EXPLORATION DEVELOPMENT AND UTILIZATION OF GEOTHERMAL RESOURCES

PREPARED FOR

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I. RESOURCE DESCRIPTION

A. Introduction

Geothermal energy is the natural heat of the earth. Man has attempted to utilize this energy through exploitation of five resource types: Magma, Hot Dry Rock (HDR), Convective Hydrothermal, Geopressured, and Radiogenic. Of these resource types only the convective hydrothermal resource has been successfully applied to electrical power production and direct heat applications, and thus this position paper will concentrate on these systems.

It has become common practice to apply a temperature classification to hydrothermal resources. High-temperature systems are those with base temperatures above 150°C, while systems of 90°-150°C are classed as intermediate temperature, and systems of less than 90°C are characterized as low-temperature (White and Williams, 1975).

It has also become common practice to classify systems as vapor-dominated vs. liquid-dominated following the characterization of White et al. (1971). The specific characteristics of these systems will be discussed in detail in subsequent sections. Briefly, a water-dominated geothermal system uses water as the heat transporting medium and is generally manifested at the surface by siliceous or carbonate hot-spring deposits. A vapor-dominated system uses water vapor as the heat transporting medium, and is formed in areas where discharge exceeds recharge of a water-dominated system so that vapor-dominated zones form through the boiling and lowering of the water table.

B. Liquid-Dominated Hydrothermal Systems

Liquid-dominated hydrothermal systems use natural liquids as their heat transporting medium. Numerous conceptual models for liquid-dominated hyrothermal systems can be cited; however, all involve permeable fluid pathways through rocks, a heat source, and fluids. The models presented for hydrothermal systems are quite similar to those developed for the formation of hydrothermal ore deposits, and insight into the processes active at depth can only be inferred from the examination of exhumed hydrothermal ore deposits.

1. Fluid Pathways

The fluid pathways of geothermal systems are used to bring fluids into an area in the crust where they can be warmed by the heat source, form a reservoir in which the fluids may reside, or convey warmed fluids toward the surface to emerge as hot spring systems. Liquid-dominated systems are characteristic of rocks which are intrinsically permeable or mechanically competant enough that they can fracture and maintain open spaces (White et al., 1971). As fluids descend along these pathways and begin to heat, they alter the rocks through which they pass. Alteration often decreases the permeability of these rocks and tectonic fracturing is required to keep these pathways open. In the Cerro Prieto system in Mexico, Lyons and van de Kamp (1980) have noted that interaction between the sediments and the hydrothermal fluids has resulted in the dissolution of some of the detrital minerals and the enhancement of permeability by the solution process.

Hot fluids ascending along pathways will continue to alter the host rocks. However, the most rapid changes in permeability will be developed where the decrease in temperature is most rapid. In these areas, the precipitation of solids, largely silica, may rapidly decrease the permeability of the fluid pathway. Also during the ascent of heated fluids, the temperature of the pathways will be elevated.

Figure I-1 shows a model for a fault-controlled system such as would be common in the Basin and Range province of the U.S. Here fluids both descend and ascend along the same or interconnected faults. Measured temperatures along this structural zone will be lower than normal along zones of descending fluids and elevated where fluids are ascending. In addition, fault zones are often found to be impermeable and will thus show temperature gradients which are a function of heat conduction.

Hydrothermal systems are often related to deep circulation of fluids in sedimentary basins. Here the fluids are guided principally by permeable lithologies within the stratigraphic horizons. Examples of this type of system are the Paris Basin and other sedimentary basins in eastern Europe which have been exploited for fluids for direct heat applications for some time (Ottlik et al., 1981). In many instances it is evident that there is both stratigraphic and structural control of fluid pathways (Mase et al., 1978; Bedinger et al., 1979; and Hobba et al., 1979).

White et al. (1971) have indicated that a typical liquid-dominated system will discharge at rates of 10^2-10^3 liters/min. When

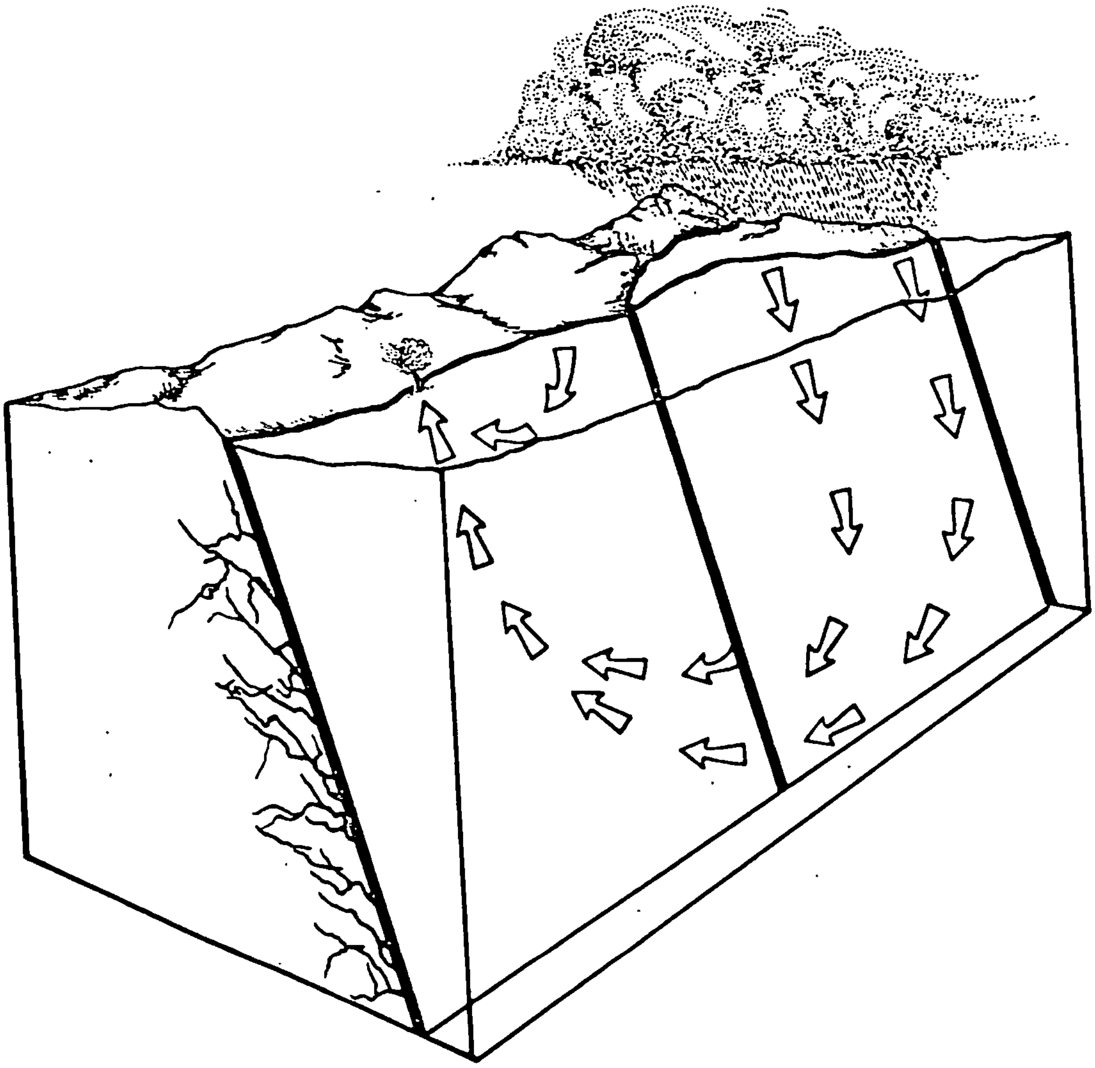


Figure I-1. Conceptual model of a fault controlled hydrothermal system.

the near-surface rocks are permeable and the water table low, such as in the Basin and Range province, much of this water may dischrge into these near-surface rocks and never reach the surface. White (1968) indicates that about 95% of the total discharge of the Steamboat Springs, Nevada thermal system may escape into the alluvial aquifers.

2. Heat Sources

The heat sources for hydrothermal convective systems are either magmatic sources or the thermal gradient of the earth. Smith and Shaw (1975) have reviewed the data from systems which are thought to derive their heat from igneous systems. Although these authors have proposed some theories that they admit are based on speculative data, the theories have held up quite well over the years since their paper was written. They have concluded that geothermal systems associated with felsic igneous systems which are younger than one million years have a high potential for being high temperature. This is because the granitic plutons that provide heat for these systems are able to reside within the upper 10 km of the crust. Evidence indicates that the more mafic magmas undergo rapid transport from their area of generation and are more likely to be erupted at the surface as flows rather than forming high-level plutonic bodies. Thus one exploration criteria for high-temperature geothermal systems is the association with volcanics of less than one million years. Examples of such systems are the calderas at Yellowstone, Valles, and Long Valley as well as Coso, California, Roosevelt Hot Springs, Utah, and Steamboat, Nevada. The andesitic systems of the Cascades province deserve special consideration because, even though exploration is just beginning, it is evident that high level plutons can exist, and with the possible exception of Meager Mountain system in British Columbia, there have been no discoveries in the province. However, a number of companies are involved in initial exploration programs. In addition, young mafic provinces are of high potential if they show evidences of differentiation to felsic end members. Examples of this would be the Imperial Valley which is thought to be located above a segment of the East Pacific Rise which has been overridden by the continent (Elders, 1979; Robinson et al., 1976).

Hydrothermal fluids are also warmed by the natural geothermal gradient of the earth. Gradients in much of the U.S. are in the range of 10°-30°C/km. However, average gradients in the Basin and Range and Cascade provinces are more like 45°-60°C/km. One of the more commonly used geothermal exploration tools is the measurement of thermal gradients in drill holes in order to calculate heat flow and identify areas of anomalous temperatures for further exploration. These methods will be discussed in more detail in a subsequent section.

Most explored hydrothermal systems have been found to reach a 'base temperature' which is characteristic of the system. This is a maximum temperature reached in drilling of the system, and temperatures do not increase above this level as greater depths are explored. The fluids have thus achieved this maximum temperature at depth and have then flowed toward the surface with little subsequent heat loss. The base temperatures in both Wairakei, New Zealand and Roosevelt Hot Springs system are approximately 260°C.

3. Fluid Chemistry

There is very strong evidence, based on stable isotope analysis, that the fluids which form hydrothermal convection systems are largely meteoric in origin (Craig, 1963). This interpretation is largely based on a characteristic positive δO^{18} shift of geothermal fluids from meteoric fluids in the vicinity of the system (Figure I-2). This shift is due to the interaction of the fluids with the heavier δO^{18} of the host rocks. Since rocks contain negligible hydrogen, there is little change in δD. Reviews of this topic may be found in Taylor (1974) and Ellis and Mahon (1977). The δO^{18} and δD values of magmatic fluids are also shown on Figure I-2, and it can be seen that for some systems the fluid may contain some component of magmatic water, but this is generally not thought to be large. The recharge system is often not considered in a geothermal exploration program but is of obvious importance in the evaluation of the longevity of the system. One concern of the developers of the Roosevelt Hot Springs geothermal system in Utah is whether the system will be viable for a desired 30-year life as a hot water system, or whether the depletion of the resource will result in a change to a vapor-dominated system or eventual depletion.

Isotopes have also been used to attempt to quantify the age of geothermal systems. The most successful has been tritium (^3H) which has a half life of 12.26 years. Minor amounts of tritium are produced by cosmic radiation in the stratosphere. However, major amounts have been put into the atmosphere by tests of thermonuclear weapons. Tritium concentration is expressed in terms of the Tritium Unit (T.U.) which is equivalent to T/H of 1×10^{-18}. In continental climates in

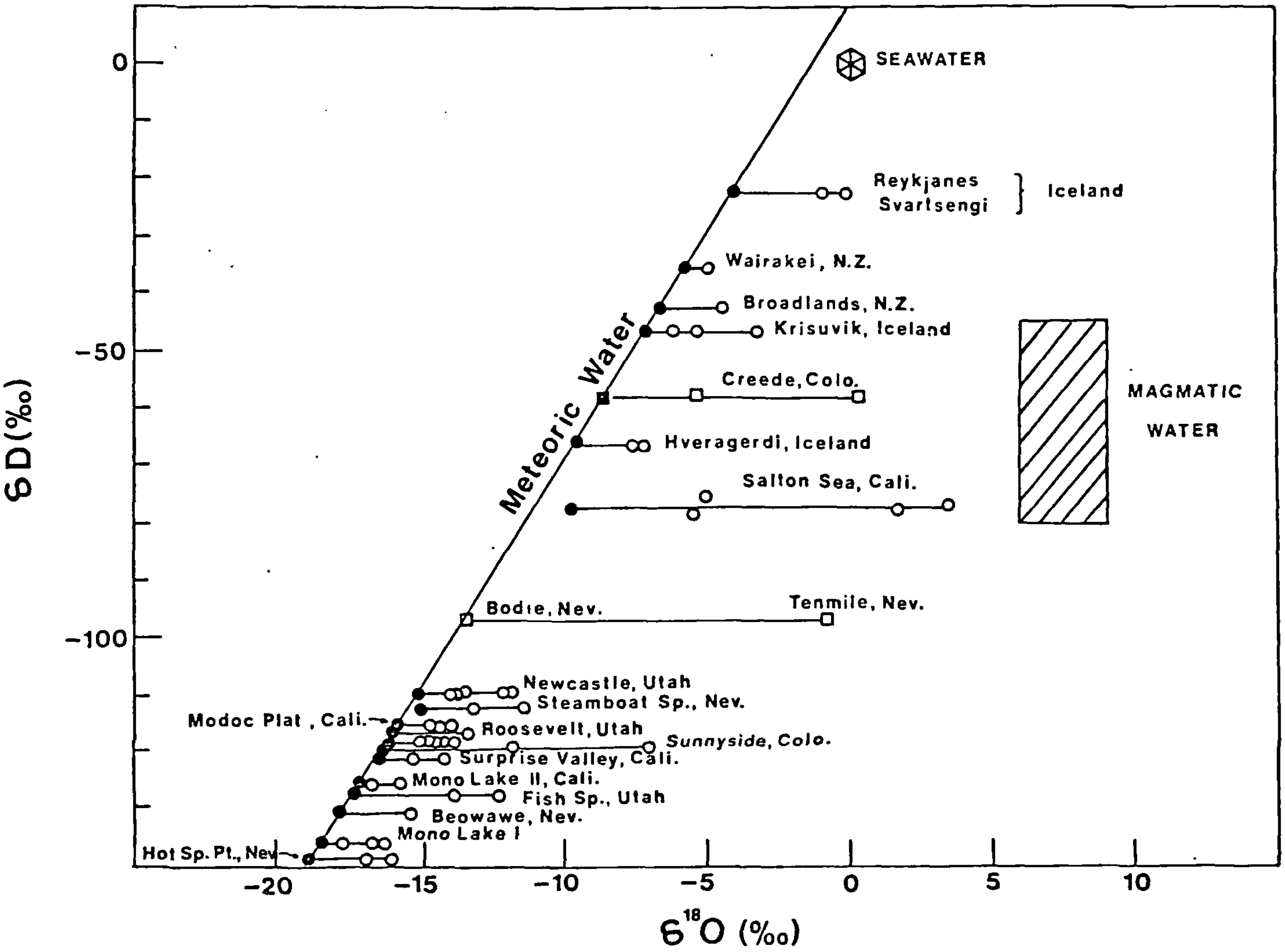


Figure I-2. Oxygen and deuterium isotopes for selected hydrothermal systems (Cole, 1980).

the temperate zone cosmic radiation produces about 10 T.U. Up to 10,000 T.U. were measured in 1963 following extensive atmospheric testing of nuclear weapons. This decreased until about 1968, and since then has remained fairly constant. Panichi and Gonfiantini (1978) have made the following generalizations concerning the age of water in the absence of mixing. A T.U. of less than 3 indicates that no water younger than 25 years is present. Values of 3 to 20 T.U. suggest that a small amount of thermonuclear tritium is present, which suggests that the fluids entered the ground water environment in the 1954-1961 time frame. If greater than 20 T.U. are found, the water is younger than 1963. More complex quantitative models for evaluating Tritium data are available (Przewlocki and Yurtsever, 1974).

The deep reservoir fluids of the explored high-temperature liquid-dominated systems are sodium chloride brines which vary greatly in composition from field to field (Table I-1). These solutions may be as dilute as potable water or can be as concentrated as the 25 weight percent solutions characterizing some of the systems in the Imperial Valley. Systems with such extreme salinities are, however, rare. Most systems currently under evaluation in the Basin and Range contain less than 10,000 ppm total dissolved solids.

Bicarbonate-rich waters are commonly found in low-temperature geothermal systems and in secondary reservoirs in the shallow portions and margins of high-temperature fields. The relationship between a sodium chloride- and bicarbonate-rich water in a high-temperature thermal system is well illustrated by their occurrence in the Indonesian field at Kawah Kamojang. These relationships were

Table I-1 Representative Analyses of Geothermal Fluids.

Sample #	1	2	3	4	5	6	7	8	9	10	11	12
Temp °C	42	47	44.5	60		89	98		255	>260	292	316
pH		7.1	7.3	3.4	7.9	7.9	9		8.4			
SiO_2 (ppm)	52	11.3	157.3	136	289	293	320	400	690	563	705	400
Ca (ppm)	257	88.2	117.9	11.5	2.6	5.0	1	10	17	8	592	28,000
Mg (ppm)	17	28.8	106	4.9	1.3	.8	<.1	37	.03	<2	.6	54
Na (ppm)	578	11.3	228.9	5.7	247	653	230	117	1,320	2,320	6,382	50,400
K (ppm)		5.4	39.2	3.6	12.9	71	16	86	225	461	1,551	17,500
Li (ppm)	.5					.7	1.3		14.2	25.3	14.5	215
HCO_3 (ppm)		39.7	391		377	305	321	12.0		232	28	7,150
SO_4 (ppm)	932	57.3	748	126	340		130	414	36	72	<3.5	5
Cl (ppm)	625	7.4	110	7.4	9.6	865	69	10	2,260	3,860	11,918	155,000
F (ppm)	2.8	.25	.59	.5	.8	1.8	17	8	8.3	6.8		15
B (ppm)	2.6					49	2.1	24.1			13.4	390
As (ppm)						2.7			4.8	4.3		12

Sample Descriptions:

1. Hot spring, Monroe Hot Springs, Utah (Mundorff, 1979). Actively depositing travertine.
2. Hot spring, Yunotani geothermal field, Japan (Parmentier and Hayashi, 1981).
3. Hot spring, Yunotani geothermal field, Japan (Parmentier and Hayashi, 1981).
4. Acid sulfate water, Yunotani geothermal field, Japan (Parmentier and Hayashi, 1981).
5. Water discharged from well,Yunotani geothermal field, Japan (Parmentier and Hayashi, 1981).
6. Hot spring, Steamboat Hot Springs, Nevada (White et al. 1971).
7. Hot spring, Beowawe, Nevada (Mariner et al. 1974).
8. Water discharged from well, The Geysers steam field (Frye; in Geothermal Resources Council Technical Session 5, 1980).
9. Well 44, Wairakei, New Zealand (Ellis and Mahon, 1977); pH measured at 20°C.
10. Brine discharged from well 54-3, Roosevelt Hot Springs, Utah (Capuano and Cole, 1981).
11. Analyses calculated from flashed brine, well M-26, Cerro Prieto (Fournier, 1981).
12. Brine discharged from well IID. #1 (Palmer, T.D., 1975) Salton Sea Geothermal Field.

documented by Mahon et al. (1980).

The Kawah Kamojang geothermal field is located in an andesitic volcanic complex. Here, wells drilled to depths of 1500 m encountered sodium bicarbonate/sulfate water in the upper parts of the thermal system and sodium chloride water at depths below about 900 m. Downhole samples and detailed lithologic logs indicate that the two fluid types form distinct reservoirs separated by a zone of intense silicification. Temperatures in the upper secondary reservoir are near 240°C.

The origin of bicarbonate-rich fluids found in the secondary reservoirs of high-temperature systems was discussed by Mahon et al. (1980 a,b). They concluded that the bicarbonate-rich fluids form by gas and steam heating of meteoric water. The final composition of the fluids is determined by the composition and volume of the gases and ground-water and the extent of water-rock interactions that occur.

4. Mineral Relationships

One important characteristic of liquid-dominated hydrothermal systems is their ability to precipitate solids. This is commonly seen at the surface as deposits of sinter which may be either carbonate (travertine) or siliceous. It is also important at depth where the precipitation of solids from solution decreases the permeability of fluid pathways. This process is commonly referred to as 'self sealing', and many workers conceptualize liquid-dominated systems as possessing a 'sealing cap' or 'self-sealed zone' (Facca and Tonani, 1967; Elders and Bird, 1976). Although the concept is a popular one, detailed examination of many hydrothermal systems fails to document

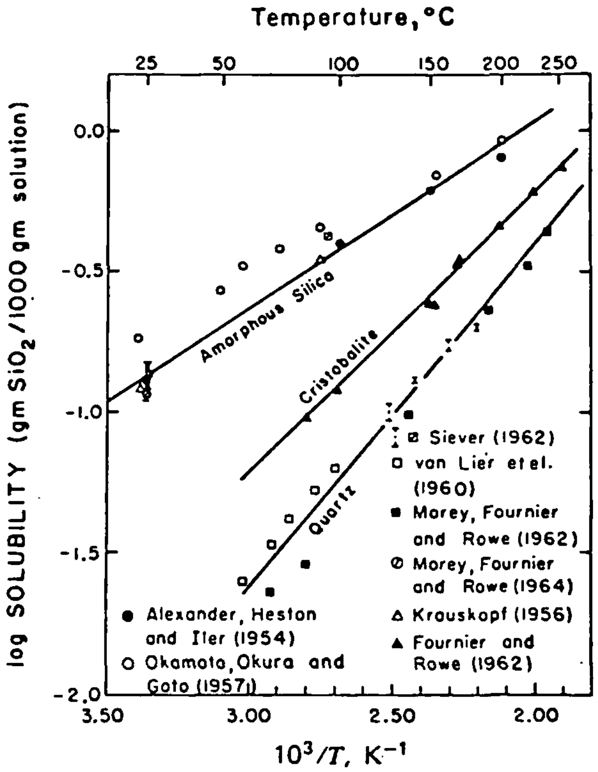


Figure I-3. Solubility of SiO_2 species in water as a function of temperature (Holland and Malinin, 1979).

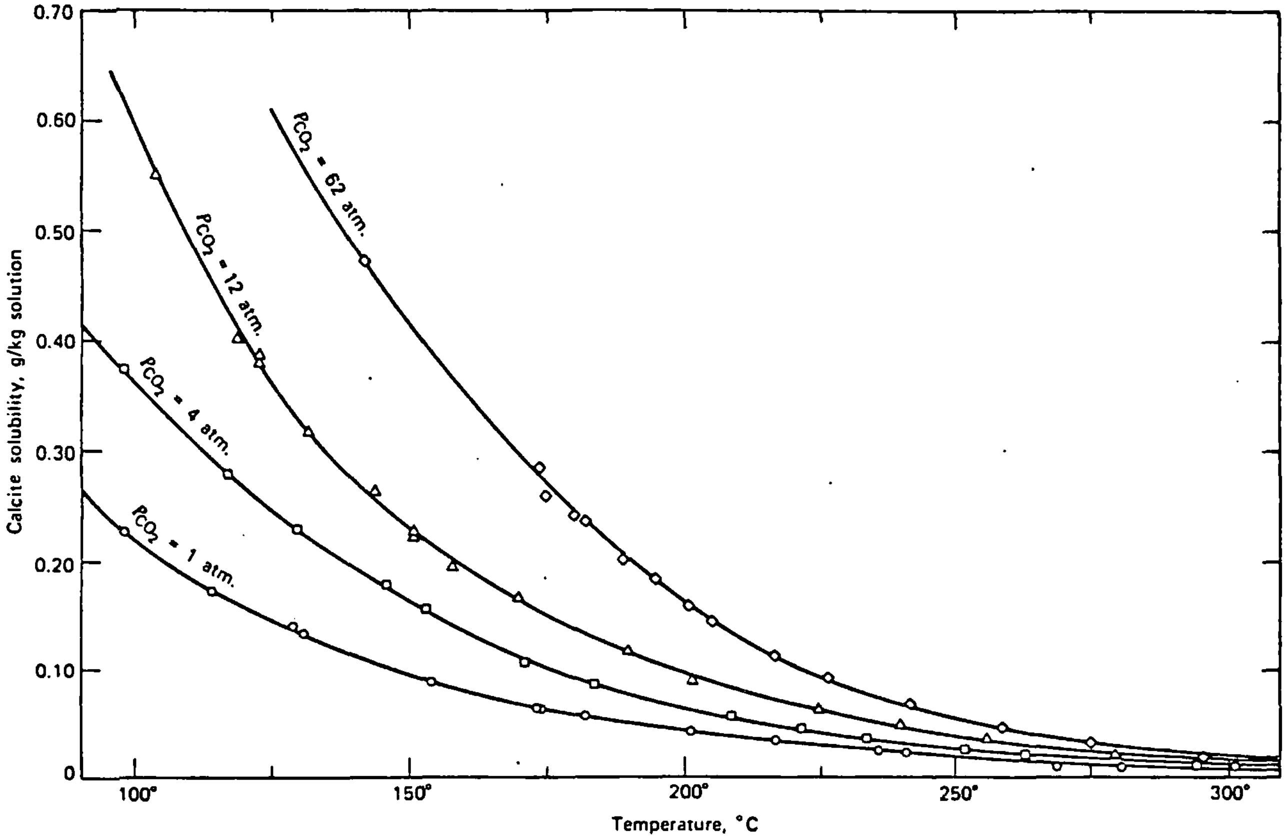


Figure I-4. Solubility of calcite in water as a funtion of temperature and P_{CO_2} (Holland and Malinin, 1979).

the systematics. This is particularly true in structurally controlled systems where fluid pathways along structures are separated by areas of impermeable rock not affected by the thermal solutions. However, within these systems self-sealing does occur along fractures, largely in locations where temperature decrease is most rapid.

In the self-sealing process, as well as the precipitation of sinters on the surface, silica and calcium carbonate are the principal phases involved. Figure I-3 shows the solubility of SiO_2 species in water as a function of temperature. The solubility of SiO_2 increases with an increase in temperature. Pressure has very little effect on this solubility relationship. Figure I-4 is a solubility diagram for calcite in water as a function of temperature and P_{CO_2}. Calcite has a retrograde solubility, i.e., it is more soluble at low temperatures than at high temperatures. However, the solubility does increase rapidly with an increase in the partial pressure of carbon dioxide. Thus, as fluids which are saturated with calcium carbonate approach the surface, $CaCO_3$ is deposited as a result of the loss of CO_2 rather than from cooling. Other carbonate species such as witherite ($BaCO_3$) and dolomite ($MgCO_3$), as well as sulfates such as anhydrite ($CaSO_4$), show solubility relationships similar to those of calcite (Holland and Malinin, 1979).

Other factors may, however, also affect the deposition of carbonates and sulfate minerals, such as variations in pH, total pressure and partial pressure of oxygen. For example, subsurface boiling, accompanied by loss of CO_2, may cause the deposition of calcite, while the deposition of anhydrite may reflect the occurrence of locally oxidizing conditions produced when upwelling fluids contact aerated non-thermal groundwater (Browne, 1978; Giggenback, 1980). Boiling may also induce the deposition of potassium feldspar and quartz. Browne (1978) suggested that coarsly bladed calcite, accompanied by potassium feldspar and quartz in The New Zealand fields, probably formed as a result of subsurface boiling.

Hot spring waters which deposit siliceous sinters have been found to nearly always contain SiO_2 concentrations of at least 240 ppm. These concentrations of silica require subsurface temperatures of at least 180°C. Because of the high solubility of amorphous silica, these fluids then must cool to about 70°C to precipitate amorphous silica. These initial amorphous precipitates are very susceptible to weathering and their preservation is dependent on protection by subsequent deposits. Once the siliceous sinters have been deposited and protected, however, they undergo polymorphic transformations to more stable species. This transformation process generally follows the sequence:

opal → christobalite → chalcedony

The sequence is well documented at Yellowstone and at Roosevelt Hot Springs and may eventually be quantified in order to allow determination of the minimum age of hot spring deposits. The process does seem to require a minor amount of burial and elevated temperatures as well as time.

Geysers are a spectacular but relatively rare feature of high-temperature liquid-dominated systems. Extensive summaries of these features can be found in White (1967), Marler and White (1975), and Rinehart (1980). In short, geysers are a type of hot spring that is characterized by episodic discharges. The episodic nature is related to congestion within the near-surface plumbing system caused by precipitation of silica. Vapor builds up in constrictions within the plumbing, and the release of this vapor unloads the system, the decrease in pressure causes the liquid to flash to steam, and the eruption ensues. These eruptions may be quite violent, throwing large blocks from the throat of the system. This can destroy the constrictions which have produced the geysering behavior in the first place, and subsequent activity may be as a normal hot spring.

Since Fenner's (1936) studies of core taken from Yellowstone, detailed mineralogic investigations of geothermal systems have confirmed a close relationship between active thermal fields and other ore depositing and low grade metamorphic systems. Comprehensive reviews of these studies have been published by Browne (1978), Ellis (1979), Weissberg et al. (1979), and Ellis and Mahon (1967).

The hydrothermal mineral assemblages of active geothermal systems are dominated by clays or zeolites at relatively low temperatures, and by chlorite, illite, K-feldspar and epidote (or wairakite) at higher temperatures (Table I-2). Quartz, calcite, pyrite and anhydrite are frequently associated with these minerals, and appear to form readily at both high and low temperatures. The relationship between temperature and mineralogy has been particularly well documented in The Cerro Prieto geothermal system in Mexico by Elders and his co-workers (Elders et al., 1979, 1978 a, b; 1977; Hoagland and Elders, 1978). Production from Cerro Prieto comes from a liquid-dominated

Table I-2. Some hydrothermal minerals in selected geothermal fields [1]

	Imperial Valley, California[a]	Yellowstone, Wyoming	The Geysers, California	Pauzhetsk, Kamchatka	Matsukawa, Japan	Otake, Japan	Tongonan, Philippines	Kawah Kamojang, Java	N.Z. Volcanic Zone	El Tatio, Chile	Low temp Iceland	High temp. Iceland	Larderello, Italy
Allophane				x									
Quartz	x	x	x	x	x	x	x	x	x	x	r?	x	x
Cristobalite		x		x	x	x	x	x	x	x			
Kaolin group	d	x	x	x	x	x	x	x	x	x			
Montmorillonite	d	x		x	x	x	x	x	x	x	x	x	
Interlayered illite-mont.	x			x	x	x	x	x	x		x	x	
Illite	x	x	x	x	x	x	x	x	x	x			
Biotite	x			x					x				
Chlorite	x	x	x	x	x	x	x	x	x	x	?	x	x
Celadonite		x		x						x	x		
Alunite			x	x	x	x	x		x				
Anhydrite	x		x	x	x	x	x	x	x	x		x	x
Sulfur			x	x	x		x		x				
Pryophyllite					r	x	r	r					
Talc	x						x						
Diaspore					x	x		x					
Calcite	x	x	x	x	x	x	x	x	x	x	x	x	x
Aragonite	x[b]						x[b]		x[b]				
Siderite			x	x			x		x	x			
Ankerite	x			x								x	
Dolomite	d												
Analcime		x		x					x		x	x	
Wairakite	x		x	x		x	x	x	x			x	x
Gmelinite											x		
Gismondine											x		
Erionite		x											
Laumontite		x		x	x	x			x	x	x	x	
Phillipsite				x									
Scolecite				x							x		
Chabazite				x							x		
Thomsonite				x							x		
Clinoptilolite		x					x						
Heulandite		x		x		x	x		x		x	x	
Stilbite											x	x	
Mordenite		x		x					x		x	x	
Prehnite	x			x					x		r?	x	
Amphibole	x			x			x					x	
Garnet	x			?								r	
Epidote	x			x		x	x	x	x		r	x	x
Clinozoisite									x				
Pectolite		x							x[b]				
Sphene	x			x			x	x	x				
Adularia	x	x	x	x		x	x	x	x	x			x
Albite	x			x		x	x	x	x			x	
Rutile				x	x	x							
Leucoxene			x	x	x		x		x				
Magnetite							x						
Hematite	x	x		x			x	x	x	x	x		
Pyrite	x	x	x	x	x	x	x	x	x	x	x	x	x
Pyrrhotite	x						x		x				x
Marcasite							x		x				
Base-metal sulfides	x						x		x				x
Fluorite		x						x					

(1) From Browne, 1978

Note: d = detrital, r = relict.

[a] includes Cerro Prieto, Baja California, Mexico.

[b] deposited in discharge pipes and channels.

reservoir with temperatures ranging up to 388°C (Mercado, 1969). The reservoir fluid is a sodium chloride brine with about 17,000 ppm total dissolved solids. The reservoir rocks consist of sandstone, shales and siltstones of the Colorado River delta and contain detrital and authigenic feldspar, kaolinite, montmorillonite, illite, chlorite, mixed layer clays, calcite, dolomite and iron oxides. Hydrothermal activity has produced temperature-dependent mineral assemblages characterized by the successive appearance of clays, illite and chlorite, calcium aluminum silicates, and finally biotite.

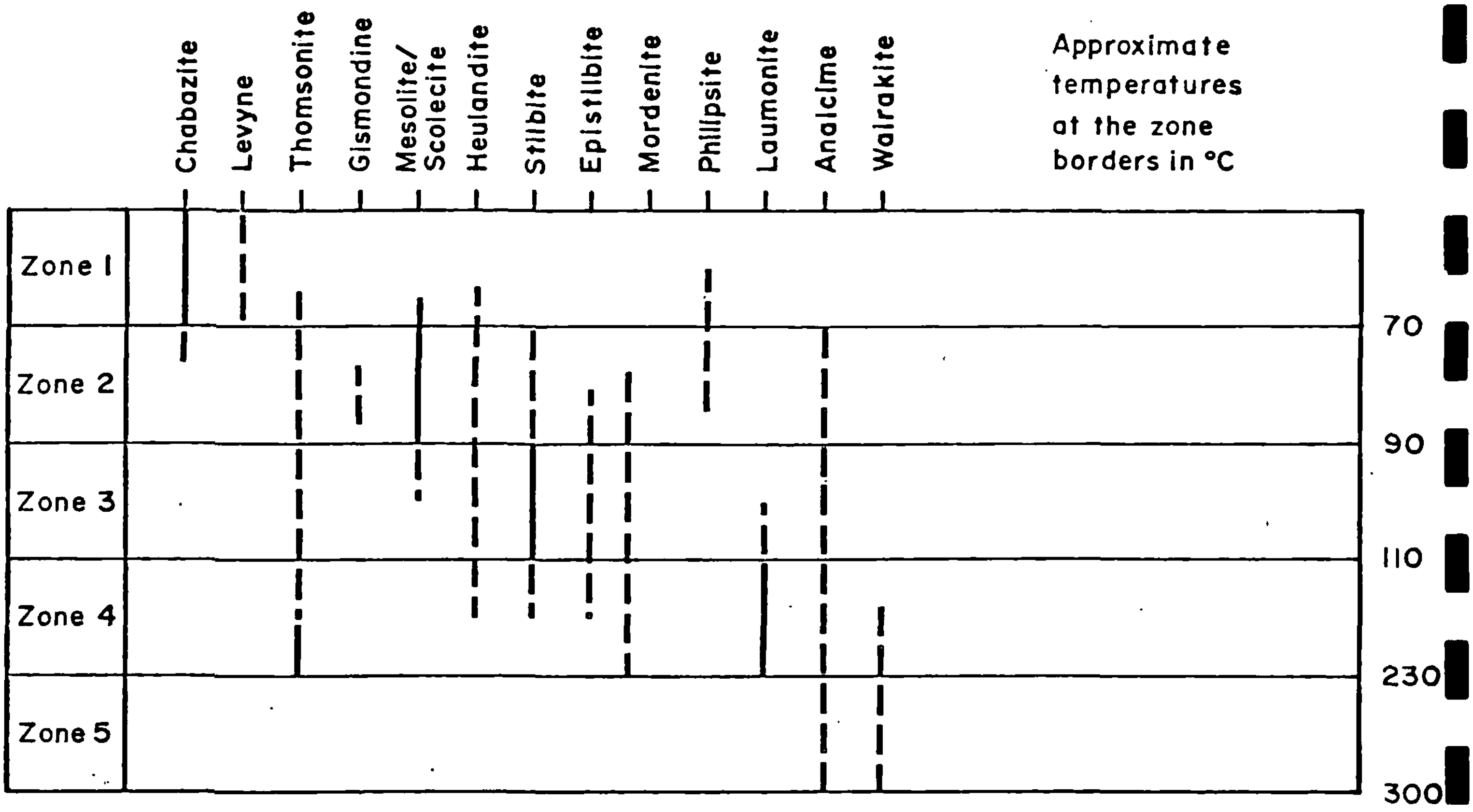
The hydrothermal minerals found in Imperial Valley systems are documented in Table I-2. As expected, the distributions of the clay and silicate minerals is strongly temperature-dependent. At the lowest temperatures below about 180°C, the stable assemblage consists of dolomite, kaolinite, montmorillonite and interlayered illite/montmorillonite. With increasing temperature and depth, montmorillonite, dolomite, kaolinite, and interlayered illite/montmorillonite disappear, and at temperatures above about 150°-180°C, the typical assemblage is illite + chlorite + potassium-feldspar + quartz. The calcium-aluminosilicates, wairakite and epidote appear only in rocks above 230-250°C. Prehnite, actinolite, diopside and biotite characterize the highest temperature assemblages associated with temperatures above about 300°C.

Mineral assemblages formed in Colorado River sediments at temperatures above 300°C are also found in the Salton Sea thermal field and have been described by Muffler and White (1969) and Kendall (1976). They show that, at temperatures above 300°C, the sediments of the Colorado River delta were converted to quartz, iron-epidote, chlorite, potassium-feldspar, and albite associated in places with potassium mica, pyrite, sphene, sphalerite and hematite. At temperatures above about 320°C, garnet, tremolite, high-temperature smectite and biotite characterize the altered rocks. Read (1976) suggested that the differences in the mineral assemblages between the Salton Sea and Cerro Prieto thermal fields result primarily from the much higher salinites at the Salton Sea (250,000 ppm compared to 17,000 ppm dissolved solids).

The distribution of the zeolite minerals is strongly influenced by temperature and rock type. For example, at low temperatures, high-silica zeolites (i.e., mordenite) form in rhyolitic rocks, whereas low silica zeolites (i.e., chabazite, thomsonite) occur in andesitic and basaltic rocks (Honda and Muffler, 1970; Browne and Ellis, 1970; Kristmannsdottir and Tomasson, 1978).

The temperature dependance on the distribution of zeolites is clearly illustrated by their occurrence in the Icelandic geothermal systems. These relationships are illustrated in Figure I-5. In general, the distribution of zeolites other than analcite and wairakite is restricted to temperatures below about 230°C although analcite and wairakite may persist up to temperatures near 300°C. Montmorillonite and mixed-layer clays are typically associated with the zeolites at temperatures up to 230°C. At higher temperatures chlorite, epidote and prehnite characterize the mineral assemblages. Quartz and calcite occur throughout the alteration sequence.

The relationships between wiarakite and epidote in the New



Zone 1 Chabazite zone

Zone 2 Mesolite/Scolecite zone

Zone 3 Stilbite zone

Zone 4 Laumontite zone

Zone 5 Zone with no zeolites
except scattered analcime
or wairakite

Figure I-5. Zeolite zones in Icelandic geothermal areas (from Kristmanndottir and Tomasson, 1978).

Zealand thermal systems were examined in detail by Browne and Ellis (1970). They showed that in the high-temperature alteration assemblages at Broadlands and Wairaki, the appearance of wairakite and epidote was limited by the carbon dioxide content of the fluid. At Broadlands high carbon dioxide contents favor the formation of calcite over wairakite and epidote, whereas at Wairaiki lower carbon dioxide contents result in the formation of wairakite and epidote.

Although the metal contents of many geothermal brines are significant, with the exception of pyrite and, in places, pyrrhotite, base metal sulfides are relatively uncommon at depth even in the deeper parts of the explored systems which deposit metal sulfides at the surface. The more commonly observed base metal sulfide minerals found at depth include sphalerite and galena, although chalcopyrite, arsenopyrite, nickel glaucodot, cobaltite and silver telluride also occur in rocks of the Broadlands field in New Zealand (Browne, 1969). In general the base metal sulfides in the Broadlands are present in rocks whose temperature range from 265°-300°C, whereas pyrrhotite is present above about 150°C (Browne and Ellis 1970; Weissberg et al., 1978). The distribution of pyrite is not sensitive to temperature.

The low-sulfide contents of the Salton Sea brines provide an explanation for the limited occurrence of base metal sulfides at depth. Here the metal-to-sulfide ratio is 10 or 15:1, and the equilibrium sulfide value of the fluids is only 15-30 ppm. The low-sulfide contents are further illustrated by the high metal-to-sulfur ratios of minerals deposited and seen in the drill core (Weissberg et al., 1978).

The interpretation of the mineral assemblages found in thermal systems in many parts of the western U.S. is complicated by the presence of minerals formed during earlier, frequently unrelated, hydrothermal events. The Roosevelt Hot Springs thermal system provides a situation where at least two distinct hydrothermal events can be recognized; an earlier event related to intrusion of the Tertiary Mineral Mountains pluton, and the present hydrothermal system (Nielson et al., 1978). Cross cutting veins, identified in drill chips suggest that the depositional histories of these events was complex. The reservoir rocks consist of Tertiary granitic rocks and Precambrian gneiss and schist containing potassium feldspar, quartz, plagioclase, biotite and hornblende. The hydrothermal minerals include clays, illite, chlorite, calcite, pyrite, quartz, hematite, epidote and anhydrite.

The extent to which the observed mineral assemblages are in equilibrium with the reservoir fluids can be tested by comparing the distribution of minerals predicted from thermodynamic data, with their distributions in the wells (Capuano and Cole, 1981; Browne and Ellis, 1970; Helgeson, 1969; Helgeson et al. 1969).

Figure I-6 illustrates the predicted distribution of alteration minerals at Roosevelt Hot Springs for reservoir temperatures of 150°, 200°, 250°, 300°C (Capuano and Cole, 1981). The reservoir fluid was calculated from analyses of brine, steam and non-condensable gases sampled at the well head. The thermodynamically predicted relationships are generally in close agreement with the

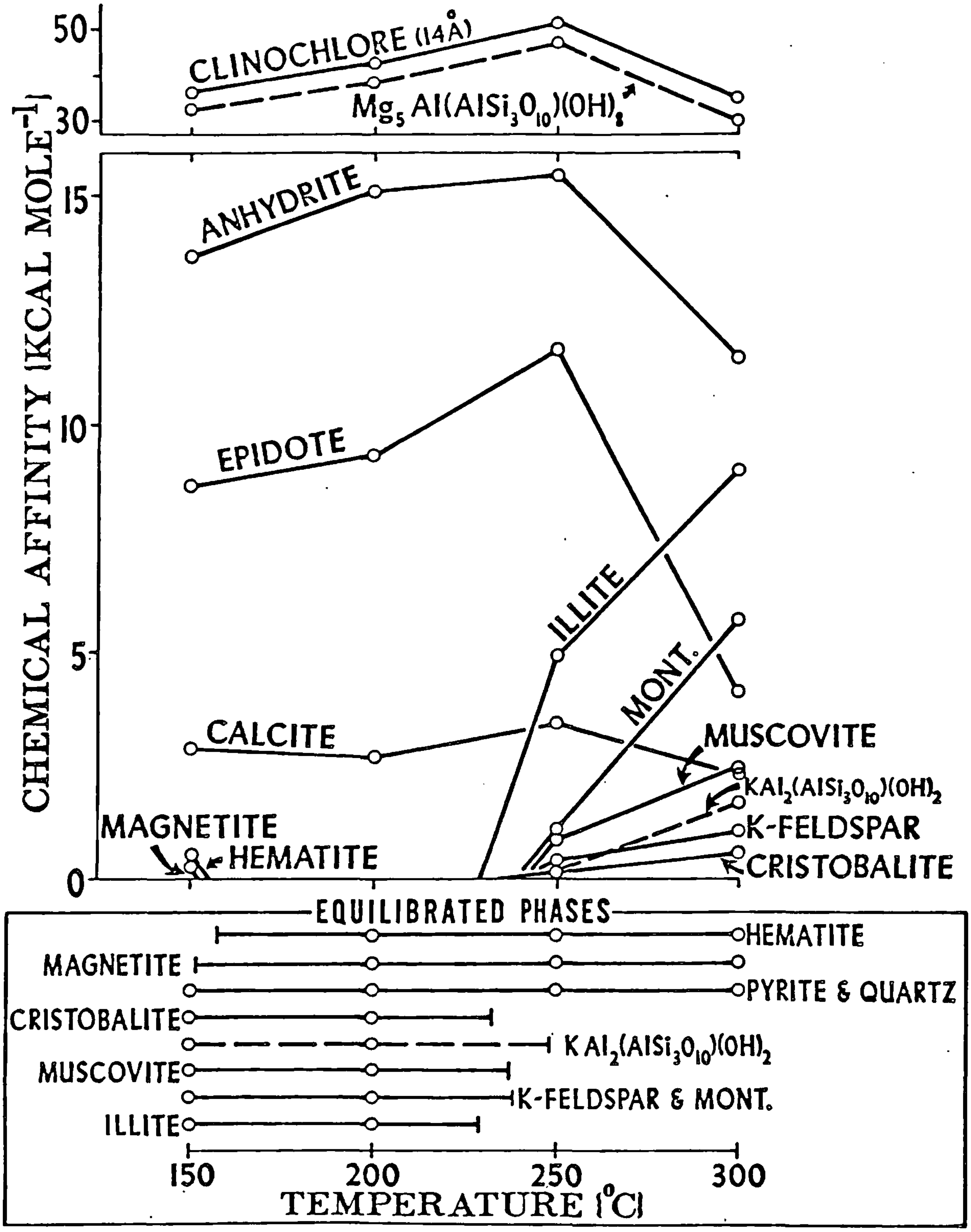


Figure I-6 Chemical affinity versus temperature diagram for the Roosevelt Hot springs reservoir fluid from 150° to 300°C taken from Capuano and Cole (1981). Chemical affinity indicates the equilibrium condition of the mineral in the fluid. A positive value, as represented on the upper portion of this figure, indicates the mineral is undersaturated with respect to the fluid. The chemical affinity is zero for mineral fluid equilibrium and below zero for supersaturation. Phases that satisfy these conditions are shown in the lower portion of the figure. The chemical affinities are calculated for the pure end-member except for the $KAl_2(AlSi_3O_{10})(OH)_2$ and $Mg_5Al(AlSi_3O_{10})(OH)_8$ components fo sericite and chlorite, respectively.

observed assemblages.

C. Vapor Dominated Systems

The term "vapor-dominated system" was applied by White et al. (1971) to geothermal systems which produce steam. The Geysers thermal field in the U.S. and Larderello in Italy are two of the most important and best studied of the vapor-dominated systems.

The characteristics of vapor-dominated systems have been summarized by White et al. (1971), Truesdell and White (1973), and Donaldson and Grant (1981). The important features of these systems are: 1) production of dry or superheated steam, 2) nearly uniform reservoir temperatures and pressures of 235°-240°C and 32-35 km/cm^3 respectively in reservoirs deeper than 350 m, and 3) surface manifestations consisting mainly of low-chloride acid springs, fumeroles, and mud pots.

Perhaps the most widely accepted model of vapor-dominated systems was proposed by White et al. (1971) and Truesdelll and White (1973). They suggested that vapor-dominated systems develop from liquid-dominated reservoirs when discharge through boiling exceeds recharge. These conditions are favored by low permeabilities in the rocks surrounding the reservoir and potent heat sources. Indeed, because pressures within the reservoir are below the corresponding hydrostatic pressures, low permeabilities on all sides of the reservoir are needed to prevent flooding by cold water.

According to this model, vapor-dominated systems consist of a steam-dominated reservoir surrounded by water-saturated rocks and underlain by a saline brine. Truesdell and White (1973) concluded from the pressure and temperature measurements which approximate those of saturated steam at its maximum enthalpy (236°C, 31.8 kg/km^3; James, 1968) that steam was the dominant phase in through-going fractures and the pressure controlling medium in the vapor-dominated zone. They suggested that liquid water is also present primarily in pore spaces and small crevices. Water saturated rocks must exist beneath the vapor-dominated region because pressures must eventually become lithostatic.

Steam can be supplied to the vapor-dominated reservoir from the water-saturated rocks on the margins of the system, from downward moving steam condensate, or from a boiling fluid beneath the reservoir. White et al. (1971) suggested that boiling of a deep-water saturated zone should result in a chloride fluid of increasing salinity. It is noteworthy that drilling at The Geysers to depths in excess of 3 km has not yet penetrated a deep chloride brine.

Liquid water has been encountered in some of the production wells within the vapor-dominated reservoir at The Geysers. Although the origin of these waters is not yet well understood, chemical analyses indicate that it is not simply condensed steam (Table I-1, analysis 8). The low-chloride and high-sodium and bicarbonate contents of the water suggest that it represents steam-heated meteoric waters contained within fractures of the reservoir.

The surface expressions of vapor-dominated reservoirs characteristically include chloride-poor acid sulfate springs with low discharges accompanied by sodium bicarbonate/sulfate springs, fumeroles, mudpots and acid altered ground (White et al., 1971). These features are formed by steam and other volatile gases such as hydrogen sulfide, ammonia, and carbon dioxide which discharge at the surface or condense in meteoric water. Non-volatile components such as chloride remain in the underlying boiling brine and are not enriched in the surface discharges. Chloride-rich springs typical of hot water systems are therefore conspicuously absent over the vapor-dominated portions of the reservoir but may occur on its margins in surrounding topographically low areas if the reservoir is relatively shallow.

The acid sulphate springs are typically a surficial feature produced by the oxidation of hydrogen sulfide to sulfuric acid. Altered ground surrounding the acid springs and fumeroles provides a striking example of reactivity of the waters. The altered areas are typically bleached and converted to a siliceous residue containing native sulfur, cinnabar, yellow sulfate minerals, and clay minerals including kaolinite and alunite. Similar acid alteration can, however, also be formed at depths where steam heating of groundwaters occurs. At Matsukawa, Japan, alunite, quartz and pyrite appear to have formed from 250°-280°C fluids with a pH near 3 (Sumi, 1969). Thus mineral assemblages in acid-altered rocks may occur at both high and low temperatures.

Hydrothermal mineral assemblages found in the vapor-dominated systems at The Geysers and Lardello are similar to those of other high-temperature liquid-dominated systems (Table I-2). For example at Lardello, potassium feldspar, epidote, chlorite, pyrite and minor calcite, quartz and sulfides occur in the deepest parts of the field and are generally compatible with measured temperatures locally in excess of 290°C (Cavarretta et al., 1980). Cavarretta et al. (1980) concluded that hydrothermal minerals were deposited in the sedimentary and metasedimentary reservoir rocks from a chloride brine during a hot-water stage that occurred prior to development of the present vapor-dominated reservoir.

Some geothermal systems have production characteristics of both vapor- and liquid-dominated systems. For example, Ngawha and Rotokava in New Zealand, and Matsukawa in Japan (Donaldson and Grant, 1981) produce dry steam but are characterized by hydrostatic rather than vapor-controlled pressures. Thus, they are actually liquid-dominated systems. These characteristics appear to be controlled by high temperatures and extremely low permeabilities ($<<10^{-15}$ m^2) which allow water adjacent to the well bores to boil and which prohibit significant recharge of the system. The production capabilites of these systems will be limited by the number of wells that can be drilled and discharged economically.

Geothermal systems characterized by features typical of vapor-dominated reservoirs are common in many parts of the Basin and Range but appear to have little potential for production of dry steam. These systems are characterized by surficial vapor caps which overlie a boiling and depressed water table. For example, the Cove Fort-Sulphurdale geothermal system in Utah is characterized by numerous fumeroles, acid-altered ground, and acid water (Moore and Samberg, 1978). Chloride-rich springs or hot spring deposits typical of liquid-dominated systems have not been found in this area. These thermal features reflect degassing and boiling of a deep hot water table, located at a depth of approximately 400 m. Deep drilling has confirmed the existence of a deep, chloride brine and the absence of significant vapor pockets above the water table.

D. Physical Properties of Fluids

As fluids pass through a hydrothermal system their physical properties change as a function of temperature, pressure, and chemical composition. The changes of the boiling point of water as a function of depth and weight percent NaCl are shown in Figure I-7. With increases in pressure, water boils at a high temperature. Also the boiling point is increased by an increase in the salt content of the fluid.

The convection process is generally thought of as being driven as a result of the decrease in density of a fluid with an increase in temperature. This relationship is demonstrated in Figure I-8. However, Straus and Schubert (1977) argue that between 25° and 300°C the viscosity of water changes by more than one order of magnitude (Figure I-9) and that the thermal expansion coefficient changes by almost two orders of magnitude. They conclude that all of these factors must be considered in the modeling of convection. The consideration of only density changes results to an overestimation of the minimum permeability necessary for convection.

Figure I-10 demonstrates how the resistivity of a geothermal fluid changes as a function of temperature and salinity. As will be discussed in a subsequent section, the mapping of electrical resistivity is a very powerful geothermal exploration tool.

E. Distribution of Hydrothermal Systems

1. Introduction

The three components required for the presence of a hydrothermal system are heat, water, and permeability. Geologic controls on these parameters determine the type and location of specific thermal

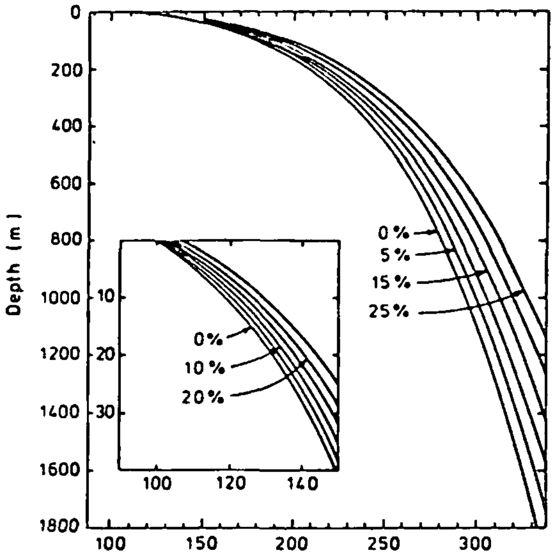


Figure I-7. Boiling point of water as a function of depth and weight percent NaCl (Haas, 1971).

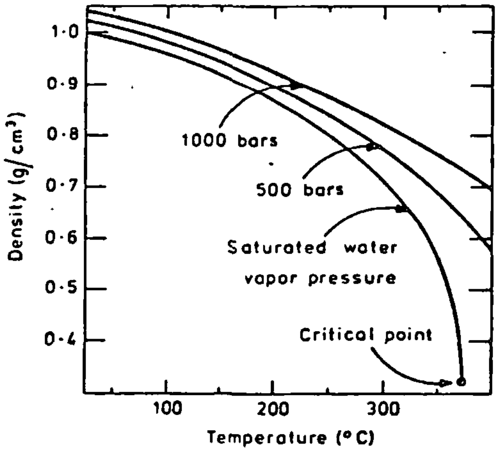


Figure I-8. Density of pure water as a function of temperature and pressure (Ellis and Mahon, 1977).

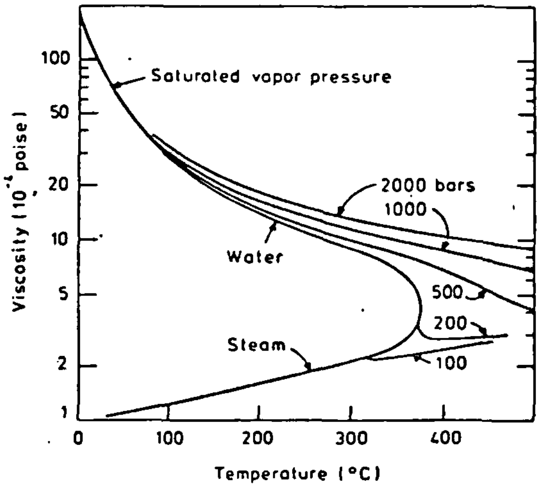


Figure I-9. Viscosity of water as a function of temperature and vapor pressure (Ellis and Mahon, 1977).

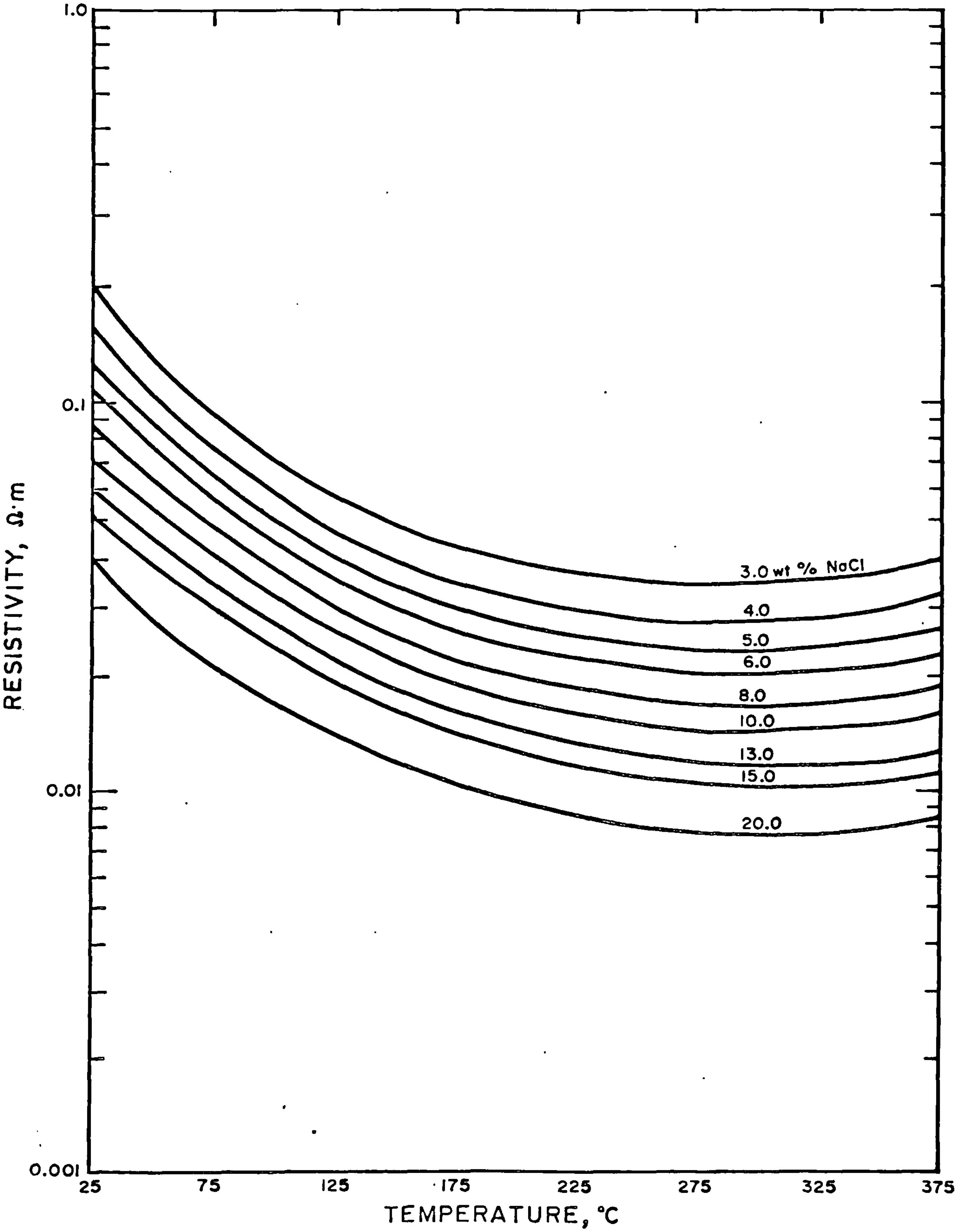


Figure I-10. Resistivity of NaCl solutions as a function of temperature.

systems. Although individual systems are controlled by local factors, broad provinces of favorable terrain may be defined on regional characteristics. No single set of geologic criteria is adequate to explain the locations of economically attractive hydrothermal resources; regional and local characteristics must be combined.

