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NEAR-SURFACE GROUNDWATER RESPONSES TO INJECTION OF GEOTHERMAL WASTES

by

Sally C. Arnold

under the Direction of
Dale R. Ralston
College of Mines and Earth Resources
Department of Geology

Idaho Water and Energy Resources
Research Institute
University of Idaho
Moscow, Idaho

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ABSTRACT

Experiences with injecting geothermal fluids have identified technical problems associated with geothermal waste disposal. This report assesses the feasibility of injection as an alternative for geothermal wastewater disposal and analyzes hydrologic controls governing the upward migration of injected fluids. Injection experiences at several geothermal developments are presented.

Testing at the Raft River KGRA in Idaho was limited to short-term injection into an interval shallower than the production interval. Results indicated there is hydraulic communication among deep and shallow wells. The potential for substantial upward migration of injected fluids is moderately high.

Injection at the Salton Sea KGRA in Californa was tested by injecting into an interval slightly deeper than the production interval. Problems included high total dissolved solids (TDS) and potential for increased subsidence and induced seismicity. The potential for substantial upward migration of injected fluids is low.

Injection at the East Mesa KGRA in California has occurred into an interval similar to the production interval. Problems are similar to those at the Salton Sea KGRA, although TDS are less. The potential for substantial upward migration of injected fluids is low.

Injection at the Otake geothermal field in Japan occurs in intervals similar to the production intervals. Problems include a high potential for injected fluids to migrate upward along fractures and silica scaling of wells and equipment.

Injection at the Hatchobaru geothermal field in Japan occurs in intervals similar to production intervals. Problems include rapid hydrodynamic breakthrough, reservoir cooling, and silica scaling of wells and equipment. The potential for substantial upward migration of injected fluids is high.

Injection at the Ahuachapan geothermal field in El Salvador occurs at intervals deeper than production intervals. Some reservoir cooling has occurred, but injection effectively stabilizes pressure declines. The potential for substantial upward migration of injected fluids is low.

Hydrogeologic and design/operational factors affecting the success of an injection program are identified. Hydrogeologic factors include subsidence, near-surface effects of injected fluids, and seismicity. Design/operational factors include hydrodynamic breakthrough, condition of the injection system and reservoir maintenance. Existing and potential effects of production/injection on these factors are assessed.

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1. INTRODUCTION

1.1. Statement of the Problem

Injecting fluids into subsurface formations is a well-established method of liquid waste disposal that has served the petroleum industry and other water-intensive industries for decades. The geothermal industry, however, has faced numerous complex problems since first attempting injection in the early 1960's. Developing hydrothermal resources requires continuous pumping of large volumes of superheated water that require disposal after the heat has been extracted for energy production.

The success or failure of an injection program depends largely upon site-specific conditions. Geology, fluid temperature and chemistry, and hydrologic flow controls vary among fields, so each injection program requires an individual design for its respective geothermal field. The inconsistency of physical and chemical parameters has created numerous problems for developers who have experienced great difficulty in operating long-term injection. Most worldwide injection programs to date have been essentially one or more series of short-term injection tests (24-1000 hrs.). For the most part, tests have been designed to identify technical problems associated with fluid injection and to assess the feasibility of injection within the hydrogeologic constraints of a given geothermal system. Field operators that have injected geothermal waste fluids for several months to several years have encountered numerous associated problems. These difficulties, depending upon each situation, may have chemical, hydrological, or operational origins. Only the Ahuachapan geothermal field in El Salvador has reported success with long-term injection. Commonly reported problems include maintaining reservoir pressure, subsidence resulting from incomplete injection, induced seismicity, chemical fouling of equipment, reservoir plugging, rapid communication of injected water among geothermal wells, and heat depletion of the geothermal reservoir by relatively cool injected fluids.

There are several practical advantages of injecting liquid wastes from thermal power plants into underground aquifers. Assuming favorable hydrogeologic conditions and proper placement of production and injection wells, these advantages are:

* Isolation of liquid wastes from the surface and prevention of surface pollution.
* Minimization of subsidence caused by withdrawal of large volumes of geothermal fluids (Note: less than 100% injection can still result in reservoir pressure declines and accompanying subsidence).
* Minimization of the decline in reservoir pressure that occurs as geothermal fluids are produced. Failure to replenish reservoir fluids by injection or adequate natural recharge can diminish reservoir fluid pressures and cause well producivity to decline.
* Provision of a mechanism to recover additional heat from the reservoir. Most geothermal heat is contained in reservoir rocks. The injected fluid scavenges heat from the rocks as it migrates through the formation toward the production wells (Sanyal, 1978).

These last two advantages can prolong the life of the geothermal reservoir.

Numerous hydrologic criteria must be evaluated before implementing an injection program. Local and regional geology control the lithologic and structural conditions surrounding the geothermal resource as well as the available permeabilities for fluid movement. The existence of primary porous media flow or secondary fracture flow influences the speed and direction of groundwater movement.

Fractures seem to dominate the permeability of most geothermal fields. The effect of fractures in geothermal reservoirs is one of the largest unknown quantities influencing predictions of reservoir behavior during development and injection. Estimating the degree of interconnection and the spacing of fractures with reservoir simulation techniques is a primary target in current geothermal research. Evaluation of groundwater flow patterns before geothermal production and resulting hydrologic gradients after production gives a reasonably clear idea of where and how fast injected fluids will flow. The degree and spatial distribution of reservoir fracturing as well as the degree of interconnection of fractures also have considerable effect on the rate of fluid transport between adjacent aquifers, both horizontally and vertically. Fracture zones and faults may facilitate vertical migration of wastes and consequent pollution of shallower aquifers. Ideally the presence of an impermeable cap rock or confining layer would prevent vertical migration of waste fluids; however, not all geothermal systems possess such a cap rock.

Little is understood about the near-surface and regional effects of continuous injection of large volumes of geothermal wastes into the ground. Over many years, there could be significant repercussions near the surface from subsurface injection. Many of these impacts can be anticipated and avoided by a carefully planned injection scheme or by a decision not to inject at all.

1.2. Purpose and Objectives

The purpose of this project is to assess the feasibility of subsurface injection as an alternative for geothermal wastewater disposal in the western United States. The general objective is to provide a detailed analysis of hydrologic controls governing the effects of injecting geothermal wastewater on overlying aquifers. Specific objectives include:

1) Search the literature to identify and select geothermal developments that use subsurface injection of wastes, particularly in fractured, volcanic, and Basin and Range geologic systems.
2) Gather available data from injection system monitoring programs for each of the selected developments and write case studies, include:
    a) Describe the geologic and hydrologic systems in which the geothermal resource occurs.
    b) Describe the available water chemistry data on the geothermal fluid and naturally occurring groundwater in the hydrogeologic system.
    c) Characterize the geothermal resource on the basis of its origin, fluid movement, and reservoir parameters.

d) Describe the injection program, including the arrangement of injection and production wells and the effects of injection seen at monitoring stations and other geothermal wells.

e) Assess environmental/physical effects, such as subsidence, seismicity, and declines in reservoir productivity.

3) Analyze hydrogeologic factors that control the effects on overlying aquifers of injecting geothermal wastewater.

2. BACKGROUND

Generating power using a liquid-dominated hydrothermal resource requires producing and disposing of large volumes of water. The amount of fluid requiring disposal depends upon several factors. Temperature of the geothermal resource controls the volume of geothermal fluid needed to run a given power plant. A 100-MW flashed-steam power plant using geothermal resources at 175^{o}C would generate about 84 x 10^6 m^3 (cubic meters) of waste fluids per year. By comparison, the same plant using resource temperatures of 285^{o}C would generate approximately 23 x 10^6 m^3 per year (Layton, 1980). Power plant size and type also influence the required volume of geothermal water.

There may be additional sources of water needing disposal besides the produced geothermal fluids. These sources depend largely upon plant design and site-specific factors governing fluid extraction. A flashed-steam type of generating cycle involves a net loss of fluid in the form of steam, so that less than 100% of the extracted fluid is returned to the reservoir via injection. If this net fluid loss is substantial, or if local conditions indicate there is long-term danger of subsidence or reservoir pressure losses, some source of make-up water may be necessary. Make-up water will doubtlessly alter temperature and chemistry of the injectate. The resulting chemical reactions can severely foul equipment and perhaps plug the reservoir near the injection well if proper precautions are not taken. Some power plant designs include cooling towers which produce small amounts of cooled water requiring disposal. Short-term well testing also produces small amounts of water. The chemical compatibility of these fluids determines if they may be mixed with geothermal fluids for injection. In the case of the Imperial Valley, California, even geothermal fluids from different wells may not be compatible.

Geologic and hydrologic properties of a geothermal field strongly influence the success or failure of an injection program. The composition of reservoir rocks contributes to the hydrochemistry of reservoir fluids. Hydrothermal alteration of reservoir rocks, particularly in sedimentary formations, may significantly impede fluid flow by reducing primary porosity and permeability. Hydrothermal alteration and induration may alternately make reservoir more susceptible to fracturing, thereby enhancing secondary porosity and permeability. The relative dominance of primary (porous media) and secondary (fractured) permeabilities is a critical factor in determining what factors control the ability to withdraw and inject geothermal fluids. Other factors to consider are the natural groundwater flow patterns and the locations of fault zones and thermal highs and lows.

There are several configurations of well fields that may be implemented on the basis of specific conditions existing at each geothermal site (Horne, 1982a). Injection and production wells may be interspersed so that injection is occuring within the production area; injection wells may be placed in the geothermal system at some distance from production wells in a side by side arrangement; or injection wells may be located outside of the geothermal system. Fluid disposal by injection requires only that the injection well penetrates a permeable formation capable of accepting the injected fluids. The permeable production horizon may be used for an injection horizon, or injected fluids may be directed to an alternate permeable zone above or below the producing horizon.

Interspersing production and injection wells may help maintain productivity by reducing reservoir pressure losses, but there is danger of reducing production temperatures with cooled reservoir fluids, particularly in a very permeable system. Reducing production temperatures would require higher volumes to be pumped, at higher cost, to achieve the same power generating capacity. A side by side arrangement of closely spaced production and injection wells can have a similar effect. Figure 2.1 is a conceptial diagram of the advancing front of injected fluids in a very permeable fractured reservoir. The injected fluids flow along fracture planes toward the production zone and perhaps upward to overlying aquifers.

Locating injection wells at some distance from production wells can provide a longer flow path for injected fluids which would likely follow a steepened, production-induced hydraulic gradient toward the producing zone. The longer flow path (provided fracture channeling can be avoided) increases fluid contact with superheated reservoir rocks and enables more heat to be gathered from the reservoir. This configuration is less advantageous for maintaining production pressures.

The relative merits of injecting into, above or below producing horizons depend largely upon site-specific conditions. These conditions may enhance or reduce the possibility of hydrodynamic or thermal breakthrough. In this paper, hydrodynamic breakthrough is defined as the

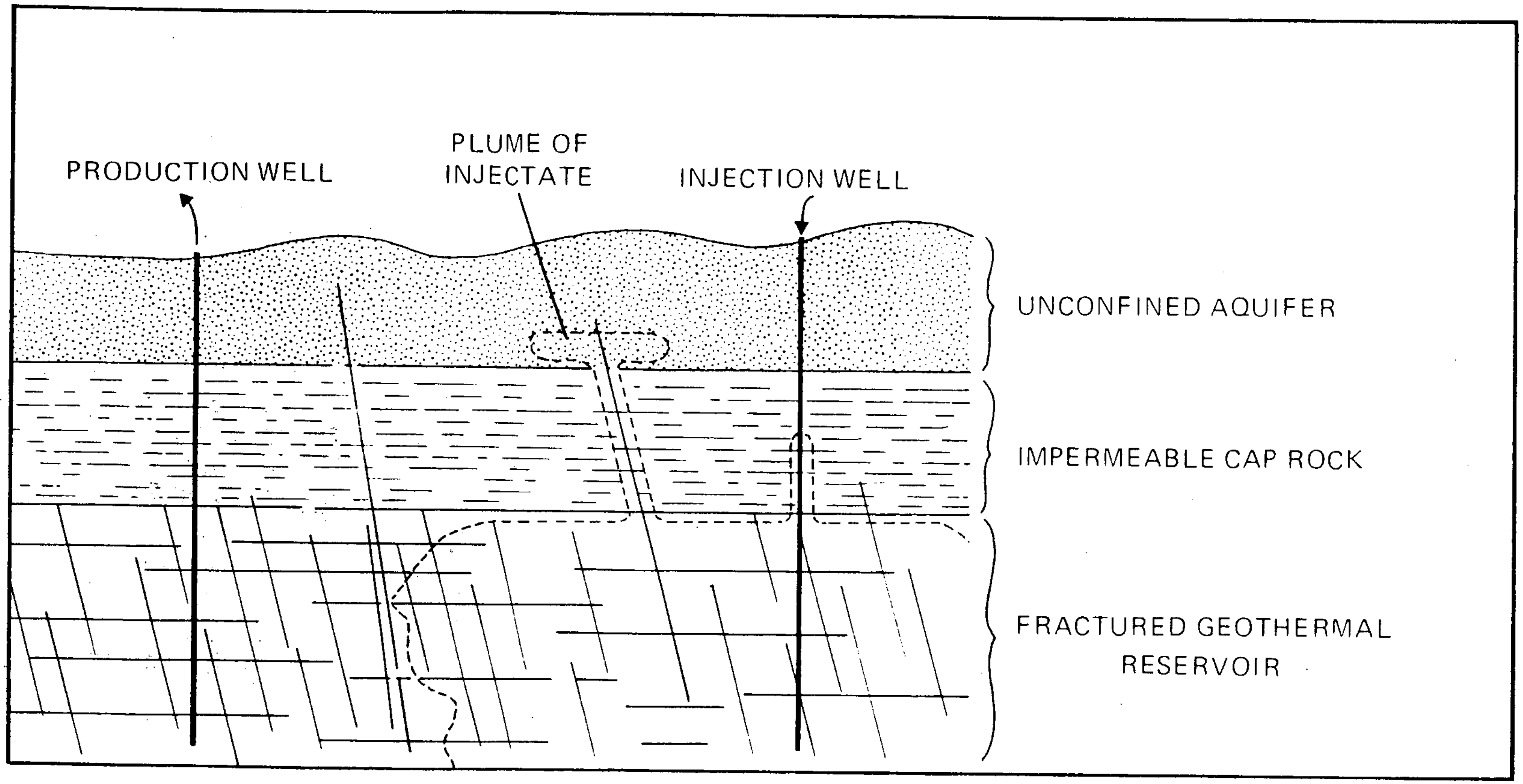

Figure 2.1 Conceptual model of the advancing plume of cooled geothermal fluids toward the producing zone and along vertical faults following injection into a fractured geothermal reservoir.

physical and chemical appearance of injected fluids at production wells. Thermal breakthrough occurs when injected fluids actually cool the reservoir rocks and, as a result, cool the native reservoir fluids. This phenomenon is much slower than hydrodynamic breakthrough.

It is necessary to define several other terms as they are used in this report. Permeability is the ability of the medium to transmit water and is a function of the medium alone. It is not to be confused here with hydraulic conductivity which is a function of both the medium and the fluid. The high variability in geothermal fluid properties prohibits using the groundwater hydrologists' definition of hydraulic conductivity with any degree of consistency without considerable correction. Injectability is used as an index of geothermal fluid properties and how they may help or hinder the injection process. Injectivity is an index reflecting the ability of a well or formation to accept geothermal fluids. It is defined as Q/ P, where Q is rate of flow and P is reservoir pressure (Howard et al., 1978). Injectivity may decrease with increased well or formation plugging or may increase with well rehabilitation or hydrofracturing. The geothermal industry uses a mass-based rate of tons/hour to measure production. In some cases it is possible to report in straight volume measurements (l/s). Both terms appear in this report.

A number of geothermal operators worldwide have done short-term injection testing to determine the feasibility of injection as a means of geothermal fluid disposal. Other developments have implemented continuous injection for long-term waste disposal. Six specific case histories of developments that have practiced injection have been selected for presentation here. They are the Raft River KGRA in Idaho; the Salton Sea and East Mesa KGRAs in the Imperial Valley of California; the Otake and Hatchobaru fields of the Otake Geothermal Area on the island of Kyushu, Japan; and the Ahuachapan geothermal field in El Salvador. These sites were selected on the basis of their varied experiences with injection and the physical factors controlling injection at each site. Experiences at each of these sites have contributed significantly to our knowledge of geothermal injection, its controlling factors, and its hydrologic and operational effects.

3. RAFT RIVER, IDAHO

3.1. Introduction

The Raft River Valley is located within the North American Basin and Range Province in south-central Idaho (Figure 3.1). The Known Geothermal Resource Area (KGRA) lies in the southern portion of the Valley near the Idaho-Utah border. The thermal zone of the liquid-dominated geothermal system produces water and steam near 150°C.

The United States Department of Energy (formerly Energy Research and Development Administration), the Raft River Rural Electric Cooperative, and the Idaho Department of Water Resources jointly initiated drilling a geothermal exploration well at Raft River in 1975. The Raft River geothermal exploration well No. 1 (RRGE-1) encountered temperatures of 146°C, thereby verifying the existence of a hydrothermal resource.

A federally funded experimental geothermal program was initiated at Raft River to show that moderate-temperature geothermal fluids can be used to generate electricity and to provide energy for direct-use applications. A 5-MW electrical generation pilot plant tested a dual-boiling binary cycle using isobutane as the working fluid. Large volumes of geothermal water supplied the power facility as well as numerous research experiments. Direct-application research included a number of intensive experiments that also resulted in large quantities of spent fluid requiring disposal. Disposal involved the piping of cooled, geothermal fluid across the well field to holding ponds to await later injection.

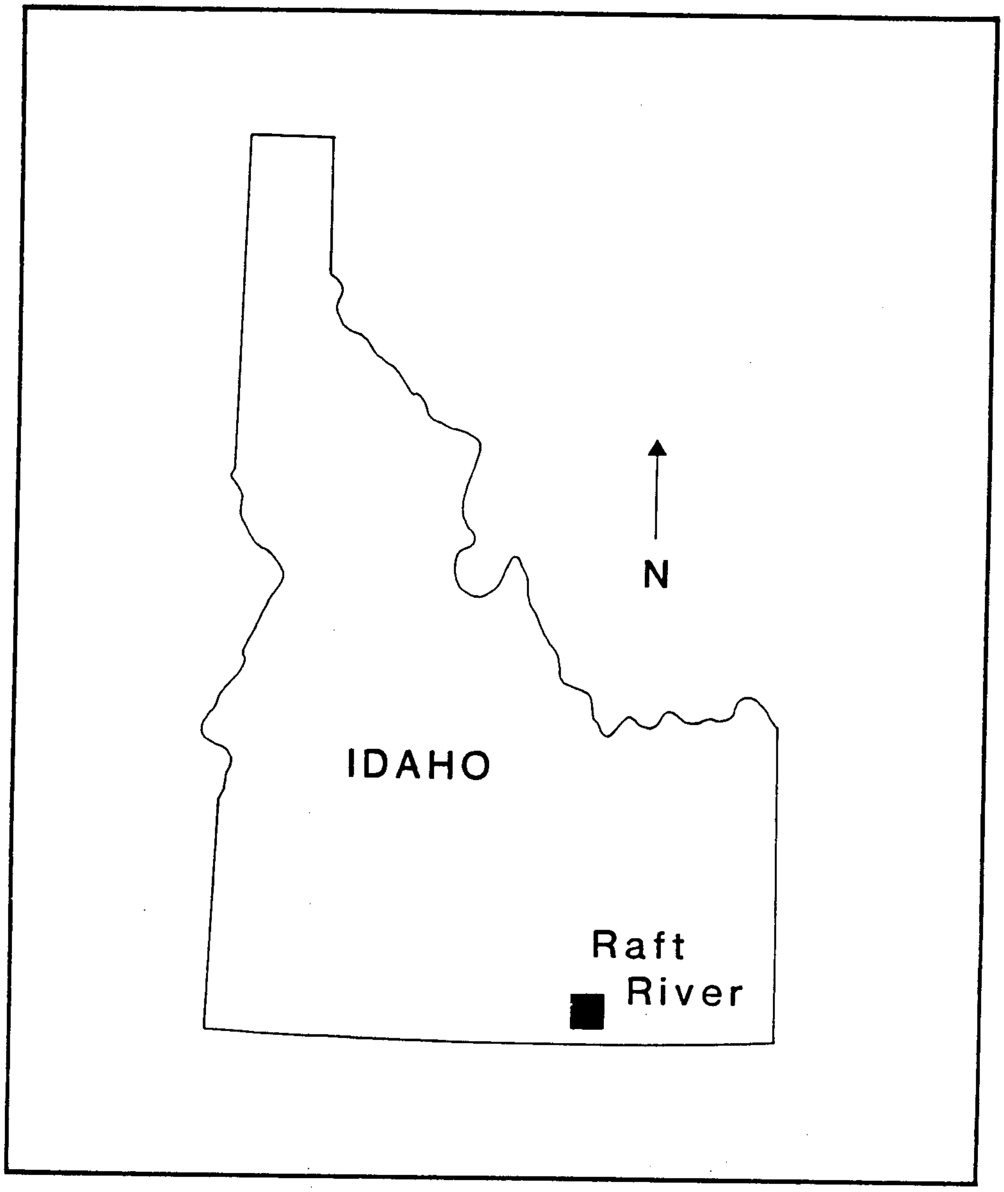

Figure 3.1 Location of the Raft River KGRA, Idaho.

The Raft River KGRA lies within an area designated by the Idaho Department of Water Resources (IDWR) in 1963 as a Critical Groundwater Basin. The designation means that additional long-term uses of the water resource will not be approved. This restriction protects the existing users of near-surface aquifers from the consequences of severe overdraft, such as degradation of water quality and excessive water level declines. Geothermal development, however, was considered by IDWR to be a temporary research project and did not require a long-term water use permit. Having begun early operations in 1974, the federally supported program ceased operating in December, 1982. The site is presently (1984) owned by a private corporation.

3.2. Geology

The Raft River Valley is a Cenozoic basin associated with Basin and Range geology in south central Idaho. In the Basin and Range Province, high ranges with complex structures are isolated from neighboring ranges by valleys that are filled with Cenzoic continental deposits. This geologic province is a desert area of low rainfall . The ranges are uplifted tilted blocks commonly bounded on one or both sides by normal faults that trend in a generally north-south direction. The region has a notably thin crust and abnormally high heat flow.

The Raft River Valley occupies part of the northernmost extension of the Basin and Range Province abutting the Snake River Plain. On the north, the Raft River Valley opens onto the Snake River Plain. The valley is bounded on the south by the Raft River Range, on the west by the Jim Sage and Cotterel Ranges, and on the east by the Black Pine Range and the Sublett Range (Figure 3.2). At the southern end of the Jim Sage Mountains, the Raft River enters the valley and flows northward. The KGRA is also at the southern end of the valley. The topography near the KGRA is characteristically alluvial fans and sediments at the edges of the Raft River flood plain (Dolenc et al., 1981).

The Raft River Valley near the KGRA is a downdropped basin with steep normal faults inferred at the rangefronts. The Bridge Fault Zone, on the west side of the valley, is a zone of principal faults exhibiting vertical displacement and steep dips. These features are exposed at the surface. The Horse Well Fault Zone is also a zone of steep normal faulting west of the Bridge zone that approximates the strike and dip of the Bridge zone (Dolenc et al., 1981)

North of the Raft River, both these fault zones terminate at a structure called the Narrows Zone, which is defined by anomalous geophysical data. The Narrows Zone trends northeast and is believed to be a basement shear (Mabey et al., 1978). The KGRA occurs at the intersection of this poorly understood Narrows structure and the Bridge Fault Zone. It is believed that hydrothermal waters circulate deeply along basement fractures, then rise locally at the intersection of the two major structures and spread laterally into Tertiary sediments. Hot water in shallow wells comes from upward leakage through fractures in deeper formations. There is no evidence of a local heat source (Mabey et al., 1978).

The lithology of the Raft River KGRA includes complex metamorphic and volcanic rocks as well as sedimentary sequences. The lithologic composition, structural characteristics and approximate thicknesses of

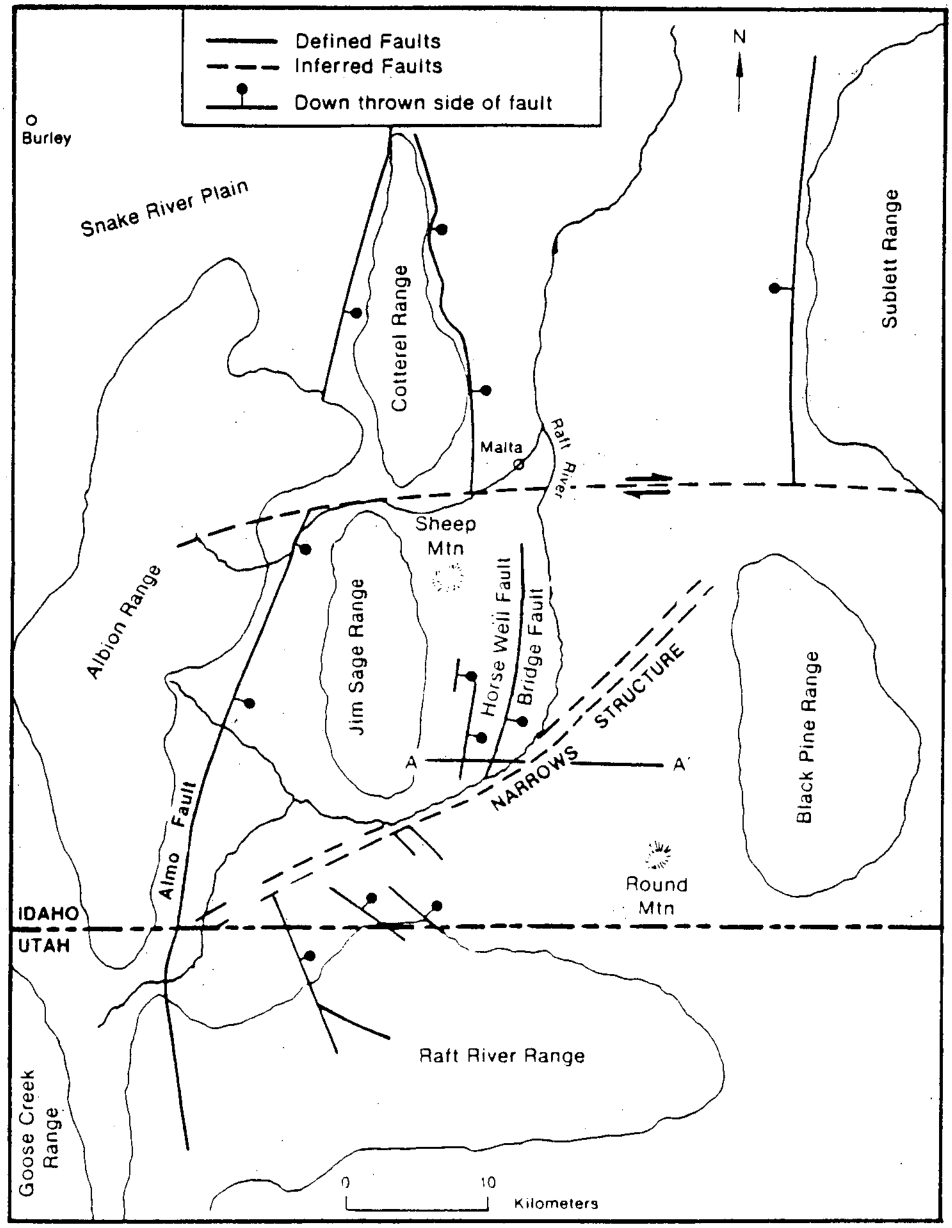

Figure 3.2 Regional geology and structure near the Raft River Valley, Idaho (from Dolenc et al., 1981).

these geologic units appear in Table 3.1. Figure 3.3 is a conceptual cross-section through the valley showing the relative position of these units.

