AN ECONOMIC ASSESSMENT OF NINE
GEOTHERMAL DIRECT USE APPLICATIONS

FINAL REPORT

December 1983

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ICF Incorporated
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Idaho Operations Office

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U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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December 1983

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Washington, D.C. 20585

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ABSTRACT

This is one of a series of three reports prepared by ICF Incorporated for the Idaho Operations Office of the U.S. Department of Energy (DOE). This report provides an economic analysis of nine federally-supported geothermal direct heat applications which were part of DOE's Program Opportunity Notice (PON) program. Three of the projects analyzed were user-owned systems, and six were district heating systems. Five of the nine projects are successful from an economic standpoint and the majority of these projects are in areas where geothermal energy has long been used for heating. The results of this analysis indicate that geothermal energy projects can be economic under certain conditions, but these conditions may not be very widespread.

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EXECUTIVE SUMMARY

Low temperature hydrothermal resources underlie vast areas of the United States, particularly in the western half of the country. While not hot enough to be economic for electricity generation, low temperature (less than 150°C) resources are well suited for direct heat applications, such as space and water heating. Preliminary results from several operational projects indicate that geothermal systems can sometimes provide energy at costs lower than more conventional fuels.

This paper describes the costs and performance of nine operational geothermal direct heat demonstration projects. The projects analyzed include three individual user-owned space and water heating systems and six district heating systems. Several important financial/institutional characteristics of the district heating systems are examined in detail.

To determine the economic potential of geothermal energy, geothermal costs are compared with the costs of natural gas and fuel oil. The approach used to compare the projects is a discounted cash flow analysis. The costs of the different projects are adjusted to account for the particular financial situation faced by each of two types of investors: private, for-profit firms and local governments. The costs of all the energy alternatives for each investor type are then converted to levelized unit costs of conventional energy displaced over a 15-year project life. Conventional fuel costs are estimated based on a recent world oil price forecast. A comparison of the levelized costs of the geothermal project and the conventional energy displaced determines whether the geothermal projects are economically attractive. The internal rate of return (IRR) on capital invested was also calculated for each project.

The results of our economic analysis of nine geothermal projects indicate that low-temperature geothermal resources can provide an inexpensive, reliable source of direct heat energy in some applications. If the geothermal resource characteristics are already fairly well-known, and if the geothermal application system is designed and operated to extract a high percentage of the available thermal energy from the resource, then a geothermal direct heat application system could prove to be a sound investment. Potential geothermal investors should be warned, however, that geothermal direct heat application projects undertaken in the past have by no means been uniformly successful. Of the nine projects reviewed in this study, four do not appear to be economic when compared to conventional alternatives. Furthermore, the nine projects evaluated are among the most advanced of 23 demonstration projects originally funded by the Department of Energy. Some of the remaining projects are still struggling through the resource development and system construction stages and may yet achieve operational status, but many others have been abandoned due to resource inadequacy. The analysis performed here indicates that geothermal energy can successfully compete with conventional energy sources under certain conditions in selected locations.

CHAPTER I

INTRODUCTION

During the last ten years, world oil prices have increased from \$7 to \$30 per barrel (in constant dollars). U.S. natural gas prices have also increased substantially, and are expected to be determined by oil prices once price controls are eliminated. Although current world oil prices are lower than they have been in the recent past, fossil fuel prices measured in constant dollars remain above the level which prevailed during most of the past several decades. As a result, alternative energy forms are becoming more competitive with conventional fuels.

One promising alternative source is geothermal energy, which includes resources with a wide range of temperatures. These resources can be suitable for applications ranging from low temperature heating to the production of high temperature steam for use in generating electricity.¹

Opportunities for the utilization of geothermal resources in direct heat applications exist throughout the western portion of the United States and in some eastern locations. Operating geothermal projects currently utilize these resources in several locations. The map in Figure 1 displays known geothermal resource areas and the locations of the projects reviewed in this report.

This report provides information on the economics of low temperature direct heat geothermal applications for space and water heating which utilize geothermal resources ranging from 100°F to 220°F. The study was undertaken for the purpose of providing potential investors with the best information currently available on (1) the costs of constructing and operating geothermal heating projects, and (2) the economics of these projects relative to conventional alternatives.

The analysis of geothermal project economics presented here is based on a comprehensive review of nine geothermal direct heat demonstration projects sponsored by the U.S. Department of Energy. Two kinds of geothermal heating systems are examined: small, user-owned systems which are owned and operated by a building owner to provide space and/or water heating for his own building(s), and district heating systems which entail the sale of geothermal energy by the system operator to a number of users.

We analyze the financial desirability of both kinds of geothermal systems for two kinds of potential investors, private firms and local governments. Due to the different costs of capital and tax treatment for different kinds of organizations, the relative costs and benefits of investing in geothermal energy differ for each of these investor types.

¹Geothermal electricity generation applications were the first large scale uses of geothermal energy. The Geysers Field in Northern California represents the most significant use of geothermal energy in the United States today.

FIGURE 1

KNOWN AND POTENTIAL HYDROTHERMAL RESOURCES

Source: Interagency Geothermal Coordinating Council, Geothermal Energy, Research, Development and Demonstration Program: Fourth Annual Report (DOE/RA-0050; IGCC-5) Washington, D.C., June 1980, p. 20.

We also examine the institutional arrangements used in existing geothermal district heating systems, including pricing formulas, customer contracts, and utility regulation. All of these factors can have important consequences for district heating system financing and the financial success of a project.

SOURCE OF THE DATA USED IN THIS REPORT

Through two Program Opportunity Notices (PONs), the U.S. Department of Energy (DOE) has provided financial support for twenty-three geothermal energy projects to obtain data about actual operating conditions and evidence of economic attractiveness for a variety of direct heat applications. Although the operating experience from these projects remains limited, some of them have achieved routine commercial scale operation or are close enough to such operation that costs and performance can be estimated with some confidence. Nine of these projects were the basis for the analysis presented in this report. These projects were all retrofit applications in which conventional fuels were replaced with geothermal energy. All nine projects use geothermal energy for space and/or water heating, either for a single institutional building or for a district heating system serving a number of buildings. Six of the projects are district heating systems, and three are small user-owned systems. The following paragraphs briefly describe the projects. More detailed project descriptions are provided in Appendix A.

District Heating

- A district heating system in Boise, Idaho is providing geothermal energy to a number of large commercial buildings in the downtown area and expects to serve additional commercial and residential customers in the future.
- A smaller scale system owned by the Haakon School District in Philip, South Dakota serves five school buildings and eight buildings in the business district.
- The Elko Heat Company in Elko, Nevada currently provides geothermal heat to three commercial users, one with several buildings, and expects to add more customers soon.
- City-operated district heating systems in Susanville, California and Klamath Falls, Oregon are each designed to serve fourteen government buildings.
- In Pagosa Springs, Colorado, the town district heating system will serve approximately sixteen businesses and public buildings. The Klamath Falls, Susanville and Pagosa Springs systems are essentially complete, but the former has not yet begun operating and the latter two are operating at reduced levels due to legal problems.

User-Owned Space and Water Heating Systems

- At St. Mary's Hospita in Pierre, South Dakota, the geothermal fluid temperature is quite low, so the goethermal energy

supplements an existing boiler and drives a heat pump to provide space and hot water heat.

- The Klamath County, Oregon YMCA uses geothermal resources to heat a swimming pool and to provide energy for other space and hot water heating requirements.
- The T-H-S Hospital in Marlin, Texas has converted to a geothermal space and water heating system but continues to rely on existing gas-fired boilers to supply a small portion of peak energy needs.

Data availability limited our analysis of the comparative economics of geothermal direct heat applications to these nine DOE-sponsored projects. The projects analyzed represent a biased sample of potential geothermal direct heat projects because all the projects included are ones which have been or are about to be completed. As a result, these nine projects are among the best of the 23 projects provided financial support by the U.S. Department of Energy. For each of the nine projects reviewed, the geothermal resource base proved adequate for the application; for untapped geothermal resources this would not always be the case. Another anomaly with these projects is that they received a substantial amount of government funds, which made efficient project management less critical to the financial outcome from the operator's perspective. Consequently, the distribution of geothermal project economics developed in this report is not necessarily indicative of the likely outcome of future similar geothermal direct heat applications. Nevertheless, the projects reviewed appear to utilize low temperature geothermal energy in circumstances that are not unique and which could be repeated in other locations for the following reasons:

- The geothermal resources utilized by the projects reviewed vary substantially in temperature, depth, and level of impurities. Resource conditions are not, in general, unusually favorable. One project requires a fluid treatment plant prior to disposal of fluid into surface waters; another reinjects the geothermal fluid back into underground reservoirs. Well depths vary from 275 to 4,300 feet, and temperatures range from 218°F down to 108°F.
- For the most part, the costs utilized in the financial analysis represent actual project experience, rather than uncertain engineering estimates. Eight of the projects are already operational, and the remaining project is expected to begin operations late in 1983, pending resolution of certain legal problems.

The results for these projects indicate that geothermal direct heat applications can be financially very attractive under the right conditions. It is the purpose of this report to assist potential investors in determining when those conditions exist.

REPORT ORGANIZATION

The remainder of this report is divided into two chapters and four appendices. Chapter II presents the methodology and assumptions used in the study.

The basic approach used was to develop a standard set of operating and financial assumptions and examine the financial attractiveness of all the projects on this basis. Chapter III presents the results of the financial analysis and draws general conclusions about geothermal direct heat project profitability. Results are presented for the standardized assumptions listed in Chapter II, and a sensitivity analysis of the effect of altering certain assumptions is also shown. The second part of Chapter III summarizes geothermal project experiences in several areas which can have important effects on district heating project economics. These include pricing, customer contracts, and permitting problems.

To assist the U.S. Department of Energy in its review of the demonstration projects, Appendix A provides an examination of the economics of the nine demonstration projects as they actually developed. For each project under review, we identify the application, provide information about resource characteristics, discuss unusual circumstances which resulted in delays, high costs, or cost overruns, and compute a simple constant-dollar payback period based on the costs as they were actually incurred. Key characteristics of district heating systems, including pricing and customer relations, are also discussed.

Appendix B includes the cost and energy data for the nine demonstration projects. Tables for each project list all capital costs in nominal dollars, showing the years in which those costs were incurred. Anticipated average annual energy deliveries and operating expenses are also included.

A detailed discussion of the federal tax treatment of geothermal costs is included as Appendix C. Appendix D describes the ICF Energy Supply Project Financial Model (FINMOD) which is used for the economic analysis of geothermal project costs.

CHAPTER II

METHODOLOGY AND ASSUMPTIONS

This review of the economics and financing of geothermal direct heat applications was undertaken to evaluate the economic potential of geothermal energy based on the experience to date in several commercial projects. We use a discounted cash flow analysis to compare the costs of supplying equivalent energy quantities from geothermal and conventional energy sources over a 15-year project life. All geothermal projects are analyzed as retrofit investments, i.e., we assume that the geothermal system replaces existing conventional heating equipment which has at least 15 remaining years of useful life. All conventional energy cost calculations, therefore, include fuel prices only and exclude equipment costs. If the existing conventional heating system were to require replacement during the 15-year period, then the conventional energy costs would be higher and the geothermal energy project would be more attractive than shown here.

Costs are evaluated from the point of view of the geothermal system investor. To broaden the applicability of the results, the investment decision is analyzed separately for two different kinds of organizations: private, for-profit firms, and local governments. Due to different costs of capital and tax treatment for different kinds of organizations, the relative costs and benefits of investing in geothermal energy differ for each of these investor types.

The geothermal projects themselves can also be divided into two groups, based on the type of application and project ownership. These two project classes are:

- district heating systems, in which the geothermal system operator sells geothermal energy to a number of customers; and
- small, user-owned space and/or water heating systems, in which a building owner develops a geothermal resource for his own use.

The treatment of project costs and revenues differs for these two groups.

MEASURES OF PROJECT SUCCESS

In this study we compute two different measures of project economic attractiveness: 1) the comparative minimum acceptable supply prices (MASPs) of energy from geothermal systems and the levelized unit prices of conventional fuels, and 2) the internal rate of return (IRR) for geothermal projects. Each of these is discussed below.

Minimum Acceptable Supply Price. The minimum acceptable supply price (MASP) is a "levelized" or constant price per unit of output which would allow all investors (both debt- and equity-holders) to exactly earn their required rate of return. The MASP essentially expresses the present value of all project costs, including returns to shareholders, as a constant unit price of the project's output. Comparing the MASP of a geothermal system with the

similarly levelized price of alternative conventional fuels shows whether or not the geothermal system provides a cost-competitive energy supply.

There are two advantages to using the MASP rather than the equivalent net present value of total discounted project costs. First, the MASP presents project costs in terms which should be familiar to energy users, namely, the cost per million Btus of energy. Second, the unit cost approach makes it easy to compare projects of different sizes. One disadvantage of a discounted levelized cost is that it may be inappropriately compared to the first year price of conventional energy.

Calculation of the MASP requires specification of a discount rate, the stream of energy delivered or displaced, and all project cash flows other than revenues. As discussed above, we used a standard set of interest and discount rates for all projects, in order to provide consistency to our analysis and enhance the usefulness of our results to potential investors.

The annual energy quantities used in our MASP calculations are million Btus of energy displaced by the geothermal project. Typically, geothermal energy is measured in terms of usable energy delivered, while fossil fuels are measured in terms of gross energy input into a fuel conversion system. To permit meaningful comparisons of energy costs and to take account of the inefficiencies in burning fossil fuels, all geothermal energy quantities are expressed in terms of the equivalent amount of conventional fuel displaced.

Levelized Unit Price of Conventional Energy. As mentioned earlier, the purpose of calculating the geothermal system MASP is to be able to compare the cost of geothermal energy with the cost of conventional energy supplies. To achieve a meaningful cost comparison, we calculated the levelized unit price for two types of conventional energy (i.e., distillate fuel oil and natural gas) using the same net present value methodology and employing the same energy units as we used in computing the geothermal MASP.

In this analysis, geothermal energy is considered to be a retrofit option. Therefore, the calculation of the unit prices for conventional fuels includes only the fuel costs which would be incurred if an energy user continued to employ an already existing boiler using these fuels. Because equipment to store and burn these fuels is assumed to be already in place, capital expenses are excluded from the analysis of conventional fuel costs. If the equipment in place has to be replaced, then the new capital equipment cost should be included in the conventional energy cost calculation.

Because the conventional fuel levelized unit price and the geothermal MASP are calculated in the same manner using the same energy units, they can be readily compared to yield a determination of geothermal project attractiveness. Thus, for user-owned systems, whenever the geothermal MASP is lower than the conventional energy levelized price, it will pay to invest in the geothermal system. District heating systems must charge a price for geothermal energy which is lower than the price of competing fuels to compensate customers for risks and retrofit costs. For district heating systems, therefore, the correct comparison is between the geothermal MASP and a price equal to some fraction of the levelized unit price of conventional fuels.

Internal Rate of Return. The minimum acceptable supply price analysis just discussed compares the levelized unit costs of geothermal systems with those of conventional fuels. That analysis calculates a constant unit energy price, given an assumed rate of return required by investors. An alternative way of evaluating the economic potential of geothermal systems is to calculate the internal rate of return which could be earned by investors, given an assumed geothermal price and the corresponding revenue stream. The revenue streams which we use in calculating the internal rates of return are the same as those used for the levelized unit price calculations. That is, for small user-owned systems, the value of energy displaced is the implicit revenue stream for the geothermal system; for district heating systems, we use two-thirds of the price of competing fuels times the quantity of energy displaced.

COSTS AND REVENUES USED IN THE ANALYSIS

Because the analysis is from the point of view of the geothermal system investor, we include only those costs which the investor himself is likely to face. Thus, unit cost calculations for geothermal district heating systems include capital costs for only the production, distribution, and disposal systems; retrofit costs are excluded, since they would generally be borne by the user, rather than by the owner or operator of the geothermal district heating system. For the three user-owned space and water heating applications, retrofit costs are included.

Similarly, user-owned systems do not sell their energy to anyone, and hence have no actual revenues as such. To evaluate the investment, the geothermal user-owner must compare the geothermal system costs with cost of conventional energy displaced. This provides a measure of the amount of money saved or lost as a result of the geothermal investment. Our analysis compares geothermal system levelized unit costs directly with the levelized unit prices of conventional fuels.

District heating systems do earn revenues; hence, our analysis compares the minimum price required to cover all investment and operating costs with a price at which the geothermal system could reasonably be expected to sell its energy. This sales price is generally directly tied to the price of competing conventional fuels. Rarely, if ever, does the geothermal price equal the conventional fuel price, however. To induce potential customers to go to the trouble and expense of retrofitting their buildings and to bear at least part of the risk that the geothermal resource might not hold out as long as expected, district heating systems must generally offer their customers a substantial discount over conventional fuel prices. Based on the experiences of the district heating systems reviewed here, we assume for this analysis that geothermal district heating systems must offer a one-third discount over conventional fuel prices.²

²Three of the six district heating systems are setting their prices at a fraction of conventional fuel prices: Susanville is charging two-thirds of the price of oil, Elko is setting its price to yield a 50 percent savings over natural gas prices, and Boise allows its customers a 30 percent savings over gas prices. Pricing rules for the other three projects do not rely on conventional fuel prices, but do result in substantial savings over the cost of conventional fuels.

Adjustments to Data

The actual experiences of the demonstration projects sponsored by the U.S. Department of Energy should provide valuable information to individuals and organizations considering investment in future geothermal projects, but certain conditions may have been specific to the particular site or project under review and may not be of general interest or provide useful insights to future investors. For example, many of the projects which we reviewed were undertaken by local governments or nonprofit organizations. Their actual financial structure and cost of capital would be irrelevant for a potential private, for-profit investor. Also, extensive DOE involvement may have caused expensive delays in two ways. First, fulfillment of DOE review and reporting requirements may have slowed progress in some cases. Second, some project sponsors might have worked harder to avoid costly delays had more of their own capital been tied up in the geothermal investment. (DOE grants covered 56 to 95 percent of project capital costs for the nine projects reviewed.)

Because the U.S. Department of Energy wanted an analysis of how well the particular projects had worked out under the actual conditions at each site, we performed a pay-back period analysis of those projects. This analysis is presented in Appendix A. However, to meet the primary purpose of this report, we attempted to draw on actual project experiences while still keeping the results general enough to be of value to future investors. We employed several techniques to achieve this goal. First, we analyzed all nine geothermal projects from the perspective of different types of investors. Second, we developed a set of standardized financial assumptions which were used to evaluate all nine projects. Finally, we based our analysis on actual energy streams and cash flows reported by the geothermal projects, but we made some minor adjustments to project costs in cases where special circumstances made it unlikely that those cost streams would be experienced again by future investors.

Cost Data

Crucial to our economic analysis is the use, wherever possible, of actual costs incurred by operating geothermal projects. Only one of the nine projects were not yet operational in the spring of 1983 when we collected our data (viz., the district heating systems in Klamath Falls and Pagosa Springs). Even at these two projects, system construction was essentially complete. Our capital cost data, therefore, should represent the actual amounts spent. Operating costs and delivered energy quantities are unfortunately less firm, since only four of the projects had been operating for at least one full heating season at the time this study was conducted.

Several minor adjustments were made to project cost data in order to ensure consistency across projects and make the analysis more useful to future investors. First, we deleted from all project cost calculations expenditures for attending DOE conferences and publicizing project results, since these expenditures have no direct bearing on normal resource development, system construction, or project operations. (These expenses generally amounted to less than two percent of total reported project costs.) In addition to these DOE-related costs, many other project costs may have been incurred indirectly due to DOE involvement as discussed above. It would be difficult at best to

place a dollar value on most of these indirect DOE-related costs, and we made no attempt to do so.

Where the special circumstances surrounding these demonstration projects resulted in expensive delays, one associated cost can be easily measured, namely, the time value of money. During periods of geothermal project inactivity, the capital which has been invested in the project lies idle, neither bringing the geothermal system closer to completion nor earning interest. The cost of such delays can be computed by multiplying the capital tied up in the geothermal investment by the discount rate, which represents the value of that capital in its next best alternative use. In at least one case (i.e., the THS Hospital), the project was unnecessarily stalled for a period of at least a year, for clearly avoidable reasons unrelated to any technical or institutional difficulties. When analyzing this project, we "assume away" the delay, so that the economic results more fairly represent the costs which would be faced by investors undertaking a similar project in the future.

For most of the demonstration projects analyzed here, the geothermal resource was already fairly well "proven" by the time the project began. Hence, the project cost data include only limited expenditures for resource exploration and confirmation. Our analysis made no attempt to adjust for this fact. However, future investors should expect to incur additional resource confirmation costs except in places where resource characteristics are already well known.

STANDARDIZED ASSUMPTIONS

To permit a meaningful comparison of cost estimates, we use a consistent set of assumptions for each investor type which is applied across all geothermal projects and conventional energy alternatives. The major assumptions cover the following areas:

- The capital structure (debt to equity ratio), interest rate on debt, and the discount rate associated with investments made by each type of investor;
- Inflation rate;
- Taxes and the tax treatment of geothermal project costs;
- Geothermal project start date and project life; and
- The fossil fuels to be compared to geothermal energy and the projected prices of these fuels over the lives of the geothermal projects.

FINANCIAL ASSUMPTIONS

In computing the costs of investment alternatives, assumptions must be made about the investor's capital structure (debt-to-equity ratio), interest rate on debt, and return on equity. These factors can vary greatly depending on the legal status of the investor. For this analysis, two sets of financial

assumptions were made, corresponding to each of the two types of investors under review: private firms and local governments.