The heat in hydrothermal systems may come either from regional anomalies or local perturbations in the earth's thermal regime. The U. S. may be divided into two broad heat flow provinces: an eastern, cooler regime, where the average heat flow is approximately 44 mW/m^2, and a western, warmer regime, where the heat flow is approximately 80 mW/m^2 (Simmons and Roy, 1969). Heat flow is defined as:

$$Q = k \cdot \frac{\Delta T}{\Delta T}$$

where k is the thermal conductivity of rocks being investigated and $\frac{\Delta T}{\Delta z}$ is the thermal gradient measured at a site. Heat flow is further discussed in the section of this paper on geophysical exploration. The important point here is that the temperature measured at a site is dependent on both the flux of heat from the mantle and crust into that site, and the thermal conductivity of the rocks present. The potential for economically attractive hydrothermal resources in the eastern U. S. is limited by its low heat flow; it will not be discussed further.

Although the western heat flow is regionally higher than eastern, specific provinces contain even greater anomalies such as the Basin and Range, the Rio Grande Rift, and the Oregon Cascades. Local perturbations, such as magmatic activity or sites of convective circulation of water, in these provinces of higher heat flow are the most favorable hydrothermal sites. Figure I-11 is a heat flow map of the western U. S. The areas within the 100 mW/m^2 contour form the most attractive regional anomalies. Some electric grade hydrothermal resources, however, such as Roosevelt Hot Springs in Utah, fall outside of these contours.

Areas of young igneous activity, because of their great potential for residual heat from intrusions, form the most attractive thermal targets. Volume, composition, emplacement history, and age of the intrusions determine the amount of residual heat in any specific system. In general, silicic systems less than one million years old, and basic systems less than 10,000 years old, form the favorable targets. These areas are shown on Figure 1-12.

Faulted terrains, particularly in regions of high heat flow, or young igneous activity form the most attractive exploration targets for hydrothermal systems. The distribution of thermal springs in the U. S. confirms this; most are found in the mountainous, faulted areas of the west. The distribution of thermal wells, with the exception of those producing from stratigraphic aquifers of the Great Plains, also follows a similar pattern.

Figure I-13 is an interpretative map of the potential for hydrothermal systems in the western U. S. Prime and secondary areas, extended reservoirs, and areas with limited potential are depicted on the map. Volcanic terrains of the margins of the Basin and Range, the Imperial Valley, the Cascades, Northern California Coast Ranges, the Rio Grande Rift, and the Snake River Plain, and Basin and Range extensional environments, form the prime areas. Margins of these

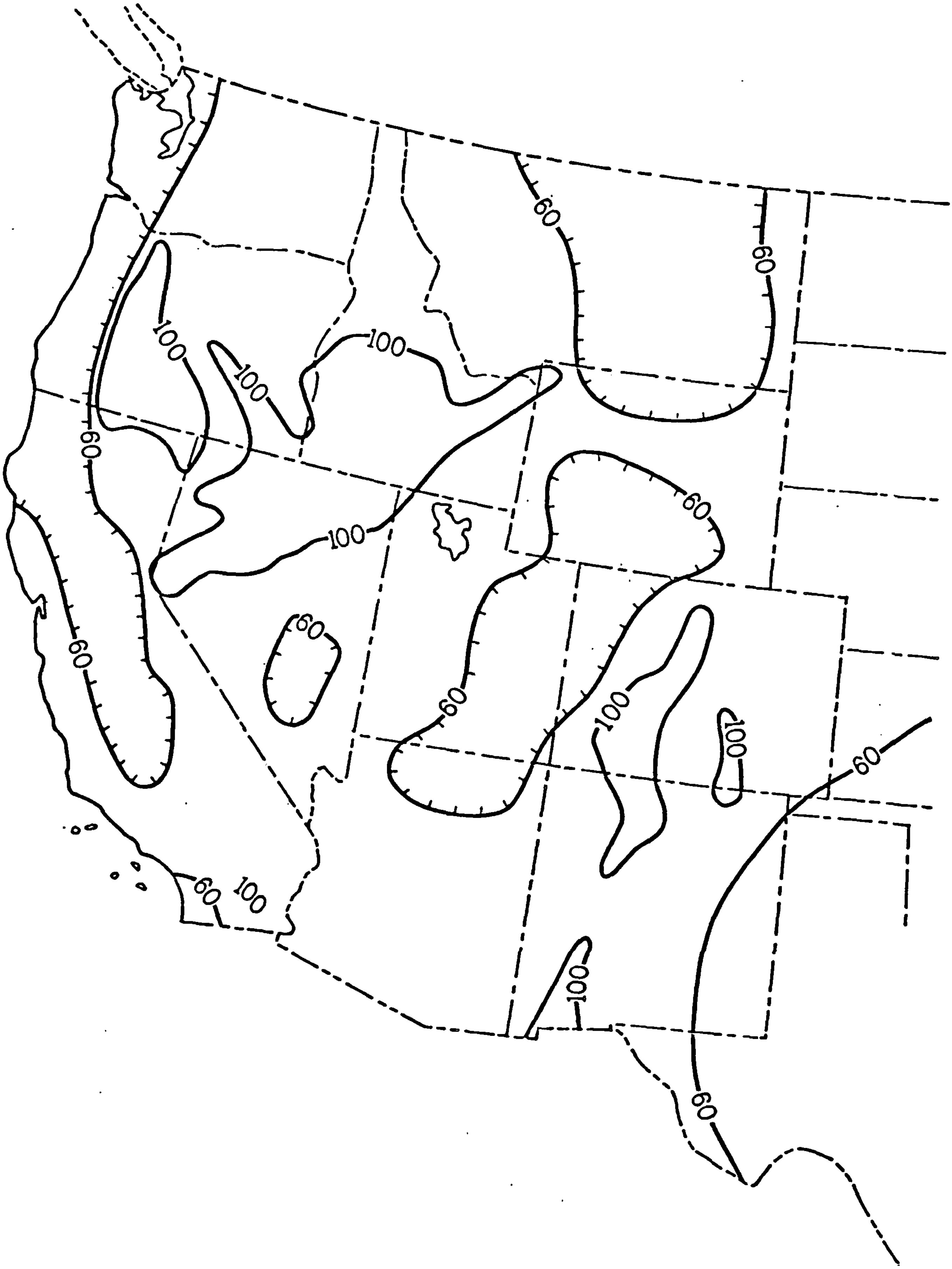


Figure I-11. Heat flow map of western United States. Contours based on Sass and Lachenbruch, 1979; Blackwell and others, 1980; Zacharakis, 1981. Contours in milliwatts per square meter mW/m^2.

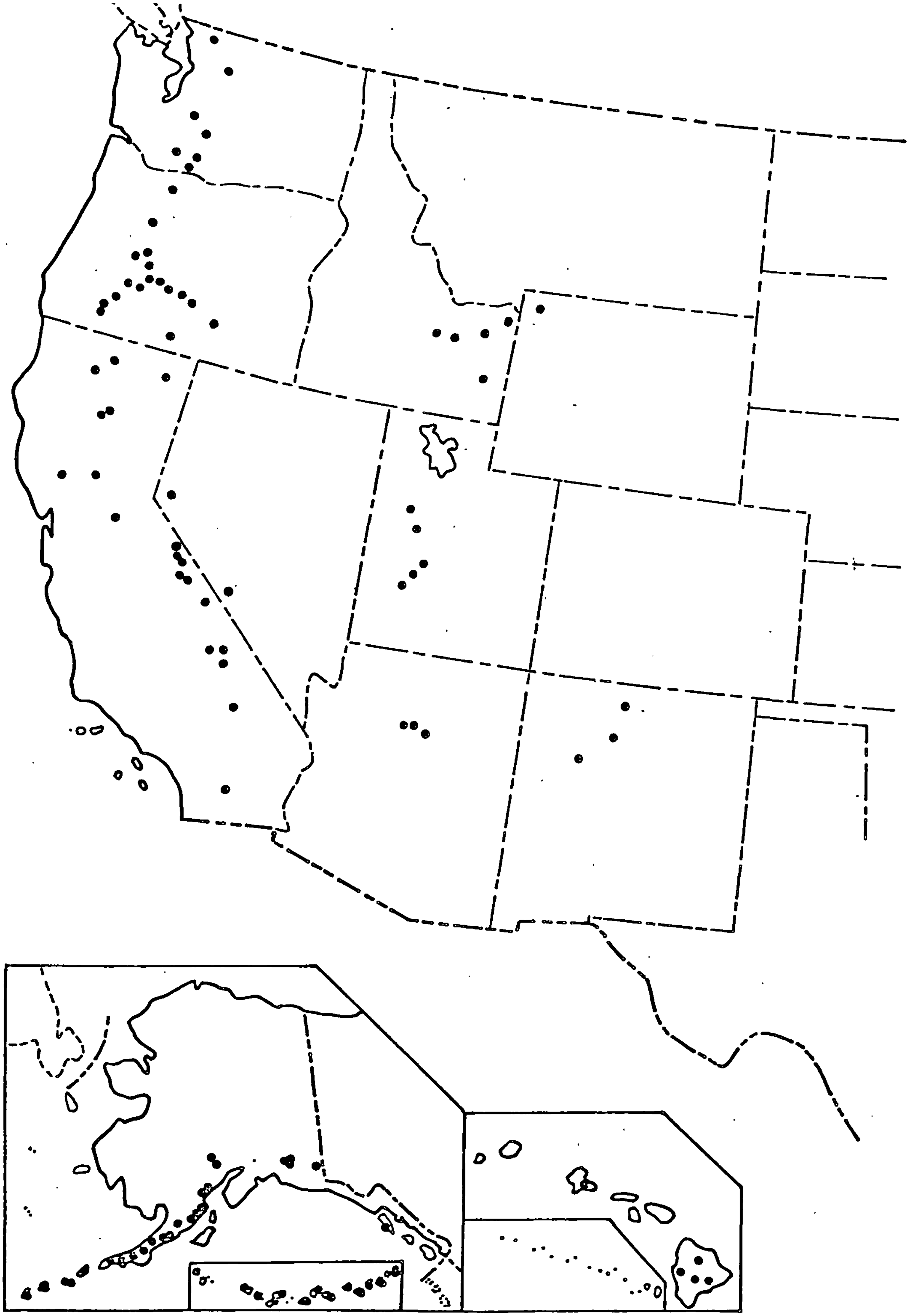


Figure I-12. Igneous systems of the western United States.

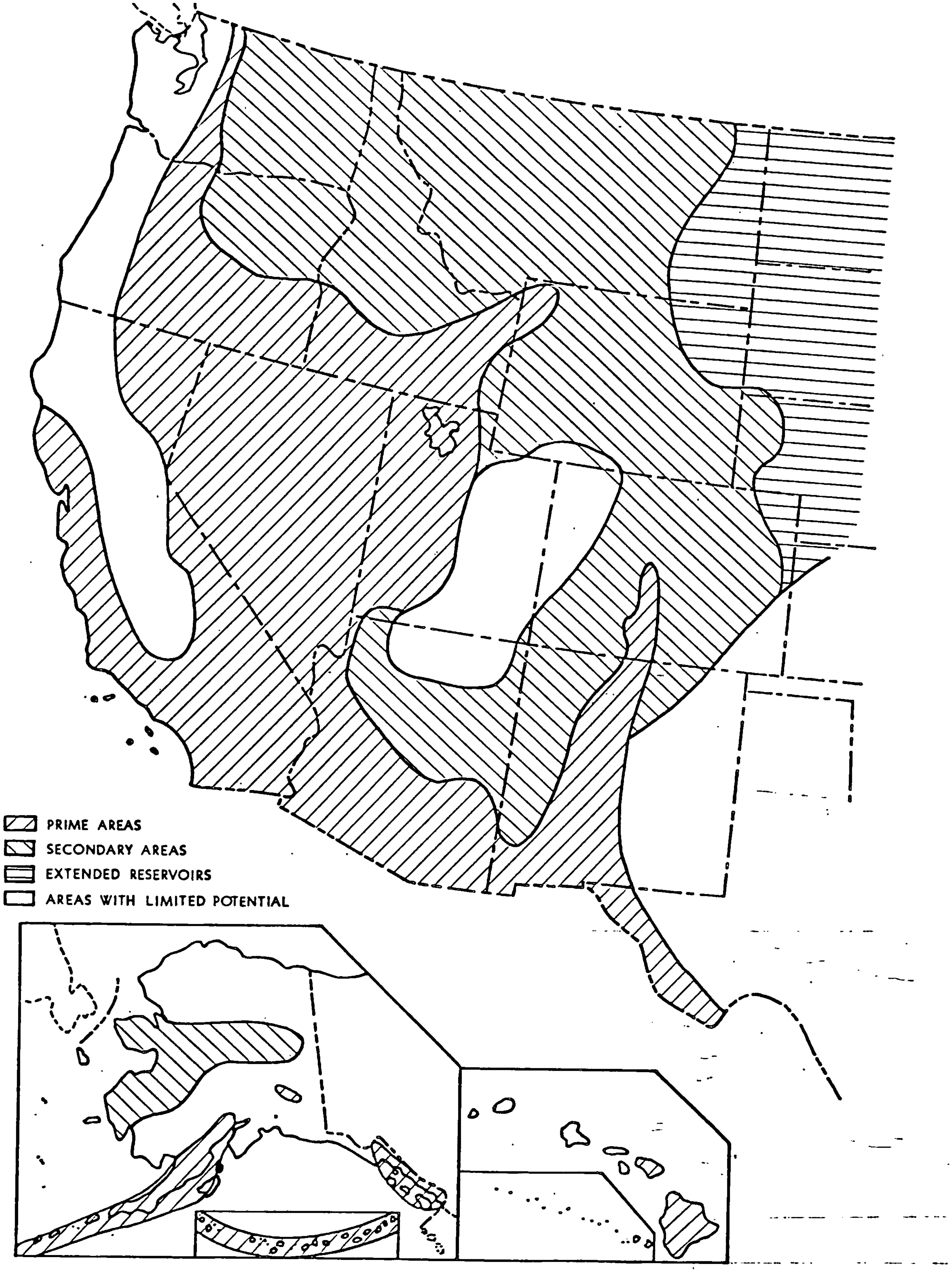
Figure I-13. Geothermal terrains of the western U.S.

Prime areas - geologic environments in these areas are generally favorable for the occurrence of electric quality resources. Many hydrothermal systems are present; young volcanism or tectonic extension is characteristic of much of this terrain.

Secondary areas - electric quality hydrothermal resources are unlikely to be present in these areas but many hydrothermal systems suitable for direct applications exist.

Extended reservoirs - those areas with deep aquifers that contain thermally anomalous water; electric potential is not present and direct applications are limited in some areas by poor water quality.

Areas with limited potential - these regions are characteristic by low heat flow, general absence of young volcanism, and few thermal springs or wells. Geologic environments of these areas generally do not favor hydrothermal systems.


▨ PRIME AREAS
▧ SECONDARY AREAS
☰ EXTENDED RESERVOIRS
☐ AREAS WITH LIMITED POTENTIAL

provinces are particularly favorable for the occurrence of attractive resources. Steamboat Springs, Nevada, Roosevelt Hot Springs, Utah, and the Valles Caldera in New Mexico are all hydrothermal systems found at the edges of provinces.

Mountainous areas, with faults, but having limited igneous activity or lower heat flow, dominate the area depicted as secondary. Many hydrothermal systems are known in these areas, but they often are lower in temperature than the systems in the prime areas. Electric grade resources are unlikely to be discovered in these areas with the present generation of target models.

Areas of extended reservoirs are generally found in the Great Plains. Although the temperatures of these waters are suitable for direct applications, water productivity and quality characteristics may be limiting factors.

The areas of limited potential shown on Figure I-13 have low heat flow and limited faulting. Although a few thermal springs are known in these areas, the geologic attractiveness and relatively unexplored nature of the prime and secondary areas, makes sites with limited potential presently unattractive for exploration emphasis.

2. Alaska

Electric-grade hydrothermal resources have been identified as possibly existing at three sites in Alaska (Turner et al., 1980); these resources have yet to be confirmed. Two of the sites are on Unalaska Island in the Aleutians, and the third is near Bailey Bay in southeastern Alaska (Motyka et al., 1980). Most of the Aleutian

Islands have been postulated to contain volcanic-related hydrothermal systems (Smith et al., 1978). The remoteness of these sites, with low market potential for either electricity or direct applications at most, suggests that they should be low-priority exploration targets.

Fracture controlled and deep stratigraphic hydrothermal systems have also been identified in Alaska (Turner et al., 1980). The fracture-controlled systems are commonly found along the margins of Cretaceous plutons; the stratigraphic systems are found in several of the deep basins. These resource types are low- or moderate-temperature; sparse population limits direct application opportunities.

3. Arizona

Hydrothermal resources of Arizona are found primarily in the Basin and Range and in the Basin and Range-Colorado Plateau transition zone (Hahman et al., 1978). The only presently identified electric-quality resource is in the Power Ranches wells area, southeast of Phoenix. A contract is under negotiation between the U.S. Air Force and a private developer to confirm this resource. Chemical geothermometry estimates above 150°C have been reported from the Clifton area (Brook et al., 1979; Hahman, 1979); this resource remains to be confirmed. Other thermal systems in the Basin and Range and the transition zone have potential for direct applications.

4. California

Electricity is presently being produced from The Geysers and the Imperial Valley areas of California. Both of these are the sites of young volcanic activity.

Other sites of young volcanism, which hold potential for electric-quality hydrothermal resources, include the Coso (Bacon and Duffield, 1980), and Long Valley (Muffler and Williams, 1976) areas. The Mono Lake area, which has young volcanism but no identified high-temperature geothermal system, and the Surprise Valley area, which has a reported bottom hole temperature of 160°C, and the Cascade volcanos, are other sites in California where high-temperature hydrothermal resources might be expected. A vapor-dominated system has been identified in Lassen National Park (Brook et al., 1979).

Thermal springs are found in most of the rest of California, with the exceptions of the Klamath Mountains and San Joaquin Valley (Higgins and Martin, 1981). Most of these other sites are limited to direct application, but a district heating system has come on line in Susanville (Edwardes, 1981), and the Department of Energy has funded a resource exploration program in conjunction with a hybrid wood waste-geothermal power plant in the Wendell area.

5. Colorado

Most hydrothermal systems of Colorado are found in the zone of high heat flow outlined on Figure I-11 (Pearl, 1980). This area includes the northern portion of the Rio Grande Rift, the Colorado mineral belt, and the eastern margin of the Colorado plateau/western slope of the Rocky Mountains.

Two sites in Colorado have been identified as having, on the basis of chemical geothermometry, potential for electric-quality resources. These are the Chalk Creek (Mt. Princeton) (Barrett and Pearl, 1978) area and the Paradise Hot Spring area (Brook et al., 1979). All other known sites have potential only for direct applications. A resource suitable for district heating has been identified in Pagosa Springs (Galloway, 1980); a system is presently under development.

6. Hawaii

Volcanic centers and associated rift zones are the most favorable hydrothermal targets in Hawaii (Thomas et al., 1980). A maximum temperature of 358°C has been recorded at the HPG-A well in the Puna rift zone on the Island of Hawaii. A well-head generator has been installed and briefly tested on this resource. Private sector concerns are drilling adjacent to the discovery well, with plans to use the resource for both generation of electricity and direct applications.

Geophysical and geochemical studies have identified several other sites with hydrothermal potential (Kauahikaua, 1981). These sites have not been confirmed by drilling.

7. Idaho

Electric power has been generated from the Raft River site in southern Idaho (T. Lawford, personal communication, 1981). This site produces hydrothermal fluids from fractured granodiorites at the northern margin of the Basin and Range province. Chemical geothermometer estimates suggest that at least two (Brook et al., 1979), and perhaps as many as 13 (Mitchell et al., 1980) other sites in Idaho have the potential for hydrothermal generation of electricity. These other sites occur in three geologic terrains: in the margins of the Snake River Plain, along fractures in the Idaho batholith, and in association with young silicic volcanic activity in the overthrust belt of southeastern Idaho. One geothermal well has been drilled along the margin of the Snake River Plain. It had a bottom hole temperature of approximately 150°C at 10,000 feet but did not contain producible fluids (Prestwich and Mink, 1979).

Hydrothermal resources have been used for direct applications for longer than 90 years in Boise, where more than 150 homes are presently heated, and a central district heating system is about to come on line (Hanson, 1981). Thermal waters in Boise are produced from a fault at the margin of the Snake River Plain. Thermal waters circulating to depth along the edge of the Idaho batholith have been used to heat portions of Ketchum since the 1930s.

Approximately 900 thermal springs and wells are known in Idaho (Idaho Department of Water Resources, 1980). Although potential for high-temperature sites is limited, many resources apparently could support industrial applications of moderate temperature resources.

8. Montana

No hydrothermal resources of electric quality have been identified in Montana (Brook et al., 1979; J. S. Sonderegger, personal communication, 1981).

The low- and moderate-temperature resources found in the state are of two types: fault-controlled systems in the mountains of western Montana, and stratigraphicaly controlled deep circulation in the sedimentary basins of eastern Montana. Maximum chemical geothermometer temperatures in western Montana are less than 140°C, and the maximum measured temperature is 103°C (Brook et al., 1979). No temperatures above 100°C have yet been reported from eastern Montana.

9. Nevada

Nevada, perhaps more than any other state, has great potential for high-temperature hydrothermal resources (Garside and Schilling, 1979). High-heat flow (Figure I-11), young volcanism, and extensive faulting make ideal conditions for the occurrence of these resources. Federal cost sharing and private exploration have helped identify electric-quality resource sites. Brook et al. (1979) list 18 of these, many of which are discussed elsewhere in this paper.

Potential for direct applications is also high (Trexler et al., 1979). An agricultural processing plant is on line at Brady's Hot Springs, a geothermal alcohol plant is operating, and space heating is taking place near Reno (Bateman and Scheibach, 1975).

10. New Mexico

Hydrothermal resources of New Mexico are found mainly along the high-heat flow zone of the Rio Grande Rift (Figure I-11), with other resources in the Basin and Range and along its margins (Swanberg, 1980). The only confirmed high-temperature resource in New Mexico is at the Valles Calderas, where temperatures up to 330°C have been reported (Dondanville, 1978). Union Oil and the Department of Energy are cost-sharing the development of this reservoir. Although no other electric-quality resources have been identified, the postulated presence of a magma body near Socorro suggests that other systems may exist (Reiter et al., 1978). Near-surface hydrothermal regimes, which may not be related to deeper systems, may mask the higher temperature resources (Morgan et al., 1981).

Most other sites in New Mexico are of direct applications quality only. A few of these may have potential for electric resources, but insufficient work has been done to confirm this. Direct application projects are on line in Las Cruces, where space heating is taking place, and will be coming on line at several industrial sites over the next year.

Recently active faults and relatively young volcanism (Seager et al., 1981), in conjunction with the regional high-heat flow, make the Rio Grande Rift and associated areas of New Mexico attractive targets. The San Juan basin of northwestern New Mexico is a site where deep stratigraphic circulation of water may lead to the development of low- and moderate-temperature hydrothermal resources; this has yet to be confirmed.

11. Oregon

Four regions of Oregon are likely to contain high-temperature hydrothermal reservoirs. These are the Cascade Range, the Basin and Range, the Brothers fault zone, and the Snake River Plain. The rest of Oregon, with the exception of portions of the Columbia Plateau, the Willamette Valley and the Coast Ranges, contains lower temperature thermal springs and wells (Riccio, 1978; Bowen et al., 1978). Several thermal sites in the western Cascades are undergoing resource assessment activities by both public sector and private organizations (Priest and Olmstead, 1981). The U. S. Geological Survey is conducting many studies in the Cascades (Duffield and Guffanti, 1981), as is the Oregon Department of Geology and Mineral Industries (Priest et al., 1981). Sunedco is presently drilling at Breitenbush Hot Springs.

The Klamath Falls area is one of the largest direct application sites in the U.S., with over 400 homes, a college, a hospital, schools, light industrial sites, and soon 14 government buildings and most of the business district heated by geothermal energy (Justus, 1979, p. 25; Derrah, 1981).

The geothermal assessment at Mt. Hood has drawn the most public attention of any geothermal project in Oregon (Riccio, 1979; White, 1980; Bowen, 1981). This work has resulted in the confirmation of a resource suitable for direct applications at Timberline Lodge. No electric-grade reservoir has been identified although 95°C fumeroles exist near the peak.

The U.S. Geological Survey has been doing geothermal assessment at Newberry caldera, which lies at the intersection of the Brothers fault zone and the Cascade Range. The Brothers fault zone forms the northern boundary of the Basin and Range in Oregon. It is composed of many high-angle normal and right-lateral faults and has been the site of much volcanic activity (Bowen et al., 1976).

The Basin and Range of Oregon contains several high temperature sites (Brook et al., 1979). The entire Basin and Range is attractive for exploration; at present the highest temperature hdrothermal sites identified are in the Alvord Desert area.

The margins of the Snake River Plain in Oregon are also attractive for resource exploration. Geochemical thermometry estimates of up to 200°C have been reported from Vale (Muffler, 1979). A temperature of 195°C has been estimated for a 10,054 ft. well near Ontario (Austin, 1981); no producable quantitites of fluid were encountered in this well.

12. Texas

The only identified potential for high-temperature hydrothermal resources is in the Hueco Tanks and Presidio Bolson areas of Texas (Roy and Taylor, 1979; Henry and Gluck, 1981; Swanberg et al., 1981). Chemical geothermometer measurements of water in west Texas suggest that the Presidio Bolson is the most attractive area (Henry, 1979). Drilling is now taking place there by both public sector and private organizations.

The direct application of low- and moderate-temperature resources that might be discovered in west Texas is limited by sparse population.

13. Utah

The majority of thermal sites in Utah lie in the Basin and Range physiographic province (Murphy, 1980; Goode, 1978). The Colorado Plateau and Rocky Mountains contain a few low temperature sites. This distribution is reflected in the contours on the heat flow map (Figure I-11).

The Roosevelt Hot Springs thermal system will be the first site with electric power on line in Utah. Young silicic igneous activity may contribute heat to the system; circulation is along faults. Other sites along the margin of the Basin and Range have young basic volcanism, but a high-temperature hydrothermal system has been identified only at Cove Fort (Brook et al., 1979).

Chemical geothermometry estimates suggest that most of the other hydrothermal systems in Utah only have potential for low- and moderate-temperature resources. Several of these sites are colocated with population centers and may present the opportunity for industrial applications, as well as space conditioning.

14. Washington

Three geothermal provinces exist in Washington: the Cascade Range, the Olympic Peninsula, and the Columbia Basin (Bloomquist et al., 1980). Young volcanic centers in the Cascade Range form the most attractive exploration sites in Washington. Limited data exist from industry exploration on the Washington Cascades; the publically available data has been compiled by the state (Korosec and Schuster, 1980).

Preliminary interpretation of heat flow data suggests that, as outlined on Figure I-11), the Cascade Range has higher thermal flux than the surrounding terrains. Blackwell (personal communication, 1980) suggests that the highest portion of this anomaly is in southern Washington, including Mt. St. Helens and Mt. Adams, but it may not continue as far north as Mt. Rainer. Schuster (personal communication, 1981) is presently seeking to resolve heat flow anomalies of the central Washington Cascades under work sponsored by the Department of Energy State Coupled Program.

The major volcanos form the most attractive exploration targets. Schuster et al. (1978) failed to identify any heat flow anomaly in an area of young Quaternary volcanism adjacent to the high Cascades. Some peripheral sites, such as the Columbia River Gorge between North Bonneville and Carson, do contain lower grade hydrothermal resources. The presence of electric quality reservoirs remains to be demonstrated in this and other similar areas.

Thermal springs and wells have been identified in both the Olympic Peninsula and the Columbia Plateau basin. Two thermal springs exist in Olympic National Park, and a slightly thermal well exists north of them. Many low-temperature thermal wells exist in the Columbia Basin. Identified resources in both of these areas are of direct application quality only.

15. Wyoming

The world's largest concentration of hydrothermal phenomena is at Yellowstone National Park in Wyoming, (Keefer, 1972; Marler, 1973). Both vapor-dominated and water-dominated systems have been identified in the Park. Due to its unique status, Yellowstone is withdrawn from exploitation. The U.S. Congress may also withdraw some lands around the Park from exploration; the extent of withdrawal has not been resolved.

No other sites suitable for electric generation have been identified thus far in Wyoming (Brook et al., 1979). Most of the thermal springs are concentrated in the zone of higher heat flow shown on Figure I-11 (Breckenridge and Hinckley, 1978).

Wyoming also contains low- and moderate-temperature hydrothermal resources associated with deep circulation of water in stratigraphic horizons such as are found in the Powder River Basin. Where these rocks have been folded, up-circulation may produce thermal springs at anticlinal crests; this is probably happening near Cody and Thermopolis (H. Heasler, personal communication, 1980).

II. EXPLORATION METHODS

A. Introduction

In this section the methods used in geothermal exploration will be discussed and evaluated. The methodology is largely adapted from methods commonly used in metals and petroleum exploration, but its application is much less mature than in those industries. This lack of maturity is largely a function of the relatively brief history of geothermal exploration.

In the following sections, many of the techniques used in geothermal exploration will be described. In addition, we will point out some of the problems which have been encountered in the use of these methods in geothermal exploration programs with which we are familiar. From these analyses, it is possible to devise optimum exploration strategies. This will be done in Section III-C of this paper.

B. Geology

1. Geothermal Deposits

The interpretation of geothermal deposits is an obvious first step in the evaluation of a geothermal prospect. From the descriptions already presented the following can be summarized (Renner et al., 1975):

(a) Deposits of siliceous sinter indicate liquid-dominated systems with base temperatures of at least 180°C;

(b) It is not possible to make temperature estimates on the basis of the deposition of travertine from a thermal system;

(c) Acid sulfate springs, mud volcanos, and acid alteration are characteristics of vapor dominated portions of hydrothermal systems. In this environment siliceous residues are often formed through the intense acid leaching of the country rock. This acid residue can be confused with siliceous sinters.

2. Mapping

Geologic mapping is one of the most basic tools of any exploration program. However, it has been our experience that it is often not used in geothermal exploration programs. It is of particular importance in dealing with structurally controlled systems to understand the fluid pathways and extrapolate these to depth to allow optimum siting of drilling. It has also been our experience that geophysical surveys have been run prior to an understanding of geology. This has led to such things as resistivity surveys located along major structures and thermal gradient programs within landslide deposits. Mapping should obviously concentrate on the interpretation of structures and geothermal systems. In most cases geothermal systems are located in areas that have experienced previous hydrothermal events. It is thus common to find a number of overlapping periods of hydrothermal alteration and mineralization. Geologic mapping serves as the ground truth for the decision to apply subsequent geochemical and geophysical surveys and is required for their optimum interpretation.

We have found that the most efficient methods of mapping utilize air photos, preferably in color at a scale of about 1:24,000. In the complex environments generally encountered, air photo mapping without ground check has been less than informative and often quite misleading.

3. Hydrology

One of the principal problems in many geothermal exploration programs is evaluating the influence of cold water aquifers which potentially mask the geothermal exploration target. This problem is particularly severe in the Cascade province, but is also important in the more arid areas such as the Basin and Range and the Snake River Plain. There are no ways of eliminating the influence of these cold aquifers. Specifics will be discussed in the sections on geochemistry, thermal methods, and electrical methods.

C. Geochemistry

1. Introduction

Geochemical investigations play an important role in geothermal exploration by providing essential information on subsurface temperatures, size and shape of the thermal system, character of the aquifers and acquicludes, and production potential of the field. This information can be obtained from careful evaluation of the chemical compositions of fluids discharged from springs and fumeroles, and from the mineral and trace element distributions in the altered rocks found at the surface and in the thermal gradient and deeper test wells.

The physical properties of the reservoir rocks are also strongly dependent on the extent of hydrothermal alteration and can be significantly altered as a result of mineral deposition in fractures and by the formations of clays. These changes may substantially affect the geophysical response of the rocks at depth. Thus an estimate of the extent and character of the hydrothermal alteration occurring at depth is needed to quantitatively interpret the geophysical responses.

2. System Classification

The surface manifestations of both liquid- and vapor-dominated geothermal systems commonly include boiling and warm springs and fumeroles which may discharge fluids of significantly different compositions representing different environments within the thermal system. These fluids may differ chemically from the deeper reservoir fluids as a result of changes accompanying mixing, dilution, boiling, or conductive cooling. In addition, the chemistry of the fluid may be further modified as constituents partially or completely reequilibrate with the reservoir rocks during the fluids' ascent to the surface. Figure II-1 illustrates the direction of these chemical changes under different conditions. Clearly the actual path taken by the fluids may be complex and the chemistry modified by more than one process. Despite this complexity, careful evaluation of fluid chemistry frequently provides diagnostic information about the subsurface characteristics of the geothermal system. Geochemical and basic hydrologic data from springs and wells is an important source of information which can be used at an early stage in the exploration program to predict the kind of fluid that will be produced. Chemical analyses of many of the hot spring systems in the U.S. are tabulated in the literature and can be supplemented at relatively low cost during reconnaissance investigations.

The model of the Yunotani geothermal field, recently proposed by Parmentier and Hyashi (1981), provides an illustrative example of how

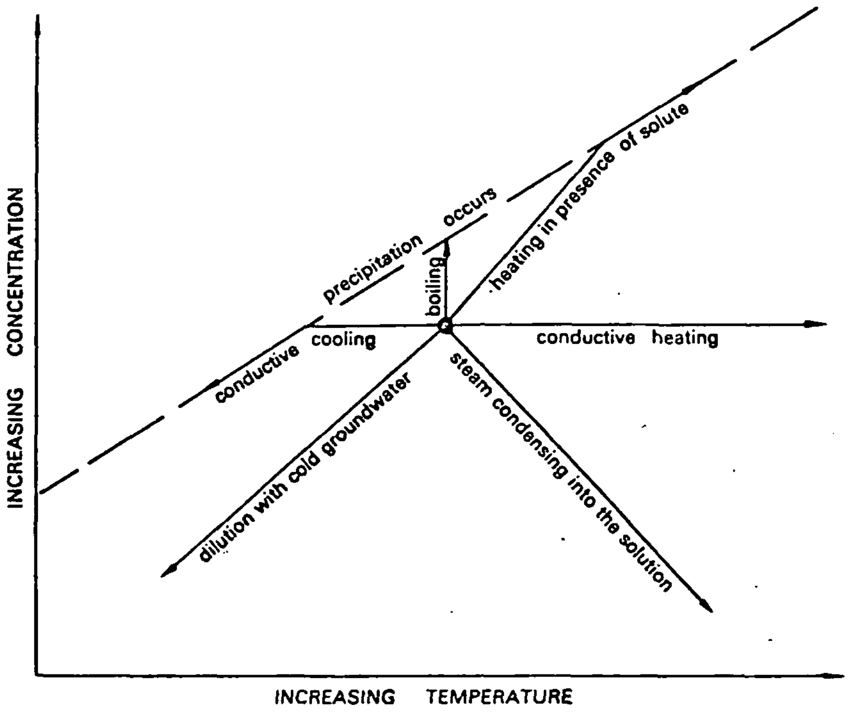


Figure II-1. Chemical changes of fluids under different processes.

geochemical data can be used to develop a working model of a complex high-temperature system. The Yunotani field contains many features typical of vapor-dominated systems and shallow wells discharge dry steam. The hydrologic and geologic complexity of this area is similar in many respects to parts of the Cascade Range.

The Yunotani field is located in the Aso caldera which is composed of Pleistocene to Recent rhyolitic and andesitic lava flows, pyroclastics and agglomerates. At high elevations the surface expression of the thermal system includes low-chloride acid to neutral sulfate springs, fumeroles, and areas of intense hydrothermal alteration characterized by clays, silica, pyrite and gypsum. These features are aligned along the northwest-trending Yunotani Fault. A travertine deposit and chloride-rich springs occur at a lower elevation.

Geochemical analyses of waters discharged from the springs and from two wells drilled to depths of 450 and 510 meters are given in Table I-1. These wells are currently producing dry steam, but both initially discharged mixtures of water and stream. The fumeroles are associated with acid sulfate water and emit gases containing high concentrations of mercury, boron and ammonia.

A comparison of the analyses and temperatures indicates that several distinct waters types, representing different thermal regimes, must be present to explain the distribution of chloride, bicarbonate and magnesium in the discharged fluids. Parmentier and Hayashi (1981) concluded that at least three distinct fluids occur: a boiling chloride brine in a deep reservoir; a low-chloride, bicarbonate sulfate water in a reservoir at shallow depths; and a magnesium-rich surface water. They suggested that the upper reservoir results from heating of meteoric water by steam and other gases derived from the deeper brine. Locally, the fumeroles discharge the gases which reach the surface.

Figure II-2 illustrates a possible relationship between the various fluids and the hydrologic regime. According to this model fluids discharged at the lowest elevation and characterized by relatively high concentrations of chloride, bicarbonate and magnesium represent a mixture of all three water types present in the system. The wells tap the upper bicarbonate/sulfate reservoir at slightly higher elevations in thermal system. The low-chloride and high bicarbonate content of the fluids that were discharged initially is consistent with the model of steam heating of meteoric waters. Relatively low permeabilities and limited recharge in this zone could explain the change in production from liquid and steam to dry steam in the shallow wells as a steam pocket gradually formed within this upper reservoir. Thermal waters characterized by a relatively low pH are locally associated with active fumeroles. These waters yield little information about the deeper reservoirs. The relatively low chloride and bicarbonate and high magnesium and calcium contents of analysis 2 (Table II-2) compared to the chloride rich spring (analysis 3) suggests that the former also has a surficial origin.

The possibility of a deeper chloride brine in the Yunotani field offers an exploration target that may be more attractive than the upper reservoir currently being exploited. Such a reservoir could

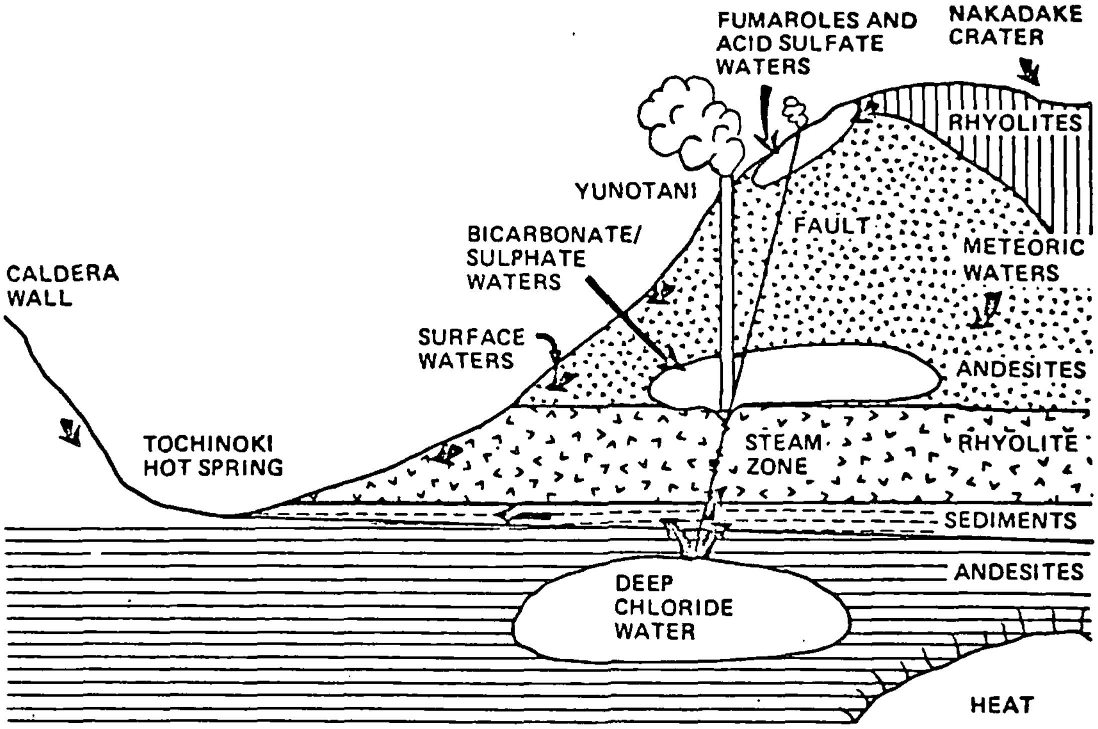


Figure II-2. Relationships between water chemistry and hydrologic regime at the Yunotani field, Japan (Parametier and Hyashi, 1981).

contain fluids with temperatures significantly greater than the measured 172-187°C temperatures of the wells.

3. Subsurface Temperature

An understanding of the temperatures at depth in the geothermal reservoir rocks is crucial to the development and exploitation of the resource. Temperatures can be determined directly through downhole measurements or estimated indirectly from the chemistry and stable isotopes (O, H, S, C) of the water, steam, gas and reservoir rocks themselves. Direct and indirect methods provide, however, different information about the reservoir.

The application of indirect methods plays a critical role in the initial assessment of a thermal field. Indirect methods based on the chemistry of the thermal fluids can provide information on deep thermal regimes within the high temperature parts of the reservoir that otherwise are unaccessable to shallow and even moderate-depth thermal gradient wells. Thus, indirect methods can be used to prioritize drilling targets and, when compared with thermal measurements made in shallow gradient wells, can be used to establish depth requirements for the deeper drilling program. During exploitation of a thermal field these geothermometers are used to monitor changes in the reservoir without requiring extensive shutting in of the wells.

Numerous qualitative thermometers, based on the cation and anion contents of the discharged fluids and on the distribution of various hydrothermal minerals and trace elements in the altered rocks, can also be used to estimate subsurface temperatures. The latter methods assume particular importance during the exploration drilling stage because they can provide immediate information on the temperatures and permeability in the well during the drilling program. In contrast, it may be several weeks after drilling before the thermal gradients in the wells "re-equilibrate" and accurate direct measurements can be made.

a. Quantitative Geothermometers

The quantitative geothermometer techniques currently available require chemical or isotopic analyses of thermal waters, steam and gas from wells and springs. These techniques can be categorized into the following groups:

1) Major element geothermometers
2) Mixing geothermometers
3) Isotope geothermometers

The underlying premise for all three categories is that temperature-dependent reactions between either the reservoir rock and fluid or evolving gases and the fluid attain equilibrium. Furthermore, no reequilibration occurs after the fluid leaves the reservoir (Fournier et al., 1974; Truesdell, 1976; Fournier, 1977; Ellis, 1979 for further details).

Several major element geothermometers have been proposed and have proven extremely valuable in accurately estimating subsurface temperatures. The relationships between the major element concentrations and temperature are given in Table II-1. An extensive review of the use of these geothermometers was recently published (Fournier 1981).

Table II-1. Equations expressing the temperature dependence of selected geothermometers. C is concentration of dissolved silica. Concentrations in mg/kg; gases in volume percent. (Fournier, 1981; Fouillac and Michard, 1981; D'Amore and Panichi, 1980).

Geothermometer	Equation	Restrictions
a. Quartz-no steam loss	$t^{o}C = \frac{1309}{5{\cdot}19 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
b. Quartz-maximum steam loss	$t^{o}C = \frac{1522}{5{\cdot}75 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
c. Chalcedony	$t^{o}C = \frac{1032}{4{\cdot}69 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
d. α-Cristobalite	$t^{o}C = \frac{1000}{4{\cdot}78 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
e. β-Cristabalite	$t^{o}C = \frac{781}{4{\cdot}51 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
f. Amorphous silica	$t^{o}C = \frac{731}{4{\cdot}52 - \log C} - 273{\cdot}15$	$t=0-250^{o}C$
g. Na/K (Fournier)	$t^{o}C = \frac{1217}{\log(Na/K) + 1{\cdot}483} - 273{\cdot}15$	$t>150^{o}C$
h. Na/K (Truesdell)	$t^{o}C = \frac{855{\cdot}6}{\log(Na/K) + 0{\cdot}8573} - 273{\cdot}15$	$t>150^{o}C$
i. Na-K-Ca	$t^{o}C = \frac{1647}{\log(Na/K) + \beta[\log(\sqrt{Ca}/Na) + 2{\cdot}06] + 2{\cdot}47}$	$t<100^{o}C$ $\beta=4/3$ $t>100^{o}C, \beta=1/3$
j. $\Delta^{18}O(SO_4^{=} - H_2O)$	$1000 \ln \alpha = 2{\cdot}88(10^{6}\,T^{-2}) - 4{\cdot}1$ $\alpha = \frac{1000+\delta^{18}O(HSO_4^{-})}{1000+\delta^{18}O(H_2O)}$ and $T = K^{o}$	
k. Na/Li	$\log Na/Li = 1000/T - 0{\cdot}38$ $\log Na/Li = 1195/T - 0{\cdot}13$	$(Cl^{-} < 0{\cdot}3M)$ $(Cl^{-} > 0{\cdot}3M)$
l. $CH_4/H_2/H_2S/CO_2$	$t^{o}C = \frac{24775}{\alpha + \beta + 36{\cdot}05} - 273{\cdot}15$ where $\alpha = 2\log\frac{CH_4}{CO_2} - 6\log\frac{H_2}{CO_2} - 3\log\frac{H_2S}{CO_2}$ $\beta = 7\log P_{CO_2}$	

Although geothermometers are empirical in nature, there are field and laboratory data available to suggest that at relatively high temperatures the major element chemistry of the fluids is controlled by temperature/pressure-dependent reactions. For example, the reactions (Ellis, 1967; Fournier and Truesdell, 1973)

K + albite = Na + K-feldspar

K + Na_xCa_y - feldspar = xNa + yCa + K-feldspar

and

K + $2H^+$ + albite = K-Mica + $6SiO_2$ + 3Na

are believed to be important in controlling the potassium, sodium, calcium contents and pH of fluids in many terraines where quartz and feldspar are abundant. The silica content appears to be limited above 180°C by the solubility of quartz (Fournier and Rowe, 1966; Mahon, 1966) and by the solubility of amorphous silica at lower temperatures. At high temperatures the concentration of magnesium is controlled by the formation of chlorite (Ellis, 1971).

Different geothermometers frequently give different results when applied to the same analyses, creating ambiguity in their interpretation. During the early stages of an exploration program when data comes largely from springs and shallow wells, there is often no reason to choose one result over another. Comparison with other data, obtained from deep wells, thermal gradient studies, and qualitative fluid and mineral thermometers may help, however, in understanding these relationships. For example, concentrations of silica can be affected by pH, subsurface temperatures calculated from the Na/K/Ca may be adversely affected by high contents of CO_2 (Pace, 1975) and Mg (Fournier and Potter, 1979), the Na/K ratio can also be affected by the addition of potassium and sodium from sedimentary rocks or by interaction with montmorillonite (Weisberg and Wilson, 1977). Subsurface boiling, and mixing can also affect the cation ratios in different ways. In general, boiling does not affect the Na/K ratio but may cause loss of CO_2 and result both in the precipitation of calcite and Na/K/Ca temperatures that are too high. Mixing can either decrease or increase the concentration of the components in solution. Geoff and Donnally (1978) argued that some of the Na/K/Ca temperatures of springs in The Geysers-Clear Lake area were anomalously high and reflected the mixing of ion-rich connate water trapped in rocks of the Great Valley Sequence with the thermal fluids. Higher concentrations of chlorine in springs issuing from the Great Valley Sequence compared to waters of the same temperature which discharge from springs in the Franciscan rocks, and electrical resistivity data support their conclusions.

For systems undergoing mixing and/or boiling, the quartz mixing geothermometer and the chloride-enthalpy relationships can give information about the temperature and chemistry of the parent fluid and the extent of mixing with local groundwaters. The use of these methods is summarized by Fournier (1981). Figure II-3 illustrates the results of the mixing calculation for the Roosevelt Hot Springs thermal area, determined from chemical analyses of the wells and springs by Capuano and Cole (1981).

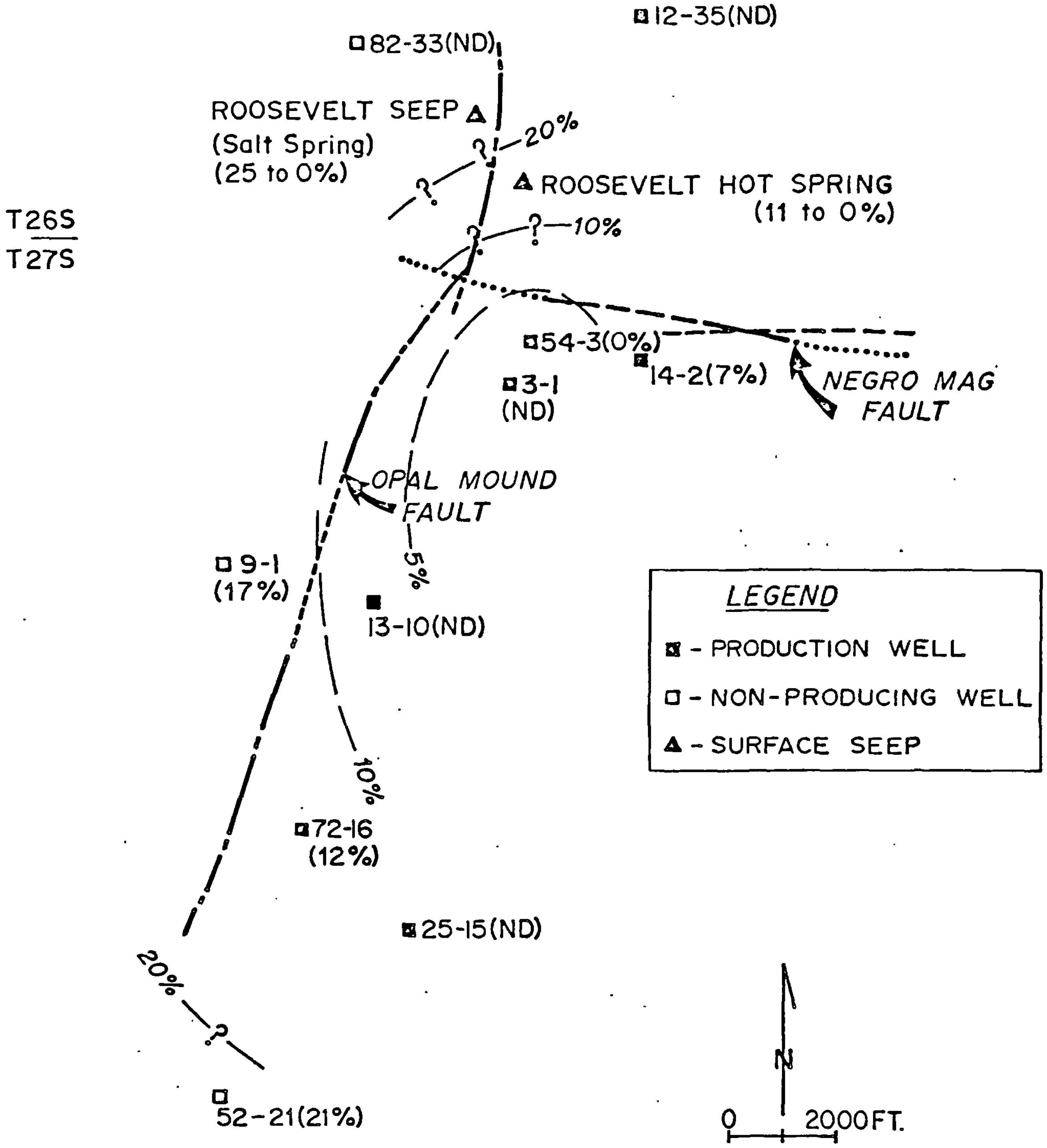


Figure II-3. Average percentage nonthermal groundwater in wells from Roosevelt Hot Springs, Utah.

These data indicate that the extent of groundwater mixing increases in all directions away from well 54-3 and that the center of upwelling is located near this well. The chloride-enthalpy relationships suggest that the reservoir fluid has a temperature of 284°C. Similar temperatures were estimated from other cation and isotope thermometers. The maximum measured temperatures are 269°C. These data strongly support 1) the initial model of the thermal system based on the geologic relationships, 2) subsurface temperatures based on the major element contents of the hot springs, and 3) qualitative fluid and mineral geothermometers (described below).

Stable isotopic fractionation data determined from coexisting gas-fluid, gas-gas and fluid-solid pairs can also provide quantitative temperature estimates. The coexisting pairs that have received the most attention and show the most promise as far as their application to geothermal systems include: 1) carbon isotopic fractionation between carbon dioxide-methane, 2) sulfur isotopic fractionation between sulfate-hydrogen sulfide, and 3) oxygen isotopic fractionation between sulfate-water, carbon dioxide-water and secondary alteration minerals (i.e., quartz, calcite)-water. The rates of isotopic reactions determine whether they will equilibrate in deep geothermal reservoirs and how rapidly reequilibration occurs in shallow reservoirs and during passage of fluids to the surface (Truesdell and Hulston, 1980). These differing rates of isotopic equilibration or reequilibration can be used to reconstruct the thermal history of the system.

b. Qualitative Fluid Geothermometers

Qualitative fluid geothermometers are used extensively during the preliminary chemical surveys to locate zones of upwelling, determine the distribution of thermal waters and directions of groundwater flow, and to determine the lithologies of the reservoir rocks. Fluid constituents that have proven to be particulary useful during these surveys include the soluble elements chlorine, boron, arsenic, cesium and bromine. Ellis and Mahon (1964, 1967) showed that the solubilities of these elements are controlled mainly by diffusion and extraction processes, and that once liberated they do not form stable secondary minerals. Changes in the concentrations of these elements as the fluids migrate from depth occur mainly from dilution or boiling. The use of atomic ratios (i.e., chloride/boron) can eliminate these effects.

Other fluid constituents that are frequently used as qualitative geothermometers include lithum, trace metals (antimony, zinc, copper, uranium, mercury), ammonia, hydrogen sulfide, and the ratios chloride/fluoride, chloride/sulfate, sodium/calcium, sodium/magnesium and chloride/bicarbonate+carbonate. In general, the concentrations and ratios increase with increasing temperature reflecting changes in constituent concentrations as a result of contamination with cold surface water, interaction between the fluids and rock at depth, and steam heating of waters (Mahon, 1970).

Maps of the distribution of chloride and boron in waters in the region containing Roosevelt Hot Springs are presented in Figures II-4 and II-5 and illustrate the use of two of these qualitative geothermometers. The data was compiled from published analyses of well and spring waters. This distribution of chloride and boron suggested that the Roosevelt Hot Springs area is indeed a major center of upwelling thermal fluids and that exploration activities should be concentrated in this area. Changes in the concentrations of chloride and boron occur as the thermal fluids are diluted with local groundwaters. Movement of the fluids appears to be first westward and then northward. The plume of westward-migrating thermal waters provides an explanation both for the relatively high thermal gradients encountered in the shallow wells and for anomalous concentrations of soil mercury which extends westward from the thermal area.

A second source of thermal fluids located at Thermo Hot Springs can be identified from the distribution of boron (southwestern portion of Figure II-4), but is indistinct on the chloride map, as a result of the variable and locally high chloride contents found in non-thermal waters throughout the area. These variations in chloride are believed to indicate the presence of shallow evaporite sequences related to Lake Bonneville within the basin.

The ratios of gases discharged from fumeroles have also been used as qualitative geothermometers. Mahon (1970) showed that fumeroles with the lowest ratios of carbon dioxide/hydrogen

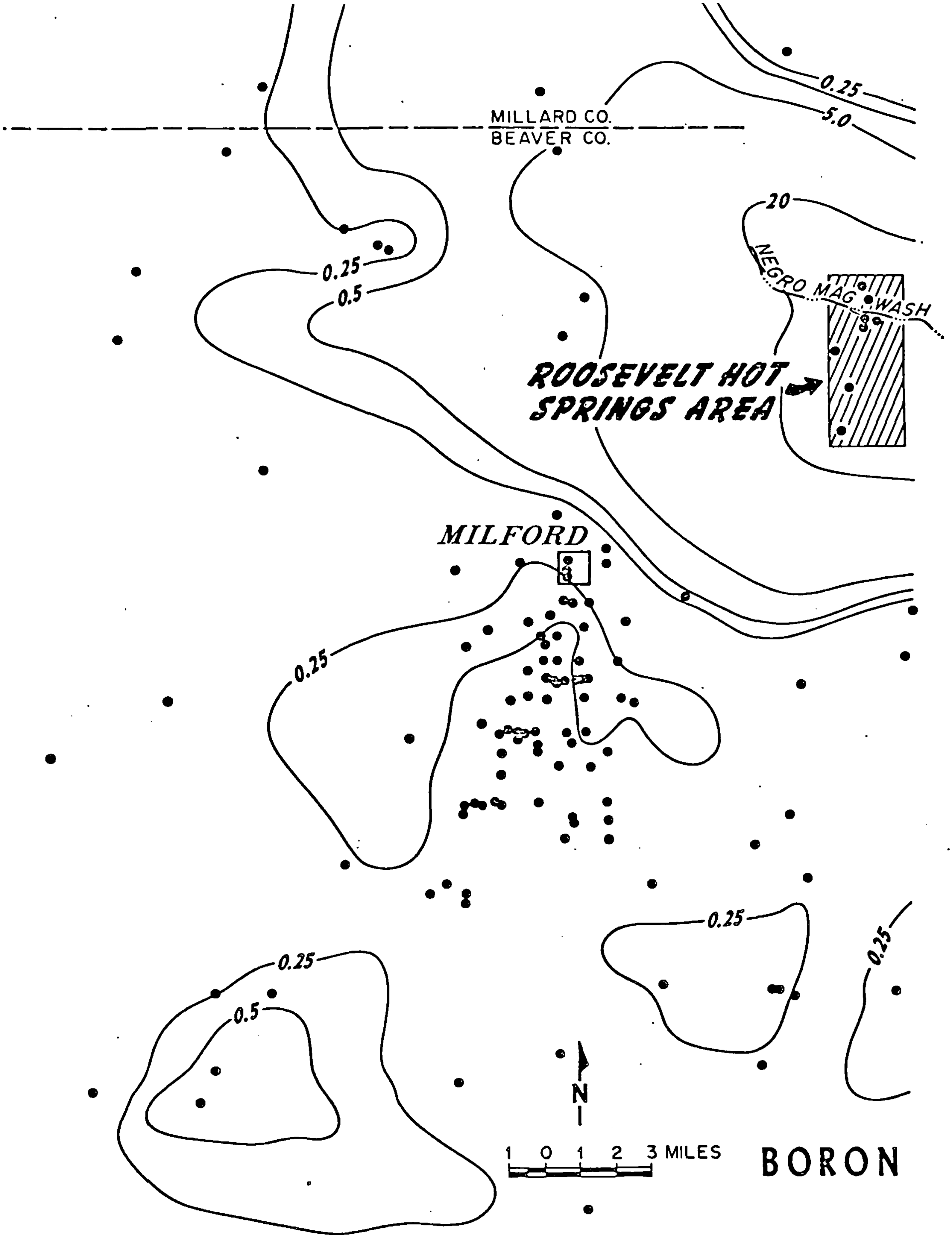


Figure II-4. Distribution of boron in groundwaters around the Roosevelt Hot Springs systems, Utah (Cole, unpublished data).

