in our reference case, it seems likely that municipal utilities will construct and operate the district heating systems at many locations. Municipal utilities have tax advantages and lower financing costs (refer to Figure 3.2). Figures 6.7-6.10 show the energy production costs, the energy transmission costs, the energy distribution costs at 90°C, and the energy distribution costs at 60°C, all under the assumption of municipal financing. Comparison with Figures 6.3-6.6 indicates that municipal financing results in about a 30% reduction in production costs, about a 10% reduction in transmission costs, and between 20% and 30% reduction in distribution costs. (The transmission cost reduction is less than the production cost reduction because the production system enjoys a depletion allowance and an intangible drilling cost write-off in addition to the investment tax credit, whereas the only tax incentive available to the transmission system is the investment tax credit. The transmission cost reduction is less than the distribution cost reduction due to the different fractions of equity financing in the two systems.) Thus, even with the National Energy Act tax incentives for the private developer (10% investment tax credit, 15% depletion allowance, and expensing of intangible drilling costs) which are taken into account in Figures 6.3-6.4, the costs under municipal financing are lower.

FIGURE 6.7. Energy Production Costs

FIGURE 6.8. Energy Transmission Costs

FIGURE 6.9. Energy Distribution Costs

FIGURE 6.10. Energy Distribution Costs

6.6.2 Well Flow Rate

Energy production costs vary inversely with well flow rate (Figure 6.11). Production costs are much more sensitive to flow rate at lower temperatures than at higher temperatures because the thermodynamic efficiency declines rapidly with temperature. Well flow rate and temperature are two of the most important resource parameters in the cost relationship. The importance of the well flow rate to production cost is that, for a constant temperature, the energy production potential from a well is proportional to flow rate. Therefore, the number of wells and the cost of the energy supply to the district heating distribution system are directly related to flow rate.

In this report, the initial well flow rate was assumed to be constant for each producing well. These flow rates are the maximum, initial flow rates. Compensation for decreases in flow rate with time is provided by replacement wells.

6.6.3 Well Cost

Other things being equal, energy production costs are directly related to the well cost (Figure 6.12). The effect of the well cost is much greater on lower quality (lower temperature and flow) resources. The cost of the well, including the pumping requirements, may be the single most important determinant of the economic viability of a geothermal resource, particularly a lower-temperature resource.

6.6.4 Downhole Pump Placement Depth

In this report, we assumed that downhole pumps would be placed at a depth of 500 feet, based on experience in Iceland and in the Paris Basin. This assumption led to downhole pump costs ranging from 10¢/MBTU for 150°C resources to 65¢/MBTU for 60°C resources. However, if it were necessary, due to excessive drawdown, to place the pumps at 1,000 feet rather than 500 feet, then the electricity requirements would double. The total costs for downhole pumps would then range from 15¢/MBTU for 150°C resources to 95¢/MBTU for 60°C resources. This hypothetical 50% increase in downhole pump costs for the East Coast normal-gradient resource could have a very negative impact on the economic viability of district heating with this resource. But if the actual drawdown is found to be comparable to the drawdown experienced in Iceland, then our 500-foot-depth assumption will be on the conservative side, and downhole pump costs will be even lower than our cost estimates.

FIGURE 6.11. Energy Production Costs As A Function of Well Flowrate

FIGURE 6.12. Energy Production Costs As A Function of Well Cost

As an alternative to lowering the pump in a well to compensate for excessive drawdown, the developer may instead try to increase the well flow rate by: (1) increasing the borehole diameter, (2) increasing the pumping rate, or (3) increasing the fracture width through various fracturing techniques. The developer will be faced with the tradeoff between the cost of one of the above options and the higher electricity requirements which would result from lowering the pump.

6.6.5 Investment Tax Credit

The National Energy Act tax incentives which are due to take effect in 1983 include a 10% investment tax credit. The current tax incentives, which are due to expire in 1983, include a 20% investment tax credit. The impact of extending the 20% tax credit indefinitely would be to lower our district heating costs by about 8%.

It has been suggested that the geothermal investment tax credit should be increased to 50%. The potential impact of a 50% investment tax credit, as compared with our reference assumption of 10%, is quite substantial. A 50% investment tax credit would lower energy production costs by about 15%, energy transmission costs by 25-35% depending upon resource temperature, and energy distribution costs by 25-40% depending upon population density. The low impact on production costs is caused by the elimination of the option to expense intangible drilling costs. Here we have assumed that there is no limitation on the total dollar value of the tax credit.

On the other hand, the National Energy Act also contains tax incentives for the individual homeowner, but these incentives are currently held to a \$2,200 maximum. Congress is considering an amendment that would raise this ceiling to 50% of outlays up to \$10,000 for geothermal equipment, for a maximum credit of \$5,000. However, this potential new ceiling is not likely to have a significant impact on the cost of district heating, mainly because the cost of retrofitting individual homes is small in comparison with the capital investment in wells and pipes. But from an institutional point of view, the impact might be significant, since any inducement that encourages the entire community to participate in a district heating venture is extremely desirable.

6.7 DISCUSSION OF RESULTS

Geothermal district heating costs were based on current state-of-the-art technology and current cost data. Technology improvements, cost reductions, and resource discoveries should be forthcoming in the geothermal field. Therefore, geothermal dis-

district heating costs will probably decline with time, leading to more widespread applications than our results would indicate.

On the other hand, institutional constraints, particularly the need to achieve, for economic reasons, nearly 100% participation in each district, may limit and slow the growth of geothermal district heating. But if the rate of increase in conventional heating prices continues as it recently has, and if the availability of conventional fuels becomes unreliable, than a shift toward geothermal district heating might be accelerated.

6.8 APPLICATION OF RESULTS TO SPECIFIC SITES

The total cost of geothermal district heating is the sum of the three components: production, transmission, and distribution. For convenience, we have included the cost of fluid disposal in the production cost. The cost of geothermal district heating at a specific site can be determined from Figures 6.3-6.6 by using the appropriate site-specific conditions. This method is applied in Section 7.0 to estimate geothermal heating costs at 157 locations throughout the country.

Appendix B illustrates the use of Figures 6.3-6.5 to determine the cost of district heating garden apartments in Reno, Nevada using the geothermal resource at Steamboat Springs, about 10 miles south of Reno. (Recall that the garden apartment represents concentrated, high-population-density applications.) We used the following assumptions for the site-specific studies:

Well Flow Rate	440,000 lb/hr
Well Life	30 years
Transmission Pipe Diameter	30 inches
Distribution Fluid Temperature	90°C

The assumptions of large transmission pipes and large demands at each location are crucial to the economic viability of geothermal district heating, if long-distance transmission is required.

CHAPTER 6.0 - REFERENCES

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7.0 COMPARATIVE COSTS AT SELECTED LOCATIONS

7.1 SUMMARY

In this section we describe the conditions under which solar and geothermal energy are competitive with conventional energy at 157 locations throughout the United States. The comparisons are made under two sets of price assumptions for conventional fuels. For convenience we will call these: (1) the low price assumption, and (2) the \$15 price assumption.

Under the low price assumption, results of the comparisons indicate that:

1. Geothermal district heating costs are lower than solar or electricity heating costs for urban centers in nearly every location, provided that the resource is nearby.
2. Solar heating costs are lower than geothermal or electricity heating costs for suburban population densities throughout most of the West and Southeast.
3. Fuel oil and natural gas heating costs are lowest in most locations -- especially locations of low solar insolation, locations too distant from geothermal resources, and locations with very short heating seasons.
4. Solar heating costs for the suburban house are generally lower than the cost of electric resistance heating. Exceptions occur in areas of low solar insolation, such as Ohio, or low electricity prices, such as the Pacific Northwest. On the average, solar heating is not competitive with fuel oil or natural gas under the low price assumption.
5. Geothermal district heating would be lowest in cost in most of the urban centers and in some suburban districts throughout the West if high-temperature hydrothermal resources were discovered near the load centers.

There are at least 6 locations where urban district heating from identified hydrothermal resources is the lowest-cost alternative. These cities are:

Boise, Idaho
Idaho Falls, Idaho
Twin Falls, Idaho
Helena, Montana
Reno, Nevada
Klamath Falls, Oregon

There are a number of other locations in the West where urban district heating from identified resources is close to being competitive with fuel oil or natural gas under the low price assumption. In New England and the North Central parts of the U.S., normal-gradient geothermal resources are nearly competitive for urban district heating with oil and natural gas under the low price assumption.

Under the \$15 price assumption, results of the comparisons are:

1. Geothermal district heating from identified high-temperature hydrothermal resources would be lowest in cost in nearly every urban center throughout the West.
2. Geothermal district heating from normal-gradient resources would be lowest in cost in nearly every urban center in the Northern half of the U.S.
3. 100% solar and solar/conventional heating would be lowest in cost for suburban districts throughout most of the country.
4. Conventional heating remains most attractive in the urban centers and in some suburban districts in the Southeastern quarter of the country (roughly the area South and East of a line running from Baltimore to Kansas City and El Paso).
5. In several locations, including both urban and suburban districts, solar, geothermal, and conventional heating are closely competitive.

7.2 INTRODUCTION

The costs of solar, geothermal, conventional and solar/conventional heating were determined at 157 locations across the United States. For each site, the nearest geothermal resource, as identified by the USGS^(7.1), was selected as a basis for comparison. In the West, a convective hydrothermal resource ($>90^{\circ}\text{C}$) was selected. In the East, a 60°C normal-gradient resource was assumed. Since new geothermal resources may be discovered nearer to each site, we determined geothermal heating costs as a function of distance using the temperature of the selected resource for reference purposes.

For the site-specific comparisons we selected two typical space heating applications which we call suburban and garden apartments. The characteristics of the suburban house are described in Appendix A. The suburban population density is assumed

to be 3,000 people/km². The characteristics of the garden apartment are also described in Appendix A. The population density for garden apartments is assumed to be 12,000 people/km². The suburban house represents low-population-density, dispersed applications, while the garden apartment represents concentrated, high-population-density applications.

Because of the sensitivity of district heating costs to population density, costs are calculated for a typical suburban population density and a typical urban (garden apartments) population density. In selecting these two district heating applications for reference, we are covering the most likely range of geothermal applications from a cost standpoint. Only very concentrated demands would be significantly lower in cost. More dispersed demands would be uneconomic in most instances. The garden apartment demand may also serve as a surrogate for mixed commercial and residential demands.

In Section 7.3 these costs are compared with the costs for solar and conventional heating at twenty-three locations (Figures 7.1 through 7.23), selected to be representative of the range of climatic and geothermal resource conditions expected throughout the U.S. It is important to emphasize "representative" since a few of the locations may have too low demand at present to support district heating. Section 7.4 presents the calculated levelized heating costs for each location in tabular form.

7.3 SITE-SPECIFIC COMPARISONS

In Figures 7.1 through 7.23* levelized heating cost is plotted versus geothermal transmission distance. Solar energy costs are shown for the optimum combined solar/conventional heating systems and for 100% solar heating. Conventional heating costs (oil, natural gas, and electrical resistance) are also shown for each location. The conventional heating costs and the solar/conventional heating costs in these figures are based on the low price assumption. In each of the locations, where no solar/conventional cost is shown, the optimum occurs at either 100% conventional heating or 100% solar heating. If the conventional cost is greater than the 100% solar cost, the optimum occurs at 100% solar; otherwise, the optimum occurs at 100% conventional.

*In Figures 7.1 through 7.23 the label "garden" refers to urban heating in the garden apartment, which we use to represent high-density applications.

The following discussion for each of the cities is based on the low price assumption for conventional fuels. Under the \$15 price assumption, geothermal energy is competitive for urban heating at nearly every location, oftentimes up to considerable distances from the geothermal resource. Figures 7.1-7.23 allow the reader to readily estimate the effect of a \$15 levelized conventional heating cost at each location. Under the \$15 price assumption solar heating is much more competitive at nearly every suburban location as discussed earlier.

In these comparisons we assumed that the geothermal fluid is transported in a 30-inch diameter pipe. For many locations the heat transport capacity of this pipe would exceed the existing heat demand at that location. However, these locations were selected to represent a range of resource and climatic conditions. Thus, the costs should be interpreted to represent the costs of meeting large heating demands under similar conditions.

Boston, MA (Figure 7.1)

Urban

Geothermal (60°C resource) district heating is lowest in cost up to a transmission distance of 2 miles. Beyond 2 miles, fuel oil is lowest in cost. Geothermal heating is competitive with natural gas up to 11 miles from the resource. Below 37 miles, geothermal is still more competitive than all-solar or all-electric heating.

Suburban

Fuel oil, natural gas and these fuels combined with solar are the lowest cost heating options for the suburban house. Geothermal at 60°C could be transported 13 miles and still be more competitive than electricity or 100% solar.

Baltimore, MD (Figure 7.2)

Urban

Fuel oil and natural gas are lowest in cost. Geothermal energy (60°C resource) could be transported for space heat up to 15 miles and still be more economic than the optimal solar/electric system.

Suburban

Fuel oil is lowest in cost, but natural gas and solar/electric are also lower in cost than geothermal. Geothermal energy could be transported up to 5 miles and

CITY: BOSTON, MA

RESOURCE: HYPOTHETICAL NORMAL GRADIENT (60°C)

FIGURE 7.1. Comparative Heating Costs for Boston, Massachusetts

FIGURE 7.2. Comparative Heating Costs for Baltimore, Maryland

remain competitive with solar energy, and up to 15 miles and remain competitive with electric heating.

Atlanta, GA (Figure 7.3)

Urban

Fuel oil and natural gas are lowest in cost. Geothermal energy (60°C resource) could be transported up to 5 miles and remain competitive with electric heating, and up to 15 miles and remain competitive with solar energy.

Suburban

Fuel oil and natural gas are lowest in cost. All-solar is lower in cost (\$21/million Btu) than geothermal. Solar/electric is \$17/million Btu and electricity is \$21/million Btu. Geothermal heating from a 60°C resource is not competitive with any other alternative for suburban heating in Atlanta.

Albuquerque, NM (Figure 7.4)

Urban

Geothermal energy (from a 273°C resource) is lowest in cost for transmission distances under 20 miles. Beyond this distance natural gas is lowest in cost. Geothermal energy could be provided from Valles Caldera, 55 miles distant, for \$13/million Btu; all other space heating alternatives are more expensive. Geothermal energy is cheaper than all-solar for transmission distances out to 70 miles.

Suburban

Solar/fuel oil, natural gas, and all-solar are lower in cost than geothermal heating. Geothermal energy is competitive with fuel oil up to 15 miles and can be transported from Valles Caldera to Albuquerque for suburban heating for \$20/million Btu.

Yuma, AZ (Figure 7.5)

Urban

Fuel oil and natural gas are lowest in cost, unless a high-temperature (182°C) geothermal resource is located within 2 miles. Expected costs from two nearby geothermal resources, Dunes and East Mesa, are both less than all-solar.

CITY: ATLANTA, GA

RESOURCE: HYPOTHETICAL NORMAL GRADIENT (60°C)

FIGURE 7.3. Comparative Heating Costs for Atlanta, Georgia

CITY: ALBUQUERQUE, NM
RESOURCE: VALLES CALDERA (273°C)

FIGURE 7.4. Comparative Heating Costs for Albuquerque, New Mexico

CITY: YUMA, AZ
 RESOURCES: EAST MESA (182°C)
 DUNES (132°C)

FIGURE 7.5. Comparative Heating Costs for Yuma, Arizona.

Suburban

Fuel oil, natural gas, and all-solar are lowest in cost. The cost of geothermal space heating in Yuma exceeds \$35/million Btu from the 182°C resource and \$38/million Btu from the 132°C resource.

Fresno, CA (Figure 7.6)

Urban

A high-temperature (227°C) geothermal resource would be lowest in cost if located within 2 miles. Beyond this distance, natural gas is lowest. The nearest identified geothermal resource, Long Valley, 80 miles away, would be competitive with solar and with electricity at that distance.

Suburban

Fuel oil and natural gas are lowest in cost. Geothermal energy could be transported up to 42 miles and be competitive with all-solar or electricity. The nearest identified geothermal resource, Long Valley, 80 miles away, is not competitive with any alternative for space heating.

