MITRE Report
M-78-86

DOE/ET/28505-T1
Distribution Category UC-66c

WELCST: Engineering Cost Model of Geothermal Wells

Description and User's Guide

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February 1979

Contract Sponsor: DOE/DGE

Contract No.: EG-77-C-01-4014
Project No.: 1526N
Dept.: W-52

DGE-4014-9

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ABSTRACT

This paper describes WELCST, a FORTRAN code for estimating the effects of R&D project results upon the future cost of geothermal wells. The code simulates the drilling and completion of a well at 27 specific U.S. geothermal prospects, given assumptions about well design and casing plan, formation drillability, and selected engineering and cost characteristics of today's drilling technology. The user may change many of the assumptions about engineering and cost characteristics to allow WELCST to simulate impacts of specific R&D projects on the estimated cost of wells at the prospects. An important capability of WELCST is that it simulates rates and costs of major drilling mishaps, based on drilling incident data from the Imperial Valley and Geysers geothermal fields. WELCST is capable of estimating geothermal well costs at liquid-dominated (hydrothermal) sites, vapor-dominated sites, geopressured sites, and Hot Dry Rock sites. The model can contribute to many system-optimization studies, and could be easily adapted to estimate well costs outside of the United States.

ACKNOWLEDGEMENTS

The authors are indebted to Clifton Carwile of the Division of Geothermal Energy, U.S. Department of Energy; Joseph Polito of Sandia Laboratories, and John Rowley of the Los Alamos Scientific Laboratories for guidance furnished during preparation of the WELCST model. Richard Pfundstein, MITRE Corporation, made valuable contributions to the analysis of interactions between rock types and drilling penetration rates.

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EXECUTIVE SUMMARY

This report describes a new engineering cost model of Geothermal wells, WELCST. WELCST was created to evaluate economic impacts of geothermal drilling technology R&D projects, but can also be used for a variety of other purposes.

WELCST calculates the cost of a geothermal well at a specific geothermal prospect, given certain physical characteristics of the prospect and engineering/cost parameters of available technology. Current or "baseline" costs are based on the performance parameters of 1978 geothermal drilling technology, assuming no R&D impacts. The potential economic impact of an R&D project, or a group of projects, is evaluated by altering the performance parameters that are most likely to be altered by the outcome of the R&D effort.

The six major components of WELCST are shown in Figure E-1. They are:

- Current technology engineering/cost parameters - These were drawn from the open literature and discussions with geothermal drilling engineers.
- R&D impacts file - Impact estimates, put in this file by the operator, alter the performance and/or cost of drilling and completion technology during execution of the computer code. There are 86 impact categories.
- Geothermal well designs - Ten borehole and casing plans typical of 1978 U.S. geothermal well designs.
- Historical geothermal drilling mishap data - Based on U.S. geothermal drilling experience, the model includes capability to estimate frequencies and costs of major types of drilling accidents and incidents. Variation of mishap frequencies and costs with well depth and rock hardness is accounted for.
- Physical characteristics of geothermal prospects - The model will estimate costs for a single well, or for wells at 27 U.S. liquid-dominated geothermal prospects. The critical parameters are: well depth, rock hardness, and bottomhole formation temperature. This file can be updated to account for new sites not in the original development scenario.

**FIGURE E-1
COMPONENTS OF WELCST MODEL**

- Well costing algorithms - These guide the cost computations in ways appropriately sensitive to the above factors.

WELCST makes explicit account of those aspects of drilling technology where current R&D seems most likely to have important impacts. These components and processes include:

- Five different types of drill bits, selected for optional performance or economics depending on downhole conditions.
- Explicit casing plans, as required by well depth, rock type, and other factors.
- Effects of mud bottom hole circulating temperature on bit lifetimes.
- Effects of drilling fluid type, mud or air, on downhole temperature and rate of penetration.
- Provision for single or multiple bottom-hole completions, and
- Provision for use of downhole motors for straight or directional drilling.

The cost accounts from which the total cost of a well is estimated are shown in Table E-1. The values in the Table indicate that the overall impact of a 20% increase in the rate of penetration of tricone insert bits, all other factors being held equal would be a 6.6 percent reduction in total well costs at sites with the indicated characteristics. This particular change can be seen to have impacts on many subaccount costs, besides the primary impact of reducing drilling time.

Table E-2 shows typical output from WELCST when used to evaluate impacts of R&D results on well costs at specific U.S. geothermal prospects. As in table E-1, the assumed R&D impact is a 20% improvement in penetration rate of tricone insert bits. The resulting economic impact ranges from a 2.1% to 19.8% cost reduction across the 27 listed prospects.

The estimated economic effects of a few other potential R&D impacts are presented in Table E-3. Those results clearly indicate that moderate to large improvements in penetration rate would have much larger economic benefits than similar degrees of improvement in bit lifetimes.

TABLE E-1

COST REPORT FOR SINGLE WELL

(Example: Impact of 20 percent increase in rate¹
of penetration of tricone insert bit)

WELL COST ACCOUNT	HOURS OF RIG TIME	COST (\$ 1978)	% OF TOTAL COST	% CHANGE FROM BASELINE COST
A. ROTATING ON BOTTOM	583.	116546.	13.7	-16.7
B. TRIPPING BITS AND MOTORS	44.	8788.	1.0	-17.7
C. CASING AND CEMENTING	150.	30041.	3.5	-0.0
D. MISHAPS	363.	72587.	8.6	-0.0
E. OTHER	144.	28880.	3.4	-14.1
1. TOTAL RIG TIME CHARGES	1284.	256842.	30.3	-10.4
2. BITS		28251.	3.3	-16.7
3. DOWNHOLE MOTOR		13129.	1.5	-0.0
4. MUD		12579.	1.5	0.0
5. FUEL		30920.	3.6	-13.3
6. DRILL PIPE		11196.	1.3	-0.0
7. WATER		14568.	1.7	-16.7
8. WASTE DISPOSAL		13574.	1.6	-9.7
9. SURFACE EQUIPMENT AND WELL HEAD		78860.	9.3	-8.0
10. CASING		80195.	9.4	0.0
11. CEMENT AND SERVICES		33484.	3.9	0.0
12. SITE PREPARATION, RIG UP & DOWN		95000.	11.2	0.0
13. MISHAP COSTS		72821.	8.6	-7.0
14. MISC. TRANSPORTATION		8235.	1.0	-5.0
15. LOGGING		26000.	3.1	0.0
16. MISCELLANEOUS		50000.	5.9	0.0
17. SUPERVISION AND OVERHEAD		23116.	2.7	-10.4
TOTAL		848768.	100.0	-6.6
DAYS TO DRILL WELL:	54.			

¹ Assumptions:

- Total Depth = 6500 feet
- Rock Type (Drillability) = Medium-Hard
- Bottom Hole Rock Temperature = 250°C
- Drilling Fluid = Mud
- Completion = Bottom 30% not cased

TABLE E-2

OUTPUT FROM WELCST: EFFECTS OF 20%
INCREASE IN RATE OF PENETRATION OF TRICONE
INSERT BITS AT 27 U.S. GEOTHERMAL PROSPECTS

GEOTHERMAL PROSPECT	WELL COST WITH R&D	WELL COST W/O R&D	PERCENT DIFFERENCE
1. BRAWLEY, CALIFORNIA	585391.	601634.	-2.7
2. COSO, CALIFORNIA	626738.	658939.	-4.9
3. EAST MESA, CALIFORNIA	582009.	597935.	-2.7
4. THE GEYSERS, CALIFORNIA (LIQUID-DOMINATED)	1186114.	1479701.	-19.8
5. GLASS MOUNTAIN, CALIFORNIA	1186114.	1479701.	-19.8
6. HEBER, CALIFORNIA	582009.	597935.	-2.7
7. LASSEN, CALIFORNIA	626738.	658939.	-4.9
8. MONG-LONG VALLEY, CALIFORNIA	626738.	658939.	-4.9
9. PUNA, HAWAII	1901600.	2201442.	-13.6
10. SALTON SEA, CALIFORNIA	465774.	475567.	-2.1
11. SURPRISE VALLEY, CALIFORNIA	626738.	658939.	-4.9
12. ALVORD, OREGON	1196511.	1443724.	-17.1
13. BAKER H.S., WASHINGTON	1186114.	1479701.	-19.8
14. BRUNEAU-GRANDVIEW, IDAHO	1186114.	1479701.	-19.8
15. RAFT RIVER, IDAHO	722543.	754383.	-4.2
16. VALE H.S., OREGON	464500.	472788.	-1.8
17. WEISER-CRANE CREEK, IDAHO	626738.	658939.	-4.9
18. BEOWAWE, NEVADA	781779.	842584.	-7.2
19. BRADY H.S., NEVADA	537585.	566574.	-5.1
20. CHANDLER, ARIZONA	1186114.	1479701.	-19.8
21. COVE FORT-SULPHURDALE, UTAH	860194.	919537.	-6.5
22. LEACH, NEVADA	1186114.	1479701.	-19.8
23. ROOSEVELT H.S., NEVADA	553312.	577897.	-4.3
24. SAFFORD, ARIZONA	1186114.	1479701.	-19.8
25. STEAMBOAT SPRINGS, NEVADA	387313.	397043.	-2.5
26. THERMO, UTAH	676954.	708794.	-4.5
27. VALLES CALDERA, NEW MEXICO	781779.	842584.	-7.2
AVERAGE	833914.	950110.	-9.2

TABLE E-3

SOME TYPICAL RESULTS FROM WELCST

VARIABLE CHANGED	MAGNITUDE OF CHANGE	WELCST RESULT: AVERAGE % CHANGE IN WELL COST
Rate of Penetration	+20%	-9.2%
	+100%	-20.1%
Life of Tricone Insert Bits	+20%	-0.5%
	+100%	-1.4%
Casing Cost	-20%	-2.2%
Mud Cost	-20%	-0.5%

While WELCST was constructed to assess economic impacts of R&D results on U.S. geothermal prospects, the model is general enough in scope to be useful in a wide variety of analytic, planning, and system optimization studies. For example, WELCST could either be used directly or adapted very easily to estimate: costs of wells in geopressured zones or hot dry rock, the economic advantages of drilling multiple wells from a single drilling pad, or well costs of geothermal development in nations other than the United States.

This report contains a detailed description of the WELCST model as well as the code for the computer programs and the data files which comprise WELCST.

1.0 INTRODUCTION

1.1 Background

WELCST is a FORTRAN code that estimates the cost of geothermal wells for electric plants at 27 liquid-dominated geothermal (hydrothermal) prospects in the United States. A major feature of WELCST is its ability to assess the likely impacts of anticipated improvements in well-drilling technology upon the costs of geothermal wells at the 27 prospects.

The model is generic in capability. It can be readily adapted to estimate well costs at other types of prospects (e.g., geopressured, vapor-dominated, non-U.S.), the dependence of those costs on technology development, and cost effects of certain novel well drilling strategies.

Important features of the model include:

- Well designs tailored to the characteristics of geothermal prospects,
- Variation of rate of penetration with rock hardness and depth,
- Estimation of the bit temperature environment while rotating, as affected by formation temperature and cooling by drilling fluid,
- Selection of bits of different types, depending on downhole conditions and drilling economics,
- Use of downhole motors for directional drilling, or optionally, for straight-hole drilling,
- Frequencies and costs of various types of drilling mishaps, accidents, and incidents, and
- Provision for altering 86 engineering and cost parameters of drilling technology, to assess economic impacts of changes in drilling techniques and technology.

The preparation of WELCST was funded by the Utilization Technology Branch (UTB) of the Division of Geothermal Energy (DGE) of the Department of Energy. The work is part of MITRE's continuing support of DGE in the areas of economic analysis, R&D program evaluation, and program planning.

WELCST was written as one component of an extensive benefit/cost analysis of current DGE Utilization Technology Branch R&D projects (1). WELCST is based on previous MITRE studies of methodology for benefit/cost analyses of DGE R&D projects (2), site-specific analyses of characteristics of geothermal prospects in the United States (3), a model of levelized busbar costs of electricity from geothermal prospects (4), a developmental ("power-on-line") scenario for U.S. geothermal prospects (3,4), and prospects for improvement of geothermal drilling technology (5). The GEOWEL model of geothermal well costs prepared by the Los Alamos Scientific Laboratory provided significant inputs to the structure and content of WELCST (6).

1.2 Purpose and Scope

The purpose of WELCST is to assist in the evaluation of future impacts on geothermal well capital cases of technology improvements in the areas of geothermal well drilling, logging, and completion technology.

While WELCST is intended to be used for estimating economic effects of selected R&D projects, it is generic enough in scope to be useful in a variety of analytic, planning, and system optimization

activities. For example, WELCST could be used directly or adapted easily to estimate costs of geopressured wells, the economic advantages of drilling multiple wells from the same drilling pad, and costs of geothermal well development in nations other than the United States.

The postulated well designs and the formulae used to estimate relationships among geothermal prospect characteristics, drilling technology parameters, and costs reflect MITRE's understanding of typical conditions at U.S. geothermal prospects. The formulae are specified at levels of detail less than those generally needed to plan a drilling and casing program for an actual geothermal well.

Similarly, the assumed relationships between technology alterations and drilling performance are necessarily tentative. These relationships have been drawn from published accounts and contacts with drilling contractors and researchers. Because only a limited amount of time could be devoted to collecting and analyzing data, many of the technical and economic relationships postulated in WELCST are subject to revision as data and understanding are refined.

It should also be noted that the cost estimates contained in the model are drawn from the point of view of a geothermal developer rather than that of a drilling company. Thus labor costs and potential labor efficiencies are not accounted for explicitly, but are subsumed within other accounts in certain traditional ways. For example, rig crew charges are included in the rig rental rate, and

labor for special services (e.g., downhole motor use and well logging) are included in equipment O&M costs or specific service charges. If necessary in the future, specific accounting of labor costs could be made without any major changes in the model.

2.0 OVERVIEW OF MODEL

2.1 Role and Structure

WELCST is one of several components of a systematic process for estimating the likely benefits of research and development projects. The specific role of WELCST is to translate estimated technical and cost impacts of specific R&D projects into reductions in the cost of drilling and completing geothermal wells. The relationship of WELCST to other components of the benefit analysis method are shown in Figure 1.

There are three main steps in the analysis of each project or group of closely related projects. First, the R&D project is analyzed to identify the type and magnitude of impacts that the project is likely to have on the performance and cost parameters of present-day drilling technology. Second, these impacts are entered into WELCST, and WELCST is executed to compute the costs of wells given these impacts, and to compare those costs to well costs based on current technology in the absence of R&D impacts. Third, the results from WELCST serve as inputs to a second computer code, GEOBEN, to compute the aggregated expected economic benefits of the R&D project across 27 geothermal prospects over a 22 year period (1978-2000).

The GEOBEN model is described in detail in Volume I of Reference 1. The rationale for the approach to benefit/cost analysis used here can be found in (1) and (2).

The major elements of WELCST are:

FIGURE 1
RELATIONSHIP OF WELCST MODEL TO OTHER
COMPONENTS OF R&D PROJECT BENEFIT/COST ANALYSIS

- A main program (WELCST) that handles data input/output and initializes parameters for the drilling of single wells,
- A subroutine (ONEWEL) that computes the cost of a single geothermal well, given specified parameters for well depth, rock hardness, bottom hole temperature, and well design,
- A file (RAJJ) of estimated technical parameters and power-on-line dates for 27 U.S. hydrothermal prospects.
- A file (DESIGN) of 11 generic well designs that are adjusted, as needed, to prospect parameters,
- A file (ENGVAR) of 86 engineering and cost factors that affect the cost of wells,
- Other files, described below, used to handle execution-time options, bit performance data, and other I/O requirements.

WELCST is maintained and operated in a time-shared environment under the MITRE/Metrek CMS terminal-servicing monitor system. WELCST code contains no provisions for direct interaction with the user. All user control of WELCST occurs through changes of data in the WELCST input files, using the FEDIT editing routines.

The data file (RAJJ) of estimated technical parameters and power on-line dates for the geothermal prospects is an updated version of the same file and information used in MITRE's Geothermal Energy Levelized Busbar Cost of Electricity Model, GELCOM (4). Thus there is strong continuity between the WELCST model and previous analyses of the development of geothermal energy in the U.S. (e.g., see references 3,4, and 5).

2.2 Run-Time Options and Generic Model Well

Run-time options are selected by changing variables in a file named "RUNOPS". RUNOPS allows the user to alter or select:

- Title of R&D project,
- Code number of R&D project,
- Optional print-out of data bases for drilling bit performance and engineering/economic variables,
- Computation of the cost of a single well, for purposes of calibrating the model,
- Updating the "baseline" cost estimates for wells at the 27 prospects. The baseline costs assume current technology, with no impacts of R&D, and
- Calculating the costs of wells at the 27 prospects, given selected impacts of R&D projects on drilling performance relationships.

The available options are described in detail in Section 3.7.

To analyze the effects of an R&D project, the operator:

- Enters the estimated impacts of the R&D project in file "ENGVAR".
- Enters the project title in RUNOPS.
- Enters numbers in RUNOPS to select the desired run-time options.
- Instructs the CMS system to execute WELCST.
- Waits for WELCST execution to end.
- Initializes the GEOBEN model (1).
- Instructs the CMS system to execute GEOBEN.

WELCST places the cost-of-well results in file WCOST data. This file is accessed by GEOBEN for further calculations that estimate the

total economic benefit expected to obtain from the technical results of the R&D project. An example of an operating session is presented in Section 5.0. Specifications of the data files are given in Section 3.0.

WELCST includes a provision for calculating the effects of R&D impacts on the cost of a single test case well. This allowed rapid calibration of the model, and provides reports of the effects of R&D impacts on costs of subcomponents of a "generic model geothermal well". Examination of the cost subaccounts for the generic well allows the operator to ascertain whether the model is behaving in expected manners.

For the analyses in this report, the generic test case well was specified as follows:

- Well depth - 6500 feet
- Rock type - Medium-Hard
- Formation Temperature - 250°C
- Well Design - Bottom 30% of borehole not cased.

This approximates as typical a set of "prospect characteristics" as can be abstracted from the 27 specified geothermal prospects (3).

2.3 The Main Program (WELCST)

WELCST has six functions, as shown in Figure 2:

- (1) Read the required data files.
- (2) Write out the contents of the data files that define what is to happen during the run.

FIGURE 2
FLOW CHART OF "WELCST" MAIN PROGRAM

- (3) Initialize parameters for the generic model well, and call the ONEWEL subroutine to compute and report the cost of that well.
- (4) Initialize parameters for each of the 27 prospect wells, and call ONEWEL to compute the cost of each.
- (5) Print the results of Step 4 and write the results of Step 4 into the WELCST DATA file, from which they can be accessed by the GEOBEN program.
- (6) Update baseline costs, if required.

If the "Print Flag" is on when ONEWEL is called, ONEWEL prints reports of rotating costs, other drilling subaccount costs, and mishap frequencies and costs (See Section 2.4).

Table 1 is an example of the output generated at Step 5. In this hypothetical case, the cost changes attributed to R&D are caused by a 20% increase in the instantaneous rate of penetration of all types of tricone insert drill bits, without change in bit life or cost. For example, this technology change decreases the estimated cost per well at Brawley, CA from \$601,634 to \$584,391, a 2.7% reduction. The "average" well cost is across one well per prospect.

2.4 Well Cost Subroutine (ONEWEL)

This section is intended to provide a general understanding of how the cost of a specific geothermal well is calculated. It also describes the reports that are available from ONEWEL.

Figure 3 indicates the main information flows within ONEWEL. Specific algorithms and program flow relationships are discussed in Section 4.0.

Footage costs, especially as affected by bit characteristics

TABLE 1
OUTPUT OF WELCST AT STEP 5

GEOHERMAL PROSPECT	WELL COST WITH R&D	WELL COST W/O R&D	PERCENT DIFFERENCE
1. BRAWLEY , CALIFORNIA	585391.	601634.	-2.7
2. COSO , CALIFORNIA	626738.	658939.	-4.9
3. EAST MESA , CALIFORNIA	582009.	597935.	-2.7
4. THE GEYSERS, CA. (LIQUID-DCMINATED)	1186114.	1479701.	-19.8
5. GLASS MOUNTAIN , CALIFORNIA	1186114.	1479701.	-19.8
6. HEBER , CALIFORNIA	582009.	597935.	-2.7
7. LASSEN , CALIFORNIA	626738.	658939.	-4.9
8. MONO-LONG VALLEY , CALIFORNIA	626738.	658939.	-4.9
9. PUNA , HAWAII	1901600.	2201442.	-13.6
10. SALTON SEA , CALIFORNIA	465774.	475567.	-2.1
11. SURPRISE VALLEY , CALIFORNIA	626738.	658939.	-4.9
12. ALVORD , OREGON	1196511.	1443724.	-17.1
13. BAKER H.S. , WASHINGTON	1186114.	1479701.	-19.8
14. BRUNEAU-GRANDVIEW , IDAHO	1186114.	1479701.	-19.8
15. RAFT RIVER , IDAHO	722543.	754383.	-4.2
16. VALE H.S. , OREGON	464500.	472788.	-1.8
17. WEISER-CRANE CREEK , IDAHO	626738.	658939.	-4.9
18. BEOWAVE , NEVADA	781779.	842584.	-7.2
19. BRADY H.S. , NEVADA	537585.	566574.	-5.1
20. CHANDLER , ARIZONA	1186114.	1479701.	-19.8
21. COVE FORT-SULPHURDALE , UTAH	860194.	919537.	-6.5
22. LEACH , NEVADA	1186114.	1479701.	-19.8
23. ROOSEVELT H.S. , NEVADA	553312.	577897.	-4.3
24. SAFFORD , ARIZONA	1186114.	1479701.	-19.8
25. STEAMBOAT SPRINGS , NEVADA	387313.	397043.	-2.5
26. THERMO , UTAH	676954.	708794.	-4.5
27. VALLES CALDERA , NEW MEXICO	781779.	842584.	-7.2
AVERAGE	833914.	950110.	-9.2

FIGURE 3
DATA, CALCULATIONS, AND REPORTS FOR
"ONEWEL" SUBROUTINE

and downhole motor performance, were given special attention in the model because many of the Geothermal Drilling R&D projects have direct or indirect impacts on these variables.

Table 2 provides a typical "Footage Cost Report" from ONEWEL. This report provides, for each stage of drilling depth and bit diameter:

- Rotating time and cost,
- Tripping time and cost,
- Bit number and cost,
- Total (and per-foot) of the above costs, and total of these costs for the well.

