A COMPARATIVE ANALYSIS OF ENERGY COSTING METHODOLOGIES

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A Comparative Analysis of Energy Costing Methodologies

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ABSTRACT

This report discusses the methodologies used for computing levelized busbar costs of electricity from geothermal (hydrothermal) resources used by 16 organizations active in the geothermal area. The methodologies are compared by (a) comparing the results obtained by using two standard data sets, (b) a theoretical analysis of the mathematical formulation of the embedded models, and (c) an examination of differences in data and assumptions. The objective is to attempt to resolve differences in estimates of geothermal (and conventional) electric power costs, upon which policies may be formulated and research, development and demonstration activities designed and implemented.

The appendix describes the proceedings of a workshop on levelized busbar costing methods which was held at MITRE/Metrek in June, 1978.

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EXECUTIVE SUMMARY

I. PURPOSE

The Division of Geothermal Energy (DGE) within the Department of Energy (DOE) makes planning decisions based, in part, on projected comparisons between the costs of geothermal energy and of other energy sources. The analysis reported in this document was prompted by the wide range of cost estimates for geothermal energy which have been published.

This report presents a review and analysis of methodologies used for estimating electricity generation costs. Sixteen organizations, including utility companies, engineering design companies, energy resource companies, and research and development contractors for the Department of Energy, were interviewed. The list of organizations was compiled jointly by DOE-DGE and Mitre/Metrek and comprises:

Utilities

San Diego Gas & Electric Co.
Southern California Edison Co.
Pacific Gas & Electric Co.

ERDA Research Contractors

Battelle Northwest Laboratories
Mitre/Metrek Division
TRW, Inc.
Jet Propulsion Laboratory
Lawrence Berkeley Laboratories
Idaho National Engineering Laboratories
Dry Lands Research Institute
Stanford Research Institute

Engineering Design Companies

Bechtel Corp.
Ben Holt, Inc.

Energy Resource Companies

Chevron Oil Co.
Union Oil Co.

Trade Association

Electric Power Research Institute

The methodologies used by these organizations are not identified by name in this report so that specific comments made will not be taken to reflect on any organization.

The main emphasis is placed upon estimation of the costs of electricity from hydrothermal resources. Many conclusions, however, apply equally well to analyses of other sources of electricity.

II. SCOPE AND APPROACH

The estimation of electricity (busbar) costs from hydrothermal resources requires two distinct sequential activities, as shown in Figure S-1. In the first phase data concerning resource characteristics comprise the input to an engineering cost model whose output is an estimate of the capital and O&M costs, and operating parameters for the geothermal plant. The second phase uses these results as inputs to a levelized busbar cost model. This model also uses financial and fiscal parameters, and derives an estimate for the cost of electricity from the plant. The geothermal operation is usually regarded as being conducted by two distinct organizations, referred

FIGURE S-1
STRUCTURE OF METHODOLOGIES FOR ESTIMATING
ELECTRICITY COSTS

to as the Producer (owner and operator of the geothermal field) and the Utility (owner and operator of the conversion and generation plant).

The main emphasis in this report is placed on review and analysis of this second phase, and the approach for conducting this involved the following steps:

- two standard data sets (i.e., plant capital and O&M costs and operating parameters and financial and economic assumptions) were, where possible, used as inputs to the financial model of each organization. These calculations were undertaken either by the organization concerned or by Mitre/Metrek using the organization's own methodology and the results are referred to as cross model comparisons.
- the assumptions and mathematical formulations of both the engineering cost models and the financial models were reviewed, compared, and critically analyzed for their effects on cost estimates; and
- the data for geothermal resources used by each organization were reviewed and analyzed;

This approach allowed the effects of differences in conceptual cost estimate data and of differences in methodologies to be examined separately.

III. RESULTS

Cross-Model Comparisons

The two standard data sets used for the cross-model comparisons are:

- 1) 50 MWe net binary plant on a 190°C resource
- 2) 50 MWe net flash plant on a 232°C resource

The detailed data sets are shown in Tables S-1 and S-2. These two cases were selected to show different balances of costs between Producer and Utility, to represent two types of resources expected to undergo early development, and to cover relatively more and less capital-intensive geothermal projects.

The results obtained are shown in Figures S-2 and S-3.

For the lower temperature geothermal power plant (Test Case 1), the lowest busbar cost is 38 mills/kWh (Company F) and the highest is 69.7 mills/kWh (Company H), with a mean value of 48.3 mills/kWh and a standard deviation of 9.5 mills/kWh. The standard deviation is about 20 percent of the mean.

For the higher temperature resource (Test Case 2), the lowest cost is 26.9 mills/kWh (Company K), and the highest is 51.7 mills/kWh (Company E). The mean is 32.1 mills/kWh, and the standard deviation is 7.4 mills/kWh, or 23 percent of the mean.

It should not be assumed that results lying closer to the mean are "better" than those lying farther away. The mean and standard deviation are merely used to illustrate the collective properties of the results.

It is clear that variations in methodology alone induce large variations in levelized busbar cost estimates, even when the same capital and O&M costs and financial and economic assumptions are used.

It is neither practical nor useful to explain exactly how much of the variance for each method investigated was caused by individual

TABLE S-1

DATA FOR TEST CASE 1
 BINARY SYSTEM, 50 MW ELECTRIC PLANT
 FIRST PLANT ON LINE DATE: 1983

TEMPERATURE IN CENTIGRADE DEGREES (BEST ESTIMATE) : 190
 WELL DEPTH IN METERS : 1500
 BRINE SALINITY : LOW
 OVERLYING ROCK TYPE : SOFT
 THE WELL FLOW RATE IS NOT SPECIFIED : THE DEFAULT FLOW RATE USED (KGM./HR.) = 266270
 SPECIFIED COST PER PRODUCTION WELL (\$) : 600000.0
 SPECIFIED COST PER INJECTION WELL (\$) : 600000.0

PRODUCER FINANCIAL DATA

DEBT FRACTION : 0.30
 ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
 REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.20
 PROPERTY TAX RATE (FRACTION) : 0.01
 REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.10
 EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
 EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
 ESCALATION FACTOR FOR O&M COSTS : 0.05
 ESCALATION FACTOR FOR ENERGY COSTS : 0.05
 ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
 LIFE SPAN OF PRODUCTION WELLS (YEARS) : 10.00
 LIFE SPAN OF INJECTION WELLS (YEARS) : 10.00
 LIFE SPAN OF PRODUCER PLANT (YEARS) : 20.00
 START UP COST MULTIPLIER : 1.081

UTILITY FINANCIAL DATA

DEBT FRACTION : 0.50
 ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
 REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.12
 PROPERTY TAX RATE (FRACTION) : 0.01
 REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.0
 EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
 EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
 ESCALATION FACTOR FOR O&M COSTS : 0.05
 ESCALATION FACTOR FOR ENERGY COSTS : 0.05
 ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
 LIFE SPAN OF UTILITY PLANT (YEARS) : 30.00
 ULTIMATE CAPACITY FACTOR : 0.80
 START UP COST MULTIPLIER : 1.038

TAX

* NUMBER OF WELLS , CAPITAL COSTBASIS AND O&M COSTS , AND REVENUE REQUIREMENTS WITHOUT ANY R&D IMPACTS *

CAPITAL COSTBASIS (1977 \$M)

16 PRODUCTION WELLS : 11.556
 7 INJECTION WELLS : 5.056
 PRODUCER PLANT EXCLUDING WELLS : 7.284
 REPLACEMENT PRODUCTION WELLS : 9.869
 REPLACEMENT INJECTION WELLS : 4.318
 REPLACEMENT PLANT : 3.214
 TOTAL FOR PRODUCTION FIELD : 41.296
 GENERATING PLANT : 35.785
 TOTAL : 77.081

O&M COSTS (1977 \$M/YR.)

PRODUCER
 GENERAL : 0.409
 WELL : 0.138
 DEEP WELL PUMP : 0.721
 SPENT BRINE TREATMENT : 0.0
 CHEMICAL & MECHANICAL CLEANING : 0.0
 TOTAL : 1.268
 UTILITY
 GENERAL : 1.288
 CHEMICAL & MECHANICAL CLEANING : 0.0
 TOTAL : 1.288

TABLE S-2

DATA FOR TEST CASE 2
FLASH SYSTEM, 50 MW ELECTRIC PLANT
FIRST PLANT ON LINE DATE: 1983

TEMPERATURE IN CENTIGRADE DEGREES (BEST ESTIMATE) : 232
WELL DEPTH IN METERS : 1500
BRINE SALINITY : LOW
OVERLYING ROCK TYPE : MEDIUM HARD
THE WELL FLOW RATE IS NOT SPECIFIED : THE DEFAULT FLOW RATE USED (KGM./HR.) = 176166
THE COST PER PRODUCTION WELL IS NOT SPECIFIED : THE DEFAULT COST PER PRODUCTION WELL (\$) = 615157.2
THE COST PER INJECTION WELL IS NOT SPECIFIED : THE DEFAULT COST PER INJECTION WELL (\$) = 615157.2

PRODUCER FINANCIAL DATA

DEBT FRACTION : 0.30
ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.20
PROPERTY TAX RATE (FRACTION) : 0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.10
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
ESCALATION FACTOR FOR O&M COSTS : 0.05
ESCALATION FACTOR FOR ENERGY COSTS : 0.05
ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
LIFE SPAN OF PRODUCTION WELLS (YEARS) : 10.00
LIFE SPAN OF INJECTION WELLS (YEARS) : 10.00
LIFE SPAN OF PRODUCER PLANT (YEARS) : 20.00
START UP COST MULTIPLIER : 1.081

UTILITY FINANCIAL DATA

DEBT FRACTION : 0.50
ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.12
PROPERTY TAX RATE (FRACTION) : 0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.0
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
ESCALATION FACTOR FOR O&M COSTS : 0.05
ESCALATION FACTOR FOR ENERGY COSTS : 0.05
ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
LIFE SPAN OF UTILITY PLANT (YEARS) : 30.00
ULTIMATE CAPACITY FACTOR : 0.80
START UP COST MULTIPLIER : 1.038

* NUMBER OF WELLS , CAPITAL COSTBASIS AND O&M COSTS , AND REVENUE REQUIREMENTS WITHOUT ANY R&D IMPACTS *

CAPITAL COSTBASIS (1977 \$M)

12 PRODUCTION WELLS : 8.886
5 INJECTION WELLS : 3.702
PRODUCER PLANT EXCLUDING WELLS : 4.560
REPLACEMENT PRODUCTION WELLS : 7.589
REPLACEMENT INJECTION WELLS : 3.162
REPLACEMENT PLANT : 2.012
TOTAL FOR PRODUCTION FIELD : 29.911
GENERATING PLANT : 23.935
TOTAL : 53.846

O&M COSTS (1977 \$M/YR.)

PRODUCER
GENERAL : 0.292
WELL : 0.105
DEEP WELL PUMP : 0.0
SPENT BRINE TREATMENT : 0.0
CHEMICAL & MECHANICAL CLEANING : 0.0
TOTAL : 0.397
UTILITY
GENERAL : 0.698
CHEMICAL & MECHANICAL CLEANING : 0.0
TOTAL : 0.698

111X

* A later version of this company's model yields a cost of 40.2 mills/kWh.

FIGURE S-2
CROSS MODEL COMPARISON, TEST CASE 1

* A later version of this company's model yields cost of 26.1 mills/kWh.

FIGURE S-3
CROSS MODEL COMPARISON, TEST CASE 2

structural differences among the models. On the other hand, a comparative review of the features that cause significant variations in results is both instructive and useful.

IV. REVIEW AND CRITIQUE OF METHODOLOGIES

This section describes the models used for levelized busbar calculations (in part 1) and the models used for engineering cost estimation (in part 2). The levelized busbar cost models are discussed first since the main emphasis of this analysis falls upon them. More detailed descriptions and discussions of the individual models used are given in Sections 2 and 3 of the main body of this report.

1) Levelized Busbar Cost Models

The main purpose of this report is to delineate and analyze differences in the levelized busbar cost models which convert capital and operating costs, plant parameters, and financial data into levelized electricity costs.

Two methods are in use. The first method involves year-by-year calculations of costs, revenues, taxes, etc. Profits are dealt with either by adopting a discounted cash flow analysis or (less commonly) by including required returns to unretired* equity in the costs each year. The latter method produces an uneven revenue requirements stream which is then levelized on a net present value basis (i.e.,

*Usually the amount of equity capital remaining after subtracting so-called "book-value" or straight-line depreciation.

the levelized imputed revenue stream is chosen to have the same net present value as the uneven revenue requirements stream).

The second method uses analytic means to derive closed-form equations which replace year-by-year calculations. These closed-form equations are usually based on the net present values of costs, taxes, capital investments, profits, revenues, etc. Profits are treated as required returns to unretired equity.

While year-by-year methods can be more detailed and flexible, they may also be more time-consuming. Year-by-year methods are most valuable where a detailed and accurate examination of a limited number of options is needed. In addition, year-by-year methods are clearly better when tax credits must be carried forward. This situation is very difficult to deal with using closed form methods. Closed-form methods may be more appropriate in situations where many different evaluations must be made (e.g., for sensitivity analyses, or for cost projections at many sites), because of their greater speed of calculation.

It appears that utility companies tend to conduct their economic analyses by calculating profits on the unretired equity in the project each year while energy resource companies tend to use discounted cash flow methods.

