JHU/APL
QM-81-112
MCGER-81-002
APRIL 1982

Geothermal Energy Market Study on the Atlantic Coastal Plain

GRITS (Version 9): Model Description and User's Guide

Peter Kroll and Sally Minch Kane, Editors
The Center for Metropolitan Planning and Research
The Johns Hopkins University, Baltimore, Maryland 21218

This work was supported by the Department of Energy
under Interagency Agreement DE-Alo1-79-ET27025.

THE JOHNS HOPKINS UNIVERSITY ■ APPLIED PHYSICS LABORATORY

DISCLAIMER

JHU/APL
QM-81-112
MCGER-81-002
APRIL 1982

Geothermal Energy Market Study on the Atlantic Coastal Plain

GRITS (Version 9): Model Description and User's Guide

Peter Kroll and Sally Minch Kane, Editors
The Center for Metropolitan Planning and Research
The Johns Hopkins University, Baltimore, Maryland 21218

Other Principal Contributors:
William F. Barron*, William J. Toth*, Kwang Yu,
Fletcher C. Paddison, and Richard Weissbrod*

*No longer associated with The Johns Hopkins University

This work was supported by the Department of Energy under Interagency Agreement DE-Alo1-79-ET27025.

THE JOHNS HOPKINS UNIVERSITY ■ APPLIED PHYSICS LABORATORY
Johns Hopkins Road, Laurel, Maryland 20707
Operating under Contract N00024-81-C-5301 with the Department of the Navy

ABSTRACT

The Geothermal Resource Interactive Temporal Simulation (GRITS) model calculates the cost and revenue streams for the lifetime of a project that utilizes low to moderate temperature geothermal resources. With these estimates, the net present value of the project is determined. The GRITS model allows preliminary economic evaluations of direct-use applications of geothermal energy under a wide range of resource, demand, and financial conditions, some of which change over the lifetime of the project.

PREFACE

The Applied Physics Laboratory (APL) and the Center for Metropolitan Planning and Research (Metro Center) of The Johns Hopkins University supported the Department of Energy's Division of Geothermal Energy (DOE/DGE) in planning and assisting in the development of geothermal energy in the eastern United States. This effort included developing scenarios that represent potential geothermal utilization, conducting energy market surveys, formulating tools to analyze and optimize the cost of geothermal energy, and a methodology for prediction of market penetration, aiding in the technology transfer to states, groups, and individuals, and general support to DOE.

The GRITS computer program, described here, has evolved and grown over the years, answering the ever-changing need for an accounting/engineering/economics code to determine the cost of geothermal energy and study the effects of parameter changes in source, engineering or economic aspects. The initial architecture was the work of Richard Weissbrod, William Barron, Kwang Yu, Peter Kroll and Fletcher Paddison. The program then evolved in expanded capability by the efforts of Peter Kroll and William J. Toth, under the direction of William Barron.

At the Applied Physics Laboratory, W. J. Toth, Roy von Briesen and Kwang Yu calibrated some of GRITS's engineering equations and provided general guidance for maintaining the engineering credibility of the model. Albert M. Stone, Fletcher C. Paddison, Claude S. Leffel and Frank Mitchell also offered suggestions and encouragement in the various stages of GRITS's enhancements.

At the Center for Metropolitan Planning and Research, the guiding hands of Sally Minch Kane, Allen Goodman, Richard Weissbrod and John Boland helped keep GRITS on the right track and moving forward. We owe a priceless debt to those numerous student research assistants who put GRITS through thousands of test runs and early-on pointed out inconsistencies and errors in the debugging stage. Their suggestions in making the program friendly and analytically useful contributed greatly to GRITS. In particular, thanks go to Julia Cohan, Bruce Nilo and Susan Mitchell. Thanks also to the secretaries Linda Strott and Louie Fringer for typing the several drafts of this report and its predecessor, and to editors Sheila Westbrook and John Kaufman.

This report documents the final version of the GRITS program (Refs. 1 through 5). GRITS is an interactive computer program that calculates, under a variety of resource, load and climatic conditions, the initial and annual costs of an installation for the direct utilization of moderate temperature hydrothermal resources. The program will continue to be available either in the form of the computer tape and/or listing, or The Johns Hopkins University Computing Center will establish a computer account for operation of the program. Technical assistance in operating the program can be obtained by establishing an agreement with Mrs. Sally Minch Kane or Mr. Peter Kroll at the Center for Metropolitan Planning and Research at The Johns Hopkins University, Baltimore, Maryland. For other information, contact Mr. F. C. Paddison at the Applied Physics Laboratory.

CONTENTS

ILLUSTRATIONS

TABLES

1. OVERVIEW

INTRODUCTION

The GRITS computer model calculates the supply costs for each year of a project directly utilizing the heat of low to moderate temperature geothermal resources. With the model, a user may make preliminary economic evaluations of community heating systems or process heating applications. In addition to computing the annual energy production and costs, the model produces several summary economic accounting measures. The two principal measures are (a) the discounted average cost, i.e., the price that equates the discounted cost and revenue streams, and (b) the net present value, i.e., the sum of the discounted cost and revenue streams. When the user specifies a selling price for the energy produced that differs from the discounted average cost of producing the energy, the net present value differs from zero. The discounted average cost indicates the value of the goods and services required to bring a unit of energy to a customer. The net present value takes into account projected market conditions through the specified selling price (or price trend) for the energy produced and indicates the potential attractiveness of the investment to developers and financiers. Other summary financial measures are also provided.

The user of the model defines a project by specifying values for a wide range of resource conditions (e.g., number of production and reinjection wells, well depth, water temperature, pumping requirements, maximum flow rate), demand conditions (e.g., user type, local weather conditions, rate of market penetration), and financial conditions (e.g., interest rate, inflation rate, project lifetime, cost of purchased energy). The large number of options provides considerable flexibility to study specific situations. To facilitate operation of the program, conditions that the user does not specify for a given run are assigned the values from the previous run. At the outset all conditions are assigned their base case or default[1] values.

The user may specify parameters for many options as time-dependent functions (e.g., declining flow rates over time, rising costs for purchased energy over time). In the discussions in the following subsections, an asterisk (*) indicates that the user may specify the parameter value, while a double asterisk (**) indicates that the user may specify the value as a time-dependent function.

---

[1] A default value is a built-in value that has been established but that may be overridden when more pertinent values become available.

GRITS is designed to provide flexibility while keeping its operation simple and inexpensive. Once he has set up a "base case scenario" or if he uses the model's existing "default scenario," the user may specify a large number of parameter values and obtain his desired analysis by changing only those values of interest. The results of model runs may be displayed on an interactive terminal, and, if desired, the detailed outputs may be directed to a line printer. GRITS currently is programmed in English units; a metric version is under consideration.

Any simulation model, even the most complex, is necessarily a highly "stylized" representation of actual conditions. While considerable effort has been devoted to specifically modeling important engineering relationships, the results provided by GRITS are influenced by simplifying assumptions. GRITS is not intended to be an economic engineering model, i.e., one whose principal purpose is to determine the minimum cost engineering solution for a particular application. Engineering relationships in GRITS are modeled with sufficient accuracy to provide insights important for economic decisions. The primary purpose of GRITS is to model the impacts of changes in specific resource and economic parameter values on the economic accounting. In this respect, GRITS fills a gap between the engineering-oriented modeling of geothermal resources and economic modeling based on only the most general engineering relationships.

GRITS permits the incorporation of as much important technical design and operating information as possible, while minimizing the cost of running the program. Although it uses relatively detailed engineering formulas to determine the size and operational characteristics of major capital components, GRITS does not include elaborate internal optimization routines for designing subsections of the utilization system. For example, submersible pumps are sized and priced on the basis of user-specified flow rates and lift requirements. In contrast, the optimization of pipe sizes and insulation thickness for specific subsections of a community heating system is assumed to be reflected in the user-specified costs per mile of installed distribution pipe. The pumps are optimized because their sizes and costs will vary greatly depending on local reservoir conditions. It is important that the cost estimates reflect these local conditions. In contrast, for all but the smallest distribution systems, the average cost per mile of the system will fall within a more narrow range and hence for preliminary evaluations can be estimated in a generally applicable manner. GRITS includes enough engineering simulation to allow the user to track the impact on the cost and revenue streams of changes in reservoir characteristics or the type of end-use. However, since the model is designed to provide preliminary economic assessments, detailed calculations that are appropriate only for much more comprehensive evaluations are simplified in the model.

GEOTHERMAL ENERGY DELIVERY SYSTEM

The general configuration of the geothermal energy delivery system that is modeled by GRITS is shown in Fig. 1. The system consists of two loops. The first is the preliminary production loop wherein hot geothermal fluids are pumped to the surface by a submersible downhole pump in the production well. At the surface, the geothermal fluids may be temporarily stored in insulation storage tanks, or accumulators, that either permit some load-leveling under peak load conditions or increase the pump cycle times under less than full capacity loads. A circulating pump at the surface moves the geothermal fluids from the accumulator to the heat exchanger, where thermal energy is transferred to the secondary loop. The cooled geothermal fluids leaving the heat exchanger are then reinjected, either into the original aquifer or into some shallower aquifer that is compatible with the cooled geothermal fluid.

The water in the secondary loop is chemically treated to control corrosion in the pipes. It is heated to a higher temperature in the heat exchanger and piped through a two-pipe distribution network to some combination of residential, commercial, or industrial users. Each customer extracts the heat he requires and returns the cooled circulating water through a return network of pipes to the wellhead for reheating.

If the geothermal resource is not hot enough to provide circulating water at the desired temperature for its users, or if the heat demand exceeds the thermal output capability of the well, a fossil-fuel boiler topping system[1] may be used to provide extra heat.

A number of variations to this system can be envisioned. For example, if the quality of the geothermal fluids is good enough that surface disposal is practical, the reinjection well can be eliminated or the geothermal fluid might be used directly in a single-loop system. Another possibility might include a water-to-water heat pump to transfer the thermal energy from the geothermal

---

[1] Topping systems as used here signify boiler systems that are used to increase circulating water temperatures because resource temperatures are too low. As such they are in constant or nearly constant use. Peaking systems mean boiler systems that are used only to supply supplement heat under peak load conditions. This is done normally by increasing circulating water temperatures; the implication is that resource temperatures are sufficient to meet base load conditions.

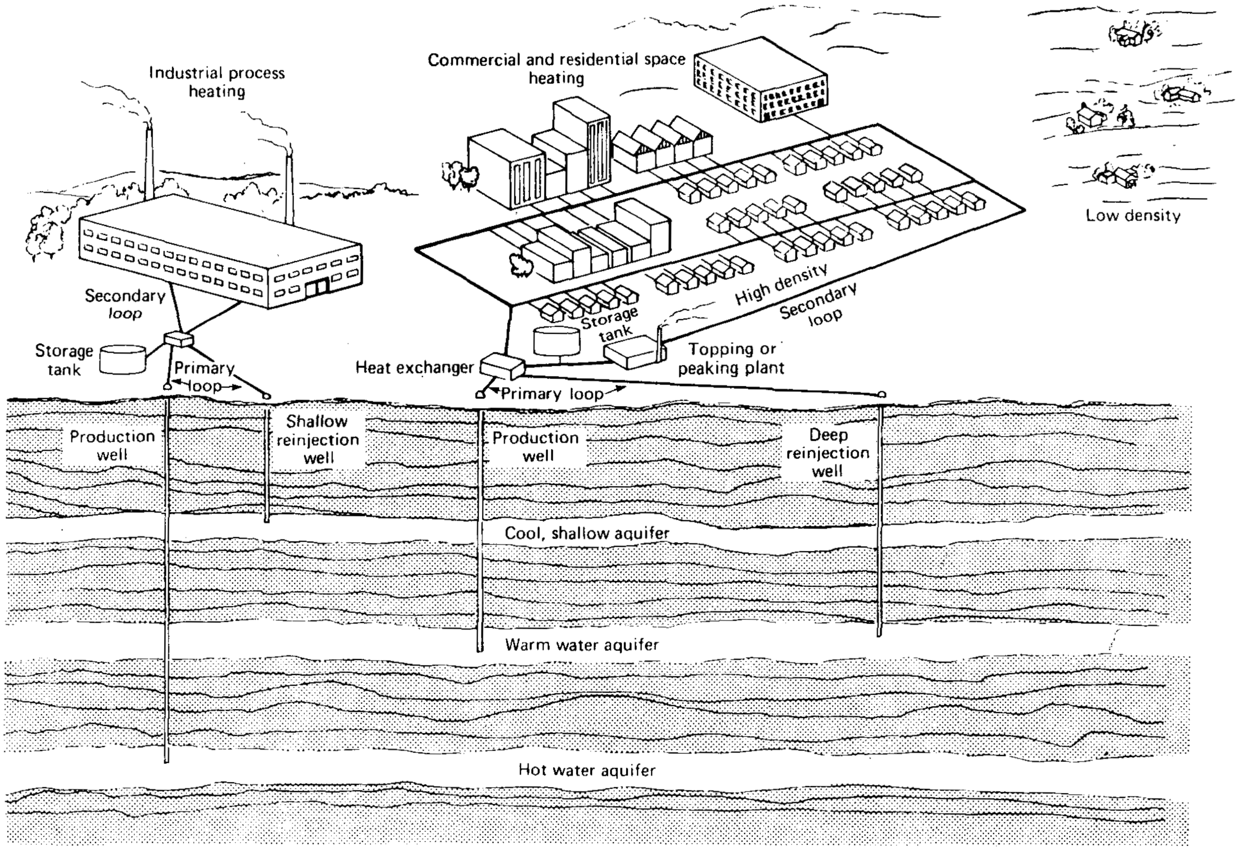

Fig. 1 Direct applications of moderate temperature geothermal energy.

fluid to the circulating water and to elevate the temperature of the circulating water above that of the resource. Still another variation might use fresh, potable water in an open secondary loop, where the customers use or dispose of the water.

Figure 1 represents a conservative system design since it is assumed that the geothermal waters are too brackish or mineralized for either direct use or surface disposal and therefore require a heat exchanger, a secondary loop, and a reinjection well. The secondary loop is assumed to be closed, which entails a two-pipe distribution network. Experience by others (Ref. 6) has shown that the topping system, which is simply a fossil-fuel-fired boiler, is for several reasons a cost-saving addition to the system. First, if the geothermal resource provides only the base load to the system, fewer wells are required and the cost savings easily exceed the cost of the boilers. Most peaking systems begin operating when the ambient temperature falls below a selected design temperature. Under periods of peak loading, the peaking system supplies the extra heat by elevating the circulating water temperature while maintaining constant flow. This allows a smaller size distribution system at additional savings. Finally, by serving the base load only, one geothermal well can be used for a longer time each heating season, which provides more energy for the same capital investment. Therefore, the hybrid system can serve more users at a lower cost than either a geothermal or fossil fuel system alone. One final advantage of a hybrid system is the ability of the peaking system to serve as a temporary backup system should problems occur in the operation of the well.

In order to specify the base load supplied by the geothermal well, the best mix of geothermal energy and topping system energy must be determined. This is done by varying the design temperature of the system to find the lowest discounted average cost of delivered energy. The design temperature is the lowest ambient temperature for which the geothermal well can supply 100% of the system's thermal needs. As ambient temperatures fall below the design temperature, the peaking system is used to supply the extra thermal energy requirements.

To meet the varying demands on the system, the production rate from the wells will vary, as will the drawdown, i.e., the level at which the water level stabilizes at full production. Based on the results of the well at Crisfield, Md. (Refs. 7, 8, and 9), maximum flow rates from a typical production well are not expected to be much more than 250 gal/min. Therefore, the model will design a system around a well that produces 250 gal/min, unless the user exercises his option to change this default value.

In order to obtain economic flow rates of up to 250 gal/min or more, a submersible pump probably will be required. As water is pumped from the well, the water level will fall until an equilibrium between aquifer productivity and pumping rate is achieved (drawdown). For ease of modeling, the difference between the equilibrium water level and the surface is expressed as a percentage of the depth of the well. Initial estimates for deeper aquifers in the Delmarva Peninsula indicate that drawdowns of up to 15% may be experienced for production rates on the order of 250 gal/min. The type of well completion (i.e., perforated casing versus screening and gravel packing) can significantly influence well drawdown, which in turn seriously affects the costs of delivering geothermal energy. Since the screening and gravel packing method is expected to provide better flow into the well, its use is assumed to reduce drawdown where this may pose a serious problem.

A plate-type stainless steel wellhead heat exchanger has been assumed, which is corrosion resistant and easily disassembled for maintenance. It is also assumed that it operates in a counterflow manner with a logarithmic-mean temperature difference across the heat exchanger of 7°F. This implies that circulating water is heated to within 7°F of the wellhead resource temperature, a stringent requirement that has been set to maximize the thermal output of the well and maintain reasonable costs.

Other system assumptions will become evident in the discussions that follow. Specific relations between parameters and specific assumptions used with the model are explained in Appendix A. The system design for the cost estimates generated by GRITS is fairly complex; however, it is felt that the overall configuration may be the most probable that will be encountered. Because of the system's complexities, the cost estimates of energy delivered by the system under default conditions are likely to be on the conservative side, but the flexibility of the GRITS model allows the specified parameters to be varied to reflect more optimistic as well as more conservative resource and operating conditions. Even with such a complex system design, geothermal energy can be cost competitive with conventional fuels for a wide variety of conditions, especially for industrial users.

EVALUATION PERIOD

The project evaluation period*, or financial lifetime of the project, includes a resource assessment phase (for exploration,

---

*As stated earlier, a single asterisk indicates that the user may specify the parameter value, while a double asterisk indicates that the user may specify the value as a time-dependent function.

testing, licensing, etc.) followed by a utilization phase (well drilling, installation of transmission and distribution system, acquisition of customers, well operation, and sales of energy). The assessment phase is specified by its duration* and annual costs*. The utilization phase is specified by duration (project evaluation period less length of assessment phase) and a large number of resource, demand, and financial conditions. If the assessment phase is given a zero time period, the evaluation period and utilization phase coincide. It is important to note that, even if the user limits the number of years reported in detail by GRITS, the period over which the project simulation is performed is defined by the full project evaluation period.

During the initial year of the utilization phase, costs are incurred for well drilling, purchase and installation of well-head equipment, and the transmission pipeline. For community heating applications, the distribution system may be installed at any starting time* and completed over any period** so long as it is installed at a rate that equals or exceeds the rate of market penetration**. Capital components are replaced in the year following the end of their expected useful life*. Typically, pumps and the central heat exchanger are replaced over the course of the utilization phase, while other components have a life exceeding this period.

OPERATING MODES

Resource-Specified and Demand-Specified Modes

Two different situations may face a potential geothermal developer. First, given a resource, he may assume that he can reach out and capture sufficient customers to use up all of the resource, or in the case of industrial process heat, that the developer has a buyer for all he could supply. This assumes that potential demand is unlimited, and that the resource could be used to capacity. Although this situation is likely to occur in many cases, it would also be useful to be able to size the system to meet only a specified demand such as a new housing or commercial development or potential industrial user.

GRITS can operate under either of these conditions. If a given resource is to be exploited fully under the assumption that whatever is available can be sold, the mode is termed "resource-constrained" or "resource-specified." If a given demand is to be satisfied (as long as the well's flow potential is not exceeded), the scenario is called "demand-constrained" or "demand-specified." (An earlier demand-specified program, DSM, is documented in Ref. 3, now superseded by GRITS.

Special Fossil-Fuel-Only Mode

A special mode of operation also is available in GRITS. Often in evaluating the desirability of a geothermal heating system, a comparison with an analogous fossil fuel fired system is useful. Option 0 (zero) permits--in the demand-specified scenario only--the ability to simulate a fossil fuel boiler supplied district heating or process heating system. (It would make no sense to have a fossil fuel system as the sole heat source in the resource constrained case. Because the geothermal resource provides no restraint on the size of the system, the system could be sized infinitely large without exceeding the resources limits.)

PROCESS HEATING ROUTINE

The user may select either a process heating routine (industrial) or a community heating routine (residential/commercial). The process heating routine calculates the cost of producing energy and delivering it from the wellhead to the plant gate via the transmission line. In the resource-specified case, the amount of heat delivered depends on the maximum thermal output of the well (based in turn on resource temperature**, reinjection temperature*, and flow rate**) and the industrial utilization factor* (the proportion of heat available from around-the-clock full pumping of the well that is utilized by the process heat user). If demand is specified, that demand is used in determining the maximum flow of the well. The capital cost of obtaining geothermal heat depends primarily on the well cost (a function of depth*), the length of the transmission* lines, and the interest charges*. Variable costs depend primarily on drawdown** and the cost of electricity** to operate the pumps. (A zero drawdown results in no cost for pumping energy or for wellhead pumps.)

COMMUNITY HEATING SYSTEM

The residential/commercial routine simulates the system that supplies dwelling units and commercial buildings through a community heating system. Housing type*, the number* and size* of commercial buildings and their heat load*, and the average hourly temperature data* determine space heating demands. Estimated sanitary hot water demands for both homes and commercial buildings are added to the space heating demand. The geothermal well supplies space heating requirements for outside temperatures at or above the design temperature* and all sanitary hot water. For temperatures below the design temperature, a fossil fuel peaking system raises the water temperature in the distribution network to meet additional requirements.

Energy from the wellhead is sent through the transmission line* to the distribution system and then to individual buildings on the system. In the resource-specified mode, the total demand served by a well depends on the maximum hourly thermal output of the well and the space and hot water requirements at the design temperature. The commercial heating demand is determined by the product of the total floor space* being served and the heating load per unit of floor space*, which is a function of the outside temperature. This demand at the design temperature is subtracted from the maximum hourly thermal output of the well, which leaves the amount available for residential heating. The remainder is divided by the space and hot water demand for the typical housing unit* (a single unit or a composite of several types) at the design temperature to determine the number of dwelling units served by the well. In addition to supplying all additional heating requirements at outside temperatures below the design temperature, the peaking system serves as a backup system that makes up energy deficiencies due to declining thermal output from the well.

In the demand-specified case, commercial demand is first satisfied, as in the resource-specified case. The total residential demand, calculated using the specified number of households and the characteristics of the typical housing unit, is then added. Once this total residential/commercial demand is calculated, the peak flow necessary to supply it is calculated. If this flow exceeds the maximum possible from the well, the simulation cannot be run; if the well can supply the flow, the maximum flow rate function is scaled proportionately.

The length of the distribution system needed to serve the commercial and residential area depends on several factors: the length of the commercial portion of the system*, data internal to the program on the density of each housing type, and the residential market saturation* (i.e., the proportion of all housing units within the market service area that ultimately join the system).

The user specifies the pace at which the distribution system is installed** (e.g., half the initial year and the remainder over the next two years). The installation should exceed or at least match the rate of market penetration**. A "rapid" market penetration could reflect mandatory participation, placement of the system in an area of new housing construction or commercial development, or special incentives to join. On the other hand, a community heating system that is just competitive with other fuels and relies on voluntary participation may experience a much slower penetration of its potential market service area.

The annual amount of energy required by system customers depends on the number of buildings and the heat load of each. Engineering relationships determine hourly space heating requirements as a function of outside temperature. The demand at a given temperature is multiplied by the average number of hours in a year that are at that temperature (see page 28). These demands are summed to determine the annual space heating demand. Sanitary hot water demand is determined on the basis of the commercial floor space and the number of households. Space heating and sanitary demands are then summed to determine total annual energy sales to system customers. All space heating demand for temperatures at or above the design temperature and all sanitary hot water demand are used to calculate the volume of water drawn annually from each well. The remaining requirements are used to determine the size of the peaking system boilers and the amount of peaking fuel required each year.

TREATMENT OF INFLATION

Prices in GRITS may be specified in real (constant) dollar terms or in nominal terms. In real-dollar calculations, the effects of the overall rate of price inflation in the economy have been eliminated, i.e., only differential price changes are considered. Economists generally prefer real-dollar calculations because they can be readily interpreted with respect to the current opportunity costs of a given outlay, e.g., the amount of goods and services that can be purchased for the same price as a unit of energy. However, because nominal costs may be useful for some financial analyses, this approach is also available (OPTION 25).

The user should understand that the price trends for peaking fuel and electricity are input to the model independently of the specified rate of inflation. The user should be sure that these trends are consistent with the real versus nominal dollar choice and, in the case of nominal dollars, with the specified rate of inflation. For example, if real costs are used and the price trend for electricity is input at 1.5%, the user is assuming that the price of electricity is rising 1.5% faster than the general rate of inflation. If nominal costs are used and the specified rate of inflation is 10%, the same price escalation for electricity must be represented by an input value of an 11.65% rate of increase.

Real-Dollar Values

While this approach facilitates the economic analysis, the standard loan repayment schedule requires special consideration. Typically, loan repayments are fixed in nominal monetary values for the entire repayment period. As inflation erodes the purchasing power of money, the real value of debt service payments decreases.

If all other prices are rising at the general rate of inflation*, then the opportunity cost (i.e., what the debt service payment could buy in the form of other goods and services) of the fixed nominal payment decreases over time. The real value of the fixed payment due in year "t" equals

$$[\text{Nominal payment} \div (1 + \text{rate of inflation})^{t}].$$

Loans indexed to inflation may be modeled through the use of a zero rate of inflation and of a real interest rate, e.g., 2 or 3% for low- or non-risk loans.

Nominal-Dollar Values

For nominal values all costs, except electricity, peaking fuel, and the selling price of the geothermal energy, are assumed to rise at the specified rate of inflation.[1] Thus, if one project includes a four-year resource assessment period and a rate of inflation of 10%, the price for each capital component is 1.46 times that for a project that has no assessment phase and bought its capital components when the four-year assessment phase was just beginning for the first project. If a piece of equipment is replaced during the project, the replacement cost is assumed to have risen at the rate of inflation. In contrast to the real-dollar approach, where debt service payments are actually devalued over time, debt service remains fixed in the nominal approach.

DISCOUNT RATE

Even if costs and revenues for different years have been reduced to the same real price equivalents, it is still important to consider the time preference for project returns. Typically, early revenues are preferred to later revenues, while later costs are preferred to costs incurred early in the project evaluation period. Several reasons support such preferences. If the income is available for productive investment, a dollar of revenue earned early in the project may be invested to provide a larger return later in the period. If a cost may be deferred to some later date, the money to meet that cost may be invested in the interim to provide a greater overall return. If income is needed for consumption, an early return means that the project's financiers must wait

---

[1] Of course, in the real-dollar approach, all prices except energy costs are also assumed (implicitly) to rise at the rate of inflation. This assumption is not shown directly in the model output, since only differential price inflation is of interest.

a shorter time for that consumption. It can be argued that, from society's point of view, the principal return from a geothermal project is the energy produced. Since such energy is very expensive to store, society prefers that it be produced annually as needed. Yet, if reliability of the geothermal resource becomes less certain as the period of exploitation lengthens, the later portion of the projected cost and revenue stream is less certain than the earlier. Less certain returns are generally valued at a lower level than more certain returns.

The distribution of projected returns through time affects their value for many reasons, including forgone investment opportunities, the need to wait longer for consumption, and the greater risk that later projected returns may not be realized. The usual method of teating this change is to reduce the value of later returns through a discount factor. Standard economic practice is to use a single rate of discount compounded annually. For example, if the discount rate is 2%, the projected return of a dollar in 10 years is valued at $0.82. The user of the model may select the appropriate discount rate* (including a zero rate if desired) to reflect time preference, opportunity cost, risk, or a combination of these.

