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Final Report

DOE/SF/16385--T1

DE88 006872

Hot Dry Rock Venture Risks Investigation

Prepared for
United States Department of Energy
San Francisco Operations Office

Contract Number: DE-AC03-86SF16385
Bechtel Job Number: 18711

By
Bechtel National, Inc.
San Francisco
January 1988

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VENTURE RISKS INVESTIGATION

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HOT DRY ROCK VENTURE RISKS INVESTIGATION

EXECUTIVE SUMMARY

ABSTRACT

This study assesses a promising resource in central Utah as the potential site of a future commercial hot dry rock (HDR) facility for generating electricity. The results indicate that, if the HDR reservoir productivity equals expectations based on preliminary results from research projects to date, a 50 MWe HDR power facility at Roosevelt Hot Springs could generate power at a cost competitive with coal-fired plants. However, it is imperative that the assumed productivity be demonstrated before funds are committed for a commercial facility.

Geotechnical

The Roosevelt Hot Springs area appears to be well suited for installing and operating an HDR power facility. A large hot granitic rock mass exists at drilling depths that are technically feasible, and water to operate the facility could be produced from the shallow aquifer underlying the site if water rights can be obtained to do so. However, adequate information is not presently available concerning the rock properties in the deep subsurface HDR target zone; drilling to the target depth is needed to furnish data to resolve these technical uncertainties.

Subsurface System

Because it is economically crucial to create a large heat transfer area per injection well pair, a concept was developed for drilling and casing an injection well, hydraulically fracturing a multilevel series of fracture intervals, and then drilling a production well targeting the fractures. This approach uses present-day equipment and techniques throughout but needs to be demonstrated in an HDR application. The information now available leaves considerable uncertainty about the expected reservoir performance; therefore,

reasonable and conservative assumptions (based on the preliminary data available) were used to define a base case design for economic evaluation. Testing that develops solid data concerning productivity and depletion rate is needed to design and adequately evaluate a potential commercial HDR project.

Surface Facilities

The wellfield surface facilities include a central pumping station, injection water distribution piping, piping to gather the hot water from the production wells, steam flash equipment, and a make-up water supply system. The two-stage flash process was selected for the power plant; this process is currently used in a number of geothermal plants to generate power from liquid-dominated resources.

Project Costs

The estimate of installed cost (in 1987 dollars) for the initial wellfield, including the HDR well pairs plus the wellfield surface facilities, is \$53 million; for the power plant, it is \$69 million. In addition, wellfield costs of \$2.7 million for tangibles and \$8.9 million intangible drilling costs will be required at 3- or 4-year intervals as new well pairs are installed to make up for reservoir temperature decline.

Environmental and Socioeconomic Issues

There are no apparent environmental or permitting constraints to developing a 50 MWe power plant at Roosevelt Hot Springs, or to conducting an industrial HDR experiment to demonstrate that HDR technology is ready for development.

The most important environmental consideration for development is obtaining the water needed to operate the facility. If rights to unused water appropriations can be acquired, these unused amounts are more than enough to meet the operating requirements.

Development Plan

The major elements of the development plan for an HDR power facility at Roosevelt Hot Springs are the following:

- o Industrial HDR experiment
- o Project preliminary design
- o Venture formation
- o Financing
- o Final design and construction

With a deliberate schedule for completing a 50 MWe facility, 1997 would be the first full year for generating commercial electric power.

Economic and Risk Assessment

The cost of electricity production from an HDR power project at Roosevelt Hot Springs could be competitive with the cost for new coal-fired plants. Electricity costs for an HDR plant are not highly sensitive to variations in any single cost component. Well pair productivity and depletion rate are crucial to economic viability of a commercial HDR facility; conclusive test results quantifying these performance variables are needed but are not yet available.

Recommendations

A site-specific industrial HDR experiment at Roosevelt Hot Springs is highly recommended to resolve the major technical issues and to obtain site-specific information needed for design and evaluation. Federal support for funding the industrial HDR experiment is recommended. A commercial-size first-of-a-kind power plant project is recommended if the industrial HDR experiment verifies the technical and economic projections.

INTRODUCTION

HDR energy production is the process of mining thermal energy from the crust of the earth in situations where the temperature is high but the existing fluids or permeability are inadequate for transporting the energy to the surface. The largest HDR systems created to date, at Fenton Hill in New Mexico and at Rosemanowes, England, are research and development projects that have proved the technology concept by drilling into hot dry rocks, hydraulically fracturing the rock mass, and extracting thermal energy by circulating water through the man-made fractures. Although HDR systems have been created on a research scale, HDR has not yet been applied commercially. This study is the first site-specific evaluation to test the commercial readiness of HDR technology.

In mid-1986, the DOE issued a request for proposals to investigate a specific site for HDR commercial venture potential. In response to this request, Bechtel National, Inc. proposed to evaluate the Roosevelt Hot Springs, Utah resource as the location for a potential 50 MWe power generating facility, and DOE awarded a contract to Bechtel for this investigation. Access to the HDR site and data were granted to Bechtel by Intermountain Geothermal Company, a wholly owned subsidiary of Chevron Resources Company which is the operator of the Roosevelt Hot Springs Unit, and the other unit partners. Figure S-1 shows the location and some of the prominent features of the Roosevelt Hot Springs resource area in south central Utah.

This report records the results of the investigation and makes recommendations for the next step toward implementing a commercial HDR facility.

SUMMARY AND CONCLUSIONS

Geotechnical Evaluation

The geotechnical evaluation of the HDR prospect at Roosevelt Hot Springs involved an assessment of the available site-specific information to estimate the HDR potential, to define the input parameters for the design of the subsurface reservoir, and to identify technical risks associated with development of a commercial HDR reservoir.

Figure S-1 Location of Roosevelt Hot Springs

Regional Tectonic Setting. The Roosevelt Hot Springs known geothermal resource area (KGRA) is on the western flanks of the central Mineral Mountains in west-central Utah. The Tertiary-age Mineral Mountains are in the Basin and Range province near its eastern margin, which is transitional to the Colorado Plateau.

Site Geology. The most promising HDR prospect area at Roosevelt Hot Springs lies to the west of the Opal Mound Fault. This fault is the structural boundary that defines the western limit of the hydrothermal field which has a 20 MWe power plant in operation.

Local Setting. The geothermal heat source for the Roosevelt Hot Springs area is believed to be associated with Pleistocene emplacement of a pluton as a result of intrusive activity. Youngest examples of nearby volcanic activity include a sequence of rhyolite flows and domes that range between 0.5 and 0.8 million years in age.

Fault History. Four major fault systems transect the central Mineral Mountains:

- o Low-angle, westward dipping faults, which are believed to have been produced by uplift of the Mineral Mountains structural block
- o A system of high-angle, northwest-striking faults, which has geometry consistent with formation in the upper fault plate during low-angle faulting between relatively rigid blocks
- o High-angle east-west trending faults, which cut the low-angle faults
- o North-south, horst-graben, extensional normal faults, which are the youngest structures in the area; the Opal Mound Fault, separating the HDR and hydrothermal fields, is prominent among these

Fault-related issues of importance to commercial HDR development include resolving the existence, orientations, and spacings of fractures at anticipated HDR reservoir depths of 7,000 to 17,000 ft (2,100 to 5,200 m). These affect the wellfield design, the ability to control the growth of

hydraulic fractures for the reservoir, the rate of water loss, and the probability of induced seismicity if long-term water loss rates are high. Published structural cross sections do not extrapolate faults deeper than 7,000 ft (2,100 m). Drilling of deep exploration and test wells would furnish data needed to resolve these issues.

Lithology. Two distinct regimes of structure, lithology, and alteration are separated by a gently westward-dipping major fault zone located at a depth of 2,800 ft (850 m) near the Opal Mound Fault. Above the fault zone, lithology is complex, alteration is moderate to intense, and evidence of structural disruption is abundant. Below the fault zone, the number of lithologies is few, the rock mass is relatively unbroken, and alteration is weak. An existing well shows that the rock to a depth of 6,885 ft (2,100 m) is granitic.