The assumptions made about capital structure and the cost of capital affect the discount rate used to compute the unit energy costs faced by each investor. A dollar earned in the future through geothermal system revenues or saved through reduced fuel consumption is not worth as much as a dollar that must be invested today. In comparing energy supply options which have differing cash flow patterns, therefore, the value of future cash flows must be discounted. The discount rate applied to an energy supply project should equal the rate of return from the best alternative investment available to the project sponsor.

The choice of the discount rate is an important determinant of the outcome of the analysis. Investments in geothermal systems, which have large initial capital costs, will not look as attractive when a high discount rate is used because the present value of future savings will be small. The following paragraphs discuss the discount rate, capital structure and cost of debt and equity capital assumptions used for each type of investor.

In analyzing the geothermal retrofit decision for private business firms, an initial debt-to-equity ratio of 50/50 was assumed. This may be a conservative estimate of the debt share. Although geothermal projects are still considered to be risky ventures, some lending institutions have indicated that they may be willing to finance up to 75 percent of project capital costs. Use of a relatively low debt to equity ratio results in higher unit geothermal costs, since a low debt-to-equity ratio implies a large share of high-cost equity capital and a small share of lower-cost debt capital.

The required real, after-tax rate of return on equity for private firms is assumed to be nine percent. With average annual inflation of 5 percent and a combined federal and state income tax rate of approximately 50 percent, this 9 percent real, after-tax return on equity is equivalent to a nominal, before-tax return of around 29 percent. The required rate of return on equity is set fairly high to capture the risk generally associated with investments in geothermal energy; the use of a lower rate of return would make the results more favorable for geothermal projects.³

The real and nominal rates of interest on corporate debt (before accounting for tax benefits from interest deductions) are assumed to be 6 and 11 percent respectively.⁴ In performing the financial analysis, interest expenses are treated as fixed costs and all cash flows (including income taxes) are discounted at the percent per year (real) return on equity rate. This method assumes that the unit cost which is calculated will be just large enough to cover all project costs including the rate of return required by equity holders.

³ $[(1.09 \times 1.05) - 1.0] \div (1 - .50) = 0.29.$

⁴ $(1.06 \times 1.05) - 1.0 = 0.11$

We have assumed that local governments undertaking geothermal investments would finance these projects entirely from new debt issues. The discount rate for local governments is set equal to the interest rate, which represents the cost of capital to these entities.

Because local governments can issue tax-exempt bonds whose interest is non-taxable income to the bondholder, the interest rates paid by local governments are generally lower than those paid by corporations. A review of interest rates during the last few years showed nominal rates paid on municipal bonds to be around 75 percent of the nominal corporate bond rate. Based on this review and on current interest rate levels, we have set the local government interest rate at 3 percent (real) or 8 percent in nominal terms.⁵

Inflation Rate

The GNP deflator is used to represent the general inflation rate for all cost and revenue streams. The actual GNP deflator was employed for all years prior to 1983; for 1983 and subsequent years, we use ICF projections of year-by-year changes in the GNP deflator. Table 1 provides a listing of the annual inflation rates used in the analysis.

Taxes and Tax Benefits

For projects undertaken by private, for-profit firms, the tax treatment of geothermal costs and revenues has a significant effect on lifecycle project costs and levelized unit costs. Three kinds of taxes are incorporated into the analysis: federal income taxes, state income taxes, and local property taxes. The federal income tax rate is set at the current maximum federal corporate tax rate of 46 percent. If the tax rate were lower, the return would be higher.

Actual state income taxes for the projects range from zero to over nine percent, and local property tax rates and methods of property tax calculation vary widely. For all the projects analyzed, we assumed a constant state income tax rate of five percent and a property tax rate equal to two percent of the undepreciated historical value of capital equipment.

Several tax benefits reduce the federal income tax liability born by geothermal projects. Depletion allowances and the expensing of intangible drilling costs serve to reduce taxable income, while the energy tax credit provides for a direct reduction of income tax liability. Accelerated depreciation allows the project sponsor to write off project costs more quickly than straight line depreciation, thus reducing income tax liability and saving money in the early project years. In computing federal income taxes, all four tax benefits are taken into account by assuming that the sponsor has enough taxable income from other operations to enable him to take full advantage of all benefits in the first year in which they

⁵(1.03 x 1.05) - 1.0 = 0.08.

TABLE 1
INFLATION RATE
(Annual Percent Change)

Year	Rate
1979	8.6
1980	9.3
1981	9.4
1982	6.0
1983	4.3
1984	5.2
1985	5.4
1986	5.2
1987	5.1
1988	5.0
1989	5.0
1990	5.0
1991	4.9
1992	4.9
1993	4.9
1994	4.9
1995	4.8
Thereafter	4.8

Source: 1979 through 1982 rates from *Economic Indicators: October 1982*, (Prepared for the Joint Economic Committee by the Council of Economic Advisors) p. 2, and *Survey of Current Business*, February 1983, p. 5; inflation rate projections for 1983 and beyond from ICF Long Term Macroeconomic Forecasts, March 31, 1983.

would be available.⁶ Typically private investors organize the ownership of projects with potential tax benefits to take advantage of those benefits.

Some states provide similar tax benefits for geothermal energy projects which may be applied against state income tax liability. For this analysis, we used a standard set of assumptions to calculate state income taxes. These assumptions include expensing of intangible drilling costs, accelerated depreciation, and no state energy tax credit. A more complete discussion of these tax issues is included in Appendix C.

⁶Our analysis assumed that the 15 percent federal business energy investment tax credit would be available throughout the construction period of all projects examined, even though the energy tax credit is currently scheduled to expire at the end of 1985.

Measurement of Energy Quantities

Typically, geothermal energy is measured in terms of usable energy delivered, while fossil fuels are measured in terms of gross energy input into a fuel conversion system. In order to take account of the inefficiencies in burning fossil fuels and to permit meaningful comparisons of energy costs, we compute all geothermal unit costs in dollars per million Btu of conventional energy displaced. To convert the delivered energy quantity reported by each project to an equivalent displaced energy amount, we assume a constant 70 percent efficiency for existing boilers across all projects. The formula for computing displaced energy is therefore:

$$\text{MMBtu Displaced} = \frac{\text{MMBtu Delivered}}{0.7}$$

In the few cases where no data were available on energy delivered, we use the project's own estimate of conventional energy displaced.⁷

Project Start-Up and Life

The nine geothermal projects reviewed in this study were initiated and came on-line over a period of several years. The Klamath County YMCA and St. Mary's Hospital geothermal heating systems began operating in 1980, for example, while the Pagosa Springs district heating system in Colorado is still not operational. Because conventional fuel costs have varied and are forecast to continue varying over time, the calculation of conventional fuel savings depends on the years during which the investments are made and the geothermal system produces energy. In the interest of consistency, we have assumed for our generalized economic analysis that investment in all geothermal projects begins in 1984. System start-up dates vary in our analysis, depending on the length of the well drilling and system construction period.⁸

⁷Fuel displacement data reported by the projects were expressed in volumetric units such as barrels of oil or thousand cubic feet of natural gas. These quantities were converted to a common unit of measurement (Btus) using the following conversion factors:

1,000 cubic feet of natural gas	=	1.02	x	10 ⁶	Btu
1 barrel No. 2 fuel oil	=	5.825	x	10 ⁶	Btu
1 barrel residual fuel	=	6.283	x	10 ⁶	Btu
1 gallon propane	=	91.6	x	10 ³	Btu
1 kWh electricity	=	3.413	x	10 ³	Btu

⁸For projects which experienced long, avoidable periods of inactivity during the well drilling or construction stages, we "assume away" these delays for purposes of conducting our generalized economic analysis. See Appendix B for more detail.

Once projects are operating, their useful lives may vary from fifteen or twenty years to fifty years or more. If the discount rate, inflation rate, conventional fuel prices, and productive life for each proposed geothermal project were known with certainty, a decision on whether or not to invest in a geothermal system could be made by comparing the project's MASP, calculated over the project's entire productive life, with the levelized unit price for the appropriate conventional fuel alternative. These quantities cannot be known with certainty, however, and most risk-averse investors would be reluctant to invest in a geothermal system if their profits depended on a very long system life. In computing the geothermal project MASPs and internal rates of return, therefore, we limit the assumed system lives to only fifteen years. Thus, even if construction of a geothermal heating system might be more economical than continued reliance on conventional fuel over the entire system life, our analysis will indicate that that system is economically superior to conventional fuel only if the system would "pay for itself" within the first fifteen years.

Fossil Fuel Prices

Because fossil fuel prices are expected to change over time, levelized fossil fuel unit prices will vary not only with the start-up year, but also with the expected energy use pattern. While some of the geothermal projects we studied expect to use approximately equal quantities of geothermal energy each year, others plan to increase energy use each year for the first several years, as more and more users hook up to the system. To be completely consistent, it would be necessary to calculate a separate unit fuel cost corresponding to each geothermal project for every conventional fuel analyzed. For the sake of simplicity, however, we included in our cost comparisons only one unit cost for each fuel. All fossil fuel costs are calculated assuming system start-up in 1988 and constant energy use in each year.⁹ Because the differences in assumed system start-up year and in the timing of energy use for the projects analyzed are not large, this simplification has only a minor effect on fossil fuel unit costs and does not significantly bias the conclusions drawn from the comparisons.

The projects reviewed for this report employ geothermal resources to replace energy previously supplied by natural gas, propane, fuel oil, and, to a small extent, electricity. Due to their high costs, these energy sources are all likely candidates for displacement by future geothermal direct heat projects located in the western United States.

To determine the competitive potential of geothermal energy, geothermal costs are compared to the costs of two alternatives: natural gas and No. 2 fuel oil (home heating oil). Residual fuel oil prices are not specifically examined; however, low-sulfur residual fuel oil prices for small quantities of residual fuel are expected to remain close to natural gas prices on a dollars per million Btu basis. The use of propane as an alternative was also not

⁹This represents a four-year delay between investment and start-up. In practice the delay is 3-6 years. [The IRR and MASP calculations for each project were based on actual construction periods, excluding avoidable delays.]

examined; however, propane prices are expected to be between residual fuel and distillate prices in the future.¹⁰

Table 2 lists the projections for natural gas and home heating oil prices used in this analysis. These prices are based on ICF's June 1983 Base Case forecast of future oil and gas prices. The natural gas prices shown are a simple average of ICF's projections for average prices of natural gas delivered to commercial and to residential customers in the interstate natural gas market.¹¹ The average of residential and commercial prices is used, since most geothermal space and water heating customers would fall into one of these two categories. The No. 2 fuel oil projections are an average for residential customers. While larger commercial customers may face prices which are slightly lower, the remote location of many geothermal projects would tend to make fuel oil prices there somewhat higher than the national average, and these two effects would be offsetting.

¹⁰Propane is used as a substitute for natural gas in isolated areas. It is a premium fuel that historically has been similar to distillate fuel oil in value. Recent oil and gas market conditions, however, led to a surplus of propane supplies, and propane prices have been more similar to residual fuel oil prices than No. 2 fuel oil prices. As the conditions generating the over-supply of propane subside, the price is likely to increase.

¹¹The interstate natural gas market includes most natural gas sales in all states except those in the West South Central region of the country.

TABLE 2
CONVENTIONAL FUEL PRICE PROJECTIONS
 (1982 Dollars)

Year	Crude Oil a/ (\$/bbl)	Natural Gas b/ (\$/MMBtu)	Heating Oil c/ (\$/MMBtu)
1984	27.27	5.00	6.89
1985	25.63	4.78	6.57
1986	26.25	4.78	6.69
1987	29.27	5.24	7.26
1988	31.16	5.41	7.63
1989	33.33	5.64	8.05
1990	33.75	6.14	8.13
1991	32.97	6.21	7.98
1992	34.12	6.50	8.20
1993	35.96	6.87	8.55
1994	36.36	7.04	8.62
1995	37.65	7.24	8.87
1996	38.48	7.48	9.04
1997	39.33	7.73	9.20
1998	40.20	7.99	9.36
1999	41.09	8.25	9.52
2000	42.00	8.53	9.69

a/ Average imported crude oil.

b/ National average of residential and commercial price in interstate markets.

c/ National average residential price.

Source: ICF's June 1983 Base Case forecast.

CHAPTER III

RESULTS AND CONCLUSIONS

This chapter discusses the profitability of the nine geothermal direct heat projects reviewed in this study and summarizes some of the key financial and institutional characteristics of the projects. The chapter is divided into two main sections. In the first section, we present the results of our economic analysis of the nine demonstration projects and consider the factors associated with commercially successful and unsuccessful projects. In the second section, we discuss some non-financial aspects of district heating projects which affect their likelihood of success.

FINANCIAL VIABILITY OF THE GEOTHERMAL PROJECTS REVIEWED

The results of our analysis of the cost competitiveness of geothermal direct heat systems are mixed. While several projects are providing geothermal energy quite inexpensively relative to conventional alternatives, other projects are clearly uneconomical. Tables 3 and 4 present the base case results for district heating systems and user-owned systems. For each type of project, the results are presented separately for private, for-profit investors and for local governments.

The first half of Table 3 presents minimum acceptable supply prices (MASPs) for geothermal energy for the district heating projects from the viewpoint of the private, for-profit investor. A price equal to two-thirds of the levelized unit prices of fuel oil and natural gas are also shown. This is the approximate fraction of natural gas and fuel oil prices at which potential users of geothermal energy appear to be willing to pay hook-up costs and take a risk on a somewhat uncertain energy supply. In three of the six projects, private investors could easily sell their geothermal energy at a level at or below two-thirds of the price of natural gas and still make an acceptable financial return on their investment. The other three projects appear to be uneconomical. Two of the three can produce geothermal energy somewhat more cheaply than the cost of fuel oil, but there is little incentive for potential customers to hook up at this price level. Competition with natural gas is even tougher; none of these higher cost projects can compete even with the full price of natural gas.

Compared to the private firm case, the analysis for local government investors shows the comparison of geothermal and conventional fuels to be slightly more favorable (or less unfavorable) for geothermal energy for all but one of the projects. The geothermal projects are less expensive for a local government due to: (i) the avoidance of taxes, and (ii) the lower cost of capital. Despite some tax benefits for geothermal project investments, the overall effect of taxation, including the higher cost of capital, leads to higher net costs for the private investor than the government investor. The results of

TABLE 3
LEVELIZED CONVENTIONAL FUEL PRICES AND
ENERGY COST ESTIMATES FOR DISTRICT HEATING SYSTEMS
 (1982 Dollars Per Million Btus)

	Geothermal a/	2/3 Natural Gas Price b/	2/3 Heating Oil Price b/
Private Firm Economics			
Boise, ID	4.05	4.57	5.73
Elko Heat Co.	3.62	4.57	5.73
Klamath Falls, OR	3.27	4.57	5.73
Pagosa Springs, CO	7.90	4.57	5.73
Philip, SD c/	10.19	4.57	5.73
Susanville, CA	7.48	4.57	5.73
Local Government Economics			
Boise, ID	3.83	4.75	5.84
Elko Heat Co.	2.89	4.75	5.84
Klamath Falls, OR	3.37	4.75	5.84
Pagosa Springs, CO	6.89	4.75	5.84
Philip, SD c/	8.94	4.75	5.84
Susanville, CA	7.11	4.75	5.84

a/ Cost per MMBtu of energy displaced. Excludes all retrofit costs for users hooking up to the system.

b/ Because geothermal district heating system customers must incur retrofit costs and are at risk in the event of system failure, geothermal energy prices are compared to 2/3 of the price of conventional fuels. The levelized full fuel prices are 1.5 times the prices shown.

c/ The Philip geothermal system is partly user-owned; however, for purposes of this study, we analyzed the Philip system in the same manner as all the other district heating systems, excluding all geothermal retrofit costs from the calculation of geothermal unit costs.

the district heating system financial analysis from the viewpoint of the local government investor are displayed in the lower half of Table 3.¹²

Table 4 presents the economic analysis results for the three individual user-owned space and water heating systems. As with the district heating systems, results for the user-owned systems are mixed. Two of the projects exhibit clear savings over both natural gas and fuel oil, for both private and local government investors. Energy obtained from the third project is substantially more expensive than the conventional alternatives.

TABLE 4
COMPARATIVE LEVELIZED ENERGY COST ESTIMATES FOR
USER-OWNED SPACE AND WATER HEATING SYSTEMS
(1982 Dollars Per Million Btu)

	Geothermal a/	Natural Gas Price	Heating Oil Price
Private Firm Economics			
Klamath County YMCA	2.91	6.86	8.59
St. Mary's Hospital	5.94 b/	6.86	8.59
THS Hospital	14.20	6.86	8.59
Local Government Economics			
Klamath County YMCA	2.90	7.12	8.76
St. Mary's Hospital	5.38	7.12	8.76
THS Hospital	12.95	7.12	8.76

a/ Cost per MMBtu of energy displaced. Includes building retrofit costs.

b/ Includes the geothermal investment tax credit even though the temperature of the resource used (108°F) is below the current minimum allowed for the credit, i.e., 50°C = 122°F.

Internal Rates of Return

The base case analysis discussed above presents the levelized unit costs for geothermal projects, given an assumed cost of capital to project investors.

¹²The lower project cost for a local government investor occurs principally as a result of the implicit federal subsidy associated with federal tax avoidance, including the tax-free nature of municipal bonds. For this reason the private firm analysis may be the more appropriate case for comparing the desirability of geothermal project investments from a national perspective.

An alternative way of examining the competitive advantage or disadvantage of geothermal energy is to calculate the internal rate of return (IRR) which could be earned by a geothermal project given a specified stream of revenues (for district heating systems) or savings (for user-owned systems).

Table 5 shows internal rates of return to corporate investors for both user-owned and district heating systems. For user-owned systems, Table 5 shows the real, after-tax IRRs which result when geothermal energy displaces both natural gas and fuel oil. For district heating systems, the IRRs are computed assuming that geothermal is sold at either two-thirds of the natural gas price or two-thirds of the heating oil prices. The internal rates of return vary greatly from -6 percent to +25 percent for district heating systems and from -6 percent to +39 percent for the small, user-owned systems.

TABLE 5

**INTERNAL RATES OF RETURN TO GEOTHERMAL PROJECTS
FOR PRIVATE, FOR-PROFIT FIRMS**
(Real, After-Tax Percentage Return on Investment)

District Heating Systems

Project	IRR Based On 2/3 Gas Price	IRR Based On 2/3 Oil Price
Boise, ID	14%	20%
Elko Heat Co.	15%	21%
Klamath Falls, OR	19%	25%
Pagosa Springs, CO	0%	4%
Philip, SD	-6%	-1%
Susanville, CA	-4%	4%

User-Owned Systems

Project	IRR Based On Gas Price	IRR Based On Fuel Oil Price
Klamath County YMCA	29%	39%
St. Mary's Hospital	13%	19%
THS Hospital	-6%	-1%

Sensitivity Analysis

The base case economic analysis is based on certain assumptions about geothermal project costs, sponsor tax status, project financing conditions and conventional fuel prices; however, some of these assumptions may not apply to all future projects. For instance, project capital structure or cost of capital may differ from the assumptions made. In addition, capital costs could be higher for some future projects, because of particular resource

characteristics or complications in the geothermal system. These costs might also be lower, due to removal of indirect DOE-related or first-of-a-kind costs.

Tax treatment of geothermal costs may also change. This will be true, for example, if the energy tax credit is not renewed upon its expiration at the end of 1985. Furthermore, because the experience with these geothermal energy projects is still limited, the estimated yearly operating costs for the projects examined may prove to be atypical.

Comparisons of geothermal and conventional energy alternatives depend on the price projections used for conventional fuels as well as on the assumptions made regarding geothermal costs and production. The fossil fuel prices used in the analysis are based on a June 1983 ICF forecast. Actual prices may prove to be lower or higher.

We have addressed these areas of uncertainty by performing a sensitivity analysis of the assumptions used to generate the initial results. The sensitivity analysis evaluates the effects on project economics and conventional fuel unit prices of changes in cost, production, financial, and economic assumptions.

To simplify the sensitivity analysis, the effect of changes in the assumptions is only examined for two projects: the Susanville district heating system and the St. Mary's Hospital geothermal system. This sensitivity analysis was performed using the tax and financial assumptions associated with a private, for-profit firm.

Tables 6 and 7 show the sensitivity analysis results for Susanville and St. Mary's, respectively. The results indicate that either major cost overruns, removal of the energy tax credit, or a substantial decrease in the 50:50 debt to equity ratio could become important additional burdens to private investors in geothermal systems. On the other hand, if capital or operating costs per unit of energy delivered can be held down (for example, by increasing energy use per gallon of fluid distributed), many otherwise marginal geothermal investments could become profitable. Substantial increases in fuel oil and natural gas prices above the levels assumed here would also improve the outlook for geothermal energy.

For the Susanville project, the costs were initially so high that the project continues to be unattractive even with favorable changes in the financial and cost assumptions. For St. Mary's Hospital the opposite is the case. Even with the unfavorable changes in the financial and cost assumptions, the project continues to be financially attractive or at least a break-even proposition.

DISCUSSION OF RESULTS

As the previous discussion has shown, the competitive position of geothermal energy vis-a-vis conventional fuels can vary greatly from project to project. While geothermal direct heat energy is a very economical alternative in certain circumstances, it is at a clear competitive disadvantage in others. In this section we shall explore some of the factors associated with geothermal direct heat project commercial success and lack of success.