INTERPRETING MODEL OUTPUTS

The treatment of debt service payments, the interrelationship between drawdown and market penetration, and the mid-period replacement of some pieces of capital equipment influence the cost trend in important ways. The user unfamiliar with the model's structure may find certain aspects of the cost trend seemingly counterintuitive. The real level of debt service payments declines over time as inflation erodes the buying power of the annual outlays to repay capital equipment loans. Variable costs will rise as utilization increases. Even at constant utilization, the cost of purchased energy (electricity to drive the downhole pumps and fossil fuel for peaking boilers) will typically rise over the life of the project. Thus, total cost (fixed plus variable) may continue to rise but will likely level off and then decline before the end of the evaluation period.

The particular level of drawdown specified by the user results from operating the well under conditions of "project maturity," i.e., maximum utilization. In the residential/commercial analysis, annual utilization levels will typically start at relatively low levels and require a year or more to reach the maximum level. During the years preceding project maturity, the actual level of drawdown is assumed to be proportionate to the degree of maturity attained to that point. For example, if the system will ultimately serve 20 commercial buildings and 1,000 housing units and will experience a 20% drawdown when this level of demand is first served, the average drawdown is assumed to be 10% in an earlier year when only 10 commercial buildings and 500 units are on the system.

While the typical evaluation period (financial project life) lasts 20 to 30 years, the expected life of some fixed plant components may be considerably shorter (e.g., 10 years for the central heat exchanger and downhole pumps). Such components are replaced in the year following the end of their expected useful lifetime. The model assumes that the nominal price of these components has been rising at the rate of inflation since the start of the utilization phase. Thus, the real cost remains unchanged. For equipment with a 10-year life, the real value of the debt service payments declines steadily over this period and then jumps in the eleventh year (replacement year) before beginning to decline again.

OPERATING GRITS

The GRITS program may be accessed by telephone using interactive terminals through the DEC-10 computer facility at the Homewood Campus of The Johns Hopkins University in Baltimore. After the user enters the system and accesses the program by typing RUN GRITS, a brief introduction is printed. To obtain a list of parameters and their corresponding option numbers, the user types HELP. The program will then ask which parameter the user wishes to change by printing out OPTION? The user types in the option number associated with the parameter of interest and presses the return key. The program will specify the unit of value to be used (e.g., degrees Fahrenheit, cost per mile) and wait for input. For some parameters where a limited range of values is accepted by the program, if the user types in an unacceptable value, the program will indicate the acceptable bounds and again request input data.

OPTIONS 0 through 9 are operational commands to display current parameter values, output program results to a line printer, specify the type of application (industrial or residential/commercial), execute and exit the program, and perform other program specifications. OPTIONS 10 through 53 allow the user to input specific parameter values for resource characteristics (e.g., wellhead temperature), demand conditions (e.g., rate of market penetration), and financial conditions (e.g., interest rate). To change a parameter value, the user enters the option, types the value, and then presses the return key; the program responds by again typing OPTION? After all desired changes have been made, the user may check the current set of values before executing the program by calling OPTION 1. To obtain printouts of model runs, the user calls OPTION 2 and specifies a file name, composed of six letters followed by a period and three additional letters. Once specified, the file remains open and records results until closed. If a file name is not specified for OPTION 2, no line printer record of that run will be made. (The user should note that creation of a file adds to the cost of operating the program. If a file is desired for some but not all runs, the user should close the file by again calling OPTION 2 for the next run and not specifying a file name, i.e., merely pressing RETURN.) OPTION 3 may be used to save a particular scenario for later use.

OPTION 7 executes the program. Final results are displayed on the user's terminal. After it is run, the program indicates its readiness to accept another set of values for the next run by printing OPTION? The user should note that the values input from the previous run are still in effect. They may be changed individually or the user may return to the original set of base case values by calling OPTION 3. After all runs have been made, the user exits the program by calling OPTION STOP. Once program execution ends, the user may request that his files be directed to the line printer.

This overview has presented some areas of the model in relatively little detail. Section 2 provides additional information on how specific resource and economic conditions are modeled in GRITS. Section 3 is a user's guide to running the GRITS program; Appendix A describes the more important engineering formulas and technical relationships internal to the model; and Appendix B lists all the options currently available in GRITS.

2. MODELING RESOURCE, DEMAND, AND FINANCIAL CONDITIONS

MODELING RESOURCE CONDITIONS

Production and Reinjection Wells

GRITS may be used to model single or multiple well systems with subsurface or surface disposal of spent geothermal fluids. The number of production and reinjection wells is specified through OPTIONS 42 and 43, respectively. The cost of each type of well (exclusive of pumps) is a function of depth. Default values currently in the model are: one production and one reinjection well each 5,000 feet deep and an unmodified well cost function, i.e., a cost coefficient of 1. The cost function coefficient may be modified by the user by OPTION 16 (see p. 69).

Extraction and Reinjection Pumping Energy Requirements

Production well pumping energy requirements are functions of the volume of water extracted and the distance it must be lifted to the surface. Reinjection energy is assumed to equal up-well pumping with a proportional adjustment for reinjection to a different depth; in other words, the requirement is multiplied by the ratio of the reinjection well depth to that of the production well.

Demand conditions, water temperature drop across the wellhead heat exchanger, and the maximum flow rate determine the volume of water extracted. Required lift is input through OPTION 26, "drawdown." This level, measured as a fraction of production well depth, is the average level to which the water in the well falls as a result of exploitation of the reservior. Artesian pressure, which typically provides some flow at the surface without pumping, may be sufficient in certain cases to meet demand. In this case, pumping is not required; a zero value for drawdown would reflect this condition.

For many situations, flow rates and the amount of pumping energy required are economic trade-offs. The nature of this interrelationship depends on the characteristics of the reservoir under study. OPTION 32 inputs maximum flow attainable from an average well. Both flow and drawdown may be specified as time-dependent functions; for example, drawdown may increase over time even with a constant flow rate because of reduced pressure within the aquifer. To keep GRITS generally applicable, the model accepts any combination of values for OPTIONS 26 and 32. The user may conduct sensitivity analyses regarding the economic nature of the trade-off by hypothesizing varying relationships between the flow and drawdown and determining the point on each function that results in the lowest cost for the energy produced.

Because usually little is known about the prospective resources, the drawdown is usually specified according to some stylized hypothetical trend over time. However, if certain information on aquifer characteristics is known, GRITS can be used to model the annual drawdown, and in turn the pumping energy, based on the aquifer parameters and pumping cycle. (This is incorporated in the drawdown OPTION 26, and supersedes the separate BIGMAC program, Ref. 4.)

Both the size of submersible pumps for the production well and the size of surface pumps for the reinjection well are determined as a function of the flow and drawdown. The life of these pumps is specified through OPTION 15. Original cost and annual maintenance are a function of size (see pages 78 through 81). The cost of each kilowatt hour of electricity to operate the pumps is specified through OPTION 20. The number of hours the pumps operate during a year depends on the volume of water extracted from a well, which in turn depends upon the utilization level (see page 27).

Thermal Output of the Well

The maximum net hourly output of energy delivered to the transmission line from the wellhead heat exchanger depends on the wellhead resource temperature (OPTION 11), the reject temperature (OPTION 21), and the maximum flow rate (OPTION 32). Utilization of this energy depends on demand conditions (see pages 55 through 63).

Central Heat Exchanger

A 7°F temperature drop across the wellhead heat exchanger is assumed. Cost estimates internal to the model assume a plate type construction with an expected life of 10 years (see page 86). the heat exchanger cost function coefficient (OPTION 17) and appropriate changes in expected equipment lifetime (OPTION 15). A zero value for OPTION 17 may be used to simulate an application in which the geothermal fluids are sent directly through the transport and distribution pipes.

Storage Tank

In order to minimize drawdown and therefore pumping energy, it is advantageous to pump longer periods of time at slower rates to reduce wear on the pumps. Thus, a storage tank near the wellhead heat exchanger may be desirable. The user indicates the capacity of this tank as the number of hours of storage at maximum flow from the well (OPTION 24). The cost of the tank is a function of capacity (see page 87). The default value is two hours of storage; a zero value for OPTION 24 eliminates the tank cost.

Transmission Line

The length of the transmission line from the wellhead to the industrial user or district distribution system is specified through OPTION 38. The cost per mile of this line depends on the number of wells and the maximum flow per well. Transmission pump costs and pumping energy requirements depend on the total flow and the length of the transmission pipe. The closed loop system from wellhead to distribution point and back to the wellhead is assumed to eliminate the effect of modest changes in elevation over the transmission distance. The user is allowed great flexibility in specifying the configuration of the transmission system, including interconnections among a number of production and reinjection wells. In this way, a variety of alternative designs can be laid out outside the model and then tested for their effect on capital and pumping costs.

MODELING DEMAND CONDITIONS

Utilization Level of the Resource

On the basis of wellhead temperature, reject temperature, and maximum flow rate, each geothermal well is capable of providing a calculated amount of energy per hour. Since demand is based on variable conditions (such as the industrial production cycle, weather conditions, or the extent of market penetration), the volume of water extracted from the well will often be less than the maximum and at times will drop to zero. Utilization refers to that fraction of the total annual amount of energy available from a well operating at capacity around the clock that the user requires.

The annual utilization factor for the industrial routine in GRITS is specified through OPTION 31. For the residential/commercial routine, the utilization level is a calculated value based on the number and types of buildings on the community heating system (OPTIONS 13 and 45 through 48), the temperature data for the region (OPTION 10), and the design temperature (OPTION 14), which determine the relative size of the geothermal base load and the fossil fuel peaking load.

Community Heating Systems

Areas Being Served. GRITS may be used to simulate a geothermal-supplied community heating system in any area for which the hourly temperature data are available.[1] Table 1 lists the U.S. cities whose data are stored in a library file accessible by GRITS. Use of the hourly data rather than the degree day information frequently used in other models lets the user optimize the relative size of the peaking system (see below).

Geothermal Base/Fossil Fuel Peaking Loads. When the level of demand depends primarily on outside temperature, it is highly inefficient to restrict the size of the system so that each customer's peak demand can be served by the geothermal well alone. If the system is expanded so that well capacity is reached at some warmer temperature (e.g., 35°F), utilization increases and the fixed costs are spread out over a large number of customers. The outside temperature at which the geothermal well reaches capacity is the design temperature (OPTION 14) of the system.

A peaking system serves incremental demand as the outside temperature falls below the design temperature. While individual customers may provide their own peaking plants, it appears to be better economically to provide this capacity by the community heating system. Among the factors favoring this approach are higher utilization of the distribution system and lower fuel costs to the system compared to those to individual operators (for example, bulk purchases or the possible use of coal in place of oil). OPTION 29 inputs the cost of peaking fuel in dollars per million Btu. This value may be input as a constant or a price trend. The amount of fuel required is a calculated value based on the size of the system, the temperature data, and the design temperature. The cost of the peaking boilers per 100,000 Btu per hour of capacity is input through OPTION 30. Peaking capacity is based on the minimum ambient temperature (OPTION 28), which typically would be somewhat below the coldest average temperature to provide a margin of safety. OPTION 28 may also be used to enlarge the boiler capacity sufficiently to provide as much backup (emergency) power as desired.

---

1. At this time, hourly temperature data for the 134 cities in Table 1 are in the model; it can accept such data for any other region.

TABLE 1

Cities for which weather data are available*

Birmingham, Alabama
Mobile, Alabama
Montgomery, Alabama
Anchorage, Alaska
Fairbanks, Alaska
Phoenix, Arizona
Tucson, Arizona
Little Rock, Arkansas
Bakersfield, California
Burbank, California
Fresno, California
Los Angeles, California
Oakland, California
Sacramento, California
San Diego, California
San Francisco, California
Colorado Springs, Colorado
Denver, Colorado
Hartford, Connecticut
Washington, D.C.
Wilmington, Delaware
Jacksonville, Florida
Miami, Florida
Orlando, Florida
Tallahassee, Florida
Tampa, Florida
West Palm Beach, Florida
Atlanta, Georgia
Augusta, Georgia
Macon, Georgia
Savannah, Georgia
Hilo, Hawaii
Honolulu, Hawaii
Boise, Idaho
Chicago, Illinois
Moline, Illinois
Springfield, Illinois
Evansville, Indiana
Fort Wayne, Indiana
Indianapolis, Indiana
South Bend, Indiana
Des Moines, Iowa
Sioux City, Iowa
Topeka, Kansas
Wichita, Kansas
Lexington, Kentucky
Louisville, Kentucky
Baton Rouge, Louisiana
Lake Charles, Louisiana
New Orleans, Louisiana
Shreveport, Louisiana
Portland, Maine
Baltimore, Maryland
Salisbury, Maryland[1]
Boston, Massachusetts
Detroit, Michigan
Flint, Michigan
Grand Rapids, Michigan
Duluth, Minnesota
Minneapolis, Minnesota
Jackson, Mississippi
Kansas City, Missouri
Saint Louis, Missouri
Springfield, Missouri
Great Falls, Montana
Omaha, Nebraska
Las Vegas, Nevada
Reno, Nevada
Atlantic City, New Jersey[2]
Newark, New Jersey
Albuquerque, New Mexico
Albany, New York
Binghamton, New York
Buffalo, New York
New York, New York
Rochester, New York
Syracuse, New York
Charlotte, North Carolina
Greensboro, North Carolina
Raleigh, North Carolina
Winston-Salem, North Carolina
Bismarck, North Dakota
Canton, Ohio
Cincinnati, Ohio
Cleveland, Ohio
Columbus, Ohio
Dayton, Ohio
Youngstown, Ohio
Oklahoma City, Oklahoma
Tulsa, Oklahoma
Medford, Oregon
Portland, Oregon
Salem, Oregon
Harrisburg, Pennsylvania
Philadelphia, Pennsylvania
Pittsburgh, Pennsylvania
Scranton, Pennsylvania
Providence, Rhode Island
Charleston, South Carolina
Columbia, South Carolina
Huron, South Dakota
Rapid City, South Dakota
Chattanooga, Tennessee
Knoxville, Tennessee
Memphis, Tennessee
Nashville, Tennessee
Amarillo, Texas
Austin, Texas
Brownsville, Texas
Corpus Christi, Texas
Dallas, Texas
El Paso, Texas
Fort Worth, Texas
Galveston, Texas
Houston, Texas
Laredo, Texas
Lubbock, Texas
Midland, Texas
San Antonio, Texas
Waco, Texas
Wichita Falls, Texas
Salt Lake City, Utah
Burlington, Vermont
Norfolk, Virginia
Richmond, Virginia
Roanoke, Virginia
Seattle-Tacoma, Washington
Spokane, Washington
San Juan, Puerto Rico
Charleston, West Virginia
Green Bay, Wisconsin
Madison, Wisconsin
Milwaukee, Wisconsin
Casper, Wyoming

---

*Listed alphabetically by state

Notes:

1. Weather data for Richmond, Virginia are actually used for Salisbury, Maryland.
2. Weather data for Wilmington, Delaware are actually used for Atlantic City, New Jersey.

The user may optimize the design temperature by varying this parameter until the lowest discounted average cost for each unit of energy is found. GRITS allows a user to loop through a range of design temperatures in one operation in order to find this optimum. The principal determinants of the optimum are the pumping energy requirements for the geothermal heat and the cost of the peaking fuel. A larger peaking system may also be viewed as reducing the risk of system failure if the well should temporarily shut down.

Distribution System. The length of the distribution system for a commercial area is a user-specified input (OPTION 50). The length for the residential/commercial area is a calculated value based on the housing type and the market saturation level (i.e., the fraction in a given area of all housing units that ultimately join the system). The cost for each mile of the installed distribution system is input through OPTION 22. The cost is assumed to reflect prior optimization of pipe sizes and insulation thicknesses. GRITS uses a default value of $250,000 per mile for the cost of the installed distribution system.

The rate at which the distribution system is installed is specified through OPTION 35 as the fraction of the total installed each year. Although this rate is independent of the rate of market penetration, it should exceed or at least equal the combined rate of market penetration for the commercial and residential portions of the system.

Commercial Area. The user models the size and makeup of the commercial area by specifying how many building types are being served (OPTION 45), the average floor space for each type (OPTION 46), and the number of buildings of each type (OPTION 48). The heating requirements of the commercial floor space in Btu per square foot per degree day and the sanitary hot water requirements in Btu per square foot per day are input through OPTION 47.

The hookup cost for each commercial building, specified by OPTION 49, includes the costs of laying the service pipe from the distribution system to the building and the cost of the energy meter to monitor consumption.

Residential Area. In order to determine the number of housing units of a given type or mixture of types that may be served by the combined residential/commercial system, commercial demand at the design temperature is subtracted from the energy available from each geothermal well at maximum flow.

GRITS include five housing types[1]: single-family suburban, single-family dense, townhouses, garden apartments, and high-rise apartments. The user may mix these five types in any combination, using OPTION 13. Space hot-water heating requirements for each housing type[2] are also specified using OPTION 13. Residential domestic hot-water heat is input, using OPTION 39.

Selection of the housing type also determines the density of the units and hence the length of the distribution system. The following densities[1] are assumed for each 400 by 200 ft block (street center to street center) in a grid system: single-family suburban, 7 units; single-family dense, 13 units; townhouses, 32 units; garden apartments, 50 units; and high-rise apartments, 120 units.

Hookup costs per housing unit, specified through OPTION 18, reflect the laying of pipe from the street center to the housing unit and the energy meter. The costs will generally be much lower on a per unit basis for apartments, which can share the service pipes, the meters, or both.

Market Saturation. To reflect conditions under which not all housing units in a given area join a community heating system, a market saturation level (OPTION 34) of less than 100% is used. As market saturation declines, the length of the distribution system required to serve the units that do join the system increases.

The market saturation level reflects the relative competitive position of the community heating system and the conversion costs for each type of housing unit. Some units (those with forced air or hot-water radiator heat) may have modest conversion costs, while others (those with electric baseboard heating) may face very high conversion costs.

Rate of Market Penetration. As noted above, the model first calculates the number of housing units to be served and then defines a service area on the assumption that a specific proportion of the units in this area will not join the system. Thus, the "market" for geothermal heat is defined on the basis of the desired number of customers and the density of units expected to join the system. The "rate of market penetration" refers, then to the pace at which

---

[1] These are modeled generally after those in GEOCITY (Ref. 10).

[2] These are modeled generally on data supplied by the Brookhaven National Laboratory (Ref. 11).

the predetermined number of customers, distributed over an area of specified size, joins the system. The distribution of joining over time depends on the user-specified functional form. It is important to remember that, when this form is not linear, a "rate" of penetration refers to specific values for the parameters in the function and not to the rate of any single year.

OPTIONS 19 and 51 input the rates of residential and commercial market penetration. The user first selects the appropriate function, (e.g., linear or log). Depending on the function selected, the program requests inputs specifying initial values, annual increments, or year of near-complete penetration. For example, if the user selects a linear function, the program requests the following inputs: initial percentage of housing or commercial units on the system and annual increase as a percentage of the final number of units on the system.

Utilization of the resource will rise as the system penetrates its market more completely each year. After the system reaches maturity (i.e., 100% market penetration for both residential and commercial areas), utilization becomes constant.

Since drawdown is related to flow and hence to utilization of the well, the drawdown specified in OPTION 26 is assumed to occur only when drawdown approaches the level specified at the same rate as the system approaches maturity, i.e., the rate of market penetration.

Industrial Process Heating System

Unlike the community heating system, the market for industrial process heat is not characterized by the distribution of many small users over a large area. Since only a few (or even one) major users represent sufficient demand for a geothermal resource, the industrial routine does not need to consider the market factors included in the community heating system analysis nor a variable demand dependent on ambient temperature. The system transports the energy from the wellhead to the user's plant gate, and the proportion of the well output indicated by the utilization factor is used by the process heat user.

MODELING FINANCIAL CONDITIONS

Economic Accounting Measures

The two principal summary measures provided by GRITS are the discounted average cost per million Btu and the net present value of the system at the end of the project evaluation period (project lifetime). The program also calculates the year in which break-even occurs, the total capital cost for the system, and other measures.

The discounted average cost is a useful measure because with only minor adjustments it may be compared directly with the cost of other space heating fuels. The net present value is useful as an indicator of the growth potential for the investment in the geothermal system. OPTION 40 allows the user to select one or both of these measures.

The discounted average cost includes both geothermal and peaking energy outputs and cost for the entire production and utilization system. To permit evaluation of strictly geothermal-related costs and outputs, the discounted average wellhead costs per million geothermal Btu are also output.

The total capital costs are simply the sum of the unamortized outlays for initial system components, exclusive of replacement costs. Typically, a very high proportion of these costs is incurred in the first year of the utilization phase; hence the capital costs are referred to here as "initial capital costs." This measure is a useful indicator of the size of the initial investment required to utilize the geothermal energy.

Calculation of the net present value requires an assumed selling price for the geothermal developer's energy output. Selling price is input through OPTION 36. Currently, the default price is pegged to 70% of that assumed for electricity (OPTION 20).

In addition, GRITS calculates the savings in operating costs due to the use of geothermal energy instead of fossil fuel. These are reported in undiscounted dollars by the program, and when the cumulative savings exceed the initial capital investment, "payback" is said to have occurred.

Evaluation Period or Lifetime of Project

The evaluation period, or project lifetime, is composed of a resource assessment phase and a utilization phase. The assessment phase is modeled in a very general manner as a total annual assessment cost occurring over a specified period (OPTION 41) before utilization of the resource. This period reflects exploration and testing costs, as well as licensing, permit acquisition, and other requirements. The utilization phase is calculated as the time remaining in the evaluation period (OPTION 33) after the assessment phase. The current default value for the evaluation period is 20 years with no assessment phase. If the user desires the results from only a subset of years in the evaluation period, this request is made during execution of the scenario (OPTION 7), not by changing the length of the evaluation period.

At the option of the user, all capital equipment must (or might not) be paid off before the end of the evaluation period.

Annual Capital Costs

The nominal annualized cost of capital loans borrowed at an interest rate of "i" and repaid over a period of "T" years is determined by multiplying the amount borrowed by the capital recovery factor (CRF):

$$\text{Amount borrowed} \times \{i \div [(1 + i)^T - 1] + i\} .$$

The CRF is calculated separately for each major component of the fixed plant on the basis of either its amortization period (which may be shorter than its useful physical life) or the end of the project evaluation period, if the amortization period is chosen to be restricted to that (both the physical life and amortization period are specified in OPTION 15). If the amortization period must end by the end of the project evaluation period, all debt will have been repaid by that time. OPTION 27 inputs the interest rate.

When costs are calculated in real dollars (OPTION 25), the model "deflates" the value of the annual debt service payment by the rate of inflation. Thus for inflation rate "r," the model values the annual debt service payments in year "t" as,

$$\frac{\text{Amount borrowed} \times \{i \div [(1 + i)^T - 1] + i\}}{(1 + r)^t} .$$

For example, a well costing \$400,000 financed at 12% interest over 20 years had a nominal annual cost of about \$53,500. In the initial year (Year 0) of the utilization phase, the real value and nominal value coincide. If inflation has progressed at an annual rate of 8% since the start of the utilization phase, the real value of the annual well cost in Year 4 is about \$39,000.

Debt Financing

Currently, GRITS assumes that all capital costs are financed through debt and that all operating costs are financed through revenues. This restriction makes the financial simulation less realistic, but introduces only relatively minor distortions in preliminary analyses. Whether they are holders of debt (e.g., bonds) or equity (e.g., common stock), investors will require similar levels of return for investments with a given level of perceived risk. Of course, investors will differ in their willingness to accept risk, in their preference for the timing of the stream of returns, and in the tax liability of different types of returns (such as dividends or interest payments versus capital gains). Such considerations will be important for more comprehensive assessments suitable to a later stage in the evaluation process. However, preliminary assessments that are concerned with more general issues affecting project viability are only minimally affected.

Taxes

A routine to calculate taxes is under consideration but is not yet implemented in GRITS. As for the method of financing, tax considerations will have a relatively minor impact on the outcome of preliminary economic assessments. Other factors such as long-term resource reliability or the cost of competing fuels are likely to be more uncertain and thus more crucial in the early stages of resource evaluation.

Interest Rate/Inflation Rate

The interest rate is composed of three basic elements: a rate of return reflecting time preference, a rate reflecting investment risk assessment, and the expected rate of inflation. A 15% interest rate may be composed of a 2% time preference (an annual 2% return for a risk-free investment in addition to compensation for inflation over the year), a 3% risk assessment (a 3% return each year as compensation for the possibility that the loan will not be repaid as expected), and a roughly 9 1/2% expected rate of inflation over each year of the loan repayment period - thus yielding an interest rate of (1.02)(1.03)(1.095) = 15%.

The interest rate is input through OPTION 27 and the rate of expected inflation through OPTION 25. Since they are specified independently, it is the user's responsibility to input an inflation rate consistent with his interest rate assumptions. Default values for these rates are 13.5% interest and 8% inflation. The base case assumes a low-risk investment, or one in which the tax benefits (e.g., municipal bonds) permit the investor to use a lower before-tax real return for time preference and risk premiums.

The use of a loan indexed to inflation may be simulated through a zero rate of inflation and an inflation-free interest rate.

Discount Rate

Returns that come later in a project evaluation period are generally valued less than those that come earlier (see page 21). The most common approach to discounting a stream of returns is to apply a single discounting factor that increases in a multiplicative manner over time, i.e., $(1 + r)^t$, where r is the discount rate and t is the number of years in the future when the return is expected.

At a 2% discount rate, a return of $1.00 will be valued at $0.98 the next year, $0.82 in 10 years, and $0.45 in 40 years. At a 6% discount rate, these returns would be $0.94, $0.56, and $0.10. The discount rate used in GRITS should reflect a real rate, that is, the effects of the general rate should not be considered. Discount rates may also include risk premiums.

Risk Assessment

Considerable uncertainty exists in regard to the long-term reliability of specific geothermal reservoirs. Wells, wellhead equipment, the transmission system, and the distribution system represent large fixed investments that must be incurred even if the resource fails to meet expectations or if demand levels fall short of projections. Thus, potential investors may view geothermal utilization systems as involving considerable amounts of risk. The user may model the level of risk assessment by adding a "risk component" to the interest rate or the discount rate. For example, the interest rate might be raised from 12% to 18% or the discount rate from 2% to 8%. Another approach is to shorten the project evaluation period (financial lifetime). Each of these changes will, of course, raise average cost and lower net present value. This approach reflects the fact that the level of risk assessed by potential private investors is a cost that the geothermal utility can possibly be forced to bear.

Cost of Major Capital Items

GRITS includes internal cost formulas for major system components. The actual cost is calculated on the basis of user-specified values for size and design of each component. To allow greater flexibility, cost formulas for several major components may be scaled up or down to suit local conditions.

Heat exchanger costs are calculated on the basis of the temperature drop (Δt) across the heat exchanger. To simulate the use of special materials, designs, or even the absence of a central heat exchanger, the user may modify the cost of this component by a coefficient input through OPTION 17 (default value = 1.00). If the use of a different material (say, specially coated alloys) is simulated, the user may wish to change the expected life of the heat exchanger in OPTION 15.

GRITS calculates well costs as a function of depth. To account for different soil conditions or other factors affecting well drilling and completion costs, the user may input a value different from 1.00 in OPTION 16 to scale the cost estimate to the desired degree.