3.3. Hydrology

The Raft River KGRA is a groundwater discharge area, although there is no visible discharge at the surface. The only hydrologic feature at the surface is the Raft River.

3.3.1. Surface Water

The Raft River drains northward through the valley to the Snake River. The designation as a river is a misnomer because it is more accurately an ephemeral stream.

3.3.2. Groundwater

Groundwater in the basin may be confined or unconfined in the unconsolidated sediments of the Salt Lake Formation or in sands and gravels of the Raft Formation and recent alluvial deposits. Recharge to these aquifers is either from local precipitation, from infiltration of local surface water and irrigation runoff, or from upward discharge from deeper aquifers.

The KGRA is a groundwater discharge area. Increasing hydraulic heads with depth indicate the net movement of water in subsurface aquifers is in an upward direction toward the surface. Most water below 300 m (meters) is confined, although localized confined conditions may exist at shallower depths. Heads in deeper aquifers range from 30 m to over 100 m above land surface in the geothermal vicinity. Most

Table 3.1. Geologic and hydrologic characteristics of formations at the Raft River KGRA, Cassia County, Idaho.[a]

Formation	Geologic Description	Hydrologic Description
Quaternary Alluvium and Colluvium	Uppermost sediments derived primarily from surrounding mountain ranges.	Shallow Aquifer: Extends from surface to about 180 m. Significant communication with deeper aquifers via fractures and faults. Receives discharging fluids from deeper units. MW-5, MW-7 completed in this aquifer.
Pleistocene Raft Formation	Poorly sorted angular, unconsolidated quartz sand and silt, tuff, minor rhyolite gravels; up to 300 m thick; fluvial and alluvial depositional environment. Replacement of primary calcite by silica; fracture filling by secondary calcite.	Upper Aquitard: Occurs from about 180-355 m. Less permeable than Shallow Aquifer; more permeable than Lower Aquitard. MW-4, MW-6, and possibly MW-3 completed in this aquitard. Lower Aquitard: Occurs from about 335-450 m. Hydrologically isolates Intermediate Aquifer from Shallow Aquifer and overlying Upper Aquitard, with respect to potentiometric heads. MW-1 completed in this aquitard.
Tertiary Salt Lake Formation	Lacustrine deposit up to 1600 m thick; increasing volcanic materials with depth. Primarily shales, siltstones, sandstones and tuff. Shales and siltstones thin-bedded to massive. Deformational structures include microfaults, breccias, ball and pillow structures, and convolute laminations. Replacement of primary calcite by silica; fracture filling by secondary calcite.	Intermediate Aquifer: Occurs from about 450-580 m. Sedimentary layers of sand and gravels; high transmissivity. Vertical communication with overlying aquitards and deeper Metamorphic and Basement Geothermal Aquifer along faults and fractures. No wells completed solely in this aquifer. Geothermal Aquitard/Aquifer: Located between 580-1700 m; fractured and consolidated sedimentary unit of variable thickness; spatially heterogeneous and anisotropic permeability; permeability controlled by fracture spacing, fracture zone widths, and secondary precipitation of calcite and silica; transmissivity greater in fault plane than in host rock. Serves as: 1) source of geothermal water for production wells; 2) sink for injection wells; 3) aquitard, reducing vertical leakage losses from injection aquifers and Metamorphic and Basement Geothermal Aquifer. Discharging flow pattern indicated by deteriorating water quality with decreased depth in vicinity of KGRA.
Precambrian Rock Assemblage (Metasediments and Adamellite Basement rocks)	Quartzites, schists, gneisses--gaulted metamorphic rocks overlying an adamellite basement.	Metamorphic and Basement Geothermal Aquifer: Begins anywhere from 1200-1700 m deep; fracture-dominated groundwater flow; believed to be principal source or local origin of geothermal fluid at Raft River KGRA. Discharges geothermal fluid to overlying units via vertical faults and fractures. Water enters wells from metasediments, adamallite after flowing from Jim Sage Mountains to Raft River floodplain.

[a]Allman et al., 1982.

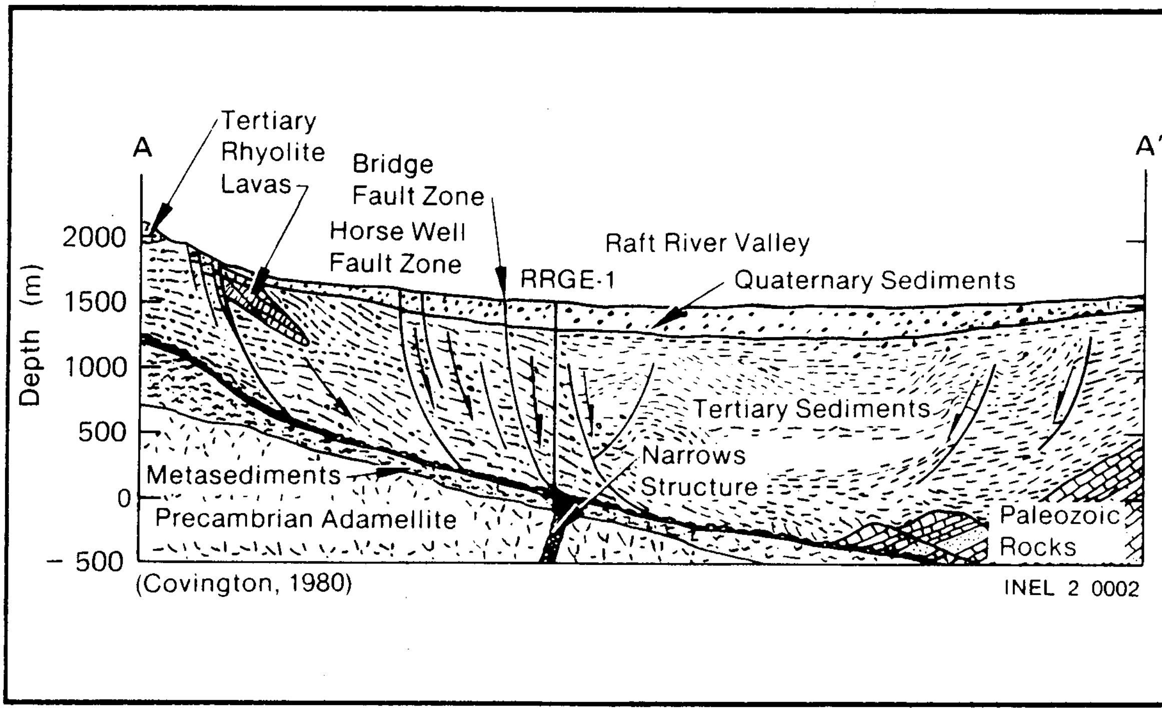

Figure 3.3 Conceptual interpretation of the Bridge Fault Zone in the Raft River KGRA (from Dolenc et al., 1981).

irrigation wells in the area show some chemical or thermal evidence of upward leakage from the deep geothermal resource (Spencer and Goldman, 1980).

3.3.2.1. Aquifers

Geologic units at the Raft River KGRA have been reorganized by Allman et al. (1982) into six hydrologic aquifer/aquitard units. These are:

1) The Shallow Aquifer
2) The Upper Aquitard
3) The Lower Aquitard
4) The Intermediate Aquifer
5) The Geothermal Aquitard/Aquifer
6) The Metamorphic and Basement Geothermal Aquifer.

These hydrologic units, their depths, and lithologies, and chemistry are briefly described in Table 3.1. Locations of wells in the KGRA are shown in Figure 3.4. Chemistry of fluids from various wells are presented in Table 3.2. Values reported are for the highest quality water obtained from each well (Allman et al., 1982).

The Shallow Aquifer has been extensively developed for domestic and irrigation uses. Hydrograph data from wells PW-3, MW-3, -5, -7, and USGS-2 indicate that yearly fluctuations of potentiometric head in most Shallow Aquifer wells correspond to annual irrigation and non-irrigation seasons (Allman et al., 1982).

In the KGRA, the Shallow Aquifer receives significant recharge from upward seepage through both nonindurated sediments and

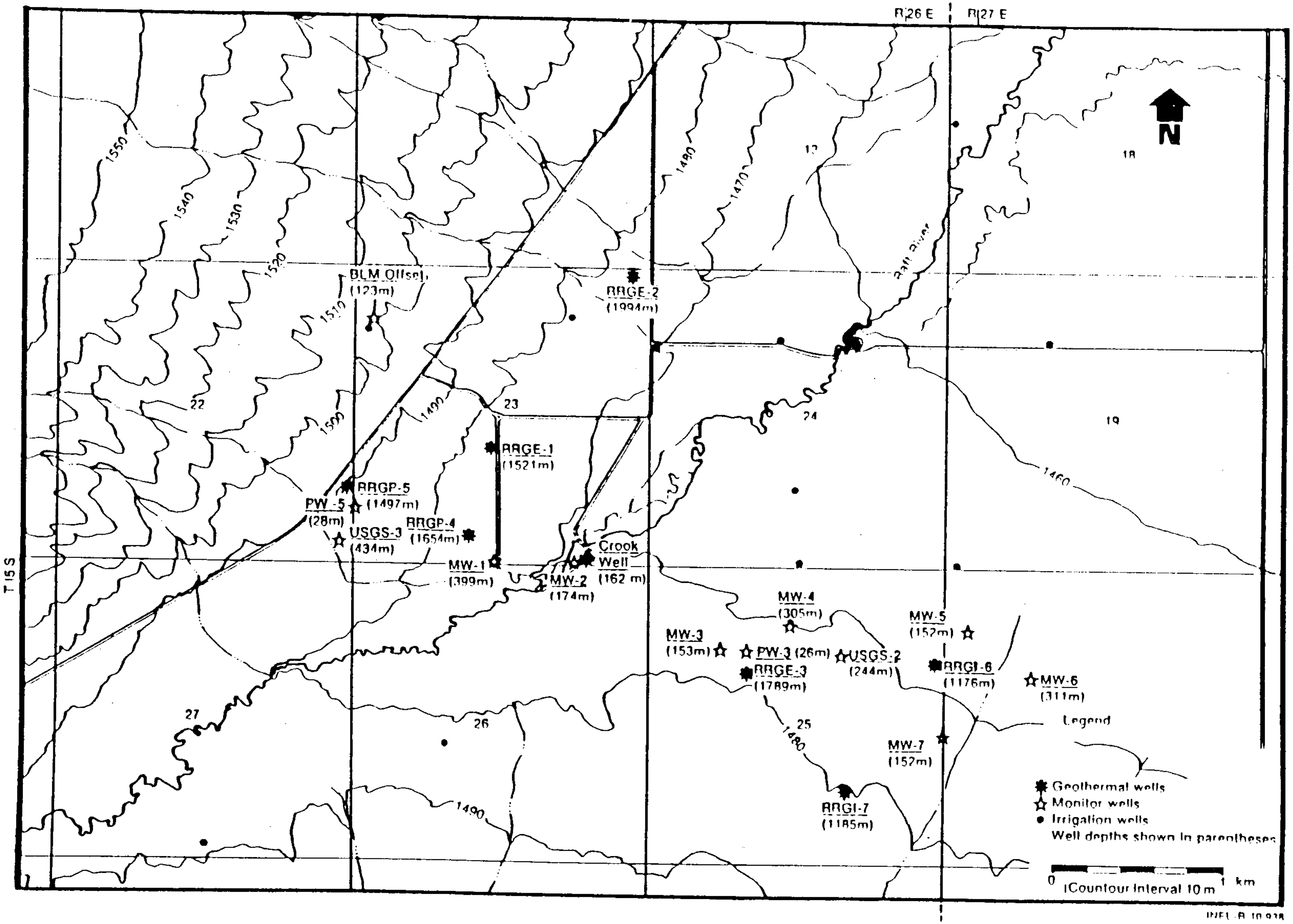

Figure 3.4 Locations of Raft River wells (from Dolenc et al., 1981).

Table 3.2. Selected physical and chemical characteristics of well waters in the Raft River Valley.[a]

Well	Depth[b] (m)		Maximum Borehole Temperature (°C)	pH	Concentration, mg/l									
	Well	Casing			Ca^{+2}	Mg^{+2}	Na^{+}	K^{+}	Li^{+}	HCO_3^{-}	SO_4^{-2}	Cl^{-}	F^{-}	SiO_2
Geothermal Wells														
RRGE-1	1521	1105	141	7.7			306			57		623	8.9	148
RRGE-2	1994	1289	144		32	0.5	336	32	1.0	61	56	592	9.9	153
RRGE-3	1789	1293	149	6.9	224	0.5	1193	105	3.1	44	60	2260	4.9	164
RRGP-4	1558	1049	142	7.4	147	0.2	1524		3.1	42		2580	4.5	136
RRGP-5B	1497	1034	135	7.5	41	0.1	484	31	1.6	35	40	800	7.2	154
RRGI-6	1176	509	107	7.2	171	1.4	2200	32	5.1	73	60	3640	5.7	134
RRGI-7	1185	623	122		350	1.5	2200			32	64	4000	4.9	127
Monitor Wells														
MW-1	399	369		7.6	215	0.4	2200	30	3.7	25	66	3680	3.4	125
MW-2	174	154	106	7.4	125	0.5	1000	25	2.5	26	57	1740	5.4	130
MW-3	153	140	71	7.5	155	6.3	1400	65	3.0	47	60	2460	5.4	111
MW-4	305	225	97	7.7	160	0.6	1520	31	3.7	27	53	2610	5.6	116
MW-5	152	124	28	7.6	107	25.0	280	14	0.3	120	27	610	0.6	
MW-6	311	274	44	7.3	207	2.4	1570	56	3.1	50	73	2770	4.9	
MW-7	152	140	35	7.6	95	20.2	333	14	0.6	125	33	650	4.9	
USGS Monitor Wells														
USGS-2	244	64	59	7.7	51	4.0	370	34	6.6	216	55	520	2.5	130
USGS-3	434	60	89	7.7	57	0.5	1270	14	1.7	61	54	2040	4.8	105
Other Geothermal[c]														
BLM[d]	123		93	7.4	44	0.7	577	21	1.4	49	65	890	7.6	120
Crook[e]	165	45	97	7.7	130	0.8	1020	32	2.6	34	56	1750	6.2	127

[a] After Allman et al., 1982.
[b] Depth to bottom of casing or to first perforations.
[c] Temperature measured at the surface.
[d] Called the Bridge well by USGS.
[e] Referred to as the Crank well in earlier publications.

faults/fractures from the underlying geothermal system. The greatest geothermal flow upward to the shallow system appears to be centered in the vicinity of the Crook Well, MW-2, and MW-3, where the intersection of a multiple fault system paralleling the Jim Sage and Raft River Mountains may create an area of greater vertical permeability.

Water quality in the Shallow Aquifer, as measured by dissolved constituents and temperature, is affected by discharge from the underlying geothermal system. Shallow domestic wells appear less affected chemically (i.e., have lower specific conductance) by this geothermal discharge than the slightly deeper irrigation wells, probably because of high quality local recharge from precipitation and surface water infiltration. Selected chemical values for wells in the Shallow Aquifer appear in Table 3.2. The poorest quality water in the Shallow Aquifer is around the Crook Well, MW-2 and MW-3.

Temperature in the Shallow Aquifer peaks near MW-2 and MW-3. Thermal gradients of wells in the Shallow Aquifer range from 0.011 to 0.030°C/m, with the exception of MW-2. MW-2 is believed to represent the Intermediate Aquifer via a fault, so the low thermal gradient in MW-2 is attributed to its proximity to the higher-temperature center of geothermal recharge to the Shallow Aquifer (Allman et al., 1982).

The aquitard separating the Shallow Aquifer and the Intermediate Aquifer consists of two units. The Upper Aquitard is less permeable than the Shallow Aquifer but more permeable than the Lower Aquitard. Each of these is described briefly in Table 3.1. The Lower Aquitard hydrologically isolates the Intermediate Aquifer from the Shallow Aquifer and overlying Upper Aquitard and separates zones with different potentiometric heads. For instance, wells monitoring the Intermediate Aquifer (MW-1, -2, -4, USGS-3, BLM offset) exhibit higher groundwater potential than wells monitoring the Upper Aquitard (MW-6) or Shallow Aquifer (PW-3, -5, MW-3, -5, -7, and USGS-2). This difference in head supports the conclusion that the Lower Aquitard is a barrier to upward flow of geothermal fluids from the Intermediate Aquifer (Allman et al., 1982). However, there is evidence the aquitard is leaky and allows some transport of fluid across it.

Groundwater quality of the Lower Aquitard degrades locally and with depth reflecting poorer-quality fluids migrating upward from the underlying Intermediate Aquifer. The distribution of specific conductance in the Lower Aquitard results from the upward leakage of geothermal fluid, the chemical reaction of groundwater with the fine-grained host rock during long residence time, and the dilution with local recharge. The Upper Aquitard, in turn, receives poor quality fluid from the Lower Aquitard, as well as fluid from the lateral flow of groundwater in both the Upper Aquitard and Shallow Aquifer. Representative chemical values for these aquitards appear in Table 3.2.

Leakage of geothermal fluid from the Intermediate Aquifer through the Lower Aquitard appears to occur via porous media flow and faults crossing the aquitard. Convection and conduction of heat from the Intermediate Aquifer and by lateral transport in the Upper Aquitard significantly influences temperatures in the Upper and Lower Aquitards (Allman et al., 1982). Shut-in temperature profiles (Allman, 1982) indicate that groundwater temperature in the Upper and Lower Aquitards decreases toward the surface.

The Intermediate Aquifer is in the Tertiary Salt Lake Formation. Its depth and geologic description appear in Table 3.1. Wells believed to be monitoring the Intermediate Aquifer include MW-1, -2, -4, USGS-3, the Crook Well, the BLM well, and the BLM offset well. Discharge of geothermal fluid from the Intermediate Aquifer to the overlying aquitard occurs in the vicinities of MW-2, -4, the BLM well, and the Crook Well. These wells are not completed in the Intermediate Aquifer, but data suggest they monitor the potentiometric head regime and water quality of this deeper aquifer. These data may be modified somewhat by leakage and potentiometric head changes in the Shallow Aquifer or in the interval separating the wells from the top of the Intermediate Aquifer. Geochemical data for the Intermediate Aquifer are suspect because of the absence of monitor wells completed entirely within the aquifer.

Temperature data for the Intermediate Aquifer are also unavailable. Temperatures throughout the Intermediate Aquifer are believed to be fairly uniform except where geothermal fluid from the Metamorphic and Basement Geothermal Aquifer leaks upward along hydraulically continuous faults. A thermally-induced convective flow system contributes to this uniform temperature phenomenon and to a reduction in lateral thermal gradients.

The geology, depth and fluid chemistry of the sedimentary Geothermal Aquitard/Aquifer are described briefly in Tables 3.1 and 3.2. Each of the geothermal production and injection wells appears to at least partially penetrate the Geothermal Aquitard/Aquifer.

The unit has three principal hydrologic functions. First, it contains considerable amounts of tuff that retard vertical porous media flow so that the unit as a whole behaves as an aquitard. Second, it is a source of geothermal water for production wells and thus is an aquifer. Interbeds of sandstone and silt function as aquifers for horizontal flow. Vertical interconnection of these aquifers is presumably poor except where transecting faults permit vertical flow. Faults are conduits of vertical geothermal fluid flow from the Metamorphic and Basement Geothermal Aquifer. Finally, the Geothermal Aquitard/Aquifer functions as a permeable hydrologic unit that will accept injected fluids. Although the Geothermal Aquitard/Aquifer is breached by numerous faults, greater potentiometric heads in wells penetrating the underlying Metamorphic and Basement Geothermal Aquifer suggest leakage losses upward are minimal.

In wells penetrating the Geothermal Aquitard/Aquifer, specific conductance increases with decreasing depth and clearly suggest a discharge area in the vicinity of the KGRA. Geothermal fluid is migrating upward and deteriorating water quality in the unit (Allman et al., 1982). Temperature data indicate that higher temperatures at shallower depths appear to be occurring in the vicinity of the KGRA. This phenomenon is also evidence of a discharge area.

The Metamorphic and Basement Geothermal Aquifer is described briefly in Table 3.1. The fractured portion of this aquifer contributes significant amounts of geothermal fluid to each of the production wells in the KGRA, except perhaps RRGE-3 (Allman et al., 1982).

Potentiometric surfaces for the Metamorphic and Basement Geothermal aquifer are higher than in overlying aquifers. Potentiometric surface data for production wells indicate that groundwater flow in the production zone is from NW to SE (Allman et al., 1982). Chemical, hydrologic and temperature data indicate the Metamorphic and Basement Geothermal Aquifer is the primary conveyer of geothermal fluid from a recharge area to the NW to the KGRA (Allman et al., 1982). Conductive heat transfer in rock masses near the KGRA may be heating the water in transit.

3.3.2.2. Groundwater Chemistry

Wellhead water quality data for RRGE-1, RRGE-2, and possibly RRGE-3 and RRGP-5 are dependent on the discharge history of each well. Selected chemical analyses from wells penetrating the various hydrologic units in the KGRA are presented in Table 3.2. These values represent the highest quality measured in each well (Allman et al., 1982). Since the wells are in a discharge area, the upgradient, deep wells have higher quality fluid than overlying aquifers. Additional chemical data are available in reports by Allman et al. (1982), Spencer and Callan (1980) and Dolenc et al. (1981).

Each of the deep geothermal wells produces sodium-chloride type waters. The low values for alkalinity range from 26 to 60 mg/l (milligram per liter) as $CaCo_3$. Total dissolved solids vary substantially among wells.

Wells RRGE-1, -2 and RRGP-5 have similar chemical properties and contain the highest concentrations of fluoride (>7 mg/l). Fluoride levels in the geothermal fluids are of concern because they exceed the recommended drinking water levels of <1.0 mg/l. The geothermal fluid disposal system must take precautions against excessive fluoride contamination of potable water supplies.

The variability of conductance in different wells suggest there are two sources of water entering the valley. Dolenc et al. (1981) present a conceptual model that indicates water containing high dissolved solids moves in from the southeast along deep basement fractures. It is heated while passing over a heat source and rises by convection to the surface near the Crook Well. Meteoric water containing low dissolved solids enters from the northwest, heats, and rises along the Bridge Fault near the BLM well (Fig. 3.5). Mixing of these two waters can explain the chemical variation among geothermal wells.

There is concern for the future quality of shallow groundwater supplies based on the conceptual model. The injection zone at the KGRA is located in the plume where water with high dissolved solids and other chemical species, such as fluoride occur in the shallow groundwater.

3.3.3. Geothermal Resource

The geothermal resource at Raft River is a fracture-controlled, liquid-dominated, moderate-temperature hydrothermal system that produces water and steam near 150°C. Geologic structure controls the expression of the thermal reservoir in the Raft River Basin. Data presented by Dolenc et al. (1981) suggest the thermal production reservoir is:

(a) controlled largely by fractures found at the contact between the metamorphic rock sequence and the Salt Lake Formation at

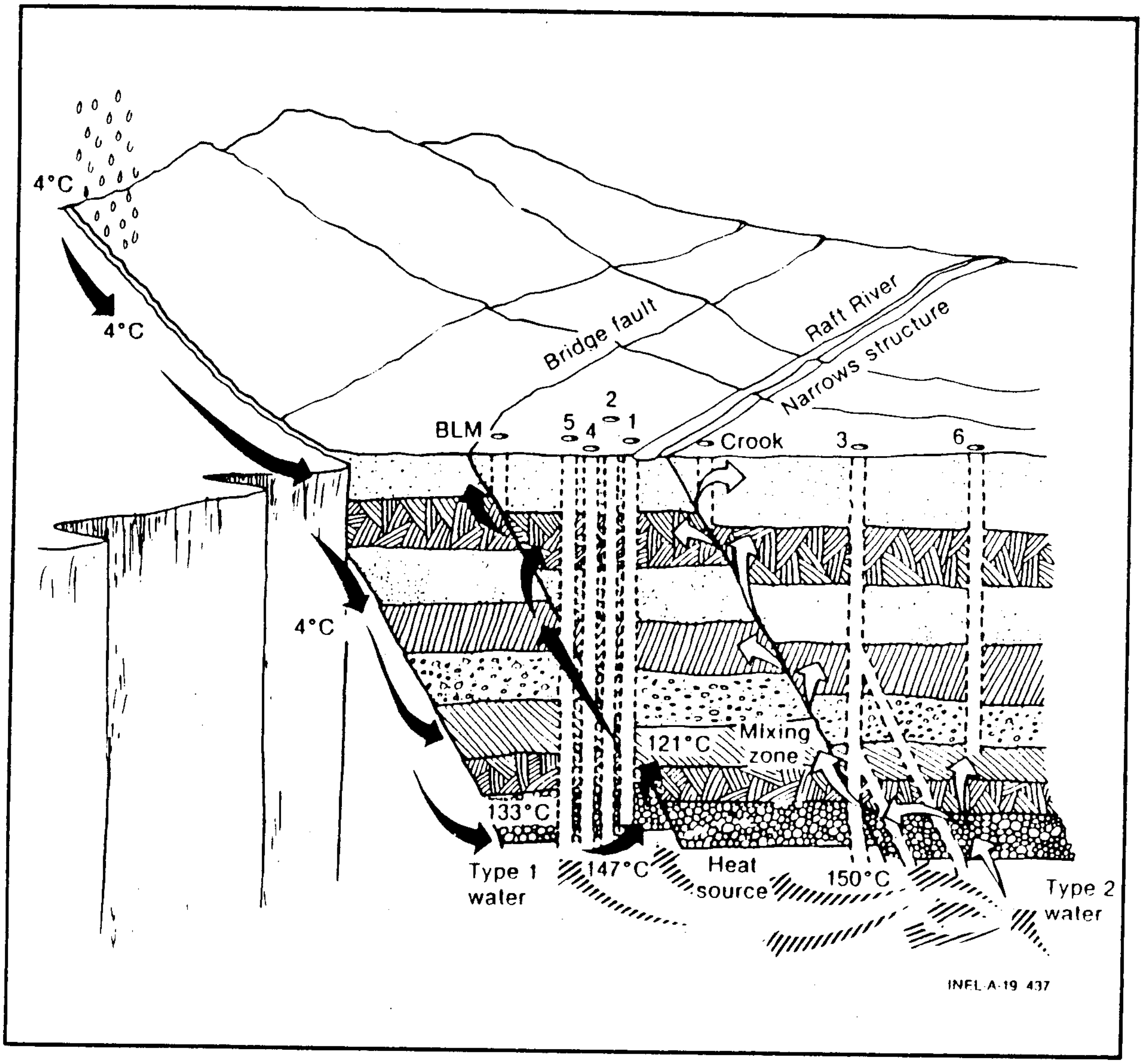

Figure 3.5 Conceptual model of flow in the Raft River KGRA, Idaho (from Dolenc et al., 1981).

the base of listric normal faulting of the Bridge and Horse Well Fault zones

(b) anisotropic, with the major axis of hydraulic conductivity coincident to the Bridge Fault Zone;

(c) hydraulically connected to the shallow thermal fluids (based upon both geochemistry and pressure response); and

(d) controlled by a mixture of diluted meteoric water recharging from the northwest and a saline chloride water entering from the southwest. (Russell, 1982, p. 6)

The KGRA is located at the intersection of the Narrows Zone and the Bridge Fault Zone. The conceptual model suggested by Dolenc et al. (1981) indicates that deep basement fractures are probable paths for circulating hydrothermal water that eventually rises at the intersection of these two major structures. The hydrothermal water then spreads laterally into Tertiary sediments. Considerable vertical fracturing in the Salt Lake Formation permits upward leakage of hot water to shallow hot wells in the valley (Crook and BLM wells).