In theory, if the parameters are correctly chosen, the results obtained will be the same irrespective of whether year-by-year or

closed-form methods are used and whether profits are analysed by discounted cash flow or returns to unretired equity.*

Significant sources of differences which have been identified include:

- Treatment of inflation. Considerable confusion exists regarding the correct way to allow for the effects of future inflation. In some cases calculations are erroneously made partially in constant dollars and partially in inflated (or current) dollars. This would affect levelized costs by about 10 percent overall. Also, where calculations are made in constant dollars, frequently the interest rates and return to equity rates used are not adjusted.** This could affect overall levelized costs by about 30 percent. Additionally, Company O alone allows the revenue stream to increase with inflation which affects levelized costs by about 60 percent overall.
- Reinvestment in replacement production wells, etc. It appears that wells may have relatively limited lives (well lives at the Geysers have been found to be about 10 years). Ignoring the probable need for reinvestment in replacement wells and plant can underestimate levelized costs by about 20 percent. Differences in assumptions regarding reinvestment (i.e., whether the wells will have to be replaced a few each year or altogether after 10 years) leads potential differences of about 10 percent in levelized costs overall.
- Fixed Charge Rates. Different methods exist for calculating the Fixed Charge Rate which is necessary for the replacement of capital and payment of debt service and taxes. These may lead to overall differences of 10 percent in levelized costs.

*See: Doan L. Phung, "The Discounted Cash Flow and Revenue Requirements Methodologies in Energy Cost Analyses," (Institute for Energy Analysis, Oak Ridge Associated Universities, Oak Ridge, TN 37830, 1977).

**These rates are commonly taken from current market rates, which are high because of expectations about continuing future inflation. Historically, the rate of interest in constant dollars has been about 2 to 3 percent.

- Assumptions Regarding Capital Investment Schedule. Different assumptions are made concerning the length of time over which construction will continue and the distribution of expenditure within this period. These could lead to about 15 percent differences in levelized costs overall.
- Choice of Discount Rate. Some companies use as the discount rate the after-tax cost of capital, some use the before-tax cost of capital (these are different because interest payments are tax-deductible expenses). This could affect the present value of cost and revenue streams by some 7 percent for the Producer and some 20 percent for the utility. The overall levelized cost effects are not clear and depend on the cost and revenue profiles over the plant life.
- Discounting Convention. Some methods use a mid-year discounting convention, some use end-of-year. This could lead to differences of 5 to 7 percent in costs.
- Tax Credit Treatment. Differences in levelized costs will be experienced according to whether tax deductions or credits in excess of actual tax liabilities are treated as income at once or are carried forward until sufficient tax liabilities are available from the project to take advantage of them. The former is equivalent to the assumption that the organization has other ongoing projects providing taxable income against which the deduction or credits can be exercised, while the latter treat the project under consideration in a "stand-alone" mode. The former assumption will generally result in lower levelized costs than the latter; the magnitude of the effect is not clear but may not be greater than 5 percent.

2) Engineering Cost Models

Five companies used detailed techno-economic simulation models to derive capital and operating cost estimates. The remaining companies estimated costs from either published data, similar industry experience, or individual judgment, and no comments are offered on these estimates.

These estimated costs were not, of course, used in making the cross-comparisons of levelized busbar costs for test cases 1 and 2 which depend upon unified data. However, these estimates do have major impacts on the perceptions of the various organizations regarding geothermal energy costs.

In the simulation models the base costs are determined on the basis of an engineering cost estimate of a predetermined conceptual design of a geothermal power system. This conceptual design is generated within the busbar cost model using built-in thermodynamic cycle optimization routines. These five techno-economic simulations differ in (1) representation of the various power system components (i.e., wells, brine distribution system, turbines, heat exchangers, etc.), (2) definition of thermodynamic states and (3) optimization technique.

A major difference in system representation is in the geothermal reservoir. In some models, the geothermal reservoir is represented by its temperature gradient, pressure gradient and flow capacity. In others, the geothermal reservoir is characterized by its well flow capacity. In this case, overlooking the temperature and pressure gradients leads to a different estimate of the available power at the bottom of the well bore, thus resulting in a different plant design and capital base cost.

Use of steam tables rather than equations of state to define the thermodynamic state of a geothermal fluid system is another source of

difference between various techno-economic simulator types of busbar cost models. Under certain circumstances the steam tables based on pure water may result in up to 80 percent underestimations in plant size and cost if corrections are not made for the dissolved solids and gases in brines, which degrade plant performance.

An iterative search type of optimization may be used by techno-economic simulations. However, these optimization techniques differ in their degree of convergence to optimality. In this respect, the conjugate search technique incorporated in some models is known to converge to a better solution than the exhaustive search technique used in others.

Techno-economic simulator types of busbar cost models also differ in their engineering cost estimation. Various models use different estimates for installed cost of major equipment. Also, experience factors and indirect cost adjustment factors used in various busbar cost models are seldom the same, and can vary by a factor of 3. Since no geothermal power plants have yet been built in this country for liquid dominated resources, it is not possible to comment on the relative accuracy of the cost-estimation processes.

Tables S-3 and S-4 show the brine flow requirements obtained for two brine temperatures from three of the simulation models. Table S-5 shows the estimated capital costs for the two temperatures published by various organizations. It is felt that, despite slight differences in choice of temperature, these results represent closely comparable

TABLE S-3

ESTIMATED BRINE FLOW REQUIREMENTS FOR 50 MW_e PLANTS AT HEBER
(10⁶ lb/hr, resource temperature = 180°C)

PLANT TYPE \ ORGANIZATION	COMPANY C	COMPANY F	COMPANY M	COMPANY O
Binary	---	8.1	6.9	8.7
Flash	10.1	---	10.0	10.2

TABLE S-4

ESTIMATED BRINE FLOW REQUIREMENTS FOR 50 MW_e NET PLANT
 AT VALLES CALDERA OR SIMILAR RESOURCE
 (10⁶ lb/hr, Resource Temperature ≈ 230°C)

ORGANIZATION PLANT TYPE	COMPANY F	COMPANY M	COMPANY O
Binary	---	2.6	3.5
Flash	2.3 *	4.0	3.8

* Company F states that a revised version of their model, available since the completion of this analysis, yields a value of 3.9.

TABLE S-5

CAPITAL COSTS FOR MODERATE AND HIGHER TEMPERATURE RESOURCES

COMPANY	CAPITAL COST- MODERATE TEMPERATURE	CAPITAL COST- HIGHER TEMPERATURE
F	34.3	24.6
C	63.1 to 69.1	--
M (Binary)	45.2	--
M (Flash)	46.5	27.0***
J	47.3*	--
H	37.9*	--
L	46.4**	47.0*
D	22.3***	--
O	59.7	46.2

* Generating plant only.

** Excluding wells.

*** Production field only.

situations. Very considerable differences in capital costs are apparent.

IV. CONCLUSIONS

The results show that a wide range of busbar costs estimates have been obtained starting from the same capital and operating costs. However, the methodologies in use are capable of giving consistent results, provided that care is exercised in the choice of assumptions and parameters.

Elements requiring special attention are:

- Treatment of Inflation - Current and constant dollars must not be mixed. In particular, treatment of depreciation and choice of interest and discount rates must be consistent with the inflation assumptions.
- Reinvestment Capital - Allowance should explicitly be made for replacement of major items, such as wells, unless it is believed that no such replacement will be necessary.
- Capital Investment Schedule - The convention appears to be to assume that the capital is expended at a point 60 percent of the way through the construction period.
- Discount Rates - If discounted cash flow and revenue requirements models are to give consistent results, the discount rate chosen must be exactly the after-tax cost of capital.
- Capital Structure - It seems that the utility will have a debt:equity ratio of 50:50, while the Producer may have up to 100 percent equity. The cost of capital for the Producer is also much higher than for the Utility (15 to 20 percent as against 10 to 12 percent).

Provided that these elements are treated consistently, variability among different methodologies should be greatly reduced. However, the establishment of complete consistency will require the

use of a standard methodology. It is recommended that this be considered for use by DGE (as a minimum and preferably throughout DOE). Such a methodology would, of course, be intended to supplement rather than supplant the methodologies now used by organizations which work with or for DGE. The use of closed-form equations for such a method would have the advantage of allowing manual calculation.

It is also recommended that a standard format be established by DGE for displaying assumptions (such as plant lives, plant capacity factors, and financial data) which are not strictly part of the methodology but which exert major influences on the apparent levelized busbar costs, and that these assumptions be clearly stated by contractors working for DGE in making economic analyses.

Finally, it seems clear that engineering design and cost estimating methods should be studied in more detail than was possible in this analysis which focused on financial aspects.

Following completion of the draft form of this report, a workshop on levelized busbar costing methods was held at MITRE/Metrek in June 1978. The proceedings of this workshop are contained in the appendix to this report, and give an insight into the degree to which a consensus exists on acceptable methods.

1.0 INTRODUCTION

1.1 Purpose of the Report

This report presents a review and analysis of methodologies in use for estimating electricity generation costs. Sixteen organizations were interviewed, including utility companies, engineering design companies, energy resource companies, and research and development contractors for the Department of Energy (DOE). This study has been performed for the DOE Division of Geothermal Energy (DGE), and particular emphasis is placed on estimation methodologies and data for electric generation from liquid-dominated hydrothermal resources. Most conclusions, however, apply equally well to analysis of other sources of electricity.

1.2 Background

The Division of Geothermal Energy in the Department of Energy deals with many different contractors, utilities and other organizations which, from time to time, compute projected costs of geothermal energy and of competing sources as an integral part of their work for and with the Division. In considering these cost estimates and estimates from other sources, wide variations have been observed. It is desirable that differences be reconciled so that valid and consistent cost estimates may be used by DGE in the course of:

- projecting the economic viability of geothermal energy in competition with other energy sources
- planning research and development strategies and goals

- evaluating the desirability and impact of policy measures and incentives
- estimating the size of the contribution which geothermal energy can make to the national energy supply
- determining the desirable extent of Federal participation in demonstration projects.

1.3 Scope and Approach

Sixteen organizations have been interviewed for this study.

The list of organizations was compiled jointly by DOE-DGE and Mitre/Metrek and comprises:

Utilities

San Diego Gas & Electric Co.
Southern California Edison Co.
Pacific Gas & Electric Co.

DOE Research Contractors

Battelle Northwest Laboratories
MITRE/METREK Division
TRW, Inc.
Jet Propulsion Laboratory
Lawrence Berkeley Laboratories
Idaho National Engineering Laboratories
Dry Lands Research Institute
Stanford Research Institute

Engineering Design Companies

Bechtel Corp.
Ben Holt, Inc.

Energy Resource Companies

Chevron Oil Co.
Union Oil Co.

Trade Association

Electric Power Research Institute

To preserve anonymity, these organizations will be referred to as "Company A", "Company B", etc. in the following material. These designations have been assigned at random. Mitre/Metrek is Company O.

An understanding of the approaches used by these organizations was obtained by review of the published literature and by in-person visits to the organizations. Particular emphasis was placed on the models, methodologies and data used for estimating costs of electricity generated from hydrothermal liquid-dominated geothermal resources. Where possible, additional information concerning cost estimates for competing sources of electricity (e.g., coal or nuclear generating plants) was collected.*

The approach used in analyzing the methodologies comprised the following stages:

- Two standard data sets (i.e., plant capital and O & M costs and operating parameters and financial assumptions) were developed by Mitre/Metrek and were, where possible, used as inputs to the methodology of each organization. These calculations were undertaken either by the organization concerned or by Mitre/Metrek using the organization's own methodology. The intent was to isolate the effects of methodological differences on the estimates of busbar costs.
- The assumptions and mathematical formulation of each methodology were reviewed, compared, and critically analyzed for their effects on cost estimates. The intent was to correlate the features of the methodologies with their effects on cost estimates.

*The material used includes published material available in mid-1977. Many models are in a state of continuing development. Where improved versions have come to our notice since the completion of this analysis, footnotes have been added. This applies particularly to companies C and F.

- The data for geothermal resources (comprising elements such as resource temperature, well flow rates, plant costs and efficiencies, and operating and maintenance costs) used by each organization were reviewed and analyzed. The intent was to reveal the effects of engineering input data on the variability of the estimates.
- The data for competing sources of electricity were reviewed, since decisions concerning geothermal energy are normally made in a context of fuel competition. This approach permitted the effects of differences in data and of differences in methodologies to be examined independently.

1.4 Report Outline

Section 2 comprises a review of the results obtained using the two standard input data sets with the different methodologies, and describes the overall structures of the different methodologies. Section 3 discusses in detail the differences in assumptions and formulations employed by the different organizations, and examines the effects of these on the cost estimates. Section 4 presents and reviews the data (plant capital and O & M costs and operating parameters, and financial data) used by the organizations. Section 5 presents data for competing sources of electricity. A bibliography of sources is provided, since, to preserve anonymity, references cannot be given.

Following circulation of the draft form of this report, a workshop on levelized busbar costing methods was held at MITRE/Metrek in June 1978. The proceedings of this workshop are given in the appendix.

2.0 COMPARATIVE RESULTS, AND QUALITATIVE DISCUSSION OF METHODOLOGIES

2.1 Cost Estimates

Table 2-1 presents busbar cost estimates (in mills/kWh) which have been published or presented by various organizations contacted for plants based on the Heber field.* Not all organizations listed in Section 1 have produced independent estimates for this resource. The costs presented range from a low of 19.1 mills/kWh to a high of 91 mills/kWh, with most common values between 30 and 50 mills/kWh.

These differences can initially be regarded as stemming from two sources: differences in data and assumptions, and differences in methodology. To show more clearly the differences due to methodology alone, which is the prime focus of this paper, two test cases (consisting of estimates based on standard input data) have been analyzed using the financial methodologies developed by the organizations contacted. The standard input data for these test cases is presented in Tables 2-2 and 2-3. Table 2-2 shows the tax rates, financial assumptions, O&M costs and capital cost bases for Test Case 1, which comprises the geothermal and power plant components of a hypothetical 50 MWe Heber-like power system, i.e., a moderate temperature (190°C) binary cycle plant. Data are presented in Table 2-3 for Test Case 2,

*The Heber field is located in the Imperial Valley in California. It has an apparent temperature near 190°C, and is likely to be the site of an early geothermal electric plant. A detailed description of the field may be found in MTR-7586, Vol. III: "Site-Specific Analysis of Geothermal Development - Data Files of Prospective Sites," The Mitre Corporation, McLean, Virginia.