The cost of an average mile of an installed dual-pipe distribution system is input through OPTION 22. The estimate is a composite one for a portion of the distribution main and the secondary lines feeding from it. For most types of community heating systems, an average cost per mile is a very convenient and useful first approximation of the actual costs that would be found in a detailed calculation of pipe sizes for subsections of the system, optimal insulation thicknesses, and trenching costs. The default value in GRITS is $250,000 per mile.

The storage tank cost is a function of capacity, which in turn is a function of the maximum flow rate (OPTION 32) and the storage time at maximum flow (OPTION 24).

The cost of each 100,000 Btu per hour of capacity for the peaking boilers is input through OPTION 30. Total boiler Btu capacity is a calculated value based on the difference in demand at the design temperature (OPTION 14) and at the minimum ambient temperature down to which the system can supply all heating requirements (OPTION 28). If the thermal output potential of the well declines as a result of values used for resource temperature or maximum flow, the capacity of the peaking system automatically expands to make up the difference.

Expected physical and economic lifetimes for major capital components are input through OPTION 15. If a component such as the pumps has an expected useful physical life less than the project lifetime, it is replaced in the year following the end of its expected lifetime. Equipment costs are amortized over the expected amortization period (financial lifetime), or if the user chooses, over the remaining years of the project evaluation period, whichever is shorter.

Operation and Maintenance Costs

Operation and maintenance costs are calculated annually as a percentage of the capital investment in the project. The default value of 1% may be changed through OPTION 44.

Cost of Purchased Energy

The user specifies the costs of peaking energy and electricity to operate the pumps through OPTIONS 29 and 20, respectively. The default value for peaking oil costs is $9.00 per million Btu, rising in real terms (i.e., after allowing for inflation) at a compound rate of 4% annually. The default price trend for electricity is $0.062 per kilowatt hour, rising at a compound rate of 2% annually.

3. RUNNING THE PROGRAM - A USER'S GUIDE

This chapter presents a brief description of the program options available in the GRITS program that is currently running on the time sharing system of The Johns Hopkins University's DEC-10 system at the Baltimore campus. The program is accessible to low- or high-speed terminals from any location, over regular telephone lines. The summary descriptions of the program options should be sufficient for the user who has knowledge of the modeling concepts used in GRITS to operate the program immediately without further instruction. Prompts by the program are intended to be self-explanatory, and an on-line help message system is available. In addition, the current status of the scenario is always available for display at the terminal.

The values of most system parameters can be changed by the program user, permitting a determination of the impact on economic measures, specific annual costs, and system characteristics caused by changes in a certain parameter. If a parameter value is not specified by the user, the program uses the default value. The default values are shown in Appendix C.

ACCESSING GRITS

GRITS is accessed from a computer terminal[1] as follows:

1. Dial the computer in Baltimore at (301) 338-7222 for low-speed lines or (301) 338-8403 for 1200 baud transmission,[2]
2. Place the telephone receiver in the acoustic coupler on the terminal, and
3. Press the RETURN key. The user must now enter the account number to access the DEC-10 system, followed by the confidential password for that account. The password will not appear on the terminal.[3]

---

[1] The terminal must be set to full duplex mode and proper speed.

[2] The Johns Hopkins DEC-10 offers both the Vadic 3400 and Bell 212A protocols for 1200 baud transmission.

[3] When this section presents user dialogue with the computer, characters typed by the user are indicated by underlining; the underlining is not actually typed by the user.

```
.LOGIN a,b

Password: _________
```

A "." will then appear at the left of the screen (a welcome message may first appear on the terminal), which means that the computer is in "monitor mode." To run the GRITS program, the user then types

```
.RUN GRITS
```

The program is now waiting to accept the first option.

SELECTING OPTIONS

After accessing GRITS, the user selects any of the available program options and follows the prompts given by the program. OPTIONS 0 through 9 are program operation commands, while OPTIONS 10 through 53 are used to adjust scenario parameters. To change a parameter, the user simply types its option number and presses the RETURN key (all responses must be followed by pressing RETURN). The program will specify the unit of value to be used (e.g., cost in dollars per million Btu) and wait for input. For some parameters, a limited range of values is accepted by the program. If the user types in an unacceptable value, the value is requested again.

For most options requiring a numeric input, if the user enters the option but then decides to leave it unchanged, he may exit from it by typing an asterisk (*). After all desired changes have been made, the user may then review the scenario or run it. (Note that the scenario is actually run only when OPTION 7 is chosen.) Once a scenario has been run, the program can immediately accept new parameters for the next run. *All parameters, once changed by the user, remain at those values until changed again.* Thus, if the well depth on the first run is changed from its default value of 5000 to 7000 ft, the well depth value will remain 7000 for subsequent runs unless changed again by the user.

ENDING THE SESSION

The user can run as many simulation scenarios as he desires. When he has finished, he must first exit from GRITS using its OPTION STOP. This places the terminal back into computer's monitor mode. If the previous run has generated any detailed printout for the line printer, the following command must be typed:

```
.PRINT/DEL/FILE:FOR FILE1.A,FILE2.B,etc.,
```

where FILE1.A,FILE2.B,etc. represent all files specified by the user in OPTION 2. This will print out the files then delete them from the system. Finally, the user must log off from the system by typing the command

```
.K/F
```

The next section describes each option (in detail if necessary). The options are presented in four categories: Operating Commands, Resource Conditions, Demand Conditions, and Financial Conditions. (The numbers associated with the options are in no particular order; they merely indicate the order in which they were added to the program. To find a particular option, check the table of contents or Appendix C.)

PROGRAM OPERATING OPTIONS

List the Available Options (OPTION H [HELP])

By typing HELP, a list of all (or a selected subset) of the available options will be displayed.

End Execution of GRITS (OPTION S [STOP])

Typing STOP will end execution of the program (the user is first given the opportunity to save the current scenario as a base-case file). STOP closes all open files and will return the user to monitor mode where he must print out any relevant files and log off from the system.

List Current Scenario Parameter Values (OPTION 1)

OPTION 1 displays the current values of all scenario parameters specified to this point by the user. Since the user may only be interested in a particular set of parameters, he may choose to see either the program operating commands (OPTIONS 0 through 9), resource, demand, or financial options, or all options.

Execute the Current Scenario (OPTION 7)

OPTION 7 tells GRITS to simulate the current scenario. If an output file has been specified earlier in OPTION 2, it is open and can receive detailed results for each year simulated as well as record the scenario parameters and the summary results for the project. If no output file is open the program will immediately ask for the level of detail going out to be reported at the terminal (see the section following the next one).

Specifying Level of Detail in an Output File. The detail of output going to the file may be selected at any of three levels. For the last three choices, a complete listing of the scenario parameters is generated in all cases. The choices are:

0. No results will be output to the file.
1. Final summary results of the project, plus a listing of the scenario, will be output to the file.
2. Full detail for *all* calculated years, plus the scenario listing, will be output to the file.
3. Full detail for *selected* years, plus the scenario listing, will be output to the file.

The last choice permits the user to have printed out selectively the detailed results for only certain years. For example, if the evaluation period of the scenario has been specified as 20 years in 5-year intervals (i.e., calculating years 0, 5, 10, 15, and 19 [year 0 is always the first year; the last year — 19 in this case — is always calculated]), the user may want to specify that only years 0, 10, and 19 be reported in detail in the printout. If the evaluation interval was instead 1 year, then the user might type, say, 0-5, 10, 19, to have those years printed.

Specifying Level of Detail to be Reported at the Terminal. GRITS will request the level of detail at which the results should be displayed on the user's terminal (note that the detail specified here will not affect what is sent to any output files that may be open). Any of four choices may be made by typing the associated number:

1. Will print out only the summary results over the project lifetime, including initial capital investment, discounted average cost, and net present value;
2. Will print out an annual summary of the project for each year of evaluation, including average costs, as well as the final summary as in 1;
3. Will print out detailed results of the scenario for *each* year of the evaluation, including each cost component and certain demand and operation statistics; as well as the final summary as in 1;
4. Will printout detailed results for *selected* years of the evaluation, including each cost component and certain demand and operation statistics; a final summary

of the project is also printed. Operation of this last choice is similar to the selective reporting to an output file.

Output to EZPLOT Data Files. Also, if OPTION 8 has been chosen to record annual data in the files for later input to a plotting program (see OPTION 8 for further details), the chosen variables will be written out for each year of the simulation or for each design temperature in the loop, depending on the user's specification of OPTION 8. These files will be automatically closed when the scenario has completed execution.

Choose Resource-Constrained or Demand-Constrained Mode (OPTION 9)

OPTION 9 tells GRITS to size the system constrained by either the specified resource or demand; this holds for both residential/commercial and industrial scenarios. If the user chooses the resource-constrained mode in OPTION 9, then the program operates by bringing enough demand on the system to use the resource fully.[1]

If OPTION 9 is used to select the demand-constrained mode, then only enough of the resource necessary to supply the specified demand is used. GRITS determines the flow necessary in the final year to supply all demand. The specified flow function is then adjusted proportionately for each year of simulation. For example, if the user initially specified OPTION 32 with a flow of 300 gal/min declining to a level of 200 gal/min by the final year, and if the flow required to meet the demand-specified scenario was only 100 gal/min, then the flow function used in the annual simulation by GRITS would be halved, making it start at 150 gal/min and drop to 100 gal/min in the final year. The user may want to change the specified flow function (and the drawdown and wellhead temperature functions, neither of which undergoes any proportional adjustment) if the results of the demand-specified scenario indicate that the estimated behavior of the resource should be revised. Such a change can have a strong effect on the system costs since, although the supply-demand balance is set in the final year of the system, the sizing of capital equipment purchases in both resource- and demand-specified scenarios is based on the maximum resource conditions such as the peak (initial) flow (150 gal/min in the example above).

---

[1] In the residential/commercial case, the number of households is rounded down to avoid fractional households; the flow is adjusted accordingly.

The commercial demand (taken as given in both the resource- and demand-constrained cases) is defined in OPTIONS 45 through 51. OPTION 52 allows the user to indicate the number of households to be placed on the system when GRITS is operating in the demand-constrained mode. OPTION 53 allows specification of the hourly industrial process heat during hours of operation in the industrial case of the demand constrained mode. It is important to note that these specified values are ignored when GRITS is running in the resource-constrained case. Similarly, after GRITS has simulated a resource-constrained scenario and has calculated a demand that can be served, that value is ignored if the demand-constrained case is then selected since whatever value was last specified as OPTION 52 or OPTION 53 remains as the specified demand. For example, suppose the user specified that OPTION 52 be 100 households. If the resource-constrained case were run, we might find that 200 households were placed on the system. If he then chose OPTION 9 and selected a demand-constrained simulation, the 100 households would be used to size the system.

Also, note that since the residential demand is independent of the commercial demand in the demand-specified case, the user can model four possible scenarios in which the demand is prescribed:

1. Industrial,
2. Residential/commercial mix,
3. Residential-alone, and
4. Commercial-alone.

The residential-alone (no commercial) scenario can be easily chosen by specifying OPTION 5 as residential/commercial, then stating that no commercial buildings will be on the system. GRITS then automatically retains the characteristics of all existing commercial building types, but sets the number of buildings in each to zero. To set a residential/commercial scenario to commercial-alone (for the demand-specified case only), choose OPTION 52 and specify zero households to be on any demand-constrained system.

Choose Residential/Commercial or Industrial Demand (OPTION 5)

OPTION 5 allows the user to select the type of demand on the system. Either residential/commercial district heating or industrial process heating can be specified. If residential/commercial is selected, the user is asked whether commercial buildings are to be included. If the response is "No", GRITS sets the number of buildings of each type to zero, but retains their characteristics in memory. In this way, subsequent scenarios will have no commercial demand, but if the user later wishes to use the earlier commercial building types with the previously declared characteristics, they can be used by specifying the number of buildings of each type using OPTION 48. This is in contrast to declaring that there be no building types by using OPTION 45 to erase all building characteristics. That would require the user to completely reenter them if they are needed later.

Other than possibly changing the number of commercial buildings to zero, *altering the scenario to either residential/commercial or industrial has no effect on any other parameters.* Resource, demand, and financial conditions remain as previously specified, until changed by the user. (Any parameters irrelevant to one type of demand or the other will be ignored, such as distribution system cost for industrial process heat.)

Save or Recall a Base Case Scenario (OPTION 3)

OPTION 3 permits saving or recalling the parameters of a previously defined scenario. The user may want to return to the standard default scenario (the one existing when the session was started). Alternatively, the user may have his own standard or basecase scenario to capture a particular application or projected configuration. GRITS handles this by saving such scenarios in a separate "scenario file."

Note that this type of file is distinct from other files mentioned in other program operating options. The user creates such a standard file by first changing all relevant operating, resource, demand, and financial conditions (and a title is recommended) using GRITS, then choosing OPTION 3 and using its suboption to specify a file name (using standard DEC-10 conventions as described in OPTION 2, below) to store the current values of all parameters in the scenario. Once such a file has been specified, it is stored permanently and can be recalled at future sessions by selecting the relevant suboption of OPTION 3. It is important to remember that this scenario (as stored) is not readable by eye and cannot be printed. To determine the contents of a scenario file, it should be recalled by using this option and then having its scenario listed by OPTION 1 or by generating a printout for a sample simulation run of the scenario. This scenario file is not to be confused with the printout file of OPTION 7, and must have a unique file name, otherwise it is possible for the user to destroy the file inadvertently.

The user should remember that when he recalls a scenario using OPTION 3, *all parameters will be replaced by whatever values were present when the scenario was saved.* In other words, recalling a scenario with this option is equivalent to redefining each option affecting the scenario (OPTIONS 0, 4, 5, and 9 through 53).

Specify a File to Receive Printout (OPTION 2)

OPTION 2 permits detailed resource, demand, and financial characteristics and complete simulation results generated by the model to be recorded in a file for every year of the simulation in order to be printed later at the line printer. (However, no output is sent to the file until a scenario is actually run using OPTION 7.) DEC-10 file names must be in the following format: 6 letters, period, 3-letter extension; e.g. ATLNTC.WDT. No blanks or special characters may be used in the file name. If the user simply presses the RETURN key without specifying a file name, data for the runs will not be stored for a hardcopy (if a file had been previously specified, this closes it). Up to 10 different output files may be specified in one run of GRITS.

Scenario Title (OPTION 4)

OPTION 4 allows the user to specify a descriptive title for the run that will be displayed on the terminal during output displays and will be recorded on the printout file if output has been requested. To replace an existing title, the option is simply called again, and the new title is typed in. To erase an existing title and replace it with nothing, simply press RETURN in response to this option's request for a title. (Note that this title is saved when a scenario is saved using OPTION 3).

Choose Fossil-Fuel-Only Scenario (or Return to Geothermal)(OPTION 0)

Ordinarily, GRITS models a geothermal system, adding a peaking boiler if necessary in the residential/commercial case. However, OPTION 0 allows the user to simulate a special case of a district heating system or industrial process heat application supplied solely by a fossil fuel boiler. Thus, for a given demand, the cost of a geothermal or hybrid geothermal system can be compared to a comparable one supplied only by fossil fuel. Note that the fossil-fuel-only scenario can only be operated in the demand-specified mode. Constraining the size of the system by the geothermal resource when no geothermal energy is being used would be inconsistent. OPTION 0 is used both to choose a fossil-fuel-only system, and to return to a geothermal one.

If OPTION 0 is used to select a fossil-fuel-only system, no geothermal capital cost components will be installed (wells, heat exchangers, upwell and reinjection pumps, and storage tank). The system will consist of a boiler large enough to supply the specified demand at the peak, through a distribution system and hookup structure. The flow that will circulate through the boiler is based on the assumption of a 30°F drop in the circulating water, from 180° to 150° for the residential/commercial case, and from 200° to 170° in the industrial process heat case:

$$f = Q/(500 \times 30°F),$$

where f is flow in gal/min and Q is peak heat flow in Btu/hr. This value for f is reported as the flow in GRIT's results when a fossil-fuel-only scenario is run. If a transmission line is needed, pumping energy will be required. The length of the transmission line will be taken to be the length of the first leg most recently specified in OPTION 38 for one well's flow to the distribution system and back. In the printed results of such a scenario, any values related to geothermal characteristics should be ignored. If after a fossil-fuel-only scenario is run, OPTION 0 is chosen again to return to a geothermal system, all previous geothermal characteristics remain active as they were most recently specified by the user. The fossil-fuel-only choice does not change the geothermal-specific values; it merely ignores them in the irrelevant computations.

Display the Most Recent Results (OPTION 6)

When the user calls this option, the results of the final year and a complete project summary of the last simulation that was run will be displayed on the user's terminal. Note that a scenario is run only when OPTION 7 has been executed. Even though the user may have changed some parameters, these will not be involved in the simulation until OPTION 7 has been run.

Record Data for Later Plotting (OPTION 8)

OPTION 8 allows the user to record certain simulation results from a GRITS run in auxiliary files for later graphical display using the Tektronix plotting program Plot-10 Easy Graphics, called EZPLOT on the Johns Hopkins computer.[1] The user may choose to

---

[1] Note to programmers: This option is self-contained in a subroutine. The subroutine could be replaced by one that, for example, tabulates all selected variables for each year, in a format suitable for summary reports.

record either selected time series results over a project's lifetime or, if the design temperature is being varied over a range of values, final project measures for each design temperature simulation. A four-character file name must be specified for each variable to be recorded by the program (press RETURN to skip a variable), These files then remain open so that the next time OPTION 7 (a scenario run) is executed, the pertinent data are recorded in these specified files for each year (or design temperature) of the simulation. The files are then closed. To record another sequence in a later run, this option must be chosen again in order to specify a new set of auxiliary files. Upon exiting the program, EZPLOT can access the files, each containing one variable, using its "ATTACH" command. Thus, with this facility, illustrative displays of selected resource, demand, and financial conditions simulated by the program can be created. It is important to note that when such graphs are desired, the user will generally want to run the simulation at intervals of one year (or 1°F system design temperature) in order to record every data point.

RESOURCE CONDITION OPTIONS

Number of Production Wells (OPTION 42)

This option is used to specify the number of production wells on the system. It influences several calculations. Since other options (depth, flow, etc.) declare the characteristics of *the average well*, the number of production wells is used in the program to determine the total cost of all production wells and total flow (and thus geothermal heat available). Also since each well has a pump and individual heat exchanger, each is sized for the average well; their total cost is then obtained by multiplying by the number of wells. Finally, the complexity of the transmission line system (OPTION 38) also depends on the number of wells; the pipe segments are sized according to the number of "wells' worth of flow" passing through each.

Average Production Well Depth (OPTION 12)

This option allows the user to specify the depth of the average production well in feet. This will affect the initial well capital cost and operational pumping energy.

Maximum Flow Rate From Average Production Well (OPTION 32)

OPTION 32 allows the user to specify the maximum flow rate (in gallons per minute) that can be extracted from the average production well. Since the resource may degrade over time, the user is allowed to specify the maximum flow as a time dependent function.

Note that this is the *maximum* flow *per well*. It is unlikely that it will be maintained 24 hours per day, 365 days per year, since space heating demand and process heating demand vary over seasons or daily operation. However, this maximum flow indicates the peak demand that can be satisfied by the resource, and therefore the limit on the system's size. GRITS determines the flow in the final year according to the specified function. In the resource-specified case, it then calculates the amount of demand that *all wells* can supply at that flow and this determines the size of the system. (To assure a whole number of households, it rounds down the flow by the proper amount.) In the demand-specified case, GRITS calculates the amount of flow needed at the peak. If the amount available is insufficient the scenario cannot be run. Otherwise, the flows in the final year and for preceding years are reduced by a factor that makes the final year's flow just sufficient to supply the specified demand. If the flow is reduced significantly from the maximum possible that is specified, the user may want to adjust the maximum flow function to reflect a less severe degree of depletion manifested as reduction in maximum flow.

With one exception, all capital equipment is sized to handle the initial year's maximum adjusted flow, which is the greatest over the project life. To size the pumps, GRITS uses the year whose combined effects of flow and drawdown require the largest pumps.

The trend of maximum flow over time can be input as any of four functions:

1. Linear,
2. Negative exponential (decreasing at an increasing rate),
3. Negative logistic ("S"-shaped), and
4. Compounded percentage rate of decrease (decreasing at a decreasing rate).

To indicate a constant maximum flow over time, choose the linear function and specify a zero rate of change. The functional relationship does not begin until after the resource assessment period is over.

For years before all demand is on the system, the maximum flow trending downward over time is only reduced proportionately to the amount of demand on the system.

Well Drawdown and Optional Aquifer Modeling (OPTION 26)

With long term extraction of water from an aquifer, it has been found that the resource suffers a certain degree of degradation in several aspects. Drawdown, the distance from ground level to the level to which the water rises without pumping, often increase with extended pumping. OPTION 26 allows the user to specify the trend of the increase in drawdown as a function over time.

The following time trends for drawdown can be modeled:

1. Linear,
2. Logarithmic, and
3. Compounded percentage rate of increase.

The drawdown function does not begin until all demand has come onto the system. In the years before full market penetration (following the resource assessment period), the specified initial drawdown is multiplied by the fraction of the ultimate demand on the system.

Since the user specifies the drawdown and flow independently, a realistic combination that is suitable for the aquifer under consideration must be maintained.

Optional Aquifer Modeling. In addition, OPTION 26 provides another special feature that can be very useful in cases where some hydrological information is available on the aquifer. If the user chooses the fourth way of calculating drawdown,

4. Function based on aquifer characteristics,

GRITS will then estimate drawdown and annual pumping energy, using a simplified model of aquifer behavior described in Appendix A and Ref. 4.

Once this choice has been made, the user is permitted to specify any of four characteristics that will affect drawdown and pumping; these are:

1. Pumping cycle,
2. Transmissivity,
3. Aquifer storage coefficient,

4. Well radius, and

0. None of the above (i.e., use current values).

(The user here may type several number choices at once to be acted on in turn.)

The pumping cycle selection may reflect any of four types of operation:

1. Continuous pumping (12 months/yr),
2. Semi-annual pumping (6 months on/6 months off),
3. Diurnal or daily pumping (12 hours on/12 hours off), and
4. Space heating application.

The first three pumping cycles are applicable to industrial process heat operations only. The fourth is for residential/commercial space heating only. The user should be aware that for the first three pumping cycles he must specify the proper industrial utilization factor (OPTION 31) that corresponds to the cycle (100%, 50%, and 50%, respectively). The space heating utilization factor is calculated from the demand due to hourly temperature variation.

The other three characteristics, transmissivity (cm^2/s), aquifer storage coefficient (dimensionless) and well radius (inches) may either be specified by the user or default values will be used.

Because the aquifer model was calculated for a simplified case, several restrictions apply: all demand must come onto the system immediately after the resource assessment period and the maximum flow must be a constant value over time. Pumps are sized using GRITS' standard equation (Appendix A) and actual space heating is based on actual demand, not on the simplified assumptions used in pumping energy equations.

Temperature at the Wellhead (OPTION 11)

The user may specify the temperature at the wellhead in Fahrenheit degrees. He should be sure to allow for a certain temperature loss between the aquifer and the wellhead. In the absence of other information, one might assume a 5°F drop from aquifer to wellhead, so that, for example, a 150° aquifer would require an input value of 145° in OPTION 11. The user may describe the wellhead temperature with any of four functional relationships over time, reflecting potential degradation of the resource with use:

1. Linear,
2. Negative exponential,
3. Negative logistic ("S"-shaped), and
4. Compounded rate of decrease.

(A constant value over time can be expressed as a linear function with a zero annual change.) The functional relationship does not begin until after the resource assessment period is over.

For years before all demand is on the system, the wellhead temperature reduction over time is only reduced proportionately to the amount of demand on the system.

The system being served will be sized according to the temperature in the final year. However, since the heat exchanger must handle the initial year's temperature, that temperature is used in calculating the heat exchanger size. The user should be sure that the temperature in the final year does not fall below the specified reject temperature.

Reject Temperature (OPTION 21)

OPTION 21 is used to specify the temperature at which the geothermal water leaves the heat exchanger after heat extraction. The difference between the wellhead temperature and reject temperature determines the amount of energy extracted from the geothermal water. The design choice of reject temperature affects the cost of the heat exchanger — for a given flow, the higher the performance, i.e. the lower the reject temperature in comparison to the wellhead temperature, the higher the cost of the heat exchanger. However, if heat is extracted more efficiently, that will decrease the amount of geothermal water needed to supply the heat, thereby having a reducing effect on heat exchanger cost.

In selecting a reject temperature, the user should remember that if the water is being reinjected into the originating aquifer, **a reject/reinjection temperature may substantially lower than the resource. (One way of dealing with this is reinjecting the waste** brine a greater distance from the production well [OPTION 38].)

Number of Reinjection Wells (OPTION 43)

OPTION 43 is used to specify the number of reinjection wells. As with OPTION 42, the total cost of reinjection wells and pumps is determined by multiplying the average cost for an individual well by the number of wells.

If there is to be no reinjection well, specify 0 wells for this option.

Depth of Reinjection Well (OPTION 23)

This option allows the user to specify the depth of the average reinjection well in feet. This will affect the initial well capital cost and operational pumping costs.

Transmission Line (or System) (OPTION 38)

This option allows the user great flexibility in specifying a transmission system between production wells and reinjection wells and the consumption point (either the juncture with the district heating distribution system, or the industrial user's plant gate). OPTION 38 (transport distance) is set up to allow the user to configure (or test a variety of configurations of) the system. The system layout is done externally by the user, so that he can take into account all the unique geographical and hydrological characteristics of the area. The input to GRITS is then indicated simply as the total length of all pipe segments classified according to the volume of flow passing through them, where the flow is described in terms of the flow per well, such as "two wells' worth of flow."

The following example will illustrate this procedure. The double lines in Fig. 2 indicate the two-way secondary loop that carries the heated water to and from the heat exchangers at the top of each well and the consuming area at the top of the figure. The single lines carry the waste brine from the production wells to the reinjection wells. For this example, the user would input to OPTION 38 that the length of pipe carrying one well's worth of flow in the main transmission system is the quantity a + c (that is, the flows from wells 2 and 3 to the first junctions). The length of the line carrying two wells' worth of flow is b, which transports that of wells 1 and 3 together. Finally, the flow from all three wells flows over length d.

Similarly, for the reinjection well flow, the amount of pipe carrying one well's worth of flow is w + x + y, while z miles of pipe transport two wells' worth of flow.

> Note: if a fossil-fuel-only system were to be modeled, the transmission distance is taken as the length of pipe most recently specified as carrying one well's worth of flow back and forth between the well and demand site.