Table 3 shows a typical "MISHAPS" cost report. This report provides:

- Estimated frequency, per production well at a specified prospect,
- Rig rental hours charged to each productive well, due to each type of accident - given the estimated frequency,
- Costs other than rig rental charged to each productive well, due to each accident - given the estimated frequency.

Section 4.8 describes the bases for mishap frequencies and costs, and the ways in which anticipated mishaps for a given geothermal prospect are charged to the cost of productive (successful) wells at that prospect. The way in which circulation is recovered has tended to depend on rock hardness, with materials added to the mud for prospects drilled in sedimentary (soft) rock and cementing used in

TABLE 2

FOOTAGE COST REPORT FROM ONEWEL SUBROUTINE

6500. FT WELL, DESIGN # 5 TITLE:GENERIC WELL DESIGN ROCK TYPE = M-HD
 BOTTOM HOLE TEMP. = 250 RIG RENT = \$ 200. PER HOUR

 *WELL * DEPTH-FEET *DIAM.*FLUID*TEMP *ROTATING TIME *TRIPPING TIME*BITS USED *COST PER STAGE *
 *STAGE*START *STOP *INCH * *DEG-C*HOURS*COST,\$ *HOURS*COST,\$ *NO. *COST,\$*TOTAL,\$ *\$/FOOT*

1	0.	150.	26.00	2.	19.	1.	250.	0.	15.	0.0	213.	478.	3.19
2	150.	1950.	9.62	2.	56.	68.	13577.	2.	331.	0.8	2835.	16742.	9.31
3	150.	1950.	17.50	2.	56.	47.	9332.	3.	617.	1.6	5706.	15655.	8.70
4	1950.	4550.	12.25	3.	66.	198.	39617.	9.	1820.	2.2	8271.	49707.	19.14
5	4550.	6500.	8.75	2.	75.	269.	53771.	17.	3442.	3.0	11226.	68439.	35.13
TOTALS													
0	0.	6500.	0.00	0.	0.	583.	116546.	31.	6225.	7.5	28251.	151022.	23.23

FLUID: 1 = AIR, 2 = WATER, 3 = MUD

TABLE 3
MISHAP REPORT FROM ONEWEL SUBROUTINE

INCIDENTS FOR GENERIC WELL

TYPE OF INCIDENT	FREQUENCY	RIG HOURS	MISC. COST
01. DOGLEG - CEMENT, REDRILL	0.082	6.	163.
02. LOST CIRCULATION - MATERIALS IN MUD	0.0	0.	0.
03. LOST CIRCULATION - CEMENT, REDRILL	1.530	171.	4590.
04. FISH FOR JUNK	1.020	44.	510.
05. FISH PIPE - RECOVER IT	0.592	43.	592.
06. FISH PIPE - FAIL, ABANDON HOLE	0.082	20.	41253.
07. FISH PIPE - FAIL, SIDETRACK, REDRILL	0.163	36.	21416.
08. SIDETRACK - UNSPECIFIED	0.255	32.	510.
09. SIDETRACK - FIRST BOTTCM WAS DRY	0.031	1.	3614.
10. COGITATION	0.173	10.	173.
 TOTAL	 3.733	 363.	 72821.

harder fractured rock. The three incident types involving fishing for drill pipe (Types 5, 6, and 7 in Table 3) are distinguished by outcomes rather than by causes. "Cogitation" (Incident Type 10) is time spent deciding what to do next, usually in a problem hole.

Table 4 presents the total well cost report provided by ONEWEL.

The report indicates:

- Twenty-two separate cost subaccounts for the specific well.
- Percent change from a "baseline" of well costs, previously calculated under the assumption that only current technology would be available to drill the well.
- Total cost to drill the well, case the well, and install the well head control equipment.
- Percentage of total well cost attributed to each of the 17 numbered accounts.
- Number of days to drill and complete the well.

Note that numbered account 1 in Table 4 incorporates the costs of all of the lettered accounts, A-E. All of the lettered accounts are based on various uses of drilling rig time, as described in Section 4.0. The rig charges due to drilling mishaps is given in account D, while additional costs due to mishaps are given in account 13.

The values in the right-most column of Table 4 show the percentage change in account cost due to the improvement in technology, compared to the same well if drilled with current technology. These costs changes are usually reductions (minus signs), but can be

TABLE 4
WELL COST REPORT FROM ONEWEL SUBROUTINE

-----WELL COST ACCOUNT-----		HOURS OF RIG TIME	COST (\$ 1978)	% OF TOTAL COST	% OF BASE- LINE COST
A. ROTATING ON BOTTOM		583.	116546.	13.7	-16.7
B. TRIPPING BITS AND MOTORS		44.	8788.	1.0	-17.7
C. CASING AND CEMENTING		150.	30041.	3.5	-0.0
D. MISHAPS		363.	72587.	8.6	-0.0
E. OTHER		144.	28880.	3.4	-14.1
1. TOTAL RIG TIME CHARGES		1284.	256842.	30.3	-10.4
18	2. BITS		28251.	3.3	-16.7
	3. DOWNHOLE MOTOR		13129.	1.5	-0.0
	4. MUD		12579.	1.5	0.0
	5. FUEL		30920.	3.6	-13.3
	6. DRILL PIPE		11196.	1.3	-0.0
	7. WATER		14568.	1.7	-16.7
	8. WASTE DISPOSAL		13574.	1.6	-9.7
	9. SURFACE EQUIPMENT AND WELL HEAD		78860.	9.3	-8.0
	10. CASING		80195.	9.4	0.0
	11. CEMENT AND SERVICES		33484.	3.9	0.0
	12. SITE PREPARATION, RIG UP & DOWN		95000.	11.2	0.0
	13. MISHAP COSTS		72821.	8.6	-7.0
	14. MISC. TRANSPORTATION		8235.	1.0	-5.0
	15. LOGGING		26000.	3.1	0.0
	16. MISCELLANEOUS		50000.	5.9	0.0
	17. SUPERVISION AND OVERHEAD		23116.	2.7	-10.4
	TOTAL		848768.	100.0	-6.6
DAYS TO DRILL WELL:		54.			

increases if there are significant novel costs associated with use of the novel technology.

For the non-technical reader, Table 5 indicates some of the factors to which some of the main cost subaccounts of Table 4 are sensitive. Table 5 provides, in schematic fashion, much information about the relationships between many of the variables and influences incorporated into the ONEWEL Subroutine. Technical details are provided in Section 4.0.

2.5 Interface Between WELCST Model and Impacts of R&D Projects

The effects of improved technology on well costs are entered to the model by changing values in the ENGVAR DATA file.

For nominal performance and costs of current drilling technology, most of the 86 variables in ENGVAR are set at 1.00. These variables are altered (by the user editing ENGVAR) to reflect expected changes in technology resulting from a specific R&D project or project group.

For example, suppose an R&D project promises to increase the rate of penetration of conventional tricone bits by 20%, at a premium in the cost of these bits of 30%. To enter these changes, the variable "YROP" would be set at 1.20 and the variable "YBTCST" would be set at 1.30. Then the model, when run, would report estimated costs of wells at each prospect, assuming these changes. Both the percentage change and the dollar change in cost per well can differ for each geothermal prospect, depending on the ways in which drilling and completion operations at each prospect are affected by the

TABLE 5

FACTORS TO WHICH SOME TERMS IN THE MODEL ARE SENSITIVE

DRILLING PARAMETER	FACTORS AFFECTING PARAMETER
1. Footage Cost	ROP, Bitlife, Bit Cost, Drilling Depth, Rig Rent, Tripping Rate
2. Rate of Penetration	Rock Hardness, Drilling Depth, Drilling Fluid, Bit Type
3. Bit Life	Bit Type - As Matched to Rock Hardness, Bit Temperature
4. Bit Temperature	Bottom Hole (Reservoir) Temperature, Drilling Depth, Drilling Fluid
5. Bit Cost	Bit Type, Bit Diameter
6. Mud Cost	Rock Type, Well Depth
7. Casing Cost	Diameter, Length
8. Cement and Services Cost	Borehole, Diameter, Casing Diameter, Casing Length, Setting Depth, Borehole Sloughing
9. Drill Pipe Cost	Drilling Fluid, Rotating Time
10. Surface Equipment Cost	Rotating Time
11. Site Preparation	(Fixed)
12. Mishap Costs	Frequencies of Drilling Incidents as Functions of Well Depth and Rock Hardness, Cost to Recover from Each Type of Mishap
13. Miscellaneous Transportation	In Proportion to Certain Other Costs
14. Logging	In Proportion to Well Depth
15. Miscellaneous	(Fixed)
16. Overhead	In Proportion to Certain Other Costs

technology change.

Similarly, if some new directional drilling control technology promised to cut the frequency of doglegs in half, given a rental charge of \$10.00 per hour, this would be evaluated in the model by setting "YFDOG" to 0.50 and elevating the rig rent to \$210 per hour from the nominal \$200 per hour by setting "YRGRNT" to $210/200 = 1.05$. This change might be economical for some prospects and not others. The model, once run, would so indicate.

Table 6 provides a list and descriptions of the variables that can be manipulated, along with the nominal performance or cost parameters assumed in the equations of WELCST and ONEWEL.

2.6 Estimation of Benefits from WELCST Results

The output from WELCST is used as input to a second model, GEOBEN, to calculate the total economic benefit due to each R&D project or project group. This "benefit" is defined as the savings occasioned by the R&D project in the total cost to produce electricity at plants at 27 geothermal prospects contained in a developmental scenario spanning the years 1979-2000.

Output is passed by WELCST into the WCOST DATA file (See Section 3.8). WCOST contains, for each of the prospects, estimates of the cost of production and injection wells given the expected R&D impacts and estimates of costs in the absence of R&D impacts ("baseline" well costs).

TABLE 6

ENGINEERING/COST VARIABLES IN "ENGVAR" FILE

VARIABLE	DESCRIPTION	NOMINAL VALUE
1. YROP	Instantaneous rate of penetration (ROP) for all tricone bits (ft/hr).	Varies with rock hardness and depth as given in ROP block in BITVAR DATA.
2. YRGRNT	Drilling rig rental rate.	\$200/hour.
3. YRTRIP	Rate of round tripping bits and motors.	1000 ft/hr.
4. YFUEL	Cost of fuel for rig, per rotating hour.	\$40/hour.
5. YCSMUD	Cost of mud.	Depends on well depth. See code.
6. YWATER	Cost of water, per rotating hour.	\$25/hour.
7. YCEMCS	Cost of cement.	\$6/ft ³ .
8. YCEMTM	Rig time to cement casing.	Depends on casing length, landing depth, diameter. See code.
9. YCACST	Casing cost, \$/foot.	Depends on grade and diameter. See code.
10. YDICST	Cost of diamond bits (less salvage).	Varies with bit diameter. See code.
11. YLDIBT	Life of diamond bits.	1.0 hours.
12. YDIROP	ROP for diamond bits.	1.0 ft/hr.

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
13. YDISEL	ROP of tricone bits at which diamond bit is selected instead.	1.0 feet/hour
14. YCMOT	Capital cost, downhole motor (less salvage).	\$5000.
15. YLFMOT	Life of downhole motor.	120 hours.
16. YCMTOP	Operation and Maintenance cost of downhole motor.	\$41.67 per hour.
17. YMTROP	ROP effect of downhole motor.	Equal to ROP of bit as affected by YROP.
18. YAFREQ	Multiplier against rate of all drilling incidents.	NOTE:
19. YFDOG	Rate of: Recovering from dogleg.	The assumed rates of drilling accidents and mishaps vary with well depth and rock hardness. See code and explanation in Section 4.8.
20. YFLCM	Rate of: Lost circulation-recovered by adding materials to mud.	
21. YFLCC	Rate of: Lost circulation-recovered by cementing and redrilling.	
22. YFFISH	Rate of: Fishing for junk.	
23. YFPIPE	Rate of: Fishing for pipe and recovering it.	

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
24. YFFAIL	Rate of: Fishing for pipe, failing, and abandoning hole.	The assumed rates of drilling accidents and mishaps vary with well depth and rock hardness. See code and explanation in Section 4.8.
25. YSIDE	Rate of: Sidetracking for unspecified reasons.	
26. YSIDBT	Rate of: Fishing for pipe, failing, sidetracking stuck pipe.	
27. YREBOT	Rate of: Sidetracking and redrilling because first bottom was dry.	
28. YSIDTI	Time required to achieve step out for sidetracking.	72 hours.
29. YSIDOL	Sidetracking cost, exclusive of rig time.	\$2000 plus downhole motor costs. See code.
30. YSIDFU	Sidetracking fuel cost, due to downhole motor use.	(YSIDFU-1) \$/hour.
31. YCOGIT	Frequency of cogitation.	See note on item 19 above.
32. YCOGTI	Cogitation time per well.	See note on item 19 above.
33. YCPIPE	Drill pipe charges, \$/foot.	Depends on well depth, rock hardness, and drilling fluid. See code.

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
34. YAC(1)	Hours rotating on bottom.	<p>Note: All of the "YAC" variables serve as direct multipliers of the total of various WELCST subaccounts. They are provided to allow for cost changes not covered by the other variables.</p>
35. YAC(2)	Hours tripping bits and motors.	
36. YAC(3)	Hours for casing and cementing.	
37. YAC(4)	Time lost due to mishaps.	
38. YAC(5)	Miscellaneous rig time.	
39. YAC(6)	Total rig charges.	
40. YAC(7)	Bit costs.	
41. YAC(8)	Downhole motor costs.	
42. YAC(9)	Mud cost.	
43. YAC(10)	Fuel cost.	
44. YAC(11)	Drill pipe cost.	
45. YAC(12)	Water cost.	
46. YAC(13)	Waste disposal cost.	
47. YAC(14)	Surface equipment and well head cost.	
48. YAC(15)	Casing cost.	

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
49. YAC(16)	Cement and cementing services cost.	See note on Variable 34.
50. YAC(17)	Cost for site preparation and rig moving.	
51. YAC(18)	Mishap costs.	
52. YAC(19)	Miscellaneous transportation.	
53. YAC(20)	Logging costs.	
54. YAC(21)	Miscellaneous.	
55. YAC(22)	Direct supervision and overhead.	
56. YAC(23)	Total cost to drill and case well.	
57. YBCJNL	Cost of sealed journal bearing bit.	100% of "NOMCST"; varies with diameter. See code.
58. YBCUNS	Cost of unsealed roller bearing bit.	70% of NOMCST.
59. YBCHOP	Cost of hole opener bit.	Varies with diameter. See code.
60. YBCMIL	Cost of mill-tooth bit.	23% of NOMCST.
61. YBLJNL	Lifetime of sealed journal bearing bit.	90 hours.
62. YBLUMU	Lifetime of unsealed bit in mud.	30 hours.

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
63. YBLUAI	Lifetime of unsealed bit in air.	18 hours.
NOTE: VARIABLES #64 - #82 SPECIFY THE PERFORMANCE AND COSTS OF AN ADVANCED DRILLING BIT.		
64. YQHDLO	Multiplier for softest rock in which bit is used.	1.0
65. YQHDHI	Multiplier for hardest rock in which bit is used.	1.0
66. YQDPLO	Multiplier for shallowest depth in which bit is used.	1,000 feet.
67. YQDPHI	Multiplier for deepest depth in which bit is used.	10,000 feet.
68. YQDILO	Multiplier for lowest diameter hole in which bit is used.	1.0 inches
69. YQDIHI	Multiplier for largest diameter hole in which bit is used.	1.0 inches
70. YQTMLO	Multiplier for lowest temperature at which bit is used.	10°C
71. YQTMHI	Multiplier for highest temperature at which bit is used.	200°C

TABLE 6 (Continued)

VARIABLE	DESCRIPTION	NOMINAL VALUE
72. YQCSTS	Cost switch. If YQCSTS=0.0, bit cost is calculated from next three variables. If YQCSTS≠0.0, YQCSTS is a multiplier for the cost of a sealed button bit.	Varies with bit diameter. See code.
73. YQCSTA	If YQCSTS=0.0: $BITCST = YQCSTA \times 1000. + YQCSTB \times DIAM \times 100.$	
74. YQCSTB	$+ YQCSTC \times 10. \times DIAM^2$; where DIAM equals borehole diameter in inches.	
75. YQCSTC		
76. YQROP	Multiplier for rate of penetration (ROP). If YQROP=0.0, YQROPX is used.	Varies with depth and hardness, see code.
77. YQROPX	Multiplier against fixed ROP.	10 feet/hour.
78. YQLIF	Multiplier against nominal bit life. If YQLIF=0.0, YQLIFX is used.	90 hours, sealed bits. 30 hours, unsealed bits.
79. YQLIFX	Multiplier against fixed bit life.	20 hours.
80 YQTMCR	Multiplier for temperature at which bit mechanical moving parts begin to wear excessively.	250°C
81. YQTIM	Multiplier for time-based charge on bit use.	\$100/hour.

TABLE 6 (Concluded)

VARIABLE	DESCRIPTION	NOMINAL VALUE
82. YQFEET	Multiplier for footage charge on bit use.	\$10/feet.
83. YBTRUN	Maximum mud temperature in which sealed bit will survive while rotating.	100°C
84. YBTSOK	Maximum mud temperature to which sealed bit can be exposed for 30 minutes during tripping.	200°C
85. YMTCRT	Temperature at which mechanical parts of downhole motor begin to fail.	250°C
86. YROTMS	Miscellaneous rig time lost during rotation.	20% of rotating time.

At this point the operator enters an "Impact Year" into a GEOBEN input file. The Impact Year is the calendar year for which the product of the R&D project is assumed to be placed in general commercial use by the beginning of the year. GEOBEN is then executed. The output of GEOBEN is a printed estimate of reduction in the cost of geothermal electricity, summed across the 27 prospects during 1979-2000.

The savings are expressed as the 1978 present value (in 1978 \$) of the sum of savings occurring in each year at each prospect. A discount rate of 10% is used to reflect the greater uncertainty of events in future years (7). This discounted total is then called the "benefit" or the "economic benefit" of the analyzed R&D project (1,2).

The GEOBEN model is based on the MITRE-developed GELCOM model of the busbar cost of electricity from geothermal prospects. The pertinent details of GELCOM can be found in Reference 4. Some few of the baseline assumptions in GELCOM were updated in October 1978 to reflect new understandings of well costs and financial implications of provisions of the National Energy Act of 1978. These revisions are detailed in Table 7.

GEOBEN computes benefits by estimating the effect of reduced well costs (or changes in other GEOBEN input parameter estimates) on the cost of single 50 MW_e plants. Each plant in the scenario is assumed to be developed at a specific prospect and to go into opera-

TABLE 7

DIFFERENCES IN BASELINE ASSUMPTIONS BETWEEN
GEOBEN (1978) AND GELCOM (1977)

PARAMETER	GEOBEN VALUE	GELCOM VALUE	REASON FOR REVISION
Net Investment Tax Credit	12%	4%	National Energy Act of 1978.
Expensing of Intangible Drilling Costs (as % of Well Costs)	70%	0%	National Energy Act of 1978.
Electricity Price Escalation Rate	3%	5%	Reconsideration of recent public utility commissions' rulings.
Property Tax Rate	2%	1%	More recent data (8).
Well lifetimes, (years) -			
• Low salinity resources	15	10	Recent estimates from industrial sources (9).
• High salinity resources	7.5	5	

tion at the end of a specific calendar year (the "Power-On-Line Year"). Table 8 shows the plant development scenario. The design of each plant is tailored to the characteristics of the prospect.

Multiple wells are required for each power plant. These include initial production wells and injection wells, and replacement wells. Replacement wells are needed because the assumed well life (e.g., 15 years) is shorter than the assumed plant life (30 years). In general, the lower the resource temperature at a prospect, the more wells required to provide and dispose of sufficient fluid flow to produce the 50 MW_e net output of each plant.

The initial wells required for each plant are assumed to be drilled during the two years preceding the end of the power-on-line year (e.g., during 1985 and 1986 for a power-on-line year of 1986). Replacement wells are required at a rate of $(N \times 1/L)$ wells per year starting in the year immediately after the power-on-line year, where N = the number of initial wells per plant, and L = the assumed lifetime in years per well.

The "Impact Year" specified before each GEOBEN run determines whether each well is priced at the baseline cost (the cost that assumes current technology only), or at the reduced cost that occurs because of the impacts of the R&D project. If the well is to be drilled before the impact year, the baseline cost is assumed. If the well is to be drilled during or after the impact year, the lowered cost due to impacts of R&D is assumed. There is no provision for changing impacts of the results of an R&D project in successive years.

TABLE 8

ELECTRIC SYSTEMS POWER-ON-LINE SCENARIO
NUMBER OF 50 MW_e PLANTS COMING ON LINE IN PERIOD

PROSPECT	TIME PERIODS											TOTAL
	I 1979 -80	II 1981 -82	III 1983 -84	IV 1985 -86	V 1987 -88	VI 1989 -90	VII 1991 -92	VIII 1993 -94	IX 1995 -96	X 1997 -98	XI 1999 -2000	
Salton Sea, CA	--	--	1	3.5	3.5	4	4	4	4	4	4	32
Valles Caldera, NM	--	--	1	2	2	2	4	4	4	4	4	27
Brady Hot Springs, NV	--	--	1	1	2	2	4	4	4	2	--	20
Brawley, CA	--	--	1	1	4	4	4	4	2	--	--	20
Roosevelt Hot Springs, UT	--	--	1	1	1	2	4	4	4	3	--	20
Beowawe, NV	--	--	1	1	1	2	4	4	4	3	--	20
Coso Hot Springs, CA	--	--	--	2	4	6	--	--	--	--	--	12
Mono-Long Valley, CA	--	--	--	1	2	2	--	--	--	--	--	5
Cove Fort-Sulfurdale, UT	--	--	--	1	1	2	4	4	4	4	4	24
Heber, CA	--	--	--	1	1	4	4	4	--	--	--	14
Geysers, CA (Hydrothermal)	--	--	--	4	4	4	4	4	--	--	--	20
East Mesa, CA	--	--	--	1	1	--	--	--	--	--	--	2
Steamboat Springs, NV	--	--	--	1	1	2	--	--	--	--	--	4
Surprise Valley, CA	--	--	--	1	1	4	4	4	4	4	4	26
Chandler, AZ	--	--	--	1	--	2	1	--	--	--	--	4
LEach, NV	--	--	--	--	1	1	4	4	4	4	4	22
Bruneau-Grandview, ID	--	--	--	--	1	2	4	4	4	4	4	23
Lassen, CA	--	--	--	--	1	1	--	--	--	--	--	2
Alvord, OR	--	--	--	--	1	1	2	2	--	--	--	6
Safford, AZ	--	--	--	--	1	--	--	--	1	--	--	2
Weiser-Crane Creek, ID	--	--	--	--	1	2	4	4	4	4	2	21
Vale Hot Springs, OR	--	--	--	--	1	1	2	2	2	2	2	12
Thermo, UT	--	--	--	--	1	--	2	4	3	--	--	10
Raft River, ID	--	--	--	--	1	1	--	--	--	--	--	2
Glass Mountain, CA	--	--	--	--	--	1	--	--	--	--	--	1
Puna, HI	--	--	--	--	--	2	8	8	2	--	--	20
Baker Hot Springs, WA	--	--	--	--	--	1	--	--	--	--	--	1
TOTAL	0	0	6	22.5	37.5	55	67	68	50	38	28	372

The Power-On-Line Scenario used in the analysis indicates that approximately 12,000 wells must be drilled for all reasons (other than exploration needs) during 1979-2000. The modal cost per well, given the characteristics assumed for the 27 prospects is on the order of \$800,000. Thus the total investment in wells against which benefits are estimated is on the order of \$9 to 10 Billion (1978 \$, non-discounted).