TABLE 2-1

SUMMARY OF PUBLISHED COST ESTIMATES OF GEOTHERMAL ELECTRICITY
FOR HEBER-LIKE SITES (1977 mills/kWh)

ORGANIZATION COST	F	C	M		O	J	H	L	D
			BINARY	FLASH					
Field Cost	21.9	29.2	17.7	21.8	28.0	52	21-26	17-20*	
Utility Cost	11.5	20.5	19.3	24.3	11.1	39	21-25	30-40*	
Total	33.4	49.7	37.0	46.1	39.1	91	42-51	47-60*	19.1

* Upper end of ranges applies to demonstration plant (estimate made by Metrek from SRI results).

TABLE 2-2

DATA FOR TEST CASE 1
 BINARY SYSTEM, 50 MW ELECTRIC PLANT
 FIRST PLANT ON LINE DATE: 1983

TEMPERATURE IN CENTIGRADE DEGREES (BEST ESTIMATE) : 190
 WELL DEPTH IN METERS : 1500
 BRINE SALINITY : LOW
 OVERLYING ROCK TYPE : SOFT
 THE WELL FLOW RATE IS NOT SPECIFIED : THE DEFAULT FLOW RATE USED (KGM./HR.) = 266270
 SPECIFIED COST PER PRODUCTION WELL (\$) : 600000.0
 SPECIFIED COST PER INJECTION WELL (\$) : 600000.0

PRODUCER FINANCIAL DATA

DEBT FRACTION : 0.30
 ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
 REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.20
 PROPERTY TAX RATE (FRACTION) : 0.01
 REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.10
 EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
 EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
 ESCALATION FACTOR FOR O&M COSTS : 0.05
 ESCALATION FACTOR FOR ENERGY COSTS : 0.05
 ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
 LIFE SPAN OF PRODUCTION WELLS (YEARS) : 10.00
 LIFE SPAN OF INJECTION WELLS (YEARS) : 10.00
 LIFE SPAN OF PRODUCER PLANT (YEARS) : 20.00
 START UP COST MULTIPLIER : 1.081

UTILITY FINANCIAL DATA

DEBT FRACTION : 0.50
 ANNUAL INTEREST RATE ON DEBT (FRACTION) : 0.08
 REQUIRED RATE OF RETURN ON EQUITY (FRACTION) : 0.12
 PROPERTY TAX RATE (FRACTION) : 0.01
 REVENUE TAX RATE OR ROYALTY (FRACTION) : 0.0
 EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) : 0.50
 EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) : 0.04
 ESCALATION FACTOR FOR O&M COSTS : 0.05
 ESCALATION FACTOR FOR ENERGY COSTS : 0.05
 ESCALATION FACTOR FOR CAPITAL COSTS : 0.05
 LIFE SPAN OF UTILITY PLANT (YEARS) : 30.00
 ULTIMATE CAPACITY FACTOR : 0.80
 START UP COST MULTIPLIER : 1.038

* NUMBER OF WELLS , CAPITAL COSTBASIS AND O&M COSTS , AND REVENUE REQUIREMENTS WITHOUT ANY R&D IMPACTS *

CAPITAL COSTBASIS (1977 \$M)

16 PRODUCTION WELLS : 11.556
 7 INJECTION WELLS : 5.056
 PRODUCER PLANT EXCLUDING WELLS : 7.284
 REPLACEMENT PRODUCTION WELLS : 9.869
 REPLACEMENT INJECTION WELLS : 4.318
 REPLACEMENT PLANT : 3.214
 TOTAL FOR PRODUCTION FIELD : 41.296
 GENERATING PLANT : 35.785
 TOTAL : 77.081

O&M COSTS (1977 \$M/YR.)

PRODUCER
 GENERAL : 0.409
 WELL : 0.138
 DEEP WELL PUMP : 0.721
 SPENT BRINE TREATMENT : 0.0
 CHEMICAL & MECHANICAL CLEANING : 0.0
 TOTAL : 1.268
 UTILITY
 GENERAL : 1.288
 CHEMICAL & MECHANICAL CLEANING : 0.0
 TOTAL : 1.288

TABLE 2-3
DATA FOR TEST CASE 2
FLASH SYSTEM, 50 MW ELECTRIC PLANT
FIRST PLANT ON LINE DATE: 1983

TEMPERATURE IN CENTIGRADE DEGREES (BEST ESTIMATE) : 232
WELL DEPTH IN METERS : 1500
BRINE SALINITY : LOW
OVERLYING ROCK TYPE : MEDIUM HARD
THE WELL FLOW RATE IS NOT SPECIFIED : THE DEFAULT FLOW RATE USED (KGM./HR.) = 176166
THE COST PER PRODUCTION WELL IS NOT SPECIFIED : THE DEFAULT COST PER PRODUCTION WELL (\$) = 615157.2
THE COST PER INJECTION WELL IS NOT SPECIFIED : THE DEFAULT COST PER INJECTION WELL (\$) = 615157.2

PRODUCER FINANCIAL DATA

DEBT FRACTION :	0.30
ANNUAL INTEREST RATE ON DEBT (FRACTION) :	0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) :	0.20
PROPERTY TAX RATE (FRACTION) :	0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) :	0.10
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) :	0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) :	0.04
ESCALATION FACTOR FOR O&M COSTS :	0.05
ESCALATION FACTOR FOR ENERGY COSTS :	0.05
ESCALATION FACTOR FOR CAPITAL COSTS :	0.05
LIFE SPAN OF PRODUCTION WELLS (YEARS) :	10.00
LIFE SPAN OF INJECTION WELLS (YEARS) :	10.00
LIFE SPAN OF PRODUCER PLANT (YEARS) :	20.00
START UP COST MULTIPLIER :	1.081

UTILITY FINANCIAL DATA

DEBT FRACTION :	0.50
ANNUAL INTEREST RATE ON DEBT (FRACTION) :	0.08
REQUIRED RATE OF RETURN ON EQUITY (FRACTION) :	0.12
PROPERTY TAX RATE (FRACTION) :	0.01
REVENUE TAX RATE OR ROYALTY (FRACTION) :	0.0
EFFECTIVE TOTAL INCOME TAX RATE (FRACTION) :	0.50
EFFECTIVE INVESTMENT TAX CREDIT (FRACTION) :	0.04
ESCALATION FACTOR FOR O&M COSTS :	0.05
ESCALATION FACTOR FOR ENERGY COSTS :	0.05
ESCALATION FACTOR FOR CAPITAL COSTS :	0.05
LIFE SPAN OF UTILITY PLANT (YEARS) :	30.00
ULTIMATE CAPACITY FACTOR :	0.80
START UP COST MULTIPLIER :	1.038

8

* NUMBER OF WELLS , CAPITAL COSTBASIS AND O&M COSTS , AND REVENUE REQUIREMENTS WITHOUT ANY R&D IMPACTS *

CAPITAL COSTBASIS (1977 \$M)

12 PRODUCTION WELLS :	8.886	
5 INJECTION WELLS :	3.702	
PRODUCER PLANT EXCLUDING WELLS :	4.560	
REPLACEMENT PRODUCTION WELLS :	7.589	
REPLACEMENT INJECTION WELLS :	3.162	
REPLACEMENT PLANT :	2.012	
TOTAL FOR PRODUCTION FIELD :	29.911	
GENERATING PLANT :	23.935	
TOTAL :	53.846	

O&M COSTS (1977 \$M/YR.)

PRODUCER		
GENERAL :	0.292	
WELL :	0.105	
DEEP WELL PUMP :	0.0	
SPENT BRINE TREATMENT :	0.0	
CHEMICAL & MECHANICAL CLEANING :	0.0	
TOTAL :	0.397	
UTILITY		
GENERAL :	0.698	
CHEMICAL & MECHANICAL CLEANING :	0.0	
TOTAL :	0.698	

a 50 MWe high temperature (232°C) flash cycle plant, similar to one which might be used at the Valles Caldera, New Mexico site.

As far as possible, the assumptions employed were kept invariant. Due to the structures of some of the models encountered this was not always possible; for instance, certain organizations reinvest in replacement production wells continuously (e.g., Companies F, J, M and O) while others assume that well reinvestment will occur in a lump at the end of the well's useful life (e.g., Company C). The effects of such differences are discussed later. Table 2-4 shows the different busbar costs arrived at for Test Cases 1 and 2 using the different methodologies. Not all the organizations listed in Section 1 which were contacted are represented in this table since in some cases it proved impossible to obtain comparable results.*

For the moderate temperature geothermal power plant (Test Case 1) the lowest busbar cost is 38 mills/kWh (Company F) and the highest is 69.7 mills/kWh (Company H), with a mean value of 48.3 mills/kWh and a standard deviation of 9.5 mills/kWh. The scatter of the various data points around the mean busbar cost is plotted in Figure 2-1. The standard deviation is about 20 percent of the mean value.

For the higher temperature resource (Test Case 2), the lowest cost is 25.4 mills/kWh (Company O), and the highest is 51.7 mills/kWh

*In a few cases, companies did not model the field operations, and Company O costs were used for the field (brine production) segment. Further, information for the Company A method was received too late for incorporation into the analysis section but the results are shown in Table 2-4.

TABLE 2-4

COMPARATIVE BUSBAR COSTS FROM VARIOUS MODELS USING THE SAME INPUT

MODEL USED	LEVELIZED BUSBAR COSTS (MILLS/kWh)	
	TEST CASE 1	TEST CASE 2
COMPANY A	39.2	25.7
COMPANY C	42.1 *	27.1 *
COMPANY D	47.3	30.6
COMPANY E	63.6	51.7
COMPANY F	38.0	28.0
COMPANY G	45.2	29.2
COMPANY H	69.7	45.2
COMPANY J	59.6	37.9
COMPANY K	39.3	26.9
COMPANY L	54.1	31.3
COMPANY M	46.5	30.3
COMPANY N	46.5	30.0
COMPANY O	39.1	25.4
COMPANY P	46.3	29.9

*A later version of this Company's model yields values of 40.2 and 26.1 mills/kWh, respectively.

* A later version of this company's model yields a cost of 40.2 mills/kWh.

FIGURE 2-1
CROSS MODEL COMPARISON, TEST CASE 1

* A later version of this company's model yields cost of 26.1 mills/kWh.

FIGURE 2-2
CROSS MODEL COMPARISON, TEST CASE 2

(Company E). The mean is 32.1 mills/kWh, and the standard deviation is 7.4 mills/kWh, or 23 percent of the mean.

It should not be assumed that a value which is closer to the mean is in any way "better" than one which is farther away. The mean is not necessarily the "correct" answer. The mean and standard deviation are merely used to indicate the collective properties of the results.

It is clear that variations in methodology alone induce variations of some tens of percentage points in the cost estimates, even when the same capital and O&M costs and operating parameters are used.

2.2 Levelized Busbar Cost Methodologies

2.2.1 Overall Structure

The basic problem which must be addressed in projecting geothermal electric energy costs is that of producing a single number, often called the "levelized busbar cost," which accurately represents the cost per unit of output for a project which has:*

- a possible duration of over 40 years from initial exploration to final plant shut-down
- a capital investment stream which, if replacement wells are necessary, may extend over the greater part of the project life
- uncertainty surrounding basic engineering cost and operating parameters
- operations likely to be split between a regulated utility company (owning and operating the generating plant) and an unregulated company (owning and operating the producing field).

*Some of these attributes are unique to geothermal, but many are shared by most forms of energy production, particularly electric generation.

The longevity of geothermal projects leads to difficulties in anticipating the future course of cost and prices, especially insofar as these are affected by inflation. The longevity also introduces the problem of reducing, to a common base, costs incurred at different times and in dollars of different value (due to inflation).

The comparative evaluation of geothermal electric energy cost methodologies involves a large number of economic, financial, and tax considerations. In essence, all the methodologies may be seen as comprising two basic models: the first model estimates capital and O&M costs, and other parameters associated with the field and conversion plant, and the second is a financial model which derives the levelized busbar cost from the results obtained from the first model. This structure is shown in Figure 2-3. This breakdown recapitulates the data vs. methodology dichotomy mentioned earlier; the first model generates the data and the second model incorporates the methodology.

In practice, the two models may each be either formal or informal; a formal model is an algorithm which derives the results from the input in a unique and well-defined way, while informal models are usually matters of judgmental estimation. Formal models usually exist as computer programs, while informal models often do not. For engineering cost estimating, it is taken that a formal model should include a thermodynamic design optimization routine, and that any model not incorporating this is therefore informal. For levelized busbar cost estimating, any model existing as a set of equations for

FIGURE 2-3
STRUCTURE OF METHODOLOGIES FOR ESTIMATING
ELECTRICITY COSTS

calculating the fixed charge rate or discounted cash flow rate of return is called formal.

2.2.2 Engineering Cost Estimates

Where a formal model is employed for deriving engineering cost estimates, it usually comprises a computer-based simulation program to represent and interrelate the techno-economic characteristics of the four main elements which constitute a geothermal power system, namely:

- (1) the geothermal reservoir,
- (2) the hot water production and transportation subsystem,
- (3) the power plant (i.e., energy conversion subsystem),
- (4) used brine disposal (i.e., injection) subsystem.

Typically, these techno-economic simulation programs are made up of two different components:

- A conceptual design subroutine based on thermodynamic process cycle optimization of the geothermal power system.
- An engineering capital and operating cost estimation subroutine based on a set of correlated cost equations.

The integrated conceptual engineering cost model combines the characteristics of geothermal resources and power plant design into a systematic set of relationships which provide capital and operating costs for generating electricity using geothermal waters.