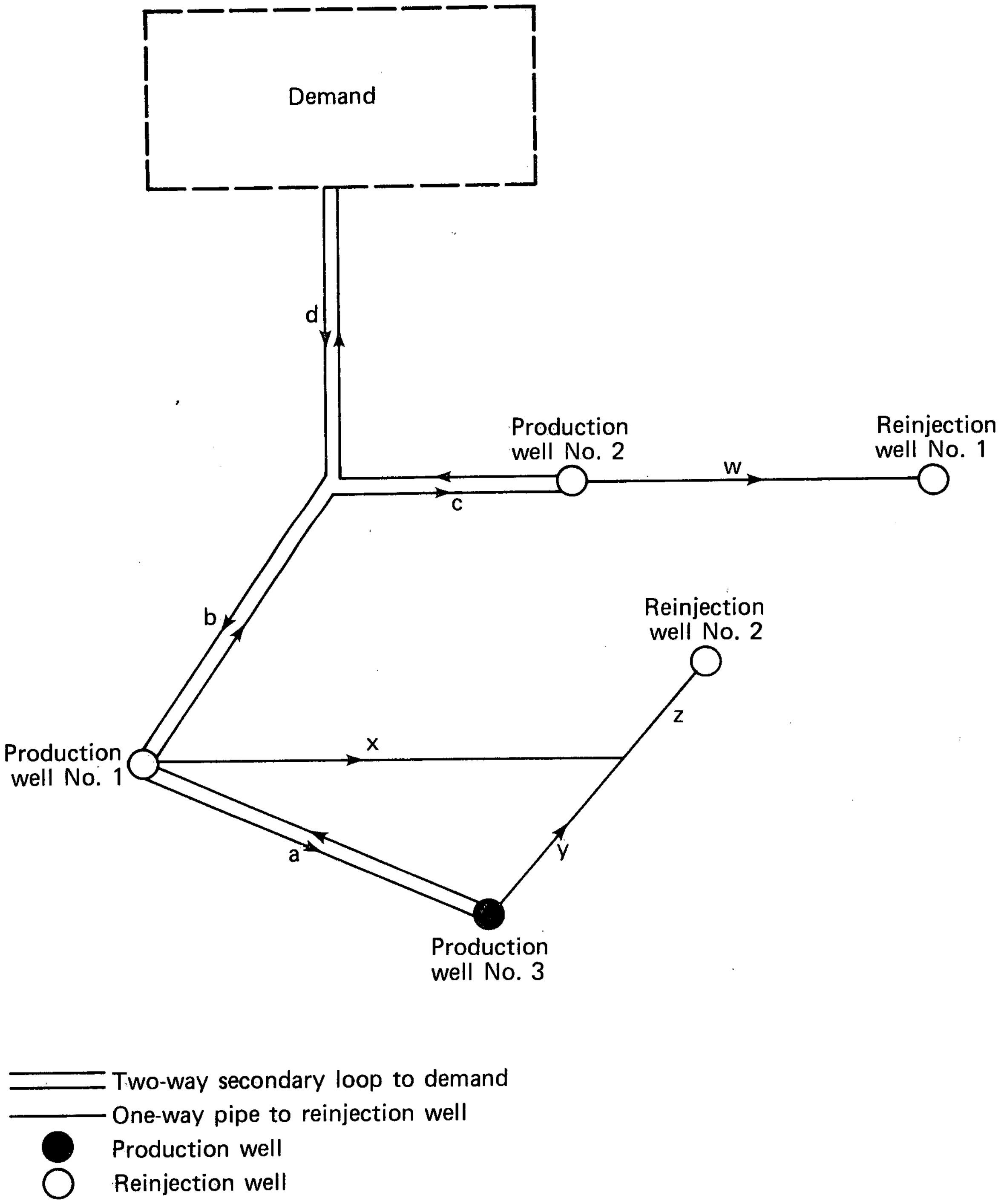

Fig. 2 **Transmission system example.**

DEMAND CONDITION OPTIONS

Residential/Commercial Specific

Choose Area Under Consideration (OPTION 10). OPTION 10 allows the user to specify the location of the area being modeled. The user is requested to type in a descriptive name of the area under consideration. Associated with this area is the hourly ambient air temperature distribution of a typical year, which is used to determine the demand for space heating by the consumers served by the geothermal heating system. (This information is not applicable to industrial process heat applications). This "hourly weather data" must then be either retrieved from a master file on line or entered from the terminal by the user. The user may obtain a list of all cities for which weather data are available by requesting it when the program offers it. Table 1 lists the cities alphabetically by state. The data are identified by a "file i.d." consisting of the first six letters (or as many as there are) of the city name (with no spaces or punctuation) followed by a period followed by the standard two letter postal abbreviation of the state. For example, New York City would have a file i.d. of NEWYOR.NY; Newark, New Jersey would have NEWARK.NJ; Hilo, Hawaii would have HILO.HA. If the user has entered the weather data from the terminal or is retrieving a previously input set of data, he must maintain this convention.

Generally, the user should be able to find a city in the master weather data file that is near enough to the area of interest to have a similar temperature distribution. If not, the user may enter his own weather data from the terminal where it will then be saved for later use according to the file i.d. specified by the user. GRITS prompts the user for weather data for twenty 5°F intervals, from [-30 to -26°F] to [+65 to +69°F]. Once all the data are entered from the terminal, there is a permanent record of the data. The data can be called in future runs of the model by specifying their file i.d.

Minimum Ambient Temperature (OPTION 28). The minimum ambient air temperature of the area to be served is used in GRITS to determine how large the peaking boiler should be sized. (As with the hourly weather data, the minimum ambient temperature is not used in industrial applications.) The boiler will be made large enough to handle all heating demand below the system design temperature down to the specified minimum ambient temperature.

When the area is changed (OPTION 10), its hourly temperature distribution for a typical year is entered into the scenario. Once this has been done, the program reports the lowest temperature and the user may choose to select this as the minimum ambient temperature to input to OPTION 28. (Choosing new weather data with OPTION 10 does *not* automatically change the "minimum ambient temperature" of OPTION 28.)

The user may not necessarily want to select the lowest temperature of a typical year as OPTION 28's minimum ambient temperature. Specifying a lower temperature would provide a safety margin for unusually cold winters. For example, if the air temperature in Salisbury, MD falls as low as 0°F in a typical year, the user may wish to declare a minimum ambient temperature of -5°F to size the boiler with a margin of safety.

On the other hand, if the user wishes to consider a scenario in which the developer might want to risk insufficient heat on a few of the coldest days of the year, the minimum ambient temperature might be specified as greater than the typical low, for example 5°F for Salisbury.

If no peaking boiler is to be installed in the system, the user should declare the minimum ambient temperature to be the same as the system design temperature. (Presumably, the design temperature will be set low enough to handle all heating demand on the system.)

System Design Temperature (OPTION 14). OPTION 14 specifies the design temperature of the system. The design temperature is that ambient air temperature down to which the geothermal energy supplies all heating requirements for the residential/commercial space heating application (it is ignored in the industrial mode). Any portion of demand not capable of being supplied by geothermal will be met by the fossil fuel boiler. The design temperature must be below 65°F in order for any space heating demand to be supplied by geothermal. (All domestic hot water heat is supplied by geothermal, regardless of the design temperature).

A single system design temperature can be specified or it can be allowed to vary over a range thereby creating a series of scenarios. Since it is a major design factor it is useful to vary the design temperature in order to find the value resulting in the optimum size of the system. For example, the user can specify that the design temperature loop be from 0°F to 65°F. Assuming the optimum value of the economic measure (such as discounted average cost) results from a design temperature within this range, the user can then specify the design temperature to be the single optimizing value, and sensitivity analyses of other parameters can be performed.

Users should be aware that if detailed results are to be printed when the scenario is run (OPTION 7) on the terminal or the output file with the design temperature loop, voluminous printout will result. Thus, printout should be selected with great prudence when looping through a wide range of design temperatures, because if care is not taken every year (for every design temperature) may be printed, one to a page. (For example, looping from 20°F to 40°F in steps of 2° for a 20 year period in 5 year increments would produce 14 pages of summary printout or 58 pages if full detail were requested, and an analogous amount of printing on the terminal, if that were requested.)

Also, OPTION 8 can be used in conjunction with the design temperature loop to assure the recording (for later plotting or tabulation) of selected summary totals for each iteration. This can be very useful in analyzing the sensitivity of economic measures to the system design temperature. Figure 3 shows the optimization of design temperature to minimize discounted average cost for a sample scenario.

Distribution System Installation Schedule (OPTION 35). OPTION 35 allows the user to declare the percentage of the residential/commercial distribution system installed each year. (It is ignored in the industrial mode.) The user should be sure that the schedule is consistent with the rates of market penetration in OPTIONS 19 and 51: the distribution system must be completed by the year that all residential and commercial demand is on line.

Residential Specific

Specified Ultimate Number of Households (OPTION 52). This option applies only in the demand-specified case. If the user wishes to run a demand-specified residential scenario, OPTION 52 is used to indicate the ultimate number of households that will come onto the system. The residential market penetration function (OPTION 19) will then be scaled to fit this specified number of households.

The number of households specified in this option is completely independent of the number that a resource-constrained run of the same scenario might project. OPTION 52 is completely ignored in the resource-constrained case. Likewise, the number of households predicted in the resource-constrained case is ignored in the demand-specified case when OPTION 52's value is used. See the description of OPTION 9 (the choice of resource- or demand-constrained mode) for further details.

Housing Types and Their Heating Demands (OPTION 13). This option allows the user to characterize the types of housing being supplied by the residential/commercial district heating system.

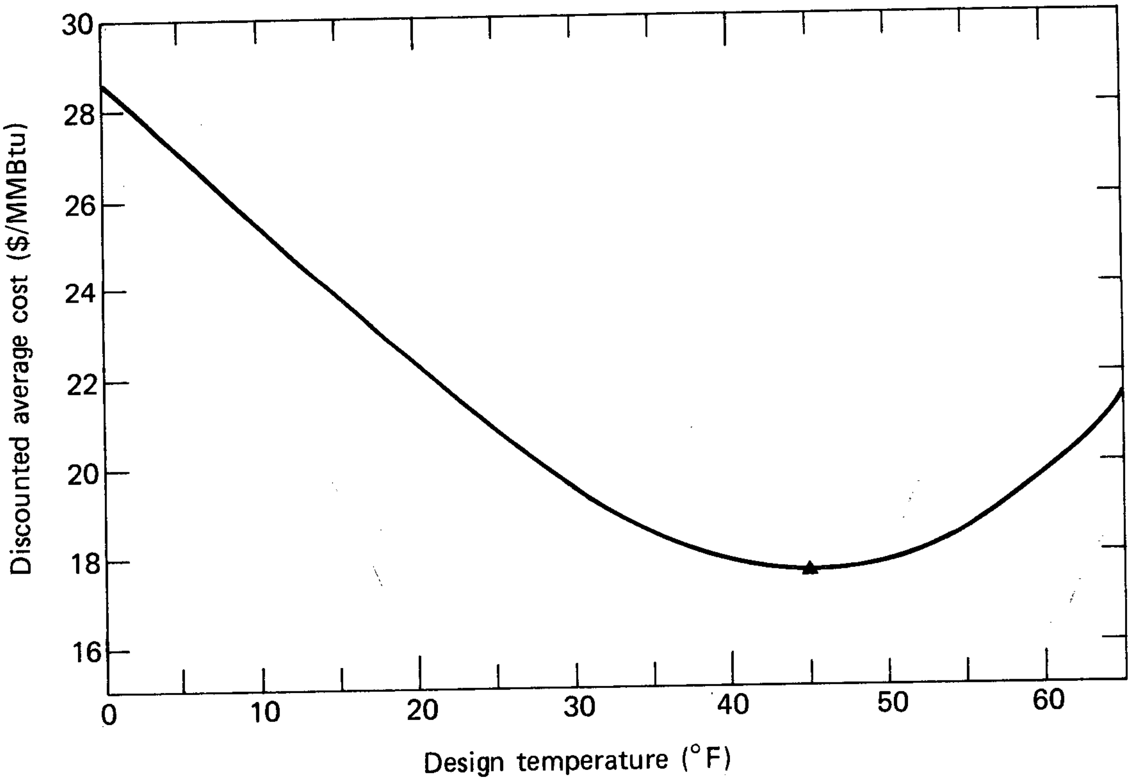

Fig. 3 Variation of discounted average cost with system design temperature loop.

(This information is ignored in the case of an industrial scenario.) The user may indicate that all housing be either

1. Single family suburban,
2. Single family dense,
3. Townhouses,
4. Garden apartments,
5. High-rise multifamily housing, or
6. A mix of all the above housing types.

If a mix is chosen, the user is then prompted to enter the distribution of the housing types on the system as percentages of the total.

The choice of housing types will influence the total heating demand, length of distribution system, and hookup cost for the average household.

In addition to the distribution of housing types on the system, OPTION 13 allows the user to specify for each housing type the space heating demand, in terms of Btu/hr per household for each degree below 65°F.

Domestic Hot Water Demand (OPTION 39). This option allows the user to specify explicitly the domestic sanitary hot water demand for the average household in millions of Btu per year. One valuable use of this option is that it can be set to zero in the case of a very low grade resource that is of too low a temperature to supply domestic hot water but can still provide space heating.

The domestic hot water demand for commercial buildings is independent of this option and is specified in OPTION 47.

Note that GRITS always assumes that the domestic hot water demand is supplied completely by geothermal — without the peaking system (except in the special case of a fossil-fuel-only system). (OPTION 39 is ignored in the industrial scenario.)

Market Saturation (OPTION 34). Market saturation is used here to mean the fraction of all households in the area that are potentially convertible to geothermal. For example, if 30% of the homes in the area under consideration have electric resistance baseboard heating, it might be assumed that the homeowners' cost to convert to a hot water or forced air heating system necessary for geothermal energy would be prohibitive, removing them as candidates for conversion. The other 70%, however, could be hooked up to a district heating system. The user would then specify that the market saturation, or ultimate density of households on the system, is 70%.

GRITS uses the market saturation value to determine the length of the residential distribution system. If 100 households are to be served in an area with 70% market saturation, the length of the system will be calculated as 143% (i.e., 1 /70%) of what would be needed to serve the same number of households without having to extend lines past 30% of the houses.

To specify the rate at which this ultimate number of households come on line, use OPTION 19 (residential market penetration). To specify the installation schedule for the distribution system, use OPTION 35.

(OPTION 34 is used only for residential calculations.)

Residential Market Penetration (OPTION 19). The user specifies the fraction of the ultimate number of households that will come on line over the project life. This is expressed as a function over time of one of the following forms

1. Linear,
2. Logistic ("S"-shaped),
3. Compounded percentage rate of increase, and
4. Logarithmic.

Full market penetration in the first year can be indicated by a linear function with 100% initial pentration and a 0% annual change.

Several points should be noted. Market penetration can begin only after the resource assessment period has been completed. The installation schedule of the distribution system is specified as a separate option (OPTION 35) and the only check for consistency is that the system is completely installed by the time all residential and commercial demand is on line. Until 100% market penetration has been achieved, any reductions in wellhead temperature and flow and increases in drawdown are proportional to the fraction of demand (total residential plus commercial) on the system; the full effect of specified functional relationships over time does not begin until all demand is on the system. Commercial market penetration is specified as a separate option (OPTION 51) and is treated independently. All demand is on the system only when 100%

market penetration has been achieved for residential (if any) and commercial (if any) service.

Market penetration is not to be confused with market saturation (OPTION 34). Market saturation defines the ultimate number of households convertible to geothermal, and market penetration is the fraction *of those* that join the system as a function of time.

Cost per Residential Hookup (OPTION 18). This option allows the user to specify the cost of a hookup to a household of each housing type. (When the program is run, the average cost for a hookup is also printed out.)

Commercial Specific Options

Define All Characteristics of Commercial Buildings (OPTION 45). This option is used to define or redefine all unique characteristics of each type of commercial building. Once a set of building types has been defined (either with this option or the default scenario), the individual characteristics for a particular type of building can be specified using OPTIONS 46 through 48.

OPTION 45 first requests input of the number of building types to be defined. Then, for each of these types, the user must specify the typical floor space per building, the space heating demand (in (Btu/ft^2)/deg-day), the domestic hot water heating demand (in (Btu/ft^2)/day), and the number of buildings of that type.

If the user has defined a set of building types and then wishes to test a scenario with no commercial buildings, the suggested method is to choose OPTION 5's residential scenario and specify no commercial buildings, rather than to specify zero building types in this option. This will automatically change the number of buildings of each type to zero while retaining the building characteristics. In this way, the building definitions can be reactivated by changing the number of buildings of each type to some positive number.

Floor Area of Commercial Building Types (OPTION 46). OPTION 46 allows the user to specify the floor space per building of a particular building type that has already been defined. The value should be entered in thousands of square feet; thus a 25,000 ft^2 building would be input as 25.

Heating Requirements of Commercial Building Types (OPTION 47). OPTION 47 allows the user to specify the heating demand for a particular building type. Both space heating requirements (in (Btu/ft^2)/deg-day) and domestic hot water heating requirements (in (Btu/ft^2)/day) must be specified.

Number of Commercial Buildings of Each Type (OPTION 48). OPTION 48 allows the user to specify the number of buildings of a particular building type. This will be used to determine the total square footage to be served (and therefore the total heating demand for that building type) plus the number of commercial hookups that will be necessary.

Rate of Commercial Market Penetration (OPTION 51). The user specifies commercial market penetration in OPTION 51 as he does in OPTION 19 (residential market penetration, page 60). It must be noted that the two sectors are independent. If residential market penetration in OPTION 19 has been specified as a linear function starting at 15% and increasing annually by 8% and OPTION 51 uses a logistic function starting at 50% and reaching 100% in year 15, then the program will simulate exactly that. Users experimenting with different market penetration rates should be careful to remain aware of the other sector's market penetration rate, since changing one will not change the other.

Also, the scheduling of the installation of the distribution system (OPTION 35) must be completed by the time all commercial demand is on the system, as it is in the residential case. For computational purposes, the program treats the coming on line of the commercial buildings as a continuous process in terms of floor space rather than as discrete buildings. Market penetration does not begin until after the resource assessment period has been completed.

Length of Distribution System for Commercial Buildings (OPTION 50). Unlike the residential portion of the district heating system where the length of the distribution system is calculated by GRITS based on housing density, the total length of the system serving commercial buildings is explicitly specified in miles by the user. It is then added to the residential system for cost calculations and reporting in the GRITS output.

Hookup Cost for Commercial Buildings (OPTION 49). OPTION 49 allows the user to specify the cost of each commercial building hookup to the district heating system. The same cost is used for each building type. This cost is multiplied by the total number of commercial buildings to determine the commercial hookup cost.

Industrial Demand Options

Industrial Utilization Factor (OPTION 31). This option is used to specify the percentage of time that the industrial process requires geothermal energy at the maximum pumping rate. For example, a plant using geothermal heat for 12 hours per day for 7 days per week would have a utilization factor of 50%. During other hours the well does not operate.

(OPTION 31 is ignored in the residential/commercial mode where the utilization is determined by the distribution of space heating demand.)

Specified Industrial Process Heat Demand (OPTION 53). This option applies only in the demand-specified case. If the user wishes to run a demand-specified industrial scenario, OPTION 53 is used to indicate the industrial process heat demand (in millions of Btu/hr) during hours of operation. The fraction of hours of the year that the process operates is specified as the industrial utilization factor (OPTION 31).

The industrial process heat demand specified in this option is completely independent of the number that a resource-constrained run of the same scenario might project. OPTION 53 is completely ignored in the resource-constrained case. Likewise, the industrial process heat supplied in the resource-constrained case is ignored in the demand-specified case when OPTION 53's value is used. See the description of OPTION 9 (the choice of resource- or demand-constrained mode) for further details.

FINANCIAL CONDITION OPTIONS

Economic Accounting Method (OPTION 40)

The user can select either or both of two economic accounting methods. Discounted average cost gives a measure of the cost of providing energy over the life of the project and does not take into account any hypothesized revenue stream. Net present value assumes a selling price of system energy (OPTION 36) and represents the present value of the stream of net revenues over the life of the project. For a full explanation of these financial measures, refer to Section 2 and Appendix A.

Length of Study Period and Interval for Cost Calculations (OPTION 33)

OPTION 33 is used to specify the length of the time period under study and the interval between cost calculations. The specified study period should be chosen to reflect the economic time frame of concern. A potential developer may be interested in specifying a length of time that is shorter than that for which the geothermal project may be capable of operating since there is a significant amount of risk involved. Because risk implies increasing doubt about the long term viability of the project, the developer may want to be certain that the project is profitable in the short run.

It should be understood that the study period includes the resource assessment period, so that a 20 year study period (years 0 to 19) with a one year resource assessment period (year 0) will only be simulated for 19 of its operating years (years 1 to 19). If a 20 year operating period is to be examined with a one year resource assessment period, the user should specify a 21 year study period (years 0 to 20) to result in a resource utilization period of the 20 years, 1 to 20.

GRITS does not permit a study period longer than 30 years.

The study period can be viewed as either a snapshot of the first years of the project or as the complete criterion for evaluation. In the first case, costs (such as capital debt service payments) may be known to continue after the end of the study period but are to be ignored. In the second case, all capital equipment must be paid off by the end of the study period. GRITS allows either of these conventions to be followed by using the OPTION 15 specification of this assumption (page 65).

The interval of cost calculations is simply a computational parameter. Ordinarily, calculations are performed for each year in the study period. However, if the user chooses he can specify a larger increment — say 5 years — between calculations to make less expensive, rough estimates. GRITS then performs a linear interpolation of total cost and revenue and energy for years skipped. Only those years calculated can be reported in the output file, plotting files, or on the terminal. Experience has shown, however, that intervals of one year should be chosen because the annual stream of costs usually shows sharp jumps (at the year of purchase of new capital equipment, for example) that are missed in a linear interpolation between skipped years with a larger interval. GRITS is so inexpensive to run that the savings of using greater calculating intervals is generally not worth the accompanying inaccuracies.

Finally, for generating output data with the plot files of OPTION 8, one year intervals are strongly recommended to maintain the smoothest and most precise curves.

Resource Assessment Period and Cost (OPTION 41)

OPTION 41 is used to specify the resource assessment period and its annual cost (in thousands of dollars). Resource assessment includes exploration, testing, and licensing. During this period, no construction, installation, purchase of equipment, or other work on the geothermal system is undertaken. Resource depletion and market penetration also do not begin until the utilization phase, nor do other costs or revenues.

Capital Equipment Life (OPTION 15)

This option allows the user to specify both the physical and financial life of the capital equipment by component:

1. Wells,
2. Piping system (distribution and transmission lines),
3. Heat exchangers,
4. Pumps,
5. Hookups,
6. Fossil fuel boiler, and
7. Storage tank.

The user may also elect to specify the same life for

0. all equipment

at once.

The physical life indicates the number of years that a capital component can operate. After a component has been on the system for its physical life, it will be replaced in the following year.

The financial life or amortization period indicates the length of time over which the equipment will be paid for in fixed (nominal dollar) debt service payments. This period may not extend beyond the physical life of the equipment (that is, it must be paid for by the end of its useful life). However, the amortization period may be shorter than the physical life, meaning that the capital component will be completely paid for before it must be replaced.

Thus, it is possible for a well that is expected to have a 30 year life to be amortized over 30 years. However, the developer may decide to amortize it over only 15 years, in which case the final 15 years would have no well debt service payments.

The previous examples implicitly assumed that the project had a 30 year evaluation period. In fact, evaluation periods for relatively risky geothermal projects are often much shorter. This means that a capital component having a 30 year amortization period would not be paid off before the end of a 20 year evaluation period.

This may be desirable if the evaluation period is viewed as a snapshot of the project's early years, rather than the full life of the project.

However, OPTION 15 permits the user to follow a special convention: if he chooses, all equipment will be paid for by the end of the evaluation period. Thus, if this flag is set and the project has a 20 year evaluation period, a capital component having a specified 30 year amortization period would actually be forced to be paid off in 20 years. Similarly, a component having both a physical and financial life of 15 years would cause a replacement to be purchased in year 15. This new component would then be amortized over only the next five years. The indication that this convention is in effect is made by an asterisk (*) next to the amortization period in scenario listings.

Real or Nominal Dollars and Inflation Rate (OPTION 25)

This option serves two purposes: first, the user selects whether calculations are to be performed in real or nominal dollars and second, the inflation rate must be selected.

The choice of real or nominal dollars requires a certain understanding of economic analysis techniques. Generally, economists prefer to calculate economic effects in terms of real (or "constant") dollars, which are units that state values in terms of base year dollars, discounting the effects of the general rate of inflation. Since future inflated dollars are worth less in purchasing power than present dollars, they should be brought back to a common base-year value for comparison to present dollars. Real dollar calculations are the recommended choice for analyses using GRITS.

An analysis using nominal (or "current") dollars estimates costs in inflated dollars that have little resemblance to the present value of a dollar. The rate of inflation specified by the user is specified as a single average number over the life of the project. It is used in GRITS's calculations for different purposes, depending on whether real or nominal dollars are being used. When the results are to be reported in real dollars, the fixed nominal annual debt service payments are actually worth less in real dollars in the future; they are deflated by the specified annual inflation rate. The operation and maintenance and pump overhaul costs are ordinarily calculated in real dollars and need no adjustment for inflation. If results are chosen to be reported in nominal dollars, the debt service payments are fixed in nominal terms, so they need no adjustment. The operating costs calculated in real terms (operation and maintenance and pump overhaul) are inflated by the specified inflation rate. For both the real and nominal dollar cases, it is assumed that the energy prices (fossil fuel, electricity, and system selling prices) have been specified in the appropriate dollar convention (real or nominal), whichever method is being used. It is the user's responsibility to maintain this consistency. Using OPTION 25 to switch from real to nominal dollars or back will not automatically adjust the energy price specifications for inflation; that must be done by the user.

Discount Rate (OPTION 37)

The user specifies the discount rate using OPTION 37. The discount rate indicates the value to the developer of receiving returns early rather than later, or of delaying payments (the rate of time preference). It may include a component that reflects risk, but none for inflation or interest. Section 2 describes the discount rate in detail. The discount rate is only used to discount future costs in computing discounted average cost and to discount revenues in the case of net present value calculations (see Appendix A). The functions of the inflation and interest rates are described elsewhere in this section, Section 2, and Appendix A.

Interest Rate (OPTION 27)

OPTION 27 is used to specify the interest rate that the developer must pay for borrowing to purchase capital equipment. The capital recovery factor used to determine the annual payments is based on this rate.

It is the responsibility of the user to be sure that the interest rate is specified correctly, since it, the discount rate, and the inflation rate are input independently and cannot be cross-checked to confirm internal consistency of the user's intentions. The interest rate should incorporate factors including time preference, risk, and inflation. See Section 2 and Appendix A for a full explanation.

Selling Price of Geothermal System Energy (OPTION 36)

OPTION 36 is used to specify the selling price of energy produced by the heating system being modeled. It is used only when a revenue stream is desired (i.e., when net present value is one of the economic accounting methods specified in OPTION 40).

The system selling price can be declared as following any of five paths over the life of the project:

1. A multiple of fossil fuel price,
2. A multiple of electricity price,
3. A constant,
4. A linear function, or
5. A compounded rate of change function.

The initial price for year 0 is input in dollars per million Btu in current base-year prices (indicated in GRITS's welcoming message). If the scenario is to be run in real dollars, the price trend should only account for real price increases, but if the scenario is to be run in nominal dollars, then the price trend should account for current dollar (including inflation) prices.

If the system selling price is chosen to be a multiple of the fossil fuel or electricity price, GRITS makes the proper unit conversion of each to dollars per million Btu before applying the multiplicative factor.

Electricity Price (OPTION 20)

The user may specify the price trend of electricity to the developer using OPTION 20. Electricity price affects GRITS's pumping costs. Also, the user may specify in OPTION 36 that the selling price of geothermal system heat be pegged to the price of electricity.