TABLE 6
SENSITIVITY ANALYSIS OF THE RESULTS FOR THE
SUSANVILLE DISTRICT HEATING SYSTEM FROM A PRIVATE INVESTOR'S PERSPECTIVE

Parameter	Parameter Change	Geothermal Price		2/3 Gas Price --- (\$/MMBtu) ---	2/3 Oil Price ---
		\$/MMBtu	% Change From Initial Price		
Base Case	None	\$7.48	-	\$4.57	\$5.73
Capital Cost	25% Increase	8.86	+18.4	4.57	5.73
	25% Decrease	6.09	-18.6	4.57	5.73
Operating Costs	25% Increase	7.96	+6.4	4.57	5.73
	25% Decrease	7.00	-6.4	4.57	5.73
Debt/Equity Ratio	25/75	9.22	+23.3	4.57	5.73
	75/25	5.67	-24.2	4.57	5.73
Real Return on Equity	25% Increase	8.09	+8.2	4.51	5.69
	25% Decrease	6.95	-7.1	4.64	5.77
Real Interest on Debt	25% Increase	7.75	+3.6	4.57	5.73
	25% Decrease	7.22	-3.6	4.57	5.73
Tax Treatment	Remove Energy Tax Credit <u>a/</u>	9.12	+21.9	4.57	5.73
Conventional Fuel Prices	25% Increase	7.48	-	5.71	7.16
	25% Decrease	7.48	-	3.43	4.30
Project Life	Evaluate Project Over 25 Years Instead of 15	6.59	-11.9	5.03	6.01

a/ Base case analysis assumes that the 15 percent business energy tax credit is available throughout the construction period for all projects.

TABLE 7
SENSITIVITY ANALYSIS OF THE RESULTS
FOR ST. MARY'S HOSPITAL FROM A PRIVATE INVESTOR'S PERSPECTIVE

Parameter	Parameter Change	Geothermal Price		Natural Gas Price --- (\$/MMBtu) ---	Fuel Oil Price ---
		\$/MMBtu	% Change From Initial Price		
Base Case	None	\$5.94	-	\$6.86	\$8.59
Capital Cost	25% Increase	7.28	+22.6	6.86	8.59
	25% Decrease	4.60	-22.6	6.86	8.59
Operating Costs	25% Increase	6.09	+2.5	6.86	8.59
	25% Decrease	5.80	-2.4	6.86	8.59
Debt/Equity Ratio	25/75	7.15	+20.4	6.86	8.59
	75/25	4.72	-20.5	6.86	8.59
Real Return on Equity	25% Increase	6.45	+8.6	6.77	8.53
	25% Decrease	5.49	-7.6	6.96	8.65
Real Interest on Debt	25% Increase	6.13	+3.2	6.86	8.59
	25% Decrease	5.76	-3.0	6.86	8.59
Tax Treatment	Remove Energy Tax Credit <u>a/</u>	6.65	+12.0 <u>b/</u>	6.86	8.59
Conventional Fuel Prices	25% Increase	5.94	-	8.58	10.74
	25% Decrease	5.94	-	5.15	6.44
Project Life	Evaluate Project Over 25 Years Instead of 15	5.07	-14.6	7.55	9.02

a/ The base case analysis assumes that the 15 percent business energy tax credit is available throughout the construction period.

b/ The effect of removing the tax credit would be greater for some other projects because a larger proportion of their capital costs are eligible for the credit.

Of the nine projects which we examined, five appear to be cost-competitive; the other four do not. Three of the five "successful" projects, the Klamath County YMCA, the City of Klamath Falls district heating system, and the Boise district heating system are located in areas where geothermal energy has been used in heating applications for a very long time. The Boise Warm Springs Water District has operated a geothermal district heating system in the Boise area since 1890, and individual building owners in Klamath Falls have been using geothermal energy for space and water heating for at least 80 years. It is not surprising that the projects in these locations are successful. The geothermal resources available in this area are dependable and are known to be so. As a result, it is easier to convince potential customers that they should hook up to the system. Additionally, in these locations project operators have more experience with geothermal energy and have set up efficient delivery and administrative systems which provide customers with the incentive to use geothermal energy in a cost-effective manner.

Of the remaining six projects located in areas which had less experience with geothermal energy utilization prior to project initiation, only two have a clear economic advantage over conventional fuels, the district heating system in Elko, Nevada and the St. Mary's Hospital project in Pierre, South Dakota.

Thermodynamic theory and an analysis of the project cost components suggest that the following physical characteristics of a project are likely to be helpful in ensuring a successful financial outcome:

- High geothermal resource temperature;
- Shallow geothermal resource depth;
- High rate of heat extraction (and utilization) per gallon of fluid extracted, i.e., a large reduction in fluid temperature;
- Short fluid distribution distances;
- High absolute rate of heat extraction (i.e., a larger project);
- Low geothermal fluid treatment or waste disposal costs.

A high resource temperature is helpful because the higher the temperature of the fluid relative to the temperature requirement in the heating application, the more heat in the fluid and the more heat per unit volume or weight that can be extracted by the heat exchangers used in the project. Therefore, with a high fluid temperature smaller (and lower cost) system components can extract the same amount of heat.

All of the other characteristics also help keep project costs down. A shallow resource depth minimizes drilling costs. A high rate of heat extraction per gallon requires a smaller distribution system to deliver the same amount of heat. A short distribution distance minimizes the loss of heat prior to delivery and reduces piping and pumping costs. A high absolute rate of heat extraction permits some economies of scale. Finally, low treatment or waste disposal costs keep the total costs of the system down.

One of the most important determinants of whether a geothermal direct heat project is successful is the level of utilization of the resource. Because total costs can remain essentially unchanged whether the user extracts a small or a large fraction of the heat from the fluid, the costs per unit of energy decrease proportionately as energy extraction per gallon goes up. At only one of the nine projects reviewed here are users currently approaching what might be considered full resource utilization. (The St. Mary's Hospital uses its geothermal resource quite effectively, starting with a fluid with a temperature of only 108°F and extracting enough heat to reduce the temperature to below 80°F.)

To assess the efficiency of geothermal energy utilization in this analysis, we defined "full resource utilization" as the lowering of geothermal fluid temperature down to 120°F (or a drop in temperature of 25°F, for projects with fluid temperatures below 145°F) with a 25 percent annual load factor assumed for all projects.¹³ Temperature drops of these magnitudes should be easily achievable using currently available technology; indeed, the St. Mary's project provides evidence that enough heat can be extracted to lower the temperature more than 25°F even when the initial fluid temperature is well below 120°F. Although this definition of full resource utilization is somewhat arbitrary, it does provide a basis for assessing resource utilization which permits a comparison of the projects.

Table 8 contains a summary of the physical and cost characteristics of the nine projects examined including an estimate of the resource utilization rate. The successful projects were a small user-owned system with a high geothermal energy utilization rate and relatively large district heating systems with reasonably high energy utilization rates. None of the projects with a low heat utilization rate provided geothermal energy at a low cost.

The projects with the most expensive unit energy cost were the THS hospital and the Philip, South Dakota district heating system. A review of those two projects indicates that they had the deepest wells. Additionally, the THS hospital project was the smallest in terms of energy utilized and had the lowest level of utilization of the heat in the fluid. The Philip district heating project also was small, had a low energy utilization rate, and required a waste treatment plant for the spent geothermal fluid.

An evaluation of the operation of the Philip, S.D. (Haakon School) project was presented at the Geothermal Resources Council's October 1983 Annual Meeting in Portland, Oregon by F. W. Childs of EG&G Idaho. The study showed that the cost of the geothermal energy used in the school could be greatly reduced if 1) the price charged the business district for waste heat from the school were increased from 10 percent to 76 percent of the value of the business district's energy savings and 2) the school's boilers were used to meet peak heating requirements so that more waste heat could be sold to the business district. Some of the other projects might be able to obtain

¹³Actual load factors for most of the projects reviewed here are estimated to be between 20 and 30 percent (Project data sheets are available from Frank Childs and Ray Sanders of EG&G Idaho, Inc. in Idaho Falls, Idaho).

TABLE 8
PROJECT CHARACTERISTICS

	Resource Temperature (°F)	Well Depth (feet)	Annual Energy Used 9 (10 Btu)	Energy Utilization c/ (Ratio)	Energy Cost (1982 \$/MMBtu)
<u>User-Owned</u>					
Klamath County YMCA	147	1,400	7.0 b/	.76	2.91
St. Mary's Hospital	108	2,200	11.4	1.11	5.94 d/
THS Hospital	153	3,885	5.0 b/	.44	14.20
<u>District Heating</u>					
Klamath Falls, OR	218 a/	625 a/	51.0 b/	.70	3.27
Elko Heat Co.	178	850	27.0	.61	3.62
Boise, ID	170 a/	1,450 a/	80.6	.74	4.05
Susanville, CA	170	935	20.7 b/	.47	7.48
Pagosa Springs, CO	140 a/	290 a/	11.9	.57	7.90
Philip, SD	157	4,300	9.5	.57	10.19

a/ Average of two or more wells.

b/ Data on energy delivery not available; amounts used here were derived by multiplying the quantity of energy displaced by an assumed 70 percent conventional boiler efficiency.

c/ For purposes of this analysis, we defined "full resource utilization (1.0)" as the lowering of geothermal fluid temperature down to 120°F (or a drop in temperature of 25°F for resources with a temperature below 145°F), with a 25 percent load factor. The formula used for determining maximum energy delivery for each project is:

$$\begin{aligned}
 &\text{Conversion Factor (viz., 4.38)} \times \text{Flow (in gallons per minute)} \\
 &\quad \times \text{Change in Temperature (in } ^\circ\text{F)} \\
 &\quad \times \text{Load Factor (i.e., .25)} \\
 &= \text{Energy (in MMBtu/year)}.
 \end{aligned}$$

d/ Includes a geothermal energy tax credit although currently the credit only applies when the resource temperature exceeds 120°F.

significant, but less spectacular energy cost reductions if their operations were evaluated.

The projects with the next most expensive unit energy costs were the Pagosa Springs and Susanville district heating systems. These projects were relatively small district heating systems with low geothermal energy utilization rates.

The St. Mary's Hospital project was marginal from an economic standpoint. Although the St. Mary's Hospital project made very efficient use of the available heat of the geothermal resource present, the very low temperature of the resource (and the relatively low amount of heat available per gallon) may have been the cause of the relatively high unit energy costs.

Although these nine projects compose a very small sample, it appears from the evidence presented here that a successful user-owned system might have a well not exceeding 2,000 feet in depth, a resource temperature of at least 140°F and an energy utilization rate of 0.7 or more. A successful district heating system might have a well not exceeding 2,000 feet, a resource temperature of at least 170°F, an energy utilization rate of at least .65, and a total energy supply level of at least 30 billion Btus annually. Of course, if some characteristics of a proposed system were much more favorable than these minimum requirements, then a system might be successful which did not meet all of the minimums stated. A project cost model could be developed which would provide a unit energy cost as a function of these and other physical characteristics, but such an effort was beyond the scope of this study.

The biggest problem for the district heating systems examined appears to be the low level of geothermal energy utilization and the small size of the project. The principal ways to improve system economics are to 1) hook up more customers within the same area to increase user density and 2) encourage each user to extract more of the available heat in the fluid. Alternatively, the "spent" geothermal fluid can be cascaded for use in lower temperature applications (e.g., heating a swimming pool). Unfortunately, the achievement of either of these requirements is difficult in a small town, and geothermal resources are often located in areas with low population density. Customers can be encouraged to make efficient use of geothermal energy through appropriate billing procedures, however, as discussed below.

Although it could be argued that the low rate of geothermal energy utilization in the projects reviewed may have biased the results against geothermal energy, several other characteristics of these projects suggest that the results of this study may in fact be biased in favor of geothermal energy. The sample of projects chosen for this analysis included only federally-supported geothermal direct heat applications which have managed to reach or are about to reach an operational stage. For all nine projects the geothermal resource proved to be adequate for the intended application. In addition, while several projects experienced delays, cost over-runs, and other difficulties, all were able to obtain sufficient financing (largely from the U.S. Department of Energy) and most were able to overcome the legal and permitting problems that stood in their way. (One district heating systems, the City of Klamath Falls system has yet to obtain permission to begin operating.) Furthermore, the geothermal cost estimates included in this report exclude

most of the resource exploration expenditures, since DOE involvement in most of these demonstration projects began only after much of the exploratory work had already been completed. Inclusion of these costs would make geothermal energy appear less favorable. [These costs may not be very significant for new projects because United States Geological Survey (USGS) and DOE-sponsored resource assessments have been performed for much of the western United States.]

In summary, experience at the nine geothermal projects examined here indicates that low-temperature geothermal resources can provide an inexpensive, reliable source of direct heat energy under certain conditions. Potential geothermal investors should be warned, however, that geothermal direct heat applications projects undertaken in the past have by no means been uniformly successful.

Of the nine projects reviewed in this study, four provide heat energy at very low unit costs, but four do not appear to be economical when compared to conventional alternatives. The other project examined appears to be a financial success, but not an overwhelming success. Furthermore, these nine projects are among the most advanced of 23 demonstration projects originally funded by the Department of Energy. Some of the remaining projects are still struggling through the resource development and system construction stages and may yet achieve operational status, but many others have been abandoned due to resource inadequacy.

OTHER FACTORS AFFECTING THE VIABILITY OF DISTRICT HEATING SYSTEMS

The above discussion focused on the costs and physical determinants of project profitability. This section provides a discussion of other factors that affect district heating projects' financing and performance. The discussion of district heating systems presented here will include the Philip, S.D. system although it is a special case because it is primarily a user-owned, institutional system. In a physical sense Philip is a true district heating system. (See Appendix A for individual project details.)

The physical characteristics and the costs of a district heating system are important aspects determining the success or failure of a project. However, the design and physical characteristics depend heavily on the level and type of participation in the system, and no system can be constructed unless financing can be obtained. The project must cultivate citizen interest and support, for citizen opposition can delay a project indefinitely. In this section we discuss some of the key characteristics of district heating systems, including billing or metering systems, customer contracts, pricing and customer assistance. Each of these factors can be important in determining how well, or whether, a district heating system operates.

Metering Systems

There are several different types of billing or metering systems available for geothermal users. The most common meters are the Btu meter, the flow meter, and the temperature drop meter. The Btu meter measures the amount of energy provided to the structure and allows a customer to be charged on a per unit of energy basis (i.e., per MMBtu). This type of meter is usually more

expensive than other types of geothermal meters and provides no incentive to extract the maximum amount of heat per gallon of fluid delivered to the structure.¹⁴ The efficiency of geothermal heating systems is determined by how much of the available heat is taken out of the circulating fluid. With a Btu meter the amount of heat used per gallon of fluid delivered is not important. Only the total amount of heat used affects the bill.

The flow meter is a much more efficient and simpler method of measuring geothermal use. This meter measures the gallons of geothermal fluid being circulated through the structure. With this type of meter an economic incentive is provided to promote efficiency. As more heat is taken out of a gallon of the fluid, fewer gallons per minute are necessary to maintain the same temperature in the structure, and the customer's bill is reduced.

A temperature drop meter measures the amount of heat taken out of the geothermal fluid as it passes through the building. This type of meter is normally used with a fixed flow system. Temperature drop meters also can provide an economic incentive for efficient use of geothermal fluid. The billing rate can be structured so that the more efficient the system is (i.e., the more heat extracted per gallon), the lower the customers' bill will be.

Overall, because they can be used to promote efficiency, flow meters and temperature drop meters are better suited to geothermal uses than Btu meters. The only difficulty that exists for both the flow and temperature drop meters is determining a pricing schedule. Of the district heating projects we have examined, three use Btu meters and two use flow meters. One project, presently using Btu meters, may require its inefficient users (those who extract little heat from each gallon of fluid delivered) to install flow meters.

Customer Contracts

The type of contract, or user agreements, that are drawn up between the system and the user has important implications for financing. For at least one project additional financing had to be raised through a private drilling fund. The private fund, however, required preliminary user agreements before any attempt to raise money was made. The preliminary agreement in this case was essentially a letter of intent. The agreement also provided the customer with a ceiling price for geothermal energy; only after the wells were proven and construction begun was a final agreement signed.¹⁵

The district heating systems which utilize contracts include prices or pricing schedules in their agreements. Several of the district heating projects do not require any contracts, and in most cases users are free to quit the system at any time. Of course, in the absence of user commitments the district heating system bears the risk of not having anyone sign on or of everyone dropping off.

¹⁴Btu meters measure both flow rates and temperature drop to calculate heat consumption, which requires the use of several pieces of equipment.

¹⁵The final Boise City agreement contained a specific pricing schedule.

The other side of the customer agreement is the systems' commitment to the user. None of the district heating projects examined here have any commitment or obligation to deliver energy to their customers.¹⁶ If, for example, the resource proves inadequate after the agreements are signed and buildings retrofitted, the system bears no responsibility.

The inability or failure of geothermal district heating systems to provide delivery guarantees underscores the risk inherent in geothermal energy projects. Although none of the systems has failed after the final customer sign-up, this risk is a serious obstacle to the widespread adoption of geothermal heating systems. Since customers must bear the risk of any system failures, they are unwilling to participate unless the energy cost savings promise to be substantial. This is likely to limit successful geothermal projects to those which can provide energy very inexpensively.

Pricing

The pricing structure that a district heating system chooses is important in attracting and keeping customers. The price cannot be too high (compared to conventional energy prices) or prospective customers will not consider it worthwhile to bear the risk, inconvenience, and expense of retrofitting their structures to use geothermal energy. Most of the prices charged by the district heating systems examined in this study are tied to conventional fuel prices and are designed to cover little more than system operating expenses. Because a large portion of these systems' capital costs were paid by the federal government, the costs the systems have to recover to avoid losing money are not very large.

Four of the five district heating systems are local governments which have relatively little incentive to try to make a profit. The private venture's pricing scheme is designed to cover operating expenses and provide a 15-20 percent return on its investment.¹⁷ Among the municipal heating systems, pricing structures vary. In one case the price of geothermal energy is two-thirds that of conventional fuel prices and in another it is 70 percent, after adjusting for efficiency. Flat rates not related to conventional fuel prices are used by the remaining municipal heating districts.

Customer Assistance

The expense and inconvenience of retrofitting is a large obstacle for district heating systems to overcome in their attempt to attract customers. In all of the projects we have examined the customer is responsible for retrofit costs, and in all but one of the projects, customers are responsible for the installation and maintenance of their own meters. Offering retrofitting

¹⁶One of Susanville's heating loops (not examined in this study) has a contract with the State of California to deliver energy for 11-1/2 years. If the resource proves inadequate an alternative energy source must be provided. Susanville has purchased resource insurance to avoid this risk.

¹⁷Initially they plan to charge 50 percent of the natural gas price.

assistance, financial or otherwise, is an important step in convincing prospective customers to hook into a geothermal district heating system.

A few projects either have, or are looking into, low interest loans for retrofits. Another plan involves financing customer retrofits over a period of years through energy cost savings. At least two projects offer preliminary engineering estimates of users' needs and retrofit costs along with financial assistance. Other projects offer workshops or published informational materials and guidelines.

Tax credits are another method of lessening retrofit expense. Retrofit costs are eligible for the federal government's 15 percent business energy tax credit and 40 percent residential energy tax credit.¹⁸ In addition, the State of Oregon also offers tax credits for users switching to geothermal energy. Oregon provides a 25 percent (up to \$1,000) tax credit to anyone who hooks up to a geothermal district heating system and another 25 percent (up to \$1,000) credit to cover the connection itself.

SUMMARY AND CONCLUSIONS

Our analysis of nine federally-funded geothermal low-temperature heating projects indicate that under some conditions geothermal energy can be competitive with conventional fuels but these conditions may not be widely available. Of the 23 projects which received federal financial support in recent years, many did not reach the operational stage due to geothermal resource limitations or other problems. Out of the nine projects reviewed in this report which have or are about to become operational, only five are or appear likely to be an economic success, and the majority of the successful projects are in areas where geothermal energy has long been used for direct heating purposes.

The characteristics of the projects examined indicate that a reasonably high resource temperature (perhaps 140°F for a user-owned system and 170°F for a district heating system) and a high utilization of the energy available from the fluid (i.e., a large temperature drop) are critical to project success. Additionally, for district heating systems a reasonable system size (perhaps 30 billion Btus of delivered heat annually) is desirable to keep costs per unit of energy delivered competitive with conventional fuels.

District Heating System Requirements

The economic success of a district heating system requires a high user participation rate within a small geographic area. Given the significant risk and expense involved with a geothermal energy-based system, potential projects may not be successful unless they have the following characteristics:

- **Customer Assistance:** Potential customers may have to be provided with information about appropriate equipment and tax credits available to them if they utilize geothermal energy.

¹⁸The residential energy tax credit is 40 percent, up to a maximum credit of \$4,000. There is no ceiling on the 15 percent business energy tax credit.

Financing for required equipment may have to be provided to customers in some cases.

- **Pricing:** Geothermal energy must be priced high enough for the investor to make a profit, but low enough to encourage potential customers to switch off conventional fuels and to save a significant amount of money net of their retrofit costs. In the analysis performed here, geothermal energy was priced at 2/3 the natural gas or heating oil price.
- **Meters:** Flow meters or temperature drop meters in constant flow installations are preferable because they provide an incentive for customers to maximize the rate of heat extraction per gallon of fluid flow. A high extraction rate is required for a successful project.
- **Contracts:** Some projects have sought a commitment from potential customers that they will use the system, but the system has generally only provided a commitment as to price, and most are not responsible if the resource proves to be inadequate. These projects may have been able to avoid signing contracts early in development because most of their capital costs were provided by the federal government. A more binding set of contract terms between the system and its customers (and resource adequacy insurance) may be necessary to obtain private financing in the future.

APPENDIX A

CASE STUDIES OF NINE GEOTHERMAL DEMONSTRATION PROJECTS

Since 1978 the U.S. Department of Energy (DOE) has funded 23 geothermal direct heat demonstration projects under its Program Opportunity Notice (PON) program. A review of nine of the most advanced projects served as the basis for the study of the commercial potential of geothermal direct heat applications which was presented in this report. The analysis of project economics discussed in the report used a set of standardized financial and institutional assumptions. In addition to this economic analysis, which was geared toward potential investors in future geothermal projects, DOE also requested an analysis of the likely payback period for each of the nine projects under the conditions which the projects actually faced.