3.4. Injection

Subsurface injection of waste fluids at the Raft River KGRA was planned because of environmental concerns associated with surface disposal of geothermal waters. Injection testing revealed several technical constraints as well. These will be described in the following subsections.

3.4.1. Injection System

There are seven geothermal wells in the Raft River KGRA (Fig. 3.4). RRGE-1, -2, -3 and RRGP-4 and -5 are production wells. They are drilled to depths of approximately 1500-2000 m from ground surface. RRG1-6 and -7 are injection wells drilled to 1185 m. The completion intervals of the injection wells overlaps slightly with those of production wells RRGE-1, RRGP-4 and -5. All the wells are completed in the Geothermal Aquitard/Aquifer. The open intervals of RRGE-2 and -3 are slightly below those of the injection wells.

The injection wells are located on the eastern edge of the wellfield, nearly 1 km from RRGE-3 and nearly 3 km from the other producing wells. The configuration of the wellfield is thus a side-by-side arrangement (as opposed to interspersed) of widely spaced production/injection wells whose injection intervals are somewhat above production intervals and overlap slightly in the same reservoir.

The original design for production and injection at Raft River was a closed system. Reasons for designing a closed system included minimizing cooling of geothermal fluid prior to injection, reducing the possibility of chemical precipitation, and preventing consumptive water loss via evaporation. Spent fluid from power generation was pumped via a pressurized pipeline directly into the injection wells. Problems with coordinating production flows for simultaneous injection resulted, and malfunction of the network forced shutdowns of operation. The failure of submersible pumps in production wells was another operational difficulty associated with the closed system.

Modification to an open system in 1981 allowed independent operation of the production and injection systems. Waste fluid flowed directly into an open pond. The cooled water (30°C) did not decrease fluid injectivity. Neither did suspended particulates increase enough to decrease injectivity. Line-shaft geothermal pumps replaced submersible geothermal pumps in July, 1981, and operated satisfactorily (Allman et al., 1982).

3.4.2. Monitoring Program

The monitor well program at Raft River was designed to monitor potentiometric water levels and water chemistry in order to predict and evaluate the effects of geothermal development on the Intermediate Aquifer. Seven monitoring wells (MW-1 through MW-7) are located near the geothermal production and injection wells (Figure 3.4). Other monitoring wells include three USGS wells (USGS-2, -3, and BLM offset) and four 30-m water table wells near RRGE-3 and RRGP-5.

Varying locations and depths of the monitoring wells were planned to detect any aquifer response to geothermal injection and to determine the degree of communication between the geothermal system and shallower aquifers. Conditions within the monitoring wells differ. Each of the wells is cased to within 10 to 50 m of total depth so that selected aquifers can be monitored.

The monitoring program emphasizes measuring wellhead pressure or water levels since these are expected to respond to hydrologic changes more rapidly than water quality. MW-1 and MW-2 are equipped with digiquartz pressure transducers, and USGS-3 has a Bristol recorder.

Remaining wells are equipped with Stevens A35 or F water level recorders. MW-4 has water level at ground level, so it has a dual system (Spencer, 1979)

3.4.3. Injection Testing

A variety of single-hole and multiple-hole injection tests were done at Raft River. Numerous parameters were measured in attempts to define the reservoir and flow system, predict its behavior over the long-term, identify potential problems in the injection system, and to predict regional effects attributable to geothermal development. Tests were performed with particular interest in the long-term effects of injection on the shallow aquifers. This section describes several types of monitoring and testing procedures used.

A seismic network was established at Raft River to collect baseline data and to monitor seismic activity during geothermal field testing, production, and injection (Thurow and Cahn, 1982). The seismic study concluded that there is an absence of macroseismic and microseismic activity normally associated with the seismically active Basin and Range Province. Seismically, the KGRA is more closely related to the less active Snake River Plain. The low levels of background seismicity in the KGRA indicates the area is a low-stress enviornment. Earthquake activity is not likely to be induced by the relatively small-scale injection activity at Raft River (Thurow and Cahn, 1982).

A surveying grid was established in 1975 to monitor potential subsidence caused by geothermal fluid withdrawal. The valley has a history of aquifer compaction and resulting subsidence in response to excessive fluid withdrawals for irrigation. However, no detectable elevation changes have resulted as a result of geothermal production or injection at Raft River (Thurow and Cahn, 1982).

In 1982, resistivity and self potential (SP) surveys were done during injection testing at RRGP-5 using RRGE-3 as the production well. Data indicated downhole fluid movement and migration in a northeasterly direction, presumably along a fracture extending from depth at the reservoir (1400 m) to near the surface (100 m deep) (UURI, 1983; Sill, 1983a and 1983b). Responses were too close to the noise levels of the instrumentation to conclude absolutely that these methods are useful for monitoring subsurface fluid movement. However, the local geology has NE-trending faults around the Narrows Structure and the Bridge Fault Zone, and SP and resistivity data closely follow these structures (UURI, 1983).

Temperature is a difficult-to-control parameter that may induce errors in pressure measurements whenever temperature changes exceed 0.006°C/min. Three pressure measuring devices were required at production and injection wells to obtain good quality pressure data during aquifer tests. Wellhead pressures for RRGI-7 were measured during the period August 9-15, 1979. The data were used to predict wellhead pressures resulting from long-term injection (Table 3.3). Demuth (1980) believes the predictions for wellhead pressure after long-term injection of 66°C water are the best estimates available based on historical temperatures and hydrologic properties of the Raft River Reservoir.

Multiple-well pressure testing during injection occurred from March 21 - June 10, 1978. An estimated 12,800 m^3 of water was injected

Table 3.3. Predictions of wellhead pressure resulting from long-term injection.[a]

Injection Temperature °C	Injection Flow l/s	Wellhead Pressure At 1 Year Pa[b]	Wellhead Pressure At 5 Years Pa[b]
129	28	1.13×10^6	1.16×10^6
129	63	2.02×10^6	2.09×10^6
129	79	2.42×10^6	2.51×10^6
66	63	3.45×10^6	3.65×10^6
66	79	4.31×10^6	4.49×10^6

[a] Converted from Demuth, 1980.

[b] Pascal: 1 Pa - 1 N/m^2 - 1.45×10^{-4} lb/in^2

into RRGI-4 (RRGP-4 became RRGI-4 after a brief conversion to an injection well) at rates of 16 to 15 l/s. The well bore was open from 550 to 850 m. The longest test during this period was 9 days injecting at 44 l/s. Pressure increases at USGS-3 (434 m deep) and MW-1 (399 m deep) were larger than expected and exceeded these wells' responses to seasonal hydrologic changes and to past geothermal development activity. The pressure increases were 34 kPa in MW-1 and 97 kPa in USGS-3. The difference in magnitude between the two wells suggests the intermediate aquifer system is both heterogeneous and anisotropic (Spencer, 1979).

During the same period, a 21-day test injecting 38 l/s was performed at RRGI-6. RRGI-6 is uncased from 516-1185 m. MW-4 (305 m deep) showed a definite pressure response with water levels rising about 0.4 m/week. MW-6 (305 m deep) showed no response. There were no true hydrologic responses in other monitor wells. The difference in responses of wells drilled to similar depths indicates the system is fracture-dominated (Spencer, 1979).

In September, 1982, a series of short-term injection and backflow tests followed by a longer-term injection test were done on RRGP-5, using RRGE-3 as the supply well. Tracer tests were done in conjunction with the geophysical testing discussed previously in this section. Tracers were added during injection and monitored during backflow in an attempt to determine their effectiveness in assessing reservoir characteristics in a one-well injection/backflow test.

In a pre-test operational check, approximately 96% of the injected tracers were recovered, indicating excellent operational control or testing. Two series of parametric tests were done together with the evaluation of assorted tracers. The first series tested the effect of increased volume of injected fluid. The second series examined the effects of extended delays between injection and backflow. A long-term injection test was intended to determine if tracer breakthrough could be obtained in a second well, RRGE-1, which is known to have a pressure connection with RRGP-5.

Three natural, conserved (i.e., unreactive with the geological formations present in the study area) tracers under conditions at Raft River are sodium, potassium, and chloride. Average backflow recovery of Na, K and Cl in one of the tests was 99%. As total volume of backflow increased, the fraction of injectate in the recovered fluid decreased, based on all three tracers. Final results of the first test series indicated that a large volume of backflow relative to volume of injectate is necessary for complete recovery of injectate. Approximately eight volumes of backflow were required to fully recover the tracer (UURI, 1983).

Downhole conductivity surveys done during injection indicated little or no mixing occurred between the tracer solution and the reservoir water within the confines of the wellbore. As the volume of injectate increased, however, mixing increased within the reservoir. Complete displacement of native reservoir fluids had not occurred after 96.5 hours of injection. Small amounts of native fluid began to return almost immediately upon backflow. Data suggested mixing of injected fluid with reservoir fluid was occurring in an orderly fracture system, rather than in a restricted flow area of an infinite aquifer as suggested by pressure data (UURI, 1983). The second test series had less definitive results. Fluid movement in the reservoir occurred in the quiescent period between termination of injection and initiation of backflow, however, the nature of the movement could not be conclusively assessed with available samples and data (UURI, 1983).

During the long-term injection/tracer test, the expected tracer breakthrough to well RRGE-1 did not occur. Neither was there any pressure response in RRGE-1 during any of the injection/backflow tests on RRGP-5. A complete analysis of the flow system around RRGP-5 was thus impossible.

In late October and early Novemeber, 1981, a two week series of tests were done to evaluate the entire production-electrical generation-injection system at Raft River. Geochemical investigations focused on suspended solids (SS) and the formation of chemical precipitates.

Cooling and loss of CO_2 are two processes associated with injection that can cause chemical precipitation. At Raft River, early cooling occurred in the holding ponds. Water was injected at about 40°C. Calcite supersaturation is unlikely to occur at these low temperatures; however, cooling Raft River water does result in water supersaturated with silica. Reaction rates for silica precipitation slow considerably below 100°C, so silica precipitation in the ponds was not expected to be a problem. No evidence of silica precipitation was apparent during testing. It is conceivable that higher temperatures in the receiving zone would accelerate silica precipitation, although loss of permeability in the aquifer material would occur slowly. Elevated temperatures in the injection zone would also reduce the solubility of calcite (Hull, 1982).

Corrosion in the injection well is a two-fold problem. First, the injection well casing deteriorates and may eventually allow contamination of cased shallow aquifers by injected fluid. Second, the reaction of free iron with silica forms a solid precipitate capable of clogging the well. The only tests done to evaluate corrosion potential during the two-week October-November, 1981, testing period were measurements of dissolved oxygen (Hull, 1982). Dissolved oxygen concentrations remained low throughout testing at RRGI-6. Concentrations rose at the beginning of tests at RRGI-7, then declined. According to Hull (1982), even low, steady concentrations of dissolved oxygen of only a few tenths of a mg/l would accelerate corrosion.

3.4.4. Constraints on Injection

Generally speaking, injecting waste fluids minimizes the potential for contaminating surface waters, reduces the risk of subsidence, and may extend the life of the geothermal resource by maintaining reservoir pressure. In some cases, injection may be a means of gleaning more heat from reservoir rocks. The primary concern at Raft River is whether injection will affect quality or quantity of water in shallow aquifers of the administratively closed groundwater basin. Geophysical and geochemical data indicate the Raft River resource is fracture-controlled and that there is already a natural upward migration of poorer-quality geothermal fluids into shallower aquifers. Should injection increase this upward flow, the Shallow Aquifer could experience an increase in temperature and a decline in water quality. Chemical contamination of injection receiving zones is not a concern, based on water quality of these zones.

There were several technical problems associated with injection at Raft River KGRA. The presence of submersible or turbine shaft pumps in the wellbores of most exploration, production or injection wells limited the acquisition of downhole data. Much data collection was limited to the wellhead or to the pipeline from production to injection wells. Thermal shock in the transite pipeline caused extensive damage to the pipe. It became necessary to discharge warm water through the pipeline prior to pump testing in order to condition the pipeline for extreme temperatures and pressures.

Regulatory constraints also exist for the Raft River KGRA. The Idaho Department of Water Resources (IDWR) declared the Raft River Basin to be a critical groundwater area in 1963. This designation restrains further groundwater development for consumptive use. The inception of geothermal development at Raft River thus raises questions concerning protection of quality and quantity of the region's limited water supplies. Long term geothermal development may be dependent upon purchasing and transferring existing water rights.

3.5. Summary

The Raft River geothermal project began as federally funded experimental research on the development of medium temperature geothermal resources. It is now owned by a private corporation.

The Raft River Valley is a downdropped basin located in the northern section of the Basin and Range geologic province. The lithology at the KGRA includes complex metamorphic and volcanic rocks as well as sedimentary sequences.

The Raft River KGRA is a groundwater discharge area exhibiting increasing hydraulic heads with depth. There is natural upward fluid migration along fractures from deep aquifers.

The Geothermal Aquitard/Aquifer, located between 580-1700 m below the surface, is the producing aquifer for geothermal fluids and the receiving aquifer for injected liquid wastes. The injection horizon is located above the producing horizons, but open intervals of injection wells and some production wells overlap slightly. Injection wells are located in a side-by-side arrangement 2-3 km from most production wells except RRGE-3, which is about 1 km away.

The geothermal resource is a fracture-controlled, liquid dominated hydrothermal system producing water and steam up to 150°C. The geothermal fluids contain elevated concentrations of fluoride (7-10 mg/l in some wells). Concern that upward migration of injected fluids might occur prompted extensive testing at Raft River. A shallow monitoring system and a variety of single-hole and multiple-hole injection tests were used to test the effects of production and injection at Raft River. Experimental injection testing included multiple-hole geophysical surveys, tracer tests, and pressure responses, as well as single-hole pressure responses, injection-backflow tests, and near-well chemical effects. Numerous technical problems interrupted and complicated injection testing, but a wealth of information about the operational and hydrogeologic systems was obtained.

4. IMPERIAL VALLEY, CALIFORNIA

4.1. Introduction

Southern California's Imperial Valley contains nearly one-third of the United States' identified hot water resources (Fig. 4.1). Several designated Known Geothermal Resource Areas (KGRAs) in the valley report temperatures ranging from 90-360°C.

The Valley is one of the most productive agricultural regions in the world. Its warm climate and approximately 475,000 acres of irrigated land enable a 365-day growing season essential for year-round food production in the continental United States. The Colorado River yearly provides over 2,800,000 acre-feet of irrigation water to the Valley. This water is conveyed through the All-American Canal and distributed via an elaborate irrigation and drainage system that ends at the Salton Sea (Butler and Pick, 1982). Over-watering of crops helps remove undesirable salts. Most irrigation water is removed by the drainage system, but some saline water percolates through the soil to recharge groundwater.

The inevitable production of liquid wastes during geothermal development and operations requires an acceptable means of disposal. The policy of Imperial County currently favors the full injection of residual geothermal fluids into the geothermal reservoirs. This policy primarily intends to protect against potential land subsidence resulting from fluid withdrawal and decreased reservoir pressures (Butler and Pick, 1982). Injection is also a means of preventing waste fluids of very high salinities from reaching crops or surface waters.

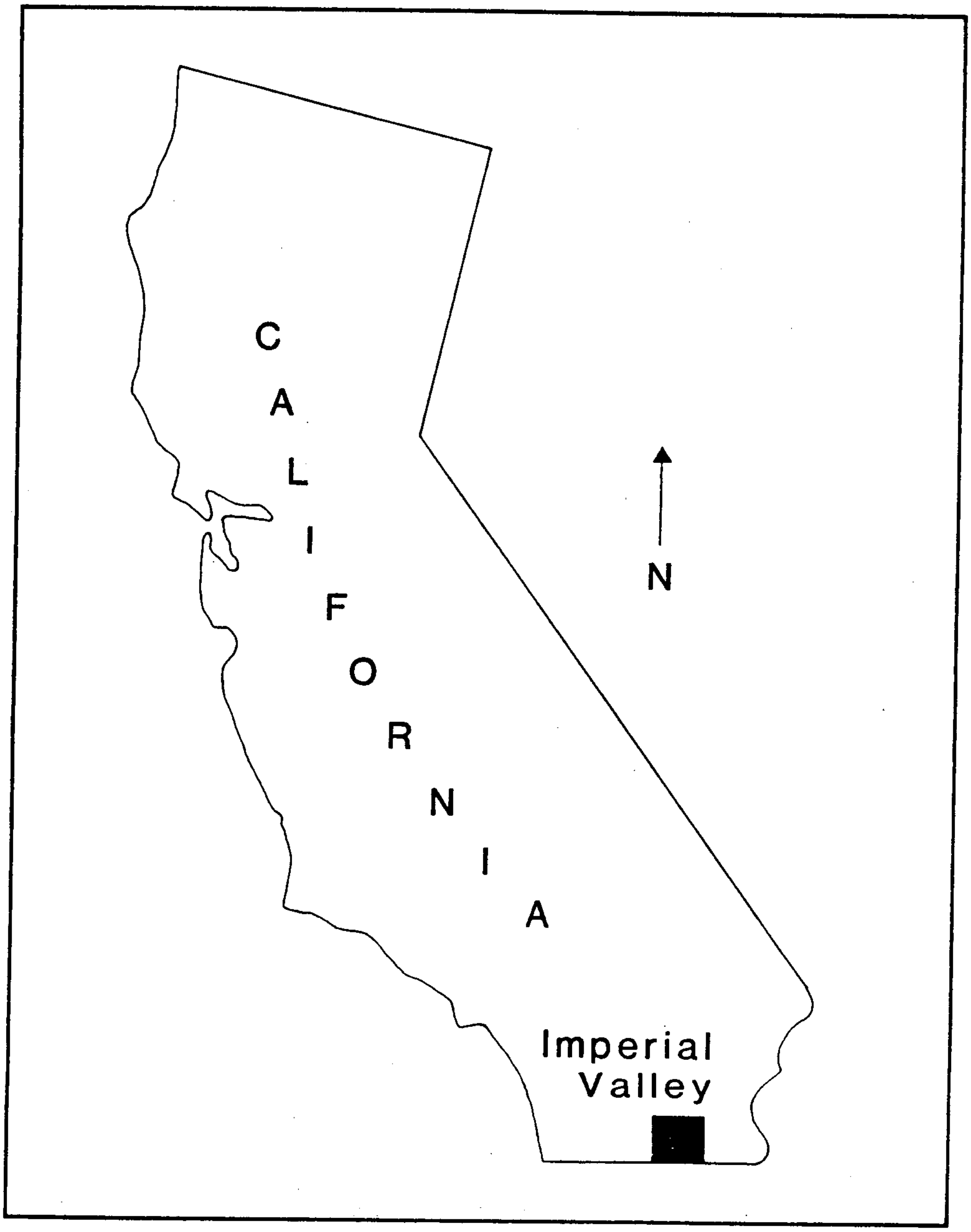

Figure 4.1 Location of the Imperial Valley, California.

Two KGRAs in the Imperial Valley have undergone short-term injection testing prior to completion or operation of new thermally powered electrical generating plants. Results of investigations at the East Mesa KGRA and the Salton Sea KGRA will be jointly considered for the purpose of this study.

4.2. Geology

The Imperial Valley occupies a portion of the Salton Trough, a geologically recent complex rift valley lying in the northerly extension of the Gulf of California. Coastal California mountains border the trough in the west, and low, block-faulted mountain ranges (the Chocolate Mountains) border it on the east (Fig. 4.2). To the north, the valley is occupied by the Salton Sea, which has a surface elevation of about -70 m. Complex strike-slip fault zones of the San Andreas fault system trend northwest through the valley. There is both substantial horizontal as well as vertical movement of the San Andreas fault zone in this region. A great deal of seismic activity occurring in the region is attributed to crustal displacements. Much of this seismic activity occurs in the vicinity of geothermal anomalies.

The Salton Trough has continuously subsided for approximately the last 10 million years, and by doing so has accumulated primarily detrital sediments ranging in thickness from 1500 m in the north to 6000 m at the Mexican border to the south (Van de Kamp, 1973). These sediments have been provided by the ancestral Colorado River, which for this entire period has discharged into the Trough from the east. Resulting sediments are complex interbedded lenticular beds of sand, silt and mud. Most

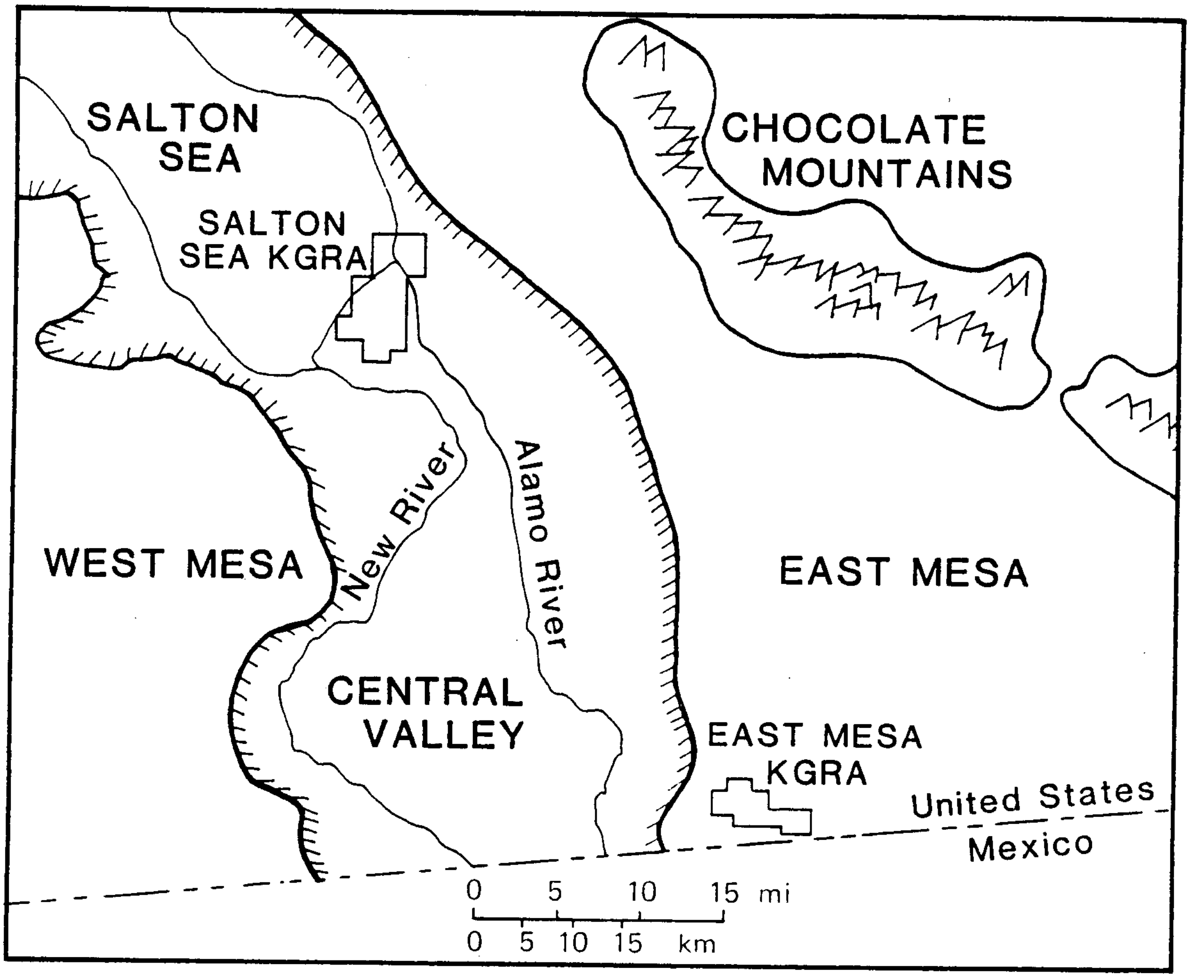

Figure 4.2 Regional geology of the Imperial Valley, California, and locations of the Salton Sea and East Mesa KGRAs.

sediments are unconsolidated, although thermal metamorphism associated with geothermal activity has caused some local lithification (Muffler and White, 1969). Metamorphism in the hottest zones has appreciably altered the porosity of the rock (Helgeson, 1968). Recent volcanism is believed to be associated with the fault system and may be the heat source for the region's geothermal anomalies (Elders, 1975).

The two geothermal fields examined in this case study are the Salton Sea Geothermal Field (SSGF), which is part of the Salton Sea KGRA, and the East Mesa KGRA. The SSGF is located at the southern end of the Salton Sea, and is entirely below sea level. Irrigation waters draining to the Salton Sea pass through the SSGF. Several faults also transect the field (Fig. 4.3). The East Mesa KGRA is located on the western margin of the East Mesa about 30 m above sea level on the eastern flank of the Salton Trough. The unirrigated terrain at East Mesa is relatively flat and desert-like and is covered by alluvium and sand dunes. Several faults transect the East Mesa geothermal field also (Fig. 4.4).