The electricity price can be declared as following any of three paths over the life of the project: (a) linear, (b) logarithmic, or (c) compounded percentage rate of increase. (A constant price can be specified by using a linear function with zero annual change.)

The initial price for year 0 is to be input in cents/kWh in current base-year prices (indicated in GRITS's welcoming message). If the scenario is to be run in nominal dollars, then the price trend should account for current dollar (including inflation) prices.

Fossil Fuel Price (OPTION 29)

The user may specify the price trend of fossil fuel using OPTION 29. The fossil fuel price is used to calculate the cost of peaking energy in system operation. It is also used to calculate savings in operating costs between the geothermal system and a comparably sized fossil-fuel-only system. (Based on a conversion efficiency from fossil fuel to heat of 75%, the amount of fossil Btu burned is assumed to be 33% more than are generated as heat). Also, the user may specify in OPTION 36 that the selling price of geothermal system heat be pegged to the price of fossil fuel.

The fossil fuel price can be declared as following any of three paths over the life of the project: (a) linear, (b) logarithmic, or (c) compounded percentage rate of increase. (A constant price can be specified by using a linear function with zero annual change.)

The initial price for year 0 is to be input in dollars per million Btu in current base-year prices (indicated in GRITS's welcoming message). If the scenario is to be run in real dollars, the price trend should only account for real price increases, but if the scenario is to be run in nominal dollars, then the price trend should account for current dollar (including inflation) prices.

Well Cost Adjustment Factor (OPTION 16)

GRITS's internal equation for calculating the cost of production and reinjection wells is based on recently published data (see Appendix A). However, a developer may have obtained a site-specific estimate for the well cost. In such a case, the user can specify a multiplier to adjust the standard estimate made by GRITS.

Once the user has specified a cost adjustment factor different from 1.0, he should note that if he later changes the well depth or number of wells (both production and reinjection) this specified adjustment factor will still apply, and will cause the total well cost to be revised according to the standard cost equation multiplied by the adjustment factor.

For example, suppose the developer has been assured by a contractor that it will cost $1 million for 5000 foot well. Running his scenario with a cost adjustment factor of 1.0, GRITS may estimate the cost to be $1.5 million. To more accurately depict the scenario, the developer might specify a cost adjustment factor of 0.67, which will cause the estimated well cost to be $1 million. Suppose that the developer wishes to check the effect on pumping if the well must be drilled 6000 feet (the contractor must still drill the well for $1 million). When the well depth is changed to 6000 feet, the estimated cost will also change, say to $1.3 million even with the 0.67 adjustment factor. So, to keep a $1 million cost, the cost adjustment factor will have to changed again. While the factor can be useful in overriding GRITS's standard cost estimating equations, this example shows the difficulties that can arise and of which the user must be aware.

Heat Exchanger Cost Adjustment Factor (OPTION 17)

This cost adjustment factor works in a manner similar to the well cost adjustment factor (OPTION 16). The multiplier can be used to reflect a more corrosion-resistant material, for example. Note that changing the flow, wellhead temperature, or reject temperature also has an effect on the heat exchanger cost, so the user should be aware that subsequent changes in any of these options will change the previously estimated cost.

Also, since the heat exchanger is sized according to the initial year's maximum flow, it must be noted that in the demand-specified mode the annual flow is adjusted proportionally so that the final year's flow just meets the specified demand. Since this adjusted flow is not known until the scenario is executed, the estimated heat exchanger cost printed out with this option may be a gross overestimate, based on a much higher flow than will actually be used in the scenario. The user should consider this fact in such a situation.

In any case, at the time the scenario is run, the proper heat exchanger costs <u>are</u> calculated.

Distribution System Pipe Costs (OPTION 22)

The average cost per mile of distribution system pipe is input using OPTION 22. As a preliminary evaluation tool, GRITS does not attempt to calculate necessary or optimum pipe sizes, so that the user takes the responsibility of estimating the cost of the pipe in the particular scenario under study. (The default value has been chosen to be within a reasonable range of typical costs.)

Boiler Cost (OPTION 30)

OPTION 30 is used to specify the cost of peaking boiler capacity (for residential/commercial or for industrial fossil-fuel-only applications. The cost is input in terms of dollars/hundred thousand Btu/hour.

Storage Tank Capacity (OPTION 24)

The cost of the storage tank is dependent on its capacity, which is generally described in terms of hours of flow. For example, if the user specifies that a system using a flow of 1000 gal/min has a storage tank capacity of 1 hour, then the program will size the tank to 60,000 gallons (1000 gal/min x 60 min/hr). If there is to be no storage tank, specify a capacity of 0 hours.

Operation and Maintenance Costs (OPTION 44)

The real annual cost of operation and maintenance (O&M) is taken as a specified percentage of total initial purchase price of all pieces of capital equipment. For example, if all capital components were purchased initially for $1 million, a 1% operation and maintenance cost would mean an annual real O&M cost of $10,000.

INTERPRETING GRITS'S OUTPUT

At the user's option, GRITS can report its simulation results at a variety of levels of detail. A few summary lines may be requested at the terminal, or a detailed printout of each year of a simulation can be made. Appendix C contains several sample printouts of basic scenario runs. Results reported at the terminal may contain almost as much annual detail, or merely several summary measures.

Generally, because of the great number of program options and the ease of use of GRITS at the terminal, the recommended procedure to operate the program is to enter the scenario through the various program options, and then to generate a printout of the scenario run as a test. Taking time to examine the printout, which contains a full listing of scenario specifications, often saves much wasted time that might occur because of not changing a forgotten option.

For each scenario run printout, the first several pages contain a listing of the scenario, followed by a table of initial purchase price of capital equipment. Annual reports for the selected years to follow, either in summary form or in full detail. In either case, the final page of the scenario's report contains the project's summary financial measures.

At this point several comments and expansions on printout results may be helpful. When detailed annual results are generated, the annual status of time-varying system parameters is shown. Several variables that are by nature fixed over time are not reported annually because of lack of space. Results reported annually include a breakdown of geothermal and total system Btu, residential and total system Btu (in the residential/commercial case), and total pumping energy. The pumping energy includes upwell, downhole, and transmission pumping. Three performance measures are also reported. The coefficient of performance is the ratio of geothermal energy extracted to total pumping energy. The measure percentage of geothermal utilization refers to the fraction of the total amount of geothermal heat potentially withdrawable during the year, that was actually extracted and used. Percentage service geothermal is the fraction of all system heat provided by geothermal.

Printed below these operating measures is a component-by-component breakdown of annual costs. Total annual gross and net revenues and costs are reported, as are costs at the wellhead. Also reported are the average annual system cost per million Btu provided, and wellhead cost per million geothermal Btu extracted. Finally, savings in operating costs over what would have been spent in using fossil fuel are reported. All of these annual cost figures are undiscounted.

In the final year's results, a starred box reports summary totals over the project life. Initial capital cost is repeated from the first pages. The net present value of the project gives a measure of the worth to the developer of the project, discounting future dollars to the present. Discounted average cost indicates the cost of producing energy over the life of the project. A developer charging the discounted cost to his customers over the life of the project would just break even (i.e. have a net present value of zero). The actual year in which break even is achieved is reported, as is the discounted average wellhead cost, where average wellhead cost is as defined above. Reported last are the discounted savings in operating cost and the year of payback, when cumulative savings passed initial capital cost.

4. SUMMARY

The GRITS model is a flexible tool for the study of the economics of the direct application of geothermal energy. The large number of options allow examination of a wide range of relationships. Once the user becomes familiar with the model's operation and selects his desired base-case parameter values, extensive sensitivity analysis may be conducted easily and inexpensively. The options available to the user of GRITS are given in Appendix B.

Persons interested in using the program should contact authors Kane or Kroll through The Johns Hopkins University Center for Metropolitan Planning and Research. Because GRITS may be enhanced in the future, inquiries about the enhancements incorporated in the program should also be directed to the authors.

Appendix A

Technical Relationships Internal to the Model

ECONOMIC CALCULATIONS

The basic annual real cost equation is

$$\text{Cost}_t = [\sum_k (\text{CRF}_k \times K_k) \div (1 + f)^{t-t_c}] + \text{EC}_t + \text{O\&M}_t, \quad \text{(A-1)}$$

where:

CRF_k = capital recovery factor for an interest rate r and a repayment period equal to the amortization period of capital component k. If the useful life of component k extends beyond its amortization period, $\text{CRF}_k = 0$ for those subsequent years;

K_k = total cost of capital component k, i.e., production and reinjection wells, downhole and surface pumps, central heat exchanger, storage tank, transmission line, distribution system and hookup equipment (connecting pipe and meter), and peaking equipment. (If the cost equation is, instead, in nominal dollars, cost of equpment purchased after $t = 0$ are assumed to have increased at the rate of inflation);

$(1 + f)^{t-t_c}$ = deflation factor for debt service charges for inflation rate f. t is the year being evaluated. If the piece of equipment is purchased in any year other than $t = 0$, it is deflated by a proportionately smaller amount since its nominal cost is presumed to have been rising at the rate of inflation in the years between the beginning of the utilization phase ($t = 0$) and the year the cost was incurred ($t = t_c$). If $(t - t_c)$ is negative, the cost is not calculated. If nominal dollars are used, $f = 0$;

EC_t = energy costs (pumping and peaking fuel) in year t (user-specified price trend should account for inflation if nominal dollars are used); and

$O\&M_t$ = fixed annual operation and maintenance costs, multiplied by $(1 + f)^t$ in year t.

Heat output at the wells in year t is calculated as

$$O_t = U_t \times \text{maximum output}_t, \tag{A-2}$$

where: O_t = the actual amount of geothermal energy consumed by the process heat user or the community heating system in year t (in Btu);

U_t = the utilization factor in year t. For the industrial routine, this is an input value; for the residential/commercial routine, it is a calculated value based on the design temperature, housing type, level of market penetration, and temperature data; and

maximum output$_t$ = the number of Btu per year that would be delivered <u>net</u> to the transmission line based on that year's temperature and flow if the system operated at 100% utilization.

Revenue in year t is calculated as

$$R_t = P_t \times (O_t + FE_t), \tag{A-3}$$

where: P_t = selling price of the system's energy output in year t, and

FE_t = energy supplied by the peaking system (fossil fuel) in year t.

The discounted average cost (DAC) is calculated as

$$\mathrm{DAC} = \frac{\sum_{t=0}^{T} \frac{\mathrm{Cost}_t}{(1 + d)^t}}{\sum_{t=0}^{T} \frac{(0_t + \mathrm{FE}_t)}{(1 + d)^t}} , \tag{A-4}$$

where d = the discount factor.

The derivation of this expression is shown in Appendix D.

Net present value (NPV) is calculated as

$$\mathrm{NPV} = \sum_{t=0}^{T} \left[\frac{P_t \times (0_t + \mathrm{FE}_t)}{(1 + d)^t} - \frac{\mathrm{Cost}_t}{(1 + d)^t} \right] . \tag{A-5}$$

The break-even point is defined as the year in which the net present value first reaches or exceeds 0.

The discounted average wellhead cost is calculated as

$$\mathrm{DAWC} = \frac{\sum_{t=0}^{T} \frac{\mathrm{Cost}_t^w}{(1 + d)^t},}{\sum_{t=0}^{T} \frac{0_t}{(1 + d)^t}} \tag{A-6}$$

where: Cost_t^w = the annual total of the costs only at the wellhead; i.e. debt service payments on wells, heat exchangers, upwell and reinjection pumps, those pumps' annual overhaul cost and pumping energy cost, and the operation and maintenance cost of those components.

Payback is said to be achieved in the year in which the savings (undiscounted) in operating costs due to an assumed conversion from fossil fuel to a hybrid geothermal system surpasses the initial capital cost.

The savings in operating costs are the difference (undiscounted) between what would have been spent to supply all system heat by burning fossil fuel and the actual operating costs.

$$\begin{aligned} \text{Savings}_t = {} & [(1.33 \times FP_t) \times (O_t + FE_t)] - \\ & [PEC_t + FFC_t + O\&M_t], \end{aligned} \tag{A-7}$$

where: FP_t = fossil fuel price in year 5 (it is multiplied by 1.33 to reflect a 75% conversion efficiency to heat),

PEC_t = total pumping energy cost in year t, and

FFC_t = total fossil fuel (peaking) energy cost in year t.

The savings are reported annually and cumulatively from the beginning of the project.

WELL COSTS

The costs of drilling, casing, and cementing either a production well or a reinjection well increase rapidly with increasing depth. Thus, to allow for accurate well costs, an analytical expression was obtained from recently published data (Refs. 13 and 14). In 1979 dollars,

$$W = 18{,}250 \times e^{(7.014\times10^{-4} \times D)} \quad \text{if } D \le 4431, \text{ or} \tag{A-8a}$$

$$W = 60{,}000 \times e^{(4.355\times10^{-4} \times D)} \quad \text{if } D > 4431, \tag{A-8b}$$

where: W = well cost in 1979 dollars, and

D = depth of well in feet.

Price indexes that are internal to the program update the costs of current dollars. The user may modify the expression by a coefficient different from 1 in OPTION 16.

SUBMERSIBLE PUMP

Pump sizes and costs vary dramatically with the depth from which geothermal waters must be pumped (Ref. 15). Since well depths, flow rates, and drawdown percentages are user-specified variables, the pump size and cost must be calculated in the model for each new set of well parameters. In order to size accurately the required pump and to provide accurate cost estimates, expressions for pump size, capital costs, maintenance costs, and operating costs have been developed with information supplied by J. F. Boutwell of Centrilift, Inc. (Ref. 16).

The dynamic pressure head that must be supplied by a downhole, submersible pump is given by (Refs. 17 and 18)

$$H(ft) = d_d + F_t + P_d , \tag{A-9}$$

where d_d is the head lift, F_t is the frictional head loss in the production tubing, and P_d is the discharge pressure head at the surface. The pump is assumed to be set about 150 ft below the lowest water level in the well under full production, f. The lowest water level is given by the well depth times the percentage of well drawdown. The frictional head losses are assumed to be 25 ft/1,000 ft of lift for nominal production tubings. The discharge pressure at the surface is assumed to be on the order of 50 psi. Any additional pressure that may be needed for surface circulation is assumed to be provided by surface pumps. Converting to pressure (in psi), the pressure head (P_H) required from the downhold pump is given by

$$P_H = 0.480\ (PC)(WD) - 20.0 , \tag{A-10}$$

where PC is the fractional well drawdown and WD is the well depth.

The fluid horsepower required is given by

$$F_{hp} = \frac{P_h f}{1714} , \tag{A-11}$$

where f is the production flow rate. In order to produce this power rating, pump inefficiencies must be considered. Pump ratings are given in terms of brake horsepower, which is defined as

$$B_{hp} = \frac{F_{hp}}{\varepsilon} , \tag{A-12}$$

where ε is the pump efficiency, which has been assumed to be 0.76 (Ref. 18). Thus, the pump size (in horsepower) required for a particular set of well conditions is given by

$$B_{hp} = [3.68 \times 10^{-4} (PC)(WD) - 1.54 \times 10^{-2}] f. \tag{A-13}$$

Costs of the pumps in 1979 dollars are then calculated by

$$C_{sp} = 1175 \times B_{hp}^{0.7} \quad \text{(Ref. 15).} \tag{A-14}$$

Price indexes that are internal to the program update the cost to current dollars.

REINJECTION PUMP (Ref. 15)

In the case where spent geothermal fluids are to be reinjected either into the aquifer from which they were taken or into a shallower aquifer with the same transmissibility, the energy required for reinjection will be the same as that required to bring the fluids to the surface, under the assumptions of an isotropic, homogeneous aquifer matrix, and no precipitation of solids to restrict flow into the aquifer, and no direct communication of pressure changes between the production well and the reinjection well (i.e., their separation distance is greater than the combined radii of influence of the two wells). Therefore, total well pumping is given by twice the production pumping energy.

The situation changes somewhat when reinjection occurs in shallower aquifers whose transmissibility is higher. For simplicity, it is assumed that the transmissibility of the reinjection aquifer scales linearly with depth, i.e.,

$$T \propto \frac{1}{D} . \tag{A-15}$$

Thus, an aquifer at half the depth has twice the transmissibility. In this case, the percentage drawdown is the same in the two wells, and the pumping energy for reinjection (RE) scales linearly with depth and can be expressed as a function of the production energy (PE), i.e.,

$$RE = PE \frac{Dr}{Dp} , \tag{A-16}$$

where Dr is the depth of the reinjection well and Dp is the depth of the production well. The model calculates the total pumping energy (TE) as

$$TE = PE\ (1 + \frac{Dr}{Dp})\ . \tag{A-17}$$

Reinjection pumps located on the surface are cheaper than submersible pumps. The reinjection pump costs in 1979 dollars (C_{rp}) are scaled as

$$C_{rp} = \$3.00 \times f + \$40.00 \times B_{hp} \times \frac{Dr}{Dp}\ , \tag{A-18}$$

where f is the flow rate in gal/min, B_{hp} is the brake horsepower currently calculated for the production well submersible pump, and the ratio Dr/Dp scales the size to reflect the smaller sized pump needed. Price indexes that are internal to the program update the cost to current dollars.

PUMP MAINTENANCE COST

The operating lifetimes of submersible pumps are extremely variable, but under conditions that might be encountered on the Atlantic Coastal Plain, operating lifetimes may be on the order of two to four years. After these periods, the pump must be pulled and reworked. Centrilift has provided estimates of annual repair costs for its submersible pumps (Ref. 16). An average of these quotations is given in 1979 dollars by

Annual surface pump maintenance = \$65 × B_{hp}.

(This is updated by GRITS's internal price indexes to current dollars.) Reinjection pumps are more readily accessible and preventive maintenance may be performed more easily and cheaply. Therefore, reinjection pump maintenance costs are given by

Annual surface pump maintenance = 1.5% × initial cost.

PUMPING ENERGY

General Model

Pumping energy (Ref. 19) for the production well is a function of production rate from the well (determined by such characteristics of the aquifer as saturated thickness and permeability) and of heating demand. The characteristics of the aquifer, generally accounted for through a user-specified well drawdown, are assumed to result from pumping to maintain a flow rate above that which would result from artesian pressure. (When more information on the aquifer is available, another model, described later in this section, can be used.) From the above, the power requirement for a downhold pump is given by

$$\text{kW} = 0.746\ B_{hp}\ . \tag{A-19}$$

However, motor inefficiency increases power requirements to

$$\text{kW} = \frac{0.746B_{hp}}{0.80} = [3.43 \times 10^{-4}\ (\text{PC})(\text{WD}) - 1.44 \times 10^{-2}]f. \tag{A-20}$$

If the well were to be operated around the clock for an entire year, the number of kilowatt hours of electricity required is given by annual kWh = [3,006 (PC)(WD) - 125.8] flow. For most applications, especially residential space heating, heat demands do not require year-round well operation. Thus, a utilization factor is required to scale the annual number of kilowatt hours of pumping energy to the specific load.

Heating demand for a housing unit is a function of ambient temperature and the type of unit. For ambient temperatures above the system design temperature, heating requirements for the total number of housing units on the district heating system are calculated as a fraction of the energy that could be supplied by the geothermal well if pumped at maximum flow. To estimate the length of time that the demand should remain at a given level, average hourly weather data for the major city climatically closest to the study area are used.

Although pumping energy is a nonlinear (convex) function of flow rate, the model uses the linear approximation of the fraction of the energy required to maintain that rate compared to the energy for maximum flow. (The linear approximation was purposely used to make the pumping energy estimates more conservative by slightly overstating the pumping energy required at most levels.) The number of hours at each flow rate is then multiplied by this fraction to obtain "full pumping equivalent hours," which are then summed and taken as a fraction of the number of hours in a year.

The model calculates the annual pumping energy as given above; the resulting value is multiplied by the fraction described above to produce an estimate of actual pumping energy required.

Special Model

When certain aquifer characteristics are known, GRITS can use an alternative drawdown and pumping energy model. This model was originally coded in BIGMAC (Ref. 4) and the following discussion is drawn from that reference. It should be noted that while the drawdown and annual pumping energy are calculated in this alternative way, the initial pump sizing uses the equation above (the general model) with the alternatively calculated drawdown.

In a program such as GRITS, that simulates the economic behavior of a geothermal system, the requirements for resource modeling are quite different from those for codes dedicated to the study of the resource itself. For example, considerations of the inhomogeneity, anisotropy, and finite-boundary effects, as well as the nonuniform temperature and chemistry-related phenomena, are best left to the more specialized programs to analyze. What is desirable in an economic simulation program is a way of handling the resource behavior that is convenient for the users, coupled with the virtue of a reasonable degree of realism without the penalty of a massive amount of computation and specialized data handling.

To this end, a decision was made to characterize the resource as a sealed, infinite, horizontal, homogeneous, isotropic aquifer of uniform characteristics, so that only minor computations will be necessary. If judiciously used, this (over-) simplified model is capable of providing reasonable answers when applied to a known resource. On the other hand, in the event that resource parameters are not known, with a suitable set of default conditions, the users can obtain what may be termed "average" results for the region and can then proceed to a sensitivity study with the variation of one or more of the resource parameters.

For the users in the Atlantic Coastal Plain, representative conditions are

Transmissivity = $T = 1.0\ \text{cm}^2/\text{s}$,

Storage coefficient = $S = 1.0 \times 10^{-4}$, and

Effective well radius = $r = 10$ in.

The transmissivity of 1.0 cm^2/s amounts to having an aquifer 200 mdarcy (mD) × 100 ft thick (or 100 mD × 200 ft, etc.) and corresponds to roughly twice that found at Crisfield, Md. (The default conditions in GRITS use $T = 0.5$ and $S = 3.9 \times 10^{-3}$ to represent Crisfield.) Finally, to aid the users with cyclic pumping requirements, it was decided to approximate the pumping energy by weighting the pumping time. It was found in more detailed calculations that this procedure results in only minor errors, all well within the resource uncertainty.

Under the conditions stated previously, for a constant pumping rate Q, the drawdown at a time t is given by

$$H(t) = \frac{Q}{4\pi T} E_1 (B/t), \qquad \text{(A-21)}$$

where

$$B = \frac{r^2 S}{4T} \quad (r = \text{the well radius}).$$

E_1 here is the well-known exponential integral of order 1 and in most instances of interest, $B/t \ll 1$ may be approximated as

$$E_1 (B/t) \approx -\gamma - \ell n(B/t), \quad \gamma = 0.57721\ldots \quad . \qquad \text{(A-22)}$$

The pumping energy consumption can be readily calculated by integrating Eq. A-21. (It should be mentioned here that the use of Eq. A-22 in the integral leads to an incorrect result because Eq. A-22 has a singularity at $t = 0$.)

The actual equations used in the program are

$$H_{ft}(t) = 0.165*(Q/T)*[16.211 + \ell n(Tt/Sr^2)] \qquad \text{(A-23)}$$

$$E_{kWh}(t) = 0.2723*(Q^2/T)*[F(t) - F(T-1)] \ , \quad t \geq 1, \qquad \text{(A-24)}$$

= pumping energy in year t,

$$F(t) = \begin{cases} t*[15.211 + \ell n(Tt/Sr^2)] \ , & t > 0 \\ 0 \ , & t \leq 0 \end{cases} \qquad \text{(A-25)}$$

Units used are

Q: GPM

T: cm^2/s

S: dimensionless

r: in.

$H_{ft}(t)$: ft (of drawdown)

$E_{kWh}(t)$: kWh (work done against gravity during t to t + 1th year)

t: yr

Pump efficiency is not included in Eq. A-24. To incorporate it, we use

$$(E_{kWh})_{Tot} = E_{kWh}/\varepsilon_{pump}. \tag{A-26}$$

The value assumed for ε_{pump} in the program is 70%.

With regard to the pumping cycles, a total of four options are incorporated into the program. They are

1. Continuous pumping. This needs no elaboration.

2. Semiannual pumping cycle. This covers the cases involving a continuous (constant rate) usage of 6 months duration followed by shutdown for 6 months repeated annually. The drawdown for this case in the t^{th} year is estimated as the drawdown that would have occurred in a continuous operation of $(t/2)^{th}$ year duration. Pumping energy for the t^{th} year is estimated as one-half of the energy that would have been required for continuous pumping in the $(t/2)^{th}$ year.

3. Daily pumping cycle. This simulates the case of 12-hour recovery, repeated daily. The drawdown in the t^{th} year will be slightly larger than 90%* of the drawdown for the t^{th} year

---

*The program uses 92%.

drawdown for continuous pumping. In the interest of conservation, the pumping energy is taken to be one-half of the energy consumption experienced in a constant pumping situation.

4. Space-heating applications. Finally, the program is capable of handling the space-heating application in which, on an annual basis, the usage (at t = 0) starts from zero, linearly increases to a maximum plateau, and decays linearly (symmetrically) back to zero at the end of the heating season. This is followed by a recovery period (summer), and the process is repeated annually. For this application, the drawdown at t^{th} year is approximated as the same as that occurring in the t/2 years with continuous pumping. The pumping energy is taken as 3/8 of that in the $(t/2)^{th}$ year with constant pumping.

The space heating application utilizes the hourly weather data for the area being analyzed because demand depends on ambient air temperature. The user must therefore be sure that the correct area, design temperature, and other demand conditions for the residential-commercial scenario are specified. Since the other three pumping cycles would typically be used for industrial applications, the user needs to specify the proper pumping cycle, utilization factor, and hourly demand (if demand specified).

RATIO OF EXTRACTED GEOTHERMAL ENERGY TO INPUT PUMPING ENERGY

The expression for the ratio of the extracted geothermal energy to the input electrical pumping energy (the coefficient of performance) is

$$\frac{\varepsilon_G}{\varepsilon_p} = \frac{\text{Geothermal heat extracted}}{\text{Pumping energy}} \equiv COP_{GT} \qquad (A\text{-}27)$$

This expression allows direct comparison of the energy efficiency of a geothermal production well to a heat pump.

HEAT EXCHANGER COST

Many applications of moderate temperature geothermal resources will require the use of a water-to-water heat exchanger at the wellhead in order to minimize corrosion and scaling of saline or mineralized waters. For the purposes of this study, plate-type heat exchangers have been considered, since they have a number of attributes such as ease of cleaning and high thermal transfer efficiency that are important in geothermal systems. The cost of any heat exchanger is a function of the logarithmic mean temperature difference, ΔTm, across the heat exchanger and the total heat flow, Q, through it, For stainless-steel-plate heat exchangers the costs (Refs. 20, 21, and 22) can be expressed in 1979 dollars as

$$C = \frac{0.331\ Q^{0.84}}{\Delta Tm}\ , \qquad \text{(A-28)}$$

where

$$\Delta Tm = \frac{(T_1 - T_3) - (T_2 - T_4)}{\ln \dfrac{(T_1 - T_3)}{(T_2 - T_4)}}\ , \qquad \text{(A-29)}$$

and $Q = 500\ f\ (T_1 - T_2)$. The heat flow, Q, is expressed in Btu per hour, f is the well flow rate, T_1 is the geothermal wellhead temperature, T_2 is the reinjection temperature, T_3 is the supply temperature in the secondary loop, and T_4 is the loop return temperature.