Reno, NV (Figure 7.7)

Urban

Geothermal district heating from a high-temperature resource (200°C) is lowest in cost for transport distances out to 45 miles. Beyond this distance, natural gas is lowest in cost. Two geothermal resources, Steamboat Springs and Moana, are within 10 miles and appear to offer the lowest-cost space heating.

Suburban

Solar/fuel oil, solar/natural gas, solar, and natural gas options are lowest in cost. Geothermal district heating from the Steamboat Springs and Moana resources is lower in cost than fuel oil or electric space heating.

Ely, NV (Figure 7.8)

Urban

Geothermal (115°C) district heating is lowest in cost at transmission distances less than 32 miles. Beyond 32 miles, the optimal combination of solar with natural gas is lowest in cost. Geothermal is competitive with natural gas at transmission distances below 34 miles. Urban heating in Ely, Nevada from the Cherry Creek re-

CITY: FRESNO, CA
RESOURCE: LONG VALLEY CALDERA (227°C)

FIGURE 7.6. Comparative Heating Costs for Fresno, California

CITY: RENO, NV
 RESOURCES: MOANA (116°C)
 STEAMBOAT SPRINGS (200°C)

FIGURE 7.7. Comparative Heating Costs for Reno, Nevada

CITY: ELY, NV
 RESOURCE: CHERRY CREEK AREA (115°C)

FIGURE 7.8. Comparative Heating Costs for Ely, Nevada

source, located 60 miles away, is less than \$12/million Btu.

Suburban

All-solar or any of the solar combination systems is lowest in cost. Geothermal suburban heating is competitive with fuel oil and electricity at distances of 40 and 58 miles, respectively. Suburban heating from the Cherry Creek resource is more costly than the other options.

San Francisco, CA (Figure 7.9)

Urban

Natural gas heating is lowest in cost. Geothermal (144°C) urban heating is lower in cost than fuel oil up to 31 miles from the resource. It is competitive with solar and solar combined with electricity at transmission distances up to 58 miles and with electric heating up to 97 miles. Calistoga Hot Springs, located 55 miles away, could supply heat to urban areas in San Francisco for \$16/million Btu, which is more economic than solar or electric heating.

Suburban

All-solar, solar/fuel oil, natural gas, and fuel oil are lower in cost than geothermal. Geothermal suburban heating is competitive with electricity up to 41 miles. Supplying heat to suburban areas of San Francisco from Calistoga Hot Springs would cost \$25/million Btu, which is more costly than the other options.

Pueblo, CO (Figure 7.10)

Urban

Geothermal (141°C resource) district heating is lowest in cost for transmission distances less than 20 miles. Above 20 miles, natural gas is lower in cost. Geothermal urban heating costs are competitive with fuel oil, solar/electric, and solar heating costs at distances of 42, 67 and 73 miles, respectively. Urban heat can be supplied to Pueblo, Colorado from the Sand Dunes Swimming Pool resource, 75 miles away, for \$14/million Btu, which is nearly competitive with solar heating.

Suburban

For suburban heating, geothermal energy (141°C resource) is not competitive with any option except electricity at any distance. It is competitive with electricity up to 55 miles from the resource. Supplying suburban heat to Pueblo, Colorado from the Sand Dunes Swimming Pool resource would cost \$20/million Btu, which is

CITY: SAN FRANCISCO, CA
 RESOURCE: CALISTOGA HOT SPRINGS (144°C)

FIGURE 7.9. Comparative Heating Costs for San Francisco, California

CITY: PUEBLO, CO
 RESOURCE: SAND DUNES SWIMMING POOL (141°C)

FIGURE 7.10. Comparative Heating Costs for Pueblo, Colorado

more costly than the other options.

Boise, ID (Figure 7.11)

Urban

At a resource temperature of 171°C (Crane Creek-Cove Creek), geothermal urban heating is lower in cost than natural gas and fuel oil below transmission distances of 84 and 89 miles, respectively. At a resource temperature of 135°C (Roystone Hot Springs), the break-even transmission distances are reduced to 56 miles for natural gas, 60 miles for fuel oil and 85 miles for electricity. A resource at 80°C (Boise) is competitive with natural gas, fuel oil and electricity for urban heating at transmission distances of 21, 23 and 34 miles, respectively. Geothermal energy from the 80°C resource can be transmitted up to 69 miles and remain lower in cost than all-solar heat. From both the 135°C resource and the 171°C resource, geothermal energy can be transmitted up to 100 miles and remain lower in cost than all-solar heat. A lower-temperature (80°C) resource in the immediate vicinity of Boise is more economic for urban space heating than any of the other alternatives. Supplying urban heat from the Roystone resource, located 25 miles away, or from the Crane Creek-Cove Creek resource, located 55 miles from Boise, is also more economical than the other options.

Suburban

Combinations of solar and conventional systems appear lowest in cost unless high-temperature (171°C) geothermal resources are located within 10 miles. Geothermal suburban heating is competitive with all-solar up to 29 miles from an 80°C resource, up to 75 miles from a 135°C resource, and beyond 100 miles from a 171°C resource. Supplying suburban heat to Boise from the Crane Creek-Cove Creek resource, located 55 miles away, is more economical (\$17/million Btu) than all-solar or all-electric heating, but it is not competitive with the other options. Supplying suburban heat to Boise from Roystone Hot Springs, located 25 miles away, is more economical (\$16/million Btu) than all-solar or all-electric but is not competitive with the other options. Supplying Boise with suburban heat from the Boise resource is more economical (\$14/million Btu) than all-solar, electric, and fuel oil heating.

FIGURE 7.11. Comparative Heating Costs for Boise, Idaho

Twin Falls, ID (Figure 7.12)

Urban

Geothermal heating from the Banbury resource (117°C and 20 miles away) is lowest in cost. At transmission distances of 61 to 65 miles, geothermal urban heating is competitive with natural gas and fuel oil. Geothermal is competitive with all-solar beyond a transmission distance of 100 miles and with electricity up to 91 miles.

Suburban

Solar combined with either fuel oil or natural gas is lowest in cost. Transmitting geothermal fluid from the Banbury area 20 miles to Twin Falls for suburban heating is more economical (\$15/million Btu) than using all-solar or electric heating. Geothermal is less economical than the other options.

Klamath Falls, OR (Figure 7.13)

Urban

Geothermal heating from the 111°C Klamath Falls resource is lowest in cost. Many residences in Klamath Falls are currently being heated economically with geothermal energy. However, heat is supplied by wells connected directly to individual residences and not through a district heating system.

Suburban

Space heating with conventional energy, combinations of solar and conventional energy, and geothermal district heating are all closely competitive. All-solar is uncompetitive. The current system of a few residences sharing a common geothermal well may be lower in cost than district heating for suburban population densities.

Seattle, WA (Figure 7.14)

Seattle is characterized by low electricity rates and low solar insolation. Electricity is lowest in cost for both urban and suburban heating. Urban heat can be supplied to Seattle from the Gamma Hot Springs resource (165°C), located 70 miles away, for \$14/million Btu; however, this is uncompetitive with conventional fuels. Solar heating is uncompetitive in this climate.

FIGURE 7.13. Comparative Heating Costs for Klamath Falls, Oregon

FIGURE 7.12. Comparative Heating Costs for Twin Falls, Idaho

CITY: SEATTLE, WA
RESOURCE: GAMMA HOT SPRINGS (165°C)

FIGURE 7.14. Comparative Heating Costs for Seattle, Washington

Helena, MT (Figure 7.15)

Urban

Geothermal urban heating from the Marysville resource (122°C, 5 miles away) is lowest in cost. Natural gas heating is slightly less expensive than geothermal heat supplied from the Broadwater resource at 118°C, 15 miles from Helena. Geothermal heating is less expensive than fuel oil, electricity or all-solar.

Suburban

Solar/fuel oil, fuel oil, and natural gas are lowest in cost. However, geothermal district heating from the Marysville resource is less expensive than electric, all-solar and solar/electric heating.

Phoenix, AZ (Figure 7.16)

Urban

Geothermal urban heating from a 165°C resource is lowest in cost for transmission distances of 6 miles or less. Beyond 6 miles, natural gas is the cheapest alternative, with fuel oil being only slightly more expensive. Space heat from the Power Ranches, Inc. Wells (165°C, 25 miles away) could be supplied to urban areas in Phoenix for about \$15/million Btu, which is cheaper than all-solar or electric heating.

Suburban

Natural gas, fuel oil, and all-solar are lowest in cost. Space heat from the Power Ranches, Inc. Wells could be supplied to suburban areas in Phoenix for about \$27/million Btu, which is cheaper than electricity.

Sacramento, CA (Figure 7.17)

Urban

Geothermal urban heating from a 144°C resource is lowest in cost for transmission distances of 1 mile or less. Beyond 1 mile, natural gas is the cheapest alternative. Space heat from Wilbur Springs (144°C, 60 miles away) could be supplied to urban areas in Sacramento for about \$17/million Btu, which is cheaper than all-solar heating, but more expensive than conventional fuels.

Suburban

Geothermal suburban heating at \$26/million Btu is the most expensive choice;

CITY: HELENA, MT
 RESOURCES: MARYSVILLE TEST WELL (122°C)
 BROADWATER HOT SPRINGS (118°C)

FIGURE 7.15. Comparative Heating Costs for Helena, Montana

CITY: PHOENIX, AZ
RESOURCE: POWER RANCHES, INC. WELLS (165°C)

FIGURE 7.16. Comparative Heating Costs for Phoenix, Arizona

CITY: SACRAMENTO, CA
RESOURCE: WILBUR SPRINGS (144°C)

FIGURE 7.17. Comparative Heating Costs for Sacramento, California

natural gas, fuel oil, electricity, and all-solar heating are lower in cost than geothermal.

Bellingham, WA (Figure 7.18)

Urban

Bellingham, like Seattle, has low electricity rates and low insolation. Electricity is lowest in cost. Urban heat from Baker Hot Springs (134°C, 35 miles away) can be supplied to Bellingham for about \$13/million Btu, which is competitive with fuel oil and natural gas, but not with electricity. Solar heating is uncompetitive in this climate.

Suburban

Geothermal suburban heat (at about \$20/million Btu) is more expensive than all the alternatives except solar.

Riverside, CA (Figure 7.19)

Urban

Natural gas is lowest in cost. Space heat from Arrowhead Hot Springs (132°C, 15 miles away) could be supplied to urban areas in Riverside for about \$14/million Btu, which is cheaper than all-solar or electric heating, but more expensive than fuel oil.

Suburban

Geothermal suburban heating (at about \$25/million Btu) is more expensive than all of the options except electricity. Fuel oil and natural gas are lower in cost than solar.

Portland, OR (Figure 7.20)

Urban

Geothermal urban heating from a 122°C resource is lowest in cost for transmission distances of 39 miles or less. Beyond 39 miles, fuel oil is the cheapest alternative. Space heat from the Mount Hood Area (122°C, 45 miles away) could be supplied to urban areas in Portland for about \$13/million Btu, which is less expensive than all of the alternatives except fuel oil.

CITY: BELLINGHAM, WA
RESOURCE: BAKER HOT SPRINGS (134°C)

FIGURE 7.18. Comparative Heating Costs for Bellingham, Washington

FIGURE 7.19. Comparative Heating Costs for Riverside, California

FIGURE 7.20. Comparative Heating Costs for Portland, Oregon

Suburban

Geothermal suburban heating (at about \$20/million Btu) is more expensive than all of the options except solar.

Idaho Falls, ID (Figure 7.21)

Urban

Geothermal urban heating from the Newdale Area (100°C, 35 miles away) is the lowest cost option in Idaho Falls (\$11.50/million Btu).

Suburban

For suburban areas in Idaho Falls, geothermal is the most expensive option (\$17/million Btu). Solar/natural gas and solar/fuel oil are lowest in cost.

Salt Lake City, UT (Figure 7.22)

Urban

Natural gas is lowest in cost. Space heat from Abraham Hot Springs (97°C, 90 miles away) could be supplied to urban areas in Salt Lake City for about \$21.50/million Btu, which is cheaper than all-solar or electric heating.

Suburban

Geothermal suburban heat is uncompetitive with all of the alternatives in Salt Lake City. Fuel oil and natural gas are lowest in cost.

Little Rock, AR (Figure 7.23)

Geothermal and solar heating are uncompetitive with natural gas and fuel oil in both urban and suburban areas in Little Rock.

7.4 LEVELIZED HEATING COSTS

Levelized heating costs using solar, geothermal, or conventional energy, which were calculated according to the methodology discussed in Chapter 3.0, are presented in Tables 7.1 through 7.5 for 157 locations across the U.S. All costs are in \$/million Btu of heat delivered.

Table 7.1 presents levelized costs of 100% solar heating (no backup) for the suburban house and the garden apartment. Also shown are the levelized costs of heating with electricity, fuel oil and natural gas. From Table 7.1 it can be seen that

CITY: IDAHO FALLS, ID
 RESOURCE: NEWDALE AREA (100°C)

FIGURE 7.21. Comparative Heating Costs for Idaho Falls, Idaho

FIGURE 7.22. Comparative Heating Costs for Salt Lake City, Utah

CITY: LITTLE ROCK, AR
 RESOURCE: HOT SPRINGS (64°C)

FIGURE 7.23. Comparative Heating Costs for Little Rock, Arkansas

TABLE 7.1. Levelized Heating Costs (\$/Million Btu) for 100% Solar and 100% Conventional

City	Solar Suburban	Solar Urban	Electricity	Fuel Oil	Natural Gas
Annette, AK	31.26	35.84	41.81	11.42	7.25
Bethel, AK	26.24	28.63	41.81	11.42	7.25
Fairbanks, AK	46.20	49.80	41.81	11.42	7.25
Matanuska, AK	44.18	48.50	41.81	11.42	7.25
Birmingham, AL	23.29	31.63	23.33	11.52	9.39
Fort Smith, AR	24.39	31.87	21.15	11.52	6.20
Little Rock, AR	25.21	33.13	23.06	11.52	6.20
Page, AZ	10.23	12.95	31.09	11.68	11.00
Phoenix, AZ	15.26	25.91	32.63	11.68	11.00
Tucson, AZ	14.27	23.22	29.10	11.68	11.00
Yuma, AZ	17.38	34.18	31.09	11.68	11.00
Davis, CA	27.41	37.99	24.17	11.93	7.70
Fresno, CA	23.63	32.73	23.72	11.96	7.70
Inyokern, CA	12.58	19.05	32.42	12.34	7.70
Los Angeles, CA	13.27	21.74	28.95	12.34	7.70
Pasadena, CA	14.61	24.19	32.42	12.34	7.70
Riverside, CA	13.47	21.62	29.85	12.34	7.70
Sacramento, CA	23.44	31.82	13.47	12.34	7.70
San Diego, CA	14.88	25.62	28.17	12.34	7.70
San Francisco, CA	11.75	16.43	22.91	12.34	7.70
San Jose, CA	20.53	29.62	23.72	12.34	7.70
Santa Maria, CA	10.19	14.87	24.17	12.34	7.70
Boulder, CO	14.28	17.53	22.42	9.79	8.07
Denver, CO	10.60	13.10	22.42	9.79	8.07
Grand Junction, CO	13.14	16.17	22.42	9.79	8.07
Grand Lake, CO	9.92	11.35	22.42	9.79	8.07
Pueblo, CO	10.92	13.74	18.34	10.49	8.07
Hartford, CT	20.43	24.11	28.25	12.92	18.25
Washington, D.C.	28.37	35.17	19.86	12.44	13.89

TABLE 7.1. (Continued)