Table 2-5 lists the organizations contacted which use informal engineering cost models and those which use formal models. Company 0 is placed in the former group because their method does not

TABLE 2-5

STRUCTURE OF METHODOLOGIES, AND CATEGORIZATION OF MODELS

PRODUCER				UTILITY			
ENGINEERING COST MODELS		FINANCIAL MODELS		ENGINEERING COST MODELS		FINANCIAL MODELS	
INFORMAL	FORMAL	ANNUALIZED	YEAR BY YEAR	INFORMAL	FORMAL	ANNUALIZED	YEAR BY YEAR
G	C	D	C	D	C	D	C
H	E	J	F	G	E	H	F
L	F	K	H	H	F	J	L
O	M	N	L		J*	K	
		O	M	L	K	M	
		P		N	M	N	
				O		O	
				P		P	

* Model not analysed in this report.

perform any design optimization procedures, although they do use a computer-based design process based upon interpolations between pre-defined (unoptimized) plant designs.

In informal engineering cost models, the base costs are either: (1) given as input data to the model based on similar industry experience or (2) estimated from published engineering data on capital cost requirement per unit energy output for different geothermal power system configurations. In either case considerable subjective judgment is involved and wide variations in base costs are thus expected.

In comparison, the base costs in formal models are engineering cost estimates for a specific conceptual design of a geothermal power system. This conceptual design is generated with the aid of thermodynamic cycle optimization routines. Formal models may differ in: (1) representation of the various power system components (i.e., wells, brine distribution systems, turbines, heat exchangers, etc.), (2) definition of thermodynamic states and (3) optimization technique. The effects of each of these differences on capital base costs are discussed in Section 3.

2.2.3 Levelized Busbar Cost Models

This section concentrates upon the model by which levelized busbar costs are derived from the engineering cost and operating parameters and the financial data. Levelized busbar costs are equivalent to revenue requirements, and always include returns to

capital (or "profit"). They are expressed in mills/kwh, and are constant over the life of the project. Generally, the entities running the geothermal field and the power plant will be quite different, and this is accommodated by separation of the financial model into two submodels.

Two basic approaches are used: either year-by-year calculations or an annualized method using closed-form expressions.

Year-by-year methods compute revenue or revenue requirements, taxes, capital charges, reinvestment, depreciation, etc. for each year of the project life, and perform a present value or levelizing calculation to arrive at levelized busbar costs. In contrast, annualized models perform the levelizing calculation analytically to derive closed-form mathematical expressions which are then used to obtain levelized busbar costs in particular cases.

Generally, year-by-year calculations are only practical when carried out on a computer; closed-form expressions may be evaluated manually (using a small calculator), although larger computers are appropriate if many evaluations are to be made (e.g., for sensitivity analysis).

The following two subsections describe the representations of year-by-year and closed-form methods, respectively, which are used by the organization interviewed.

Table 2-5 illustrates the classification of models, and assigns the various models used by the organizations contacted to their

appropriate categories. Where companies are omitted either no data were available or the company has no model in this category.

2.2.3.1 Year-by-Year Calculations. The approach of making detailed year-by-year calculations is adopted by Companies C, F, H, L, and M. Company H uses a variant of the Company M computer program for computing field costs.*

Within the limits of the year-by-year approach, no two of these organizations use methods which are quite the same. Detailed descriptions may be found in the Appendix; however, the broad outlines of the approaches are as follows.

Company F**

This model is primarily designed to derive the thermodynamic and engineering parameters of plant design. From these factors, cost and operating data are derived, and a detailed statement of cash flow and power costs is provided. First, the total deductible operating expenses are accumulated, including depreciation, depletion, interest, and ad valorem taxes. State and Federal income taxes are calculated on the net income after deductible expenses are subtracted from a (constant) revenue stream derived from energy sales. Payments to outstanding equity are made in the year in which they fall due; remaining funds go to recover equity and repay debt. The (constant)

*A different method of calculation is employed to derive the fixed charge rate for the utility portion of the project, resulting in quite different total cost estimates.

**A revised version of this model is now available.

revenue level is chosen so that all equity is recovered and all debt is repaid exactly at the end of the (assumed) plant life. Calculations are performed in constant dollars.

Company C*

This model deals only with financial analysis; all cost and operating parameters must be supplied to the program. This method computes, year by year, the income required to meet all costs, pay all taxes and recover a specified amount of capital. Pre-operational costs appear to be capitalized. This revenue stream naturally varies from year to year.

The levelized cost is obtained as the present value of this revenue requirement stream divided by the power output. Calculations are made in constant dollars.

Companies M and H

The model under consideration is similar to the Company C model in that it performs only financial calculations. The printout is rather less detailed than that of Company C. Year-by-year calculations are performed only for the field portion of geothermal projects; the utility side is handled by a fixed charge rate approach. Within the field calculations, the revenue requirement is set such that the discounted cash flow rate of return** is equal to the weighted cost of

*A revised model is now available. This takes into account inflation and escalation, and employs DCF methods using a growth revenue stream.

**The discounted cash flow rate of return (DCFROR) is that discount rate which gives the cash flow a net present value of exactly zero.

capital to the field operator. The program assumes a constant margin (or net income) and, hence, a variable stream to achieve this. Calculations are performed in constant dollars*.

Company L

This model, like the preceding one, applies year-by-year calculations to the field and an annualized method to the utility plant. The computer print-out is more detailed than those of Companies C or M, though not so detailed as that of Company F. For the field, this model uses the approach of getting a discounted cash flow rate of return equal to equity cost of capital of the field operator. Unlike Company M, this is achieved using a constant revenue stream, whose level is chosen to give the correct cash flow.

Closed Form Methods

Closed form models are used by Companies D, J, K, N, O, and P. Company H also has a closed form model for the utility portion of the calculations. All are based upon the concept of a fixed charge rate (FCR) which is applied to the capital investment and which covers interest, taxes, return to equity, repayment of capital and, sometimes, insurance and administrative expense. Operating and maintenance and fuel costs (if any) are added to the capital charges to obtain revenue requirements. Companies D, J and K adopt FCR values without giving analytic descriptions of the method by which they were derived, although Companies D and J give breakdowns of the

*Company H subsequently modifies the results to take account of inflation.

FCR into components such as: return to equity, interest, taxes, administrative expenses, etc. Companies N, O and P, in contrast, have similar, quite elaborate mathematical formulae for calculating the FCR based upon rates of interest and return to equity, debt/equity ratio, project life and tax rate. Companies H and M, which use an annualized method only for the utility (generating plant) portion of the operation, do not give details of their methodology, although H appears to use a method similar to that of N, O and P.

3.0 QUANTITATIVE ANALYSIS OF ASSUMPTIONS AND METHODS, AND CRITIQUE

3.1 Quantitative Analysis of Assumption and Methods

It is by no means a simple matter to disentangle the impacts of various differences on the final estimates of busbar cost. In keeping with the structure adopted in the preceding section, we shall first discuss differences in base cost estimation (i.e., capital and O&M cost estimates), and then discuss differences in financial assumptions and levelized formulation of the busbar cost models separately.

3.1.1 Differences in Base Cost Estimation

The different approaches used in making base capital and O&M cost estimates have been outlined in Section 2. As noted there, formal models may differ in (1) representation of the various power system components (i.e., wells, brine distribution systems, turbines, heat exchangers, etc.), (2) definition of thermodynamic states and (3) optimization technique. The effect of each of these differences on capital base cost is discussed below.

- System Representation. The major difference in system representation in various models is in the geothermal reservoir. In some models (e.g., Company F) the geothermal reservoir is represented by its wellhead temperature and pressure and flow capacity. In others, the geothermal reservoir is characterized by its well flow capacity. In this case, overlooking the temperature and pressure gradients leads to a different estimate of the available power at the bottom of the well bore, thus resulting in a different plant design and capital base cost.
- Definition of Thermodynamic State. The thermodynamic state of a system is defined by the thermodynamic properties of the working fluid involved. In general, two different approaches may be used to determine the working fluid thermodynamic properties (i.e., temperature, pressure, heat content, and

entropy); (1) the thermodynamic (steam) table approach and (2) the equation of state approach. These approaches differ in their accuracy for different fluids. This difference in accuracy is ultimately reflected in the estimated size of process equipment and cost. Steam tables are inaccurate when the fluid contains an appreciable quantity of dissolved non-condensable gas, do not adequately represent properties of dilute geothermal brines, and are inadequate for high salinity brines (e.g., Imperial Valley brines). Moreover, tabular data are often not available in regions near the critical temperature of the fluid or where the pressure is above the critical pressure. Conceptual busbar cost models using the steam table approach to determine the geothermal fluid thermodynamic state are thus expected to lead to an underestimated size and cost of the geothermal power system.

- Optimization Technique. The ultimate goal of the various conceptual busbar cost models is to optimize the geothermal thermodynamic power cycle for minimum capital cost or minimum cost of energy. Invariably an iterative search type of optimization is used for this purpose. None of these optimization techniques guarantees true optimization for the type of highly nonlinear objective cost functions generated by a busbar cost model. However, these optimization techniques differ in their degree of convergence to optimality depending upon:
 - (1) Initial guess by which the optimization search is started,
 - (2) The search step size by which the initial guess is improved in each iteration,
 - (3) The efficiency of the search technique used,
 - (4) The stopping criterion, or criteria, which determines when the program is stopped and no more iterations are allowed.

In general, the conjugate search techniques* (e.g., Fletcher-Powell optimization method) are more efficient than the exhaustive search

*Techniques which generate a sequence of search directions along lines of steepest descent - see David M. Himmelblau: Applied Nonlinear Programming, (McGraw-Hill), pp. 96-98.

technique. The use of Fletcher-Powell methods in Company E's model may thus be expected to converge to a better solution and hence lead to a lower capital base cost.

The net results of differences in approach can, in some circumstances be quite significant. Tables 3-1 and 3-2 show brine flow rates required for plants at Heber-like and Valles Caldera-like resources, as estimated by Companies C, F, and M. Company O estimates are also included although these are not derived from optimized designs. It can be seen that, although the flow estimates for a flash-cycle plant at Heber are in good agreement, the estimates for binary-cycle plants at Heber and for binary or flash plants at Valles Caldera show wide variations, of the order of 25 to 50 percent. A critical discussion of the differences in approach follows in Section 3-2.

In addition to design differences, there also exist differences in the engineering cost estimation parameters used. Invariably a factored estimate* approach is used in all the conceptual cost models examined in this report. In this approach, the total capital cost base is determined from estimates on installed cost of major equipment by the equation:

$$C = \sum c_i \cdot e_i \cdot a_i$$

*See D. Rudd & C. Watson, Strategy of Process Engineering, (Wiley & Sons, 1968).

TABLE 3-1

ESTIMATED BRINE FLOW REQUIREMENTS FOR 50 MW_e PLANTS AT HEBER
 (10⁶ lb/hr, resource temperature = 180°C)

ORGANIZATION PLANT TYPE	COMPANY C	COMPANY F	COMPANY M	COMPANY O
Binary	---	8.1	6.9	8.7
Flash	10.1	---	10.0	10.2

TABLE 3-2

ESTIMATED BRINE FLOW REQUIREMENTS FOR 50 MW_e NET PLANT
 AT VALLES CALDERA OR SIMILAR RESOURCE
 (10⁶ lb/hr, Resource Temperature ≈ 230°C)

ORGANIZATION PLANT TYPE	COMPANY F	COMPANY M	COMPANY O
Binary	---	2.6	3.5
Flash	2.3 *	4.0	3.8

* Company F states that a revised version of their model, available since the completion of this analysis, yields a value of 3.9.

where

- c = the total capital cost base
- and c_i = the estimated costs of major field and power plant equipment,
- and e_i = the experience factors for the field and power plant respectively, and
- and a_i = the indirect cost adjustment factors for the field and power plant respectively.

Different conceptual busbar cost models may thus lead to different total capital cost bases even for geothermal power systems of the same conceptual design and output. Experience factors and indirect cost adjustment factors used in various models are seldom the same and can vary by a factor of 3. Various models may also have different estimates for installed cost of major equipment. The accuracy of estimation is a function of both the breakdown of a given conceptual design into its major components and the validity of the vendor estimates used for each major component.

Where informal models are used, of course, very wide differences may be found. These are not amenable to analysis since the methods by which they are found are generally not specified. The plant cost estimates which have been published for moderate and higher temperature resources are presented in Section 4.

3.1.2 Differences in Financial Assumption and Levelized Busbar Cost Models

All types of busbar cost models are designed to determine the discounted cash flow associated with the construction, operation

and maintenance of a geothermal power system. However, different models may result in patterns of cash flow which are not equivalent* due to differences in financial assumptions and tax considerations. As shown in Table 3-3, the major assumptions that affect the discounted value (i.e., present worth of patterns of cash flow) and hence the busbar cost are:

- Discounting convention
- Cost of money (i.e., discounting interest rate)
- Distribution of investment during construction period
- Well reinvestment schedule
- Tax considerations (i.e., tax assumptions and preferential tax treatment).

The major differences are discussed below.

Discounting Convention:

As shown in Table 3-3 only two discounting conventions are in common use by the various busbar cost models, namely: the mid-year and end-of-year discounting conventions. The mid-year convention implies that money is received or expended in mid-year. In the end-of-year convention, the assumption is that money is received or expended only at the end of the discounting year. The present worth discounting factor for models using the mid-year discounting convention is $[1/(1 + i)^{j-0.5}]$, where i is the discounting interest rate and j is the compounding period. In comparison, models using the end-of-year discounting convention have a present worth factor of $[1/(1 + i)^j]$. Models using the mid-year discounting convention

*i.e., cash flows which have different discounted net present values.

