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Geothermal Wells: A Forecast of Drilling Activity

Gerald L. Brown, A. J. Mansure, J. N. Miewald
BDM Corporation

Prepared by Sandia National Laboratories, Albuquerque, New Mexico 87185 and Livermore, California 94550 for the United States Department of Energy under Contract DE-AC04-76DP00789

Printed July 1981

Prepared for Sandia National Laboratories
under Contract No. 62-0258

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Printed in the United States of America
Available from:
National Technical Information Service
U. S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price: Printed Copy $4.50; Microfiche $3.00

SAND81-7127 Category UC-66c
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GEOTHERMAL WELLS: A FORECAST OF DRILLING ACTIVITY

Gerald L. Brown, A. J. Mansure, and J. M. Miewald

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ABSTRACT

The report forecasts numbers and problems for geothermal wells expected to be drilled in the United States between 1981 and 2000 AD. The 3800 wells forecasted for major electric power projects (totaling 6 GWe of capacity) are categorized by type (production, etc.), and by location (The Geysers, etc.). 6000 wells are forecasted for direct heat projects (totalling 0.02 Quads per year). Equations are developed for forecasting the number of wells, and data is presented. Drilling and completion problems in The Geysers, The Imperial Valley, Roosevelt Hot Springs, the Valles Caldera, northern Nevada, Klamath Falls, Reno, Alaska, and Pagosa Springs are discussed. Likely areas for near term direct heat projects are identified.

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FOREWORD

This report (BDM/TAC-80-557-TR-R2) has been prepared by The BDM Corporation, 1801 Randolph Road, S.E., Albuquerque, New Mexico 87106 for Sandia Laboratories under contract 62-0258. The report forecasts when and where significant geothermal activity will occur in the United States to the turn of the century, and estimates the numbers and characteristics of wells needed to support the activity. Contributors to this report were G. L. Brown, Dr. A. J. Mansure, and J. M. Miewald of The BDM Corporation. Special thanks is extended to Dr. Charles Carson of Sandia Corporation for his help and guidance in the preparation of this report.

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GEOTHERMAL WELLS: A FORECAST OF DRILLING ACTIVITY

Executive Summary

The first purpose of this report is to specify the numbers of each type of geothermal well to be drilled in the United States for each 5-year period to 2000 A.D. The report presents forecasts of the growth of geothermally supplied electric power and direct heat uses. The report then quantifies the different types of geothermal wells needed to support the forecast capacity.

The second purpose of this report is to discuss, in terms of geology and drilling problems, each geothermal resource which is forecasted to reach a significant capacity. When geologies and problems are matched against forecasted well types and quantities, some appreciation of the frequency of certain problems can be obtained. This, in turn, should provide insight into the absolute and relative impacts of technologies that will eliminate or reduce one or more problems.

The rate of growth of electric capacity at geothermal resource areas is expected to be 15 to 25 percent per year (after an initial critical size is reached) until natural or economic limits are approached. Five resource areas in the United States should grow to significant capacity by the end of the century (figure 1). The best estimates of the numbers of wells that must be drilled in each 5-year period to support the electric capacity are given in figure 2. About 3800 geothermal wells are expected to be drilled in support of all electric power projects in the United States from 1981 to 2000 A.D. at a cost of well over two billion dollars. Half of the wells are expected to be drilled in the Imperial Valley. The reported numbers include production, exploration, injection, and replacement wells. The Geysers area is expected to retain most of the drilling activity for the next 5 years. By the 1990's, the Imperial Valley is expected to contain most of the drilling activity.

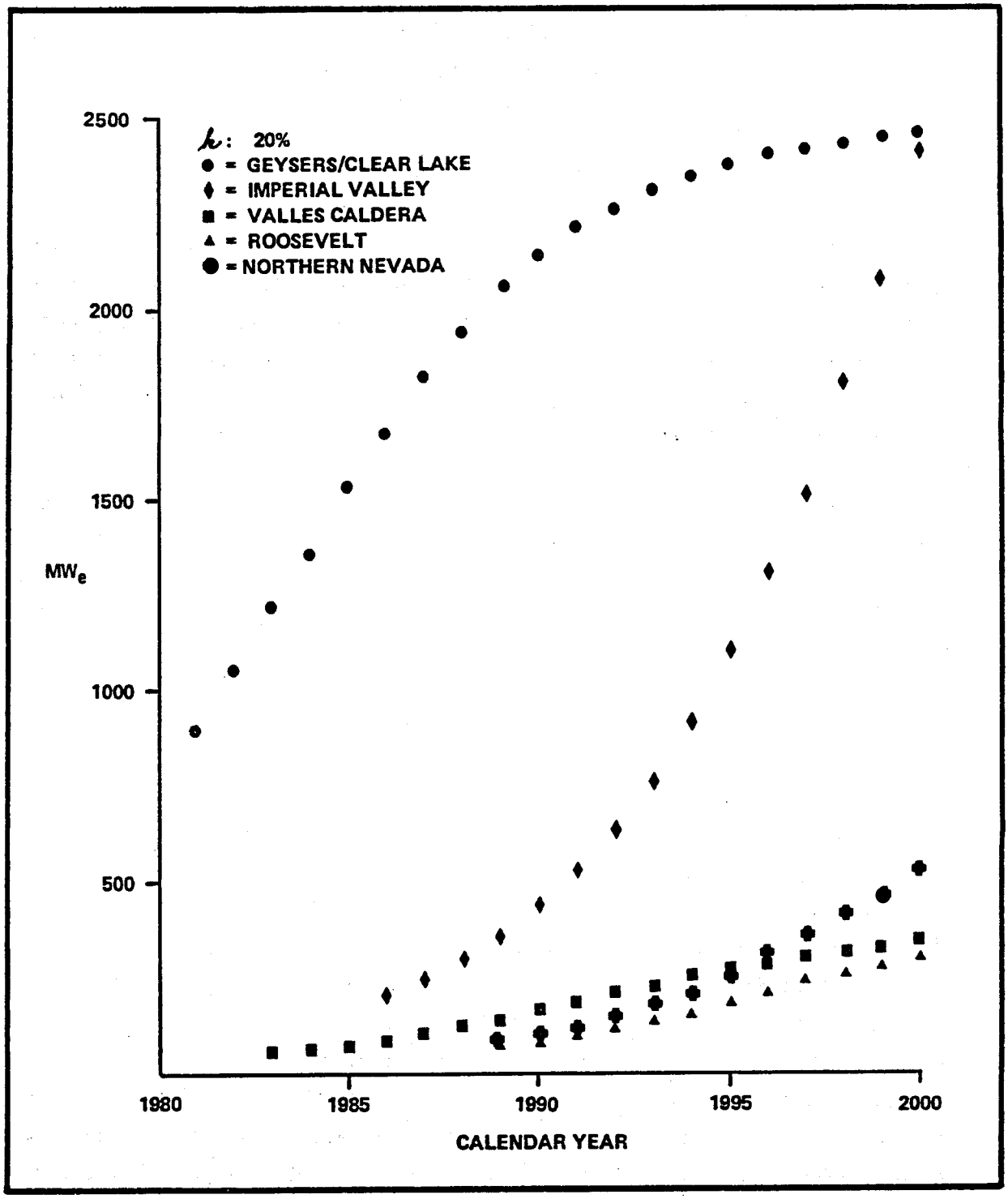

Figure 1. Forecast of Geothermal Electric Power Capacity

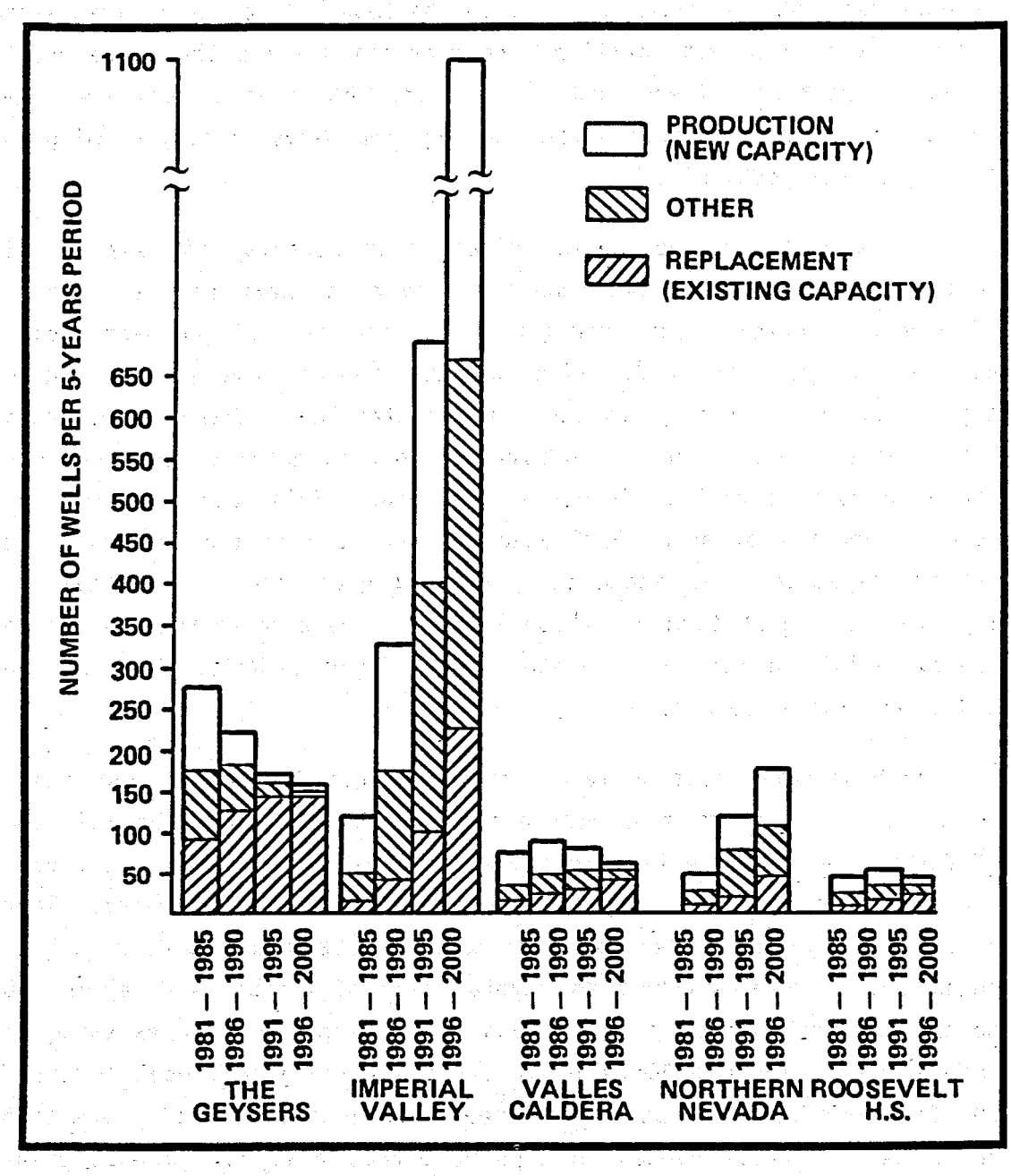

Figure 2. Numbers and Types of Wells to Support the Growth of Geothermal Electric Generating Capacity as Forecasted in Five Resource Areas

The expected preponderance of wells in the Imperial Valley indicates that problems associated with drilling and completing wells there are quantitatively important. These problems include obtaining a reliable cement job, thermal shock, corrosion and scaling from heavy brines, pumping, and plugging of reinjection wells.

The forecast for geothermal direct heat capacity is less certain. Substantial increases in Government aid over the next 10 years might be sufficient to develop one Quad (10^{15} Btu) per year of geothermal direct heat use by the year 2000. Without such funding, the growth of direct heat capacity is likely to be less spectacular. Without substantial Government aid, but with a favorable economic climate, direct heat might grow at a rate as high as 14 percent per year. This rate of growth would yield a capacity of about 0.02 Quads by the turn of the century. Areas that are expected to dominate the growth of geothermal direct heat capacity over the short term are those locations where geothermal direct heat already exists (such as Klamath Falls, Oregon; Vale, Oregon; Reno, Nevada; and Boise, Idaho).