City	Solar Suburban	Solar Urban	Electricity	Fuel Oil	Natural Gas
Apalachicola, FL	17.72	31.35	25.63	13.88	14.00
Gainesville, FL	18.84	35.56	25.21	13.88	14.00
Jacksonville, FL	19.59	34.03	27.51	13.88	14.00
Pensacola, FL	21.01	34.07	24.97	13.88	14.00
Tallahassee, FL	17.53	29.13	24.68	13.88	14.00
Tampa, FL	17.80	40.25	24.68	13.88	14.00
Atlanta, GA	20.85	27.98	21.29	11.58	9.57
Griffin, GA	19.51	26.95	24.89	11.58	9.57
Macon, GA	19.71	28.85	21.29	11.58	9.57
Savannah, GA	20.28	30.84	26.71	11.58	9.57
Boise, ID	22.39	26.66	17.15	13.94	13.55
Idaho Falls, ID ^(a)	15.92	18.73	17.15	13.94	13.55
Pocatello, ID	15.92	18.73	17.15	13.94	13.55
Twin Falls, ID	22.25	26.19	17.15	13.94	13.55
Chicago, IL	25.38	29.86	22.38	12.06	9.57
Lemont, IL	25.79	30.32	21.33	11.93	9.57
Peoria, IL	27.81	32.63	22.46	11.39	9.57
Fort Wayne, IN	28.77	33.65	22.77	12.31	8.71
Indianapolis, IN	35.06	41.35	20.51	12.31	8.71
Ames, IA	21.30	24.87	26.61	12.31	8.19
Des Moines, IA	24.96	29.04	21.52	11.29	8.19
Dodge City, KA	12.88	16.19	25.26	11.13	6.42
Manhattan, KA	20.99	25.49	20.90	11.42	6.42
Wichita, KA	17.65	22.00	20.80	11.42	6.42
Lexington, KY	22.86	28.07	19.98	11.87	7.77
Louisville, KY	29.78	36.27	19.98	10.37	7.77
Lake Charles, LA	20.99	34.96	17.47	11.10	8.19
New Orleans, LA	26.74	44.22	17.51	11.04	8.19
Shreveport, LA	23.45	34.07	16.06	11.10	8.19

TABLE 7.1. (Continued)

<u>City</u>	<u>Solar Suburban</u>	<u>Solar Urban</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Caribou, ME	20.96	23.53	26.63	11.58	21.78
Portland, ME	18.32	21.33	22.59	11.58	21.78
Annapolis, MD	24.92	30.67	28.87	12.19	13.37
Baltimore, MD	24.15	29.58	28.87	12.19	13.37
Silver Hill, MD	24.35	30.41	28.01	12.44	13.37
Amherst, MA	38.42	44.29	32.71	12.60	17.31
Blue Hill, MA	31.68	37.42	32.81	12.82	17.31
Boston, MA	25.08	29.37	32.71	12.60	17.31
Lynn, MA	39.86	46.80	27.41	12.82	17.31
Natick, MA	24.88	29.28	32.81	12.82	17.31
Detroit, MI	35.98	41.66	21.29	12.15	9.39
E. Lansing, MI	37.33	42.82	19.88	12.15	9.39
Lansing, MI	32.48	37.38	19.88	12.15	9.39
Sault St. Marie, MI	23.61	26.62	16.16	12.15	9.39
Duluth, MN	23.61	26.43	27.41	11.83	9.09
Minneapolis-St. Paul, MN	28.00	31.76	30.00	12.15	9.09
St. Cloud, MN	18.02	20.53	29.18	12.15	9.09
Jackson, MS	23.96	34.27	25.11	9.47	8.67
Columbia, MO	22.66	27.54	26.18	11.58	8.82
Kansas City, MO	22.94	27.77	26.41	11.58	8.82
St. Louis, MO	25.92	31.62	41.97	11.58	8.82
Springfield, MO	24.33	29.96	24.82	11.58	8.82
Billings, MT	15.54	18.23	17.82	10.81	7.13
Glasgow, MT	14.00	16.09	17.82	10.81	7.13
Great Falls, MT	15.78	18.36	19.30	10.56	7.13
Helena, MT ^(b)	15.78	18.36	19.30	10.56	7.13
Summit, MT	18.21	27.91	18.20	10.79	7.29
Lincoln, NB	18.95	22.69	43.12	11.58	7.40
N. Omaha, NB	16.60	19.67	36.18	11.26	7.40

TABLE 7.1. (Continued)

<u>City</u>	<u>Solar Suburban</u>	<u>Solar Urban</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Ely, NV	9.51	11.39	17.25	15.69	9.20
Las Vegas, NV	13.45	19.43	19.34	15.69	9.20
Reno, NV	10.29	12.76	28.42	15.69	9.20
Atlantic City, NJ	20.07	24.83	30.61	12.79	14.49
Trenton, NJ	22.34	27.26	32.55	12.79	14.49
Albuquerque, NM	11.06	14.56	31.01	11.07	8.52
Albany, NY	29.08	33.58	22.75	12.54	13.85
Binghamton, NY	32.56	37.24	25.87	12.54	13.85
Ithaca, NY	41.32	47.20	25.87	13.08	13.85
New York, NY	39.96	47.95	45.19	13.08	13.85
Rochester, NY	31.21	36.07	25.87	12.54	13.85
Schnectady, NY	38.27	43.94	22.75	12.54	13.85
Syracuse, NY	38.04	43.79	22.75	12.54	13.85

TABLE 7.1. (Continued)

<u>City</u>	<u>Solar Suburban</u>	<u>Solar Urban</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Asheville, NC	17.57	22.32	27.66	12.34	11.98
Cape Hatteras, NC	16.54	23.32	22.92	12.34	11.98
Charlotte, NC	19.10	25.56	22.92	12.86	11.98
Greensboro, NC	21.09	27.02	22.92	12.86	11.98
Greenville-Spartanburg, NC	20.26	27.11	30.04	12.34	11.98
Raleigh, NC	17.63	23.27	27.66	12.34	11.98
Raleigh-Durham, NC	19.91	26.06	22.92	12.34	11.98
Bismark, ND	16.55	18.87	27.43	11.77	8.60
Fargo, ND	25.44	28.57	24.89	11.80	8.60
Cleveland, OH	42.10	48.83	29.57	12.44	9.46
Columbus, OH	37.05	43.55	25.79	11.80	9.46
Dayton, OH	27.65	32.80	25.79	12.15	9.46
Put-In-Bay, OH	41.65	48.54	29.57	12.44	9.46
Oklahoma City, OK	15.79	20.79	20.37	11.42	7.36
Stillwater, OK	19.83	25.78	23.63	11.42	7.36
Tulsa, OK	21.37	27.57	23.63	11.42	7.36
Astoria, OR	31.21	37.20	17.52	11.93	13.97
Corvallis, OR	44.39	53.06	17.52	11.93	13.97
Klamath Falls, OR(c)	36.93	44.25	17.52	11.96	13.97
Medford, OR	36.93	44.25	17.52	11.96	13.97
Portland, OR	43.21	51.77	17.52	11.96	13.97
Philadelphia, PA	23.60	28.80	25.38	12.63	10.85
Pittsburg, PA	27.56	33.01	28.54	13.11	10.85
State College, PA	36.19	42.13	20.39	12.63	10.85
Newport, RI	21.33	25.45	27.70	12.60	17.16
Charleston, SC	19.34	29.19	27.90	12.86	11.30
Rapid City, SD	12.53	14.85	24.23	11.20	7.81
Chattanooga, TN	24.34	31.49	16.76	11.29	7.55
Memphis, TN	24.76	32.55	15.79	10.91	7.55
Nashville, TN	31.28	39.55	15.79	11.13	7.55
Oak Ridge, TN	30.15	37.73	14.82	11.29	7.55

TABLE 7.1. (Continued)

<u>City</u>	<u>Solar Suburban</u>	<u>Solar Urban</u>	<u>Electricity</u>	<u>Fuel Oil</u>	<u>Natural Gas</u>
Abilene, TX	16.36	23.38	24.48	11.10	10.02
Amarillo, TX	12.34	16.16	23.28	11.10	10.02
Big Spring, TX	16.73	23.90	21.76	11.10	10.02
Brownsville, TX	21.76	49.69	29.40	11.10	10.02
Corpus Christi, TX	22.48	43.97	25.89	11.10	10.02
Dallas, TX	21.06	30.47	20.96	11.10	10.02
El Paso, TX	12.85	18.67	29.55	11.10	10.02
Fort Worth, TX	17.90	25.93	21.76	11.10	10.02
Houston, TX	23.04	38.21	20.92	11.10	10.02
Midland, TX	15.78	22.67	20.68	11.10	10.02
Port Arthur, TX	24.16	39.11	23.43	11.10	10.02
San Antonio, TX	18.75	31.02	26.39	11.10	10.02
Salt Lake City, UT	20.61	24.53	23.06	10.59	6.57
Mt. Weather, VA	20.55	24.64	29.38	12.57	12.69
Norfolk, VA	20.81	27.20	29.38	12.57	12.69
Richmond, VA	23.25	29.46	29.38	12.57	12.69
Bellingham, WA ^(d)	55.77	67.23	6.53	12.34	12.80
Prosser, WA	27.26	32.38	9.26	12.34	12.80
Pullman, WA	23.84	27.83	10.51	12.34	12.80
Richland, WA	45.80	54.64	9.61	12.34	12.80
Seattle, WA	55.77	67.23	6.53	12.34	12.80
Spokane, WA	27.07	31.34	10.47	12.34	12.80
Green Bay, WI	28.72	32.59	23.80	11.80	10.44
Madison, WI	23.83	27.31	20.53	10.88	10.44
Milwaukee, WI	27.45	31.46	21.62	11.80	10.44
Parkersburg, WV	37.66	45.26	27.64	11.26	8.97
Lander, WY	9.73	11.61	16.71	11.93	7.02
Laramie, WY	10.47	12.24	16.71	11.93	7.02

(a) Data for Pocatello used

(b) Data for Great Falls used

(c) Data for Medford used

(d) Data for Seattle used

for a given location the cost of solar heating the suburban house is lower than the cost of heating the garden apartment. Solar heating costs for the suburban house are lower than the electric heating cost in most locations. Exceptions occur in areas of low solar insolation, such as Ohio, and/or areas with low electric rates, such as the Pacific Northwest. Of the 157 cities analyzed, solar heating the suburban house was more economic than natural gas heating under the low price assumption in only three locations: Page, Arizona, Ely, Nevada and Caribou, Maine. High solar insolation in Page and Ely and high natural gas costs in Maine cause solar heating to be more economic in these locations. Solar heating is competitive with fuel oil heating for the suburban house only in areas of high solar insolation in the Southwest.

Solar energy is competitive with electricity for heating the garden apartment in Southwestern states where solar insolation is high and in localized areas in the East and Midwest where electricity prices are high. Solar heating is competitive with fuel oil heating for the garden apartment in three of the 157 locations: Ely and Reno, Nevada and Lander, Wyoming. Solar heating is not competitive with natural gas heating for the garden apartment at any of the 157 locations.

Table 7.2 lists the optimal cost of a solar heating system with a conventional energy backup for the suburban house and the garden apartment. Listed in parentheses is the annual solar load fraction at the optimum. In all cases the suburban heating cost is lower than the garden apartment heating cost. At 14 locations, primarily in Southern California, Arizona, New Mexico and Nevada, the optimum occurs at 100% solar heating for the suburban house with electric backup. The optimum occurs at 100% solar heating for the garden apartment with electric backup in only four locations: Page, Arizona, Inyokern and Santa Maria, California, and Albuquerque, New Mexico. In no case did the optimum occur at 100% solar for systems with fuel oil or natural gas backup. In most cases, for these two fuels the optimum occurs at a solar load fraction of zero. That is, in these cases it is uneconomical for solar to supply any part of the load.

In 92% of the cities analyzed, solar/electric heating is more economic than electric heat for suburban houses, and in 77% of the cities it is more economic than electricity alone for heating the garden apartment. Solar with fuel oil backup is more economic for suburban heating at about one-third of the sites analyzed. Solar/fuel oil heating is less expensive than fuel oil alone for heating the garden apartment

TABLE 7.2. Optimal System Levelized Heating Costs (\$/Million Btu) and Solar Load Fractions^(a)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Annette, AK	23.66(.745)	26.01(.716)	11.42(0)	11.42(0)	7.25(0)	7.25(0)
Bethel, AK	21.02(.783)	22.34(.765)	10.46(.452)	11.24(.434)	7.25(0)	7.25(0)
Fairbanks, AK	25.40(.647)	26.55(.632)	11.16(.354)	11.42(0)	7.25(0)	7.25(0)
Matanuska, AK	25.55(.657)	27.05(.638)	11.42(0)	11.42(0)	7.25(0)	7.25(0)
Birmingham, AL	18.22(.709)	23.21(.642)	11.52(0)	11.52(0)	9.39(0)	9.39(0)
Fort Smith, AR	17.54(.657)	21.15(0)	11.52(0)	11.52(0)	6.20(0)	6.20(0)
Little Rock, AR	18.46(.672)	22.81(.612)	11.52(0)	11.52(0)	6.20(0)	6.20(0)
Page, AZ	10.23(1.00)	12.95(1.00)	9.08(.781)	11.20(.737)	8.93(.763)	11.00(0)
Phoenix, AZ	15.26(1.00)	25.81(.959)	11.68(0)	11.68(0)	11.00(0)	11.00(0)
Tucson, AZ	14.27(1.00)	23.11(.953)	11.68(0)	11.68(0)	11.00(0)	11.00(0)
Yuma, AZ	17.38(1.00)	33.60(.899)	11.68(0)	11.68(0)	11.00(0)	11.00(0)
Davis, CA	19.41(.674)	24.17(0)	11.93(0)	11.93(0)	7.70(0)	7.70(0)
Fresno, CA	18.14(.715)	23.50(.648)	11.96(0)	11.96(0)	7.70(0)	7.70(0)
Inyokern, CA	12.58(1.00)	19.05(1.00)	11.67(.809)	12.34(0)	7.70(0)	7.70(0)
Los Angeles, CA	13.27(1.00)	21.73(.986)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
Pasadena, CA	14.61(1.00)	24.15(.974)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
Riverside, CA	13.47(1.00)	21.61(.986)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
Sacramento, CA	13.47(0)	13.47(0)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
San Diego, CA	14.88(1.00)	25.40(.933)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
San Francisco, CA	11.75(1.00)	16.43(.927)	10.79(.804)	12.34(0)	7.70(0)	7.70(0)
San Jose, CA	17.42(.771)	23.53(.697)	12.34(0)	12.34(0)	7.70(0)	7.70(0)
Santa Maria, CA	10.19(1.00)	14.87(1.00)	9.90(.887)	12.34(0)	7.70(0)	7.70(0)
Boulder, CO	13.14(.840)	15.62(.799)	9.77(.591)	9.79(0)	8.07(0)	8.07(0)
Denver, CO	10.54(.963)	12.87(.922)	8.65(.701)	9.79(0)	8.07(0)	8.07(0)
Grand Junction, CO	12.44(.872)	14.88(.831)	9.45(.621)	9.79(0)	8.07(0)	8.07(0)
Grand Lake, CO	9.75(.936)	11.03(.912)	7.58(.686)	8.55(.661)	7.00(.628)	7.92(.603)
Pueblo, CO	10.57(.897)	12.99(.852)	9.13(.720)	10.49(0)	8.08(0)	8.07(0)
Hartford, CT	17.04(.772)	19.37(.737)	12.05(.548)	12.92(0)	14.18(.647)	16.15(.611)
Washington, D.C.	17.15(.586)	19.86(0)	12.44(0)	12.44(0)	13.89(0)	13.89(0)