4.3. Hydrology

4.3.1. Surface Water

The Colorado River provides over 3.7×10^9 m^3 of water to the Imperial Valley via irrigation canals each year (Snoeberger et al., 1978). The salinity of this water is about 850 mg/l total dissolved solids (TDS). TDS in surface waters in the Valley ranges from about 900 mg/l in the All American Canal to over 39,000 mg/l in the Salton Sea (Table 4.1). The Salton Sea is about 75 m below sea level and serves as

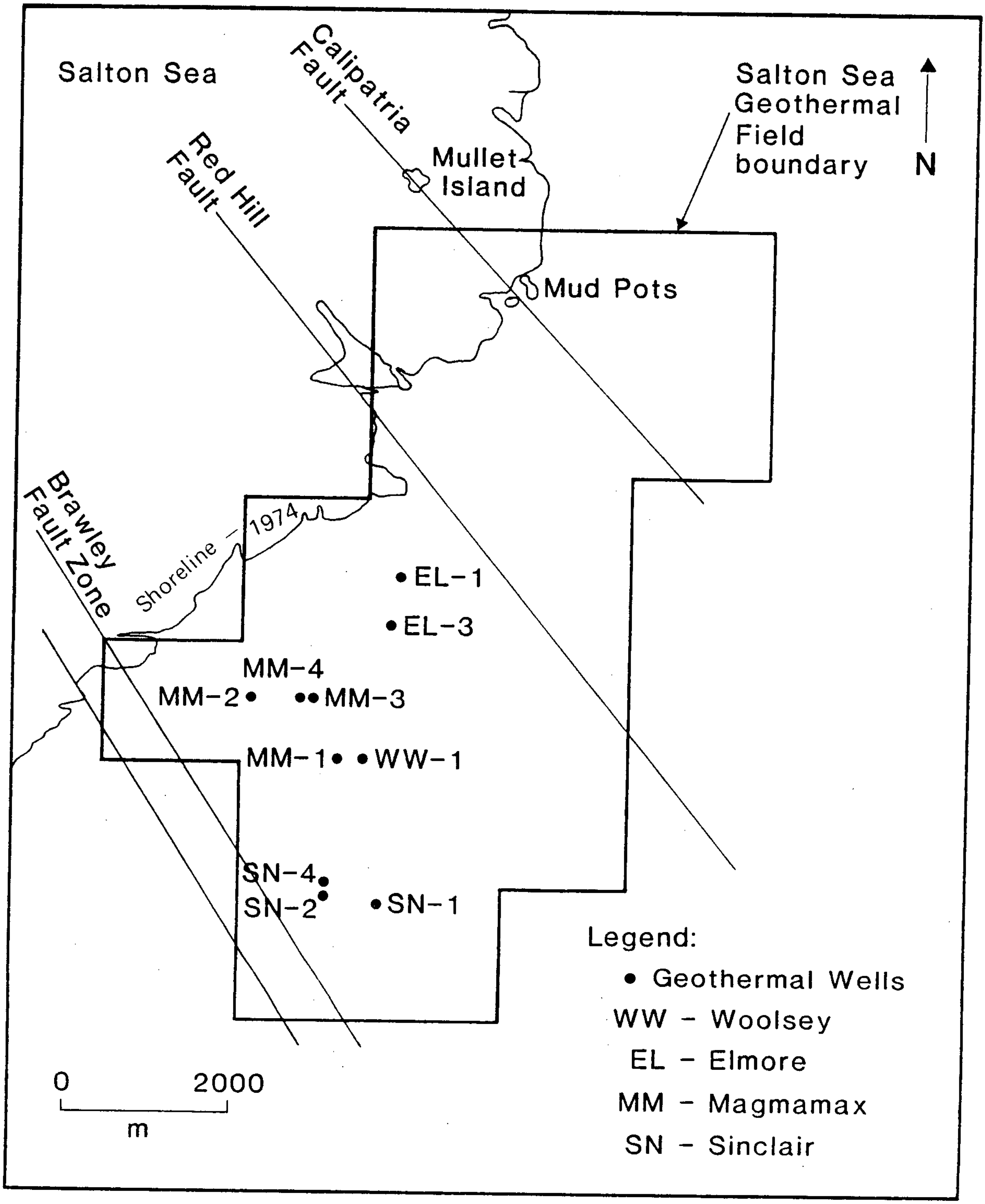

Figure 4.3 Locations of wells at the Salton Sea Geothermal Loop Experimental Facility (GLEF), Imperial Valley, California (after Schroeder, 1976).

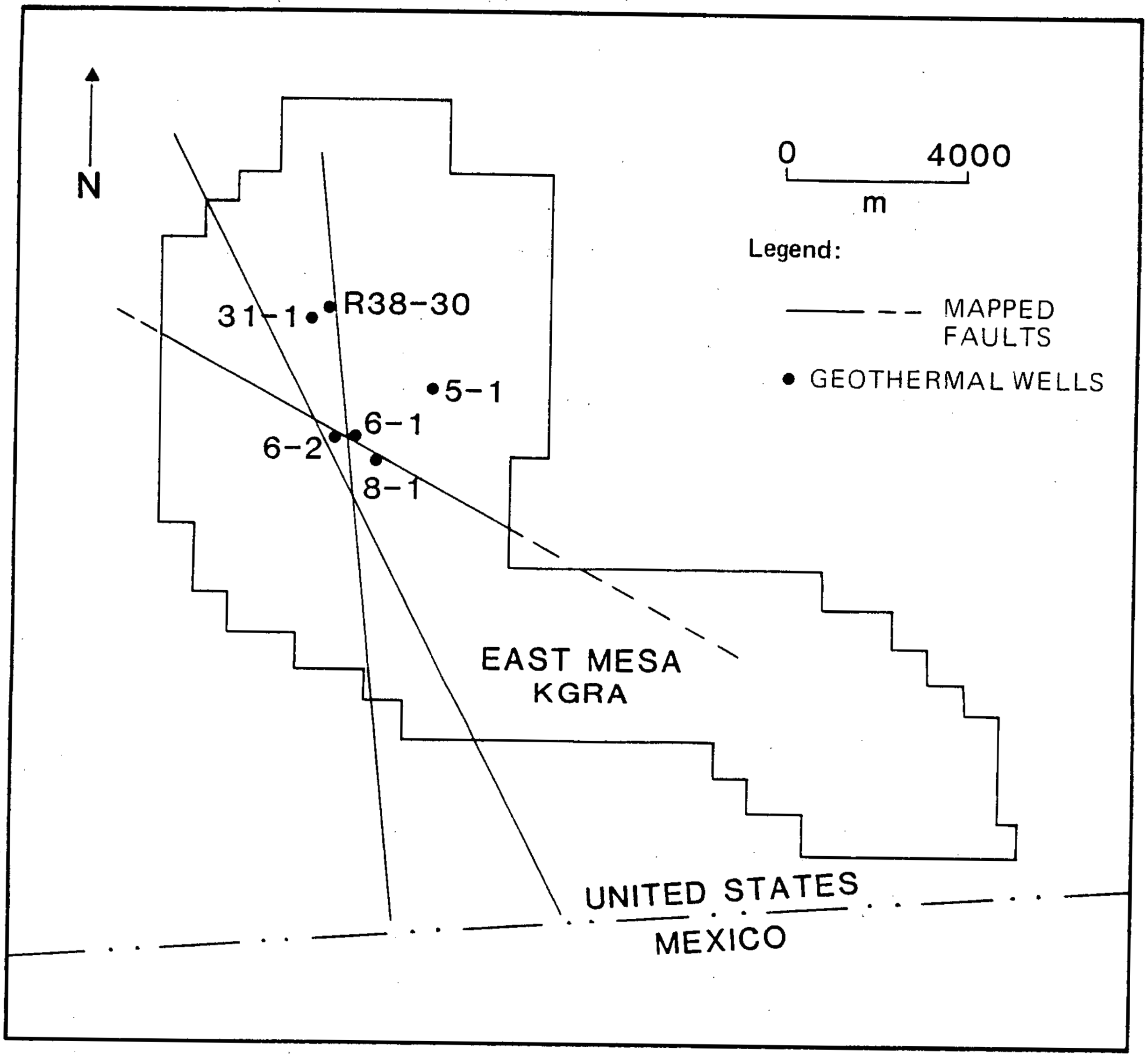

Figure 4.4 Locations of selected geothermal wells at the East Mesa KGRA, Imperial Valley, California (after Swanberg, 1976).

Table 4.1. Total dissolved solids content of rivers contributing water to the Imperial Valley, California.

Water Body	Volume m^3/yr	TDS ppm
Colorado River	3.4×10^9	850-900
New River	5.2×10^8	3300-4300
Alamo River	8.0×10^8	2300
Salton Sea	-	39,000

a drainage sink in the Valley. The New and Alamo rivers flow northwestward to the Sea, as does return flow from irrigation.

4.3.2. Groundwater

The groundwater reservoir in Imperial Valley consists of Cenozoic valley fill deposits that may be greater than 6000 m thick. The upper few thousand meters is principally a heterogeneous sequence of non-marine deposts containing groundwater of variable quality that may or may not be suitable for use. The considerable variability in chemical quality of the groundwater is attributable to the compositional differences in the sources of recharge and the high evaporation rate in this hot arid climate (Loeltz et al., 1975). At greater depths the water is too saline for irrigation and other use. There is poor hydraulic communication between water in the deeper deposits and water in the shallower deposits. Interbedded sands, silts and muds are at least partially responsible for the reduced vertical hydraulic conductivity.

Hundreds of wells have been drilled to various depths and through a number of different depositional materials in the Valley. Some flow at the surface, some do not, depending upon both depth and location in the Valley.

Some private wells produce hot water which is used for heating homes. Most wells are of small diameter and supply only small quantities of water for home, and stock uses. TDS range from a few hundred to more than 1000 mg/l.

Upward discharge from the deeper aquifers to irrigation drains occurs principally near the east edge of the irrigated area. There is also upward leakage to the New and Alamo rivers and in the vicinity of the Salton Sea. The amount of yearly leakage is estimated to be small (Loeltz et al., 1975).

4.3.2.1. Aquifers

Fairly similar aquifer descriptions exist for both the SSGF and the East Mesa KGRA. Salton Trough fill deposits are layered, interfingering, sedimentary sequences that have variable permeabilities and hydraulic heads.

At the SSGF, a cap rock about 300-350 m thick confines the underlying geothermal reservoir and functions as a barrier to deep convection currents and upward flow of geothermal fluids. The upper 180 m of the cap rock is composed of unconsolidated silt, sand and gravel that serve as near-surface aquifers. The lower portion of the cap rock is an impermeable silt-clay sequence (Morse and Stone, 1979). Some natural upward flow to the surface does occur, to form mudpots, and hot springs, but the flow is presumably restricted to local faults. These large faults are evidently principal conduits of upward vertical flow of geothermal fluids across the cap rock.

Below the cap rock, the geothermal reservoir rocks at SSGF are layered sequences of shale and sandstone. Hydrothermal alteration of reservoir rocks increases with depth, starting at bottom of the cap rock until greater than 2100 m deep. As a result, the upper rocks are not fully indurated and are believed to maintain their primary permeability. The rocks become more indurated as hydrothermal alteration increases with depth. Evidence of natural fracturing suggests that secondary porosity and permeability are dominant in the lower depths (Morse and Stone, 1979). Major crustal seismic activity is believed to have caused the fracturing. The producing wells at SSGF are producing at intervals ranging between about 570 to 2160 m (Schroeder, 1976). Wells used for injection testing (MM-3, MM-2, and EL-3) are completed between approximately 630 and 1370 m in both the Upper and Lower geothermal reservoirs.

At the East Mesa KGRA, temperature and permeability data from U.S. Bureau of Reclamation (USBR) wells 31-1, 6-2, 6-1, 5-1 and 8-1 indicate there is a confining clay cap extending to about 600 m deep. No springs or other expressions of the geothermal resource exist at the surface. Primary permeabilty increases with depth between 600 and 900 m as clay content decreases and sand content increases. Much of the media are unconsolidated or semiconsolidated. The interval 750-900 m represents the upper portion of the geothermal reservoir (Swanberg, 1976). The remainder of the geothermal reservoir below 900 m is similar in composition, but contact with geothermal fluid has altered some of the rock, causing induration, and sands are less permeable. Primary permeability decreases in this zone, and secondary fracturing is the dominant permeabiliy. USBR production wells (31-1, 6-2, 6-1 and 8-1) are completed in this lower reservoir with slotted or perforated intervals ranging between about 1508 to 2433 m (Mathias, 1976). The USBR injection well, 5-1, is completed within this interval also. The USBR wells are experimental research wells and are not used for commercial power production.

Three postulated faults traverse the East Mesa geothermal anomaly and may be conduits for the rise of geothermal fluids from a deep igneous heat source to the geothermal reservoir. These faults and associated fractures may also facilitate vertical migration of injected fluids or rapid contact between heat-depleted injected fluids and the production reservoir. The degree to which these phenomona may occur is largely dependent on size of the geothermal resource, well spacings, disparities of slotted intervals, and vertical and permeabilities of the media.

4.3.2.2. Groundwater Chemistry

The chemical quality of the groundwater of the Salton Trough is highly variable. Numerous chemical analyses have been done on water from wells throughout the valley. The analyses are grouped geographically in Table 4.2 and discussed by Loeltz et al. (1975). Representative chemistries of water from geothermal production wells also appear in Table 4.2. The variability is likely attributable to the groundwater origins. Some of the deeper groundwater might be slightly altered connate water. Shallower water occurring in the deltaic deposits may

Table 4.2. Selected characteristics of fluids taken from deep geothermal wells, local shallow wells and surface waters of the Imperial Valley, California.

	Date Sampled	Interval Sampled ft	pH	Total Dissolved Solids mg/l	Specific Conductance μmhos 25°C	Composition, mg/l HCO_3^-	Ca^+	Cl^-	Fl^-	Fe	Li	Mg	Mn	Si	SiO_2	K	Na	K+Na
Wells from Salton Sea KGRA[a]																		
Sinclair 4	4-23-75	--	--	290,000	--	--	29,000	--	--	1,450	--	71	1,230	249	--	15,800	70,000	85,800
Magmamax 1	8-10-76	--	--	208,000	--	--	20,000	121,000	--	256	141	80	690	202	--	8,600	42,000	50,600
Magmamax 2	3-18-76	--	--	244,000	--	--	27,200	142,000	22	1,910	192	148	1,290	410	--	16,600	53,600	70,200
Wells from East Mesa KGRA																		
Mesa 6-1	6-09-76	--	5.45	26,300	40,000	202	1,360	15,850	0.99	8.8	40	17.2	0.95	--	320	1,050	8,100	9,150
Mesa 6-2	6-00-76	--	6.12	5,000	6,000	156	16.4	2,142	1.23	<0.10	4	0.24	0.05	--	269	150	1,700	1,850
Mesa 8-1	6-22-76	--	6.27	1,600	3,200	173	8.5	500	1.60	<0.10	1.1	<0.05	0.05	--	389	70	610	680
Selected Shallow Wells Near East Mesa KGRA[b]																		
15S/16E	1-18-62	50-52	7.9	7,150	12,700	267	238	3,840	--	--	--	172	--	--	40	--	--	2,230
	7-31-61	360-430	8.3	787	1,360	450	8.2	159	3	--	--	1.6	--	--	14	--	--	300
16S/17E	2-24-64	155-157	8.0	1,270	2,340	296	49	508	0.9	--	--	21	--	--	21	--	--	403
16S/18E	2-16-65	134-136	7.7	2,860	4,900	123	127	1,320	--	--	--	49	--	--	30	--	--	860
	9-16-64	298-300	8.1	708	1,200	134	23	192	1.3	--	--	7.7	--	--	21	5.4	216	221.4
Selected Shallow Wells Near Salton Sea KGRA[b]																		
11S/13E	5-10-62	145-147	7.4	1,600	3,120	100	3	710	--	--	--	134	--	--	3	--	--	384
12S/13E	7-10-62	113-115	7.2	2,020	9,370	40	476	2,900	--	--	--	202	--	--	2	--	--	1,300
12S/14E	7-10-62	145-147	7.4	5,400	19,800	408	810	5,850	--	--	--	822	--	--	18	--	--	3,400
Representative Surface Waters[c]																		
Canal[d]	Samples	--	--	930	--	140	94	140	0.46	0.01	0.06	33	0.007	4.4	--	5.6	155.6	155.6
Sump	col-	--	--	7,600	--	360	570	2,300	0.92	0.05	0.44	270	1.3	7.8	--	19	1,600	1,619
Drain	lected	--	--	3,300	--	280	210	640	0.58	0.02	0.19	94	0.15	5.5	--	11	510	521
River[e]	from	--	--	3,700	--	220	220	1,300	1.15	0.03	0.45	120	0.16	7.1	--	24	860	844
	4-76 to																	
	1-78																	

[a]Salton Sea and East Mesa geothermal well data reported by Snoeberger and Hill, 1978.

[b]Loeltz et al., 1975. Wells were selected on the basis of proximity to injection sites at the East Mesa and Salton Sea KGRAs.

[c]Layton et al., ed., 1980.

[d]Canals contain water imported from the Colorado River.

[e]New and Alamo Rivers.

contain evaporation residuals from prehistoric freshwater lakes and may be fresh or moderately saline. Storm runoff has probably leached soluable evaporite from sedimentary rocks above the water table. Small lenses of fresh groundwater may be the result of runoff impoundment from ephemeral desert washes against sand dunes (Loeltz et al., 1975). The variability in sources of recharge coupled with a dry arid climate and high evaporation rate also affect groundwater quality.

4.3.3. Geothermal Resource

The origin of geothermal resources in Imperial County is linked with the San Andras Fault and with spreading centers associated with the East Pacific River under the Pacific Ocean. Collision of the North American and Pacific Plates has resulted in expansion of the Salton Trough of the Imperial Valley and extensive block faulting along its flanks (Butler and Pick, 1982). The major heat source in the valley is probably groundwater brines heated by magmatic emplacement in the crust and portions of the lower basement (Biehler and Lee, 1977). There is disagreement over whether or not the entire valley trough is a single vast geothermal reservoir. Some people believe it is; others believe that additional areas besides the KGRAs are undergoing recent magma emplacements within the valley basement.

Salinity is a major problem of the geothermal resources of Imperial County. Salinity increases in the county to the northwest toward the Salton Sea where most of the KGRA resources lie. Varying substantially from field to field, salinity also varies within a single KGRA from well to well. The Salton Sea KGRA, which is the largest and has the highest recoverable heat content of all the KGRAs in the valley, has the poorest quality geothermal fluids. Salinity increases with depth, and brines may be rich in metals such as maganese, zinc, lead cooper, and silver.

Temperatures of geothermal fluids in Imperial County range from a high of about 360°C to intermediate temperature systems of 90 to 150°C. The Salton Sea KGRA is the hottest area followed by Brawley, Heber, East Mesa and the Dunes. In most places the geothermal resource is located at a range of about 800-4000 m deep (Butler and Pick, 1982) but the upper and lower limits may vary slightly.

A portion of the Salton Sea KGRA known as the Salton Sea Geothermal Field (SSGF) and the East Mesa KGRA have undergone short-term injection testing. Injection experience in these two KGRAs are the focus of this case study. These fields have characteristically different brines and slightly different geologic conditions.

The SSGF reservoir is liquid-dominated with deep well temperatures as high as 360°C. Reservoir fluid is a saline, slightly acidic brine, containing up to one third by weight of dissolved solids. The extent of the geothermal reservoir is probably limited only by temperature, since the rock appears to be liquid-saturated throughout the reservoir beneath the SSGF (Butler and Pick, 1982). The geothermal reservoir capped by thick shale (Table 4.3) is believed to be separated into "Upper" and "Lower" reservoirs on the basis of degree of hydrothermal alteration. A 12 m-thick shale layer divides these reservoirs (Schroeder, 1976). The unaltered Upper reservoir is very porous and has a high permeability and productivity. Its temperature and dissolved solids are less than those

Table 4.3. Geologic and hydrologic characteristics of the Salton Trough near the Salton Sea KGRA, Imperial Valley, California.

Hydrogeologic Unit	Geologic Description[a]	Hydrologic Description
Upper Sediments	Deltaic valley fill deposits; discontinuous beds of unconsolidated sands, silts and clays.	Aquifers in various layers of depositional sands; permeabilities primary and principally horizontal; vertical flow retarded by clay lenses; variable water quality; receives substantial recharge from irrigation drainage ditches.
Cap Rock	Continuous clay (called shale by some authors) about 350 m thick; breached by several inferred faults.	Impermeable aquitard; hydrologically and thermally isolates geothermal reservoir from shallow aquifer; extent of vertical fracturing unknown; bottom of cap rock defines top of geothermal reservoir; temperature approximately $200^{\circ}C$.
Upper Reservoir	Lacustrine and alluvial deposits of sand, silt and clay; bedded sandstone with shale lenses and layers; average thickness about 450 m; fault zones trend NW accompanied by undetermined extent.	Average primary sandstone porosity estimated at 15-30% (Schroeder, 1976) decreasing with proximity to underlying shale "barrier"; horizontal permeabilities higher in upper sands, decreasing with depth; vertical permeabilities relatively low, reservoir rocks fully saturated.
Shale "Barrier"	Shale 12 m thick; dips to NW; extent of fracturing unknown.	Extent of fractured and vertical permeability unknown; head differences across the "barrier" unavailable; temperature approximately $300^{\circ}C$.
Lower Reservoir	Continued bedded sandstone with shale lenses and layers; thickness 1000 m, depth to granite basement variable; appreciable hydrothermal alteration/metamorphism; extensive fracturing at depth.	Primary porosities and permeabilities decreased by hydrothermal alteration causing mineral precipitation above $300^{\circ}C$ (Schroeder, 1976); extensive fracturing and increased secondary porosity and permeability at depth; temperature approximately $280^{\circ}C^{+}$; main producing geothermal reservoir.

[a]Schroeder, 1976.

of the lower reservoir. The altered Lower reservoir is believed to be twice the size of the Upper reservoir, but the storativity and permeability of the rock matrix are less. Secondary porosity and permeability are dominant in the hydrothermally altered zone and evidently are a result of ongoing natural fracturing (Morse and Stone, 1979). The geothermal fluids have variable TDS of >160,00 ppm.

At the East Mesa KGRA, the liquid-dominated geothermal reservoir is confined beneath a clay cap reported to be around 600 m thick and consisting of about 60% clay (Swanberg, 1976). The clay effectively seals the geothermal reservoir from the surface and is a barrier to vertical flow. Vertical flow occurs principally in large faults. The hydrologic features of the geothermal reservoir are discussed in greater detail in the preceding Section 4.3.2.1. The temperature of the geothermal resource at East Mesa is around 200^{o}C.

4.4. Injection

Imperial County favors subsurface injection of geothermal fluids over the long term primarily as a means to minimize local subsidence by maintaining reservoir pore water pressures. Injection is also expected to prolong the life of the geothermal reservoir by recharging the depleted production reservoir. Heat-depleted brines traveling through superheated rocks between injection and production wells are expected to reheat so that production temperatures and pressures will not decline substantially. The chemistry of injected fluids is a result of the chemistry of the production fluids, but the two are not the same. Injected fluids are likely to have undergone temperature depletion, in-line pressure changes, concentration by means of steam flashing, and numerous accompanying chemical reactions by the time they reach the injection wellhead. At Imperial Valley KGRAs, it is probable that some sort of make-up water has been added as well, which further alters the original chemistry and temperature. The end result is a fluid requiring very site-specific handling technology for maximum injectability. Pretreatment of the brine is commonly necessary, particularly at the SSGF, where solids concentrations are high. Production water varies from KGRA to KGRA, and even from well to well in the Imperial Valley, and so injection conditions will vary. Even injecting combined fluids from two neighboring production wells can have different results than if only one production well were used.

4.4.1. Injection System

There are several operators developing geothermal resources in the Imperial Valley. At the Salton Sea geothermal field, Union Oil Company has been producing and injecting geothermal fluids since 1982. Specific details of their injection program, including well configurations, injectate properties and pretreatment are not available. Flashing of geothermal fluids at their 10 MW plant results in a loss of fluid volume, so that slightly less than 100% is being injected back to the reservoir (Whitescarver, 1984). The net volume loss is small compared to the size of the geothermal reservoir, and no related ill effects have been documented.

The San Diego Gas and Electric Company operates a Geothermal Loop Experimental Facility (GLEF) at the Salton Sea KGRA, and considerable injection testing has occurred there. The wellfield at the Salton Sea GLEF is shown in Figure 4.3. Magmamax 1 (MM-1) and Woolsey 1 (W-1) are the primary producing wells for the GLEF. MM-3 was the main injection well until it became plugged and went out of service in July, 1978; MM-2 then became the primary injection well. MM-4 was designed and is used as an observation well (Morse and Stone, 1979). Depths of some of these wells appear in Table 4.4.

The injection system at the GLEF is an open system. As hot geothermal fluids (190-220°C) are flashed, steam escapes. The resulting waste fluids are diminished in volume and temperature (100°C) (Snoeberger and Hill, 1978). Chemical precipitation on equipment and in the well is a severe problem, and numerous studies on fluid treatment prior to injection have been made (Owen et al., 1978, 1979; Quong et al., 1978). These studies are not discussed here, although a brief discussion of the detrimental near-well chemical effects is in Section 4.4.3.

At the East Mesa geothermal field, Magma Power Company has been injecting waste fluids from their 10 MW power facility since October 1, 1982. Magma Power's wells include five slant-drilled production wells drilled to depths ranging around 2100 m (Butler and Pick, 1982). Three injection wells are located about one mile from the power plant. At least one of these injection wells (46-7) is drilled to nearly 1000 m (Table 4.4). Data for the remaining two injection wells and four of the production wells are not at hand.

The Magma Power facility is a binary plant that utilizes isobutane as the working fluid in the primary loop and propane in the second loop.

Table 4.4. Depths and slotted intervals of geothermal wells in the Imperial Valley, California.

	Total Depth (m)	Plugged-back Depth (m)	Perforated or Slotted Interval (m)
Salton Sea GLEF			
Production Wells[a]			
Magmamax 1 (MM-1)	882	723	565-712
Woolsey 1 (WW-1)	754		586-746
Injection Wells[a]			
Magmamax 2 (MM-2)	1373		1189-1370
Magmamax 3 (MM-3)	1257	980	823-967
Observation Wells[b]			
Elmore 3 (EL-3)	787		631-787
Sinclair 3 (SN-3)	1616		
East Mesa			
USBR Production Wells[c]			
6-1	2433		2075-2179 (perforated) 2238-2433 (slotted)
6-2	1816		1663-1816
8-1	1829		1508-1829
31-1	1882		1652-1882
USBR Injection Well[c]			
5-1	1830		1525-1830
Magma Power Production Well[d]			
48-7	2200		1634-2200
Magma Power Injection Well			
46-7	974		691-974

[a] Towse and Palmer, 1976.
[b] Schroeder, 1976
[c] Mathias, 1976.
[d] Jorda, 1980.

Heat is transferred from the geothermal fluid to the working fluid in a heat exchanger, thus no steam flashing is necessary. There is no net fluid loss to steam, so one hundred percent of the produced geothermal fluid volume is returned to the geothermal reservoir via injection (Hinrichs, 1984).

Several U.S. Bureau of Reclamation wells at East Mesa have been used experimently for production and injection. Their locations are shown in Figure 4.4. The production wells are 6-1, 6-2, 8-1, and 31-1. Well 5-1 is an injection well. Depths of these wells range approximately from 1800 to 2400 m (Table 4.4).

4.4.2. Monitoring Program

No near-surface monitoring program has been established at East Mesa or at Salton Sea. Monitoring data from area wells and surficial springs are almost non-existent. The California Department of Oil and Gas regulates subsurface fluid injection in California. Shallow usable aquifers must be cased off and the casings checked regularly for defects that might allow communication among aquifers via the wellbore.

Union Oil Company has continuously operated a 10 MW steam flash plant since mid-1982. Geothermal wells produce fluids from depths of 570 to 2160 m. All of the residual geothermal fluids are injected to a depth range of approximately 630 to 1370 m (Whitescarver, 1984). Flow rates (and presumably temperatures and pressures) are monitored in production and injection wells, but are not available for presentation here. Any other well monitoring that Union may or may not do is proprietary information.

Union Oil monitors the surface visually for surface manifestations of hydrologic features. Several pre-existing springs and mud pots appear to be aligned along area faults. Union Oil also monitors subsidence; none has been reported to be associated with geothermal producton as of May, 1984. Net fluid withdrawals are so small relative to the immense size of the reservoir, that no future subsidence is anticipated. Indeed, the relatively small-scale injection seems to have little, if any effect (Whitescarver, 1984). There are good background seismic data available for the Imperial Valley. Union Oil has been monitoring seismics as production and injection proceed; they have reported no substantial changes in seismicity associated with injection.

The Magma Power Company has been injecting 160 l/s of geothermal wastewater continuously since starting a binary magmamax facility at East Mesa on October 1, 1982. The injection interval for Magma Power's wells is about 610-910 m, whereas the production interval for Magma Power's wells is about 1370-1430 m. The stratigraphy and hydrologic features of the injection and production intervals are presented in Section 4.3.2.1. (Hinrichs, 1984).

Magma Power does not use area wells for shallow monitoring purposes. All of their geothermal wells are being used and are unavailable for constant monitoring other than for pressure, temperature, and production and injection rates (Hinrichs, 1984).