Subsurface State of Stress. The magnitudes of the principal stresses at the average target bottomhole depth of 12,000 ft (3,660 m) are not presently known. Furthermore, the breakdown stress that must be overcome to initiate hydraulic fracture growth or to stimulate displacement on existing joints cannot be deduced from available site data. Based on the natural deviation of two wells in the HDR prospect area and the orientation of the most recent faulting, the direction of the minimum compressive stress, σ_3 , is expected to be ESE-WNW.

Fracturing Characteristics of Basement Rocks. Since information on deep subsurface jointing is not presently available, a conceptual well design and a drill-fracture-drill sequence for installation of the injection and production wells were developed that will accommodate a wide range of orientation and length of the hydraulic fractures. Based on hydraulic fracture operations at Fenton Hill and Rosemanowes, relative shear displacement of existing joint faces may occur and thereby create self-propping fractures with apertures sufficiently large for water circulation.

Drilling Characteristics. Drilling rates for two existing wells were 7 to 13 ft/hr (2.1 to 3.7 m/hr) in the basement rock. Since the natural wellbore deviations of the existing wells define a plane parallel to the Opal Mound Fault, the HDR wellbores will probably require directional control to force the deviations perpendicular to that plane in the necessary ESE direction.

Potential for Induced Seismicity. During operation of an HDR reservoir, thermal stress cracking of the reservoir rock is expected to occur slowly and continuously at the rock/water interface; thus, the likelihood of building up an unrelieved stress that could generate a significant seismic shock is remote. In addition, the probability of significant induced seismicity resulting from water leakage into the rock surrounding the reservoir is minimized by plans to create the heat-exchange reservoir in impermeable rock well away from major natural faults. Onsite measurements of thermally and hydraulically induced microseismic activity at Fenton Hill and Rosemanowes have detected only very low level tremors, typically 4 to 7 orders of magnitude (extrapolated Richter scale) below the level of human sensitivity.

Subsurface Temperature and Thermal Energy. Temperature gradient data indicate that the depth to a nominal HDR reservoir temperature of 300°C (572°F) is shallowest near the Opal Mound Fault. Depths to similar temperature increase northward, westward, and southward from that location.

The HDR resource within the existing participating unit for geothermal production appears to have potential for supplying several hundred MWe for a period of greater than 30 years.

Hydrogeology and Water Availability. It is estimated that 3,900 gpm (6,300 acre-ft/yr) of water will be needed to replenish the losses from a 50 MWe HDR facility. This water could be obtained from a shallow aquifer if rights to do so can be acquired. Due to the distance and low transmissivity between the Roosevelt Hot Springs area and the town of Milford (8 miles or 13 km south), pumping operations for a HDR facility at Roosevelt Hot Springs are not expected to affect the water supply near the town. Also, a

potentiometric surface map indicates that the underground water flow from Roosevelt Hot Springs is toward the northwest. The proposed wellfield for make-up water lies within the most highly contaminated area of the aquifer, directly down gradient from the hydrothermal field. However, no undue problems associated with the use of this water are anticipated for an HDR facility.

Overall Geotechnical Assessment. The Roosevelt Hot Springs area appears to be well suited for installation and operation of an HDR power facility with the most promising region lying to the west of the Opal Mound Fault and south of the Hot Springs Fault. The shallowest occurrence of possibly commercial HDR temperatures is in the eastern portion of this region.

Although a wealth of surface and near-surface data were available for this study, major issues that are important to technical risk mitigation and cost estimates remain unanswered. These concern the following rock properties in the deep subsurface HDR target zone:

- o Persistence of faults at HDR reservoir depths
- o Orientations of faults at depth
- o Orientation of the principal stresses at depth
- o Magnitude of closure stress that must be exceeded to stimulate hydraulic fracture growth
- o Spacing and orientation of deep subsurface joint sets that may affect hydraulic fracture orientations, hydraulic fracture size, and the rate of water loss
- o Temperatures at depth
- o Confirmation that pressures needed to drive fluid circulation are low enough to control water loss and pumping costs

Subsurface System Design

Well Design and Completions Program. Results obtained early in the study emphasized the economic importance of creating large heat transfer area (fracture surface) per well pair and maximizing the target temperature consistent with technical constraints and cost considerations. This led to

a concept for installing multiple, discretely created fractures using the following sequence:

- o Drill an injection well to the depth corresponding to the target temperature (an average of 3,660 m or 12,000 ft for 300°C or 572°F at Roosevelt Hot Springs). Deviate the bore 20 to 25 degrees below 2,590 m (8,500 ft).
- o Place and cement casing to the bottom of the injection well (7 in. liner in the deviated lower portion of the wellbore).
- o Extend the depth of the injection well by 20 to 60 m (66 to 200 ft).
- o Run 7 in. tubing from the surface to the top of the 7 in. liner. Hydraulically fracture the open-hole interval pumping through the 7 in. tubing and liner. The water used for hydraulic fracturing cools the wellbore for subsequent logging and perforating. During the hydraulic fracturing operation, use microseismic monitors to map the subsurface fractures.
- o Allow the wellhead pressure to decay to 3,000 psi (20 MPa). Do not flow back the fracture fluid.
- o Set a cast iron, casing cement retainer ring as a casing packer near the bottom of the 7 in. liner.
- o Perforate 10 to 25 m (30 to 80 ft) of the wellbore for the second fracture interval.
- o Hydraulically fracture the second interval while using microseismic monitors to map the fractures.
- o Repeat the four steps above until 12 fracture intervals have been created in the injection well.
- o Drill a production well approximately parallel to the injection well targeting the fracture zones with the deviated portion 250 to 500 m (820 to 1,640 ft) above the deviated section of the injection well.

Although this is an aggressive hydraulic fracturing program, present-day equipment and techniques are used throughout. Installing a high quality cement job is a key requirement. Also, the casing throughout the fracture length is designed to withstand fracturing pressures from both the inside and the outside. Major advantages of this approach compared to that used at Fenton Hill and Rosemanowes are:

- o More reliable casing packers (retainer rings) are used instead of open-hole packers.
- o Hydraulic horsepower and surface safety hazard are minimized by low friction loss through relatively large-diameter fracture tubing.
- o Time-consuming flow back of the fracture fluid is not required.
- o Damage to the wellbore, which might result from repeated thermal cycling, is minimized by sequentially installing multiple fracture intervals, requiring a single episode of wellbore cooling.
- o The fractures are mapped microseismically, which permits targeting the production well to the fractured zones.

Hydraulic Fracture Modeling. Maximizing the amount of heat transfer area exposed by each fracture is crucial to HDR well productivity and longevity. Based on preliminary information from Fenton Hill and Rosemanowes, the following estimates of the initial heat transfer area and growth after beginning production are reasonable and conservative:

- o 100,000 m² (1,080,000 ft²) effective heat transfer area per fracture interval initially
- o Doubling of the effective heat transfer area within the first year of plant operation (Although growth probably continues beyond the first year, it is assumed to stop at that time.)

Because multiple fractures in one fracture interval were observed at both Fenton Hill and Rosemanowes, effective heat transfer areas significantly larger than 100,000 m² (1,080,000 ft²) with greater productivity may be feasible with proper targeting of the production well. However, the maximum feasible size of the effective heat transfer area that can be accessed in each fracture interval has not been demonstrated. Because the initial size of the heat transfer area and the rate and magnitude of its growth after operation begins are crucial to reservoir performance and project economics, they should be satisfactorily demonstrated by tests before commitment to build a commercial facility.

Conceptual Wellfield Design. Because thermal drawdown will decrease the power output of a well pair, a technique is needed to make up for the diminished well production to maintain the required plant electrical output for 30 years. The proposed approach for coping with well pair depletion is the addition of new well pairs. Restimulation by fracturing additional intervals in existing wells may not be feasible due to lower temperatures in the remaining wellbore intervals. However, as the size and location of the fractures become better understood and more reliably located, other restimulation methods, such as drilling additional production wells, may be identified as cost-effective ways to maintain production.