TABLE 7.2. (Continued)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Apalachicola, FL	17.58(.943)	25.63(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Gainesville, FL	18.60(.928)	25.21(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Jacksonville, FL	19.16(.906)	27.51(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Pensacola, FL	19.29(.818)	24.97(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Tallahassee, FL	17.14(.907)	24.68(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Tampa, FL	17.80(1.00)	24.68(0)	13.88(0)	13.88(0)	14.00(0)	14.00(0)
Atlanta, GA	16.68(.718)	21.14(.654)	11.58(0)	11.58(0)	9.57(0)	9.57(0)
Griffin, GA	17.22(.795)	22.44(.726)	11.58(0)	11.58(0)	9.57(0)	9.57(0)
Macon, GA	17.13(.765)	21.29(0)	11.58(0)	11.58(0)	9.57(0)	9.57(0)
Savannah, GA	18.75(.833)	26.65(.739)	11.58(0)	11.58(0)	9.57(0)	9.57(0)
Boise, ID	13.76(.614)	15.82(.580)	12.44(.561)	13.94(0)	12.27(.553)	13.55(0)
Idaho Falls, ID ^(b)	12.06(.708)	13.77(.676)	11.03(.650)	12.64(.619)	10.89(.642)	12.49(.611)
Pocatello, ID	12.06(.708)	13.77(.676)	11.03(.650)	12.64(.619)	10.89(.642)	12.49(.611)
Twin Falls, ID	13.71(.611)	15.60(.579)	12.37(.557)	13.94(.524)	12.20(.549)	13.55(0)
Chicago, IL	16.82(.640)	18.99(.604)	12.06(0)	12.06(0)	9.57(0)	9.57(0)
Lemont, IL	16.51(.622)	18.64(.587)	11.93(0)	11.93(0)	9.57(0)	9.57(0)
Peoria, IL	17.14(.617)	19.28(.583)	11.39(0)	11.39(0)	9.57(0)	9.57(0)
Fort Wayne, IN	17.35(.612)	19.46(.579)	12.31(0)	12.31(0)	8.71(0)	8.71(0)
Indianapolis, IN	17.62(.534)	19.88(.499)	12.31(0)	12.31(0)	8.71(0)	8.71(0)
Ames, IA	16.78(.739)	18.87(.706)	11.69(.522)	12.31(0)	8.19(0)	8.19(0)
Des Moines, IA	16.05(.634)	17.98(.602)	11.29(0)	11.29(0)	8.19(0)	8.19(0)
Dodge City, KA	12.65(.927)	15.53(.881)	10.08(.676)	11.13(0)	6.42(0)	6.42(0)
Manhattan, KA	15.46(.685)	17.99(.644)	11.42(0)	11.42(0)	6.42(0)	6.42(0)
Wichita, KA	14.58(.748)	17.43(.702)	11.42(0)	11.42(0)	6.42(0)	6.42(0)
Lexington, KY	15.61(.651)	18.33(.608)	11.87(0)	11.87(0)	7.77(0)	7.77(0)
Louisville, KY	17.16(.572)	19.92(.529)	10.37(0)	10.37(0)	7.77(0)	7.77(0)

TABLE 7.2. (Continued)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Lake Charles, LA	17.47(0)	17.47(0)	11.10(0)	11.10(0)	8.19(0)	8.19(0)
New Orleans, LA	17.51(0)	17.51(0)	11.04(0)	11.04(0)	8.19(0)	8.19(0)
Shreveport, LA	16.06(0)	16.06(0)	11.10(0)	11.10(0)	8.19(0)	8.19(0)
Caribou, ME	16.03(.734)	17.47(.710)	10.55(.508)	11.58(0)	14.61(.679)	15.94(.655)
Portland, ME	14.49(.738)	16.32(.707)	10.69(.550)	11.58(0)	14.27(.728)	16.08(.697)
Anapolis, MD	19.30(.725)	22.55(.680)	12.19(0)	12.19(0)	13.37(0)	13.37(0)
Baltimore, MD	18.99(.734)	22.13(.690)	12.19(0)	12.19(0)	13.37(0)	13.37(0)
Silver Hill, MD	19.04(.727)	22.53(.679)	12.44(0)	12.44(0)	13.37(0)	13.37(0)
Amherst, MA	22.96(.627)	25.24(.596)	12.60(0)	12.60(0)	16.10(.465)	17.31(0)
Blue Hill, MA	22.07(.681)	24.79(.644)	12.82(0)	12.82(0)	15.93(.509)	17.31(0)
Boston, MA	19.80(.747)	22.24(.713)	12.48(.484)	12.60(0)	14.69(.571)	16.60(.537)
Lynn, MA	21.43(.574)	23.90(.540)	12.82(0)	12.82(0)	16.58(.457)	17.31(0)
Natick, MA	19.76(.751)	22.28(.716)	12.61(.493)	12.82(0)	14.69(.575)	16.67(.540)
Detroit, MI	17.75(.537)	19.72(.506)	12.15(0)	12.15(0)	9.39(0)	9.39(0)
E. Lansing, MI	17.11(.509)	18.90(.480)	12.15(0)	12.15(0)	9.39(0)	9.39(0)
Lansing, MI	16.61(.541)	18.41(.511)	12.15(0)	12.15(0)	9.39(0)	9.39(0)
Sault Ste. Marie, MI	12.97(.571)	14.24(.547)	11.11(.497)	12.15(0)	9.39(0)	9.39(0)
Duluth, MN	16.95(.708)	18.40(.684)	10.91(.486)	11.83(0)	9.09(0)	9.09(0)
Minneapolis-St. Paul, MN	19.30(.686)	21.09(.660)	11.90(.449)	12.15(0)	9.09(0)	9.09(0)
St. Cloud, MN	15.68(.810)	17.37(.783)	10.64(.562)	11.87(.535)	9.09(0)	9.09(0)
Jackson, MS	19.55(.732)	25.11(0)	9.47(0)	9.47(0)	8.67(0)	8.67(0)
Columbia, MO	17.49(.724)	20.29(.683)	11.58(0)	11.58(0)	8.82(0)	8.82(0)
Kansas City, MO	17.65(.722)	20.40(.682)	11.58(0)	11.58(0)	8.82(0)	8.82(0)
St. Louis, MO	22.45(.813)	26.08(.770)	11.58(0)	11.58(0)	8.82(0)	8.82(0)
Springfield, MO	16.33(.701)	19.18(.665)	11.38(.529)	11.58(0)	8.82(0)	8.82(0)
Billings, MT	12.26(.725)	13.97(.693)	9.88(.581)	10.81(0)	7.13(0)	7.13(0)
Glasgow, MT	11.38(.751)	12.75(.724)	9.18(.608)	10.36(.581)	7.13(0)	7.13(0)
Great Falls, MT	12.58(.740)	14.20(.710)	9.63(.569)	10.56(0)	7.13(0)	7.13(0)
Helena, MT(c)	12.58(.740)	14.20(.710)	9.63(.569)	10.56(0)	7.13(0)	7.13(0)
Summit, MT	12.15(.675)	14.91(.565)	9.29(.541)	10.56(0)	7.13(0)	7.13(0)

TABLE 7.2. (Continued)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Lincoln, NB	18.42(.920)	21.49(.882)	11.24(.545)	11.58(0)	7.40(0)	7.40(0)
N. Omaha, NB	16.09(.914)	18.62(.879)	10.51(.573)	11.26(0)	7.40(0)	7.40(0)
Ely, NV	9.20(.899)	10.81(.866)	9.02(.870)	10.58(.837)	7.68(.704)	9.03(.671)
Las Vegas, NV	13.07(.895)	18.18(.819)	12.57(.830)	15.69(0)	9.20(0)	9.20(0)
Reno, NV	10.29(1.00)	12.75(.996)	9.65(.855)	11.67(.816)	8.23(.693)	9.20(0)
Atlantic City, NJ	17.73(.813)	21.01(.768)	12.50(.563)	12.79(0)	13.21(.599)	14.49(0)
Trenton, NJ	19.07(.791)	27.26(.749)	12.75(.528)	12.79(0)	13.52(.563)	14.49(0)
Albuquerque, NM	11.06(1.00)	14.56(1.00)	9.71(.756)	11.07(0)	8.52(0)	8.52(0)
Albany, NY	17.03(.610)	18.91(.580)	12.35(.457)	12.54(0)	13.04(.483)	13.85(0)
Binghampton, NY	18.92(.610)	20.78(.582)	12.54(0)	12.54(0)	13.38(.451)	13.85(0)
Ithaca, NY	20.42(.550)	22.33(.521)	13.08(0)	13.08(0)	13.85(0)	13.85(0)
New York, NY	28.64(.702)	32.33(.661)	13.08(0)	13.08(0)	13.85(0)	13.85(0)
Rochester, NY	18.86(.622)	20.89(.591)	12.54(0)	12.54(0)	13.45(.460)	13.85(0)
Schnectady, NY	19.14(.527)	21.06(.496)	12.54(0)	12.54(0)	13.85(0)	13.85(0)
Syracuse, NY	18.77(.536)	20.71(.506)	12.54(0)	12.54(0)	13.85(0)	13.85(0)
Asheville, NC	16.02(.837)	19.52(.788)	11.98(.604)	12.34(0)	11.84(.595)	11.98(0)
Cape Hatteras, NC	15.40(.843)	20.66(.771)	12.34(0)	12.34(0)	11.98(0)	11.98(0)
Charlotte, NC	16.37(.770)	20.76(.708)	12.86(0)	12.86(0)	11.98(0)	11.98(0)
Greensboro, NC	16.69(.723)	20.30(.670)	12.86(0)	12.86(0)	11.98(0)	11.98(0)
Greenville-Spartanburg, NC	18.34(.827)	23.24(.764)	12.34(0)	12.34(0)	11.98(0)	11.98(0)
Raleigh, NC	16.45(.853)	20.77(.794)	12.34(0)	12.34(0)	11.98(0)	11.98(0)
Raleigh-Durham, NC	16.53(.749)	20.52(.691)	12.34(0)	12.34(0)	11.98(0)	11.98(0)
Bismark, ND	14.52(.818)	16.12(.792)	10.07(.580)	11.26(.554)	8.60(0)	8.60(0)
Fargo, ND	16.78(.662)	18.23(.638)	11.22(.465)	11.80(0)	8.60(0)	8.60(0)
Cleveland, OH	22.21(.583)	24.51(.552)	12.44(0)	12.44(0)	9.46(0)	9.46(0)
Columbus, OH	20.07(.581)	22.47(.547)	11.80(0)	11.80(0)	9.46(0)	9.46(0)
Dayton, OH	18.47(.657)	20.92(.621)	12.15(0)	12.15(0)	9.46(0)	9.46(0)
Put-in-Bay, OH	22.54(.582)	24.96(.548)	12.44(0)	12.44(0)	9.46(0)	9.46(0)

TABLE 7.2. (Continued)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Oklahoma City, OK	14.15(.803)	17.84(.745)	11.42(0)	11.42(0)	7.36(0)	7.36(0)
Stillwater, OK	16.59(.757)	20.47(.701)	11.42(0)	11.42(0)	7.36(0)	7.36(0)
Tulsa, OK	17.22(.730)	21.05(.674)	11.42(0)	11.42(0)	7.36(0)	7.36(0)
Astoria, OR	15.21(.541)	17.46(.506)	11.93(0)	11.93(0)	13.49(.486)	13.97(0)
Corvallis, OR	16.31(.473)	17.52(0)	11.93(0)	11.93(0)	13.97(0)	13.97(0)
Klamath Falls, OR ^(d)	15.68(.512)	17.52(0)	11.96(0)	11.96(0)	13.85(.460)	13.97(0)
Medford, OR	15.68(.512)	17.52(0)	11.96(0)	11.96(0)	13.85(.460)	13.97(0)
Portland, OR	16.98(.456)	17.52(0)	11.96(0)	11.96(0)	13.97(0)	13.97(0)
Philadelphia, PA	17.74(.704)	20.63(.661)	12.63(0)	12.63(0)	10.85(0)	10.85(0)
Pittsburgh, PA	19.53(.687)	22.27(.648)	13.11(0)	13.11(0)	10.85(0)	10.85(0)
State College, PA	17.56(.522)	19.60(.490)	12.63(0)	12.63(0)	10.85(0)	10.85(0)
Newport, RI	17.28(.755)	19.78(.717)	12.12(.534)	12.60(0)	14.04(.620)	16.15(.583)
Charleston, SC	18.39(.866)	26.12(.773)	12.86(0)	12.86(0)	11.30(0)	11.30(0)
Rapid City, SD	12.02(.895)	13.94(.862)	9.33(.663)	10.82(.630)	7.81(0)	7.81(0)
Chattanooga, TN	15.64(.591)	16.76(0)	11.29(0)	11.29(0)	7.55(0)	7.55(0)
Memphis, TN	15.56(.572)	15.79(0)	10.91(0)	10.91(0)	7.55(0)	7.55(0)
Nashville, TN	15.79(0)	15.79(0)	11.13(0)	11.13(0)	7.55(0)	7.55(0)
Oak Ridge, TN	14.82(0)	14.82(0)	11.29(0)	11.29(0)	7.55(0)	7.55(0)
Abilene, TX	15.67(.877)	21.37(.800)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Amarillo, TX	12.21(.942)	15.63(.887)	10.26(.710)	11.10(0)	9.93(.678)	10.02(0)
Big Spring, TX	15.49(.831)	21.01(.754)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Brownsville, TX	21.69(.962)	29.40(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Corpus Christi, TX	21.39(.854)	25.89(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Dallas, TX	17.54(.731)	20.96(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
El Paso, TX	12.85(1.00)	18.65(.978)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Fort Worth, TX	16.24(.808)	21.76(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Houston, TX	19.50(.732)	20.92(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Midland, TX	14.79(.843)	20.24(.765)	11.10(0)	11.10(0)	10.02(0)	10.02(0)

TABLE 7.2. (Continued)

City	Electric Backup		Fuel Oil Backup		Natural Gas Backup	
	Suburban	Urban	Suburban	Urban	Suburban	Urban
Port Arthur, TX	20.38(.739)	23.43(.629)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
San Antonio, TX	18.24(.897)	26.39(0)	11.10(0)	11.10(0)	10.02(0)	10.02(0)
Salt Lake City, UT	15.44(.714)	17.66(.679)	10.59(0)	10.59(0)	6.57(0)	6.57(0)
Mt. Weather, VA	17.44(.785)	20.09(.747)	12.08(.543)	12.57(0)	12.14(.546)	12.69(0)
Norfolk, VA	18.35(.805)	22.74(.747)	12.57(0)	12.57(0)	12.69(0)	12.69(0)
Richmond, VA	19.07(.758)	22.89(.707)	12.57(0)	12.57(0)	12.69(0)	12.69(0)
Bellingham, WA ^(e)	6.53(0)	6.53(0)	12.34(0)	12.34(0)	12.80(0)	12.80(0)
Prosser, WA	9.26(0)	9.26(0)	12.01(.493)	12.34(0)	12.24(.502)	12.80(0)
Pullman, WA	10.51(0)	10.51(0)	11.53(.514)	12.34(0)	11.75(.523)	12.80(0)
Richland, WA	9.61(0)	9.61(0)	12.34(0)	12.34(0)	12.80(0)	12.80(0)
Seattle, WA	6.53(0)	6.53(0)	12.34(0)	12.34(0)	12.80(0)	12.80(0)
Spokane, WA	10.47(0)	10.47(0)	11.38(.481)	12.34(0)	12.06(.490)	12.80(0)
Green Bay, WI	17.25(.620)	18.88(.593)	11.73(.437)	11.80(0)	10.44(0)	10.44(0)
Madison, WI	15.22(.631)	16.86(.603)	10.88(0)	10.88(0)	10.44(0)	10.44(0)
Milwaukee, WI	16.28(.609)	17.99(.580)	11.74(.451)	11.80(0)	10.44(0)	10.44(0)
Parkersburg, WY	21.54(.593)	24.47(.553)	11.26(0)	11.26(0)	8.97(0)	8.97(0)
Lander, WY	9.30(.880)	10.88(.848)	8.49(.775)	9.91(.742)	7.01(.609)	7.02(0)
Laramie, WY	9.67(.842)	11.06(.813)	8.68(.738)	9.93(.709)	7.01(.574)	7.02(0)

a. Solar load fractions listed in parentheses

b. Data for Pocatello used

c. Data for Great Falls used

d. Data for Medford used

e. Data for Seattle used

in only 10% of the locations. In 17% of the locations a solar/natural gas system for suburban heating is less expensive than natural gas alone. In only 6% of the cities solar/natural gas heating is less expensive than natural gas for heating the garden apartment.

However, if fuel oil and natural gas prices were to increase to a point corresponding to a levelized heating cost of \$15/million Btu, it is likely that solar/conventional heating would become attractive in many more locations. Under the \$15 conventional fuel cost assumption, levelized costs were determined for solar/conventional heat at each of the study locations. These levelized costs and the solar load fractions for the optimal system are listed for each city in Table 7.3. At a conventional fuel heating cost of \$15, the optimum does not occur at 100% solar in any of the cities. However, in 82% of the cities, solar/conventional, with solar supplying more than 40% of the load, is more economic than conventional heating alone for the suburban house. In 31% of the cities solar/conventional heating was more economic than conventional fuels at \$15 for heating the garden apartment; again, with solar supplying more than 40% of the heat. These percentages represent a significant increase above locations which were economic for solar/fuel oil or solar/natural gas heating under our low price assumption.