The geothermal reservoir at East Mesa, as of May, 1984, has not stablized to a steady state drawdown with the production and injection rate of 160 l/s. There is no evidence of flow boundaries or of communication between Magma Power's injection and production zones.

These zones are measured only for transient pressures and temperatures. Neither is there any visible or measurable evidence of communication of fluids between the injection zone and shallow aquifers (Hinrichs, 1984) although shallow monitoring data are scant.

4.4.3. Injection Testing

Most available information on injection testing in the Imperial Valley is concerned with near-well engineering such as chemical fouling of equipment, formation plugging, and the resulting loss of injectivity. Most testing to date, has been limited to single-hole tests that focus on these problems. Multi-well production and interference testing provide more information about hydrology in the Imperial Valley KGRAs than to the documented single-well injection tests.

4.4.3.1. Single-Well Testing

Several single-well production and injection tests were done on geothermal wells in the East Mesa KGRA beginning in 1976 (Howard et al., 1978; McEdwards and Benson, 1978). Generally consistent pressure data for USBR wells 8-1 and 6-1 are typical of a single production zone (Howard et al., 1978). Data for USBR Wells 5-1 and 6-2 do not exhibit the same consistency. Injection step-test data for 5-1 suggest that the well encounters a vertical fracture that may have been induced by high injection pressures in the perforated interval (1525-1830 m). The result is an increased transmissivity value. A spinner survey showed all flow leaving the wellbore in a 122 m interval at the top of the perforated interval. The injection log exhibited a rapid drop in pressure

(8.3×10^7 to 2.8×10^7 Pa) at a constant injection rate (6 l/s). Finally, the measured injectivity index increased as the rate of injection increased (Howard et al., 1978; McEdwards and Benson, 1978). The injectivity index is defined by Howard et al. (1978) as Q/ P, where Q is the rate of flow and P is the reservoir pressure. The injectivity index in 5-1 later dropped, presumably as a result of plugging the fracture surface during injection. The particulate plugging in the well was enhanced by incompatible fluid chemistries. Fracturing the formation thus did not necessarily enhance injectivity, except in the short term.

Pressure data for well 6-2 indicate there are two producing reservoirs for this well. The more permeable reservoir is in the upper 150 m of the perforations. The less permeable zone is deeper in the well. Well-log permeability data support this conclusion. Production well 6-1, like 5-1, was damaged by scaling and plugging.

Variable-rate injection into Republic Geothermal's well 18-28 showed increased injection pressures with successive segments of the injection test. The increased pressures are indicative of increasing skin effects. The rapidly increasing skin values suggest there is chemical activity occurring in the well. The pressures were not considered to be sufficiently high to induce fracturing of the formation at depth (McEdwards and Benson, 1978).

The principal chemical effect observed at the Salton Sea GLEF during injection is the precipitation of amorphous silica and other soluble metallic salts (Snoeberger and Hill, 1978; Hill and Otto, 1977; Vetter and Kandarpa, 1982). This deposition of solids occurs in the injecton well and in the near-well formation resulting in the gradual plugging of each and in gradual increases in injection pressures (Morse, 1978). In 1978, the MM-3 injection well at the Salton Sea GLEF became completely disabled as a result of chemical precipitation. MM-2 substituted as an injector while attempts were made to rehabilitate MM-3. Fluid treatment prior to injection became necessary in order to extend the life of the injection well (Owen et al., 1978; Owen et al., 1979; Quong et al., 1978; Morse, 1978). At the East Mesa KGRA, the relatively good water quality does not require pretreatment (Jorda, 1980), but chemical precipitation in the wells and formation have been documented (Howard et al., 1978; McEdwards and Benson, 1978).

Magma Power's injection well 46-7 at East Mesa was badly impaired as a result of sediment fill that occurred during shut-ins between injection tests. Injectivity improved at least seven-fold by subsequently backflowing the well (Jorda, 1980). A small continuous flow during quiescent periods was recommended to help prevent sediment fill (Jorda, 1980).

Huff-Puff tests (monitored backflow of injected tracers) were done at East Mesa in summer, 1983 (Michels, 1983). Steam-flashed geothermal fluids, supplemented by $CaCO_3$ scale inhibitors, were used as the injection fluids. Republic Geothermal well 38-30 was the producing well and 56-30 and 56-19 were the injectors. The deposition of $CaCO_3$ was expected to eventually occur: 1) once the residual inhibitor in the brine declined to below a minimum concentration; 2) as inhibitor stability declined at elevated rock temperatures in the injection zone; and 3) as contact occurred between the injectate and rock surface area in the injection zone. The tests were designed to 1) determine the distance the fluid travels from the wellbore before $CaCO_3$ deposition occurs, and 2) compare the amount of $CaCo_3$ deposition with available space in the reservoir rock's porosity (Michels, 1983). Calcium was used as a tracer of the injectate's reactivity and as an indicator of the inhibitor's effectiveness. Non deposition of $CaCO_3$ in well 56-19 was the result of environmental and compositional changes. These included minor temperature variations and sharp changes in ionic strength and activity coefficients. Calcium deposition did occur in 56-30. Injecting into well 56-30 then backflowing the well for several injection volumes showed a deficit of calcium concentrations in the native fluids. The deficiency indicated that calcium deposition was occurring in the reservoir rocks. The deficiency also suggested that the source of calcium was the native fluids that never had direct contact with the injectate. The injectate evidently equilibrated chemically with reservoir rocks which, in turn, acted as an intermediary between the injectate and native fluids. The equilibration involved easily reversed reactions with several carbonate species. The rocks then behaved as Bronsted acids and bases, thereby influencing carbonate equilibria in the injectate and the native fluids. This mechanism is apparently how the calcium deposition occurred (Michels, 1983).

4.4.3.2. Multi-Well Testing

Multi-well interference testing provided more information about the behavior of the wellfield as a whole than did single-well injection testing. Numerous production and interference tests were done at the

East Mesa KGRA in 1976 and 1977, (Howard et al., 1978). These tests utilized all available wells in the northern, southern, and central portions of the KGRA. Analyses of data from interference tests enabled the location of hydraulic barriers, inference of reservoir recharge, and the confirmation that there is hydrologic continuity between the northern and southern sectors of the geothermal field. The interference tests provided average estimates of reservoir parameters such as transmissivity and storativity (Howard et al., 1978). Transmissivity estimates in the northern part of the field are consistently higher than in the central part and may be a function of the degree of metamorphism associated with the geothermal fluids (Howard et al., 1978). Several no-flow boundaries are inferred from numerous interference tests. Producing USBR wells 6-1 and 6-2 and observing pressure responses in Well 31-1 in the northern portion of the field indicated there is hydrologic continuity among these three wells (see Fig. 4.4 for well locations). Well 8-1 did not respond to production from 6-2 or 6-1 indicating an absence of hydrologic continuity between 8-1 and 6-2, and 8-1 and 6-1. Well 8-1 seems to have some continuity with wells from the southern portion of the field (Howard et al., 1978).

The general hydrologic situation at the East Mesa KGRA seems to be one of localized no-flow boundaries (Narasimhan et al., 1977; Howard et al., 1978). The boundaries are probably associated with regional faulting and reservoir heterogeneities such as shale layers. Heterogeneity and anisotropy in the geothermal reservoir are prevalent. It is difficult to characterize the geothermal reservoir on the basis of conventional parameters such as storativity and transmissivity because of inherent reservoir variabilities. Little is known about the arrangement of sands and other permeable zones that transmit water within the reservoir. Well tests are unreliable for predicting even the near-well values for storativity and transmissivity. These characteristics must be estimated from geophysical and lithological logs.

At the SSGF, three surveys of pressure drop off following injection were done at MM-3 during active injection testing from May, 1976 to April, 1978 (Morse and Stone, 1979). Pressure responses to injection into MM-3 (measured at ~808 m) suggest the injection reservoir (790 to 850 m) is moderately permeable both near and away from the well. Pressure data also indicate there are important flow components in both matrix and fracture permeability in the injection zone (Morse and Stone, 1979).

Production testing at the SSGF in 1977 and 1978 utilized wells MM-1 and WW-1 in efforts to predict permeability of sands in the geothermal production zone from drawdown and pressure data results proved to be unrealiable (Morse and Stone, 1979). Wells MM-4,SN-3, and EL-3 were equipped as observation wells at various times during the testing to observe interference effects of production and injection testing. Pressure transients were recorded at shallow depths (45-140 m) in each of these wells. In the summer of 1977, MM-4 was used to observe vertical interference caused by injection into MM-3. Areally, the two wells are about 15 m apart. Vertically, the top of the injection interval in MM-3 is about 24 m below the bottom of MM-4. A 12 m-thick shale layer lies between the bottom of MM-4 and the injection zone. MM-4 is completed in the Upper geothermal reservoir, whereas the injection interval of MM-3 is in the top of the Lower geothermal reservoir. There were initial pressure responses in MM-4 to injection in MM-3, indicating vertical communication between the Upper and Lower geothermal reservoirs across the shale layer. The shale may be leaky or, there may have been an incomplete cement bond around the MM-3 casing allowing vertical leakage. No pressure responses in MM-4 to injection into MM-3 were detectable by the beginning of 1978 (Morse and Stone, 1979).

Responses in SH-3 and EL-3 to production and injection in the GLEF were very small. These wells are located far from the injection and production wells (Fig. 4.2), and the tests may have been insufficiently long to observe a substantial response. There was no evidence of local positive or negative hydrologic boundaries in the reservoir (Morse and Stone, 1979).

The dangers of subsidence in the Imperial Valley are discussed in detail in Section 4.4.4., following this section. Subsidence has been monitored during both geothermal production and injection at the Salton Sea and East Mesa KGRAs. There is no evidence that subsidence has increased as a result of geothermal development. The net loss of fluid after injection is believed to be small, relative to the immense size of the reservoir, so that local or regional subsidence is not anticipated.

The potential for induced seismicity is discussed in detail in Section 4.4.4. There is no evidence that subsurface injection at current volumes and pressures will increase seismic activity in the region.

4.4.4. Constraints on Injection

Increased land subsidence is a possible consequence of geothermal energy production in the Imperial Valley. Existing natural subsidence is regional and has not been known to cause serious damange to lands or property in the Valley. The concern over increased land subsidence stems from the potential adverse effects of localized differential settling on the Valley's gravity-based irrigation and drainage systems. Significant changes in surface slopes could severely disrupt irrigation and thereby the crop production which is so economically important to the region.

Imperial County has a full injection policy that requires all withdrawn fluids (or an equal volume of another fluid) to be injected back to the reservoir. The intention is to maintain reservoir pore water pressure and prevent aquifer compaction and subsidence. Layton et al. (1980) modeled reservoir conditions in Imperial Valley and concluded that partial injection results in more subsidence than full injection as a result of net pressure losses. They also concluded that closely spaced production wells would produce more subsidence than wells spaced farther apart. Optimum spacing depends upon local conditions.

The possible effects of subsidence in the Imperial Valley, based on Layton's model, are numerous. In some areas, slope changes of even a few centimeters may alter the effectiveness of irrigation or may reverse flow in irrigation canals altogether. Without mitigation measures, the affected acreages could be removed from agricultural production at an economic loss to growers. Regional drainage would be altered by a substantial subsidence basin. Changing water flow velocities and increased water levels in the canals as their elevation decreases relative to surrounding lands would drastically alter the existing irrigation systems at huge economic cost.

At the Salton Sea, there is already a problem with rising water levels and the encroachment of salt water on the geothermal field. Dikes provide some protection, but rising sea levels combined with declining elevations increase the risk of flooding (Layton et al., 1980).

A possible consequence of fluid injection in the Valley is induced seismicity. Seismic levels are already naturally high because of the active fault systems, and there has been measurable crustal displacement in this century. Land subsidence is commonly associated with seismic activity in faulted zones. Measurable earthquakes are common, particularly along the Brawley and Imperial Fault Zones which are the area's most active (Layton et al., 1980).

The concern that subsurface fluid injection could enhance seismic activity in the Imperial Valley results from two prior experiences at other locations. At the Rocky Mountain Arsenal near Denver, Colorado, earthquakes resulted from the injection of waste fluids (Healy et al., 1968; Raleigh et al., 1975). At Rangely, Colorado it was shown that increasing long-term injection pressure beyond a threshold pressure for the given reservoir would induce seismic events. Raleigh et al. (1975) concluded the mechanism for this phenomenon was decreased physical strength of the rock body caused by injection and the existence of a substantial seismic stress field. Reduced rock strength may be caused by forced lubrication of rock fracture planes and by induced fracturing. Naturally the potential for increased communication and leakage of injected fluids between adjacent aquifers is greater with induced fracturing. As a result, a standard commonly applied by various states limits injection pressure at the formation face to 0.8 psi per foot of depth. This pressure is generally less than that expected to fracture most reservoir rocks, but there are cases, such as those in Colorado, where the fracture pressure is lower than the standard. The occurrence of fracturing can be detected from changes in injection pressure as exemplified in USBR well 5-1, but the pressures at which fracturing will occur cannot be predicted (Layton et al., 1980). There is experience that short-term injection (a few hours to a few days) at pressures above fracture pressure does not induce seismic activity in the short-term (Layton et al., 1980).

Naturally high levels of seismicity in the Imperial Valley are associated with the KGRAs. Indeed, earthquake swarms near these areas are common. Distinguishing induced seismic activity from natural seismic activity in these areas is a problem. Fortunately there are baseline seismic data available that indicate the natural activity occurs at greater depth than the depth expected for injection. Thus focal depth may be the factor distinguishing the cause of earthquakes near producing geothermal fields.

The extent to which natural upward discharge from the geothermal reservoir would increase or decrease as a result of artificial injection is unknown. Locally, geothermal fluids are believed to move upward along fracture planes and may spread laterally into permeable sediments (Fig. 4.5). This flow pattern would explain local variations in groundwater chemistry and elevated temperatures in some near-surface

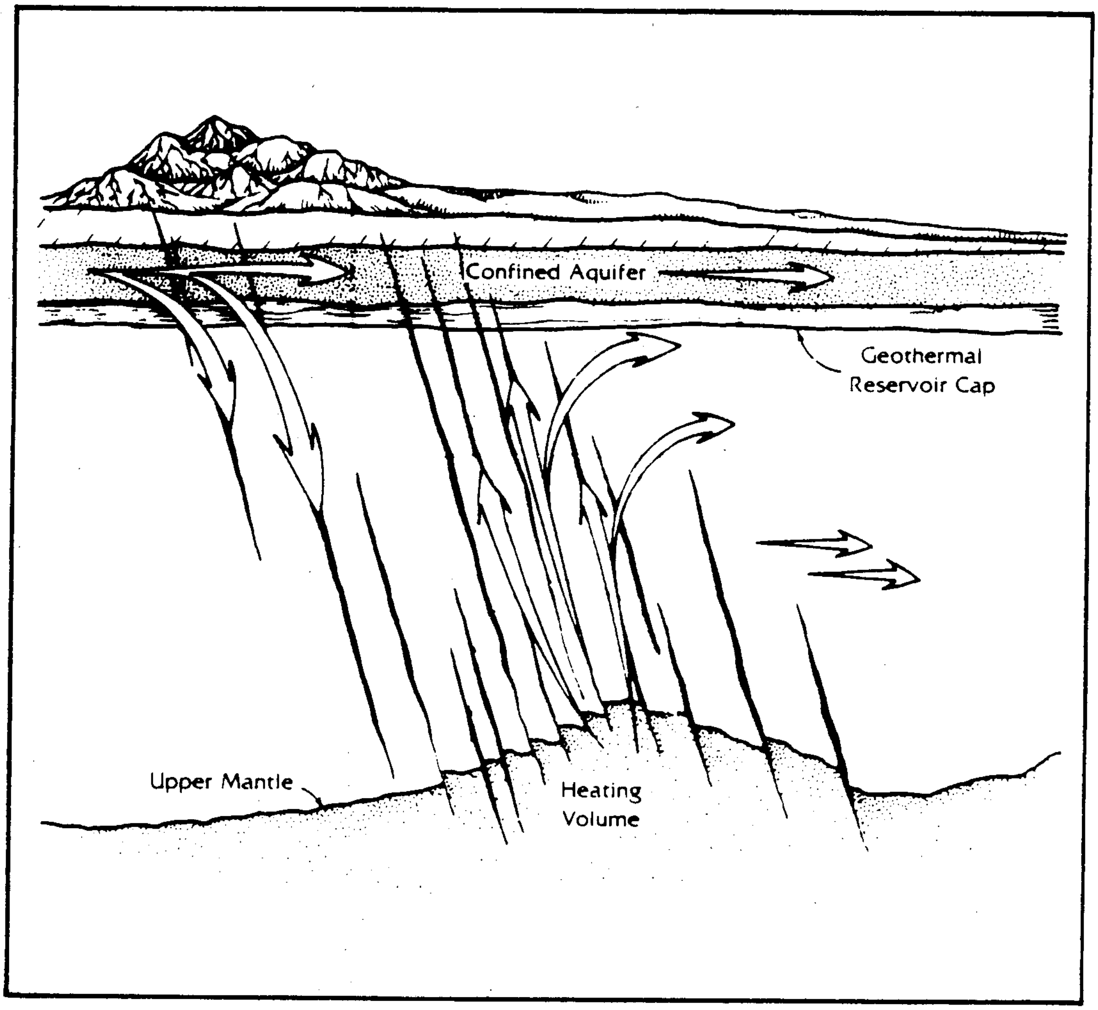

Figure 4.5 Conceptual cross section and flow pattern of the East Mesa geothermal system, Imperial Valley, California (after Riney et al., 1980).

wells. Several conditions exist that minimize induced upward flow and thereby reduce potentially harmful effects on near-surface water supplies. First, the very thick cap rock at both the Salton Sea and East Mesa KGRAs is an aquitard that effectively seals the geothermal reservoir from surface, both hydrologically and thermally. Communication of fluids across the cap rock along fault planes is minimal. Second, within the geothermal reservoir itself, clay lenses and hydrothermally altered zones restrict vertical porous media flow. Fluids would have to find a well-connected fracture passage to cross 1000 m or more of overburden to the surface. Finally, the very large estimated volume of the geothermal reservoir(s) dwarfs the current scale of goethermal development in the Imperial Valley. At current development levels, no effects of injection on overlying near-surface aquifers have been detected, and none is anticipated. The potential effects of increased injection over the long term are unknown.

Injection pressures in well tests have been high enough to fracture the reservoir rock at depth (Howard et al., 1978), but injection pressures are generally lower. It is conceivable that such hydrofracturing might facilitate upward flow if the injection well is located sufficiently close to a fault zone so as to establish a hydraulic connection. At East Mesa, USBR injection well 5-1 was located a mile away from production wells in a non-faulted area to avoid such hydraulic connection with production wells. Such consideration in locating injectors may be effective in protecting overlying freshwater aquifers as well.

4.5. Summary

The Imperial Valley occupies a portion of the Salton Trough, a sediment-filled rift valley that is tectonically active. Crustal displacements have resulted in structural faulting and elevated seismicity. Groundwater in the valley is located in heterogeneous and anisotropic valley fill deposits. Groundwater quality varies considerably both areally and vertically as a result of variable sources of recharge and a hot, dry climate.

A thick clay cap rock separates and hydrologically isolates the near-surface aquifers from the deeper geothermal reservoir. Faults locally breach this cap rock and presumably provide pathways for limited upward migration of geothermal fluids.

The upper geothermal reservoir exhibits primary permeabilities in porous media flow. Increasing hydrothermal alteration with depth reduces primary permeabilities, and secondary fracture flow dominates. The geothermal reservoir is a layered series of sedimentary rock units. Clay lenses and hydrothermally altered zones may serve as aquicludes to vertical flow.

Multi-well tests at East Mesa and Salton Sea KGRAs indicate there is hydraulic communication among some wells at depth. Testing at East Mesa has shown that several negative and positive boundaries exist within the KGRA. Testing at the Salton Sea KGRA has not indicated the existence of hydrologic boundaries, although several faults transect the KGRA. No evidence of injected fluids moving upward toward the surface has been documented, however there is no monitoring system utilizing shallow wells for chemical and pressure data collection.

Single-well injection tests revealed severe chemical precipitation clogging wells and plugging formations at the Salton Sea GLEF. Chemical deposition so severely shortened the injection life of MM-3 that brine pretreatment methods to remove TDS had to be investigated. Chemical deposition and sediment fill at East Mesa KGRA reduced injectivity of some wells, but backflow tests have improved some of these wells.

There appears to be little evidence that injecting geothermal fluids will cause adverse effects on near-surface wells in the Imperial Valley. Minute chemical effects would be hard to detect, as the water quality in most valley wells varies.

5. OTAKE GEOTHERMAL AREA, JAPAN

5.1. Introduction

The Japanese islands are geologically located in the Circum-Pacific Zone on the margin of the Pacific basin. These islands have a long history of tectonic and volcanic activity. There are well over 200 localities throughout the islands that exhibit geothermal activity in the forms of fumaroles, hot springs, and other geothermal manifestations (Hayashida and Ezima, 1970).

Future electrical energy demands are expected to continue to increase in Japan. The development of indigenous geothermal resources has become a means of meeting some of these energy demands. There are five liquid-dominated geothermal fields in production in Japan that inject waste fluids. These are Otake, Hatchobaru, Onuma, Onikobe and Kakkonda. Each produce steam in water in ratios from 1:2 to 1:6, and each injects 100% of its produced fluids (Horne, 1982a). With the exception of Otake, these fields have experienced rapid interference between production and injection wells and a resulting decline in productivity.

This study examines the Otake and Hatchobaru geothermal fields located in the Otake Geothermal Area on the island of Kyushu (Fig. 5.1). Kyushu is located in southwestern Japan. These two fields were chosen on the basis of their different reservoir experiences under similar conditions in the same geographical area. These experiences are described in Section 5.4.3.

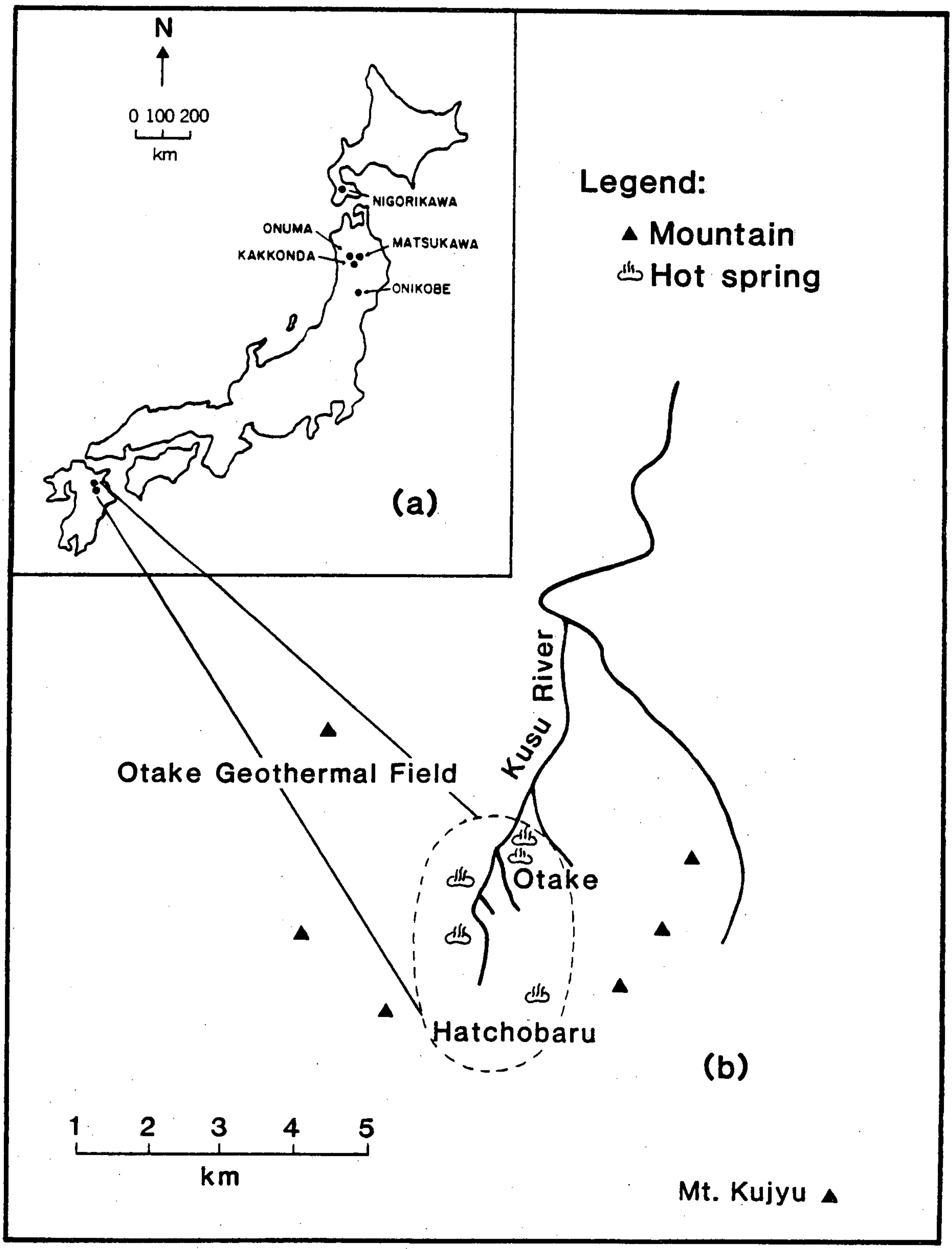

Figure 5.1 Location of the Otake Geothermal Area, Kyushu, Japan: (a) Copyright © 1982 SPE–AIME; (b) after Hayashida and Ezima, 1970.

5.2. Geology

The island of Kyushu (41,950 km^2) occupies the geologic junction between Honshu (the main island) and the Ryuku island arc and has thus become an important province for studying geotectonics and Cenozoic volcanism (Yamasaki and Hayashi, 1976). The Otake Geothermal Area is located in a depression zone associated with local and regional active volcanoes. A thick Quaternary formation containing predominantly volcanic rock series fills this depression zone.

The Quaternary volcanics are generally divided into two groups: the middle Pleistocene Kuju complex and the lower Pleistocene Hohi complex (Table 5.1) (Fig. 5.2). The thin Miocene Kusu sediment group underlies the Hohi complex. Below the Kusu group, or where it is absent, lies the andesitic Usa group.

The Otake Geothermal Area includes both the Otake geothermal field to the north and the Hatchobaru geothermal field to the south. Figure 5.3 depicts a schematic conception of geologc structure in the geothermal area. The Otake geothermal field occurs in a regional caldera structure about 900-1100 m above sea level and is dissected by the Kusu River. Geophysical surveys indicate the field is a small horst nearly a kilometer wide from east to west and about 3-4 km long north to south. Hot springs and fumaroles comprise the natural, surficial geothermal activity at the Otake field. Geothermal water issues primarily from faults and fractures in the deep Kusu and Usa sediment groups at Hatchobaru and to some extent from lava and tuff breccias in the Hohi complex at Otake and Hatchobaru (Ellis and Mahon, 1977). The Hohi andesites behave as a confining reservoir cap rock. Extensive

Table 5.1. Geologic and hydrologic characteristics of the Otake Geothermal Area, Japan.[a]

Geologic Complex	Description	Hydrogeology
Kujyu Volcanic Complex (Middle Pleistocene)	Andesitic lavas, hornblende andesites, lava domes, pyroclastics.	
Hohi Volcanic Complex (Lower Pleistocene)	Pyroxene andesites (cap rock) overlying pyroclastics and lava and tuff breccias; faults and associated fractures prevalent; hydrothermal alteration along fissure flow planes; about 1000 m thick.	Dominant permeability in fracture flow; periodic good water and steam geothermal production from tuff breccias in the middle formation of the Hohi Complex (200-400 m deep); some geothermal production from fractures in overlying andesites.
----- Pliocene peneplanation -----		
Kusu Group (Upper Miocene)	Lake deposits and pyroclastics: alternating tuffs, sandstone pebbles and mudstone; faults, fractures, hydrothermal alteration prevalent; andesite lavas, also highly fractured.	Substantial geothermal production just below the peneplanation unconformity either in the thin Kusu Group or, in its absence, the Usa Group.
Usa Group (Middle Miocene)	Andesites, lavas, pyroclastics.	