A trade-off must be made between high heat exchanger cost at low values of ΔTm, and high reinjection temperatures for the geothermal waters for large values of ΔTm. Since pumping energy is likely to be one of the largest costs in a geothermal system and since the knee of the cost curve is somewhat pronounced, ΔTm has been set at 7°F. This simplifies the cost equation to

$$C = 0.050\ Q^{0.837} \qquad \text{(A-30)}$$

The user specifies the wellhead temperature, T_1, and the reinjection temperature, T_2, and the program calculates the cost. The default values for T_1 and T_2 are 150 and 90°F, respectively.

STORAGE TANK COST

After a survey of several vendors involved in the construction of large storage tanks, an expression for the costs in 1979 dollars has been developed (Ref. 23):

$$C_{ST} = \$0.951V + \$8.70V^{2/3} + \$44{,}600, \tag{A-31}$$

where V is the tank volume in gallons. The expression applies to tanks from 30,000 to 1,000,000 gallons capacity; these tank sizes correspond to storage times for the output from a nominal geothermal well (500 gal/min) of 1 hour to about 1-1/2 days. Price indexes are used internally by GRITS to update to current dollars.

DEMAND FOR SPACE HEATING

In a single-family detached home, the hourly demand for space heating may be given by $(65 - T_0) \times H_i$. The default value is 1200 (Btu/hr)/°F (Ref. 24). For other types of residential housing, the space heating may be expressed in a form similar to the above expression (Ref. 11). The hourly demand on the system is $(65 - T_0) \times H_i \times N_i$, for a community containing several housing types, where H_i is the space heating demand required by other types of housing units, and N_i is the number of houses of type i that use the system.* The heating demands for the given housing types in the model are shown in Table A-1.

Table A-1

Heating demand by housing type

Housing type	H_i* [(Btu/hr)/°F]	Approximate size (ft^2)
Single family, suburban	1200	1600
Single family, dense	1200	1600
Townhouse or rowhouse	780	1000
Garden apartment	420	1000
High-rise apartment	348	800

---

*The value H_i reflects the various sizes of the different housing types as well as the resulting reduced heating load because of shared walls, ceilings, etc. The approximate size for an average unit is shown. The values of H_i were obtained from data that included a large mix of housing stock.

The average number of hours during which the ambient temperature is in a given temperature range (i.e., the time-temperature distribution) is available for 134 cities (page 29). Data for additional cities may be input by the user.

DOMESTIC HOT WATER DEMAND

GRITS assumes that all housing units regardless of type consume the same amount of domestic hot water heat per year that the user specifies using OPTION 39. The default value in GRITS is 20.1 million Btu's per year (Ref. 25). A peak demand of 2.4 times the average hourly demand is assumed when the system is being sized. Thus for single-family units, at a design temperature of 30°F, the peak geothermal load per unit for the default demand is

$$[1200\ (65 - 30) + 5500] = 47{,}500\ \text{Btu/h}$$

BOILER SIZE

The boiler for the peaking system is sized by computing the difference in heating demand at a lowest expected ambient temperature for a given locale and the heating demand at the design temperature (DT) (Ref. 6). The boiler costs include buildings for the boilers and default estimates of $1,500 per 10^5 Btu/h of capacity.

FOSSIL FUEL REQUIREMENTS

The fossil fuel requirements to supply the peak loads are derived from the hourly weather data. Using the time-temperature distribution, the hourly loads to be supplied by the boiler are determined for each expected ambient temperature below the design temperature. This load is multiplied by the average number of hours in a year during which the ambient temperature is expected to be at that level. To account for boiler inefficiencies, heat requirements are multiplied by 1.33, the reciprocal of the 75% boiler efficiency assumed in the model.

COST OF DISTRIBUTION SYSTEM

The cost of the distribution system is found by multiplying the total length of the system by a user-specified cost per mile of installed insulated dual pipe (for a two-way circulation), with a default value of $250,000. This amount is just above the cost suggested in the Brookhaven National Laboratory study (Ref. 26) and is close to the median value of pipe costs surveyed by John Beebee (Ref. 27).

LENGTH OF DISTRIBUTION SYSTEM

The length of the distribution system is determined by the total number of households to be served by the system and the density and market saturation level of these users. Density levels for various types of houses are taken from GEOCITY (Ref. 10) and converted to a block density based on a grid system of 400 by 200 ft blocks (street center to street center). This results in the densities per block given in Table A-2.

Table A-2

Housing densities per block

Type of Residence	No. of households per block
Single family, suburban	7.3
Single family, dense	12.9
Townhouse or rowhouse	32.1
Garden apartment	50.4
High-rise apartment	119.3

The length of the distribution system is then measured directly, based on the block length. This is the length that would occur under 100% saturation. To account for nonparticipation by some households, the length of the system is multiplied by the reciprocal of a user-specified market saturation level (the default value is 70%).

COST OF TRANSMISSION SYSTEM

The cost of transmission depends on the length of the system and the volume of water transported. Transmission pipe diameter is calculated from the volume and an assumed optimal flow rate. The cost per unit length of transmission pipe of a given diameter is given below (Refs. 22 and 28). The cost formula in 1979 dollars used in the model is

$$\$/\text{mile} = 132{,}528 \times d^{0.806} \quad \text{(for temperatures less than 250°F, representing plastic-cased steel pipe)} \qquad \text{(A-32)}$$

and

$/mile = 432,749 × exp(0.128 × d) (for steel cased pipe used for temperatures greater than or equal to 250°F) (A-33)

where: d = pipe diameter in in. = $0.2350\sqrt{Q}$ (Ref. 29), and

Q = flow in gal/min.

These costs are for a two-way pipe laid in the same trench. For one-way pipe such as that which carries the heat-depleted brine from production well to reinjection well, the cost is taken as two-thirds of the cost of laying a similar length of two-way pipe.

The cost of the transmission line pump in 1979 dollars is calculated in the following manner:

$$C_p = n\ C_o, \tag{A-34}$$

where: if $Q \leq 110$ gal/min, then

$$n = (89.232\ Q^{-0.617}\ L),$$

$$C_o = 213\ Q^{0.352}\ ;$$

or: if $Q > 110$ gal/min, then

$$n = (35.112\ Q^{-0.617}\ L)\ ,$$

$$C_o = 118\ Q^{0.661}\ ;$$

where n is rounded up to the nearest integer, Q is the flow in gal/min, and L is the length in miles (Ref. 29).

Pumping energy required to pump for a full year is given by

$$E_p = 34181\ Q^{0.315}\ L\ , \tag{A-35}$$

where E_p is the pumping energy in kilowatt hours. The cost of electricity per kilowatt hour is a user-specified variable.

CAPITAL RECOVERY FACTORS

While pump maintenance costs, pumping energy costs, and fossil fuel requirements may be calculated directly on an annual basis, the remaining cost components must be determined on an annual basis through the use of a CRF that reflects the cost of borrowed funds and the specific life expectancy of individual system components (and thus the assumed amortization period). The interest rate is held constant for all system components under a given model run. Although a developer might choose to amortize all system components over a single period in calculating his financial costs, the actual life expectancy of each component is the more relevant factor in determining economic costs. The user may choose to amortize the equipment over a period shorter than the useful life. If the useful life and amortization period extend beyond the project evaluation period and the program user has decided not to have all capital equipment paid for by the end of the evaluation period, the payments beyond the end of the period will not be considered in the project evaluation. In this case, the full project life cannot be considered to have been evaluated; rather, an early snapshot of project is being studied.

The capital recovery factors are determined directly from user-specified or default values. The capital recovery factor reflects the annual payment required to repay a loan at i% interest over n time periods, which is given by

$$CRF = \frac{i}{(1 + i)^n - 1} + i \ , \qquad (A-36)$$

where i is expressed as its decimal equivalent.

Table A-3 shows the capital recovery factors for a range of interest rates and amortization periods. The amortization periods used in the model are based on life expectancies of each system component in order to be consistent with an economic rather than a financial approach. Wells, the distribution system, and hookups are expected to last about 30 years and the wellhead heat exchanger and in-well pumps about 10 years. These lifetimes are the default values, which may be changed by the user. A financial approach may be simulated by changing the amortization periods and interest rates to reflect the desired financial conditions.

Table A-3

Capital recovery factor by interest rate and time

Interest rate (%)	Repayment period (yr)				
	10	15	20	25	30
8	0.149	0.117	0.102	0.094	0.089
10	0.163	0.131	0.117	0.110	0.106
12	0.177	0.149	0.134	0.127	0.124
14	0.192	0.163	0.151	0.145	0.143
18	0.222	0.196	0.187	0.183	0.181

Appendix B

Options Available to the User of GRITS

Option No.	Parameters
HELP	Types out this list of possible inputs
STOP	End execution of GRITS
0	Specify system as being supplied completely by a fossil fuel boiler, or return it to geothermal
1	Type out the current scenario parameters
2	Name of file to receive output of GRITS. The file name must follow standard DEC-10 conventions.
3	Save or recall a basecase scenario
4	Type in run name (up to 80 characters)
5	Select whether the model is for residential/commercial or industrial sales (residential/commercial is default)
6	Retype results of most recent scenario run
7	Run the current scenario
8	Generate data files for tabulation or later plot generation
9	Choose if system is sized according to resource or demand constraints
10	Area under consideration
11	Water temperature at wellhead (°F)
12	Average depth of upwell (in feet)
13	Housing type, and space heating demand, either 1 - Single family suburban 2 - Single family dense 3 - Townhouses 4 - Garden apartments 5 - High-rise multi-family housing 6 - Mixed housing
14	Design temperature of system (°F)
15	Capital equipment life for: 0 - All equipment 1 - Wells 2 - Piping system 3 - Heat exchanger 4 - Pumps 5 - Hookups 6 - Peaking system boiler (fossil fuel) 7 - Storage tank
16	Adjustment factor for cost of average well
17	Adjustment factor for cost of heat exchanger

18	Cost per hookup ($)
19	Residential market penetration (percentage of ultimate number of households on system)
20	Price of electricity (¢/kWh)
21	Reject temperature (°F)
22	Pipe costs for distribution system (thousands of dollars/mile)
23	Depth of average reinjection well (ft)
24	Storage tank capacity (hours of flow)
25	Inflation rate — ave. annual rate for life of project (%)
26	Well drawdown (and optional aquifer modeling)
27	Interest rate (%)
28	Minimum ambient temperature (°F)
29	Fossil fuel price ($1/million Btu)
30	Boiler cost ($/hundred thousand Btu/hour)
31	Industrial utilization factor (%)
32	Maximum flow rate of water from well (gal/min)
33	Length of study period* and interval for cost calculations (years)
34	Ultimate density of households on geothermal system (%)
35	Percentage of distribution system installed each year
36	Selling price of system energy ($/million Btu)
37	Discount rate — time preference only (%)
38	Transport distance (miles)
39	Annual domestic hot water demand per household (million Btu/year)
40	Economic accounting method
41	Resource assessment period and cost
42	Number of production wells
43	Number of reinjection wells
44	Operation and maintenance costs (% of initial capital equipment costs)
45	Define all characteristics of commercial buildings
46	Floor area of commercial building types (ft^2/building)
47	Heat requirements of commercial building types
	1 - Space heat [(Btu/°F)/(ft^2/day)]
48	2 - Hot water heat [(Btu/ft^2)/day]

---

*This defines the lifetime of the project. The choice to observe only a selected subset of the series of annual results is made upon execution of the scenario in OPTION 7.

49	Hookup cost for commercial buildings ($/hookup)
50	Length of distribution system for commercial buildings (miles)
51	Rate of commercial market penetration (%)
52	Final number of households (if system sized according to known demand)
53	Industrial process heat demand (if system sized according to known demand)

Appendix C

SAMPLE OUTPUT OF DEFAULT SCENARIOS

** GRITS **

Geothermal Resource Interactive Temporal Simulation

Version 9

Designed by Bill Barron, Peter Kroll, & Sally Kane

Written by Peter Kroll

Center for Metropolitan Planning & Research
The Johns Hopkins University
Baltimore, Maryland 21218

September 1981

Example 1. Default Residential/Commercial Scenario with Resource Specified

(Base period for costs is 2nd Quarter,1981)

```
     Residential-Commercial Scenario Parameters

Program Operating Conditions
----------------------------
#  0   Standard geothermal system
#  2   Output file name:                 MANUAL.OUT
#  4   Title of scenario:  (displayed above, if any)
#  5   Residential-Commercial service chosen.
#  8   Data files will not be generated.
#  9   System will be sized according to RESOURCE conditions.

Resource Condition Parameters
-----------------------------
# 42   Number of production wells:             1
# 12   Depth of upwell (feet):              5000.
# 11   Wellhead water temp.(deg. Fahr.)
          linear function used with:
            initial water temp.=    150.0
            annual drop in temp.=     0.0
# 21   Reject temperature (deg. Fahr.):     90.0
# 43   Number of reinjection wells:            1
# 23   Depth of reinjection well (feet):    5000.
# 26   Drawdown of upwell (percent)
          linear function used with:
            initial drawdown= 15.00
            annual change=     0.00
# 32   Maximum flow per well (gpm)
          linear function used with:
            initial flow=        250.00
            annual change=         0.00
# 38   Transport distance (miles) carrying flow of...
         1 wells' flow to distn. system:    0.250

Residential-Commercial Demand Condition Parameters
--------------------------------------------------
# 10   Area under consideration:      Salisbury, Md.
# 14   System design temp.(deg. Fahr.):       38
# 28   Min. ambient temperature (deg. Fahr.):  -5.
# 35   Fraction of distribution system installed:
          in year  0 = 50.000%
          in year  1 = 12.500%
          in year  2 = 12.500%
          in year  3 = 12.500%
          in year  4 = 12.500%
```

(Listing continued on next page)

(cont'd) Example 1. Default Residential/Commercial Scenario with Resource Specified

```
(Residential-Specific)
# 13    Percentages of housing types on system:
          Housing type                 (%)    (Btu/hr/deg)
            1-single family suburban:   0.000      1200.
            2-single family dense:     20.000      1200.
            3-townhouse:               40.000       780.
            4-garden apts.:            40.000       420.
            5-high rise:                0.000       348.
# 34    Market saturation (%):                   70.00
# 19    Rate of residential market penetration
           linear function used with:
             initial percentage=  15.00
             annual change     =   8.00
# 18    Hookup cost per household:
          Housing type                  ($)
            1-single family suburban:   1500.00
            2-single family dense:      1500.00
            3-townhouse:                1500.00
            4-garden apts.:              400.00
            5-high rise:                 400.00
        Avg hookup cost per household: 1060.00
# 39    Domestic hot water(mil.Btu/yr/hh):   20.10

(Commercial-Specific)
# 45    Number of types of commercial buildings:   2
# 46    Avg. floor space for each commercial building of
           type  1 :     4.000 thousand sq. ft.
           type  2 :    10.000 thousand sq. ft.
# 47    Average heat demand for
        Buildings     Space Heat      Hot Water Heat
           of      (Btu/sqft/deg/day)  (Btu/sqft/day)
         type  1:         9.0             0.0
         type  2:         9.0             0.0
# 48    Number of commercial buildings of
           type  1 :     5
           type  2 :     2
# 51    Rate of commercial market penetration
           linear function used with:
             initial percentage=  50.00
             annual change     =  25.00
# 50    Length of commercial distrib. sys:   0.20 miles
# 49    Avg cost per hookup of a commer. bldg: $    1000.
```

(Listing continued on next page)

(cont'd) Example 1. Default Residential/Commercial Scenario with Resource Specified

```
Financial Condition Parameters
------------------------------
# 40   Economic accounting method: NPV & Disc Avg Cost
# 36   System selling price ($/mil. Btu):
          selling price is a multiple of:
          electricity price, factor=          0.70
# 33   Study period: 20 years; Intervals of  1 year
# 41   Resource assessment period            0 yrs
       Ann'l resource assess. cost($thous):     0.
# 16   Well cost adjustment factor:          1.000
# 17   Heat exch. cost adjustment factor:   1.000
# 24   Storage tank capacity:   2.0 hours of flow
# 15   Capital Equipment  Amort. Per.  Phys. Life
         Wells              30. yrs*     30. yrs
         Piping system      30. yrs*     30. yrs
         Heat exchanger     10. yrs*     10. yrs
         Pumps              10. yrs*     10. yrs
         Hookups            30. yrs*     30. yrs
         Peaking boiler     30. yrs*     30. yrs
         Storage tank       30. yrs*     30. yrs
        *(reduced as needed to end in study period)
# 37   Discount rate (percent):               2.00
# 27   Interest rate (percent):              13.50
# 25   Cost calculations are in REAL dollars
       Inflation rate (percent):              8.00
# 20   Cost of electricity (cts/kwh)
          compounding function used with:
            initial elec. price=    6.20
            percent annual change=  2.00
# 29   Fossil fuel cost ($/mil. Btu)
          compounding function used with:
            initial foss. fuel price=   9.000
            percent annual change=      4.000
# 44   Oper. & maint. cost (% of capital):   1.00%
# 30   Boiler cost($/100K Btu/hr):         1500.00
# 22   Distrib sys pipe cost($thou/mi):    250.000


* *  Cost of Initial Capital Equipment  * *
-----------------------------------------------
Wells:                  $    1344.811 thousand
Distribution system:    $     265.964 thousand
Heat exchangers:        $      35.472 thousand
Pumps:                  $      34.092 thousand
Hookups:                $     308.040 thousand
Boiler:                 $     141.565 thousand
Transport system:       $     119.236 thousand
Storage tank:           $      69.804 thousand
-----------------------------------------------
* Total *               $    2318.983 thousand

     (Base period for costs is 2nd Quarter,1981)
```

Example 1. Default Residential/Commercial Scenario with Resource Specified

```
        Residential-Commercial Scenario in Year  0
-------------------------------------------------------
Option                                          Value
-------------------------------------------------------
   0    Standard Geothermal System
   9    System sized to use all of available resource.
  10    Area under consideration:     Salisbury, Md.
  11    Wellhead water temp.(deg. Fahr.):    150.0
  12    Depth of upwell (feet):               5000.
  13    Housing type: 6; Sp.Ht.(Btu/hr/deg):   720.
  14    System design temp.(deg. Fahr.):        38
  15    Capital Equipment  Amort. Per.  Phys. Life
          Wells             30. yrs*     30. yrs
          Piping system     30. yrs*     30. yrs
          Heat exchanger    10. yrs*     10. yrs
          In-well pumps     10. yrs*     10. yrs
          Hookups           30. yrs*     30. yrs
          Peaking boiler    30. yrs*     30. yrs
          Storage tank      30. yrs*     30. yrs
  16    Well cost adjustment factor:         1.000
  17    Heat exch. cost adjustment factor:   1.000
  18    Average cost per hookup:    $        1060.
  19    Mkt penetration: 15.0%;  Households:   43.
  20    Cost of electricity (cts/kwh):       6.200
  21    Reject temperature (deg.Fahr.):       90.0
  22    Distrib sys pipe cost($thou/mi):   250.000

  23    Depth of reinjection well (feet):     5000.
  24    Storage tank capacity (gallons):     29966.
  25    Real/Nominal$:R;  Inflation rate(%):  8.00
  26    Drawdown of upwell (percent):          2.53
  27    Interest rate (percent):              13.50
  28    Min. ambient temperature (deg.Fahr.):   -5.
  29    Fossil fuel cost ($/mil. Btu):         9.00
  30    Boiler cost($/100K Btu/hr):         1500.00
  32    Maximum flow per well (gal/min):     249.71
  33    Study period: 20 yrs; Intervals of  1 year
  34    Market saturation (%):               70.00
  35    Pct. of distrib. sys. built this year:  50.
  36    System selling price ($/mil. Btu):   12.72
  37    Discount rate (in percent):           2.00
  38    Transport distance (miles):          0.250
  39    Domestic hot water(mil.Btu/yr/hh):   20.10
  40    Economic accounting method: NPV & Disc. Avg. Cost
  41    Resource assessment: 0 yrs @ $thou     0./yr
  42    Number of production wells:             1
  43    Number of reinjection wells:            1
  44    Oper. & maint. cost (% of capital):  1.00%
  46    Comm. floorspace on line(thou.sq ft):   20.
  49    Cost per commercial hookup: $       1000.00
  51    Mkt penetration: 50.0%;   Buildings:     4.

*Amort. per. reduced as needed to end in study period.
```

```
Results of Residential-Commercial Model for Year  0
------------------------------------------------------

------------------------------------------------------
Peak total flow (gpm):                          249.71
Length of distribution system:              0.53 miles
Total residential Btu's (millions):            3931.94
Total geothermal Btu's (millions):             4263.24
Total system Btu's (millions):                 4686.75
Pumping energy:                    0.015 million kwh
Coefficient of performance:                      85.76
Percentage geothermal utilization:                6.50
Percentage service geothermal:                   90.96
Annualized costs           (thousands of dollars):
  Well costs:                             197.218
  Distribution system costs:               19.502
  Heat exchanger costs:                     6.668
  Original pump costs:                      6.409
  Hookup costs:                             7.135
  Pump overhaul costs:                      5.233
  Pumping costs:                            0.903
  Peaking boiler costs:                    20.761
  Fossil fuel costs:                        5.069
  Transport cost:                          17.486
  Storage tank cost:                       10.237
  Operation and maintenance costs:         23.190
  Resource assessment costs:                0.000
  ----------------------------------------------
  Total annual wellhead costs:            229.417
  Total annual system costs:              319.812

  Wellhead cost per geo mil. Btu($):       53.81
  System cost per mil. Btu($):             68.24

  Revenue ($ thousands):                  59.615
  Net revenue ($ thousands):            -260.197

  Oper cost saved this yr($thou):         26.938
  Tot. oper. cost savings($thou):         26.938




  (Base period for costs is 2nd Quarter,1981)
```

Example 1. Default Residential/Commercial Scenario with Resource Specified

```
     Residential-Commercial Scenario in Year 19
-----------------------------------------------------
Option                                     Value
-----------------------------------------------------
  0    Standard Geothermal System
  9    System sized to use all of available resource.
 10    Area under consideration:     Salisbury, Md.
 11    Wellhead water temp.(deg. Fahr.):    150.0
 12    Depth of upwell (feet):               5000.
 13    Housing type: 6; Sp.Ht.(Btu/hr/deg):   720.
 14    System design temp.(deg. Fahr.):        38
 15    Capital Equipment  Amort. Per.  Phys. Life
         Wells              30. yrs*     30. yrs
         Piping system      30. yrs*     30. yrs
         Heat exchanger     10. yrs*     10. yrs
         In-well pumps      10. yrs*     10. yrs
         Hookups            30. yrs*     30. yrs
         Peaking boiler     30. yrs*     30. yrs
         Storage tank       30. yrs*     30. yrs
 16    Well cost adjustment factor:         1.000
 17    Heat exch. cost adjustment factor:   1.000
 18    Average cost per hookup:        $     1060.
 19    Mkt penetration:100.0%;  Households:   284.
 20    Cost of electricity (cts/kwh):       9.032
 21    Reject temperature (deg.Fahr.):       90.0
 22    Distrib sys pipe cost($thou/mi):   250.000

 23    Depth of reinjection well (feet):     5000.
 24    Storage tank capacity (gallons):     29966.
 25    Real/Nominal$:R;  Inflation rate(%):  8.00
 26    Drawdown of upwell (percent):         15.00
 27    Interest rate (percent):              13.50
 28    Min. ambient temperature (deg.Fahr.):  -5.
 29    Fossil fuel cost ($/mil. Btu):        18.96
 30    Boiler cost($/100K Btu/hr):         1500.00
 32    Maximum flow per well (gal/min):     249.71
 33    Study period: 20 yrs; Intervals of   1 year
 34    Market saturation (%):                70.00
 35    Pct. of distrib. sys. built this year:   0.
 36    System selling price ($/mil. Btu):    18.53
 37    Discount rate (in percent):            2.00
 38    Transport distance (miles):           0.250
 39    Domestic hot water(mil.Btu/yr/hh):    20.10
 40    Economic accounting method: NPV & Disc. Avg. Cost
 41    Resource assessment: 0 yrs @ $thou     0./yr
 42    Number of production wells:               1
 43    Number of reinjection wells:              1
 44    Oper. & maint. cost (% of capital):   1.00%
 46    Comm. floorspace on line(thou.sq ft):    40.
 49    Cost per commercial hookup: $       1000.00
 51    Mkt penetration:100.0%;    Buildings:     7.

*Amort. per. reduced as needed to end in study period.
```

```
Results of Residential-Commercial Model for Year 19
---------------------------------------------------

---------------------------------------------------
Peak total flow (gpm):                         249.71
Length of distribution system:            1.06 miles
Total residential Btu's (millions):       26212.91
Total geothermal Btu's (millions):        25287.44
Total system Btu's (millions):            27722.53
Pumping energy:                     0.447 million kwh
Coefficient of performance:                   16.57
Percentage geothermal utilization:            38.53
Percentage service geothermal:                91.22
Annualized costs          (thousands of dollars):
  Well costs:                           45.698
  Distribution system costs:            10.217
  Heat exchanger costs:                  3.336
  Original pump costs:                   3.206
  Hookup costs:                         17.926
  Pump overhaul costs:                   5.233
  Pumping costs:                        40.387
  Peaking boiler costs:                  4.810
  Fossil fuel costs:                    61.410
  Transport cost:                        4.052
  Storage tank cost:                     2.372
  Operation and maintenance costs:      23.190
  Resource assessment costs:             0.000
  ----------------------------------------------
  Total annual wellhead costs:         108.189
  Total annual system costs:           221.836

  Wellhead cost per geo mil. Btu($):     4.28
  System cost per mil. Btu($):           8.00

  Revenue ($ thousands):               513.709
  Net revenue ($ thousands):           291.873

  Oper cost saved this yr($thou):      574.147
  Tot. oper. cost savings($thou):     6445.120


******************Totals Over Project Life******************
*** Initial Capital Cost:   2318.983 thousand dollars     ***
*** Net Present Value:       824.304 thousand dollars     ***
*** Discounted Average Cost:  13.447 dollars/million Btu ***
*** Disc. Avg Wellhead Cost:   8.520 dollars/million Btu ***
*** Break-even point achieved in year 15                  ***
*** Tot. Oper. Cost Saved:  6445.120 thousand dollars     ***
*** Payback completed in year 11                          ***
************************************************************

     (Base period for costs is 2nd Quarter,1981)
```

Example 2. Default Industrial Scenario with Resource Specified

```
     (Base period for costs is 2nd Quarter,1981)

           Industrial Scenario Parameters

Program Operating Conditions
----------------------------
#  0   Standard geothermal system
#  2   Output file name:                      MANUAL.OUT
#  4   Title of scenario:  (displayed above, if any)
#  5   Industrial service chosen.
#  8   Data files will not be generated.
#  9   System will be sized according to RESOURCE conditions.

Resource Condition Parameters
-----------------------------
# 42   Number of production wells:                 1
# 12   Depth of upwell (feet):                 5000.
# 11   Wellhead water temp.(deg. Fahr.)
          linear function used with:
            initial water temp.=    150.0
            annual drop in temp.=     0.0
# 21   Reject temperature (deg. Fahr.):         90.0
# 43   Number of reinjection wells:                1
# 23   Depth of reinjection well (feet):       5000.
# 26   Drawdown of upwell (percent)
          linear function used with:
            initial drawdown= 15.00
            annual change=     0.00
# 32   Maximum flow per well (gpm)
          linear function used with:
            initial flow=        250.00
            annual change=         0.00
# 38   Transport distance (miles) carrying flow of...
         1 wells' flow to distn. system:    0.250

Industrial Demand Condition Parameters
--------------------------------------
# 31   Industrial utilization factor (%):   35.00
```