Table 7.4 presents levelized geothermal heating costs for the Western convective hydrothermal resources ($>90^{\circ}\text{C}$). The nearest resource to each city is listed along with its distance from the city. These distances are straight-line approximations and do not account for irregular terrain. For both the suburban house and the garden apartment, levelized heating costs are listed at three locations: (1) at the wellhead (0 miles), (2) at the city, and (3) 50 miles from the wellhead. This provides an indication of how near this or a similar resource must be located to be competitive.

Table 7.5 presents levelized heating costs for normal-gradient resources (60°C). Thermal gradients presented in the table represent a regional average of thermal gradient data presented by the USGS^(7.1). Levelized heating costs for the suburban house and the garden apartment are listed at three locations: (1) at the wellhead (0 miles), (2) one mile from the wellhead (reference assumption), and (3) ten miles from the wellhead. Again, this indicates how near the resource must be located to be competitive.

TABLE 7.3. Levelized Solar/Conventional Heating Costs in \$/Million Btu
(\$15 Conventional Fuel Price Assumption)

City	Suburban	Urban
Annette, AK	14.16(.491) ^(a)	15.57(0)
Bethel, AK	12.55(.530)	13.41(.513)
Fairbanks, AK	13.68(.424)	14.44(.409)
Matanuska, AK	14.02(.428)	14.95(.410)
Birmingham, AL	14.98(.595)	15.00(0)
Fort Smith, AR	14.87(.570)	15.00(0)
Little Rock, AR	15.00(0)	15.00(0)
Page, AZ	9.75(.871)	12.04(.827)
Phoenix, AZ	14.55(.846)	15.00(0)
Tucson, AZ	13.72(.862)	15.00(0)
Yuma, AZ	15.00(0)	15.00(0)
Davis, CA	15.00(0)	15.00(0)
Fresno, CA	14.78(.604)	15.00(0)
Inyokern, CA	12.16(.880)	15.00(0)
Los Angeles, CA	12.97(.897)	15.00(0)
Pasadena, CA	13.99(.856)	15.00(0)
Riverside, CA	13.07(.883)	15.00(0)
Sacramento, CA	14.51(.603)	15.00(0)
San Diego, CA	14.36(.867)	15.00(0)
San Francisco, CA	11.30(.876)	14.98(.807)
San Jose, CA	14.42(.657)	15.00(0)
Santa Maria, CA	10.15(.958)	14.51(.888)
Boulder, CO	11.69(.730)	13.89(.689)
Denver, CO	9.92(.847)	11.96(.807)
Grand Junction, CO	11.20(.761)	13.36(.720)
Grand Lake, CO	8.96(.826)	10.06(.801)
Pueblo, CO	10.21(.845)	12.51(.800)
Hartford, CT	13.18(.601)	14.45(.566)
Washington, D.C.	14.63(.519)	15.00(0)
Apalachicola, FL	15.00(0)	15.00(0)
Gainesville, FL	15.00(0)	15.00(0)
Jacksonville, FL	15.00(0)	15.00(0)
Pensacola, FL	15.00(0)	15.00(0)
Tallahassee, FL	15.00(0)	15.00(0)
Tampa, FL	15.00(0)	15.00(0)
Atlanta, GA	14.82(.628)	15.00(0)
Griffin, GA	14.72(.659)	15.00(0)
Macon, GA	14.93(.672)	15.00(0)
Savannah, GA	15.00(0)	15.00(0)
Boise, ID	13.13(.589)	14.94(.555)
Idaho Falls, ID ^(b)	11.57(.681)	13.23(.649)
Pocatello, ID	11.57(.681)	13.23(.649)
Twin Falls, ID	13.07(.586)	14.91(.553)

TABLE 7.3. (Continued)

City	Suburban	Urban
Ames, IA	13.14(.588)	14.87(.555)
Des Moines, IA	13.62(.547)	14.97(.515)
Chicago, IL	14.04(.539)	15.00(0)
Lemont, IL	14.10(.535)	15.00(0)
Peoria, IL	14.18(.520)	15.00(0)
Fort Wayne, IN	14.22(.513)	15.00(0)
Indianapolis, IN	14.95(.463)	15.00(0)
Dodge City, KA	11.28(.778)	13.72(.733)
Manhattan, KA	13.56(.602)	15.00(0)
Wichita, KA	13.05(.663)	15.00(0)
Lexington, KY	13.92(.583)	15.00(0)
Louisville, KY	14.92(.505)	15.00(0)
Lake Charles, LA	15.00(0)	15.00(0)
New Orleans, LA	15.00(0)	15.00(0)
Shreveport, LA	15.00(0)	15.00(0)
Caribou, ME	12.35(.588)	13.53(.564)
Portland, ME	12.31(.633)	13.92(.602)
Annapolis, MD	14.60(.553)	15.00(0)
Baltimore, MD	14.42(.561)	15.00(0)
Silver Hill, MD	14.71(.562)	15.00(0)
Amherst, MA	14.95(.438)	15.00(0)
Blue Hill, MA	14.83(.480)	15.00(0)
Boston, MA	13.92(.542)	15.00(0)
Lynn, MA	15.00(0)	15.00(0)
Natick, MA	13.92(.542)	15.50(0)
Detroit, MI	14.88(.457)	15.00(0)
E. Lansing, MI	14.86(.447)	15.00(0)
Lansing, MI	14.50(.478)	15.00(0)
Sault Ste. Marie, MI	12.70(.561)	13.96(.537)
Duluth, MN	12.69(.558)	13.86(.535)
Minneapolis-St. Paul,	13.66(.514)	14.75(.487)
St. Cloud, MN	12.00(.631)	13.32(.604)
Jackson, MS	15.00(0)	15.00(0)
Columbia, MO	13.86(.581)	15.00(0)
Kansas City, MO	13.90(.575)	15.00(0)
St. Louis, MO	14.52(.544)	15.00(0)
Springfield, MO	13.11(.596)	15.00(0)
Billings, MT	11.60(.686)	13.23(.654)
Glasgow, MT	10.78(.72)	12.08(.685)
Great Falls, MT	11.50(.679)	13.01(.649)
Helena, MT(c)	11.50(.679)	13.01(.649)
Summit, MT	11.49(.679)	13.00(.649)
Lincoln, NE	12.88(.630)	14.92(.592)
N. Omaha, NE	12.13(.667)	13.93(.632)

TABLE 7.3. (Continued)

City	Garden	Urban
Ely, NV	9.00(.867)	10.56(.834)
Las Vegas, NV	12.55(.827)	15.00(0)
Reno, NV	9.63(.853)	11.65(.814)
Atlantic City, NJ	13.62(.619)	15.00(0)
Trenton, NJ	13.98(.583)	15.00(0)
Albuquerque, NM	10.54(.865)	13.48(.811)
Albany, NY	13.90(.513)	15.00(0)
Binghamton, NY	14.29(.480)	15.00(0)
Ithaca, NY	15.00(0)	15.00(0)
New York, NY	15.00(0)	15.00(0)
Rochester, NY	14.34(.491)	15.00(0)
Schneectady, NY	14.90(.426)	15.00(0)
Syracuse, NY	14.81(.439)	15.00(0)
Asheville, NC	13.14(.671)	15.00(0)
Cape Hatteras, NC	13.85(.728)	15.00(0)
Charlotte, NC	14.29(.657)	15.00(0)
Greensboro, NC	14.27(.613)	15.00(0)
Greenville-Spartanburg, NC	14.60(.637)	15.00(0)
Raleigh, NC	13.47(.681)	15.00(0)
Raleigh-Durham, NC	14.29(.636)	15.00(0)
Bismark, ND	11.51(.659)	12.80(.633)
Fargo, ND	13.08(.538)	14.31(.513)
Cleveland, OH	14.89(.424)	15.00(0)
Columbus, OH	14.61(.454)	15.00(0)
Dayton, OH	14.34(.523)	15.00(0)
Put-in-Bay, OH	15.00(0)	15.00(0)
Oklahoma City, OK	13.02(.721)	15.00(0)
Stillwater, OK	14.17(.636)	15.00(0)
Tulsa, OK	14.58(.608)	15.00(0)
Astoria, OR	14.28(.512)	15.00(0)
Corvallis, OR	14.82(.447)	15.00(0)
Klamath Falls, OR ^(d)	14.69(.485)	15.00(0)
Medford, OR	14.69(.485)	15.00(0)
Portland, OR	15.00(0)	15.00(0)
Philadelphia, PA	14.21(.567)	15.00(0)
Pittsburgh, PA	14.51(.524)	15.00(0)
State College, PA	14.54(.453)	15.00(0)
Newport, RI	13.42(.593)	14.84(.56)
Charleston, SC	15.00(0)	15.00(0)
Rapid City, SD	10.58(.762)	12.21(.729)
Chattanooga, TN	14.54(.570)	15.00(0)
Memphis, TN	14.89(.568)	15.00(0)
Nashville, TN	15.00(0)	15.00(0)
Oak Ridge, TN	14.97(.508)	15.00(0)

TABLE 7.3. (Continued)

City	Suburban	Urban
Abilene, TX	14.00(.738)	15.00(0)
Amarillo, TX	11.30(.816)	14.31(.762)
Big Spring, TX	14.14(.728)	15.00(0)
Brownsville, TX	15.00(0)	15.00(0)
Corpus Christi, TX	15.00(0)	15.00(0)
Dallas, TX	15.00(0)	15.00(0)
El Paso, TX	12.22(.853)	15.00(0)
Fort Worth, TX	14.76(.706)	15.00(0)
Houston, TX	15.00(0)	15.00(0)
Midland, TX	13.78(.756)	15.00(0)
Port Arthur, TX	15.00(0)	15.00(0)
San Antonio, TX	15.00(0)	15.00(0)
Salt Lake City, UT	12.92(.608)	14.88(.573)
Mt. Weather, VA	13.36(.604)	14.93(.566)
Norfolk, VA	14.52(.621)	15.00(0)
Richmond, VA	14.63(.580)	15.00(0)
Bellingham, WA ^(e)	15.00(0)	15.00(0)
Prosser, WA	13.55(.549)	15.00(0)
Pullman, WA	12.99(.572)	14.71(.542)
Richland, WA	14.97(.439)	15.00(0)
Seattle, WA	15.00(0)	15.00(0)
Spokane, WA	13.40(.539)	14.55(.510)
Green Bay, WI	13.70(.509)	14.57(.483)
Madison, WI	13.21(.556)	14.71(.528)
Milwaukee, WI	13.66(.523)	14.75(.494)
Parkersburg, WY	15.00(0)	15.00(0)
Lander, WY	9.15(.858)	10.69(.825)
Laramie, WY	9.47(.820)	10.84(.791)

a. Solar load fractions listed in parentheses

b. Data for Pocatello used

c. Data for Great Falls used

d. Data for Medford used

e. Data for Seattle used

TABLE 7.4. Geothermal Levelized Heating Costs (\$/million BTU)--
Convective Hydrothermal Resources

City	Resource	Temperature °C	Distance Miles	Suburban			Urban		
				0 Miles	At City	50 Miles	0 Miles	At City	50 Miles
Annette, AK ^(a)	Bailey Bay	162	70	10.91	15.88	14.96	5.05	10.02	8.60
	Hot Springs								
	Bell Island								
	Hot Springs	126	65	11.76	18.00	17.23	5.90	12.14	10.70
Bethel, AK ^(a)	Clear Creek	103	280	10.43	29.75	14.36	4.33	24.21	7.88
Fairbanks, AK ^(a)	Tolwana	126	45	9.90	12.24	12.86	3.89	6.28	6.54
Matanuska, AK ^(a)	Manley (Baker)	94	265	11.38	37.88	17.08	5.03	32.06	10.13
Page, AZ	Newcastle Area	130	130	12.98	28.32	19.70	5.86	20.81	11.61
Phoenix, AZ	Power Ranches								
	Inc. Wells	165	25	21.23	27.44	33.88	9.33	15.34	18.73
Tucson, AZ	Power Ranches								
	Inc., Wells	165	80	19.00	35.00	30.40	8.41	22.49	17.21
	San Simon Well	135	90	20.40	42.63	34.47	9.64	29.26	20.54
Yuma, AZ	East Mesa	182	35	24.46	35.41	41.55	8.82	19.70	20.37
	Dunes	132	25	28.56	38.77	50.21	11.59	22.54	26.19
Davis, CA	Sulphur Bank Mine								
	(Hot Bolata)	194	60	16.33	26.35	25.85	6.82	15.82	14.32
	Calistoga Hot								
	Springs	144	45	17.31	25.46	27.62	7.60	14.94	15.75
Fresno, CA	Long Valley								
	Caldera	227	80	15.43	30.55	24.43	6.18	20.64	13.33
Inyokern, CA	Coso Area	220	15	15.81	18.38	25.55	6.35	8.60	13.85
Los Angeles, CA	Arrowhead								
	Hot Springs	132	55	20.47	34.39	34.89	9.15	21.47	20.35
Pasadena, CA	Arrowhead								
	Hot Springs	132	45	21.69	33.89	37.13	9.60	20.31	21.50
Riverside, CA	Arrowhead								
	Hot Springs	132	15	19.86	24.54	34.28	8.77	14.12	19.32
Sacramento, CA	Wilbur Springs								
	Area	144	60	15.76	26.34	25.05	6.57	17.01	13.97
San Diego, CA	Westmorland	217	90	21.06	41.85	34.22	8.20	25.12	17.60
San Francisco, CA	Calistoga								
	Hot Springs	144	55	16.11	25.16	24.71	6.99	16.14	14.04
San Jose, CA	Calistoga								
	Hot Springs	144	90	17.73	34.92	28.61	7.73	22.76	16.08
Santa Maria, CA	Sespe								
	Hot Springs	131	85	16.96	32.52	27.39	7.52	21.72	15.87
Boulder, CO	Routt Hot								
	Springs	130	90	12.73	23.08	19.28	5.67	15.66	11.22
Denver, CO	Mt. Princeton								
	Hot Springs Area	112	90	12.69	24.48	20.15	5.91	17.52	12.36
Grand Junction, CO	Penny (Avalanche)								
	Hot Springs	105	70	13.39	23.82	21.88	6.25	16.19	13.35
Grand Lake, CO ^(b)	Routt Hot								
	Springs	130	55	10.58	14.10	14.23	4.33	7.85	7.53
Pueblo, CO	Sand Dunes								
	Swimming Pool	141	75	12.40	20.39	18.27	5.49	13.78	10.49

TABLE 7.4. (Continued)

City	Resource	Temperature °C	Distance Miles	Suburban			Urban		
				0 Miles	At City	50 Miles	0 Miles	At City	50 Miles
Boise, ID	Crane Creek-Cove Creek	171	55	11.25	16.80	16.09	4.48	10.59	8.63
	Roystone Hot Springs	135	25	11.91	15.79	17.84	5.01	9.62	10.16
Idaho Falls, ID	Newdale Area	100	35	12.43	17.38	19.67	5.76	11.51	12.01
Pocatello, ID	Maple Grove	93	55	12.96	21.32	21.62	6.22	14.47	13.72
Twin Falls, ID	Hot Springs								
	Banbury Area	117	20	12.36	14.67	19.08	6.04	8.52	11.79
Great Falls, MT	Marysville Test Well	122	75	11.65	18.55	16.89	5.09	12.07	9.74
Helena, MT	Marysville Test Well	122	5	11.65	12.06	16.89	5.09	6.23	9.74
	Broadwater Hot Springs	118	15	11.75	13.08	17.28	5.18	7.28	10.08
Ely, NV	Cherry Creek Area	115	60	11.81	17.65	17.56	5.25	11.83	10.35
Las Vegas, NV	Tecopa Hot Springs	126	65	17.70	31.35	29.67	8.14	20.82	17.89
Reno, NV	Steamboat Springs	200	10	10.66	11.70	15.39	4.15	5.78	8.20
	Moana Area	116	5	12.55	13.04	19.73	5.78	6.94	11.93
Albuquerque, NM	Valles Caldera	273	55	13.04	20.07	19.36	4.20	12.76	9.45
Astoria, OR	Mount Hood Area	122	115	13.67	28.51	21.02	5.52	19.90	11.77
Corvallis, OR	Breitenbush Hot Springs	125	60	13.87	22.15	21.73	6.25	14.17	12.85
Klamath Falls, OR	Klamath Falls	111	0	13.60	13.87	22.32	6.02	7.15	13.42
Medford, OR	Klamath Hills Area	124	60	13.78	21.82	21.42	6.23	14.03	12.73
Portland, OR	Mount Hood Area	122	45	13.46	19.99	21.55	5.82	12.98	12.57
El Paso, TX	Radium Hot Springs	98	60	19.40	36.50	35.64	9.27	24.39	21.87
Salt Lake City, UT	Abraham Hot Springs	97	90	13.32	27.95	22.32	6.40	21.53	14.10

TABLE 7.4. (Continued)

City	Resource	Temperature °C	Distance Miles	Suburban			Urban		
				0 Miles	At City	50 Miles	0 Miles	At City	50 Miles
Bellingham, WA	Baker Hot Springs	134	35	14.24	20.00	21.76	6.14	12.73	12.39
Richland, WA	Medical Hot Springs	96	105	15.16	35.01	25.93	7.24	26.46	16.39
Seattle, WA	Gamm Hot Springs	165	70	13.65	21.74	19.75	5.68	14.40	10.78
Lander, WY	Granite Hot Springs	93	90	12.52	24.85	20.33	5.92	18.34	12.82
Laramie, WY	Routt Hot Springs	130	80	11.10	17.18	15.43	4.69	10.85	8.54

(a) Based on continental U.S. costs.