The beneficial heat derived from direct heat wells can vary greatly. The beneficial heat from a well drilled to heat a single home is about 10^8 Btu/yr, whereas the beneficial heat from a well drilled to support an industrial process often would be more than 1000 times greater. Therefore, the number of wells needed to support 0.02 Quads (0.02×10^{15} Btu) ranges from several hundred to several tens of thousands depending upon the mix of applications. Based upon the average size of existing uses (Reference 1), about 6000 wells of all types would be needed to support 0.02 Quads of direct heat use per year. Under this set of assumptions, the number of wells needed to support direct heat is somewhat greater than the number needed to support forecasted electric capacity.

Table 1 indicates the number of wells needed in each 5-year period to support a growth rate of 14 percent per year. New production wells are assumed to be drilled 2 years before project completion. Other types of wells (injection, wildcat, and replacement) are assumed to be roughly equal in total numbers to new production wells.

Table 1
Wells Needed to Support Direct Heat Capacity

	Time Period			
	1981-85	1986-90	1991-95	1996-2000
Wells (All Types)	400	800	1600	3200

It is anticipated that most geothermal wells for direct heat will be drilled by drilling firms with experience in the water, shallow oil and gas, and mining industries. The life cycle cost of geothermal wells for direct heat is expected to be influenced by high rates of corrosion in down-hole equipment, pumps, and materials. Special problems of drilling in residential areas include noise, lack of space for rigs and mud pits, restrictions on drilling at night, and property damage. State laws and codes often prevent drilling firms from drilling as deep or as hot as needed without special equipment (such as blowout preventers). Other problems include cooling the drilling mud and getting the casing into the hole.

Introduction

Geothermal wells are always a major part of the total cost of a project that uses geothermal energy. Recent studies indicate that well costs average 55 percent of the cost of electrical projects and 35 percent of the cost of direct heat projects (References 2 and 3).

It should be possible to reduce the cost of drilling deep geothermal wells by 50 percent or more. Deep geothermal wells cost two to four times as much as oil wells of similar depth -- largely because the geothermal drillers are forced to borrow oil industry technology that is not optimized for the needs of geothermal drilling and completion.

Existing technologies can be improved or adapted to lower the cost of geothermal well drilling and completion. Selection of the technologies to develop is a problem because a given technology may be appropriate for one type of geothermal well, but inappropriate for another type. An optimal decision concerning the technologies to be developed should be based in part upon an appreciation of the different types of wells and the relative abundance of each type.

The purpose of this report is to specify the types and abundance of geothermal wells to be drilled over the next 20 years. The first major division in type is between wells for electrical projects and wells for direct heat projects. Wells for electrical projects are the topic of the first section of this report; wells for direct heat projects are the topic of the second section.

Geothermal Wells for Electrical Power Projects

Some General Observations

The factors that affect well costs for electric power projects differ among the various geothermal resources. Likewise, the technologies to reduce well costs may not apply equally at each resource. The relative importance of cost factors and technologies depends in part upon the growth of electrical capacity at each resource. If the growth of electrical capacity at some resources is such that their capacity remains very small compared to capacity at other resources, then those resources can be excluded from further consideration on the grounds that they will make no important contribution to the decision of which problems to solve or which drilling technologies to develop. Studies of the growth of electrical capacity have been published by others (see Reference 4, for example). However, those studies by others were done for different reasons and do not answer the questions to which this study is directed.

The empirical evidence indicates that electrical capacity from a specific resource area does not grow at all until some minimum set of favorable criteria are met. After this time, it grows quickly (15 to 25 percent a year in the cases of The Geysers and Cerro Prieto) until its size reaches some limiting factor(s). The growth potential of electrical capacity at known geothermal resources has been reviewed, and the ones expected to meet criteria for significant growth of electrical capacity in this century are listed in figure 3. Other known resources are not expected to achieve significant electrical capacity because of high development cost (e.g., Raft River), lack of suitable markets (e.g., Puna, Hawaii), or some combination of unfavorable factors (e.g., Coso).

All the resources listed in figure 3 are hydrothermal in nature. Geopressured and hot dry rock (HDR) resources are expected to make a relatively insignificant impact upon the numbers of geothermal wells to be drilled for electric power projects prior to the year 2000 A.D. References 5 and 6 contain the detailed assessments of HDR and geopressured growth.

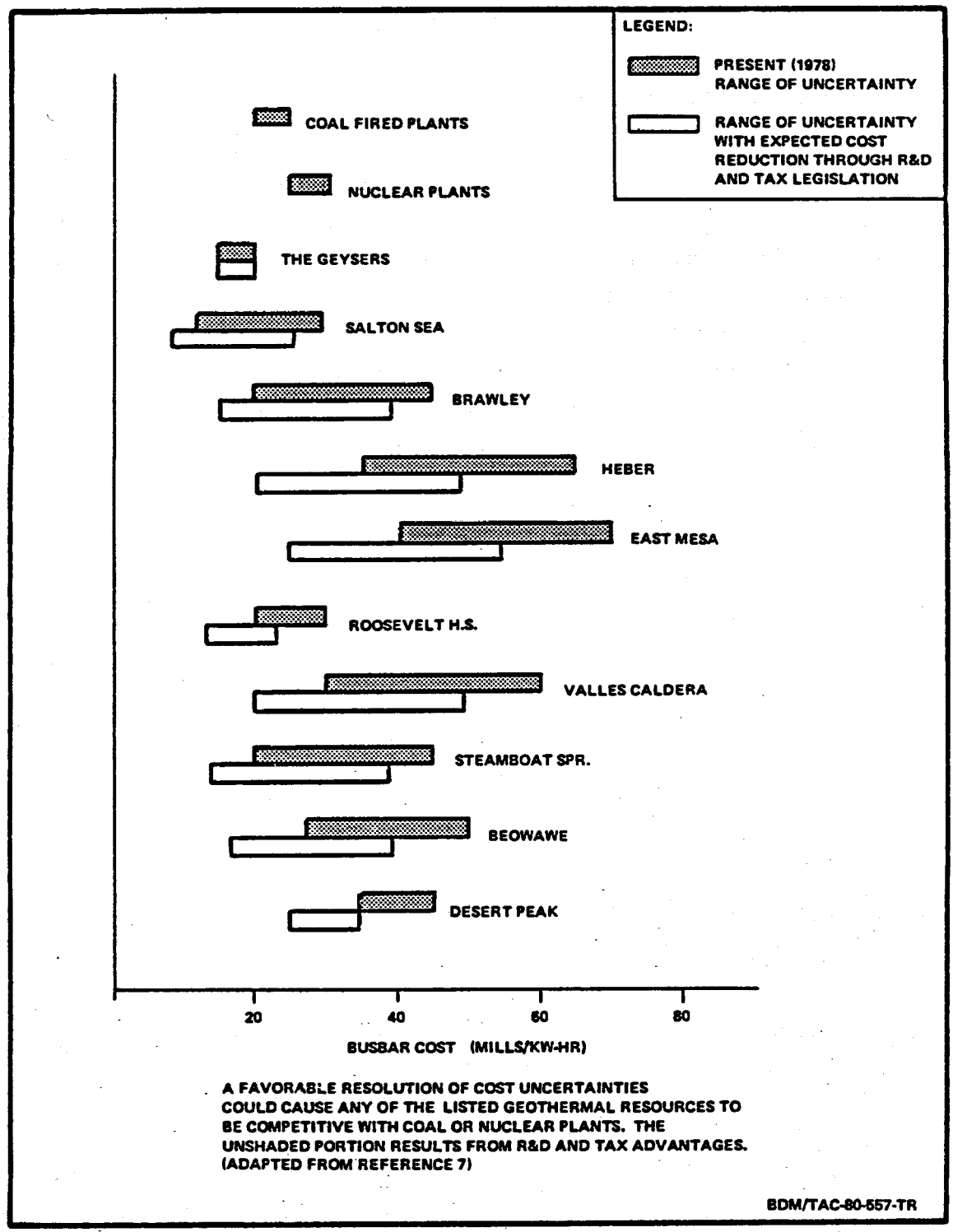

Figure 3. Geothermal Resources with Busbar Electric Costs Comparable with Conventional Sources of Electricity

The following sections discuss the growth and nature of the resources listed in figure 3 as well as the types and numbers of wells drilled at each resource during each 5 year period to the year 2000.

Methodology for Estimating Numbers of Wells

Geothermal wells are drilled to: a) locate and define new reservoirs, b) provide the production and injection wells required by new plants, and c) replace depleted wells at existing power plants. The number of new wells (a and b above) for a given reservoir will be proportional to the rate of growth of generating capacity (dM/dt) of that reservoir. The number of replacement wells (c above) for a given reservoir will be proportional to the electrical generating capacity on line (M) at the reservoir.

The number of new wells required will be the growth in capacity ΔM divided by the productivity per well (P) all multiplied by the ratio of the total number of new wells drilled to the number of successful production wells (r), i.e.

$$\text{New Wells} = \frac{r}{P} \Delta M \qquad \text{(Eq. 1)}$$

Estimates of P, the average productivity per well, can be made from actual well tests (well flow rate, temperature, and fluid quality) on individual wells; or the estimates can be based on historical information as to the number of production wells drilled per megawatt of capacity for a typical plant in the field being evaluated. The ratio of total wells drilled to the number of successful production wells, r, must be based on historical data on drilling in the reservoir being evaluated. On the average, the new wells are expected to be drilled about 3 years before the new electrical capacity is due to come on-line.

The number of replacement wells required will be the capacity on-line (M) times the ratio of the total number of new wells drilled to the number of successful production wells (r) times the replacement ratio (R) all divided by the productivity per well (P), or

$$\text{Replacement wells} = \frac{rRM}{P} \qquad \text{(Eq. 2)}$$

R, the replacement ratio, is determined from historical data on the fraction of wells that must be replaced each year to sustain production. The replacement wells, on the average, are expected to be drilled about one year before they are needed.

In addition to estimates of the coefficients (r, R, and P), estimates of the number of new wells and replacement wells require that generating capacity (M) be forecasted as a function of time. After successful demonstration, a geothermal electric power project should grow rapidly until natural, economic, or political limits are approached. Historical growth at The Geysers and at Cerro Prieto (15 to 25 percent per year) typify this growth process. The capacity has been assumed to grow from an initial critical value (M_o) at a rate initially proportional to the capacity on-line but at a rate that decreases as the maximum resource capacity (M_m) is approached according to

$$\frac{dM}{dt} = \frac{k}{M_m} M (M_m - M) \qquad \text{(Eq. 3)}$$

M_o, the initial critical capacity, is estimated from the size of typical geothermal power plants and the development plans of the local utilities. M_m, the maximum resource capacity, is a function of the geology of a reservoir and can be obtained from Reference 8 or other sources. The solution to the above differential equation for the growth of capacity is

$$M = \frac{M_m}{(M_m/M_o - 1)e^{-kt} + 1} \qquad \text{(Eq. 4)}$$

The constant, k, is evaluated from the initial growth of 20 percent per year and the above differential equation by

$$0.2 = \frac{\Delta M}{M} = \frac{\Delta t}{M_o} \left.\frac{dM}{dt}\right|_{t=o} ; \Delta t = 1 \text{ year}$$

or rearranging and substituting into Eq. 3

$$\left.\frac{dM}{dt}\right|_{t=o} = 0.2M_o/\text{year} = \frac{k}{M_m} M_o(M_m - M_o)$$

and solving for k,

$$k = \frac{0.2M_m \ /\text{year}}{M_m - M_o} \qquad \text{(Eq. 5)}$$

Figure 1 shows the capacities predicted by these formulas (Eq. 4 and 5) using the data of table 2. From these estimates of capacity and the above relationships for new wells and replacement wells, the total number of wells to be drilled in each reservoir was calculated.