TABLE 3-3
FEATURES OF LEVELIZED BUSBAR COST MODELS

ORGANIZATION FEATURE	COMPANY O	COMPANY N	COMPANY D	COMPANY P	COMPANY J	COMPANY L	COMPANY F	COMPANY C	COMPANY E	COMPANY H AND M	COMPANY K
• Discounting Convention	End of year	End of year	End of year	End of year	Mid-year	Mid-year	Mid-year	End of year	Not applicable	Mid-year	
• Discount Rate	After tax	After tax	Before tax	Before tax	Given						
• Construction Years Investment Profile	Continuous		Lumped	Lumped	Continuous		Continuous	Lumped	Not applicable	Lumped	
• Reinvestment Schedule	Uniform rate						Uniform rate	Lumped at Multiples of Well-life*	Not applicable	Uniform rate	
• Tax Considerations											
A. Preferential Tax											
• Accelerated Depreciation	S.Y.D.	S.Y.D.		S.Y.D.		S.Y.D.	S.Y.D. or St. line	DDB & ST line	Not applicable	S.Y.D.	
• Depletion Allowance	None	None	None	None	None	None	None ⁺	None	Not applicable	Included	
• Expensing of Intangible Drilling Cost	None	None	None	None	None	None	Included	None	Not applicable	Included	
B. Investment Tax Credit	Included	Included		Included		Included	None ⁺	Included	Not applicable	Included	
C. Other Taxes											
• Royalty and Gross Revenue Tax						Field Revenue Royalty	Included	Field Revenue Royalty	Not applicable	Field Revenue Royalty	
• Ad Valorem/Property Tax	Included	Included	Included	Included	Included	Included	Included	Included	Included	Included	
BUSBAR COST COMPUTATION	RR	RR	RR	RR	Year by Year	Year by Year	Year by Year	Year by Year	RR	Year by Year	

* For test cases with specified well lives; otherwise this company does not deal with this question.

** Used also by Company E for thermodynamic calculations.

+ These features are available in a later version of this model.

(e.g., Company F) will thus result in a discounted cash flow value that is higher by a factor of $1 + i$ than those models using the end-of-year discounting convention. For a discount rate, i , of 10 percent for example, the Company F model will result in a cash flow present value per dollar that is 4.9 percent higher* than other models using the end-of-year discounting convention.

Cost of Money (i.e., Discounting Interest Rate):

The terms "cost of capital" and "cost of money" are often used interchangeably. Regardless of semantic differences the cost of money includes return to equity (i.e., common and preferred stocks) and interest payments to debt. The "cost of money" is thus a weighted average of the relative contributions of debt and equity for a given structure of invested capital. This weighted cost of capital represents the discount rate used in calculating the present value of future cash streams. Table 3-3 provides a comparison of the "weighted cost" of capital (i.e., cost of money) formulations used by various busbar cost models. In Table 3-3 some models use "after tax" weighted cost of capital, while others do not make tax adjustment. The discounting rate in these models is related by the equation:

$$i = r - TD_F \cdot D_R \quad (2)$$

where,

i refers to the after tax discount rate,

r is the before the tax discount rate,

$$*(1.1 - 1) \times 100 = (1.049 - 1) \times 100 = 4.9 \text{ percent}$$

T is the effective tax rate,

D_F is the debt fraction in invested capital and

D_R is the interest rate on borrowed money.

Equation (2) indicates that i will always be smaller than r by the amount of tax savings realized from interest paid on borrowed money (i.e., $TD_F D_R$). Other things being equal, busbar models using the after-tax discount rate i , will thus result in a higher present value per dollar of a given cash stream than those models using the before tax discount rate r . The approximate percent change in present value is given by the ratio:

$$\frac{\frac{1}{i} \left(1 - \frac{1}{(1+i)^n} \right)}{\frac{1}{r} \left(1 - \frac{1}{(1+r)^n} \right)}$$

The effect is some 7 percent for the Producer and over 20 percent for the Utility, under the assumptions of Test Cases 1 and 2.

Distribution of Investment During Construction Period:

A geothermal power system may require anywhere from two to six years for completion of construction. Different busbar cost models use different expenditure profiles over these years of construction. As seen in Table 3-3 the Company F model uses a profile expressed by a continuous distribution function of the form:

$$c(t) = 100/[1 + \exp K(a-t)], \quad (3)$$

where, $c(t)$ = cumulative expenditure at time t ,

$K = 0.847$, and

$a = 60$ percent time point of the construction period.

Other expenditure profiles assume expenditure during construction to be lumped at a point located at the 60 percent time point of the construction period. The comparative impact of the foregoing expenditure profiles on the present value of the cash flow generated by various busbar cost models is shown in Table 3-4. Figure 3-1 shows that models with a continuous expenditure profile during construction period will always have a higher present value of cash flow irrespective of the total duration of construction time. For the assumptions of Test Cases 1 and 2, this could change the levelized overall costs by 10 to 20 percent.

Well Reinvestment Schedule:

As existing geothermal wells become depleted new wells have to be established to maintain the required level of hot water supply to the associated power plant.* Recurring capital investment in new geothermal wells is therefore necessary during the operating life of a geothermal power plant. This expenditure flow is treated differently in different busbar cost models. Table 3-3 shows two types of reinvestment schedules to be in common use: (1) the uniform reinvestment schedule and (2) the lumped reinvestment schedule. In the uniform reinvestment schedules the wells are replaced at a uniform rate equal to the reciprocal of the specified well life used in the busbar cost model. The lumped reinvestment schedule requires

*Some models ignore this. See Sections 3.2.1 and 4.1 and 4.2.

TABLE 3-4

IMPACT OF VARIOUS MODEL FEATURES ON P.V. OF CASH STREAMS, CAPITAL BASIS, BUSBAR COST

ORGANIZATION MODEL FEATURE	F	C	M	L	H	G
• Discounting Convention	$\frac{1}{(1+i)^{j-\frac{1}{2}}}$ j = time pt.	$\frac{1}{(1+i)^j}$	$\frac{1}{(1+i)^{j-\frac{1}{2}}}$		$\frac{1}{(1+i)^{j-\frac{1}{2}}}$	
• Distribution of Inv. during Construction over x years	$C_{av} \cdot (1+i)^x \sum_{j=0}^x (P/F, i, j)$ C_{av} = AV. Fract. Dist.	$(1+i)^{.4x}$	$(1+i)^{.4x}$	$(1+i)^{.4x}$	$(1+i)^{.4x}$	
• Well Reinvestment Schedule	$\frac{1}{W} * \frac{(1+i)^\eta - 1}{i(1+i)^\eta}$ W = Well life η = Economic life i = Discounting Factor	$\frac{1 - 1/(1+i)^\eta}{(1+i)^W - 1}$	$\frac{1}{W} * \frac{(1+i)^\eta - 1}{i(1+i)^\eta}$		$\frac{1}{W} * \frac{(1+i)^\eta - 1}{i(1+i)^\eta}$	
• Basic Tax Assumption	$(FCR)_1$	$(FCR)_2$	$(FCR)_3$	$(FCR)_4$	$(FCR)_5$	
• AFDC (C_{AF})	C_{AF1}	C_{AF2}	C_{AF3}	C_{AF4}	C_{AF5}	
• Inflation/ or Escalation	_____	_____	$\frac{1 - \frac{1+e}{1+i}^\eta}{i - e}$ e = Escalation rate i = Discounting rate η = Economic life	_____	$\frac{1 - \frac{1+e}{1+i}^\eta}{i - e}$	
• Allowance for Field Exp. Development Cost	Increase Capital Cost	_____	Increase Capital Cost	Increase Capital by Development Cost	Increase Capital Cost	
• Inflation of Revenue St. (AE)	_____	_____	_____	_____	_____

FIGURE 3-1
IMPACT OF INVESTMENT DISTRIBUTION DURING CONSTRUCTION
ON PRESENT VALUE FACTOR OF CASH FLOW STREAMS

a lumped investment for well renewal at equal time intervals corresponding to the lifetime of the well. Thus, if the well life is assumed to be 10 years, well reinvestment will occur at intervals of 10 years along the operating life span of a geothermal power plant.

The impact of the two foregoing reinvestment schedules on the present value of the cash flow in each case is shown in Table 3-4 for various busbar cost models. For convenience of comparison this impact is depicted to Figure 3-2 for various values of well life (w), and compound interest (i). Figure 3-2 indicates that the uniform reinvestment schedule will always result in a higher present value of cash flow than the lumped one, irrespective of well life. For commonly expected values of i (i.e., 10 to 15 percent per year) the present value may be higher by 50 to 200 percent. This could lead to an increase of about 15 percent in the Producer's levelized cost.

Tax Consideration

Basic tax assumptions, (e.g, depreciation method, preferential tax treatments, etc.), effective tax rate specified and other tax considerations have significant influence on the comparative pattern of cash flow of various busbar cost models. These tax considerations determine the timing and extent of tax expenditure or savings and hence define the final after-tax shape of the cash flow for the various models involved. As shown in Table 3-2 different models differ basically in the following basic tax assumptions and consideration.

FIGURE 3-2
IMPACT OF WELL REINVESTMENT SCHEDULE ON P.V. OF CASH FLOW STREAMS

- Tax Preferences. These include accelerated depreciation, depletion allowance, and expensing of intangible drilling cost. Accelerated depreciation involves employing a rapid depreciation schedule that results in less taxable income and hence in more cash flow in earlier years of a geothermal power plant tax life.* Most busbar cost models use the sum-of-year's-digits (S.Y.D.) accelerated depreciation method. Others (e.g., Company C) use the double declining balance (DDB) accelerated depreciation. In reality, a company would use the fastest possible depreciation method (in a present-value sense). This may be either S.Y.D. or D.D.B. (switching to straight line depreciation half-way through the depreciation life), depending upon depreciation life and discount rate. It must also be noted that interest expenses incurred during construction may be capitalized but cannot be depreciated for tax purposes.

In contrast to depreciation, percentage depletion allowance is related to sales, rather than to investment. Percentage depletion will thus affect the revenue stream of a cash flow. The Company M model is the only model that includes a 22 percent well revenue depletion allowance. Other things being equal, the Company M model is thus expected to result in the lowest present worth of taxes, and hence the lowest revenue requirements.

The effect of expensing a specified intangible fraction of drilling cost is a tax savings resulting from a quicker writeoff

*Tax life refers to the allowable depreciation life of an asset for tax purposes.

of the drilling expenses. Only Companies F and M include this preferential tax assumption. The benefits of preferential taxation will once again be reflected in high present worth cash flow pattern and hence reduced busbar cost; the effect is roughly 10 percent.

- Investment Tax Credit. The investment tax credit is designed to reduce tax liability by a specified percentage of the total cost of depreciable tangible assets intended to be used for more than three years. The effect of an investment tax credit allowance would thus be to lower the initial effective capital cost. It appears that a 15 percent investment tax credit would lower overall costs by less than 10 percent.

- Carryforward of Tax Credits or Deductions

In the early stages of operation of a project, it is likely that allowable tax deductions or credits will exceed tax liability. This excess can either be treated as income, under the assumption that it can be used against tax liabilities elsewhere in the organization, or carried forward (within limits) until sufficient income becomes available from the project to take advantage of it. The former assumption may be appropriate for larger corporations with many sources of income, while the lower assumption may be appropriate for corporations having only one or very few projects. Clearly the former assumption will result in lower levelized costs than the latter. The size of the effect is not clear but may be less than 5 percent.

- Capital Structure and Financial Assumptions. Different capital structures and financial assumptions have different tax implications as a result of their effect on the Income Tax Factors.

$$ITF = \left(\frac{T}{1-T} \right) * \left(1 - \left(\frac{D_F D_R}{E_R} \right) \right) \quad (4)$$

where T is the effective tax rate, D_F and D_R are the capital debt fraction and debt interest rate respectively, and E_R is the rate of return on equity.

A capital structure with 100 percent equity will result in the highest income tax factor for a given effective tax rate. Lower equity levels will result in correspondingly lower income tax factors and will hence reduce income tax requirements.

Turning now to the methodologies employed in the levelized busbar cost models, we have noted in Section 2, and it is also shown in Table 3-3, that two methods are in common use in busbar computation, namely: the discounted year-by-year cash flow method (i.e., DCF) and the minimum revenue requirement technique (RR). The minimum revenue requirement technique is perhaps easier to apply but the discounted cash flow method offers greater flexibility. For example, the discounted cash flow method coupled with year-by-year calculations can easily cope with such things as interest during construction period, varying project lives, investment tax credit, preferential tax treatment and allowance for the tax effect of salvage and working capital. In addition, the discounted cash flow method provides the actual cash flow situation on a year-to-year basis.

It has been shown that DCF and RR methods can give the same levelized cost if all parameters, particularly discount rate, are correctly chosen.*

3.2 Critique

The methodologies used by the organizations contacted have now been described in detail and this section makes critical analyses of these methodologies. In keeping with the structure used earlier, the methods for deriving capital and O&M cost estimates (engineering cost estimates) are first discussed; then the methods for computing levelized busbar costs are analyzed.

3.2.1 Engineering Cost Estimates

Starting with the estimating of engineering costs, those methodologies which employ informal methods are clearly less desirable than those using formal methods, if it is desired to compare the costs of different hydrothermal resources with each other or with competing energy sources on a consistent basis.

The lack of optimization in informal design methods could lead to significant under or over-design in, for example, the Company O results, but in practice their cost estimates are quite well in line with the consensus of other organizations. This can be seen by examining Tables 4-2 and 4-5, which give capital cost estimates for the Heber-like and Valles Caldera-like systems.

*See: Doan L. Phung, "The Discounted Cash Flow and Revenue Requirement Methodologies in Energy Cost Analysis," (Institute For Energy Analysis, Oak Ridge Associated Universities, Oak Ridge, TN 37830, Feb., 1977) for numerical examples.

The thermodynamic analysis in the Company F model is open to question. It appears that errors around 80 percent may be introduced under certain circumstances due to the presence of dissolved solids in the brine.* As noted in Section 2 this would tend to lead to under-designed plants. This is demonstrated in Section 4, where Table 4-1 shows that the Company F model produces a considerably lower conversion plant capital cost estimate than any of the other published results.