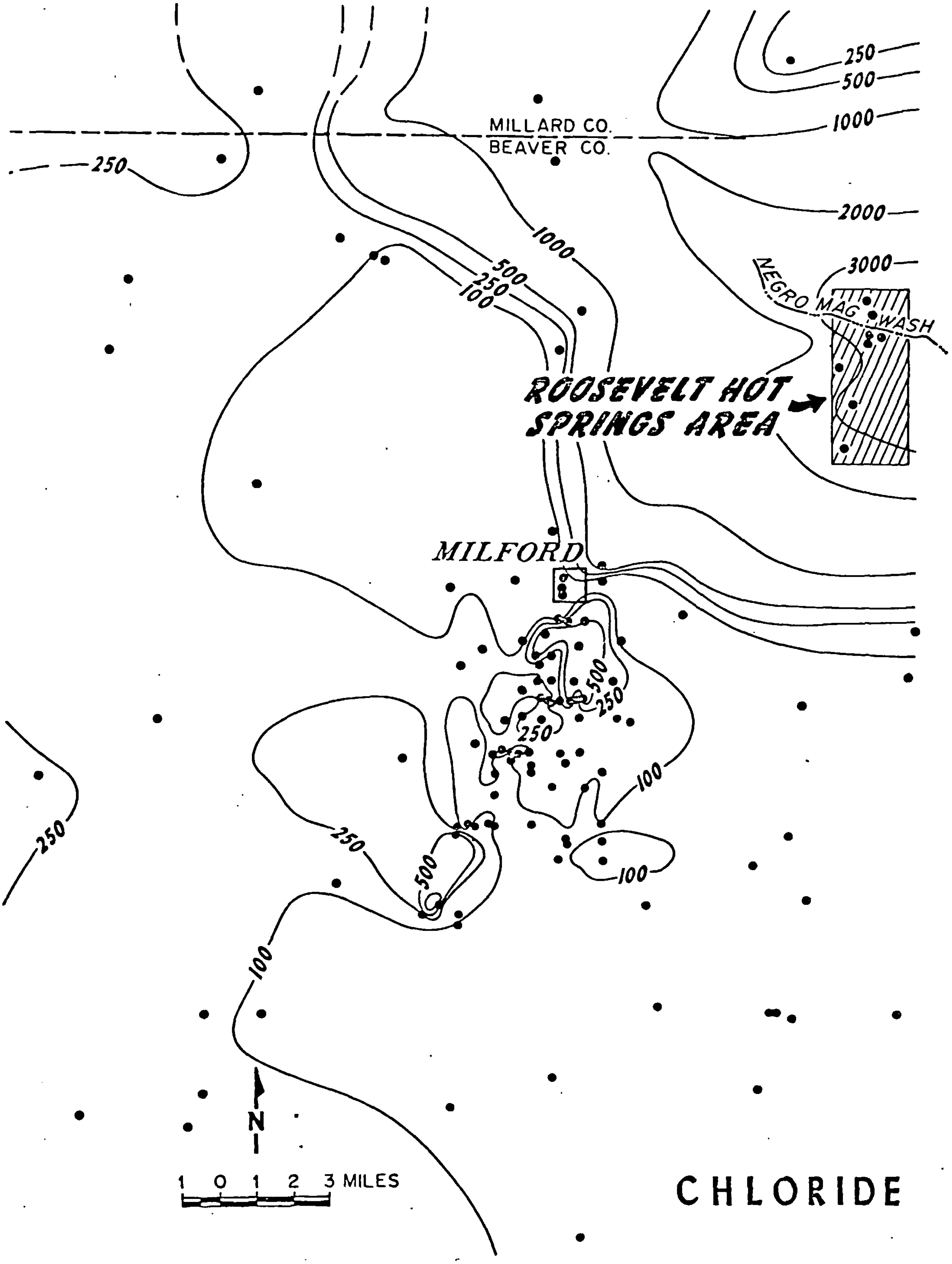


Figure II-5. Distribution of chloride in groundwaters around the Roosevelt Hot Springs geothermal system, Utah (Cole, unpublished data).

sulfide, carbon dioxide/ammonia and carbon dioxide/hydrogen were the most directly connected to the deep aquifers. The concentrations of these constituents are controlled by steam-rock reactions which can rapidly deplete the contents of hydrogen sulfide, ammonia and hydrogen in the steam. The longer the steam path to the surface is, the greater these depletions are likely to be.

4. Trace Element Distribution

Trace and major element dispersion patterns can provide additional information on the temperatures, size, and shape of the thermal system. Because many trace elements can be transported and redistributed at low temperatures before appreciable hydrothermal alteration has occurred, trace element studies supplement data obtained during mineralogical investigations.

Ewers and Keays (1977) published the first comprehensive study of trace element distributions in an active thermal system. Their work, based principally on the chemistry of hot spring deposits, well bore precipitates and hydrothermally altered rocks from two drill holes in the Broadlands thermal area of New Zealand, documented a crude metalliferous zoning characterized by enrichments of arsenic, antimony, gold and thallium in the near-surface parts of the field and higher concentrations of silver, selenium, telluriude, bismuth, lead, zinc, copper and cobalt at depth. More recent studies, conducted mainly at ESL, have substantially expanded upon this earlier work. Trace element distributions in the Roosevelt Hot Springs area of Utah are perhaps the best documented of any thermal system and provide a clear example of the use of trace element investigations during the various stages of the geothermal assessment program (Christiansen et al., 1980; Capuano and Moore, 1980; Bamford et al., 1980; Capuano and Bamford, 1978). Trace element distribution studies of deep wells in The Geysers (Moore unpublished data) the Cascades and other areas of the Basin and Range have confirmed the application of multielement studies in a variety of geologic terrains.

At Roosevelt Hot Springs the distributions of mercury, arsenic and lithium appear to provide the clearest expression of fluid-rock interaction. The concentrations of mercury and arsenic in soils are presented in Figure II-6 and the distributions of all three elements in wells 14-2 (productive), 72-16 (productive) and 52-21 (unproductive) are illustrated in Figure II-7. Despite the locally high concentrations of these elements in the soils and hot spring deposits (Table II-2), their concentrations in the fluids are relatively low (arsenic, 4 ppm; lithium, 28 ppm), and it appears that effective concentrating mechanisms and the duration of activity may be more important than their elemental concentrations in the brines (Weissberg et al., 1979).

High mercury concentrations in soil over high-temperature geothermal systems has been noted by many workers, (i.e., Juncal and Bell, 1981; Matlick and Shiraki, 1981; Phelps and Busek, 1980; Klansman and Landress, 1978). At Roosevelt Hot Springs the distribution of soil mercury mimicks the distribution of heat flow values and appears to be controlled primarily by the northeast-

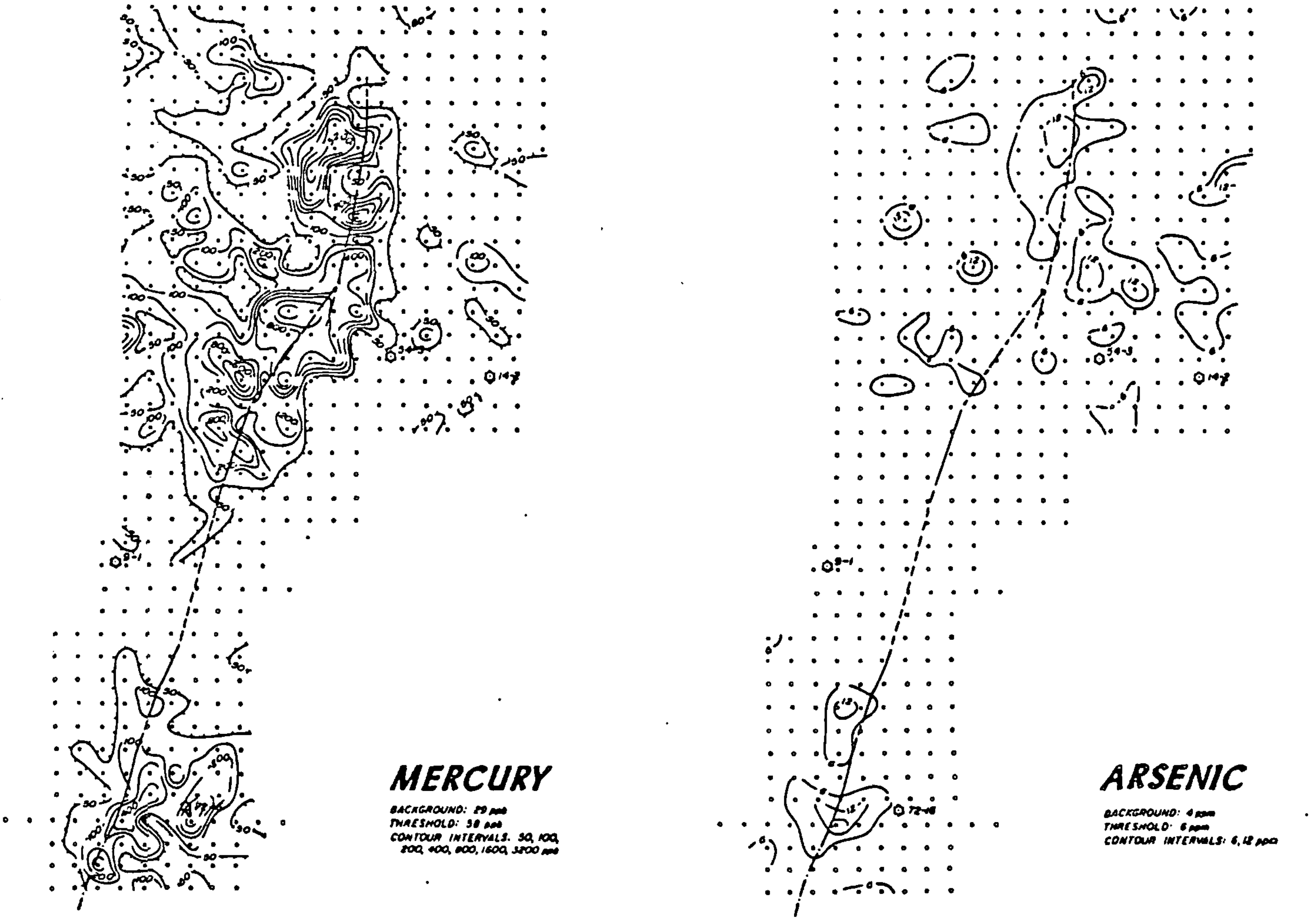


Figure II-6. Concentrations of arsenic and mercury in soils from Roosevelt Hot Springs, Utah.

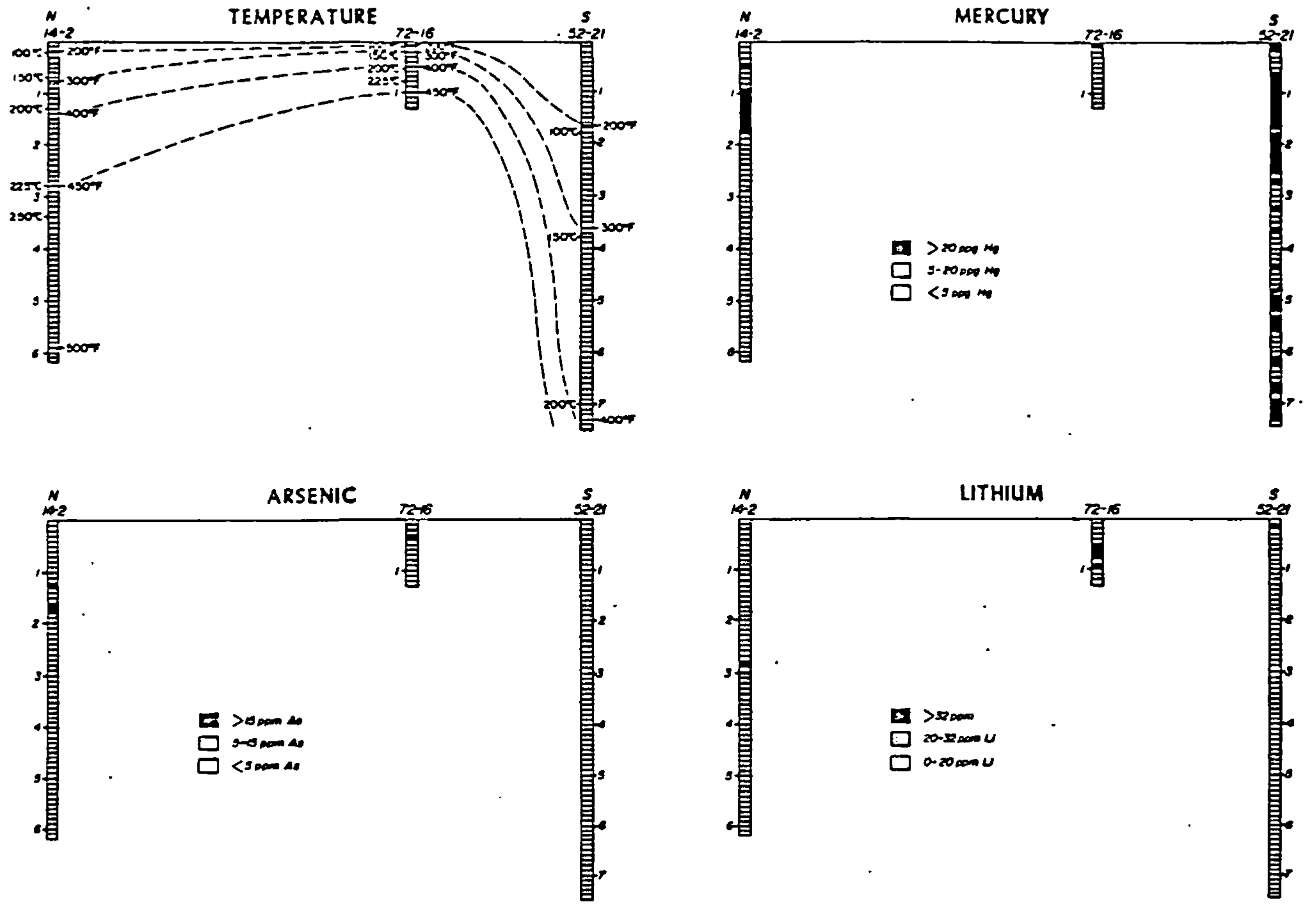


Figure II-7. Temperature and trace element distributions in drill holes Utah State 14-2, 72-16 and 52-21. Each geochemical analysis represents a 100-foot composite sample. Hot-water entries occur between 1600 and 1800 feet and at approximately 2860 feet in Utah State 14-2 and at approximately 300 and 600 feet in Utah State 72-16. a) Temperature distribution; b) distribution of mercury; c) distribution of arsenic, and d) distribution of lithium (from Christensen et al., 1980).

Table II-2 Geochemistry of Selected Surface Samples, Roosevelt Hot Springs, Utah[1]

Element	600	605	607
Na(%)	.15	1.55	1.79
K (%)	.14	3.62	3.12
Ca(%)	.14	.35	.39
Mg(%)	.01	.10	.10
Fe(%)	.02	1.61	.74
Al(%)	.09	6.64	5.18
Ti(ppm)	19	2370	560
P	---	428	651
Sr	33	264	386
Ba	---	485	4.9%
Cr	---	7	9
Mn	388	71	18.8%
Co	---	3	28
Ni	---	5	---
Cu	---	8	231
Mo	---	---	5
Pb	---	19	68
Zn	1	18	23
Cd	---	1	4
Ag*	---	---	1
Au*	4	---	.1
As*	145	6	858
Sb*	243	11	291
W	---	---	2940
Li	11	5	17
Be	99.8	2.8	18.6
Zr	---	32	17
La	---	44	37
Ce	---	70	42
Th	---	---	---
Hg*(ppb)	352	5500	2210

1) from Bamford et al. 1980.

* As determined colorimetrically; Sb, Au and Ag by AAS, Hg by gold film detector; all others by ICPQ.
--- Indicates not detected.

Sample Number	Sample Description
UTMM-600	Chalcedonic sinter from Opal Mound.
UTMM-605	Altered alluvium near fumarole.
UTMM-607	Manganese-cemented alluvium.

trending Opal Mound Fault which forms the western boundary of the field. Anomalous concentrations of arsenic in the soils are restricted to hot spring deposits. Significant concentrations of mercury were also encountered in the shallow thermal gradient wells drilled in the areas characterized by high thermal gradients.

The distributions of arsenic and lithium at depth are broadly similar but appear to be related to different depositional mechanisms. Arsenic is contained mainly in pyrite or iron oxides after pyrite, whereas lithium occurs within clays and micas. As expected, the deposition of these elements occurs only within the higher temperature portions of the system. Mercury exhibits an inverse relationship with temperature and is concentrated primarily in the cooler outer portions of the thermal system to depths marked approximately by the 200°C isotherm.

Christensen et al. (1980) have experimentally investigated the mobility of mercury by measuring its progressive loss from drill cuttings and surface samples heated in air. These studies demonstrated that by 200°C Hg loss had become significant and had reached a maximum by 250°C. They concluded that mercury is present mainly as a native metal and suggested that its distribution reflects the present thermal configuration of the geothermal system. These observations suggest that the mercury contents of subsurface samples can be used as a geothermometer in active geothermal systems.

Systematic mapping of the mercury concentrations in thermal gradient and deeper wells can be used to help locate the boundaries of the system and assess the potential of dry holes which may be in communication with the reservoir but are too shallow to penetrate it.

5. Other Geochemical Observations

There is abundant evidence that many of the physical and chemical characteristics of active thermal systems are intimately related to the permeabilities of the reservoir rocks and the duration of hydrothermal activity. Although these parameters have proven to be extremely difficult to quantify, some information can be obtained from the geochemical observations described in the preceeding sections and from additional isotopic and geochronological investigations.

During hydrothermal alteration, changes in the isotopic compositions of both the fluid and rocks occur. These changes can be related to six variables 1) time, 2) fraction of exchange toward equilibrium, 3) mole ratio of oxygen in the water and rock, 4) grain size, 5) rock density, and 6) isotopic rate constant. A relationship between these variables is given by Cole (1980). This model appears to be a particularly useful tool for predicting water/rock ratios in systems where the time of fluid interaction can be estimated independently (i.e., through tritium or hydrologic techniques).

Fission track systematics can also be applied to problems in geothermal areas. Dating of apatite can be used to estimate the age of recent heating events within geothermal areas by utilizing the well-documented annealing properties of this mineral. Apatite dating can also be used, along with fission track dates of zircon, to model the long-term thermal history of a geothermal area. The tectonic history of a region may also be modeled using fission track techniques. Estimates of uplift rate and denudation rates of mountain ranges may be made. It is also possible to model subsidence rates of sedimentary basins from bore-hole samples.

D. Geophysics

1. Introduction

Geophysics typically, and appropriately, plays a major role in the exploration for and delineation of geothermal systems. Even in the case of known geothermal systems with obvious surface manifestations, such as The Geysers, Roosevelt Hot Springs (Utah), and Beowawe (Nevada), geophysical methods have played a major role in understanding the subsurface geology, in siting exploration and production well tests and in otherwise delineating the geothermal reservoir. The exploration for blind geothermal systems is clearly the realm of inventive geology and correct application of geophysical methods. Few organizations could support a costly high-risk drilling program without some rationale and lower-cost data base for specific target selection.

The technical literature which includes the geophysical expression of geothermal systems or exploration related studies is diverse and, for a relatively new field, voluminous. Most of the earlier studies are rather academic in content and emphasize heat flow per se rather than geothermal exploration. Interest in the development of alternate energy sources and high funding levels by the U. S. Department of Energy and the United Nations have resulted in a great amount of geophysical technique development and the reporting of numerous case histories or isolated data sets during the last ten years. Most of the appropriate, original source technical papers have been published in these journals and symposia: Journal of Geophysical Research - Solid Earth (Red); Geophysics; Geothermal

Resources Council Transactions; U. N. Symposiums on the Development and Use of Geothermal Resources; U. S. Geological Survey Publications and Open-File Reports; and a variety of reports sponsored by the Department of Energy/Division of Geothermal Energy (DOE/DGE).

The exploration for and delineation of productive geothermal reservoirs is proving to be a high risk investment; the probability of a successful geothermal discovery may be less than that for a major mineral or petroleum discovery. Numerous geophysical techniques have been tried, and promoted, to reduce ambiguity in target selection and to maximize the effectiveness of drill hole dollars. Obviously the successful application of a given technique is dependent on the particular geologic environment, specific reservoir type, geologic signal-to-noise ratio for the technique, cost of application, timing, and other factors. With this in mind we will venture some generalizations, specific references, and opinions on the more commonly used geophysical exploration techniques.

2. Thermal Methods

Three basic requirements for a productive geothermal system are: 1) a heat source, 2) fluids to transport the thermal energy and 3) permeable pathways along which the fluids move. The thermal methods respond directly to these characteristics and are therefore the most direct indicators of the geothermal resource. Several techniques are available to study thermal characteristics.

Some remote sensing methods may be appropriate to an early stage (reconnaissance) exploration program. Thermal infrared scanning as reported by Strangway and Holmer (1966) is one technique. The spatial resolution (approximately 100 m) and temperature difference resolution (0.1°C) possible with airborne imaging systems are adequate to map surface thermal anomalies from aircraft and, in some cases, spacecraft. The varied aspects of surface slope angles, vegetative cover, thermal emmissivity, thermal inertia and shallow hydrology often obscure the presence of surface thermal anomalies. Airborne remote sensing methods may be appropriate for reconnaissance geothermal exploration in remote or previously unexplored areas.

A less sophisticated but more appropriate airborne technique which has been used (but poorly documented) is snow melt photography. Austin reportedly has made use of aerial photographs taken soon after a snowstorm to help delineate a warm surface area at Coso Hot Springs KGRA, in California. The potential is good for locating previously unknown hot springs and structures carring thermal fluids at moderate depth. The principal limitations are the timing necessary to carry out the survey and, once again, the overriding effect of near-surface hydrology.

One more reconnaissance method to determine near-surface temperatures is a shallow temperature survey. With a hand-held or truck-mounted power auger a large number of holes are bored to depths of 1 to 2 meters (LeShack, 1977; Olmsted, 1977). Plastic (PVC) pipe with a sealed bottom is inserted into the hole, the hole is backfilled around the pipe, and the pipe filled with a solution of water or water-ethylene-glycol. After the temperature is stabilized (several hours to a few days), a series of temperature measurements is are made, perhaps over a period of a few months. A 'mini' gradient can be determined by measuring at multiple depths, i.e., 20 cm, 50 cm, 1 m, 1.5 m and so on. The advantage of the method is that a large number of holes can be drilled to cover a fairly large area at low or moderate cost. Our recent (1981) cost estimate for a survey with a grid of 100 shallow (1 m) holes covering 20 sq. mi. was $13,000 to $16,000.

The use of shallow temperature surveys has been limited because of the uncertainty that these temperatures are related to the temperature distribution at depth. The principal unknowns and disturbing factors are near-surface hydrology, soil thermal properties, topographic and slope corrections, and short-term variations. At Long Valley and Coso Hot Springs areas in California, and Soda Lakes in Nevada, however, shallow temperature measurements (LeShack, 1977; Olmstead, 1977) seem to delineate the area of anomalous heat flow in a low-cost manner. In the absence of substantial surface thermal manifestations or favorable geology and without obvious near-surface cold-water flow, a shallow temperature survey of about 10 to 40 sq km could be the best basis on which to plan a shallow (30-200 m) thermal gradient program. Most of the shallow temperature surveys to date in the western United States have been sponsored by academic or government funds, to the best of our knowledge. Thus there seems to be a limited acceptance by industry of this technique (Ward et al., 1981).

The generally applied thermal methods all result from the direct measurement of temperature in a stabilized borehole. Variations of this basic measurement give rise to thermal gradient, heat flow, and predicted temperature parameters commonly used in geothermal exploration. Several papers and texts describe details and refinements of the method and the results of regional or detailed heat flow studies, for instance: Lachenbruch, 1978; Sass, et al., 1971; Chapman and Pollack, 1977; Rybach and Muffler, 1981. Table II-3 provides a brief summary of terms and units for these key thermal parameters.

Table II-3. Basic definition, thermal parameters

Parameter	Formulation	Units		Conversion
Thermal Gradient	$\frac{dT}{dZ} \cong \frac{\Delta T}{\Delta Z}$	$\frac{^{o}C}{Km}$	$\frac{^{o}F}{100\ ft.}$	$\frac{^{o}C}{Km} = 18.23\,^{o}F/_{100\ Ft.}$
Heat Flow	$q = \frac{dT}{dZ} \cdot K$	$\frac{mW}{m^2}$	HFU	$1\ HFU = 41.8\ \frac{mW}{m^2}$
Thermal Conductivity	$K \equiv k\rho c$ where ρ=density k=diffusivity c=specific heat	$\frac{W}{m}$	—	—
Temperature	T	°C	°F	$°C = [°F-32]\ \frac{5}{9}$

Table II-4. Thermal conductivity of various rocks
at room temperature

Rock type	Thermal conductivity (W/m, K)
Granite	2.5-3.8
Gabbro/basalt	1.7-2.5
Quartz monzonite	2.54
Biotite gneiss	2.00
Limestone	1.7-3.3
Dolomite, salt	∿5.0
Sandstone	1.2-4.2
Shale	0.8-2.1
Volcanic tuffs*	1.2-2.1
Alluvial fan	1.64
Water	0.6

*Depending on porosity

Table II-5. Typical continental heat flow provinces (after Jessop and Lewis, 1978)

Province	Geologic/geothermal charactertistics	Mean surface heat flow, q(0) (mW/m^2)	Reduced (mantle) heat flow, q (mW/m^2)	h (km)
Eastern U.S.A.	Tectonically stable continental area, conductive heat transfer	57	33	7.5
Basin and Range, U.S.A.	Area with acitve spreading tectonism, strong convective heat flow components	92	59	9.4
Sierra Nevada, U.S.A.	Heat flow transient due to former subduction tectonism	39	17	10.1
Precambrian Shields (average)	Stable continental shield	60	21	14.4

A simplified form for equating these parameters (assuming K varies with depth only and heat sources are neglected) is (Rybach and Muffler, 1981)

$$T(d) = To + q \int_o^d \frac{dz}{K(z)} .$$

Tables II-4 and II-5 summarize measured thermal conductivity values and typical continental heat flow provinces, respectively.

The limitations on the use of the thermal gradient method are generally imposed by the drilling program. The main factor is drilling cost, but environmental restrictions, land control, permitting, and time involved are other considerations. A prudent exploration program utilizes the growing heat flow or thermal gradient data base compiled by the USGS and academic workers over the years and then develops a cost-effective drilling program. Costs are minimized by short drill holes (if the gradient information ~~are~~ is really meaningful), good logistics, and good contractors. A convenient classification for drill hole depth informally adopted by the geothermal industry is : shallow, 30 to 200 m (100 to 600 ft.); intermediate, 230 to 500 m (700 to 1500 ft); and deep, 500 to 1000 m (1500 to 3000 ft). Some classifications would omit the intermediate depth range.

The principal problems with shallow holes include: cold water movement (overflow) in response to near-surface hydrology that masks the effects of a thermal regime at depth; and holes that do not penetrate the true ground water table and do not adequately sample the conductive thermal regime at depth. Ward et al. (1980) note a ratio of shallow to deep thermal gradient holes typically between 1:5 || and 1:10 for Basin and Range geothermal exploration. This would be inappropriate for the Snake River Plain with known cold water overflow to depths below 1000 feet. It may also be inappropriate for high relief areas of active recharge, such as the Cascades. Certainly the depth of holes in an exploration program is a site-specific or regional determination.

shallow to deep = 1 in 10? (reversed) ||

Logistical planning has improved the cost effectiveness of some thermal gradient programs familiar to us. One experienced exploration group directs its drilling contractor to pull off the hole and install pipe at the end of a given day, thus minimizing moving activities within a drilling period.

Should the thermal survey data be expressed as heat flow, thermal gradient or temperature at a given depth? Some groups determine all three parameters (AMAX, Open-file data) and add a temperature projection to a given depth. The cost of thermal conductivity determinations is low but delays may be substantial (a limited number of contractors measure K routinely). Thermal conductivity determinations permit a better quantification of the thermal flux and establish a more uniform parameter for comparing data in different rock types, both within a hole and from hole to hole. A change of gradient on a temperature log may result from a lithologic change rather than from proximity to fluid conduits. Experienced thermal explorationists would utilize a limited number of thermal conductivity determinations to answer specific questions if their evaluation of thermal data includes an integration of rock type (thermal conductivity) changes.

Wilson and Chapman (1980) present an excellent in-depth study of thermal exploration data at Roosevelt Hot Springs, Utah. The planning of drill hole depths, number of conductivity determinations and other aspects of the study are more of an academic exercise than a cost-effective exploration effort, however.

3. Electrical Methods

a. Introduction

A wide variety of electrical geophysical methods ~~have~~ has been used in geothermal exploration. As noted earlier in our discussion of the physical properties of geothermal systems, thermal waters become increasingly conductive with increasing salinity and with increasing temperature (Figure I-10). In addition the long-term interaction between thermal fluids and the subsurface environment gives rise to extensive wall rock alteration (Moskowitz and Norton, 1977). The alteration produces conductive mineral assemblages such as clays and may develop additional porosity. This environment of low-resistivity pore fluids and conductive mineral assemblages is typically an excellent target for the electrical exploration techniques already well developed.

b. Magnetotelluric (MT) Studies

The magnetotelluric (MT) method is routinely used in both the reconnaissance and detailed stages of geothermal exploration. The earth's electric and magnetic fields vary as a function of frequency in response to natural electrical (telluric) currents flowing within the earth's crust. Through precise measurements of the electric and magnetic field components made at the surface, one may obtain information relating to the impedance distribution (i.e., electrical resistivity) to depths as great as 40 km within the earth's crust. The reader is referred to an excellent paper by Vozoff (1972) for a detailed description of the method.

Ward et al. (1981) noted that MT was used in most of the Basin and Range exploration programs which they reviewed. They attribute this to its advertised great depth of exploration and ability to detect the hot rock source of heat at depths of several tens of kilometers. Neither of these attributes is necessarily correct.

For a three-dimensionally inhomogeneous earth, one's ability to predict the distribution of resistivities at depth is severely limited by the influence of surficial conductors such as alluvial fill or shallow alteration zones (Wannamaker et al., 1980). The conductivity of magma at elevated temperatures is strongly dependent upon the partial pressure of water (Duba, 1974). Hot dry rocks are good insulators almost by definition.

The most complete interpretation effort described to date for a detailed MT data base (93 stations) in a geothermal environment is the work of Wannamaker et al. (1980) at Roosevelt Hot Springs. Their extensive two- and three-dimensional model studies clearly indicate the limitations of 1-D and 2-D modeling at Roosevelt Hot Springs and probably for most Basin and Range type geothermal reservoir areas. A few of their more general conclusions should should be restated here:

1. Current gathering in the valley results in a regional distortion of the electric field affecting all stations at Roosevelt Hot Springs for lower frequencies.
2. The TM (transverse magnetic) mode is most appropriate for 2-D interpretation and has yielded good results for geometrically regular 3-D prisms.
3. A geometrically regular reservoir of conductive brine beneath the thermal anomaly seems improbable, so the search for any economic hydrothermal reservoir at Roosevelt Hot Springs using MT must be considered unsuccessful at this time. If

present, it is not resolved by the 2-D TM (transverse magnetic) algorithm. The brine-saturated reservoir zone is clearly 3-D and difficult to model satisfactorily with present interpretation capabilities.

4. A deep heat source for the geothermal system also has not been discerned by MT interpretation at this time. Uncertainties about the physiochemical state of this source (a hot but solidified magma chamber is not likely detectable by any electrical method) as well as the probable 3-D nature of its geometry again make difficult its understanding with present modeling expertise.

A recent numerical model interpretation for MT data at the Tuscarora, NV geothermal area is reported by Mackelprang (1981). Mackelprang's model results show that an extreme range of ambiguity exists for equal equivalent fits to the observed MT data. Here again a near-surface conductive zone associated with thermal springs, and conductive valley fill dominate the response of any deep-seated conductive reservoir.

A recent paper by Stanley (1981) presented the results of a 97 station MT survey of the Cascades volcanos region. Mozley and Goldstein (1981) report a more detailed study which attempted to define resistivity structure around Mount Hood. Both studies present interesting results in an academic sense but neither indicates a successful, high resolution delineation of geothermal features.

The MT method is expensive - perhaps $30,000 to $50,000 for a 25 station survey in reasonably accessible areas. Numerical modeling to arrive at a reasonable (but still ambiguous) model solution using two-dimensional or three-dimensional algorithms could easily add $3,000 to $10,000 in costs. We do not consider the method appropriate for reservoir delineation or drill hole siting. It seems more applicable to regional, academic-oriented studies or jointly funded reconnaissance surveys. don't agree

c. Electrical Resistivity

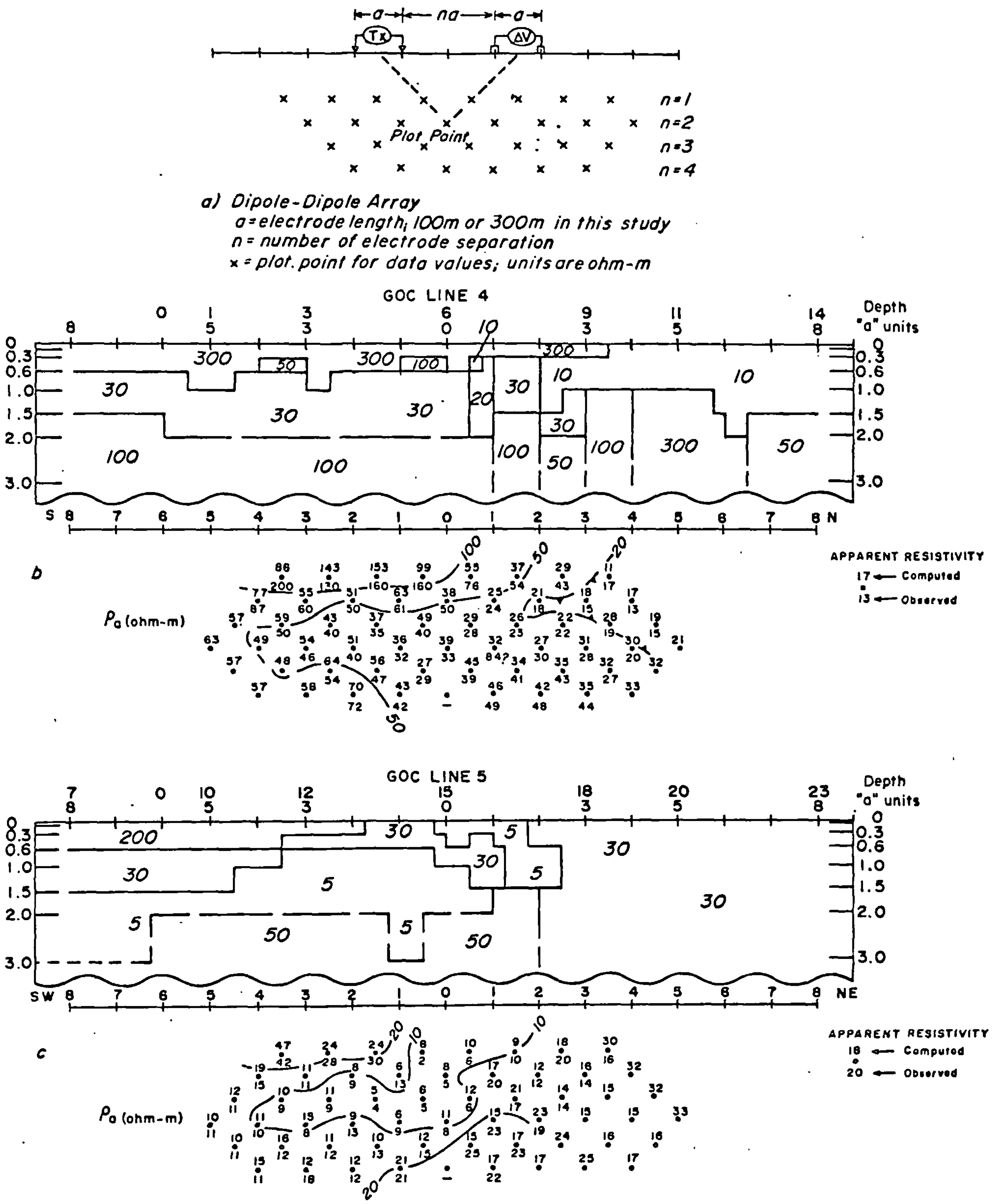
The electrical resistivity method is routinely used in mineral exploration and, in specialized arrays, for hydrologic and engineering studies. Two arrays often used in geothermal exploration are the Schlumberger array, for vertical sounding, and the dipole-dipole array for profiling.

Interpretation of Schlumberger data assumes a one-dimensional geometry (layered earth). In most geothermal environments, expanding the current electrode spread length moves the electrodes across lateral resistivity variations and thus invalidates the interpreted resistivity variation as a function of depth only. This array is clearly not suited for the complex geometries of active tectonic environments.

The dipole-dipole array uses multiple transmitter and receiver spreads, a constant dipole length, and expanding distance between transmitter and receiver spreads to record a large number of apparent resistivity values. This array responds to horizontal as well as vertical resistivity variations. The data are plotted ~~up~~ in the form of a pseudosection as shown in Figure II-8 and can be interpreted either quantitatively or qualitatively. The survey profile is generally chosen perpendicular to known or suspected geologic structures in order to achieve the largest resistivity contrasts and highest spatial resolution, and to facilitate subsequent two-dimensional numerical modeling. The current flow paths for this array permit good resolution of lateral changes in resistivity. This characteristic makes the array well suited to detailed exploration in complex (faulted, intrusive, volcanic) geologic environments.

The quantitative interpretation of dipole-dipole data is normally accomplished through an iterative forward modeling approach, although some inverse interpretation methods are being developed. We have had the opportunity to complete numerical model interpretations for dipole-dipole resitivity data of seven high-temperature geothermal areas in Nevada, for Coso Hot Springs, CA, and for Roosevelt Hot Springs (Figure II-8) and Cove Fort-Sulphurdale, UT. Low-resistivity zones are associated with the geothermal systems in all cases. At Cove Fort-Sulphurdale a modeled body of 5 sq km and 4-5 ohm-m resistivity characterizes much of the geothermal system. The low-resistivity zone at Roosevelt Hot Springs is more complex but correlates very well with the high-heat flow area (> 800 mW/m^2). Our interpretations of the two major geothermal systems in the Rift Valley of Africa (Olkaria, Kenya; Lakes District, Ethiopia) show similar results.

The effective depth of exploration for the method is



a) Dipole-dipole array geometry and plotting convention

b) GOC line 4: Numerical model

c) GOC line 5: Numerical model

Figure II-8. Dipole-dipole electrical resistivity survey from Roosevelt Hot Springs, Utah.

approximately twice the electrode length when read to the sixth (n=6) separation. Thus an electrode separation (a) of 300 m (∿ 1000 ft) should yield interpretable results for resistivity discontinuities 600 m (∿ 2000 ft) deep. Model studies by Smith et al. (1981) indicate an even greater depth range of 2.5 to 3 times a. Lateral resolution is reduced as electrode separation increases, and the wire lengths and logistics become cumbersome for very large dipole lengths. Dipole lengths of 450 m and 600 m may be the largest practical for most geothermal exploration, and these would afford 'depth penetration' to at least 900 or 1200 m. The electrical resistivity method, using the dipole-dipole array in particular, should be considered essential to drill siting in most geothermal environments.

d. Electromagnetic Soundings

Other resistivity measurements utilize the bipole-dipole or roving dipole array for reconnaissance-type resistivity mapping. Studies by Frangos and Ward (1980) and Hohmann and Jiracek (1979) show that these measurements are very sensitive to the (almost random) placement of the transmitter source and the results are often difficult to interpret correctly. These arrays should only be considered if a reconnaissance resistivity program is undertaken without specific target areas.

Several other techniques are available to determine the earth's resistivity structure to various depths. Lawrence Berkeley Laboratory (LBL) has developed a large moment controlled-source electromagnetic sounding system, the EM-60, that reportedly yields resistivity results comparable to, but less detailed than, the dipole-dipole array (Wilt et al., 1981). Sandberg and Hohmann (1980) describe a controlled source audio-magnetotelluric (CSAMT) survey at Roosevelt Hot Springs which compares well with dipole-dipole resistivity data for shallow depths (less than 100 m). Our present evaluation is that these methods offer no advantages over dipole-dipole resistivity for exploration depths of 300 m or greater. The methods are not routinely available through survey contractors and, partially because of this, are not cost-competitive.

e. Induced Polarization

Induced polarization (IP) measurements are the primary geophysical techniques for detecting buried disseminated sulfide deposits. Polarization effects can also arise from clay minerals and zeolites, which this has led to some experimental IP surveys in geothermal areas (i.e., Chu et al., 1979; Ross, 1980). We have observed two major problems which make IP ineffective in *some* geothermal environments. Pyrite distribtuions which may be unrelated to the present geothermal system can dominate and confuse the weaker clay or zeolite responses. Long observation times are required to record low-frequency signals in low-resisitivity environments, and the low frequencies are required for accurate coupling removal to establish the true polarization effect. The recording of induced polarization data could substantially increase the time and cost of the resisitivity survey, and the resistivity information itself is probably the better indicator of the geothermal system.

f. Self-potential (SP) Studies

Self-potential surveys have been used by a few of the major firms engaged in geothermal exploration (Ward et al., 1981). Recent papers by Corwin and Hoover (1979), Fitterman (1979), Sill (1981) and Hulse (1979) present a theoretical basis, model results, and observed data showing the utility of the method for geologic mapping and geothermal exploration. Two geothermal phenomena which give rise to SP anomalies are thermoelectric coupling and electrokinetic coupling (Corwin and Hoover, 1979). Thermoelectric coupling describes the phenomenon whereby a voltage gradient is generated across a given rock sample in response to an existing (or imposed) temperature gradient. Electrokinetic coupling (also called the streaming potential) results from the flow of a fluid through a porous medium. For a simple capillary tube the governing expression is

$$E = \frac{\rho\varepsilon\zeta}{4\pi\eta}\,\Delta P$$

where ρ = electrical resistivity, ε = dielectric constant, η is the viscosity of the pore fluid, ΔP is the pressure drop along the flow path, and ζ is the voltage across the Helmholtz double layer.

Well-defined self-potential anomalies have been defined at several major geothermal areas: Kyle Hot Springs, Beowawe and Leach Hot Springs, NV; Kilauea volcano, HI; Yellowstone National Park, WY; Raft River, ID; Roosevelt Hot Springs and Red Hills, UT. Anomaly amplitudes of 100 mV are common. Both polar and dipolar anomalies have been observed in the Basin and Range geothermal areas.

There are several non-geothermal causes for self-potential anomalies including soil type changes, formational effects, topographic differences, non-thermal water flow, and mineralization. These certainly complicate the use of the method, together with the fact that several geothermal areas have no significant self-potential anomaly.

Some industry geophysicists have commented, off the record/ that self-potential surveys may be their most cost-effective exploration method. The method is relatively low-cost, and a reasonably detailed survey for 50 sq km (20 sq mi) can be completed for less than $20,000. While the utility of the method seems to have been demonstrated for the Basin and Range, one can anticipate major problems in the Cascades due to severe topographic effects and strong near-surface hydrologic flow related to recharge. Inclusion of self-potential surveys in the exploration program must be considered on a site-specific basis.

4. Seismic Methods

a. Introduction

A broad spectrum of seismic methods have has been tried in geothermal exploration. Passive seismic data include long-term historical records of major earthquake activity, microearthquake surveys and, at a lower magnitude of naturally occurring seismic disturbance, seismic emissions or "noise" surveys. Active seismic methods used include refraction, CDP "Vibroseis" and dynamite source reflection, and simple weight drop reflection surveys.

On a regional scale areas of high seismicity, as indicated by earthquake recording networks, define active tectonic provinces which include most areas of geothermal potential in the western United States. Unfortunately many seismic zones have little geothermal potential.

Microearthquake surveys have been completed in several geothermal areas including Coso Hot Springs and The Geysers, CA; Tuscarora and McCoy, NV; Roosevelt Hot Springs and Cove Fort-Sulphurdale, Utah; and Raft River, ID. Some general observations may apply to the seismic behavior of these systems. Earthquake activity is generally episodic rather than continuous. Earthquake swarms, sometimes including tens to hundreds of events over a few days, may be typical. Earthquake magnitudes are small, generally -0.5 < M < 2.8, with shallow focal depths generally less than 5 km. The data are interpreted in terms of P-wave delays, S-wave attenuation, and position and alignment of epicenters. The alignment of recent events at Roosevelt Hot Springs and Cove Fort-Sulphurdale may be very important in understanding reservoir geology but still do does not appear to indicate high priority drilling targets.

not microearthquake — teleseismic data are, though

Microearthquake surveys may play a more important role in exploration for deeper, blind geothermal systems where cold water overflow masks near surface thermal and electrical characteristics, such as the Snake River Plain and the Cascade

Province. In these areas portable seismometers should be in place for three to six months rather than the typical one month survey generally offered by contractors. The location of epicenters within two km and depths to one km accuracy should be a later stage design goal for the surveys.

lateral location is usually better than vertical

b. Seismic Emissions Survey

Seismic emissions surveys have been promoted by several geophysical contractors as a geothermal exploration method in which the seismic emissions or "noise" would hopefully delineate active fault and fracture zones possibly associated with geothermal activity. The method employs an array of geophones (four or five) spaced approximately 610 m apart. In surveys at Roosevelt Hot Springs (Katz, 1977a; 1977b), data were recorded at each array for one to three days. Five such stations within a 36 to 41 Km^2 area constituted a survey. The data were edited and processed with algorithms which determined the noise source locations based on delay times computed for a half-space velocity model and the correlation of these delays with the observed data. This procedure was completed for a northern and a southern survey block at Roosevelt Hot Springs.

As employed at Roosevelt Hot Springs, the seismic emissions survey may indicate areas of geothermally induced seismic noise but clearly records other noise sources and is imprecise in defining geothermal conduits. The correlation procedure is severely limited by model simplicity and velocity assumptions and generally recognizes source direction more accurately than distance to the seismic noise source. A more refined velocity model could perhaps improve the resolution of the noise source areas through a higher correlation of source-to-geophone array delay times. It is unlikely that the velocity model could be refined enough to justify inclusion of the method in geothermal exploration in complex geologic environments.

The relative cost-effectiveness of the passive seismic methods in locating hidden reservoirs is still very much in doubt but may be gaining acceptance by industry in the expanding search for blind geothermal systems.

c. Seismic refraction

Seismic refraction profiles have been recorded at The Geysers, Yellowstone National Park, Roosevelt Hot Springs, and probably several other geothermal areas. These studies may be appropriate for regional- scale structural or crustal studies (attenuation by magma chambers, etc.), but they do not have the spatial resolution or signal averaging appropriate for prospect-scale delineation. Hill et al. (1981) recently reported on a 270 km long profile from Mount Hood to Crater Lake in the Cascades and presented their results in terms of crustal velocity structure.

d. Reflection seismic surveys

Until recently there had been limited application of reflection seismic methods in volcanic-covered regions and in the Basin and Range. Improved data processing and recording techniques have met with some success in the exploration of these complex "bad record" areas.

Ross et al. (1981) reported very usable CDP seismic survey data at San Emidio, Stillwater, Soda Lake and Dixie Valley in the Basin and Range. These surveys were conducted over alluvial or lakebed-filled valleys and deeper volcanic units. The data mapped basin border faults, the thickness of basin fill, and buried volcanic units. Data recorded over shallow or outcropping volcanics at Beowawe suffered from strong early reflections, substantial ringing, and poor energy penetration to depth. Extensive seismic surveys over Columbia River basalts near Hanford, Washington provide little geologic information other than the depth to the top of basalts. Applegate and Donaldson (personal communication) have reported some success near Raft River in the Snake River Plain, although some of the data are not interpretable.

Inclusion of reflection seismic surveys in the detailed exploration program is not generally advisable in volcanic-covered areas, but the method should certainly be considered for alluvial or sediment-covered areas. Quality CDP (Common Depth Point) surveys, together with the required data processing, currently cost $6000 to $9000 per line mile, exclusive of mobilization/demobilization charges.

5. Magnetic Methods

The inclusion of aeromagnetic data in a given geothermal exploration program should be given careful consideration. There are two major areas in which the magnetic data are applicable: Curie point isotherm determinations; and interpretation for subsurface geologic information.

Curie point isotherm studies have been reported in the literature by Bhattacharyya (1978), Shuey et al. (1977), Aiken et al. (1981) and many others. At least two geophysical contractors have promoted Curie isotherm surveys while selling airborne surveys and interpretational services. It is indeed desirable to know the locations of shallow high-temperature areas within the earth's crust but these interpretations are dependent on many assumptions and incur problems. It is assumed that long wavelength negative anomalies due to lithologic changes (i.e., alluvial basins in the Basin and Range) do not significantly perturb the interpretation, and that the bottom of a magnetized crustal block is due to temperatures above Curie point rather than to deep-seated lithologic changes. Numerous other limitations apply to the interpretational algorithms and the data themselves. Our present judgement is that: Curie point depth anomalies have been determined with unknown accuracy in some cases; it is a regional exploration guide except perhaps in active volcanic provinces; many interpreted Curie point highs are really lithologic changes at depth or lateral geologic changes.

Aeromagnetic surveys are widely used by industry in petroleum and mineral exploration in attempting to map subsurface structure and lithologic changes. The use in geothermal exploration should closely follow that of mineral exploration, for most geothermal resources are located in active tectonic environments characterized by a broad range of volcanic and intrusive rocks and often by active structural movement. Magnetic susceptibility often varies from 0 to 7000 μcgs units in these rock types and provides major magnetization changes which delineate geologic units. The scale of many geothermal systems is also similar to porphyry-type mineral ocurrences.

Regional aeromagnetic data are often available as part of state sponsored, USGS, or NURE magnetic survey programs. These data, as at the Baltazor and Carson Sink areas, often show major structural features and aid in forming a generalized geologic model for otherwise covered geology prospect areas. These regional data are generally too widely spaced and/or too high to warrant detailed quantitative model interpretation.

Aeromagnetic data acquisition is relatively inexpensive compared to most geophysical exploration methods. A detailed survey appropriate for geologic information in support of a geothermal program would require a line spacing of one quarter to one half mile (0.5 to 1.0 km) and terrain clearance of 500 to 1000 feet (150 to 300 m). The approximate cost for a survey of 450 sq mi at 3 lines per mile, $20 per line mile, would be $12,000. A state-of-the-art interpretation supported by numerical modeling could add another $3000. The $15,000 may be the cost equivalent of three or four shallow thermal gradient holes.

The locations of geologic structures (faults, fracture zones), intrusives, silicic domes and possibly major alteration areas (speculative) are apparent on data we have examined from: the Coso Hot Springs KGRA, CA, from Baltazor, Tuscarora, McCoy, Beowawe, NV, from Cove Fort-Sulphurdale and Roosevelt Hot Springs, UT, and from a moderate-temperature prospect near Alamosa, CO along the northern extension of the Rio Grande Rift. Figure II-9 from the Roosevelt Hot Springs area illustrates this point. Structure L2, striking east across the outcrop of the Mineral Mountains, extends this key structure well beyond its mapped area in the range (Ross et al., in prep.). The eastern margin of magnetic sources numbered 7a and 7b lies along the intermittent occurrence of the Opal Mound Fault and extends the position of this feature and defines an upthrown tilted block of basement gneiss.

Mabey (1980) has reported on the use of aeromagnetic data for the Raft River area of the Snake River Plain. Bacon (1981) interprets major structural trends and fault zones from aeromagnetic data in the Cascades. Couch et al. (1981) report Curie point isotherm minima of 5 to 9 km for several areas within the Cascade Mountains area, again based upon magnetic interpretation.

The general utility of the method, the applicability to numerical modeling, the low unit costs, all argue strongly for inclusion of detailed aeromagnetic studies in the well-considered geothermal exploration program.

6. Gravity Method

Gravity data is often acquired or compiled in the early stages of an exploration program. Regional data, with station densities of 1 station per sq km to 1 station per 25 sq km, may be available as the result of USGS studies, the Department of Defense (DOD) regional data compilation, or of university or state supported geophysical

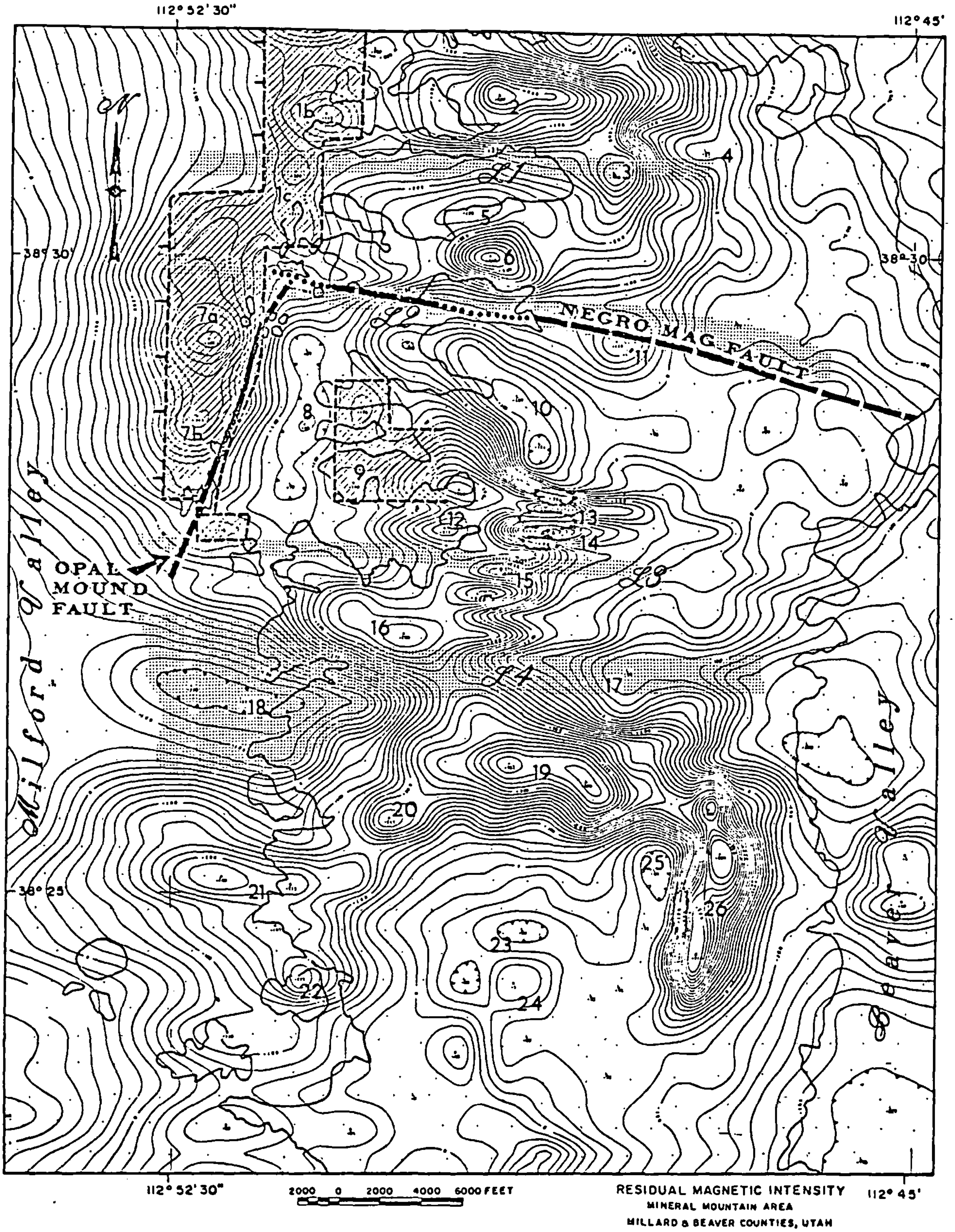


Figure II-9. Aeromagnetic survey from the Roosevelt Hot Springs area, Utah.

studies. These data are generally the starting point for detailed survey design rather than the basis for detailed interpretation.

The contribution from gravity data is much the same as from aeromagnetics, that is, structural and lithologic information. The location of Basin and Range faults, thickness of alluvial fill and thickness of volcanic cover are problems addressed by gravity surveys for both the mining and geothermal industry. The delineation of low-density silicic intrusives, magma chambers in the Cascades, or major structural zones of crustal significance are other applications of the method.

At the Roosevelt Hot Springs, Utah, gravity data contribute little to the specific delineation of the geothermal system but do indicate that no major vertical offsets occur along range front faults (Ross et al., in prep). Nearby at Cove Fort-Sulphurdale the gravity data map the many faults which define the Beaver-Cove Fort graben and add substantially to the geologic model for the area (Figure II-10). In a similar manner the gravity data have delineated major faults which probably control the geothermal fluid flow at Alamosa, CO (Mackelprang, in prep.) and at Baltazor Hot Springs (Edquist, 1980). Biehler (1971) reports the delineation of a gravity high in the Imperial Valley of California which he attributes to the precipitation of silica and carbonates in sediments above the hydrothermal system.

Regional gravity studies and their interpretation play a major role in understanding the tectonic framework of geothermal systems in the Cascade Range. Bacon (1981) reports a contiguous zone of gravity

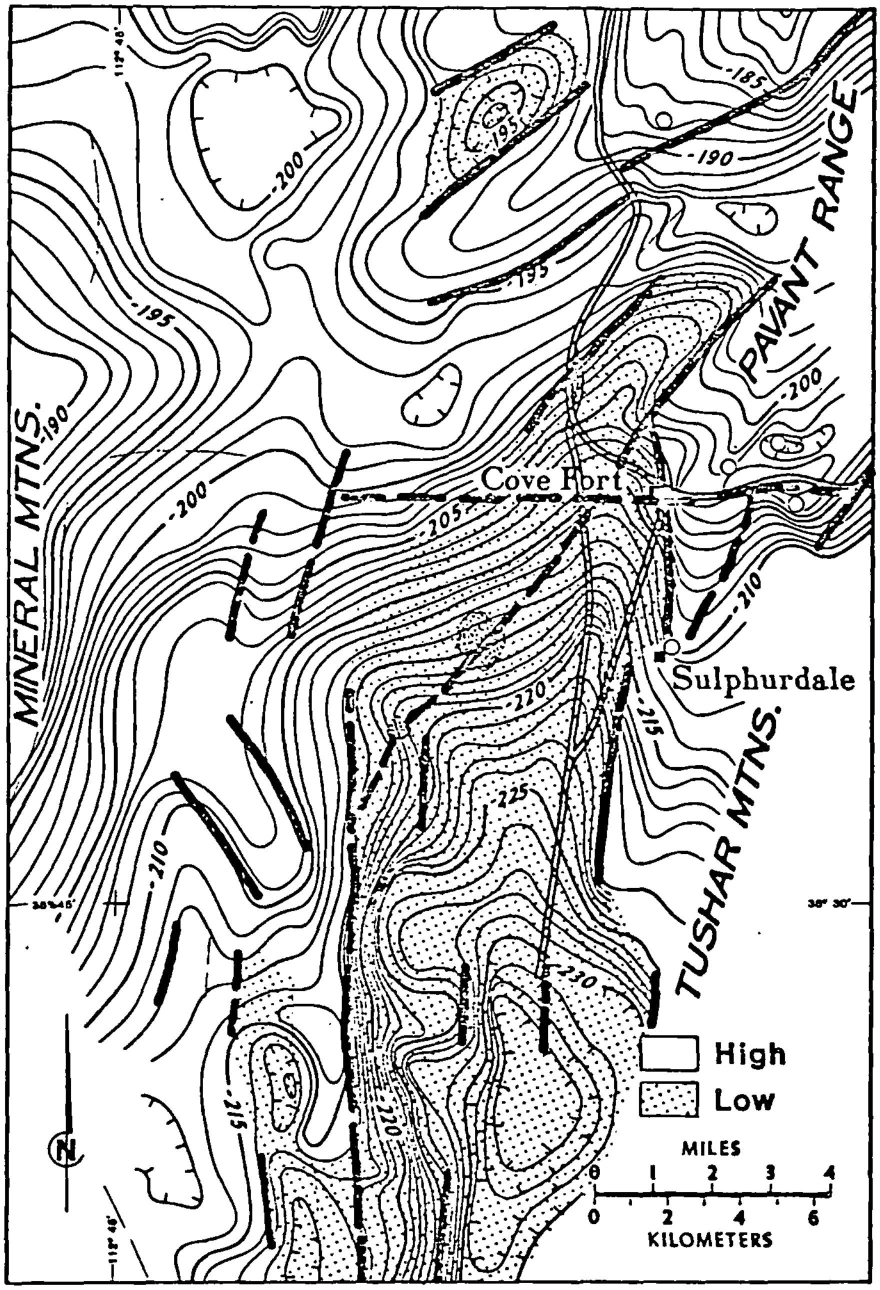


Figure II-10. Bouguer gravity from the Cove Fort-Sulphurdale area, Utah.

lows west of the High Cascades in central Oregon and notes that these define major structural trends and delineate fault zones which may localize the movement of geothermal fluids. The zone of gravity lows coincides with (1) an abrupt east-to-west decrease in heat flow from High Cascades values of 100 to 40 mW/m^2, and (2) a substantial east-to-west increase in depth to the lower crustal conductor defined by magnetotelluric soundings. Couch et al. (1981) report similar interpretations. Williams and Finn (1981) have described complexities in gravity data reduction especially important to the Cascade Province. They report that the large silicic volcanos (calderas exceeding 10 km diameter) produce gravity lows when proper densities (2.15 to 2.35 g/cm^3) are used for the Bouguer reduction. All other volcanos produce gravity highs as a result of higher-density subvolcanic intrusive complexes.

It would appear that gravity data could also contribute to a detailed exploration program in most geothermal environments. Regional data for the particular area should first be studied to see if detailed surveys should be included in the exploration program. The contract cost of detailed surveys, complete with elevation control and complete data reduction, would probably be in the range of $30 to $50 per station.