This appendix contains a description of the actual experiences of the nine projects. For each project, we identify the application, provide information about system and resource characteristics, and discuss unusual circumstances which resulted in delays, high costs, or cost overruns. Key characteristics of the district heating systems including pricing and customer relations are also discussed. In addition, we present the simple, constant-dollar payback period for each project based on costs as they were actually incurred.

PAYBACK PERIOD ANALYSIS

The simple payback period for each project is the number of years expected to elapse (starting with the year on-line) before cumulative project revenues equal cumulative project costs. In computing cumulative project costs, we counted all costs, including operating costs and all capital expenditures, regardless of whether they were financed by the project sponsors, by the U.S. Department of Energy (DOE), or by any other entity.

The future revenues in each year for each of the nine demonstration projects were estimated in one of two ways. For smaller institutional projects where the geothermal system owner and user are one and the same, we used the estimated value of conventional energy displaced as a proxy for geothermal system revenues. This value was computed by multiplying the quantity of conventional energy expected to be replaced each year by the price per unit of energy. Since energy prices have not remained constant in either nominal or real terms in the recent past and are not expected to do so in the future, our calculation of payback periods required us to forecast the level of conventional fuel prices over the next several years at each of the geothermal project sites. To make these forecasts, we started with ICF national energy price projections and adjusted these projections for each location in question. These adjustments were made by comparing ICF's June 1983 national price forecasts with the actual oil and gas prices currently charged at each geothermal location and then assuming that this dollar price differential remained constant in real terms throughout the forecast period. The ICF energy price forecasts used as the basis for this analysis are presented in Chapter II of this report.

For district heating systems we used the price at which the system planned to sell its product, rather than the price of competing fuels, to compute project revenues. In most cases, the district heating systems indicated that they would be pricing their product in such a way as to provide customers a certain percentage savings over conventional fuel costs. For example, the Boise district heating system expects to provide its customers with a 30 percent savings over the price of natural gas. To compute Boise's revenues we multiplied the expected cost of natural gas in Boise each year, computed as indicated above for the user-owned systems, times 0.7. The exact pricing formula for each district heating system is discussed below.

The simple payback period calculation does not include any discounting of project costs or revenues. We did, however, adjust for inflation by converting all costs and expected revenues to 1982 dollars before computing the payback period. Without this adjustment, the payback periods would have appeared much shorter, since later year (inflated) dollars would be used to pay back earlier year costs.

Table A-1 contains a summary of the costs, some physical characteristics, and the simple payback period for each of the nine geothermal projects reviewed. A review of the data in the table indicates that four of the projects can expect to complete a constant dollar payback of their capital and operating costs in 6-10 years. These are the same four projects which appeared financially attractive when reviewed in the main body of this report. The other projects have an expected constant dollar payback period of 14-28 years.

DESCRIPTION OF THE INDIVIDUAL PROJECTS

There are five district heating projects, Susanville, Pagosa Springs, Boise, Klamath Falls, and Elko, and three user-owned systems, St. Mary's Hospital, Torbett-Hutchings-Smith (T-H-S) Memorial Hospital, and Klamath County YMCA. The project in Philip is a unique case because it combines elements of both user-owned, and district heating systems. Each project section begins with a brief description of the project and continues with information on:

- Capital costs--major expenditures including cost overruns and delays;
- Operation and maintenance costs--normal annual out-of-pocket expenses, both current and anticipated; and
- Energy quantities--both design capacity and current operating levels.

Tables listing these costs are included in Appendix B.

Susanville District Heating System

The geothermal district heating system in Susanville, California is designed to provide space heating for three separate district heating loops. The "uptown" geothermal loop, in operation for the 1982/1983 heating season, circulates 170°F fluid, extracted at 800 gpm. To supply space and water heat to fourteen public buildings, stainless steel tube and shell heat exchangers

TABLE A-1

SUMMARY DESCRIPTION OF PROJECT DATA

<u>Project</u>	<u>Well Depth</u> (feet)	<u>Fluid Temperature</u> (°F)	<u>Flow Rate</u> (gpm)	<u>Start-Up of Operations</u>	<u>Capital Cost</u> (1982 \$) (thousands)	<u>Annual O&M^{b/} Cost</u> (1982 \$) (thousands)	<u>Annual Energy Delivered</u> (10 ⁹ Btu)	<u>Payback Period</u> (years)
<u>District Heating Systems</u>								
Boise, ID	2,010	155	2,000 to 4,000	1983	3,985	51.7	80.6 ^{b/}	10
	800	172	From all wells					
	1,893		Combined					
	1,103	172						
Elko, NV	850	178	700	1983	1,126	21.6	27.0 ^{b/}	10
Klamath Falls, OR	350	218	680	1983 ^{b/}	2,801	9.0	51.0 ^{a/} , ^{b/}	14-17
Pagosa Springs	275	148	900	1984 ^{b/}	1,570	19.0	11.9 ^{b/}	16
	300	131						
Philip, SD	4,300	157	340	1980	885	7.6	9.5	22
Susanville, CA	935	170	718	1982	1,748	57.0	20.7 ^{a/} , ^{b/}	17
<u>Small Institutional Projects</u>								
Klamath County, YMCA (Klamath Falls, OR)	1,400	147	310	1980	333	2.1	7.0 ^{a/}	6
St. Mary's Hospital (Pierre, SD)	2,200	108	375	1980	920	10.0	11.4	8
T-H-S Hospital (Marlin, TX)	3,885	153	315	1982	1,287	6.6	5.0 ^{a/}	28

^{a/} Data not available from project; estimated from energy displacement data.

^{b/} Expected.

are located at the retrofitted buildings. The estimated cost for the uptown loop is \$1.6 million.¹ A second geothermal district heating loop is under construction to provide 110 residences with space and water heat. Plans have recently been developed for an extension of this loop to include a greenhouse. The cost of this second loop is estimated at \$800,000. Finally, the Litchfield prison facility is to be supplied with geothermal fluid from two new production wells. Plans underway also allow a planned industrial park access to the spent fluid once it leaves the prison. Total estimated cost for the Litchfield facility is \$2.5 million.

The discussion here will focus on the DOE sponsored or "uptown" district heating loop. As mentioned above, total capital expenditures, in current dollars, came to approximately \$1.58 million. Design and planning was responsible for almost 40 percent of the total project cost, followed by piping at approximately 27 percent. Even though the total project came in under budget, there was a \$7,000 to \$8,000 cost overrun for drilling the well. The overrun was a result of drilling conditions being more severe than anticipated. (See Appendix B for a detailed breakdown of capital expenditures.)

Susanville's present level of operation is about half that of its design capacity. This is due to the fact that California considers geothermal fluid a hazardous waste. Consequently, Susanville is having difficulty finding a suitable disposal method and obtaining permits. This controversy resulted in a 12-16 month delay.

Operating and maintenance costs for the initial abbreviated heating season (from December 1982 to March 1983) were approximately \$12,500 of which \$5,500 was for electricity to run the pump. At the current level of operation, annual O&M expenses are estimated to be about \$30,000. During the 1983/1984 heating season, when Susanville expects to be fully operational, annual operation and maintenance costs will nearly double to about \$57,000.

When the second half of the system's users are hooked up, the district heating loop will displace the equivalent of about 29,000 MMBtus of No. 2 fuel oil. Actual energy displaced for the 4-month 1982/1983 heating season was 41,149 gallons of No. 2 fuel oil or 5,707 MMBtus.

The revenues for the Susanville system were calculated using a geothermal price equal to two-thirds the price of No. 2 fuel oil.² This price is designed to cover normal operating and maintenance costs only; any major expansion to the system would have to be financed through alternative sources of funding. The revenues for the first year, based on 50 percent system

¹This cost figure and the capital costs listed in the other eight project descriptions are in nominal, as-spent dollars. In contrast, the capital costs listed in Table A-1 are in constant 1982 dollars.

²The user agreement between Susanville Municipal Energy Corporation and Hassen Union High School states that the price for geothermal energy will be pegged at two-thirds the price of oil priced at 72¢ per therm and that the cost per therm shall not increase at greater than 5 percent per year during 1984 and 1985.

capacity and a geothermal price of \$5.11 per MMBtu, would be almost \$46,000. The second year, however, if Susanville is operating at full capacity as planned, revenues would jump to over \$133,000 despite a lower expected geothermal price (due to lower oil prices) of \$4.90 per MMBtu. If the system obtains all the customers it anticipates, the resulting payback period for Susanville would be 17 years. However, not all of the anticipated customers have made their retrofit investments.

The City of Susanville has created a municipal district heating utility, Susanville Municipal Energy Corp (SMEC) which is a wholly owned subsidiary of the City of Susanville. As a municipal utility, SMEC is not subject to regulation by the California Public Utilities Commission as are other utilities.

Most of the retrofitted buildings have kept their conventional heating equipment and are therefore free to purchase as much or as little geothermal energy as they like. Retaining their original heating equipment makes sense because there is no commitment or obligation on behalf of SMEC to deliver geothermal fluids. Susanville plans no long-term user contracts. If the resource turns out to be inadequate SMEC bears no responsibility to its customers.

SMEC also has no responsibility for retrofitting; users are responsible for secondary piping and all necessary equipment from the property line on. Susanville has decided to use Btu meters to measure usage. The customer must also pay for the purchase and installation of the meter.

Susanville is currently working with the California Alternative Energy Financing Source Authority and the Bank of America to negotiate an industrial revenue bond sale to finance building retrofits for the residential loop. If this effort is successful, businesses will set up a low-interest loan pool to finance residential system retrofits. SMEC is also examining the possibility of financing retrofits through energy cost savings but this option will be employed chiefly in the two non-residential district heating loops.

Boise District Heating System

Geothermal resources have been used for heating in Boise, Idaho for about 90 years. The city is presently upgrading and expanding its existing residential geothermal system and developing a new district heating system that will provide heat to the downtown central business district. The heating of several state office buildings is still under negotiation. The new system, which began operation in March 1983, already includes 12 retrofitted buildings and is in the process of connecting eleven more. The geothermal fluid from the two production wells, which flows at approximately 1,700 gpm at a temperature of 170°F, will be discharged into the Boise River. Geothermal heat is expected to displace about 115,140 MMBtu of natural gas, at a cost of \$3.8 million.

Boise has utilized its geothermal resources for decades and had established the Boise Warm Springs Water District (BWSWD). As a result, there are two geothermal heating districts operating in Boise, the BWSWD and the new City of Boise district (Boise Geothermal). The analysis here focuses only on the new district heating system being developed by the City of Boise.

Over one-fourth of the total capital cost was spent to develop Boise's four wells. The wells were drilled by a private firm at a cost of over \$1 million.³ The construction cost for the system was the largest expenditure, constituting more than one-half of total expenditures. Operation and maintenance costs for the first year's operation are estimated at \$43,600;⁴ this estimate is based on a 1,500 gpm pumping rate. The system hardware has the capacity to pump 4,000 gpm with a corresponding annual O&M of over \$90,000 (1982 dollars), but it does not have the users required to utilize the system at this capacity in the immediate future. Even more importantly, although the system is designed for 4,000 gpm, the resource itself has only been proven for up to 2,000 gpm.

Presently Boise is delivering about 80,600 MMBtus of energy and displacing approximately 115,000 MMBtus of natural gas. At its peak capacity, the Boise system would be able to displace at least 300,000 MMBtus of conventional energy.

Revenues for the Boise system will, of course, depend on its usage. The pricing scheme Boise is currently using guarantees a 30 percent saving over the price of natural gas if the user removes enough heat per gallon to reduce the temperature by 50°F.⁵ The geothermal starting price will be 70 percent of the price of natural gas adjusted for conventional system efficiency.⁶ Using an adjusted (for efficiency and savings) gas price of \$3.69 per MMBtu and assuming a quantity of 115,140 MMBtus, the expected first year revenues would be about \$373,000. Using this pricing formula, the total system costs, and the first-year sales quantities, a 10-year payback could be achieved.

The Boise City geothermal system encountered a number of delays. Obtaining rights to the military reserve where the well sites are located delayed the project about a year. Disposal permits from the State Department of health stalled operation another 10-12 months. The environmental report held up the project for between 4-6 months at the onset of the project. Also when some of the engineering estimates exceeded the available funds, Boise was forced to find additional financing.⁷ Developing the service rate schedule turned out to be a very time consuming project which took almost two years to complete. Finally, there were some delays caused by a lack of coordination between the timing of system con-

³This does not include pumps and pump houses.

⁴The BWSWD, which simply upgraded its existing system, has operation and maintenance costs of over \$118,000 per year since it is a much older system.

⁵If the user doesn't take out this much heat, he pays more per million Btu because he is charged on a gallonage basis.

⁶The formula is:

$$\frac{P_{\text{Natural Gas}}}{.75} \times .7$$

⁷In order to finance well drilling a private drilling fund was created which raised about \$2.5 million.

struction and building retrofits. Many of the retrofit agreements were signed in mid-1981, but some users are just beginning to retrofit their buildings. The Boise system began operation in the spring of 1983 and spent most of April and May eliminating start-up problems. One particular problem was that the water arriving at some buildings was not as hot as it should have been.

The Boise system provides no guarantees of energy supply to users. If the resource proves inadequate at some time in the future, the city has no obligation to deliver energy. Neither is there any commitment on the cutomers' part. If users choose to drop off, the system will be forced to bear the consequences. The property line is the boundary between the system and the user. The Btu meters will be located in the public right of way and maintained by the city, but installation will be the users' responsibility.

Customer retrofits are the responsibility of the customer as well. Boise has provided preliminary estimates of prospective users' needs and retrofit cost. The city has also provided workshops for vendors, and the Economic Development Department of the City of Boise is considering offering users low-interest loans to finance retrofits.

Pagosa Springs District Heating System

In the town of Pagosa Springs, Colorado, a geothermal district heating system will supply heat to at least 16 businesses and public buildings. Two shallow wells (300 feet and 275 feet) will provide 131°F and 148°F fluid, respectively, from a Dakota sandstone aquifer at a combined total flow rate of up to 1,800 gpm. Clean city water will be heated using heat exchangers. The heated city water will then be circulated to users through two independent closed loops. Contruction of the distribution system and some of the building retrofits has been completed. When fully operational, the system is expected to deliver 11,860 million Btu annually, replacing approximately 16,950 million Btus of natural gas. In the first year of operations, now scheduled for the 1983-1984 heating season, the geothermal system will operate at approximately two-thirds capacity. Total project capital costs are estimated at \$1,434,000 as of September 30, 1983; yearly O&M costs will be \$19,000 at full capacity.

Pagosa Springs capital expenditures are made up for the most part by system construction costs, primarily piping. These costs accounted for over 50 percent of total expense. While the well costs made up only 20 percent, the well costs for Pagosa Springs are considerably higher than originally estimated due to several factors: 1) the geothermal resource was heavily artesian and consequently difficult to manage; 2) the drill site itself was located in a riverbed where surface rubble made it difficult to drill; and 3) of three wells that were drilled, one was dry and of no use.⁸

Revenues for Pagosa Springs are based on a flat 52¢ per therm rate. With this pricing schedule first-year revenues of approximately \$98,500 net of O&M costs can be expected. There is a proposal to charge very inefficient users a

⁸Superior Auto turned over their own well to the city to participate in the district heating system.

gallons rate of 6.5¢ per 100 gallons, but no decision has been reached. With the present price of 52¢ per therm, the simple payback would be 16 years.

As a municipal utility Pagosa Springs is not subject to regulation by the state. A furor has been created over water rights, however, and the state has been drawn into the battle to settle the issue. There has been strong citizen opposition to the district heating system's use of the geothermal resource. Many members of the community have their own geothermal wells and are afraid that the city may draw down the level of the underground reservoir. The matter is expected to be settled in time for the 1983/1984 heating season.

Pagosa Springs has no commitment to provide geothermal heating to its customers. If for some reason (e.g., inadequate resources) the system fails, it has no obligation to continue providing energy. Customers are responsible for retrofitting their buildings, including secondary piping from the property line to the structure. The city is paying for installation and maintenance of the Btu meters necessary for billing. The city is also offering supportive assistance in retrofit engineering. Originally, money was allocated to pay for retrofits for the first 50 customers, but, due to the lengthy delays in getting the project started, that money is no longer available.

Klamath Falls District Heating System

The downtown geothermal heating district in Klamath Falls, Oregon will use geothermal fluids to heat 14 public buildings. The 218°F fluid will flow at 680 gpm and will be transported from the production well via the primary pipeline to a large central heat exchanger. After the fluid passes through the central heat exchanger, it will then be distributed downtown via the secondary pipeline. The discharge water is then disposed of through a reinjection well, some 2,500 feet from the production well. Annual geothermal energy consumption is estimated to be 51,000 MMBtus per year. A second, residential system is approximately 80 percent complete. A new heat exchanger will remove heat from the fluid in the primary pipeline to heat water in a secondary pipeline to serve 120 homes. The primary pipeline's fluid temperature will be lowered approximately 5°F when construction is complete. Funds for construction are being provided by a Community Development Block Grant of \$300,000.

The Klamath Falls project thus consists of two heating loops, one business, and one residential. The remainder of this discussion deals only with the DOE funded "business" loop. Total estimated cost of the project is \$2.58 million. By far the largest system expenditure was on piping, both primary and secondary, amounting to over 50 percent of total capital costs. Due to shallow well depths and favorable drilling conditions, well costs were considerably lower than in the other projects, totaling only \$64,000. The heat exchanger building, at a cost of \$221,000 (and not eligible for the energy tax credit) was a 100 percent overrun. The overrun occurred because the conceptual design estimates were far too low. Operation and maintenance costs are expected to be approximately \$9,000 per year. The Klamath Falls system expects to deliver about 51,000 MMBtus per year, which will displace almost 73,000 MMBtus of natural gas and electricity.

The Klamath Falls district heating system's revenues will be based on a fixed rate per MMBtu, in the range of \$2 to \$3, but not related to any conventional energy prices. The exact rate has not been decided yet, but it will be designed to cover the cost of the system over 20 years. Based on a price of \$2.50 per MMBtu, annual revenues would be about \$173,000 net of O&M costs. By charging \$3 per MMBtu, the system could realize over \$209,000 a year in net revenues. The simple payback period for the project would be 17 years at a price of \$2.50 per MMBtu and 14 years at \$3.00 per MMBtu.

The City of Klamath Falls encountered some difficulties regarding geothermal regulation.⁹ Similar to Pagosa Springs, citizen reaction has caused serious delays in the start-up of the geothermal system. Citizens objected to the pumping of additional fluids from the geothermal reservoir, delaying the project from Spring 1982 to at least Fall 1983. A Circuit Court judge has ruled that the city has the right to set its own geothermal regulations. This issue has still not been resolved, pending settlement of a law suit. In addition, during earlier project phases, the two-stage design approval process required by DOE delayed the project another six months.

Klamath Falls heating system currently has no commitments on the part of either the users or the heating system. However, any major system expansions in the future may require some kind of commitment from users before the system will undertake a capital investment.

The present boundary between the user's property and district heating system property is the Btu meter, usually located on the property line. The heating district pays for pipes up to the meter, and the user is responsible for pipes and all other equipment beyond the meter.

Retrofit assistance, which is primarily applicable to the residential system, is available in several forms. The Community Development Block Grant has set aside \$200,000 to be used for a revolving retrofit loan fund. Also, two bills have been passed in the Oregon legislature. The first bill offers taxpayers a 25 percent tax credit (up to \$1,000) for retrofit costs if they connect to a geothermal heating system, and the second offers 25 percent (up to \$1,000) for the expense of the connection itself.

Elko District Heating System

The Elko Heat Company geothermal project in Elko, Nevada is a private venture designed to provide geothermal heat to a bank, a motel, and a commercial laundry. The production well is artesian, approximately 850 feet deep with 165°F fluid flowing at 500 gpm. The geothermal fluid will be circulated directly through the local bank's existing radiator or fan coil system, while the motel/casino will utilize a heat exchanger to heat a closed hydronic loop. The planned system will displace 100 percent of both buildings' space and water requirements. The third application, a commercial linen supply company, will use the geothermal fluid directly for washing. The system is expected to

⁹In Oregon geothermal resources above 2,000 feet and under 230°F are regulated by the Department of Water Resources.

deliver approximately 17,500 MMBtus of energy per year at a total estimated cost of \$1.07 million.

Elko Heat Company is the only private district heating venture analyzed. Because of various financial and tax advantages, Elko Heat created a separate company, called Heat Elko which sells the geothermal heat back to Elko Heat.¹⁰ Elko spent almost \$170,000 on resource assessment, more than any of the other eight projects. It also had a number of cost overruns. The piping cost an estimated \$400,000 more than planned due to the relocation of the planned well from 500 to 3,000 feet from the users. Costs for the disposal system, approximately \$35,000, had not been included in the original budget. An additional \$12,000 to \$14,000 was needed for engineering estimates to evaluate the different alternatives for the disposal system.

Elko also had its share of delays. Obtaining water rights delayed the project about one year from 1980 to 1981. Further delays of 6 to 9 months came when the water rights permit had to be amended for consumptive use.¹¹ Disposal system selection caused another 2 to 3 months delay as did the testing of a prototype heat exchanger. Operation and maintenance costs are budgeted for \$21,600 per year. \$1,800 is budgeted for electricity to run pumps and other equipment, but Elko presently is using artesian pressure and does not have to run its pumps.

The geothermal system is currently displacing 28,600 MMBtus of natural gas per year and displacing 100 percent of its users' natural gas needs. At capacity Elko's well is capable of displacing about 38,600 MMBtus per year.