Companies C and M also employ thermodynamic optimization in their plant designs. Insufficient information is available to enable us to comment on their methodologies.

Since no geothermal plants have been built in this country for liquid-dominated resources, it is not possible to comment on the relative accuracies of the parameters employed in the actual cost-estimating process, i.e., the transition from an optimized thermodynamic design to a set of hardware specifications and associated purchase and operating cost estimates.

In the matter of plant and equipment lifetimes, many organizations ignore the question of replacing production wells from time to time throughout the plant life either from reduced brine flow or deterioration of the casing, etc. From experience at The Geysers and

*A subsequent version of this model can allow for dissolved solids in the brine.

elsewhere, it appears that this is likely to be necessary. Of those organizations which address this question (namely F, L, M and O), Company O makes by far the most conservative assumptions, with producing* well replacements being taken as 10 percent/year, and injecting wells being replaced at 5 percent/year. This will of course lead to considerably higher costs of power. For Company O, the present value of required future well replacements may be almost as much as the original investment in wells. Companies F and L also require significant replacements of producing wells, which will tend to raise their costs.

Ignoring possible requirements for replacement wells and plant could reduce overall costs by some 20 percent.

The question as to whether a continuous or lumped reinvestment in wells will be necessary cannot now be answered. It has been noted in Section 3-1 that continuous reinvestment always leads to higher costs, other things being equal.

3.2.2 Levelized Busbar Cost Models

Turning to the financial assumptions associated with the levelized busbar cost models, and the models themselves, it is clear that many of the assumptions are a matter of convention (such as choice of mid-year or end-year discounting). Insofar as "correct" choices can be specified, it seems that the methodology should use the after-tax

*Note that production wells which are not producing, i.e., spare or standby wells, are not assumed to need replacement.

discount rate (i.e., in the nomenclature of Section 3-1), and should be able to include tax allowances such as depletion allowances, allowed expensing of intangible drilling costs, investment tax credit, and so forth.

We shall discuss the mathematical formulations of year-by-year and closed form levelized busbar cost models separately.

Year-by-year calculations have the potential to be most accurate and flexible. There is a basic choice to be made between methods which pay returns to equity and methods which rely on discounted cash flow rate of return (DCFROR). The return to equity method pays stockholders at a constant percentage rate on their outstanding (i.e., unrefined or undepreciated) equity, and may later levelize their cost stream. This method therefore depends heavily on the equity outstanding which is normally taken to be equal to the (depreciated) capital value. The DCF method in contrast calculates the cash flow year by year and then relies upon the DCFROR to express the value of the project; the question of payments to stockholders is thus avoided. The choice of method may depend upon the philosophy of the organization being modelled, for both methods can be regarded as correct. Generally utility companies or similar organizations use the return to equity method while unregulated companies tend to use DCF methods, which have been developed more recently.

A second choice lies between assuming a smooth revenue stream which will overall meet the costs and pay equity in each year, or

calculating the revenue requirements each year and then taking an average or present value of this stream to determine the levelized cost. It is not clear which method is preferable; in reality, revenue will be smooth and will not vary from year to year as costs vary, although long-term cost-related variations may and probably will occur as a result of rate-setting by Public Utilities Commissions, and contractual escalation clauses. A smooth revenue stream will result in different taxes being paid from a variable stream.

These two choices, each with two selections, yield a total of four different possible combinations (i.e., two times two). The four methods of year-by-year calculations analyzed here (Companies C, F, H, L, and M*) cover exactly these four combinations.

All four methods attempt to perform the calculations in constant dollars, although there are some inconsistencies in their treatment of inflation. Problems arise when current dollars and constant dollars are mixed. Current dollars are dollars in use in any year and their value changes from year to year due to inflation (for example, bread which cost 50 cents in 1967 costs \$1.00 in 1977--the value of the dollar has declined). Constant dollars are the currency value of a particular fixed year and do not change. Certain costs and tax allowances, such as interest on debt and depreciation, are fixed in current dollars; that is, the dollar amount to be paid in

*Companies H and M use essentially the same methodology for estimating the field costs; however, they use different methodologies for the conversion plant portion.

any year is fixed and is independent of inflation. However, the dollar amounts of other costs (such as operating and maintenance costs) vary from year to year with inflation, while probably remaining approximately fixed in real (constant) dollars. All methods report depreciation, etc., in current dollars and O&M in fixed dollars. Mixing the two different kinds of dollars leads to inconsistent results; for instance, if the utility costs for Test Case 1 are computed using mixed dollars, the apparent cost in mills/kWh is reduced by 12 percent, because the contribution from O&M costs is falsely understated.

All four methods also exhibit inconsistencies in the choice of cost of capital. (Although this is strictly an item of data, it is closely connected with the treatment of inflation and is thus discussed here.) If they are truly operating in constant dollars, the rates of return on equity and interest on debt appropriate to that should be used, whereas they all use rates of return on equity and interest which are taken from the current market values and thus have inflationary expectations built in. Roughly, the rates should be reduced by the current inflation to account for this. Using the corrected cost of money with a consistent constant dollar calculation yields exactly the same cost in mills/kWh as using a correct current-dollar cost method. However, using inconsistent mixed dollar calculations and incorrect cost of capital rates increases the apparent levelized busbar cost of electricity by 38 percent, for the utility part of Test Case 1.

In short, the handling of inflation by all these methods is inconsistent; serious discrepancies could be introduced when comparing projects with very different lives or very different ratios of O&M costs to capital costs.

In considering the closed-form levelized busbar cost models, the following symbols will be used:

T = effective income tax rate = $\frac{(\text{Federal income tax rate}) + (\text{State income tax rate}) - (\text{Federal income tax rate}) \times (\text{State income tax rate})}{1}$

D_F = debt fraction of capital

E_{PF} = preferred equity of capital

E_F = equity of capital

D_R = interest rate on debt

E_{PR} = return to preferred equity

E_R = return to equity

ESC = escalation rate

C_t = capital expenditure in year t

n = project life

K = 8766 x capacity factor

t_p = annual property tax

$CRF_{i,n}$ = Capital Recovery Factor over n years at interest rate i ; this is the fraction of the original investment which must be recovered each year in order to pay interest (a return to equity) and recover the capital in exactly n years.

$$= \frac{i (1 + i)^N}{(1 + i)^N - 1}$$

R = weighted cost of capital (see Table 3-3)

S = start-up year

b = begin construction year

g = revenue tax or royalty rate

PE = equity proportion = $\frac{1}{r} (E_{PF} \cdot E_{PR} + E_F \cdot E_R)$

M = depreciation life of unit

$F_{r,m} = (CRF_{r,m})^{-1}$

ITAXC = investment tax credit rate

As noted above, all the closed-form models computed a capital Fixed Charge Rate (FCR) and then add O&M and fuel costs.

Table 3-6 compares the different formulations used by the different methods. It can be seen that the method used by Company K is very simple, amounting to the choice of a FCR (guided by comparison with FCR's used by utility companies in practice), and the addition of O&M and fuel costs to the capital changes. This makes sensitivity analysis for capital costs and tax incentives impossible. It must be pointed out, in fairness to Company K, that this method was not intended to be used for anything other than preliminary evaluations of busbar costs.

Of the remaining methods, Companies D and J provide FCR's which are broken down into components (so much return to capital, so much for taxes, etc.), but do not give details as to how these numbers were obtained. Company H provides a similar levelized annual capital

TABLE 3-5

FORMULATIONS FOR MAJOR FACTORS USED IN CLOSED-FORM METHODS

Organization Factor	COMPANY P	COMPANY K	COMPANY N	COMPANY J	COMPANY D	COMPANY O
Weighted Cost of Capital, r	$D_F \cdot D_R + E_{PF} \cdot E_{PR} + E_F \cdot E_R$	-	$(1-T)D_F \cdot D_R + E_{PF} \cdot E_{PR} + E_F \cdot E_R$	Given	(as P)	(as N)
Capital Cost Basis (Total Capital Cost), C	$\sum_{t=0}^{s+n} C_t (1+ESC)^{t-s} (1+r)^{s-t}$	Capital cost basis given	(as P)	Capital cost including Afdc are given; method seems same as Company P	(as P)	(as P)
Escalation Adjustment, D_{ESC}	$1 - \frac{(1+ESC)^n}{1+r}$		(as P)		(as P)	(as P)
Fuel Base Adjustment Factor, FA	$(D_{ESC})_{fuel} \times (CRF_{r,n})$	Not used	(as P)	(as P)	(as P)	(as P)
O&M Base Adjustment Factor, OMA	$(D_{ESC})_{O\&M} \times (CRF_{r,n})$	Not used	(as P)	(as P)	(as P)	(as P)
Annualized Energy Factor, AE	$K = \text{annual electricity output}$	K	K	K	K	$(D_{ESC})_{energy} \times (K) \times (CRF_{r,n})$
Income Tax, t_{inc}	$\left(\frac{T}{1-T}\right) PE \cdot (CRF_{r,n} - \frac{1}{n})$	Not used	$\left(\frac{T}{1-T}\right) (CRF_{r,n} - \frac{1}{n})$	-	-	(as P)
Accelerated Depreciation, dep	$\left(\frac{T}{1-T}\right) \left(1 - \frac{TD_F D_R}{r}\right) \times \left[\frac{2CRF_{r,n}(M-F_m)}{m(m+1) \cdot r} - \frac{1}{n}\right]$	-	$\left(\frac{T}{1-T}\right) \left[\frac{2CRF_{r,n}(M-F_m)}{m(m+1)r}\right]$	-	-	$\left(\frac{T}{1-T}\right) \left[\frac{2CRF_{r,n}(M-F_m)}{m(m+1)r}\right] - \frac{1}{n}$
Investment Tax Credit ITC	$CRF_{r,n} \cdot \left(\frac{1}{1-T}\right) \left(\frac{1TAXC}{1+r}\right)$	-	(as P)	-	-	(as P)
Fixed Charge Rate, FCR	$CRF_{r,n} + \text{time} + tp - \text{dep} - \text{ITC}$	Given	(as P)	Given	Given	(as P)
Busbar Cost	$\frac{1}{AE} (C \cdot FCR + O\&M \cdot OMA + fuel \cdot FA) \cdot \frac{1}{(1-g)}$	$\frac{1}{AE} (C \cdot FCR + O\&M + fuel)$	(as P)	(as P)	(as P)	(as P)

$$* F_m = (CRF_{r,n})^{-1}$$

charge rate. All methods (except Company K) explicitly consider the effects of inflation and/or escalation; in the case of fuel* and O&M costs they all use equivalent formulations. However, the validity of applying an inflation correction to a fluid cost which is partly inflation independent (being based on the field operator's initial capital costs) as is done by Company H can be questioned.

Companies N, O and P calculate the FCR from basic data; they all use slightly different formulations to do so.

A difference of 20 percent in the FCR could make a difference of about 15 percent in the overall levelized busbar cost. In computing the weighted cost of capital, r , the formulation used by Companies N and O is correct under the assumption that the interest expense can always be treated as a tax-deductible expense, i.e., under the assumption that the organization always has a positive net income. Since the weighted cost of capital is universally used as the discount rate, differences here can be significant. In calculating the Income Tax Factors, T_{inc} , the formulation used by Companies O and P is better, for essentially the same reason; income tax has to be paid only on the income which comprises profits to equity.

In calculating the accelerated Depreciation Factor, dep (see Table 3-6), the Company N formulation does not appear to allow for the fact that the value of accelerated depreciation means the value above regular straight-line depreciation, since the value of straight

*In the case of geothermal energy "fuel" usually means geothermal fluid supplied by the field operator to the electrical generating plant.

line depreciation has already been taken into account as the factor $\frac{(-1)}{n}$ in calculating the Income Tax Factor. The reason for the difference between formulations of Companies O and P is because Company P makes allowances for retirement dispersion (i.e., variations in equipment lifetimes); this more sophisticated approach is preferable.

The remaining parameters are handled similarly by Companies N, O and P. It should be noted that the Company O formulation has been extended to cope with depletion allowance and allowing expensing of intangible drilling costs; however, the formulation of Companies N and P could equally well be extended.

It is notable that all the closed-form methods (except that of Company K) explicitly include consideration of escalation/inflation in the cost streams, and do so correctly, unlike the year-by-year methods reviewed above.* The Company O formulation is unique in that it also allows for escalation inflation in the revenue stream. This formulation will yield levelized energy costs which appear to be about 30 to 40 percent lower than with the other methods, if it is assumed that the revenue stream will increase (in current dollars) at the general inflation rate of roughly 5 percent. This is because the cost given is the first-year cost; in the formulations of Companies D, H, J, N and P, this cost then decreases (in real terms) year by year with inflation, necessitating a higher initial value to achieve the same present worth as the Company O value.

*However, the ability to incorporate inflationary corrections is not always used.

This is essentially a matter of which convention is used to report the result as it is very easy to change back and forth.* It could be argued that the assumption that the revenue stream will inflate is more accurate for nonregulated entities, such as the field operator, whereas the Utility's revenue will be determined by costs which are partly fixed (capital charges) and partly affected by inflation (O&M and fuel costs). In view of the pessimistic assumptions made by Company O concerning well replacement, it is undoubtedly the assumption concerning future revenue inflation which makes their busbar cost estimates about the same value as the other organizations; in other words, if they used the same (more optimistic) assumptions regarding well replacements as most of the other companies, their estimates of levelized busbar cost for Test Cases 1 and 2 would appear much lower than the norm.

*Company O costs should be multiplied by 1.4 and 1.6 for the Producer and the Utility, respectively, for projects with a 30-year life, and financial data as in Test Cases 1 and 2.