If needed, the number of wells drilled before the reservoir reached critical size was calculated according to:

$$\text{Initial wells} = (\tfrac{1}{2}) \frac{rM_o}{p}$$

The (½) factor was assumed to correct for wells already drilled. All numbers of wells have been rounded off to the nearest five or ten.

The Geysers

The past growth of and future plans for electric power capacity at The Geysers is summarized in table 3. Table 3 indicates that from 1967 to 1979, The Geysers generating capacity grew at an annual average rate of 24 percent. Assuming a two year slip in planned additions from table 3 the average yearly growth from 1979 to 1990 would be 12 percent. An electrical capacity of 2.5 GWe is the expected maximum capacity for

Table 2
Well Counting Parameters

Resource	Initial Size[1] (M_o)	Initial Wells	Growth Starts (t_o)	Productivity[2] (P)	Replacement Rate[3] (R)	Ratio[4] (r)	Maximum Size[1] (M_m)	k for 20% per year
Geysers/Clear Lake	900	130[5]	1981	7±3	.044	2±.3	2500	0.263
Imperial Valley	200	50	1986±1	4±1	(.044)[6]	2±.3	7000	0.206
Valles Caldera	50	15	1983±1	3	.033	2	400	0.229
Northern Nevada	100	20	1990±2	(5±1)[6]	(.044)[6]	(2)[6]	1200	0.218
Roosevelt H. S.	70	15	1989±1	5±1	(.044)[6]	(2)[6]	400	0.242

[1] MW_e

[2] MW_e per production well

[3] The fraction of the wells that must be replaced each year. Note: for a 15-year well life and an assumed 30-year project life, each well will have to be replaced once and the replacement rate will be 0.033. The 0.044 rate corresponds to a 13-year well life.

[4] Total wells divided by production wells

[5] Already drilled

[6] Numbers in parentheses are estimates that are not backed by any actual data

Table 3

Status of Geothermal Development at the Geysers*

UTILIZER (UNIT)	CUMULATIVE CAPACITY (MW_e)	ON LINE	STATUS/COMMENTS
PG&E (1)	11	1960	
PG&E (2)	24	1963	
PG&E (3)	51	1967	
PG&E (4)	78	1968	
PG&E (5,6)	184	1971	
PG&E (7,8)	290	1972	
PG&E (9,10)	396	1973	
PG&E (11)	502	1974	
PG&E (12)	608	3/79	
PG&E (15)	663	7/79	
PG&E (13)	798	4/80	
PG&E (14)	908	8/80	
PG&E (17)	1,018	8/82	Application approved 9/20/79. Construction starts 4/1/80.
PG&E (16)	1,128	1/83	Application resubmittal accepted 2/21/80.
NCPA (2)	1,238	1982	Application decision 3/12/80.
DWR(Bottlerock)	1,293	1983	Application extension granted.
PG&E (18)	1,403	1982	Application decision expected 4/16/80.
PG&E (19)	1,513	1986(?)	PG&E not satisfied with proof of resource.
NCPA (1)	1,579	1985	Notice of intent decision about 3/80.
DWR(S. Geysers)	1,634	1984	Notice of intent submitted 10/22/79; accepted on 11/19/79.
SMUD (1)	1,689	1984	12 month application submitted 2/19/80.
DWR (unnamed)	1,744	1987	Notice of intent plan delayed. Developer suing Lake Co.
PG&E (20)	1,854	1985	Relocated between 18 & 14. Application excepted 3/89.
PG&E (21)	1,964	1986	Cobb Mt. resource not proven.
SMUD (2)	2,019	1985	Negotiating steam supply.
SMUD (3)	2,074	1986	Negotiating steam supply.
PG&E (22,23,24)	2,404	1988+	If steam supply available.

*Adapted from information received from the California Energy Commission, March, 1980.

The Geysers resource area (reference 8 estimates 1.6 GWe for 30 years). The electrical capacity should remain near equilibrium in the 1990's. During the 1990's, plants built in the 1960's will be retired and replaced, possibly with plants in the areas around Clear Lake.

Table 4 shows the number of wells that must be drilled in The Geysers to support the projected growth shown in figure 1. The numbers of wells are derived from calculations using equations 1 and 2 and parameter estimates from table 2.

The series of events that created The Geysers reservoir is most easily understood in the context of plate tectonics. A collision between the ocean and continental plates caused the Franciscan marine formation to be highly folded and metamorphosed as it was thrust under the Great Valley sequence. Later, the two plates began to move past each other, and the thrust faults were obscured by new, high-angle transform faults. The area is tectonically active, and the steam production is primarily from fracture zones in the Franciscan formation. The steam zone occurs at varying depths. The Franciscan is primarily graywacke and minor shale with greenstone (extrusive and intrusive basalts) of secondary importance (Reference 9). Drilling is made difficult by the presence of large lenses of serpentine along major faults. The serpentine is typically

Table 4
The Geysers Drilling Activity

	Period			
Well Type	1981-1985	1986-1990	1991-1995	1996-2000
Production	95	45	15	5
Replacement	85	130	150	150
Other*	95	45	15	5
TOTAL	275	220	180	160

*Includes stepout wells, dry wells, and injection wells.

drilled with mud and cased over to prevent hole sloughing. Several geologic cross-sections of The Geysers area showing the location of the steam reservoir are contained in Reference 9.

Figure 4 is a random statistical sample of wells at The Geysers. Well depths have tended to increase with time. This may be due in part to the fact that the steam production rate is related to the number of fractures intersected. As drilling techniques have matured, it may be that the cost trade-offs between drilling and increased production have favored increased well depth. The tendency for the average depth of wells to increase may also be due to drilling in areas where the steam resource is deeper. The top of the steam resource can vary in depth from as little as 2000 feet to over 6000 feet beneath the surface (Reference 9). The expected average depth for wells drilled after 1980 is about 9000 feet.

Drilling and completion problems in The Geysers derive primarily from two factors--high temperatures and extensive fracture systems. Fractures, sometimes more than two feet wide, cause extensive loss of circulation of the drilling fluid. Conventional methods of sealing the well bore from these fractures have not met with much success. Cement squeezes have proven to be the best conventional approach, but there is generally a high cost in rig idle time (6-8 hours typically), while awaiting special cement crews and equipment (Reference 10). A product which could be extruded safely through the drill bit itself would be the desired solution to the problem.

The high formation temperatures (240°C) in The Geysers tend to reduce bit life. Studies indicate that steel bits become soft, thus reducing bit life to 25 percent of normal (Reference 11). Most conventional drilling equipments contain elastomers that disintegrate at high temperatures.

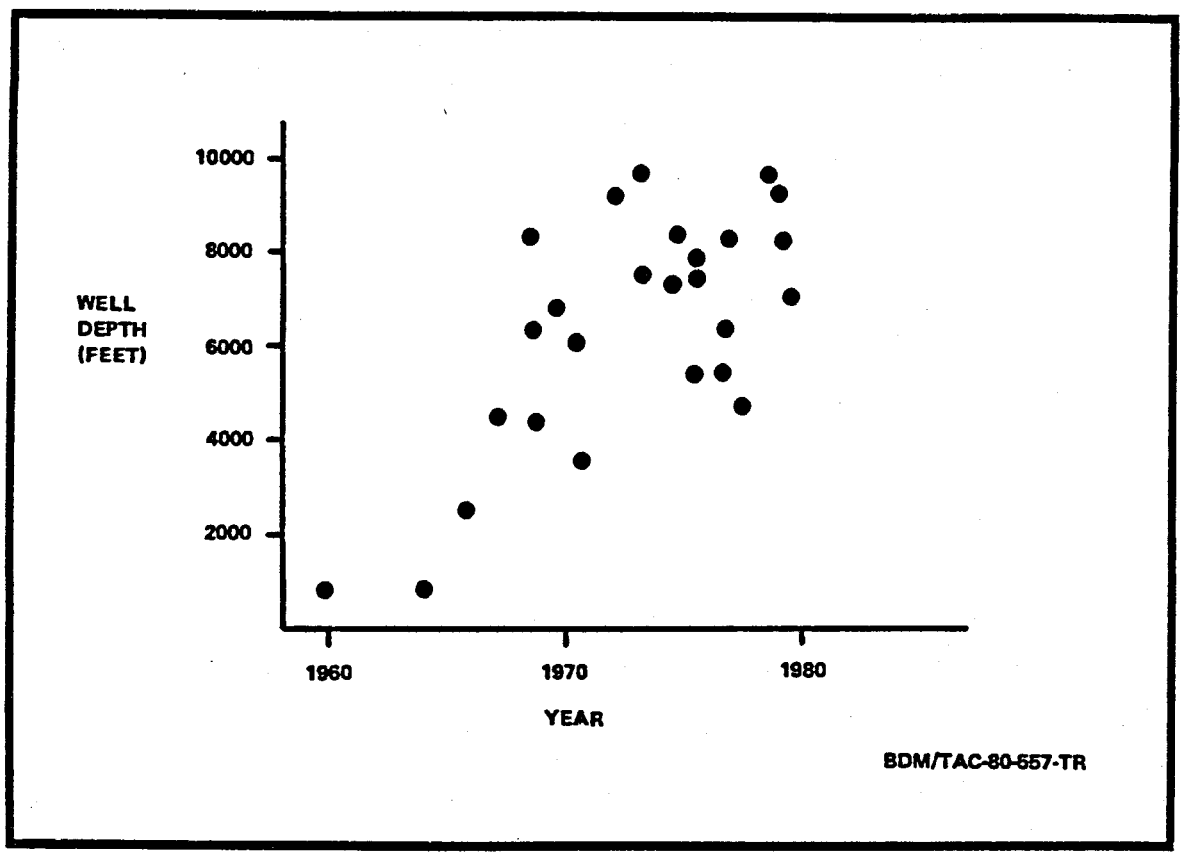

Figure 4. Well Depth at the Geysers

Another significant drilling problem at The Geysers involves the presence of serpentine (heaving shale). The serpentine will slough easily and can lead to severe washout problems. Wells must be drilled with mud until the areas of sepentine have been passed and cased off. Once competent rock is reached, drilling generally switches to air. Air drilling is advantageous because it allows drilling the steam-dominated fractures without severe loss of circulation and also because it avoids plugging producing fractures with mud. However, air drilling is not without problems. The high velocity (up to 10,000 ft/min) mixture of cuttings, air, steam, and corrosive gases moving up the well bore creates a severe erosion and corrosion problem for the drill string. The wear and tear on drill pipe in The Geysers wells is such that the average useful life of a section of drill pipe is seven wells. Introduction of blended amines into the compressed air has helped to increase drill pipe life (Reference 13). Eroded drill pipe can be salvaged through hard banding. Air drilling also allows H_2S to escape. This problem is presently solved by introducing H_2O_2 and NaOH into the drilling fluid mixture.

Wells at The Geysers are usually directionally drilled - first, because of limited space for drilling platforms and mud pits, and second, because directional holes are more likely to intercept producing steam fractures. Directional drilling introduces problems that might be solved with the proper innovations in technology.

Noise associated with drilling is also an environmental problem at The Geysers. Electric rigs are required in some areas (Reference 12).

A typical drilling program at The Geysers is summarized below:

(1) Drill (mud) 17.5" to 500'. Open to 26". Cement 20" casing.
(2) Drill (mud) 17.5" to 2500'. Cement 13-3/8 casing.
(3) Drill (mud) 12.25" to 5000'. Cement 9-5/8 casing.
(4) Drill (air) 8.75" to 9000'. Open hole completion.

At this point, a new casing string is often cemented in from 5000 feet to the surface in order to guard against premature failure in the original casing.