Two important site-specific operating characteristics were assumed because data specific to Roosevelt Hot Springs are not available at present:

- o The steady-state reservoir leakage was assumed to be 10 percent of the circulation rate; this was experienced during one of the longest test runs at Fenton Hill and approached by the longest test at Rosemanowes.
- o The pressure at the injection wellhead was assumed to be 1,500 psi (10 MPa); this pressure was used for much of the testing at Fenton Hill and Rosemanowes.

The cost sensitivity for both of these assumptions was evaluated during the economic and risk assessment phase of the study. In addition, performance estimates assume uniform flow distribution among the fracture intervals; this in turn assumes that, if needed, the methods currently used in oil field waterflood operations to restrict flow in particular intervals will achieve reasonably uniform flow.

The following characteristics were used as the average values for a base case injection/production well pair for the economic analysis:

- o 300°C (572°F) target bottomhole temperature
- o 12 fracture intervals
- o 100,000 m² (1,080,000 ft²) effective heat transfer area per fracture interval
- o Doubling of the heat transfer area within the first year of well pair production

- o 10 l/s (160 gpm) per fracture interval
- o 12 MWe initial salable power declining to 2 MWe after 30 years
- o For 50 MWe of salable power
  - 4 injection/production well pairs initially
  - 8 additional well pairs over 30-year plant life

Table S-1 summarizes the estimated costs for an HDR injection/production well pair drilled to 12,000 ft (3,660 m) at Roosevelt Hot Springs. These costs include site preparation, rig operations, casing/cementing, hydraulic fracturing, and wellhead fixtures.

Table S-1
AVERAGE COST PER HDR INJECTION/PRODUCTION WELL PAIR
(\$ million, 1987)

<u>Item</u>	<u>Cost</u>
Pumping services	2.2
Wireline services	<u>0.2</u>
Subtotal	2.4
15% contingency	<u>0.4</u>
Subtotal	2.8
Drilling and casing (two wells)	6.7
Microseismic mapping	<u>0.1</u>
Subtotal	9.6
Management fee	<u>0.5</u>
Total	10.1

For comparison, average costs for oil and gas wells drilled to 12,000 ft (3,660 m) in Utah are about \$1 million and \$2 million, respectively, in 1987 dollars.

Surface Facilities

The surface facilities include all the systems and equipment needed to operate the HDR underground reservoir and to produce electric power. Since the two-stage flash process was selected for the power plant, the wellfield surface facilities include two stages of flash vessels as shown in Figure S-2.

Wellfield. The wellfield surface facilities include the injection, gathering, and flash systems plus the make-up water supply.

The injection system distributes water to the injection wellheads with enough pressure to produce the needed flow rate through the fractured reservoir. It consists of an injection water storage tank, a set of centrally located booster and injection pumps, and distribution piping to deliver the water to the injection wellheads.

Weak alteration expected in the reservoir rock means that carbon dioxide concentration is likely to be low in the flashed steam and that carbonate scaling is not likely to be significant for the HDR wells or surface facilities.

Potential silica scaling problems in the reservoir can be controlled by dilution with a small amount of additional make-up water that is insignificant compared to the make-up water needed for other reasons.

The gathering system transports the hot water from the production wellheads through carbon steel, aboveground piping to the centrally located flash system.

The flash system converts part of the hot water to steam in two stages (225 psia and 31 psia) and transports it to the power plant.

The make-up water supply furnishes water needed for operating the facility. Up to 3,900 gpm (6,300 acre-ft/year) of water from 13 wells is pumped about 2 miles (3.2 km) to the injection water storage tank where it is mixed with warm water from the low pressure flash vessels. Based on available chemical analyses, no requirement for water treatment before injection is anticipated.

Figure S-2 HDR Facility Plot Plan

Alternate piping is also provided to divert part or all the well water to a holding pond for water used in hydraulic fracturing operations.

Power Plant. The two-stage flash process was selected for this HDR application because of its proven commercial service, its high energy conversion efficiency for the relatively high water temperatures expected, and its relatively low cost. In this process, steam is admitted to the turbine at two different pressures with the combined steam exhausting to a surface condenser.

Heat given up by the condensing steam is absorbed by the circulating water from the cooling tower. Condensate from the condenser is used as cooling tower make-up. Excess condensate not evaporated in the cooling tower is returned to the wellfield injection water storage tank for reservoir injection.

The electrical systems, turbine building, and auxiliary systems of the power plant are similar to those for an equal capacity power plant for other geothermal resources.

A 138 kV line from the power plant connects to an existing 138 kV Utah Power and Light Company line approximately 4 miles (6 km) from the HDR plant. In addition, approximately 14 miles (22 km) of existing line is upgraded to carry the additional power.

Project Cost Estimate

Estimates of capital and O&M costs for the four initial well pairs, the wellfield surface facilities, and the power plant are summarized in Table S-2. In addition, wellfield costs of \$2.7 million for wellfield surface facilities and tangible well costs plus \$8.9 million intangible drilling costs will be required at 3- or 4-year intervals as new well pairs are installed to make up for reservoir temperature decline.

Environmental and Socioeconomic Issues

There are no apparent environmental or permitting constraints to developing a 50 MWe power plant at Roosevelt Hot Springs, or to conducting an industrial HDR experiment to demonstrate that HDR technology is ready for development.

Table S-2

SUMMARY OF ESTIMATED PROJECT COSTS**WELLFIELD - Four Initial Well Pairs**

Wellfield Capital Costs (1987 \$ millions)

Surface Facilities	9.3	
Tangible Well Costs	4.3(a)	
Capitalized Interest	2.7	
Total Wellfield Initial Investment	<u>16.3</u>	
Preproduction Costs	1.1	
Total Initial Wellfield Capital Costs	<u>17.4</u>	
Intangible Drilling Costs		35.2(a)
Total Initial Wellfield Costs		<u>52.6</u>

Wellfield O&M Costs

Fixed O&M Costs (1987 \$ millions per year)	1.35
Variable O&M Costs	
Make-up water purchases (mills/kWh)	0.45
Geothermal resource royalties - 10 % of wellfield gross receipts	
Electrical power (range in 1987 \$) - 1.4 million/year to 4.4 million/year	

POWER PLANT

Power Plant Capital Costs (1987 \$ millions)

Power Plant and Transmission Line	56.5	
Allowance for Funds Used During Construction (AFDC)	10.5	
Preproduction Costs	1.9	
Total Power Plant Capital Costs	<u>68.9</u>	
Power Plant O&M Costs (1987 \$ millions per year)	2.3	

(a) The total of tangible and intangible drilling costs is \$39.5 million. This is \$600,000 less than four times the \$10.1 million cost of a typical well pair given in Table S-1. The difference results from adjustments to the mobilization costs and to repeated use of a single frac pond.

The most important environmental consideration for development is obtaining the water needed to operate the facility. Although all available groundwater in the Milford Valley area is appropriated, the unused amounts are more than sufficient for a 50 MWe HDR power plant. If the water rights can be acquired, water wells drilled nearby could supply the operating requirements.

The major impact during construction, the socioeconomic effects of in-migration of the construction work force, will be temporary and generally beneficial to the local economy.

During operation, the environmental impacts will be relatively small since there will be low levels of air emissions, no point source water effluents, and little solid or hazardous waste.

The critical path for permitting is likely to be the air quality permit which may require 1 year of monitoring and could require up to an additional year after submittal for the permit to be issued.

Development Plan

The development plan describes the elements of and a schedule for a venture project to build a commercial HDR facility at Roosevelt Hot Springs.

Figure S-3 shows the major elements as discussed below and the schedule.