(b) Population is too low to warrant designation as an urban area.

TABLE 7.5. Geothermal Levelized Heating Costs (\$/Million Btu) -
Normal-Gradient Resources

City	Assumed Thermal Gradient °C/km	Suburban			Urban		
		0 Mile	1 Mile	10 Miles	0 Mile	1 Mile	10 Miles
Birmingham, AL	30	32.28	33.11	40.55	21.98	22.73	29.49
Fort Smith, AR	40	25.13	25.87	32.47	15.93	16.61	22.68
Little Rock, AR	40	25.53	26.28	33.04	16.18	16.87	23.07
Hartford, CT	30	20.03	20.47	24.39	13.66	14.09	17.90
Washington, D.C.	30	25.96	26.57	32.08	17.72	18.30	23.52
Apalachicola, FL	24	65.13	66.50	78.89	42.79	43.89	53.81
Gainesville, FL	24	69.23	70.73	84.25	46.73	47.96	58.97
Jacksonville, FL	24	63.58	64.95	77.34	42.32	43.43	53.34
Pensacola, FL	24	56.98	58.20	69.22	39.61	40.64	49.94
Tallahassee, FL	24	57.08	58.31	69.32	39.65	40.68	49.97
Tampa, FL	24	82.36	84.19	100.72	52.36	53.74	66.13
Atlanta, GA	30	26.23	27.02	34.10	16.79	17.50	23.97
Griffin, GA	30	32.33	33.16	40.59	22.37	23.14	30.05
Macon, GA	30	36.19	37.16	45.91	24.80	25.67	33.49
Savannah, GA	30	39.54	40.65	50.56	26.60	27.54	36.04
Boise, ID	45	13.90	14.37	18.55	7.76	8.16	11.79
Chicago, IL	30	20.32	20.77	24.79	13.91	14.35	18.27
Lemont, IL	30	20.32	20.77	24.79	13.91	14.35	18.27
Peoria, IL	30	20.32	20.77	24.79	14.04	14.48	18.45
Fort Wayne, IN	30	20.17	20.61	24.58	13.91	14.35	18.27
Indianapolis, IN	30	20.38	20.86	25.23	14.34	14.81	19.05

TABLE 7.5. (Continued)

City	Assumed Thermal Gradient °C/km	Suburban			Urban		
		0 Mile	1 Mile	10 Miles	0 Mile	1 Mile	10 Miles
Ames, IA	30	19.38	19.79	23.46	13.17	13.58	17.21
Des Moines, IA	30	19.51	19.92	23.65	13.29	13.70	17.37
Dodge City, KA	30	23.27	23.80	28.60	15.86	16.37	20.95
Manhattan, KA	30	22.76	23.27	27.92	15.65	16.15	20.65
Wichita, KA	30	24.30	24.86	29.90	16.52	17.06	21.86
Lexington, KY	30	24.03	24.58	29.54	16.51	17.05	21.85
Louisville, KY	30	24.55	25.12	30.24	16.73	17.27	22.14
Lake Charles, LA	60	36.55	37.82	49.25	20.88	21.94	31.53
New Orleans, LA	60	35.90	37.22	49.12	20.93	22.00	31.95
Shreveport, LA	60	27.20	28.17	36.92	16.73	17.60	25.42
Caribou, ME	30	16.68	16.98	19.69	10.69	10.99	13.66
Portland, ME	30	18.71	19.09	22.51	12.64	13.02	16.43
Annapolis, MD	30	24.66	25.23	30.36	16.97	17.52	22.47
Baltimore, MD	30	20.62	21.16	26.08	13.47	14.01	18.83
Silver Hill, MD	30	25.98	26.59	32.10	17.72	18.30	23.52
Amherst, MA	30	19.65	20.06	23.83	13.41	13.83	17.55
Blue Hill, MA	30	20.03	20.47	24.39	13.66	14.09	17.90
Boston, MA	30	18.54	19.03	23.44	11.93	12.40	16.60
Lynn, MA	30	21.41	21.89	26.20	14.70	15.17	19.35
Natick, MA	30	20.32	20.77	24.79	13.91	14.35	18.27
Detroit, MI	30	20.02	20.46	24.38	13.66	14.09	17.90
E. Lansing, MI	30	19.26	19.66	23.29	13.06	13.46	17.04
Lansing, MI	30	19.26	19.66	23.29	13.06	13.46	17.04
Sault St. Marie, MI	30	17.14	17.46	20.32	11.17	11.49	14.35
Duluth, MN	30	16.63	16.92	19.60	10.75	11.05	13.75
Minneapolis- St. Paul, MN	30	17.91	18.26	21.39	11.89	12.23	15.36
St. Cloud, MN	30	17.30	17.62	20.54	11.32	11.64	14.55

TABLE 7.5. (Continued)

City	Assumed Thermal Gradient °C/km	Suburban			Urban		
		0 Mile	1 Mile	10 Miles	0 Mile	1 Mile	10 Miles
Jackson, MS	60	27.08	28.05	36.80	16.68	17.55	25.38
Columbia, MO	30	23.27	23.80	28.60	15.86	16.37	20.95
Kansas City, MO	30	22.76	23.27	27.92	15.65	16.15	20.65
St. Louis, MO	30	24.03	24.58	29.54	16.51	17.05	21.85
Springfield, MO	30	24.66	25.23	30.36	16.97	17.52	22.47
Billings, MT	54	15.37	15.76	19.21	9.29	9.67	13.13
Glasgow, MT	54	14.30	14.62	17.48	8.32	8.64	11.50
Summit, MT	54	13.45	13.70	15.93	7.61	7.86	10.13
Lincoln, NB	40	15.90	16.24	19.34	9.65	9.99	13.03
N. Omaha, NB	40	17.04	17.45	21.22	10.85	11.26	14.99
Atlantic City, NJ	30	24.28	24.85	29.89	16.52	17.06	21.86
Trenton, NJ	30	23.38	23.92	28.72	16.07	16.58	21.23
Albany, NY	30	19.26	19.66	23.29	13.06	13.46	17.04
Binghamton, NY	30	18.81	19.20	22.65	12.73	13.11	16.57
Ithaca, NY	30	19.14	19.54	23.12	13.06	13.46	17.04
New York, NY	30	23.94	24.49	29.45	16.30	16.82	21.54
Rochester, NY	30	19.51	19.92	23.65	13.29	13.70	17.37
Schnectady, NY	30	19.38	19.79	23.46	13.17	13.58	17.21
Syracuse, NY	30	19.63	20.05	23.82	13.29	13.70	17.37
Asheville, NC	30	25.95	26.56	32.07	17.72	18.30	23.53
Cape Hatteras, NC	30	32.88	33.72	41.36	22.80	23.59	30.67
Charlotte, NC	30	30.20	30.95	37.71	20.79	21.49	27.82
Greensboro, NC	30	27.51	28.17	34.12	18.83	19.45	25.06
Greenville- Spartanburg, NC	30	30.27	31.02	37.78	20.81	21.51	27.84
Raleigh, NC	30	28.80	29.50	35.83	19.76	20.42	26.37
Raleigh-Durham, NC	30	28.80	29.50	35.83	19.76	20.42	26.37
Bismark, ND	40	15.17	15.49	18.35	9.20	9.51	12.38
Fargo, ND	40	15.05	15.37	18.18	9.09	9.41	12.22

TABLE 7.5. (Continued)

City	Assumed Thermal Gradient °C/km	Suburban			Urban		
		0 Mile	1 Mile	10 Miles	0 Mile	1 Mile	10 Miles
Cleveland, OH	30	20.32	20.77	24.79	13.91	14.35	18.27
Columbus, OH	30	21.41	21.89	26.20	14.70	15.17	19.35
Dayton, OH	30	21.41	21.89	26.20	14.70	15.17	19.35
Put-in-Bay, OH	30	20.64	21.10	25.23	14.20	14.65	18.67
Oklahoma City, OK	35	25.40	26.08	32.15	16.72	17.35	23.08
Stillwater, OK	35	25.72	26.41	32.60	16.97	17.62	23.45
Tulsa, OK	35	25.41	26.09	32.16	16.73	17.36	23.09
Philadelphia, PA	30	23.68	24.22	29.09	16.10	16.62	21.26
Pittsburg, PA	30	22.47	22.98	27.56	15.44	15.93	20.38
State College, PA	30	20.32	20.77	24.79	13.91	14.35	18.27
Newport, RI	30	21.06	21.53	25.78	13.92	14.97	19.10
Charleston, SC	30	37.78	38.81	48.10	25.94	26.86	35.12
Rapid City, SD	40	16.42	16.81	20.26	10.35	10.73	14.19
Chattanooga, TN	30	28.80	29.50	35.83	19.76	20.42	26.37
Memphis, TN	30	30.20	30.95	37.71	20.46	21.14	27.34
Nashville, TN	30	27.95	28.63	34.70	19.13	19.77	25.49
Oak Ridge, TN	30	26.81	27.45	33.17	18.52	19.13	24.64
Abilene, TX	35	30.21	31.08	38.91	19.86	20.65	27.73
Amarillo, TX	35	23.66	24.27	29.78	15.70	16.29	21.61
Big Spring, TX	35	30.23	31.10	38.93	19.87	20.66	27.74
Brownsville, TX	60	48.27	50.22	67.71	27.37	28.87	42.39
Corpus Christi, TX	60	43.14	44.80	59.67	24.00	25.27	36.71
Dallas, TX	35	32.44	33.42	42.16	21.48	22.35	30.18
Fort Worth, TX	35	31.33	32.25	40.51	20.65	21.48	28.91
Houston, TX	60	37.93	39.25	51.14	21.54	22.64	32.56
Midland, TX	35	30.28	31.10	38.93	19.87	20.66	27.74
Port Arthur, TX	60	34.36	35.63	47.06	19.79	20.83	30.12
San Antonio, TX	35	41.06	42.33	53.77	25.40	26.43	35.73

TABLE 7.5. (Continued)

City	Assumed Thermal Gradient °C/km	Suburban			Urban		
		0 Mile	1 Mile	10 Miles	0 Mile	1 Mile	10 Miles
Mt. Weather, VA	30	21.41	21.89	26.20	14.70	15.17	19.35
Norfolk, VA	30	29.16	29.88	36.34	19.76	20.42	26.37
Richmond, VA	30	27.37	28.03	33.98	18.53	19.14	24.65
Prosser, WA	40	18.58	19.06	23.43	11.93	12.40	16.58
Pullman, WA	35	18.05	18.47	22.23	11.85	12.27	15.99
Richland, WA	35	21.75	22.30	27.26	14.13	14.65	19.29
Spokane, WA	60	15.59	16.00	19.67	9.42	9.83	13.46
Green Bay, WI	30	18.01	21.53	21.53	11.97	12.32	15.49
Madison, WI	30	18.29	18.65	21.93	12.24	12.60	15.87
Milwaukee, WI	30	18.65	19.03	22.42	12.54	12.91	16.30
Parkersburg, WV	30	23.94	24.49	29.45	16.11	16.63	21.28

Examining Tables 7.1 through 7.4, it can be seen that at the wellhead geothermal district heating for garden apartments is lower in cost than solar, conventional or solar/conventional heating in nearly all locations. For 15% of the Western locations, those characterized by high annual heating loads and high resource temperatures, geothermal heating is lowest in cost up to 50 miles from the wellhead. From Table 7.5 it can be seen that low-cost geothermal heating from normal-gradient resources for garden apartments depends on a high annual heat load. Therefore, normal-gradient heating is most competitive in the Northern half of the United States. In general, the regions above 3300°C-days/year are favorable for urban heating from normal-gradient resources and regions above 1600°C-days/year are favorable for urban heating with the higher-temperature hydrothermal resources in the West.

7.4 DISCUSSION OF RESULTS

These costs were developed from a systems-analysis viewpoint, using several simplifying reference assumptions. These reference assumptions were selected to represent typical or average conditions. Obviously, the actual heating costs for a particular dwelling or location will vary depending on the actual conditions. Therefore, these results should not be viewed as precise costs for each location, but rather as describing the conditions under which solar and geothermal energy are or are not competitive with conventional energy.

The results of the site-specific comparisons can be summarized as follows.

Under the low price assumption:

1. Geothermal district heating costs are lower than solar or electricity heating costs for urban centers in nearly every location, provided that the resource is nearby.
2. Solar heating costs are lower than geothermal or electricity heating costs for suburban population densities throughout most of the West and Southeast.
3. Fuel oil and natural gas heating costs are lowest in most locations -- especially locations of low solar insolation, locations too distant from geothermal resources, and locations with very short heating seasons.

Under the \$15 price assumption:

1. Geothermal district heating in urban centers is most economic in nearly all

locations north of a line extending roughly from Baltimore to Los Angeles.

2. Solar and solar/conventional heating are most economic in suburban and rural areas throughout most of the country.
3. Conventional heating is most economic in the South and in other locations which: (a) are too distant from geothermal resources, or (b) receive low solar insolation.

Solar heating costs were based on current technology and current costs for solar collectors and other equipment. Improvements in solar technology and consequent reductions in costs should be forthcoming; therefore, solar heating costs will probably tend to become lower with time, leading to more widespread applications than our results show. However, in many locations hills, trees, tall buildings, and other restrictions may block and limit solar heating applications.

Geothermal heating costs were also based on current technology and current cost data. Improvements, cost reductions, and resource discoveries should also be forthcoming in the geothermal district heating field. Although this analysis assumed private utility financing, it seems likely that municipal utilities with their lower financing costs will construct and operate the district heating systems at many locations. Geothermal heating costs will probably trend lower with time, leading to more widespread applications than our results show.

The geothermal district heating costs were based on several simplifying assumptions. The more important of these were that local topography was assumed to be flat, construction was assumed to be in new areas, and total participation within the heating district was assumed. These are important conditions since circuitous routing, construction in established areas, and low participation would increase costs.

The rate of increase in conventional heating prices may be much higher than assumed, particularly over the near-term. The recent sharp price increases in foreign oil and natural gas supplies and the phased decontrol of domestic prices are not adequately reflected in the low price assumption. Thus, the \$15 levelized conventional heating cost assumption appears more representative of both the current marginal cost and the long-term cost of conventional heating. In addition, the availability of conventional fuels may become unreliable. These occurrences would accelerate a shift toward solar and geothermal energy.