7. Well Logging

A program of well log recording and log interpretation is recommended for each exploration well. The objectives of geothermal well logging parallel those of petroleum logging and include: the identification of lithologies and lithologic changes; the location and identification of fracture zones and structures; determination of borehole conditions such as lost circulation zones, mud invasion zones, borehole enlargement or washout; porosity determination (often inaccurate for igneous and volcanic rocks); and temperature identification of fluid entries (i.e., hot or cold fluids).

The need for well logging is reinforced as the recovery of drill cuttings decreases, and with an increase in hole sloughing, mixing of cuttings within the hole, and mud return lag. A much more accurate location (in depth) of lithologic features and potential production zones is possible through logging and log interpretation, and this is required for successful hole stimulation and well completion activities. Well surveys are often used in geothermal wells and typically distinguish major deviations from the vertical, often following high angle structures or zones of weakness.

A program of geophysical well logging will likely be compromised by the availability of contract logging crews and high-temperature tools, and by the cost of the surveys themselves and standby rig time. It may be necessary to circulate the hole prior to logging to prevent tool failure in high-temperature holes. Hole caving situations which require immediate casing would also compromise the logging program. The most useful logs for geothermal wells include: mud log, temperature log, neutron, caliper, density, resistivity and gamma ray logs. Accoustic, self-potential, and pressure logs may, of course, contribute information but would generally be given a lower priority. Reports by Glenn and Hulen (1979) and Glenn, Ross and Atwood (1980) discuss log interpretation in geothermal environments in additional detail and give additional references. Composite well log plots which include lithologic and petrologic data have been found to be very useful in understanding the reservoir geology and its physical properties.

III. EXPLORATION RESULTS AND RECOMMENDATIONS

A. Drilling Success Ratios

The determination of the success of a geothermal well is somewhat subjective. In general, we will consider a well successful if it encounters fluids at a temperature and flow rate which will achieve the desired purpose of the well, such as the generation of electrical power. In a number of instances, wells drilled for electrical applications have encountered fluids which are suitable for direct heat applications but not for the generation of electricity. These wells are considered failures in our evaluation. This is justified by the fact that few if any of these wells are now being used in direct heat projects, although some are undergoing testing. This phenomena is due to the lack of interest of most of the major geothermal producers in direct heat applications.

An annual update of geothermal drilling in the western United States is provided in issues of Geothermal Energy Magazine (Smith et al., 1976, 1977, 1978, 1979, 1980; Ehni, 1981). Some of the results of the past five years of geothermal drilling are presented in Table III-1. Clearly the available data are too scanty to provide statistically significant conclusions. However, some trends are perhaps developing. The total number of wells drilled ~~are~~ is increasing regularly. Most of these are either producers or step-out wells within known districts, principally The Geysers and the Imperial Valley. Table III-2 illustrates general data for The Geysers geothermal field, including development, step-out, workover, and exploration wells. This area is characterized by impressive success ratios (successful wells divided by total wells

Table III-1. Drilling data for the geothermal industry in the western United States (from Smith et al., 1976, 1977, 1978, 1979, 1980; Enhi, 1981).

						WILDCATS		
YEAR	TOTAL HOLES	TOTAL FOOTAGE	TOTAL WELLS	TOTAL PRODUCERS	SUCCESS RATIO	TOTAL	PRODUCERS	SUCCESS RATIO
1975	51	355,143	46	37	.80	6	1	.17
1976	65	437,752	52	39	.75	21	2-3	.09-.14
1977	52	374,129	47	25	.53	15	0	0
1978	58	433,703	49	30	.61	13	2	.15
1979	77	552,329	61	42	.69	17	2	.12
1980	82	595,002	66	51	.77	15	2	.13

Total holes include production wells, wildcats, injection wells, and deep observation holes.
Total wells include total holes minus wells drilled for injection, observation, and workover.

Table III-2. Drilling data for The Geysers geothermal field, including development, stepout, and exploration holes (references of Table III-1. Footage drilled includes workovers. NA indicates data not available.)

YEAR	1975	1976	1977	1978	1979	1980
drilled	24	30	32	25	31	38
producers	20	20	19	14	25	35
workover	NA	NA	NA	2	2	4
success ratio	.83	.66	.59	.56	.81	.92
footage	197,373	243,936	260,495	237,481	289,311	323,329

drilled) unequaled elsewhere in the geothermal industry. Table III-3 gives drilling data for the western U.S. excluding that done in The Geysers geothermal field.

In contrast with the success rates at The Geysers, Table III-4 presents information from Union Oil Company's Baca Project of the Valles Caldera in New Mexico. The project has been underway since 1973. Since 1978 the U.S. Department of Energy and Public Service Company of New Mexico have participated with Union in the 50 MW Baca Geothermal Demonstration Power Plant. All data generated by that project are now in the public domain. Prior to the initiation of the GDPP, Union had drilled 10 wells, four of which were able to produce 320,000 lbs/hr of steam. Since then twelve bottom hole locations have been drilled with only one producer, which contributes 30,000 lbs/hr steam to the total. The entire project is now in jeopardy. Part of the reason for this difficulty is that the project area and the size of the power plant have been defined by agreement. Therefore it is not possible for Union to explore their adjacent lands or change the size of the power plant. This does not change the fact that, rather than improving drilling success as the project matured, Union suffered the opposite. The principal problem with the lack of productivity has been the low permeability of the geothermal reservoir. Temperatures in most of the holes are at least 250°C with geothermometers suggesting reservoir temperatures over 300°C.

Success ratios of drilling in frontier environments can be formulated by looking at data from the Industry Coupled Program sponsored by the Department of Energy between 1978 and 1981. The

Table III-3. Drilling data for the western U. S. excluding The Geysers. Footages are for total drilled including injection, observation, workover, development, stepout, and exploration (references of Table III-1.)

	TOTAL WELLS	TOTAL FOOTAGE	TOTAL PRODUCERS	SUCCESS RATIO
1975	22	157,771	17	.77
1976	22	193,816	19	.86
1977	17	113,634	6	.35
1978	24	196,222	16	.67
1979	30	263,018	17	.57
1980	28	271,673	16	.57

Table III-4. Drilling results from Union Oil Company's Baca Project

TOTAL WELLS: 19 original
6 redrill
25

FOOTAGE: 117,788 original
8,947 redrill (incomplete)

TOTAL COMMERCIAL WELLS: 5 (2 additional, mechanical failures)

TOTAL STEAM: 350,000 lbs/hr (15 MWe)

SUCCESS RATIO: 0.20

SUBTOTAL WELL COSTS: $15,739,000 (4 wells not included) program was designed to eliminate some of the risk by the financial participation of the federal government. The government had no influence over the exploration projects of the companies but was entitled to data generated by those projects. These data were then placed in the public domain to be used by the exploration community. The wells drilled under this program are listed in Table III-5 with the general statistics provided in Table III-6. The success ratio is a low 0.13. In defense of this low ratio it should be stated that these were comparatively high-risk wells, and all but about three could be considered rank wildcats. The data presented are probably a good indication of the probable success ratios of wildcat wells drilled within the Basin and Range province.

Since 1975 there have been four new geothermal fields discovered within the United States. In 1975 Phillips Petroleum Co. discovered Roosevelt Hot Springs system near the town of Milford, Utah. Sunedco discovered a geothermal system in Dixie Valley, Nevada in 1978. That same year McCullough Geothermal (now MCR Geothermal Corp.) and Geothermal Kinetics Inc. (GKI) discovered the South Brawley field in the Imperial Valley. In 1979 Phillips Petroleum Co. discovered the Steamboat Hot Springs system south of Reno, Nevada. At the present time several fields are undergoing evaluation; these include Chevron's Beowawe project in Nevada and Phillip's Desert Peak project, also in Nevada.

B. Drilling Costs

Costs of drilling within the U.S. have been escalating at rates above the average annual rate of inflation. Chappell et al. (1979) have

Table III-5. Summary of holes drilled under DOE's Industry Coupled Program

Area	Company	Well	Depth	T Max	Status
Roosevelt Hot Springs, UT	Getty	52-21	7500'	398°F	Non-commercial
	GPC	GPC-15	1900'	162°F	T-gradient
Cove Fort/Sulphurdale, UT			42-7	7735'	344°FNon-commercial
		31-33	5221'	294°F	Non-commercial
		14-29	2620'	198°F	Abandoned
Beowawe, NV	Chevron	85-18	5927'	354°F	Producer
	Getty	76-17	9005'	336°F	Non-commercial
Dixie Valley, NV	Southland Royalty	45-14	9022'	385°F	Non-commercial
		66-21	9780'	336°F	Non-commercial
Stillwater, NV	Union	Debraga #2	6946'	336°F	Non-commercial
		Richard Weishaupt #1	10014'	353°F	Non-commercial
Humboldt House, NV	Phillips	Campbell "E" No. 2	8061'	312°F	Non-commercial
Desert Peak, NV	Phillips	B-23-1	9641'	414°F	Future Producer
Soda Lake, NV	Chevron	63-33	2000'	297°F	T-gradient
		11-33	2000'	367°F	T-gradient
Colado, NV	Getty	44x-10	7965'	282°F	Non-commercial
Leach H.S., NV	Aminoil	11-36	8565'	260°F	Non-commercial
McCoy, NV	AMAX	14-7	2010'	140°F	T-gradient
		66-8	2510'	216°F	T-gradient
Tuscarora, NV	AMAX	66-5	5454'	225°F	Non-commercial

Table III-6. Drilling results from DOE's Industry Coupled Program

WELLS DRILLED: 20 (5 deep thermal gradient; 15 production)

FOOTAGE DRILLED: 124,723

PRODUCTIVE WELLS: 2

SUCCESS RATIO: 0.13

Table III-7. Correction factors for drilling costs.

YEAR	$/ft INDEX *	% INCREASE	1979 $ INDEX
1973	84.5		2.29
1974	100.0	+18.3	1.93
1975	118.2	+18.2	1.63
1976	128.2	+ 8.5	1.51
1977	144.9	+13.0	1.33
1978	165.9	+14.5	1.16
1979	193.1	+16.4	1.00
1980	204.1	+ 5.7	.95
1981	(231.7)	(+13.5)	(.83)

* Oil & Gas Journal (May 19, 1980; May 11, 1981)

( ) estimate equivalent to average of cost from 1973 to 1980 reviewed the costs of geothermal wells and inflation factors for those well costs. The inflation factors for geothermal drilling were found to be similar to those published for oil and gas drilling (Oil and Gas Journal, May, 1979), and since the oil and gas inflation factors are based on such a large data base, they were used to correct the drilling costs to constant dollars. We have continued this practice, and subsequent drilling costs will be stated in equivalent 1979 prices. The correction factors for drilling costs are shown in Table III-7. Surprisingly, data for 1980 shows a lower than normal increase of only 5.7%. Inflation factors for 1981 drilling are estimated as being equivalent to the average increase of 13.5% of costs/foot over the past 7 years. The correction factors of Table III-7 have been applied to the costs of 50 geothermal wells drilled between 1973 and 1981. Figure III-1 shows well costs as a function of depth for those wells. These data are principally for production wells although two deep thermal gradient holes are also included. The data base is somewhat selective in that it does not contain data from wells drilled in The Geysers geothermal field or from the Imperial Valley. In addition, it does contain information from wells that were drilled for low- and intermediate-temperature direct heat applications (8 wells) as well as those that were drilled to develop electrical potential. We have attempted to fit regression lines to the data shown on Figure III-1 but have not achieved very satisfactory results. It is clear that there is a large variation in geothermal well costs. Many times this can be attributed to the resolve of a group to push on to a target objective in spite of extreme drilling conditions. In general, however, it is felt that Figure III-1 indicates the general range of expenditures that can be expected in the drilling

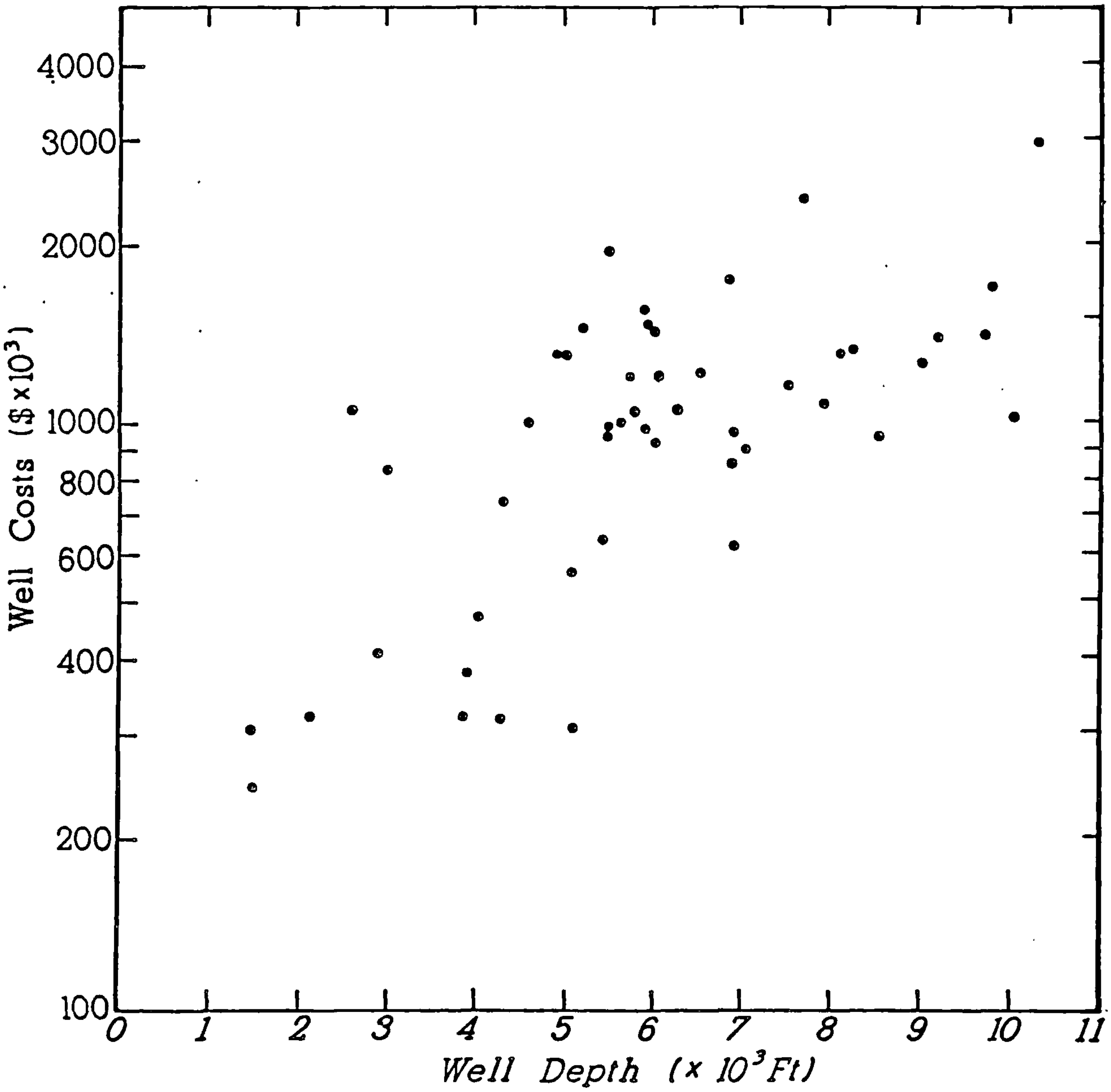


Figure III-1. Geothermal well costs in 1979 dollars as a function of depth.

of deep tests in geothermal prospect areas including The Geysers.

The same type of variation is found in drilling costs from individual project areas. Figure III-2 shows the cost per foot of wells drilled between 1973 and 1979 in the Baca project area of New Mexico. It can be seen that there is a large variation in costs but that this variation stays relatively constant although the costs are undergoing a steady increase due to inflation.

As was discussed in the section on exploration methods, it is standard procedure to drill thermal gradient holes during an exploration program. These holes are normally drilled by rotary methods. The depths are, of course, determined by local conditions, but 500 feet is an average during the initial stages of an exploration program. Companies presently budget about $10/foot for the drilling and preservation of these holes. Many companies also put a time limit on each hole to avoid high costs in the event that difficult drilling is encountered. For initial thermal gradient programs prior to the definition of a prospect area, it is common to set a limit of 500 feet or two days of drilling, which ever comes first.

Deep thermal gradient tests up to and exceeding 2000 feet are also commonly drilled during an exploration program. In the reconnaissance stage these are often drilled as a cooperative venture by several companies interested in the same district. In addition, they are often drilled in prospect areas prior to drilling a much more expensive production well. In general, the deep thermal gradient holes are drilled by rotary methods and preserved for future thermal measurements using either PVC or iron pipe. Oil and Gas Journal (June 1, 1981)

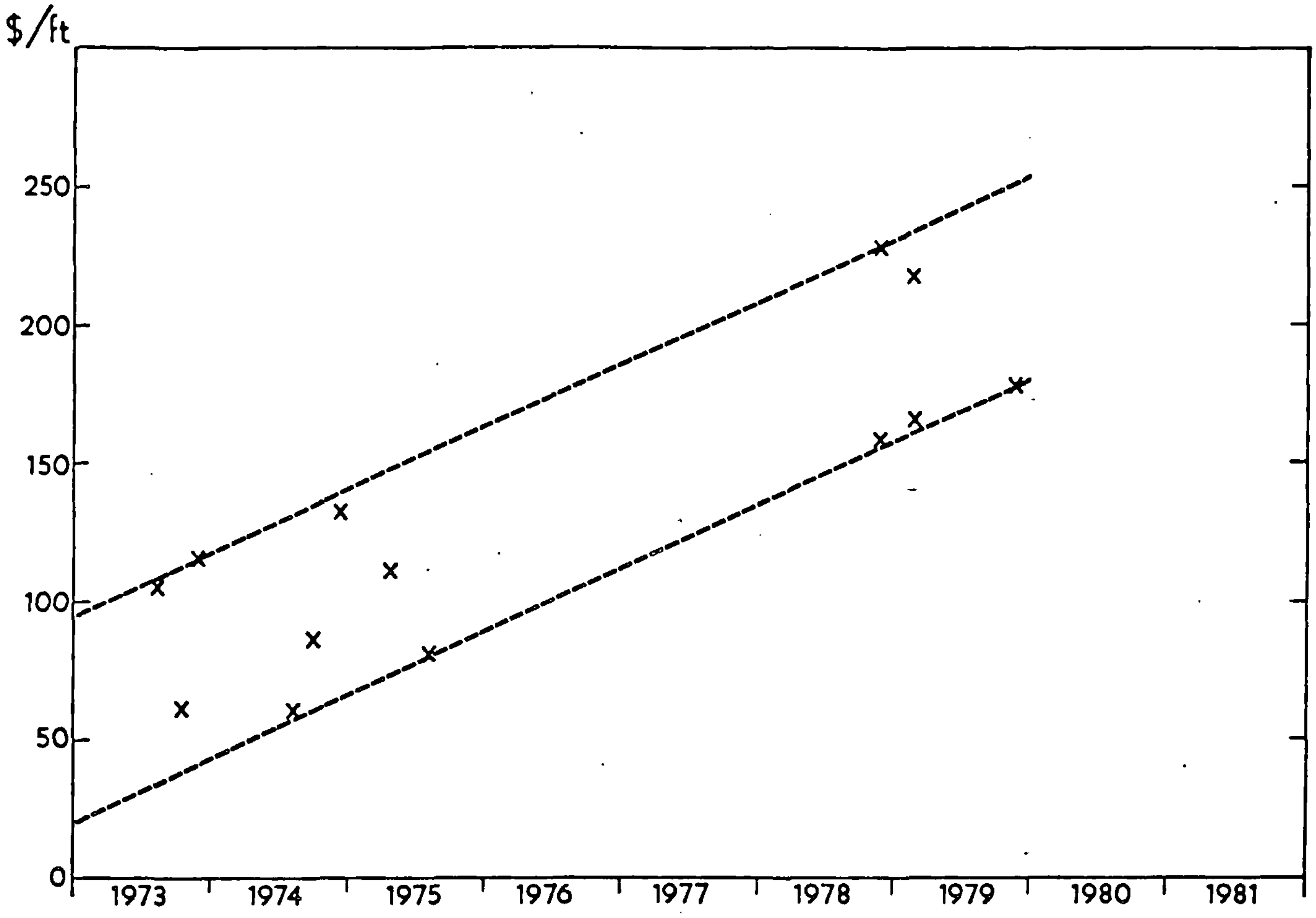


Figure III-2. Drilling costs of the Baca project, New Mexico.

suggests that the costs per foot for holes from 0-1249' is $32.45, and $34.10 for holes between 1250' and 2499'.

C. Exploration Strategy

1. Introduction

Our general exploration philosophy is outlined in Ward et al. (1981) which is included with this report as Appendix I. The philosophy is based on our exploration experience as well as having had the opportunity to observe the different approaches to exploration practiced within the geothermal exploration community.

We favor the use of exploration models; that is, conceptual models of the exploration target which are continually updated and refined as additional exploration data are collected. In this way an understanding of the exploration target is developed which is of use in the assessment of that individual target and other similar types of targets. Exploration methods are applied to solve specific problems and answer questions. They are directed to the ultimate siting of exploration drilling. Each prospect will present its own set of problems and will be in some ways unique. Thus 'cook book' exploration procedures are not likely to be successful. Many inexperienced companies have applied as many different methods as possible to a prospect, hoping that a target will be indicated by the data but failing to analyze the different data sets as they are developed. This method of operation has proved to be both expensive and unsuccessful.

Because of Homestake's stated interest in The Geysers and the Basin & Range and Cascade provinces, we will discuss these three areas individually. It should be remembered that the exploration strategies presented should be used as a generalized guide to methods and the sequence in which they are employed. We prefer to see the less expensive methods employed early in the exploration sequence to set the stage for the more expensive methods such as drilling.

2. Basin and Range Province.

Our exploration strategy for the Basin and Range province has been published (Ward et al., 1981) and is included as Appendix I. The general strategy presented in that paper is shown in Figure III-3.

Although three high-temperature systems have been discovered in the Basin and Range (Roosevelt Hot Springs, Dixie Valley, and Steamboat), the province is largely one where future activity will be considered as wildcatting. Numerous areas within this province have had the temperatures necessary to produce electricity but either have not had the permeability or the supply of water necessary to make them viable. Most of the areas which have had hot spring activity at the surface have either been explored or are under lease. Future exploration will attempt to locate systems which have no surface manifestations. These targets will be more difficult and expensive to explore than those to date.

3. Cascades Province

The Cascades province is the premier frontier area of geothermal exploration. Although most major geothermal companies do have land positions in the Cascades, few deep tests have been drilled up to

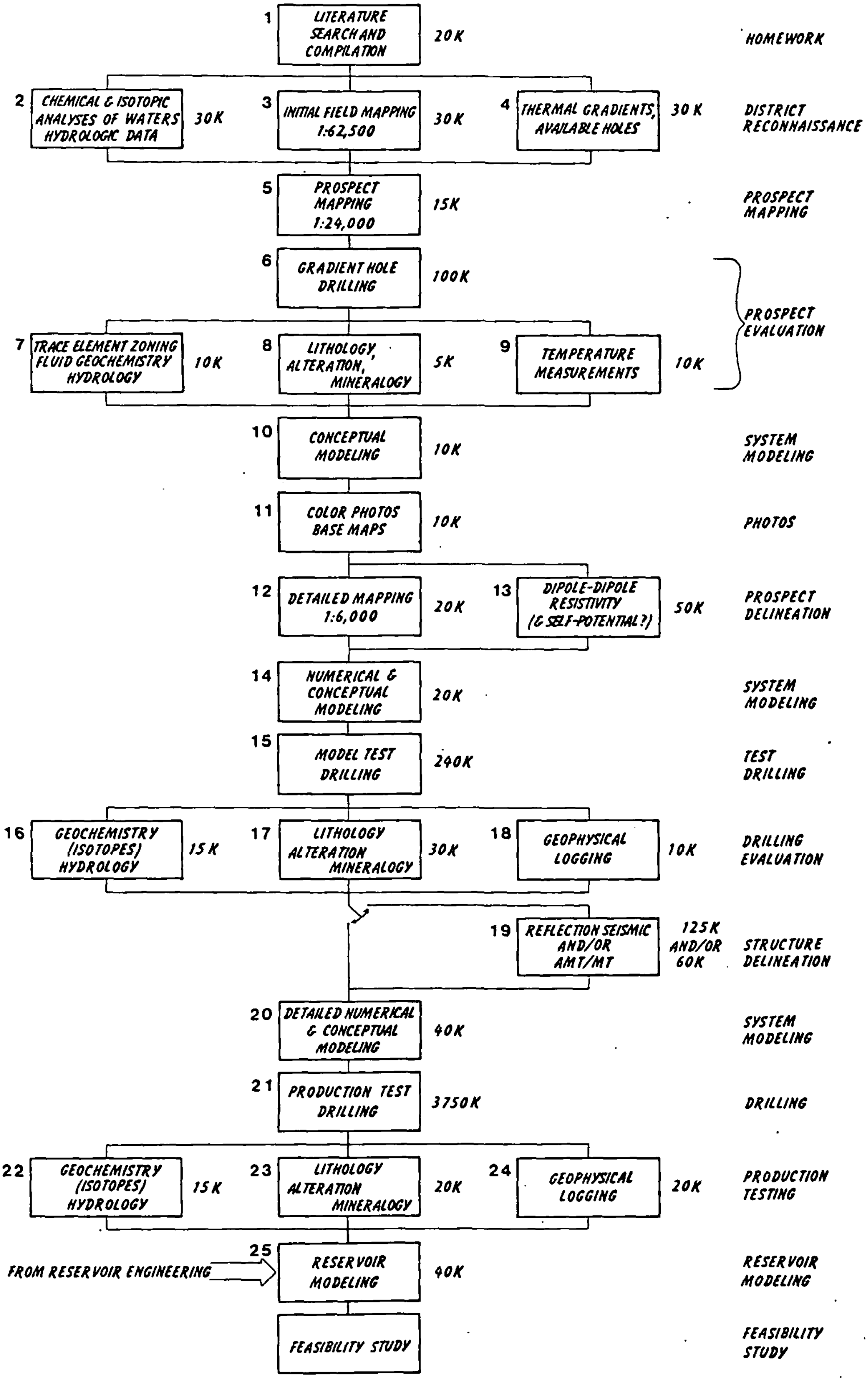


Figure III-3. Suggested high-temperature hydrothermal exploration strategy. Numbers at left of blocks indicate operating sequence. K numbers at right of blocks indicate estimated dollar cost in thousands (Ward et al., 1981).

this time. This has been due to Forest Service restrictions as well as exploration problems. The principal exploration problem is the high rainfall which produces high-volume near-surface aquifers which influence heat flow measurements and dilute any thermal spring activity. However, as shown by the recent eruption of Mt. Saint Helens, this is an area where it should be possible to find hydrothermal systems associated with near-surface intrusive activity. We would suggest basing an exploration program on the identification of areas with near-surface intrusive activity and the development of exploration programs around these areas.

The proposed strategy would involve the following stages:

(a) Literature Study designed to locate areas which are likely to have near-surface intrusive bodies. This compilation would involve evaluation of regional gravity, seismic, and aeromagnetic data as well as water chemistry, geology, and any available temperature gradient information.

(b) Once likely areas are identified, geologic mapping should be initiated as the first field activity. Because of heavy vegatation and sparse outcrops in most areas, air photos are an indispensible aid in the mapping program. Mapping should concentrate on structure, alteration, and the chronology of igneous events. During this time spring systems should be investigated with samples collected for water geochemistry.

(c) Aeromagnetics may be valuable at this stage of the exploration sequence to identify structural trends. The method is relatively inexpensive and cost-effective in areas of poor exposure and difficult access.

(d) Microearthquake surveys tend to be expensive but may be extemely valuable to locate active structures which may be related to buried heat sources. Certainly, before this technique is applied there should be evidence that the prospect region is seismically active and that meaningful data can be collected and analyzed.

(e) Deep temperature gradient holes should be drilled to evaluate the geology as well as to search for thermal anomalies. This type of hole will provide information which will allow an evaluation of the usefulness and necessity of additional exploration methods. Hydrologic information should also be collected at this time to evaluate the depth requirement of any additional temperature gradient work.

(f) Deep drilling could be attempted at this stage if warranted by the information developed.

Perhaps the best understood of the thermal fields in the Cascade Range and its northern extension, the Garibaldi Volcanic Belt, are the Newberry Volcano geothermal system in Oregon and the Meager Creek geothermal system in Canada. The exploration of these fields has not yet been completed. Nevertheless, the potential of the Cascades is well illustrated by the results obtained to date.

Both the Newberry and Meager Creek systems are characterized by recent volcanic activity. At Newberry rhyolite activity occurred approximately 1400 years ago with the eruption of obsidian flows (Macleod et al., 1981). An intermediate-depth well in 1981 drilled to 3057 feet by the U. S. Geological Survey encountered temperatures of 265°C and confirmed the potential of this electric-grade resource.

The Meager Creek field is located on the southern flank of Mount Meager, the northernmost volcano in the Garibaldi Volcanic Belt. A description of the geologic relationships in this field and a summary of the results of the assessment program are provided by Fairbank and others (1981). Fourteen 300 to 600 m gradient wells and one deep well have been drilled in an area of low resistivity containing hot spring deposits, thermal springs and seeps. These wells have documented the existence of a high-temperature reservoir with temperatures of at least 200°C in Mesozoic granitic rocks that underlie the volcanic complex.

4. The Geysers

The most efficient strategy for acquiring geothermal production from The Geysers field would be to joint-venture exploration with one or more of the major companies which are currently operating in the area. Success ratios such as shown in Table III-2 would be difficult for a newcomer to equal. The land situation would also pose problems for a totally new exploration effort.

Although most of the methods previously discussed are applicable in The Geysers, the results of most exploration activities remains proprietary.

IV. Reservoir Engineering

A. Introduction

Geothermal resources exist in an enormous range of geomorphic types, temperatures, locations, and applications (as outlined above in this paper). In northern California, Oregon, Washington, and in the Basin and Range states the geothermal resources range in type from dry steam reservoirs (Geysers) to nearly groundwater temperature aquifers. As might be expected, the drilling, testing, and methods for estimating resource characteristics depend heavily on the geology, the reservoir temperature, and the stage of development of the resource. The latter is extremely important -- for example, a well drilling or testing plan will be designed differently for a wildcat exploration project as compared to drilling at a known resource. In the former case the drilling plan will allow the engineer flexibility in the well completion, and often well-testing of lost-circulation zones will be part of the drilling procedure. In the case of a known resource where at least a few wells have been drilled, the detailed well completion can be planned in advance. In these cases the well test plan can be very specific with regard to depths, drilling fluids, cement composition, etc.

Although there is a large variety of types of geothermal resources, there are some general approaches to be taken in every case. We will review the general methodology and include some examples of particular cases that are appropriate for the Northwest and the Basin and Range geothermal resources.

B. Reservoir Characteristics

The presence or absence of fractures can have a profound impact on whether a well will produce or accept fluids. The fracture aperture size, the fracture spacing, and the comparative matrix permeability and porosity are the most important aspects. If fractures are widely spaced ($\gtrsim$ 200 ft separation) they will behave as oriented flow channels whose thermal depletion will be rapid if cool fluid is injected. If the fractures are closely spaced ($\lesssim$ 150 ft separation) they will appear and behave as an equivalent porous matrix material. In order to develop a model of how the resource will behave, the fracture representation must be known.

The material properties include the thermal and mechanical rock parameters. For fluid flow management the quantities $(k/\mu)h$ and $(\phi C)h$ must be determined.

k/μ is a mobility term

ϕC is a storage term

h is the "effective" reservoir height.

The mobility determines how the fluid moves in the reservoir, the storage determines the amount of fluid available, and the two quantities determine the long-term reservoir behavior. The effective reservoir height determines the total rate at which a particular well can flow.

The boundaries to flow can be of several different types. There can be boundaries which prevent fluid from flowing (barriers), and boundaries which contribute fluid (leaky). These are often fault-related types of boundaries, but other geological features also appear as a boundary to flow. Producing intervals that "pinch out," and regions in which either the rock type changes or mineral deposition has occurred also appear as boundaries. The latter phenomenon is common in high-temperature geothermal systems. The minerals epidote, illite, and chlorite are found along the 220 - 250°C (430 - 490°F) isotherms in sandstone reservoirs. The mineral biotite is found along the 320 - 340°C (600 - 650°F) isotherms. These minerals reduce the existing pore space and permeability of the reservoir rock, in some cases these mineral zones form an imperfect "cap rock" for the production zones.

In sedimentary systems the reservoir rock exists largely as interbedded sands and shales. The sand layers often have different grain sizes and different degrees of cementation. This results in different porosity and permeability in the different layers and in the horizontal and vertical directions. In general, the shales are essentially impermeable compared to sands, but this is only true in the absence of fractures. When fluid is removed or injected, the most permeable zones are the first to flow, and the zones with less permeability allow almost no fluid motion. This relative flow from different zones depends upon the pressure difference each zone is subjected to. If the wellbore pressure differs from the fluid pressure in the rock by a given amount, each producing layer will contribute a characteristic amount. If the wellbore flow rate is increased, the pressure difference (drawdown) increases and the amounts of fluid from each zone increase. A similar qualitative picture can be outlined for fractures in porous (or semiporous) permeable rock. Initially, the most permeable rock releases its fluid. After a certain amount of time (determined by the comparative permeabilities and porosity) the less permeable zone begins to release fluid.

The reservoir fluid properties are important for many reasons, and it is not necessary to discuss the obvious reasons for obtaining data. The fluid properties that are needed for reservoir and wellbore simulation include the equation of state, the liquid and steam saturation curves, the fluid viscosity, and the fluid heat capacity. These quantities all depend strongly on temperature and must be defined over the temperature range of interest. The fluid heat conductivity is also very desirable, but known representative values are usually satisfactory.

To describe the reservoir characteristics requires a knowledge of the location and properties of fractures, and knowledge of the formation material properties (porosity, permeability, heat capacity, etc.). The hydraulic boundaries both open and closed must be determined, as well as barriers to flow associated with mineral deposition zones. The lithology of the production and injection zones is required to determine direction of fluid flow and the reserves in place.

C. Wellbore Characteristics

When a well has been shutin for an extended period, the wellbore adopts the temperature of the surrounding formation and the water level reflects the static reservoir pressure. The condition of the casing and the effects of perforations and slots can be observed in these profiles. As the fluid moves from the reservoir to the wellbore and then up the wellbore to the wellhead, fluid expansion takes place. This expansion can be accompanied by gas exsolution, brine decompression, and steam flashing. Simultaneously, heat transfer between the flowing fluid and the rock outside the wellbore is taking place. The evolution of gas from solution results in thermodynamic and fluid dynamic effects that are not completely understood. In order to model the behavior of flowing wells without making costly field measurements, the heat transfer, fluid flow regimes, and fluid properties must be determined from measured flowing well profiles of temperature, pressure, and fluid velocity.

The fluid chemistry in the reservoir is important to know in order to determine whether the reservoir will reach the gas bubble point or steam flash-point during long-term production. The latter is important to determine because of the effects of these phenomena on the lifetime of the resource. Downhole samples of fluid provide the best representative sample of reservoir fluid, but only if the sample is obtained before flashing takes place in the wellbore, and only if the sample is obtained without flashing occurring during the sampling procedure. The latter requires that the sampling tool remain open, allowing wellbore fluid to flow-through up until the time at which a sample is to be taken.

As the reservoir fluid moves into the wellbore, the flow is predominantly from the most permeable zones, as described above. The relative velocities of these flows can be used to confirm geophysical and geological logs of the formation with regard to the presence of fractures, the relative flow capabilities of production or injection zones, and casing integrity.

To determine the static reservoir conditions, to determine downhole conditions without making downhole measurements, to determine the locations of producing and injection zones, to determine the fluid properties in the reservoir, and to determine casing integrity, wellbore profiles of pressure, temperature and flow versus depth must be measured for different rates.

D. Wellhead Fluid Characteristics

The wellhead enthalpy is one of the most crucial quantities to be determined. Together with the mass flow rate, the enthalpy of the wellhead fluid provides data on available power at the wellhead for all of the operating conditions that will be encountered during field operation. Enthalpy values are then used by the surface-facility design engineers as a basis for their equipment designs. There are several ways that this data can be obtained.

The fluid can reach the wellhead as a two-phase mixture in high temperature wells. The total fluid enthalpy is given by

$h = (xh_s + (1-x)h_L)(1-y) + yh_g$

h_s = enthalpy of steam

h_L = enthalpy of liquid

h_g = enthalpy of non-condensibles

x = quality = (mass steam)/Q = Q steam/Q

y = gas mass fraction = Q gas/Q

Q steam = steam mass flow rate

Q gas = gas mass flow rate

Q = total mass flow rate

The available wellhead power is the product hQ. This product is obviously not the available electric power or even the available steam power. The latter depends on the wellhead net steam fraction, and the former depends on heat losses, turbine efficiency, etc. When the total power is available to the surface equipment and plant designers, they can proceed to size, design, and cost (in detail) their equipment. Clearly, this wellhead available power (as a function of mass flow rate) is not the same for every well in the field. The wellhead conditions depend on the resource (temperature, flow characteristics, etc.), the wellbore (size, depth, etc.), and the wellhead pressure (this may be controlled by the surface equipment), and these parameters will vary somewhat throughout the field. The information needed for surface equipment design is a set of curves showing wellhead pressure, temperature, and enthalpy as a function of total mass flow rate. Figures IV-1 and IV-2 show examples of wellhead pressure versus total mass flowrate, and available wellhead energy versus pressure for a well that is 5500 ft. deep and a resource that is 300°C (575 F). These plots allow the plant designer to choose wellhead conditions that will maximize the available wellhead power output from the wells.

From the previous discussion and equations, it is clear that the wellhead characteristics can be obtained in several different ways. The most direct way to determine the available wellhead power is to measure the steam, gas, and brine mass flow rates. These rates give x and y directly. Measurements of the temperature and pressure then give the complete thermodynamic states of the gas, steam and liquid (assuming local thermodynamic equilibrium).

To determine the wellhead fluid characteristics, the mass flow-rates of the non-condensible gases, steam, and brine must be measured. These values can then be used, with the enthalpy of the single phases (gas, steam, and liquid), to determine the total enthalpy of the wellhead fluid. Together, the wellhead enthalpies and mass flow-rates provide curves of available wellhead power as a function of total mass flow-rate.

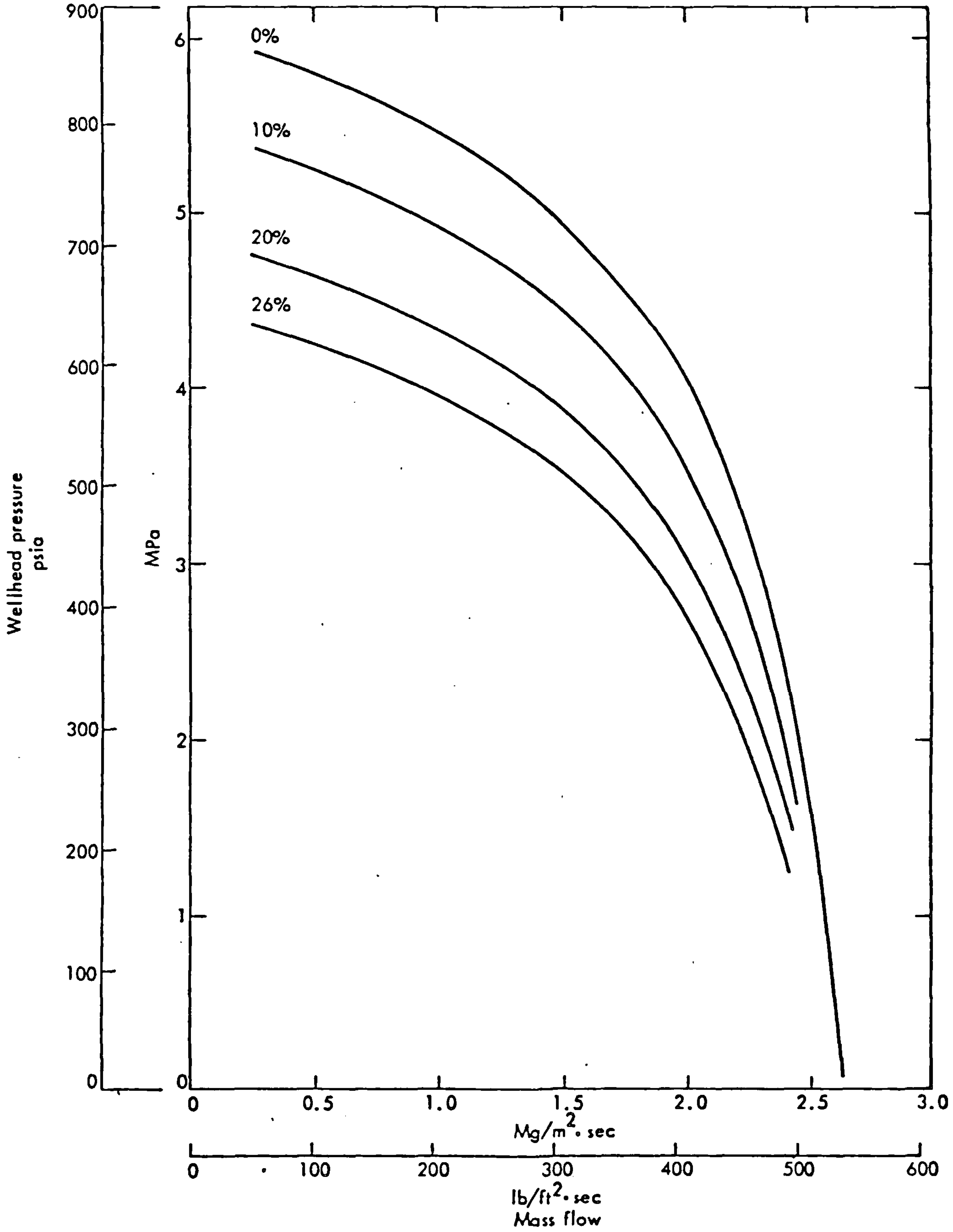


Figure IV-1. Wellhead pressure versus total mass flow rate.

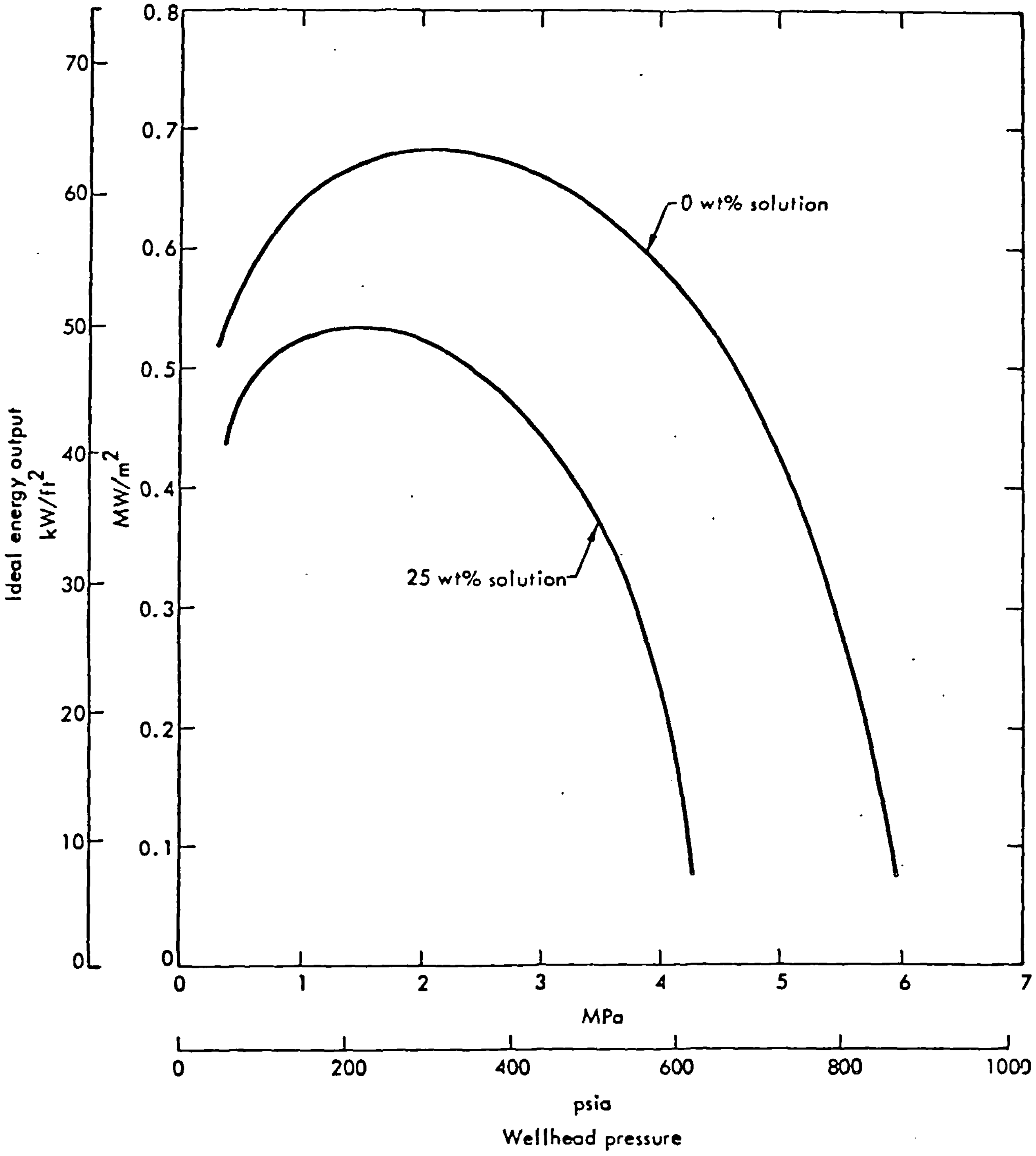


Figure IV-2. Available wellhead energy versus pressure.

E. Drilling and Completing

As indicated above, drilling and well completions will depend on the resource characteristics. For example, at The Geysers field a drill rig capable of reaching depths of 12,000 feet is required. In addition, as reservoir pressure is below the hydrostatic pressure for the reservoir depth, the drill rig must be capable of drilling with air as well as mud. The air capacity must be in excess of 3000 cu-ft/min to attain sufficient velocity to lift the cuttings out of the well. The use of air is required in the low pressure formations in order to prevent damage of the production zones (usually fractures) from heavy drilling fluids that would be lost to the underpressured fractures.

In the case of liquid-dominated resources where the reservoir fluids are usually a saline brine, the drilling follows the same procedures as for the vapor-dominated case down to the top of the reservoir, that is, the drilling is with mud to the top of the reservoir, or first fracture zone, at which point a switch is made to water. The water used for drillng is a saline brine, preferably reservoir fluid, in order to prevent damage to fractures or pore porosity when fluid is lost. When reservoir fluid is not available from nearby wells, the drilling fluid is made up of an artificial brine composed primarily of potassium chloride. The exact choice of the drilling fluid chemistry depends on the reservoir brine composition and the required weight of the drilling fluid that is needed to remove the drill cuttings and to control the well during drilling. In the case of low-temperature resources, the drilling is often done using very low-cost water well technology; the wellhead equipment and rig requirements for temperatures below 100°C and depths that are less than 2000 ft. can be easily satisfied by small truck-mounted rigs. Only in special cases is the use of a large rig for low-temperature resources economical.

Well completion depends on many factors, a few of which are summarized below:

- depths of the groundwater aquifers
- expected well production rates
- lithology and fracture locations
- reservoir temperatures and pressures
- depth at which flashing will occur (when applicable)
- production interval lithology and rock type (slots, perforations, open-hole, etc.)
- well purpose (production, injection, or other use)
- well fluids (corrosion, hydrogen embrittlement, erosion, etc.)

Groundwater aquifers must always be protected by appropriate casing design. This is required regardless of the use for which the well is intended. High-pressure wells require conductor, surface, and production strings as shown in Figure IV-3. Lower-pressure flows and competent rock can sometimes be accommodated without the surface casing. In some situations the production casing does not need to be tied back to the surface as shown in Figure IV-3. In high-velocity flows the fluid can reach sonic speed at the wellhead, or below, and the flow rate is limited in this case (choking flow). When the well is expected to reach flow rates that are high enough to be self-choking, the wellbore diameter is designed as large as possible. The use of casing strings that are not tied back to the surface is useful in these cases and allows the maximum wellbore diameter. The choice of any well design must always be made with the safety and integrity of the well of paramount importance.

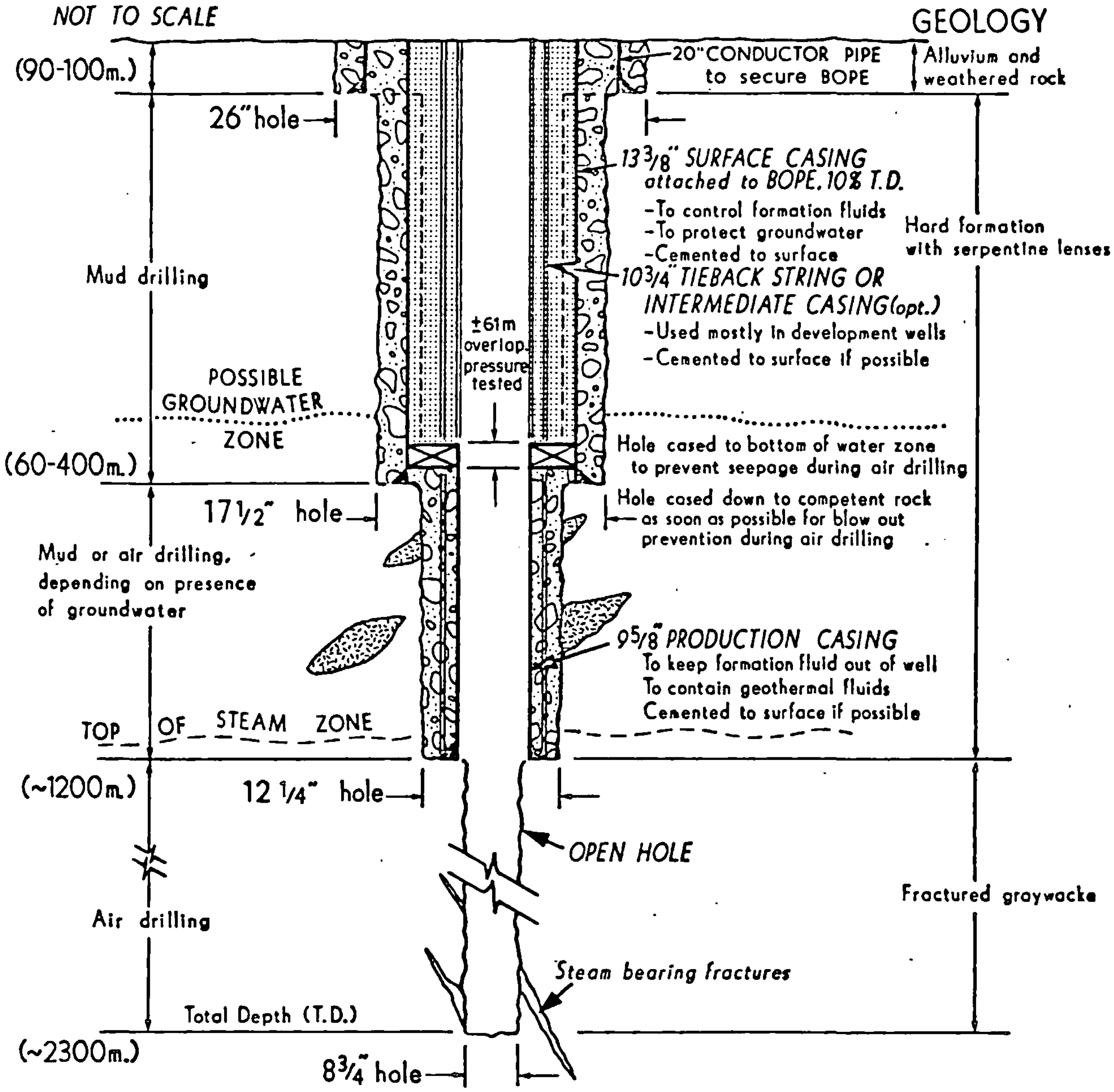


Figure IV-3: Typical drilling and casing programs in The Geysers.

F. Testing and Analysis

There are numerous tests that are used for special purposes. There are tests for determining the productivity (or injectivity), tests to determine the limits (if any) of the reservoir, tests to provide the reservoir material parameters, and tests to determine the condition of the wellbore (for damage during drilling or changes in the wellbore during production or injection). There are tests to determine whether fractures are present, tests designed to provide required data in the least amount of flow time, and many other specially designed testing and analysis methods designed to provide specific data. It is often advantageous to make measurements in more than one well during a flow test. This allows a determination of the presence of reservoir discontinuities (for example faults or lithological discontinuities).

Following the completion of a well it is usually important to flow the well as soon as possible after drilling to clean out foreign matter and drill cuttings. For economic reasons this initial flow test is usually carried out by disposing of the fluid to the mud pit or a convenient surface disposal location. In addition to disposing of the fluids in the cheapest way, a minimum of measurements are usually taken. This type of test is intended to provide an indication of the flow capacity of the well, in addition to the cleanout mentioned previously. High-temperature wells require expensive phase separation equipment to accurately measure the total flow rate, and this accuracy is often sacrificed for economic reasons during these pit tests. Low-temperature wells can usually be tested without expensive equipment and the flow period is then determined solely by the ability to dispose of the fluid. Since the flow is usually to the mud pits, the flow period is limited (by the pit capacity) to a few hours, at most. Geothermal wells with subsurface static water levels require artificial lift to initiate the flow. Compressed air is sometimes used for the lift, but often the static water level requires the use of liquid nitrogen to initiate the well flow.

Low-temperature wells are sometimes artesian and can be tested without artificial lift. But most of the time a downhole pump is required and, in the cases where continuous lift is necessary, the pumping constitutes a complication and substantial added cost. In the case where a combination of high temperatures and downhole pumping is necesary, the project may not be feasible due to the current limitations on availability of reliable, low cost equipment.

Pit tests are used to establish whether the well productivity is satisfactory. Long-term productivity or injectivity tests are required after the well is completed and after the well is accepted as either a potential producer or an exploration well. Usually the long-term tests consist of flow periods of about 30 days or more. Two types of tests are used to provide the necessary information about the wellbore and reservoir. One type of test uses three or more flow rates to provide a productivity curve. This type of test is essential to determine downhole and wellhead characteristics for the ultimate design of surface equipment and energy conversion designs. The second type of test uses drawdown and buildup data to provide the wellbore and reservoir flow capability and the reservoir capacity (storage). In the case of high-temperature wells that flash in the wellbore, the standard petroleum engineering methods for well test analysis are sometimes not adequate due to thermal and two-phase effects that are outside of the applicability of the models. In these cases a combination of the test methods mentioned above are used to provide the necessary reservoir data.

In addition, whenever possible, measurements are made in nearby wells. These interference measurements provide some of the needed data, but nearby wells that penetrate the reservoir are not always available.

Long-term tests, when carried out at a constant flow rate, can also provide information on reservoir limits through the application of standard reservoir engineering analysis methods. But the problems with thermal effects and two-phase effects often make the choice of well test design difficult due to the fact that the multiple-rate testing that is essential for productivity data obscures the reservoir limit effects. Usually a well test is designed to provide the most important data at that time. For low-temperature cases where the cost of testing is a fraction of the cost of high-temperature testing, the required information can be obtained by scheduling more than one test. All of the long-term tests require fluid disposal capability, either to an injection well or to a suitable surface location. Since the brine being produced is almost always lower in quality than surface or groundwater, it must almost always be disposed of in deep injection wells. Many states require that the produced brine be reinjected into the same aquifer that it was produced from regardless of the comparative brine quality after being cleaned up for injection.

Downhole well measurements are required to obtain the necessary information about the wellbore and reservoir. For high-temperature wells, there are only a few downhole instruments that are currently suitable and available commercially or from service companies. In order to reduce the need for downhole measurements, flowing well profiles are taken during the long-term well tests in order to provide "calibration" of numerical wellbore simulators. The subsequent use of the simulator then allows wellhead measurements during subsequent well tests of the same or similar wells. This does not reduce the cost by a large amount, but it does eliminate the need for downhole surveys during the testing, and the danger of losing equipment in the well is eliminated also.

G. Reserves in Place

Heat reserves are present in both the rocks and fluid in the reservoir. The fluid exists in a compressed state initially, and the fluid expansion (governed by the fluid compressibility) determines the transient well behavior. The flow of fluid to the wellbore is governed by the permeability (porosity) and the fluid viscosity. The porosity and permeability are material properties, and the viscosity is a fluid property. The latter is highly dependent upon the fluid temperature, and directly governs the steady-state flow. The viscosities are well known for water and steam at all relevant pressures and temperatures and the viscosity of brine is known for high TDS and high temperatures. For most resource calculations, the mobility (permeability divided by viscosity (k/μ)) can be used and is determinable from measurements. The brine compressibility can be determined from the brine equation of state.

The first approximation used to estimate the reserves in place is obtained by adding all productive volumes above a specified temperature. These volumes are multiplied by the appropriate porosity to obtain the energy in the fluid and the energy in the rock. They are:

Q_f = $\rho_f \, \phi \, C_{vf} \Delta TV$ (fluid)

Q_r = $\rho_r (1- \phi) C_{vr} \, \Delta TV$ (rock)

ρ = density

ϕ = porosity (volume of pores/unit volume)

C_v = heat capacity

ΔT = $T_{res} - T_{ref}$

T_{res} = reservoir temperature

T_{ref} = specified reference temperature

V = resource volume

The ratio of heat in rocks to heat in fluid is usually

$$Q_r/Q_f \approx 3 \text{ to } 4$$

for example, typical values at ∿ 270°C and ∿ 3000 psi are

$$\rho_f \approx 1000 \text{ kg/m}^3$$

$$\phi \approx 0.1$$

$$C_{vf} \approx 4800 \text{ J/kg.k}$$

$$C_{vr} \approx 1000 \text{ J/kg.k}$$

$$\rho_r \approx 2000 \text{ kg/m}^3$$

which gives

$$Q_r/Q_f \approx 3.75$$

It is important to determine the type and location of the producing zones. If the production is solely from fractures, the flow will be high, but the total amount of fluid will be small (fracture porosity can be $\lesssim$ 1/10 matrix porosity). If the production is solely from matrix pores, the flow is much lower than from fractures and the amount of fluid in place is much higher.

Fluid injected into rocks with matrix pores "sweeps" essentially all of the heat from the rock since the matrix pores present such a large amount of surface area for heat exchange. Fluid injected into widely spaced fractures quickly cools the rock near the fracture, and the low thermal diffusivity of the rock prevents appreciable amounts of heat from being transferred to the fluid in the fracture.

To determine the reserves in place, we need to know the location and vertical thickness of the producing zones, whether the production is from fractures or matrix pores (or both), and whether the producing zones are continuous over large horizontal areas. We also need to know the material-parameter values (porosity, fracture spacing, heat capacity, etc.).

H. Recoverable Reserves

The recoverable reserves are the amounts of the reserves in place that can be extracted from the reservoir by appropriate fluid flow management. Four factors are important in geothermal fluid flow management. They are "swept volumes," the "average reservoir pressure," the "time of temperature breakthrough," and the amount of "natural recharge." The swept volumes refer to the volume occupied by injected fluid at the time of temperature breakthrough. In some cases, when injection is not practiced, or the fluid is not injected in the producing vicinity, no volumes are swept.

The average reservoir pressure declines during production of the reservoir fluids and, as the average reservoir pressure declines, the capability of the reservoir to deliver fluid to the wells declines. If the wellhead pressure is allowed to decline with time, then the flow-rate can be held approximately constant, up to a point. Usually, the end-use of the fluid dictates the wellhead pressure. When the wellhead pressure is held constant, the flow-rate declines in conjunction with the average reservoir pressure. Injection of fluid can decrease the rate at which the average reservoir pressure declines since the injection tends to increase reservoir pressure.