Industrial HDR Experiment. Commercial success of an HDR system depends on being able to install several large fractures in each injection well and on the long-term thermal performance of the subsurface reservoir. Although the estimates of expected performance used in this study appear reasonable and conservative from the short-term tests at Fenton Hill and Rosemanowes, the following crucial aspects of reservoir thermal performance have not been demonstrated:

- o Total effective heat transfer area that can be created per well pair by hydraulic fracturing using a multilevel pack-off approach
- o Growth rate of effective heat transfer area after production begins
- o Long-term thermal drawdown characteristics

Year	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Industrial HDR Experiment										
Drill and test a pair of test injection and production wells	x	~~xxxx~~	~~xxxx~~	~~xxxx~~	~~xxxx~~	~~xxx~~				
Secure water rights for 50 MWe HDR power facility		x	xxxx	xxx						
Drill and test two water wells				x	xxx					
Develop a numerical model to simulate, evaluate, and predict reservoir performance		x	xxxx	xxxx	xxxx	xx				
Perform additional geology and geophysical evaluation		x	xxxx	x						
Drill exploration and observation wells		x	xxxx	xxxx	xxx					
Secure permits		xx								
Project Preliminary Design						xx				
Venture Formation						xx	~~xxx~~			
Negotiate power sales agreement						xx	xx			
Prepare permitting plan and submit initial applications						xx	xx			
Financing							xx	xx		
Final Design and Construction										
Wellfield										
Design and drill HDR injection and production wells								xx	xxxx	xx
Design and construct injection, gathering, and flash systems								xx	xxxx	xxx
Drill water wells and install pumps								xxxx	xxxx	
Construct make-up water pipeline								xx	xx	
Secure permits							xx	xx		
Power Plant										
Develop detail design for power plant							~~xx~~	xxxx	xxxx	xx
Construct power plant							~~xxxx~~	~~xxxx~~	~~xxx~~	
Perform power plant startup										~~xx~~
Secure permits							xxxx			
— Critical Path										

Figure S-3 HDR Project Schedule

Therefore, a test verification of both the drilling/completion concept and the reservoir performance is needed prior to installation of a commercial facility.

A satisfactory test to obtain the needed well and reservoir information involves:

- o Drilling and casing a full-depth (about 12,000 ft or 3,660 m for bottomhole temperature of 572°F or 300°C), full-bore injection well
- o Fracturing a number of intervals (Four to six fracture intervals may be sufficient for a test of concept compared to 12 fracture intervals envisioned for a commercial well pair.)
- o Drilling a full-depth, full-bore production well
- o Flowing the well pair for about 2 years at a rate somewhat greater than commercial optimum to project long-term thermal performance

This test would be accompanied by other related activities (water rights acquisition and water-well testing, HDR reservoir numerical thermal modeling, additional geologic and geophysical data acquisition and interpretation, and drilling of exploration and observation wells) that either support the HDR reservoir test directly or reduce the risks associated with commercial development.

The industrial HDR experiment is expected to require approximately 5 years from 1988 through 1992. Because the critical path for this part of the overall project schedule involves 3-1/2 years of activities that must be sequential, there are limited opportunities to accelerate the activities on the critical path.

The cost of the industrial HDR experiment (\$20 million to \$40 million) to obtain the needed data is prohibitive to private industry such as commercial geothermal resource developers, primarily because of the major technical uncertainties. Therefore, federal funding is needed to advance HDR technology with this industrial HDR experiment at Roosevelt Hot Springs. Other parties, such as the state of Utah and the resource developer, may cost share a portion of this experiment although no specific commitments have been made to date.

Project Preliminary Design. Once the results of the industrial HDR experiment are available, a preliminary design of the HDR project at Roosevelt Hot Springs should be prepared to estimate costs and performance using more accurate and complete data than are presently available. This preliminary design should address all the facilities needed for the HDR project. The resulting cost and performance estimates form the basis for economic projections needed in venture formation and financing. The schedule time for this design work is expected to be about 6 months, ending in the fourth quarter 1992.

Venture Formation. If the overall economics of the prospective HDR facility are sufficiently attractive to justify development, participants need to devise a business plan to carry out the project. The plan should provide for ownership, financing, and commercial arrangements which are mutually beneficial. As a part of the venture formation, binding agreements should be negotiated and signed by the following active participants:

- o Resource developer
- o Power plant owner
- o Power purchaser (if needed)
- o Wheeling utility (if needed)

The project schedule anticipates completion of this phase by the third quarter of 1993.

Financing. In the course of developing the formal agreements among the HDR venture participants, needs for debt financing may be identified. Although discussions with possible lenders may begin prior to signing the venture formation documents, specific discussions are expected to intensify once the active participants agree on their various roles.

The project schedule shows completion of the financing phase late in 1993, before start of construction. However, construction could be started using equity funds or construction loans before long-term loan arrangements are completed.

Final Design and Construction. The critical path for final design and construction is the schedule for the power plant; power plant construction is expected to require approximately 3 years, with intensive design work starting about 6 months before start of construction. The wellfield drilling and construction can be fitted to the power plant schedule. Commercial power production starts in late 1996 or early 1997, with 1997 being the first full year of production for purposes of economic projections.

Economic and Risk Assessment

The economic and risk assessment concentrated on the comparative cost of electricity, commercial viability, and sensitivity to cost components and technical risks.

Levelized Revenue Requirements. Levelized revenue requirements were estimated for the following ownership arrangement as the base case:

- o The HDR resource is developed and operated by a non-utility resource developer.
- o The power plant is owned and operated by Utah Power and Light Company since the Roosevelt Hot Springs resource is within its service area.

Among the many economic parameters assumed for this evaluation, two of the prominent ones are the return on common stock for the resource developer (18 percent) and the power plant owner (15 percent). The constant dollar (1987) revenue requirements for the base case facility may be summarized as follows:

	<u>Mills/kWh</u>
Wellfield	28.2
Power Plant	<u>21.6</u>
Total	49.8

Comparative Cost of Electricity. Figure S-4 illustrates how the cost of electricity production from an HDR power project compares with the cost for other options that are commercially available in Utah. The capital and operating costs used in evaluating these alternative power technologies represent conceptual level estimates from Bechtel's database. This comparison shows that an HDR project could produce electricity at costs competitive with coal-fired plants using Utah coal. On the other hand, a hydrothermal plant at Roosevelt Hot Springs could produce electricity at a significantly lower cost; this difference is due primarily to lower drilling and completion costs for hydrothermal and to higher plant output needed to supply pumping power for HDR wellfield operation. With this economic advantage, the hydrothermal resource at Roosevelt Hot Springs is likely to be fully committed by the time HDR testing can be completed and a commercial HDR plant can be built.

Figure S-4 Cost of Electricity Production

Even with conservative base case assumptions for reservoir performance, the revenue requirement for HDR at Roosevelt Hot Springs (49.8 mills/kWh) is competitive with a new coal-fired power plant in Utah (at 52 to 53 mills/kWh). This promising result is dependent to a large degree on the ability to create a sufficiently large fractured area per well pair to justify the cost of installing the wells.

Sensitivity Analyses. A number of sensitivity analyses were performed to determine the impact of variations in cost and performance estimates. For these analyses, variations were selected arbitrarily to test sensitivity; they are not estimates of uncertainty. Table S-3 summarizes the results of these analyses. In general, the sensitivity to a change in any one of these variables is moderate, suggesting that steam and electricity costs are not highly sensitive to variations in any single cost component.

Wellfield Financial Analysis. Projected cash flow and return on equity based on a number of expected market prices for steam were calculated to furnish additional information that a resource developer typically uses to evaluate a project. Figure S-5 summarizes these results. If the steam were transferred at the present energy price (13 mills/kWh) for qualifying facilities in Utah, the resource developer would earn less than 2 percent internal rate of return, which is too low to be attractive. By contrast, to earn 15 percent internal rate of return (equivalent to the allowed return for a private utility company in Utah), the market price for steam would need to be about 29 mills/kWh. For higher rate of return to meet typical expectations of resource developers, the market price needs to be correspondingly higher.