[a] Yamasaki and Hayashi, 1976.

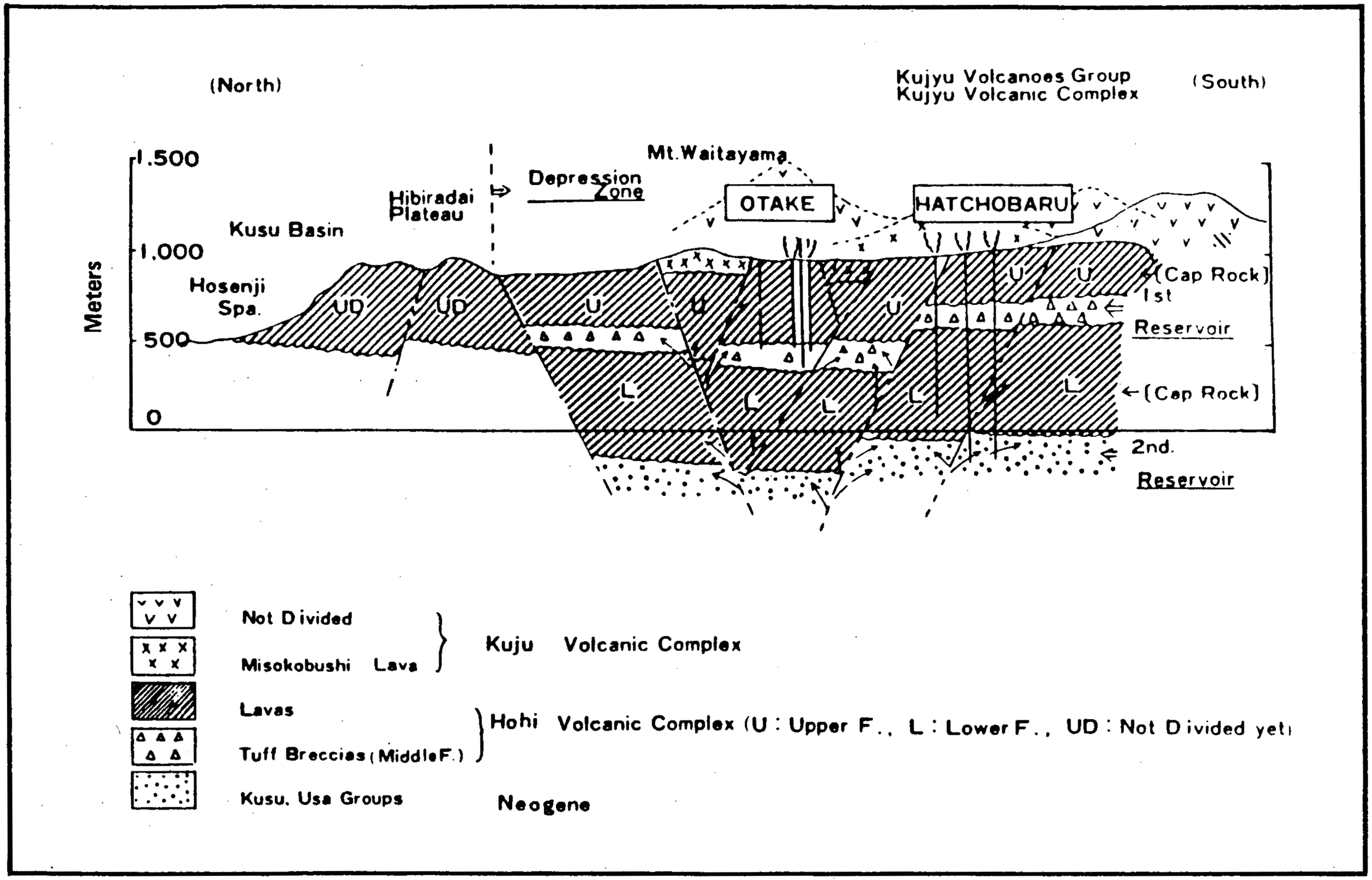

Figure 5.2 Regional geologic cross section through the Otake Geothermal Area (from Yamasaki et al., 1970).

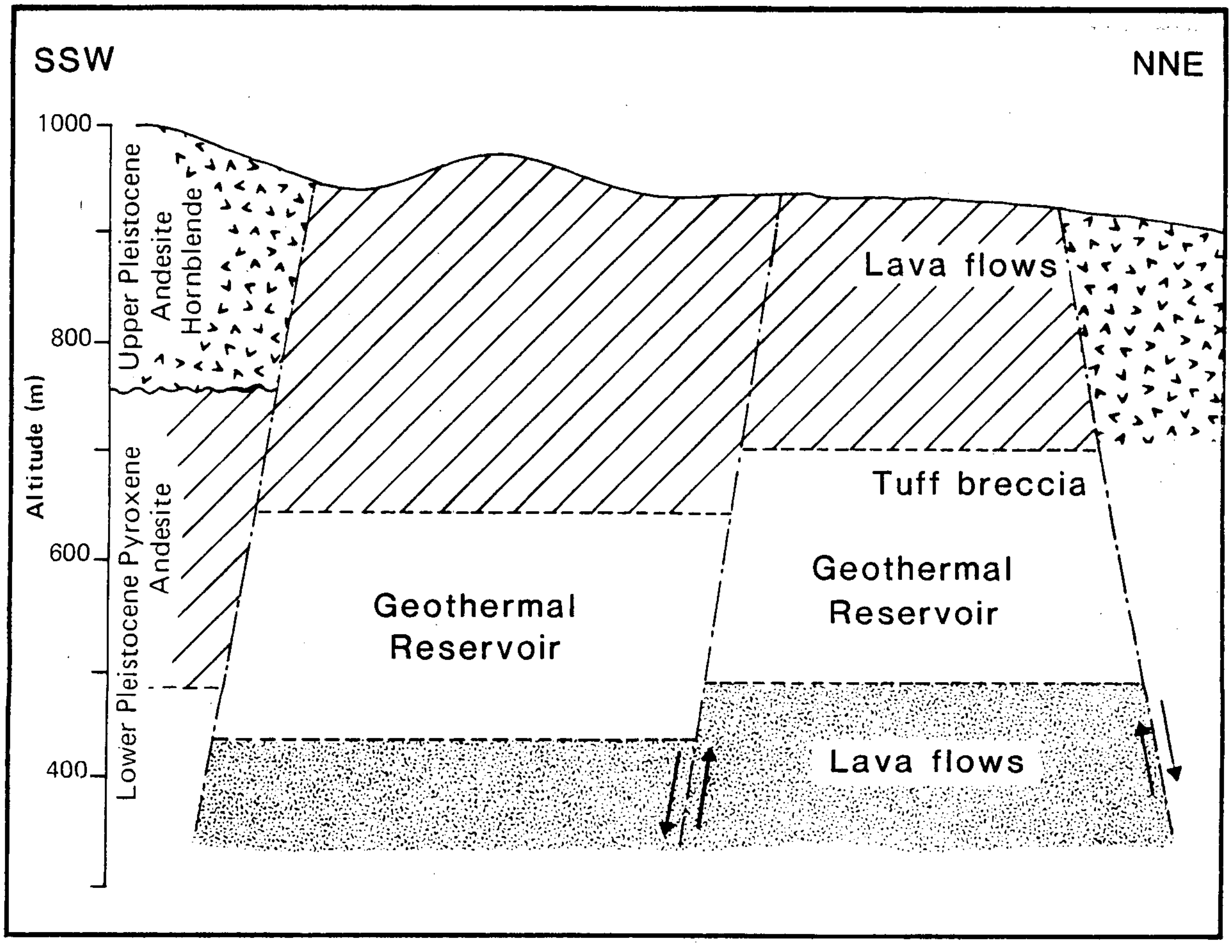

Figure 5.3 Schematic cross-section showing faults and the geothermal reservoir in the Otake Geothermal Area, Japan (after Hayashi, et al., 1978).

hydrothermal alteration is known to exist along faults and fracture planes that are or have been in contact with geothermal fluids. The resulting mineralogy of the altered rock indicates whether environmental conditions are acidic or basic. Both situations exist at the Otake field.

The Hatchobaru geothermal field is also a small horst of Quaternary andesites overlying the Miocene basement. Acid conditions and alteration exist as deeply as 600-700 m. Some wells produce acidic sulfate-chloride water. The natural geothermal features here are steam fumaroles.

Many of the confirmed or presumed faults in the Otake Geothermal Area trend NW-SE or east-west. These faults and numerous associated fissures and joints may allow upward flow of geothermal fluids. The resulting surficial geothermal manifestations are fumaroles and hot springs. Fractured permeability may be an important local control on hydrothermal activity (Yamasaki and Hayashi, 1976).

5.3. Hydrology

5.3.1. Surface Water

The Kusu River flows northward through the Otake Geothermal Area passing through the Hatchobaru field and slightly to the west of the Otake field (Fig. 5.1). Both fields have wells placed as closely as 50 m from the river, but no hydrologic connections between injection zones and the surface water have been identified. The chemical characteristics of the Kusu River are unavailable.

5.3.2. Groundwater

There is scant information available on the occurrence and nature of near-surface groundwater in the Otake Geothermal Area. Water levels and groundwater quality are unknown. Table 5.1 describes the hydrogeology of volcanic rocks in the area.

The fractured nature of the volcanic rocks in the area indicate there is high permeability along fracture planes and in brecciated zones. The rapid flow of injected geothermal fluids among wells at Hatchobaru confirms this. Secondary permeability and porosity dominate fluid movement and aquifer productivity in both the geothermal reservoir and overlying aquifer units. The occurrence of fracturing is important to consider for locating production and injection wells.

5.3.2.1. Aquifers

No description of discrete aquifer units is available. The near-surface Kuju Volcanic Complex consists largely of lavas of unknown permeability. This complex is well faulted and fractured as a result of its association with tectonic activity. It conceivably has the ability to receive and transmit geothermal fluids rapidly along fracture planes, providing fractures are well connected. At the Hatchobaru field, fractures are responsible for rapid flows among wells completed near 1000 m in depth. At the Otake field, there is less well interference and apparently less fracture flow among wells completed near 500 m in depth, although fractures and faults are evident.

The andesites in the Upper Hohi Volcanic Complex serve as a confining cap rock to the underlying geothermal reservoir. Fractures permit some vertical fluid migration across the cap rock, as is evidenced by local surficial hot springs and fumaroles. The middle formation of the Hohi Volcanic Complex has dominant permeability in fracture flow and occasionally yields water and steam thermal discharges from tuff breccias at about 200-400 m (Hayashida and Ezima, 1970). Clearly fracture flow dominates both horizontal and vertical permeabilities.

At the base of the Hohi complex and the top of the underlying Kusu Group (or Usa Group, where the Kusu is absent at Hatchobaru) there is an unconformity known as the Pliocene peneplanation (Table 5.1). The upper part of the group just below this unconformity is believed to be a significant and productive geothermal reservoir. The base of the Usa Group is unknown, but the top has been penetrated in the Otake Geothermal Area by Hatchobaru wells. There is substantial steam production in these wells.

5.3.2.2. Groundwater Chemistry

Background groundwater chemistry is not available. Chemistry of geothermal production fluids from the Otake wells 6, 7, 9, 10 and Hatchobaru 1 appears in Table 5.2 . Chemical properties of fluids from both fields are fairly similar despite the approximately 500 m difference in depth between completion intervals.

5.3.3. Geothermal Resource

The liquid-dominated geothermal resource at the Otake Geothermal Area occurs primarily in fractures of the volcanic rocks described in Section 5.2. The great amount of heat stored in these rocks presumably

Table 5.2. Selected water chemistry in geothermal wells in the Otake and Hatchobaru fields of the Otake Geothermal Area, Japan.[a,b,c]

Well	Depth (m)	Temperature (^{o}C)	pH	Conductivity umho/cm	Total Solids	Cl-	SiO_2	Ca^{+2}	Mg^{+2}	Na^{+}	K^{+}	SO_4^{-2}
Otake												
6	500		8.4	2750	2450	1010	414	15.0	4.8	670	70	200
7	350		8.0	3510	3530	1760	525	17.2	6.0	920	100	96
9	550	248[d]	6.7	3500	3810	1630	668	20.7	10.0	940	110	145
10	600		8.0	5100	4030	1720	612	31.2	7.8	1060	140	95
Hatchobaru												
1	785			5400	4720	1900	680					140

[a] Data from Hayashida and Ezima (1970).

[b] Concentrations in mg/l in waters collected at atmospheric pressure; pH measured in cooled waters.

[c] Koga (1970).

originates from ancient and current volcanic activity and constitutes the heat source for geothermal fluids. Large faults have been encountered at depth in geothermal wells. Hydrothermal alteration along fracture planes is evidence of rock-water contact at elevated temperatures and pressures.

Most of the geothermal wells in the Otake field produce a water-steam mixture directly from rock fractures. Well No. 8, however, uniquely discharges saturated steam alone. The production of steam from reservoir fractures is atypical. In most worldwide experience, geothermal steam is produced from the porous medium beneath a confining cap rock (Hayashida and Ezima, 1970). The average temperature of the discharge at Otake is 230°C. Temperatures have reached as high as 250°C (Ellis and Mahon, 1977).

At Hatchobaru, the steam/water ratio is markedly higher than at Otake. This condition makes the potential for power generation more favorable due to higher inlet steam pressures and increased power production capabilities per unit volume. A summary of production and injection appears in Table 5.3. Average and maximum temperatures at Hatchobaru are 250°C and 300°C, respectively (Ellis and Mahon, 1977). Since 1977, a 55 MW (maximum capacity) power plant has been on line at Hatchobaru. A second 55 MW plant is expected to be on line in 1985. By comparison, there is only a 12 MW plant at the Otake field (since 1967) (Yasumichi, 1982). The geothermal production water at the Otake is high in silica and arsenic. The high levels of arsenic prompted the decision to inject the wastes (versus ponding or channel disposal) to protect the Kusu River. Arsenic levels in the Kusu River or in geothermal fluids are not reported in available literature. Silica is on

Table 5.3. Summary of injection and production at Otake and Hatchobaru geothermal fields, Japan, September, 1980.[a]

	Hatchobaru	Otake
Capacity, MW	55	12
1980 production, MW	55	12
<u>Production Wells</u>		
Number of wells	8	4
Average depth, m	1000	500
Total steam, t/h[b]	400	120
Wellhead pressure, kPa	481	304
<u>Reinjection Wells</u>		
Number of wells	14	8
Average depth, m	1000	500
Total flow, t/hr[b]	400	680
Temperature, °C	60 to 95	95
Pressure, kPa	0	0
Configuration	by side equal depths	by side equal depths
Tracer flow rate, m/h	up to 80	0.3
Comments	silica scaling	accepts water from Hatchobaru, at 175 t/hr

[a] (after Horne, 1982)
[b] t/h = tons/hour (mass flow)

the order of 400-600 mg/L (Table 5.2), and silica deposition is responsible for a certain amount of injection well and formation plugging. A similar loss of injectivity has occurred at Hatchobaru as a result of silica deposition.

5.4. Injection

Kyushu Electric Power Company, Inc. has been injecting geothermal fluids at the Otake geothermal field since 1972 to avoid chemical pollution of surface waters. All injection wells at Otake meet a fault plane at depths of 300 to 500 m. These depths correspond to the depth of the primary production zone (Hayashi et al, 1978). Kyushu Electric Power Company has been injecting geothermal waste fluids at the Hatchobaru geothermal field since 1977. At about 1000 m in depth, the Hatchobaru injection wells encounter an unconformity that corresponds to the main production reservoir there (Hayashi et al, 1978). This unconformity is said to represent what is known as the Pliocene peneplanation, an erosional surface documented by Yamasaki and Hayashi (1976).

5.4.1. Injection System

The configuration of injection/production wells at Otake places injection on one side of the field and production on the other, at similar depths (Fig. 5.4). The same side-by-side arrangement is used at Hatchobaru (Fig. 5.5), with injection in the northwest and production in the southeast. Injection and production wells are drilled to similar depths because no other permeable zone for producing or receiving fluids is known to be available. Production and injection wells meet the same

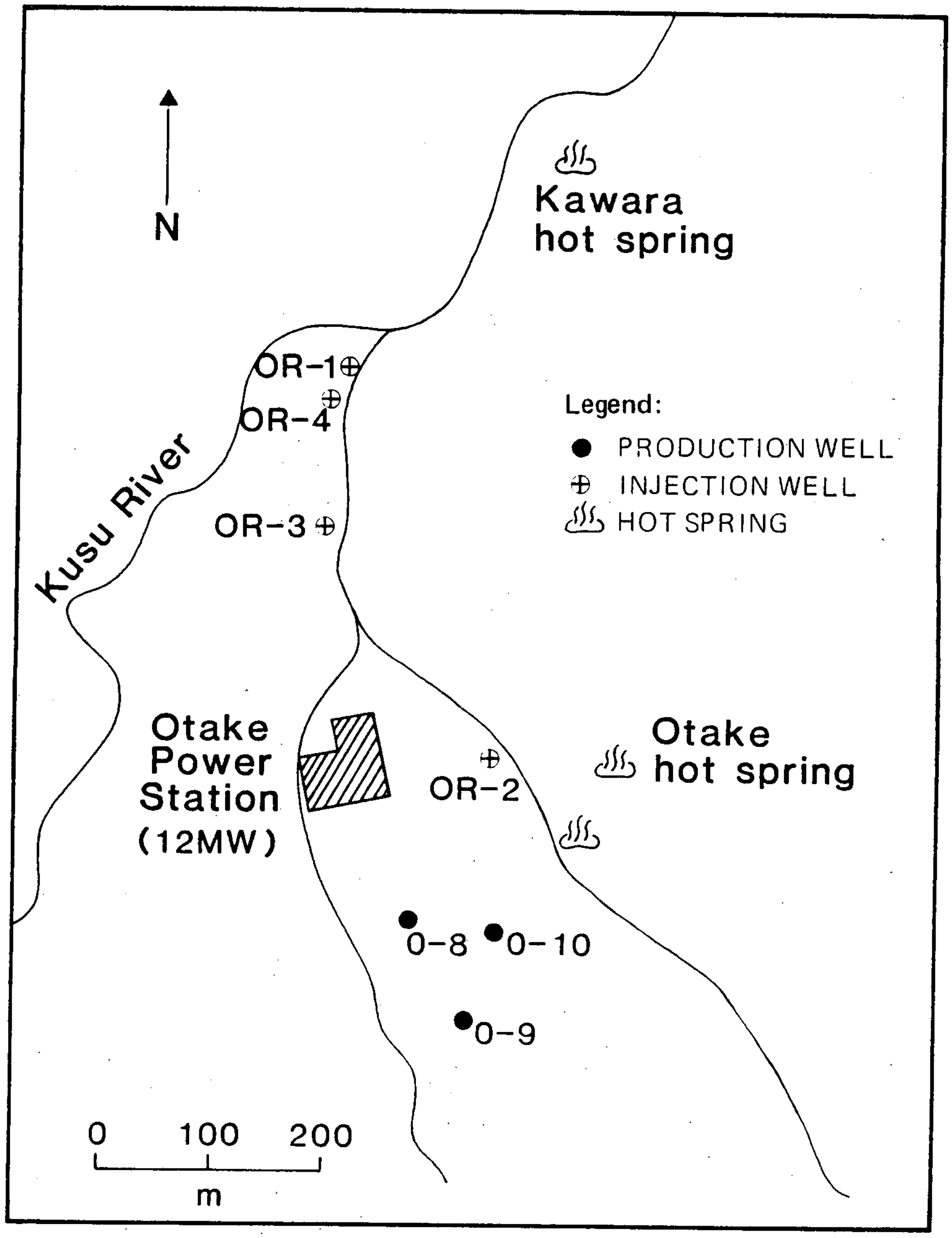

Figure 5.4 Locations of geothermal production and injection wells at the Otake geothermal field, Japan (after Hayashi, et al., 1978).

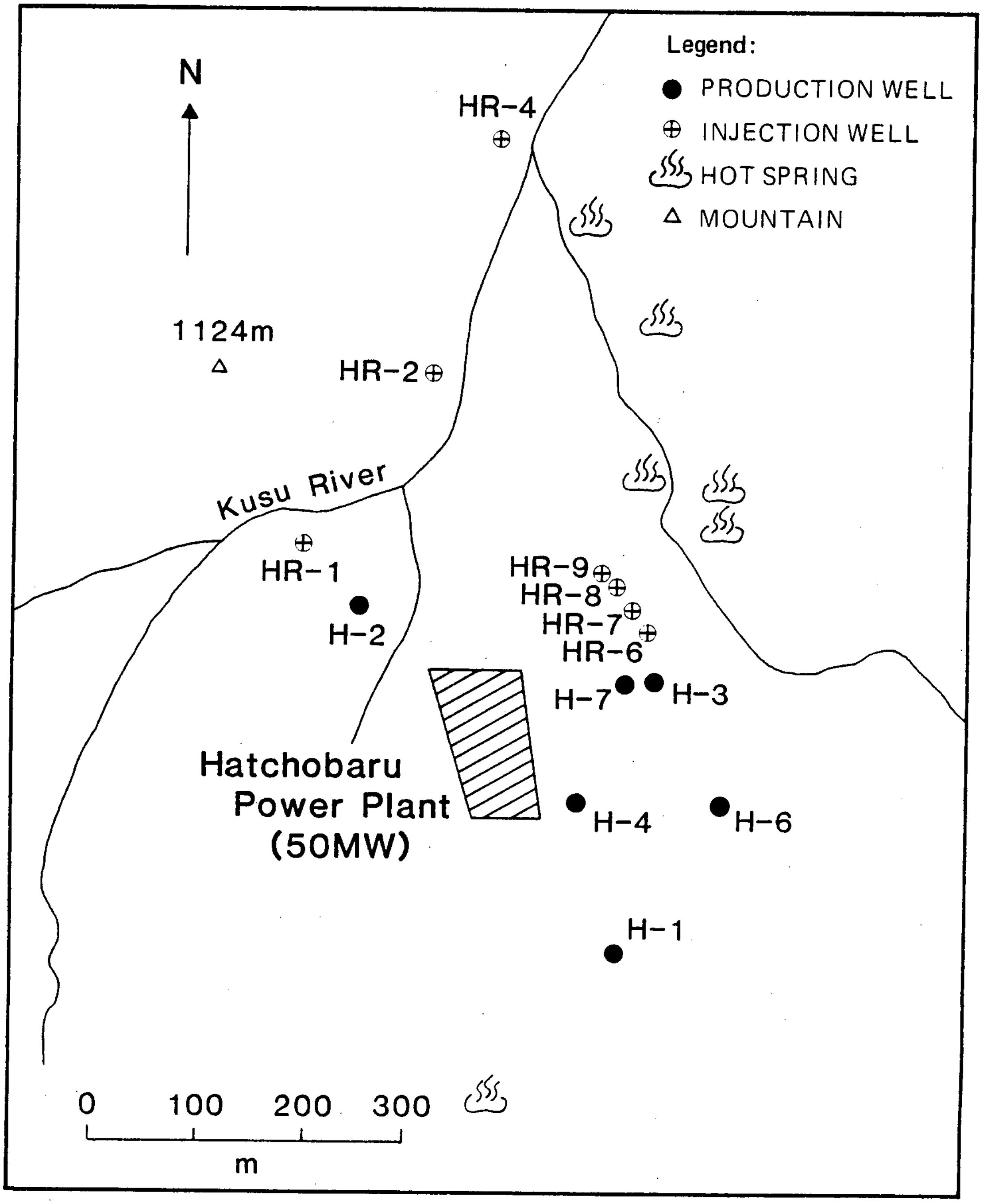

Figure 5.5 Locations of geothermal production and injection wells at the Hatchobaru geothermal field, Japan (after Hayashi, et al., 1978).

unconformity with high permeabilities at Hatchobaru. Otake injection wells encounter a fault plane with high permeabilities. At both Otake and Hatchobaru the hot water is injected at atmospheric pressure.

The 12 MW power station at Otake separates the mixture of steam and hot water with a steam separater at the wellhead. The residual hot water totals more than 400 t/hr (tons/hour), and the full volume requires injection (Kubota and Aosaki, 1976). The total volume of injectate produced at Hatchobaru, including waste water from the station, is about 575 t/hr. This volume is split for injection at both the Otake and Hatchobaru geothermal fields. Otake receives water from Hatchobaru at a rate of 175 t/hr (Horne, 1982b).

The higher steam content at the 55 MW Hatchobaru power station enables the use of a double flash system. Double flashing effectively reduces injection volumes and pressures. The higher steam content permits greater power production per unit volume that must be injected. The final volume requiring injection is substantially reduced from the production volume. A summary of injection and handling at Otake and Hatchobaru appears in Table 5.3.

Some of the injection wellheads at Hatchobaru are very close (<100 m) to production wellheads, although directional drilling of production wells effectively increases the horizontal distance between producing/injecting intervals. Distances between Otake producers and injectors are appoximately 150-500 m.

5.4.2. Monitoring Program

No specific monitoring system is described in the available literature. Temperature and pressure changes are monitored in geothermal wells. These parameters are used to assess reservoir enthalpy. Chemical studies are designed to test for geothermal fluids leaking to the surface. After three years of injection, no leakage was detected (Kubota and Aosaki, 1976). Surface waters are sampled periodically also, primarily for salinity analysis. Detectors are located near injection wells to measure seismic activity.

5.4.3. Injection Testing

Tracer tests utilizing fluorescein dye and potassium iodide at Hatchobaru show there is a strong hydraulic connection between some wells. Tracer returns were detected as early as two hours after injection. The speed of tracer movement in the reservoir has been reported by Horne (1982b) to be as high as 80 m/hr and provides strong evidence that channeling among wells is occurring. Substantial tracer returns have been measured over distances of 600 m. Tracer returns from several Hatchobaru tests appear in Table 5.4. These tracer tests enabled the identification of potential problems associated with channeling flow among wells. The site owner and operator, Kyushu Electric Power, has avoided some of these problems by injecting some Hatchobaru fluids at Otake.