The Imperial Valley

The Imperial Valley is likely to be the next geothermal resource area to experience rapid growth. The resource area is near two large markets (Los Angeles and San Diego) with high electricity costs. It is in a state (California) with institutional experience with geothermal power. It is near a similar, proven geothermal field (Cerro Prieto). Finally, geothermal research and development are at an advanced stage in the Imperial Valley due to extensive drilling and testing.

The Imperial Valley Known Geothermal Resource Areas (KGRA's) are indicated in figure 5. The total electrical capacity from geothermal in the Imperial Valley is about 7GWe for 30 years with a breakdown of 3.4GW at the Salton Sea, 1.7GW at Westmorland, 0.6GW at Heber, 0.6GW at Brawley, and 0.4GW at East Mesa (Reference 8). The Salton Sea and Westmorland areas account for 75 percent of the estimated resources in the Imperial Valley. Glamis and the Dunes are not expected to reach significant electrical capacity before the end of the century.

Table 5 contains the available information on development plans in each area. The Imperial Valley is expected to reach a capacity of 200 MWe of geothermal power by 1986. After 1986, the geothermal electrical capacity is forecasted to increase at an average rate of 20 percent per year. The forecast is based upon the empirical evidence provided by growth at The Geysers and at Cerro Prieto. A simplification of the analysis is that each KGRA contributes equally to the growth of electrical capacity. Under this assumption, each KGRA would have 500 MWe of capacity by 2000 AD. A capacity of 500 MWe represents saturation for Heber, East Mesa, and Brawley. Environmental issues are not expected to preclude growth to 2.5 GWe capacity. Potentially, the most serious

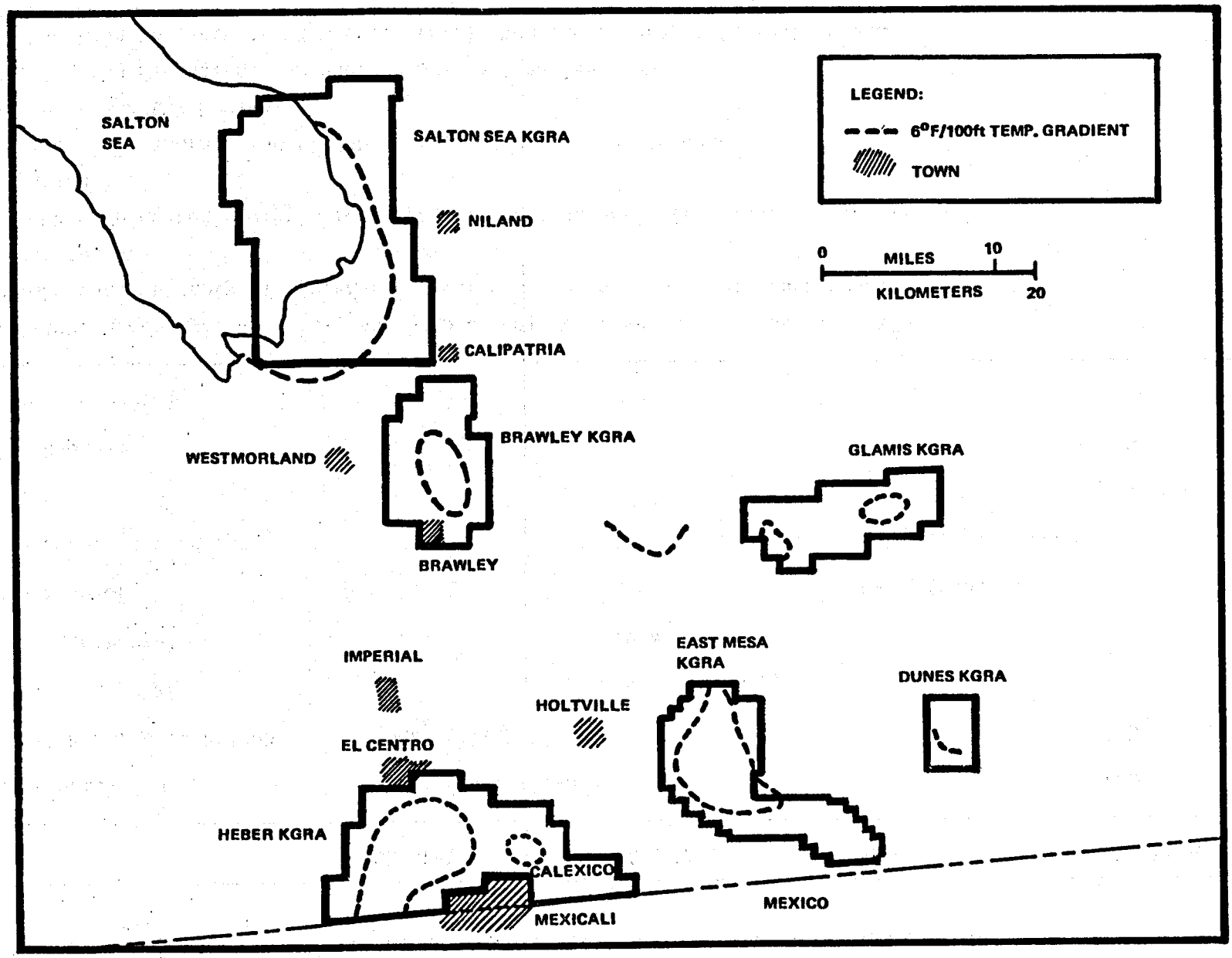

Figure 5. Geothermal Resources in the Imperial Valley

Table 5

Current Geothermal Development Plans In The Imperial Valley

	BRAWLEY	EAST MESA	HEBER	SALTON SEA
MCR Geothermal & DWR[1]	45MW$_e$ (dual flash)[2]			55MW$_e$
Union Oil & So. Cal. Edison	10MW$_e$ (flash)[5]			10MW$_e$ (flash)[10]
Magma Power & SDG&E		10MW$_e$ (binary)[3]		
Republic Geothermal		50MW$_e$[4]		
Chevron & SDG&E			45MW$_e$ (binary)[6]	
Chevron & So. Cal. Edison			50MW$_e$ (dual flash)[7]	
Magma & SDG&E				23 & 49MW$_e$ (flash)[8]
Mapco & Republic				50MW$_e$[9]
Republic Geothermal				49MW$_e$

[1] McCulloch, Geothermal Kinetics, and CA Dept. of Water Resources. On line 1985.

[2] Have DOE Load Guaranty of $49.4M (earliest on line is 1985). At south Brawley.

[3] "Operational".

[4] Have DOE Loan Guaranty of $9M for Reservoir Development. (Earliest on line is 1984.)

[5] "Operational".

[6] SDG&E/DOE Cost Share 50/50 ($123M Plant). Binary plant 1984-86.

[7] Leverage Lease ($70M Plant).

[8] SDG&E Seeking Financing From DOE. 23MWe on line 1982-1983.

[9] Have DOE Loan Guaranty of $29M (Reservoir), but incremental. At Westmorland. On line 1984+.

[10] On line 1982.

environmental obstacle to full development of the geothermal resources under the Imperial Valley resides in the issue of land subsidence. Localized subsidence of even a few inches could seriously disturb irrigation and drainage patterns. A requirement to inject as much fluid into the ground as is taken out will almost certainly be imposed upon the developers. Since cooling tower fluid losses will approach 20 percent of the geothermal fluid throughput, about 200,000 acre-feet a year of make-up water will be needed to support 2.5 GWe. About one million acre-feet of irrigation waste water flows into the Salton Sea each year. If 200,000 acre-feet a year of this waste water were to be diverted to the power plants, the area of the Salton Sea would shrink by about 20 percent.

Table 6 shows the numbers of geothermal wells that will be required in each 5 year period to support the forecasted growth in capacity. The estimates were made using equations 1 and 2 and the parameter values in table 2.

Table 6
Projected Imperial Valley Drilling Activity

	Period			
Well Type	1981-1985	1986-1990	1991-1995	1996-2000
Production	90**	140	290	430
Replacement	10	40	100	230
Other*	40	140	290	430
TOTAL	140	320	680	1090

* Mostly injection wells.
**Includes 50 initial wells.

Several deep exploration wells have been drilled at East Mesa which have allowed the reservoir to be fairly well characterized. In major features, the East Mesa reservoir is typical of reservoirs in the Imperial Valley, although others may be shallower, hotter, and contain fluids with higher concentrations of minerals. The East Mesa reservoir overburden consists of a zone of impermeable, clay dominated sediments from near the surface to 1800 feet, followed by a transition zone of decreasing clay content and increasing permeability to a depth of 2300 feet. The geothermal reservoir extends from 2300 feet to a total depth of 6600 feet. Below 6600 feet, the clay content increases, and permeability declines sharply. The reservoir, about 40 km^2 in area, is apparently recharged from below by hot fluids percolating upwards through the impermeable floor of the reservoir along active faults. The reservoir is convective, with a vertical temperature gradient of 30°C per kilometer. At a depth of 5400 feet, the reservoir temperature is between 150 and 200°C. The model of the reservoir is a layer of unconsolidated to semi-consolidated sediments consisting of 75 percent sand (with a mean porosity of 20 percent and a permeability of 100 md.) and saturated with water at 170°C. The estimated volume of hot water in the reservoir is nine trillion cubic meters. For more information on the East Mesa Reservoir, see Reference 14. Cross-sections of the Heber and Salton Sea reservoirs are contained in References 15 and 16.

The Salton Sea reservoir deserves special mention since it is by far the largest (in terms of heat content) of all reservoirs in the Imperial Valley. The Salton Sea reservoir temperature is hotter (350°C) and the geothermal fluid is more saline (250,000 PPM) than at any other Imperial Valley reservoir. The high temperatures and heavy brines have caused the technical problems of reservoir development to be greater in general at the Salton Sea than at other Imperial Valley reservoirs, but the potential rewards are also greater. The area of the Salton Sea reservoir (about 65 km^2) would support 800 wells (assuming 20-acre spacing). With 800 wells, a maximum capacity of over 3 GWe could be achieved. However,

the Salton Sea itself covers a large portion of the reservoir, so that full development might require expensive offshore operations. The typical production well at the Salton Sea will deliver 400,000 pounds per hour of fluid (17 percent steam by weight) at a pressure of 250 psi (Reference 16). Production wells are expected to be about 3000 to 4000 feet deep at the Salton Sea.

Drilling rates, problems, and programs in the Imperial Valley should closely resemble those at the geothermally powered electric plant at Cerro Prieto, Mexico. Therefore, a brief discussion of the problems that have been encountered at Cerro Prieto is presented.

Since the Cerro Prieto reservoir is subnormally to normally pressured, light weight drilling muds are used to control formation fluids and minimize lost circulation. Mud invasion of the production zones is usually flushed out by formation fluids during well testing. Temperature control of the mud is the major drilling problem at Cerro Prieto, and each drilling rig has a mud cooling tower. Control of solids in the mud is also a problem that has been solved with steel mud tanks and desilters. Identification of producing zones combines cutting analysis, drilling rates, and temperature logs. Mingling of produced water from different temperature zones causes major scaling problems, so there is a limit to improving well production by multiple completions. Production problems at Cerro Prieto are primarily related to casing failure and poor cementing. H_2S limits the use of high strength steel because of corrosion when the well temperature drops below 392°F. Casing failure is a likely consequence of thermal shock, so the common practice at Cerro Prieto is to take at least a month to bring a well up to production temperature and to avoid shutting in the well. A separate, cemented-in production string is used to further avoid casing failures. Cementing problems are caused by the high well bore temperatures and low well bore fracture pressures. Logging to analyze cement placement and strength has proven unreliable. The critical aspect of cementing is to isolate the casing from cooler formation waters. Perhaps the greatest single

problem associated with drilling operations is the fact that summertime temperatures often exceed 120°F. Such high temperatures make drilling operations difficult and slow. For further details on drilling at Cerro Prieto, see Reference 17.