Risk Assessment. Potential cost impacts were investigated for the prominent performance characteristics that cannot be confidently predicted with the HDR data currently available. Table S-4 summarizes these results and shows that well pair productivity and depletion rate are key performance variables that have pronounced effects on project economics; for both, the performance is likely to be better because conservative assumptions were used for the base case, and the project economics would be significantly improved. However, greater productivity and/or slower depletion must be demonstrated by test results. Likewise, if actual performance is poorer than for the base case,

Table S-3

SENSITIVITY OF REVENUE REQUIREMENTS TO COST COMPONENTS

Cost Component	Base Case	Sensitivity Test	Cost of Steam (mills/kWh) (a)	Power Plant Costs (mills/kWh) (a)	Total (mills/kWh) (a)
Base Case	—	—	28.2	21.6	49.8
Intangible drilling cost	\$35.16 million	-25% to +25%	24.2 to 32.3	21.6	45.8 to 53.9
Tangible drilling cost	\$4.36 million	-25% to +25%	27.6 to 28.8	21.6	49.2 to 50.4
Wellfield surface facilities	\$9.30 million	-25% to +25%	26.8 to 29.6	21.6	48.4 to 51.2
Wellfield fixed O&M	\$1.35 million/yr	-25% to +25%	27.3 to 29.1	21.6	48.9 to 50.7
Capacity factor	90%	85% to 95%	29.9 to 26.7	22.9 to 20.5	52.8 to 47.2
Return on equity-wellfield	18%	16% to 20%	26.4 to 30.2	21.6	48.0 to 51.8
Power plant capital cost	\$56.5 million	-25% to +25%	28.2	17.0 to 26.0	45.2 to 54.2
Power plant fixed O&M	\$2.3 million/yr	-25% to +25%	28.2	20.4 to 22.9	48.6 to 51.1

(a) Constant 1987 dollars

Table S-4

SENSITIVITY OF REVENUE REQUIREMENTS TO TECHNICAL RISKS

Item	Wellfield Revenue Requirement (a) (mills/kWh)	Power Plant Revenue Requirement (a) (mills/kWh)	Total Revenue Requirement (a) (mills/kWh)	Difference from Base Case (mills/kWh)
BASE CASE	28.2	21.6	49.8	-
100,000 sq m per fracture interval				
2X growth within one year				
10 percent reservoir leakage				
1500 psi injection pressure				
WELL PRODUCTIVITY				
200,000 sq m per fracture interval	18.2	21.5	39.7	-10.1
2X growth within one year				
100,000 sq m per fracture interval	44.5	21.8	66.3	16.5
No growth during operation				
DEPLETION RATE				
More rapid depletion	35.7	23.2	58.9	9.1
(Twice as fast as for Base Case)				
Slower depletion	23.8	21.0	44.8	-5.0
(One-half as fast as for Base Case)				
RESERVOIR LEAKAGE				
Greater reservoir leakage	29.9	21.6	51.5	1.7
(20 percent reservoir leakage)				
Lower reservoir leakage	27.9	21.6	49.5	-0.3
(5 percent reservoir leakage)				
INJECTION PRESSURE				
Greater injection pressure	30.2	22.3	52.5	2.7
(2000 psi injection pressure)				
Lower injection pressure	26.8	21.3	48.1	-1.7
(1000 psi injection pressure)				

(a) Constant 1987 dollars

Figure S-5 Internal Rate of Return for HDR Resource Developer

serious adverse economic consequences could result. Testing that develops solid data for evaluating productivity and depletion rate is imperative before commitment for a commercial project. Reservoir leakage and injection pressure could significantly affect project economics, but they are lower order effects compared to well pair productivity and depletion rate. Site-specific testing to determine the values of these two variables and to mitigate the associated risks is needed.

RECOMMENDATIONS

The results of the economic analysis using reasonable and possibly conservative assumptions and present-day drilling/completion technology show hot dry rock technology to be competitive with new coal-fired power generation. These results are so promising that a site-specific industrial HDR experiment at Roosevelt Hot Springs is highly recommended. The industrial HDR experiment would demonstrate:

- o The ability to:
  - Create multiple intervals with large fractures
  - Predict the size, orientation, and location of the fractures created
  - Target and drill through the multiple fractures to access the maximum feasible heat transfer area
- o The long-term thermal performance of a commercial-sized reservoir created for heat mining

Site-specific information for further developing a commercial first-of-a-kind project would also be obtained and would include needed data on:

- o Temperature/depth profiles
- o Reservoir leakage
- o Injection wellhead pressure
- o Persistence of faults at reservoir depths
- o Orientation of faults at reservoir depths
- o Spacing and orientation of deep subsurface joint sets
- o Magnitude of closure stress and pressure needed to stimulate fractures

The technical uncertainties of HDR technology and the moderate earnings expectation currently prevent industry-funded resource development even though installation of an HDR facility appears to require straight-forward but aggressive application of existing drilling, fracturing, and seismic monitoring technology. Furthermore, the electric energy market for the foreseeable future does not provide enough economic incentive for a private developer to invest in HDR energy technology development. Therefore, federal support for funding the industrial HDR experiment is recommended. Cost sharing by others, including industry participants and the state of Utah, is also recommended; however, these sources can be expected to provide only a small fraction of the funding required.

Further, a commercial-size first-of-a-kind power plant project is recommended if the industrial HDR experiment verifies the technical and economic projections. To attract private industry participation in this first-of-a-kind project, resource risk needs to be mitigated and additional economic incentives need to be provided by some combination of federal government participation in the venture (for example, a federal cooperative agreement), tax incentives, insurance, and multiple industry participation.

Section 1

INTRODUCTION

This study assesses a promising resource in central Utah as the potential site of a future commercial hot dry rock (HDR) facility for generating electricity. HDR energy production is the process of mining thermal energy from the earth's crust in situations where the temperature is high but the existing fluids or permeability are inadequate for transporting the energy to the surface. HDR systems created to date in New Mexico and at Rosemanowes, England are research and development projects that have proved the technology concept by drilling into hot dry rocks, hydraulically fracturing the rock mass, and extracting thermal energy by circulating water through the man-made fractures. Although HDR systems have been created on a research scale, HDR technology has not yet been applied commercially. This study is the first site-specific evaluation to assess the commercial readiness of HDR technology.

The pioneering HDR research and development work is an ongoing project at the Fenton Hill site in New Mexico conducted by Los Alamos National Laboratory (LANL) with funding by the U.S. Department of Energy (DOE). This project involves creating and testing an HDR reservoir. It has demonstrated that hot granitic rock (exceeding 250°C or 480°F) can be drilled; a reservoir can be created in the hot rock by hydraulic fracturing; and thermal energy can be extracted by circulating water through the man-made reservoir.

A smaller HDR research and development project is being conducted by the Camborne School of Mines at Rosemanowes in the southwestern part of the United Kingdom. It uses the same concept as the Fenton Hill project - drilling, hydraulic fracturing, circulating - to mine thermal energy from hot granitic rock.

In mid-1986, the DOE issued a request for proposals to investigate a specific site for HDR commercial venture potential. In response to this request, Bechtel National, Inc. proposed to evaluate the Roosevelt Hot Springs, Utah resource as the location for a potential 50 MWe power generating facility, and

DOE awarded a contract to Bechtel for this investigation. Intermountain Geothermal Company (a wholly owned subsidiary of Chevron Resources Company, which is the operator of the Roosevelt Hot Springs Unit) and the other members of the geothermal operating unit for the Roosevelt Hot Springs resource allowed access to the site and made available all HDR-related data from the site.

Bechtel's investigation adhered to the following ground rules concerning the technology:

- o Currently available geotechnical data were used to evaluate the HDR characteristics of the Roosevelt Hot Springs site; no additional geotechnical field work was performed.
- o Current technology or reasonable extensions were used for well and reservoir design. Specifically, current HDR technology and engineering information, or reasonable extensions, from the Fenton Hill and Rosemanowes projects were applied.
- o Current technology or reasonable extensions were used in the design concepts for the surface facilities.