Elko is presently charging its first three customers 50 percent of the price of natural gas. At a geothermal price of \$2.92, (in 1982 dollars) first-year revenues should be over \$91,000. As a private venture the owners of the Elko system are looking for a 15 percent to 20 percent rate of return, as well as a 5-year payback on their own investment. Using the payback calculations as previously described and maintaining the 50 percent pricing scheme, a payback of all the costs can be expected in approximately 10 years. In the future, Elko is planning to charge a gallonage rate of \$1 per 1,000 gallons of geothermal fluid.¹²

Under a strict interpretation of Nevada law, Elko Heat Co. is a public utility, and it is currently applying for public utility status. As a utility, Elko Heat Co. would have to meet certain requirements (e.g., it must enter into contracts with users for at least 3 years) and must pay a mil levy. However, the Nevada Public Service Commission probably will not regulate Elko's prices and rates of return.

¹⁰Heat Elko Co. qualifies as a subchapter S corporation which allows the owners and not the corporation to take advantage of tax credits. Both Heat Elko Co. and Elko Heat Co. have the same owners.

¹¹Defined as water not reinjected into the same aquifer.

¹²This still results in a 50 percent saving if the user takes 30°F from the geothermal fluid.

The Company's property extends to 5 feet outside of the users' property line. Installation and maintenance of flow meters are the responsibility of the users, and meters are located inside the users' buildings.¹³ The customer is responsible for building retrofits, but Elko Heat Co. does offer a preliminary estimate of user's needs.

St. Mary's Hospital

The geothermal heating system at St. Mary's Hospital in Pierre, South Dakota has been operational since October 1980. 108°F water from the Madison aquifer is used for space heating and preheating of domestic hot water in an existing, retrofitted hospital building and in a new hospital wing. The 2,200 foot well flows at 375 gpm. After flowing through plate-type heat exchangers, the geothermal fluid is discharged to the Missouri River.

St. Mary's Hospital, a non-profit organization, spent approximately \$758,000 converting to geothermal energy. The largest expenditure was for the well, approximately \$271,000, which cost more than expected due to a longer than anticipated drilling process. St. Mary's also had a large outlay of \$151,5000 for equipment that is not used exclusively with geothermal energy.¹⁴ Operation and maintenance costs are currently estimated to be \$10,000 annually. However, some distribution piping had to be replaced due to corrosion after only one heating season, which left the system out of service from December 1981 to March 1982. The replacement was required partly as a result of a misinterpretation of the engineering specifications by the mechanical contractor and partly because of the experimental nature of the project.

St. Mary's geothermal system is expected to deliver 11,400 MMBtus, displacing 118,000 gallons of No. 2 fuel oil. In its first two years of operation, it displaced 60,000 gallons and 115,000 gallons of No. 2 fuel oil, respectively. This energy was used to provide 100 percent of the space heating in the north building and approximately 17 percent of the space heating requirements for the south building and annexes. Calculating the simple payback as described above, it will take 8 years to recover the initial investment.

Torbett-Hutchings-Smith Memorial Hospital

Torbett-Hutchings-Smith (T-H-S) Memorial Hospital in Marilin, Texas has installed a geothermal heating system to provide space and water heating for its 130-bed facility. The 3,885 foot production well produces 155°F fluid, which is pumped at a rate of 160 gpm to four plate heat exchangers. The spent geothermal fluid enters the city sewer system and is eventually discharged into the Brazos River.

The total cost for the project was \$1,139,000. This total includes over \$50,000 in DOE related costs, as well as \$100,000 for an injection well that was never used. T-H-S Hospital also incurred cost overruns on the production

¹³The initial 3 users will use temperature drop meters.

¹⁴This expenditure is not eligible for the energy tax credit.

well. The well had to be drilled 400 feet deeper than originally planned because the resource did not produce as well as expected. The additional drilling expense may prove to be unnecessary, however, because the well was intentionally designed to produce 10 to 15 percent more heat than the hospital requires. The project also cost more than originally estimated because the system was expanded to include space heating in addition to water heating. Cost estimates (based on system operation since January 1982) for operation and maintenance costs are expected to be about \$6,600 per year, with approximately \$1,700 a year for electricity to run the pumps. Replacement costs for the submersible well pump (every seven years) and variable frequency drive are additional maintenance expenses. The system is expected to displace 7,140 MMBtus of natural gas per year. (Using an estimated boiler efficiency of 70 percent, this is equivalent to annual geothermal energy delivery of 5,000 MMBtus.) Even though all water heat and between 80 and 90 percent of space heat is being provided by the geothermal system, gas savings are lower than originally expected.

Savings for the first year of operation, assuming a gas price of \$4.22 per MMBtu, would be approximately \$24,000. As the gas price increases, the amount of savings will also increase. Using ICF's natural gas price forecast to calculate a simple payback period, it will take about 28 years to recover the \$1.14 million invested.

Klamath County YMCA

Operation of the geothermal system at the YMCA in Klamath Falls, Oregon began in April 1980. A plate-type stainless steel heat exchanger transfers heat from the 147°F geothermal fluid to a separate fluid which is circulated to heat a swimming pool and provide space and domestic hot water heating to the YMCA building. Geothermal fluid flows at 60 to 250 gpm (depending on heating needs) from a 1,400 foot production well and is reinjected into a 2,000 foot injection well. The system provides approximately 7,000 million Btus per year. Total capital costs for the project were \$268,500. Yearly operating costs are \$2,000.

Klamath Falls YMCA spent a little over \$70,000 for its production well and almost \$60,000 on its reinjection well. Together these well costs constitute almost 50 percent of total expenditures. Operation and maintenance costs are estimated to be approximately \$2,000 per year. Electricity required by the variable drive pump is about \$100 per month in winter and \$20 per month during the summer, which is much higher than expected. The YMCA is presently displacing about 10,000 MMBtus per year of natural gas. This figure is about 10 percent higher than originally estimated due to some structural remodeling as well as an increase in water heating due to an increase in membership.

Savings from the YMCA's geothermal system for the first year, based on 1980 gas price of \$5.83 per MMBtu, were about \$56,000. The total payback period is a brief 6 years.

Overall, the Klamath Falls YMCA has been an excellent example of a geothermal heat application. The system provides adequate space and water heat and also heats the swimming pool year-round. Unfortunately, during the summer the heated pool keeps the rest of the building uncomfortably hot. The

YMCA is considering trying to tie in an air conditioning system that utilizes geothermal energy.

Philip, South Dakota

The Philip geothermal project comprises a small-scale district heating system. 157°F fluid flowing at 300 gpm from a 4,300 foot well in the Madison aquifer is supplied to five school buildings and is then cascaded to eight business district buildings. After treatment in a barium chloride plant to remove Radium 226, the fluid is discharged to the Bad River. The geothermal system is designed to deliver 9,500 million Btus to buildings which were previously heated by fuel oil, propane, and electricity. Operation of the system began in November 1980. The total project capital costs were \$883,672; yearly O&M costs will total approximately \$7,600.

The Haakon School District's geothermal project is a unique combination of institutional and district heating. Originally, the School District decided to undertake a geothermal heating project for its own use. When businesses located along the disposal line became interested, the School District decided to sell the spent fluid to the businesses.

Almost one-third of the total capital costs was spent on drilling the well. Several delays were encountered in drilling the well, partly due to the loss of a number of bits in the well bore, but the well itself did not overrun its budget. Piping made up another one-third of capital costs. After the well was completed, the geothermal fluid was found to contain radium, which necessitated adding a treatment plant to the system. The entire cost of the treatment plant was a cost overrun because it had not been anticipated. In addition, major delays were incurred during the design and construction of the treatment plant. Architect's fees for the entire system were also underestimated, resulting in at least a \$12,000 overrun.

Currently the school buildings and eight commercial businesses are hooked up to the system, which is expected to displace about 13,600 MMBtus of electricity, No. 2 fuel oil and propane. Recent measurements of heat extraction indicate that less heat is being used.

Revenues for the Philip system present an interesting twist, since the venture originated as a user-owned arrangement. Consequently, the School District is only interested in its energy savings and not in recovering part of its investment from the businesses. The School District has decided to charge a flat fee to the business district of \$2,500 per year for the first five years, doubling by 1990. The fee is designed to defray some of the costs of the barium chloride treatment plant. The businesses have set up a business heating district corporation which pays the fee.¹⁵ The payback period was calculated on the basis of the School District's fuel cost savings, with the \$2,500 fee added in as extra income. The payback period would be approximately

¹⁵A share of the corporation's costs are paid by each business depending on the flow requirements for each building. The corporation also paid \$52,000 for the business district lateral pipelines.

22 years with over \$62,000 in savings the first year, assuming a 1981 fuel oil price of \$9.49 per MMBtu.

The Haakon School District is not really selling its spent fluid to the businesses; it can be viewed more as a maintenance contract. The school district is not subject to any government regulation, but it did need a state water permit. One of the stipulations of the water permit was that the school district try and find secondary users for the fluid.

The main line to the treatment plant belongs to the School District where it uses flow meters measuring the flow from the well, through the school system and to the business district line. All of the lateral pipes off of the mainline belong to the users. Some of the businesses have their own meters and some do not so it is difficult to determine exactly how much geothermal fluid/energy is going to each business building. Since the school district is not in the business of selling geothermal energy it provides no customer retrofitting assistance.

APPENDIX B

PROJECT COST AND ENERGY DATA

Detailed cost data were collected for each project. Tables B-1 to B-9 present the data for each of the nine projects. The capital costs shown are in nominal dollars, in the years in which those costs were incurred. Costs are broken down in as much detail as possible for each project. Anticipated average annual operating costs (in 1982 dollars) and average energy delivered are included as well. For those projects which have been operating for some time, we also list estimates of actual operating expenses and energy quantities for the initial heating seasons.

Several important points must be made regarding the way in which these data are used in our analyses. First, retrofit costs are included here for informational purposes whenever available. However, for district heating systems, customer retrofit costs are excluded in calculating both the "actual" simple payback period discussed above and the geothermal levelized unit costs and internal rates of return presented in Chapter III of this report. (The reasons for excluding retrofit costs for district heating projects are discussed in Chapter II.) Second, the capital costs listed in this appendix are all in nominal or "as-spent" dollars. To compute the project payback periods, we first converted all capital costs into real (1982) dollars using the inflation factors listed in Chapter II. Expected project revenues in all years were also valued in 1982 dollars to maintain consistency.

Third, while the "actual" payback period calculations included all project capital costs, the economic analysis shown in Chapter III excluded direct DOE-related costs such as expenditures for report writing and conferences. In addition, for the economic analysis of the T-H-S Hospital, we shortened the actual construction period by one year to remove the effect of delays caused by DOE involvement in the project.

Finally, the payback period calculations and the economic analysis treat energy quantities and operating costs slightly differently. A few of the district heating systems which we reviewed are hooking up their customers over a period of two or three years. For these systems, the payback period calculations based on actual project experience take these "scale-up" periods into account. The economic analysis in the body of the report, in contrast, assumes that all projects are fully operational starting with the first year on line, with no scale-up period. The assumed amount of energy delivered in that analysis is listed in the tables as "expected" delivered energy.

TABLE B-1
SUSANVILLE DISTRICT HEATING SYSTEM

	Year						Total
	1979	1980 Phase I	1980 Phase II	1981	1982	1983	
o Resource Assessment and Preliminary Design							
Permitting	1,904						1,904
Drill Site Justification	10,223	777					11,000
Environmental Report	8,316						8,316
o Well Costs							
Wellhead				105,002			105,002
Tangible Well Equipment 1/			13,549	1,173			14,722
Intangible Drilling Costs 2/	8,064	6,196	112,223	26,545			153,028
o System Construction Costs							
Design/Planning/Bidding	180,592	67,742	105,950	250,913			605,917
Piping				411,000	17,186		428,186
Pump				33,700			33,700
Disposal System				35,900			35,900
Cooling Tower				10,000			10,000
o General and Administrative Expenses	28,783	10,792	64,845	55,993			160,413
o Total Capital Costs	237,882	85,507	300,567	930,226	17,186		1,571,368
o Retrofit Costs							540,200
Hassen Union High School				427,700			
Washington High School				40,000			
Veterans' Hall				59,699			
Jail				66,801			
o Normal Annual Operating Expenses						30,000 8/	
o Delivered Energy (MMBtu) 7/							
Estimated Actual						4,000	
Expected (Assumed in Project Analysis)						20,700	

See footnotes attached.

TABLE B-2
BOISE DISTRICT HEATING SYSTEM

	Year					
	1979	1980	1981	1982	1983	Total
o Resource Assessment and Preliminary Design						
Feasibility Study or Conceptual Design	12,667	16,365				29,032
Environmental Report, Geology and Disposal	13,333	31,019		63,023		107,375
o Well Costs						
Tangible Well Equipment 1/			300,030			300,030
Intangible Drilling Costs 2/			700,070			700,070
o System Construction Costs						
Design/Planning/Bidding			108,611	78,883	16,242	203,736
Construction Cost				1,924,511	231,877	2,156,388
o General and Administrative Expenses	29,067	75,431	95,892	116,738	23,479	340,607
o Market & Rate Study	11,333	5,565	2,125	6,972	2,123	28,118
o Direct DOE-Related Costs						
Public Awareness	2,000	9,457				11,457
o Total Capital Costs	68,400	137,837	1,206,728	2,127,104	273,721	3,813,790
o Retrofit Costs				500,000	980,000 4/	1,480,000
o Normal Annual Operating Costs					51,660	
o Delivered Energy (MMBtu)						
Estimated Actual					80,600	
Expected (Assumed in Project Analysis)					80,600	

See footnotes attached.

TABLE B-3

PAGOSA SPRINGS DISTRICT HEATING SYSTEM

	Year						Total
	1979	1980	1981	1982	1983	1984	
o Resource Assessment and Preliminary Design							
Feasibility Study or Conceptual Design	12,000	3,500	17,500				33,000
Permitting				26,000	33,000		59,000
Geological & Geophysical Exploration		10,000					10,000
Environmental Report	3,880						3,880
o Well Costs							
Tangible Well Equipment 1/		26,000					26,000
Intangible Drilling Costs 2/	5,500	258,500					264,000
o System Construction Costs							
Design/Planning/Bidding			60,400		10,000		70,400
System Construction (Piping Mostly)			726,468				726,468
Heat Exchange Equipment			35,000				35,000
O&M Manual					10,000		10,000
Existing Facility Credit (Rights of Way)	115,500						115,500
o General and Administrative Expenses	8,000	8,000	8,000	8,000	8,000		40,000
o Direct DOE-Related Costs							
Conferences	2,861	2,861	2,861	2,861	2,861		14,305
Publicity	2,902	3,225	1,829				7,956
Reporting	4,071	4,215	2,864	1,287	5,709		18,146
o Total Capital Costs	154,714	316,301	854,922	38,148	69,570		1,433,655
o Retrofit Costs			54,600				54,600
o Normal Annual Operating Expenses					19,000		
o Delivered Energy (MMBtu) 6/							
Estimated Actual					(not operating)		
Expected (Assumed in Project Analysis)					11,900		

See footnotes attached.

B-4

TABLE B-4

KLAMATH FALLS DISTRICT HEATING SYSTEM

	Year						Total
	1978	1979	1980	1981	1982	1983	
o Resource Assessment and Preliminary Design							
Feasibility Study or Conceptual Design	13,632						13,632
Geological & Geophysical Exploration	40,000	40,000					80,000
o Well Costs							
Tangible Well Equipment 1/		1,100	1,100				2,200
Intangible Drilling Costs 2/		30,883	30,882				61,765
o System Construction Costs							
Design/Planning/Bidding	17,500	17,500	45,000	45,000			125,000
Piping				1,359,141			1,359,141
Heat Exchange Equipment				28,000			28,000
Control System				46,076			46,076
Pumps, Plumbing & Mechanical				288,346			288,346
Retrofit Engineering			74,500	74,500			149,000
Heat Exchanger Building				221,395			221,395
Pump Test				148,000			148,000
o General and Administrative Expenses	19,764	19,764	8,470	8,470			56,468
o Total Capital Costs	90,896	109,247	159,952	2,218,928	0	0	2,579,023
o Retrofit Costs							172,300
State Office Building					24,000		
State Office of Veterans Affairs					7,000		
County Court House Annex				3,800			
County Library				15,000			
County Jail					50,000		
County Court House				12,000			
Veterans' Memorial				9,500			
Old City Hall & Police Dept.				15,000			
City Hall Annex				16,000			
U.S. Post Office				20,000			
State Employment Office				5,000			
City Fire Station				10,000			
o Normal Annual Operating Expenses					9,000		
o Delivered Energy (MMBtu) 6/							
Estimated Actual						(not operating)	
Expected (Assumed in Project Analysis)						51,000	

See footnotes attached.

TABLE B-5
ELKO DISTRICT HEATING SYSTEM

	Year					Total
	1979	1980	1981	1982	1983	
o Resource Assessment and Preliminary Design						
Permitting and Legal			6,240	86,174	2,000	94,414
Geological & Geophysical Exploration	40,006	117,420	12,157	157		169,740
Environmental Report	11,786	450				12,236
Land Purchase & Easement			33,225			33,225
o Well Costs						
Tangible Well Equipment 1/		1,426	19,721	50,159		71,306
Intangible Drilling Costs 2/		4,277	59,162	61,295		124,734
o System Construction Costs						
Design/Planning/Bidding		41,747	33,502	74,006		149,225
Distribution System				299,531	18,000	317,531
Heat Exchange Equipment				4,579		4,579
Pump House				3,500		3,500
Effluent Disposal System				33,905		33,905
o General and Administrative Expenses						
Construction Management				36,024		36,024
Monitoring & Evaluation				1,233	18,500	19,733
o Total Capital Costs	51,792	165,320	164,007	650,563	38,500	1,070,182
o Retrofit Costs				275,000	106,000	381,000
o Normal Annual Operating Expenses					21,600	
o Delivered Energy (MMBtu)						
Estimated Actual					20,000	
Expected (Assumed in Project Analysis)					27,000	

See footnotes attached.

TABLE B-6

ST. MARY'S HOSPITAL PROJECT

	Year						Total
	1978	1979	1980	1981	1982	1983	
o Resource Assessment and Preliminary Design							
Geological & Geophysical Exploration		1,273					1,273
Environmental Report	9,131						9,131
Legal Fees	352	293	3				648
o Well Costs							
Design/Planning/Bidding for Well	8,930	8,570					17,500
Well House		1,245					1,245
Tangible Well Equipment 1/		56,272					56,272
Intangible Drilling Costs 2/		269,908	1,103				271,011
o System Construction Costs							
Design/Planning/Bidding		10,333	10,804				21,137
Application System Construction			141,475				141,475
Disposal System Construction		1,400	25,122				26,522
Replacement Pipe				23,000			23,000
Special Categories Required for Tax Purposes:							
a) Geothermal Space Heating System in New Buildings			23,439				23,439
b) Equipment Normally Used with Both Geothermal and Non-Geothermal Energy 3/			151,459				151,459
o General and Administrative Expenses	5,271	4,488	1,931				11,690
o Direct DOE-Related Costs							
Conferences	282	363	1,497				2,142
Publicity			51				51
o Total Capital Costs	23,966	354,145	356,884	23,000	0	0	757,995
o Normal Annual Operating Expenses				10,000	10,000	10,000	
o Delivered Energy (MMBtu)							
Estimated Actual				5,800	11,100	11,400	
Expected (Assumed in Project Analysis)						11,400	

See footnotes attached.

TABLE B-7

TORBETT-HUTCHINGS-SMITH MEMORIAL HOSPITAL PROJECT

	Year					Total
	1979	1980	1981	1982	1983	
o Resource Assessment and Preliminary Design						
Environmental Report	12,462					12,462
Environmental Monitoring				12,500		12,500
o Well Costs						
Tangible Well Equipment 1/	44,900					44,900
Intangible Drilling Costs 2/	179,400					179,400
o System Construction Costs						
Architecture, Engineering & Permitting		217,069				217,069
Injection Well	100,000					100,000
Acceptance Testing				23,374		23,374
System Monitoring				9,810		9,810
O&M Manual				5,026		5,026
Construction			192,850	192,850		385,700
Materials Testing				5,000	5,000	10,000
o General and Administrative Expenses	17,744	17,744	17,744	17,744	17,744	88,720
o Direct DOE-Related Costs						
Public Awareness		8,029	8,029	8,029		24,087
Reporting	5,225	5,225	5,225	5,225	5,225	26,125
o Total Capital Costs	359,731	248,067	223,848	279,558	27,969	1,139,173
o Normal Annual Operating Expenses				6,600	6,600	
o Delivered Energy (MMBtu)						
Estimated Actual				5,000	5,000	
Expected (Assumed in Project Analysis)					5,000	

See footnotes attached.

TABLE B-8
KLAMATH FALLS, YMCA PROJECT

	Year						
	<u>1978</u>	<u>1979</u>	<u>1980</u>	<u>1981</u>	<u>1982</u>	<u>1983</u>	<u>Total</u>
o Resource Assessment and Preliminary Design							
Environmental Report		419					419
Legal Fees		2,000					2,000
o Well Costs							
Reinjection Well	58,254						58,254
Tangible Well Equipment 1/		39,281					39,281
Intangible Drilling Costs 2/		30,763					30,763
o System Construction Costs							
Design/Planning/Bidding		8,300	700				9,000
System Construction & Testing		360	93,625				93,985
o General and Administrative Expenses		2,340	11,170				13,510
o Direct DOE-Related Costs							
Conferences		605	1,210				1,815
Reporting		2,850	16,600				19,450
o Total Capital Costs	58,254	86,918	123,305	0	0	0	268,477
o Normal Annual Operating Expenses				2,000	2,000	2,000	
o Delivered Energy (MMBtu) 7/							
Estimated Actual				7,000	7,000	7,000	
Expected (Assumed in Project Analysis)						7,000	

See footnotes attached.