In summary, based on the similarity of the Imperial Valley to Cerro Prieto, the drilling problems of the Imperial Valley are not insurmountable, but the price to drill through these problems with present technology can be considerable. Conversations with people who are knowledgeable of current drilling in the Imperial Valley support this contention. The cost of the geothermal well field is one of the most, if not the most, important factor in the levelized bus-bar cost of electricity produced from goethermal resources. At Cerro Prieto, there has been a historical trend to deeper wells. The deeper formations tend to be fracture-dominated rather than porosity-dominated, and severe lost circulation problems are encountered in these formations (Reference 17). This trend will probably also occur in the Imperial Valley. So while lost circulation has not yet caused many wells in the Imperial Valley to be stopped short of projected total depth, lost circulation may become more of a problem in the future. While successful drilling and completion techniques have been developed at Cerro Prieto, the techniques employed to circumvent problems are often expensive. To avoid casing failures, for example, the production string is cemented back to the surface. Production from a given well is usually limited because waters from different zones have different chemistries and temperatures, causing severe scaling problems. This creates a need for additional wells, for accurate formation and water chemistry evaluation, and for completion techniques such as in-flow control. Since the science of injection is still being developed, the techniques, problems, and costs associated with large scale reinjection of fluids in the Imperial Valley have not yet been established.

Northern Nevada

The geothermal resources of northern Nevada are more widely separated and less uniform than those of the Imperial Valley. Consequently, the mutual growth of electrical capacity at Nevada's resources is likely to be less closely coupled than is the case for the Imperial Valley. The Nevada resources are in an early stage of resource exploration and development. Furthermore, the markets for electricity are not as attractive as those near the Imperial Valley. All these factors indicate that growth of geothermal electric capacity in northern Nevada will lag growth in the Imperial Valley.

The geothermal resources of nothern Nevada expected to achieve significant amounts of electrical capacity are Steamboat Springs, Desert Peak, and Beowawe. Table 7 presents some basic information on these three resources. There is much uncertainty concerning the size, temperature, and other characteristics of the Nevada resources. The development scenario should, therefore, be viewed as representative rather than accurate. Since there is no basis for assuming preferential growth, equal growth of capacity at the three reservoirs is assumed. The northern Nevada resources are estimated to attain an electrical capacity of 100 MW_e by 1990. After 1990, the overall capacity should increase at 20 percent per year based on the empirical evidence of the Geysers and Cerro Prieto. Table 8 presents estimates for the number of wells needed to support the estimated growth. Estimates were made using equations 1 and 2 and the parameter values of table 2.

Table 7

Northern Nevada Geothermal Resources

GEOTHERMAL RESOURCE	RESERVOIR TEMP (°C)	MW_e FOR 30 YR.	DISSOLVED SOLIDS (PPM)	LITHOLOGY (thousands of feet below surface)
Desert Peak (4 wells, Phillips)	220	750	2000	Tuffs (0-4) Schists, Hornfels (4-7) Faulted Granite (7-10)
Steamboat Springs (6 wells, Thermal Power)	200	350	2500	Granite, Metamophics, Volcanics (0-1)
Beowawe (15 wells, Chevron & Magma)	230	130	1500	Basalt, Tuff, Alluvium (0-4) Andesite, Tuff, Alluvium (4) Quartzite, Chert, Shale (4-6)

Table 8
Projected Northern Nevada Drilling Activity

Well Type	Period 1981-85	1986-90	1991-95	1996-2000
Production	---	40**	50	65
Replacement	---	5	20	40
Other*	---	20	50	65
TOTAL		65	120	170

* Mostly reinjection, but a significant fraction of dry wells.
**Includes 20 initial wells

The Nevada resources are located in the Basin and Range Province. Lithologic profiles are indicated in figure 6. Fluid chemistry varies from 2000 ± 500 PPM (mostly NaCl) at Steamboat Springs and Desert Peak to 1000 PPM (mostly Na-HCO_3) at Beowawe. Lost circulation has been noted as a problem. At Beowawe, low permeability of the reservoir rock and scaling due to high silica content of the fluid may be problems. Stimulation of flow may be needed at some reservoirs (Reference 7). Steamboat Springs is a shallow resource; wells there are 1000-3000 feet deep. Wells at Beowawe and Desert Peak may average 8000 feet in depth.

Roosevelt Hot Springs

Roosevelt Hot Springs, near Milford, Utah, is an example of a good resource in search of a market. Philips Petroleum, the reservoir developer, has in principal an agreement with Utah Power and Light (UP&L). UP&L is to build a 20 MWe demonstration plant and purchase geothermal steam from Philips. The demonstration plant may be on-line by 1983. A

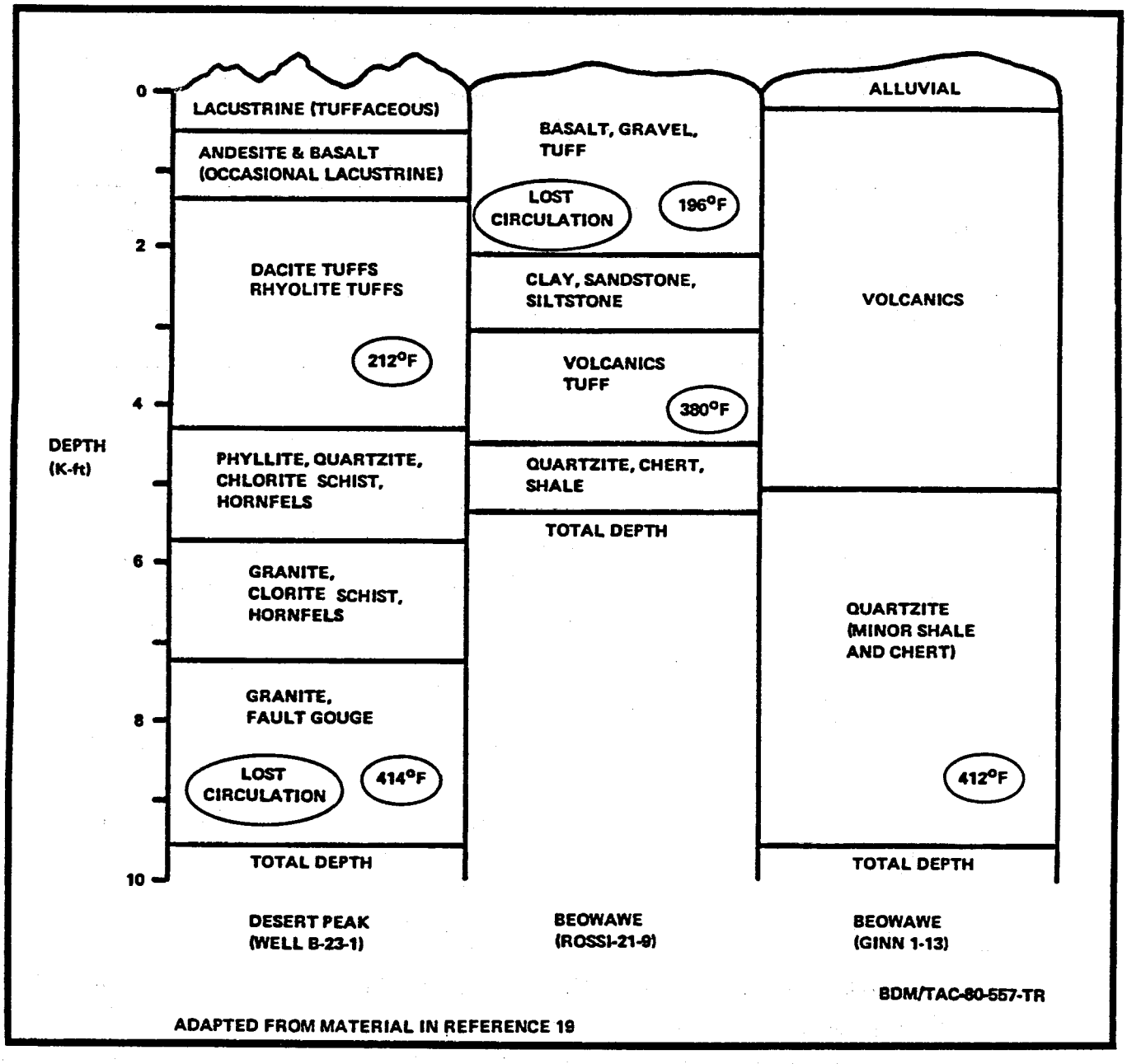

Figure 6. Northern Nevada Well Profiles

50 MWe plant is estimated to be operational in 1989. This estimate is based on a probable Philips/Utah Power and Light agreement on a 10-20 MWe plant on-line by 1983, and a decision in 1985 to proceed with construction of a 50 MWe plant. The capacity is expected to approach the reservoir capacity (estimated at 350 MWe in Reference 18 by 2000 A.D. Growth could be limited by problems of ground subsidence and a lack of make-up water for injection to prevent subsidence.

Table 9 shows the numbers of wells of each type that are needed to support the projected growth. A flow test (48 hours) on Utah State 14-2 gave 483,000 lbm/hr with 445 Btu/lbm, which yields 88,000 lbm/hr of 70 psig steam. This flow would generate 4.5 MWe (Reference 19). Utah State 72-16 flowed 1,300,000 lbm/hr and would provide 12.5 MWe (Reference 19). Uncertainties about long-term well flow characteristics are reflected in the estimates for replacement and injection wells.

The geothermal system at Roosevelt Hot Springs is controlled by structures cutting plutonic and metamorphic rocks. A low-angle normal fault (offset 600 meters) features intense mylonitization of the crystalline rock. The hanging wall is highly brecciated where friction has produced steeply dipping mylonite zones. The mylonite has been altered and silicified to produce a brittle, impermeable rock. Jointing increases permeability adjacent to mylonite zones. Permeability at shallower depths occurs at the contact of the mylonite zones and steeper faults (Reference 20).

Table 9
Roosevelt Hot Springs Drilling Activity

Well Type	Period 1981-85	1986-90	1991-95	1996-2000
Production	---	35**	25	15
Replacement	---	5	15	25
Other*	---	20	25	15
TOTAL		60	65	55

* Includes injection and a high fraction of dry wells.
**Includes 15 initial wells.

Figure 7 is a cross-section through the field. The lithology is so complex and variable that all wells are essentially wildcats. Eleven wells were drilled from 1975 to 1979. About 5 wells are considered good producers. Typical well depth is 6000 to 7500 feet, but two were 2800 feet deep and one was only 1200 feet deep (the 1200 foot well is the best producer). Injection wells may be a problem unless, as preliminary reservoir analysis has suggested, the reservoir becomes steam dominated in time.

The eleven wells at Roosevelt averaged 51 days to drill and complete. The two wells drilled to 7500 feet took 90 days each. Drilling rates have averaged 130 feet/day, with a low of 18 and a high of 254. The 18 feet/day well was the 12.5 MWe well which kept threatening to blow out.