These ground rules limited the technology base to the current state of the art so that commercial development could proceed if the project economics are favorable and the technical risks are acceptable. Use of these ground rules during this investigation helped emphasize some important technology gaps where additional HDR data are needed before expected project performance and economics can be adequately evaluated.

This report records the results of the investigation and makes recommendations for the next step toward implementing a commercial HDR facility. Specifically, each section addresses a portion of the investigation as follows:

- o Section 2 assesses the available site-specific geotechnical data to estimate the HDR potential, to select a prospect area for an initial HDR facility, to define the input parameters required for the subsurface reservoir design, and to mitigate the technical risks associated with development and operation of a commercial HDR reservoir system at Roosevelt Hot Springs.
- o Section 3 discusses the iterative modeling procedure used to design the subsurface reservoir and presents the resulting design and cost estimates.

- o Section 4 discusses the functions, selection, design, and cost estimates for the wellfield surface facilities and describes the power plant needed to generate electricity from the thermal energy delivered by operating the subsurface reservoir.
- o Section 5 discusses the major environmental and socioeconomic factors concerning development of a 50 MWe HDR facility at the Roosevelt Hot Springs site.
- o Section 6 presents a phased development plan to carry a commercial HDR project at Roosevelt Hot Springs through construction and startup; it describes the elements needed for the venture project and presents a schedule for accomplishing the needed activities.
- o Section 7 investigates the economics and risks associated with the project, including sensitivity analyses and an evaluation of the technical and economic risks.
- o Section 8 presents the conclusions and recommendations resulting from this investigation, including a recommendation for the next step in commercial development of HDR technology in general and commercialization at Roosevelt Hot Springs in particular.

Section 2

GEOTECHNICAL EVALUATION

2.1 INTRODUCTION

The Roosevelt Hot Springs geothermal area is located in west-central Utah, about 8 miles (13 km) northeast of the town of Milford in Beaver County, Utah. This area contains a water-dominated hydrothermal resource and an HDR resource. Development of the hydrothermal resource has begun with a 20 MWe flashed-steam power plant that started operation in 1984. The power plant is owned and operated by Utah Power and Light Company (UP&L), and the steam is produced from hot geothermal water by Intermountain Geothermal Company (a wholly owned subsidiary of Chevron Resources Company), the operator for the Roosevelt Hot Springs geothermal operating unit.

The area that has been made available for HDR consideration is located west and north of the hydrothermal resource. The key area of interest for HDR development (shallowest basement rock and highest thermal gradient) is in the western portion of the existing geothermal operating unit to the west of the hydrothermal field.

2.1.1 Assessment of Available Site-Specific Geotechnical Literature

The geotechnical evaluation of the HDR prospect at Roosevelt Hot Springs involves an assessment of the large volume of available site-specific geotechnical literature to estimate the HDR potential, to define the input parameters required for the subsurface reservoir design, and to define factors that mitigate the technical risks associated with development and operation of a commercial HDR reservoir system.

Site data were reviewed to establish a consistent interpretation of data relating to factors expected to strongly affect the success of a 50 MWe reservoir. The following considerations were paramount in our evaluations:

- o The areal extent of the HDR wellfield must be large enough to support at least 50 MWe generation for 30 years.
- o The preferred reservoir lithology is impermeable, granodiorite-quartz monzonite-quartz diorite rather than the banded and foliated Precambrian gneiss or the unconformably overlying sedimentary sequence to limit water losses.
- o It is desirable to locate the wellfield in an area with low fault density to avoid high fluid losses from the subsurface reservoir to existing faults and to allay concerns about the possibility of induced seismicity.
- o The persistence of surface faults to reservoir depths and fault orientations at these depths must be extrapolated for purposes of this analysis from existing geophysical, borehole, and drilling data.
- o Thermal gradients at HDR depths within the nonconvective crystalline basement and definition of the 3-dimensional variation in subsurface temperature within the geothermal unit must be extrapolated from temperature data obtained from existing dry wells that bottom in the crystalline basement. Extrapolations must be based on thermal gradients measured in the conductive basement rocks where temperature increases linearly with depth. Long extrapolation distances require verification of HDR target temperatures by deep drilling at the site.

2.1.2 Overview of Literature Sources

Since the mid-1970s, the University of Utah and the Earth Science Laboratory of the University of Utah Research Institute have studied aspects of the regional and local geology, geochemistry, and geophysics (e.g., Crosby 1973; Gertson and Smith 1979; Glenn and Hulen 1979; Nielsen et al. 1978; Nielson, Evans, and Sibbett 1986; Parry, Benson, and Miller 1976; Ross, Nielson, and Moore 1982; Sibbett and Nielson 1980; Ward et al. 1978). These data were made available through the Department of Energy's Industry Coupled Program. These site-specific studies primarily focused on geothermal exploration methods and on the formulation of conceptual models of the hydrothermal field at Roosevelt Hot Springs. This literature includes papers which attempt to define the geographic, geologic (structural and lithologic) extent of the hydrothermal resource, magmatic history, the origin of recharge water, and the impact of brine leakage from the hydrothermal field on shallow-aquifer geochemistry in the Milford Valley. The density of data is greatest within and near the structurally controlled hydrothermal field that lies to the east of the Opal

Mound Fault and south of the Hot Springs Fault (Negro Mag Fault zone) on the western side of the Mineral Mountains (Figure 2-1).

Additional site data obtained previously by geothermal resource exploration and development companies (Phillips Petroleum Company and MCR Geothermal Corporation) and published in various university and government documents include interpreted cuttings logs, geophysical well logs, and/or driller's logs for Wells 9-1 and 1-26 that bottom in hot, crystalline basement rocks within the HDR region (Glenn and Hulen 1979; Lenzer, Crosby, and Berge 1976; Shannon et al. 1983; Yusas and Bruhn 1979). Intermountain Geothermal Company made available all technical data from its Roosevelt Hot Springs files. Particularly valuable information not previously available in the public domain includes daily driller's logs for Wells 9-1 and 51-21 (Phillips and Getty Oil Co., respectively), directional transmissivity data across the hydrothermal field, and compendium tables, fault maps, and geologic cross sections of the geothermal unit.

As a part of the HDR technology transfer program, Los Alamos National Laboratory performed an evaluation of the HDR potential of the Roosevelt Hot Springs. Published papers by East (1981); Glenn, Hulen, and Nielson (1980); Goff and Decker (1982); and Shannon et al. (1983) and an unpublished document (Vuataz and Goff) review regional and local geology, data from Wells 9-1 and 1-26, and hydrogeology and surface hydrology.

2.2 REGIONAL TECTONIC SETTING

The Roosevelt Hot Springs KGRA is located on the western flanks of the central Mineral Mountains in west-central Utah. The Tertiary-age Mineral Mountains are a north-trending horst that is bounded by normal faults and represents the largest exposure of intrusive igneous rocks in the state of Utah (East 1981; Sibbett and Nielson 1980). The Mineral Mountains are located in the Basin and Range physiographic province near its eastern margin, transitional to the Colorado Plateau. The transition zone is characterized by a thin crustal layer approximately 25 km (16 miles) deep, that suggests a mantle upwarping greater than 80 km (50 miles) wide (East 1981; Ross, Nielson, and Moore

Figure 2-1 Location of Roosevelt Hot Springs

1982). This mantle unwarping produces high regional heat flow in excess of 105 MW/m^2 in contrast to $92 \pm 8 \text{ MW/m}^2$ average in the Basin and Range province and $50 \pm 8 \text{ MW/m}^2$ average in the Colorado Plateau (East 1981; Sass et al. 1980). High heat flow values potentially indicate shallower depths to commercial HDR temperatures. This transitional zone includes several KGRAs. The Mineral Mountains are also included within the western edge of the Intermountain Seismic Belt (Smith 1977; Smith and Sbar 1974), a 1,300 km (810-mile) long, 100 km (62-mile) wide zone of historical earthquake activity that extends northward from southern Arizona through western Montana.