The time at which cold injected fluid reaches the hot production well is determined by many factors. Some of them are:

- presence or absence of fractures
- well spacing
- size of the prodtion/injection zones
- flow rates
- production/injection temperatures
- location of injection relative to production

Natural recharge is the amount of heat and/or fluid being introduced into the reservoir. This recharge can occur under either steady-state or non-equilibrium conditions. Examples of natural recharge include upwelling of hot fluids along faults, vertical migration of cool fluids through fractures or pores, and hydrological flow from contiguous aquifers (for example, the west to east flow from the Cucapa Mountains to Cerro Prieto). Recharge of fluids tends to maintain the average reservoir pressure at high levels, however, the recharge is usually only meaningful on geological time scales because the extraction rate required for power production greatly exceeds the natural recharge in almost all cases. The recharge of heat by conduction through the rock is much too slow to play any role in power production.

In general, the procedure has been to manage the fluid flow such that the recoverable reserves are obtained without temperature breakthrough. The simplest way to do that is to locate injection wells outside the producing wellfield. The reason for this approach is that there is seldom sufficient information regarding the continuity or homogeneity of the reservoir rock to allow a satisfactory assessment of the risk of premature breakthrough. In addition, few people appreciate the importance of the heat in the reservoir rock, or fully understand how to capture that heat.

To determine the recoverable reserves requires a wellfield management strategy chosen to maximize the amount of power to be extracted. To do so requires determination of the reservoir and wellbore flow characteristics, the number of wells, the ratio of numbers of producers to numbers of injectors, etc.

I. Depletion

As the heat and fluid are withdrawn from the reservoir, the temperature and pressure decline. This steady decrease in the heat and fluid reserves constitutes a depletion of the resource. The lifetime of the reservoir for specified power production can be determined if the rate of depletion can be estimated. This estimate must be updated every year or two as production data is obtained. The first estimate is made during resource utilization design studies. As actual field production data is obtained, the lifetime estimates are updated. The rate at which the resource is depleted -- for a given level of heat and fluid withdrawal -- is related to how the flow conditions in the wellbores will change with time, how the average reservoir pressure and temperature will change with time, and (ultimately) how many fill-in or stepout wells will be drilled to maintain the project's power-production design level.

Simple calculations can be used to predict the pressure depletion for a given production strategy. However, the traditional volumetric oilfield depletion-analysis methods cannot be used for geothermal systems due to the hydrothermal nature of the resource. The geothermal resource is not a volume of liquid that is removed from the rock, but rather, the resource is a combination of heat and fluid.

To predict the depletion behavior requires reservoir simulation of the production and injection approach to field exploitation. Simulation can be useful only if the reservoir and fluid characteristics are known (equation of state, initial reservoir conditions, natural recharge if any, reservoir lithology, and reservoir parameters).

J. Optimum Resource Recovery

The reserves of heat energy are present in both the rock and fluid and, as outlined above, the heat in the rocks can be 4 times larger than the heat in the fluid (or more). For this reason, the optimum field management is based on a production/injection strategy that will maximize the heat withdrawn from the rocks. The only way to do so is to inject a major fraction of the produced brine in such a way as to "sweep" the heat from the rocks to the production wells. In vapor-dominated reservoirs the amount of condensate is very small, and makeup water is required to extract appreciable quantities of heat from the rocks. This is currently the approach at The Geysers, where surplus water from Squaw Creek is being injected to support reservoir pressures in the Big Geysers region.

Standard petroleum engineering methods can be used to estimate drawdowns in production wells for proposed well patterns. The types of patterns that can be used are 5-spot, 7-spot, line-drives, and variations of these patterns. Recently wellfields are beginning to be designed using off-shore technology, i.e., "island drilling pads." This approach has most utility in The Geysers or other prospects where the topography is rugged, and suitable drillsites or power plant locations are difficult to find. In mountainous terrain, such as the Cascades, this might be a necessary approach to take. For less formidable conditions, the advantages of minimal pipeline lengths with island drilling must be balanced economically against the increased cost of directional drilling. The latter increases drilling costs by approximately 1/3, thus the use of slant drilling is usually not desirable unless there are other considerations to be taken into account.

Reservoir depletion results in a decrease in reservoir pressure or, if the power plant inlet requires constant pressure, a decrease in flow rate in order to maintain the pressure. To provide a relatively constant amount of power, fill-in or stepout drilling is required during the project amortization period (usually 25 or 30 years).

K. In Situ Precipitation

Precipitation of minerals during production and injection of geothermal fluids can occur if the fluid saturation for the given temperature, pressure, and concentration is exceeded. The most common compounds in geothermal brines that can result in precipitation of solids are the silicates, sulfates, and carbonates. The solubilities of these compounds are all strongly temperature dependent. The silica solubility increases with temperature (Figure I-3) as does the solubility of sulfates. The carbonate solubility has a "reverse" dependence on temperature and drops steeply at temperatures above 120°C (Figure I-4).

During production of fluids from geothermal reservoirs there is usually a very large pressure drop near the wellbore (sandface). The pressure drops vary from $\approx$ 50 psi in a very good producer to as much as 1000 psi in relatively poor producers. Even in wells having a large pressure drop (sandface pressure minus the initial reservoir pressure), the pressure gradient is small at a distance of a few feet from the wellbore. Not only is the pressure gradient small in the reservoir, but the temperature of the fluid away from the wellbore is essentially unchanged from the deep reservoir temperature. There are only two cases where significant temperature drops can occur in the reservoir during production. These two cases are when flashing (phase change) occurs in the rock matrix or when high velocity flow in fractures occurs.

During injection of fluids two fronts develop in the reservoir. The first is the fluid displacement front, called the hydrodynamic front. The second is the thermal front, and it trails behind the hydrodynamic front. At the hydrodynamic radius the injected fluid must be chemically compatible with the reservoir fluid to prevent precipitation. At the hydrodynamic radius the fluid temperature is the reservoir temperature and no temperature-related precipitation occurs. If injection is taking place into a porous matrix rock the temperature of the injected fluid is very close to the reservoir temperature from the thermal front out to the hydrodynamic front. For any injected particle the time before reaching the thermal front is given by (time before heating)

$$t_c = \frac{R}{1-R}\, t_i \approx 0.4\, t_i,$$

Where $R = \phi\, \rho_f C_v + (1-\phi)\rho_r C_{vr}$, and t is the time at which the cool particle is injected with respect to the time that injection began (i.e., the zero reference is when the well began flowing). The hydro-front radius and the thermal-front radius are related to the ideal case of a homogeneous medium by

$$\frac{r_{hydro}}{r_{thermal}} = \frac{1}{R} \approx 3$$

A sharp temperature change occurs across the thermal front and can result in supersaturated conditions if the injected brine is rich in carbonates (i.e., if the solution has a reverse solubility curve).

To prevent precipitation during injection, the injected fluid chemistry must be compatible with the reservoir fluid at the hydrodynamic front and must not reach supersaturation at the thermal front (i.e., only a decrease in solubility with temperature increase can cause a problem). Precipitation can occur during production if flashing occurs in the wellbore or in the reservoir. Single-phase conditions usually do not result in precipitation, since the temperature drop for a given pressure drop is relatively small in the wellbore and almost negligible in the reservoir rock. If two-phase conditions develop due to the pressure drop during production, nothing can be done to prevent precipitation if the reservoir brine is saturated in silicates or sulfates. There are no known cases of reservoir damage due to precipitation, but there are numerous cases of wellbore scaling. The latter condition can be corrected by reworking the well, if economical.

V. INSTITUTIONAL CONSIDERATIONS

A. Land Acquisition

1. Federal Land:

Prior to December 24, 1970, there was no legal authority under which the Department of Interior's Bureau of Land Management could lease, sell or otherwise grant access to the geothermal resources beneath the federal lands. Attempts at obtaining geothermal rights under the Mining Laws (of 1866, 1820 and 1872), the Mineral Leasing Act of 1920, and the Materials Act of 1947 had all been rebuffed by the Interior Department Solicitor as in excess of statutory authority. When this position became clear in 1961, the drive for a new statute began. Nine years and one Presidential veto (by Lyndon Johnson in 1966) later, the Geothermal Steam Act of 1970 (PL 91-581) was passed and signed into law by Richard Nixon. This Act serves as the exclusive means for granting and administering rights to explore and develop geothermal resources underlying federal lands and on land subject to a mineral reservation. It is one of the most exclusive and significant laws affecting the pace and direction of geothermal energy development. The Secretary of the Interior, through the offices of the Bureau of Land Management (BLM), is authorized to issue leases for geothermal resources on public lands.

All federal lands open to geothermal leasing fall under two general classifications. Lands in a "Known Geothermal Resource Area" (KGRA) require competitive bidding to acquire the lease rights. Other lands are classified as "Potential Geothermal Resource Areas" (PGRA) and are leased to the first qualified person applying for a lease.

Lands specifically excluded from the operation of the Act are national parks, national recreation areas, fish hatcheries, wildlife management areas, and Indian lands. Although a significant breakthrough, it had a few not-so-helpful provisions:

(a) Grandfather: The right of those pioneering firms ("grandfather") to convert their mining claims, oil and gas leases, etc., to geothermal leases was severely truncated.

An overall acreage limit of 10,240 "conversion" acres was set, "substantial expenditures" prior to Steam Act passage had to be shown, and the cut-off date was September 7, 1965, (the date of Senate passage of the Vetos Act), not Dec. 24, 1970. Worse, if the lands were in a KGRA, the "grandfather" only got the right to match the high bid when (and if) a lease sale on that acreage came up.

(b) The KGRA System: This feature posed real problems. The Steam Act definition of a "Known Geothermal Resources Area" (KGRA) was taken, not from the Mineral Leasing Act of 1920 (where at least one commercial well was required to trigger the "Know" tag and competitive bidding), but from the broad language of a 1914 U.S. Supreme Court decision (U.S. v. So. Pacific).

Thus many rank wildcat areas were nonetheless auctioned competitvely, after a lengthy environmental review process. Predictably, they drew either no bids or only token offerings.

(f) Mineral-Severed Lands: In a few key areas, including The Geysers, the U.S. had sold (patented) the surface of the land to homesteaders under various statutes but "reserved" to itself the subsurface, or mineral estate. The Steam Act could have declared geothermal resources as included therein but chose instead to direct the Justice Department to bring a suit to quit title. That action (U.S. v. Union Oil) began in 1971 and was not concluded until October 1977 (under the title "Ottoboni v. U.S."). Although it eventually held for the U.S., this valuable acreage was not leasable for the entire period of the litigation.

Delays and sluggishness in the federal geothermal leasing program led to the inclusion of the Streamlining of the Geothermal Land Program in President Carter's first National Energy Plan in April 1977.

In the Steam Act, Congress took no position on the water rights/geothermal rights question. Nearly a century of federal/state conflict was hidden by the disclaimer recorded in Section 20 of the Steam Act. The Desert Land Act of 1877 had seemingly granted the waters on or under the federal lands in the West to the states themselves. But in a long series of cases dating back to at least 1897, the U.S. Supreme Court had carved out a large exception called "Federal Reserved Rights." These, they have held on numerous occasions, were water rights which the U.S. impliedly "reserved" for carrying out the purposes of various "land withdrawals" or "reservations" it carved upon the federal lands, including national monuments and Indian reservations. A 1976 case (U.S. v. Cappaert) appeared to have extended this doctrine to groundwater. But a 1978 Supreme Court decision on the non-inclusion of such water in the "location" rights granted under the mining laws "U.S. v. Charlestown

Products" showed the awareness of the high court to the political sensitivity of the states on this question.

2. State and Private Land:

Rights to explore state lands for geothermal resource development are governed by statutes and regulations (See Appendix II). The leasing of state lands is summarized, for the major development states, in Table V-1.

Highlighting the crucial nature of the water rights issue are the various state's definitions of "geothermal resources." In particular, four had simply included it in their "water" definition, three explicitly and one by implication. Two states characterize the resource as "sui generous." They state that geothermal resources are "close to" and "would affect" both minerals and water.

Hawaii is so far the only state to flatly claim public ownership. Though the Hawaii statute clearly classes geothermal as a "mineral", all minerals/subsurface in the state are claimed by the state government as the legal successor to King Kamehameha who once owned all the land and distributed it with a "mineral reservation" in favor of himself.

Most state statutes are modeled after either the Steam Act or the 1965 California model. They do not specifically say "mineral" but in three court cases thus far decided, they have held that geothermal resources are minerals under: the (now-repealed) Stockraising Homestead Act of 1916 (U.S. v. Union Oil, supra); the mineral reservations in various transfers of California State-owned lands

TABLE V-1
Leasing of state lands
(from Sacarto, 1976, revised 1979)

	Non-KGRA Lands		KGPA Lands (Competitive Leasing)	
State	Newly Offered	Application Overlap	Bidding Factor	Designation Criteria
Alaska	. . . .	. . . .	(A)	(A)
Arizona	By application	Qualifications or Cash bonus bidding	Cash bonus	Geology and/or competitive interest
California	(A)	(A)	Cash bonus or other (H)	Geology and/or competitive interest(H)
Colorado	(A)	(A)	(A)	(A)
Hawaii	. . . .	. . . .	(A)	All land awarded competitively(G)
Idaho	Public drawing (30-day filing)	By application		Producing well
Louisiana	(B)	(B)	(B)	(B)
Montana	Competitive	Competitive	Cash bonus	All lands awarded competitively
Nevada	(C)	(C)	(C)	(C)
New Mexico	Competitive (30-day filing)	By application	Cash bonus	Determined by Commissioner of Lands
Oregon	Public drawing (30-day filing)	By application	Cash bonus (D)	Geology and/or producing well
Texas	(B)	(B)	(B)	(B)
Utah	Cash Bonus (E) (15-day filing)	By application	(E)	(E)
Washington	Competitive	Competitive	Cash bonus (F)	All lands awarded competitively
Wyoming	. . . .	. . . .	(A)	(A)

Specified by state land commissioners.

Regulations not finalized.

Moratorium on leasing of state lands.

If no bids received, Division of State lands may reclassify for non-competive leasing.

Lands are offered non-competitively by order of application, except when they are newly offered Newly offered lands are leased by cash bonus bidding.

Unlike Montana, if a tract receives no bid, it is withdrawn.

Board of Land and Natural Resources by a two-thirds vote may award a non-competitive lease to occupier of mineral reserve lands.

Single biddable factor only, plus negotiable royalty rate up to 16-2/3%.

(Pariani v. California); and in a private deed's mineral reservation clause (Union Oil v. Geothermal Kinetics). This is the result mostly in keeping with the usage of geothermal resources as an energy fuel.

The laws governing geothermal resources in the eight major geothermal development states are summarized below:

California - By far the greatest number of laws pertaining to geothermal resources exist in California. California passed the first state law defining geothermal resources in 1965 (ACPRC § 3700). Title to some low-temperature geothermal resources may be obtained through application to the Geothermal Resources Board (ACORC § 3742). All geothermal resources are regulated by the Division of Oil and Gas, Department of Conservation.

Applicable laws include ACPRC § 3700, § 3800, §6407, and §6903 (1981).

Idaho - The state of Idaho declares geothermal resources to be "sui generous" (IC § 42-4002). Ownership rights are not specifically granted to holders of either the surface estate or mineral estate. Instead, the focus is on water rights and use of the geothermal medium: if the resource is to be used as a "mineral source" or as an "energy source", a geothermal permit is required (IC § 42-4003). All other uses of geothermal resources require a valid water rights permit. There are many exceptions to this law, e.g., greenhouses and hot baths, where only a valid water rights permit is needed. (IC §42-4003).

Montana - Montana, like Washington and Idaho, declares geothermal resources to be "sui generous", i.e., of its own kind, class or nature (RCM § 81-2602). Resources are treated as groundwater for purposes of well permitting, which is administered by the Department of Natural Resources and Conservation.

Nevada - Nevada has a short statute defining geothermal resources but without granting ownership or specifying relationship to groundwater (NRS § 534A). A geothermal bill introduced into the 1981 Nevada Legislature would expand the definition of geothermal resources, define heat extraction as a beneficial use of water, and maintain jurisdiction over all geothermal resources with the State Engineer.

Oregon - Oregon law grants ownership rights to geothermal resources over 250°F to the owner of the surface overlying the resource (ORS § 522). Resources above 250°F are regulated much the same as oil and gas. Geothermal resources below 250° (and from wells 2000 feet deep) are regulated as groundwater, although no specific statute defines them as such. Two bills introduced into the 1981 Oregon Legislature attempted to clarify agency jurisdiction and cooperation according to depth and well temperature. Oregon is the only state in the BPA area to adopt enabling legislation for local geothermal district heating formation (ORS § 523). For purposes of heating district acquisition, geothermal resources can be any temperature.

Utah - Until 1981, Utah possessed the briefest geothermal statute of the states examined. The 1973 legislation merely gave regulatory authority for geothermal exploration and development to the Utah Divsion of Water Rights (UCA § 73-1-20). The Geothermal Conservation Act of 1981, passed by the Utah Legislature, defines geothermal energy as earth temperatures above 250°F. Water below that temperature would be regulated as groundwater. Both resources above and below 250°F would be regulated by the State Engineer and Division of Water Rights. No ownership rights were explicitly granted in the recent legislation.

Washington - Washington defines geothermal resources as only those resources from which it is "technologically practical to produce electricity" (RCWA § 79.76). Washington resources are characterized as "sui generous, being neither a mineral resource or water resource....." (RCWA § 79.76). In addition to the above definitions, a 1979 amendment to the Washington law specifically declares geothermal resources to be the property of the surface owner (RCWA § 79.76). The Department of Natural Resources regulates geothermal resources. The great majority of hydrothermal resources which will be encountered are left in the realm of water resources. As technology improves, however, the low temperature of "geothermal resources" will drop to include what are presently "water resources" in Washington.

Wyoming - The state of Wyoming only recently enacted legislation addressing geothermal resources. House Bill 283, signed into law February 26, 1981, amends Wyoming water law defining geothermal resources as groundwater and specifying that the extraction of heat is a beneficial use of water. The State Engineer will regulate geothermal development.

B. Development Regulations

1. Environmental

The federal legislation applicable to the environmental concerns of geothermal development is identified in Table V-2 and discussed below.

(a) Geothermal Steam Act - PL91-581 (1970)

The U.S. Geological Survey (USGS) administers post-lease requirements so that release to the environment can be controlled. The principal set of environmental requirements is stated in GRO Order No. 4 which states that all operations conducted under a geothermal lease on federal lands must conform with all federal and state water, air, and pollution control standards.

(b) Federal and Geothermal Energy Research, Development and Demonstration Act of 1974 - PL93-410.

The purposes of the Federal Geothermal Energy R, D&D Act were: (1) to further the conducting of research, development and demonstrations in geothermal energy technologies, (2) to develop a geothermal energy coordination and management project, (3) to carry out a program of demonstrations in technologies for utilization of geothermal resources, and (4) to establish a loan guarantee program for the financing of geothermal energy development. The loan guarantee agreement, according to this regulation, will include terms and conditions for the protections

TABLE V-2

COMPENDIUM OF FEDERAL ENVIRONMENTAL LAWS AFFECTING GEOTHERMAL ENERGY UTILIZATION

Geothermal Steam Act (1970) PL91-581

Federal Geothermal Energy Research, Development and Demonstration Act (1974) PL93-410

Clean Air Act (1970) PL91-604, as amended by PL92-157, PL93-15, PL93-319, and PL95-95

National Environmental Policy Act (1969) PL91-190, as amended by PL94-52 and PL94-83

Federal Water Pollution Control Act (1972) PL92-500, PL93-243, and PL95-217

Occupational Safety and Health Act (1970) PL91-596

Noise Control Act (1972) PL92-574

Safe Drinking Water Act PL93-523

Resource Conservation and Recovery Act (1976) PL89-272, as amended by PL91-512, PL93-611, and PL94-580

Toxic Substances Control Act (1976) PL94-469

Federal Nonnuclear Energy Research and Development Act (1974)

Marine Protection, Research, and Sanctuaries Act (1972) PL92-532, as amended by PL93-254, PL93-472, PL93-472, PL94-62, PL94-326, and PL95-153

Fish and Wildlife Coordination Act (1958) PL85-624, as amended by PL89-72

Soil and Water Resources Conservations Act (1977) PL 95-195

Endangered Species Act (1973) PL93-205, as amended by PL94-325, PL94-359, PL95-712, PL95-632, PL96-159

National Historic Preservation Act (1966, 16 U.S.C. 470 and accompanying regulations.

of the quality of the environment. The loan guarantee now is apparently being phased out.

(c) Clear Air Act - PL91-604 (1970).

The Clean Air Act specifically sets ambient air standards for six pollutants: No_x, SO_x, CO, particulates, hydrocarbons, and photochemical oxidants. The Act does not, however, set federal standards for H_2S, CO_2, or radon emissions which can be associated with geothermal sources. These standards are left to the individual states to regulate. Ambient standards for H_2S have been established in California, Montana and Wyoming. Sections of the Act which may have a significant impact on geothermal energy development are examined below to understand the manner in which this law effects approval of an individual project.

* New Source Performance Standards (NSPS). Section III of the Clean Air Act and Section 109 of the 1977 Amendments allow the Administrator of the Environmental Protection Agency (EPA) to establish New Source Performance Standards for air pollutants from stationary source categories. Once established, these standards become applicable to all new sources in such a category. This is likely to be the principal route for federal regulation of air emissions, although such standards have not been developed yet for the geothermal industry. NSPS are published as regulations in Section 40 , CFR Part 60.

* National Ambient Air Quality Standards (NAAQS). NAAQS defines the quality of air which must be achieved to prevent adverse effects. Many critical features of the program originate from

this foundation, including the dependency of control requirements on adequate data and analysis to identify the source of pollution affecting air quality, and to determine what reductions and controls are needed to achieve the specific air quality objectives.

* Prevention of Significant Deterioration (PSD). PSD is a regulatory program requiring preconstruction approval of new plants with significant potential for deterioration of clean air areas. Of all the laws placing environmental controls on geothermal operations, the Clean Air Act sets the most restrictive and confusing limits to prevent significant deterioration. PSD limits apply in areas of the country which are already cleaner than required to meet the ambient air quality standards.

(d) National Environmental Policy Act. PL91-190 (1969).

The National Environmental Policy Act (NEPA), a major federal statutory level for environmental quality, imposes a broad responsibility on federal agencies to take environmental values into account in their planning and decision making. NEPA requires that Congress and all federal agencies submit an Environmental Impact Statement (EIS) for any project that directly or indirectly significantly affects the environment and uses federal funding, federal land, or requires a federal permit for operation. This provides for the consideration of environmental consequences of federal actions.

(e) Water Pollution Control Act - PL92-500 (1972).

The Water Pollution Control Act awards the primary responsibility for water pollution control to each state. States are required to set water quality standards subject to EPA approval to fulfill federal requirements. An antidegradation statement must be prepared, the purpose of which is to prohibit the deterioration of waters whose existing quality is higher than established standards.

(f) Occupational Safety and Health Act - P191-596 (1970).

This Act establishes the Occupational Safety and Health Administration which has the responsibility to establish regulations that protect workers from hazards of the workplace. In geothermal development, hazards include noise exposure levels and hazardous contaminants.

(g) Noise Control Act - PL92-574 (1972).

This Act contains broad noise control provisions for regulating and labeling products, many of which are used at geothermal facilities. In addition, EPA has been given coordinating authority over all programs of other federal agencies relating to noise research and noise control. It has also been given authority to ensure that all federal facilities comply with appropriate federal, state, and local noise regulations.

(h) Safe Drinking Water Act - P193-523.

This Act, administered by the EPA, allows and provides for state implementation of its provisions. Part C of the Act, "Protection of Underground Sources of Drinking Water," requires states to establish an Underground Injection Control Program so that underground water supplies will be protected against contamination. The regulations control the injection of any material that may endanger the quality of drinking water by either causing adverse health effects or making the water distasteful.

(i) Resource Conservation and Recovery Act - PL94-580 (1976). This Act sets up regulations concerning the disposal of solid waste to protect the quality of groundwater, surface water, and ambient air. The regulation of nonhazardous solid waste is charged to state agencies using specified criteria established by EPA. Disposal of hazardous solid wastes are regulated on the federal level to protect the public from contamination. Regulations developed under this Act are likely to have significant ramifications for geothermal operations where spent brine surface impoundments are used and where waste sludges are created.

(j) Toxic Substances Control Act - PL94-469. This Act is aimed principally at manufacturers and distributors of toxic chemicals to control indiscriminate proliferation of such materials in the environment. The provisions of the Act can conceivably apply to minerals which might be commercially produced from geothermal developments. The Toxic Substances Control Act, unlike the others thus far described, does not provide for state control of the program, but does allow states to apply rules not in conflict with the Act.

(k) Federal Nonnuclear Energy Research and Development Act of 1974. This Act mandated the activities of the Energy Research and Development Administration (ERDA), now the Department of Energy.

One of those activities is the active encouragement of geothermal energy technology development through commercial demonstration. The Act (Section 6b, 3k) also provides for the acceleration of commercial demonstration of environmental control systems for energy technologies. The objectives are restated in several problem identification and planning reports prepared by ERDA.

(l) Fish and Wildlife Coordination Act, Endangered Species Act, Wilderness Act, Marine Protection, Research and Sanctuaries Act. These federal laws do not directly address pollution control and its requirements, but they are major concerns affecting the environment. They allow for prohibition of, or advisory action against, certain activities in the interest of preserving wildlife habitats and aesthetic values. They also allow for or require mitigating measures where harm may occur.

(m) National Historic Preservation Act.
Promulgation of this Act has provided a set of procedures for identification, protection, and, where possible, preservation of significant cultural resources on federal lands. This has also been explicitly extended to cover all federal agency activities that affect non-federal lands, as is implied by the Antiquities Act of 1906.

For specific environmental regulations, an individual state may enforce the federal regulations or may have adopted regulations of its own. One must check with the appropriate state regulatory agencies to determine if compliance with federal regulations is either necessary or sufficient. In addition to environmental regulations, most states have promulgated regulations concerning the construction and drilling of wells; in many cases, regulations specific to geothermal wells have been adopted. A summary of state regulations pertaining to geothermal development is presented in Appendix III. This summary is not meant to be complete, therefore, it should be used only as a guide to state regulations and administering agencies.

2. State Exploration and Development Regulations

Geothermal exploration on state lands involving negligible surface disturbance may or may not require a permit or lease. In some cases, the developer may be allowed to proceed at will or after notifying the state lands officer. Intensive exploration and development operations will, however, require permits and leases. The manner in which exploration permits and development leases are issued and the requirements then imposed are summarized for the key geothermal states in Appendix II.

3. Public Utility Considerations

Public utility considerations are an important element of geothermal project planning for both electric generation and direct heat systems involving distribution. For electric generation, recent federal law and regulations mandate utility power purchases from small geothermal producers at potentially attractive rates, while eliminating the prospect of burdensome regulation which formerly would have resulted from such transactions. Unfortunately, these incentives are not currently available for direct heat distribution.

(a) Electric generation

Electric supplies have long been treated as public utilities subject to regulation under both state and federal law, without regard to the source used to generate their power. However, recent federal legislation has mandated important regulatory exemptions for certain power producers using geothermal or other alternative sources. Beyond that, it has gone far toward assuring a market for geothermally-produced power at prices designed to encourage widespread development.

The legislation affecting these changes is Title II of the Public Utility Regulatory Policies Act of 1978 ("PURPA"), as amended by the Energy Security Act of 1980. Its primary purpose is to encourage alternative power production and cogeneration by nonutilities. Toward that end, PURPA's operative provisions address two historic obstacles to independent electric generation: conventional utility resistance to purchasing or transmitting power from nonutility generators, and the prospect of burdensome public utility regulation resulting from such transactions.

Those intended to benefit from PURPA include "small power production" and "cogeneration" facilities. A "small power production facility" (SPPF) is defined as one which produces up to 80 MW of electricty from biomass, waste, renewable resources or geothermal. (PURPA § 201, as amended) A "cogeneration facility" (CGF) means one which produces electricity and "steam or...heat...used for industrial, commercial, heating or cooling purposes, regardless of fuel source or facility size." (PURPA § 201) Under these definitions, a geothermal facility might be considered either a SPPF or a CGF, depending upon its size and the form of its energy output.

As originally enacted in 1978, PURPA benefits were afforded only to "qualifying" SPPFs or CGFs. "Qualifying" facilities were those meeting standards and owned not more than 50% by an electric utility or related enterprise. (PURPA §§201, 210; 18 CFR §292.2060). The 1980 Energy Security Act amended PURPA to clarify its application to geothermal power producers and in the process eliminated the "qualifying" requirement as a condition of eligibility for certain of its benefits discussed below. (Energy Security Act §643, amending PURPA §§201, 210)

PURPA's most far-reaching benefits for geothermal power producers and cogenerators are those designed to overcome traditional utility reluctance to purchase or transmit independently generated power. First, the Act authorizes the Federal Energy Regulatory Commission (FERC) to order the physical connection of geothermal power facilities with utility transmission facilities, and to require related actions which may be necessary to make such connections effective (PURPA §§202,210). Second, it empowers FERC to order electric utilities to provide transmission services to geothermal power producers (PURPA §203). Third and most important, PURPA directs FERC to prescribe rules requiring electric utilities to purchase electric energy from, and to sell backup, supplemental and maintenance power to, qualifying SPPFs and CGFs (PURPA §210).

The utility power purchase requirement is at the heart of PURPA. The Act and its implementing regulations (18 CFR §§292..101, et seq.) permit FERC to require utility purchases at rates equal to the purchasing utility's "avoided cost"--that is, the cost which the utility would incur to generate equivalent power or to purchase it elsewhere. Avoided costs are to include not only avoided energy costs--i.e., fuel and operating and maintenance expenses--but also avoided capacity costs--i.e., capital costs of new plant and equipment which can be deferred or avoided by reason of firm power purchases from qualifying facilities (18 CFR §292-304).

Methods of determining avoided costs have been left to the state regulatory commissions charged with implementing PURPA, and vary from state to state. The important point is that the avoided cost approach offers geothermal and other small power producers and cogenerators the opportunity to sell their ouput at rates equaling the purchasing utility's highest-cost power, rather than the lower average cost rates which alternative power producers might command without PURPA. Thus the Act not only ensures a market for efficient geothermal producers, but also authorizes the highest possible price for their output consistent with the interests of electric utility ratepayers.

Recognizing that potential investors in SPPF or CGF must have some firm basis for estimating the financial feasibility and expected return on investment of such projects before proceeding, the Act and regulations require electric utilities to make available detailed data concerning present and anticipated future avoided costs of energy and capacity on the utility's system (PURPA §133; 18 CFR §292.302). In the meantime, some state utility commissions have independently established avoided cost figures to assist potential small power producers and cogenerators in project planning.

In the same spirit, PURPA recognized that investment in nonconventional electric generation has been hampered by the prospect of regulatory delays and low rates of return imposed by traditional utility regulation. FERC regulations accordingly provide a simple notice procedure by which SPPF and CGF may become "qualifying" facilities; no formal certification or approval is required (18CFR §292.207). More importantly, the Act authorizes rules exempting qualifying small power producers and cogenerators in general, and "geothermal small power production facilities of not more than 80 MW capacity" in particular, from the major burdens of federal and state utility regulations (PURPA §210 (e), as amended). Because the quoted language (added by the Energy Security Act) is not limited to "qualifying"--i.e., nonutility-owned--facilities, FERC has assumed the authority to exempt utility-owned geothermal facilities from such regulation as well. It has already done so with respect to the federal Public Utility Holding Company Act, and is considering similar action as to the Federal Power Act and certain state regulations.

(b) Heat Distribution

By its terms, PURPA applies only to electric generation, not to direct heat applications, which are beyond federal regulatory jurisdiction. However, commercial geothermal heating operations generally will be subject to state utility regulation under existing law if they involve distribution to more than a few users served under individually negotiated supply contracts. Although this prospect has profound implications for private development, relatively few developers have yet pursued distribution projects to the point where utility considerations have become critical. For this reason, most state legislatures and utility commissions have not had occasion to focus on the implications of traditional regulatory concepts in this area, or to refine these concepts to encourage direct heat development as PURPA has done for electric generation.

C. Tax Considerations:

Prior to the Energy Tax Act of 1978 the federal tax treatment accorded geothermal energy was for the most part a judicial decisions. The leading case was Authur E. Reich 52 T.C. 7000 (1969) aff'd, 454F. 2d 1157 (9th Cir. 1972) which held that the intangible drilling deduction and the percentage depletion allowance applied to the geothermal drilling at The Geysers. This legislation was not much help for, at best, it only applied to vapor dominated geothermal resources. Furthermore, the Internal Revenue Service refused to abide by Reich and was contesting both the intangible drilling deduction and depletion on activities and income from The Geysers.

1. The Energy Tax Act of 1978 ("Act")

The Act gave geothermal the intangible drilling deduction and percentage depletion. In addition, the Act provided certain favorable tax credits for certain equipment which used geothermal energy.

(a) Definition of Resource

The various new provisions relate to "geothermal desposits" which are defined as "a geothermal reservoir consisting of natural heat which is stored in rocks or in an aqueous liquid or vapor (whether or not under pressure)." The reservoir must be located within the United States or a possession. This definition appears broad enough to include all of the known forms of the resource including steam, hot liquids and hot dry rocks. Geopressurized methane is dealt with in the Act on its own; it is treated sometimes as being sui generis, and other times as a gas.

(b) Intangible Drilling costs-§402 of the Act

(i) Options to expense intangible drilling costs. Amends §263 (c) of the Code to provide that option to expense intangible drilling costs (Treas. Reg. 1.612-4(a)) applied to the drilling of geothermal wells. This may be the most important and helpful provision of the Act since it permits an investor to elect to write off that portion of the investment which relates to the intangible drilling costs even though the well is productive.

(ii) Application of at risk rules to geothermal deposits - Amends §465 (c) of the code to provide that the amount of losses deducted in a year relating to a geothermal deposit cannot exceed the total amount the taxpayer is at risk with regard to the property at the end of the taxable year. The effect of this provision is to eliminate the use of non-recourse financing to increase available deductions.

(iii) Minimum tax on geothermal wells - Amends §57(a)(11) of the Code to provide that to the extent the taxpayer has "excess intangible drilling costs" which exceed his net geothermal income, he will have preference income subject to the minimum tax.

Excess intangible drilling costs result when the intangible costs expensed exceed the deduction which would have resulted had the taxpayer capitalized the intangible costs on productive wells and amortized them on a straight-line (120 month) basis from the time of first production (or to the extent the expensed costs exceeded what would have been available under cost depletion.)

(iv) Recapture of intangible costs expensed upon disposition of geothermal deposit at a gain - Amends §1254 (a) of Code to provide that a taxpayer disposing of a geothermal property at a gain must recognize ordinary income as opposed to capital gains to the extent that the intangible costs deducted exceed that which would have been allowed had the intangible costs been capitalized and amortized on a straight-line basis (120 Months) from the time the property went into production (or what would have been available under cost depletion).

(c) Percentage Depletion-§403 of Act §613 of the Code is amended to provide for percentage depletion on income from geothermal deposits. The applicable percentage is as follows:

Taxable Year Beginning in	Percentage
1982	18
1983	16
1984 and thereafter	15

Percentage depletion generates preference income.

(d) Tax Credits

Residential Energy Credit - §101 of Act - Creates a new §44C of Code to provide, inter alia, for a non-refundable credit against taxes for certain equipment which uses geothermal energy (deemed a "renewable energy source").

The amount of the credit is as follows:

a. 30% of the expenditure up to $2,000;

b. 20% of the expenditure from $2,000 to $10,000.

Thus the maximum credit is $2,200.

The equipment must be used in the taxpayer's principal residence located in the United States. The original use must begin with the taxpayer and the equipment must be reasonably expected to remain in operation for at least five years. The equipment must transmit or use geothermal energy and must meet certain performance and quality standards. The credit may be carried over to future years and related to equipment purchased after April 20, 1977, and before January 1, 1986 "alternative energy property" or "specially defined energy property."

"Alternative energy property" is defined as equipment "used to produce, distribute or use energy derived from a geothermal deposit . . . but only in the case of electricity generated by geothermal power up to (but not including) the electrical transmission stage."

"Specially defined energy property" is a list of enumerated items including a heat exchanger, etc. "the principal purpose of which is reducing the amount of energy consumed in any existing industrial or commercial process and which is installed in connection with an existing industrial or commercial facility."

The tax credit was 10% and is non-refundable but applies only for the period October 1, 1978, through December 31, 1982. The taxpayer must be the original user of the property and the property must have a useful life of three years or more.

2. Economic Recovery Tax Act of 1981

The principal thrust of the Economic Recovery Tax Act of 1981 and its corollary, the recent federal budget reductions, is to bring about substantial improvements in the Nation's economy. The new law makes fundamental changes to the tax system which will have a significant impact upon the financial strategies of businesses. A new mandatory accelerated cost recovery system (ACRS) has been established to provide for more rapid depreciation of capital assets and liberalization of the investment tax credit. ACRS will apply to assets placed in service after December 31, 1980. The cost of tangible depreciable property is recovered over 3-, 5-, 10-, or 15-year periods, which is significantly shorter under ACRS than under prior law. The 25% tax credit for incremental research and development expenditure will be available for some geothermal activities. In addition, opportunities to shift available tax benefits have been specifically expanded by the Act.

An important factor in current and future tax planning is the large number of effective dates contained in the new law. A number of changes are retroactively effective to various dates in 1981. Many changes take effect at the beginning of 1982, and some several years later. In addition some are subject to transitional rules spanning several years. Timing of project initiation, to insure the placing of assets in service by the end of the taxable year becomes extremely practical. This is because all ACRS property, regardless of when placed in service during the year, is allowed one-half of a year's depreciation. In addition to accelerating depreciation, the investment credit will be available one year earlier.

The new law encourages investment in both new and used property by establishing new investment credit rules. A 6% credit applies to qualified property in the 3-year depreciation class, and 10% for all other qualified property. The investment credit carry over is extended to 15 years. The used property limitation is raised from $100,000 to $125,000 in tax years beginning in 1981 and $150,000 in tax years beginning after 1984.

The investment tax credit acceptance rules are modified to reflect the liberalized credit percentages. Table V-4 shows the percentage of qualified bases on which recapture is computed.

Figure V-3 presents an accelerated cost recovery system overview developed by Cooper and Lybrand.

TABLE V-3

ACCELERATED COST RECOVERY SYSTEM OVERVIEW

(Excluding Foreign Assets)

Class	3-Year	5-Year	10-Year	15-Year	15-Year Real Property
CONTENTS OF CLASS:	• Cars • Light trucks • R&D equipment • ADR midpoint of 4 years or less	• Most machinery and equipment (not in 3- or 10-year class) • Single purpose agricultural structures • Petroleum storage facilities • Public utility property with ADR midpoint of 18 years or less	• Railroad tank cars • Public utility property ADR midpoint of 18.5 to 25 years • Recreational facilities and theme park structures • Qualified coal conversion property of public utilities • Depreciable real property with ADR midpoint of 12.5 years or less • Manufactured homes	• Public utility property with ADR midpoint of over 25 years	• Real property (other than items redesignated personal property in 5-year class or real property in 10-year class)
LIMITED EXPENSING OF PROPERTY IN YEAR PLACED IN SERVICE:[1]	Yes	Yes	Yes	Yes	No
INVESTMENT CREDIT:	6%	10%	10% (except real property)	10%	-0-
OPTIONAL EXTENDED RECOVERY PERIODS:	5 or 12 years	12 or 25 years	25 or 35 years	35 or 45 years	35 or 45 years
HALF-YEAR CONVENTION:[2]	Yes	Yes	Yes	Yes	No (Prorated by months)
METHODS USED FOR RATES:[3]	1981-1984 150% DB/SL 1985 175% DB/SYD 1986 200% DB/SYD	Same as 3-year	Same as 3-year	Same as 3-year	• Low income housing. 200% DB/SL • All other real property: 175% DB/SL
DEPRECIATION IN YEAR OF DISPOSITION	None	None	None	None	Prorated by months
RECAPTURE:[4]	In full	In full	In full	In full	• No recapture Property using S L • Excess of accelerated over SL: Residential using accelerated • Full recapture: Commercial using accelerated
ITC RECAPTURE:	2 percentage points for each year below 3	2 percentage points for each year below 5	2 percentage points for each year below 5	2 percentage points for each year below 5	N.A

[1] Annual Limits:

1982 and 1983	$ 5,000
1984 and 1985	$ 7,500
After 1985	$10,000

[2] The half-year convention has been built into the recovery tables. The full amount provided in the tables for the first year is deductible regardless of the month placed in service.

[3] Straight-line is optional for all classes but must be used if extended recovery is elected

[4] Recapture of expensed items is immediate and overrides installment sale provisions.

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Table V-4
Recapture Rules

Year held	3-year property	5-, 10-, 15-year property
Less than 1	100%	100%
between 1 & 2	66%	80%
between 2 & 3	33%	60%
between 3 & 4	----	40%
between 4 & 5	----	20%

The energy credits operate independent of the ITC. Thus, a particular component of the geothermal facility might qualify for one credit or the other or both. Qualified geothermal equipment is provided with a 15% energy tax credit, with an expirtion date of December 31, 1985. Experience has shown to date that typically the total dollar savings from combined ITC & ETC will be approximately 2% of an average 80% of total costs. For example, on a $20,000,000 plant combined credit would be approximately $4,000,000.

3. State Tax Systems

With the passage of the 1981 Tax Act, state and local taxation should now be given greater attention as federal tax rates are reduced and funds available to state and local governments come under increasing pressure because of the reduction of available federal subsidies and property tax reform.

Currently of the fifteen states with known geothermal resources, Nevada, Texas, Washington and Wyoming have no state personal or corporate income tax. Alaska, Colorado, Hawaii, Idaho, Montana and New Mexico apply their income tax levies to adjusted gross income as calculated for federal income tax. But five states have an independently determined income tax: Arizona, California, Louisiana, Oregon and Utah. Their differences from the federal law are largely due to the state provisions concerning percentage depletion for resource extraction industries.

Two states, California and Arizona, provide two examples of how complex the state tax picture can be. California has a Franchise Tax and a Corporate Income Tax. The Franchise Tax is for the privilege of exercising a corporate franchise within the state. The tax rate is 9% of net income attributable to California. Insofar as the Franchise Tax overlaps the Corporated Income Tax, the amount due under the franchise is offset against the amount due under the income tax. The computation of income for both the franchise tax and the income tax follows generally the pattern of the federal income tax and interpretations of the federal law by the Treasury Department, with the exception of depletion provisions. The tax rate for the income tax is also 9%.

Prior to 1975, California provisions for depletion allowance for all oil, gas and other minerals conformed basically to federal law. However, California did not follow the Federal Tax Reduction Act of 1975 which eliminated percentage depletion for oil and gas wells (with a few exceptions). California merely placed a limit on the total amount deductible by each individual taxpayer. These limitations apply only after the total accumulated depletion allowed or allowable exceeds the adjusted cost of the property.

A deduction of 22% of gross income (less rentals and royalties) for the taxable year is allowed for oil and gas properties. This deduction may not exceed 50% of taxable income computed without allowance for depletion. In addition, where the deduction exceeds $1.5 million and is greater than the adjusted cost of the taxpayer's interest in the property, the deduction is reduced. The reduction equals 125% of the amount in excess of $1.5 million (Cal. Rev. & Tax Code §17686).

For oil and gas, California follows federal provisions for intangible drilling costs. (Ca. Rev. & Tax Code §24423. Cal. Admin. Reg. 24831 (d)). Exploration expenditures may not be deducted for oil and gas but they may for other minerals. Geothermal exploration, development or percentage-depletion deductions are not specifically allowed but, in practice, companies at The Geysers have been allowed percentage depletion and deductions for intangible drilling costs.

In 1977, Arizona raised its corporate tax rates and then raised them again in 1978. But Arizona does specifically provide for a depletion allowance and depreciation in computing new income. The depletion allowance is 27 1/2% of gross income, excluding an amount equal to any rents or royalties paid in respect to the property. The allowance cannot exceed 50% of the taxpayer's net income computed without allowance for depletion from the property, except that in no case will the depletion allowance be less than it would be if computed without reference to this provision. Also, expenditures paid or incurred during the income-tax year for the development of a geothermal resource well, if paid or incurred after 12/31/53, may be deducted from gross income or charged to the capital account. Amounts up to $75,000 paid or incurred for the purpose of ascertaining the existence, location, extent or quality of any deposit of geothermal resources are allowed as a deduction.

VI. UTILIZATION

A. Introduction

Man has utilized the natural heat of the earth for centuries. Historical records reveal its use as a direct source of heat for cooking, bathing, space heating and medicinal purposes in many areas throughout the world. Early in the 1900's in Italy, geothermal energy was used for the first time as a prime energy source for the generation of electricity. During the same time frame a district heating system was installed in Boise, Idaho. The system serviced 400 customers at its peak and is still in operation. The largest district heating system in current operation is in Reykjavik, Iceland. It serves a population of about 90,000 people, and has a rated capacity of 350 MWt. In the United States geothermal power production began in 1920 at The Geysers in California with the operation of a small captive use unit. Large-scale commercial development at The Geysers by Magma and Thermal Power, Union Oil, and Pacific Gas and Electric started in 1960.

The two types of uses of goehtermal resources discussed above are commonly referred to as "direct use" (non-electric) and "electric". These terms usually appear in the literature in conjunction with the units "megawatts thermal (MWt)" and "megawatts electric (MWe)", respectively. Worldwide direct use of geothermal currently is in the range of 7000 to 8000 MWt. Worldwide electric generating capacity is slightly in excess of 2500 MWe.

B. Production of Electricity from Geothermal Energy

1. Production of Electricity

Interest in the production of electric power from geothermal resources has increased significantly in the last several years. Most of the interest, both public and private, is focused on the exploitation of liquid-dominated reservoirs.

The hydrothermal resource is a probably exhaustible reserve of high pressure, high temperature, aqueous solution of salts and gases in varying proportions. As this solution is made to flow upwards through the well into regions of lower static pressure, it may flash to steam if at some point the static pressure falls below the saturation pressure for the prevailing temperature. The saturation pressure is close to the vapor pressure of pure water, but differs slightly due to the influence of dissolved substances on the boiling point. Accordingly, a given resource may supply:

(a) wet steam ("vapor-dominated");
(b) saturated or superheated (dry) steam ("vapor-dominated");
(c) a liquid solution whose pressure is higher than at saturation for the given temperature ("liquid-dominated");
(d) a low quality, liquid-vapor mixture ("liquid-dominated").

With the exception of the Wairakei plant in New Zealand, it has been only within the last eight years that any resource other than a dry steam, vapor-dominated field has been exploited for electric power production.

There are four basic types of energy conversion systems in use today for generation of electricity from steam. They are:

- Dry steam systems
- Flash steam systems
- Binary systems
- Total flow systems

These systems and their derivations are discussed below.

a. Dry Steam systems

Of all types of geothermal resources, the simplest to exploit for electrical power production is the dry steam resource. Power plants at The Geysers (California), Larderello and Monte Amiata (Italy) and Matsukawa, Onikobe and Kakkonda (Japan) all operate with dry steam.

The schematic in Figure VI-1 is a highly simplified flow diagram for such a system. Steam flows from the well and is routed directly through the turbine. As the steam moves through the turbine it expands and imparts rotational motion, which in turn is transmitted to the generator. The steam, at a lower temperature and pressure, exits the turbine and is condensed and the water is available for reinjection. Waste heat is removed from the condenser and is vented to the atmosphere through the cooling tower. The sketch shows a condensing turbine with a mechanically induced draft cooling tower. All Italian geothermal powerplants use natural draft towers and some of their plants use noncondensing, exhausting-to-atmosphere turbines.

The energy conversion processes are shown in the temperature-entropy (T-s) diagram in Figure VI-2. The expansion process from 1 to 2 takes place irreversibly (i.e., non-isentropically).

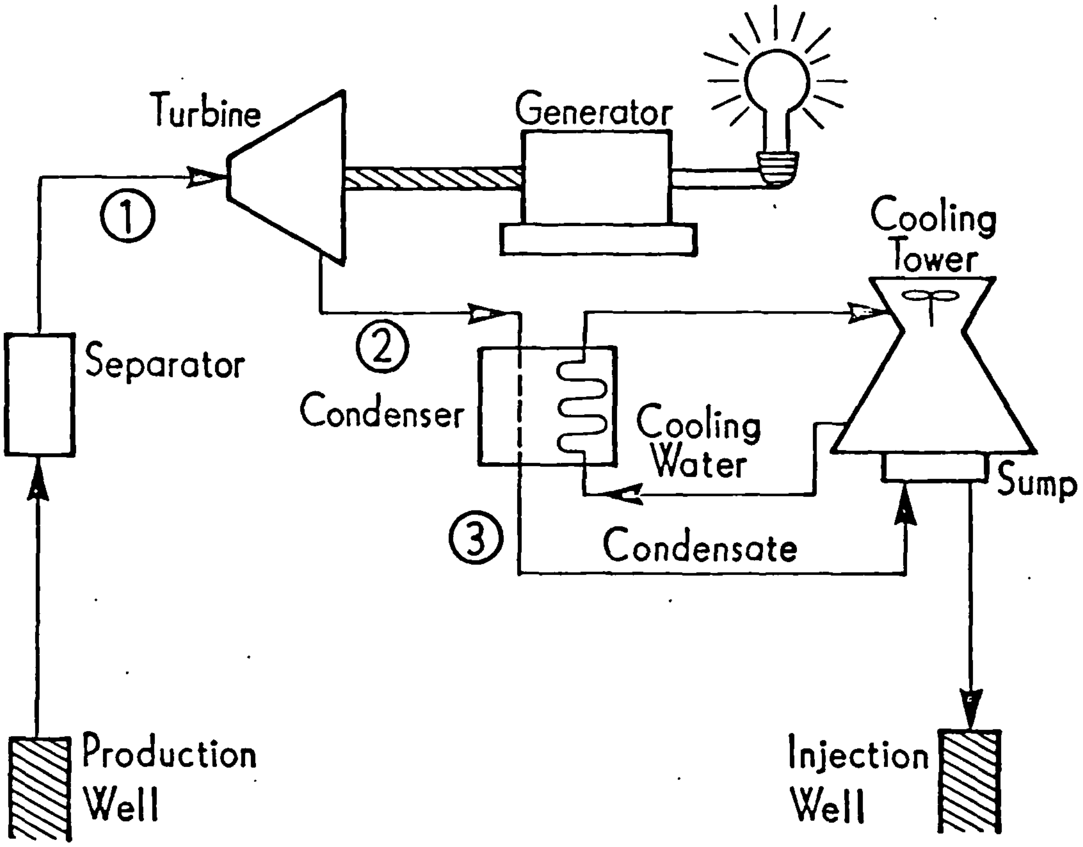

Figure VI-1. Dry steam system, flow diagram.

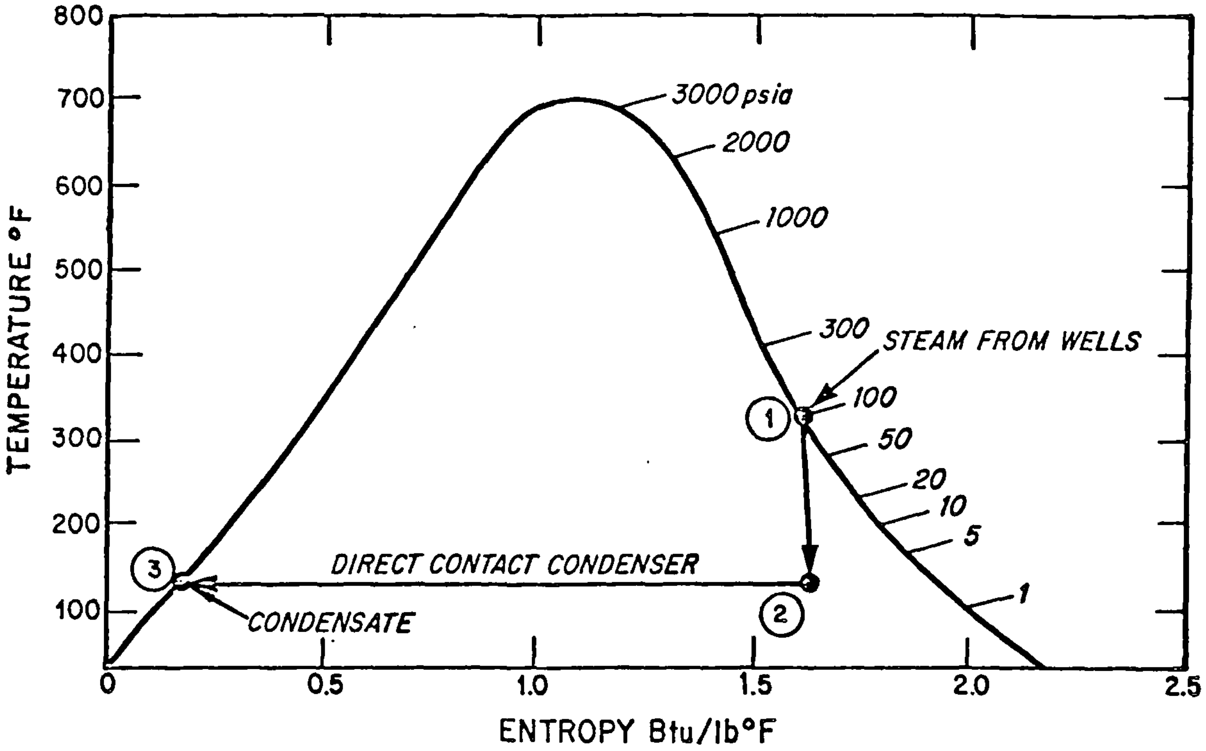

Figure VI-2. Dry steam system cycle diagram.

As can be seen from the T-s diagram, the working fluid does not undergo a cycle in the usual sense of the word. It is admitted to the turbine at 1, condensed at 3, and either evaporated from the stack of the cooling tower or reinjected into the reservoir as liquid from the cooling tower cold well overflow. Thus, the usual definition of the cycle efficiency should not be used to assess the overall performance of the plant. In that definition, the efficiency is given as

$$n = \dot{W}_{net}/\dot{Q}$$

where $\dot{W}_{net}$ is the net power output (turbine output minus pumping) and $\dot{Q}$ is the rate at which heat is supplied to the working fluid. Since $\dot{Q}$ is produced geothermally and not by the consumption of fuel, its determination becomes ambiguous.

The appropriate measure of plant performance in the thermodynamic sense is the utilization efficiency n_u which compares the plant output to the maximum theoretically obtainable output: i.e.,

$$n_u = \dot{W}_{net}/\dot{E} ,$$

where $\dot{E}$ is called the exergy and is defined as the difference per unit time between the energy theoretically available from the entering working fluid and the energy theoretically available from the working fluid at the ambient or sink condition.

Power plants such as those at The Geysers have utilization efficiencies in excess of 60%.

b. Flash Steam Systems

Liquid-dominated resources require that steam be produced from the heated liquid prior to being directed to the turbine. It is common in the case of unpumped geothermal wells for the wellhead product to consist of a two-phase mixture of liquid and vapor. The quality of the mixture (i.e., the mass function of the vapor phase) depends on the reservoir properties and the wellhead pressure. It is not difficult to separate the steam and water phases, either at each wellhead, at centrally located separator stations, or at the power house. Plants which use a single stage of steam separation are called "separated steam plants". Examples of such plants are found at: Cerro Prieto (Mexico), Ahuachapan (El Salvador), Otake and Onuma (Japan) and Pauzhetka (Soviet Union).

In all likelihood, the fluid condition in the reservoir is that of a compressed liquid at elevated temperature. As the fluid comes to the surface under a reduced pressure, it flashes to steam and attains a wellhead quality ranging from about 20 to 65 weight % steam.

The plant equipment is essentially the same as for the dry steam system: the differences include the addition of the separator and a ball float check valve to prevent massive ingestion of water by the turbine in the event of a liquid backup in the separator.

The thermodynamic analysis for flash systems is similar to that for dry steam systems. The mass flow rate through the turbine is equal to the mass flow rate of geothermal fluid passing from the well times the quality of the goethermal fluid. Also the exergy of the geothermal fluid must be calculated from the energy theoretically available from the geothermal fluid and it must include the contribution of the liquid portion even though it is discarded as waste for this plant. Consequently, the utilization efficiency for separated steam systems is lower than that for either the dry steam or the double- or multi-flash systems to be described in following sections. The utilization efficiency of the Cerro Prieto plant, for example, is about 45%. The representative flow diagram and thermodynamic cycle for the flash steam system are shown as Figure VI-3 and VI-4, respectively.

The special case when the geothermal fluid emerges at the wellhead as a liquid under pressure (essentially a saturated liquid) leads to what is called a single-flash steam system. The flashing process, instead of occurring in the wellbore as in the case of the separated steam system, occurs in surface equipment designed to reduce the fluid pressure to some optimum value. Otherwise, the single-flash steam system is similar to the separated steam system.

In most geothermal power plants which are fed from a number of unpumped wells, only a few may produce saturated (or compressed) liquid; thus the single flash system is not in practical use.

The term "dual-flash steam system" is somewhat of a misnomer

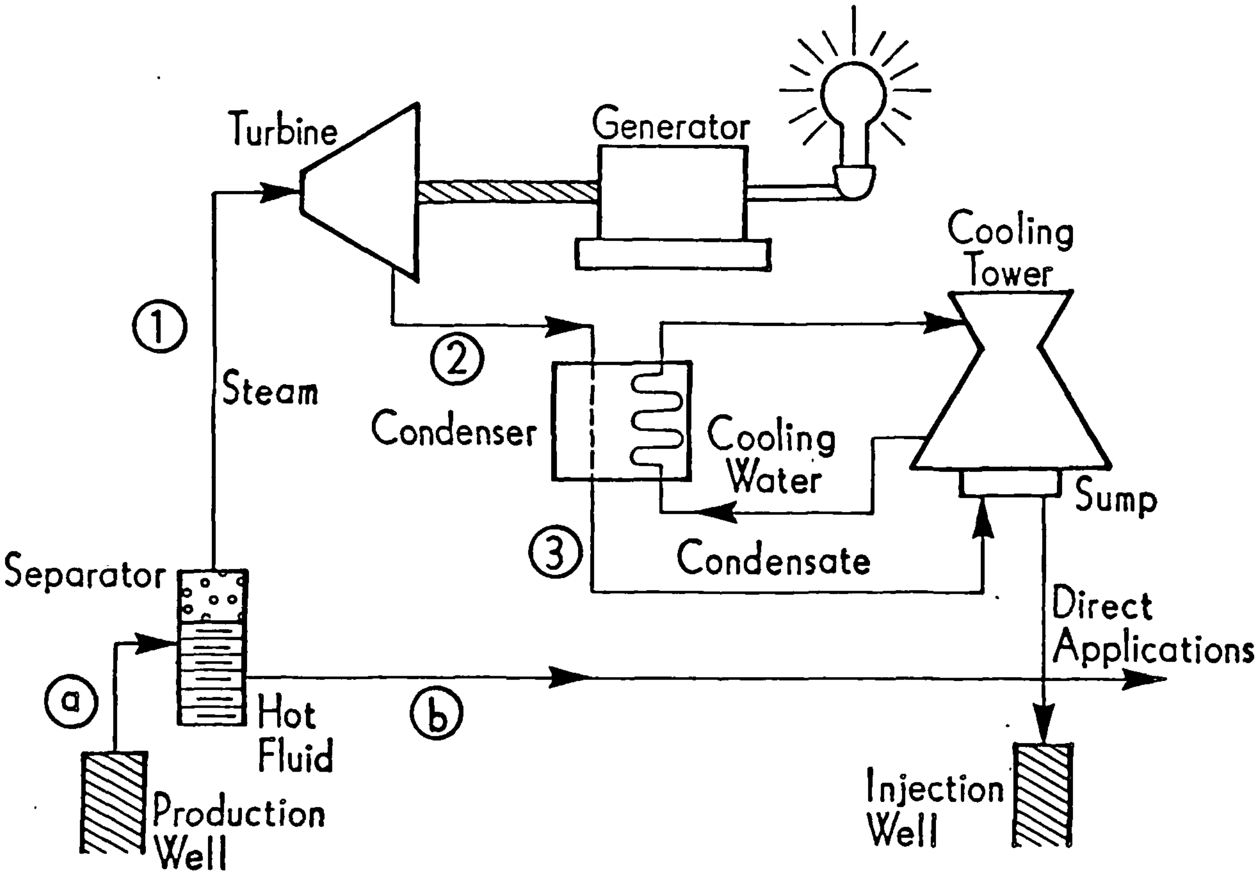

Figure VI-3. Flash steam system, flow diagram.