TABLE B-9
PHILIP, SOUTH DAKOTA PROJECT

	Year						Total
	1978	1979	1980	1981	1982	1983	
o Resource Assessment and Preliminary Design							
Feasibility Study or Conceptual Design	1,504						1,504
Geological & Geophysical Exploration & Water Rights	3,453						3,453
Environmental Report	429						429
Well Site	5,000						5,000
Legal Fees & Water Rights	365						365
o Well Costs							
Design/Planning/Bidding for Well	410	10,935					11,345
Tangible Well Equipment 1/		71,977	311				72,288
Intangible Drilling Costs 2/	7,120	227,345	1,261				235,726
o System Construction Costs							
Design/Planning/Bidding		17,675	22,779	6,862	1,243	2,021	50,580
Piping			324,604				324,604
Heat Exchange Equipment			13,600				13,600
Testing & Recording Equipment				846			846
Legal Fees		422	769				1,191
Disposal System		7,198	99,628	7,699	1,086		115,611
Testing		2,653	104				2,757
o General and Administrative Expenses	4,673	8,659	5,314	3,673	2,319		24,638
o Direct DOE-Related Costs							
Conferences	1,642	1,407	3,174	1,953			8,176
Reporting	108	1,128	487	464	2,387	6,985	11,559
o Total Capital Costs	24,704	349,399	472,031	21,497	7,035	9,006	883,672
o School Retrofit Cost			219,174	7,699	1,086		227,959
o Business Retrofits 5/							116,412
Bank			9,411				
Foodstore			12,362				
Garage #1			20,487				
Garage #2			36,010				
Garage #3			20,226				
Appliance Store			5,733				
Law Office				5,689			
Fire Hall				6,494			
o Normal Annual Operating Expenses				4,000	7,650	7,650	
o Delivered Energy (MMBtu)							
Estimated Actual: School				4,700	4,700	4,700	
Business					3,200	3,200	
Expected (Assumed in Project Analysis)						9,500	

See footnotes attached.

FOOTNOTES TO TABLES B-1 THROUGH B-9

1/ Tangible well equipment includes all physical well property with salvage value (e.g., pumps, valves, casing).

2/ Intangible drilling costs include amounts paid for labor, fuel, repairs, hauling, and supplies used in well site preparation and in well drilling, completion, and testing.

3/ Equipment not used exclusively with geothermal energy includes, for example, piping and coils which will normally be used with both geothermally heated fluids and boiler fluids heated by conventional fuels.

4/ Estimated figure to complete district heating system retrofit.

5/ Business retrofits are included for informational purposes only and were not used in any of the analysis.

6/ Estimate; project not currently operating.

7/ Estimated from energy displaced.

8/ First year O&M costs; normal expected to be \$57,000.

APPENDIX C

FEDERAL INCOME TAX TREATMENT OF GEOTHERMAL COSTS

For private sector geothermal developers, federal income taxes and tax benefits have a significant impact on total project costs and levelized unit costs. Three kinds of tax benefits have particular importance for geothermal projects: the percentage depletion allowance, the energy tax credit, and the expensing of intangible drilling costs. These benefits are outlined in the paragraphs below and discussed in more detail in the following sections of this appendix. The financial analysis discussed in Chapters II and III of this report assumed that the private sector geothermal developer has a large enough taxable income from other operations to enable him to take full advantage of all tax benefits in the first year in which these benefits would be available.

Intangible drilling costs are defined as all costs for labor, fuel, repairs, hauling, and supplies incurred in well site preparation, and in drilling, completing, and testing production wells. That is, the intangible drilling cost category includes all well development costs except those incurred for tangible well equipment such as pumps, valves, and casing. Normally, similar construction costs would have to be capitalized as assets in the year they were incurred, and only gradually written off as expenses through yearly depreciation deductions. However, for oil, gas, and geothermal wells, Congress has allowed the full amount of intangible drilling costs to be deducted from taxable income as expenses in the year incurred if the taxpayer chooses to do so. If the taxpayer chooses to capitalize, rather than expense intangible drilling costs, then these costs would be eligible for both the energy and investment tax credits.

Depletion deductions are normally used to recover the costs of nonrenewable natural resources which are used up through extraction. For geothermal resources, all costs of acquiring property and determining its potential for production must be capitalized and depleted, that is, deducted as expenses from taxable income over the life of the resource. These costs include the sales price of land or lease bonus bids, costs incurred in obtaining drilling permits, geological and geophysical exploration costs, and environmental assessment costs. The basic method of depletion is "cost depletion," in which the depletion deduction is tied to the quantities produced and to actual resource costs. To encourage resource development and to compensate developers for the particular financial risks which they face, Congress has allowed a special kind of depletion called "percentage depletion," which usually results in a higher deduction and hence a lower income tax liability. Percentage depletion may be used for geothermal resources, mines, and certain oil and gas wells.

To promote the development of alternative energy sources and lessen dependence on nonrenewable fossil fuels, the Congress has enacted an Energy Tax Credit applicable to investments in geothermal and other alternative

energy property. This energy credit may be applied in addition to the regular investment tax credit.

For each kind of geothermal project cost, Table C-1 details the appropriate tax treatment, including the applicability of the energy and regular investment tax credits.

COST AND PERCENTAGE DEPLETION ALLOWANCES

Two methods of depletion are available to the geothermal producer: COST DEPLETION, which is similar to depreciation, and PERCENTAGE DEPLETION, based on a percentage of gross income from the geothermal property. Because percentage depletion is computed as a percentage of income derived from the sale of resources produced, it may only be used by taxpayers who extract geothermal resources and sell them to distributors or end users. Taxpaying producers who extract geothermal resources for their own energy use must use cost depletion rather than percentage depletion.

In cases where both cost and percentage depletion are allowed (i.e., whenever geothermal resources are sold) the producer must calculate both the cost and percentage depletion each year and must use that method which yields the largest deduction for that year. In practice, most depletion is taken as percentage depletion, since percentage depletion generally yields much larger deductions than cost depletion. In addition, deductions for cost depletion end when the book value of the property (i.e., the accumulated acquisition and exploration costs less the accumulated depletion deductions) is reduced to zero. In contrast, percentage depletion continues indefinitely, even after the book value of the property has been reduced to zero. The methodology for calculating each of the two kinds of depletion is described below.

Cost Depletion

Cost depletion is calculated on a units of production basis. To compute cost depletion, the book value of the property (cost less previous depletion deductions) is multiplied by the ratio of the number of units produced and sold during the year to the estimated total number of units that will be produced over the remaining life of the property. The book value is reduced after each year by the amount of depletion deducted for that year, no matter whether cost or percentage depletion is used.

Percentage Depletion

Percentage depletion is calculated as a percentage of gross income from the geothermal property (i.e., gross revenues less royalties paid). Starting in 1984, the applicable percentage for geothermal resources is 15 percent per year. The maximum allowable percentage depletion deduction is 50 percent of taxable income from the property (before the depletion deduction).

Percentage depletion continues indefinitely, even after the book value of the property has been reduced to zero. However, the excess of percentage depletion deductions over the original cost is considered a "preference item" subject to a minimum tax. A discussion of minimum tax on tax preference items

TABLE C-1
TAX TREATMENT OF PROJECT COSTS

Cost Category	Tax Treatment
<ul style="list-style-type: none"> • Resource Acquisition and Related Costs: <ul style="list-style-type: none"> -- Lease Bonus Bid -- Purchase Price of Land -- Permitting -- Geological & Geophysical Exploration -- Environmental Assessment -- Other 	All resource acquisition and related costs are capitalized and subsequently recovered through cost or percentage depletion allowances.
<ul style="list-style-type: none"> • Well Drilling: <ul style="list-style-type: none"> -- Tangible Well Equipment¹ -- Intangible Drilling Costs² 	<p>Capitalized and depreciated; eligible for regular ITC and energy tax credit.</p> <p>May be expensed or capitalized at taxpayer's option. If expensed, intangible drilling costs become an item of tax preference subject to minimum tax.</p>
<ul style="list-style-type: none"> • Geothermal System Construction: <ul style="list-style-type: none"> -- Geothermal Space Heating System in New Buildings -- Any Equipment Not Used Exclusively with Geothermal Energy³ -- Most Other Construction Costs 	<p>Capitalized and depreciated; eligible for energy credit only.</p> <p>Capitalized and depreciated; eligible for regular ITC only.</p> <p>Capitalized and depreciated, eligible for both regular ITC and energy credit.</p>
<ul style="list-style-type: none"> • General and Administrative Expenses 	Expensed.

¹Tangible well equipment includes all physical well property with salvage value (e.g., pumps, valves, casing).

²Intangible drilling costs include amounts paid for labor, fuel, repairs, hauling, and supplies used in well site preparation and in well drilling, completion, and testing.

³Equipment not used exclusively with geothermal energy includes, for example, piping and coils which will normally be used with both geothermally heated fluids and boiler fluids heated by conventional fuels.

is presented in the next section. Table C-2 provides examples of cost and percentage depletion calculations.

MINIMUM TAX ON TAX PREFERENCE ITEMS

Two kinds of expensed items associated with geothermal projects may be considered tax preference items subject to a minimum tax. These are:

- expensed intangible drilling costs, and
- percentage depletion deductions over and above the original value of the property.

The minimum tax is currently equal to 15 percent of net tax preference items. To compute the net preference items, a corporation first adds together all its tax preference items for the year and then subtracts an exemption from this total. The exemption is equal to the greater of \$10,000 and the corporation's regular income tax liability. Thus, if the total of a corporation's tax preference items is smaller than its regular income tax liability, net tax preferences will be less than zero, and the corporation will not be required to pay the minimum tax. (It will, however, still have to pay the full amount of its regular income tax liability.) The financial analysis of geothermal projects presented in this report assumes that the project sponsor's regular income tax liability is always large enough to shield any depletion deductions and intangible drilling costs which might otherwise be subject to minimum tax.

DEPRECIATION

The Economic Recovery Tax Act of 1981 authorized businesses to use a special method of accelerated depreciation deductions in calculating federal income tax liability. The method specified by the 1981 Act and revised by the Tax Equity and Fiscal Responsibility Act of 1982 is called the Accelerated Cost Recovery System, or ACRS. Under ACRS, all machinery and equipment is grouped into four classes of property, with depreciable lives of 3, 5, 10, and 15 years, respectively. Automobiles, light duty trucks, equipment used in research and development, and other short-lived equipment is classed as 3-year property. Most other equipment except long-lived public utility property is considered 5-year property, regardless of the actual life of the equipment. In this analysis, all geothermal equipment was assumed to be 5-year property. The percentages of original equipment cost which may be depreciated each year are specified by law, and are designed to approximate the 150 percent declining balance switching to straight-line method. Table C-3 lists the allowable yearly depreciation deduction percentages for 3-, 5-, 10-, and 15-year property. These percentages are applied to the amount of the original investment minus one-half of any regular or energy investment tax credits taken.¹

¹In lieu of deducting half of the regular investment tax credit from the depreciable basis of the property, the taxpayer may instead elect to reduce the tax credit from 6 to 4 percent for three-year property and from 10 to 8 percent for all other property. This option of reducing the tax credit rather than reducing the depreciation deductions applies only to the regular investment tax credit and does not extend to the energy tax credit.

TABLE C-2
COST AND PERCENTAGE DEPLETION
 Sample Calculations

3-Year Project--\$50,000 Resource Cost--15% Percentage
 Depletion Allowance--100 Units Produced During Project Life

	Year 1	Year 2	Year 3
Revenues (net of royalty payments)	\$150K	\$200K	\$150K
Expenses	-130	-110	-100
	<hr/>	<hr/>	<hr/>
Taxable Income Before Depletion	\$ 20K	\$ 90K	\$ 50K
A) 15 Percent of Revenues	\$ 22.5K	\$ 30K	\$ 22.5K
B) 50 Percent of Taxable Income	\$ 10K	\$ 45K	\$ 25K
Percentage Depletion (Smaller of A and B)	\$ 10K	\$ 30K	\$ 22.5K
C) Production	30 Units	40 Units	30 Units
D) Production this Year Plus Quantity Remaining to be Produced in Subse- quent Years	100 Units	70 Units	30 Units
E) Book Value	\$ 50K	\$ 35K	\$ 5K
Cost Depletion (C ÷ D x E)	\$ 15K	\$ 20K	\$ 5K
Depletion Deduction (Larger of Percentage and Cost Depletion)	\$ 15K	\$ 30K	\$ 22.5K
Beginning Book Value	\$ 50K	\$ 35K	\$ 5K
Less Depletion Deduction	-15	-30	-22.5
	<hr/>	<hr/>	<hr/>
Year End Book Value	\$ 35K	\$ 5K	0
Amount Subject to Minimum Tax (Depletion Deduction Over and Above Basis in Property)			\$ 17.5K

TABLE C-3
ACRS DEPRECIATION DEDUCTIONS (PERCENT) FOR
3-, 5-, 10-, AND 15-YEAR PROPERTY

Depreciation Percentage by Property Class				
Year	3-Year	5-Year	10-Year	15-Year
1	25%	15%	8%	5%
2	38	22	14	10
3	37	21	12	9
4		21	10	8
5		21	10	7
6			10	7
7			9	6
8			9	6
9			9	6
10			9	6
11				6
12				6
13				6
14				6
15				6

REGULAR INVESTMENT TAX CREDIT

In general, a taxpayer investing in certain business property may claim an investment tax credit (ITC), which serves to directly reduce his income tax liability by the amount of the credit.²

Amount of Credit. The credit is calculated as a percentage of the cost of acquiring property and placing it in service. The applicable percentage is 6 percent for qualifying equipment classified as 3-year property under the Accelerated Cost Recovery System of depreciation and 10 percent for all other eligible property. This analysis assumes all qualifying geothermal equipment receives the full 10 percent credit.

Upper Limit on ITC. The ITC may be used to offset 100 percent of the taxpayer's tax liability up to \$25,000 and 85 percent of the tax liability over \$25,000. To avoid undue complexity, this analysis of geothermal projects has assumed that the ITC may be used to offset 100 percent of the tax liability, regardless of amount.

²See Internal Revenue Code Section 1.46 for complete regulations governing the regular investment tax credit.

Carry-Backs and Carry-Forwards. If the taxpayer's income tax liability in the year of investment is smaller than the income tax credit, the credit may be "carried back" and applied to the three previous years' income tax liabilities or "carried forward" for seven years.

Qualifying Property. To qualify for the credit, the business property must be tangible, depreciable property used in manufacturing, production, or extraction, or in furnishing electricity, gas or water. All costs associated with acquiring qualified property and placing it in service, such as design and installation charges, are also eligible. Buildings and structural components of buildings are not eligible for the regular ITC.

Timing of ITC. Ordinarily, property is eligible for the tax credit in the year in which the property is placed in service, or placed in a condition of readiness and availability for service. However, for equipment which has a construction period of two or more years, the taxpayer may elect to claim advance tax credits for construction progress payments, as they accrue.

ENERGY TAX CREDIT

Amount and Dates of Energy Credit. In addition to the regular investment tax credit, taxpayers may claim a tax credit for investing in geothermal and other "alternative" energy property. The energy tax credit is 40 percent, up to a maximum credit of \$4,000, for residences and 15 percent (with no ceiling) for businesses. The energy credit was created by the Energy Tax Act of 1978 and increased under the Crude Oil Windfall Profit Tax Act of 1980 and is applicable to investments made from 1978 through 1985.³

Qualified Equipment. Equipment used to produce, distribute, or use geothermal energy is eligible for the energy credit. This would include piping, radiators, fan coils, and heat exchangers, as well as wellhead and downhole equipment for production wells. Disposal equipment, including reinjection wells, will probably also be eligible for the energy credit, although the IRS has not yet made a definitive ruling on this issue.

Minimum Temperature Requirement

In order for any geothermal equipment to qualify for the energy credit, the geothermal fluid must be hotter than 50°C (122°F) under the current regulations.

Exclusive Use Rule. The existence of a backup, conventional fuel system for peaking or topping disqualifies from eligibility for the energy tax credit all items of equipment which use both geothermal and conventional energy. Thus, for example, pipes and fan coils which receive fluids both from a conventional boiler and from a geothermal heat exchanger would not qualify for the energy credit. However, those items of equipment which are associated exclusively with geothermal energy, such as the well, heat exchanger, and distribution equipment between the well and the heat exchanger, would still qualify.

³Regulations governing the Energy Tax Credit appear in the Federal Register, Vol. 46, No. 15, January 23, 1981.

Other Rules Applicable to Energy Credit. In general, the rules for the regular investment tax credit also apply to the energy credit, with two major exceptions. 1) Buildings and structural components of buildings do not qualify for the regular investment tax credit, but they may qualify for the energy credit. Items that fall in this category include geothermal heating systems in new buildings (since heating systems are considered structural components) and structures to house pumps and other qualifying geothermal energy property. 2) The energy credit may offset 100 percent of the income tax liability remaining after taking any applicable regular investment tax credits (i.e., the credit is not reduced above \$25,000, as it is for the regular ITC).

APPENDIX D

THE ICF ENERGY SUPPLY PROJECT FINANCIAL MODEL¹

This appendix describes the financial model used in this study to evaluate the costs of producing, transporting, and using geothermal energy in direct heat applications. The model uses information on capital and operating costs, production, tax policies, inflation, financial structure, and costs of capital to calculate unit costs as well as several other measures of project attractiveness. The following section discusses the overall approach of the model and briefly describes the alternative model outputs. Next, the input data required by the model are listed, and available options are reviewed. The final section suggests a variety of applications for which the model's analytic tools may be appropriate.

MODEL APPROACH AND OUTPUTS

The financial model contains two segments, which offer alternative means of evaluating the economics of an energy supply project. In the "breakeven" segment, the model calculates the present value of all project costs, as well as a unit product price which would allow all investors (lenders and shareholders) to receive the rate of return required for them to invest. This unit product price is known as the "minimum acceptable supply price" or "MASP." The timing of production and of all cash outlays and the time value of money are all explicitly accounted for in calculating the MASP. A decision to invest in a project can be made by comparing the MASP to the levelized unit price of alternative conventional fuels.

In contrast, the "alternate revenue stream" segment calculates the cash flows associated with a pre-specified product price or annual revenue stream and uses this cash flow stream to derive an implied internal rate of return (IRR) for the project. The alternate revenue stream method uses the same information about production and project costs as the breakeven method uses. However, instead of employing a user-specified discount rate, the alternate revenue stream method calculates the discount rate, or IRR, at which the project would have a net present value equal to zero. Investment decisions can then be made by comparing the IRR with some hurdle rate--a required rate of return--and investing in a project if the IRR is higher than the hurdle rate.

¹The ICF Energy Supply Project Financial Model was originally developed for the Office of Policy and Evaluation of the U.S. Department of Energy. For a more detailed description of the model logic and capabilities, see ICF Incorporated, Energy Supply Project Financial Model, prepared for the Office of Finance and Tax Policy, U.S. Department of Energy, April 1982, revised July 1983.

In addition to generating the project IRR, the alternate revenue stream segment also calculates the "levelized unit price" which is equivalent to the actual price or revenue stream entered by the user. The levelized unit price is a constant price per unit of output and is computed in the same manner as the MASP. If projected price paths for one or more conventional fuels are entered in the alternate revenue stream section of the model, the model will calculate the levelized unit prices of those fuels. Thus, the breakeven and alternate revenue stream segments can be used together to compare the unit cost of geothermal energy (as reflected in the MASP) with the unit costs of conventional fuels (as represented by the levelized unit prices). Use of the model in this manner will also allow the user to determine the IRR which could be realized by geothermal project sponsors if the price of geothermal energy were set equal to a given conventional fuel price.

For both the breakeven and the alternate revenue stream segments, the model produces annual project income statements, sources and uses of funds statements, and balance sheets. The **Income Statement** provides a measure of an energy supply project's performance on an annual basis. It focuses on reporting net income, which equals the difference between the revenues generated and the assets consumed in producing, transporting, and using the geothermal energy. The **Sources and Uses of Funds Statement** supplements income statement information by explaining changes in the financial position of a project on a year-by-year basis. This statement focuses on changes in working capital, but also reports other significant changes in financial position. In reviewing this statement, the user can assess changes in a project's liquidity and structure of its assets and equity by observing (i) acquisitions and sales of noncurrent assets and (ii) transactions with debt and equity instruments.

The **Balance Sheet** summarizes the project's financial position at a point in time for each year of the project. The balance sheet describes the project's assets in the forms in which they are held (e.g., cash or equipment) and the interests that have claims on the assets (e.g., lenders, governments, equity owners).

An illustrative FINMOD output file is included at the end of this appendix.

MODEL INPUT OPTIONS

In order to generate the financial statements and calculate the project evaluation measures discussed above, the financial model requires the user to enter values for the following items:

- Cost Data
 - Capital costs
 - O&M costs
- Tax Factors
 - Income tax rates
 - Property tax rates

- Gross receipts tax rates
- Investment tax credit rates
- Depreciation Factors
 - Method
 - Life of equipment for tax purposes
- Depletion Method (if applicable)
- Financial Data
 - Capital structure
 - Interest rate
 - Cost of equity capital (for breakeven segment)
- Production Stream
- Price or Revenue Stream (for alternate revenue stream segment)

Several optional formats are permitted for many of these inputs. For example, most cost and price data may be entered in either real or nominal dollars. If depletion deductions are relevant for the investment project in question, the model can calculate those deductions using either the cost or the percentage depletion methods. Six optional depreciation methods are provided, including straight-line depreciation, units-of-production depreciation, the "ACRS" accelerated depreciation schedule authorized under the Economic Recovery Act of 1981, and several other accelerated depreciation methods. Finally, for projects partially or wholly financed through debt, the model allows the user to specify one of several alternative debt repayment schedules.

All these options lend the financial model a high degree of flexibility which makes it a useful analytical tool for a variety of applications. The final section of this appendix discusses some of these model uses.