The central part of the Mineral Mountains is structurally high relative to adjacent Basin and Range mountains and relative to the northern and southern parts of the Mineral Mountains (Ross, Nielson, and Moore 1982). This central portion comprises Tertiary plutonic rocks of the Mineral Mountains intrusive complex and the only outcropping of Precambrian metamorphic rocks (Sibbett and Nielsen 1980).

The regional tectonic grain is north-south Basin and Range block faulting cut by east trending, high-angle faults that are thought to be relic transform faults of late-Mesozoic to early Cenozoic age (Cook et al. 1975). The east-trending faults are believed to be related to the deep-seated structural trend represented by the Pioche-Reaver-Tushar mineral belt (Stokes 1968).

2.3 SITE GEOLOGY

Site geology is discussed below in terms of local setting, fault history, lithology, subsurface state of stress, fracturing characteristics of basement rocks, drilling characteristics, and seismicity.

2.3.1 Local Setting

The Roosevelt Hot Springs KGRA is located approximately 13 km (8 miles) northeast of Milford in Beaver County, Utah. Within the boundaries of the geothermal unit that is operated by Intermountain Geothermal Company, the HDR prospect comprises the area to the west of the Opal Mound Fault - the structural boundary that defines the western limit of the existing, commercial hydrothermal field (Figure 2-2).

Figure 2-2 Location of HDR Area at Roosevelt Hot Springs

Geology of the central Mineral Mountains was mapped in detail by Sibbett and Nielson (1980). The geology in the vicinity of the hydrothermal system and a proposed evolution of the Mineral Mountains intrusive were studied by Nielson, Evans, and Sibbett (1986) and Nielson et al. (1978).

The geothermal heat source is believed to be associated with Pleistocene emplacement of a pluton (Gertson and Smith 1979; Nielson, Evans, and Sibbett 1986). Intrusive activity has been dated to Oligocene time, and volcanic activity continues to the present. Youngest examples include a sequence of rhyolite flows and domes that range between 0.8 and 0.5 million years ago (Lipman et al. 1977).

2.3.2 Fault History

Nielson et al. (1978); Nielson, Evans, and Sibbett (1986); and Ross, Nielson, and Moore (1982) identify four major fault systems that transect the central Mineral Mountains. Geologic and geophysical well logs (Glenn, Hulen, and Nielson 1980) provide some information on the subsurface orientation of faults. However, fault locations based on borehole data from wells that intercept the igneous basement are available only in proximity to the Opal Mound Fault from Wells 9-1 and 52-21. Ward et al. (1978) summarize geological, geochemical, and geophysical exploration surveys of the Roosevelt Hot Springs thermal area that were completed by the University of Utah.

Low-Angle Faults. Uplift of the Mineral Mountains structural block is believed to have produced westward-dipping, low-angle, listric (concave-upward fracture surfaces that curve, gently then more steeply from horizontal) normal faults. The most prominent of these in the HDR prospect area is the Wildhorse Canyon Fault (Figures 2-3 and 2-4). Zones of intense cataclasis were produced along the fault surface. Ross, Nielson, and Moore (1982) interpret the depth to the Wildhorse Canyon Fault at 2,700 to 3,500 feet (823 to 1,067 meters) within the portion of the geothermal unit that lies to the west of the Opal Mound Fault (Figure 2-4).

LEGEND

Qal	alluvium, siliceous sinter	Trf	rhyolite flows
Qb	basalt	Tg	granite, quartz monzonite, and syenite
Qrd	rhyolite domes, with centers	Tdb	diorite
Qra	pyroclastic deposits	PCbg	metasediments
Qrf	rhyolite flows	PEbg	banded gneiss

Source: Ross, Nielson, and Moore (1982)

Figure 2-3 Geologic Map of Roosevelt Hot Springs KGRA and Vicinity

Source: Nielson, Evans, and Sibbett (1986)

Figure 2-4 East-West Cross Section Showing Gently Dipping Wildhorse Canyon Fault and Westward Increase in Depth to Crystalline Basement

High-Angle, Northwest-Striking Faults. These faults appear as cataclastic zones within the hanging wall of the Wild Horse Canyon Fault, the principal low-angle fault block (Figure 2-4). Generally, they do not penetrate the foot wall. The geometry of the high-angle faults is consistent with their formation in the upper fault plate accompanying the low-angle faulting between relatively rigid blocks.

East-West Trending, Steeply Dipping Faults. High-angle east-west trending faults such as the Hot Springs Fault (Negro Mag Fault zone) cut the low-angle faults. Figure 2-5, an interpreted fracture map of the Roosevelt Hot Springs KGRA, shows several lineaments parallel to the Hot Springs Fault. Relative offset and throw on the Hot Springs Fault is unconfirmed by mapping since its trace across the Mineral Mountains is straight, and there is a lack of recognizable offset in the structurally nondistinctive igneous rock types. However, a total magnetic residual intensity map from Ward et al. (1978) suggests 2 km (1.2 miles) of right-lateral offset along the Hot Springs Fault (Figure 2-6). Similarly, this map suggests that the southern boundary of the

- G = Geologic observation
M = Aeromagnetic survey
P = Mapped by photos
R = Resistivity survey

Modified from Ward et al. (1978)

Figure 2-5 Lineament Map of Roosevelt Hot Springs

Source: Modified from Ward et al. (1978)

Figure 2-6 Total Aeromagnetic Intensity Residual Map of Roosevelt Hot Springs

hydrothermal field corresponds to another, parallel, east-west trending magnetic lineament that lies just to the north of Well 52-21.

The linear expression of the Hot Springs Fault across the Mineral Mountains indicates an approximately vertical fault-plane orientation in the near surface. The east-west trend parallels the Pioche-Beaver-Tushar mineral belt (Stokes 1978) and may be related to movements along this structural feature. Nielson, Evans, and Sibbett (1986) suggest that this system of faults may provide the hydrological conduits through which the geothermal system is recharged. Unpublished data on microseismic monitoring (Zandt and Nielson) have been interpreted to show that the Hot Springs Fault zone currently is an active locus of episodic swarms of earthquakes of extrapolated Richter magnitudes less than one.

High-Angle, North-Northeast Striking Faults. The approximately north-south, horst-graben, extensional normal faults are the youngest structures in the area (Ross, Nielson, and Moore 1982). The Opal Mound Fault is the eastward-dipping eastern boundary of a 0.2 km (0.1-mile) wide horst. A west-side-down, west-dipping pair of normal faults defines the western margin of the Opal Mound horst. This western boundary fault zone is intercepted by Well 9-1 at depths of 5,700 to 5,800 ft (1,737 to 1,768 m) and at 6,250 to 6,320 ft (1,905 to 1,926 m). Although the alluvial surface on the west side of the Mineral Mountains is cut by numerous north-northeast trending normal faults (Figure 2-5), interpreted geophysical data obtained from gravity surveys (Figure 2-7) and seismic reflection profiling (Figure 2-8) show that the bedrock surface may dip gently westward toward the axis of the Milford Valley with only minor offsets by high-angle faults (Nielson, Evans, and Sibbett 1986). However, a fault-slip diagram from Smith and Bruhn (1984) (Figure 2-9) demonstrates the manner in which a series of parallel, high-angle, normal faults can mimic the expression of a gently dipping listric surface on a seismic cross section. Both interpretations are consistent with the mechanism of Basin-and-Range block faulting.

The number and spacing of these nearly vertical normal faults in the HDR prospect area are difficult to document. Surface expression and visible offsets are rare. The fault map of Figure 2-5 relies on photographs, geologic

Source: Ward et al. (1978)

Figure 2-7 Interpreted East-West Gravity Profile of Roosevelt Hot Springs

Source: Smith and Bruhn (1984)

Figure 2-8 East-West Seismic Reflection Profile of Milford Valley

Source: Smith and Bruhn (1984)

Figure 2-9 Geometry of High-Angle Normal Faults that may Generate a Listric-Fault Image on Seismic Reflection Profiles

observations, electrical resistivity, and an aeromagnetic survey to locate fractures. Most of the fractures located by geophysical surveys have not been verified directly by drilling or surface mapping. Therefore, their existence and the possible depths to which they persist are speculative.