Valles Caldera

The Valles Caldera, in northern New Mexico, is in an advanced stage of reservoir development. Several production wells are on line, and site

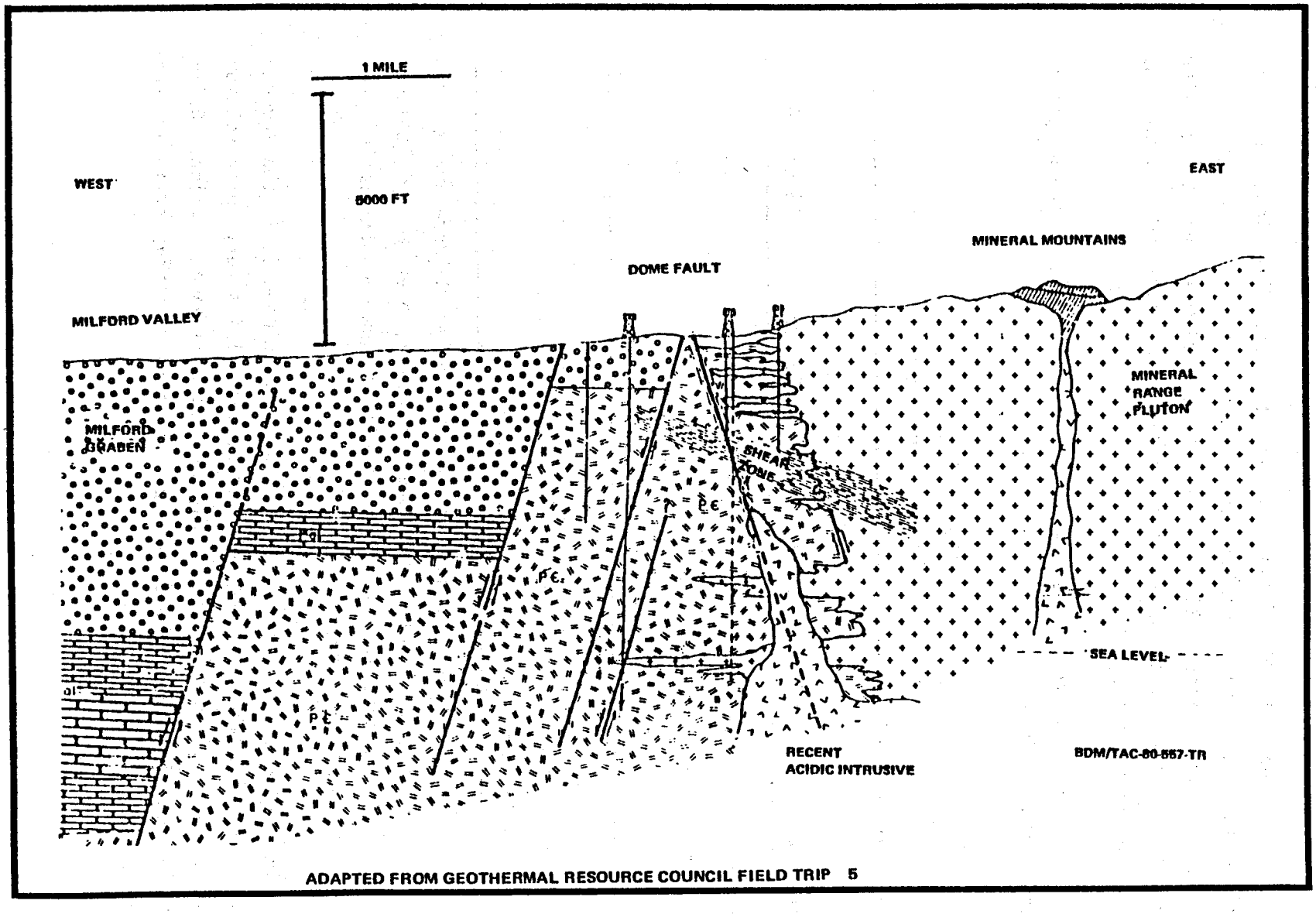

Figure 7. Cross Section of Roosevelt Hot Springs

preparation for a 50 MWe flash plant has started. The plant should be on-line in 1983. The electrical capacity should grow at a rate of 20 percent per year after 1983 to a maximum of 400 MWe. Growth could be limited or delayed by court decisions in favor of nearby Native Americans who are against the project.

Table 10 shows the number of wells needed to support the projected electrical capacity.

Table 10
Valles Caldera Drilling Activity

	Period			
Well Type	1981-85	1986-90	1991-95	1996-2000
Production	45**	40	30	15
Replacement	5	15	30	40
Other*	30	40	30	15
TOTAL	80	95	90	70

* Mostly injection and dry wells.
**Includes 15 initial wells

All of the present production in the Valles Caldera comes from fractures in the Bandelier Tuff (see figure 8), even though geologic studies indicate that the reservoir extends to greater depths in older volcanic and sedimentary rocks.

The geothermal resource presently being developed is in the Redondo Creek area. Redondo Creek was selected because of its very thick section of Bandelier Tuff with a porous, highly fractured basal section. Drilling in Redondo Creek should be representative of other parts of the reservoir.

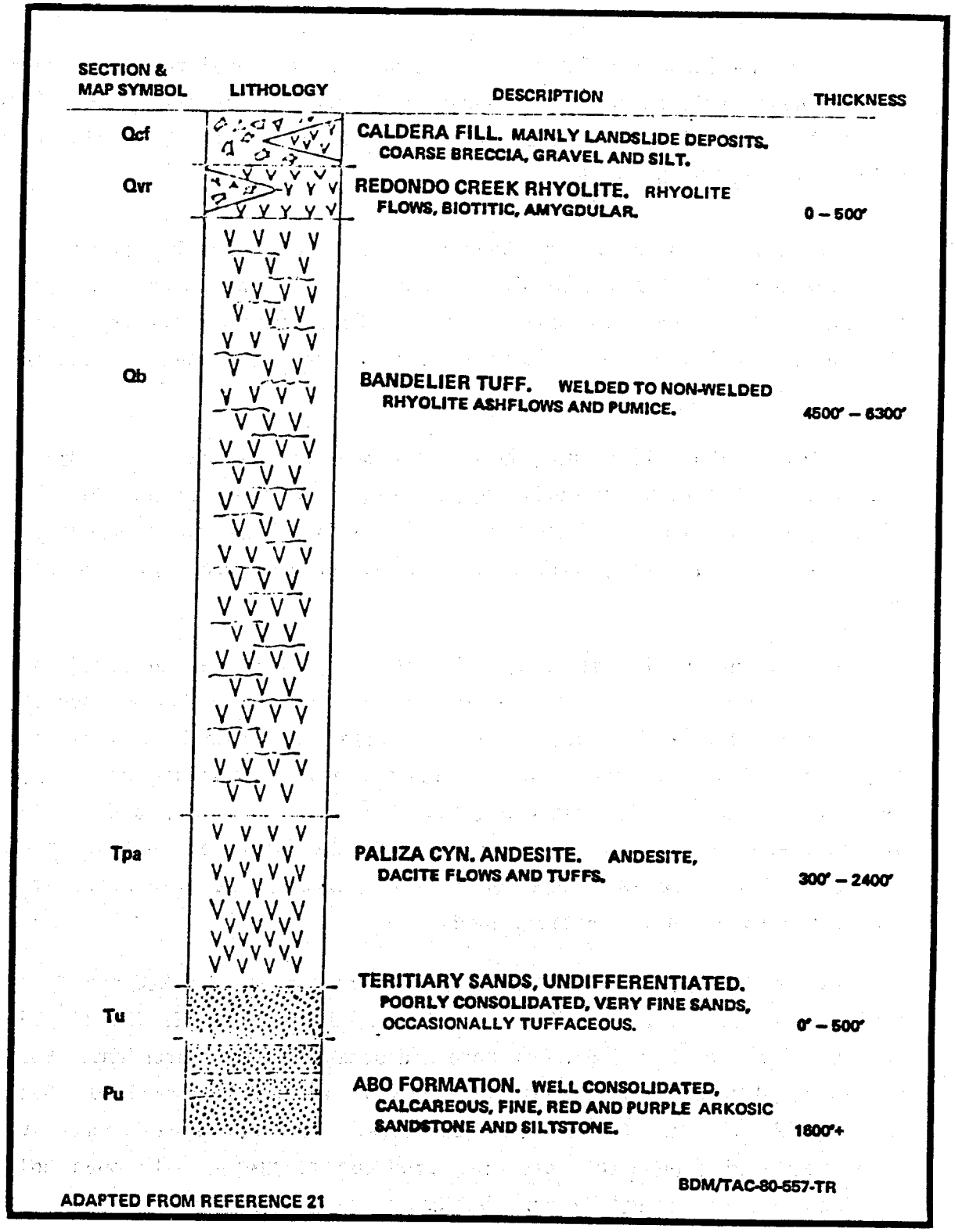

Figure 8. Valles Caldera Lithology

Above the Bandelier Tuff is the Redondo Creek Rhyolite and Caldera fill. These sections have a tendency to slough. They are mud-drilled and must be cased-off to prevent sticking the drill pipe and losing the hole as occurred with Baca No. 5.

The upper portion of the Bandelier Tuff is a densely welded tuff with low porosity and negligible fractures. This upper Bandelier Tuff, together with the sections above it, forms the caprock for the reservoir. The lower portion is more pumicey, porous, and consistently contains permeable fractures.

Below the Bandelier Tuff, both the upper part of the Paliza Canyon andesite and the Tertiary sands are potential production zones. Baca No. 10 did penetrate the Tertiary sands, but the formation was so unconsolidated that it was not possible to stop the flow of sand into the well bore.

Present production strategy calls for completion in the lower part of the Bandelier Tuff and the upper part of the Paliza Canyon andesite and to allow fluids from the rest of the reservior to drain or flow into these producing formations along fracture zones. Developing methods of drilling and completing that would allow the identification and tapping of isolated fractures in the upper part of the Bandelier Tuff would be valuable. Even more important would be the development of a method for completing a well in the Tertiary Sands.

As of June 1979, 12 wells had been drilled in the Redondo Creek field. The wells are Baca No. 4, 5, 5A, 6, 9, 10, 11, 12, 13, 14, 15, and 16. Baca No. 5 and 9 were abandoned because of hole problems. Baca No. 10 was damaged during completion and will have to be redrilled. Baca No. 5A, 12, 14, and 16 were nonproductive. Baca No. 6 was productive when completed (the only potential producer completed with open hole because a liner could not be run), but has since started sloughing.

Drilling wells in the Redondo Creek area has presented difficult technical problems. The reservoir formations being drilled are considerably under pressured with respect to normal hydrostatic pressure for cold water. Using mud as the drilling fluid in the reservoir often causes severe lost circulation due to the large pressure differential between the well bore and the formation. Drilling with air causes sloughing of the formations and results in a high risk of losing the hole. A new procedure was first tried on Baca No. 11 which was the first of six successful drilling and completion programs in a row (see Reference 22 for details). Prior to that, two of six wells were completed and tested successfully. Baca No. 11 was drilled to 3650 feet using mud. From 3650 feet to total depth, aerated water was used. Aerating the water causes corrosion problems in the drill string. Various inhibitors have been tried; ammonia has yielded the best results but is expensive.

Drilling problems at the Redondo Creek site have included sloughing, stripper rubber failure, pipe ram failure, blooie line failure, stuck drill pipe, hole problems preventing running of a liner, excessive drill pipe drag, lost logging tools, junk dropped down the hole, plugged bits, lost circulation, and others. Estimates of the frequency of these problems would not be straightforward because of the evolution of drilling practices from mud drilling through aerated water drilling, and because different wells have varying thicknesses of each section, and finally because complete drilling records are only available on about half of the wells. Further analysis of these drilling problems could probably be done by careful examination of the driller's log followed by discussions with the driller. Conclusions should be based on expert opinions as much as on quantative analysis.

In the case of lost circulation, some preliminary observations can be made. Prior to aerated water drilling, drilling records do not list many lost circulation zones (two each for Baca No. 4, 5, 6, 10). Starting with Baca No. 11 and the aerated water drilling program, each producing well had many lost circulation zones (8, 10, 11 zones for Baca No.

11, 13, 15 respectively). The nonproducers Baca No. 12 and 14 had only 4 and 1 lost circulation zones respectively. The nonproducer Baca No. 16 had 10 lost circulation zones, but in this well considerable length of hole was drilled ahead under lost circulation with considerable drilling problems. Using the aerated water drilling program results in an average of seven lost circulations per well, each requiring a day or two additional drilling time. The producers average twice as many lost circulations as the nonproducers.

Temperatures in the caprock (∿ 2000 feet) increase at 10 to 30°F/100 feet. In the best parts of the reservoir, there is no significant increase in temperature with depth. Usually the pressure in the caprock either remains at atmospheric or else increases to about 400 psi at the base of the caprock (∿ 2000 feet). (Normal hydrostatic for cold water is about 866 psi at 2000 feet.) One should be careful in interpreting these pressures at the base of the caprock because they are probably upward extrapolations of reservoir pressures rather than pore pressures of the caprock. In the reservoir, the pressure increases at a rate of about 4 psi/ft and remains less than hydrostatic pressure for cold water.