Both production and injection wells at Hatchobaru meet the same unconformity having high permeability. The rapid channeling of fluids among Hatchobaru wells caused a production decline in some wells. Wells

Table 5.4. Resulsts of tracer tests at the Hatchobaru geothermal field, Japan.[a]

Injection Well	Injection Rate (t/h)[b]	Production Well	Production Rate (t/h)[b]	Tracer Flow Speed (m/h)[b]
HR-17	350	H-7	127	78
		H-4	140	76
		H-13	40	58
		H-3	NA	16
		H-14	126	*
		H-10	75	*
H-6	40	H-14	126	35
		H-7	127	29
		H-4	140	8
		H-13	40	2
H-9R	70	H-13	40	62
		H-7	127	*
		H-4	140	*
H-3[c]	NA	H-6	NA	33.8
		H-7	NA	9.0
		H-4	NA	6.1

[a] Kyushu Electric Power Company, 1979, reported by Horne, 1982b.
[b] t/h = tons/hour; m/h = meters/hour
[c] Hayashi et al., 1978
NA = No data available
* Secondary return only

H-4 and H-7, which repeatedly showed evidence of tracer returns, have experienced declines in two-phase flow rates. Well H-4 is no longer in production. Enthalpies in all production wells at Hatchobaru have decreased as a result of thermal and hydraulic interference (Hayashi et al, 1978). Predictably, overall field performance has declined.

Tracer tests performed at Otake indicate the speed of tracer movement is about 0.3 m/hr (Hayashi et al, 1978). It took around 600 hours for a tracer injected into OR-2 to reach wells 0-8, 0-9, and 0-10 (Table 5.5). The rapid channeling of flow seen at Hatchobaru does not occur at Otake, indicating little communication among wells at Otake.

Table 5.5. Results of a tracer test using KI at the Otake geothermal field, Japan.[a]

Production Well	Well Distance From OR-2 (m)	Detection Time (hr)	Flow Speed (m/hr)
0-8	125	580	0.215
0-9	203	620	0.327
0-10	140	650	0.215

[a]Kyushu Electric Power Company, 1976, as reported by Hayashi et al., 1978

Injection solely as a means of waste disposal appears to be successful at Japanese geothermal fields. Permeable zones that will accept large volumes of water are available. Injection as a means of reservoir maintenance is less successful. In other worldwide experience, injecting waste fluids is a way to recycle fluids and glean more heat from reservoir rocks. Stablizing declining production pressures by injecting fluids prolongs the productive life of the geothermal reservoir. The Japanese experience is clearly one of detrimental effects. The close well spacing and hydraulic communication at Hatchobaru have allowed hydraulic breakthrough to occur too rapidly, so that the declines in enthalpy have actually reduced productivity. The same reduction in productivity has been observed at other Japanese geothermal fields. Injection at Otake temporarily increased vapor flow, thereby improving productivity. Eventually, however, a production well located near the permeable fault plane penetrated by the injection wells was totally damaged as a result of thermal interference. By 1975, the improvement stopped, and the field's former rate of production decline, observed before injection, resumed (Horne, 1982a).

Silica deposition resulted in a loss of injectivity in both Otake and Hatchobaru injection wells. The feasibility of removing silica and arsenic is being examined by the site operator.

After injecting continuously for three years at Otake, the static water level in the injection well OR-1 has risen at least 30 m. As of 1976, the depth to water was 120 m (Kubota and Aosaki, 1976). No evidence of seismic activity induced by injection has been recorded.

5.4.4. Constraints on Injection

The geothermal wastewater at Otake has been injected since 1972 because of its arsenic content. No report of arsenic levels was available for this report, but disposal to a pond prior to 1972 was considered to be a threat to nearby surface waters, including the Kusu River.

Available literature does not mention ground subsidence associated with geothermal fluid withdrawal or injection in Japan. The production/injection zones at both Otake and Hatchobaru are in competent volcanic rocks, thus significant subsidence would not be expected to result from fluid withdrawal. Some seismic activity has been associated with fluid injection at the Matsushiro geothermal field in Japan (Ohtake, 1974), but not at Otake or Hatchobaru.

Legally, there is great environmental concern about protecting Japanese national parks and scenic areas (Nakamura et al., 1976). A number of these areas are located near geothermal developments. The extent to which environmental laws govern injection specifically is unknown, but the decision to inject at the Otake field, at least, indicates environmental concern.

The potential for degrading usable groundwater as a consequence of fluid injection at the Otake Geothermal Area is minimal. There is naturally occurring upward migration of geothermal fluids, as indicated by surficial hot springs and fumaroles. Upward flow is probably along fracture planes as there are several volcanic units that behave as aquicludes to vertical porous media flow. These conditions probably preclude the contamination of surface waters or usable groundwaters on a large scale. Injection at Hatchobaru and Otake occurs at 0 kPa, so the high pressures commonly required for injection in other systems are absent. The low injection pressures also help minimize any induced increase in upward fluid flow. In the Hatchobaru field, the rapid hydrodynamic breakthrough of injected fluids at the production wells indicates that the injected fluids are flowing along preferential flow paths, possibly fractures, toward the production wells. The net mass extraction at both fields reduces reservoir pressures creating a pressure sink in the production zone. Injected fluids are likely to follow the steeper hydraulic gradient toward the pressure sink. This preferred flow path could actually reduce the hydraulic potential for upward fracture flow. Increased contact of geothermal fluids with fresh groundwater in overlying aquifers as a result of fluid injection seems an unlikely prospect in the Otake Geothermal Area.

Several technical constraints exist. At five injecting geothermal fields (Otake, Hatchobaru, Onikobe, Kakkonda, and Onuma), only Otake has not experienced severe problems with hydrodynamic breakthrough. Closely spaced production and injection wells at Hatchobaru are strongly connected by reservoir fractures; thus cooled injected fluid rapidly reaches the production area and decreases the enthalpy of the steam and water discharge. The resulting loss of productivity precludes 100% injection and has forced partial injection of Hatchobaru water at Otake, where communication between wells is less.

There are decreases in injectivity over time at both Hatchobaru and Otake due to silica deposition. Injectivity is simply the ability of the reservoir (and/or injection well) to accept large volumes of fluid. The detrimental near-well effects have required Kyushu Electric Power Co. to do research on the removal of silica from injection water (Horne, 1982a).

5.5. Summary

Geothermal activity in Japan is associated with regional tectonic and volcanic activity. At the Otake Geothermal Area, groundwater aquifers and geothermal reservoir are comprised of volcanic rock series. There is high permeability along fault and fracture planes and in brecciated zones. These permeable horizons are capable of producing and accepting large volumes of fluid. In the Hatchobaru geothermal field, there is substantial and rapid communication among closely spaced injection and production wells drilled to about 1000 m. As a result, temperatures in Hatchobaru production wells have declined, thereby diminishing two-phase flow. This production decline has occurred in several other Japanese fields also. The Otake geothermal field has not experienced this severe loss in productivity. Productivity declines are at steady rates expected from normal development. There is no apparent channeling among wells drilled to about 500 m.

Injection occurs at the Otake Geothermal Area because of concern for polluting surface waters with arsenic. Regular chemical analysis of water samples had not revealed any evidence of geothermal fluid migration to the surface as of 1976 (Kubota and Aosaki, 1976).

There is a dominant horizontal component to groundwater flow in the Otake Geothermal Area. Layered volcanic tuffs and lavas effectively restrict upward flow, presumably to localized fracture zones. Surficial hot springs and fumaroles are evidence that geothermal fluid does migrate to the surface.

6. AHUACHAPAN GEOTHERMAL FIELD, EL SALVADOR

6.1. Introduction

Ahuachapan is one of several geothermal fields in El Salvador. It is located in the far western portion of the country about 40 kilometers from the Pacific Ocean and about 20 kilometers from the Guatemalan border (Fig. 6.1). The liquid-dominated geothermal reservoir has a base temperature of about 240°C (Grant et al., 1982) but temperatures up to 300°C have been reported (Cuellar et al., 1981).

A two-unit 60 MW power plant has been operating since 1975-1976. In 1977 these units produced 32.3% of the total electric power generated in the country (Cuellar et al., 1981). A third unit with a 35 MW capacity came on line in 1982, boosting the total generating capacity at Ahuachapan to 95 MW. Einarsson et al. (1976) estimate the full potential of the geothermal field to be 100 to 200 MW.

6.2. Geology

The regional geology of El Salvador is a structural graben that trends east-west across the country. The trough is filled with Quaternary volcanic cones that comprise a major volcanic chain across the country.

The Ahuachapan geothermal field is on the northeastern slopes of a range of composite Quaternary volcanoes at an elevation of about 800 m above sea level. It is associated with the southern flank of the central Salvadoran graben median trough. Pliocene tectonic activity produced extensive regional faulting believed to have controlled the sinking of the graben and the extrusion of volcanic material. The field is lower to

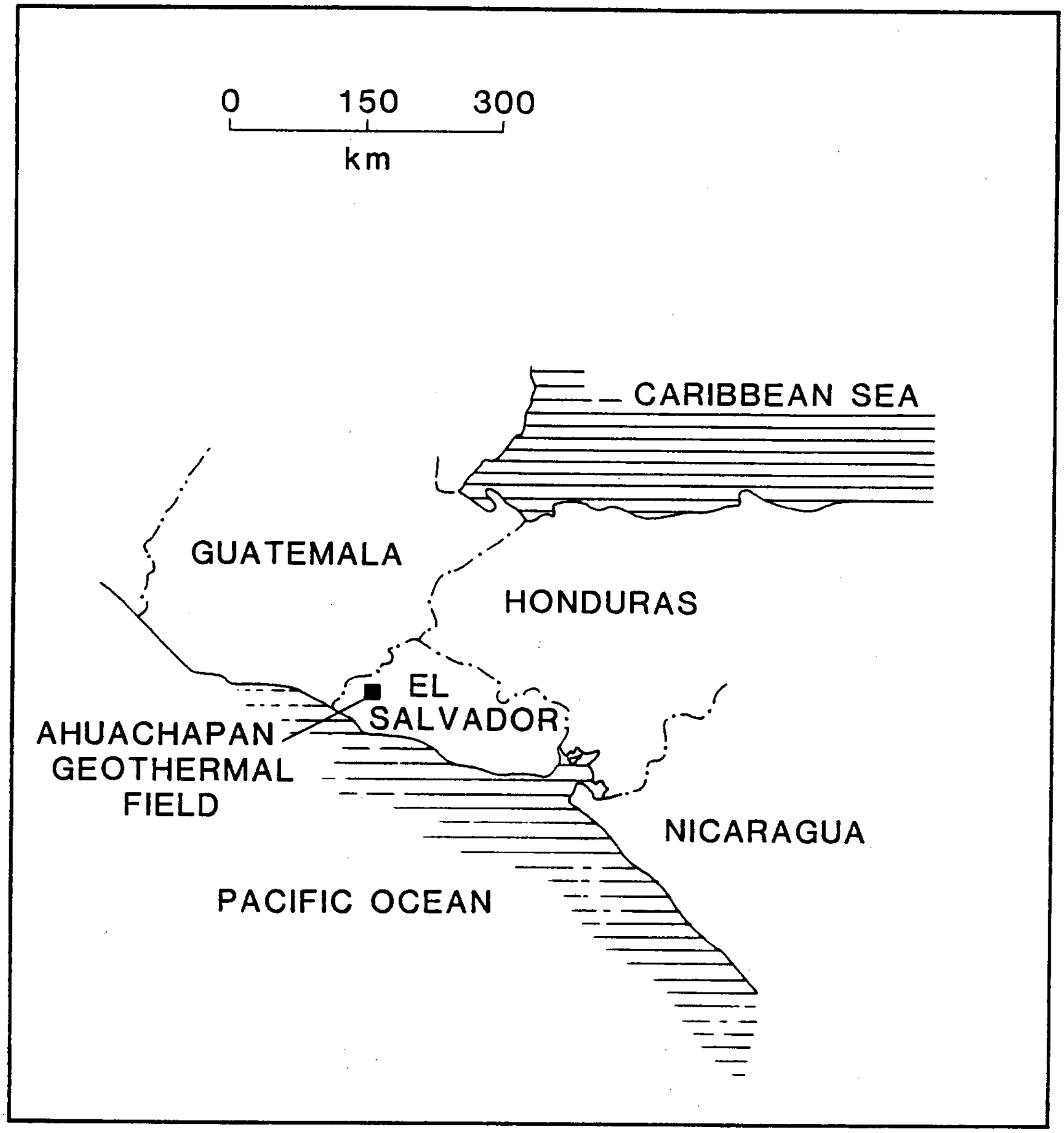

Figure 6.1 Location of Ahuachapan geothermal field, El Salvador.

the north and northwest, reflecting the subsidence of the graben (Cuellar et al., 1981).

Faults and fractures oriented in 3 main directions seem to control regional and local structure. A series of step faults, trending parallel to the graben structure in an E-W direction, limits the geothermal field on the north. A second NE-trending fault system borders the field to the west. Finally a younger system of faults and fractures, associated with superficial hydrothermal activity, trends NNW. This latest system of faults may be responsible for the fractured permeability of the Ahuachapan reservoir formations (Cuellar et al., 1981). The stratigraphic sequences of the area are described in Table 6.1 and shown in Figure 6.2.

6.3. Hydrology

Intensive geothermal investigations at Ahuachapan have revealed a very permeable geothermal flow system limited by structural faults at its edges. Regional flow within the graben is toward the north. Hydrogeology outside the geothermal field is poorly understood. Initial injection attempts indicate permeability decreases outside the geothermal field.

6.3.1. Surface Water

The Paz River forms the border between El Salvador and Guatemala. It is the principal river draining the Ahuachapan geothermal field. Flow in the river is variable according to seasons, but may be as low as 10 to 15 m^3/sec in the dry part of the year (Einarsson et al., 1976). The

Table 6.1. Geologic and hydrologic characteristics of the Ahuachpan geothermal field, El Salvador[a].

Geologic Unit	Geologic Description	Hydrologic Description
Surficial Deposits	Tuffs and detritic-talus pumices covering lavas of the Laguna Verde Complex.	<u>Shallow Aquifer</u> - very shallow unconfined aquifer with variable flow responding rapidly to rainfall infiltration; waters generally of calcium carbonate type, locally sulfatic; aquifer of local interest only in uphill part of geothermal field; feeds some surface springs.
Laguna Verde Volcanic Complex (Holocene)	Andesitic lava flows with some pyroclastics; thinkness up to 200 m.	Behaves as an aquiclude to shallow and saturated aquifers.
Tuff and Lava Formation (Pleistocene)	Predominantly tuffs in the upper part; lava intercolations with tuffs in the lower part; thickness up to 500 m.	<u>Saturated Aquifer</u> - recharge by direct infiltration; shallow free surface tapped by local domestic wells; surfaces at several springs on the plain north of the geothermal area; principal northerly flow component; slow piezometric response to rainfall; generally calcium-sodium carbonate water, locally mixed with water migrating upward along fractures from saline aquifer.
Young Agglomerate (Pleistocene)	Volcanic agglomerate with occasional lava intercalations; thickness up to 400 m.	Essentially impermeable, save for scattered faulting; behaves as a confining cap rock to the underlying geothermal reservoir.
Andesites of Ahuachapan (Plio-Pleistocene)	Lavas with pyroclastic intercalations; contains columnar jointing related to cooling and tectonic fracturing; thickness up to 300 m.	<u>Saline Aquifer</u> - producing formation of the geothermal reservoir; secondary, anisotropic permeability in joints, fractures and contact surfaces between formations.
Ancient Agglomerates	Agglomerates with breccia intercalations in the lower portion; thickness greater than 400 m.	Moderate permeability in breccias; receiving reservoir for injected fluids.

[a]Cuellar et al., 1981.

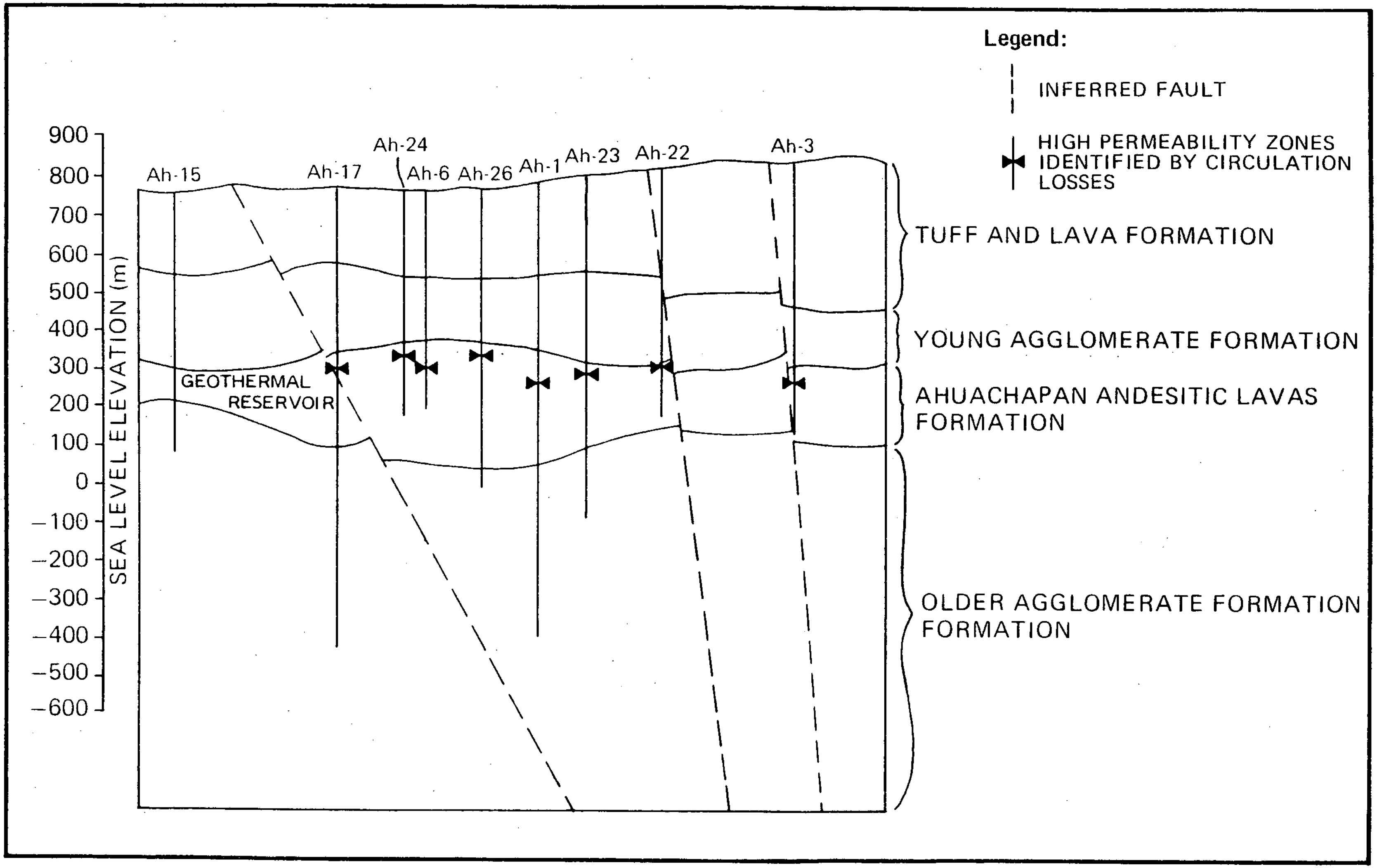

Figure 6.2 Geological section and selected geothermal wells of the Ahuachapan geothermal field, El Salvador (after Cuellar, et al., 1978).

river was initially considered as an avenue for geothermal waste fluid disposal, but was found to have severe long-term limitations. River water is used for irrigation and must be protected from chemical contaminants that might be harmful to crops. Boron, for example, would have to be strictly limited. Secondly, the river is only able to accommodate volumes equivalent to those produced by a 30 MW plant. This is a fraction of the volume requiring disposal today and would prove to be even less adequate as the full estimated potential of the geothermal field is reached.

6.3.2. Groundwater

The Ahuachapan geothermal area is a groundwater discharge area. The pressurized thermal fluids rise from the southeast and east and ultimately discharge at the surface further north. The surficial geothermal activity within the geothermal area originates from steam that separates from geothermal fluid in the deep geothermal reservoir and migrates upward along fracture planes. The principal permeability in the volcanic rocks at Ahuachapan is in secondary faults and fractures. The permeability is therefore variable and anisotropic. Highest transmissivities are assumed to be horizontal and oriented in the directions of the predominant fault trends described in Section 6.2 (Cuellar et al., 1981).

There is some local domestic use of groundwater in the uphill southern portion of the structural graben that defines the geothermal field. These local wells tap the Shallow and Saturated Aquifers described in Table 6.1.

6.3.2.1. Aquifers

There are three producing aquifers in the Ahuachapan field. Their descriptions appear in Table 6.1. All three exist in fractured volcanic rocks. The unconfined Shallow and Saturated Aquifers supply local domestic wells on the southern uphill end of the geothermal field. Rainwater infiltration to the Shallow Aquifer feeds several springs on the slopes of the Laguna Verde and the Laguna de Las Ninfas volcanoes. The flow rate in this aquifer responds rapidly to rainfall. The shallow free surface of the Saturated Aquifer also supplies several springs on the plain north of the geothermal area. Its piezometric surface, however, responds slowly to rainfall. The hydraulic gradient and resulting principal flow component in this aquifer is to the north (Romagnoli et al., 1976). The graben dips slightly in that general direction. The confined Saline Aquifer is the geothermal reservoir. The geothermal wells are completed in this aquifer. The Saline Aquifer is discussed in more detail in Section 6.3.3.

The geology, natural flow, chemistry and the depths of permeable zones all indicate there is a strong horizontal structure to the Ahuachapan geothermal area (Grant et al., 1982). Horizontal and vertical permeabilities in each aquifer are greater along faults, fractures, joints and bedding planes than through the aquifer media. The occurrence of fractures is clearly indicated by the loss of circulation during drilling. This anisotropy results in variable but predominantly horizontal flow within the aquifer. Production capacities are hard to predict. The selection of sites for production and injection wells in such a system can be difficult when considering economic production requirements and reservoir maintenance.

The Shallow and Saturated Aquifers are separated by an aquiclude of andesitic lavas that retards vertical flow. The rate of leakage across this unit is unknown, but the presence of surficial thermal springs in the area is evidence that vertical migration does occur.

The Saturated and Saline (geothermal) Aquifers are separated by a thick, impermeable volcanic agglomerate that acts as a confining cap rock to the underlying geothermal reservoir. Fractures do breach the cap rock, however, and pressurized geothermal fluids are able to move along fracture planes toward the surface.

6.3.2.2. Groundwater Chemistry

Groundwater in each aquifer has a characteristic background chemistry, but the fractured vertical permeability of the Ahuachapan geothemal field allows some localized mixing of waters from different aquifers. Water in the Shallow Aquifer is generally of the calcium carbonate type, although locally they may be sulfatic with residues lower than 500 mg/l (Einarsson et al., 1976).

Specific ion concentrations for background chemical species in the Shallow and Saturated Aquifers are unavailable. Chemical characteristics of some thermal springs are in Table 6.2. Values for chemical species in the springs may be influenced by a certain amount of mixing of deep thermal water or steam and shallower groundwater. The groundwater of the Saturated Aquifer is generally of calcium-sodium carbonate type. Dissolved solids are below 400 mg/l. The Salitre spring, by contrast,

Table 6.2. Selected chemical and physical characteristics of waters from thermal springs and geothermal wells of the Ahuachapan geothermal area, El Salvador[a,b].

Source	Well depth[c] (m)	Temperature °C	pH	Na^+	K^+	Ca^{++}	Mg^{++}	Cl^-	$SO_4^=$	HCO_3^-	SiO_2	B
Thermal Springs												
A		31	7.1	20	6	17	9	1.2	3.0	158	117.0	0.3
B		26	8.0	13	13	14	7	2.1	1.0	111	107	8.0
C		22	6.2	6	1	15	2	1.2	3.0	75	65	6.2
D		25	8.2	10	3	15	8	1.4	3.0	114	102	8.2
E		30	8.0	26	1	54	13	2	9.5	290	64	8.0
F		87	8.0	768	18	201	1	1,528	224	52	114	8.0
G		93	8.3	526	19	124	tr	421	870	45	77	8.3
H		85	8.0	566	9	124	1	772	410	37	81	8.0
I		99	8.2	592	15	94	tr	716	504	33	108	8.2
L		25	7.6	5.4	10	8	2	1.3	4.5	39	46	7.6
M		70	6.8	378	39	29	8	479	35	377	235	6.8
Geothermal Wells												
Ah-1	1205	98[d]	7.4	6120	995	416	tr	11,046	28	29	663	7.4
Ah-6	591	97[d]	7.2	6260	1055	443	tr	11,432	27	24	620	7.2

[a] Romagnoli et al., 1976.

[b] Concentrations in mg/l.

[c] Cuellar et al., 1981.

[d] Ellis and Mahon (1977, p. 70) report 230°C at a source depth of 1195 m.

has a sodium-chloride chemistry and an elevated temperature (70^{o}C). It has higher residues of 600-1700 mg/l. The differences in chemistry and temperature are believed to be a result of admixture with water from the deep Saline Aquifer that is moving upward along fractures (Romagnoli et al, 1976).

The Saline Aquifer is the producing geothermal reservoir. Waters in the Saline Aquifer are a sodium-chloride type with high salinity. Residues reach as high as 22,000 mg/l (Einarsson et al., 1976). Chemical concentrations measured in geothermal wells Ah-1 and Ah-6 are presented in Table 6.2.

6.3.3. Geothermal Resource

The Ahuachapan andesite is the producing reservoir of geothermal steam and water in the Ahuachapan geothermal field. The highly fractured permeable zone at the top of the formation is known as the Saline Aquifer. Temperatures in this aquifer are around 240-245^{o}C (Einarsson et al., 1976).

A hydrogeologic model of the system indicates the Ahuachapan field is a discharge area. Geothermal fluids are thought to rise from the east and southeast from some unknown source, travel primarily horizontally through the reservoir via fractures, and discharge further north. Surficial thermal activity is attributed to steam and hot water separating from deep geothermal fluids, migrating upward along fracture planes, and mixing with discharges from shallower aquifers. Resistivity data (Romagnoli et al., 1976) support this model as it applies to the origin and chemistry of the surficial thermal springs.

6.4. Injection

The highly mineralized waters produced by the Ahuachapan geothermal field presented a major problem in the initial stages of field development. Arsenic and boron, in particular, represented potential threats to irrigation waters and domestic supplies. Total disposal to the Paz River and desalination proved to be unacceptable alternatives, so injection experiments for subsurface disposal began in 1970. These large-scale experiments were designed to test and evaluate methods of injecting highly mineralized geothermal water and were concluded to be generally very successful (Einarsson et al., 1976).

The spent geothermal fluids are injected within the active hydrothermal system for several reasons. Little was known about deep hydrologic conditions outside of the geothermal system. There was concern that injected fluids might emerge in an undesirable place and create local pollution problems. Within the undisturbed geothermal system, the very mineralized water did not emerge from the reservoir near unpolluted water supplies. Simultaneous production and injection was expected to minimize disturbance and the potential for new emergence of poor quality water. The high reservoir permeability would reduce energy costs for pumping also. The cooling effect of waste fluids on the geothermal reservoir was expected to be small. Finally, injection offered a means of recycling fluid and heat within the reservoir, thereby extending its productive life (Einarsson et al., 1976). Continued injection since 1970 apparently had no adverse effects on production wells until 1978, when some temperature declines were observed

(Grant et al., 1982). A continuous production/injection program began in 1975 and has been operating ever since.