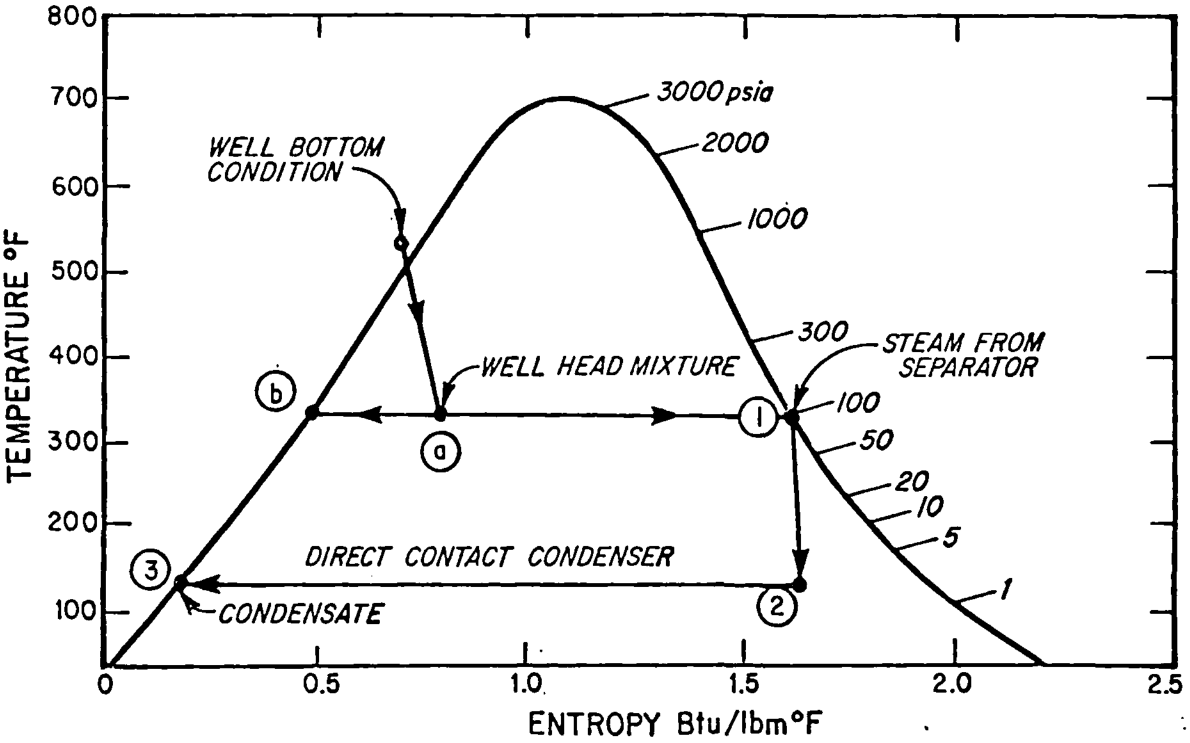

Figure VI-4. Flashed steam system, cycle diagram.

in certain cases should be called a "separated-steam/single-flash system" since plants of this type generally operate with a two-phase geothermal fluid at the wellhead. The term dual- or double-flash arises from the fact that two flashes occur, one below the surface (typically in the wellbore) and one above the surface in a specially-designed flash tank. As an alternative there may be two stages of flashing in different separators on the surface. Thus a two-stage process of steam production and utilization is used, the second stage capturing a portion of the energy which otherwise would be wasted.

Plants of this type are located at Hatchobaru (Japan) and Krafla (Iceland). The essential difference between this and the single-stage system is that a dual-pressure (or pass-in) turbine or two individual turbines arranged in a tandem-compound fashion are used. The high-pressure steam from the first separation flows through the high-pressure portion of the turbine and produces work. The second flash produces additional steam from the liquid fraction of the first separation by an additional pressure drop. This low pressure steam is mixed with the steam from the high-pressure turbine at a pass-in section of the turbine or is introduced into the low-pressure tandem turbine.

A multi-flash plant uses more than two levels of steam pressure at turbine entry points. There is only one example of this type in existence, namely the power plant at Wairakei, New Zealand. This particular arrangement resulted from design considerations related not solely to the geothermal power station but from requirements for an auxiliary plant that was to have used a portion of the steam from the power plant for industrial purposes.

c. Binary Cycle Systems

These systems are called "binary cycle" because a secondary working fluid (a fluorocarbon or hydrocarbon) is used in the Rankine cycle with the geothermal fluid merely providing the required thermal energy to vaporize and superheat the secondary working fluid.

A flow diagram and a cycle diagram in pressure-enthalpy coordinates are shown in Figures IV-5 and VI-6 respectively. The cycle diagram is for the case where isobutane is the working fluid and is shown for a supercritical heat exchange cycle from 1 to 5.

Five geothermal power plants have been operated on this principal. They are:

(1) Soviet Union - World's first geothermal binary plant, constructed at Paratacka on the Kamchatka Peninsula, operational 1967 to late 1970's, 680 KWe, geothermal fluid temperature is 81.5°C (179°F).

(2) Japan - two plants constructed at Otake, and Mori, Japan 1 MWe each, Mori plant uses refrigerant 114, Otake plant uses isobutane, geothermal fluid temperature is 130°C (266°F).

(3) Magmamax - Dual binary plant, East Mesa, California, 11.2 MWe, uses propane and isobutane as working fluids, completed 1980, design has yielded operational problems, geothermal

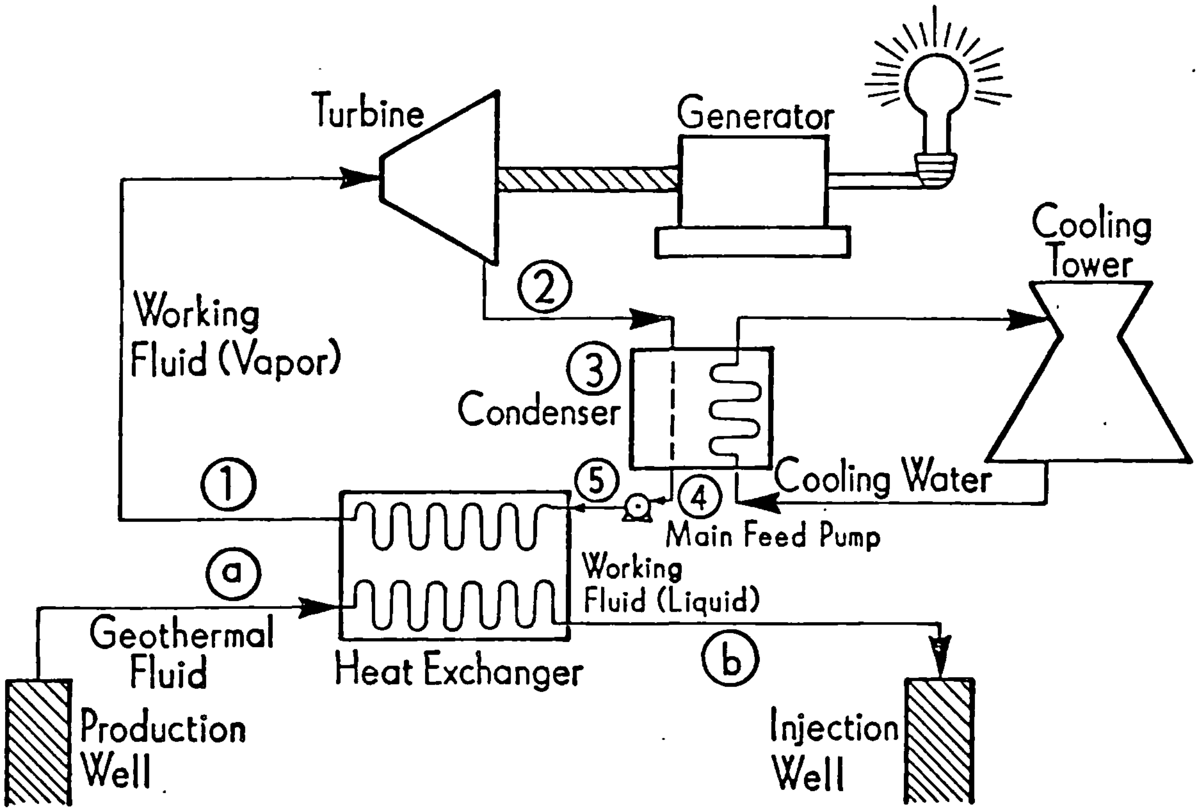

Figure VI-5. Binary system, flow diagram.

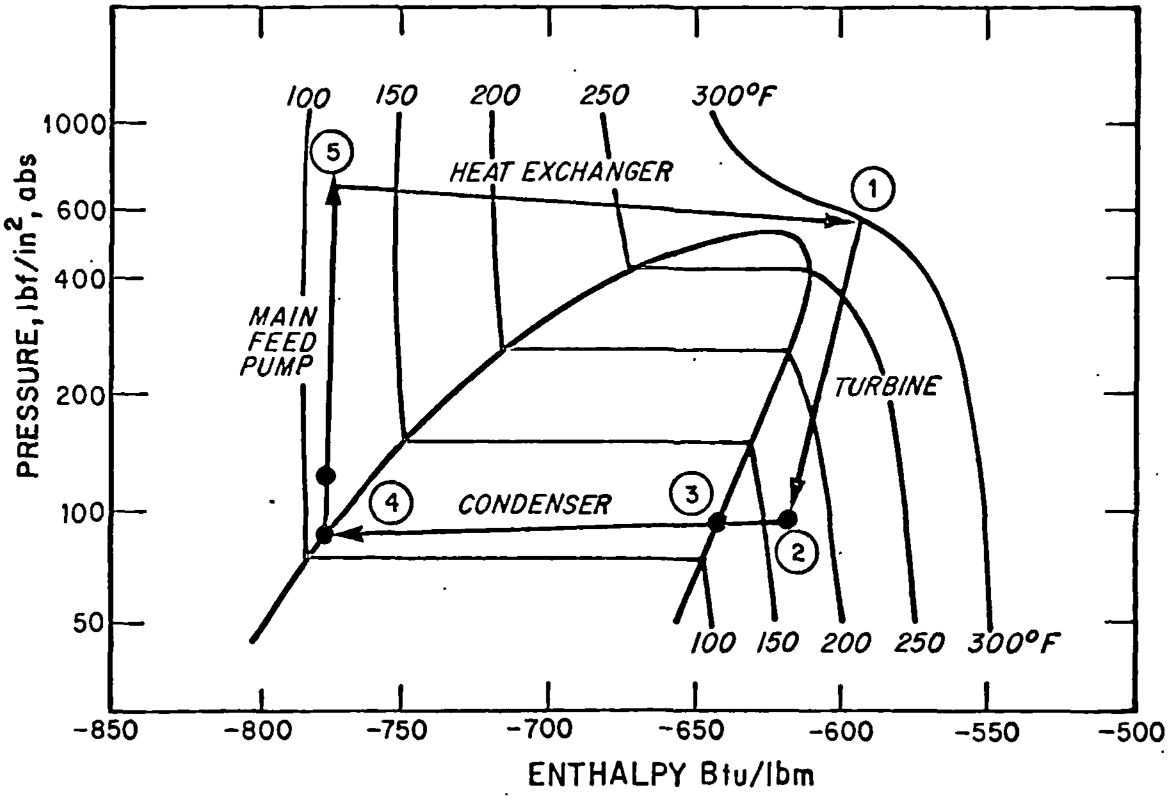

Figure VI-6. Binary system, cycle diagram.

fluid temperature 182°C (360°F).

(4) Raft River - Binary plant, Raft River, Idaho, working fluid is isobutane, 5 MWe (gross), geothermal fluid temperature 143°C (290°F). Operations started November, 1981.

A number of advantages are claimed for a binary cycle when compared to a flash steam system. These include:

- more suited to low-temperature hydrothermal resource
- smaller turbine size for given output
- less expensive turbine for given output
- high-pressure operation throughout, eliminating vacuum operating problems of air in-leakage, etc.
- higher isentropic turbine efficiencies
- lower turbine rotor inertia giving lower maximum coupling torque caused by generator overloads
- reduced stress and vibration problems with turbine blades because of lower tip speeds
- condensing temperatures can be lower, giving better cycle efficiency
- less cavitation damage in boiler feed pumps
- completely dry expansion eliminating erosion problems.

Some of the disadvantages include:

- suitable secondary working fluids are expensive
- no leaks can be permitted
- heat exchangers are major elements and are costly
- huge brine flow rates are needed for a reasonable size

plant, leading to disposal problems

* flammability of certain hydrocarbon working fluids.

d. Total Flow Systems

A large group of conversion concepts include total flow devices. These devices make use of the fact that most energy can be recovered by isentropic expansion of the wellhead fluid. An isenthalpic expansion, such as throttling in a flashed steam cycle, increases entrophy and thus reduces the amount of recoverable energy. For an ideal total flow cycle, a nozzle would convert all of the enthalpy drop in an isentropic expansion to kinetic energy and the device would then convert all of the kinetic energy to electricity. The utilization or conversion efficiency is the electricity generated divided by the isentropic enthalapy drop. The utilization efficiency must be in the 50% to 70% range in order to be competitive with the more conventional binary and flashed steam cycles. Several types of total flow devices are available and may be used as wellhead units while waiting for a large power plant to come on line or in areas where power demand is small. A brief discussion of several of the total flow devices is presented below:

(i) Bladeless Turbine - patented in 1913, operates by boundary layer drag on closely spaced disks, commercially available through General Enertech for geothermal applications.

(ii) Biphase Rotary Separator - has undergone substantial development and testing, designed to separate gas from liquid, generate power and repressurize the liquid.

Biphase Corp. estimates that more than 50% of the kinetic energy from the nozzle expansion can be recovered. This results in about 25% more total power output than a single-stage flashed steam plant for a medium temperature reservoir. A 20 KWe unit has been built and tested. A 1.6 MWe unit has been built and is being installed at Roosevelt Hot Springs.

(iii) Helical Rotary Screw Expander - a positive displacement device has found extensive use in gas compression and works on the principle of the meshing screws causing pockets of decreasing volume during compression. By reversing theis process, expansion of a fluid can inport rotation to the screws of the expander. The expander can be used in environments where scaling is a problem since the meshing action limits scale buildup on the rotor surfaces. This device has been developed by Hydrothermal Power Co. A 62.5 KWe expander has been tested and achieved greater than 50% utilization efficiency.

2. Status of the Industry

a. Technology

Commercially proven technology is available for cost-competitive power generation from both vapor- and liquid-dominated geothermal resources. Geothermal energy has been utilized by many nations in a variety of locations under differing operational conditions, with substantial success. Whether it presents an economically attractive alternative to other fuels is a question depending upon the degree of difficulty of implementation at a specific site. The production of geothermal energy from the wellbore utilizes oil and gas technology to a great degree, and the technical problems encountered are similar to those of the petroleum industry. These problems, however, are generally more severe due to high temperature and highly corrosive fluids, and handling these problems strains the state-of-the-art of petroleum industry technology. The major problem areas include:

* Marginal drilling techniques
* Lack of adequate high-temperature drilling muds and other fluids
* Need for longer-lived drill bits
* Lack of sufficient and reliable well instrumentation

None of these problem areas constitute an insurmountable hinderance to the development of the resource. They serve mainly to increase costs.

Utilization of the vapor-dominated resource, essentially dry steam, presents little in the way of technical problems. Existing technological problems focus on removal and handling of the noncondensible gases and requirements for injection. Utilization of the liquid-dominated resource presents more technical problems as the economic limit is stretched to include more saline resources and lower-temperature resources.

The major problem areas include:

* Incompatability of tubular goods and cements in high operating temperatures of production wells (500°F to

700°F);

- Lack of proven well/reservoir stimulation techniques;
- Handling of highly saline geothermal fluids. High salinity can cause scaling on components, corrosion of components, failure of instruments and increased difficulty in reinjection of energy-spent fluids;
- Unavailability of pumps and materials that can withstand the high temperatures and corrosive conditions;
- The requirements for costly environmental control.

None of the above mentioned problem areas present sufficient technical problems to inhibit development of prime resources but keeps the marginal resources marginal.

b. Development/Power On-Line Status

Fourteen countries generate some of their electricity from geothermal energy. The fraction contributed by geothermal energy ranges from a negligible amount to as much as 30%. Over 110 individual generating units are currently on-line, with a total installed capacity of more than 2500 MWe. The present annual worldwide growth rate is about 15%. This rate is expected to be maintained for the next 2 to 3 years. Table VI-1 contains the best information available concerning the status of power-on-line for the countries employing geothermal energy to produce electricity.

TABLE VI - 1

Installed Geothermal Generating Capacity

Country	Generating Capacity, MW No. Units	 July 1981
United States	18	932.2
Philippines	11	446.0
Italy	39	439.6
New Zealand	14	202.6
Mexico	5	180.0
Japan	7	168.0
El Salvador	3	95.0
Iceland	5	41.0
Kenya	1	15.0
Soviet Union	1	11.0
Azores	1	3.0
Indonesia	2	2.3
China	7	1.9
Turkey	1	0.5
Totals	115	2538.1

A 1981 survey of the nation's electric utilities by the Electric Power Research Institute (EPRI) predicted a rapid growth of geothermal generating capacity through the year 2000. Announced plans for geothermal capacity for 2000 has grown to 4500 MWe, an increase of 36% from a similar 1980 survey. More than half of this announced capacity is from liquid-dominated resources. Survey trends indicate that the possible growth of geothermal electricity could result in 10,800 MWe by 2000, representing an overall growth rate of 12% per annum over the rest of the century.

3. Economics

The development of a geothermal power generation system is capital-intensive, requires expert planning, and demands extended time from initial expenditure until positive income is achieved. Development requires extensive engineering and approximately two years negotiation with governmental agencies.

To obtain a comparison of geothermal with the more widely used fuels is quite difficult because each geothermal area requires a specific plant design for that particular area. The steam price of 16.5 mills per kwh at The Geysers, CA, is as inexpensive as geothermal energy can be expected to be in the U.S. today. This is a dry steam fuel, and the operators have more than a decade of experience in drilling, completion, and production operationp. Optimum techniques have been developed so that maximum steam production per dollar invested can be maintained. The high energy content of the fluid provides a competitive heat rate. Collection systems are relatively easy to construct, and the simple plant and reinjection facilities suffice. The cost of the wells are frequently higher than $750,000 - $1,000,000, but the high energy content of the steam yields a minimal energy price.

The wide variety of estimates of fuel costs and electricity generating costs derives from treatment of fuel processing and storage expense, income taxes, ad valorem taxes, insurance, interest during construction, return on investment required, and specific requirements for plants in the area of operation for the estimating companies. The developer usually expects to earn a minimum of 25 to 30% ROI on his equity portion. The exploration and producing investors have learned that a minimum acceptable return on investment for their portion of the projects is 20 to 25% ROI.

Next to reliability of supply, the utilities' desire to use geothermal energy in electrical generating systems is dependent upon price being low enough to make its use worthwhile. Much like coal and uranium, geothermal fuel prices will be negotiated price between the supplier and the user. Each geothermal field will have significant differences in design so a uniform price cannot be expected for construction of the production facilities or for construction of the conversion plant.

The basic structure of price must provide an attractive rate of return to the prospector. To achieve this, the prospector's risk capital and time at risk before income is derived must be minimized. Most important, the revenue should reflect the actual value of the energy sold.

Steam prices at The Geysers are a matter of public record with the State of California. This steam is the least expensive of all thermal systems employed for electrical generation in the U.S. To obtain a comparison of hot water flash steam plants with other energy sources, it is necessary to use developments outside of the U.S.A. The economics of some flash steam projects are impressive. At Cerro Prieto seventy-five megawatts have now been developed and work is underway for the next 75 MWe. The first unit of 75 MWe was developed for $264/KWe, and produced electricity for approximately 8 mills tax free. Today, costs would be about two and one-half times that amount. It is estimated the second 75 MW plant will produce electricity for about 16 mills tax free.

The economic and financial analyses for a geothermal development must take into account many parameters. The key parameters are listed in Table VI-2. Also of major importance is the development schedule for the plant and field. A representative schedule is shown in Figure VI-7. The accompanying capital expenditure schedule is depicted in Figure VI-8. Estimated power capital costs for a 50 MWe dry steam power plant, typical of those at The Geysers, is presented in Table VI-3. This table is not intended as a cost estimate; it is only included to give the reader a feel for development costs.

TABLE VI-2

Key Economic Parameters

Temperature of Resource
Type of Resource
Exploration costs
Land Acquisition
Resource Artesian Head
Well Depth
Producer/Injector Ratio
Spare Well Fraction
Well Flow Rate
  - Free Flow
  - Pumped
Estimated Well Life
Drywell Fraction
Well Rework

Capital Cost of Plant
Plant Capacity Factor
Cost of Transmission of Grid
Parasitic Losses
Operation Expense
Environmental Mitigation
Royalty Rate
Tax Considerations
Insurance Premiums
  - Operational
  - Reservoir
Inflation Rate
  - Goods & Service
  - Sales
Financing Arrangements

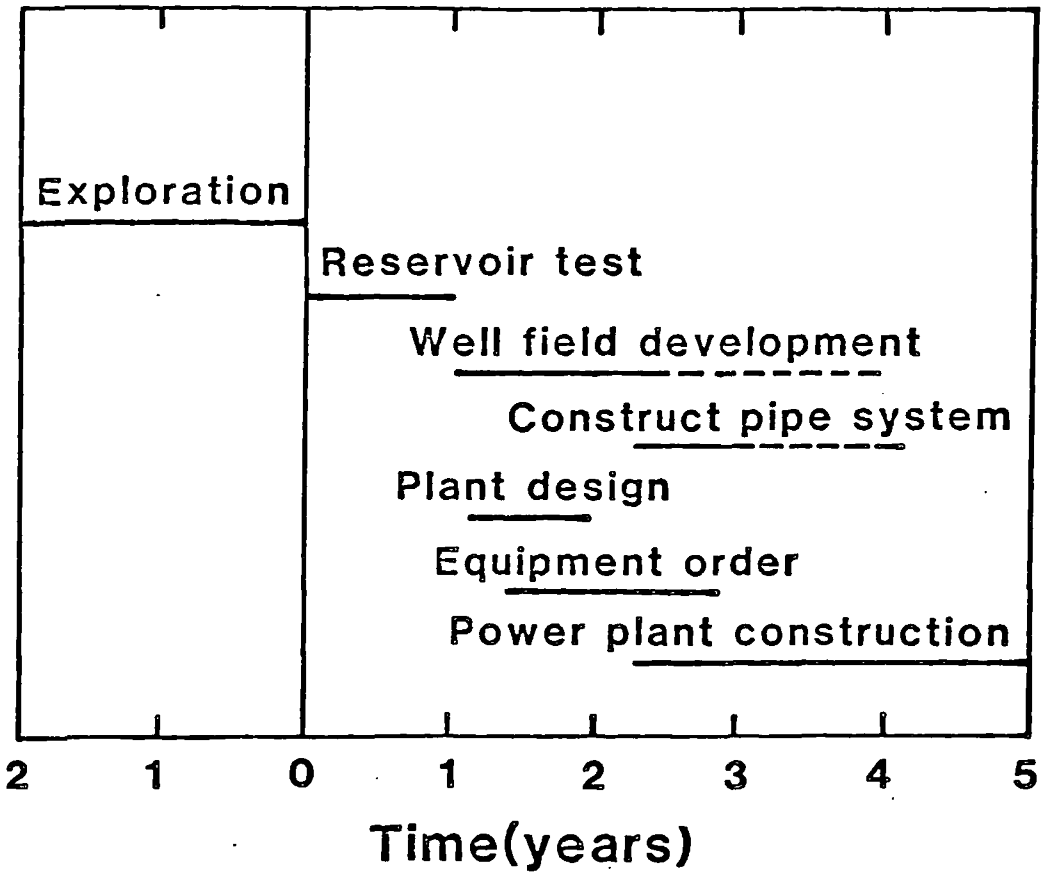

Figure VI-7. Representative schedule for field and plant development.

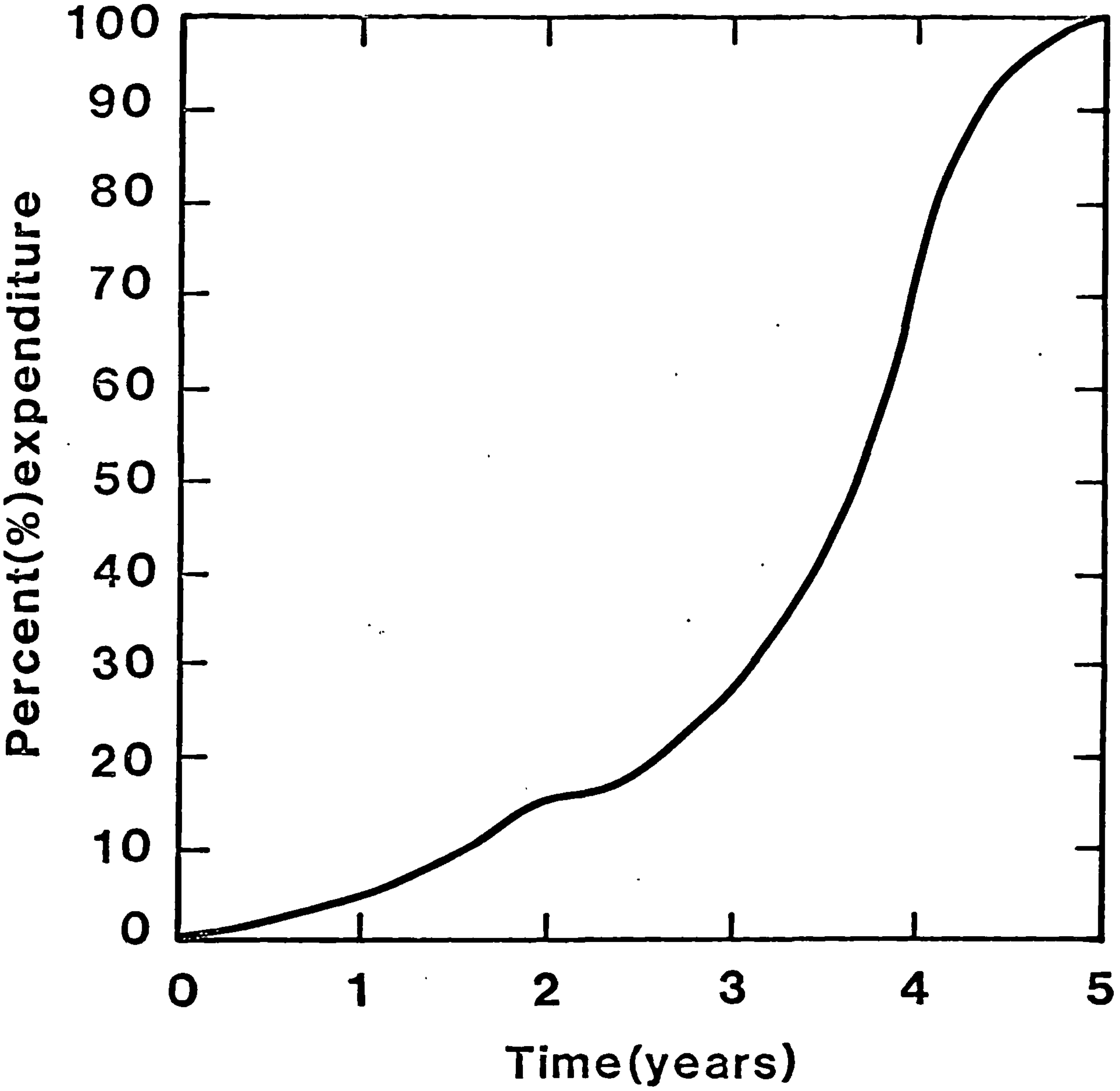

Figure VI-8. Capital expenditure schedule.

TABLE VI-3

Typical Power Plant Capital

(50 MWe, 1981 dollars)

	$ x 1000
Plants Costs	
Direct Costs	
Civil	550
Power House & Foundation	1,200
Turbine - Generator	6,400
Cooling Tower & Basin	2,400
Piping & Vessels	10,400
Electrical	1,950
	$22,900
Indirect Costs	
Design & Construction Management	2,900
Construction Labor	8,800
Contingency, Fees, Taxes, Etc.	4,700
Plant Start Up	300
	$16,700
Total Plant Capital Costs	$39,600
Field Capital	
Direct Costs	
Wellhead Equipment & Piping	7,000
Production Well Drilling (12 wells @ $880,000 each)	10,560
Injection Well Drilling (6 wells @ $880,000 each)	5,280
	$22,800
Indirect Costs	
Project Engineering & Reservoir Testing	4,200
Total Field Capital	$27,040
TOTAL OPERATION POWER FACILITY CAPITAL COSTS	$66,640

C. Direct Utilization of Geothermal Energy

1. Introduction

Direct utilization of geothermal energy for space and process heating for the most part utilizes known technology. Basically, hot water is hot water whether from a boiler or from the earth. The utilization of geothermal energy requires only straightforward engineering designs rather than revolutionary advances and major scientific discoveries. The technology, reliability, economics and environmental acceptability have been demonstrated throughout the world. However, it must be remembered that each resource is different and the systems must be designed accordingly.

Direct utilization of geothermal energy was probably practiced by early man for cooking and heating. Recorded history shows uses by Romans, Chinese, Japanese, Turks, Icelanders, Central Europeans and Maori of New Zealand for bathing, cooking and space heating. These uses have continued to today where, for example, over 1500 hot-spring resorts exist in Japan, visited by 100 million guests every year.

Early industrial applications include the use by the Etruscans of boric acid deposited by the steam and hot water at Lardarello, Italy. They used the deposits to make enamels to decorate their vases. Commercial extraction of the acid started in 1818, and by 1835, nine factories had been constructed in the regions. Municipal district heating was first undertaken in Boise, Idaho and in Klamath Falls, Oregon in the late 1800's. Today 7,000 to 8,000 MWt are utilized in the world for space heating and cooling (space conditioning), agriculture and aquaculture production, and for industrial processes. Of this figure, 1200-1300 MWt are used for space heating and cooling; approximately 6000 MWt for agriculture, aquaculture, and animal husbandry and over 200 MWt are used for industrial processes.

Generally, the agriculture-related uses require the lowest temperatures, with values from 27-82°C (80-180°F) being typical. Use of wastewater has wide applications here. The amount and types of chemicals and dissolved gases, such as boron, arsenic and hydrogen sulfide, are a major factor for this use. Heat exchangers and proper venting of gases may be necessary in some cases to solve this problem. Almost all of the agricultural-related energy utilization is in the Soviet Union where over 5000 MWt are reported being used.

Space heating generally utilizes temperatures in the range 66-100°C (150-212°F) with 38°C (100°F) being used in some marginal cases and with heat pumps extending this range down to 13°C (55°F). The leading user of geothermal energy for space heating is Iceland, where over 50 percent of the country is provided with geothermal heat. The only commercial application of cooling is in Rotorua, New Zealand, at the International Hotel; however, many other applications are presently being developed.

Industrial processing typically requires the highest temperatures, using both steam and super-heated water. Temperatures up to or beyond 150°C (300°F) are normally desired; however, lower temperatures can be used in some cases, especially for drying of various agricultural products. Resources at temperatures in excess of 150°C would ordinarily be considered for electrical power generation. Although there are relatively few examples of industrial processing using geothermal energy, they represent a wide range of applications, from drying of wool, fish, earth and lumber, to pulp and paper processing and chemical extraction. The two largest industrial uses are the diatomaceous earth drying plant in Iceland and the paper and wood processing plant in New Zealand.

A visual representation of the required temperature for various direct-thermal uses is shown in Figure VI-9. The flow diagram for a basic direct utilization system is presented as Figure VI-10. The heat exchanger is typically the interface between the geothermal system and the user system. In cases where high quality geothermal fluid is available, the heat exchanger and secondary loop shown in the diagram may be eliminated.

The main advantages of direct utilization of geothermal energy are:

* High conversion efficiency (80-90 percent),
* The use of low-temperature resources, which are numerous and readily available,
* The use of many off-the-shelf items for exploitation (pumps, controls, pipe, etc.),
* Short development time as compared to electrical energy development, and
* Lower-temperature resources require less expensive well development, shallower wells, and can be drilled with less sophistocated drilling equipment in many cases.

All of these advantages can give a favorable economic situation

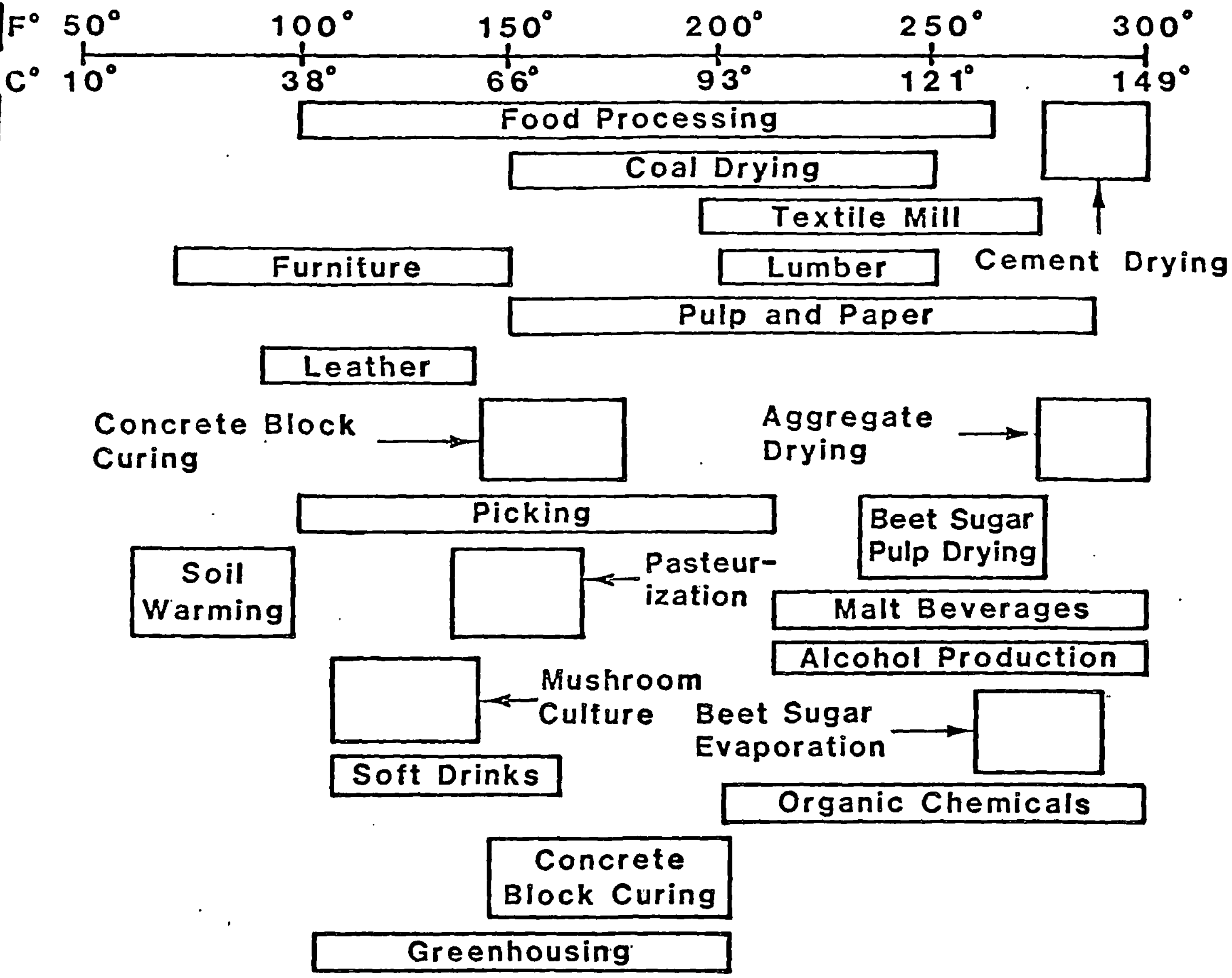

Figure VI-9. Resource temperature versus direct heat applications.

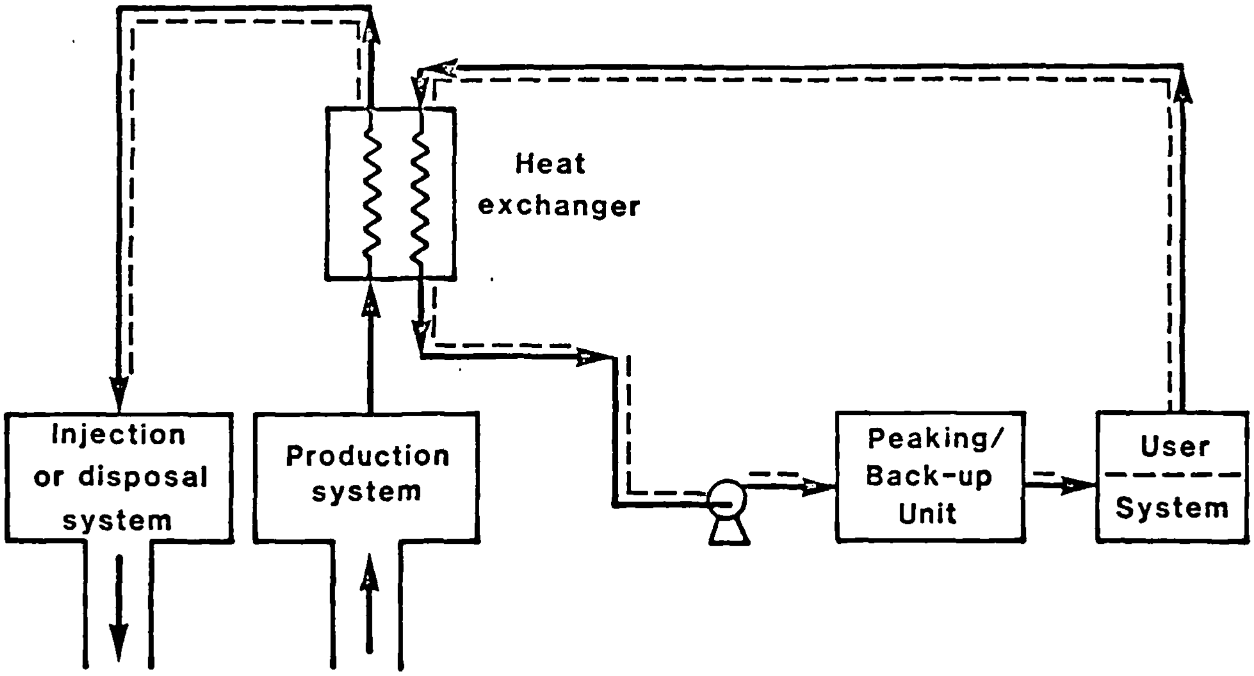

Figure VI-10. Geothermal direct heat utilization system.

compared to conventional fuel. At present prices, many geothermal applications will cost about the same or less than the corresponding fossil-fuel cost.

The economics are greatly enhanced where cascading (multi-stage use) is considered. The Japanese optimize cascading where geothermal fluids are first used for electrical power production, then space heating, cooking and finally bathing (at Otake). Here, an attempt is made to squeeze the last drop of energy from the fluid at a little additional field capitalization and operating cost. Lower-temperature cascading could consider space heating, agriculture, bathing/swimming pools and snow melting. Low- and intermediate-temperature geothermal resources can also be used to meet the base load of an energy demand. Heat pumps and fossil fuel can then be used to meet the peak demands, thus conserving the resource and minimizing capital investments.

2. Current Utilization

Traditionally, direct use of geothermal energy has been on a small scale by individuals. Surface hot springs were utilized and shallow wells could be justified with on-the-spot use or short transmission distances in uninsulated pipes or channels. However, at today's prices for development and hardware, the cost savings of these individual uses are often marginal. Large-scale use demands require more production and can thus justify deeper wells, longer transmission distances, more sophisticated utilization, and lower utilization temperatures.

Most of the present developments involve large-scale projects, such as district heating (Iceland), greenhouse complexes (Hungary) or major industrial use (New Zealand). Heat exchangers are also becoming more efficient and better adapted to geothermal use by allowing the use of lower-temperature waters and highly saline fluids. Heat pumps are extending geothermal development into traditionally non-geothermal countries, such as France, Austria and Denmark, as well as the eastern U.S.

a. Space conditioning

The most famous space-heating project in the world is the Reykjavik municipal heating project, serving about 97 percent of the 113,000 people in the capital city of Iceland. At present, a total of 1.0 x10^{10} gallons (3.8 x 10^{10} liters) of geothermal fluid are used annually to supply 16,000 homes with space heating. One field supplies water through two 14-inch and one 28-inch (35 and 79 cm) diameter pipelines over a 12 mile (19 km) distance. Insulated storage tanks of 2.6 x 10^7 liters (6.9 x 19^6 gallons) are used to meet peak flows and provide an emergency supply in the event of breakdown in the system. A fossil-fuel fired peaking station is used to boost the 80°C water to 110°C (176°F-110°F) during 15 to 20 of the coldest days of the year. The city is served by 9 pumping stations, distributing fluid through 320 km (200 miles) of pipelines. The entire system provides 1840 GWh per year or 420 MWt (including the peaking station).

b. Agriculture and aquaculture

In Hungary, green house heating is second only to the USSR, with over 1.2 million m^2 (13 million ft^2) being geothermally heated. Many of these greenhouses are built on rollers so they can be pulled off their location by tractors, the ground cultivated with large equipment, and then the green house returned to its location. In addition, to minimize cost, much of the building-structure pipe-supporting system also acts as the supply and heat radiation system for the geothermal fluid. About 60 wells are used for animal husbandry projects, mainly for heating and cleaning of animal shelters. Priority is given to agricultural use of geothermal energy in Hungary, as this increases the volume and variety of production.

Some experimental work is being performed with grain, hay, tobacco and paprika drying. In these cases, hot water supplies heat to forced-air heat exchangers and 49-60°C (120-140°F) air is blown over the product to be dried.

In Japan, greenhouses cover about 14,600 m^2 (157,000 ft^2) where a variety of vegetables and flowers are grown. Many large greenhouses are operated as tropical gardens for sightseeing purposes. Raising poultry through the use of geothermal energy has been a very successful enterprise. Here, under-the-floor heating is utilized in sheds where 40,000 chickens are raised annually. Another successful business is breeding and raising carp and eels. Eels are the most profitable and are raised in 25-cm by 6-m (10-in diameter by 20-ft) long earthenware pipes. Water in the pipes is held at 23°C (73°F) by mixing hot spring water with river water. The adult eels weigh from 100-150 g, (3-1/2 to 5 1/4 oz.) with a total annual production of 3800 kg (8400 lbs) being bred purely for sightseeing purposes. In combination with greenhouses offering tropical flora, alligator farms are offering increasingly large inducement to the local growth of the tourist industry.

Excellent examples of greenhouse operations exist in the U.S., the largest being the Honey Lake Hydroponic Farms complex near Susanville, California. Cucumbers and tomatoes are grown in a hydroponic system. Heat is provided to the greenhouses by geothermal fluid. At present, 30 greenhouses have been constructed, with expansion planned to over 200 units. Channel catfish are raised by Fish Breeders of Idaho near Buhl, using geothermal water. Using 380 l/s (6000 gpm) of 32°C (90°F) water, approximately 230,000 kg (500,000 lbs) of fish are raised annually.

c. Industrial processes

An example of industrial processing is the use of geothermal steam for the Tasman Pulp and Paper Company in New Zealand. Here, 100-125 MW (18 tons/hr steam) of thermal energy are used for lumber drying, black liquor evaporation, and pulp and paper drying. The total investment cost for geothermal to date is $6.8 million, the majority of which has been for well development. This amounts to approximately $70 per kWt and reduces the price of energy to 70 percent of conventional fuels for an annual savings of $12.3 million. The annual maintenance costs are 2 percent of the capital cost.

In northern Iceland, a diatomaceous slurry is dredged from Lake Myratn. This slurry is transported through a pipeline and held in storage ponds. The moisture, starting at 80 percent, is removed in large rotary-drum driers using high-temperature geothermal steam. The plant produces 27,000 tons of diatomite filteraids per year, most of which are used in beer processing.

Two industrial-processing uses of geothermal energy of note are in the U.S.: Medo-Bel Creamery in Klamath Falls, where low-temperature fluid is used for pasteurizing milk, and Geothermal Food Processors at Brady Hot Springs, Nevada, where high-temperature fluid is used for dehydration of onions and other vegetables. Table VI-4 presents world wide industrial processing applications using geothermal energy.

3. Industrial Applications

Industrial use represents 40% of our national energy consumption, the single largest share, with residential space conditioning and water heating using 20%, commercial space conditioning and water heating using 15%, and transportation accounting for the remaining 25%.

The energy used by industry can be broken into the following categories:

Process Steam	40.6%
Electric Drive	19.2%
Electrolitic Process	2.8%
Direct Process Heat	27.8%
Feedstocks & Chemicals	8.8%
Other	0.8%
	100.0%

Process steam and direct process heat account for 68.4% of the

TABLE VI-4

CURRENT INDUSTRIAL PROCESSES USING GEOTHERMAL ENERGY

APPLICATION	COUNTRY	DESCRIPTION OF APPLICATION
Wood and Paper Industry		
Pulp & Paper	New Zealand	Processing and a small amount of electrical power generation. Kraft process used.
Timber Drying	New Zealand	Kiln operation.
Washing & Drying of Wood	Iceland	Steam drying.
Mining		
Diatomaceous Earth Plant	Iceland	Production of dried diatomaceous earth recovered by wet-mining techniques.
Chemicals		
Salt Plant	Japan, Phillipines	Production of salt from sea water.
Sulphur Mining	Japan	Sulfur extraction from the gases issuing from a volcano.
Boric Acid, Ammonium Bicarbonate, Ammonium Sulphate, Sulphur	Italy	Includes recovery of substances from the volatile components which accompany the geothermal steam.
Miscellaneous		
Confectionary Industry	Japan	
Grain Drying	Phillipines	Geothermal steam heats rotary kiln dryer.
Brewing and Distillation	Japan	
Stock Fish Drying	Iceland	Fish drying in shelf dryers.
Curing Cement Building Slabs	Iceland	Curing of light aggregate cement building slabs.
Seaweed	Iceland	Drying seaweed for export.
Onion Drying	United States	Dehydration of onions.
Milk Pasteurization	United States	Milk processing using low-temperature resource.

total industrial use of energy, much of which can potentially be supplied by hydrothermal energy. Today, high-temperature processing is being practiced in many cases only because those are the temperatures naturally achieved when fossil fuel is consumed. Typical processes which can be operated in the low- to moderate temperature range, together with the percentage of the process energy needs as a function of maximum temperature required, are given in Table VI-5.

TABLE VI-5

TYPICAL INDUSTRIAL PROCESS HEAT REQUIREMENTS

	40°C- 60°C	60°C- 80°C	80°C- 100°C	100°C- 120°C	120°C 140°C	140°C- 160°C	160°C- 180°C	180°C- 200°C	200°C
Dehydrated Fruits & Vegetables	0	100%	→	→	→	→	→	→	→
Concrete Block - Low-Pressure	0	100%	→	→	→	→	→	→	→
Autoclave	0	0	0	0	0	0	0	100%	→
Frozen Fruit & Vegetables	0	0	39%	100%	→	→	→	→	→
Poultry Dressing	100%	→	→	→	→	→	→	→	→
Meat Packing	0	99%	100%	→	→	→	→	→	→
Prepared Feeds - Pellets	0	0	100%	→	→	→	→	→	→
- Alfalfa Drying	0	0	0	0	0	0	0	0	100%
Plastic Materials	0	0	0	0	0	0	0	00	100%
Dairy Industry - Cheese	23%	100%	→	→	→	→	→	→	→
- Condensed Milk	0	63%	63%	93%	100%	→	→	→	→
- Dried Milk	0	0	42%	66%	71%	71%	71%	100%	→
- Fluid Milk	0	0	100%	→	→	→	→	→	→
Soft Drinks	61%	100%	→	→	→	→	→	→	→
Soaps	0	0	0	1%	—	—	—	—	100%
Detergents	0	0	0	52%	—	—	—	—	100%

In many processes, time and temperature can be traded off to permit the use of lower-temperature energy sources. Thus, there are potentially many additional processes which can be adapted to low-temperature energy sources.

The basic processes which are considered to be in the range of geothermal applications are:

- Preheating
- Washing
- Cooking, blanching and peeling
- Evaporation
- Sterilization
- Distilling and separating
- Drying
- Refrigeration
- Biogas production

These industrial applications use thermal energy in the temperature range up to 150°C (300°F); it should be noted that the application potential can be expanded with increased resource temperature. A discussion of the basic processes is presented below.

a. Preheat

Geothermal energy can be effectively used to preheat boiler and other process-feed water in a wide range of industries. Many manufacturing industries utilize boilers distributing steam throughout the plants. For a variety of reasons, much of the condensate is not returned. This imposes a considerable load on the boiler for feed-water heating of incoming water at typically

10-16°C (50-60°F) up to the temperature at which it is introduced into the boiler, typically 93-149°C (200-300°F), depending on the system. The geothermal resource can often be used to offload the boiler of some or all of this preheating load. A wide variety of industries use, for various processes, large quantities of feed water which can be preheated or heated geothermally to the use temperature. Some of these applications also use heat-reclaim methods which must be analyzed when evaluating the potential for geothermal use.

b. Washing

Large amounts of low-temperature energy 35-93°C (95-200°F) are consumed in several industries for washing and clean-up. One principal consumer is food processing, with major uses in meat packing for scalding, carcass wash and clean-up 60°C (140°F); in soft-drink container and returnable bottle washing 77°C (170°F); in poultry dressing as well as canning and other food processes. Textile industry finishing plants are another large consumer of wash water at 93°C (200°F). Smaller amounts are used for plastic 88-93°C (190-200°F) and leather 49°C (120°F). Most of these are consuptive uses. Sizeable amounts of hot wate rand other hot fluids at temperatures under 93°C (200°F) are used in the several metal-fabricating industries (fabricated metal products, machinery and transportation equipment) for part degreasing, bonderizing and washing processes. Most of these are non-consumptive uses with a 6-14°C (10-20°F) range in the fluid and in the reheating to the use temperature.

c. Peeling and blanching

Many food-processing operations require produce peeling. In the typical peeling operation, the produce is introduced into a hot bath (which may be caustic) and the skin or outer layer, after softening, is mechanically scrubbed or washed off. Peeling equipment is usually a continous-flow type in which the stream or hot water is applied directly to the produce steam or indirectly by heating a produce bath. In most instances, produce contact time is short.

Blanching operations are similar to peeling. Produce is usually introduced into a blancher to inhibit enzyme action, provide produce coating, or for cooking. Blanching may be either a continuous or batch operation. Typical blanching fluids require closely controlled properties. Thus, it is unlikely that geothermal fluids could be used directly in blanchers and peelers because of the water quality. Geothermal fluids could, however, provide the energy through heat exchangers.

The temperature range for most of the peeling and blanching system is 77 - 104°C (170-220°). These heating requirements are readily adaptable to geothermal resources.

d. Evaporation and distillation

Evaporators and distillators are routinely found in many processing plants to aid in concentrating a product or separating products by distillation. Most frequently the evaporator will operate as a batch process in which a quantity of product is introduced and maintained at some given temperature for a period of time. The source temperature requirements vary with the product being evaporated. However, in a majority of agricultural processes, water is being driven off; and in these cases, operating temperatures of 82 - 121°C (180 - 250°F) are typical. In some circumstances, the evaporators operate at reduced pressures which decrease temperature needs and improve product quality. Evaporators are commonly found in sugar processing, mint distilling and organic liquor processes. Evaporators, depending upon temperature and flow-rate requirements, can be readily adapted to geothermal energy as the primary heat source. The energy can be transferred through secondary heat exchangers to the working fluids or, in some instances, used directly at the evaporator, depending upon existing plant designs or adaptations to new plant expansions.

e. Sterilizing

Sterilizers are used extensively in a wide range of industries and include applications such as equipment sterilization in the meat-packing and food-processing industries and sterilization for the canning and bottling industry. Most sterilizers operate at temperatures of 104 - 121°C (220 - 250°F) and would utilize geothermal energy with the use of heat exchangers to heat the potable sterilizer water. Many sterilizers operate in a continuous mode. Equipment washdown and sterilization, however, may occur periodically or at shift changes.

f. Drying

Many industries utilize heat at temperatures under 149°C (300°F) for evaporating water or to dry the product, material or part. The largest consumers are pulp and paper drying and textile product drying--mostly in the 93 - 149°C (200 - 300°F) range.

Other large consumers of energy for drying are in beet-pulp drying, malt-beverage and distilled-liquor grain drying and cement drying. Additional large energy consumers in the drying application area are grain, lumber kiln, plywood and veneer drying. Smaller consuming industries having drying applications include coal, sugar, furniture, rubber, leather, copper concentrate, potash, soybean meal, tobacco, pharmaceutical tablet and capsule, explosives and paving-aggregate drying.

g. Refrigeration

Cooling can be accomplished from geothermal energy through lithium-bromide and ammonia absorption refrigeration systems. The lithium-bromide system is the most common because it has water as the refrigerant; however, it is limited to cooling above the freezing point of water and has as its major application the delivery of chilled water for comfort or process cooling and dehumidification. These units may be either one- or two-stage. The two-stage units require higher temperatures -- about 163°C (325°F) -- but also have a higher COP (cooling output/source energy input), being about 1 to 1.1. The single-stage units are currently receiving substantial research emphasis in regard to use with solar energy and can be driven with hot water at temperatures somewhat below 88°C (190°F) and will typically have a COP of 0.65.

For geothermally driven refigeration at temperatures below the freezing point of water, the ammonia absorption systems must be considered. These can operate down to about -40°C (-40°F) evaporator temperature. However, these systems are normally only applied in very large tonnage capacities (100 tons and above) and have seen limited use. For the lower-temperature refrigeration, the driving temperature must be at or above about 121°C (250°F) for a reasonable performance.

h. Biogas generation

The decomposition of organic matter in the absence of oxygen is called anaerobic fermentation and is the basis of biogas production. Anaerobic fermentation of organic products results in methane, carbon dioxide, hydrogen, traces of other gases and the production of some heat. The residue remaining is hygienic, rich in nutrients and high in nitrogen. Weed seeds and potentially damaging germs are killed by the absence of oxygen during the fermentation process rather than by the significantly higher heat generated by the aerobic (in the presence of oxygen) process.

The efficiency and rate of anaerobic fermentation are affected by temperature, relative concentration of carbon and nitrogen, pH and solids concentration.

The biogas-producing activities are optimal in temperatures ranging from 29-42°C (85-105°F) although digestion will occur from freezing to 69°C (32-156°F). Fermentation, however, is less stable in the higher of these two ranges and, consequently, biogas units are typically maintained in the lower optimal range.

The key equipment element in the biogas process is the enclosed biomass digestion tank. The temperature of such digesters is controlled by the addition of heat to maintain the desired 29-41°C, (85-105°F) temperature range. This heating can be accomplished by circulating hot water through metal coils either inside the tank or in the tank walls; insulation is typically provided to minimize heating requirements.

4. Parametric Review

The decision to develop and use a geothermal resource for direct application must be studied thoroughly from both technical and economic viewpoints. As one would suspect, the technical (geologic and engineering) issues and the economic issues are interrelated to the extent that a potential user or developer must continue analyzing the merits of the direct use project as additional data become available from the development activities. Fourteen major areas of consideration have been identified for further review herein:

a. Site selection

In geothermal development the site of development must be near the resource. In selecting the best geothermal site, the following areas must be reviewed and analyzed: (a) resource adequacy, (b) availability of properly skilled labor pool, (c) availability of raw materials, (d) availability of proper transportation that is compatible with the facility raw materials required and the resulting product shipments, (e) community acceptance, (f) availability of process water, (g) distance to market, (h) availability of support energy, (i) availability of support services, (j) topography and (k) climate.

b. Exploration

The amount of explortio needed to define a geothermal system and to site successful wells varies from area to area. The primary objective of surface geology, geochemistry and geophysics is to make the drilling program as cost effective as possible. Obviously if explortion and/or drilling costs are too high. The whole project becomes economic, so the goal is to keep these costs as small as possible while at the same time collecting enough data to have confidence in reservoir temperature, productivity, longeivity and chemistry.

c. Resource Depth/cost

Well costs are not linear with respect to depth. The development of deep wells becomes quite expensive. The energy requirements for a development must be carefully balanced against anticipated well drilling costs. For some small energy use projects a developer must select a fairly well-known shallow field to minimize both his exploration and well drilling costs.

d. Resource Production

The issues that have to be included in the analysis concerning resource production are (a) number of production and injection wells, (b) average well productivity, (c) wellhead temperature, (d) bottom hole static pressure, (e) formation permeability and (f) annual operating hours.

e. Engineering

Normal design practices used with other energy systems often must be altered to be compatible with geothermal conditions. Process changes may be required and low-temperature technology techniques such as fluidized bed technology, vapor recompression, and vacuum distillation may be desirable. Corrosion and scaling present unique materials selection problems that can be very critical to selecting a proper engineering design. Design costs could be greater than state-of-art design costs.

f. Utilization Factor

The utilization factor, the percentage of the time the system is being operated, is critical in amoratization of energy production and delivery system expense. Utilization factor is calculated by dividing the amount of energy actually used by the yearly capacity of the system. Typical utilization factors are (a) Industry: 75%-95%, and (b) Space Heating: 20%-30%.

g. Use Temperature (Temperature Differential - ΔT)

The temperature requirements for industrial uses are critical to the engineering and economic analysis. A developer must determine the amount of process heat that can be obtained from a specific geothermal resource and decide what percentage of his process heat requirements can be fulfilled by the resource. Temperature boosting may be required if the geothermal resource supply temperature is inadequate. Temperature boosting must be analyzed carefully since this technique is usually not economical for processes that would require a major part of the supply fluid to be elevated in temperature. The ΔT or amount of energy that can be removed from the supply fluid is also extremely critical. The larger ΔT the less fluid required from out of the ground. These fluids not only must be pumped from the ground but also be pumped through pipes and heat exchangers before being disposed of. ΔT is a function of supply temperature and use temperature. The closer these two temperatures approach each other, the smaller the ΔT available for utilization. Figure VI-14 illustrates the importance of obtaining a large ΔT to minimize energy costs.

h. Pumping Costs

Pumping costs are the expenses incurred in bringing the fluid out of the ground, delivering it to the point of use, and disposing of it after energy removal. These three expense factors are dependent upon (a) fluid draw down level in the well(s), (b) topography, (c) pipe sizing, (d) fluid delivery distance, and (e) fluid disposal technique.

i. Fluid Transmission

The parameters that need to be included in a fluid transmission analysis are (a) mass flow rate, (b) pipeline length, (c) inlet temperature, (d) fluid velocity, (e) insulation requirements, (f) inlet pressure and (g) annual operating hours.

j. Water Quality

Water quality varies greatly from geothermal resource to resource. Geothermal fluid temperature and chemistry are closely related in that there is a general increase in total dissolved solids as temperature increases. The chemical components found in the fluids are a function of the local, in situ geology. The chemical components present in geothermal fluids are the primary causes of corrosion and scaling when fluids are used as heat sources. Corrosion and scaling can be controlled through material selection and process control.

k. Disposal

The energy-expended fluids must be disposed of after the heat extraction is completed. The disposal technique selected should be reviewed in light of accepted practices and cost. The four common options for geothermal fluid disposal are: (a) discharge to surface waters if the fluids are environmentally benign; (b) discharge to evaporation/infiltration areas; (c) injection into shallow, intermediate or deep aquifers depending upon local conditions and environmental regulations; or (d) used for secondary purposes - energy expended geothermal fluid could be beneficially used for agricultural or other purposes but may require treatment before use.

l. Heat Exchangers

The principal reason for having heat exchangers in geothermal systems is to extract heat while confining the geothermal waters to locations where corrosion and scaling may be controlled or where cleaning and replacement is easy and economic. There will always be a temperature differential (Δ T) between primary and secondary fluids any time a heat exchanger is used. The smaller Δ T the larger and more expensive the heat exchanger will be. Approach temperatures of less than 5°C are usually more economic. The principal types of heat exchangers used in geothermal system design are (a) shell-in-tube heat exchanger, (b) plate heat exchanger, (c) fluidized bed heat exchanger (d) direct control heat exchanger (e) plastic-tube heat exchanger, and (f) down hole heat exchangers.

m. Institutional Consideration

Many institutional matters must be addressed during project development. The major areas are (a) water law, (b) leases, (c) resource ownership, (d) drilling regulations, (e) land use plans, (f) rights-of-ways or easement, and (g) permitting.

n. Environmental

Although geothermal energy development is typically environmentally benign, a developer still must address at least the following issues: (a) seismicity, (b) subsidence, (c) resource depletion, (d) aquifer interference, (e) fresh water contamination, (f) surface disposal, (g) noise, (h) air quality, (i) fogging, (j) flora and fauna, (k) socioeconomic and (l) fluid disposal.

o. Investment

The investment in geothermal development must be analyzed from the developer's financial position. Issues that should be addressed are: (a) risk taking ability, (b) tax position, (c) competitive fuel costing (short and long range), (d) cost of investment capital, (e) availability of debt and equity financing, and (f) overall project economics.