(Listing continued on next page)

```
(cont'd) Example 2.  Default Industrial Scenario with Resource Specified

Financial Condition Parameters
------------------------------
# 40    Economic accounting method: NPV & Disc Avg Cost
# 36    System selling price ($/mil. Btu):
           selling price is a multiple of:
           electricity price, factor=        0.70
# 33    Study period: 20 years; Intervals of  1 year
# 41    Resource assessment period          0 yrs
        Ann'l resource assess. cost($thous):    0.
# 16    Well cost adjustment factor:        1.000
# 17    Heat exch. cost adjustment factor:   1.000
# 24    Storage tank capacity:   2.0 hours of flow
# 15    Capital Equipment  Amort. Per.  Phys. Life
          Wells              30. yrs*     30. yrs
          Piping system      30. yrs*     30. yrs
          Heat exchanger     10. yrs*     10. yrs
          In-well pumps      10. yrs*     10. yrs
          Storage tank       30. yrs*     30. yrs
         *(reduced as needed to end in study period)
# 37    Discount rate (percent):              2.00
# 27    Interest rate (percent):             13.50
# 25    Cost calculations are in REAL dollars
        Inflation rate (percent):             8.00
# 20    Cost of electricity (cts/kwh)
           compounding function used with:
             initial elec. price=    6.20
             percent annual change=  2.00
# 44    Oper. & maint. cost (% of capital):   1.00%


* *  Cost of Initial Capital Equipment  * *
-------------------------------------------
Wells:                   $    1344.811 thousand
Heat exchangers:         $      35.506 thousand
Pumps:                   $      34.119 thousand
Transport system:        $     119.291 thousand
Storage tank:            $      69.816 thousand
-------------------------------------------
* Total *                $    1603.543 thousand

     (Base period for costs is 2nd Quarter,1981)
```

```
                  Example 2.  Default Industrial Scenario with Resource Specified

         Industrial Scenario in Year  0
---------------------------------------------------------
Option                                            Value
---------------------------------------------------------
   0    Standard Geothermal System
   9    System sized to use all of available resource.
  10    Area under consideration:     Salisbury, Md.
  11    Wellhead water temp.(deg. Fahr.):    150.0
  12    Depth of upwell (feet):               5000.

  15    Capital Equipment  Amort. Per.   Phys. Life
          Wells              30. yrs*     30. yrs
          Piping system      30. yrs*     30. yrs
          Heat exchanger     10. yrs*     10. yrs
          In-well pumps      10. yrs*     10. yrs
          Storage tank       30. yrs*     30. yrs
  16    Well cost adjustment factor:         1.000
  17    Heat exch. cost adjustment factor:   1.000

  20    Cost of electricity (cts/kwh):       6.200
  21    Reject temperature (deg.Fahr.):       90.0
  23    Depth of reinjection well (feet):     5000.
  24    Storage tank capacity (gallons):     30000.
  25    Real/Nominal$:R;  Inflation rate(%):  8.00
  26    Drawdown of upwell (percent):        15.00
  27    Interest rate (percent):             13.50

  31    Industrial utilization factor (%):   35.00
  32    Maximum flow per well (gal/min):    250.00
  33    Study period: 20 yrs; Intervals of  1 year
  36    System selling price ($/mil. Btu):   12.72
  37    Discount rate (in percent):           2.00
  38    Transport distance (miles):          0.250
  40    Economic accounting method: NPV & Disc. Avg. Cost
  41    Resource assessment: 0 yrs @ $thou     0./yr
  42    Number of production wells:              1
  43    Number of reinjection wells:             1
  44    Oper. & maint. cost (% of capital):   1.00%

*Amort. per. reduced as needed to end in study period.
```

```
     Results of Industrial Model for Year  0
---------------------------------------------------------

---------------------------------------------------------
Peak total flow (gpm):                            250.00
Total system Btu's (millions):                  22995.00
Pumping energy:                        0.407 million kwh
Coefficient of performance:                        16.58
Annualized Costs           (thousands of dollars):
    Well costs:                              197.218
    Heat exchanger costs:                      6.675
    Original pump costs:                       6.414
    Pump overhaul costs:                       5.239
    Annual pumping costs:                     25.208
    Transport costs:                          17.494
    Storage tank costs:                       10.239
    Operation and maintenance costs:          16.035
    Resource assessment costs:                 0.000
    ---------------------------------------------
    Total annual wellhead costs:             252.020
    Total annual system costs:               284.522

    Wellhead cost per geo mil. Btu($):        10.96
    System cost per mil. Btu($):               12.37

    Revenue ($ thousands):                   292.492
    Net revenue ($ thousands):                 7.970
    (Breakeven point achieved in this year)
    Oper cost saved this yr($thou):          234.007
    Tot. oper. cost savings($thou):          234.007

    (Base period for costs is 2nd Quarter,1981)
```

Example 2. Default Industrial Scenario with Resource Specified

```
            Industrial Scenario in Year 19
------------------------------------------------------
Option                                           Value
------------------------------------------------------
   0    Standard Geothermal System
   9    System sized to use all of available resource.
  10    Area under consideration:     Salisbury, Md.
  11    Wellhead water temp.(deg. Fahr.):    150.0
  12    Depth of upwell (feet):               5000.

  15    Capital Equipment  Amort. Per.  Phys. Life
          Wells             30. yrs*     30. yrs
          Piping system     30. yrs*     30. yrs
          Heat exchanger    10. yrs*     10. yrs
          In-well pumps     10. yrs*     10. yrs
          Storage tank      30. yrs*     30. yrs
  16    Well cost adjustment factor:         1.000
  17    Heat exch. cost adjustment factor:   1.000


  20    Cost of electricity (cts/kwh):       9.032
  21    Reject temperature (deg.Fahr.):       90.0
  23    Depth of reinjection well (feet):     5000.
  24    Storage tank capacity (gallons):     30000.
  25    Real/Nominal$:R;  Inflation rate(%):  8.00
  26    Drawdown of upwell (percent):        15.00
  27    Interest rate (percent):             13.50

  31    Industrial utilization factor (%):   35.00
  32    Maximum flow per well (gal/min):    250.00
  33    Study period: 20 yrs; Intervals of  1 year
  36    System selling price ($/mil. Btu):   18.53
  37    Discount rate (in percent):           2.00
  38    Transport distance (miles):          0.250
  40    Economic accounting method: NPV & Disc. Avg. Cost
  41    Resource assessment: 0 yrs @ $thou     0./yr
  42    Number of production wells:              1
  43    Number of reinjection wells:             1
  44    Oper. & maint. cost (% of capital):  1.00%


*Amort. per. reduced as needed to end in study period.
```

```
          Results of Industrial Model for Year 19
  -------------------------------------------------

  -------------------------------------------------
  Peak total flow (gpm):                     250.00
  Total system Btu's (millions):           22995.00
  Pumping energy:                 0.407 million kwh
  Coefficient of performance:                 16.58
  Annualized Costs          (thousands of dollars):
    Well costs:                            45.698
    Heat exchanger costs:                   3.339
    Original pump costs:                    3.209
    Pump overhaul costs:                    5.239
    Annual pumping costs:                  36.723
    Transport costs:                        4.054
    Storage tank costs:                     2.372
    Operation and maintenance costs:       16.035
    Resource assessment costs:              0.000
    ------------------------------------------
    Total annual wellhead costs:          104.847
    Total annual system costs:            116.669

    Wellhead cost per geo mil. Btu($):      4.56
    System cost per mil. Btu($):            5.07

    Revenue ($ thousands):                426.106
    Net revenue ($ thousands):            309.437

    Oper cost saved this yr($thou):       527.152
    Tot. oper. cost savings($thou):      7263.230


******************Totals Over Project Life******************
*** Initial Capital Cost:   1603.543 thousand dollars     ***
*** Net Present Value:      2743.817 thousand dollars     ***
*** Discounted Average Cost:   8.099 dollars/million Btu ***
*** Disc. Avg Wellhead Cost:   7.210 dollars/million Btu ***
*** Break-even point achieved in year  0                  ***
*** Tot. Oper. Cost Saved:  7263.230 thousand dollars     ***
*** Payback completed in year  6                          ***
***********************************************************

    (Base period for costs is 2nd Quarter,1981)
```

Example 3. Drawdown and Pumping Energy Calculated Using Aquifer Characteristics

```
     (Base period for costs is 2nd Quarter,1981)

           Industrial Scenario Parameters

Program Operating Conditions
----------------------------
#  0   Standard geothermal system
#  2   Output file name:                  MANUAL.OUT
#  4   Title of scenario:  (displayed above, if any)
#  5   Industrial service chosen.
#  8   Data files will not be generated.
#  9   System will be sized according to RESOURCE conditions.

Resource Condition Parameters
-----------------------------
# 42   Number of production wells:              1
# 12   Depth of upwell (feet):               5000.
# 11   Wellhead water temp.(deg. Fahr.)
          linear function used with:
            initial water temp.=    150.0
            annual drop in temp.=     0.0
# 21   Reject temperature (deg. Fahr.):      90.0
# 43   Number of reinjection wells:             1
# 23   Depth of reinjection well (feet):     5000.
# 26   Drawdown of upwell (percent)
          determined from aquifer characteristics:
            Pumping cycle:  Diurnal (12 hours daily)
            Transmissivity=  0.500 sq.cm./sec.
            Aq.Stor.Coef.= 0.003900; Well Radius=10.0 in.
# 32   Maximum flow per well (gpm)
          linear function used with:
            initial flow=        250.00
            annual change=         0.00
# 38   Transport distance (miles) carrying flow of...
         1 wells' flow to distn. system:    0.250

Industrial Demand Condition Parameters
--------------------------------------
# 31   Industrial utilization factor (%):   50.00
```

(Listing continued on next page)

```
(cont´d) Example 3.  Drawdown and Pumping Energy Calculated Using Aquifer Characteristics

Financial Condition Parameters
------------------------------
# 40    Economic accounting method: NPV & Disc Avg Cost
# 36    System selling price ($/mil. Btu):
           selling price is a multiple of:
           electricity price, factor=         0.70
# 33    Study period: 20 years; Intervals of  1 year
# 41    Resource assessment period           0 yrs
        Ann´l resource assess. cost($thous):     0.
# 16    Well cost adjustment factor:         1.000
# 17    Heat exch. cost adjustment factor:   1.000
# 24    Storage tank capacity:   2.0 hours of flow
# 15    Capital Equipment  Amort. Per.  Phys. Life
          Wells              30. yrs*     30. yrs
          Piping system      30. yrs*     30. yrs
          Heat exchanger     10. yrs*     10. yrs
          In-well pumps      10. yrs*     10. yrs
          Storage tank       30. yrs*     30. yrs
         *(reduced as needed to end in study period)
# 37    Discount rate (percent):              2.00
# 27    Interest rate (percent):             13.50
# 25    Cost calculations are in REAL dollars
        Inflation rate (percent):             8.00
# 20    Cost of electricity (cts/kwh)
           compounding function used with:
             initial elec. price=    6.20
             percent annual change=  2.00
# 44    Oper. & maint. cost (% of capital):   1.00%

* *  Cost of Initial Capital Equipment  * *
------------------------------------------
Wells:                    $    1344.811 thousand
Heat exchangers:          $      35.506 thousand
Pumps:                    $      54.270 thousand
Transport system:         $     119.291 thousand
Storage tank:             $      69.816 thousand
------------------------------------------
* Total *                 $    1623.694 thousand

     (Base period for costs is 2nd Quarter,1981)
```

Example 3. Drawdown and Pumping Energy Calculated Using Aquifer Characteristics

```
             Industrial Scenario in Year  0
-----------------------------------------------------
Option                                         Value
-----------------------------------------------------
   0    Standard Geothermal System
   9    System sized to use all of available resource.
  10    Area under consideration:     Salisbury, Md.
  11    Wellhead water temp.(deg. Fahr.):     150.0
  12    Depth of upwell (feet):                5000.

  15    Capital Equipment   Amort. Per.   Phys. Life
          Wells              30. yrs*      30. yrs
          Piping system      30. yrs*      30. yrs
          Heat exchanger     10. yrs*      10. yrs
          In-well pumps      10. yrs*      10. yrs
          Storage tank       30. yrs*      30. yrs
  16    Well cost adjustment factor:          1.000
  17    Heat exch. cost adjustment factor:    1.000


  20    Cost of electricity (cts/kwh):        6.200
  21    Reject temperature (deg.Fahr.):        90.0
  23    Depth of reinjection well (feet):      5000.
  24    Storage tank capacity (gallons):      30000.
  25    Real/Nominal$:R;  Inflation rate(%):   8.00
  26    Drawdown of upwell (percent):         24.99
  27    Interest rate (percent):              13.50

  31    Industrial utilization factor (%):    50.00
  32    Maximum flow per well (gal/min):     250.00
  33    Study period: 20 yrs; Intervals of   1 year
  36    System selling price ($/mil. Btu):    12.72
  37    Discount rate (in percent):            2.00
  38    Transport distance (miles):           0.250
  40    Economic accounting method: NPV & Disc. Avg. Cost
  41    Resource assessment: 0 yrs @ $thou      0./yr
  42    Number of production wells:                1
  43    Number of reinjection wells:               1
  44    Oper. & maint. cost (% of capital):    1.00%

*Amort. per. reduced as needed to end in study period.
```

```
      Results of Industrial Model for Year  0
------------------------------------------------------

------------------------------------------------------
Peak total flow (gpm):                          250.00
Total system Btu's (millions):                32850.00
Pumping energy:                    0.800 million kwh
Coefficient of performance:                      12.03
Annualized Costs          (thousands of dollars):
  Well costs:                              197.218
  Heat exchanger costs:                      6.675
  Original pump costs:                      10.202
  Pump overhaul costs:                      10.545
  Annual pumping costs:                     49.623
  Transport costs:                          17.494
  Storage tank costs:                       10.239
  Operation and maintenance costs:          16.237
  Resource assessment costs:                 0.000
  -----------------------------------------------
  Total annual wellhead costs:             238.219
  Total annual system costs:               318.233

  Wellhead cost per geo mil. Btu($):         7.25
  System cost per mil. Btu($):               9.69

  Revenue ($ thousands):                   417.846
  Net revenue ($ thousands):                99.613
  (Breakeven point achieved in this year)
  Oper cost saved this yr($thou):          327.355
  Tot. oper. cost savings($thou):          327.355

  (Base period for costs is 2nd Quarter,1981)
```

Example 3. Drawdown and Pumping Energy Calculated Using Aquifer Characteristics

```
             Industrial Scenario in Year 19
-------------------------------------------------------
Option                                      Value
-------------------------------------------------------
  0   Standard Geothermal System
  9   System sized to use all of available resource.
 10   Area under consideration:    Salisbury, Md.
 11   Wellhead water temp.(deg. Fahr.):   150.0
 12   Depth of upwell (feet):               5000.

 15   Capital Equipment  Amort. Per.  Phys. Life
        Wells             30. yrs*     30. yrs
        Piping system     30. yrs*     30. yrs
        Heat exchanger    10. yrs*     10. yrs
        In-well pumps     10. yrs*     10. yrs
        Storage tank      30. yrs*     30. yrs
 16   Well cost adjustment factor:      1.000
 17   Heat exch. cost adjustment factor:   1.000


 20   Cost of electricity (cts/kwh):       9.032
 21   Reject temperature (deg.Fahr.):       90.0
 23   Depth of reinjection well (feet):    5000.
 24   Storage tank capacity (gallons):    30000.
 25   Real/Nominal$:R;  Inflation rate(%):  8.00
 26   Drawdown of upwell (percent):        29.53
 27   Interest rate (percent):             13.50

 31   Industrial utilization factor (%):   50.00
 32   Maximum flow per well (gal/min):    250.00
 33   Study period: 20 yrs; Intervals of   1 year
 36   System selling price ($/mil. Btu):   18.53
 37   Discount rate (in percent):           2.00
 38   Transport distance (miles):          0.250
 40   Economic accounting method: NPV & Disc. Avg. Cost
 41   Resource assessment: 0 yrs @ $thou     0./yr
 42   Number of production wells:              1
 43   Number of reinjection wells:             1
 44   Oper. & maint. cost (% of capital):   1.00%

*Amort. per. reduced as needed to end in study period.
```

```
          Results of Industrial Model for Year 19
------------------------------------------------------

------------------------------------------------------
Peak total flow (gpm):                         250.00
Total system Btu's (millions):               32850.00
Pumping energy:                   0.993 million kwh
Coefficient of performance:                      9.69
Annualized Costs          (thousands of dollars):
  Well costs:                          45.698
  Heat exchanger costs:                 3.339
  Original pump costs:                  5.104
  Pump overhaul costs:                 10.545
  Annual pumping costs:                89.728
  Transport costs:                      4.054
  Storage tank costs:                   2.372
  Operation and maintenance costs:     16.237
  Resource assessment costs:            0.000
  -------------------------------------------
  Total annual wellhead costs:         78.603
  Total annual system costs:          177.077

  Wellhead cost per geo mil. Btu($):    2.39
  System cost per mil. Btu($):          5.39

  Revenue ($ thousands):              608.722
  Net revenue ($ thousands):          431.646

  Oper cost saved this yr($thou):     722.479
  Tot. oper. cost savings($thou):    9952.249


******************Totals Over Project Life*****************
*** Initial Capital Cost:   1623.694 thousand dollars     ***
*** Net Present Value:      4443.745 thousand dollars     ***
*** Discounted Average Cost:   7.142 dollars/million Btu ***
*** Disc. Avg Wellhead Cost:   4.456 dollars/million Btu ***
*** Break-even point achieved in year  0                 ***
*** Tot. Oper. Cost Saved:  9952.249 thousand dollars     ***
*** Payback completed in year  4                         ***
***********************************************************

     (Base period for costs is 2nd Quarter,1981)
```

Example 4. Special Fossil-Fuel-Only Case of District Heating System

(Base period for costs is 2nd Quarter,1981)

```
     Residential-Commercial Scenario Parameters

Program Operating Conditions
----------------------------
#  0   "Fossil-Fuel-Only" system--ignore geothermal
#  2   Output file name:                 MANUAL.OUT
#  4   Title of scenario:  (displayed above, if any)
#  5   Residential-Commercial service chosen.
#  8   Data files will not be generated.
#  9   System will be sized according to DEMAND conditions.

Resource Condition Parameters
-----------------------------
# 38   Transport distance (miles):          0.25

Residential-Commercial Demand Condition Parameters
--------------------------------------------------
# 10   Area under consideration:     Salisbury, Md.
# 14   System design temp.(deg. Fahr.):       38
# 28   Min. ambient temperature (deg. Fahr.):  -5.
# 35   Fraction of distribution system installed:
          in year  0 = 50.000%
          in year  1 = 12.500%
          in year  2 = 12.500%
          in year  3 = 12.500%
          in year  4 = 12.500%
```

(Listing continued on next page)

```
(cont'd) Example 4.  Special Fossil-Fuel-Only Case of District Heating System

(Residential-Specific)
# 52   Ultimate number of households:          [illegible]34.
# 13   Percentages of housing types on system:
         Housing type                   (%)    (Btu/hr/deg)
          1-single family suburban:   0.000       1200.
          2-single family dense:     20.000       1200.
          3-townhouse:               40.000        780.
          4-garden apts.:            40.000        420.
          5-high rise:                0.000        348.
# 34   Market saturation (%):                   70.00
# 19   Rate of residential market penetration
          linear function used with:
            initial percentage=  15.00
            annual change     =   8.00
# 18   Hookup cost per household:
         Housing type                     ($)
          1-single family suburban:   1500.00
          2-single family dense:      1500.00
          3-townhouse:                1500.00
          4-garden apts.:              400.00
          5-high rise:                 400.00
       Avg hookup cost per household: 1060.00
# 39   Domestic hot water(mil.Btu/yr/hh):   20.10

(Commercial-Specific)
# 45   Number of types of commercial buildings:   2
# 46   Avg. floor space for each commercial building of
          type  1 :      4.000 thousand sq. ft.
          type  2 :     10.000 thousand sq. ft.
# 47   Average heat demand for
       Buildings      Space Heat       Hot Water Heat
          of       (Btu/sqft/deg/day)  (Btu/sqft/day)
        type  1:          9.0               0.0
        type  2:          9.0               0.0
# 48   Number of commercial buildings of
          type  1 :    5
          type  2 :    2
# 51   Rate of commercial market penetration
          linear function used with:
            initial percentage=  50.00
            annual change     =  25.00
# 50   Length of commercial distrib. sys:   0.20 miles
# 49   Avg cost per hookup of a commer. bldg: $   1000.

     (Listing continued on next page)
```

```
(cont´d) Example 4.  Special Fossil-Fuel-Only Case of District Heating System

Financial Condition Parameters
------------------------------
# 40   Economic accounting method: NPV & Disc Avg Cost
# 36   System selling price ($/mil. Btu):
          selling price is a multiple of:
          electricity price, factor=         0.70
# 33   Study period: 20 years; Intervals of  1 year
# 41   Resource assessment period           0 yrs
       Ann´l resource assess. cost($thous):     0.
# 16   Well cost adjustment factor:         1.000
# 17   Heat exch. cost adjustment factor:   1.000
# 24   Storage tank capacity:   2.0 hours of flow
# 15   Capital Equipment  Amort. Per.  Phys. Life
         Wells              30. yrs*      30. yrs
         Piping system      30. yrs*      30. yrs
         Heat exchanger     10. yrs*      10. yrs
         Pumps              10. yrs*      10. yrs
         Hookups            30. yrs*      30. yrs
         Peaking boiler     30. yrs*      30. yrs
         Storage tank       30. yrs*      30. yrs
        *(reduced as needed to end in study period)
# 37   Discount rate (percent):              2.00
# 27   Interest rate (percent):             13.50
# 25   Cost calculations are in REAL dollars
       Inflation rate (percent):             8.00
# 20   Cost of electricity (cts/kwh)
          compounding function used with:
            initial elec. price=    6.20
            percent annual change=  2.00
# 29   Fossil fuel cost ($/mil. Btu)
          compounding function used with:
            initial foss. fuel price=   9.000
            percent annual change=      4.000
# 44   Oper. & maint. cost (% of capital):   1.00%
# 30   Boiler cost($/100K Btu/hr):        1500.00
# 22   Distrib sys pipe cost($thou/mi):   250.000


* *  Cost of Initial Capital Equipment  * *
-------------------------------------------
Distribution system:  $     265.964 thousand
Pumps:                $       6.119 thousand
Hookups:              $     308.040 thousand
Boiler:               $     253.936 thousand
Transport system:     $     218.984 thousand
-------------------------------------------
* Total *             $    1053.042 thousand

     (Base period for costs is 2nd Quarter,1981)
```

Example 4. Special Fossil-Fuel-Only Case of District Heating System

```
      Residential-Commercial Scenario in Year  0
-----------------------------------------------------
Option                                          Value
-----------------------------------------------------
  0    "Fossil-Fuel-Only" System (ignore geothermal).
  9    System sized to meet the specified demand.
 10    Area under consideration:     Salisbury, Md.
 11    Wellhead water temp.(deg. Fahr.):      150.0
 12    Depth of upwell (feet):                5000.
 13    Housing type: 6; Sp.Ht.(Btu/hr/deg):    720.
 14    System design temp.(deg. Fahr.):         38
 15    Capital Equipment   Amort. Per.   Phys. Life
         Wells               30. yrs*      30. yrs
         Piping system       30. yrs*      30. yrs
         Heat exchanger      10. yrs*      10. yrs
         In-well pumps       10. yrs*      10. yrs
         Hookups             30. yrs*      30. yrs
         Peaking boiler      30. yrs*      30. yrs
         Storage tank        30. yrs*      30. yrs
 16    Well cost adjustment factor:          1.000
 17    Heat exch. cost adjustment factor:    1.000
 18    Average cost per hookup:     $        1060.
 19    Mkt penetration: 15.0%; Households:     43.
 20    Cost of electricity (cts/kwh):        6.200
 21    Reject temperature (deg.Fahr.):        90.0
 22    Distrib sys pipe cost($thou/mi):    250.000

 23    Depth of reinjection well (feet):      5000.
 24    Storage tank capacity (gallons):          0.
 25    Real/Nominal$:R;  Inflation rate(%):   8.00
 26    Drawdown of upwell (percent):           0.00
 27    Interest rate (percent):               13.50
 28    Min. ambient temperature (deg.Fahr.):    -5.
 29    Fossil fuel cost ($/mil. Btu):          9.00
 30    Boiler cost($/100K Btu/hr):          1500.00
 32    Maximum flow per well (gal/min):     1128.60
 33    Study period: 20 yrs; Intervals of  1 year
 34    Market saturation (%):                 70.00
 35    Pct. of distrib. sys. built this year:  50.
 36    System selling price ($/mil. Btu):     12.72
 37    Discount rate (in percent):             2.00
 38    Transport distance (miles):            0.250
 39    Domestic hot water(mil.Btu/yr/hh):     20.10
 40    Economic accounting method: NPV & Disc. Avg. Cost
 41    Resource assessment: 0 yrs @ $thou      0./yr
 42    Number of production wells:                1
 43    Number of reinjection wells:               1
 44    Oper. & maint. cost (% of capital):    1.00%
 46    Comm. floorspace on line(thou.sq ft):    20.
 49    Cost per commercial hookup: $        1000.00
 51    Mkt penetration: 50.0%;   Buildings:      4.
 52    Specified number of households:        284.
```

```
Results of Residential-Commercial Model for Year  0
--------------------------------------------------

--------------------------------------------------
 * *  ignore geothermal-related figures * *
Peak total flow (gpm):                    1128.60
Length of distribution system:         0.53 miles
Total residential Btu's (millions):       3931.94
Total geothermal Btu's (millions):           0.00
Total system Btu's (millions):            4686.75
Pumping energy:                0.005 million kwh
Coefficient of performance:         *************
Percentage geothermal utilization:           0.00
Percentage service geothermal:               0.00
Annualized costs          (thousands of dollars):
  Well costs:                            0.000
  Distribution system costs:            19.502
  Heat exchanger costs:                  0.000
  Original pump costs:                   1.150
  Hookup costs:                          7.135
  Pump overhaul costs:                   0.092
  Pumping costs:                         0.307
  Peaking boiler costs:                 37.240
  Fossil fuel costs:                    56.100
  Transport cost:                       32.114
  Storage tank cost:                     0.000
  Operation and maintenance costs:      10.530
  Resource assessment costs:             0.000
  ----------------------------------------
  Total annual wellhead costs:*************
  Total annual system costs:           164.171

  Wellhead cost per geo mil. Btu($):*******
  System cost per mil. Btu($):           35.03

  Revenue ($ thousands):                59.615
  Net revenue ($ thousands):          -104.556

  Oper cost saved this yr($thou):      -10.837
  Tot. oper. cost savings($thou):      -10.837
```

*Amort. per. reduced as needed to end in study period.