4.0 DATA COMPARISONS

The preceding chapters have concentrated on variations in levelized busbar cost estimates caused by differences in methodology. This chapter, in contrast, examines quite a different aspect of the problem, namely, the effects of differences in data and assumptions. Differences in data and assumptions (such as tax rates and allowances, costs of capital, and inflation rates) can be the cause of significant variation in levelized busbar cost estimates.

Most of the published data is for the Heber, California, resource. This is presented and discussed in Subsection 4.1; data published by Company K for the Raft River, Idaho, resource are also presented in this subsection although the data are not strictly comparable because Raft River is much cooler than Heber. A small amount of data are available for higher-temperature resources (mostly for Valles Caldera, NM), and these are presented in Subsection 4.2.

4.1 Moderate Temperature Resources

Table 4-1 summarizes the data published by Companies C, D, F, H, J, L, M and O. It can be seen that the estimates of resource characteristics are very similar (with the exception of Company K, which is, of course, looking at a different site). Proposed plant sizes are also closely comparable (45-50 MW_e net); however, major differences are apparent in project life. Companies D, H and L give low values, apparently based upon a demonstration plant argument, but the estimates which Company L makes for non-demonstration plants in the

TABLE 4-1

COMPARISON OF DATA AND ASSUMPTIONS FOR MODERATE-TEMPERATURE RESOURCES

Parameter	Company	F	C	M	M	K	J	H	L	D	O
Site	Heber	Heber	Heber	Heber	Heber	Raft River		Heber	Heber	Heber	Heber
System Type	Binary	Flash	Binary	Flash	Binary	Binary		Binary	Binary	Binary	Binary
Resource Temp., °C	180	182	182	182	149			182	180	177	190
MWe, Net	46	50	50	50	50			50	45	50	50
Project Life, Yrs.	30	30	25	25				20 or 30	15-20	20	30
Capacity Factor	0.85	0.85	0.85	0.85	0.85	0.65 0.85		0.75	0.75	0.85	0.76(effective) ⁺
Inflation	NO	NO	NO	NO	NO	6%		NO	NO	5%	5%
Escalation	NO	NO	NO	NO	NO	1% labor .5% fuel		NO	NO	-	-
<u>Field</u>											
Capital Cost of Wells*	8.6	12.0	7.1	9.5	26.7					17.2	16.6
Capital Cost of Surface Plant*	6.1	12.1	7.1	7.7	13.2				11.4	5.1	7.3
Debt/Equity Ratio	48/52	-/100	-/100	-/100					/100		30/70
Interest on Debt, %	8	-	-	-	-				-		8
Return to Equity, %	15	20	15	15					20		20
After tax cost of Capital, %	10.3	20.0	15.0	15.0					20.0		15.4
O&M Cost, **	1.73		2.09	2.64							1.27
No. of Production Wells	20	14	12	16						13	16
No. of Injection Wells	9	6	6	8						12	7
No. of Replacement Production Wells	32		\$253,000 \$/yr						\$1,000,000 \$/yr		40
No. of Replacement Injection Wells	0										18
<u>Utility</u>											
Capital Cost*	19.6 ⁺⁺	39.0-45.2	31.2	29.3	53.0	47.3	37.9	35-37.9			35.8
Debt/Equity Ratio	59/41	59/49	50/50	50/50		88/12	65/35	55/44			50/50
Interest on Debt, %	8.0	9.5	9.0	9.0			9.0	9.0			8.0
Return to Equity, %	12.0	12.0	12.0	12.0			13.0	13.0			12.0
After tax cost of Capital, %	7.2	8.3	8.1	8.1			7.3	8.2			8.0
FCR, %					15.0	21.8	16.74 to 18.25				
O&M Cost	0.49		1.27	1.24	0.42***	1.86****	1.59				1.29

* Adjusted to include AFDC, 1977 \$ x 10⁶** 1977 \$ x 10⁶/yr

*** Given as 1.0 mills/KWh

**** Given as 5.3 mills/KWh

⁺⁺ Allows for start up losses.⁺⁺ A revised version of this model yields 24.0.

Imperial Valley (which does not include information on plant life) are not very different in other respects, so that these estimates of plant life may represent their best judgment for non-demonstration plants also.

Assumed capacity factors vary from 0.65 to 0.85, with Companies H, J, L and D being the lowest.

The data used to derive most projections do not include any estimates of inflation* (which may seriously distort their results, as noted earlier). Where inflation and escalation are included, the estimates lie in the 5 to 7 annual percent range.

Considerable differences are apparent in the estimated capital cost of the Heber well field and associated surface plant, the lowest value being \$14.2 million (Company M) and the highest being \$24.1 million (Company C). (Company K is higher at \$39.9 million, but this is a different field. The lower temperature, harder rock and greater depth at Raft River all combine to raise costs.) The differences are caused by variations in assumptions concerning:

- well cost
- well flow rate
- plant cycle and thermal efficiency.

The number of wells assumed (which depends inversely on well flow rate and plant efficiency) varies from 12 (Company M) to 20 (Company F). The assumptions regarding replacement of production and

*Although several methods have the ability to do so.

injection wells also vary widely. Most studies ignore the question; however, it appears likely (from experience at The Geysers and elsewhere) that production wells in particular will have a limited life and that replacement will be necessary. If the wells lasted for 15 years, it would be necessary to drill twice as many replacement wells over a 30-year plant life as were originally drilled to get the plant on-line, if the brine production level were to be maintained and if wells failed gradually over their lifetimes. This would represent a significant extra cost for the plant operations.

Company F assumes that 32 replacement wells will be needed for 20 original wells, a replacement rate of 5.3 percent per year.* Company M assumes an interim capital replacement rate of \$253,000 per year; this is equivalent to about 0.4 wells per year (if it were all spent on wells), for a replacement rate of 3.3 percent per year. Company L assumes an interim capital replacement of \$1.0 million per year; they do not specify the number of production wells required or the cost so that the replacement rate cannot be estimated. Company O assumes a replacement rate of 8.3 percent per year; this is by far the highest value. This rate is also assumed by Company O injection well replacement. O&M costs for the producer ranges from \$1.27 to \$2.60 million/year.

*Note that replacement rate is calculated on the total number of production wells drilled, which may include spare wells. Thus replacement rate $< 1/\text{well life}$.

The capital structures assumed for the Producer are relatively similar and are based on the developer's using mostly risk equity at a relatively high rate of return.* Company F is alone in assuming a debt proportion of more than 40 percent; Company O assumes 30 percent. Most companies assume 100 percent equity.

Turning to the utility, the estimated capital investments range from \$19.6 million (Company F) to \$47.3 million (Company J). O&M costs also range widely; from \$0.49 (Company F) to \$1.86 (Company J) million/year. (Company K shows \$0.42 million for a lower temperature resource.) Capital structures of all models are very similar, the net weighted after-tax cost of capital varying only between 7.2 percent (Company F) and 8.3 percent (Company C).

A serious point must be raised with respect to the rates of return, however, and it hinges upon the same point concerning the relationships of inflated and current dollars which has given problems before. For calculations made in constant dollars (as the majority of these are), return to equity and interest on debt should be adjusted for inflation; an interest rate of 8 percent in current (inflated) dollars at an inflation rate of 5 percent is equivalent to an interest rate of about 3 percent in constant dollars.** Thus, use of rates of return and interest rates which include inflationary

*However, projects which obtain a loan guaranty from the Federal Government Geothermal Loan Guaranty Program could have a debt/equity ratio as high as 75:25. This would radically reduce the financing costs.

**Of course, income tax deductions for interest payments would be taken into current dollars, not constant dollars.

expectations in a constant dollar calculation can seriously overstate the costs for capital-intensive projects such as geothermal development. The same argument applies to the choice of discount rate in DCF calculations. Also, if the costs are higher in the early years (due for example to accelerated depreciation), then the use of a too high discount rate will lead to overstatement of levelized revenue requirements.

Assumptions regarding income taxes are very similar between all organizations; the only significant differences lie in tax incentive assumptions (i.e., investment tax credit, depletion allowance, expensing intangibles). Table 4-2 summarizes these data. Many organizations do not explicitly state their assumptions; if the field is not modelled (merely represented as a fuel cost, as by Companies H and J) then tax incentives applicable to the field (depletion, expensing) are not mentioned. Company K rolls all taxes, etc., into a single assumed fixed charge rate.

Table 4-3 summarizes the cost of electricity estimates which have been published for Heber-like resources. The cost estimates range from 19.1 mills/kWh (Company D) to 63 mills/kWh (Company J). No estimates other than Company D's are below 33 mills/kWh; that of Company L, however, also ranges up to 60 mills/kWh.

These cost estimates are, of course, a question of both data and methodology. In general, Companies H, J and L have data and assumptions which would tend to raise costs (e.g., short plant lives, high

TABLE 4-2

INCOME TAX ASSUMPTIONS FOR MODERATE TEMPERATURE RESOURCES

COMPANY	C	D	F	H	J	K	L	M
Federal Income Tax %	48	50	48	48	50	X	48	48
State Income Tax %	9	0	7	9	0	X	9	9
Property Tax % (including admin. costs)		3.0*	2.5*	2*	2.7*	X	(\$175,000 per year)	2.5*
Investment Tax Credit %	X	4	0	X	4	X	X	10
Depletion Allowance	X	X	0	X	X	X	X	22
Expensing Intangible Drilling Costs ***	X	X	66	X	X	X	X	70
Royalty or Revenue Tax	X	X	10**	X	X	X	12.5**	12.5**

* Utility only.

** Producer only.

*** % of well costs expended.

X = not given

TABLE 4-3

SUMMARY OF ELECTRICITY COST ESTIMATES FOR HEBER-LIKE SITES (1977 mills/kWh)

Organization	Co. C	Co. D	Co. F	Co. H	Co. J	Co. L	Co. M		Co. O
							Binary	Flash	
Field Cost	29.2		21.9	21-26	52	17-20*	17.7	21.8	28.0
Utility Cost	20.5		11.5	21-25	39	30-40*	19.3	24.3	11.1
Total	49.7	19.1	33.4	42-51	91	47-60*	37.0	46.1	39.1

* Upper end of ranges applies to demonstration plant (estimate made by METREK from Company L results)

capital costs, low capacity factors). Company F has low capital costs,* and a low cost of money for the Producer, and comes out with the second lowest electricity cost. Company D gives very limited information; their field data seems in line with the general norm so that it is not clear why they emerge with such a low cost estimate.

The range of estimates (19.1 to 91 mills/kWh) may be compared with the range of 38 to 69.7 mills/kWh obtained in response to Test Case 1, the standard data set representing a Heber-like resource (Table 2-4). The range obtained here is wider, in spite of the fact that there are about 40 percent fewer organizations in the sample (8 against 13 in Table 2-4). The inclusion of more results might be expected to widen the range obtained in this subsection further. The result is not unexpected since the effects of differences in data and methodology acting together would be expected to be greater than the differences due to methodology alone.

4.2 Higher Temperature Resources

Few published analyses are available for higher temperature resources. Four sets of data are summarized in Table 4-4; the temperatures for which the plants are designed are only roughly comparable, lying in the 210°C to 260°C range.

The capital and O&M costs vary widely; field capital costs in \$ millions range from 7.7 (Company F) to 37.0 (Company M), and utility capital costs range from 20.8 (Company F) to 47 (Company L). O&M

*Which exclude contingency; some other estimates may include contingency but most are not explicit on this point.

TABLE 4-4

SUMMARY OF DATA FOR HIGH-TEMPERATURE RESOURCES

ORGANIZATION PARAMETER	COMPANY F	COMPANY M	COMPANY L	COMPANY O
Site	-	Valles Caldera	-	Valles Caldera
System Type	Flash	Flash	Flash	Flash
Resource Temperature °C	210°C	260°C	210-260°C	240°C
MW _e Net	50	50	50	50
Project Life, Years	30	25		30
Capacity Factor	.85	.85	.75	.76 Effective
Inflation	No	No	No	5%
Escalation	No	No	No	0%
<u>Field</u>				
Capital Cost of Production Wells*	3.2	16.5	-	18.9
Capital Cost of Injection Wells*	4.5	10.5	-	4.0
Surface Plant*	-	-	-	-
Debt/Equity Ratio	42:58	0:100	15% DCFROR	30:70
Interest on Debt, %	8	-	-	8
Return to Equity, %	15	15	-	20
After tax of cost of capital, %	10.3	15.0	-	15.4
O&M Cost**	0.90	1.38	-	0.55
Number of Pond Wells	8	16	-	11
Number of Injection Wells	3	4	-	5
Number of Replacement Wells	22	35.5	-	28
<u>Utility</u>				
Capital Cost*	24.6		47	23.3
Debt/Equity Ratio	59:41	50:50	-	50:50
Interest on Debt, %	8	9	15% DCFROR	8
Return to Equity, %	12	12	-	12
After tax cost of capital, %	7.2	8.1	-	8.0
O&M Cost**	0.14	1.31	-	0.68

* \$ Million.

** \$ Million/Year.

costs for the field in \$ millions/yr range from 0.55 (Company O) to 1.38 (Company M), and for the Utility from 0.14 (Company F) to 1.31 (Company M). The latter differ by a factor of 9.

It would be expected that lower resource temperatures would lead to higher cost estimates. However, this does not seem to be the case; for instance, Company F with the lowest resource temperature also has a low cost estimate.

These variations in cost estimates must be a matter for concern; they cannot all be correct, so serious errors must be present in some electricity cost estimates from this source alone.

The assumptions regarding well lives are much the same as those made by the same organizations for moderate temperature resources; Companies F and O assume 10-year production well lives, and Companies L and M do not explicitly address the problem, although Company M allows for field degradation by requiring an extra two production wells later in the plant's life.

Table 4-5 summarizes tax assumptions, which are much the same as those used by these organizations for moderate temperature sites, and Table 4-6 summarizes cost of electricity estimates. The estimates vary considerably, not only in magnitude but also in the proportion represented by field and utility costs. The range (19.1 to 44.5 mills/kWh) may be compared with the range of estimates for Test Case 2 (26.9 to 51.7 mills/kWh).* The former dispersion is a little wider;

*Table 2-4.