Sensitivity analysis of the effect of reduced costs on calculated benefits indicate that over the range of 0% to 20% in reduction of cost per well, each 1 percent reduction in well cost generates a net benefit of approximately \$50 Million (present value, 1978 \$, discount rate of 10%).

2.7 Some Typical Results

Table 9 shows some typical impacts of changes in WELCST input variables on the cost of wells and cost of power. The results from WELCST (third column) are expressed as percentage changes in estimated well costs averaged across a single well at each of the 27 geothermal prospects. The results from GEOBEN (last column) are the estimates of the total cost savings in electricity production, weighted appropriately by the number of 50 MW_e plants expected per prospect, and the years in which the plants are expected to be placed in operation.

TABLE 9
SOME TYPICAL RESULTS FROM WELCST AND GEOBEN

VARIABLE CHANGED	MAGNITUDE OF CHANGE	WELCST RESULT: AVERAGE % CHANGE IN WELL COST	GEOBEN RESULT: SAVINGS IN COST OF ELECTRICITY PRODUCTION (\$ MILLIONS, 1978) ¹
Rate of Penetration	+20% +100%	-9.2% -20.1%	505.5 1,049.4
Bit Life	+20% +100%	-0.5% -1.4%	22.6 71.0
Casing Cost	-20%	-2.2%	93.2
Mud Cost	-20%	-0.5%	22.6

¹ Present value (1978 \$); discounted at 10% per year.

3.0 DATA FILES

This section describes the contents and format of the 11 data files used by WELCST and ONEWEL.

3.1 WELCST EXEC

This file contains statements that are used at execution time to assign DATA file names to symbolic file numbers, and to initiate execution of the WELCST program.

3.2 BITVAR DATA

This file contains data on the technical performance of drilling bits, including rate of penetration (ft/hr), bit lifetime (hr), and bit costs (1978 \$). The current version of WELCST uses only the rate of penetration (ROP) data; bit lifetimes and costs are computed from algorithms internal to WELCST lifetimes, and costs are retained in this file for only special purpose uses.

The file consists of 3 blocks of records, with 15 records to each block. From the top of the file, the blocks are: ROP, Life, Cost. From the top of each block, successive records represent performance values for successive 1000-foot depth intervals. Record 1 is for 0-1000 ft, while Record 15 is for 14,000-15,000 feet.

Each record consists of 4 columns, in a 4F10.2 format. The columns represent different rock hardnesses. The left column is "Soft" rock, followed by "Medium", "Medium-Hard", and "Hard".

3.3 DESIGN DATA

This file contains borehole dimensions and casing plans for 11

different kinds of geothermal wells. Each type of well is represented by 10 consecutive records. The file contains 110 records.

The file contains the following designs, in sequence from the top of the file:

<u>DESIGN NUMBER</u>	<u>DESIGN DESCRIPTION</u>
1	Shallow, no pump, cased bottom
2	Shallow, no pump, open bottom
3	Shallow, no pump, multiple bottom
4	Intermediate, pump, cased bottom
5	Intermediate, pump, open bottom
6	Intermediate, pump, multiple bottom
7	Deep, for Geopressured prospects
8	Shallow, pump, cased bottom
9	Intermediate, open bottom, bottom air-drilled
10	Well for gravity head system
11	Scratch file

The design descriptors designate:

Shallow: Bottom at 1000-3000 ft (305-914m)

Intermediate: Bottom at 3000-10,000 ft (915-3047m)

Deep: Bottom at 10,000-15,000 ft (3048-4572m)

Pump: Upper casing diameter is large enough to accept a downhole pump.

Cased Bottom: Bottom portion of well is cased with a perforated liner.

Open Bottom: Bottom portion of well is uncased.

Multiple Bottom: The well has three legs at the bottom, to tap into multiple fracture systems.

Scratch File: Spare file for test runs on alternate well designs.

Each of the 10 records in a design specifies one interval of borehole and/or casing. The format for each record is: 3X, F7.0, F7.0, F6.2, F7.0, F7.0, F6.2, F6.2, F5.1. In order, the data values represent:

- (1) Depth of start of borehole interval, feet.
- (2) Depth of bottom of borehole interval, feet.
- (3) Diameter of borehole interval, inches.
- (4) Depth of start of casing interval, feet.
- (5) Depth of bottom of casing interval, feet.
- (6) O.D. for casing interval, inches.
- (7) Fraction of casing cemented to borehole. If this number is zero, a liner is being cemented to casing. If this number is greater than one, the casing is hung without being cemented.
- (8) Drilling fluid used for borehole interval.
(1.0 = Air, 2.0 = Water, 3.0 Mud)

3.4 ENGVAR DATA

This file contains 86 engineering and cost variables that can be changed by the operator to alter drilling performance and cost parameters in the WELCST model. For nominal performance of current drilling technology, most of these factors are set equal to 1.00.

The format of this file provides for alternating rows of variable names and variable values. The variable name records are in format 10 (2A4). The variable values are in format 10 (F8.2). The names used in this file are identical to variable names used in the ONEWEL FORTRAN subroutine.

Table 6 lists the variable names, what they represent, and the nominal value assumed by the WELCST program when the variable value is set to 1.0.

3.5 ENGS AV DATA

This file is a backup file for ENGVAR DATA. It contains the values assumed for all the ENGVAR variables when the model contains only "current technology". The format is identical to that of ENGVAR DATA.

3.6 DUMSIT DATA

This file contains data for a dummy geothermal site that is used to calculate the costs of the "generic model well". The well is specified as: Depth = 6500 ft, Rock = Medium-Hard, Bottom Hole Temperature = 230°C, Well Design = 5.

The format of this file conforms directly to that of RAJJ DATA, below.

3.7 RUNOPS DATA

This file contains values for 10 program switches used in WELCST and ONEWEL. The switches are named IROP1 through IROP10. The file consists of one record with format 10 (1X, 11).

At this time, functions are specified for the first seven switches. The last three are not used. The functions of these switches are shown in Table 10.

3.8 WCOST DATA

This file contains baseline well cost data for each of the 27 prospects, baseline cost subaccount data for the generic model well, and receives the result well costs for the 27 prospects. This file is used to transfer the results of WELCST runs to other programs.

TABLE 10

FUNCTIONS OF PROGRAM SWITCHES IN RUNOPS FILE

SWITCH	OPTIONS AND FUNCTIONS
IROP1	<p>1 = Production run. Calculate and report costs of DUMSIT well and 27 wells in RAJJ file.</p> <p>2 = Development run. Calculate and report DUMSIT well only.</p> <p>3 = Baseline alteration for DUMSIT well. Calculate a DUMSIT well only, and insert the results in the generic well baseline portion of WCOST file.</p> <p>4 = Baseline alteration for prospect wells. Calculate results for the 27 wells in RAJJ file, and insert results in the prospects portion of WCOST file.</p> <p>5 = Production run. As per "1" above, but suppresses detailed reports on DUMSIT well.</p>
IROP2	<p>0 = Skip.</p> <p>1 = Write out BITVAR DATA during run.</p>
IROP3	<p>0 = Skip.</p> <p>1 = Write out design data for generic model well.</p>
IROP4	<p>0 = Skip.</p> <p>1 = Write out ENGVAR DATA during run.</p>
IROP5	<p>0 = Skip.</p> <p>1 = Downhole motor is used for all drilling.</p>
IROP6	<p>0 = Single bottom designs used in all rock types.</p> <p>1 = Triple bottom designs used in Medium and harder rock.</p>
IROP7	<p>0 = Baseline value of well cost is substituted for calculated result if the well cost with R&D is higher than the baseline cost.</p> <p>1 = Calculated value of well cost is reported even if higher than baseline cost.</p>

Block 1 of this file consists of 27 records, one for each of the prospects contained in RAJJ DATA, in the order in which the prospects appear in RAJJ DATA. The format of each record is 4F10.0. The first value is the baseline cost (without R&D) of a production well. The second value is the result cost (with R&D) of a production well. The third value is the baseline cost of an injection well. The fourth value is the result cost of an injection well.

Block 2 of this file consists of 3 records with format 8F10.0. These records contain the baseline costs (without R&D) for each of 23 subaccounts for the generic model well calculated from the DUMSIT data.

3.9 WELSAV DATA

This file is a backup file for WCOST DATA. All values saved in this file assume current technology or "baseline" values. The format is identical to that of WCOST DATA.

3.10 TITLES DATA

This file contains 33 records, each with format 10A4. Each record contains one title used in printed reports generated by the ONEWEL subroutine.

3.11 RAJJ DATA

This file contains 27 blocks of records. Each block contains data on known or estimated characteristics of one liquid-dominated (hydrothermal) geothermal prospect in the United States. The estimates are drawn from Reference 3 and, except for a few changes based

on new data, are identical to the data base used for the GELCOM cost of power model (4).

Table 11 describes the contents and format of each data block. Table 12 lists the changes made in prospect data prior to all runs made with the WELCST model.

TABLE 11

DATA RECORD FORMAT FOR FILE: RAJJ DATA

	COLUMN	CONTENTS	FORMAT
RECORD 1:	1-72	SITE--Name of the Geothermal Resource	18A4
RECORD 2:	1-6	NPLANT--Number of Power Plants (Maximum 12)	I6
RECORD 3/4:	1-78	Power on Line Years for the NPLANT Power Plants	13I6/ 7I6
RECORD 5:	1-6	ITEMP--Best Resource Temperature Estimate ($^{\circ}$ C)	I6
	7-12	ITEMPH--High Resource Temperature Estimate ($^{\circ}$ C)	I6
	13-18	ITEMPL--Low Resource Temperature Estimate ($^{\circ}$ C)	I6
RECORD 6:	1-6	ISYSTP--System Kind 1 indicates Flash System 0 indicates Binary System	I6
	7-12	IDEPH--Resource Depth (meters)	I6
	13-18	IRKTYP--Geological Formation Hardness 1 designates soft rocks 2 designates medium rocks 3 designates medium-hard rocks 4 designates hard rocks	I6
	19-24	ISAL--Brine Salinity 1 defines High Salinity 2 defines Low Salinity	I6
	29-30	IDSGN--Well Design Number	I6
RECORD 7:	1-10	IFLOW--Well Flow Rate (kgm/hr) 1 will assume Default Conditions	I10
	11-20	IPWCST--Cost per Production Well (\$) 1 will assume Default Conditions	I10
	21-30	IIWCST--Cost per Injection Well (\$) 1 will assume Default Conditions	I10
RECORD 8:	1-6	ALP1--Life Span of a Production Well	F6.2
	7-12	ALP2--Life Span of an Injection Well	F6.2
	13-18	ALP3--Life Span of a Producer Plant	F6.2
	19-24	ALP4--Life Span of a Utility Plant	F6.2

TABLE 12

PROSPECT CHARACTERISTICS UPDATED DURING DEVELOPMENT OF THE WELCST MODEL

PROSPECT	CHARACTERISTIC	NEW ESTIMATE	OLD ESTIMATE (5)
Geysers, CA	Rock Hardness	Medium-Hard (10)	Medium
Raft River, ID	Rock Hardness	Medium (11)	Soft
Chandler, AZ	Rock Hardness	Medium-Hard (12)	Medium
East Mesa, CA	Well Depth	2.0 km (13)	1.5 km
Heber, CA	Well Depth	2.0 km (13)	1.5 km

Reference numbers indicate source for new estimate or explanation of revisions.

4.0 DETAILS OF WELL COST CALCULATIONS

Each time the WELCST program calculates the cost of a geothermal well it specifies four critical parameters for a real or hypothetical prospect, and then calls the ONEWEL subroutine to estimate the cost of the well. This section describes some of the details and origins of the cost estimation procedures used in ONEWEL.

The four main input parameters that specify the cost of each well, given a fixed set of assumptions about the performance and costs of drilling devices and procedures, are:

- Well depth,
- Well design,
- Hardness or drillability of the rock being drilled, and
- Bottom hole formation temperature.

A listing of the FORTRAN code for ONEWEL is given in Section 6.2. The listing is sprinkled with liberal commentary that should allow a programmer/analyst to decipher easily the details of what occurs within each section of the program. Therefore this section concentrates on the relatively global aspects of the computations, and is detailed only with respect to specific algorithms and assumptions of the performance of drilling technology components.

4.1 Development and General Structure of ONEWEL

The activities leading to the development of the cost of wells code are shown in Figure 4. The algorithms and assumptions used in ONEWEL are a blend of many types of information from many sources.

FIGURE 4
ACTIVITIES USED TO DEVELOP WELL COST MODEL

The sources of information include:

1. Total costs of certain wells drilled at selected geothermal prospects,
2. Subaccount costs available for all or certain parts of a very few geothermal wells,
3. Reports from geothermal drillers of their rough or documented estimates of the technical performance and performance limitations of drilling devices,
4. Reports from equipment manufacturers of equipment prices and their knowledge of equipment performance under geothermal conditions,
5. Knowledge gained by various DGE Research and Development contractors in their attempts to analyze dominant failure modes of oil well drilling equipment used in geothermal settings, and
6. Rules of thumb for equipment and operations performance and costs as set forth in various handbooks of oil well design and drilling practice.

The resulting model is a marriage of convenience between empirical facts and analytical knowledge about land-based rotary moderate depth drilling in general, and geothermal drilling in particular. The consistent emphasis during the development of the model has been to avoid either ignoring or overemphasizing the importance of any single body of engineering information or drilling lore.

During the initial phases of developing ONEWEL it became apparent that much of the reported performance of drilling equipment seemed to be slanted toward the optimistic and somewhat "best case" side of reality. This positive slant was incorporated into the main part of the drilling code. Accordingly, the main part of the WELCST model drills geothermal wells as if they were straight holes, of full gage,

never interrupted by junk in the hole, cave-ins, multiple episodes of lost circulation, or any other standard nightmare of real drilling experience. To balance and complete this overly optimistic picture, a fair amount of time was spent analyzing drilling records from the Geysers and the Imperial Valley to derive rough estimates for the frequency and costs of major mishaps in recent geothermal drilling experience. These "mishaps", as they are called in WELCST, contribute a major source of geothermal drilling costs.

The general sequence of calculations in ONEWEL is shown in Figure 5. There are seven main sets of calculations in ONEWEL.

1. Well Design - The well design selected for each prospect is found from file DESIGN DATA, and then adjusted to the total borehole depth for the prospect.
2. Footage Costs - The cost of drilling the borehole is calculated. This includes rig time for rotating and tripping bits, and total bit costs. This part of the code is based on the standard footage cost equation (5), but is sensitive to complex interactions of a number of technical parameters. These include:
 - Drilling depth,
 - Formation rock temperature,
 - Drilling fluid type,
 - Drilling fluid temperature,
 - Hole diameter,
 - Bit type, life, and cost,
 - Rig rental rate,
 - Tripping velocity,
 - Use of downhole motors, and

FIGURE 5
CALCULATION SEQUENCE IN SUBROUTINE ONEWEL

• **Special characteristics and costs of novel bits.**

These costs can be reported in the "Footage Cost Report" (see Table 2 above). This report and the others shown in Figure 5 are usually printed only for a generic model well rather than for all 27 prospects. The reports allow the operator to check whether the model is behaving as expected, in response to changed assumptions about the performance of technology.

3. Other Rotating Costs - These are costs that are proportional to drilling time and severity. They include: Downhole motor for straight drilling, Fuel, Water, Drill pipe charges, and Mud. They are in general built up in parallel to the footage costs, but appear only in the Well Cost Report.
4. Casing and Cementing Costs - These are calculated independently of the footage costs. They are sensitive primarily to borehole and casing depths and diameters.
5. Mishap Costs - A major segment of the subroutine is devoted to estimating the frequencies and costs of drilling incidents and accidents. These are in general proportional to well depth and rock hardness. In most cases, mishaps are treated as causing additions to rig time charges plus special costs for equipment or manpower needed to recover from the mishaps. But in two cases where an entire hole or a substantial portion of a hole are abandoned, a fraction of the total well cost is simply added to the final total to reflect the cost due to these events.

This latter component of the calculations is handled by the outermost loop of WELCST (Figure 6). The cost of each well is calculated in two passes. On the first pass, the accident frequency is set to zero for all categories of mishap, and the "shadow cost" of the well with no accidents is calculated. On the second pass, the accident frequencies are non-zero, and the required percentage of the shadow cost is added to the total cost to account for events where portions of the borehole are abandoned.

6. Other Costs - These include the items shown in the largest box in Figure 5. Once they have been estimated, they and all other costs can be printed in the "Well Cost Report", which consists of 22

FIGURE 6
ONEWEL SUBROUTINE MAKES TWO PASSES TO BASE COSTS
OF CERTAIN ACCIDENTS OF AN INITIAL ESTIMATE
OF WELL COST

subaccounts and a Total (See Table 4, above).

7. Output to Calling Program - ONEWEL returns only the total cost of the specified wells to the calling program, WELCST.

4.2 Well Designs

Each well is drilled to a preselected design taken from the DESIGN DATA file. This file is described in Section 3.3, and listed in Section 7.0. The design selected for each geothermal prospect is specified in the variable "IDSGN" in record number 6 in the RAJJ DATA file (see Section 3.11).

While 10 different designs have been specified and are carried in the DESIGN file, only 3 designs are used to drill the 27 prospects in the WELCST model. These are:

- Design 2 - Shallow depth (1000-3000 ft.), open bottom. Used for one prospect with an estimated well depth of 0.8 km (2625 ft.) drilled in Medium-Hard rock.
- Design 4 - Intermediate depth (3000-10,000 ft.), large enough in upper part of the well to accept a downhole pump, cased to bottom. Used for all prospects drilled in Soft rock.
- Design 5 - Intermediate depth (3000-10,000 ft.), large enough to accomodate downhole pump, lowest 30% of well uncased. Used for all prospects of this depth where the rock is Medium, Medium-Hard, or Hard.

The plan for Design 4 is shown in Figure 7. The hole for the 150 foot conductor casing is assumed to be drilled in a single pass with an inexpensive large bit. The 17½ inch hole is drilled in two passes. The first pass uses an 9 5/8 inch bit to provide a pilot

FIGURE 7
DESIGN FOR INTERMEDIATE DEPTH CASED-TO-BOTTOM
GEOHERMAL WELL
(TD = 3,000 TO 10,000 FEET)

hole for the 17½ inch hole-opener bit used on the second pass. Pilot hole requirements are built into the well designs. The listings for DESIGN DATA in Section 7.0 contain the details.

The designs in DESIGN DATA are generic; they are intended to cover a range of depths. The depth dimensions for borehole and casing are adjusted to the total well depth specified for each prospect before cost calculations are made. Except for the conductor hole and conductor casing depth, which are fixed at 150 ft, the borehole bottom depths and the casing top and landing depths are reduced in linear proportion to the ratio between the well depth for the specific prospect and the total depth for the well design. For example, suppose Well Design 4, with its total depth of 10,000 ft is used for a prospect with a 6000 ft well depth. The landing depth for the 9 5/8 intermediate casing is set at 7000 ft for the generic well and at $7000 \times (6000/10,000) = 4200$ ft for the prospect well. The top of this casing for the prospect well would be set at $2700 \times (6000/10,000) = 1620$ ft.

The designs were selected from reports of borehole and casing plans used recently at United States geothermal prospects. Data that were especially important in specifying the generic well designs in WELCST include well plans from the Imperial Valley (9,14,15), the Geysers (14,15), and the Raft River (16) geothermal prospects.

The designs have the following characteristics in common:

- (1) At total depth the borehole diameter is 8 3/4 inches.
If the bottom is cased, the casing O.D. is 6 5/8 inches.

- (2) The borehole diameter must be large enough to run the casing when the borehole is somewhat crooked or sloughed. The casing-bit programs described by Gatlin (17, Figure 14.20) for West Texas oil wells are similar to those described for geothermal wells, and were used in the generic well designs.
- (3) The inner diameter of upper stage casings must be large enough to allow the bits for the lower borehole to be tripped through the casing. The "drift diameter" of the casing, which is slightly smaller than the casing I.D., determines the maximum diameter of the bit that can be tripped through the casing. The required casing O.D.s were taken from Craft et al. (18, Table 2.15), given the assumption that casing grades of J-55 or higher quality are required in geothermal wells.
- (4) Holes larger than 12½ inch diameter are drilled using hole-opener bits, which require the existence of a pilot hole of suitable diameter. The diameter of the required pilot holes was taken from specifications for Reed Tool Company piloted reaming bits (19, page 12).

Casing grades are not specified in the well designs. These are discussed in Section 4.7.

For systems-evaluation reasons, a switch was built into ONEWEL to assist in analyzing the cost effects of using multiple completions from a common upper part of a well. This drilling strategy has recently been used to good effect at the Raft River prospect on experimental well RRGE-3, where two additional legs enhanced fluid production 3 to 5 times for a 20% increase in drilling cost (16). The switch is labeled "IROP 6" (See Table 10, Section 3.7). When IROP6 = 0, the nominal single bottom designs described immediately above are used. When IROP6 = 1, triple bottom designs (Design 3 for

for shallow wells, Design 6 for intermediate depth wells) are used in all prospects where the rock is estimated to be Medium, Medium-Hard, or Hard. Figure 8 shows the design used for the intermediate depth wells when triple completions are assumed.