6.4.1. Injection System

As of 1978, twenty-nine production and injection wells had been drilled in the Ahuachapan geothermal field. Fig. 6.3 shows the relative locations of most of these wells. Depths of the wells ranged from 591 m to 1524 m. All wells are located within an area about 4 km^2 in size. Two injection wells were located outside the production area to minimize potential interference with production wells. Four of the twenty-nine wells are injection wells (Ah-2, Ah-8, Ah-17, and Ah-29). Wells Ah-17 and Ah-29 are double purpose wells and may be used for production also. Their location is close to the production wells, and they are completed in the production reservoir. The lithologic columns of Ah-17 and Ah-29 indicate they are completed in 400 m and 325 m of reservoir thickness, respectively. Injection Ah-2 and Ah-8 are also completed in the production reservoir. They show a reservoir thickness of only 105 m and 75 m, respectively (Cuellar et al., 1981). Total depths of all the injection wells are not given. Depths of production wells appear in Table 6.3. Figure 6.2 shows the relative depths of some of the geothermal wells and permeable zones in the geothermal reservoir. The well field arrangement is thus one of areally interspersed injection and production wells. It is not known how closely injection horizons in Ah-2, Ah-8, Ah-17, or Ah-29 correspond to producing horizons in production wells.

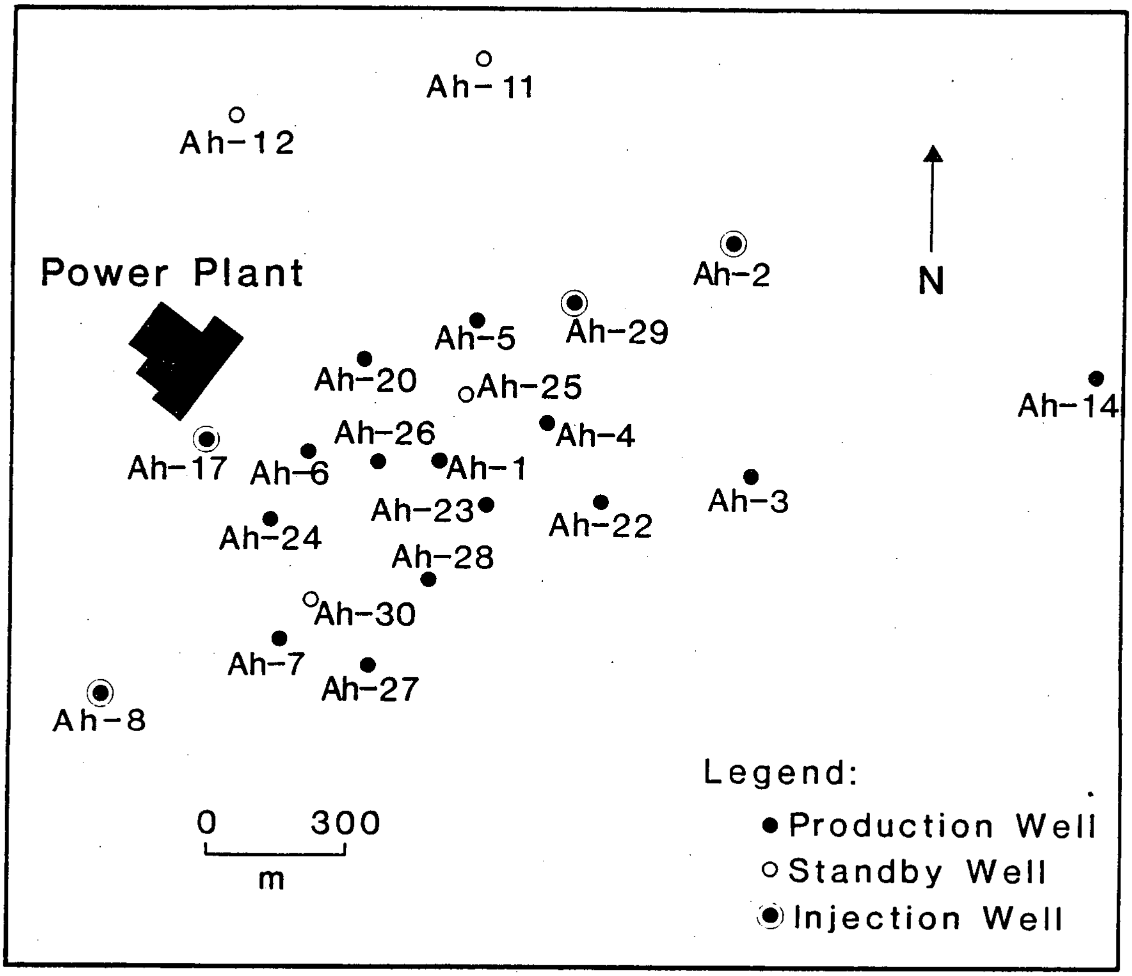

Figure 6.3 Locations of geothermal production and injection wells in the Ahuachapan geothermal field, El Salvador (after Cuellar et al., 1978).

Table 6.3. Depths of Ahuachapan geothermal production wells, El Salvador[a].

	Ah-1	Ah-4	Ah-5	Ah-6	Ah-7	Ah-20	Ah-21	Ah-22	Ah-24	Ah-26
Total depth (m)	1205	640	952	591	950	600	849	659.5	850	804
Top of andesitic formation (meters above sea level)	300	315	284	383	285	370	350	315	380	391

[a]Cuellar et al., 1981.

Fluid extraction at Ahuachapan has been divided into two periods of development and production. Estimates of extracted and injected mass during those periods appear in Table 6.4. Only a fraction of the total fluid mass produced is returned to the reservoir after steam flashing. Injection, even on a scale that is small relative to production, apparently stablizes pressure losses in the reservoir, and the dominating effect of extraction or injection is difficult to determine (Cuellar et al., 1978).

Table 6.4. Extracted and injected mass during development and production periods at the Ahuachapan geothermal field, El Salvador.

Mass (tons)	Development 1968-1975	Production 1975-1978	Total
Extracted	23,317,800	48,228,933	71,546,733
Injected	1,850,060	19,218,384	21,068,444
Net extracted	21,467,740	29,010,549	50,478,289

[a] Cuellar et al., 1978.

6.4.2. Monitoring Program

A monitoring system was established at Ahuachapan to ascertain the effects of injection of the Shallow and Saturatad Aquifers. These aquifers are the source of potable water for domestic supplies, and the potential for contamination from the mineralized geothermal water is of concern.

A system of observation points including water wells, surface springs and boreholes provided water samples which were chemically analyzed before and during the period of initial injection testing. The purpose of these analyses was to determine how quickly and to what extent injected fluid would migrate from the injection well to the shallow aquifers or to production wells in the geothermal field. These observation points continue to provide useful monitoring data. A discussion of some injection test results as determined from monitoring data is in Section 6.4.3.

6.4.3. Injection Testing

Initial plans for injection at Ahuachapan called for injecting in a well (Ah-10) outside of the active geothermal area. Permeabilities in the penetrated formations were too low to accept the required volumes of fluid without excessively high pumping costs. Subsequent injection has occurred within the active geothermal system.

The silica and carbonate composition of the water posed a danger of chemical fouling of equipment and plugging the receiving formation. A study of chemical equilibria and physical factors governing reactions indicated that if steam and water were separated above 150°C, and if the water was maintained at this temperature until injection into the reservoir, mineral deposition could be avoided (Einarsson et al., 1976). The separator and injection system were set and maintained at 152-153°C.

6.4.3.1. Single-Well Tests

Well Ah-5 was the first experimental injection well at Ahuachapan. It was designed as a dual purpose well, primarily for production but also for injection experiments. Ah-5 penetrates the principal production horizon at about 500 m depth as well as another permeable horizon at about 800 m. A retractable, perforated liner was installed extending from the production casing to the bottom of the well at 952 m. This design was an attempt to inject the water into the deeper permeable horizons. The single-hole tests described here were done on Ah-5.

A total of 1,927,000 tons of water were injected in a series of injection tests over a period of 244 days in 1971. Downhole temperature logs were made in the injection well before, during and after injection testing. Cooling occurred over the entire length of the well but was greatest in the deeper permeable horizon, indicating the waste fluids were entering the reservoir at that point. Temperature recovery was slowest in the deeper zone. Full recovery took nearly seven months (Einarsson et al., 1976). Pressure profiles for Ah-5 taken before and during injection show a decrease in pressure in the deeper zone, which supports the conclusion that it is highly permeable.

Caliper tests of the injection well casing and inspection of the pipeline showed there were no traces of scaling within the system. No plugging or increased pressures could be attributed to mineral deposition. After 244 days there appeared to be no danger of system impairment due to scaling under the described test conditions (Einarsson et al., 1976).

6.4.3.2. Multi-Well Tests

During early testing at Ahuachapan geothermal field, variations in temperature, pressure, chemistry and the detection of injected tracers were used to monitor movement of injected fluids (Einarsson et al., 1976). Monitoring stations included geothermal wells, shallow fresh-water wells, and surficial springs. Except for low-level tracer detection, no changes were seen. Tritium injected into Ah-5 appeared in low levels at geothermal production wells Ah-1, Ah-6, and Ah-7. The tritium may have moved horizontally toward these wells. It may also have descended in the reservoir with the injected fluids (that are cooler and denser than native fluids), become diluted, then ascended with convection currents in the reservoir (Einarsson et al., 1976). No tracer was detected in surface springs or shallow wells.

It was determined that a chemical front precedes a cooling front of injected fluids. The cooling front is marked by the actual cooling of the reservoir rocks by injected fluids. Cooling of production zone rocks by injectate has been technically called thermal breakthrough. The chemical front is a determination of where the leading edge of the injected plume is located. Hydrodynamic breakthrough occurs when this plume reaches the producing zone. Long-term monitoring at Ahuachapan has shown that the concept of hydrodynamic breakthrough is useful in monitoring the movement of injected fluids. Repeated analyses for chloride in production wells have given some indication of the general direction of flow from injection wells. Injection wells Ah-17 and Ah-29 penetrate permeable zones at different depths. Water injected into Ah-29 moves toward the center of the geothermal field and to the east. Water injected into Ah-17 flows to the center of the geothermal field (Cuellar et al., 1981). No breakthrough to shallow groundwater has been documented.

Pressure responses in the geothermal field are very sensitive to varying rates of production and injection. Production Testing in 1975 indicated the reservoir pressure gradually declined as a result of net mass extraction. As a result, production rates fell. Injection effectively stablized the pressure and a new equilibrium state was established. Injection at Ahuachapan also helps build a steam zone which can be developed. Pressure distributions before and after intensive production showed that regional pressure declines tend to follow the permeable reservoir toward the south (Cuellar et al., 1981). It is unknown whether or not pressure changes in shallow wells as a result of geothermal development have been documented.

6.4.4. Constraints on Injection

There is some concern that subsurface injection near vertical fractures on faults could allow highly mineralized fluids to migrate upward and contaminate the shallow groundwater. This phenomenon has not been documented. The reservoir cap rock composed of Ahuachapan andesites (up to 400 m thick), is impermeable and confines the geothermal reservoir. It is an effective barrier to vertical flow. The variable density between cooled injected fluids and hot, native reservoir fluids may result in the downward flow of the more dense injectate instead of channeled horizontal flow or natural upward discharge.

The primary constraints on injection at the Ahuachapan geothermal field are related to reservoir management. The volume of the geothermal reservoir has been estimated to be 100 km^3 (Einarsson et al., 1976). Large scale production over many years, however, can advance the cooling of reservoir rocks and ultimately reduce productivity. Rapid flow of injected fluids along fractures can hasten this decline. Spacing of injection and production wells is a critical factor affecting the life of the reservoir. Intensive studies of the Ahuachapan geothermal system concluded that injection and production zones should be spaced at least 1.1-1.5 km apart. It was recommended that water should be injected several hundred meters below the producing horizons (Einarsson et al., 1976).

6.5. Summary

Groundwater in the Ahuachapan geothermal field occurs in relatively flat-lying volcanic rocks of a structural graben. Regional tectonic activity caused faulting, the formation of the regional horst and graben structure, and the extrusion of volcanic material. The heat source for the geothermal reservoir is probably associated with volcanic activity. The geothermal reservoir is a highly permeable zone located approximately 600-900 m below land surface. Secondary permeability in fractures is dominant. Geothermal waste fluids are injected into different permeable horizons of the geothermal reservoir. These waste fluids represent only a fraction of the total mass production from the reservoir, so there is a net pressure loss in the geothermal system. Over time, pressure losses have caused steady pressure declines. Injecting waste fluids has helped stablize these pressure losses. Injection as a means of recycling fluids and gleaning more heat from reservoir rocks has worked well. There has been some expected local cooling of the reservoir rocks near injection wells. Once injection has stopped, temperature recovery in these rocks is very slow.

There is no evidence indicating there is increased contamination of shallower, fresh water supplies as a result of injection. There is chemical evidence that the injectate ultimately moves toward the geothermal production zone along the gradient created by a pressure sink. This sink can be traced as it progresses through the permeable reservoir.

7. DISCUSSION

The hydrogeologic setting and the design/operational parameters of a geothermal development are the primary factors controlling the success of geothermal liquid waste injection. Each geothermal development possesses a site-specific combination of conditions that require a production and injection strategy designed particularly for that system. Careful planning of a production/injection strategy can effectively protect near-surface resources as well as prolong the useful life of the geothermal reservoir, geothermal wells, and fluid handling equipment.

Potential impacts from injection may be classified in terms of several hydrogeologic and design/operational factors. Subsidence in unconsolidated formations may occur following excessive fluid withdrawal and reservoir compaction. Replacing the extracted fluids with injected fluids can minimize pressure losses and the potential for subsidence. The upward migration of injected fluids to shallow, usable aquifers may occur along hydrologic pathways. The mixing of geothermal waste water and shallow groundwater can diminish the quality and usability of near-surface water supplies. In areas of naturally high seismic activity, there is concern that fluid injection will raise reservoir pressures and increase seismic levels further. This phenomenon has severe implications in earthquake-prone regions.

Operationally, the hydrodynamic breakthrough of cooled injected fluids from injection wells to production wells can reduce production temperatures and reservoir productivity. On the other hand, injecting fluids to boost the falling pressures of the producing reservoir is an effective means of reservoir pressure maintenance and can prolong the reservoir's productive life. Finally, injecting fluids of variable water quality at various temperatures and pressures may result in numerous chemical reactions that cause plugging or precipitation of solids on equipment as well as the formation. Chemical fouling creates serious fluid handling difficulties at the surface.

Specific hydrogeologic and design/operational factors that strongly influence an injection program are presented in Tables 7.1 and 7.2. These are described as they apply to each of the six geothermal sites in this report. Injection and production intervals at the Salton Sea and East Mesa KGRAs are those of wells at the GLEF and USBR sites, respectively, and do not necessarily apply to wells of any other operators. The quantity of injected fluids is expressed as an estimated percentage of the total quantity of extracted fluids. Only the chemical constituents of greatest concern for fluid handling at each site are mentioned.

Existing conditions and potential effects of production and injection at each of the six geothermal sites appear in Tables 7.3 and 7.4. The effects described are those associated only with geothermal development and do not include background or natural conditions. For instance, historical measurements indicate there has been some subsidence in the Raft River Valley, but none has been associated with existing geothermal development (Table 7.3).

Table 7.3 focuses on selected hydrogeologic factors that may be affected by production and injection. These factors include subsidence, near-surface movement of injected fluid, and seismicity. Subsidence is a

Table 7.1. Description of hydrogeologic factors that govern the injection of geothermal waste fluids into subsurface formations.

Geothermal Area	Reservoir Type	Principal Confining Layer	Migration Avenues to Surface and Other Wells
Raft River KGRA	Metamorphic and volcanic rocks as well as sedimentary sequences	Continuous sediments and igneous rocks of Upper and Lower Aquitards; thickness up to 300 m	Fracture-dominated permeability in mostly sediments but also metamorphic and igneous rocks
Salton Sea KGRA	Unconsolidated and consolidated detrital sediments, including some hydrothermally altered rocks at depth	Continuous clay cap rock; thickness 300-350 m	Localized vertical faults and increasing fracture permeability at depth
East Mesa KGRA	Unconsolidated and consolidated detrital sediments, including some hydrothermally altered rocks at depth	Continuous clay cap rock; thickness up to 600 m	Localized vertical faults and increasing fracture permeability at depth
Otake	Tuff breccias of Middle Hohi Volcanic Complex	Continuous pyroxene andesite lavas of Upper Hohi Volcanic Complex	Vertical faults, pervasive fractures, and brecciated zones
Hatchobaru	Lake deposits and propylites	Volcanics of Hohi Volcanic Complex, particularly andesites; total thickness about 800 m	Vertical faults, pervasive fractures, and brecciated zones
Ahuachapan	Andesitic lavas and pyroclastics	Volcanic agglomerate; thickness up to 400 m	Vertical faults, pervasive fractures

Table 7.2. Description of design/operational factors that govern the injection of geothermal waste fluids into subsurface formations.

Geothermal Area	Relative Injection-Production Depths	Relative Injection-Production Well Locations	Relative Injection-Production Quantities	Fluid Chemistry Affecting Injectibility
Raft River KGRA	Injection interval (500-1200 m) slightly above production interval (1100-2000 m)	Side-by-side; 1-3 km apart	Nearly 100% injection for intermittent testing	Suspended Solids
Salton Sea KGRA	Injection interval (820-1370 m) slightly below primary production interval (560-750 m) at the GLEF; well configurations of other operators unknown	Interspersed	Nearly 100% continuous injection in Union Oil Co. wells	High total dissolved solids; silica scaling
East Mesa KGRA	Injection interval in USBR wells (1525-1830 m) approximately equivalent to some production intervals (1510-1830 m) and above others (2075-2430 m)	Side-by-side; 1-3 km apart	Nearly 100% injection for intermittent testing at USBR wells; 100% continuous injection in Magma Power Co. wells	High total dissolved solids; silica scaling
Otake	Injection intervals approximately equivalent to production intervals (near 500 m)	Side-by-side; 150-500 m apart	Nearly 100% continuous injection	Silica scaling
Hatchobaru	Injection intervals approximately equivalent to production intervals (near 1000 m)	Side-by-side; 50-600 m apart	Substantially less than 100% continuous injection	Silica scaling
Ahuachapan	Injection intervals (600-900 m) generally below production interval (300-400 m)	Interspersed	Approximately 40% continuous injection	Potential for silica scaling

Table 7.3. Existing and potential effects of geothermal production and injection on selected hydrogeologic factors.

Geothermal Area	Subsidence		Near-Surface Movement of Injected Fluid		Seismicity	
	Existing	Potential	Existing	Potential	Existing	Potential
Raft River KGRA	None	Some potential but none anticipated based on relative production and injection volumes	None Detected	Potential increases with time because some injectate enters the uncased Intermediate Aquifer in RRG1-6 (at 509-580 m deep); highly permeable Intermediate Aquifer is well-connected hydrologically to shallow reservoirs; high injection pressures may increase upward migration of injectate	No increases detected	No increases anticipated at current injection pressures
Salton Sea KGRA	None	Significant potential but none anticipated based on relative production and injection volumes	None Detected	Low potential based on presence of 300-350 m-thick impermeable clay cap rock and only localized faulting	No increases detected	No increases anticipated at current injection pressures
East Mesa KGRA	None	Significant potential but none anticipated based on relative production and injection volumes	None Detected	Low potential based on presence of 600 m-thick impermeable clay cap rock and only localized faulting	No increases detected	No increases anticipated at current injection pressures
Otake	None	Very low potential because of competent volcanic rocks	Information not Available	High potential because of well-developed vertical hydraulic continuity in fractures	No increases detected	No increases anticipated based on low injection pressures
Hatchobaru	None	Very low potential because of competent volcanic rocks	Information not Available	High potential because of well-developed vertical hydraulic continuity in fractures	No increases detected	No increases anticipated based on low injection pressures
Ahuachapan	None	Very low potential because of competent volcanic rocks	None Detected	Low potential based on presence of two overlying impermeable units; one of which, the confining cap rock is up to 400 m-thick and contains only scattered faulting	Information not available	No increases anticipated at current injection pressures

Table 7.4. Existing and potential effects of geothermal production and injection on selected design/operational factors.

Geothermal Area	Hydrodynamic Breakthrough		Condition of Injection System		Reservoir Maintenance	
	Existing	Potential	Existing	Potential	Existing	Potential
Raft River KGRA	None	Low potential based upon distance (1-3 km) between injection and production wells, relative positions of producing and receiving horizons, and groundwater discharging conditions	Chemical precipitation well/formation plugging	Continued precipitation will shorten life of the well and plug the near-well receiving zone	Brief pressure declines observed in some wells attributable to short-term geothermal production and injection; no long-term trends available	Long-term pressure declines expected as production progresses dependent upon injection in a shallower zone
Salton Sea KGRA	None	Sufficient data are not available upon which to base an evaluation of potential	Chemical precipi- and well/formation plugging reduced by pretreatment	Continued precipitation will shorten life of the well and plug the near-well receiving zone, but at a reduced rate due to pretreatment	Information not available	Short-term pressure declines expected as production continues, dependent upon injection in production zones
East Mesa KGRA	None	Moderate potential based upon distance (1-3 km) between injection and production wells and the similarity of injection and production zones	Some chemical precipitation and well/formation plugging	Continued precipitation will shorten life of the well and plug the near-well receiving zone without well rehabilitation techniques or pretreatment	Reservoir has not stablized with production	Long-term or short-term pressure declines expected as production continues in shallower or production zones, respectively
Otake	Delayed, low-level breakthrough	Continued low-level breakthrough	Chemical precipitation and well plugging	Continued precipitation will shorten life of the well and possibly plug the near well receiving zone	Steady pressure declines with production, but rate of decline reduced by injection	Reservoir pressures approach steady state with injection and production in similar zones
Hatchobaru	Rapid breakthrough	Continued rapid breakthrough	Chemical precipitation and well plugging	Continued precipitation will shorten life of the well and possibly plug the near well receiving zone	Steady pressure declines with production, production enthalpies decreased by injection	Productivity declines attributable to steam depletion resulting from hydrodynamic breakthrough of cooled injected fluids
Ahuachapan	Delayed, low-level breakthrough	Continued, low-level breakthrough	No chemical precipitation or well plugging as result of maintaining system temperature >150°C	No precipitation or plugging anticipated	Steady pressure declines with production, stablized by injection	Steady pressure declines expected as production continues at greater rate than injection

function of lithology and the net volume of fluid extraction. The near-surface movement of injected fluid is a function of hydrogeologic conditions, the location of injection wells and injection intervals, and the injection pressures. Seismicity is a function of regional tectonic activity, and induced seismicity is a function of injection pressures and volumes. With the exception of Raft River, the potential effects of production and injection in Table 7.3 are predicted on the basis of existing operating conditions (as nearly as they can be determined) and do not consider proposed future development that may have different operating characteristics. The Raft River power facility is not currently operating (June, 1984), so judgements in Tables 7.3 and 7.4 have been based on existing hydrogeologic conditions and the original wellfield design parameters. These parameters may change with future development by the new owners of the site.

Table 7.4 focuses on selected design/operational factors that may be affected by production and injection. These factors include hydrodynamic breakthrough, the condition of the injection system, and maintenance of the geothermal reservoir. Hydrodynamic breakthrough is a function of hydrogeology and the configuration of the wellfield. The condition of the injection system depends largely upon the chemical and physical parameters of the injected fluids and, to some extent, near-well permeability. Reservoir maintenance is a function of hydrogeology, wellfield configuration, and relative volumes of produced and injected fluids. The tables show that there are some striking similarities among the six geothermal sites presented in this report. Each area is a groundwater discharge area. Some sort of impermeable cap rock confines each geothermal reservoir and isolates it hydrologically from the surface. Each geothermal area contains significant permeabilities in fractures. Localized faults and fractured zones breach the cap rocks in some places and allow limited upward discharge of geothermal fluids. The extent to which upward migration occurs varies among the sites.

There is currently no subsidence associated with geothermal activity at any of the sites. Subsidence is a potential problem in the sites containing significant amounts of clays and sediments that might compact as a result of fluid withdrawal. The extent of subsidence is also a function of the injection program. Subsidence is probably not a potential problem in areas containing competent volcanic rocks.

The potential for near-surface movement of injected fluids varies with injection pressures and the extent of vertical hydraulic communication between the receiving reservoir and overlying aquifers. The magnitude of these parameters varies among the six sites. The potential for upward migration seems highest at the pervasively fractured Otake Geothermal Area. The potential seems lowest at the Imperial Valley KGRAs.

There has been no reported seismic activity induced by injection at any of the sites. However, at some sites that already exhibit high seismicity (such as the Salton Sea and East Mesa KGRAs), any increases in seismicity caused by injection could have severe repercussions.

Existing and potential hydrodynamic breakthrough is variable among the sites. This variability is a direct result of the combinations of hydrogeologic and design/operational conditions. Severe hydrodynamic breakthrough has occurred at the Hatchobaru geothermal field, yet seems to be of minor concern at the Raft River, Salton Sea and East Mesa KGRAs.

Chemical composition of geothermal fluids varies from site to site; but fluids at all sites have the potential to cause severe precipitation and plugging in injection wells and the receiving formation if they are not correctly handled at the surface. Pretreatment of fluids (as at the Salton Sea KGRA) and maintaining an elevated system temperature (as at Ahuachapan) have been used to improve geothermal fluid injectability.

Maintaining the geothermal reservoir for optimum productivity is important to both the economics and longevity of generating electrical power from a geothermal resource. Initial pressure declines are expected in early stages of fluid extraction. Injection has been used as a means to stablize pressure declines and help reach steady-state conditions. Injection into the producing reservoir can be particularly effective in this way. Injection above the producing reservoir, particularly in a discharging system, is unlikely to fully stablize the pressures of the producing zones because the full complement of injected fluids probably would not reach the production area. Injection to horizons below the producing reservoir in a discharging system is likely to be more effective than injecting above but less effective than injecting into the geothermal reservoir. The Raft River KGRA can probably expect continued substantial pressure declines in the geothermal production horizons as a result of injection intervals being above production intervals. Reservoir pressures at the Otake geothermal field appear to have stablized, although Hatchobaru has lost productivity as a result of reservoir cooling. Each of these fields utilizes a side-by-side injection/production configuration. The Ahuachapan geothermal field generally injects only a fraction of the total mass extracted to horizons below the producing reservoir. There has been some loss of temperature, but even partial injection has helped to stablize reservoir pressures.

It has become clear that the two overriding controls on injecting geothermal fluids at a given site are the existing hydrogeologic factors and the design/operational characteristics of the power plant and wellfield. Careful consideration of each of these parameters and implementation of an appropriate injection program can mean the difference between a successful program and one frought with technical difficulties.

8. CONCLUSIONS

1. Very limited data are available worldwide on geothermal waste fluid injection. Data on the near-surface effects of geothermal injection are particularly lacking.
2. Each of the case studies examined in this report demonstrates some degree of technical difficulty with injection. The nature and extent of these problems are dependent upon site-specific hydrogeologic and design/operational factors.
3. Three factors of the hydrogeologic setting are most important with respect to injection: a) subsidence, b) near-surface movement of the injected fluid, and c) seismicity. Subsidence and seismicity can be controlled largely by operational factors such as withdrawal rates and injection pressures. Near-surface movement of the injected fluids is primarily controlled by hydrogeologic conditions such as fractured controlled vertical permeability.
4. Three design/operational factors are most important with respect to injection: a) hydrodynamic breakthrough, b) condition of the injection system, and c) reservoir maintenance. Hydrodynamic breakthrough is primarily dependent upon the permeability of the reservoir but can be minimized by careful design of the wellfield. The condition of the injection system can be controlled at the surface prior to injection of fluids to the reservoir. Reservoir maintenance can also be controlled at the surface by the design of the wellfield and by control of the amount and condition of the injected fluid.

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