Both solar and geothermal heating offer the potential for a non-air-polluting energy supply. The picture of smoke-free Reykjavik in the dead of winter graphically portrays this advantage of geothermal energy; as local air sheds become loaded with emissions, the availability of non-polluting heating sources will become very important to the survival or growth of the local economy.

On balance, both solar and geothermal will probably become more desirable and competitive in cost with conventional heating than this study indicates. However, the rate of penetration of these new energy sources into the space heating market will probably be slow, even under favorable competitive conditions. First, because the new technologies will probably have to compete with the average cost, rather than the marginal cost, of conventional energy. Second, the inertia to take the risk of new technology will be strong until a large economic incentive is achieved. And third, institutional barriers, particularly in organizing district heating systems, will be difficult to resolve.

Implementation of geothermal district heating on a large scale will require resolution of a number of significant problems^(7.2). First, because the economics of district heating is strongly dependent on a concentrated demand, it will be necessary to achieve near total participation within a district. Second, the economics of heat transport requires a large market to achieve economies of scale. Third, issues related to environmental control of production and transmission facilities may present obstacles. Organizing both large and concentrated markets will require much effort and may present numerous legal and regulatory problems.

The transmission or distribution of geothermal heat over distances in excess of five miles is an entirely new area for investors and regulators. As such, one may anticipate major implementation problems to arise. With the exception of oil pipelines and some surface pipeline conduits for drinking water, there are no major precedents available for either the financing or the regulation of hot water pipelines. It is likely that many new environmental standards will be necessary when considering potential impacts of piping hot water over long distances. There are also likely to be controversies over the acquisition of rights-of-way for a hot water pipeline, and liability issues related to potential ruptures of a hot water line.

Issues related to the disposal of spent geothermal fluids, land use, visual impacts, subsidence, noise, and other pollution-related matters will certainly arise.

Unfortunately, extended delays are frequent when standards are ambiguous or not yet in place.

Economic considerations will dictate some differences between utilizing the higher-temperature convective hydrothermal resources of the West and the normal-gradient resources in the East. Since the high-temperature resources are not expected to underlie broad regions, they will be economically exploitable at only specific locations. Since these locations will usually be somewhat distant from population centers, economics will dictate that these resources be employed on a large scale to take advantage of the economies of scale associated with heat transport.

On the other hand, normal-gradient resources will, by definition, underlie all demands. If a geothermal resource lies directly beneath the demand, the economics of district heating may favor limiting the district size to match the capacity of a production well. This will minimize production, transmission, and distribution costs. For instance, the French, in exploiting the normal-gradient resource of the Paris Basin, appear to be adopting this approach. The "dogger formation", a normal-gradient resource containing 60°C water, underlies the entire Paris Basin. This resource is tapped to heat housing complexes immediately above using a "doublet", a combination of one production and one reinjection well. Most normal-gradient resources will be developed in the immediate vicinity of the demand.

CHAPTER 7.0 - REFERENCES

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Energy Review, Volume 6, No. 3, May-June 1979.

8.0 COMPARATIVE ECONOMICS OF SOLAR, CONVENTIONAL AND GEOTHERMAL HEATING

8.1 SUMMARY

Residential space and hot water heating costs using conventional, solar, and geothermal energy were presented in earlier chapters. This chapter will present generalized envelopes of conditions under which geothermal, solar, or solar/conventional systems are likely to be competitive with conventional fuels at levelized heating costs of \$10/million Btu and \$15/million Btu.

Heating costs for all fuels are very sensitive to different site-specific parameters. Geothermal district heating is very dependent on population density, climate and distance from the resource to the heating district. The economics is also related to resource temperature, depth and production rates. Solar costs are dependent on solar insolation and the annual heat demand at the location. Conventional fuel costs vary with locality and with the utility system within a given region. The choice of the lowest-cost heating system depends on the cost and availability of fuels and heat delivery systems at each location. However, the comparative conditions under which each energy source will be economic can be defined.

In general, it can be assumed that the heating system chosen for a new residence will utilize the lowest-cost fuel available. Under our low price assumption, the levelized heating costs for conventional systems using the cheapest available fuel in the cities analyzed ranged from \$6.20/million Btu to \$13.88/million Btu. The median cost of \$10/million Btu will be used as the basis for comparing solar and geothermal heating costs to conventional fuel heating costs under our low price assumption. This levelized cost is equivalent to a current unit cost of 2¢/kWh of electricity, 46¢/gallon of fuel oil, or 27¢/therm of natural gas^(a). Low-cost natural gas comprises the majority of the cases below the median, whereas fuel oil and electricity prices are generally above the median. That is, few locations have electricity or fuel oil prices at or below 2¢/kWh or 46¢/gallon, respectively.

a. These are the equivalent current unit costs under the reference assumptions of electricity and fuel oil escalating at 7% per year and natural gas at 10% per year. Without inflation these costs are about equivalent to \$6.50/million Btu of delivered heat at the assumed furnace efficiencies.

Natural gas is the lowest-cost fuel in most locations under the low price assumption. However, under decontrol it is likely that natural gas will become competitively priced with fuel oil. Fuel oil prices used in our low price assumption are indicative of early 1979 values and do not reflect recent sharp OPEC price increases. With the continued threat of increase in foreign oil prices, it is likely that the low price assumption is now too low for valid comparisons. For this reason, analyses were also performed assuming a levelized conventional cost of \$15/million Btu. This levelized cost is equivalent to current unit prices of about 3¢/kWh of electricity, 75¢/gallon of fuel oil, or 45¢/therm of natural gas^(a).

Under lower conventional fuel price assumptions, which appeared more likely prior to 1979, geothermal energy would competitively provide about 4% (0.6 quads) and solar would competitively provide about 10% (1.8 quads) of the annual space heat demand. Conventional energy, of course, would continue to dominate the space heating market under these conditions. Although the percentage contributions of solar and geothermal in this case are low, the annual dollar volumes in equivalent energy sales would be huge -- on the order of \$18 billion for solar and \$6 billion for geothermal. In terms of equivalent barrels of oil saved annually, this would be 300 million barrels for solar and 100 million barrels for geothermal.

The competitive outlook for geothermal and solar heating changed dramatically during the past year. With the recent sharp price increases in imported oil and natural gas and the planned decontrol of domestic prices, geothermal and solar energy will become competitive for space heating throughout most of the country. Under these new conditions, geothermal energy could competitively provide about 40% of the national demand for space heat and domestic hot water (about 7 quads based on 1980 demands). Nearly all of the geothermal energy demand would be in high-population-density urban areas. Solar energy could competitively provide about 50% (about 9 quads) of the annual demand. Most of the solar energy demand would be concentrated in suburban and rural areas. Conventional energy should remain competitive for about 30% (about 5 quads) of the annual demand. Conventional energy demand would be concentrated in the South and as supplemental energy for solar/conventional systems. Geothermal, solar, and conventional energy would be equally competitive for about 20% of the annual demand, which is why the individual market shares add to 120%.

a. Again, under the reference price escalation assumptions.

The conditions under which solar, geothermal and solar/conventional heating are potentially competitive with \$10/million Btu and \$15/million Btu conventional heating were determined. Results of cost analyses indicate that:

- Compared to conventional heating costs of \$10/million Btu, geothermal heating is potentially attractive in Northwestern urban centers characterized by resource temperatures above 90°C, transmission distances below 50 miles, and annual heat loads greater than 3300°C-days/year. Geothermal suburban heating is not competitive with conventional heating under this low price assumption.
- With levelized conventional costs of \$15/million Btu, geothermal urban district heating is potentially attractive North of a line extending roughly from Los Angeles to Baltimore. That is, regions with a heat demand above 3000°C-days/year are generally favorable for urban heating from normal-gradient resources and regions above 1600°C-days/year are favorable for urban district heating from higher-temperature hydrothermal resources. Geothermal suburban district heating is potentially attractive in limited areas of the Northwest characterized by: (1) high annual heat demands (greater than 4000°C-days/year) for normal-gradient resources, or (2) annual heat demands above 2200°C-days/year for convective hydrothermal resources with transmission distances less than 15 miles.
- 100% solar heating for the suburban house, compared to a levelized conventional cost of \$10/million Btu, is attractive only in locations receiving more than 400 langleys/day, with an annual heat demand above 2800°C-days/year. Supplying 100% solar heat to the garden apartment is not competitive with conventional fuels at this price.
- Compared to conventional heating costs of \$15/million Btu, 100% solar heating for the suburban house is potentially attractive in the Southwest and Rocky Mountain regions. In general, these areas are characterized by daily solar insolation greater than 375 langleys and heat loads greater than 1400°C-days/yr. Supplying 100% solar heating to the garden apartment is potentially attractive in limited areas in the Rocky Mountain and Southwestern states. These areas are characterized by annual heat loads greater than 2800°C-days/year and daily insolation greater than 375 langleys.
- Solar/conventional systems for suburban residential heating with solar supplying at least 40% of the load are attractive in locations receiving at least

350 langleys/day and with annual heat demands above 2200°C-days/year when conventional fuel heating costs are \$10/million Btu. Solar/conventional systems for the garden apartment are attractive compared to conventional fuels at this price only in localized areas characterized by insolation greater than 375 langleys/day and heat demands above 4000°C-days/year.

- At a levelized conventional heating cost of \$15/million Btu, solar/conventional heating systems with solar supplying more than 40% of the load are potentially attractive for suburban home heating in locations where the heat load is greater than 1000°C-days/year and solar insolation exceeds 325 langleys/day. Solar/conventional heating systems are potentially attractive for urban heating where annual heat loads exceed 2800°C-days/year and insolation exceeds 325 langleys/day.
- Conventional heating systems at \$10/million Btu will remain attractive for urban heating in areas where geothermal resource temperatures are below 90°C or transmission distances for higher-temperature resources exceed 50 miles. Conventional systems at this price will remain attractive for suburban heating where solar insolation is below 375 langleys/day, and in areas where insolation is below 475 langleys/day with an annual heat demand less than 1400°C-days/year.
- Conventional heating at \$15/million Btu will remain attractive for the suburban house in areas of low heat demand or low solar insolation. In general, these areas have a heat demand less than 1600°C-days/year, or daily solar insolation less than 325 langleys. Conventional heating for garden apartments will remain attractive at this cost in most of the Southeast and in some areas in the Southwest. In general, these areas have: (1) daily solar insolation less than 350 langleys, (2) heat demands below 2800°C-days/year and geothermal resource temperatures less than 130°C, or (3) heat demands below 2800°C-days/year and transmission distances greater than 30 miles for resources above 130°C.

Section 8.2 is a regional analysis of the economics of residential heating under two scenarios, (1) with a median levelized conventional heating cost of \$10/million Btu, and (2) with a median levelized conventional heating cost of \$15/million Btu. Sections 8.3 and 8.4 discuss comparative fuel economics by heating application (i.e., suburban or urban residential heating).

8.2 THE POTENTIAL OF SOLAR AND GEOTHERMAL HEATING UNDER TWO SCENARIOS

This section presents the envelope of conditions under which solar, geothermal, or solar/conventional energy is likely to be attractive for residential heating compared to conventional levelized heating costs of \$10/million Btu or \$15/million Btu. The ten-dollar figure is indicative of assumptions made early in 1979 prior to OPEC oil price increases and the 15-dollar figure is a later assumption thought to be representative of current and near-term conditions. These figures, then, represent a range of most likely levelized conventional heating costs.

For each conventional heating cost assumption, locations where geothermal heating is lower in cost than the median conventional cost were plotted. Figure 8.1 shows locations where geothermal heating costs are below \$10/million Btu and Figure 8.2 shows locations at which geothermal heating costs are below \$15/million Btu. As shown in the figures, when competing with \$15/million Btu conventional fuel, geothermal is competitive in about four times as many locations as when competing with \$10/million Btu conventional fuel. Also, at \$15/million Btu, geothermal heat for suburban houses is attractive in some locations, whereas with the \$10 assumption geothermal suburban heating is not competitive in any of the locations.

With reference to Figures 8.1 and 8.2, a set of conditions under which geothermal heating is potentially attractive with respect to each levelized conventional heating cost assumption was developed. A one-mile transmission distance was assumed for the Eastern normal-gradient resource, and the transmission distance for Western convective hydrothermal resources was assumed to be the straight-line distance to the city studied.

Compared to conventional heating costs of \$10/million Btu, geothermal heating is potentially attractive in Northwestern urban centers characterized by resource temperatures above 90°C and annual heat loads greater than 3300°C-days/year. In general, transmission distances must be below 50 miles. As shown in Figure 8.1, geothermal heating for suburban houses is not competitive with conventional heating at this price.

With levelized conventional heating costs of \$15/million Btu, as shown in Figure 8.2, urban district heating from geothermal resources is potentially attractive in urban centers North of a line extending roughly from Los Angeles to Baltimore. In general, regions with annual heat loads above 3000°C-days/year are favorable for urban heating from normal-gradient resources and regions with annual heat loads above

FIGURE 8.1. Locations at Which Levelized Geothermal Heating Costs Are Below \$10/Million Btu

FIGURE 8.2. Locations at Which Levelized Geothermal Heating Costs Are Below \$15/Million Btu

1600°C-days/year are favorable for urban district heating from higher-temperature hydrothermal resources. Suburban district heating is potentially attractive only in limited areas of the West characterized by high annual heat loads and short geothermal transmission distances. In general, the annual heat load in these areas exceeds 4000°C-days/year and transmission distances are less than 15 miles.

Figure 8.3 shows locations at which levelized 100% solar heating costs are below \$10/million Btu and Figure 8.4 shows locations at which levelized 100% solar heating costs are below \$15/million Btu. The number of cities where solar is competitive with conventional heating is tripled when a levelized conventional heating cost of \$15/million Btu is assumed. Also, solar heating the garden apartment becomes attractive at some locations at conventional costs of \$15/million Btu, whereas at a conventional cost of \$10/million Btu, 100% solar heating for the garden apartment is not competitive.

The locations at which 100% solar heating for the suburban house is attractive with respect to \$10/million Btu conventional heat are characterized by daily solar insolation greater than 400 langleys and heat demands greater than 2800°C-days/year. Supplying 100% solar heat to the garden apartment is not competitive with conventional heat at \$10/million Btu.

From Figure 8.4, locations at which 100% solar levelized heating costs are less than \$15/million Btu are concentrated primarily in the Southwest and Rocky Mountain regions. These regions are characterized by high solar insolation and high annual heat demand. Solar heating the suburban house is potentially attractive in regions characterized by daily solar insolation greater than 375 langleys and annual heat loads above 1400°C-days/year. In general, solar heating the garden apartment is competitive with the median conventional cost of \$15/million Btu where daily solar insolation exceeds 375 langleys and the annual heat load is greater than 2800°C-days/year. Unlike geothermal district heating, solar heating is more attractive for the suburban house than for the garden apartment. The suburban house is representative of suburban and rural space heating applications; the garden apartment is representative of urban heating applications.

The locations at which the cost of a solar/conventional heating system (with solar supplying at least 40% of the load) is less than \$10 and \$15/million Btu are shown in Figures 8.5 and 8.6, respectively. From the figures it is apparent that solar/conventional heating at conventional costs of \$15/million Btu is attractive

FIGURE 8.3. Locations at Which Levelized 100% Solar Heating Costs
Are Below \$10/Million Btu

FIGURE 8.4. Locations at Which Levelized 100% Solar Heating Costs
Are Below \$15/Million Btu

FIGURE 8.5. Locations at Which Levelized Solar/Conventional Costs Are Below \$10/Million Btu

FIGURE 8.6. Locations at Which Levelized Solar/Conventional Costs Are Below \$15/Million Btu

throughout most of the United States for suburban heating. However, at conventional costs of \$10/million Btu, areas where solar/conventional heating are attractive are limited to the Rocky Mountain and Western Great Plains regions.

With reference to Figure 8.5, the envelope of conditions under which solar/conventional heating is competitive with conventional heat at a levelized price of \$10/million Btu was developed. In general, solar/conventional systems for suburban residential heating with solar supplying at least 40% of the load are attractive in locations receiving at least 350 langleys/day and with heat demands above 2200°C-days/year. Solar/conventional heating for the garden apartment is attractive compared to conventional fuels at \$10/million Btu only in localized areas characterized by daily insolation greater than 375 langleys and heat demands above 4000°C-days/year.