4.3 Footage Cost Calculations

In ONEWEL, "footage costs" include all rig rent and bit costs. The main factors to which footage costs are sensitive include: well depth, rate of penetration, well diameter, drilling rig rental rate, bit life, bit cost, and round tripping rate.

ONEWEL treats relationships between these variables as follows:

- (1) The borehole is broken into a sequence of contiguous borehole segments. The boundaries between segments represent either a change in borehole diameter specified by the well design, or 1000 foot intervals of well depth.
- (2) Values for rate of penetration are specified in a table (File BITVAR, Array ZROP (14,4)). The values decrease with depth and are specified for successive 1000 foot intervals from 0 to 15,000 feet. The values also depend on rock hardness, and are specified for Soft, Medium, Medium-Hard, and Hard rock.
- (3) Bit life and cost depend on the type of bit selected. The bit selection assumptions are described separately in Section 4.5, below. Bit selection depends primarily on rock hardness, borehole diameter, drilling depth, and drilling fluid temperature at the bottom of the hole. Once a bit is selected, its lifetime and cost are passed to the footage equation.
- (4) Rig rental rate and round trip velocity are fixed at nominal values of \$200/hour and 1000 ft/hr, respectively. Rig rental rate and trip velocity are entered directly into the footage cost equation.

**BIT
DIAMETER
(IN)**

**CASING
DIAMETER
(IN)**

**DEPTH
(FT)**

26

20

17 1/2

13 3/8

12 1/4

9 5/8

8 3/4 UNCASED HOLE
WITH TWO DIRECTIONALLY-
DRILLED STEP-OUTS

0

150

0.3 TD - 300

0.3 TD

0.7 TD

0.8 TD

TD

**FIGURE 8
DESIGN FOR MULTIPLY-COMPLETED GEOTHERMAL WELL
(TD = 3,000 TO 10,000 FEET)**

Figure 9 illustrates the definition and derivation of "borehole segments". Each segment has a starting depth, START, and a stopping depth, ASTOP. START for segment N is equal to ASTOP for segment N-1. ASTOP for segment N is then taken to be the first lower depth at which either the borehole diameter, DIAM, changes or the ROP changes. Thus each segment has total length, DFOOT, of 1000 feet or less for which the borehole (bit) diameter and ROP are set at constant values.

Figure 10 shows the sequence of calculation in the program loop used to "drill" the entire well. The drilling fluid temperature is calculated for each segment (see Section 4.4) as an input to the bit selection routines (Section 4.5). A downhole motor can be selected for straight hole drilling with certain bits by setting program control switch IROP5 equal to 1.

The footage cost per borehole segment, is the sum of three separate costs:

- CBIT = cost of bits to drill segment
- CDRILL = rig rent due to rotating time
- CTRIP = rig rent due to tripping time.

These costs are calculated by the following equations:

$$CBIT = BITCST * (DFOOT / (ROP * BITLIF))$$

$$CDRILL = (DFOOT / ROP) * 200. * YRGRNT$$

$$CTRIP = (DFOOT / (ROP * BITLIF)) * ((START + ASTOP) / 2.) * (YRTRIP * (1. / 1000.)) * 200. * YRGRNT,$$

FIGURE 9
DERIVATION OF BOREHOLE SEGMENTS FOR FOOTAGE
COST CALCULATIONS

FIGURE 10
PROGRAM LOOP FOR CALCULATING FOOTAGE COSTS IN
BOREHOLE SEGMENTS

where:

BITCST = cost per bit, \$

DFOOT = length of segment, feet

ROP = rate of penetration, feet/hr

BITLIF = life per bit, hr

200. = nominal rig rent charge, \$200/hr

YRGRNT = rig rent adjustment factor, nominal value = 1.0

START = depth of top of segment, ft

ASTOP = depth of segment bottom, ft

1./1000 = nominal round trip rate, 1 hour per 1000 ft

YRTRIP = round trip rate adjustment factor, nominal value = 1.0.

Table 13 lists the rate of penetration (ROP) values used in ONEWEL. Finding data and relationships from which to estimate these values was one of the most difficult tasks in building this model. The numbers selected represent a meld of data from personal communications from active geothermal drillers, relationships described in the open literature (e.g., 17, pp. 114-141), and overall adjustments made to initial ROP estimates to make the model match reported estimates of the number of days needed to drill and complete specific wells (e.g., 15). The inputs to this process are too complex to document here. The authors believe that the selected numbers are correct to within about 20% of "true" values.

The tabulated values include all time the bit is downhole and rotating. The ROPs are "effective" ROPs instead of instantaneous

TABLE 13

RATE OF PENETRATION ESTIMATES USED IN ONEWEL CALCULATIONS

DRILLING DEPTH SEGMENT, FEET	ROP, FEET/HOUR			
	ROCK HARDNESS			
	SOFT	MEDIUM	MEDIUM-HARD	HARD
0 - 1,000	100.0	50.0	25.0	12.0
1,000 - 2,000	80.0	40.0	20.0	10.0
2,000 - 3,000	60.0	30.0	15.0	7.5
3,000 - 4,000	40.0	20.0	10.0	6.0
4,000 - 5,000	30.0	15.0	8.0	5.0
5,000 - 6,000	20.0	10.0	6.0	4.0
6,000 - 7,000	15.0	8.0	5.0	3.0
7,000 - 8,000	10.0	6.0	4.0	2.5
8,000 - 9,000	7.0	5.0	3.5	2.0
9,000 - 10,000	6.0	4.0	3.0	2.0
10,000 - 11,000	5.5	3.5	2.5	2.0
11,000 - 12,000	5.0	3.0	2.5	2.0
12,000 - 13,000	5.0	3.0	2.5	2.0
13,000 - 14,000	5.0	3.0	2.5	2.0
14,000 - 15,000	5.0	3.0	2.5	2.0

values. They incorporate time spent reaming.

4.4 Drilling Fluid Temperature

Drill bit lifetime is affected in many ways by the elevated temperatures encountered in drilling geothermal wells. For example, both bearing seals and the metal components of bearings fail more rapidly at high temperatures. Very little information exists about the operating temperatures of specific bit components during drilling because it is very difficult to measure these directly. However, some rough rules of thumb for relating bit life to the temperature of the drilling fluid (mud or air) as it circulates through and around the bit have been worked out recently on the basis of field observations and DGE-sponsored R&D.

If the drilling fluid is mud, circulation keeps the bottom hole circulating temperature (BHCT) significantly below the formation temperature of the rock being drilled and removes much heat from the bit. Air circulation provides much less cooling. This section describes how WELCST estimates BHCT as the variable "TMUD". Relationships between TMUD and bit lifetimes are described in Section 4.5, "Bit Selection".

TMUD is a useful variable for analysis of drilling systems because it can be estimated for a particular well by fairly advanced computer codes, and can be both controlled and measured in laboratory high temperature drilling simulating test rigs developed at Terra Tek, Inc. under DGE funding (20). TMUD can also be measured directly if the bit is

downhole but not rotating, but this seems to have been done only rarely (21,22).

TMUD does not explicitly take into account bit heating due to rotary friction or different temperatures in different parts of bits, (e.g., in cutters, lugs, bearings, and seals). Nonetheless, TMUD provides a useful hypothetical variable against which to measure and estimate bit lifetimes.

TMUD is affected by many real variables. The treatment of TMUD used in WELCST is based on the study by W.J. McDonald of Maurer Engineering of equilibrium and transient bottom hole circulating temperatures under geothermal conditions (21). In WELCST, TMUD is a computed function of:

- Reservoir temperature,
- Well and drilling depth,
- Type of drilling fluid, and
- Round trip time.

Other significant variables affecting TMUD for which fixed assumptions are used in WELCST are:

- Mud circulation rate: 200 gallons per minute
- Mud density: 10 pounds/gallon
- Mud inlet temperature: 65°C (150°F)
- Drill string and wellbore diameters:
4.5 inches and 8.625 inches, respectively.
- Heat transfer coefficients: as per page 10 of Reference 21.

Equilibrium and transient values of TMUD must be distinguished because they impose different limits on bit lifetimes. The equilibrium TMUD is the temperature assumed by the mud in the vicinity of the bit given continuous circulation for (infinitely) long times. McDonald used the Holmes and Swift model to estimate equilibrium temperatures (23). The transient values of TMUD occur when circulation is interrupted to trip the bit. TMUD rises because the heat of the formation rock is no longer carried away from the borehole bottom by the mud. McDonald points out that transient temperatures are difficult to either measure or model. The values assumed in WELCST are compromises between conflicting estimates presented by McDonald from two different models.

In WELCST, the first input to the calculation of TMUD at each drilling depth is an estimate of the rock formation temperature in the interval to be drilled, TROCK, the undisturbed formation temperature. The geothermal gradient (change in TROCK with depth) is not necessarily linear with depth. In many geothermal wells the temperature increases most rapidly with depth in the upper part of the well (24, 25). This was factored into the model by the curve shown in Figure 11. The upper linear segment accounts for three quarters of the bottom hole formation temperature in the top half of the well. The second segment accounts for the remaining quarter of the temperature differential. Surface temperature is assumed to be 15°C (60°F).

The equation for TMUD was interpolated from McDonald's data from runs of the Holmes and Swift model. When well depths are limited to

FIGURE 11
FORMATION TEMPERATURE VS. DEPTH RELATIONSHIP
ASSUMED IN WELCST

15,000 feet, as they are in WELCST, the bottom hole equilibrium circulating temperature TMUD is estimated to within 1 or 2 °C of McDonald's simulated values by:

$$TMUD = T_{INLET} + (T_{ROCK} - T_{INLET}) * (0.023) * (D - 3.0),$$

for drilling depths greater than 3000 feet, where:

T_{INLET} = Mud inlet temperature in °C,

T_{ROCK} = Formation temperature in °C, and

D = Borehole depth in 1000s of feet.

For drilling depths under 3000 feet, TMUD is assumed to be the inlet temperature. For the current analyses, the mud inlet temperature is assumed to be 65°C (150°F).

Once mud circulation is interrupted, the bottom hole temperature begins to increase again because it is warmed by the formation. McDonald's study suggests that the rate of warming is relatively fast initially: 60% to 80% of the warming occurs in the first 4 hours. By the end of 15 hours, the longest round trip time considered in the model, the bottom hole mud temperature reaches only about 80% to 90% of the original rock temperature.

This temperature after interrupted circulation is incorporated in the model as a "soak" temperature, TSOAK, to which a new bit is exposed for an estimated 30 minutes at the end of its trip into the well. As a first order approximation to data presented by McDonald, TSOAK is assumed to be given by:

$$TSOAK = TMUD + 0.9 * (T_F - TMUD) * \left(1.0 - e^{-\left(\frac{TRIP}{4}\right)} \right),$$

where:

TMUD = Bottom hole circulating temperature at start of trip, °C

T_F = Formation temperature (if undisturbed by drilling) at bottom hole, °C

TRIP = Round trip time, hours.

Thus, as trip times become longer, the residual effect of cooling during the immediately previous circulation period becomes smaller.

Air circulation provides much less cooling than does mud. WELCST assumes that when air is used as the drilling fluid, the ambient temperature near the bit will be the formation temperature, T_{ROCK}, minus 15°C.

4.5 Bit Selection and Downhole Motor Use

ONEWEL selects one of six different simulated bits to drill each borehole segment. Five of these are conventional bits, modelled after the performance of bits used today in geothermal drilling. The sixth is an "advanced bit" built into ONEWEL to simulate novel products of certain R&D projects. The technical and cost parameters of the advanced bit can be varied in many ways:

These bits, their major characteristics, and the bit selection criteria are listed in Table 14. The downhole motor (as used for straight-hole drilling) is included in the Table because it will typically alter the rate of penetration when used in conjunction with a selected bit, as described below.

Most geothermal drilling is done with sealed journal-bearing

TABLE 14

MAJOR CHARACTERISTICS OF BITS AND DOWNHOLE MOTOR IN ONEWEL

DEVICE	SIGNIFICANT SELECTION CRITERIA	ASSUMED LIFE (HR)	ASSUMED COST
1. Hole Opener Bit	Hole diameter greater than 12.25 in.	30	$\$680 + \$170.8 \times \text{DIAM}$
2. Mill Tooth Bit	Rock is soft and drilling depth is less than 3000 feet	30	20% of NOMCST
3. Sealed Journal Bearing Insert Bit	TMUD <100 * YBTRUN °C TSOAK <200 * YBTSOK °C	90	NOMCST = \$3758. - \$696.2 * DIAM + \$67.16 * DIAM ** 2
4. Unsealed Roller Bearing Insert Bit	Borehole too hot for sealed insert bit	30 in mud 18 in air	70% of NOMCST
5. Advanced Bit (Research Bit)	Less expensive to use than bit 3 or bit 4	Life and cost are specified by input parameters to generalized equations.	
6. Diamond Bit	ROP $\leq$ 4 ft/hr	25	$\$1500. * \text{DIAM}$ - \$5700
7. Downhole Motor for Straight Hole Drilling	Assumed not to be used in 1978 drilling practice. Used when program switch IROP5 = 1	120 (nominal)	$\$5000 + \$42/\text{hr}$ (nominal)

insert bits. This bit (simulated) drills most of the footage at the 27 prospects included in the model's prospect data base (RAJJ DATA file). The four other conventional bits are used when special circumstances make them more economical. For example, unsealed roller-bearing bits are used when the drilling fluid is too hot for the seals of journal bearings to withstand. Mill tooth bits with roller bearings are used in the upper portions of boreholes in soft rock because their gouging, scraping action removes rock more rapidly than the crushing action of insert bits.

Diamond bits are used to drill hard dense strata that can not be crushed easily by insert bits. The stratigraphy of most of the 27 prospects considered here is not known well enough to predict where and how much diamond bits will be used in geothermal drilling. The model assumes that diamond bits will be used for drilling when the rate of penetration is less than or equal to 4.0 feet per hour. This assumption was made to allow certain research bits a moderate amount of footage in which to compete against conventional diamond bits.

The costs of journal-bearing insert bits, mill tooth bits, hole openers, and unsealed roller bearing insert bits were taken from current price lists for journal-bearing bits (19, 26, 27). July 1978 prices for journal-bearing insert bits of diameters between 8 3/4 and 12 1/2 inches are modelled closely by the equation:

$$\text{NOMCST} = 3758. - 696.2 * \text{DIAM} + 67.16 \text{ DIAM} ** 2,$$

where NOMCST = price of bit in 1978 \$, and DIAM = diameter of bit in inches.

Mill tooth bits cost approximately 23% of NOMCST, given the same diameter. Unsealed roller bearing bits cost approximately 70% of NOMCST. Hole opener costs (from Reference 19) and diamond bit costs are modelled by separate cost equations (See listing in Section 6.2). The diamond bit cost assumes a Christensen MD-24 bit with a salvage value of 40 percent of the diamond weight (28).

The estimates of bit lifetime for the five conventional bits were based on discussions with geothermal drillers, bit manufacturers, and bit research and development scientists. In field practice, bit lifetimes tend to be quite variable, with the variability increasing as the rock gets harder or more fractured. The estimates assumed in ONEWEL are taken in part from drilling records and in part from drillers' "best estimates" of what "typical" lifetimes pertain in various formations.

ONEWEL selects the bit for a given borehole segment (see Section 4.3 for definition of "segment") by considering the selection criteria in a particular sequence. The sequence is shown in Figure 12. The hole opener is considered first, and then the mill tooth bit. If either of these bits is selected, the code proceeds directly to the footage cost calculation for the segment. If neither is selected, the code then tentatively selects a sealed (journal bearing) or unsealed (roller bearing) insert bit.

A sealed bit is selected if TMUD and TSOAK (see Section 4.4) are less than temperature limits specified for the seal materials of this

FIGURE 12
SEQUENCE OF BIT SELECTION DECISIONS IN ONEWEL

bit. Otherwise, the unsealed bit is selected. Once selected, either of these two bits is compared to the "advanced" bit to determine if it is technically feasible and economically beneficial to use the advanced bit. If so, the advanced bit will be selected.

Sealed insert bits, unsealed insert bits, and novel bits are then compared to the conventional diamond bit, on the basis of limits of rate of penetration, as described above. One of the four is finally selected. These four bits can be used in conjunction with a downhole motor for straight hole drilling, if the WELCST operator so chooses.

The "advanced bit" is a hypothetical bit whose performance and cost parameters can be manipulated extensively by the operator of WELCST to model the expected performance of novel bits from R&D. Table 6 in Section 2.5 lists the 17 variables in the ENGVAR file that define the advanced bits. These are variables 64 through 80; the name of each variable starts with the letters "YQ" as an identification tag. The user should consult Table 6 in conjunction with the ONEWEL listing to specify advanced bit characteristics.

Life and cost estimates for downhole motor performance are based on discussions with drillers on using motors for directional drilling at the Geysers. It was assumed that half of the reported daily costs are attributable to capital costs, and half are due to operational expenses. The motor is controlled by program switch IROP5 (see Table 10).

It is assumed that the downhole motor is not used for straight hole drilling in conventional geothermal drilling in 1978, but can be "switched in" for evaluating expected results of R&D projects attempting to develop motors for this use. As indicated in Figure 12, the ONEWEL downhole motor can be used with the sealed insert (journal bearing) bit, unsealed insert bit, advanced bit, and diamond bit, but not used with hole openers or mill tooth bits.

4.6 Other Rotating Costs

The costs considered in this section include: Water, Drill Pipe charges, Downhole Motor for directional drilling, Fuel, and Mud. The cost estimates are based primarily on Glass's report of recent costs for Geysers and Imperial Valley wells (15).

4.6.1 Water

The amount and cost of water used while drilling is assumed to be proportional to the number of hours the bit spends rotating. The cost of water is fixed at \$25 per hour of mud-based drilling. The cost of water for air drilling is one-third of that for mud-based drilling.

4.6.2 Drill Pipe Charges

Drill pipe charges include costs of inspection, hard-banding if needed, and replacement of drill pipe damaged by abnormally severe drilling conditions (15). The charge for each borehole segment is calculated by:

$$\text{PIPCST} = \$0.45 * \text{HARD} * \text{DFOOT}$$
 if mud or water is the drilling fluid, and by:

PIPCST = $\$4.25 * \text{HARD} * \text{DFOOT}$ if air is the drilling fluid, where: HARD = rock hardness (1 = "SOFT", etc.) and DFOOT = length of the borehole segment in feet.

4.6.3 Downhole Motor for Directional Drilling

Besides the downhole motor charges for straight-hole drilling incurred as described in Section 4.5, ONEWEL includes provisions for use of downhole motors for directional drilling.

All wells are assumed to have some deviation problems that are remedied by use of a downhole motor. For this purpose, the motor is assumed to be used for two days, at a depth of 1000 feet, in all wells. The cost per day of using the motor is shown in line 7 of Table 14, Section 4.5.

If multiple bottom-hole completions are selected as described for Well Design number 6 (Figure 8, Section 4.2), the downhole motor is used to kick out from the main borehole. It is assumed that each of the two kickouts require 3 days of motor use and one trip of the motor through 90% of the total depth of the well.

4.6.4 Fuel

ONEWEL assumes that fuel is used at either a high rate (FUELHI = \$40./hr nominal) or a low rate (FUELLO = \$8./hr nominal). The high rate is charged while the bit is rotating. The low rate is charged for tripping. Some of the operations required while completing the well and while recovering from drilling mishaps incur additional fuel charges. These additions are explained in Sections 4.7 and 4.8.

4.6.5 Mud

The equation for mud costs in ONEWEL was taken from LASL's GEOWELL code (6). The GEOWELL equation was adjusted to 1978 costs by calibrating it to Glass's values for recent geothermal wells (15).

For wells greater than 5000 feet total depth the mud cost is given by:

$$\text{CSTMUD} = \$36,456 - 14,523 * A + 1,669 * A ** 2,$$

where A = well total depth in 1000s of feet.

For wells shallower than 5000 feet:

$$\text{CSTMUD} = \$36,456 * A/5.0.$$

These equations assume that mud cost is a function of well depth alone. While this assumption is adequate for the present purpose, it does not take into consideration many important influences of drilling conditions (such as temperature) upon mud costs. If ONEWEL should be improved in the future, it would seem profitable to devote some attention to relationships between both mud costs and mud performance to other components of drilling technology.

Mud costs are likely to be sensitive in important ways to: borehole temperature, rock permeability, presence of fractures, rock hardness, and mud circulation rate and formation pressure. From a system optimization viewpoint, effects of mud performance upon other components of drilling would need to be considered in an adequate simulation of the general effects of mud upon well costs. For example, mud plays important roles in maintaining the integrity of the borehole

while drilling and in the rate at which rock particles are removed from the bit cutting faces. Effects of mud properties upon these kinds of operations need to be considered in future more comprehensive models of geothermal mud engineering economics.

4.7 Completion Costs

Completion costs include: Casing, Cementing, and Well Head.

4.7.1 Casing

Casing designs for geothermal wells require special attention to well temperature and fluid composition. Some of the factors that must be considered in geothermal casing plans include casing elongation due to temperature changes, cement strength retrogression, corrosion, and scaling (9). To account for these effects requires much data about the geology and hydrology of specific geothermal prospects, a requirement which at present can be met only for the Geysers and Imperial Valley.

The cost of casing in ONEWEL is set at the average typical cost for a given diameter reported for surface pipes and liners at the Geysers and the Imperial Valley (15). The casing used at these sites is a mix of API (American Petroleum Institute) grades K-55 and N-80 (9).

The cost per foot, CPF, of all casing except for conductor casing is assumed to be:

$$\begin{aligned} \text{CPF} &= 10. + 1.54 * (\text{DIAM} - 7.0), \text{ if DIAM} > 7.0, \text{ and} \\ &= 10., \text{ if DIAM} \leq 7.0, \end{aligned}$$

where DIAM is the outer diameter of the casing in inches.

Conductor casing is less expensive. Its cost is assumed to be:

$$CPF = 10. + 0.44 (D - 7.0).$$

These estimates agree reasonably well with those assumed in the GEOWEL model (6) and those discussed by Kennedy and Wolke (29). The formulae tend to underestimate slightly Geysers casing costs, and to overestimate slightly Imperial Valley casing costs. However, until additional data permit development of better generic casing plans for the remaining prospects, further refinement of these casing cost equations would be speculative.