Interactive planning and analysis throughout the complete sequence of geothermal project development, using the salient factors outlined above, will provide an industrial developer a firm basis for proper and positive action at each decision point.

5. Economic Factors

The applications of geothermal energy are as widely varied as the temperature ranges and technology allow. The applications range from warming ponds for aquaculture to powering large industrial processes. Experience has shown that the transmission of geothermal energy through pipelines is expensive. Therefore, the best results can be obtained by locating the demand for energy in close proximity to the resource. Geological work needs to be accomplished to determine that a resource exists at a reasonable depth with adequate temperature and with acceptable flow rates. A preliminary system design must be completed to determine the technical feasibility of the project. Once these items are established, a preliminary economic analysis should be completed. The economic analysis should be a step-by-step process which evaluates the development costs, capital costs, and the operating and maintenance costs with respect to revenue generated in order to insure a suitable return on investment. Since geothermal is an alternative source of energy, in most cases, it is reasonable to compare it with conventional forms of energy. To be economically feasible, it must be competitive.

The cost structure of geothermal energy requires a relatively large capital investment at the beginning of the project with small annual operating costs occurring throughout the life of the project. Performing economic analyses involving alternative energy systems becomes more complicated due to the fact that competitive forms of energy are escalating at different rates and most forms of energy are escalating more rapidly than the economic inflation rate. Therefore, inflation rates for the competitors must be differentially escalated over the life of the project.

Economic feasibility studies involving geothermal application typically fall into one of these categories:

- those that are highly feasible;
- those that are marginally feasibile; and
- those that are not feasible.

As conventional fuels escalate in price more rapidly, those geothermal projects which were marginally feasible will become highly feasible and some non-feasible projects will move into the marginal category. Therefore, when escalating the prices of conventional fuels over the life of a project, one should be realistic with inflation rates.

Table VI-6 is a guide to the cost data that should be considered in an economic analysis. To insure that the proper perspective is maintained in regards to the capital investment required by geothermal development, the time value of money must be considered.

TABLE VI-6

Key Elements for Economic Analysis of Geothermal Direct Applications Projects

Capital Investment of the Geothermal System

A. Wells and well-head equipment
  1. Production wells
  2. Production well pumps
  3. Well-head buildings
  4. Power hook-up and controls

B. Piping Network
  1. Primary supply pipeline
    a. Excavation, bedding and backfill
    b. Concrete tunnels where applicable
    c. Pipeline
    d. Fittings
    e. Insulation
    f. Installation
    g. Special costs such as highway crossings, railroad crossings, riverbed crossings, etc.
  2. Secondary distribution system
    a. Excavation, bedding and backfill
    b. Concrete tunnels were applicable
    c. Pipeline
    d. Fittings
    e. Insulation
    f. Installation

C. Heat exchanger system
  1. Heat exchanger
  2. Circulation pumps
  3. Heat exchanger building
  4. Control system and power hook-ups
  5. Other equipment
    a. Expansion surge tanks
    b. Flashers
    c. Reservoirs, etc.

D. Retrofit costs (If retrofitting an old facility)
  1. Piping
  2. Heat exchangers
    a. Fan coil units
    b. Convectors
  3. Controls and hook-up
  4. Other special equipment required

E. Overhead costs
  1. Engineering
  2. Contingencies
  3. Other

Annual Costs of the Geothermal System (Table VI-6 cont.)

A. Operating costs
    1. Power requirements (kilowatt hours plus cost per kwh)
        a. Pumping
        b. Circulation
        c. Controls
        d. Operating personnel salaries
    2. Operators' salaries
    3. Other
        a. Billing

B. Maintenance Costs
    1. Periodic maintenance
        a. Wells
        b. Pipelines
        c. Heat exchangers
        d. Pumps
    2. Maintenance personnel salaries
    3. Shops

VII. Environmental Considerations

A. Introduction

The environmental impact from the development of geothermal resources is dependent upon a number of factors, including the biological, geographic, geological, physical, climatological, and demographic characteristics of the area to be developed. In addition, the mineral resources as well as aesthetic, scenic, recreational, agricultural, industrial, and other potential land uses must be considered. Other important factors are the physical and chemical character of the geothermal fluid and the relationship between the geothermal reservoir and fresh water aquifers. Environmental evaluations must recognize the potential environmental benefits which may be derived from the utilization of this resource in relationship to an equivalent amount of energy derived from alternative sources. If geothermal exploration, development, and production activities are properly planned, regulated, and operated, these resources may provide an environmentally beneficial energy source. Table VII-1 addresses the major concerns and controls that may be encountered during geothermal development.

The two basic types of geothermal systems (vapor-dominated and liquid-dominated) pose quite different environmental problems. The vapor-dominated systems generally yield relatively pure steam with small amounts of other gases, minerals, etc., such as boron, carbon dioxide, hydrogen, methane, arsenic, nitrogen, hydrogen sulfide, mercury, radon, and ammonia. Analysis of condensates of such vapors commonly indicates a water containing predominantly dissolved ammonium and bicarbonate

TABLE VII-1. ENVIRONMENTAL EFFECTS AND CONTROLS IN GEOTHERMAL DEVELOPMENT

CONCERN	POLLUTANT	EFFECT	CONTROL	REQUIREMENT FOR CONTROL
AIR QUALITY	Hydrogen Sulfide	Strong Odor. Possible contribution to SO_x and acid rain problems.	Iron Catalyst Process: downstream, direct contact condenser.	Occurrence requiring control uncommon. H_2S standards in some states. Monitoring on rig floors may be a safety requirement.
		Toxic at high concentrations.	Stretford Process: downstream steam, surface condenser.	
			EIC Process: upstream steam.	
			Dow Oxygenation Process: upstream liquid (promising).	
			Variety of other processes under evaluation or being tentatively considered, mostly for steam systems.	
	Particulates, dust	Visibility, reduced vegetation growth, health effects.	Closed flow systems with filters. Oil, water, or vegetation cover or dust producing surfaces.	Federal standards for ambient particulate levels.
	Others: radon, ammonia, hydrocarbons, boron, mercury, carbon dioxide.	Radioactive effects of radon, but others largely unknown and not generally expected to be significant.	Closed flow systems. Removal possible for some contaminants.	National emission standards for hazardous air pollutants.
LIQUID DISCHARGES/ WATER	Geothermal fluid; dissolved solids, trace metals, inorganic compounds, temperature. Drilling wastes: muds, cuttings, metals, inorganic compounds, treatment chemicals.	Contamination and thermal pollution of surface, ground, ocean waters, and soils.		Federal & state water quality standards. Controls are site-specific
			Treatment of discharge. Preinjection modeling & proper management practices.	Treatment may or may not be needed, but disposal is always required.
			Use of suitable non-geothermal water for environmentally sensitive purposes.	

LIQUID DISCHARGES/ WATER Con't.			Low pressure injection. Byproduct recovery. Evaporation.	
	Thermal energy.	Heat introduced into atmosphere and/or bodies of of water. Adverse affect on aquatic life.	Incorporation of state-of-the-art engineering design and procedures for optimal energy conversion efficiency.	Thermal standards included in surface water quality regulations.
			Cooling of liquids prior to discharge.	
SUBSIDENCE/ UPLIFT		May adversely affect topography, bodies of water, drainage, land uses, man-made features, and ecological habitats. Some subsidence may be tolerated without adverse impact.	Careful siting.	Geothermal Steam Act (federal lands only) GRO order 4.
			Fluid injection (geothermal) or non-geothermal).	
			Production and/or injection modification.	
SEISMICITY		Withdrawal and/or injection of geothermal fluids may enhance or trigger earth movement.	Careful siting (including study of seismic history	Geothermal Steam Act (federal lands only) GRO order 4.
			Production and/or injection modification.	
HYDROLOGIC ALTERATION		May adversely affect water supply, groundwater quality, and geologic formations.	Thorough reservoir and site assessment and engineering.	Federal and state regulations require protection of groundwater quality. Water rights provide legal protection.
			Production and/or injection modification.	
			Appropriate drilling procedures and technology.	
LAND USE AND DISTURBANCE		Interference with other land uses.	Minimization of total land area used.	
		Adverse affect on natural drainage.	Careful development and site planning and discussion with impacted (both positively and negatively) parties.	
		Adverse affect on flora and fauna.		
		Adverse affect on aesthetic qualities of area.	Minimization of vegetation clearing and implementation of	

			existing soil erosion control techniques.	
		Destruction of heritage resources.	Site-specific measures to achieve compatibility with other land uses.	
NOISE		Hearing-impairment Nuisance.	Shielding, attenuation, silencers; careful siting; scheduling of noise activities; miscellaneous devices and methods.	OSHA requirements. Control required for drilling and associated operations; other other controls on as-needed basis.
SOLID WASTES	Residual sludges from air and/or water treatments.	Contamination of surface and ground waters, and soils.	Sludge treatment. Byproduct recovery.	Resource Conservation and Recovery Act. Disposal of solids only a problem where liquid and/or air treatments are used; some solids from drilling operations may need disposal.
	Drilling wastes: muds, metals, inorganic compounds, treatment chemicals, cuttings.	Requires land area.	Proper landfill disposal.	
SOCIO-ECONOMIC CONSIDERATIONS		Impacts on local lifestyles, economic tax base, and cultural, religious, and political factors.	Careful development planning and discussion with interested parties.	Site-specific mitigation measures most important at at planning stage.

ions.

Hot-water systems may yield a wide chemical variety of hot mineralized or saline waters. For example, the geothermal fluid of the Salton Sea KGRA in California is a highly concentrated brine. Conversely, the geothermal fluids in other areas such as Oregon and Idaho may be of sufficient purity to be used directly for irrigation or other fresh water uses.

Certain environmental impacts will be common to all geothermal developments while others will be unique to a single field or individual lease. The envionmental impacts and the mitigating measures taken to lessen or eliminate such impacts will vary depending upon the characteristics of each specific lease site and the phase of geothermal development.

B. Air Quality

Air pollution resulting from the development of geothermal resources has been one of the prime environmental concerns of the industry. Constituents such as arsenic, mercury and boric acid are often released; however, the prime concern has been the emission of noncondensible gases such as carbon dioxide, hydrogen sulfide and radon. Because of the nontoxic nature of CO_2 relatively limited attention is given to this pollutant.

Hydrogen sulfide (H_2S) has received the greatest amount of environmental attention. This is due to its low odor threshold (detectable at 0.03 ppm), and serious health consequences at high concentrations. H_2S is heavier than air, thus, it can accumulate in low areas if ventilation is inadequate and may become trapped in valleys during air inversion conditions. H_2S may also harm vegetation, form acid rains which affect surface water chemistry, and accelerate the corrosion of exposed metals and other surface coatings. Current OSHA regulations cite an acceptable continuous ceiling concentration in the work place of 20 ppm; however, complaints in reference to noxious odors may originate at concentrations as low as 0.03 ppm. To date, federal standards have only been suggested for H_2S. Several states have atmospheric H_2S standards based on ambient levels. The Geysers resource contains significant quantities of H_2S. Since large-scale power production has occurred the release of H_2S has prompted opposition. While ambient concentrations have been below toxic levels, local opposition combined with occasional violations of the State Ambient Air Quality Standard of 30 ppb have resulted in strict local air pollution control district regulations.

There are two current power plant H_2S abatement systems in operation at The Geysers: the Iron-Catalyst-Peroxide-Caustic (ICPC) system on the existing units and the Stratford-Peroxide-Surface Condenser (SPSC) system on the new units. Both of these systems are downstream (downstream of the turbine) systems. The system can be brought up to abatement efficiencies in the 99+% range. The problem areas that exist are large quantities of sludge with the ICPC system and high reagent chemical costs with the SPSC system.

H_2S control technology is still under development to increase efficiencies and reduce costs. Geothermal controls in use for H_2S (and most of those under development) are designed for removal of this constituent from steam and are not generally applicable to liquid-based direct uses. Only one control system receiving serious technical evaluation, the Dow oxygenation process, is designed to extract H_2S from geothermal liquids (at the wellhead); this promising abatement technique has not been field-tested yet. Removal efficiencies in excess of 90% are indicated for the process, but special materials (e.g., Teflon) will be required at certain locations in the plant. No controls have been designed for emissions other than H_2S at geothermal facilities.

Atmospheric release of the radioactive noble gas radon (^{222}Rn), its daughters and precursors, may be of concern if concentrations are high. Radon mixes with steam and flows to the surface where it may escape through any natural or artificial opening. In California, the state health standard for radon in an uncontrolled area is 3pCi/l (one picocurie of radon is about 6.8×10^{-21} kg).

Particulates may also be a serious concern for geothermal resource developments, particularly in the arid West. In most cases, the concern is fugitive dust rather than salt particles formed from the geothermal fluid. Fugitive dust can be minimized through the use of proper construction practices and can be controlled using gravel, oil, water, or paving on the drill site and access roads. The method employed depends on the severity of the problem and the expected permanence of the site.

Vehicle and engine emissions, including SO_x, CO, hydrocarbons and NO_x, while not unique to geothermal, should be taken into consideration in evaluating air emissions.

Although some pollutant emissions will inevitably occur during well drilling and testing, these will be of a minor and temporary nature. Air emissions from longer-term operations can be mitigated and virtually eliminated by employing a closed-loop system.

C. Liquid Discharges/Water Quality

The primary sources of possible contamination are fluids produced from the well and, of shorter duration, the drilling fluid and cuttings. Concerns include not only thermal and chemical contamination of surface water resulting from improper fluid containment or disposal, but also contamination of groundwater. Groundwater contamination can result not only from seepage from surface containment but from invasion of geothermal fluids due to inadequate well casing and completion.

The quantity and nature of liquid discharges from geothermal drilling depend on the type of drill rig and drilling fluid, the quality of the geothermal fluid, the depth of the well, the producibility of the hole, the type and duration of well testing, and the type of utilization system that will be installed. Of these, the major unknown is the water quality of the geothermal fluid.

Although typically of small consequence, the possibility of fluid leaks and spills at a geothermal site should be anticipated and provisions made for the safe containment and handling of these fluids at points where potential risks exist. The primary source of spills in geothermal drilling is loss of well control or a well blowout. Mechanisms for preventing or controlling blowouts are more than adequate for geothermal wells in low-temperature, low-pressure reservoirs.

Geothermal liquid discharges require disposal whether or not they require prior treatment. The disposal of geothermal liquids depends on 1) the quality of liquid, 2) the volume of the liquid, 3) the existing and expected regulations, and 4) the availability of disposal options. In general, the cleaner the liquid, the easier and less expensive the disposal method. For example, effluents that meet water quality standards may be discharged to surface drainage or applied to constructive surface uses if subsurface injection is not required. On the other hand, it is more expensive and more difficult to dispose of discharges not meeting such standards. Disposal may also be required for reasons other than simply getting rid of the energy-expended fluid, e.g., disposal by injection to prevent subsidence.

The two major types of disposal are injection to the subsurface and surface discharge.

1. Subsurface Injection

The return of spent geothermal fluids to subsurface formations is an important consideration for any geothermal requirement. Injection may serve other useful purposes in addition to ensuring environmentally-acceptable disposal of geothermal fluids. It is the main technique for preventing subsidence. When the producing reservoir is the receiving formation, the consumptive use of the geothermal fluid is decreased and the useful life of the field may be extended by maintaining reservoir pressure.

If the geothermal fluid is utilized in open systems, injection may be proceded by settling in ponds or tanks and/or by filtration to remove suspended solids. Chemical or physical deaeration to reduce the corrosiveness of the fluid may be required.

The primary considerations in evaluating the injection potential for a particular site are:

* existing and expected regulatory requirements,
* geological suitability of the reservoir for injection,
* cost of drilling and operating the injection wells compared to alternative disposal methods,
* operational aspects such as the pressure required to achieve the desired injection rate and the decline of this rate with time.

There are a number of important factors which must be taken into account to maximize the efficiency and environmental safety of injection. First, the injection well(s) must be carefully located and completed to ensure isolation of injected fluids from higher-quality groundwater resources. Cooling and pressure declines in the injection well bore may result in formation plugging by the position of dissolved and suspended solids. This may require pre-injection treatment of the liquid, increased injection pressure, well stimulation, and ultimately the drilling of new injection wells. Major problems of chemical precipitation, scale formation, and corrosion in injection systems which have been experienced in geothermal operations are predominantly a function of the characteristically high-salinity levels of the high-temperature fluids utilized. Therefore, low-salinity fluids can be expected to present less severe problems of this type.

2. Surface Disposal

Surface disposal is typically not an option, in the United States, for electric power generation stations. The quantity of fluid required to produce electricity in the megawatt range is too large to readily be accommodated on the surface. Many direct use (lower fluid demand) projects are compatible with surface fluid disposal. The three surface disposal options are rivers and lakes, land application, and evaporation ponds. Discharge to rivers and lakes is generally the most economic method; it is also the most regulated. Assuming the chemical quality of the geothermal fluid is such that degradation does not occur, the greatest potential impact on surface bodies of water is thermal pollution, which may be mitigated by cooling prior to disposal.

Land application may be acceptable in cases where the fluids are of sufficient high quality or where their constituents are biodegradable. Beneficial impacts can result, particularly in arid areas. The volume of liquid that can be disposed, and the land area required, will depend largely on climatic conditions, the infiltration capacity of the soil, ion exchange capabilities of the soil, and the quality standards imposed where runoff is allowed. Erosion can be a concern if application methods are poorly designed or managed.

Where large land areas are available, evaporation ponds can provide a very simple approach to disposal, especially in arid regions where evaporation rates are high. Unless the soil is impermeable, the pond may be required to be lined to sealed with, for example, clay, rubber, asphalt, concrete, or plastics to prevent groundwater pollution. In a few instances, it may be possible to enhance natural salt marshes as a wildlife habitat.

D. Subsidence/Uplift

Subsidence or uplift can result from the production or injection of fluids during geothermal development. Subsidence associated with the production of gas, petroleum and water has been documented in many areas, including Houston, Texas; Las Vegas, Nevada; and the San Joaquin Valley of California. The Wairakei geothermal field in New Zealand has subsided up to 7 m due to testing and production since 1952.

Subsidence generally occurs where there are youthful, relatively unconsolidated sedimentary rocks of Cenozoic age, such as the basin fill encountered in many areas of the Western Cordillera and the Coastal Plains. The withdrawal of fluid causes a decrease in the hydrostatic head of an aquifer, which in turn causes a transfer of additional load to the matrix. Small amounts of generally elastic compaction in coarse-grained aquitards can occur.

Subsidence or uplift can be a major concern for long-term operation. One should note that, in many areas, significant land deformation can occur without serious impact to surface facilities.

Control or minimization of subsidence can be achieved by minimizing fluid pressure reductions in the geothermal reservoir. This can be facilitated most directly by injection of spent geothermal or other fluids. The control of well spacing and fluid extraction rates may allow natural recharge to compensate, to some degree, for declines resulting from production.

E. Seismicity

The relationship between microseismic activity and the movement of geothermal fluids and cold groundwater at depth is not well understood. In most areas, no data are available to allow even an attempt to characterize such a relationship. Microseismicity may be a significant indicator of changes in the fracture system that provides the subterranean plumbing for the hydrothermal reservoir.

Injection of fluids may cause local changes in pressure within the reservoir that could initiate seismic activity. Such seismic activity induced by the injection of fluids has been reported at the U.S. Army Rocky Mountain Arsenal near Denver and in an oil field near Rangely, Colorado. However, injection of waste fluids has not caused an increase in seismic activity in the Otake, Japan, geothermal field (Kubota and Aosaki, 1975). Scientists suspect that increased microseismic activity may be occurring at The Geysers geothermal field in California, but data on baseline conditions are too sketchy to allow analysis. The effect of injection upon seismic activity may be highly variable, being related to the rock properties and state of stress occurring in each area.

Ground shaking can cause major structural damage, including disruption of pipelines and geothermal wells. However, reports on seismic performance of oil wells in Alaska and California indicates that wells are able to withstand considerable bedrock accelerations and durations of shaking.

It appears that the possibility of injection-induced earthquakes may be alleviated by minimizing the difference between the injection pressure and the original pore pressure of the reservoir fluids. Induced seismicity is a potential problem particularly if there is a fault near the injection area. For the most part, control of enhanced seismicity is limited to careful site selection, well selection, seismic monitoring, and modification of production and/or injection if seismic events are identified.

F. Hydrologic Alterations

The production and injection of geothermal fluids can affect not only existing geothermal resources, but also freshwater aquifers. The degree to which this is a concern depends on local hydrology and the interconnection between the geothermal resource and other water sources.

To exercise control over potential hydrologic alterations, a developer must rely on thorough reservoir and site assessments and quality engineering practices. A number of precautions can be taken during drilling and after production has begun. In particular, production and/or injection well integrity must be safeguarded by using suitable materials and equipment and adhering to proper operating procedures. Proper depth placement of impervious well casing can help ensure that shallow aquifers are neither inadvertently tapped in production wells nor injected into where this must be avoided. Seepage from any existing or proposed ponds must be considered, as well as potential surface leakages and spills. These latter problems are essentially a matter of good housekeeping practices.

Monitoring wells can be drilled into groundwater aquifers to determine if communication exists with the geothermal product and/or injection formations. In cases where the geothermal reservoir is not completely isolated from shallow aquifers or surface water supplies, state water rights laws will usually prove sufficient for reconciling any resultant water-use conflicts.

Water resource conflicts may not be present in some areas while requiring very careful and restrictive water management policies in others. It is possible, however, that where injection of all extracted geothermal fluids is not needed as a subsidence countermeasure and where such spent fluids are of a satisfactory quality for surface disposal, geothermal development may actually improve the area's water supply, a point in favor of development.

G. Land Use/Disturbance

Controls to ensure the compatibility of geothermal utilization with the surrounding environment are primarily non-technological in nature and involve thoughtful and comprehensive planning of field development and the application of ameliorating procedures to unacceptable aspects of the development. In most cases, land use conflicts will be site-specific issues and must be dealt with on this basis. It may be possible in some situations to avoid interfering with existing on-site or adjacent land uses. A positive aspect of geothermal development is that it can complement existing land uses. For example, heat and/or water could be supplied for secondary uses such as greenhousing, agriculture, livestock needs, or for the enhancement of natural salt water marshes.

The effects of loss of vegetation cover and increased soil erosion and dust can be mitigated by commonly practiced soil erosion techniques such as the installation of drains, mulch, and matting, revegetation measures, and minimization of the total land area disturbed. In addition, roadways can be watered down or oiled to control airborne dust.

Pipelines, which can be very extensive, can be buried where this is practicable. In fact, there are a few considerations other than land compatability which may favor below-surface pipelines, such as reduced heat loss from the system, the ability to use less expensive piping materials, and protection from sub-freezing temperatures.

The land area required for the drill site includes the space needed for the actual drilling rig, mud pits, holding ponds, vehicle access, and storage of drilling equipment. An area requirement of 1/2 to 2 acres is typical. After well completion, the drill site can be restored to retain little visual evidence of the well other than the above-ground well-head equipment and piping.

Impacts on wildlife resulting from disturbances to natural habitat areas can be largely minimized by siting the wells, distribution systems, roads, and end-use facilities to avoid unusual or critical habitats for sensitive or endangered species.

Objections to development relating to potential deterioration of aesthetic qualities can be addressed to a large extent by good design, architectural, landscaping, and land maintenance practices.

H. Noise

Noise levels associated with geothermal drilling can exceed 100 dBA. The potential impact on humans and wildlife depends on the proximity of habitats to the drill site and the sensitivity of the affected species. Noise will be an important environmental consideration in populated areas and may affect the drilling schedule. Higher noise levels may affect the aural efficiency of such wildlife whose defense or hunting mechanisms depend largely on sound. Extremely sensitive species such as nesting raptors may also present serious concerns.

Existing technology, combined with careful site planning, is adequate for noise control and the associated costs can be relatively low. Noise attenuation can often be very effectively accomplished with simple designs. A variety of silencers are available to attenuate noise from escaping air and fluid, ranging from relatively simple rock-filled chambers or pits, through baffled mufflers, to large twin-cylinder centrifugal expansion towers. Noise from machinery operation can be reduced by applying accepted techniques such as shielding, baffling, vibration dampening, proper alignment, and adequate lubrication. Noise from permanent facilities can often be dampened by judicious placement, taking advantage of the acoustic qualities of topography and vegetation. Noise associated with well drilling, cleanout, and flow testing is temporary and may be scheduled to have minimum impact on local communities.

I. Safety

There are no occupational health and safety problems that cannot be effectively addressed by appropriate engineering design and safety procedures. The controls needed, many of which are regulatory requirements, include both preventative and corrective measures and the establishment of adequate medical procedures. Risks during well drilling and testing differ from those during plant operation, but in both cases one of the greatest potential hazards is from the accidental release of hot and pressurized fluids. Binary systems also present the hazard of handling high temperature and pressure organic working fluids.

The greatest potential danger during drilling is a well blowout that can occur if sufficient weight and gravity-head pressure are not maintained in the drilling fluid column. Accepted practice is to weight the drilling fluid with sufficient high-density materials to counterbalance the expected formation pressures and to incorporate wellhead blowout devices.

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Exploration Strategy for High-Temperature Hydrothermal Systems in Basin and Range Province[1]

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ABSTRACT

A 15-phase strategy of exploration for high-temperature convective hydrothermal resources in the Basin and Range province features a balanced mix of geologic, geochemical, geophysical, hydrologic, and drilling activities. The strategy, based on a study of data submitted under the Department of Energy's Industry Coupled Case Study Program, provides justification for inclusion or exclusion of all pertinent exploration methods. With continuing research on methods of exploration for, and modeling of, convective hydrothermal systems, this strategy is expected to change and become more cost-effective with time. The basic strategy may vary with the geology or hydrology. Personal preferences, budgetary constraints, time and land position constraints, and varied experience may cause industrial geothermal exploration managers to differ with our strategy. For those just entering geothermal exploration, the strategy should be particularly useful; many of its elements may apply in other geologic settings.

INTRODUCTION

Geothermal energy is derived from the heat of the earth. The average heat flowing conductively to the earth's surface is 0.08 W/sq m. If we multiply this value by the total surface area of the earth (5.1×10^{14} sq m), we obtain the total heat flowing from the earth as 4.1×10^{13} W or 41,000,000 MW. Only a fraction of this energy can be extracted economically under current market conditions. However, the crust of the earth contains local hot spots from which extraction of energy, either for direct heat applications or for conversion to electricity, is economical at present.

Geothermal hot spots are manifested as a continuum of seven accepted resource types: magma, hot dry rock, convective hydrothermal, geothermal gradient, deep sedimentary basin, geopressured, and radiogenic. Within the Basin and Range province the most important high-temperature resource type, and the one with which this paper will be specifically concerned, is the convective hydrothermal system.

A generalized model of a convective hydrothermal system is shown in Figure 1. By way of fractures and faults, cold meteoric water descends to the vicinity of a heat source where it heats and convects upward through other structures to the upper parts of the system. Here it is discharged as hot springs, flows laterally along permeable horizons, or is prevented from escaping by a cap rock of low permeability. Many systems may reach temperatures of over 350°C, although temperatures of 275°C and less are more common. In relatively rare instances, boiling at the upper surface of a water table may produce a vapor-dominated hydrothermal system (White et al, 1971).

Hot-water-dominated convective hydrothermal systems are generally classified as high temperature (>150°C), intermediate temperature (90 to 150°C), and low temperature (<90°C; White and Williams, 1975; Muffler, 1979). Although some of these systems may derive their heat from still molten or hot, crystallized plutonic masses (Smith and Shaw, 1975), others show no association with recent plutonic activity but derive their heat from deep circulation along fault zones in areas of high thermal gradients.

CHARACTERISTICS OF CONVECTIVE HYDROTHERMAL SYSTEMS

Although generalized cross sections of convective hydrothermal systems (Fig. 1) are instructive for showing basic characteristics, these systems are much more complex than the figure indicates. Indeed, the lower parts of the systems, and in particular the heat sources, are speculative. In this paper we shall refer to specific hydrothermal systems in Nevada and Utah (Fig. 2). Figures 3, 4, and 5, as examples, show interpreted cross sections through the upper parts of geothermal systems at Roosevelt Hot Springs, Utah, Cove Fort-Sulphurdale, Utah, and Leach Hot Springs, Nevada. These figures emphasize the structural geology of these areas; unfortunately insufficient work has been done to document the fluid-flow paths within them. Roosevelt Hot

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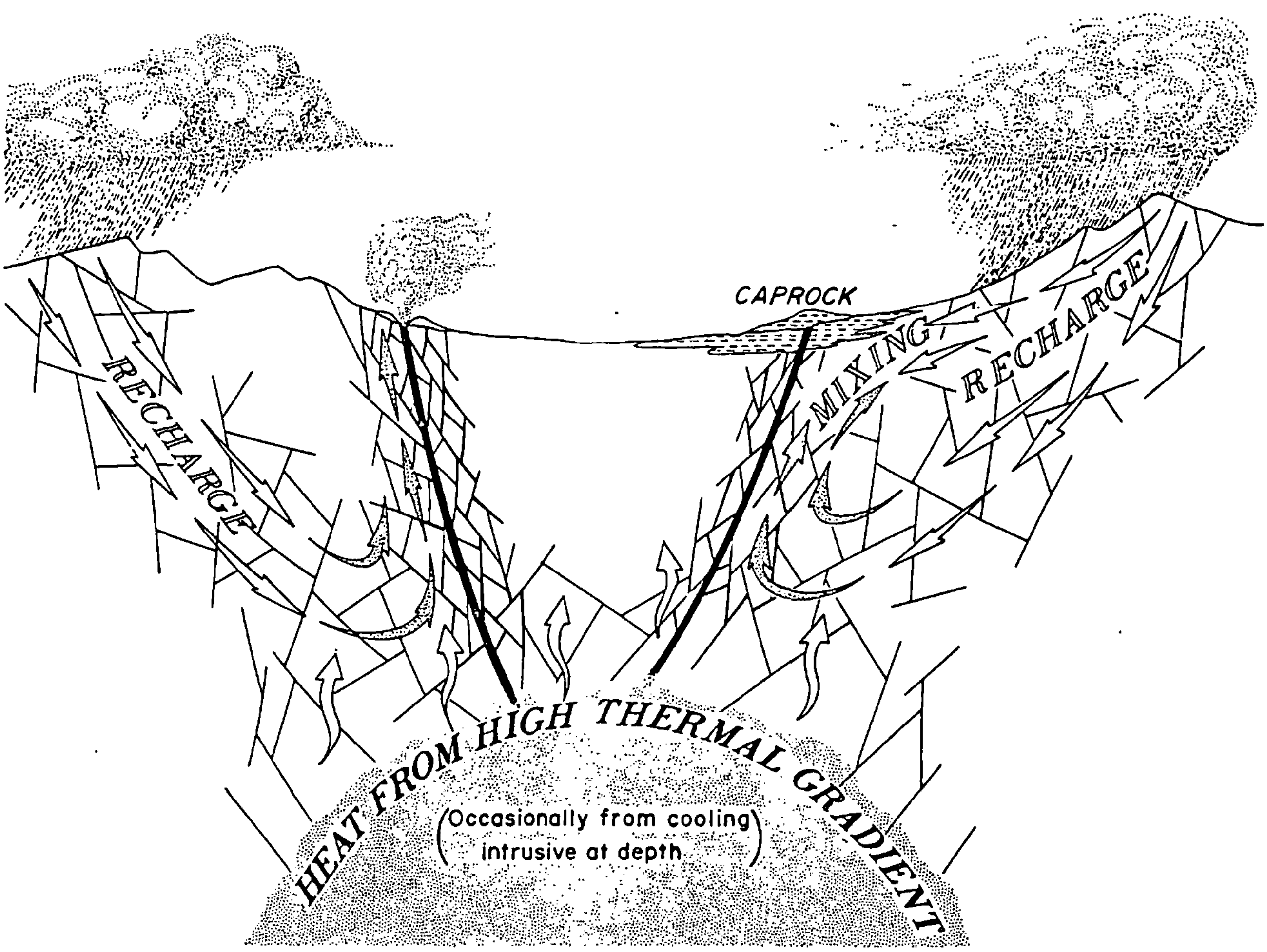


FIG. 1—Generalized model of convective hydrothermal system.

Springs is thought to derive its heat from a cooling magma body at depth; sources of heat for the other systems are unknown, but it is speculated that these systems derive their heat from deep circulation along faults in zones of high thermal gradients.

Figures 3 through 5 show that hydrothermal systems within the Basin and Range province are structurally complex and require two- and three-dimensional modeling. All have undergone several periods of faulting and some have undergone repetitive igneous intrusion. Therefore, it is crucial for the explorationist to understand which of the structures in such areas controls the hydrothermal system and to separate the latter from structures which do not channel fluids but only complicate the geology. Clearly the structure must be understood early in the exploration process for an exploration program to be conducted efficiently (Nielson and Moore, 1979).

In addition to the geologic complexity of the Basin and Range province, practical considerations must be taken into account in defining individual exploration strategies. Extreme topography in some areas complicates not only the performance of geophysical surveys but also the modeling of the results of those surveys (Fox et al, 1978). The presence of playas may negate the usefulness of some of the electrical surveys commonly used in the exploration process. In addition, saline ground waters common in this environment can produce misleading interpretations if the common chemical geothermometers are not correctly applied. The complexity of the basin fill in this province can result in stacked aquifers separated by impermeable horizons. This clearly presents problems for the interpretation of thermal measurements. The basin-fill alluvium and volcanic rocks often negate the usefulness of the seismic techniques. Our experience with the limitations of individual methods is discussed in a subsequent section.

NORTHERN NEVADA PROGRAM

In an attempt to accelerate the development of high-temperature geothermal resources by private industry, the Department of Energy, Division of Geothermal Energy, initiated the Industry Coupled Case Study Program in 1977. The program is designed to offset high initial costs and reduce exploration risk through cost-sharing with industrial partners. In exchange for the government funding, all technical data obtained as part of the agreed-upon exploration program are released to the Department of Energy and made public. In addition, a substantial amount and a variety of existing data generally emphasizing early stage exploration are acquired as part of the DOE/Company contract.

Phase I of the Industry Coupled Case Study Program resulted in contracts for work at two major geothermal systems in southern Utah. Phase II includes work at 12 high-temperature systems in northern Nevada. A summary of the data packages already submitted or forthcoming under Phase II, supplemented by a coherent program from one Phase I area, is presented in Table 1.

Although one or more companies have not submitted all of the geoscience exploration data they obtained for a given area, and hence the data reported may not be a complete list of exploration techniques used, we believe this summary reflects a representative sample of the methods used by the various companies. One is immediately impressed by the diversity of exploration strategies, although certain common denominators are evident as shown in Table 2.

PREVIOUS STUDIES

Ward (1977) summarized the exploration strategies from the literature up to the time of his writing. He referenced articles by Banwell (1970, 1974), Combs and Muffler (1973), Dolan (1975), Furumoto (1976), B. Greider (1975, unpub. ms.), McNitt (1976), and Meidav and Tonani (1976), and showed a strategy containing elements common to his own analysis for the eastern Basin and Range province and to those of the other referenced authors for the areas with which they were then familiar.

McEuen et al (1979) provided analyses of exploration architectures required for each of 12 different physiographic provinces. Their report used tables from an earlier report by Dhillon et al (1978). Table 3 (after Dhillon et al, 1978) lists the applicability of various methods obtained from sampling 35 opinions from individuals and companies. The differences between Tables 2 and 3 are numerous. The common conclusions

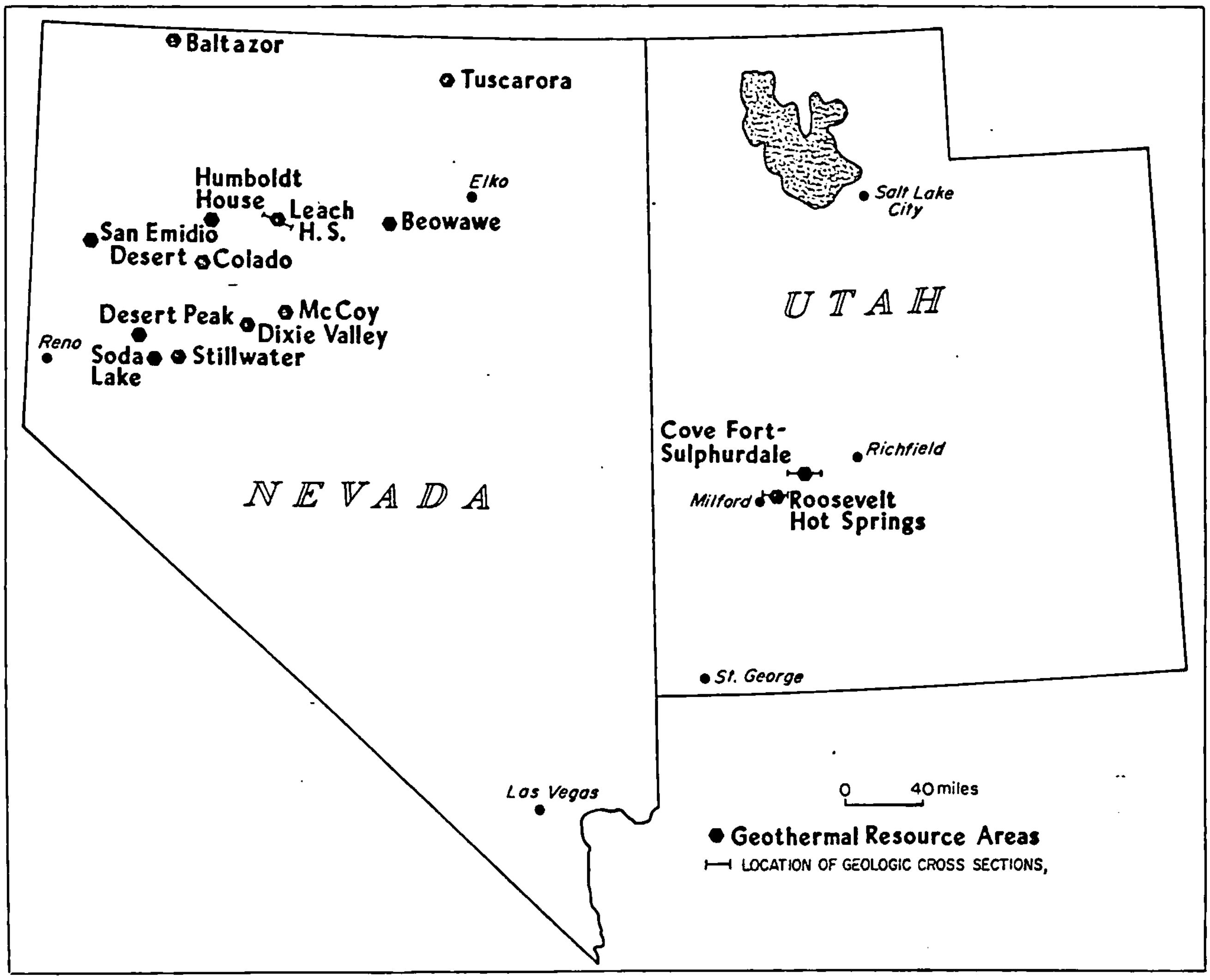


FIG. 2—Index map of Industry Coupled Program hydrothermal systems. Indicated cross sections shown on Figures 3, 4, and 5.

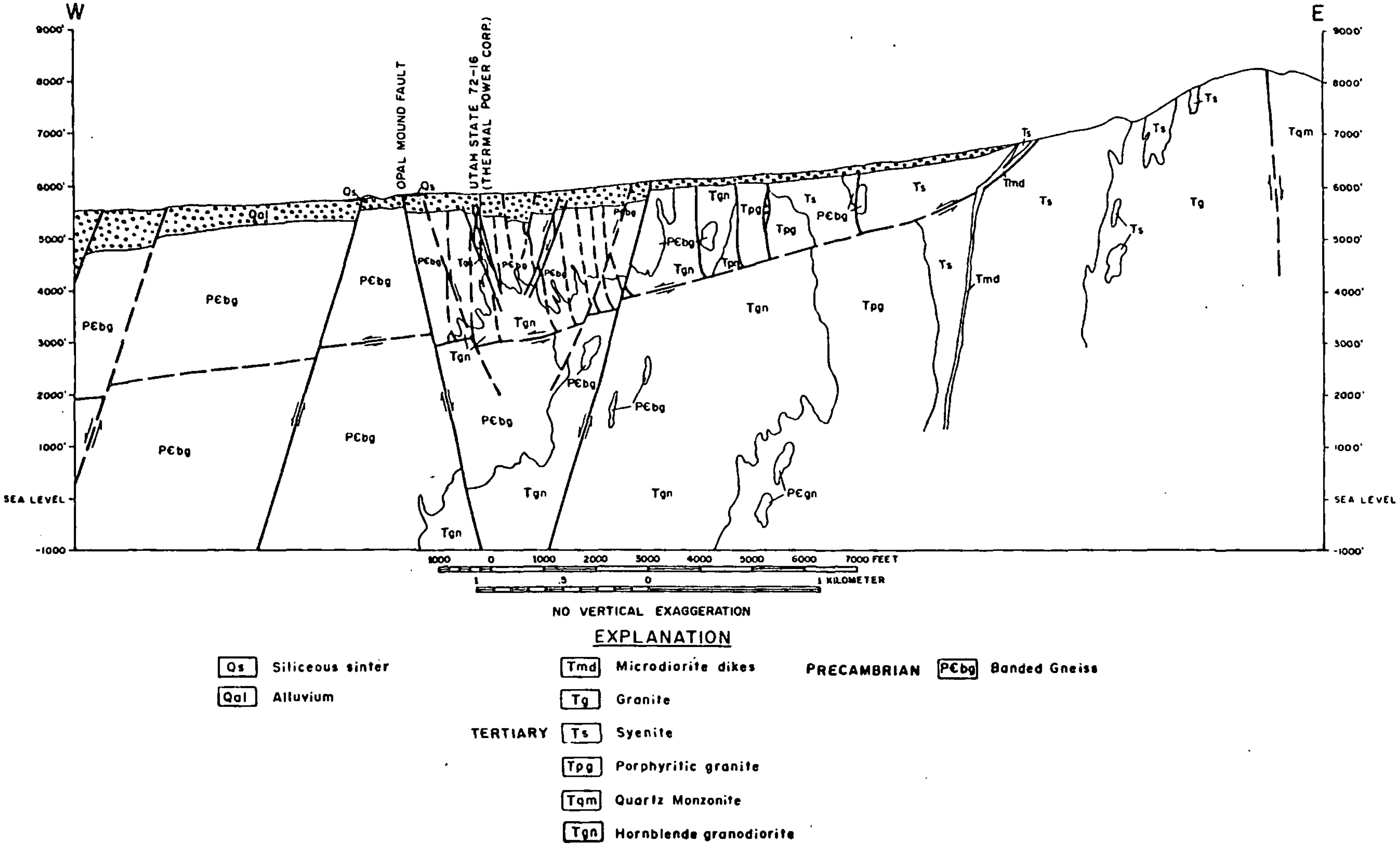


FIG. 3—Geologic cross section of Roosevelt Hot Springs KGRA, Utah (Nielson et al, 1978). Depths are in feet. For location, see Figure 2.

from comparison of the two tables are: (1) thermal methods rank universally highest; (2) surface geology mapping is usually but not always employed; (3) gravimetry is usually employed; (4) some form of electrical method is usually employed; (5) seismic, magnetic, and geochemical methods fall somewhat lower on the priority list; (6) geology and fluid geochemistry, ranked 2 and 3 by Dhillon et al (1978) are poorly represented in the deliverables from the Industry Coupled Case Study Program.

Goldstein (1977) earlier had made an analysis similar to that of the MITRE Corp., but he restricted his attention to northern Nevada. Ball et al (1979) presented an exploration, assessment, and confirmation strategy for the high-temperature resources in the eastern part of the Basin and Range province. Their conclusions are similar to the preceding six conclusions with the exception that photographic imagery and geochemical methods are of high priority in the reconnaissance phase of exploration whereas active seismic methods are of high priority in the detailed phase.

CURRENT ASSESSMENT OF METHODS

We will now consider the methods individually as listed in Table 1 and evaluate their applicability in the

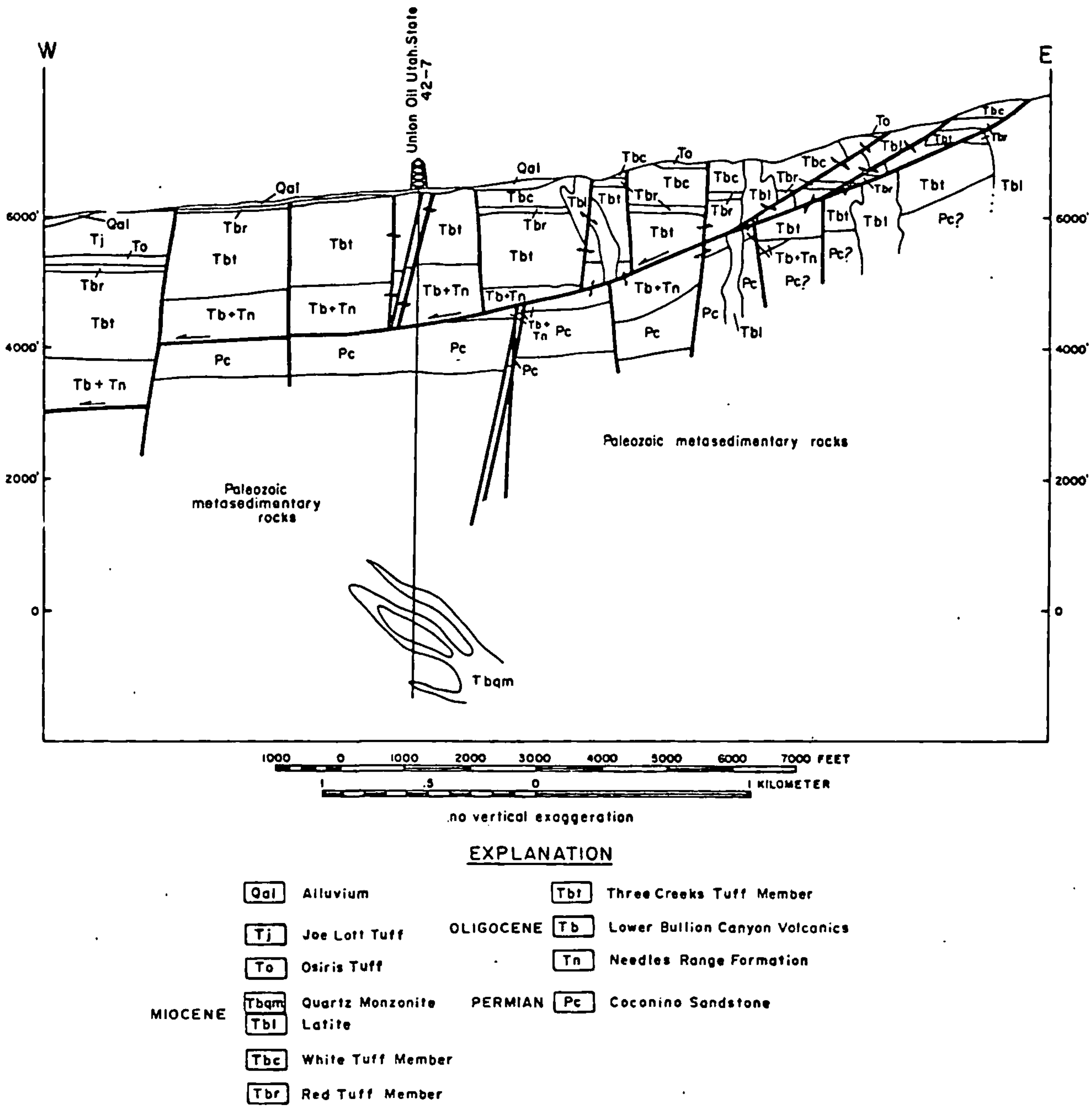
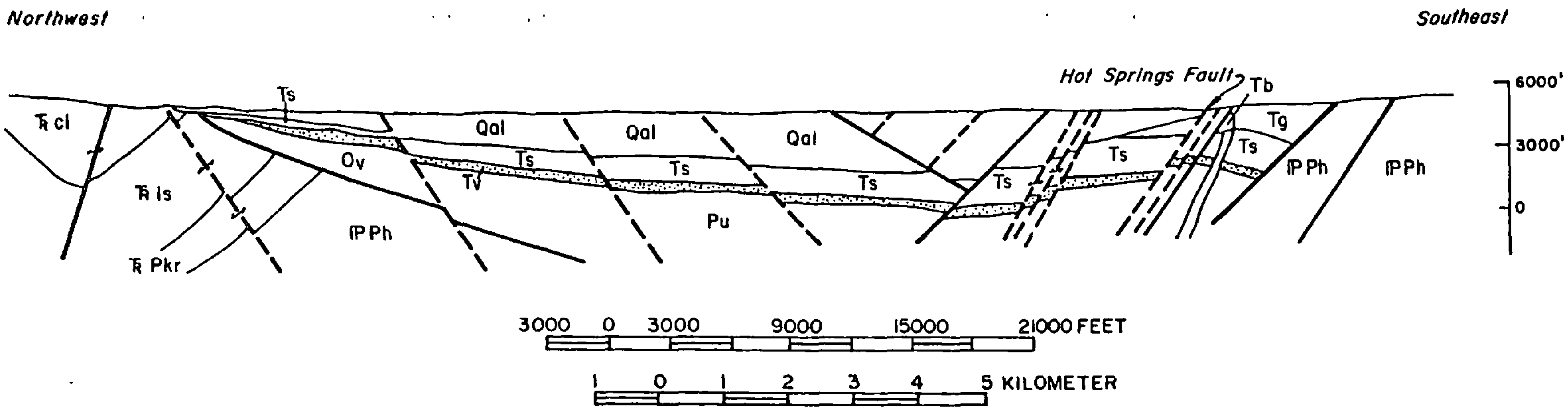


FIG. 4—Geologic cross section of Cove Fort-Sulphurdale KGRA, Utah (Moore and Samberg, 1979). Depths are in feet. For location, see Figure 2.



EXPLANATION

QUATERNARY	Qal	Alluvium		₸ cl	Triassic clastic rocks
	Tb	Basalt	MESOZOIC	₸ ls	Triassic calcareous rocks
	Tg	Gravel		₸ Pkr	Koipato formation
TERTIARY	Ts	Sediments and tuffaceous rocks		IP Ph	Havallah sequence
	Tv	Intermediate to acidic volcanic rocks	PALEOZOIC	Ov	Valmy formation
				Pu	Undifferentiated Paleozoic rocks-complexly folded and faulted

FIG. 5—Geologic cross section of Leach Hot Springs KGRA, Nevada (Beyer et al, 1976). Depths are in feet. For location, see Figure 2.

Basin and Range province for areas of some surface expression.

Geologic Mapping

Our evaluation of the exploration efforts included in the Industry Coupled Case Study Program is that geologic mapping is always used in the early program stages, both regional and reconnaissance, but is then largely ignored until drill cuttings return from the first exploration hole. Detailed (1:24,000) geologic mapping of a prospect-size area, 20 to 60 sq km, is not generally done. Instead shortcuts are taken which include compilation of existing maps, photogeology, and perhaps only routine application of several geophysical methods. Complete alteration and structural studies often are omitted or are underfunded.

Our observations reveal that inadequate geologic

Table 1. Geothermal Exploration Strategy Indicated by Industry Coupled Program Data Packages

Data	Baltazor (EPP)	Tuscarora (AM)	McCoy (AM)	Leach H.S. (AO)	Colado (G)	Beowawe (G)	Beowawe (C)	San Emidio (C)	Soda Lake (C)	Stillwater (U)	Dixie Valley (SR)	Desert Peak (P)	Humboldt H. (P)	Cove Fort-Sulphurdale (U)
Gravity	E	X	X	E	E	X		E		E		E	E	E
Ground Mag.					E	X						E		
Aeromag.	E	X	X				E				E			E
Elec. Res.					E	X	E	E	E	E				E
Magnetotelluric		X	X	X	E		E		E	E	E	E	E	
Audio Magnetotelluric					E									
Self Potential		X	X				E	E						
Seismic Emissions							E	E						E
Microearthquake	E	X	X				E							
Seismic Refl. (weight drop)							E		E					E
Seismic Refl. (CDP12 or 24 fold)			X	X			X	E	E					
Geology	E			E				E			E X	E	E	E
Geochemistry	E			E							E			E
Shallow Temperature											X			
Shallow Thermal Gradient	E	E X	E X	X	E X	X		E	E	E	E			E
Deep Thermal Gradient	X	X	X	X	X	X			E X		E X	E		E
Exploration Well	X	X	X	X	X	X	E	E	E	E	X	X	X	E X
Flow Test (if appropriate	X	X	X	X	X	X	X			X	X	X	X	X

*See Figure 2 for locations.

Company Explanation:

EPP — Earth Power Production
AM — Amax Exploration Inc.
AO — Aminoil USA, Inc.
G — Getty Oil Co.
C — Chevron Resources Co.
U — Union Oil Co. of Ca.
SR — Southland Royalty Co.
P — Phillips Petroleum Co.

E = EXISTING DATA
X = NEW PROGRAM

Table 2. Technique Use by Industry Coupled Case Study Program

Method	Cases (%)	Priority
Shallow Thermal Gradient (~100 m)	71	1
Deep Thermal Gradient (~600 m)	71	1
Magnetotelluric (MT)	71	1
Gravity	71	1
Magnetics	57	2
Geologic Mapping	50	3
Resistivity	50	3
Passive Seismic	43	4
Active Seismic	43	4
Self Potential	29	5
Geochemistry	29	5

mapping by companies may result, for example, in geophysical survey lines along major structures and thermal gradient holes being drilled inadvertently on structural intersections. Without proper recognition of these geologic features, and the bias they interject into the geophysical measurements, the survey or temperature data can be misinterpreted. We believe that detailed geologic mapping would be cost-effective as soon as a commitment is made to acquire land. This commitment would imply intent to carry out a shallow thermal gradient survey and supportive geophysics, as a minimum effort.

We do not naively ignore the possibilities of alluvial or even volcanic cover which may not warrant detailed mapping. This must be assessed as the project proceeds. Neither are we unaware of problems of land acquisition and needs for preliminary encouragement to sell an area to management. We recognize that these considerations may prevent a systematic geologic program.

We presume that detailed mapping is often omitted because it takes longer, requires an experienced and well-trained staff, and is generally still in progress when the geophysical results are obtained. We envision a continuing mapping program, depending on existing maps and outcrop availability, which would allow 1:24,000-scale mapping prior to drilling thermal gradient holes and completing detailed electrical or seismic surveys. Subsequently the base could be refined to include fracture and alteration mapping at 1:12,000 or 1:6,000 for those parts of the area which seem to have most potential. This level of mapping would be completed prior to siting deep thermal-gradient tests or exploration wells.

In conjunction with geologic mapping, it is often desirable to collect suites of samples for petrographic analysis, physical property measurements, geochemical orientation surveys, and potassium-argon and fission-track dating. The locations of these samples should be documented carefully to aid in interpretation of results.

Geochemistry

Aqueous geochemistry ranks third in usage in Table 3, and is probably not correctly represented by the deliverables in Tables 1 and 2. Chemical geothermometry and aqueous geochemistry of available springs and wells is common to most regional and reconnaissance efforts (Truesdall, 1976; Fournier, 1977). It is certainly practiced in the thermal-gradient and exploration-well stage also. The low ranking of geochemistry in Table 2 indicates that geochemical data were not submitted as a deliverable item. The low ranking could also represent the limited interest in soil geochemistry and trace-element surveys. Ewers and Keays (1977) reported well-developed zoning of volatile elements and precious metals in the Broadlands geothermal field, New Zealand. As our case studies and technique development work proceed, we find multielement zoning patterns have developed about high-temperature geothermal systems and about high-temperature fluid entries in geothermal wells (Bamford, 1978). Fluid entries have also been effectively delineated by oxygen isotopes and hydrothermal mineralogy (Browne, 1970; Kendall, 1976; Elders et al, 1978). To a large extent the distribution of radon and mercury can be used to locate zones of past and present permeability and as such can be an aid in mapping and siting of drill holes (Capuano and Bamford, 1978; Nielson, 1978).

Hydrology

No hydrologic data packages were submitted under the Industry Coupled Case Study Program, although we are aware that most companies do not neglect this fundamental data set. Regional hydrologic data are available for many of the basins in the Basin and Range, and this is undoubtedly considered in the initial compilation stages of the project. Such information as number of aquifers, elevation of water table, regional-flow patterns, and water chemistry can be extremely valuable in the initial stages of the exploration program. In addition, hydrologic information is often collected in conjunction with thermal-gradient drilling.

Gravity Method

Gravity methods are often employed. A regional gravity map, with a station density of 1 station per 3 sq km to 1 station per 25 sq km, is generally available as the result of U.S. Geological Survey (USGS) regional studies, of the Department of Defense regional data compilation, or of university-related geophysical studies. Many compilations of these data have been accepted as adequate and several companies supplement this base with detailed profiles. The method offers a relatively low-cost delineation of shallow Basin and Range faults and of alluvial thicknesses. The resolution of these features improves with quantitative numerical modeling but the method is often limited by spatial wavelength aliasing, inadequate density information, relatively small density contrasts, and lack of precise elevation control.

Ground Magnetic Method

Ground magnetic data are sometimes acquired as an addendum to the gravity survey at a modest additional

Table 3. Regional Applicability of Exploration/Assessment Technique*

Technique	Overall	Salton Trough	Basin And Range	Cas-cades	Basaltic Island Region	Snake River Plain	Wasatch Front	Rio Grande Rift	Geysers	Aleutian Arc Island	Appa-lachian	Eastern And SE Plutons	Geo-pressured
Thermal Method	1	1	1	1	2	1	1	1	1	1	1	1	2
Surface Geo-logic Mapping	2	9	2	2	1	2	2	2	2	2	3	5	9
Gravimetry	3	2	7	5	4	3	7	7	3	4	2	2	5
Electrical Methods	4	3	4	3	3	8	4	3	8	5	8	6	7
Borehole Logging	5	5	8	10	10	4	8	9	7	3	15	4	1
Seismic Methods	6	4	5	8	6	6	5	5	6	6	9	7	3
Liquid Geochemistry	7	6	3	4	5	9	3	4	5	7	6	8	4
Air Photogeology	8	7	6	7	8	5	9	8	4	9	7	9	12
Age Dating	9	10	9	6	7	7	6	6	9	8	10	10	14
Magnetics	10	8	10	9	9	10	10	10	10	11	4	3	6
Gas Geochemistry	11	11	13	13	11	13	13	13	11	12	11	12	8
Remote Sensing	12	12	12	12	13	11	11	11	12	13	12	11	10
Thermal Infrared	13	13	11	11	12	12	12	12	13	10	13	13	11
Other	14	14	14	14	14	14	14	14	14	14	14	14	13

*After Dhillon et al (1978).
1 = Most Applicable to 14 = Least Applicable

charge. The typical station spacing for a gravity survey may severely limit the spatial frequency content of the magnetic survey and considerably reduce its utility. Near-surface magnetic contrasts, arising mainly from Tertiary volcanic rocks within a mountain range or at shallow depth in the alluvium often dominate the ground magnetic survey and this, coupled with a limited survey area, reduces the interpretative value of the survey data. As expected, and as Table 1 demonstrates, airborne magnetic surveys are favored by most of the geothermal companies.

Aeromagnetic Method

Regional aeromagnetic data are generally available for the Basin and Range province as part of the USGS regional mapping programs. These data are normally obtained as high-altitude barometric flights with a 2 to 4-km flight-line separation. These data, as at the Baltazor and Carson Sink areas, often show major structural features and aid in forming a generalized geologic model for the prospect area. The data are not sufficiently detailed to warrant quantitative model interpretations or accurate delineation of structural or intrusive features. Follow-up surveys have often been flown at a 0.5 to 1-km line separation as draped flights 50 to 300 m above the mean topographic surface.