USES OF THE MODEL

One of the primary purposes of the model is to enable its users to assess the prospects for the commercial success of a proposed energy supply project. As discussed above, the minimum acceptable supply price calculated by the model can be directly compared to similarly levelized costs of competing energy projects to assess the relative attractiveness of two or more projects in the marketplace. The model also allows the user to examine the financial viability of a proposed energy supply project in terms of its annual requirements for additional financing. That is, the model can utilize an exogenously-determined pattern of unit prices to generate financial statements for each year of the project. This capability allows users to detect potential cash flow difficulties, as well as to assess how quickly the project would provide sufficient returns to project sponsors to repay their investment and the financial costs associated with that investment.

Another use of the model would involve estimating the kind and level of subsidies that the government would need to provide for a project to avoid short-term or long-term difficulties in the marketplace. Such difficulties could arise from numerous sources, and may be related to business, financial, market, economical, or institutional factors. To reduce risks and improve project economics, the government may wish to provide one or more subsidies to project sponsors. Such subsidies could include equity contributions, repayable grants, low-cost loans or loan guarantees, investment or production tax credits, excise tax exemptions, faster depreciation write-offs, higher depletion allowances, or guaranteed minimum prices. The model is designed to allow easy comparison of different subsidy packages. The user can specify varying subsidy characteristics for a planned energy project. The resultant levelized unit costs for each subsidy package will indicate the relative effectiveness of the subsidy options. Alternatively, a few iterations will allow the user to determine the level of a particular subsidy required to achieve a given levelized unit cost. The income tax, sales tax, and tax credit streams generated for each subsidy option aid in the assessment of the total net cost to the Treasury of the subsidy.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
SUMMARY OF RESULTS

RESULTS FOR BREAKEVEN ANALYSIS

NET PRESENT VALUE 1159440. DOLLARS
MINIMUM ACCEPTABLE SUPPLY PRICE 7.48 \$/MMBTU

ALTERNATE REVENUE STREAM 1 (Natural Gas Price)

NET PRESENT VALUE 1064170. DOLLARS
INTERNAL RATE OF RETURN (REAL) 8.80 PERCENT
LEVELIZED UNIT PRICE 6.86 \$/MMBTU

ALTERNATE REVENUE STREAM 2 (Home heating Oil Price)

NET PRESENT VALUE 1331965. DOLLARS
INTERNAL RATE OF RETURN (REAL) 14.21 PERCENT
LEVELIZED UNIT PRICE 8.59 \$/MMBTU

ALTERNATE REVENUE STREAM 3 (2/3 Heating Oil Price)

NET PRESENT VALUE 888161. DOLLARS
INTERNAL RATE OF RETURN (REAL) 3.57 PERCENT
LEVELIZED UNIT PRICE 5.73 \$/MMBTU

ALTERNATE REVENUE STREAM 4 (2/3 Gas Price)

NET PRESENT VALUE 709423. DOLLARS
INTERNAL RATE OF RETURN (REAL) -3.90 PERCENT
LEVELIZED UNIT PRICE 4.57 \$/MMBTU

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
BREAKEVEN REVENUE STREAM
INCOME STATEMENT (TAX)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 REVENUES	0.	0.	0.	0.	0.	0.	297130.	311986.	327585.	343637.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	0.	0.	0.	0.	0.	0.	76528.	80354.	84372.	88506.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
8 : INTEREST	0.	0.	0.	17917.	40323.	106636.	109940.	106892.	103500.	98754.
9 : MISCELLANEOUS	0.	0.	0.	0.	0.	0.	30742.	28546.	26350.	24154.
10 : OTHER EXPENSES	0.	0.	51213.	260221.	106477.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	0.	0.	-51213.	-278138.	-146800.	-106636.	-134329.	-217122.	-185801.	-166941.
12 LESS: INCOME TAX	0.	0.	-24941.	-135453.	-71492.	-51932.	-65418.	-105739.	-90485.	-81300.
13 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-68911.	-111384.	-95316.	-85641.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-68911.	-111384.	-95316.	-85641.
15 PLUS: DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
16 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	0.	0.	-26272.	-142685.	-75309.	-54704.	145339.	201932.	203848.	213523.
18 PROCEEDS LONG-TERM BONDS	0.	0.	152875.	197457.	584250.	38340.	-26972.	-30020.	-33411.	-38158.
19 PROCEEDS STOCK	0.	0.	90110.	134660.	310952.	32846.	-118366.	-171912.	-170437.	-175365.
20 TOTAL SOURCES OF FUNDS	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	28419.	1042.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	251058.	251188.	1093192.	21975.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	62765.	62797.	273298.	5494.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	-0.	0.	-1.	-0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	0.	0.	-69123.	-89913.	-181065.	-16695.	52568.	66710.	57787.	52001.
27 CUM. NPV CASH FLOW	0.	0.	-69123.	-159036.	-340101.	-356796.	-304227.	-237518.	-179731.	-127730.
28 CUM. CASH FLOW (PAYBACK)	0.	0.	-90110.	-224771.	-535723.	-568569.	-450202.	-278290.	-107854.	67512.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
BREAKEVEN REVENUE STREAM
INCOME STATEMENT (TAX)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1 REVENUES	360475.	378138.	396666.	415706.	435659.	456571.	478486.	501453.	525522.	550746.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : OSM	92843.	97392.	102164.	107068.	112207.	117593.	123238.	129153.	135352.	141849.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.
8 : INTEREST	94484.	89736.	84457.	77886.	71340.	64068.	55989.	47015.	37046.	25970.
9 : MISCELLANEOUS	21958.	19762.	17567.	15371.	13175.	10979.	8783.	6587.	4392.	2196.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-147974.	169283.	190514.	213417.	236973.	261966.	288511.	316733.	346768.	378767.
12 LESS: INCOME TAX	-72063.	82441.	92780.	103934.	115406.	127578.	140505.	154249.	168876.	184459.
13 PROFITS AFTER TAX	-75911.	86842.	97734.	109483.	121567.	134389.	148006.	162484.	177892.	194307.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	-75911.	86842.	97734.	109483.	121567.	134389.	148006.	162484.	177892.	194307.
15 PLUS: DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPLETION	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	223253.	88806.	99698.	111447.	123531.	136353.	149970.	164448.	179856.	196272.
18 PROCEEDS LONG-TERM BONDS	-42427.	-47175.	-52454.	-59026.	-65572.	-72844.	-80922.	-89896.	-99866.	-110941.
19 PROCEEDS STOCK	-180826.	-41631.	-47244.	-52421.	-57960.	-63509.	-69048.	-74552.	-79991.	-85331.
20 TOTAL SOURCES OF FUNDS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	46895.	9442.	9371.	9103.	8811.	8452.	8044.	7603.	7141.	6669.
27 COM. NPV CASH FLOW	-80835.	-71393.	-62022.	-52919.	-44108.	-35656.	-27613.	-20010.	-12868.	-6199.
28 COM. CASH FLOW (PAYBACK)	248337.	289968.	337212.	389633.	447593.	511102.	580151.	654702.	734693.	820024.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
BREAKEVEN REVENUE STREAM
INCOME STATEMENT (TAX)

	2002
1 REVENUES	577191.
2 PLUS: OTHER INCOME	0.
3 LESS: ROYALTIES	0.
4 : O&M	148658.
5 : OTHER TAXES	0.
6 : DEPRECIATION	0.
7 : DEPLETION	1964.
8 : INTEREST	13667.
9 : MISCELLANEOUS	0.
10 : OTHER EXPENSES	0.
11 PROFITS BEFORE TAXES	412893.
12 LESS: INCOME TAX	201079.
13 PROFITS AFTER TAX	211814.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	211814.
15 PLUS: DEPRECIATION	0.
16 : DEPLETION	1964.
17 TOTAL FROM OPERATIONS	213778.
18 PROCEEDS LONG-TERM BONDS	-123244.
19 PROCEEDS STOCK	-90534.
20 TOTAL SOURCES OF FUNDS	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.
22 PURCH OF BLDGS/EQUIP	0.
23 LESS: ITC	0.
24 TOTAL OTHER USES OF FUND	0.

25 NET CHANGE IN WC	0.
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26 NPV CASH FLOW TO COM. EQ	6194.
27 CUM. NPV CASH FLOW	-5.
28 CUM. CASH FLOW (PAYBACK)	910557.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
BREAK-EVEN REVENUE STREAM
BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	0.	0.	251059.	502246.	1595438.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	523637.	820837.	1118037.
5NET PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1405128.	1093776.	796576.	499377.
6GROSS NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	0.	0.	0.	0.	0.	0.	1964.	3928.	5892.	7856.
8NET NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	27497.	25533.	23569.	21605.
9 TOTAL ASSETS	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	0.	0.	152875.	350332.	934582.	972922.	945950.	915930.	882518.	844361.
11EQUITY BALANCE	0.	0.	126603.	181375.	690318.	673953.	486676.	203380.	-62373.	-323379.
12 TOTAL LIAB+EQUITY	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
13MARKET VALUE OF EQUITY	0.	0.	90110.	238185.	584073.	701952.	685016.	612088.	530096.	430751.
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001

ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.
5NET PLANT IN SERVICE	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
6GROSS NATURAL RESOURCES	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	9820.	11785.	13749.	15713.	17677.	19641.	21605.	23569.	25533.	27497.
8NET NATURAL RESOURCES	19641.	17677.	15713.	13749.	11785.	9820.	7856.	5892.	3928.	1964.
9 TOTAL ASSETS	221818.	219854.	217890.	215926.	213962.	211998.	210034.	208070.	206105.	204141.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	801933.	754758.	702305.	643279.	577707.	504863.	423941.	334045.	234179.	123239.
11EQUITY BALANCE	-580115.	-534904.	-484415.	-427353.	-363745.	-292866.	-213908.	-125976.	-28074.	80903.
12 TOTAL LIAB+EQUITY	221818.	219854.	217890.	215926.	213962.	211998.	210034.	208070.	206105.	204141.
13MARKET VALUE OF EQUITY	311699.	314769.	312665.	304742.	290152.	267937.	237021.	196201.	144133.	79316.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
BREAKEVEN REVENUE STREAM
BALANCE SHEET

2002

ASSETS

1CASH	0.
2OTHER WORKING CAPITAL	0.
3GROSS PLANT IN SERVICE	1617413.
4ACCUMULATED DEPRECIATION	1415236.
5NET PLANT IN SERVICE	202177.
6GROSS NATURAL RESOURCES	29461.
7ACCUMULATED DEPLETION	29461.
8NET NATURAL RESOURCES	0.
9 TOTAL ASSETS	202177.

LIABILITIES AND OWNERS EQUITY

10DEBT BALANCE	-6.
11EQUITY BALANCE	202183.
12 TOTAL LIAB+EQUITY	202177.

13MARKET VALUE OF EQUITY	70.
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CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 1
INCOME STATEMENT (TAX)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1REVENUES	0.	0.	0.	0.	0.	0.	214998.	235345.	269020.	285419.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : OSM	0.	0.	0.	0.	0.	0.	76528.	80354.	84372.	88506.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
8 : INTEREST	0.	0.	0.	17917.	40323.	106636.	109940.	106892.	103500.	98754.
9 : MISCELLANEOUS	0.	0.	0.	0.	0.	0.	30742.	28546.	26350.	24154.
10 : OTHER EXPENSES	0.	0.	51213.	260221.	106477.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	0.	0.	-51213.	-278138.	-146800.	-106636.	-216461.	-293763.	-244366.	-225159.
12 LESS: INCOME TAX	0.	0.	-24941.	-135453.	-71492.	-51932.	-105417.	-143063.	-119006.	-109652.
13 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-111045.	-150701.	-125360.	-115507.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-111045.	-150701.	-125360.	-115507.
15 PLUS: DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
16 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	0.	0.	-26272.	-142685.	-75309.	-54704.	103205.	162616.	173804.	183657.
18 PROCEEDS LONG-TERM BONDS	0.	0.	152875.	197457.	584250.	38340.	-26972.	-30020.	-33411.	-38158.
19 PROCEEDS STOCK	0.	0.	90110.	134660.	310952.	32846.	-76233.	-132596.	-140393.	-145499.
20 TOTAL SOURCES OF FUNDS	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	28419.	1042.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	251058.	251188.	1093192.	21975.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	62765.	62797.	273298.	5494.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	-1.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	0.	0.	-69123.	-89913.	-181065.	-16695.	33856.	51453.	47600.	43145.
27 CUM. NPV CASH FLOW	0.	0.	-69123.	-159036.	-340101.	-356796.	-322940.	-271487.	-223886.	-180742.
28 CUM. CASH FLOW (PAYBACK)	0.	0.	-90110.	-224771.	-535723.	-568569.	-492336.	-359741.	-219348.	-73849.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 1
INCOME STATEMENT (TAX)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1 REVENUES	313386.	347454.	373499.	402546.	435853.	472040.	511337.	553318.	599558.	648961.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : OSM	92841.	97392.	102164.	107068.	112207.	117593.	123238.	129153.	135352.	141849.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	1964.	52118.	56025.	60382.	65378.	70806.	76700.	82998.	89934.	97344.
8 : INTEREST	94484.	89736.	84457.	77886.	71340.	64068.	55989.	47015.	37046.	25970.
9 : MISCELLANEOUS	21958.	19762.	17567.	15371.	13175.	10979.	8783.	6587.	4392.	2196.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-195063.	88445.	113285.	141840.	173753.	208594.	246626.	287565.	332835.	381602.
12 LESS: INCOME TAX	-94996.	43073.	55170.	69076.	84618.	101585.	120107.	140044.	162090.	185840.
13 PROFITS AFTER TAX	-100067.	45372.	58115.	72764.	89135.	107009.	126519.	147521.	170744.	195762.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	-100067.	45372.	58115.	72764.	89135.	107009.	126519.	147521.	170744.	195762.
15 PLUS: DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPLETION	1964.	52118.	56025.	60382.	65378.	70806.	76700.	82998.	89934.	97344.
17 TOTAL FROM OPERATIONS	199096.	97490.	114140.	133146.	154513.	177815.	203219.	230519.	260678.	293106.
18 PROCEEDS LONG-TERM BONDS	-42427.	-47175.	-52454.	-59026.	-65572.	-72844.	-80922.	-89896.	-99866.	-110941.
19 PROCEEDS STOCK	-156669.	-50315.	-61686.	-74120.	-88941.	-104971.	-122297.	-140622.	-160812.	-182165.
20 TOTAL SOURCES OF FUNDS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	40630.	11412.	12236.	12871.	13520.	13969.	14247.	14341.	14357.	14237.
27 COM. NPV CASH FLOW	-140112.	-128700.	-116463.	-103592.	-90072.	-76103.	-61856.	-47515.	-33158.	-18921.
28 COM. CASH FLOW (PAYBACK)	92820.	133136.	194822.	269942.	357883.	462854.	585152.	725774.	886586.	1068751.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 1
INCOME STATEMENT (TAX)

1	REVENUES	2002
		703270.
2	PLUS: OTHER INCOME	0.
3	LESS: ROYALTIES	0.
4	: O&M	148658.
5	: OTHER TAXES	0.
6	: DEPRECIATION	0.
7	: DEPLETION	105490.
8	: INTEREST	13667.
9	: MISCELLANEOUS	0.
10	: OTHER EXPENSES	0.
11	PROFITS BEFORE TAXES	435455.
12	LESS: INCOME TAX	212066.
13	PROFITS AFTER TAX	223388.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14	PROFITS AFTER TAX	223388.
15	PLUS: DEPRECIATION	0.
16	: DEPLETION	105490.
17	TOTAL FROM OPERATIONS	328879.
18	PROCEEDS LONG-TERM BONDS	-123244.
19	PROCEEDS STOCK	-205635.
20	TOTAL SOURCES OF FUNDS	0.

OTHER USES OF FUNDS

21	PURCH OF NAT RESOURCES	0.
22	PURCH OF BLDGS/EQUIP	0.
23	LESS: ITC	0.
24	TOTAL OTHER USES OF FUND	0.

25	NET CHANGE IN WC	0.
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26	NPV CASH FLOW TO COM. EQ	14069.
27	CUM. NPV CASH FLOW	-4852.
28	CUM. CASH FLOW (PAYBACK)	1274385.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 1
BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 GROSS PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1617413.	1617413.	1617413.	1617413.
4 ACCUMULATED DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	523637.	820837.	1118037.
5 NET PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1405128.	1093776.	796576.	499377.
6 GROSS NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7 ACCUMULATED DEPLETION	0.	0.	0.	0.	0.	0.	1964.	3928.	5892.	7856.
8 NET NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	27497.	25533.	23569.	21605.
9 TOTAL ASSETS	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
LIABILITIES AND OWNERS EQUITY										
10 DEBT BALANCE	0.	0.	152875.	350332.	934582.	972922.	945950.	915930.	882518.	844361.
11 EQUITY BALANCE	0.	0.	126603.	181375.	690318.	673953.	486676.	203380.	-62373.	-323379.
12 TOTAL LIAB+EQUITY	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
13 MARKET VALUE OF EQUITY	0.	0.	90110.	238185.	584073.	701952.	727150.	699626.	660328.	609525.
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001

ASSETS										
1 CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2 OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 GROSS PLANT IN SERVICE	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.
4 ACCUMULATED DEPRECIATION	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.
5 NET PLANT IN SERVICE	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
6 GROSS NATURAL RESOURCES	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7 ACCUMULATED DEPLETION	9820.	61939.	117963.	178345.	243723.	314529.	391230.	474227.	564161.	661505.
8 NET NATURAL RESOURCES	19641.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9 TOTAL ASSETS	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
LIABILITIES AND OWNERS EQUITY										
10 DEBT BALANCE	801933.	754758.	702305.	643279.	577707.	504863.	423941.	334045.	234179.	123239.
11 EQUITY BALANCE	-580115.	-552581.	-500127.	-441102.	-375530.	-302686.	-221764.	-131868.	-32002.	78939.
12 TOTAL LIAB+EQUITY	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
13 MARKET VALUE OF EQUITY	540268.	567431.	587120.	596558.	592517.	571872.	530962.	465904.	371399.	242090.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 1
BALANCE SHEET

2002

ASSETS

1CASH	0.
2OTHER WORKING CAPITAL	0.
3GROSS PLANT IN SERVICE	1617413.
4ACCUMULATED DEPRECIATION	1415236.
5NET PLANT IN SERVICE	202177.
6GROSS NATURAL RESOURCES	29461.
7ACCUMULATED DEPLETION	766995.
8NET NATURAL RESOURCES	0.
9 TOTAL ASSETS	202177.

LIABILITIES AND OWNERS EQUITY

10DEBT BALANCE	-6.
11EQUITY BALANCE	202183.
12 TOTAL LIAB+EQUITY	202177.

13MARKET VALUE OF EQUITY	70909.
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CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 2
INCOME STATEMENT (TAX)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 REVENUES	0.	0.	0.	0.	0.	0.	303223.	335910.	356210.	366770.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	0.	0.	0.	0.	0.	0.	76528.	80354.	84372.	88506.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
8 : INTEREST	0.	0.	0.	17917.	40323.	106636.	109940.	106892.	103500.	98754.
9 : MISCELLANEOUS	0.	0.	0.	0.	0.	0.	30742.	28546.	26350.	24154.
10 : OTHER EXPENSES	0.	0.	51213.	260221.	106477.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	0.	0.	-51213.	-278138.	-146800.	-106636.	-128236.	-193199.	-157176.	-143808.
12 LESS: INCOME TAX	0.	0.	-24941.	-135453.	-71492.	-51932.	-62451.	-94088.	-76545.	-70034.
13 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-65785.	-99111.	-80631.	-73774.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-65785.	-99111.	-80631.	-73774.
15 PLUS: DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
16 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	0.	0.	-26272.	-142685.	-75309.	-54704.	148464.	214205.	218533.	225390.
18 PROCEEDS LONG-TERM BONDS	0.	0.	152875.	197457.	584250.	38340.	-26972.	-30020.	-33411.	-38158.
19 PROCEEDS STOCK	0.	0.	90110.	134650.	310952.	32846.	-121492.	-184185.	-185121.	-187233.
20 TOTAL SOURCES OF FUNDS	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	28419.	1042.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	251058.	251188.	1093192.	21975.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	62765.	62797.	273298.	5494.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	-1.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EO	0.	0.	-69123.	-89913.	-181065.	-16695.	53957.	71472.	62766.	55520.
27 CHM. NPV CASH FLOW	0.	0.	-69123.	-159036.	-340101.	-356796.	-302839.	-231367.	-168601.	-113082.
28 CHM. CASH FLOW (PAYBACK)	0.	0.	-90110.	-224771.	-535723.	-568569.	-447077.	-262892.	-77771.	109462.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 2
INCOME STATEMENT (TAX)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1 REVENUES	395348.	432421.	457323.	493175.	526753.	561807.	599013.	638496.	681092.	727043.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : OSM	92843.	97392.	102164.	107068.	112207.	117593.	123238.	129153.	135352.	141849.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	1964.	64863.	68599.	73976.	79013.	84271.	89852.	95774.	102164.	109056.
8 : INTEREST	94484.	89736.	84457.	77886.	71340.	64068.	55989.	47015.	37046.	25970.
9 : MISCELLANEOUS	21958.	19762.	17567.	15371.	13175.	10979.	8783.	6587.	4392.	2196.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-113101.	160667.	184537.	218874.	251018.	284896.	321150.	359966.	402139.	447971.
12 LESS: INCOME TAX	-55080.	78245.	89869.	106592.	122246.	138744.	156400.	175303.	195842.	218162.
13 PROFITS AFTER TAX	-58021.	82422.	94667.	112282.	128772.	146152.	164750.	184663.	206297.	229809.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	-58021.	82422.	94667.	112282.	128772.	146152.	164750.	184663.	206297.	229809.
15 PLUS: DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPLETION	1964.	64863.	68599.	73976.	79013.	84271.	89852.	95774.	102164.	109056.
17 TOTAL FROM OPERATIONS	241143.	147285.	163266.	186259.	207785.	230423.	254602.	280437.	308461.	338866.
18 PROCEEDS LONG-TERM BONDS	-42427.	-47175.	-52454.	-59026.	-65572.	-72844.	-80922.	-89896.	-99866.	-110941.
19 PROCEEDS STOCK	-198716.	-100110.	-110812.	-127233.	-142213.	-157579.	-173680.	-190541.	-208595.	-227925.
20 TOTAL SOURCES OF FUNDS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	51534.	22706.	21981.	22094.	21619.	20970.	20233.	19432.	18623.	17813.
27 COM. NPV CASH FLOW	-61548.	-38841.	-16861.	5233.	26852.	47822.	68055.	87487.	106109.	123923.
28 COM. CASH FLOW (PAYBACK)	308178.	408288.	519100.	646333.	788546.	946125.	1119804.	1310344.	1518939.	1746863.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 2
INCOME STATEMENT (TAX)

	2002
1REVENUES	775836.
2 PLUS:OTHER INCOME	0.
3 LESS:ROYALTIES	0.
4 :O&M	148658.
5 :OTHER TAXES	0.
6 :DEPRECIATION	0.
7 :DEPLETION	116375.
8 :INTEREST	13667.
9 :MISCELLANEOUS	0.
10 :OTHER EXPENSES	0.
11PROFITS BEFORE TAXES	497136.
12 LESS:INCOME TAX	242105.
13PROFITS AFTER TAX	255031.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14PROFITS AFTER TAX	255031.
15 PLUS: DEPRECIATION	0.
16 : DEPLETION	116375.
17TOTAL FROM OPERATIONS	371406.
18PROCEEDS LONG-TERM BONDS	-123244.
19PROCEEDS STOCK	-248162.
20TOTAL SOURCES OF FUNDS	0.