TABLE 4-5

ASSUMPTIONS FOR HIGHER-TEMPERATURE RESOURCES

Organization Parameter	Company D	Company F	Company L	Company M
Federal Income Tax, %	50	48	55	48
State Income Tax, %	0	0	0	9
Property Tax, % (including admin. costs)	1	2.5*	X	2.5*
Investment Tax Credit, %	4	No	7	10
Depletion Allowance, %	No	No	No	22
Expensing Intangible Drilling Costs, %	No	67	No	70
Royalty or Revenue Tax	10**	10** (4% for utility)	12.5**	12.5**
*Utility Only % of well costs expensed		**Producer Only X = not given		

TABLE 4-6

SUMMARY OF COST ESTIMATES OF GEOTHERMAL ELECTRICITY
FOR HIGHER TEMPERATURE RESOURCES
(1977 mills/kWh)

	Company D	Company F	Company L	Company M
Field Cost	25.3	10.9	19.1	22.3
Utility Cost	6.8	8.2	25.4	19.1
Total	32.1	19.1	44.5	41.4

since there are many fewer organizations represented in this subsection (4 as against 13 in Table 2-4), the inclusion of more estimates might be expected to widen the dispersion still further. This result is not unexpected. The combination of differences in data and methodology taken together would be expected to give a wider range than data differences alone.

SECTION 5

COMPARISON OF COMPETING POWER GENERATION SYSTEMS

5.0 INTRODUCTION

Utilities buy additions to generating capacity to meet expected demand at the minimum cost of electricity production. The lifecycle busbar cost is thus an important decision criterion.

All prospects currently postulated for hydrothermal geothermal-electric generation are located in the Western States Coordinating Council Region of the National Electricity Reliability Council for electricity generation. This region comprises the states of Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington and Wyoming, as well as part of British Columbia. Within the Western States Region, the major sources of electricity which will be competing with geothermal energy for new baseload generating capacity additions during the 1980-1990 period are coal and nuclear power. *

In a recent Metrek geothermal prospect-specific analysis,** the likely competitive energy sources and costs of electricity were determined on a regional basis using data in Table 5-1. The Pacific

*Hydropower additions will be mainly used for peaking power.

**R. K. Trehan, et al., "Site-Specific Analysis of Geothermal Development - Scenarios and Requirements," MTR 7586, Vol. II (in process).

TABLE 5-1
PARAMETERS FOR CALCULATION OF COSTS OF ELECTRICITY FOR
NUCLEAR AND COAL PLANTS
(MITRE CORPORATION)

	COAL PLANTS		NUCLEAR PLANTS	
	Pacific Census Region	Mountain Census Region	Pacific Census Region	Mountain Census Region
Capital Cost, 1976 \$/kW	683	600	816	717
O&M Cost, 1976 \$/kW/Yr	21.2	21.2	12.0	12.0
Plant Life, Yrs.	30	30	30	30
Effective Capacity Factor	0.70	0.70	0.70	0.70
Burn Rate (Btu/kWh)	9751	9751	10340	10340
Fuel Price (1976, \$/10 ⁶ Btu)	69.0	41.0	46.0	46.0
<u>Fuel Escalation Rates</u> (per cent per year)				
NEP Scenario	11.4% to 1985, 6.5% after			
RTS Scenario	5.9% to 1985, 6.5% after			
High Escalation	-		8.1% to 1990, 9.8% after	
Low Escalation	-		8.1% to 1990, 7.8% after	

Region comprises California, Washington, and Oregon, and the Mountain Region comprises New Mexico, Utah, Nevada, Montana, Idaho, Wyoming, and Colorado. As shown in Table 5-2, the cost range of competing energy sources is 16.7 to 28.1 mills/kWh depending upon region, scenario, fuel type and date.

In general, coal is expected to be plentiful and relatively inexpensive throughout the Mountain Region, and plant additions in this region are therefore expected to be predominantly coal-fired. In the Southwest region and in the eastern part of the Northwest Region, geothermal energy will be mainly competing against baseload coal plants, at an expected cost of about 20.0 mills/kWh for plants coming on-line in 1985, rising to about 20.6 mills/kWh for plants coming on-line in 1990.

In the western part of the Northwest Region, the main competitor is expected to be nuclear. California obtains some of its power from the Northwest; in addition, nuclear plants (such as the Sun Desert Plant near the Imperial Valley) are proposed in the state. It is therefore assumed that nuclear will be the main competitor in California also.* The cost of nuclear power additions in the Pacific Region is expected to be 24.5 mills/kWh for plants coming on-line in 1985, rising to 27.0 mills/kWh to plants coming on-line in 1990.

Table 5-3 represents the cost data and assumptions used by Companies H and J for comparing among the three baseload power

*This assumption may be invalidated by recent events in California.

TABLE 5-2

LEVELIZED BUSBAR COSTS OF ELECTRICITY FROM COAL
 (1977 mills/kWhr)
 (MITRE CORPORATION)

PLANT-ON-LINE DATE AND SCENARIO	REGION/PLANT TYPE			
	Pacific		Mountain	
	Coal	Nuclear	Coal	Nuclear
1985 National Energy Plan	27.0	-	20.0	-
1985 Recent Trends Scenario	21.5	-	16.7	-
1985 High Escalation	-	24.5	-	23.2
1985 Low Escalation	-	22.2	-	20.9
1990 National Energy Plan	28.1	-	20.6	-
1990 Recent Trends Scenario	22.8	-	17.5	-
1990 High Escalation	-	27.0	-	25.7
1990 Low Escalation	-	23.4	-	22.3

TABLE 5-3

COMPETING ENERGY RESOURCES AND ASSUMPTIONS

	Company H			Company J		
	Coal Conventional	Nuclear LWR	Geothermal Liquid-Dom.	Coal Conventional	Nuclear LWR	Geothermal Liquid-Dom.
Capacity Cost \$/kW	704	904	604	980	980	1040
Operating Capacity	585/2000	500/2000	60/100	300/1000	260/1300	10/50 MW
O&M Cost \$/kW/Yr	22	6.5	42	44.68	6	34.8
Plant Life	35	30	30	35	30	30
Effective Capacity Factor	.75	.88	.75	66	75	65-85
Heat Rate (Btu/kWh)	9500	10162	31600	10500	10500	21500
Fuel Cost						
Fuel Price	.139¢/10 ⁶ Btu	58.5¢/10 ⁶ Btu	66¢/10 ⁶ Btu	120¢/10 ⁶ Btu	55¢/10 ⁶ Btu	85.56¢/10 ⁶ Btu
Fixed Charges Rate	.1648	.1553	.167	21.4	21.4	20.8
Construction Years	9	10	4	10	12	7
Busbar Cost (mil/kWh)	45.45	39.2	67	71	53	91

Note: All costs have been corrected to 1977\$

generation sources: coal, nuclear and geothermal. In both comparative situations, the geothermal energy source is not competitive with either coal or nuclear for electric power generation.

5.1 Data and Assumptions

For consistency of comparison, the Metrek revenue requirements model is used to compute the busbar cost for geothermal coal and nuclear sources of power generation. Table 5-4 shows the data and assumptions used for calculating costs of electricity from nuclear, coal and geothermal resources for optimistic and pessimistic comparative situations.

The financial assumptions and other tax data are similar to those normally used by various utilities in computing levelized busbar costs of electricity. For convenience, these data are shown lumped into a single fixed charge rate for each of the competing sources of power generation. The expenditure profile during the construction period for each of the competing power generation sources is shown in Table 5-5. It is assumed that cash for each year's construction increment is borrowed and spent at the start of the year and that the interest must be paid on the current dollar cash flow at a compound interest rate of 8 percent until the power generation unit is put into service. The capital cost at completion of construction is the sum of the current dollar cash flow and the accrued interest charges during construction period expressed in 1977 dollars. The general inflation rate for capital costs, O&M costs and the revenue stream is taken to be 5 percent per year.

TABLE 5-4
GENERAL COMPARATIVE DATA
FOR VARIOUS COMPETING SOURCES OF POWER GENERATION

Parameters	Coal Plants		Nuclear Plants		Geothermal Plants	
	Optimistic Estimate	Pessimistic Estimate	Optimistic Estimate	Pessimistic Estimate	Optimistic Estimate	Pessimistic Estimate
Capital Cost 1976 \$	600	683	717	816	551	1026
O&M Cost 1976 \$/kW/Yr	21.2	33.92	12.0	29.14	42	84
7/ Plant Life	30.0	35.0	30.0	35.0	20.0	30.0
Effective Capacity Factor	0.70	0.70	0.70	0.70	.80	.65
Burn Rate (Btu/kWh)	9751	10324	10340	11007	--	--
Fuel Cost (\$/kW/Yr)	24.515	43.68	29.166	31.04	--	--
Fuel Price (1976¢ /10 ⁶ Btu)	41.0	69.0	46.0	46.0	--	--
Fixed Charge Rate	.208	.207	.209	.208	.231	.211

TABLE 5-5

EXPENDITURE PROFILE DURING CONSTRUCTION YEARS
FOR VARIOUS COMPETING POWER GENERATION SOURCES

Year Prior to In Service Date	Percent Distribution of Investment During Construction Years					
	Coal		Nuclear		Geothermal	
	Pessimistic	Optimistic	Pessimistic	Optimistic	Pessimistic	Optimistic
1	3	2	4	2	7	8
2	8	7	10	7	42	46
3	26	11	18	11	39	46
4	28	29	18	29	6	
5	18	34	16	34	4	
6	12	17	16	17	1	
7	3		10		1	
8	1		4			
9	.5		1			
10	.5		1			
11			1			
12			1			
Percent Increase in Total Plant Cost Due to AFDC	100	44	129	44	76	21

Table 5-6 shows the levelized busbar costs of electricity generated from coal, nuclear and geothermal power in 1977 dollars, under optimistic and pessimistic comparative situations.

5.2 Discussion of Results

Inspection of Table 5-6 indicates that the geothermal power generation cost has the largest uncertainty (19 to 54 mills/kWh). The large overlap in the uncertainty bands of the three competing sources indicates that site-specific considerations, system-specific assumptions, and decision factors other than busbar cost are controlling. For example, regional differences may exist in plant capital cost due to such factors as varying labor rates and transportation charges.

System-specific assumptions include capital cost (\$/kW), O&M cost (\$/kW/yr), heat rate, net power generation and construction period. Of these assumptions the construction period constitutes the major advantage of the geothermal power plant over either coal or nuclear power plant since it has the shortest construction period. Funds employed in the process of construction incur interest charges that can substantially increase the final cost of a given plant depending on the length of the construction period. Even for the shortest possible construction period for coal or nuclear power plant shown in Table 5-5, the interest on funds during construction period increases the final plant cost in either case by as much as 44 percent. The corresponding increase in the total geothermal power plant cost is only 21 percent.

TABLE 5-6

LIFECYCLE LEVELIZED BUSBAR COSTS OF ELECTRICITY
CALCULATED BY METREK METHOD FOR VARIOUS
COMPETING SOURCES OF POWER GENERATION

Comparative Situation	Power Generation Source		
	Coal (mills/kWh)	Nuclear (mills/kWh)	Geothermal (mills/kWh)
Optimistic	25.3	28.2	19
Pessimistic	40.8	47.9	54

The amount of interest incurred during the construction period is also affected by the choice of common date (i.e., common date for start of construction or common startup in-service date) for comparison between competing power generation options. In the context of rapid inflation, the choice of the common in-service date as the reference time for comparison tends to favor the power generating units with long construction periods (i.e., coal or nuclear power generating sources). Choosing the common start of construction date as the reference time, however, would be more advantageous to power generating units which are capable of being constructed over a shorter time frame (e.g., geothermal power plants). In this report, the common date chosen for comparison between the competing sources of power generation is the start-up or year in-service date. A built-in bias against geothermal power plants should therefore be expected due to the short construction period of such plants.

The relative costs of the major factors in electric power production (i.e., capital equipment, fuel and O&M costs) may change over time due to price escalation. In recent years, both construction (i.e., materials and labor) and fuel costs have risen much more rapidly than prices in other sectors of the economy. Even a small percentage difference in escalation rates can produce significant differences when compounded over a long lifecycle (e.g., 30 years). Underestimation of future increase in escalation rates for fuel may

result in a bias against fuel saving capital intensive power generation alternatives (e.g., nuclear), since fuel escalation for these plants would affect a smaller proportion of the electricity cost.

6.0 CONCLUSIONS AND RECOMMENDATIONS

This survey has shown that major variations in projected costs of electricity from geothermal (hydrothermal) resources can be traced to differences in the methodology by which these costs are computed, even starting from the same input data (capital and operating costs and parameters, and financial data such as inherent and tax rates and capital ratios). By extension, the same variation will exist for other energy sources, since the same differences in methodology will apply.

It is recommended that a standard methodology be established for the computation of energy costs, and that this procedure be used in addition to the varied computations which may be performed by the organizations originating projected costs. The standard methodology should have the following features:

- applicability to a wide range of energy sources
- ease of comprehension and computation
- ability to perform sensitivity analyses for physical and financial parameters
- ability to incorporate fiscal incentives (e.g., investment tax credit, depletion allowance)

Ideally, the methodology should find use throughout DOE in order to aid comparison of different energy sources; as a minimum, its use within DGE should become standard for reconciling different estimates.

It is also apparent that major differences exist in capital and operating cost estimates produced for similar resources by different organizations. Future projections of relative economic competitiveness of different energy sources may be critically affected by these differences. At a minimum, they could seriously distort present decisions on capital investment, R&D strategy, and energy taxation. Reconciliation of methodological and data differences and establishment of standards should therefore be a matter of priority.

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