From Figure 8.6, which shows where solar/conventional heating is less than \$15/million Btu with solar supplying more than 40% of the heat load, the envelope of conditions under which solar/conventional heat is attractive was developed. As shown in the figure, solar-assisted conventional heating systems are potentially attractive in a wide variety of locations throughout the U.S. Solar/conventional systems for heating the suburban house are more economic than those for heating the garden apartment. In general, combined solar/conventional heating systems are economic for suburban houses in locations with annual heat loads greater than 1000°C-days/year and for garden apartments where annual heat loads are greater than 2800°C-days/year.

Figures 8.7 and 8.8 show cities where 100% solar, geothermal, and combined solar/conventional heating systems cannot compete with conventional fuels alone for residential heating. These two figures are composites of Figures 8.1 through 8.6.

Conventional heating will remain more attractive for heating the garden apartment than for heating the suburban house. This is largely due to the ability of solar to reduce the cost of a solar/conventional system in suburban heating applications. Conditions, in terms of solar and geothermal parameters, under which conventional fuels will remain attractive at levelized costs of \$10/million Btu and \$15/million Btu were derived from these figures.

In general, conventional heating systems at \$10/million Btu will remain attractive for urban heating in areas where geothermal resource temperatures are below 90°C or transmission distances exceed 50 miles. Conventional heating for suburban houses will remain attractive at this price where solar insolation is below 375 langleys/day, and in areas where solar insolation is less than 475 langleys/day with an annual

FIGURE 8.7. Locations Unfavorable for Solar, Geothermal and Combined Solar/Conventional Residential Heating

FIGURE 8.8. Locations Unfavorable for Solar, Geothermal and Combined Solar/Conventional Residential Heating

heat demand less than 1400°C-days/year.

At costs of \$15/million Btu, conventional heating will remain attractive in areas of low solar insolation, or low geothermal resource temperature combined with a low annual heat demand. In general, conventional heating for suburban homes is attractive where daily solar insolation is less than 325 langleys or in climates with heat demands less than 1200°C-days/year. Locations where heating the garden apartment with conventional fuels will remain attractive are characterized by geothermal resource temperatures below 90°C in climates with annual heat demands below 3000°C-days/year.

8.3 SUBURBAN RESIDENTIAL HEATING

The following discussion of the economics of suburban residential heating is based on analyses of the house shown in Figure A.1. In general, suburban heating is characterized by a high heat demand per dwelling unit and a low heat demand per population density. As discussed in previous sections, solar heating is less expensive when heat demand per unit is high and geothermal heating is less expensive when heat demand per population density is high. Conventional heating costs are independent of these parameters.

From figures presented in Section 8.2, it was determined that conventional heating was generally the most economic for the suburban house when conventional heating costs are \$10/million Btu. However, at a conventional heating cost of \$15/million Btu, the optimal combined solar/conventional system is most economic in most locations.

Under certain conditions, convective hydrothermal geothermal resources could be competitive with solar energy or conventional fuels for suburban heating. Figures 8.9 and 8.10 show geothermal transmission distances at which geothermal levelized heating costs are equivalent to median levelized solar or conventional heating costs for two different climates. Median solar and conventional levelized heating costs are indicated by the dashed lines in the figures. The median levelized solar heating cost is about \$21/million Btu. The median conventional fuel costs are shown for the two scenarios described in Section 8.1. Table 8.1 lists conditions under which geothermal energy is competitive with 100% solar heating at \$21/million Btu in a city (such as Salt Lake City) with an annual heat demand of 3300°C-days and a city (such as Riverside, California) with an annual heat demand of 1100°C-days. These data are taken from Figures 8.9 and 8.10.

FIGURE 8.9. Competitive Geothermal Transmission Distances for Suburban Houses in 3300°C-Day Climates

FIGURE 8.10. Competitive Geothermal Transmission Distances For Suburban Houses in 1100°C-Day Climates

TABLE 8.1. Maximum Transmission Distances at Which Geothermal Suburban Home Heating is Less Than \$21/Million Btu

<u>Temperature (°C)</u>	<u>Climate (°C Days/Yr)</u>	<u>Maximum Transmission Distance (Miles)</u>
150°C	3300	100
150°C	1100	17
100°C	3300	50
80°C	3300	25
60°C	3300	8

Figures 8.9 and 8.10 show that geothermal heating for suburban houses is not likely to be competitive with conventional heating at a median cost of \$10/million Btu. At a conventional heating cost of \$15/million Btu, geothermal heating may be attractive in climates where the heat demand is above 3300°C-days/year under the following conditions:

1. transmission distances below 40 miles for a 150°C resource,
2. transmission distances below 12 miles for a 100°C resource, and
3. transmission distances below 3 miles for an 80°C resource.

Resource temperatures below 80°C are not likely to be competitive for suburban home heating.

8.4 URBAN RESIDENTIAL HEATING

The following discussion of urban residential heating is based on analyses of the garden apartment shown in Figure A.3. The garden apartment, typical of urban residential heating applications, is characterized by low heat demand per dwelling unit and high heat demand per population density. Geothermal heating costs are lower in areas with high heat demand per population density and solar heating costs are lower in areas with high heat demand per dwelling unit. Conventional heating costs are independent of these parameters.

In general, conventional heating is the most economic for the garden apartment at levelized costs of \$10/million Btu. However, at a conventional heating cost of \$15/million Btu, solar/conventional and geothermal heating become the most economic, except in the Southeast.

Figures 8.11 and 8.12 show the levelized heating cost of the garden apartment in two climates as a function of geothermal transmission distance. The median cost of 100% solar heating is \$27/million Btu and the median costs of conventional fuels under two scenarios are \$10 and \$15/million Btu. Table 8.2 lists the conditions, taken from the figures, at which geothermal heating is competitive with 100% solar heating for the garden apartment.

TABLE 8.2. Maximum Transmission Distances at Which Geothermal Garden Apartment Heating is Less Than \$27/Million Btu

<u>Resource Temperature (°C)</u>	<u>Climate (°C-Days/Yr)</u>	<u>Maximum Transmission Distance (Miles)</u>
150°C	3300	above 150
150°C	1100	95
100°C	3300	125
100°C	1100	45
80°C	3300	75
80°C	1100	25
60°C	3300	35
60°C	1100	3

Geothermal resources in northern climates (3300°C-days) can be transmitted significant distances and remain more economic than solar for heating the garden apartment.

As shown in Figures 8.11 and 8.12, at a median conventional fuel price of \$10/million Btu, geothermal heating is most economic for heating the garden apartment under the following conditions:

1. transmission distance less than 50 miles for a 150°C resource in a 3300°C-day climate,
2. transmission distance less than 10 miles for a 150°C resource in an 1100°C-day climate,
3. transmission distance less than 20 miles for a 100°C resource in a 3300°C-day climate, and
4. transmission distance less than 6 miles for an 80°C resource in a 3300°C-day climate.

FIGURE 8.11. Competitive Geothermal Transmission Distances For Garden Apartments in 3300°C-Day Climates

FIGURE 8.12. Competitive Geothermal Transmission Distances For Garden Apartments in 1100°C-Day Climates

Resource temperatures below 130°C are not likely to be competitive with conventional fuels at \$10/million Btu in an 1100°C-day climate for garden apartment heating. Resource temperatures below 70°C are not likely to be competitive with conventional fuels at \$10/million Btu in the 3300°C-day climate.

From Figures 8.11 and 8.12, it can be seen that geothermal heating for the garden apartment is competitive with conventional heating at \$15/million Btu under the conditions listed in Table 8.3.

TABLE 8.3. Maximum Transmission Distances at Which Geothermal Garden Apartment Heating is Less Than \$15/Million Btu

<u>Resource Temperature (°C)</u>	<u>Climate (°C-Days/Yr)</u>	<u>Maximum Transmission Distance (Miles)</u>
150°C	3300	105
150°C	1100	35
100°C	3300	50
100°C	1100	10
80°C	3300	25
80°C	1100	2
60°C	3300	8

Resources below about 80°C do not appear to be competitive with conventional fuels at \$15/million Btu for heating the garden apartment in 1100°C-day climates. Convective hydrothermal resources (above 90°C) can be transmitted significant distances in any climate and remain competitive with conventional heating at \$15/million Btu.

APPENDIX A

FIGURE A.1. Plan of Suburban Residential House
54 x 30 ft. Attached Garage Not Shown

Design Parameters:

Heat Loss Coefficient: 6.5 Million Btu/°F/yr

Hot Water Load: 16.4 Million Btu/yr

(60 gal/day with a 50°C (90°F) temperature rise)

Dimensions

Floor ft²: 1620

Exterior Wall Area ft²: 918 (Net Glass)

Garage Wall Area ft²: 240

Window Glass ft²: 186

Door Area ft²: 21

Ceiling ft²: 1620

Story Height ft²: 8

Construction Parameters

Floor: Maple finish flooring on yellow pine subflooring

Exterior Walls: Brick veneer, building paper, wood sheathing, studding, metal lath, 2 inch insulation

Ceiling: Metal lath and plaster, 6 in. insulation

Windows: Double hung, wood windows

FIGURE A.2. Plan for High-Density Single Family Home

Design Parameters:

Heat Loss Coefficient: 4.14 Million Btu/°F/yr

Hot Water Load: 14.5 Million Btu/yr

(55 gal/day with a 50°C (90°F) temperature rise)

Dimensions:

Floor ft²: 1000

Exterior Walls ft²: 865

Window ft²: 133

Door ft²: 42

Ceiling ft²: 1000

Story Height ft : 8

Construction Parameters:

Floor: Maple finish flooring on yellow pine subflooring

Exterior Walls: Brick veneer, building paper, wood sheathing, studding, metal lath, 2 inch insulation

Ceiling: Metal lath and plaster, 6 in. insulation

Windows: Double hung wood windows

FIGURE A.3. Plan for Garden Apartment Unit

Design Parameters:

Heat Loss Coefficient: 167.9 Million Btu/°F/yr
(60 apartment units per building)

Hot Water Load: 83 Million Btu/yr
(3030 gal/day with a 50°C (90°F) temperature rise)

Dimensions:

Floor ft²: 990
Exterior Walls ft²: 617
Windows ft²: 82
Door ft²: 21
Ceiling: 1/2 (990) for Heat Loss
Story Height ft: 8

Construction Parameters:

Floor: Maple finish flooring on yellow pine subflooring
Exterior Walls: Brick veneer, building paper, wood sheathing, studding, metal lath, 2 inch insulation
Ceiling: Metal lath and plaster, 6 in. insulation
Windows: Double hung wood windows

FIGURE A.4. Plan for Townhouse Unit

Design Parameters:

Heat Loss Coefficient: 109.5 Million Btu/°F/yr
(30 units per building)

Hot Water Load: 41.6 Million Btu/yr
(1515 gal/day with a 50°C (90°F) temperature rise)

Dimensions:

Floor ft²: 506 (1st Story)

Floor ft²: 506 (2nd Story)

Exterior Wall ft²: 582

Window ft²: 124

Door ft²: 21

Ceiling ft²: 506

Story Height ft: 8

Construction Parameters:

Floor: Maple finish flooring on yellow pine subflooring

Exterior Walls: Brick veneer, building paper, wood sheathing, studding, metal lath, 2 inch insulation

Ceiling: Metal lath and plaster, 6 in. insulation

Windows: Double hung wood windows

FIGURE A.5. Plan for High-Rise Apartment Unit

Design Parameters:

Heat Loss Coefficient: 210.5 Million Btu/ $^{\circ}$ F/yr
(108 units per building)

Hot Water Load: 147.8 Million Btu/yr
(5400 gal/day with a 50 $^{\circ}$ C (90 $^{\circ}$ F) temperature rise)

Dimensions:

Floor ft²: 780

Exterior Wall ft²: 370

Windows ft²: 78

Door ft²: 21

Roof ft²: 1/9 (780) for Heat Loss

Story Height ft: 8

Construction Parameters:

Exterior Walls: Brick veneer, building paper, wood sheathing, studding, metal lath, 2 inch insulation

Ceiling: Metal lath and plaster, 6 in. insulation

Double hung wood windows

APPENDIX B

APPLICATION OF RESULTS TO SPECIFIC SITES

The purpose of this appendix is to illustrate the use of Figures 6.3-6.5 to determine the cost of geothermal district heating at a specific site. We will calculate the cost of district heating in Reno, Nevada using the geothermal resource at Steamboat Springs, approximately 10 miles south of Reno. The USGS estimate of the subsurface temperature at Steamboat Springs is 200°C, and the reservoir is assumed to lie between 0.3 km and 3.0 km below the surface.

ENERGY PRODUCTION COSTS

The cost of a production well drilled to the midpoint of the reservoir (1.65 km in this case) is \$340,000, based on the drilling cost models in GEOCITY. The assumed well flowrate is 199,760 kg/hr (equal to our reference value of 440,000 lb/hr). The ratio of well cost to well flowrate is 1.70. However, we should also include the cost of injection wells. If we assume that each injection well has sufficient capacity to absorb the flow from 2 production wells, the appropriate well cost to use is $(\$340,000)(1 + 1/2) = \$510,000$. The ratio of this well cost to the well flowrate is now 2.55. Therefore, the estimated wellhead energy production cost from Figure 6.3 is about \$0.80 per million Btu. (Note that this cost is obtained from reading the 150°C resource curve; actually, the production cost for a 200°C resource would be slightly less than \$0.80 per million Btu.)

As shown in the list of assumptions on Figure 6.3, the energy production costs are based on a load factor of 0.50. The load factor in Reno, which has 3345 Centigrade heating degree days, is only about 0.38. Therefore, the energy production cost from Figure 6.3 must be ratioed by $(0.5/0.38)$, which results in a cost of \$1.05 per million Btu. This higher cost reflects the lower degree of utilization of the production and injection well system. Figure B.1 shows the typical load factor as a function of climate, but some variation from these values in the actual load factor at a specific location may be expected.

ENERGY TRANSMISSION COSTS

The cost of fluid transmission from Steamboat Springs to Reno is obtained directly from Figure 6.4, since the actual transmission distance is 10 miles and Fig-

FIGURE B.1. Distribution System Load Factor As A Function of Climate

ure 6.4 is based on a transmission distance of 10 miles. (If the distance were actually 20 miles, the transmission cost from Figure 6.4 would have to be multiplied by 20/10.)

From previous work we know that if long distance transmission is involved, geothermal transmission pipe will have to be large (at least 24 inches in diameter in most applications) in order to be economically feasible. Thus, for this study we have assumed that the transmission pipe will have a 30-inch diameter in all cases. This corresponds to a flowrate of 5.5×10^6 lb/hr. The energy transmission cost for 150°C fluid for 10 miles at a flowrate of 5.5×10^6 lb/hr is about \$0.62 per million Btu. For this study we assumed that all resources with subsurface temperatures greater than or equal to 150°C are transmitted at 150°C, which is a realistic representation of the state-of-the-art technology. Again, this cost must be ratioed by (0.5/0.38) to account for the difference in load factor, which results in a cost of \$0.82 per million Btu. The transmission cost might be reduced if it is feasible to transport higher temperature water. We know of only one instance of higher temperature transmission (180°C).

ENERGY DISTRIBUTION COSTS

Energy distribution costs are obtained from Figure 6.5. For garden apartments, the cost is read from the graph at a population density of 18,300 people per square kilometer, which corresponds to the typical density in a district of garden apartments. The cost for a 3345°C day climate is about \$3.20 per million Btu. (The load factor multiplication operation does not need to be performed on this cost, since it has already been calculated and is implicit in Figure 6.5.) It is important to note that Figure 6.5 can only be used when the resource temperature is greater than 90°C. For normal-gradient resources, Figure 6.6, which shows the costs for distributing 60°C fluid, must be used.

TOTAL COST

The total cost of district heating garden apartments in Reno is the sum of these three costs, which is \$5.07 per million Btu. This cost is then levelized, as described in Section 3.3, to yield the levelized cost of \$5.78 per million Btu, which is shown in Table 7.4.

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