4.7.2 Cementing

Cement and cementing services costs in ONEWEL are based on the analysis by D.K. Smith (30).

The amount of cement required is determined by the volume of the annulus to be cemented. This is dependent on the outer diameter of the casing and the diameter of the borehole to which the casing is cemented. Borehole sloughing in softer formations is accounted for by an appropriate volume correction safety factor.

Rig time required for cementing is compounded from: time to run casing, time to mix cement, time to pump cement, time to wait on cement, and time to prepare for next cementing or drilling operation. The greatest portion of the total cementing time is comprised of the last two operations. Cementing is done in stages if the casing length is greater than 3000 feet. Rig fuel is charged at the low fuel rate for the entire casing operation.

The cost of special equipment for cementing is assumed to be 40% of the cement cost. The cost of cementing services is assumed to be 60% of the cement costs.

The results of this analysis agree very well with those from the more aggregated equations used in GEOWELL (6). The reader should refer to the source code, Section 6.2 for details of the equations.

4.7.3 Well Head Equipment

A charge of \$20,000 for well head equipment and its installation is assumed. This is subsumed under cost subaccount number 14, "Surface Equipment".

4.8 Mishaps While Drilling

Most published analyses of geothermal well costs neglect explicit treatment of the economic impacts of accidents and incidents encountered while drilling. ONEWEL includes well-founded estimates of the frequencies, costs, and delays of major drilling mishaps.

The estimates were developed from geothermal drilling records made available to MITRE for research purposes by the Los Alamos Scientific Laboratory. The records cover 130 geothermal wells drilled through 1973; 39 wells from the Imperial Valley and 91 wells from the Geysers.

Ten major types of drilling mishaps were identified in the records (Table 15, Table 3). These were: Doglegs, two types of lost circulation (Types 2 and 3), fishing for junk, fishing for pipe-with three different outcomes (Types 5, 6, and 7), sidetracking (Types 8 and 9) and cogitation.

TABLE 15

FREQUENCIES OF DRILLING MISHAPS

TYPE OF MISHAP	ROCK HARNESS RANGE	FREQUENCY OF MISHAP AS FUNCTION OF ROCK HARDNESS ⁽¹⁾	ENGVAR FILE PARAMETER TO ADJUST FREQUENCY
1. Dogleg, Cement and Redrill	1 2 - 4	0.0 $0.04 * AFREQ (2)$	YFDOG
2. Lost Circulation, Recovered with Materials in Mud	1 - 2 3 - 4	0.20/HARD 0.0	YFLCM
3. Lost Circulation, Cement and Redrill	1 2 3 - 4	0.0 1.0 1.5	YFLCC
4. Fishing for Junk	1 - 4	$0.5 * AFREQ(2)$	YFFISH
5. Fish for Pipe and Recover it	1 - 4	$0.29 * AFREQ(2)$	YFPIPE
6. Fish for Pipe, Fail, Abandon Hole	1 - 4	0.08	YFFAIL
7. Fish for Pipe, Fail, Sidetrack and Redrill	1 - 4	$0.08 * AFREQ(2)$	YSIDBT
8. Sidetrack for Unspecified Reason	1 - 4	$0.03 * AFREQ(2)$	YSIDE
9. Sidetrack After First Bottom is Dry	1 - 4	0.03	YREBOT
10. Cogitation	1 - 4	$0.085 * AFREQ(2)$	YCOGIT

Notes: (1) All frequencies are proportional to well depth. Frequencies shown are for a nominal depth of 6373 feet.

(2) $AFREQ = (0.5 + 0.5 * HARD) * YAFREQ * DEEP/6373.$, where HARD = rock hardness, DEEP = well depth, and YAFREQ is the ENGVAR file parameter that affects all mishap frequencies.

The frequency and amount of time required to recover from each mishap type was tabulated. Geothermal drilling contractors were then contacted to determine if the estimates were reasonable, and to ascertain typical costs (rather than rig time and rent) required to recover from each mishap type.

The impressions of the drillers concurred with the drilling records for all but one type of mishap. Type 2, "Lost Circulation-Recovered by adding lost circulation materials to mud", appeared to have been under reported in the records. The frequency used in ONEWEL for this mishap type is that reported by the drillers.

The tabulated frequencies of mishaps appeared to be affected by both rock hardness and well depth. Table 15 shows how mishap frequencies are affected by rock hardness. The listed frequencies are for a nominal depth of 6373 feet, the average depth of wells in the drilling records. For each well simulated by ONEWEL, the nominal frequency of each mishap type is multiplied by the well's total depth and divided by 6373.

In Table 15, as elsewhere in ONEWEL, rock hardness values are given by 1 = Soft, 2 = Medium, 3 = Medium-Hard, and 4 = Hard. To scale the tabulated mishap frequencies to rock hardness, Imperial Valley wells were assumed to be representative of "Soft" rock, and Geysers wells to be representative of "Medium-Hard" rock. For six of the mishap types, mishap frequency was directly proportional to rock hardness. In these cases ONEWEL calculates the frequency in

proportion to a variable named "AFREQ" which accounts for hardness and depth effects:

$$AFREQ = (0.5 + 0.5 * HARD) * YAFREQ * DEEP / 6373.,$$

where:

HARD = Rock Hardness,

DEEP = Well Depth in feet, and

YAFREQ = the ENGVAR file parameter that affects all mishap frequencies when changed (Nominal value = 1.00).

The calculated frequency of each of these 6 mishap types is then given by:

$$ACFR (i) = f_i * YPARAM * AFREQ,$$

where:

f_i = the frequency of incident i found in the drilling record, and

YPARAM = the ENGVAR file parameter that affects a specific mishap frequency (column 4 in Table 15, Nominal value = 1.00).

For example, for a well of depth 6373 feet in soft rock, AFREQ would be equal to 1.0, and the frequency of fishing for junk (Mishap Type 4) would be 0.5. That is, one episode of fishing for junk would be expected to occur in 50% of the wells drilled in such a prospect. If YAFREQ is set equal to 0.0 prior to a run of WELCST, all accident frequencies would be set at zero, and the reported cost would be that of a mishap-free well.

Two types of mishaps (Number 6 and Number 9) appear to occur at the same frequency at either Imperial Valley and the Geysers. These

were made independent of rock hardness in ONEWEL.

Lost circulation incidents (Mishap Types 2 and 3) are handled parametrically in ONEWEL, because their frequency and the method of recovering from them varies markedly with rock type. In Soft (usually sedimentary) rock, lost circulation is relatively infrequent and controlled by adding lost-circulation materials to the mud. Most Medium-Hard and Hard formations are highly fractured; lost circulation is more frequent and requires that the culprit fracture be sealed with cement. Medium hardness formations are assumed to exhibit both types of lost circulation to some degree.

The requirements for recovering from mishaps are shown in Table 16. Costs for recovering are estimated in terms of rig hours, fuel, and "other" costs. Rig time estimates were derived from the drilling records. Fuel costs and other costs were estimated by MITRE, in most cases in consultation with geothermal drillers. Rig hours are reported on Line A of the Well Cost Report (Table 4, Section 2.4). Fuel costs are added to other fuel costs on Line 5 of the Well Cost Report. "Other" mishap costs are listed separately on Line 13 of the report.

It should be noted that in three cases (Mishap Types 6, 7, and 9), a substantial amount of drilled hole is abandoned. In these cases ONEWEL adds a certain fraction of the total well cost (70%, 20%, 18%, respectively) to the accumulating well cost, rather than "redrilling" the abandoned portion of hole via use of the footage routine. It is here that the "two-pass loop" described in Figure 6

TABLE 16

REQUIREMENTS FOR RECOVERING FROM DRILLING MISHAPS

TYPE OF MISHAP	RIG TIME, HOURS	FUEL TIME HOURS, RATE	\$, OTHER
1. Dogleg, Cement and Redrill	72	48, HIGH	\$2000, plus 2 days of downhole motor use.
2. Lost Circulation; Recovered with Materials in Mud	24	24, HIGH	\$1000.
3. Lost Circulation; Cement and Redrill	112	48, HIGH	\$3000, plus 2 days of downhole motor use.
4. Fishing for Junk	43	43, LOW	\$500.
5. Fish for Pipe and Recover it	72	24, HIGH	\$1000.
6. Fish for Pipe, Fail, Abandon Hole	220	72, HIGH	\$5000, plus 70% of the well total cost spread over non-abandoned holes.
7. Fish for Pipe, Fail, Sidetrack and Redrill	220	200 ¹ , HIGH	\$2000, plus 20% of the well cost for the abandoned portion, plus time and costs for one sidetrack.
8. Sidetrack for Unspecified Reason	298	200, HIGH	\$2000.
9. Sidetrack after First Bottom is Dry	24	72 ¹ , HIGH	\$2000, plus 18% of the well cost for the abandoned portion, plus time and costs for one sidetrack.
10. Cogitation	60	0	\$1000.

Notes: 1 - Includes fuel for sidetracking.

of Section 4.1 is used.

For Mishap Type 6, "Fish for pipe, fail, abandon hole", the costs due to this type of incident are distributed in appropriate proportions to wells that are not abandoned. This is the only allowance made in WELCST for non-productive geothermal wells. While an allowance is made in the GEOBEN program (1, Volume I) for non-productive wells (by requiring that each generating plant have 20% more wells than needed to meet the minimum fluid-production requirement), forecasting the success ratio (7) or dry-hole fraction (31) for drilling in U.S. geothermal prospects appears to be worth further study.

4.9 Other Costs

All additional costs are described in Table 17. These are drawn, in the main, from Reference 15, and thus reflect current practice at the Geysers and Imperial Valley prospects.

They include:

- Miscellaneous Rig Time,
- Waste Disposal,
- Surface Equipment,
- Site Preparation, Rig Up and Rig Down,
- Miscellaneous Transportation,
- Logging,
- Miscellaneous, and
- Supervision and Overhead.

TABLE 17

OTHER COSTS

LINE IN WELL COST REPORT	DESCRIPTION	ESTIMATED COST
E	Miscellaneous Rig Time	20% of rig cost for Rotating on Bottom, plus 5% of rig costs for Tripping, Setting Casing, and Mishaps.
8	Waste Disposal	50% of sum of mud costs and water costs.
9	Surface Equipment	(\$350. + \$250. * HARD) * Days of Rig Time, plus WELL HEAD cost (See Section 4.7.3).
12	Site Preparation, Rig Up and Rig Down	Fixed at \$95,000.
14	Miscellaneous Transportation	2% of costs on Lines 2-12 of Well Cost Report.
15	Logging	\$4.00 per foot of total well depth.
16	Miscellaneous	\$50,000, plus additional \$50,000 if well depth exceeds 10,000 feet.
17	Supervision and Overhead	9% of total rig rent.

5.0 EXAMPLE OF OPERATING SESSION

Table 18 is an annotated listing of the interactions of a user and the CMS terminal system for one run of WELCST and GEOBEN. User inputs are lower case. Computer responses are upper case. Bracketed annotations explain the purpose of user entries.

TABLE 18

EXAMPLE OF WELCST SESSION

[User has logged on to the system.]

R; T=0.01/0.03 13:49:01

[User asks for display of DUMSIT DATA file to check that the contents of that file]
[specify the desired generic model well.]

print dumsit data

R; T=0.02/0.08 13:49:26

[File contents were displayed on screen, and needed no revision. User copies ENGSAV]
[DATA into ENGVAR DATA to set all ENGVAR variables at nominal values. Then user]
[edits ENGVAR DATA to set the rate of penetration at 150% of the nominal value.]

copyfile engsav data a engvar data a (rep

R; T=0.12/0.24 13:50:03

fedit engvar data

FEDIT

n

YROP	YRGENT	YRTRIP	YFUEL	YCSMUD	YWATER	YCEMCS	YCEMTM	YCACST	YDICST
------	--------	--------	-------	--------	--------	--------	--------	--------	--------

n

1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
------	------	------	------	------	------	------	------	------	------

c/0/5/

1.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
------	------	------	------	------	------	------	------	------	------

file

R; T=0.11/0.41 13:51:09

[All needed variables are specified. User initiates execution of WELCST.]

TABLE 18 (Continued)

R; T=0.11/0.41 13:51:09
 welcstb
 SET BLIP DIG.DIG.
 GL TXTLIB FORTHOD1
 FI 01 DISK BITVAR DATA A1
 FI 02 DISK DESIGN DATA A1
 FI 03 DISK ENGVAR DATA A1
 FI 04 DISK DUMSIT DATA A1
 FI 07 DISK TITLES DATA A1
 FI 06 PRINTER
 FI 10 DISK RUNOPS DATA A1
 FI 11 DISK WCOST DATA A1
 FI 09 DISK RAJJ DATA A1
 LOAD WELCSTB
 START
 DMSLIO740I EXECUTION BEGINS...

89

[While WELCST is running, the word "DIG" is signalled on the terminal to indicate]
 [rate of execution.]

DIG.DIG.
 DIG.DIG.
 DIG.DIG.
 R; T=6.29/7.57 13:51:56

[WELCST execution is completed. Results from WELCST run are in file WCOST, to be used]
 [by GEOBEN code. User initializes GEOBEN by initializing file RADFILJ DATA, then]
 [executing GEOBEN.]

TABLE 18 (Continued)

copyfile radfilsav data a radfilj data a (rep
R; T=0.12/0.25 13:52:41
geoben
SET BLIP THINKS..
GL TXTLIB FORTMOD1
FI 01 DISK COMCOFJ DATA A1
FI 02 DISK WELCOFJ DATA A1
FI 03 DISK ROCOFJ DATA A1
FI 04 DISK RRNDJ DATA A1
FILEDEF FT05F001 TERMINAL
FILEDEF FT06F001 TERMINAL
FI 07 DISK RAJJ DATA A1
FI 08 PRINTER (LRECL 133 BLOCK 133 RECFM FA)
FI 09 DISK RADFILJ DATA A1
FI 10 DISK FINANCP DATA A1
FI 11 DISK GELPF DATA A1
FI 12 DISK WCOST DATA A1
LOAD GELCOMP
START
DMSLIO740I EXECUTION BEGINS...

[GEOBEN interacts with the user to establish a few needed parameters, and then]
proceeds to benefit calculations.]

WELCOME TO GELCOM. PLEASE ENTER RUN TITLE (UP TO 72 CHARACTERS) :
example drill bit

NEED TO DETERMINE THE EFFECTS OF R&D IMPACTS ? SAY YES, OR NO.

yes

NEED TO WRITE PASSFILE FOR COST BENEFIT ANALYSIS?
ANSWER YES OR NO

yes

TABLE 18 (Concluded)

ENTER CONSTANT DOLLAR C/B DISCOUNT RATE AS A FRACTION FORMAT F(5.3)
 .1

ENTER NO. OF SITES IN FORMAT (I2)
 27

NEED TO READ WELL COST FILE? ANSWER YES OR NO
 yes

DO YOU WISH TO USE STANDARD DATA AND SUPPRESS FURTHER INTERACTIVE FUNCTIONS? ANSWER YES OR NO.
 yes

SPECIFY PRINT OPTION IN FORMAT (I2)
 0 = SHORT PRINTOUT, ALL SITES
 1 = FULL PRINTOUT
 2 = PRINTOUT FOR SITES 1-3 ONLY, LAST PLANTS ONLY

16

2
 THINKS..
 THINKS..
 THINKS..
 THINKS..
 THINKS..
 THINKS..
 FILEDEF FT03F001 DISK GIMPF DATA * (RECFM F LRECL 80 BLOCK 80)
 FILEDEF FT04F001 DISK GELPF DATA * (RECFM F LRECL 80 BLOCK 80)
 FILEDEF FT05F001 DISK SUMDIP DATA * (RECFM F LRECL 80 BLOCK 80)
 FILEDEF FT08F001 PRINTER
 GLOBAL TXTLIB FORTMOD1
 LOAD SUMDIP
 START
 DMSLIO740I EXECUTION BEGINS...
 R; T=15.81/18.59 13:54:49

[GEOBEN has finished. Results are waiting at the printer. User initializes next]
 [WELCST calculation, or signs off to terminate the session.]

6.0 FORTRAN SOURCE CODE

6.1 WELCST Source Code

The FORTRAN source code for the WELCST main program is shown on the following pages. WELCST calls only subroutine ONEWEL, which is listed in Section 6.2.

```

C      WEICST
C      MAIN PROGRAM.
C      COMPUTES EXPECTED COST OF WELLS AT
C      A GENERIC DUMMY SITE, AND AT 27
C      GEOTHERMAL PROSPECTS IN THE UNITED STATES.
C
C      DAN ENTINGH, MITRE, 20 JULY 1978
C
C      SUBROUTINES CALLED:
C      ONEWEL (IDRRPT,WELTOT)
C
C      FILES USED:
C      BITVAR,DESIGN,ENGVAR,DUMSIT,RUNOPS,W COST,TITLES,RAJJ
C
C      COMMON ZROP(4,15), ZBITLF(4,15), ZBTCST(4,15),
C      1DESIGN(11,10,8), SITE(18), PRJTTL(18), EVRNAM(10,10,2),
C      2EV(10,10), CSTPRO(27), CSTPRN(27), ACTNAM(23,10), DUMDOL(23),
C      3TITLE(33,10), YAC(23),CSTIJO(27),CSTIJN(27)
C
C      COMMON SSS, ISYSTP, KDEPTH, KXHARD, KSAL,
C      1IDSGN, IROP1, IROP2, IROP3, IROP4, IROP5, IROP6,
C      2IROP7, IROP8, IROP9, IROP10,KTMPBH
C
C      DIMENSION IPERSPC(27,6), PRSNAM(27,10)
C
C      READ DATA FILES:
C      FILES NEEDED FOR ALL RUNS:
C      BIT PERFORMANCE DATA:
C
C      READ (1,2901) AZILCH
2901  FORMAT (A4)
      DO 10 I=1,15
10    READ (1,2902) (ZROP(J,I),J=1,4)
2902  FORMAT (4F10.2)
      READ (1,2901) AZILCH
      DO 11 I=1,15
11    READ (1,2902) (ZBITLF(J,I),J=1,4)
      READ (1,2901) AZILCH
      DO 12 I=1,15
12    READ (1,2902) (ZBTCST(J,I),J=1,4)
      KO = 1
      WRITE (6,2) KO
2    FORMAT (T10,I6)
C
C      WELL - DESIGN DATA:
C      DO 15 I = 1,11
C      DO 15 J = 1,10
15    READ (2,2905) (DESIGN(I,J,K),K=1,8)
2905  FORMAT (3X,F7.0,F7.0,F6.2,F7.0,F7.0,F6.2,
1F6.2,F5.1)
      KO = 2
      WRITE(6,2) KO
C
C      ENGINEERING VARIABLES
C      DO 16 I = 1,10

```



```

      READ (3,2907) (EVRNAM(I,J,1),EVRNAM(I,J,2),J=1,10)
16  READ (3,2908) (EV(I,J),J=1,10)
2907 FORMAT (20A4)
2908 FORMAT (10F8.2)
      KO = 3
      WRITE(6,2) KO
C
C   GENERIC WELL MODEL (DUMMY) DATA:
C   (THIS DATA DEFINES A TEST CASE GENERIC WELL)
      READ (4,2909) (SITE(I),I=1,10),KTMPBH,ISYSTP,
1KDEPTH,KXHARD,KSAL,IDSGN
2909 FORMAT (10A4,////,I6,/,5I6,/)
      KO = 4
      WRITE(6,2) KO
C   KDEPTH IS IN FEET, HERE.
C
C   RUNTIME OPTION CODES:
      READ(10,2910) IROP1,IROP2,IROP3,IROP4,IROP5,
1IROP6,IROP7,IROP8,IROP9,IROP10
2910 FORMAT (10(1X,I1))
      READ(10,2911) IPRJCD,(PRJTTL(J),J=1,18)
2911 FORMAT (I6,/,18A4)
      KO = 5
      WRITE(6,2) KO
C
C   READ IN DATA FROM 27 PROSPECTS,IFF NEEDED.
      IF ((IROP1.EQ.2).OR.(IROP1.EQ.3)) GO TO 20
      DO 18 I = 1,27
18  READ (9,2909) (PRSNAM(I,J),J=1,10),(IPRSPC(I,K),
1K=1,6)
      KO = 6
      WRITE(6,2) KO
20  CONTINUE
C
C   BASELINE DATA:
      READ(11,2915) (CSTPRO(I),CSTPRN(I),CSTIJO(I),CSTIJN(I),
1I=1,27)
2915 FORMAT (4F10.0)
2916 FORMAT (8F10.0)
C   ACCOUNTS ON GENERIC TEST CASE WELL:
      READ(11,2916) (DUMDOL(I),I=1,23)
      REWIND 11
      KO = 7
      WRITE(6,2) KO
C
C   TITLES FOR DRILLING COST REPORTS:
      DO 22 I=1,33
22  READ (7,2917) (TITLE(I,J),J=1,10)
2917 FORMAT (10A4)
      KO = 8
      WRITE(6,2) KO
C
C   WORKING SECTION OF PROGRAM.
C
C   WRITE PROJECT NO., NAME, OP-CODES