Data packages submitted as part of the Industry Coupled Case Study Program and discussions with companies and contractors indicate some interest in Curie point isotherm interpretation of magnetic data. Selected profiles have been flown at several altitudes in an attempt to refine these interpretations. The Curie point interpretation as applied to most known Basin and Range target areas has several problems: (1) the lateral extent of the Curie isotherm high is several times the size of a typical deep fault circulation system; (2) interference at this scale of reversely polarized volcanic units and widely varying susceptibilities complicates the interpretation; (3) there is uncertainty in determining the depth to the bottom of a prism model. Shuey et al (1977) have discussed these and other problems with Curie depth determinations. Yet another problem is multilevel data interpretations which assume two-dimensional geology in far more complex settings.

Magnetotelluric (MT) Method

If one were to accept Tables 1 and 2 at face value, then the MT method would be recommended for use in hydrothermal system exploration due to its advertised attributes of great depth of exploration and ability to detect the hot rock source of heat at depths of several tens of kilometers. Unfortunately, neither of these attributes is necessarily correct. In a three-dimensionally inhomogeneous earth, one's ability to predict the distribution of resistivities at depth is severely limited by the influence of surficial conductors such as alluvial fill or shallow alteration zones (Wannamaker et al, 1978). That a hot rock, when molten, is necessarily a good conductor of electricity must be conjectural, for conductivity in magma at elevated temperature is dependent upon the partial pressure of water (Duba, 1974). Hot dry rocks are good insulators almost by definition. If one uses only the standard one- or even two-dimensional MT interpretation methods when dealing with a three-dimensional earth, then one has no assurance that the method is capable of detecting a hot rock source by means of its assumed high conductivity. Means for surmounting this latter problem are evident (Wannamaker et al, 1980) but are seldom applied. Accordingly, we do not recommend using the MT method until late in the exploration sequence when one is justified in applying the higher cost techniques. The poor lateral resolution of MT interpretation does not make the method well-suited for siting a drill hole to intersect a given structure in the advanced stage of exploration, but it may be used effectively by a consortium of companies for early reconnaissance evaluation of a region.

Electrical Resistivity Method

Resistivity surveys, particularly with the dipole-dipole array, have been used by many companies. A major limitation is the sensitivity to geologic changes at depth which is no more than twice the electrode separation, that is, generally in the range of 600 m for a 300-m dipole using dipole spacings to n = 6 (Roy and Apparao, 1971; Ward et al, 1978). The survey data are sensitive to lateral variations in resistivity, and hence are generally well suited to delineation of high-angle structures, but are not sensitive to dip. Through detailed numerical modeling (Beyer, 1977), a useful map of intrinsic resistivity distributions to depths of 500 m can be generated. At Roosevelt Hot Springs and Cove Fort-Sulphurdale, Known Geothermal Resource Areas (KGRAs) in Utah, low (5 to 10 ohm-m) resistivity zones have been mapped which are probably related to hot, conductive fluids and large zones of wall-rock alteration. Similar results have been obtained for several prospects in northern Nevada.

Self-Potential (SP) Method

Self-potential surveys are being used by a few of the major firms engaged in geothermal exploration. Recent papers by Corwin and Hoover (1979), Fitterman (1979), and Hulse (1979) present a theoretical basis and observed data showing the utility of the method for geologic mapping and geothermal exploration. Our observations are that either polar or dipolar patterns of self-potential anomalies can occur in the Basin and Range province. Sometimes the two patterns are superimposed. Ambiguity in interpretation must therefore be expected. Anomalous patterns often relate to known geologic structures, suggesting a dominant role for the electrokinetic as opposed to the thermoelectric coupling models. Some geophysicists have stated, off the record, that SP surveys are their most cost-effective exploration method, but this may be in part a commentary on the relatively low cost of field surveys. We would reserve their use for a late stage of exploration when resistivity data are also available and where any clue to fluid flow is helpful and justifiable to offset high drilling costs.

Passive Seismic Methods

Within this category fall all the earthquake, microearthquake, and seismic noise or emissions thought to relate to hot-spring or deep-reservoir activity and to active structural deformation. Areas of thick alluvial cover often manifest high noise levels which may obscure the reservoir signature sought in many seismic-noise surveys, if such signature exists (Katz, 1976). Liaw and McEvilly (1979) discussed these problems as evident in studies at Grass Valley, Nevada, and Douze and Laster (1979) discussed them in relation to studies at Roosevelt Hot Springs. The relative cost-effectiveness of the passive seismic methods in locating hidden reservoirs is still very much in doubt, as indicated by limited acceptance (Tables 1, 3) and the conclusions of a recent workshop devoted to these methods (Ward, 1978).

Reflection Seismic Methods

We have inspected reflection seismic data for several Basin and Range geothermal areas including Roosevelt Hot Springs KGRA, Utah, and San Emidio, Soda Lake, and Beowawe in Nevada. The data are generally of two types: shallow penetration weight-drop-type seismic surveys and conventional 12- or 24-fold CDP surveys with various types of processing. The data from the shallow surveys are ambiguous in interpretation and are best evaluated in terms of outcropping geology and other geophysical data. Although the cost is relatively low, it is not apparent that these latter data are cost-effective in structural and bedding delineation in the typical Basin and Range geothermal areas.

Conventional seismic surveys appear to give good definition of Basin and Range border faulting and depths to the base of alluvial fill at Roosevelt Hot Springs KGRA, Utah, and Soda Lake, San Emidio, and Grass Valley, Nevada. In an area of limited outcrop, such as the Carson Sink region, the reflection seismic method would appear to be cost-effective in the delineation of structures and bedding to depths of about 1,000 m. One seismic line which crosses the Mineral Mountains at Roosevelt Hot Springs KGRA shows little obvious lithologic or structural information within the range itself, or within the reservoir, but substantial structural information along the range front. At Beowawe, extensive and varied digital processing was ineffective in eliminating the ringing due to a complex near-surface volcanic section. Majer (1978) found reflection data extremely useful in delineating structure in Grass Valley, Nevada. The cost of this method and the mixed results observed argue against its routine inclusion in a geothermal exploration program. However, where the geology appears to be permissive for reasonable reflection quality, and where predictable acoustic contrasts exist, this may be the most cost-effective way to site exploration wells.

Thermal Methods

The thermal methods are clearly recognized as the most direct indicator of the geothermal resource as indicated in Tables 1-3. Shallow temperature measurements in holes 1 m deep are seldom used because of unknowns in near-surface hydrology, soil thermal properties, topographic corrections, and short-term variations. At the Long Valley and Coso Hot Spring areas in California, and Soda Lakes, Nevada, however, shallow temperature measurements (Le Shack, 1977; Olmsted, 1977) seem to delineate the area of anomalous heat flow in a low-cost manner. In the absence of substantial surface thermal manifestations or favorable geology and without obvious near-surface cold-water flow, a shallow temperature survey of about 5 to 20 sq km could be the best basis on which to plan a shallow (30 to 200 m) thermal gradient program.

Shallow thermal gradient holes ranging from 30 to 200 m deep are almost always used. The holes are logged for temperature and the chips can be used in stratigraphic, alteration, and geochemical studies. In many places it is advisable to measure thermal conductivities and determine heat-flow values. The thermal gradients and observed temperatures still may be influenced by shallow ground-water flow which may obscure or offset the deep thermal anomaly. The omissions of a shallow thermal gradient program in Table 1 probably reflect in two examples data obtained but not submitted as part of the Industry Coupled Case Study Program. In the third example, an exploration well was drilled directly on surface geothermal features and previous high-temperature drilling results. The need for a more systematic thermal gradient data base has since been recognized and was recently completed as a supplemental part of the DOE/Company program.

Deep thermal gradient holes may range in depth from 300 to more than 1,000 m, but generally are in the 300 to 600-m range. The ratio of shallow to deep thermal gradient holes varies but typically is between 1 to 5 and 1 to 10. Results from these holes will help determine the siting of exploration wells (Benoit, 1978).

STRATEGY

As indicated in the foregoing, hydrothermal convection of fluids through structures is a phenomenon that occurs in high-, moderate-, and low-temperature environments. Although systems are basically similar, each has its own unique characteristics. Thus, although a general exploration strategy for hydrothermal systems can be proposed, the strategy will require some modification to fit the demands of most individual exploration projects.

We propose the formulation of exploration models and the constant updating of these models as exploration proceeds. We feel that the most efficient exploration programs are based on a knowledge of the physical/chemical processes within a convection system and interpretation of the geologic, geochemical, geophysical, and hydrologic manifestations of these processes. For each increment of exploration dollars, these models should be updated and the important controlling parameters of systems should be documented, analyzed, and understood. A genetic model is the end point of the entire process with the exploration model approaching the genetic model with each new increment of data. In short, it is not necessary to understand fully a system to explore it; it is sufficient to understand the fundamental processes of a system and to understand its detection by various exploration tools.

Figure 6 portrays our recommended basic strategy for exploring for high-temperature hydrothermal resources in the Basin and Range province in areas of surface thermal manifestations. As noted earlier, modifications to this strategy may be required for specific prospects. The strategy assumes that one starts with a nominal district of 3,000 sq km and finds one high-priority prospect in this area which eventually demands a production test. If other prospects are found in the district, they are herein considered of lower priority than the one drilled for production. We consider that the strategy recommended is a minimum one, yet its cost through drilling and logging and subsequent reservoir modeling is estimated to be $4.6 million if both seismic reflection and magnetotelluric surveys are included.

Where do these costs arise? Each box in the flow diagram of Figure 6 depicts a function or functions whose cost estimate is shown on the right of the box. The sequence of events in the flow diagram has been carefully considered to provide the most cost-effective data gathering consistent with the risk involved. By design, the risk of failure should become less as one moves downward in the diagram, that is, forward in time, so that higher cost or less demonstrated, yet promising, exploration techniques can be justified late but not early. Let us discuss each box, by number.

Literature and Data Search, Compilation, and Analysis (Fig. 6, Box 1)

Invariably, aerial photography, satellite imagery, regional geologic maps, water chemistry, regional gravity data, regional aeromagnetic data, plus relevant geologic reports are available prior to a company's entry into a district. The functions of box 1 dictate that these data must be located, compiled, analyzed, and integrated as a basis for designing the rest of the exploration strategy.

Subsurface information is often available from water wells and oil tests. This material is of use in defining basin stratigraphy, regional hydrologic patterns, and occasionally subsurface temperatures. Compilation of well locations and depths is important for defining the location of wells to be sampled during the district reconnaissance stage.

Chemical and Isotopic Analyses of Waters (Fig. 6, Box 2)

Where the chemistry and light stable isotope analyses of spring and well waters are available in a district, these data are utilized in empirical geothermometric formulae to predict the temperature of last water-rock equilibration, hoping thereby to predict the temperature of the hydrothermal fluid in the reservoir. If the analyses are not available or are of uncertain reliability, the collection and analyses of spring and well waters are usually made. Although the water-temperature predictions from such analyses have uncertainties due to fluid mixing and to the effects of soluble components in wall rocks unrelated to the thermal event, they are nevertheless extremely useful in locating prospects.

During sampling of available wells, pertinent hydrologic data, such as depth to the water table, should be collected.

Initial Field Mapping (Fig. 6, Box 3)

With air photos, imagery, and geologic maps in hand, initial field mapping can be designed to coincide with the initial geochemical sampling and thermal-gradient measurements. Collection of samples of young volcanic and intrusive rocks should be performed at this time. Geologic maps at a scale of 1:62,500, or even more detailed, are available for parts of the Basin and Range province, but these maps are of variable quality and usefulness for the geothermal explorationist. If the area under consideration contains known geothermal resources, it is often advisable to map it in detail at an early stage to document the structural and lithologic controls. Reconnaissance mapping at this stage will also confirm the quality of existing maps and will be valuable in interpreting features defined by the aerial photography. Analysis of these results and the data collected simultaneously in boxes 2 and 4 provide an excellent data base for the definition of a prospect of greater interest.

Thermal Gradients, Available Holes (Fig. 6, Box 4)

Many companies concerned with exploration for high-temperature hydrothermal resources have vigorous programs of measuring temperatures versus depth in all available water wells, oil and gas wells, and mining drill holes. This reconnaissance data collection can be extremely valuable in pinpointing hot spots, but care must be taken to evaluate such effects as cold-water mixing and overflow.

Prospect Mapping (Fig. 6, Box 5)

The homework and district-reconnaissance studies of boxes 1 through 4 invariably lead to identification of a number of prospects. Although not all hot spots are found in the district reconnaissance studies, those that are found are typically given priority and are mapped. We consider it important that, providing exposures are suitable, geologic mapping at a scale of approximately 1:24,000 be done early in the prospect-evaluation stage. Depending on the complexity of an area, a geologist can generally cover a minimum of 3 sq km per day. Thus several man-weeks of effort can generate a detailed geologic map which will be invaluable in planning and

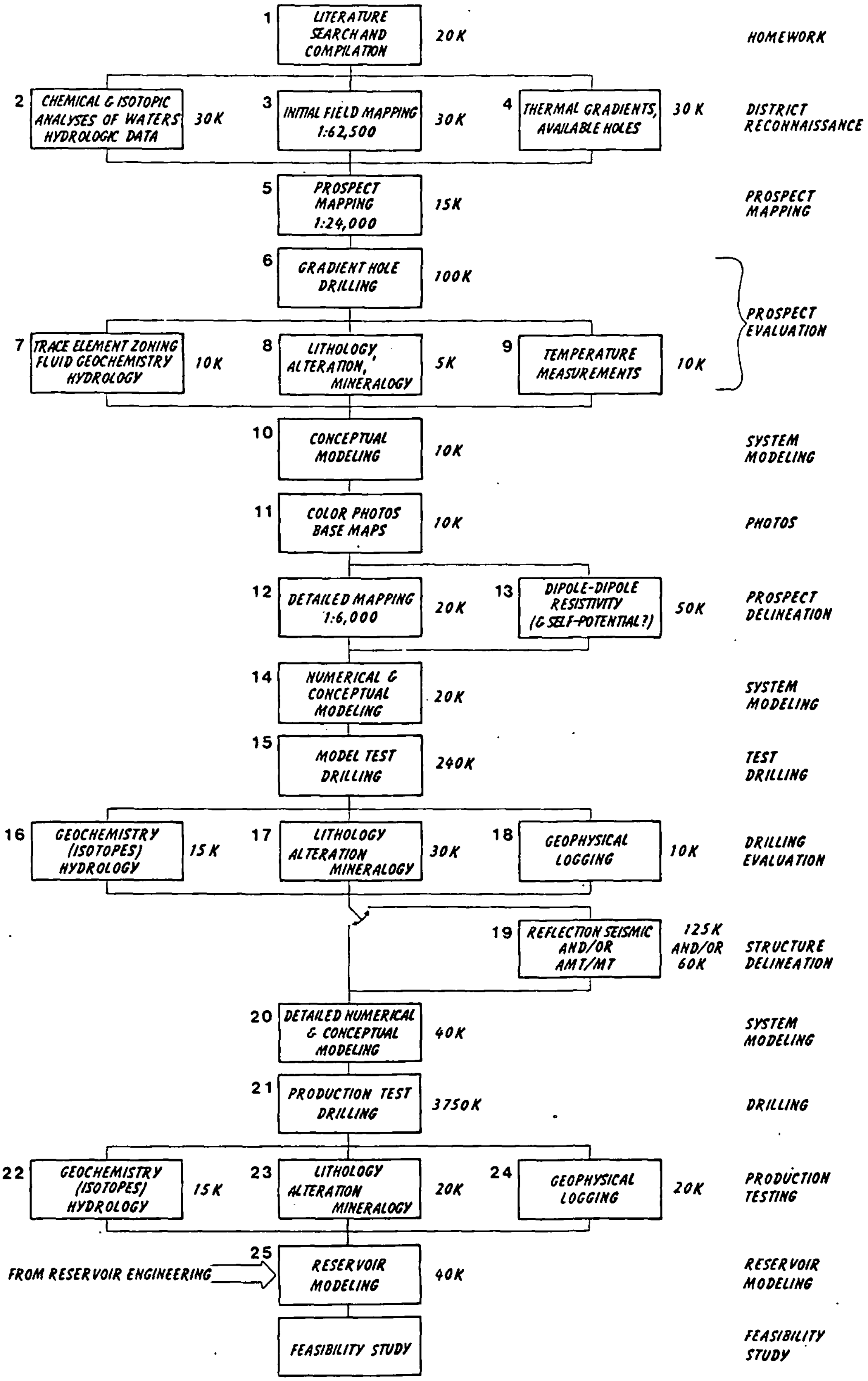


FIG. 6—Suggested high-temperature hydrothermal exploration strategy. Numbers at left of blocks indicate operating sequence. *K* numbers at right of blocks indicate estimated dollar cost in thousands.

interpreting subsequent drilling and geophysical and geochemical surveys. Our experience with data collected by companies participating in DOE's Industry Coupled Case Study Program has been that the completion of a detailed map at this early stage in the exploration program might have suggested to some companies that they not drill thermal-gradient holes at structural intersections or run resistivity lines along major structures; topographic access may dictate otherwise. We shall assume, for the purposes of the subsequent discussion, that only the top-priority prospect will initially warrant detailed investigation.

Drill Gradient Holes, Lithology and Alteration, Temperature Measurements, Geochemistry (Fig. 6, Boxes 6-9)

It is customary to drill about 20 holes 30 to 160 m deep in each high-priority prospect indicated earlier. The problem of cold-water overflow reducing near-surface gradients is generally recognized and is serious. Nevertheless, the gradient measurements in these specifically drilled holes are, perhaps, the most fundamental data to be acquired in the early stages of hydrothermal exploration.

Although temperature measurements are the principal product of these drill holes, additional data can be acquired at relatively low cost. Thermal-conductivity measurements on cores or chips will permit the gradient measurements to be converted to heat flow. Lithologic logging of the holes may give important information concerning hydrothermal alteration and mineral deposition, and can be tied with the surface mapping to give valuable insight into the structural geology. Trace-element analyses of cuttings can be done at small cost to investigate the possibility of geochemical zoning (Ewers and Keays, 1977; Bamford, 1978). Determination of depth to the water table and chemistry of waters encountered will begin to develop a hydrologic data base which will prove to be of great value in subsequent stages of exploration.

Conceptual Modeling (Fig. 6, Box 10)

Completion of the shallow-temperature measurement program is a major milestone in the history of a prospect. This is the appropriate time for the explorationists to formalize their target concepts with the development of a conceptual model. The process should integrate the prospect-specific geologic mapping, geochemical, alteration, and thermal-gradient information and relate these to the broader reconnaissance data base. The output of the process is a target model consistent with the data; some contradictory information will now become apparent. Parameters identified may include lateral extent, depth, heat-source types, and temperature. The options for testing the model in the most efficient manner should be evaluated prior to proceeding. A maximum of 2 man-months, at a cost of less than $10,000, would be required for this activity.

Obtain Color Air Photos and Base Map (Fig. 6, Box 11)

In areas where adequate stereo air-photo coverage and good base maps are available this step will be unnecessary. However, when dealing with an area with complex structural and alteration patterns, it is often most efficient to obtain low-altitude, color aerial photography. These photos provide an excellent base for detailed geologic mapping and can be used to generate detailed topographic base maps.

Detailed Mapping 1:6,000 (Fig. 6, Box 12)

Mapping in greater detail than 1:24,000 may not be necessary, but many added details may be required to answer specific structural questions or to unravel complex alteration patterns. In general, the purpose of this step is to understand the geologic setting as completely as possible prior to initiating the expensive surveys and drilling indicated in the latter half of the exploration process.

Dipole-Dipole Resistivity Survey (Fig. 6, Box 13)

A dipole-dipole resistivity survey should be planned to extend the results of surface geologic mapping to depth. Typically, survey lines are oriented as nearly perpendicular to geologic strike and structures as possible. The dipole length may range between 150 and 600 m to reach the appropriate compromise between lateral resolution and the increased response to features at depth. A dipole separation of 300 m seems to be preferred by the industry in the Basin and Range province. The data should be recorded to at least $n = 6$ (sixth separation) to allow confidence in subsequent interpretation to depth.

An option not generally exercised is the recording of induced polarization (IP) data along key profiles of the survey (Chu et al, 1980). This may be warranted if trace-element or lithologic studies suggest sulfide zoning which may be related to the geothermal system, or if this parameter can further discriminate between geologic units at depth. The cost of these added data depends on the increased recording time and local noise levels. We do not advocate routine inclusion of IP measurements. A maximum of $50,000 would be required for contract services for the basic resistivity survey, providing 60 line-km of control and numerical modeling of the data. A self-potential survey may be included for fluid-flow information.

Numerical and Conceptual Modeling (Fig. 6, Box 14)

Numerical modeling should be applied to two data sets to test and subsequently modify the conceptual model. The shallow-temperature hole data should be combined with measured or assumed thermal conductivity to produce a heat-flow map. A better definition of the heat source may be apparent after attempts to model this distribution of heat flow by means of forward calculations, or inversion.

A detailed modeling of the resistivity data can be completed using contract services or two- and three-dimensional computer programs now available (Killpack and Hohmann, 1979). A definitive intepretation of resistivity structure to depths of about one-fifth the extreme electrode separation will often be possible. Especially useful outputs from the process are the location of Basin and Range faults and areas of low resistivity associated with hot conductive fluids and altered rock. Although the reservoir itself may be too deep to detect, zones of leakage to the surface may be delineated. These geometric models place new constraints on the conceptual model, as does the more detailed geologic mapping. The model is updated, and serves as the basis for siting intermediate-depth drill testing. The cost, suggested at $20,000, is justified by the commitment of the subsequent drilling.

Model Test Drilling and Logging (Fig. 6, Box 15)

The northern Nevada studies indicate that most companies drill two or more 500 to 800-m slim holes which are referred to variously as deep geothermal-gradient holes, stratigraphic-test wells, or as model test-drill holes. These holes serve to evaluate (a) shallow cold-water overflow or mixing and (b) shallow thermal aquifers as at Desert Peak, Nevada (Benoit, 1978). They also serve to provide a preliminary test of the conceptual model of the geothermal system. We recommend three such holes at an estimated cost of $80,000 each. Although practice varies from company to company, we recommend temperature, resistivity, gamma, and SP logging rather than acquisition of a full suite of logs.

Isotopes, Chemistry, Hydrology (Fig. 6, Box 16)

The model test drilling yields cuttings and fluids which permit one or more of the following: (a) isotopic and chemical geothermometric predictions of temperature in the reservoir, (b) the possibility of identifying the source of recharge to the system, and (c) estimation of the permeability of the reservoir by water/rock ratio analyses (Elders et al, 1978). An understanding of the hydrology of the system can be improved by such inexpensive studies.

Lithology and Alteration Studies (Fig. 6, Box 17)

Lithologic logging is important in determining the subsurface geologic relations. Logging should emphasize the correlation of cuttings with units delineated during the geologic mapping. With this information, geologic cross sections can be drawn and conceptual models of the geometry of the system refined. By relating the cuttings to the surface geology, the three-dimensional structural setting can be defined. Fault zones may appear as areas of gouge or mylonite. Often faults are the focus of areas of hydrothermal alteration. However, many times the fault zones are unspectacular in cuttings and must be delineated on the basis of known geologic relations, such as attenuation and juxtaposition of units, which can only be explained by faulting.

The geologic cross sections drawn at this time should integrate all of the data sets accumulated. It is particularly important that the geologic, geochemical, and geophysical models be compatible. Discrepancies in interpretation should be rationalized or eliminated.

Geophysical Logging (Fig. 6, Box 18)

Thermal measurements will be made in the model test drilling. For a small additional investment, SP, resistivity, and gamma logs can be run to provide additional stratigraphic control. This type of logging is commonly done in the uranium exploration industry and numerous low-cost logging units are available. However, most of these units are not designed to operate in high-temperature environments. Velocity and density logs could also be obtained, at a significant increase in cost, to assist in the design or interpretation of any subsequent reflection seismic survey.

Reflection Seismic and Audio Magnetotelluric/Magnetotelluric (AMT/MT; Fig. 6, Box 19)

In our strategy we have allowed for the possibility of using either or both of the reflection seismic and AMT/MT methods to assist in mapping structures or fracture systems; 25 km of seismic reflection data of $5,000 per line-kilometer and 30 AMT/MT stations at $2,000 per station are used in the estimate. In some places one or both methods will be inapplicable and hence this box can be bypassed or limited to one method.

Detailed Numerical and Conceptual Modeling (Fig. 6, Box 20)

The target concept is again updated prior to deep drilling in our strategy. Refinements in the numerical models may be possible through hydrology and chemical geothermometry, and through stratigraphic drilling and seismic data; 2 man-months and computer support may be required for this third update of the integrated numerical and conceptual model.

Production Test Drilling and Logging (Fig. 6, Box 21)

Known production test wells in the Basin and Range province have ranged from 382 m at Thermal Power Co. Utah State 72-16 at Roosevelt Hot Springs to 2,939 m at Phillips Petroleum Co. Desert Peak well B-23-1. Deeper drilling to 4,000 m is rumored. If one assumes three production test wells of 1,525 m at an average cost of $1,250,000 (including box 24, full suite logging and brief flow test), then the cost of box 21 is $3,750,000 and this seems to be a typical expenditure.

Isotopes, Chemistry, and Hydrology (Fig. 6, Box 22)

All activities of box 16 are repeated here. Additionally, down-hole temperatures and pressures and their variations during the brief (24 hour nominal) flow test are available to provide further assessment of the reservoir.

Lithology and Alteration Studies (Fig. 6, Box 23)

Lithologic logging of the cuttings from deep drilling should again concentrate on correlating the lithologies with the surface mapping, identifying structures, and characterizing alteration assemblages. The results will provide data needed to draw geologic cross sections through the prospect area and may define small-scale structures that control fluid flow. These cross sections must now be compatible with relations shown by surface mapping, deep- and intermediate-depth drill results, and numerical modeling of geophysical surveys completed. Obviously, discrepancies in the interpretation of various data sets will be present and must be rationalized by remodeling or collection of additional data.

Characterization of alteration assemblages has been shown to yield important information on the location of production zones and the permeabilities of individual units (Browne, 1970, 1978). In addition it is often possible to document the chemical and thermal history of the system by using alteration assemblages (Browne, 1978) and fluid inclusion results (Burruss and Hollister, 1979).

Characterization of the mineralogy of test holes is crucial in facilitating the interpretation of geophysical well logs (Glenn and Hulen, 1979).

Geophysical Logs (Fig. 6, Box 24)

A thorough study of the suite of geophysical logs, well-coordinated with geochemical and lithologic studies, is mandatory. The results are an improved assessment of reservoir temperatures, fracture porosity and permeability, location of hot and cold fluid entries, and the identification of various reservoir-rock properties. For $20,000 we envision digitizing and replotting the various logs to a common depth scale with lithology and cross plots for unit discrimination and physical property evaluation. One man-month of interpretation time by an experienced well log analyst for each of three well tests is expected.

Reservoir Modeling (Fig. 6, Box 25)

The last update of the model considered here is a product consistent with the drilling results, the physical properties determined from the geophysical logs, and the surface geophysical and geochemical data. We do not necessarily imply a rigorous multidata-set numerical-model solution, but rather models from individual different data bases which are now internally consistent, or largely so.

Through flow testing and geometric modeling a preliminary reservoir model is available as the main input to the feasibility study. A decision to enter production implies continued monitoring of key variables and the modification of the reservoir model.

CONCLUSIONS

In the previous section we have presented our recommended strategy for exploration for high-temperature hydrothermal resources in the Basin and Range province and our justification for this choice of strategy. It is an expensive strategy, costing between $680,000 and $865,000 per prospect prior to production test drilling. We justify such large expenditures on the basis that we wish to minimize the risk of a poorly placed production test well when such wells often cost $1,000,000 to $1,800,000. The ratio of predrilling costs to the cost of the first hole therefore is approximately 0.5 under this strategy.

Research in exploration and assessment technology is expected to lead to introduction of new methods (e.g., controlled source electromagnetic methods), reintroduction of old methods, and more cost-effective use of some methods. Hence the strategy we recommend will be updated by a more cost-effective one when new or improved technology becomes available and when we make the next major step in developing conceptual models of high-temperature convective hydrothermal systems. Further, the strategy may evolve from the current one which is primarily directed to convective hydrothermal systems with surface manifestations to one primarily directed toward blind systems.

The broadly experienced geothermal exploration manager may wish to differ with our recommended strategy for various reasons including personal preference, budgetary constraints, time and land position constraints, and environmental or legal constraints. Our intent is not to force uniformity in exploration but to offer our recommendations based upon our collective experience and observations. The newcomer to geothermal exploration is expected to benefit more from this manuscript than the veteran geothermal explorationist.

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APPENDIX II

State Geothermal Lease Provision and Law and Regulations Regarding Development

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties
Alaska	10 years	One 5-year term if drilling for duration of commercial production, up to 40 years	20-year intervals beginning 35 years after commercial production; and at end of first 40-year lease period
Arizona	10 years	2 years if drilling; for duration of commercial production	....
California	10 years	So long as geothermal resources are produced or capable of being produced in commercial quantities, up to 99 years	10-year intervals, beginning no sooner than 20 years and no later than 30 years after commercial production
Colorado	10 years	For duration of commercial production; lacking production, at discretion of state land board	Minimum royalty: 5-year intervals

Annual Rental	Royalties	Acreage Limits
Variable; $1/acre minimum	Primary: 10-15% Byproduct: 2-10% Minimum: $2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres (5,750 for submerged lands) Maximum state holdings: 25,600 acres
Not less than $1/acre	Primary: at least 12.5% Byproducts: at least 12.5% Shut-in: 4 times annual rental per year	Maximum lease: 2,560 acres (4 sections) (confined to 6 miles square)
$1/acre	Primary: 10% Byproduct: between 2 & 10% Minimum: $2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres Maximum state holdings: 25,600 acres (includes acreage under exploration permit)
$1/acre	Primary: 10% Byproduct: 5%	....

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties
Hawaii	10 years	So long as geothermal resources or byproducts are produced in commercial quantities, up to 65 years; 5 years with diligent drilling without production, or with shut-in well without market	15-year intervals, beginning 35 years after the lease date
Idaho	10 years	For duration of commercial production or drilling operations to at least 1000 feet, up to 40 years beyond primary term	....
Louisiana	At most 10 years	For duration of commercial production or development operations	....
Montana	10 years	For duration of commercial production or drilling	10-year intervals, beginning 20 years after lease date

Annual Rental	Royalties	Acreage Limits
State: as bid or set in lease Surface occupant: as agreed or set by Board of Land and Natural Resources	Primary: 10-20% Byproduct: 5-10%	Minimum lease: 100 acres Maximum lease: 5,000 acres, or 2,560 acres if length of tract is more than 6 times the width Maximum state holdings: 80,000 undeveloped acres
First 5 years: $1/acre Second 5 years: $2/acre Thereafter: $3/acre	Primary 10% Byproduct: 5%	Minimum lease: all state lands within a section must be leased Maximum lease: 640 acres Maximum state holdings: interest in 50 township-and-ranges
At least $1/acre or 1/2 cash bonus, whichever is greater	Primary: at least 10% Byproduct: at least 5%	Maximum lease: 5,000 acres
At least $1/acre	Primary: at least 10% Byproduct: between 2 & 5% Shut-in: set in lease Minimum: $2/acre/year	Maximum lease: 640 acres

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties
Nevada	....	....	....
New Mexico	5 years	So long as geothermal resources are produced or capable of being produced in commercial quantities if production is maintained. Secondary 5-year lease available if production is not maintained; if production is lost, Commission may extend lease in one-year increments up to three years	10-year intervals, beginning 20 years after lease date
Oregon	10 years	10 years, if royalties in any year of preceding term equalled or exceeded annual rental due under lease; 5 years, if no production but discovery has been made or is deemed imminent; maximum of 50 years from lease date	....

Annual Rental	Royalties	Acreage Limits
$1/acre	Primary: 12.5% Byproduct: 5.0%	....
$1/acre $5/acre for leases extended for second 5-year term without production	Primary: 10-15% (KGRA lands) Byproduct: between 2 & 10% Recreation or Therapeutic: between 2 & 10% Powerplant: 8% (net revenue) Minimum: $2/acre/year	Minimum lease: 640 acres Maximum lease: 2,560 acres Maximum state holdings: 51,200 acres
Years 1-3: $1/acre Year 4: $3/acre Years 5-10: $5/acre Years renewed: $5/acre	Primary: 10% Byproduct: 1% demineralized water (rentals paid each year deducted from royalties due)	Minimum lease: 40 acres

State	Primary Term	Renewal	Renegotiation of Rentals and Royalties
Texas	(No lease terms established	....	....
Utah	10 years	For duration of commercial production; or one-year terms, in absence of production, upon payment of $5/acre advance royalty	3-year intervals
Washington	5 years	So long as drilling with diligence; or upon commercial discovery, up to 20 years	....
Wyoming	10 years	So long as geothermal resources produced or capable of being produced in commercial quantities	10-year intervals

Annual Rental	Royalties	Acreage Limits
(No lease terms established	....	
$1/acre	Primary: 10% Byproduct: 10% (net proceeds)	Minimum lease: 40 acres Maximum lease: 640 to 2,560 acres, at discretion of director of state lands
At least $1/acre At least $5/acre upon commercial production Minimum: $5/acre/year	Primary: 10% Byproduct: at least 4% (net proceeds)	Minimum lease: 40 acres Maximum lease: 640 acres
$2/acre	Primary: 10% Byproduct: 5%	Minimum lease: 640 acres Maximum lease: 2,560 acres

State Laws and Regulations Regarding Exploration and Development of Geothermal Resources

ALASKA

Statutes: Geothermal Resources Act (1971) AK. Stat.
Leasing: Div. of Lands - Regulations & Statutes Pertaining to Coal and Other Leasable Minerals (1974) - 11 A.A.C. 84.700...
Drilling: Div. of Oil & Gas - 11 A.A.C. 94.730... (1974)

ARIZONA

Statutes: Geothermal Resources (1972); amen. HB 2257 (1977) A.R.S. 27-651...
Leasing: Land Dept. - Geothermal Resources (1972) T. 12C.5.A.22 (under revision)
Drilling: Oil & Gas Conservation Comm. - General Rules & Regulations Governing the Conservation of Geothermal Resources (1972) T.27C.4.A.4

CALIFORNIA

Statutes: Leasing - Geothermal Resources Act (1976) Pub. Res. Code 3700...
Leasing: State Lands Comm. - Leases & Prospecting Permits for Geothermal Resources (1970) C.A.C. 225000...
Drilling: Div. of Oil & gas - Statewide Geothermal Regulations (1976) C.A.C. 1900
Siting: Energy Comm. - Provisions Applicable to Geothermal Notices & Applications (1978) DRAFT

COLORADO

Statutes: Geothermal Resources Act (1974) C.R.S. 34-70-101...
Leasing: Board of Land Commissioner - Special Rules & Regulations Relating to Geothermal Resources Leases (1972) SLB #248-1
Drilling: Oil & Gas Conservation Comm. - Rules & Regulations for the Development & Production of Geothermal Resources (1976) G101...

HAWAII

Statutes: Government Mineral Rights (1974); amend. HB 3033 (1978) H.R.S. 182.1...
Leasing: Dept. of Land & Natural Resources - Regulations on Leasing & Drilling Geothermal Resources (1978) Reg. No. 8
Drilling: Reg. No. 8

IDAHO

Statutes: Leasing - Geothermal Resources Leasing Act (1975) ID Code 47-1601...
Production - Geothermal Resources Act (1974, as amend.) ID Code 42-4001...
Leasing: Board of Land Commissioner - Rules & Regulations Governing the Issuance of Geothermal Resources leases (1974; under revision)
Drilling: Water Resource Board - Drilling for Geothermal Resources (1978)

LOUISIANA

Statutes: Geothermal Energy Resources (1976) L.R.S. 30:800...; Geothermal & Geopressure Energy Research & Development Act (1975) L.R.S. 30:681
Leasing: Mineral Board - none (oil & gas model likely)
Drilling: Office of Conservation - Statewide Order 29-P (1978)

MARYLAND

Statutes: Geothermal Resources Act (1978) A.C.M. 8-8A-01...
Leasing: Not available
Drilling: Not available

MONTANA

Statutes: Leasing - Lease of Geothermal Resources (1974) R.C.M. 81-2601...
Siting - Major Facilities Siting Act (1975, as amend.) R.C.M. 70-801...
Filing bottom-hole temperatures - Act to Facilitate the Discovery of Geothermal Energy Sources (1975) R.C.M. 60-127, 144, 148
Leasing: Dept. of State Lands - Geothermal Rules & Regulations (1975) M.A.C. 26-2.6(2)
Drilling: Dept. of Natural Resources & Conservation - Geothermal Investigation Reports (1975) M.A.C. 36-2.8 (14)

NEVADA

Statutes: Leasing - An Act Relating to State Lands (1975) N.R.S. 322.030...
Production - An Act Relating to Geothermal Resources (1975) N.R.S. 534A.010...
Leasing: Div. of Lands - pending
Drilling: Div. of Water Resources - Regulations Pertaining to Exploration Drilling (1978)

NEW MEXICO

Statutes: Geothermal Resources Act (1967) N.M.S.A. 7-15-1... Geothermal Resources Conservation Act (1975; Chap. 272)
Leasing: State Land Office - Rules & Regulations Relating to Geothermal Resources Leases (1971)
Drilling: Oil Conservation Div. - Rules & Regulations for Geothermal Resources (1974)

OREGON

Statutes: Geothermal Resources (1975) O.R.S. 522.005... Geothermal Heating Districts (1975) O.R.S. 523.010...
Leasing: Div. of State Lands - Geothermal Lease Regulations (1975) 75-010...
Drilling: Dept. of Geology & Mineral Industries - Rules, Regulations & Laws Relating to Exploration & Development of Geothermal Resources (1977) 632-20-005...

TEXAS

Statutes: Geothermal Resources Act (1975) V.A.C.S. Art.5421s
Leasing: Railroad Comm./Div. of Oil & Gas - none (oil & gas model likely)
Drilling: Railroad Comm./Div. of Oil & Gas - Rules Having General Application to Oil, Gas & Geothermal Resource Operation (1976) 051.02.02.000 School Land Board - Rules & Regulations Governing Drilling & Producing on Permanent Free School Lands (1974; general)

UTAH

Statutes: Water & Irrigation Laws (1973) U.C.A. 73-1-120
Leasing: Div. of Lands - Rules & Regulations Governing Issuance of Mineral Leases (1973); Geothermal Steam Lease Agreement (1973)
Drilling: Div. of Water Rights - Rules & Regulations for Wells Used for the Discovery & Production of Geothermal Energy (1978)

WASHINGTON

Statutes: Geothermal Resources Act (1974) T.79 R.C.W.
Leasing: Dept. of Natural Resources - Geothermal Leasing Policy (1978) DRAFT
Drilling: Dept. of Natural Resources - none

WYOMING

Statutes: Underground Water 91973) WY Stat. 41-121

Leasing: Board of Land Commissioner - Rules & Regulations Governing the Issuance of Geothermal Resource Permits & Leases (1975)

Drilling: Oil & Gas Conservation Comm. - Rules & Regulations (1975; general)

APPENDIX III

State Regulations Applicable to Geothermal Resource Development

ALASKA

Legislation Rules and Regulations	1. Geothermal Resources Leasing Act of 1971, State Law 38.05.181 (1971). 2. Leasing Regulations - 11AAC 84.700 to 84.720 (1974). 3. Drilling Regulations - 11AAC 94.730 (1974).
Administrative/Regulatory Agency and Other Agencies Responsible	1. Dept. of Natural Resources 2. Dept. of Environmental Conservation (may be requested to assist DNR in taking those measures necessary to protect natural resources and prevent pollution of the state's waters).
Environmental Protection Requirements	The commissioner of the Dept. of Natural Resources has authority to require tests or work of the owner of a geothermal well in order to prevent pollution of the state's watershed and to protect the natural resources.

ARIZONA

Legislation Rules and Regulations	1. Arizona Geothermal Resources Statute, Article 4 Sections 27-651 to 27-666 (1972). 2. Leasing Regulations - Land Dept. Regulations, Ch. 5, Art. 21 (R12-5-801 to 811). 3. Drilling Regulations - "General Rules and Regulations Governing the Conservation of Geothermal Resources," Oil & Gas Conservation Commission (Title 27, Ch. 4, Art. 21), 1972.
Administrative/Regulatory Agency and Other Agencies Responsible	1. Oil & Gas Conservation Commission
Environmental Protection Requirements	Power Plant Transmission Line Siting Commission (1971), Article 6.2, requires "Certificate of Environmental Compatability" as evidence of approval by state of sites for a plant or transmission line or both.

CALIFORNIA

Legislation Rules and Regulations

1. California Environmental Quality Act of 1970.
2. Geothermal Resources Act of 1967, Public Resources Code, Div. 6, Part 2, Ch. 3, Article 5.5 (6902-6925) (Statutes of 1967, Ch. 1398).
3. Drilling Regulations - Publication No. PRC02 of the California Division of Oil & Gas - California Laws for Conservation of Geothermal Resources.
4. Leasing Regulations - Public Resources Code, Div. 6, Part 2, Ch. 3, Art. 5.5 (Statutes of 1967, Ch. 1398) also Ch. 4, Secs. 3714-5, 3723.5, and 3728.5 (1974).
5. Title 2, California Administrative Code, Div. 3 (Geothermal operations on state forests).
6. Title 14, California Administrative Code, Div. 2. (All regulations for Geothermal Development concerning the Division of Oil & Gas).
7. Title 14, California Administrative Code, Div. 6. (Deals with environmental quality, the evaluation of projects, and the preparation and evaluation of environmental impact reports).

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Administrative/Regulatory Agency and Other Agencies Responsible	1. Dept. of Conservation - Div. of Oil & Gas - Div. of Forestry 2. Geothermal Resources Board 3. State Lands Commission 4. Additional agencies whose rules and provisions the must comply with: - Dept. of Fish & Game - Dept. of Industrial Safety - Calif. Public Utilities Commission - Solid Waste Management Board - State Water Resources Control Board - Calif. Energy Resources Development Commission - Air Resources Board - State Board of Equalization
Environmental Protection Requirements	For multiple and phase projects - where individual projects are, or a phased project is to be undertaken and where the total undertaking comprises a project with significant environmental effect, the Div. must prepare a single EIR for the ultimate project unless: a. The project's environmental effect will be better known at the conclusion of a particular phase, and b. The Commission retains a discretionary approval over all phases.
Additional Comments	Where an individual project is a necessary precedent for action on a larger project, or commits the State Lands Commission to a larger project, with significant environmental effect, an EIR must be prepared that addresses the scope of the larger project. Where one project is of several similar projects of a public agency, but is not deemed a part of a larger undertaking or a larger project, the agency may prepare one EIR for all projects, or one for each project, but should discuss impacts on a cumulative basis in either case.

Where a project with potentially significant effect on the environment is to be undertaken by a local agency, but requires state approval or financial assistance, the state agency shall require the local agency to prepare the EIR or Negative Declaration. This must be done where federal funds are involved, but only if a state agency has discretionary authority over the use of those funds.

California has a state clearing house for geothermal development operated by the Governor's Office of Planning and Research.

COLORADO

Legislation Rules and Regulations	1. Colorado Geothermal Resources Act of 1974, Section 1, Ch. 100, Article 100, Colorado Revised Statues, 1963, as amended. 2. Regulations under which geothermal operations must abide by and include the following: 3. Colorado Water Quality Control Act of 1973, Rules for Subsurface Disposal Systems. 4. Rules and Regulations, Rules of Practice and Procedure, and the Oil & Gas Conservation Act (Publication of the Oil & Gas Conservation Commission). 5. Water Quality Standards and Stream Classification (Publication of the Water Quality Control Commission, 1974). 6. Leasing Regulations - State Board of Land Commissioners a. "Special Rules and Regulations Relating to Geothermal Resources Leases" (Form #248-1 - 1972).
Administrative/Regulatory Agency and Other Agencies Responsible	1. Oil & Gas Conservation Commission 2. State Board of Land Commission 3. Water Quality Control Commission 4. Dept. of Health 5. Air Pollution Control Board
Environmental Protection Requirements	A written statement describing measures that will be taken to protect against land subsidence, contamination of surface and groundwaters and the air, and excessive noise levels is required from applicant prior to issuance of permit.

HAWAII

Legislation Rules and Regulations	1. State Law: Ch. 182 (Government Mineral Rights) as amended (H.B. 2197-74). 2. Leasing and Drilling Regulations: "Regulation of Geothermal Mining of State Lands and Reserved Lands of Hawaii" (Draft).
Administrative/Regulatory Agency and Other Agencies Responsible	1. Dept. of Land and Natural Resources

IDAHO

Legislation Rules and Regulations	1. Idaho Geothermal Resources Act of 1972, Idaho Code Sections 42-4001 to 42-4015 (amended 1974); Sections 47-1601 to 47-1611 (1972). 2. Leasing Regulations - "Rules and Regulations Governing the Issuance of Geothermal Resources Leases," Board of Land Commissioners, 1974. 3. Drilling Regulations - "Drilling for Geothermal Resources: Rules and Regulations & Minimum Well Construction Standards," Dept. of Water Resources, 1975.
Administrative/Regulatory Agency and Other Agencies Responsible	1. Dept. of Water Resources 2. Board of Land Commissioners
Environmental Protection Requirements	The Water Resources Board has authority to ensure the adequacy of measures proposed to safeguard the environment of the area around the site of the proposed well from unreasonable contamination or pollution. The Board may require additional geologic, geochemical, and engineering plans, reports, and records as necessary for the administration of the Geothermal Resources Act of 1972. Permit to Construct required for new and modified stationary sources (site information, plans, description, specifications, and drawings should accompany the application) - See Idaho Air Pollution Control Act.
Additional Comments	Geothermal resources in the State of Idaho are considered sui-generis, being neither a mineral nor a water resource, but closely related to and possibly affecting and affected by water and mineral resources.

LOUISIANA

Legislation Rules and Regulations	1. Louisiana Geothermal and Geopressured Energy Research and Development Act of 1975, Title 30, Part VI, Ch. 7, Subpart A (Act 735; 1975). 2. Louisiana Geothermal Resources Act, Title 30, Ch. 8 (Act 784; 1975).
Administrative/Regulatory Agency and Other Agencies Responsible	1. State Dept. of Conservation - State Mineral Board
Environmental Protection Requirements	An impact statement is required from the State Mineral Board before an applicant's geothermal lease is processed.
Additional Comments	A geothermal lease is subordinate to any oil, gas, or mineral lease issued prior to or following the issuance of a geothermal lease.

MONTANA

Legislation Rules and Regulations	1. State Law: Sections 81-2061 to 81-2613 (Ch. 111, Laws of 1974); Section 60 (amended 1975, S.B. 79); Section 70-820 (amended 1975; H.B. 581). 2. Leasing Regulations: "Geothermal Rules and Regulations," Title 81, Ch. 6, Montana Administrative Code, 1975. 3. Drilling Regulations: "Geothermal Investigation Reports," 36-2.8(14), Montana Administrative Code.
Administrative/Regulatory Agency and Other Agencies Responsible	1. Dept. of Natural Resources & Conservation 2. Dept. of State Lands
Environmental Protection Requirements	A narrative statement is required from the lessee describing the proposed measures to be taken for protection of the environment, including the prevention or control of (1) fires, (2) soil erosion, (3) pollution of the surface and groundwater, (4) damage to fish and wildlife or other natural resources, and (5) air and noise pollution.
Additional Comments	Where there are conflicting leases, including geothermal, coal, mineral and oil and gas leases, involving the same land, the person who first was issued a lease shall be entitled to priority of rights.

NEVADA

Legislation Rules and Regulations	1. Nevada Water Laws Amendment of 1975, Title 48, Sections 2 to 5 (S.B. 158; 1975); Sections 322.030 to 322.060 (S.B. 158; 1975) 2. Leasing Regulations: (Leasing moratorium on state lands since 1967). 3. Drilling Regulations: (Geothermal regulations pending) State Water Law and well drilling regulations.
Administrative/Regulatory Agency and Other Agencies Responsible	1. State Dept. of Conservation: Natural Resources a. Div. of Water Resources b. State Engineer c. State Land Use Planning Agency (1973)
Environmental Protection Requirements	The Utility Environmental Protection Act (1971) requires an EIS.

NEW MEXICO

Legislation Rules and Regulations	1. "Geothermal Resources Act," 7-15-1 to 7-15-28 (Ch. 158, Laws of 1967). 2. "Geothermal Resources Conservation Act" (Ch. 272, Laws of 1975); 72-20-5(D). (Ch. 289, Laws of 1975). 3. Energy Resources Act (Laws of 1975; Ch. 289) 65-12-1 to 16, Sec. 63-18, Laws of 1967, Ch. 143. 4. Leasing Regulations: "Rules and Regulations Relating to Geothermal Resources Leases," State Land Office, 1971. 5. Drilling Regulations - "Geothermal Resources: Rules & Regulations," Oil Conservation Commission, 1974.
Administrative/Regulatory Agency and Other Agencies Responsible	1. Oil Conservation Commission 2. Public Land Commission 3. State Board of Public Health
Environmental Protection Requirements	Environmental impact statement required - see Environmental Improvement Act of 1972.
Additional Comments	Persons conducting geothermal operations on U.S. Government land shall also comply with all applicable state rules and regulations which are not in conflict therewith. Geothermal operations are required to be conducted in such a manner as to afford maximum reasonable protection to the environment.

OREGON

Legislation Rules and Regulations

1. Geothermal Resources Control Act of 1975, H.B. 2040; 1975 (amending 1971 "Geothermal Resources Act"); H.B. 3185, 1975 (geothermal heating districts).
2. Administrative Order No. 4, Blowout Prevention Rules - Geothermal Prevention Rules - Geothermal Prospect Wells (1976).
3. Leasing Regulations: "Geothermal Regulations," Ch. 632, Div. 2 (20-005 through 20-170), Administrative Rules Compilation, 1972 (Dept. of Geology and Mineral Industries.

Administrative/Regulatory Agency and Other Agencies Responsible

1. Dept. of Geology and Mineral Industries
2. Div. of State Lands
3. Dept. of Environmental Quality
4. State Fish & Wildlife Commission
5. Land Conservation and Development Commission
6. Dept. of Energy
7. Water Resources Board
8. State Soil & Water Conservation
9. State Parks Superintendent
10. State Highway Engineer
11. Nuclear & Thermal Energy Council
12. State Board of Energy
13. Oregon Div. of Employment
14. Div. of Health
15. Bureau of Labor
16. Workmen's Compensation Dept.

OREGON - Con't.

	17. Dept. of Revenue
	18. Public Utility Commission
Environmental Protection Requirements	Environmental impact report (EIR) required--see Geothermal Leasing Regulations, Div. of State Lands (75-010 to 75-605). Rules and guides for preparing the EIR are described in the Div. of State Lands Rules 75-625 and 75-635. Also see Geothermal Regulations, Sections 20-005 through 20-170 of Ch. 632 of the Oregon Administrative Rules Compilation for requirements for environmental protection of the Dept. of Geology and Mineral Industries. The State Dept. of Environmental Quality if responsible for controlling solid waste disposal and discharge of pollutants into air and public waters by the issuance of permits.

TEXAS

Legislation Rules and Regulations	1. Geothermal Resources Act of 1975 (S.B. 685; 1975). 2. Drilling Regulations: a. "Rules and Regulations Governing Drilling and Producing on Permanent Free School Lands," School Land Board, 1974. b. Railroad Commission of Texas - Rules Having Statewide General Application to Oil, Gas, and Geothermal Resources Operations within the State of Texas (051.02.02.000 to 051.02.02.080), Texas Railroad Commission, Oil & Gas Div., 1976.
Administrative/Regulatory Agency and Other Agencies Responsible	1. Railroad Commission of Texas 2. Texas Water Quality Board (involved in saltwater disposal -well applications)
Environmental Protection Requirements	Oil and Gas Docket No. 20-65, 518 includes general statements specifying that the waters of Texas be protected during any oil, gas, or geothermal resource development operation.

UTAH

Legislation Rules and Regulations	1. State Law: Sec. 73-1-20, (Ch. 189; Laws of 1973). 2. Leasing Regulations - "Rules and Regulations Governing the Issuance of Mineral Leases," State Land Board, 1973. "Geothermal Steam Lease and Agreement" (1973) (the lease form contains the regulations). 3. Drilling Regulations - "Rules and Regulations of the Div. of Water Rights for the Discovery and Production of Geothermal Energy in the State of Utah" (Draft - 1975).
Administrative/Regulatory Agency and Other Agencies Responsible	1. Div. of Water Rights 2. State Land Board
Environmental Protection Requirements	The owner of a proposed injection well shall provide the Div. of Water Rights with such information it deems necessary for the evaluation of the impact of such injection on the geothermal reservoir and other natural resources.
Additional Comments	The state lessee has a prior right to a separate mineral lease for minerals of possible recoverable value found in formations intercepted by mining or drilling operations in connection with geothermal production.

WASHINGTON

Legislation Rules and Regulations	1. Geothermal Resources Act of 1974 (Sub. H.B. 135; 1974). 2. Leasing Regulations - "Geothermal Leasing Policy," Dept. of State Lands (Draft, 1975). 3. Drilling Regulations - "Geothermal Rules and Regulations," Dept. of Natural Resources (Draft, 1975)
Administrative/Regulatory Agency and Other Agencies Responsible	1. Div. of Mines and Geology of the Dept. of Natural Resources 2. Dept. of Ecology
Environmental Protection Requirements	The Dept. of Ecology is the agency with the responsibility to manage and develop air and water resources in an orderly, efficient and effective manner. Uses a form of EIS.
Additional Comments	Dept. of Natural Resources has authority to condition permits to reduce negative environmental impacts. The State of Washington has declared geothermal resources to be sui-generis. Refer to Additional Comments for Idaho, this table.

WYOMING

Legislation Rules and Regulations	1. State Law: Title 41, Ch. 2, Art. 9 - "Underground Water" - Sec. 41-121 amended in 1973 to include "hot water and geothermal steam" as underground waters. 2. Leasing Regulations: "Rules and Regulations Governing the Issuance of Geothermal Resource Permits and Leases," State Board of Land Commissioners, 1973. 3. Drilling Regulations: (pending) Oil and Gas Conservation Commission.
Administrative/Regulatory Agency and Other Agencies Responsible	1. State Board of Land Commissioners 2. Dept. of Environmental Quality (Water Control Board) 3. Dept. of Game & Fish
Environmental Protection Requirements	Permit applications must include a statement describing the quality and proposed use of underlying groundwaters and adjacent surface waters, and a statement of proposed liquid, solid, or gaseous waste disposal methods necessary for the protection and preservation of existing land and water uses.

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RECOVERY OF METALS FROM GEOTHERMAL SYSTEMS

A SUPPLEMENT TO

EXPLORATION DEVELOPMENT AND UTILIZATION OF GEOTHERMAL RESOURCES

PREPARED FOR
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RECOVERY OF METALS
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Prepared for
Homestake Mining Company
San Francisco, California

by

BERKELEY GROUP INC.
Ronald C. Schroeder

The status of present geothermal systems as mineralizing systems has long been recognized. It is also fairly common knowledge that the scales being deposited in some developed geothermal systems contain large concentrations of metals. There is little published information on these concentrations, particularly where precious metals are concerned. However, several companies are known to be considering the extraction of metals from their geothermal brines as credits in the economics of geothermal energy production.

The chemistry of geothermal brines varies over considerable ranges as has been demonstrated previously in this paper. In general, mineral recovery is only possible from geothermal liquid brines that have high total dissolved solids content. The compounds present in appreciable amounts in vapor-dominated systems include CO_2, ammonia, hydrogen sulfide, and boron. Table 1 shows average steam content in weight percent for a steam well. In areas where injection of condensate has taken place, the associated boron levels are much higher, but still not worth further discussion.

The liquid-dominated systems often are high in total dissolved solids if the reservoir temperature exceeds $\gtrsim 250^{\circ}C$. Tables 2 and 3 show representative brine compositions for two different resources in the Imperial Valley. Other high temperature resources (in Utah, Oregon, and Northern California) show much lower concentrations of dissolved solids.

Repeated brine analyses usually show a large range of values of dissolved ions, and this may be due to fluctuations in brine chemistry, sampling techniques and analysis. Not only are the sample analyses inconsistent in dissolved solids, but they often do not indicate important constituents. For example, silver is very seldom an element that is determined in the brine analyses, yet flecks of native silver appear in scale from the Salton Sea system. In silica-based scale (opaline) silver and sulfide minerals (digenite, bornite, chalcocite, stromeyerite, pyrite, sphalerite, etc.) are dispersed throughout. Native lead (Pb) has been recovered from South Brawley scale and Fe, Cu, Ag, and Pb appear in elemental form.

Care must be taken in discussing scale composition. The deposition conditions, temperature, pressure, steam saturation, and hydrodynamic motion all play a role in how scale forms, and what compounds occur. In flow regimes where gas exsolution, or shock waves exist, unusual scale accumulations occur. Likewise, in the turbulent regions geothermal scale deposits are different from the laminar flow portions of pipes.

The flow rates of geothermal wells vary enormously along with all of the other parameters. In general, the geothermal wells are considered uneconomical if the flow rates are below ≈ 10 kg/s . Some exceptional wells flow at rates exceeding 100 kg/s. Taking these numbers as the upper and lower limits of flow allows estimates for the production rates of the ionic species from Tables 2 and 3 (some elements are not included because the ionic analyses are not available--such as gold, silver, and uranium).

Table 4 shows the upper and lower limits of production of certain metals in kg/day/well. Usually, if power is being extracted from the geothermal brine (i.e., > 2 MWe/well) the number of wells/mi^2 is between 5 and 15, depending upon production rates, temperature, etc. Thus the figures for each producing section are 5 to 15 times the figures shown in Table 4.

This brief discussion has not developed the subject of mineral extraction from geothermal brine in detail. The problems associated with processing millions of gallons of brine/day are staggering. When the problems associated with the removal of heat from the brine, and separation of the most desirable elements or compounds from the brine are also considered, it is apparent that mineral extraction would require a very large and complicated installation. In several current power-generation projects the "sludge" that is removed from the brine is rich in metals. In at least two developments now underway, this sludge will be removed during the power production process, and the contained minerals will be recovered. Although the current projects for mineral extraction are not designed to recover many of the available valuable constituents, metal extraction greatly increases the economics of geothermal development.

Table 1. Composition of steam from Geysers geothermal wells (weight percent)

	Low	High	Average
H_2O	96.59	99.88	99.60
CO_2	3.06	.029	.326
H_2S	.0005	.106	.022
CH_4	.0013	.145	.019
C_2H_6	.0003	.0019	.0008
NH_3	.00094	.106	.019
H_2	.0011	.022	.006
N_2	.0006	.064	.005
H_3BO_3	.0012	.22	.009

Table 2. Brine composition (sampled at the wellhead) for a Niland (Salton Sea Geothermal Field) well in mg/l.

	Water Soluble	Water Insoluble
Na	58000	55
K	11000	10
Mg	110	2
Mn	760	4
Fe	240	40
Cu	0.8	0.6
Zn	280	2
Pb	35	5
Ca	23000	21
Li	170	0.5
Al	180	5
Ba	800	15
Sr	533	
SiO_2	375	220
Cl	121800	
F	200	
B	390	
SO_4	113	
Total Solids	218350	
Wellhead T	115°C	
Reservoir T	300°C	

Table 3. Brine composition (sampled at the wellhead) for a South Brawley geothermal field in mg/l.

	Sample #1	Sample #2
Na	86800	80900
K	13500	11300
Mg	540	500
Mn	1550	1350
Fe	6320	5600
Cu		
Zn	1800	1500
Pb	420	300
Ca	30200	26600
Li	400	320
Al	< 3	< 3
Ba	3100	2800
Sr	2450	2150
SiO_2	240	635
Cl	214370	190000
F		
B	385	300
SO_4	< 1	< 1
pH	4.8 to 5.2	
Total Solids	326210	
Wellhead T	~105°C	
Reservoir T	271°C	

Table 4. Daily production of metals from a South Brawley well in kilograms per day at the rates shown.

Flow Rate	10 kg/s*	100 kg/s**	mg/l in the brine	min/max $ value ***
Mg	450	4500	520	
Mn	1210	12100	1400	
Fe	5140	51400	5950	
Zn	1425	14250	1650	1400 to 14000
Pb	310	3100	360	230 to 2300
Li	310	3100	360	
Ba	2550	25500	2950	
Sr	1990	19900	2300	

We have assumed, for simplicity, that 1 liter of brine ≈ 1 kg.

* 86400 kg/day
** 8640000 kg/day
*** based on recent cash price

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