Geothermal Wells for Direct Heat Projects

Some General Observations

The growth of geothermal application direct heat use is much less definitive than the growth of geothermal electric power use. For instance, the growth of geothermal direct heat use is much more dependent upon future political decisions at the national and state level. These decisions cannot be forseen in advance. By way of illustration, consider the divergence between government policy statements and the present state of affairs. DOE has announced a goal of one Quad (10^{15} Btu) of geothermal direct heat use per year by the end of the century. At present, the amount used is one-tenth of one percent of this goal. More than a thousand large projects would be needed to meet the goal. The total market for direct heat in the West is about five Quads, so that the goal represents a 20 percent share of the market. To meet such a goal, the government would have to provide the fledgling industry with aid on the order of one billion dollars over the next ten years. See Reference 23 for further details.

The first step toward determining where, when, and how much growth will take place by 2000 A.D. is to specify the nature of the industry and markets. Government and industry documents have been studied to determine where direct heat projects exist, and where growth is likely over the short term. The characteristics of the resources and the nature of drilling problems have been ascertained to the extent possible through conversations with people in the field - drillers and consultants to drillers. The results are summarized below, and then detailed on a state-by-state basis.

Summary of Results

The growth of geothermal direct heat use is likely to remain quite modest over the short term. Where good markets and proven resources are

close together (Klamath Falls, Reno, Boise, and a few other places), new uses will be added to existing uses. Technologies that lower the costs of projects would contribute to growth, but such technologies will take time to develop and diffuse into the industry. Assuming the government does not dramatically increase its commitment of funds to geothermal, an average growth of no more than 14 percent per year to the end of the century is estimated. Such a rate of growth would yield about 0.02 Quads of geothermal energy use per year by the end of the century (2 percent of the DOE goal).

It would be beneficial to have some estimates of useful net energy output per well. The geothermal energy demand could then be translated into numbers of wells. This cannot be done unless the growth can be accurately apportioned between large and small users. Wells for small users might average 0.2 μQ (micro-Quads) per year, whereas wells for large users might average 100 μQ per year. Hence, the number of wells to support .02 Quads varies from 100,000 wells to 200 wells depending upon the percentage of large users.

The problems that affect the costs of direct heat wells can probably be specified, but wells for large users may be affected by different problems and costs than wells for small users.

The deep, hot wells for geothermal direct heat projects will be drilled by the same firms that drill wells for electrical projects. However, the number of such wells is likely to be a small fraction of the number of similar wells for electrical projects. Consequently, no special consideration of technologies for deep direct heat wells has been made.

One aspect of the study was to determine if water and mineral well drillers who also drill geothermal wells are confronted with a set of special geothermal problems. If not, then technologies to improve geothermal wells may be lost against a background of millions of water and shallow mineral wells. There do seem to be some common aspects of

geothermal drilling, however, that might confront the water or mineral driller with special problems. Geothermal drilling is much more likely to occur in urban areas than other types of drilling. Geothermal drilling is perceived as more dangerous and risky. Geothermal drilling is often deeper, and in difficult volcanic and fractured formations. Geothermal drilling results in higher well bore temperatures. Geothermal fluids are often corrosive and may present special disposal problems.

The investigation of drilling problems seems to support the hypothesis that geothermal direct heat drilling presents special or unique problems to the contractor. Drilling in urban areas presents problems that most drilling firms cannot deal with in an effective manner. Noise, lack of space, and property damage may contribute to higher drilling costs in urban areas. Drillers are often prevented from working at night due to excessive noise. Lack of space often means that mud pits can't be built. Special precautions must be exercised to reduce property damage from mud or geothermal fluid.

The perceived dangers of geothermal drilling present problems to drillers. State laws often require special permits and equipment (such as blow out preventers) which most water and mineral drillers don't have.

The difficult formations and high temperatures often exceed the capabilities of the contractor's rigs and down hole equipment. Problems with pumping the hot, corrosive fluids have also been cited. Pumps and casing programs that are adequate for water wells often lead to unacceptably short lifetimes in the presence of geothermal fluids.

These problems make it very likely that a specialized segment of the drilling industry will gradually evolve. This segment would consist of firms that find it profitable to invest in the special equipment, materials, licences, and training needed to compete in the geothermal direct heat drilling market. Such an eventuality is predicated on the

assumptions that the geothermal direct heat industry will attain significant size, and that well costs will remain an important economic consideration to developers.

Oregon

Four of the 14 Known Geothermal Resource Areas (KGRAs) and potential geothermal resource areas in Oregon have near-term potential for geothermal direct heat applications. Klamath Falls, Lakeview, and Vale already have direct use on line, with plans for additional development both in space heating and process heating.

The Vale KGRA is located in an area with a population of approximately 25000 people. Food processing is the major industrial activity in the areas. Three greenhouses have been using nearby hot springs for over 20 years. A mushroom-growing facility plans to use the fluid for heating and cooling applications. The general public in the Vale area is very supportive of geothermal development.

The Mount Hood KGRA is experiencing considerable exploration activity. Plans are to supply space heating and snow melting for the Timberline Lodge (the largest single building consumer of heating oil in Oregon at 38000 gallons per month). There is also a plan to lay a 48-inch pipeline over the 69-kilometer distance from Mount Hood to Portland. The general public is likely to be extremely negative to development at Mount Hood. Much of the area may be classified as wilderness or roadless areas.

Klamath Falls has the highest concentration of direct use geothermal applications in the United States. This use takes the form primarily of space and hot water heating. More than 400 geothermal wells provide water for heating more than 500 structures including homes, public schools, the Oregon Institute of Technology campus, the hospital, and several commercial buildings. Industrial applications include milk

pasteurization, snow melting, floor warming, concrete curing, and greenhouses. Potential new geothermal applications include a geothermal heating district, more greenhouses, and an industrial park. In the first phase the district project plans heat for 14 Government buildings. The first phase of the project will require two wells, each 300 meters deep. Phase II would heat about 110 additional buildings. Both the public and the city of Klamath Falls are actively encouraging further geothermal development.

The Lakeview KGRA is located in an area with a population of about 3000. Current projects include space heating for a motel and 10 homes, and heating for 3000 square feet of greenhouses. Lakeview has sponsored a feasibility study of a direct heating system. The economic analysis pointed out the need for a large process heating project if the geothermal project were to be an economic venture. Possible process heat applications include alfalfa and grain drying, commercial refrigeration, greenhouses, feedlots, and meat processing. The people of the area are receptive to geothermal development. A large number of landowners have leased their geothermal rights to development companies.

The reservoir temperatures in the four Oregon areas range from 120°C at Klamath Falls to 170°C at Vale. Depth to the reservoirs is 2000 feet or more. Present usage comes from shallower (200 to 1000 feet) wells with cooler temperatures. The total dissolved solids is about 1000 ppm in each reservoir area. The dominant chemicals are sodium sulfate at Klamath Falls and sodium chloride at Vale. The estimated total usable heat content of the Klamath Falls and Vale KGRAs are about 50 Quads each. The heat content at Lakeview is estimated at about 6 Quads. The overburden at Klamath Falls is typically lake-bed sediments and volcanics. The overburden at Vale is primarily loosely consolidated sandstone and siltstone with some limestone and interbedded basalts. The Lakeview overburden and reservoir is primarily composed of andesite, basalt, and andesite tuffs.

Much of the drilling of geothermal wells in Klamath Falls is done with cable tool rigs. Cable tool rigs are used primarily because of space limitations in built-up areas. Small rotary rigs are occasionally used in Klamath Falls. Generally, rotary drilling is done with air since the wells are typically quite shallow (about 200 to 300 feet deep). The cost of a completed well to the user ranges from about 3,000 dollars for a well 140 feet deep to about 20,000 dollars for a well 1000 feet deep. The drillers of shallow geothermal wells at Klamath Falls are limited by law to depths of 2,000 feet or less and temperatures of 250°F or less. A major problem in drilling at Klamath Falls is the restricted areas in which to maneuver and set up drilling rigs. Rotary drilling with mud would be potentially quicker, cheaper, and safer than either cable tool or air drilling. However, the need for mud pits and the cleanup problems associated with mud drilling in urban areas make it impractical. Typically, there is no reinjection of geothermal fluid at Klamath Falls from those wells that are currently being pumped. The shallow wells used to heat individual homes are not pumped. These shallow wells are drilled 30 centimeters in diameter and cased with a 20-centimeter diameter casing perforated at the top and also at the bottom of the hot water zone. City water is pumped through pipes down into and out of the wells. A stong convection cell is created within the well bore which allows a good transfer of heat from the geothermal fluid to the city water. Another problem at Klamath Falls is that well life can be as little as seven years. In the past, wells were abandoned due to the cost of reworking and recasing the well. These old wells are presently being reclaimed at 25 to 50 percent of the cost of a new well. The future of direct heat applications at Klamath Falls will probably contain a large fraction of somewhat cooler geothermal fluid in the 70 to 80°C range. Heat pumps will probably be used on a large scale.

Washington

It is unlikely that there will be any significant geothermal direct heat development in the State of Washington before the year 2000. Washington has only one known geothermal resource with a temperature greater than 150°C., and only two known resources with temperatures between 90 and 150°C. (one of which is in a national forest). The state has four known resources with temperatures of less than 90°C. as listed in Reference 8. None of the known resources is estimated to be of sufficient size to support a substantial direct heat application, even if they were located in populated areas. Most of the resources are in regions of high ecological and aesthetic values; therefore, it is unlikely that the public would be positive about the development of the resources. The Forest Service has failed to prepare the necessary Environmental Impact Statements which has delayed leasing.

The resource potential in Washington must be more clearly defined before anything definite can be said about where and when geothermal development may take place in that state.

Idaho

The development of geothermal direct heat in the Boise area should dominate geothermal development in Idaho over the short term. Idaho has many geothermal areas, but they are either far from a commercial market or else they suffer from a lack of resource definition.

There are four geothermal resources within the corporate limits of the City of Boise. The four resource areas are: (1) the penitentiary grounds; (2) Warm Springs Water District; (3) Old Fort Boise military reservation; and (4) Camels Back Park. The Barber Industrial Park is located at a geothermal resource area and has two small lumber mills and a large brick manufacturing company. By the year 2000, the city hopes to have a new subdivision of 11000 units heated entirely by geothermal energy.

The penitentiary grounds is a 300-acre site located adjacent to the main production well at the Warm Springs Water District. This area is a prime candidate for more construction of state offices.

The Warm Springs Water District services 175 homes and businesses with geothermal heating.

In 1977, ERDA drilled two wells more than 250 meters deep in the Fort Boise barracks area to prove the existence of a resource. The wells have a bottom hole temperature of 74°C. Pump tests indicate the presence of a large reservoir. This area has adequate energy potential to meet the space heating demands of the Capitol Mall and the present buildings located on the property. The Capitol Mall requires approximately 700 μ Quads of energy per year. A conversion to geothermal heat could be accomplished by 1985 provided that development of the reservoir begins promptly.

Several other areas of Idaho have chance for significant geothermal direct heat use by the turn of the century. These areas are subjectively assessed in table 11.

Table 11

Geothermal Growth in Idaho

Location	Resource	Market	Potential (Relative)
Boise	Varied, extensive	Large & close	Excellent
Napma-Caldwell	Cool, undiscovered	Large	Fair
Brunea-Grandview	Extremely large	None?	Poor
Twin Falls	Large, up to 45°C	Large	Good
Raft River	Large, hot	Uncertain	Fair
Rexburg	Moderate size and temp.	Moderate	Fair
Preston	Moderate	Uncertain	Poor

At Twin Falls, several 300-400 meter deep wells have artesian flows of up to 4000 liters per minute at up to 45°C. The College of Southern Idaho has drilled one such well, and plans to heat the campus using heat pumps.