```

```

        WRITE (6,2020) IPRJCD, (PRJTTL(J),J=1,18)
2020 FORMAT (1H1,/,T10,'WELCST RUN NUMBER: ',
        1I6,/,T10,'PROJECT: ',18A4,/)
        WRITE (6,2021) IROP1, IROP2, IROP3, IROP4,
        1IROP5, IROP6, IROP7, IROP8, IROP9, IROP10
2021 FORMAT (T10, 'RUN-TIME OPTION CODES',
C
        1//, T10, 10I4)
C
        WRITE OUT DESIRED DATA BASES
        IF (IROP2.EQ.0) GO TO 40
        WRITE (6,2930)
2930 FORMAT (1H1,///,T10,'BIT PERFORMANCE DATA',/,
        1T10, 'RATE OF PENETRATION',/)
        DO 32 I = 1,15
        32 WRITE (6,2931) (ZROP(J,I),J=1,4)
2931 FORMAT (T10,4F10.2)
        WRITE (6,2932)
2932 FORMAT (/, T10, 'BIT LIFE', /)
        DO 33 I = 1,15
        33 WRITE (6, 2931) (ZBITLF(J,I),J=1,4)
        WRITE (6,2933)
2933 FORMAT (/, T10, 'BIT COST', /)
        DO 34 I = 1,15
        34 WRITE (6,2931) (ZBTCST(J,I),J=1,4)
        40 CONTINUE
        IF (IROP3.EQ.0) GO TO 45
C
        WRITE OUT DUMMY WELL DESIGN DATA
        WRITE (6,2935) IDSGN
2935 FORMAT (1H1, ///, T10, 'DESIGN OF GENERIC WELL', //,
        1T10, 'DESIGN NUMBER: ', I6, //)
        DO 42 I = 1,10
        42 WRITE (6,2936) I, (DESIGN(IDSGN,I,J),J=1,8)
2936 FORMAT (T10,I2,2X,8F10.2)
        WRITE (6,2037) (SITE(I),I=1,10),KTHPBH,ISYSTP,KDEPTH,KXHARD,
        1KSAL,IDSGN
2037 FORMAT(///,T10,'GENERIC WELL PARAMETERS',/,T10,'NAME = ',10A4,
        1/,T10,'TEMPERATURE = ',I6,/,T10,'SYSTEM TYPE = ',I6,/,T10,
        2'DEPTH = ',I6,/,T10,'HARDNESS = ',I6,/,T10,'SALINITY = ',I6,/,
        3T10,'WELL DESIGN = ',I6,/)
        45 CONTINUE
        IF (IROP4.EQ.0) GO TO 50
C
        WRITE OUT ENGINEERING VARIABLES
        WRITE (6,2937)
2937 FORMAT (1H1, ///, T10, 'ENGINEERING VARIABLES', ///)
        DO 46 I = 1,10
        WRITE (6,2938) (EVRNAM(I,J,1),EVRNAM(I,J,2),J=1,10)
        46 WRITE (6,2939) (EV(I,J),J=1,10)
2938 FORMAT (T10, 20A4)
2939 FORMAT (T10, 10(F6.2,2X),/)
        50 CONTINUE
C
C
        COMPUTE THE DUMMY WELL
        WELTOT = 0.0
        IDRRPT = 1
        IF (IROP1.EQ.5) IDRRPT=0

```

```

      CALL ONEWEL (IDRRPT, WELTOT)
C     DUMMY WELL IS DONE.
C     PRINT TOTAL COST IF REPORT WAS SUPPRESSED
      IF (IDRRPT.EQ.0) WRITE (6,2100) WELTOT
2100  FORMAT (1H1, '////', T10, 'GENERIC WELL
      1COST = $ ',F10.0)
C
C     NOW COMPUTE THE PROSPECT WELLS IF CALLED FOR.
      IF ((IROP1.EQ.2).OR.(IROP1.EQ.3)) GO TO 220
C     INITIALIZE ACCOUNTS
      AVGDOL = 0.0
      AVGBAS = 0.0
      AVGCHN = 0.0
C     WRITE THE HEADER
      WRITE (6,2020) IPRJCD, (PEJTTL(J),J=1,18)
      WRITE (6,2103)
2103  FORMAT (T10, 'GEO THERMAL PROSPECT',T56,'WELL COST',
      1T68,'WELL COST',T81,'PERCENT',/,T56,'WITH R&D'
      2,T69,'W/O R&D',T80,'DIFFERENCE',/)
C     MAIN LOOP STARTS HERE
      DO 200 I = 1,27
      KTMPBH = IPRSPC (I,1)
      ISYSTP = IPRSPC (I,2)
      DEPTH = IPRSPC (I,3)
      KXHARD = IPRSPC (I,4)
      KSAL = IPRSPC (I,5)
      IDSGN = IPRSPC (I,6)
C
C     CONVERT UNCASSED DESIGNS TO TRIPLE BOTTOMS:
      IF (IROP6 .EQ. 0) GO TO 60
      IF (IDSGN .EQ. 2) IDSGN = 3
      IF (IDSGN .EQ. 5) IDSGN = 6
60    CONTINUE
C
C     CONVERT METERS TO FEET
      KDEPTH = DEPTH *100./(2.54*12.)
      WELTOT = 0.
C
C     CALCULATE THE COST
      CALL ONEWEL (0,WELTOT)
C     FIND THE COST CHANGE
      CSTPRN (I) = WELTOT
      IF (CSTPRO(I).LE.0.) CSTPRO(I)=WELTOT
      DELTA = (WELTOT-CSTPRO(I))*100.0/(CSTPRO(I) + .0001)
C     CANCEL OUT COST INCREASES UNLESS IROP7=1.
      IF (DELTA.LE.0.) GO TO 70
      IF (IROP7.EQ.1.) GO TO 70
      CSTPRN (I) = CSTPRO (I)
      DELTA = 0.
      WELTOT = CSTPRO (I)
70    CONTINUE
C
C     BUILD UP RESULTS FOR AVERAGES
      AVGDOL = AVGDOL + WELTOT
      AVGBAS = AVGBAS + CSTPRO (I)

```

```

      AVGCHN = AVGCHN + DELTA
C      WRITE A LINE OF RESULTS
      WRITE (6,2120) I, (PRSNAM(I,J),J=1,10),
      1CSTPRN(I),CSTPRO(I),DELTA
2120  FORMAT (T7,I2,'.',1X,10A4,5X,F10.0,2X,
      2F10.0,4X,F5.1)
      200 CONTINUE
C
C      CALCULATE AVERAGES AND WRITE THEM
      AVGDOL = AVGDOL/27.
      AVGBAS = AVGBAS/27.
      AVGCHN = AVGCHN/27.
      WRITE (6,2122) AVGDOL,AVGBAS,AVGCHN
2122  FORMAT (/,T10,'AVERAGE',T56,
      1F10.0,T68,F10.0,T82,F5.1)
C
C      THIS CONCLUDES THE MAIN REPORT
C
C      CHANGE PROSPECTS BASELINE COSTS IF NEEDED
      IF(IROP1.NE.4) GO TO 220
      DO 210 I = 1,27
210   CSTPRO(I) = CSTPRN(I)
220   CONTINUE
      DO 221 I=1,27
      CSTIJN(I) = CSTPRN(I)
C
221  CSTIJO(I) = CSTPRO(I)
C      PUSH COST RESULTS INTO OUTPUT FILE
      WRITE(11,2915) (CSTPRO(I),CSTPRN(I),CSTIJO(I),CSTIJN(I),
      1I=1,27)
      WRITE(11,2916) (DUMDOL(I),I=1,23)
C
      STOP
      END

```

6.2 ONEWEL Source Code

The FORTRAN source code listing for the ONEWEL subroutine is shown on the following pages. The subroutine is called by WELCST. ONEWEL calls no other subroutines.

```

SUBROUTINE ONEWEL(IDRPT,WELICT)
C
C   THIS ROUTINE CALCULATES THE COST OF DRILLING ONE WELL,
C   GIVEN PROSPECT PARAMETERS, WELL DESIGN, AND DATA ON
C   DRILLING DEVICE PARAMETERS AND COSTS.
C
C   BESIDES THE TECHNOLOGY PARAMETERS INCLUDED IN COMMON BLOCKS,
C   THE FOLLOWING VARIABLES MUST INCLUDE PROSPECT-SPECIFIC
C   DATA BEFORE ONEWEL IS CALLED:
C   KTMPLH = BOTTOMHOLE (FORMATION) TEMPERATURE IN DEGREES CENTIGRADE
C   KDEPTH = DEPTH OF WELL IN FEET
C   KXHARD = ROCK TYPE (1-4)
C   IDSGN = DESIGN NUMBER FOR WELL
C   IDRPT = REPORT FLAG:
C   IF = 1, WELL COST IS PRINTED, IF = 0, ONLY TOTAL COST
C   IS REPORTED TO CALLING PROGRAM IN "WELICT".
C
C   COMMON BLOCKS:
C   COMMON ZROP(4,15), ZBITLF(4,15), ZBTCST(4,15), DESIGN(11,10,6),
1   SITE(18), PROJTL(18), EVNAM(10,10,2), EV(10,10),
2   CSTPRC(27), CSTPRN(27), ACTNAM(23,10), DUMDCL(23),
3   TITLE(55,10), YAC(23), CSTIJC(27), CSTIJN(27)
C   COMMON SINGLE VALUED VARIABLES:
C   COMMON SSS, ISYSTP, KULPTH, KXHARD, KSAL, IDSGN, IRCP1, IRCP2,
1   IRCP3, IRCP4, IRCP5, IRCP6, IRCP7, IRCP8, IRCP9, IRCP10, KTMPLH
C
C   DIMENSION WKDSGN(10,8), SUMS(20,20), HOURS(23), COST(23),
1   ACPR(11), ACHK(11), ACDEL(11), PERCNT(23), CHANGE(23), RCKNUM(5)
C   DATA RCKNUM/'UNDF','SFT','MED.','M-HD','HARD'/
C
C   CONVERT ENGINEERING VARIABLE FILE DATA TO MNEMONIC LABELS
C   YRCP = EV(1,1)
C   YKURT = EV(1,2)
C   YRTKIP = EV(1,3)
C   YFUEL = EV(1,4)
C   YCSMUD = EV(1,5)
C   YWATER = EV(1,6)
C   YCEMCS = EV(1,7)
C   YCEMTM = EV(1,8)
C   YCALST = EV(1,9)
C   YCICST = EV(1,10)
C   YLDIBT = EV(2,1)
C   YDIRCP = EV(2,2)
C   YDISEL = EV(2,3)
C   YCMUT = EV(2,4)
C   YLFMLT = EV(2,5)
C   YCHTLP = EV(2,6)
C   YMTRCP = EV(2,7)

```

YAFREQ = EV(2,8)
 YFDCG = EV(2,9)
 YFLCM = EV(2,10)
 YFLCC = EV(3,1)
 YFFISH = EV(3,2)
 YFPIPE = EV(3,3)
 YFFAIL = EV(3,4)
 YSIDE = EV(3,5)
 YSIDBT = EV(3,6)
 YREBCT = EV(3,7)
 YSIDTI = EV(3,8)
 YSIDCL = EV(3,9)
 YSIDFU = EV(3,10)
 YCOGIT = EV(4,1)
 YCOGTI = EV(4,2)
 YCPIPE = EV(4,3)
 DG 5 K = 44, 66
 I = (K-1)/10
 J = K-I*10
 L = K-43
 5 YAC(L) = EV(I,J)
 YBCJNL = EV(6,7)
 YBCUNS = EV(6,8)
 YBCHCP = EV(6,9)
 YBCMIL = EV(6,10)
 YBLJNL = EV(7,1)
 YBLUMU = EV(7,2)
 YBLUAI = EV(7,3)
 YQHDLG = EV(7,4)
 YQHDHI = EV(7,5)
 YQDPLC = EV(7,6)
 YQDPHI = EV(7,7)
 YQDILG = EV(7,8)
 YQDIHI = EV(7,9)
 YQTMLC = EV(7,10)
 YQTMHI = EV(8,1)
 YQCSTS = EV(8,2)
 YQCSTA = EV(8,3)
 YQCSTB = EV(8,4)
 YQCSTC = EV(8,5)
 YQROP = EV(8,6)
 YQRGXP = EV(8,7)
 YQLIF = EV(8,8)
 YQLIFX = EV(8,9)
 YQTMCR = EV(8,10)
 YQTIM = EV(9,1)
 YQFEET = EV(9,2)
 YBTRUN = EV(9,3)

```

YBTCK = EV(9,4)
YMTCKT = EV(9,5)
YRCFMS = EV(9,6)

C
C LOOPS THROUGH ONCE TO GET TOTAL COST FOR USE IN MISHAP COST
C CALCULATIONS. PASS ONE IS WITHOUT MISHAPS; PASS TWO CALCULATES
C MISHAPS AND PRINTS REPORTS IF NEEDED.
IPASSR = 1
IF(YAFREC .LE. 0.) IPASSR = 2
SAVEAC = YAFREC
YAFREC = 0.
ISVDRP = IDRRPT
WELTCT = 0.

C
C ENTRY POINT FOR BOTH PASSES:
10 CONTINUE
IDRRPT = ISVDRP
TURN OFF REPORTS ON PASS ONE:
IF(IPASSR .EQ. 1) IDRRPT = 0

C
C INITIALIZE VALUES AND ACCOUNTS:
C
C SUMS FOR FOOTAGE COST ACCOUNTS:
DC 20 I = 1,20
DC 20 J = 1,20
20 SUMS(I,J) = 0.0001
DC 22 I = 1,23
HOURS(I) = 0.0001
COST(I) = 0.0001
22 CONTINUE

C
C TRIPPING RATE, HR/FT, ROUND TRIP
RTRIP = (1.0/1000.)*YKTRIP
C
C RIG KENT RATE, $ PER HOUR
RGKENT = 200.*YRGKNT
C
C NOMINAL BIT COST (1978):
NCMCST = 3758.-696.2*DIAM+67.16*DIAM**2
C
C FUEL COST RATE, $ PER ROTATING HOUR
FUELRT = 40.0*YFUEL
FUELLC = 0.2*FUELRT
C
C DOWNHOLE MOTOR COSTS, ETC.
CSTMCT = 5000.*YCMCT
FLFMCT = 120.*YLFMCT
CMUTCP = 41.67*YCMTCP
C
C DOWNHOLE MOTOR, CHARGE/DAY:
CSTMTC = CSTMCT*24./FLFMCT + 24.*CMUTCP
C
C DIAMOND BIT FLAG
IDIFLG = 0

```



```

C NOTE: YMTROP SHOULD BE USED TO ENTER ANY INCREASED ROP DUE TO
C USE OF MOTOR.
C CRITICAL BIT TEMPERATURES, DEGREES C:
  TLSEAL = 100.*YBITRON
  TLSCAK = 200.*YTSCK
  XTMPBH = KIMPHH
C WATER TIME ACCOUNT
  WATRAT = 25.*YWATER
  WATTIM = 0.0
C DRILLING PIPE COST ACCOUNT
  CSPIPE = 0.0
C
C THE CALCULATIONS START HERE.
C
C FIND CASING DESIGN AND ADJUST IT TO TOTAL DEPTH
C FOR THIS PROSPECT.
  DC 37 I = 1,10
  DC 37 J = 1,8
  WKDSGN(I,J) = DESIGN(IDSGN,I,J)
37 CONTINUE
C WORKING FILE FILLED; FIND MAXIMUM HOLE DEPTH IN DESIGN.
  IF(KDEPTH .LE. 1001) KDEPTH = 1050
  XTDPH = KDEPTH
  DMAX = 0.0
  DC 38 I = 1,10
  IF(DMAX .LT. WKDSGN(I,2)) DMAX = WKDSGN(I,2)
38 CONTINUE
  IF(DMAX .LE. 0.0) DMAX = XTDPH
C CALCULATE SCALE FACTOR
  SF = XTDPH/DMAX
C ADJUST THE DESIGN; CONDUCTOR CASING (FIRST DESIGN INTERVAL)
C IS NOT CHANGED.
  DC 40 I = 2,10
    WKDSGN(I,1) = WKDSGN(I,1)*SF
    IF(WKDSGN(I,1) .LT. 150.) WKDSGN(I,1) = 150.
    WKDSGN(I,2) = WKDSGN(I,2)*SF
    WKDSGN(I,4) = WKDSGN(I,4)*SF
    WKDSGN(I,5) = WKDSGN(I,5)*SF
40 CONTINUE
C IF THERE ARE OTHER ADJUSTMENTS TO DESIGN, THEY SHOULD BE
C DONE HERE.
C
C PROCEED TO DRILL THE WELL:
C FIRST BORE HOLE INTERVAL
  NCASE = 1
C
C ENTRY POINT FOR ALL BOREHOLE INTERVALS:
1010 DSTART = WKDSGN(NCASE,1)

```

```

DSTOP = WKDSGN(NCASE,2)
DIAM = WKDSGN(NCASE,3)
C EXIT ON DSTOP = 0.0
IF(DSTOP .EQ. 0.0) GO TO 1010
C START OF BOREHOLE INTERVAL; FIRST SEGMENT
START = DSTART
C
C CALCULATE BOUNDARIES OF SEGMENT
C FIRST SEGMENT OF NEW INTERVAL:
C NSEG = DSTART/1000. + 1.
1020 SEGSTP = NSEG*1000 - 1
ASTOP = SEGSTP
IF(SEGSTP .GT. DSTOP) ASTOP = DSTOP
DFOOT = ASTOP - START
C
C RATE OF PENETRATION:
C RCP = ZRCP(KXHARD,NSEG)*YRCP
C
C FIND BIT TEMPERATURE
C ROCK TEMPERATURE:
C DPHALF = XTDPH/2.
C THALFD = 15. + 0.75*(XTMPBH - 15.)
C AVERAGE DEPTH FOR SEGMENT
DAVG = (START + ASTOP)/2.
IF(DAVG .GT. DPHALF) GO TO 1022
C BIT IS IN UPPER HALF OF HOLE:
TROCK = 15. + DAVG*(THALFD - 15.)/DPHALF
GO TO 1024
C BIT IS IN LOWER HALF OF HOLE:
1022 TROCK = 2.*THALFD - XTMPBH + 2.*(XTMPBH - THALFD)*DAVG/XTDPH
1024 CONTINUE
C
C ADJUST BIT TEMPERATURE TO ACCOUNT FOR EFFECT OF FLUID
DFLUID = WKDSGN(NCASE,8)
IF(DFLUID .LT. 1.) DFLUID = 2.
IF(DFLUID .EQ. 1.) GO TO 1026
C FLUID IS MUD OR WATER, MUCH COOLING
TMUD = 65. + (TROCK - 65.)*0.023*(DAVG - 3000.)/1000.
IF(DAVG .LT. 3000.) TMUD = 65
IF(TMUD .GT. TROCK) TMUD = TROCK
C SOAK TEMPERATURE DEPENDS ON TRIP TIME:
XTRIP = RTRIP*DAVG
TSOAK = TMUD + 0.9*(TROCK - TMUD)*(1.0 - EXP(-XTRIP/4.0))
GO TO 1029
C
C FLUID IS AIR, LITTLE COOLING
1026 TMUD = TROCK - 15.
C ALSO HERE: CORRECT RCP FOR AIR DRILLING