OTHER USES OF FUNDS

21PURCH OF NAT RESOURCES	0.
22PURCH OF BLDGS/EQUIP	0.
23 LESS: ITC	0.
24TOTAL OTHER USES OF FUND	0.

25NET CHANGE IN WC	0.
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26NPV CASH FLOW TO COM. EQ	16978.
27CUM. NPV CASH FLOW	140901.
28CUM. CASH FLOW (PAYBACK)	1995024.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 2
BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	523637.	820837.	1118037.
5NET PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1405128.	1093776.	796576.	499377.
6GROSS NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	0.	0.	0.	0.	0.	0.	1964.	3928.	5892.	7856.
8NET NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	27497.	25533.	23569.	21605.
9 TOTAL ASSETS	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	0.	0.	152875.	350332.	934582.	972922.	945950.	915930.	882518.	844361.
11EQUITY BALANCE	0.	0.	126603.	181375.	690318.	673953.	486676.	203380.	-62373.	-323379.
12 TOTAL LIAB+EQUITY	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
13MARKET VALUE OF EQUITY	0.	0.	90110.	238185.	584073.	701952.	681891.	596237.	497271.	381352.
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001

ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.
5NET PLANT IN SERVICE	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
6GROSS NATURAL RESOURCES	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	9920.	74684.	143282.	217258.	296271.	380542.	470394.	566168.	668332.	777388.
8NET NATURAL RESOURCES	19641.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9 TOTAL ASSETS	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	801933.	754758.	702305.	643279.	577707.	504863.	423941.	334045.	234179.	123239.
11EQUITY BALANCE	-580115.	-552581.	-500127.	-441102.	-375530.	-302686.	-221764.	-131868.	-32002.	78939.
12 TOTAL LIAB+EQUITY	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
13MARKET VALUE OF EQUITY	237325.	171249.	84996.	-30141.	-176643.	-359362.	-584185.	-857865.	-1188548.	-1585622.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 2
BALANCE SHEET

2002

ASSETS

1CASH	0.
2OTHER WORKING CAPITAL	0.
3GROSS PLANT IN SERVICE	1617413.
4ACCUMULATED DEPRECIATION	1415236.
5NET PLANT IN SERVICE	202177.
6GROSS NATURAL RESOURCES	29461.
7ACCUMULATED DEPLETION	893764.
8NET NATURAL RESOURCES	0.
9 TOTAL ASSETS	202177.

LIABILITIES AND OWNERS EQUITY

10DEBT BALANCE	-6.
11EQUITY BALANCE	202183.
12 TOTAL LIAB+EQUITY	202177.

13MARKET VALUE OF EQUITY -2059445.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 3
INCOME STATEMENT (TAX)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 REVENUES	0.	0.	0.	0.	0.	0.	202281.	224079.	237473.	244513.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : OSM	0.	0.	0.	0.	0.	0.	76528.	80354.	84372.	88506.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
8 : INTEREST	0.	0.	0.	17917.	40323.	106636.	109940.	106892.	103500.	98754.
9 : MISCELLANEOUS	0.	0.	0.	0.	0.	0.	30742.	28546.	26350.	24154.
10 : OTHER EXPENSES	0.	0.	51213.	260221.	106477.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	0.	0.	-51213.	-278138.	-146800.	-106636.	-229178.	-305030.	-275912.	-266065.
12 LESS: INCOME TAX	0.	0.	-24941.	-135453.	-71492.	-51932.	-111610.	-148549.	-134369.	-129573.
13 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-117568.	-156480.	-141543.	-136491.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-117568.	-156480.	-141543.	-136491.
15 PLUS: DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
16 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	0.	0.	-26272.	-142685.	-75309.	-54704.	96681.	156836.	157621.	162673.
18 PROCEEDS LONG-TERM BONDS	0.	0.	152875.	197457.	584250.	38340.	-26972.	-30020.	-33411.	-38158.
19 PROCEEDS STOCK	0.	0.	90110.	134660.	310952.	32846.	-69709.	-126816.	-124209.	-124515.
20 TOTAL SOURCES OF FUNDS	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	28419.	1042.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	251058.	251188.	1093192.	21975.	0.	0.	0.	0.
23 LESS: JTC	0.	0.	62765.	62797.	273298.	5494.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	-1.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	0.	0.	-69123.	-89913.	-181065.	-16695.	30959.	49210.	42113.	36922.
27 COM. NPV CASH FLOW	0.	0.	-69123.	-159036.	-340101.	-356796.	-325837.	-276627.	-234513.	-197591.
28 COM. CASH FLOW (PAYBACK)	0.	0.	-90110.	-224771.	-535723.	-568569.	-498860.	-372044.	-247835.	-123320.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 3
INCOME STATEMENT (TAX)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1 REVENUES	263726.	288281.	305059.	328598.	351363.	374334.	399342.	425887.	454061.	484695.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	92843.	97392.	102164.	107068.	112207.	117593.	123238.	129153.	135352.	141849.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	1964.	40695.	45759.	49290.	52704.	56150.	59901.	63883.	68109.	72704.
8 : INTEREST	94484.	89736.	84457.	77886.	71340.	64068.	55989.	47015.	37046.	25970.
9 : MISCELLANEOUS	21958.	19762.	17567.	15371.	13175.	10979.	8783.	6587.	4392.	2196.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-244723.	40695.	55112.	78984.	101936.	125544.	151430.	179249.	209163.	241976.
12 LESS: INCOME TAX	-119180.	19818.	26839.	38465.	49643.	61140.	73746.	87294.	101862.	117842.
13 PROFITS AFTER TAX	-125543.	20876.	28272.	40519.	52293.	64404.	77684.	91955.	107301.	124134.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	-125543.	20876.	28272.	40519.	52293.	64404.	77684.	91955.	107301.	124134.
15 PLUS: DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPLETION	1964.	40695.	45759.	49290.	52704.	56150.	59901.	63883.	68109.	72704.
17 TOTAL FROM OPERATIONS	173621.	61571.	74031.	89808.	104998.	120554.	137585.	155838.	175410.	196838.
18 PROCEEDS LONG-TERM BONDS	-42427.	-47175.	-52454.	-59026.	-65572.	-72844.	-80922.	-89896.	-99866.	-110941.
19 PROCEEDS STOCK	-131194.	-14396.	-21577.	-30782.	-39426.	-47711.	-56663.	-65941.	-75544.	-85897.
20 TOTAL SOURCES OF FUNDS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. 30	34023.	3265.	4280.	5345.	5993.	6349.	6601.	6725.	6744.	6713.
27 CUM. NPV CASH FLOW	-163568.	-160303.	-156022.	-150677.	-144684.	-138334.	-131733.	-125009.	-118264.	-111551.
28 CUM. CASH FLOW (PAYBACK)	7874.	22270.	43847.	74630.	114056.	161766.	218429.	284371.	359915.	445811.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 3
INCOME STATEMENT (TAX)

1	REVENUES	2002
2	PLUS: OTHER INCOME	517224.
3	LESS: ROYALTIES	0.
4	: O&M	148658.
5	: OTHER TAXES	0.
6	: DEPRECIATION	0.
7	: DEPLETION	77584.
8	: INTEREST	13667.
9	: MISCELLANEOUS	0.
10	: OTHER EXPENSES	0.
11	PROFITS BEFORE TAXES	277316.
12	LESS: INCOME TAX	135053.
13	PROFITS AFTER TAX	142263.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14	PROFITS AFTER TAX	142263.
15	PLUS: DEPRECIATION	0.
16	: DEPLETION	77584.
17	TOTAL FROM OPERATIONS	219846.
18	PROCEEDS LONG-TERM BONDS	-123244.
19	PROCEEDS STOCK	-96602.
20	TOTAL SOURCES OF FUNDS	0.

OTHER USES OF FUNDS

21	PURCH OF NAT RESOURCES	0.
22	PURCH OF BLDGS/EQUIP	0.
23	LESS: ITC	0.
24	TOTAL OTHER USES OF FUND	0.

25	NET CHANGE IN WC	0.
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26	NPV CASH FLOW TO COM. EO	6609.
27	CUM. NPV CASH FLOW	-104942.
28	CUM. CASH FLOW (PAYBACK)	542414.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 3
BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	523637.	820837.	1118037.
5NET PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1405128.	1093776.	796576.	499377.
6GROSS NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	0.	0.	0.	0.	0.	0.	1964.	3928.	5892.	7856.
8NET NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	27497.	25533.	23569.	21605.
9 TOTAL ASSETS	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	0.	0.	152875.	350332.	934582.	972922.	945950.	915930.	882518.	844361.
11EQUITY BALANCE	0.	0.	126603.	181375.	690318.	673953.	486676.	203380.	-62373.	-323379.
12 TOTAL LIAB+EQUITY	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
13MARKET VALUE OF EQUITY	0.	0.	90110.	238185.	584073.	701952.	733674.	712872.	691672.	666348.
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001

ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.
5NET PLANT IN SERVICE	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
6GROSS NATURAL RESOURCES	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	9820.	50515.	96274.	145564.	198268.	254418.	314320.	378203.	446312.	519016.
8NET NATURAL RESOURCES	19641.	0.	0.	0.	0.	0.	0.	0.	0.	0.
9 TOTAL ASSETS	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	801933.	754758.	702305.	643279.	577707.	504863.	423941.	334045.	234179.	123239.
11EQUITY BALANCE	-580115.	-552581.	-500127.	-441102.	-375530.	-302686.	-221764.	-131868.	-32002.	78939.
12 TOTAL LIAB+EQUITY	221818.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
13MARKET VALUE OF EQUITY	630715.	706769.	786548.	867705.	951769.	1039513.	1130790.	1225779.	1324684.	1427312.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 3
BALANCE SHEET

2002

ASSETS

1CASH	0.
2OTHER WORKING CAPITAL	0.
3GROSS PLANT IN SERVICE	1617413.
4ACCUMULATED DEPRECIATION	1415236.
5NET PLANT IN SERVICE	202177.
6GROSS NATURAL RESOURCES	29461.
7ACCUMULATED DEPLETION	596600.
8NET NATURAL RESOURCES	0.
9 TOTAL ASSETS	202177.

LIABILITIES AND OWNERS EQUITY

10DEBT BALANCE	-6.
11EQUITY BALANCE	202183.
12 TOTAL LIAB+EQUITY	202177.

13MARKET VALUE OF EQUITY 1533839.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 4
INCOME STATEMENT (TAX)

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
1 REVENUES	0.	0.	0.	0.	0.	0.	143465.	156897.	179200.	190279.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	0.	0.	0.	0.	0.	0.	76528.	80354.	84372.	88506.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
7 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
8 : INTEREST	0.	0.	0.	17917.	40323.	106636.	109940.	106892.	103500.	98754.
9 : MISCELLANEOUS	0.	0.	0.	0.	0.	0.	30742.	28546.	26350.	24154.
10 : OTHER EXPENSES	0.	0.	51213.	260221.	106477.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	0.	0.	-51213.	-278138.	-146800.	-106636.	-287995.	-372212.	-334185.	-320299.
12 LESS: INCOME TAX	0.	0.	-24941.	-135453.	-71492.	-51932.	-140253.	-181267.	-162748.	-155985.
13 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-147741.	-190945.	-171437.	-164313.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	0.	0.	-26272.	-142685.	-75309.	-54704.	-147741.	-190945.	-171437.	-164313.
15 PLUS: DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	311352.	297200.	297200.
16 : DEPLETION	0.	0.	0.	0.	0.	0.	1964.	1964.	1964.	1964.
17 TOTAL FROM OPERATIONS	0.	0.	-26272.	-142685.	-75309.	-54704.	66508.	122371.	127727.	134850.
18 PROCEEDS LONG-TERM BONDS	0.	0.	152875.	197457.	584250.	38340.	-26972.	-30020.	-33411.	-38158.
19 PROCEEDS STOCK	0.	0.	90110.	134660.	310952.	32846.	-39536.	-92351.	-94315.	-96693.
20 TOTAL SOURCES OF FUNDS	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	28419.	1042.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	251058.	251188.	1093192.	21975.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	62765.	62797.	273298.	5494.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	216713.	189433.	819894.	16481.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	-1.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EQ	0.	0.	-69123.	-89913.	-181065.	-16695.	17559.	35836.	31978.	28672.
27 COM. NPV CASH FLOW	0.	0.	-69123.	-159036.	-340101.	-356796.	-339237.	-303401.	-271423.	-242751.
28 COM. CASH FLOW (PAYBACK)	0.	0.	-90110.	-224771.	-535723.	-568569.	-529033.	-436681.	-342366.	-245673.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 4
INCOME STATEMENT (TAX)

	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
1 REVENUES	208763.	231636.	248822.	268549.	290763.	314490.	341104.	368879.	399939.	432395.
2 PLUS: OTHER INCOME	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3 LESS: ROYALTIES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
4 : O&M	92843.	97392.	102164.	107068.	112207.	117593.	123238.	129153.	135352.	141849.
5 : OTHER TAXES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
6 : DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
7 : DEPLETION	1964.	12373.	22317.	34112.	43614.	47173.	51166.	55332.	59991.	64859.
8 : INTEREST	94484.	89736.	84457.	77886.	71340.	64068.	55989.	47015.	37046.	25970.
9 : MISCELLANEOUS	21958.	19762.	17567.	15371.	13175.	10979.	8783.	6587.	4392.	2196.
10 : OTHER EXPENSES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
11 PROFITS BEFORE TAXES	-299686.	12373.	22317.	34112.	50426.	74676.	101928.	130792.	163159.	197521.
12 LESS: INCOME TAX	-145947.	6025.	10868.	16613.	24558.	36367.	49639.	63695.	79458.	96193.
13 PROFITS AFTER TAX	-153739.	6347.	11449.	17500.	25869.	38309.	52289.	67096.	83701.	101328.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14 PROFITS AFTER TAX	-153739.	6347.	11449.	17500.	25869.	38309.	52289.	67096.	83701.	101328.
15 PLUS: DEPRECIATION	297200.	0.	0.	0.	0.	0.	0.	0.	0.	0.
16 : DEPLETION	1964.	12373.	22317.	34112.	43614.	47173.	51166.	55332.	59991.	64859.
17 TOTAL FROM OPERATIONS	145425.	18720.	33765.	51612.	69483.	85482.	103455.	122428.	143692.	166187.
18 PROCEEDS LONG-TERM BONDS	-42427.	-47175.	-52454.	-59026.	-65572.	-72844.	-80922.	-89896.	-99866.	-110941.
19 PROCEEDS STOCK	-102997.	28455.	18689.	7414.	-3911.	-12639.	-22533.	-32532.	-43826.	-55247.
20 TOTAL SOURCES OF FUNDS	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

OTHER USES OF FUNDS

21 PURCH OF NAT RESOURCES	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
22 PURCH OF BLDGS/EQUIP	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
23 LESS: ITC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
24 TOTAL OTHER USES OF FUND	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.

25 NET CHANGE IN WC	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
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26 NPV CASH FLOW TO COM. EO	26711.	-6454.	-3707.	-1287.	595.	1682.	2625.	3318.	3913.	4318.
27 CUM. NPV CASH FLOW	-216040.	-222494.	-226201.	-227488.	-226894.	-225212.	-222587.	-219269.	-215356.	-211039.
28 CUM. CASH FLOW (PAYBACK)	-142676.	-171131.	-189820.	-197233.	-193322.	-180683.	-158151.	-125619.	-81793.	-26547.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 4
INCOME STATEMENT (TAX)

	2002
1REVENUES	468589.
2 PLUS:OTHER INCOME	0.
3 LESS:ROYALTIES	0.
4 :OSM	148658.
5 :OTHER TAXES	0.
6 :DEPRECIATION	0.
7 :DEPLETION	70288.
8 :INTEREST	13667.
9 :MISCELLANEOUS	0.
10 :OTHER EXPENSES	0.
11PROFITS BEFORE TAXES	235976.
12 LESS:INCOME TAX	114920.
13PROFITS AFTER TAX	121056.

SOURCES AND USES OF FUNDS (TAX)

SOURCES OF FUNDS

14PROFITS AFTER TAX	121056.
15 PLUS: DEPRECIATION	0.
16 : DEPLETION	70288.
17TOTAL FROM OPERATIONS	191344.
18PROCEEDS LONG-TERM BONDS	-123244.
19PROCEEDS STOCK	-68100.
20TOTAL SOURCES OF FUNDS	0.

OTHER USES OF FUNDS

21PURCH OF NAT RESOURCES	0.
22PURCH OF BLDGS/EQUIP	0.
23 LESS: ITC	0.
24TOTAL OTHER USES OF FUND	0.

25NET CHANGE IN WC	0.
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26NPV CASH FLOW TO COM. EQ	4659.
27CUM. NPV CASH FLOW	-206379.
28CUM. CASH FLOW (PAYBACK)	41553.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 4
BALANCE SHEET

	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	0.	0.	0.	0.	0.	0.	212285.	523637.	820837.	1118037.
5NET PLANT IN SERVICE	0.	0.	251058.	502246.	1595438.	1617413.	1405128.	1093776.	796576.	499377.
6GROSS NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	0.	0.	0.	0.	0.	0.	1964.	3928.	5892.	7856.
8NET NATURAL RESOURCES	0.	0.	28419.	29461.	29461.	29461.	27497.	25533.	23569.	21605.
9 TOTAL ASSETS	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	0.	0.	152875.	350332.	934582.	972922.	945950.	915930.	882518.	844361.
11EQUITY BALANCE	0.	0.	126603.	181375.	690318.	673953.	486676.	203380.	-62373.	-323379.
12 TOTAL LIAB+EQUITY	0.	0.	279477.	531708.	1624900.	1646875.	1432625.	1119309.	820146.	520982.
13MARKET VALUE OF EQUITY	0.	0.	90110.	238185.	584073.	701952.	763847.	781870.	800533.	818643.
	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001

ASSETS										
1CASH	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
2OTHER WORKING CAPITAL	0.	0.	0.	0.	0.	0.	0.	0.	0.	0.
3GROSS PLANT IN SERVICE	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.	1617413.
4ACCUMULATED DEPRECIATION	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.	1415236.
5NET PLANT IN SERVICE	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
6GROSS NATURAL RESOURCES	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.	29461.
7ACCUMULATED DEPLETION	9820.	22193.	44510.	78622.	122237.	169410.	220576.	275908.	335898.	400758.
8NET NATURAL RESOURCES	19641.	7268.	0.	0.	0.	0.	0.	0.	0.	0.
9 TOTAL ASSETS	221818.	209446.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
LIABILITIES AND OWNERS EQUITY										
10DEBT BALANCE	801933.	754758.	702305.	643279.	577707.	504863.	423941.	334045.	234179.	123239.
11EQUITY BALANCE	-580115.	-545313.	-500127.	-441102.	-375530.	-302686.	-221764.	-131868.	-32002.	78939.
12 TOTAL LIAB+EQUITY	221818.	209446.	202177.	202177.	202177.	202177.	202177.	202177.	202177.	202177.
13MARKET VALUE OF EQUITY	833046.	980968.	1140335.	1310036.	1492564.	1692342.	1910658.	2150045.	2412207.	2700258.

CITY OF SUSANVILLE, SUSANVILLE, CA
PRIVATE FIRM -- BASE CASE -- 7-6-83
USING ALTERNATE REVENUE STREAM 4
BALANCE SHEET

2002

ASSETS

1CASH	0.
2OTHER WORKING CAPITAL	0.
3GROSS PLANT IN SERVICE	1617413.
4ACCUMULATED DEPRECIATION	1415236.
5NET PLANT IN SERVICE	202177.
6GROSS NATURAL RESOURCES	29461.
7ACCUMULATED DEPLETION	471046.
8NET NATURAL RESOURCES	0.
9 TOTAL ASSETS	202177.

LIABILITIES AND OWNERS EQUITY

10DEBT BALANCE	-6.
11EQUITY BALANCE	202183.
12 TOTAL LIAB+EQUITY	202177.

13MARKET VALUE OF EQUITY	3016450.
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