Nevada

According to the Nevada Bureau of Mines and Geology, over 34 geothermal areas in Nevada are physically capable of supporting direct heat applications. However, Nevada lacks substantial markets that could use these resources. Only 21 cities in Nevada have populations larger than 3500 people. Of these, only Reno, Sparks, Carson City, Babbitt, Hawthorne, Elko, and Carlin are close enough to utilize any of these resources. Most identified resources are too isolated to be considered for industrial process heating projects. One area which may be able to support such projects is the corridor between the towns of Winnemucca and Elko. Four geothermal resource areas straddle this corridor, including the Beowawe KGRA; both Interstate 40 and the Southern Pacific Railroad are nearby.

The major development of geothermal direct heat over the next 20 years is expected to take place in The Reno/Sparks areas. The Moana Hot Springs resource underlies portions of the cities, and Steamboat Hot Springs is only a few miles away. The present population of 175000 is projected to reach at least 350000 by the end of the century.

The Moana Hot Springs resource is a large, moderately high temperature (116°C) resource that has been used for space heating for many years. At present, it is used to heat swimming pools, churches, commercial buildings and more than 60 residences. It would be difficult to use the Moana resource for industrial or agricultural projects since it is located within an area largely built up and zoned residential and commercial. The area of the resource is about five square miles. The water

temperature at the Moana resource ranges from 70 to 95°C at depths greater than 100 feet. Twenty wells are presently being drilled in the Moana resource area and more than 100 additional wells are planned over the next year. Drilling problems in the Reno area resemble those in Klamath Falls, Oregon. Noise is a very important problem because the area is densly populated. The wells are drilled with mud, using tank trucks as substitute mud pits. Water is not adequate as a drilling fluid since it won't build up an adequate filter cake. Much of the drilling in Reno is done with cable tool rigs.

Reno is close to Steamboat Hot Springs, a large, high-temperature resource. Although much of the Steamboat Springs resource is hot enough (over 150°C.) for electrical power generation, some marginal areas may be developed for direct heat applications. One developer is considering a project at Steamboat Springs to provide heat for more than 6000 residences in the Reno area.

The possible deployment of the MX missile to Nevada could have major implications to the development of geothermal resources in the state. However, the uncertainties are such that nothing meaningful can be said at this point.

Montana

Direct heat applications for geothermal energy in Montana are not expected to be significant over the next 20 years. Few, if any, of the resources are believed large enough to support a significant amount of development. Even if a given resource were large enough, most of the resources are located in sparsely populated areas or areas with poor transportation facilities. There is also a lack of economic incentive because cheap natural gas is piped into Montana from Canada. Montana produces twice as much energy from its hydropower plants, coal mining,

oil, and natural gas fields as it demands. The tax credits are so small that they barely enter into any economic considerations for geothermal direct heat systems.

Arizona

There are potential resources in the state in areas with substantial population including Maricopa and Pima counties, but none of the applications proposed for these areas is under development at the present time. Some of the applications which have been proposed are space air conditioning, geothermal assisted in-situ solution mining, direct thermal use for food processing, and electrical power generation. A proposed new development of 571 homes in Phoenix's west side is slated for geothermal heating and cooling. Construction is planned for late 1980 or 1981 (Reference 24).

The laws in Arizona are quite conducive to development. No Environmental Impact Statements are required; geothermal resources are exempt from state water laws; and the state offers a number of tax incentives to potential geothermal developers. It is possible that geothermal developments in Arizona will occur very quickly, but given the current level of development, it is very difficult to make any predictions as to when or where this development may occur.

Colorado

Colorado has more than 50 known geothermal resources. However, none of the resources is very large. They total an estimated 0.35 Quads of useable heat content. By comparison, Klamath Falls, Oregon, has at least ten times as much useable heat content in a single resource.

The areas with the greatest potential for development are the San Luis Valley, Pagosa Springs, and Glenwood Springs. These areas could grow to 0.001 Quads of geothermal energy use each year by the year 2000. Three shallow (300 ft) wells have been drilled at Pagosa Springs. The second well was dry.

The drilling was performed by B&B Drilling of Grand Junction, Colorado, a mineral exploration company. The rig they used is slightly heavier than a water well rig and is capable of drilling to 3500 feet. Since the wells were drilled in town behind the Court House, noise and space were problems. Because of the noise, most drilling was done during the day. There was room for a small mud pit but the pit wasn't large enough to handle enough mud to do the job all at once. The mud had to be mixed in small batches which took a lot of time. The small size of the pit did not allow for proper cooling of the fluid. This caused the rubber swabs on the mud pumps to become spongy. Most of the other drilling problems occurred in drilling the first well and were caused by a lack of preparedness and experience on B&B's part, since it was the first geothermal well they had ever drilled. These problems included not having rubber swabs designed for geothermal drilling, not having drill pipe big enough to handle the 26 inch bit used in the first phase of drilling, and setting the kelly bushing so high as to make pumping mud into the well difficult. These problems were alleviated in the following wells. The third well took 10 days to drill, as compared to 3 weeks for the first well.

Alaska

The state of Alaska contains numerous direct heat resources of potentially large size. Direct applications of hot springs currently account for over 16 micro-Quads per year, mostly used for residential and greenhouse space heating, and for recreation (Reference 25). The lack of markets of significant size is the major limitation to large scale development of geothermal in Alaska.

Three areas appear most likely to grow to significant size in the short term - Kotzebue, Adak, and Unalaska.

Adak Naval Air Station, located in the central Aleutian Islands, has 5000 people. Presently they generate power with generators run on jet

fuel. Two exploratory wells have been drilled. One well, to 2000 feet, had a bottom hole temperature of 150°F. Geothermal exploration is managed from China Lake, California.

These wells were drilled by Hamilton Drilling of Anchorage, a mining exploration company. The two wells were "contractually" successful but were disappointing geothermally. The first was drilled to 1100 feet in volcanic ash and never hit bedrock. The second, drilled to 2000 feet, had a temperature gradient of only 11°C/100 m, not as high as had been anticipated. The major drilling problems were caused by drilling in ash instead of bedrock, or as has been said, "drilling drilling mud." Over 900 feet had to be redrilled.

More exploratory wells are planned but production wells will not be drilled until the project is funded by Congress, hopefully in 1982.

Geyser Bight is a hot resource (210°C) on Umnak Island in the eastern Aleutians. Development would depend upon the viability of locating suitable industries in the area. Hot Springs Cove is a larger, cooler (155°C) resource on the same island. Exploration will begin soon on Unalaska, and island adjacent to Umnak. A high geothermal potential, along with strong interest on the part of the city council and the 13 seafood processing companies located there has prompted the request for exploration. Much work must be done before the geothermal potential (if there is any) can be tapped, but if the potential exists, the industry and population could support a moderate size geothermal development.

Exploration is also occurring at Pilgrim Springs, northeast of Nome. It will be used as a demonstration site. There is not enough populaton in the area for it to become a significant development area (Reference 26).

California

California is still in the planning stages as far as direct heat geothermal applications are concerned, and no comprehensive study of the resource utilization potential in the state was available. Many of the areas with geothermal resources suffer from the poor quality of the geothermal fluid. Often it is a brine or has excessive amounts of other dissolved solids such as boron. Another problem California has is lack of space heating requirements in areas with good geothermal resources. This is especially true in the Imperial Valley.

The Small Power Producers office in Sacramento does not believe that there will be any direct heat projects in California of significant size in the foreseeable future. Some of the possibilities for smaller projects include Susanville, Honey Lake, the Fort Bidwell Indian Reservation, Kelseyville, and Calestoga.

It appears that there may be a shallow resource in Kelseyville but the water could not be used directly for the agriculture of the area. The agricultural products in Kelseyville are all very sensitive to boron - which is highly concentrated in the geothermal fluid.

There may be a possibility of a well field at Calestoga if the proper permits can be obtained. The current user of the resource is reluctant to give up his monopoly on the use. A lot of politics are involved in this development.

The Small Power Producers office describes the current work at Susanville as a one-well project to heat 14 buildings in town with hopes of expanding it into an industrial park if industries can be attracted to the area. At the present time the well has not been drilled. They are looking for a driller to do it. The BLM has drilled a few exploratory wells. An addition there is a greenhouse operation 28 miles east of

Susanville with over 30 geothermally heated greenhouses. The 102°C geothermal water is pumped from a 630 foot well drilled in 1962. Plans called for a 95,000 square foot earthen floor greenhouse to be built.

It is conceivable that there would be significant applications in California in the next 20 years. Some possible areas include Mammoth Lake, the Geysers, and the Imperial Valley. The USGS estimates that the Casa Diablo Geothermal field near Mammoth Lake is large enough to handle space heating and snow melting in the area for 200 years (Reference 28).

Utah

The potential for direct heat geothermal application in Utah appears to lie in small projects with limited requirements for wells. Many of the direct use resources explored recently in Utah have not developed into the high temperature or high flow resources that were anticipated. The dissapointing results have occurred in areas with large populations and industrial centers. These areas would have a large potential for geothermal commercialization, but the resources do not appear to be capable of supporting a large development. Table 12 gives estimates of the geothermal energy potential in Salt Lake County. Current projects in Salt Lake County include space heating the prison and the Utah Roses greenhouses.

There has been some thought given to utilizing heat pumps which may greatly increase the resource potential.

The fact that Utah's energy costs from conventional fuels are among the lowest in the nation has an adverse impact on geothermal direct heat development.

Table 12

Estimated Hydrothermal Energy - Salt Lake County

Hot Springs	Max. Temp. (°C)	Estimated Beneficial Use (μQ/year)
Wasatch	40°C	5 - 16
Beck's	55°C	7 - 10
Crystal	86°C	7 - 10
Hobo	37°C	---

Assumed ΔT = 15°F; beneficial use factor = 0.24. The estimates are derived from existing flow rates, we assume. Wells might increase the total beneficial use.

New Mexico

Results from studies on the geothermal potential in the state of New Mexico indicate that significant potential exists, especially in the Rio Grande Rift area. It has been estimated that there are 4 Quads of energy in the 49 known hydrothermal systems in the state. Table 13 indicates areas with geothermal potential. The major developments will probably take place in the south central part of the state. In particular, the Las Alturas area could undergo significant development because of its location near Las Cruces and the NMSU campus. Radium Springs, also near Las Cruces, may become a significant industrial application area.

The Lightning Dock KGRA seems to possess a large resource of sufficient temperature to support a plant processing agricultural products.

The Albuquerque area is a large market with possibly large, but unproven, geothermal resources.

Table 13 contains other resources which could conceivably achieve significant growth.

Other States

Several other states have some potential to contribute to geothermal direct heat utilization to a significant degree before the end of the century. These include Hawaii, Texas, Wyoming, North Dakota, South Dakota, Arkansas, New Hampshire, and Maryland.

Large areas of the Dakotas are underlain by warm water artesian aquifers such as the Madison formation. Wyoming presents a paradox. No significant growth of geothermal use is expected, and yet the state possesses 90 percent of the present use of geothermal direct heat (for enhanced oil recovery) and also possesses one of the largest and highest quality known geothermal resources (at Yellowstone). There are recent indications that the Concord-Manchester-Nashua urban industrial region of New Hampshire may be underlain by low temperature geothermal resources of commercial size.

Table 13

Geothermal Direct Heat Growth in New Mexico

Best Chance for Significant Growth[1]	Other Areas Which Could Achieve Significant Growth[2]
Lightning Dock	Socorro
Radium Springs	Truth or Consequences
Las Alturas	Kilborne Hole
Albuquerque Area	San Ysidro
	Valle Grande Area
	Ojo Caliente
	Gila Hot Springs
	Faywood Hot Springs
	Cliff Area

[1]Based upon proximity to large urban, industrial, or agricultural markets, and known or probable geothermal resources.

[2]Based upon known geothermal resources but uncertain economics and markets.

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