```

```

IF(DAVG.GT.4000.) GO TO 1028
RCP = RCP*(1. + 1.0*DAVG/4000.)
GO TO 1029
1028 RCP = RCP*2.0
1029 CONTINUE
TBIT = TRUCK

C
C SELECT BIT TYPE:
C
C HOLE-OPENER USED IF DIAMETER IS ABOVE 12.25 INCHES:
IF(DIAM.LE.12.25) GO TO 1030
BITCST = (680. + 170.6*DIAM)*YBCHCP
BITLIF = 30.
C IF CONDUCTOR HOLE, DRILL IN SOFT ROCK
IF(NSEG.NE.1) GO TO 1060
RCP = 2*RCP(1,1)*YRCP
GO TO 1060
C SEALED TOOTH BIT IS USED ABOVE 3000 FT, IF THE ROCK IS SOFT:
1030 IF(ASTCP.GT.3000.) GO TO 1031
IF(KX.HARD.NE.1) GO TO 1031
BITCST = 0.23*NUMCST*YBGMIL
BITLIF = 30.
GO TO 1055
C
C SEALED JOURNAL INSERT BIT USED IF SEAL TEMPERATURE
LIMITS ARE NOT EXCEEDED:
1031 IF(TMUD.GT.TLSEAL) GO TO 1032
IF(TSCAK.GT.TLSCAK) GO TO 1032
BITCST = NUMCST*YBCJNL
BITLIF = 90.*YBLJNL
GO TO 1035
C
C UNSEALED ROLLER BEARING BIT USED:
1032 BITCST = 0.70*NUMCST*YBLUNS
BITLIF = 30.*YBLUNU
C IF DRILLING IN AIR, LIFE IS LESS:
IF(DFLUID.EQ.1) BITLIF=18.*YELLAI
1035 CONTINUE
C COST TO DRILL WITH SELECTED CONVENTIONAL BIT:
BITNUM = DFOOT/(RCP*BITLIF)
COST1 = BITNUM*(BITCST + DAVG*RTrip*KORENT) + DFOOT*RGRENT/RCP
C SAVE VALUES FOR SELECTED BIT:
SVCST = BITCST
SVRCP = RCP
SVLIF = BITLIF
C
C DETERMINE IF ADVANCED BIT IS TO BE USED.
C SET FLAG TO INDICATE ADVANCED BIT IS SELECTED:

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      IBIT = 2
C     CHECK LIMITS OF CONDITIONS FOR BIT USE:
      IF(DIAM .LT. YQDILC) GC TO 1040
      IF(DIAM .GT. YQDIHI) GC TO 1040
      HARD = KXHARD
      IF(HARD .LT. YQHDLC) GC TO 1040
      IF(HARD .GT. YQHDIH) GC TO 1040
      IF(DAVG .LT. YQDPLC*1000.) GC TO 1040
      IF(DAVG .GT. YQDPHI*10000.) GC TO 1040
      IF(IBIT .LT. YQIMLU*10.) GC TO 1040
      IF(TLIT .GT. YQIMHI*200.) GC TO 1040
      BITCST = YQCSTS*NLMCST
      IF(YQCSTS .EQ. 0) BITCST=YQCSTA*1000.+YQCS18*DIAM*100.+
      1YQCSTC*10.*DIAM**2
      IF(YGRUP .NE. 0) RCP = RCP*YGRCP
      IF(YGRUP .EQ. 0) RCP = YGRUPX*10.
      IF(YQLIF .NE. 0) GC TO 1038
      BITLIF = 20.*YQLIFX
      GC TO 1039
1038 BITLIF = BITLIF*YQLIF
1039 CONTINUE
C
C     COST TO USE ADVANCED BIT:
      BITNUM = DFCT/(RCP*BITLIF)
      COST2 = BITNUM*(BITCST + DAVG*RTIP*RGRENT) + DFCT*(RGRENT/RCP
      1 + YCFEET*10.) + (DFCT/ROP)*YCTIP*100.
C     THIS INCLUDES ANY SPECIAL TIME OR FEETAGE COSTS
C
C     SELECT MOST ECONOMICAL BIT.
      IF(COST2 .LT. COST1) GC TO 1047
C     RESTORE ORIGINALLY SELECTED BIT
1040 BITCST = SVCST
      RCP = SVRCP
      BITLIF = SVLIF
      COSTXX = COST1
      IBIT = 1
      GC TO 1043
1047 COSTXX = COST2
1043 CONTINUE
C
C     SUBSTITUTE DIAMOND BIT IF ROP IS LOW:
      TSTRCP = 1.*YDISEL
      IF(RCP .GT. TSTRCP) GC TO 1045
C     DIAMOND BIT NOT USED IN AIR DRILLING:
      IF(DFLUID .EQ. 1.) GC TO 1045
      BITCST = YDIBST*(1500.*DIAM - 5700.)
      RCP = YDIROP*1.
      BITLIF = YLDIBT*1.

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      IDIFLG = 1
      IBIT   = 3
1045 CONTINUE
C
C   DOWNHOLE MOTOR USES AND COSTS FOR STRAIGHT HOLE DRILLING:
C   SKIP CUT IF MOTOR NOT USED:
1055 IF(IRCP5 .NE. 1) GO TO 1060
C   SKIP CUT IF MOTOR WOULD GET TOO HOT:
      IF(TMUD.GT.(100.*YMTCRT)) GO TO 1060
C   ADJUST RCP:
      RCP = RCP*YMTROP
C   FRACTION OF MOTOR LIFE USED IN THIS SEGMENT OF HOLE
      FMLF = DFCOT/(RCP*FLFMOT)
C   MOTOR CAPITAL COST, THIS SEGMENT
      CMOT = FMLF*LCSTMCT
C   ADD MOTOR OPERATING COST, PER HOUR
      CMOT = CMOT + CMOTLP*(DFCOT/RCP)
C   MOTOR TRIPPING TIME; ASSUMES ONE TRIP DUE TO END OF MOTOR LIFE.
      TRPMCT = FMLF*(START + ASTOP)*RTTRIP/2.0
C
C   PUT THESE COSTS INTO ACCOUNTS
      CLST(8) = CCST(8) + CMOT
      HOURS(2) = HOURS(2) + TRPMCT
1060 CONTINUE
C
C   CALCULATE RESULTS FOR THIS SEGMENT OF BOREHOLE.
C
C   A. NUMBER OF BITS:
      BITNUM = DFCOT/(RCP*BITLIF)
C   B. BIT COST:
      CBIT = BITNUM*BITCST
C   HERE, ADD SPECIAL CHARGES FOR ADVANCED BIT TO BIT COST.
      IF(IBIT .NE. 2) GO TO 1061
      CBIT = CBIT + 100.*YCTIM*DFCOT/RCP + 10.*YQFEET*DFCOT
1061 CONTINUE
C   C. DRILLING TIME:
      TDRILL = DFCOT/RCP
C   D. DRILLING COST:
      CDRILL = TDRILL*RGRENT
C   E. TRIPPING TIME:
C   ADDS ONE TRIP IF DIAMETER CHANGES
      TRPNUM = BITNUM
      IF(ASTOP .EQ. 0STOP) TRPNUM = AINT(BITNUM) + 1.0
      TTRIP = TRPNUM*(START + ASTOP)*RTTRIP/2.0
C   F. TRIP COST:
      CTRIP = TTRIP*RGRENT
C   G. AVERAGE OPERATING TEMPERATURE:
C   BUILD IT UP IN SUMS(1,5)

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C      BUILD UP FOOTAGE MADE IN SUMS(1,20)
C      SUMS(NCASE,5) = SUMS(NCASE,5) + TMUD*DFLCT
C      SUMS(NCASE,20) = SUMS(NCASE,20) + DFGG1
C      AVERAGE THIS BEFORE PRINTING SUMS
C      H. WATER ACCOUNT:
C      IF(DFLUID .EQ. 1.0) GO TO 1062
C      WATTIM = WATTIM + TDFILL
C      GO TO 1063
1062 WATTIM = WATTIM + TDFILL/3.0
1063 CONTINUE

C      DRILLING PIPE CHARGE, THIS SEGMENT, $/FOOT DRILLED
C      HARD) = KXHARD
C      PIPCST = 0.45*HARD*DFLCT
C      IF(DFLUID .EQ. 1) PIPCST = PIPCST*9.4
C      ADD TO THE RUNNING SUM:
C      CSPIPE = CSPIPE + PIPCST
C      BUILD UP THE SUMS.
C      SUMS(NCASE,10) = SUMS(NCASE,10) + BITNUM
C      SUMS(NCASE,11) = SUMS(NCASE,11) + LBIT
C      SUMS(NCASE,6) = SUMS(NCASE,6) + TDRILL
C      SUMS(NCASE,7) = SUMS(NCASE,7) + CDRILL
C      SUMS(NCASE,8) = SUMS(NCASE,8) + TTRIP
C      SUMS(NCASE,9) = SUMS(NCASE,9) + LTRIP
C      SUMS(NCASE,12) = SUMS(NCASE,12) + LBIT + CDRILL + CTRIP

C      FOOTAGE SEGMENT IS DRILLED. PREPARE FOR NEXT SEGMENT IF THERE
C      IS LNF:
C      NSEG = NSEG + 1
C      START = (NSEG - 1)*1000
C      IF NOT STOPPING AT END OF CASING INTERVAL, DO THE NEXT SEGMENT.
C      IF(ASTOP .LT. DSTOP) GO TO 1020

C      DROP-THROUGH HERE MEANS A CASING INTERVAL HAS BEEN COMPLETED.
C
C      FINALIZE THE SUMS FOR THIS INTERVAL:
C      SUMS(NCASE,1) = DSTART
C      SUMS(NCASE,2) = DSTOP
C      SUMS(NCASE,3) = DIAM
C      SUMS(NCASE,4) = DFLUID
C      TEMPERATURE AVERAGE:
C      SUMS(NCASE,5) = SUMS(NCASE,5)/SUMS(NCASE,20)
C      FOOTAGE COST FOR INTERVAL:
C      SUMS(NCASE,13) = SUMS(NCASE,12)/SUMS(NCASE,20)
C      THESE SUMS ARE STORED UNTIL REPORT IS PRINTED.
C
C      PREPARE FOR NEXT INTERVAL:
C      NCASE = NCASE + 1

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C      TRAP OUT ON TOO MANY INTERVALS:
      IF(NCASE .LT. 20) GO TO 1010
C      DRILLING IS COMPLETED, FIND TOTALS, ETC.
C      TOTAL NUMBER OF SEGMENTS DRILLED:
1070 NCASE = NCASE - 1
C
C      FINALIZE THE SUMS.
      DO 1080 I = 1, NCASE
      DO 1080 J = 6, 12
1080 SUMS(20, J) = SUMS(20, J) + SUMS(1, J)
      SUMS(20, 1) = 0.0
      SUMS(20, 2) = ASTCP
      SUMS(20, 13) = SUMS(20, 12) / ASTLP
C
C      PRINT THE TABLE, IF THE PRINTING FLAG IS ON.
      IF(IDRKPT .NE. 1) GO TO 1090
C
C      PRINT THE DRILLING COST REPORT:
C      INITIALIZE VALUES:
      RCKNAM = RCKNCM(1)
      IF(KXHARD .EQ. 1) RCKNAM = RCKNCM(2)
      IF(KXHARD .EQ. 2) RCKNAM = RCKNCM(3)
      IF(KXHARD .EQ. 3) RCKNAM = RCKNCM(4)
      IF(KXHARD .EQ. 4) RCKNAM = RCKNCM(5)
C      PROSPECT NAMES MUST BE IN ARRAY PRJTTL(18)
C      WRITE HEADERS
      WRITE(6, 2001)
2001 FORMAT('1', //, T50, 'FLCTAGE COST REPORT', //)
      WRITE(6, 2002) ASTCP, ILSGN, (PRJTTL(I), I=1, 7), RCKNAM, KTMPBH, RGRENT
2002 FORMAT(T10, F6.0, 1X, 'FT WELL, DESIGN # ', 12, ' TITLE: ', 7A4,
1' RCK TYPE = ', A4, /, T10, 'BOTTOM HOLE TEMP. = ', 16, 3X,
2' RIG RENT = $ ', F6.0, ' PER HOUR', //)
C      COLUMN HEADERS
      WRITE(6, 2003)
2003 FORMAT(T10, 96(1H*))
      WRITE(6, 2004)
2004 FORMAT(T10, '*WELL * DEPTH-FEET *DIAM.*FLUID*TEMP *ROTATING TIME *
1TRIPPING TIME*BITS USED *COST PER STAGE *')
      WRITE(6, 2005)
2005 FORMAT(T10, '*STAGE*START *STCP *INCH *', 5X, '*DEG-C*HOURS*COST,$
1*HOURS*COST,$ *NO. *COST,$*TOTAL,$ *$/FLCT*')
      WRITE(6, 2003)
      WRITE(6, 2006)
2006 FORMAT(//)
      DO 1100 I = 1, NCASE
C      WRITE LINES OF RESULTS
1100 WRITE(6, 2007) I, (SUMS(1, J), J=1, 13)
2007 FORMAT(T10, 12, 3X, F6.0, 1X, F6.0, 3X, F5.2, 2X, F2.0, 3X, F4.0, 2X, F5.0,

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      11X,F7.0,1X,F5.0,1X,F7.0,1X,F4.1,1X,F7.0,1X,F8.0,1X,F6.2)
C      WRITE TOTALS
      WRITE(6,2008)
2008 FORMAT(110,'TOTALS')
      I=0
      WRITE(6,2007) 1,(SUMS(20,J),J=1,13)
      WRITE(6,2009)
2009 FORMAT(//,110,'FLUID: 1 = AIR, 2 = WATER, 3 = MUD')
C      INDICATE WHETHER DIAMOND BIT WAS USED
      IF(10IFLG .NE. 1) GO TO 1090
      WRITE(6,2010)
2010 FORMAT(//,110,'DIAMOND BIT WAS USED FOR PART OF THIS DRILLING')
C
C      LOGTAG REPORT COMPLETED
C
1090 CONTINUE
C      TRANSFER SUMS TO HOURS AND COSTS ACCOUNTS:
C      ROTATING TIME AND BITS:
      HOURS(1) = SUMS(20,6)
      HOURS(2) = HOURS(2) + SUMS(20,8)
      COST(7) = SUMS(20,11)
C
C      MOTOR COST FOR STRAIGHT HOLE IS ALREADY ENTERED.
C      ADD MOTOR COST FOR DIRECTIONAL DRILLING AT TOP OF HOLE
C      (TWO DAYS):
      COST(8) = COST(8) + 2.*CSTMTD
C      TRIP THE MOTOR 1000 FEET:
      HOURS(2) = HOURS(2) + 1000.*RTRIP
C      ADD MOTOR COST FOR MULTIPLE STEP CUTS IF DESIGN NO. 6 IS USED
      IF(10DSGN .NE. 6) GO TO 1092
      COST(8) = COST(8) + 6.*CSTMTD
C      TRIP THE MOTOR TWICE THROUGH 90% OF TOTAL DEPTH:
      HOURS(2) = HOURS(2) + 1.8*XTDPTH*RTRIP
1092 CONTINUE
C
C      FUEL:
      COST(10) = COST(10) + HOURS(1)*FUELHI + HOURS(2)*FUELLO
C
C      WATER:
      COST(12) = WATTIM*WATRAT
C
C      MUD COSTS (FROM GLCWELL, $1975)
      A = XTDPTH/1000.
      CSTMUD = 21912. - 8729.*A + 1003.25*A**2
      IF(A .LE. 5.) CSTMUD = 3267.*A/5.
C      INFLATE TO $1978, AT 10 PERCENT/YEAR:
      CSTMUD = CSTMUD*1.331*YLCMUD
C      CALIBRATION FACTOR

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CSTMUD = 1.25*CSTMUD
COST(9) = CSTMUD
C
C DRILLING PIPE COST:
COST(11) = CSPPIPE*YCPPIPE
C
C CASING COSTS:
C FIRST SEGMENT IS CONDUCTOR CASING, LOWER COST
1200 CPF = 10. + .435*(WKDSGN(1,6) - 7.)
IF(CPF .LT. 10.) CPF = 10.
CASCST = CPF*(WKDSGN(1,5) - WKDSGN(1,4))
C OTHER SEGMENTS ARE AT HIGHER COST FOR STRONGER CASING:
DO 1210 I = 2,10
IF(WKDSGN(I,5) .LE. 0.0) GO TO 1210
CPF = 10. + 1.538*(WKDSGN(I,6) - 7.)
IF(CPF .LT. 10.) CPF = 10.
CASCST = CASCST + CPF*(WKDSGN(I,5) - WKDSGN(I,4))
1210 CONTINUE
COST(15) = CASCST*YCACST
C CEMENTING COSTS:
C
C INITIALIZE TIME AND VOLUME
CENTIM = 0.0
CEMVOL = 0.0
C RUN AND CEMENT SECTIONS OF CASING
DO 1220 I = 1,10
DLAND = WKDSGN(I,5)
IF(DLAND .LE. 0.0) GO TO 1220
DLENG = DLAND - WKDSGN(I,4)
DID = WKDSGN(I,6)/12.
DDD = .308*DID - .014
IF(DDD .GT. .5) DDD=.5
IF(DDD .LT. .17) DDD=.17
DGD = DID + DDD
FRCK = KXHARD
FRCEM = WKDSGN(I,7)
C VOLUME CORRECTION FACTOR FOR ROCK AND HOLE FRACTION
VCRFAC = FRCEM*(1.5 - FRCK/10.)
C TIME TO SET CASING:
TSC = DLAND/2000.
IF(KXHARD .EQ. 1) TSC = TSC*2.
C SECTION OF CASING NOT CEMENTED:
IF(WKDSGN(I,7) .GT. 1.) GO TO 1215
C NUMBER OF STAGES FOR CEMENTING:
NSTAGE = DLENG/3000. + .9999
FSTAGE = NSTAGE
SLENG = DLENG/FSTAGE
C VOLUME OF CEMENT BY ANNULUS VOLUME(CU.FT.):

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      VCL = SLENG*3.1416*(DCD**2. - CID**2.)/4.
C    CORRECT FOR ROCK TYPE
      VCL = VOL*VCRFAC
C    ADD TO TOTAL VOLUME
      CEMVCL = CEMVCL + VCL
C    MIX CEMENT, HOURS:
      CEMTIM = CEMTIM + VCL/1200.
C    PUMPING DISTANCE AND TIME:
      DISTP = FSTAGE*WKDSGN(1,4) + SLENG*FSTAGE*(FSTAGE + 1.)/2.
      PUMTIM = DISTP/12000.
      CEMTIM = CEMTIM + PUMTIM
C    WAIT ON CEMENT AND PREPARE FOR NEXT STAGE OR DRILLING
C    OPERATION:
      CEMTIM = CEMTIM + 48.*FSTAGE
C    ADD TIME TO SET THE CASING, WITH OR WITHOUT CEMENT:
1215   CEMTIM = CEMTIM + TSC
1220 CONTINUE
C    PLACE CEMENTING COSTS INTO COSTS AND HOURS
C    COST OF CEMENT, $/CUBIC FT:
      COST(16) = 6.*CEMVCL*YCEMCS.
C    COST OF EQUIPMENT(0.4) AND SERVICES(0.6):
      COST(16) = 2.*COST(16)
C    RIG TIME WHILE CEMENTING:
      HOURS(3) = CEMTIM*YCEMTM
C
C    FUEL COST, AT LOW RATE:
      COST(10) = COST(10) + CEMTIM*FUELLC
C
C    COSTS OF ACCIDENTS ENCOUNTERED WHILE DRILLING:
C
C    FREQUENCY BASELINE:
      HARD = KXHARD
      DEEP = KDEPTH
      AFREQ = (.5 + .5*HARD)*YAFREQ*DEEP/6373.
C    INITIALIZE ACCIDENT ACCOUNTS
      DC 1225 I = 1,11
      ACFR(I) = 0.
      ACHR(I) = 0.
1225   ACDOL(I) = 0.
C
C    DOGLEG; CEMENT AND REDRILL:
      ACFR(1) = AFREQ*YFDCG*.04
      IF(KXHARD .EQ. 1) ACFR(1) = 0.
      ACHR(1) = ACFR(1)*78.
      ACDOL(1) = ACFR(1)*2000.
      ACFUEL = 48.*FUELHI*ACFR(1)
C    DOWNHOLE MOTOR USED:
      COST(8) = COST(8) + ACFR(1)*2.*CSTMTD

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C      HOURS(2) = HOURS(2) + ACFR(1)*4200.*RTRIP
C
C      LOST CIRCULATION, RECOVERED WITH MATERIALS IN MUD:
ACFR(2) = YAFREQ*YFLCM*.2*DEEP/(6373.*HARD)
IF(HARD .GT. 2.) ACFR(2) = 0.
ACHR(2) = ACFR(2)*48.
ACDOL(2) = ACFR(2)*1000.
ACFUEL = ACFUEL + 24.*FUELHI*ACFR(2)
C
C      LOST CIRCULATION, CEMENT AND REGRILL:
ACFR(3) = YAFREQ*YFLCC*1.5*DEEP/6373.
IF(HARD .EQ. 1.) ACFR(3) = 0.
IF(HARD .EQ. 2.) ACFR(3) = ACFR(3)*2./3.
ACHR(3) = ACFR(3)*112.
ACDOL(3) = ACFR(3)*3000.
ACFUEL = ACFUEL + 48.*FUELHI*ACFR(3)
C      DOWNHOLE MOTOR:
COST(8) = COST(8) + ACFR(3)*2.*CSTMTD
HOURS(2) = HOURS(2) + ACFR(3)*5500.*RTRIP
C
C      FISHING FOR JUNK
ACFR(4) = AFREQ*YFFISH*.5
ACHR(4) = ACFR(4)*43.
ACDOL(4) = ACFR(4)*500.
ACFUEL = ACFUEL + 43.*FUELLO*ACFR(4)
C
C      FISH FOR PIPE AND RECOVER IT
ACFR(5) = AFREQ*YFPIPE*.29
ACHR(5) = ACFR(5)*72.
ACDOL(5) = ACFR(5)*1000.
ACFUEL = ACFUEL + 24.*FUELHI*ACFR(5)
C
C      FISH FOR PIPE, FAIL, ABANDON HOLE:
FRIP = YAFREQ*YFFAIL*.08*DEEP/6373.
ACFR(6) = FRIP
ACHR(6) = FRIP*220./(1. - FRIP)
ACDOL(6) = 5000.*FRIP
C      SHADOW COST DUE TO LCST WELL = WELTGT FROM PASS ONE
ACDOL(6) = ACDOL(6) + .7*COSTSH*FRIP
C      SPREAD THIS OVER NONABANDONED WELLS:
ACDOL(6) = ACDOL(6)/(1. - FRIP)
ACFUEL = ACFUEL + 72.*FUELHI*FRIP/(1. - FRIP)
C
C      UNSPECIFIED SIDETRACK (ACCOUNT #8):
ACFR(8) = AFREQ*YSIDE*.03
ACHR(8) = ACFR(8)*298.
ACDOL(8) = 2000.*ACFR(8)
ACFUEL = ACFUEL + 200.*FUELHI*ACFR(8)

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C      FISH FOR PIPE, FAIL, SIDETRACK AND REDRILL
C
C      SHADOW COST FOR CEMENT, PIPE, REDRILL:
C      SCSTRD = .2*COSTSH
C      ACFR(7) = AFREQ*YSIDBT*.08
C      ACFR(8) = ACFR(8) + ACFR(7)
C      ACHR(7) = ACFR(7)*220.
C      ACHR(8) = ACHR(8) + ACFR(7)*72.
C      ACDGL(7) = SCSTRD*ACFR(7)
C      ACDGL(8) = ACDGL(8) + 2000.*ACFR(7)
C      ACFUEL = ACFUEL + 200.*FUELHI*ACFR(7)
C
C      SIDETRACK AFTER FIRST BOTTOM IS DRY:
C      ACFR(9) = YAFREQ*YREBOT*.03*DEEP/6373.
C      SHADOW COST OF THIS:
C      SREBOT = .18*COSTSH
C      ACFR(8) = ACFR(8) + ACFR(9)
C      ACHR(9) = 24.*ACFR(9)
C      ACHR(8) = ACHR(8) + ACFR(9)*72.
C      ACDGL(9) = SREBOT*ACFR(9)
C      ACDGL(8) = ACDGL(8) + 2000.*ACFR(9)
C      ACFUEL = ACFUEL + 72.*FUELHI*ACFR(9)
C
C      ENTRIES FOR ADJUSTING SIDETRACK TIME, COST, FUEL
C      ACHR(8) = ACHR(8)*YSIDTI
C      COST(8) = COST(8) + ACHR(8)*CSTMTD/24.
C      HOURS(2) = HOURS(2) + 3.*ACFR(8)*4000.*RTrip
C      ACDGL(8) = ACDGL(8)*YSIDGL
C      ACFUEL = ACFUEL - (1. - YSIDFU)*72.*ACFR(8)
C
C      COGITATION TIME
C      ACFR(10) = .085*YCCGIT*AFREQ
C      ACHR(10) = ACFR(10)*60.*YCOGTI
C      ACDGL(10) = 1000.*ACFR(10)
C      THIS COST IS FOR CONSULTING; THERE IS NO FUEL COST FOR
C      COGITATION.
C
C      FORM THE SUMS
C      DO 1240 I = 1,10
C          ACFR(11) = ACFR(11) + ACFR(I)
C          ACHR(11) = ACHR(11) + ACHR(I)
C          ACDGL(11) = ACDGL(11) + ACDGL(I)
1240 CONTINUE
C      ACDGL(11) = ACDGL(11) + .001
C
C      REMOVE REDUNDANT FREQUENCY FOR SIDETRACKS
C      ACFR(11) = ACFR(11) - ACFR(9) - ACFR(7)

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C
C   NOW READY TO PRINT INCIDENT REPORT, IF THIS IS A DUMMY WELL,
C   AND WE ARE ON PASS TWO.
C   IF(IORRPT .NE. 1) GO TO 1250
C
C   WRITE(6,2020)
2020 FORMAT(///,T10,'INCIDENTS FOR GENERIC WELL',///,T10,
1'TYPE OF INCIDENT',T50,'FREQUENCY RIG HOURS MISC. COST',/)
C   PRINT COLUMNS OF MISHAP DATA
C   DO 1042 I = 1,10
1042 WRITE(6,2021)(TITLE(I,J),J=1,10),ACFR(1),ACHR(1),ACDCL(1)
2021 FORMAT(T10,10A4,F5.3,5X,F5.0,5X,F8.0)
C   WRITE(6,2022) ACFR(11), ACHR(11), ACDCL(11)
2022 FORMAT(//,T13,'TOTAL',T50,F5.3,5X,F5.0,5X,F8.0)
C   HERE ENDS THE WRITING OF MISHAP DATA
C
C   1250 CONTINUE
C   PUSH MISHAP TOTALS INTO APPROPRIATE DRILLING REPORT ACCOUNTS:
C   HOURS(4) = ACHR(11)
C   COST(18) = ACDCL(11)
C   COST(10) = COST(10) + ACFUEL
C   FINALIZE VALUES IN RIG ACCOUNTS
C   HOURS(1) = HOURS(1)*YAC(1)
C   DO 1252 I = 2,4
C   HOURS(I) = HOURS(I)*YAC(I)
1252 HOURS(6) = HOURS(6) + HOURS(1)
C   HOURS(5) = HOURS(5) + .05*HOURS(6)*YAC(5) + .2*YRDTMS*HOURS(1)
C   HOURS(6) = HOURS(6) + HOURS(5) + HOURS(1)
C   DO 1253 I = 1,5
C   COST(I) = HOURS(I)*RGRENT*YAC(6)
1253 COST(6) = COST(6) + COST(I)
C
C   THAT'S IT FOR RIG TIME AND COSTS
C   OTHER COSTS:
C   UPGRADE ALL COSTS FIGURED TIL NOW:
C
C   DO 1255 I = 7,12
1255 COST(I) = COST(I)*YAC(I)
C   COST(15) = COST(15)*YAC(15)
C   COST(16) = COST(16)*YAC(16)
C   COST(18) = COST(18)*YAC(18)
C
C   WASTE DISPOSAL:
C   COST(13) = YAC(13)*(COST(9)+COST(12))/2.
C
C   SURFACE EQUIPMENT:
C   COST(14) = YAC(14)*(350.+250.*HARD)*HOURS(6)/24.
C