(Base period for costs is 2nd Quarter,1981)

Example 4. Special Fossil-Fuel-Only Case of District Heating System

```
        Residential-Commercial Scenario in Year 19
-------------------------------------------------------
Option                                            Value
-------------------------------------------------------
  0   "Fossil-Fuel-Only" System (ignore geothermal).
  9   System sized to meet the specified demand.
 10   Area under consideration:      Salisbury, Md.
 11   Wellhead water temp.(deg. Fahr.):      150.0
 12   Depth of upwell (feet):                5000.
 13   Housing type: 6; Sp.Ht.(Btu/hr/deg):    720.
 14   System design temp.(deg. Fahr.):          38
 15   Capital Equipment   Amort. Per.   Phys. Life
        Wells               30. yrs*      30. yrs
        Piping system       30. yrs*      30. yrs
        Heat exchanger      10. yrs*      10. yrs
        In-well pumps       10. yrs*      10. yrs
        Hookups             30. yrs*      30. yrs
        Peaking boiler      30. yrs*      30. yrs
        Storage tank        30. yrs*      30. yrs
 16   Well cost adjustment factor:          1.000
 17   Heat exch. cost adjustment factor:    1.000
 18   Average cost per hookup:      $       1060.
 19   Mkt penetration:100.0%; Households:    284.
 20   Cost of electricity (cts/kwh):        9.032
 21   Reject temperature (deg.Fahr.):        90.0
 22   Distrib sys pipe cost($thou/mi):    250.000

 23   Depth of reinjection well (feet):      5000.
 24   Storage tank capacity (gallons):          0.
 25   Real/Nominal$:R;  Inflation rate(%):   8.00
 26   Drawdown of upwell (percent):          0.00
 27   Interest rate (percent):              13.50
 28   Min. ambient temperature (deg.Fahr.):   -5.
 29   Fossil fuel cost ($/mil. Btu):        18.96
 30   Boiler cost($/100K Btu/hr):         1500.00
 32   Maximum flow per well (gal/min):    1128.60
 33   Study period: 20 yrs; Intervals of   1 year
 34   Market saturation (%):                70.00
 35   Pct. of distrib. sys. built this year:   0.
 36   System selling price ($/mil. Btu):    18.53
 37   Discount rate (in percent):            2.00
 38   Transport distance (miles):           0.250
 39   Domestic hot water(mil.Btu/yr/hh):    20.10
 40   Economic accounting method: NPV & Disc. Avg. Cost
 41   Resource assessment: 0 yrs @ $thou      0./yr
 42   Number of production wells:              1
 43   Number of reinjection wells:             1
 44   Oper. & maint. cost (% of capital):   1.00%
 46   Comm. floorspace on line(thou.sq ft):   40.
 49   Cost per commercial hookup: $       1000.00
 51   Mkt penetration:100.0%;  Buildings:      7.
 52   Specified number of households:        284.

*Amort. per. reduced as needed to end in study period.
```

```
Results of Residential-Commercial Model for Year 19
-----------------------------------------------------

-----------------------------------------------------
  * *  ignore geothermal-related figures * *
Peak total flow (gpm):                       1128.60
Length of distribution system:            1.06 miles
Total residential Btu's (millions):         26212.91
Total geothermal Btu's (millions):              0.00
Total system Btu's (millions):              27722.53
Pumping energy:                    0.029 million kwh
Coefficient of performance:            *************
Percentage geothermal utilization:              0.00
Percentage service geothermal:                  0.00
Annualized costs          (thousands of dollars):
  Well costs:                              0.000
  Distribution system costs:              10.217
  Heat exchanger costs:                    0.000
  Original pump costs:                     0.575
  Hookup costs:                           17.926
  Pump overhaul costs:                     0.092
  Pumping costs:                           2.641
  Peaking boiler costs:                    8.629
  Fossil fuel costs:                     699.134
  Transport cost:                          7.441
  Storage tank cost:                       0.000
  Operation and maintenance costs:        10.530
  Resource assessment costs:               0.000
  ------------------------------------------------
  Total annual wellhead costs:*************
  Total annual system costs:             757.185

  Wellhead cost per geo mil. Btu($):*******
  System cost per mil. Btu($):             27.31

  Revenue ($ thousands):                 513.709
  Net revenue ($ thousands):            -243.477

  Oper cost saved this yr($thou):        -13.172
  Tot. oper. cost savings($thou):       -245.528

*****************Totals Over Project Life*****************
*** Initial Capital Cost:    1053.042 thousand dollars    ***
*** Net Present Value:      -2557.418 thousand dollars    ***
*** Discounted Average Cost:  23.413 dollars/million Btu ***
*** Disc. Avg Wellhead Cost:******** dollars/million Btu ***
***            Break-even point not reached               ***
*** Tot. Oper. Cost Saved:  -245.528 thousand dollars     ***
***                 Payback not achieved                  ***
***********************************************************

 (Base period for costs is 2nd Quarter,1981)
```

Appendix D

Derivation of the Expression for Discounted Average Cost

The net present value of a stream of revenues and costs of a project can be expressed as

$$NPV = \sum_{t=0}^{T} \frac{(R_t - C_t)}{(1 + d)^t} ,$$

where: R_t = revenues in year t,

C_t = costs in year t.

d = discount rate,

t = year of evaluation, and

T = last year in evaluation.

What we want to consider is the case where the net present value over the project life equals zero. That is, the project just breaks even at the end.

$$NPV = \sum_{t=0}^{T} \frac{(R_t - C_t)}{(1 + d)^t} = 0 \quad ;$$

so

$$0 = \sum_{t=0}^{T} \frac{R_t}{(1 + d)^t} - \frac{C_t}{(1 + d)^t} ,$$

$$0 = \sum_{t=0}^{T} \frac{R_t}{(1 + d)^t} - \sum_{t=0}^{T} \frac{C_t}{(1 + d)^t} ,$$

and

$$\sum_{t=0}^{T} \frac{C_t}{(1+d)^t} = \sum_{t=0}^{T} \frac{R_t}{(1+d)^t} .$$

We recall that in basic economic terms, if we set the price of a good at its average cost, the total revenues will equal the total cost of the goods sold, resulting in a net revenue of zero.

Analogously for a time stream, the discounted average cost is the number that if we set the selling price equal to it, the net present value of the net revenue stream will be zero.

Therefore, returning to our equation, we are trying to solve for p, the fixed selling price, which is the discounted average cost, where

$$p \times Btu_t = R_t$$

such that

$$\sum_{t=0}^{T} \frac{C_t}{(1+d)^t} = \sum_{t=0}^{T} \frac{R_t}{(1+d)^t}$$

$$= \sum_{t=0}^{T} \frac{p \times Btu_t}{(1+d)^t}$$

$$= p \sum_{t=0}^{T} \frac{Btu_t}{(1+d)^t} ,$$

and solving for p,

$$\frac{\sum_{t=0}^{T} \frac{C_t}{(1+d)^t}}{\sum_{t=0}^{T} \frac{Btu_t}{(1+d)^t}} = p = \text{discounted average cost}$$

(Note that the denominators $(1 + d)^t$ do not cancel out because of the summations.)

Appendix E

Updating GRITS's Base-Year Costs

All costs in the model's structural equations are in 1979 dollars and are adjusted by price indexes to the base-year dollars reported on the program output. To update the base year of dollars in the future, price indexes must be altered within the programs's BLOCK DATA subroutine. Price indexes are those of producers' durable equipment obtained from the U.S. Department of Commerce Bureau of Economic Analysis for the categories (1) mining and oilfield equipment, (2) fabricated metals, and (3) general industry machinery.

All other costs that the user can specify using one of the available options must be updated by the user, and also must be updated in the program subroutine that reinitializes the default scenario (DEFAUL).

Table E-1 indicates the price index that should be associated with each capital component. Table E-2 lists, for those updating the internally calculated or externally specified costs, the means of updating all component costs.

Table E-1

Price indexes for capital cost components.

Component	Equipment index category
Well	Mining and oilfield (1)
Distribution system*	Fabricated metals (2)
Heat exchanger	Fabricated metals (2)
Pumps	General industry machinery (3)
Hookups*	Fabricated metals (2)
Pump replacement	General industry machinery (3)
Boiler*	Fabricated metals (2)
Transport line	Fabricated metals (2)
Storage Tank	Fabricated metals (2)

---

*Since these costs are completely user-specified options, they will not be affected by a change in the BLOCK DATA price index specifications. It is suggested, however, that these indexes be used to calculate the new user-specified values.

Table E-2

Cost components that must be updated when base year is changed.

Component	Via update of price index[1]	Via update of parameters[2]
Boiler		#38: BOIL
Distribution system		#22: PIPE
Hookup		#18,49: HOOKUP(1,..,7)
Well	PINDEX(1)	
Pumps	PINDEX(3)	
Pump overhaul	PINDEX(3)	
Heat exchanger	PINDEX(2)	
Transmission line	PINDEX(2)	
Storage tank	PINDEX(2)	
Electricity cost		#20: ELEFCN, etc.
Fossil fuel cost		#29: FOSFCN, etc.
System selling price		#36: GEOFCN, etc.
Operating & maintenance		#44: OANDM

Notes:

[1] The price indexes in the BLOCK DATA subroutine must be revised. Indexes are based on producers durable equipment data supplied in quarterly reports by the Bureau of Economic Analysis. GRITS uses a base year of 1979; i.e. the index for 1979 is 1.00. The three categories used are PINDEX(1): mining and oilfield equipment; PINDEX(2): fabricated metals; and PINDEX(3): general industry machinery.

[2] These costs are completely specified by the user, so new values should be input directly by choosing the indicated options running GRITS. In addition, the default scenario should be updated, by revising the DEFAUL subroutine for the indicated variable(s). Particular attention should be given to the units of measurements used internally in the program.

REFERENCES

1. "Definition of Markets for Geothermal Energy in Northern Atlantic Coastal Plain," JHU/APL GEMS-002, May 1980.

2. W. Barron, P. Kroll, R. Weissbrod, and W. Toth, "GRITS: A Computer Program for the Economic Evaluation of Direct-use Applications of Geothermal Energy," APL/JHU GEMS-008 QM-80-077, Jun 1980.

3. P. Kroll, W. Barron, and W. Toth, "The Demand Specified Model for Direct Applications of Geothermal Energy: A User's Guide," APL/JHU QM-80-131, Dec 1980.

4. P. Kroll, W. Barron, K. Yu, and W. Toth, "BIGMAC — Basic Interactive Geothermal Model with Aquifer Characterization," APL/JHU QM-81-089, Aug 1981.

5. "Geothermal Energy Market Penetration: Development of a Model for the Residential Sector," JHU/APL GEMS-006, Sep 1979.

6. J. F. Kunze, "Geothermal Space Heating: The Symbiosis with Fossil Fuel," Proc. 12th IECEC, pp. 810-815, 1977.

7. K. Yu and F. C. Paddison, "Technical Assistance — Hydrothermal Resource Application in the Eastern U.S.," Proceedings, Geothermal Resource Council, 9-10 Sep 1980.

8. K. Yu, "Crisfield Maryland, Well Characteristics Determined Using All Test Data." Minutes, Technical Information Interchange Meeting, APL/JHU QM-79-261, Dec 1979.

9. "Department of Energy, DOE/Crisfield Airport No. 1 Well, Somerset County, Maryland. Part I: Drilling and Completion. Part II: Well Test Analysis," Gruy Federal, Inc., Houston, TX, Oct 1979.

10. C. McDonald, C. Bloomster, and S. Schulte, "GEOCITY: A Computer Code for Calculating Costs of District Heating Using Geothermal Resources," BNWL-2208, Feb 1977.

11. R. Tessmer, Brookhaven National Laboratory, personal communication, 14 Jul 1978.

12. "1976 Joint Association Survey on Drilling Costs," American Petroleum Institute, p. 8, Dec 1977.

13. K. Yu, "Geothermal Well Drilling Cost, Another Fit," JHU/APL QM-81-008, 19 Jan 1981.

14. J. F. Kunze, et al., "Reservoir Development and Management," pp. 3-21, Chapter 3 in Geothermal Resources Council Special Report No. 7, Direct Utilization of Geothermal Energy: A Technical Handbook, 1980.

15. W. J. Toth, "GREES/GRITS Model Equations," JHU/APL QM-79-166, 10 Jul 1979.

16. J. F. Boutwell, Centrilift, Inc. (subsidiary of Borg-Warner Corp.), private communication and system quotations.

17. Submersible Pump Handbook (2nd ed.), Centrilift, Inc., 1978.

18. Centrilift Pump Catalog and Performance Data, Centrilift, Inc., 1978.

19. R. Weissbrod, et al., "Economic Evaluation Model for Direct Use of Moderate Temperature (up to 250°F) Geothermal Resources in the Northern Atlantic Coastal Plain," APL/JHU GEMS-003, Jun 1979.

20. R. W. Newman, "Heat Exchanger Costs," APL/JHU QM-78-164/AS-039, 11 Aug 1978.

21. R. W. Henderson, "Heat Exchanger Costs, Geothermal Water to Process Water," APL/JHU QM-79-063/AS-070, 28 Mar 1979.

22. R. von Briesen, "Documenting and Updating Water to Water Plate Heat Exchanger for GRITS," APL/JHU CQO-3087, 10 Aug 1981.

23. W. J. Toth, "Costs for Insulated Storage Tanks," JHU/APL QM-79-189, 2 Aug 1979.

24. Idaho National Engineering Laboratory (INEL), "Rules of Thumb for Geothermal Direct Applications," U.S. Department of Energy, Idaho Operations Office, Sep 1978.

25. W. J. Toth, "Residential Hot Water Demands," JHU/APL QM-80-004/AS-090, 8 Jan 1980.

26. W. F. Barron and W. J. Toth, "BNL Progress Report to DOE/DGE," JHU/APL QM-78-227/AS-062, 5 Oct 1978.

27. J. Beebee, "Cost of Hot Water Pipes," Geothermal Coordinating Group meeting, Univ. Virginia, 9 Aug 1978.

28. I. Oliker and A. M. Rubin, "Piping Networks for District Heating Applications," presented at 71st Annual Conference, International District Heating Association, Harbor Springs, Michigan, 23-25 Jun 1980.

29. W. J. Toth and R. W. Henderson, "Pumping Energy Equations for a Geothermal Transmission," JHU/APL QM-79-250/AS-084, 6 Nov 1979.

INDEX

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
U. S. GOVERNMENT			
DEPARTMENT OF ENERGY/ DGHT	Washington, DC	A. D. Allen	1
		R. Benson	1
		J. C. Bresee	1
		C. Bufe	1
		R. Burr	1
		D. Clements	1
		R. Costello	1
		G. De La Torre	1
		G. Ellis	1
		D. J. Feck	1
		J. Flynn	1
		G. Hooper	1
		A. J. Jelacic	1
		J. Kaminsky	1
		D. Lombard	1
		L. Lehr	1
		P. Labrie	1
		R. La Sala	1
		J. Mock	1
		G. Redding	1
		R. S. H. Toms	1
		K. A. Walters	1
DOE/WET	Washington, DC	E. Peterson	1
DOE/EV	Washington, DC	F. Hudson	1
DOE/Dallas	Dallas, TX	D. Greenwall	1
DOE/IG	Washington, DC	E. Z. Heller	1
DOE/Geothermal Programs,			
San Francisco Operations Office	Oakland, CA		3
Idaho Operations Office	Idaho Falls, ID		5
DOE/Nevada Operations Office	Las Vegas, NV	J. Cotter	1
OTHER GOVERNMENT AGENCIES			
U.S.G.S.	Menlo Park, CA	M. Reed	1
		W. Duffield	1
		P. Muffler	1
	Reston, VA	D. Klick	1
Economic Development Admin.	Washington, DC	I. M. Baill	1
NASA Flight Test Center	Wallops Island, VA	P. C. Mears	1
NOAA/OSG	Washington, DC	D. Attaway	1
NTIS	Springfield, VA		25
DEPARTMENT OF DEFENSE			
Dir. for Energy Policy, DoD	Washington, DC	Director	1
U.S. Air Force			
Hq. USAF/LEEEU	Washington, DC	Code USAF/LEEEU	1
Hq. USAF/RDPDT	Washington, DC	A. Eaffy	1
AFAPL/POE	WPAFB, OH		1
Dover AFB	Dover, DE	A. Day	6
Scott AFB	Scott AFB, IL	A. G. Glover	1
Department of the Navy			
OASN (R&D)	Washington, DC	R. Leonard, Rm 5E 787	1
NAVFAC	Alexandria, VA	W. Adams	1
		E. Doheney	1
NAVPRO	Laurel, MD		1
NWC/China Lake	China Lake, CA	C. Austin	1
NAVMAT	Washington, DC	NMAT 08T3	1
U.S. Naval Academy	Annapolis, MD	D. Edsall	1
Naval Air Rework Facility			
Naval Air Station	Norfolk, VA	W. J. Maxwell, Code 640	3
Naval Civil Eng. Lab.	Pt. Hueneme, CA	D. G. Homes	1
		E. H. Early	1

***Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.**

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
STATE AND LOCAL AGENCIES			
<u>Alabama</u>			
State Energy Management Board	Montgomery, AL	Director	1
Geological Survey of Alabama University of Alabama	University, AL	State Geologist	1
<u>Arkansas</u>			
Arkansas State Energy Office	Little Rock, AR	Director	1
<u>California</u>			
California Energy Commission	Sacramento, CA	S. Willard	1
<u>Colorado</u>			
National Conf. of State Legislatures	Denver, CO	K. Wonstolen	1
<u>Delaware</u>			
State Energy Office	Dover, DE	J. Mancus	1
State Legislature	Dover, DE	H. B. McDowell, III	1
University of Delaware Delaware Geological Survey	Newark, DE	State Geologist	1
<u>Florida</u>			
Energy Management Administration	Tallahassee, FL	Director	1
Bureau of Geology, Dept. of Natural Resources	Tallahassee, FL		1
<u>Georgia</u>			
State Energy Office	Atlanta, GA	Director	1
Dept. of Natural Resources Earth and Water Div.	Atlanta, GA	Director and State Geologist	1
<u>Illinois</u>			
Energy Resource Commission	Springfield, IL		1
Illinois State Geological Survey	Urbana, IL	Chief	1
<u>Indiana</u>			
Dept. of Commerce Energy Group	Indianapolis, IN		1
Dept. of Natural Resources, Geological Survey	Bloomington, IN	State Geologist	1
<u>Iowa</u>			
Energy Policy Council	Des Moines, IA	Chairman	1
Iowa Geological Survey	Iowa City, IA	State Geologist	1
<u>Kansas</u>			
Kansas Energy Office	Topeka, KS	Director	1
Kansas Geological Survey University of Kansas	Lawrence, KS	Director	1
<u>Kentucky</u>			
Kentucky Energy Council	Frankfort, KY	Chairman	1
Kentucky Geological Survey	Lexington, KY	Director and State Geologist	1

*Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
STATE AND LOCAL AGENCIES (Cont'd)			
Louisiana			
Louisiana Geological Survey	Baton Rouge, LA	C. Groat	
Maryland			
Energy Policy Office	Baltimore, MD	Director	1
Dept. of Natural Resources		P. Massicot	1
Water Supply Div.	Annapolis, MD	C. Pieper	1
Dept. of State Planning			
Coastal Zone Management	Salisbury, MD	E. Phillips	1
Mayor and Council of Berlin	Berlin, MD	R. Birely	1
Michigan			
Michigan Dept. of Natural Resources, Geological Survey Div.	Lansing, MI	State Geologist	1
Mississippi			
Assistant to the Governor	Jackson, MS		1
Mississippi Geological Survey	Jackson, MS	Director and State Geologist	1
Missouri			
Missouri Energy Agency	Jefferson City, MO	Director	1
Missouri Geological Survey, Div. of Geological Survey	Rolla, MO	Director and State Geologist	1
Nebraska			
Office of Energy Coordinator and State Tax Commissioner	Lincoln, NE		1
Univ. of Nebraska Conservation and Survey Div.	Lincoln, NE	Director and State Geologist	1
New Jersey			
State Energy Office	Newark, NJ		1
Geologic Survey	Trenton, NJ	Commissioner	1
New Mexico			
New Mexico State Univ. New Mexico Energy Inst.	Las Cruces, NM	J. Marlin	6
New York			
Cayuga Co. Planning Board	Auburn, NY	V. K. Mital	1
ERDA	Albany, NY	B. Krakow	1
State Energy Office	Albany, NY	T. Maxwell	1
Town of Auburn	Auburn, NY	P. Lattimore	2
North Carolina			
Dept. of Natural & Econ. Resources Office of Earth Resources	Raleigh, NC	Director	1
Dept. of Commerce			
Energy Division	Raleigh, NC	Director	1
North Carolina Energy Inst.	Research Triangle Park, NC	Director	1

*Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
STATE AND LOCAL AGENCIES (Cont'd)			
North Dakota			
Geological Survey	Grand Forks, ND		1
Office of Energy Management and Conservation	Bismarck, ND		1
Ohio			
Energy Advisory Council	Columbus, OH		1
Ohio Dept. of Natural Rsources Div. of Geological Survey	Columbus, OH	Div. Chief and State Geologist	1
Oklahoma			
Governor's Advisory Council on Energy	Oklahoma City, OK		1
Pennsylvania			
Governor's Energy Council	Harrisburg, PA		1
Dept. of Environmental Resources Bureau of Topographic and Geological Survey	Harrisburg, PA	Director and State Geologist	1
South Carolina			
Div. of Geology	Columbia, SC	State Geologist	1
Energy Management Office	Columbia, SC	Director	1
South Dakota			
Geological Survey	Vermillion, SD		1
Office of Energy Policy	Pierre, SD		1
Tennessee			
Tennessee Energy Office	Nashville, TN	Director	1
Dept. of Conservation, Div. of Geology	Nashville, TN	State Geologist	1
Texas			
Univ. of Texas, Dept. of Petroleum Engineering	Austin, TX	M. Dorfman	1
Virginia			
Div. of Mineral Resources	Charlottesville, VA	State Geologist and Commissioner	1
		R. DeKay	1
Emergency Energy Services Virginia State Office	Richmond, VA	J. Johansen	1
Energy Office	Richmond, VA	Director	1
Virginia Industrial Development Authority, Accomack County	Parksley, VA	S. K. Schubart	1
Water Control Board	Richmond, VA	A. Giles	1
Virginia Water Center	Blacksburg, VA	M. Hrezo	1
West Virginia			
West Virginia Geological and Economic Survey	Morgantown, WV	Director and State Geologist	1

*Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
LABORATORIES			
Argonne Nat'l. Lab.	Argonne, IL	L. Bryant	1
		P. F. Gustafson	1
Batelle Pacific NW Lab.	Richland, WA	C. H. Bloomster	1
		L. L. Fassbender	1
		D. W. Shannon	1
Brookhaven Nat'l. Lab.	Upton, NY	A. Reisman	1
Lawrence Livermore Lab.	Livermore, CA	A. L. Austin	1
Lawrence Berkeley Lab.	Berkeley, CA	N. Goldstein	1
		K. F. Mirk	1
		W. Yen	1
Los Alamos Scientific Lab.	Oak Ridge, TN	R. C. Feber	1
		A. W. Laughlin	1
		J. Maxwell	1
		G. Morris	1
Oak Ridge Nat'l. Lab.	Oak Ridge, TN	J. Griess	1
		W. Barron	1
COLLEGES AND UNIVERSITIES			
Institute for Energy Analysis	Oak Ridge, TN	N. L. Treat	1
		C. E. Whittle	1
		W. P. Staub	1
Oregon Inst. of Technology	Klamath Falls, OR	D. Karr	7
Oregon State University	Corvallis, OR	G. M. Reistadt	1
The Johns Hopkins University Center Metro Plan. and Res.	Baltimore, MD	Director	1
		S. Kane	14
University of Maryland	Cambridge, MD	Dept. of Engineering, J. Lankford	1
University of Maryland	College Park, MD	Library	1
University of Maryland	Princess Anne, MD	Library	1
University of Virginia	Charlottesville, VA	S. F. Singer	1
Virginia Polytechnic Inst. and State University	Blacksburg, VA	J. K. Costain	1
		L. Glover	1
COMPANIES			
A. C. Schultes & Sons, Inc.	Woodbury, NJ	L. Ahlman	1
Burns and Roe Industrial Services Corp.	Paramus, NJ	R. M. Costello	1
		M. I. Knebel	1
Campbell Soup Co.	Camden, NJ		1
The Brand Corp.	Annapolis, MD	W. Carroll	1
Centrilift, Inc.	Tulsa, OK	J. F. Boutwell	1
CH2M Hill	Reston, VA	R. Dagostaro	1
	Boise, ID	J. C. Austin	1
Columbia LNG Corp.	Wilmington, DE	A. Litchfield	1
Dames and Moore	Cranford, NJ	President	1
D'Appalonia Consulting Engineers	Pittsburgh, PA	C. Schubert	1
Delmarva Drilling Co.	Bridgeville, DE		1
Delmarva Poultry Industry, Inc.	Georgetown, DE	W. Stephens	1
Delmarva Power and Light	Wilmington, DE	W. D. Ferguson	1
Dunn Geoscience Corp.	Latham, NY	J. R. Dunn	1
EBASCO Services, Inc.	New York, NY	R. Cummins	1
EBL Engineers, Inc.	Salisbury, MD	R. H. Stratemeyer	1
EG&G Idaho, Inc.	Idaho Falls, ID	W. J. Toth	1
Energy Exploration, Inc.	Research Triangle Park, NC	M. Beam	1
Energy Systems, Inc.	Anchorage, AK	W. Ogle	1
General Ener-Tech., Inc.	San Diego, CA	C. R. Possell	1
Gipe Associates, Consulting Engineers	Timonium, MD		1
Gruy Federal, Inc.	Arlington, VA	J. Renner	1
Kidde Consultants, Inc.	Newark, DE	R. R. Ruggis	1
Malone and Williams, Architects	Salisbury, MD	J. H. Sprinkle	1
Nabisco, Inc.	East Hanover, NJ	Manager of Tech.	1

---

*Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.

INITIAL DISTRIBUTION EXTERNAL TO THE APPLIED PHYSICS LABORATORY*

ORGANIZATION	LOCATION	ATTENTION	No. of Copies
COMPANIES (Cont'd)			
Pamlico Refineries, Inc.	Raeford, NC	F. Clark, Jr.	1
Raytheon Company	Burlington, MA	A. Slater	1
R. G. Jacques Associates	Albany, NY	C. A. Hall	1
Resource Communities, Inc.	Santa Fe, NM	J. Estoque	1
Salisbury Wicomico Economic Development Corp.	Salisbury, MD	R. L. Kiley	1
Standard Brands, Inc.	Wilton, CT	W. B. Sharp	1
Shore Engineering	Melfa, VA	A. Grothous	1
Solar Energetics	Wilmington, DE	B. Weber	10
Sperry Vickers	Jackson, MS	D. J. Tearpock	1
Sydnor Hydrodynamics, Inc.	Richmond, VA	E. Henely	1
Systems Development Corp.	Santa Monica, CA	F. Zimmerman	1
The Armfield Organization	Winston-Salem, NC	W. A. Armfield, Jr.	1
The Mitre Corp.	McLean, VA	D. Entingh	1
United Indian Planners Assoc.	Washington, DC	D. Larson	1
USS Agri-Chemical	Atlanta, GA	R. F. McFarlin	1
Westinghouse Elec. Corp.	Staunton, VA	R. C. Neiss	1
Worthington Pump Corp.	Washington, DC	R. L. French	1
FOREIGN INSTITUTIONS			
Sunderland Polytechnic	Great Britain	R. Harrison	1

*Initial distribution of this document within the Applied Physics Laboratory has been made in accordance with a list on file in the APL Technical Publications Group.