```

```

C      ADD $20,000 FOR WELL HEAD:
      COST(14) = COST(14) + 20000.
C
C      SITE AND RIG PREPARATION:
      CCST(17) = 95000.*YAL(17)
C
C      PARTIAL SUM OF ACCOUNTS 2-12
      DC 1260 I = 7,17
1260 COST(23) = COST(23) + COST(I)
C
C      MISCELLANEOUS TRANSPORTATION
      COST(19) = .02*COST(23)*YAC(19)
C
C      MISCELLANEOUS
      COST(21) = 50000.*YAL(21)
      IF(XTDPH .GT. 10000) CCST(21)=100000.*YAC(21)
C
C      LOGGING
      CCST(20) = 4.*XTDPH*YAC(20)
C
C      DIRECT SUPERVISION (5% OF RIG RENT)
      COST(22) = .09*COST(4)*YAC(22)
C
C      FINAL TOTAL FOR COSTS
      DC 1262 I = 18,22
1262 CCST(23) = COST(23) + CCST(I)
      COST(23) = COST(23) + COST(6)
      WELTCT = COST(23)
C
C      NOW READY TO DO BASELINE WORK IF NEEDED AND WRITE THE FINAL
      REPORT ON DUMMY WELL.
C
C      IF(IDRRPT .NE. 1) GO TO 1999
C      FIND % OF TOTAL COST, AND COMPARE TO BASELINE DUMMY WELL
      DC 1265 I = 1,23
      PERCNT(I) = 100.*COST(I)/WELTCT
      IF(DUMDCL(I) .EQ. 0.) DUMDCL(I) = COST(I)
1265 CHANGE(I) = 100.*(COST(I)-DUMDCL(I))/DUMDCL(I)
C
C      IF REQUESTED, CHANGE THE DUMMY BASELINE MATRIX VALUES:
      IF(IRCPI .NE. 3) GO TO 1268
      DC 1267 I = 1,23
1267 DUMDCL(I) = COST(I)
1268 CONTINUE
C
C      PRINT RESULTS ON DUMMY WELL:
      WRITE(6,2048) IPRJCD,(PRJTTL(J),J=1,18)
2048 FORMAT(1H1,/,T12,'WELCST RUN NUMBER: ',I6,/,T10,'PROJECT: ',

```

```

118A4,///,T35,'GENERIC MODEL WELL RESULTS',//)
WRITE(6,2050)
2050 FORMAT(T12,'-----WELL COST ACCOUNT-----',T54,
1'HOURS OF',T68,'CCST',T80,'% CF',T89,'% CF BASE-',/,T54,
2'RIG TIME',T66,'($ 1978)',T77,'TOTAL CCST',T89,'LINE COST',//)
DO 1270 I = 1,6
K = I+10
1270 WRITE(6,2052)(TITLE(K,J),J=1,10),HOURS(I),COST(I),PERCNT(I),
1CHANGE(I)
2052 FORMAT(T11,10A4,4X,F5.0,6X,F8.0,5X,F5.1,5X,F8.1)
WRITE(6,2054)
2054 FORMAT(/)
DO 1273 I = 7,23
K = I+10
1273 WRITE(6,2053)(TITLE(K,J),J=1,10),CCST(I),PERCNT(I),CHANGE(I)
2053 FORMAT(T11,10A4,15X,F8.0,5X,F5.1,8X,F5.1)
C
C TOTAL NUMBER OF DAYS WITH RIG UP:
RZDAYS = HOURS(6)/24.
WRITE(6,2055) RZDAYS
2055 FORMAT(/,T14,'DAYS TO DRILL WELL:',T56,F4.0)
C
C REPORT IS COMPLETED
1999 CONTINUE
C
C SAVE SHADOW COST
CCSTSH = WELTOT
YAFREQ = SAVEAC
IPASSR = IPASSR + 1
IF(IPASSR.EQ. 2) GO TO 10
C
CONTINUE
RETURN
END

```

7.0 DATA FILE LISTINGS

FILE: WELCSTB EXEC A

SET BLIP DIG.DIG.
GL TXTLIB FORTMOD1
FI 01 DISK BITVAR DATA A1
FI 02 DISK DESIGN DATA A1
FI 03 DISK ENGVAR DATA A1
FI 04 DISK DUMSIT DATA A1
FI 07 DISK TITLES DATA A1
FI 06 PRINTER
FI 10 DISK RUNOPS DATA A1
FI 11 DISK WCOST DATA A1
FI 09 DISK RAJJ DATA A1
LOAD WELCSTB
START

FILE: BITVAR DATA A

ROP				
100.	50.	25.0	12.	
80.	40.	20.	10.	
60.	30.	15.	7.5	
40.	20.	10.	6.	
30.	15.	8.	5.	
20.	10.	6.	4.	
15.	8.	5.	3.	
10.	6.	4.	2.5	
7.	5.	3.5	2.	
6.	4.	3.	2.	
5.5	3.5	2.5	2.	
5.	3.0	2.5	2.	
5.	3.	2.5	2.	
5.	3.	2.5	2.	
5.	3.	2.5	2.	

FILE: DESIGN DATA A

1	0.	150.	17.50	0.	150.	13.38	1.00	2.0
2	150.	1000.	12.25	0.	1000.	9.62	0.85	3.0
3	1000.	3000.	8.75	800.	3000.	6.62	0.95	2.0
4	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.
1	0.	150.	17.50	0.	150.	13.38	1.0	2.0
2	150.	1000.	12.25	0.	1000.	9.62	0.85	3.0
3	1000.	3000.	8.75	800.	0.	0.	9.99	2.0
4	0.	0.	0.	0.	0.	0.	0.	0.
5	0.	0.	0.	0.	0.	0.	0.	0.
6	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.
1	0.	150.	17.50	0.	150.	13.38	1.00	2.0
2	150.	1000.	12.25	0.	1000.	9.62	0.85	3.0
3	1000.	3000.	8.75	800.	2000.	6.62	0.80	2.0
4	2000.	3000.	8.75	0.	0.	0.00	9.99	2.0
5	2000.	3000.	8.75	0.	0.	0.00	9.99	2.0
6	0.	0.	0.	0.	0.	0.00	0.00	0.0
7	0.	0.	0.	0.	0.	0.00	0.00	0.0
8	0.	0.	0.	0.	0.	0.00	0.00	0.0
9	0.	0.	0.	0.	0.	0.00	0.00	0.0
10	0.	0.	0.	0.	0.	0.00	0.00	0.0
1	0.	150.	26.	0.	150.	20.	1.00	2.0
2	150.	3000.	9.62	0.	3000.	13.38	0.95	2.0
3	150.	3000.	17.50	2700.	7000.	9.62	0.93	2.0
4	3000.	7000.	12.25	6700.	10000.	6.62	0.90	3.0
5	7000.	10000.	8.75	0.	0.	0.	0.	2.0
6	0.	0.	0.	0.	0.	0.	0.	0.
7	0.	0.	0.	0.	0.	0.	0.	0.
8	0.	0.	0.	0.	0.	0.	0.	0.
9	0.	0.	0.	0.	0.	0.	0.	0.
10	0.	0.	0.	0.	0.	0.	0.	0.
1	0.	150.	26.0	0.	150.	20.0	1.00	2.
2	150.	3000.	9.62	0.	3000.	13.38	0.95	2.
3	150.	3000.	17.50	2700.	7000.	9.62	0.93	2.
4	3000.	7000.	12.25	0.	0.	0.0	9.99	3.
5	7000.	10000.	8.75	0.	0.	0.0	0.0	2.
6	0.	0.	0.	0.	0.	0.0	0.0	0.
7	0.	0.	0.	0.	0.	0.0	0.0	0.
8	0.	0.	0.	0.	0.	0.0	0.0	0.
9	0.	0.	0.	0.	0.	0.0	0.0	0.
10	0.	0.	0.	0.	0.	0.0	0.0	0.
1	0.	150.	26.	0.	150.	20.0	1.0	2.
2	150.	3000.	9.62	0.	3000.	13.38	0.95	3.
3	150.	3000.	17.50	2700.	7000.	9.62	0.95	3.
4	3000.	7000.	12.25	0.	0.	0.0	9.99	3.
5	7000.	10000.	8.75	0.	0.	0.0	9.99	2.

6	8000.	10000.	8.75	0.	0.	0.0	9.99	2.
7	8000.	10000.	8.75	0.	0.	0.0	0.0	2.
8	0.	0.	0.	0.	0.	0.0	0.0	0.
9	0.	0.	0.	0.	0.	0.0	0.0	0.
10	0.	0.	0.	0.	0.	0.0	0.0	0.
1	0.	150.	32.	0.	150.	26.	1.0	2.
2	150.	1100.	9.62	0.	1100.	20.	0.86	3.
3	150.	1100.	17.50	0.	8000.	13.38	0.86	3.
4	150.	1100.	26.00	0.	14000.	9.62	0.43	3.
5	1100.	8000.	9.62	13800.	15000.	7.62	0.83	3.
6	1100.	8000.	17.50	0.	15000.	5.50	9.99	3.
7	8000.	14000.	12.25	0.	0.	0.0	0.0	3.
8	14000.	15000.	9.62	0.	0.	0.0	0.0	3.
9	0.	0.	0.0	0.	0.	0.0	0.0	0.
10	0.	0.	0.0	0.	0.	0.0	0.0	0.
1	0.	150.	26.0	0.	150.	20.0	1.0	2.
2	150.	1200.	9.62	0.	1200.	13.38	0.88	2.
3	150.	1200.	17.50	1000.	3000.	6.62	0.90	3.
4	1200.	3000.	8.75	0.	0.	0.0	0.0	2.
5	0.	0.	0.0	0.	0.	0.0	0.0	0.
6	0.	0.	0.0	0.	0.	0.0	0.0	0.
7	0.	0.	0.0	0.	0.	0.0	0.0	0.
8	0.	0.	0.0	0.	0.	0.0	0.0	0.
9	0.	0.	0.0	0.	0.	0.0	0.0	0.
10	0.	0.	0.0	0.	0.	0.0	0.0	0.
1	0.	150.	26.00	0.	150.	20.00	1.00	2.
2	150.	3000.	9.62	0.	3000.	13.38	0.95	3.
3	150.	3000.	17.50	2700.	7000.	9.62	0.93	3.
4	3000.	7000.	12.25	0.	0.	0.0	9.99	3.
5	7000.	10000.	8.75	0.	0.	0.0	0.0	1.
6	0.	0.	0.0	0.	0.	0.0	0.0	0.
7	0.	0.	0.0	0.	0.	0.0	0.0	0.
8	0.	0.	0.0	0.	0.	0.0	0.0	0.
9	0.	0.	0.0	0.	0.	0.0	0.0	0.
10	0.	0.	0.0	0.	0.	0.0	0.0	0.
1	0.	200.	36.0	0.	200.	30.0	1.0	2.
2	200.	2120.	9.62	200.	640.	28.0	1.0	2.
3	200.	2120.	17.50	640.	1400.	24.0	1.0	2.
4	200.	640.	34.0	1400.	2120.	22.0	1.0	2.
5	640.	2120.	30.00	2120.	7000.	9.62	1.0	3.
6	2120.	7000.	12.25	6700.	10000.	6.62	0.9	3.
7	7000.	10000.	8.75	0.	0.	0.0	0.0	2.
8	0.	0.	0.	0.	0.	0.0	0.0	0.
9	0.	0.	0.	0.	0.	0.0	0.0	0.
10	0.	0.	0.	0.	0.	0.0	0.0	0.
1	0.	150.	30.0	0.	150.	26.	1.00	2.
2	150.	1100.	9.62	0.	1100.	20.	.86	3.
3	150.	1100.	17.50	0.	8000.	13.38	.86	3.
4	150.	1100.	24.00	0.	14000.	9.62	.43	3.
5	1100.	8000.	9.62	13800.	15000.	7.62	.83	3.
6	1100.	8000.	17.50	0.	15000.	5.50	9.99	3.
7	8000.	14000.	12.25	0.	0.	0.0	0.0	3.
8	14000.	15000.	8.50	0.	0.	0.0	0.0	3.
9	0.	0.	0.0	0.	0.	0.0	0.0	0.
10	0.	0.	0.0	0.	0.	0.0	0.0	0.

FILE: ENGVAR DATA A

YROP	YRGRNT	YRTRIP	YFUEL	YCSHOD	YWATER	YCENCS	YCENTH	YCACST	YDICST
1.50	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YLDIST	YDIROP	YDISEL	YCHOT	YLFHOT	YCHTOP	YHTROP	YAFREQ	YFDOG	YFLCH
25.00	3.000	4.00	1.00	1.00	1.00	1.00	1.00	01.00	1.00
YFLCC	YFFISH	YFPIPE	YFFAIL	YSIDE	YSIDBT	YREBDT	YSIDTI	YSIDOL	YSIDFU
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YCOGIT	YCOGTI	YCFIPE	YAC(1)	YAC(2)	YAC(3)	YAC(4)	YAC(5)	YAC(6)	YAC(7)
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YAC(8)	YAC(9)	YAC(10)	YAC(11)	YAC(12)	YAC(13)	YAC(14)	YAC(15)	YAC(16)	YAC(17)
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YAC(18)	YAC(19)	YAC(20)	YAC(21)	YAC(22)	YAC(23)	YBCJNL	YBCUNS	YBCNOP	YBCNIL
1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YBLJNL	YBLUNU	YBLUAI	YQHDLO	YQHDLI	YQDPLO	YQDPHI	YQDILO	YQDIHI	YQTNLO
1.00	1.00	1.00	2.00	1.00	0.15	2.00	8.75	12.25	1.00
YQTHHI	YQCSTS	YQCSTA	YQCSTB	YQCSTC	YQROP	YQROPX	YQLIF	YQLIFX	YQTNCR
1.00	0.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
YQTHI	YQFEET	YBTRUN	YBTSOK	YMTCRT	YROTMS				
0.00	0.00	1.00	1.00	1.00	1.00				
DD									
1.00									

FILE: DUMSIT DATA A

GENERIC WELL DESIGN

12	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	
1998	1999	2000											
250	270	230											
0	6500	3	2	5									
	1	1		1									
10.0	10.0	30.0	30.0										

FILE: RUNOPS DATA A

1 1 1 1 0 0 0 0 0 0
000001
GENERIC WELL DESIGN

FILE: WCOST

DATA

A

601634.	567350.	601634.	567350.				
658939.	593164.	658939.	593164.				
597935.	566082.	597935.	566082.				
1479701.	1085941.	1479701.	1085941.				
1479701.	1085941.	1479701.	1085941.				
597935.	566082.	597935.	566082.				
658939.	593164.	658939.	593164.				
658939.	593164.	658939.	593164.				
2201442.	1642017.	2201442.	1642017.				
475567.	457230.	475567.	457230.				
658939.	593164.	658939.	593164.				
1443724.	1008229.	1443724.	1008229.				
1479701.	1085941.	1479701.	1085941.				
1479701.	1085941.	1479701.	1085941.				
754383.	690704.	754383.	690704.				
472788.	456212.	472788.	456212.				
658939.	593164.	658939.	593164.				
842584.	722408.	842584.	722408.				
566574.	508596.	566574.	508596.				
1479701.	1085941.	1479701.	1085941.				
919537.	798872.	919537.	798872.				
1479701.	1085941.	1479701.	1085941.				
577897.	528727.	577897.	528727.				
1479701.	1085941.	1479701.	1085941.				
397043.	377583.	397043.	377583.				
708794.	645115.	708794.	645115.				
842584.	722408.	842584.	722408.				
139855.	10682.	30041.	72587.	33636.	286801.	33902.	13129.
12579.	35657.	11196.	17482.	15031.	85725.	80195.	33484.
95000.	78310.	8668.	26000.	50000.	25812.	908970.	

FILE: RAJJ DATA A

BRAWLEY, CALIFORNIA

11	1983	1985	1987	1988	1989	1990	1991	1992	1993	1994	1995
260	300	200									
0	2000	1	1	4							
	1	400000	400000								
7.50	7.50	10.00	20.00								

COSO, CALIFORNIA

6	1985	1986	1987	1988	1989	1990
220	240	150				
1	1500	3	0	5		
	1	1	1	1		
15.00	15.00	20.00	30.00			

EAST MESA, CALIFORNIA

2	1985	1988
180	225	150
0	2000	1
	1	600000
15.00	15.00	20.00
		30.00

THE GEYSERS, CA. (LIQUID-DOMINATED)

10	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994
200	190	260								
0	2500	3	0	5						
	1	1	1	1						
15.00	15.00	20.00	30.00							

GLASS MOUNTAIN, CALIFORNIA

1	1990
210	250
1	2500
	1
15.00	15.00
	20.00
	30.00

HEBER, CALIFORNIA

11	1983	1985	1987	1988	1991	1992	1993	1994	1995	1996	1997
190	225	150									
0	2000	1	0	4							
	1	600000	600000								
15.00	15.00	20.00	30.00								

LASSEN, CALIFORNIA

2	1987	1990
240	300	180
1	1500	3
	1	1
		0
		5

15.00 15.00 20.00 30.00
 MONO-LONG VALLEY, CALIFORNIA

3
 1985 1987 1990
 220 250 200
 1 1500 3 0 5
 1 1 1

15.00 15.00 20.00 30.00
 PUHA, HAWAII

6
 1990 1991 1992 1993 1994 1995
 356 390 320
 1 2500 4 0 5
 1 1 1

15.00 15.00 20.00 30.00
 SALTON SEA, CALIFORNIA

17
 1983 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996
 1997 1998 1999 2000
 340 360 300
 0 1500 1 1 4
 1 400000 400000

7.50 7.50 10.00 20.00
 SURPRISE VALLEY, CALIFORNIA

14
 1986 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999
 2000
 175 225 110
 0 1500 3 0 5
 1 1 1

15.00 15.00 20.00 30.00
 ALVORD, OREGON

6
 1987 1990 1991 1992 1993 1994
 200 240 150
 0 2000 4 0 5
 1 1 1

15.00 15.00 20.00 30.00
 BAKER H.S., WASHINGTON

1
 1990
 165 190 145
 0 2500 3 0 5
 1 1 1

15.00 15.00 20.00 30.00
 BRUNEAU-GRANDVIEW, IDAHO

12
 1987 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000
 210 250 160
 0 2500 3 0 5

15.00 15.00 20.00 30.00
RAFT RIVER, IDAHO

2
1988 1990

140 170 130
0 2000 2 0 4
1 607000 607000

15.00 15.00 20.00 30.00
VALE H.S., OREGON

12
1988 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000

160 180 145
0 1500 1 0 4
1 1

15.00 15.00 20.00 30.00
WEISER-CRANE CREEK, IDAHO

11
1988 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999

160 250 130
0 1500 3 0 5
1 1

15.00 15.00 20.00 30.00
BEOWAWE, NEVADA

12
1983 1986 1988 1990 1991 1992 1993 1994 1995 1996 1997 1998

240 280 165
1 1500 4 0 5
1 1

15.00 15.00 20.00 30.00
BRADY H.S., NEVADA

11
1983 1986 1988 1990 1991 1992 1993 1994 1995 1996 1997

214 230 200
1 1000 4 0 5
1 1

15.00 15.00 20.00 30.00
CHANDLER, ARIZONA

3
1986 1990 1991

178 200 150
0 2500 3 0 5
1 1

15.00 15.00 20.00 30.00
COVE FORT-SULPHURDALE, UTAH

14
1985 1987 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999
2000
200 240 100

0	2000	3	0	5															
15.00	15.00	20.00	30.00	1															
LEACH, NEVADA																			
12	1987	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000							
170	200	140																	
0	2500	3	0	5															
15.00	15.00	20.00	30.00	1															
ROOSEVELT H.S., NEVADA																			
12	1983	1986	1988	1990	1991	1992	1993	1994	1995	1996	1997	1998							
230	260	200																	
1	1300	3	0	5															
363000			1	1															
15.00	15.00	20.00	30.00																
SAFFORD, ARIZONA																			
2	1987	1991																	
210	250	160																	
0	2500	3	0	5															
15.00	15.00	20.00	30.00	1															
STEAMBOAT SPRINGS, NEVADA																			
3	1985	1988	1990																
210	250	180																	
1	800	3	0	1															
15.00	15.00	20.00	30.00	1															
THERMO, UTAH																			
6	1988	1992	1993	1994	1995	1996													
200	225	140																	
0	2000	2	0	5															
15.00	15.00	20.00	30.00	1															
VALLES CALDERA, NEW MEXICO																			
14	1983	1986	1988	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999						
2000	240	300	100																
1	1500	4	0	5															
15.00	15.00	20.00	30.00	1															

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