Since HDR reservoir depths are anticipated to be 7,000 to 16,000 ft (2,100 to 4,900 m), it is important to the commercial HDR development at Roosevelt Hot Springs to resolve the existence, orientation, and spacing of fractures at these depths. These data affect the wellfield design, the ability to control the growth of the hydraulic fractures for the heat-exchange reservoir, the rate of water loss from the reservoir, and the potential for significant induced seismicity if sustained water-loss rates and flow impedance are high. Published structural cross sections (e.g., Figure 2-4) do not extrapolate faults deeper than 7,000 ft (2,100 m) because there is insufficient evidence to form the basis for extrapolations. Section 2.6 of this report lists recommendations for deep exploration and test wells that would furnish these critical data.

2.3.3 Lithology

Several detailed discussions of lithologies that occur within the Roosevelt Hot Springs area have been published. Glenn and Hulen (1979); Glenn, Hulen, and Nielson (1980); and Nielson et al. (1978) are especially comprehensive in their treatment of mineralogy, intensity of chemical alteration, and rock texture. The following discussion of rock types in the vicinity of the Opal Mound Fault is summarized from Glenn, Hulen, and Nielson (1980), who present the results of a logging study of Well 9-1.

Well 9-1 contains two distinct regimes of structure, lithology, and alteration that are separated by a major fault zone between 2,740 ft (835 m) and 2,770 ft (844 m). This boundary corresponds to the Wildhorse Canyon Fault in Figure 2-4 (Nielson, Evans, and Sibbett 1986). Above the fault zone, lithology is complex; alteration is moderate to intense; and evidence of structural disruption is abundant. Below the fault zone, there are few lithologies, the rock mass is relatively unbroken, and alteration is weak.

Stratigraphy at Well 9-1. Glenn, Hulen, and Nielson (1980) discuss seven major rock types that were encountered in Well 9-1:

- o Biotite-quartz-feldspar gneiss
- o Biotite-pyroxene-hornblende diorite
- o Hornblende-biotite granodiorite to quartz monzonite
- o Hornblende-biotite quartz monzonite
- o Hornblende-biotite granite
- o Microdiorite and andesite
- o Cataclasite zones

The gneiss occurs in significant quantities only above the fault zone centered at 2,755 ft (840 m). It ranges from highly foliated (common) to massive in structure and locally is intensely altered. This rock correlates with surface occurrences of the Precambrian banded gneiss. A schematic drawing of the stratigraphy at Well 9-1 is given in Figure 2-10.

The diorite occurs only above the Wildhorse Canyon Fault and has no surface-outcrop equivalent at Roosevelt Hot Springs. With the exception of cataclasite, it is the most intensely altered rock type encountered in Well 9-1. The quartz and potassium feldspar in the diorite are commonly highly strained when examined in thin section. Structurally, this rock type is massive.

The granodiorite to quartz monzonite correlates most readily with surface mappings of biotite diorite and biotite granodiorite (Sibbett and Nielson 1980). The granodiorite to quartz monzonite is referred to as granodiorite in most of the literature. It has two occurrences in Well 9-1. The upper granodiorite is in fault contact with the gneiss at 2,750 ft (838 m) and extends to 3,550 ft (1,082 m). The lower occurrence, at 5,830 ft (1,777 m) to total depth, has a sharp upper contact which probably is fault controlled.

Hornblende-biotite quartz monzonite occurs in the depth interval 4,100 to 5,830 ft (1,250 to 1,777 m). It has a medium-grained, hypidiomorphic-granular

17-1/2 in. hole
13-3/8 in. CSG
to 107 ft

12-1/4 in. hole
9-5/8 in. CSG
to 800 ft

8-1/2 in. hole
5-1/2 in. CSG
to 4,198 ft

8-1/2 in. hole
to TD

Qal: f. - v. coarse sand and volcanics.

Biotite-quartz-feldspar gneiss and biotite-pyroxene-hornblende diorite. Moderately to locally intensely altered. Three major cataclasite zones: 2,215 - 2,230 ft, 2,410 - 2,430 ft, 2,740 - 2,770 ft. Numerous minor occurrences of cataclasite.

Granite: med. grained, weakly altered.
Gneiss and diorite.

Granodiorite: possibly weakly metamorphosed granodiorite to quartz monzonite, med. grained, hypidiomorphic granular, k-feldspar fresh, plag. partially altered.

Granite: quartz poor, med. grained, weakly hydrothermally altered.

Hornblende - biotite quartz monzonite: med. grained, hypidiomorphic granular. Gradational upper contact with granite. Cataclasite zones at 4,760 - 4,770 ft, 5,790 - 5,810 ft. Fault contact at lower boundary.

Granodiorite to quartz monzonite, f-med. grained, hypidiomorphic granular, k-feldspar fresh, plag. partially altered.

Figure 2-10 Stratigraphy at Well 9-1

texture and is uniform in composition except where modified by hydrothermal alteration. Its upper contact with granite is gradational. The lower contact with granodiorite is sharp and probably fault controlled. This rock type correlates closely with the Tertiary quartz monzonite that was mapped at the surface by Sibbett and Nielson (1980).

A distinctive quartz-poor granite was encountered in two intervals in Well 9-1: from 2,620 to 2,710 ft (799 to 826 m) and from 3,550 to 4,100 ft (1,082 to 1,250 m). It is medium grained and hypidiomorphic granular. It correlates most closely with surface mappings of Tertiary syenite (Nielson et al. 1978). It is weakly hydrothermally altered.

Microdiorite and andesite occur only in minor amounts in several short intervals: 980 to 995 ft (298 to 303 m), 1,390 to 1,405 ft (424 to 428 m), 1,525 to 1,540 ft (465 to 469 m), 2,490 to 2,500 ft (759 to 762 m), and 3,430 to 3,490 ft (1,045 to 1,064 m). Although compositionally similar, these rocks are texturally disparate, ranging from cryptocrystalline to porphyritic and exhibiting flow foliation or massive textures. They correlate with surface occurrences of Tertiary microdiorite dikes identified in Nielson et al. (1978).

Cataclasites that are typical of propylitic alteration or greenschist-facies metamorphism occur in three major and numerous minor zones above the Wildhorse Canyon Fault. Only two such zones were encountered below 2,770 ft (840 m): 4,760 to 4,770 ft (1,451 to 1,454 m) and 5,790 to 5,810 ft (1,765 to 1,771 m).

Stratigraphy at Acord 1-26. Depths to all lithologic units are expected to increase westward. The depth to crystalline basement is substantially increased 3.5 miles (5.6 km) west-northwest of Well 9-1 (refer to Figure 2-4). The 12,645 ft (3,854 m) Acord 1-26 hot dry well, drilled by the MCR Geothermal Corporation encountered Tertiary crystalline basement rock at a depth of 10,400 ft (3,170 m). Shannon et al. (1983) describe the lithologies at Acord 1-26 shown in Figure 2-11. In stratigraphic sequence, the lithologies at Acord 1-26 include:

- o Basal 98 ft (30 m) of migmatitic quartz schist and gneiss
- o 2,150 ft (655 m) Tertiary biotite monzonite

Source: Shannon et al. (1983)

Figure 2-11 Generalized Stratigraphy at Acord 1-26

- o 2,297 ft (700 m) of conglomerate and sandstone
- o 1,034 ft (315 m) of volcanic rocks. The basal sub-unit is 240 ft (73 m) of basalt overlain by 190 ft (58 m) of rhyolite, 492 ft (150 m) of dacite, and 112 ft (34 m) of andesite
- o 1,280 ft (390 m) of sandstone, 443 ft (135 m) of siltstone, 1,050 ft (320 m) of arkosic sandstone and conglomerate, 623 ft (190 m) of claystone, and 394 ft (120 m) of sandstone, conglomerate, siltstone, and claystone
- o 3,280 ft (1,000 m) of unconsolidated sediments, chiefly clays and sands

2.3.4 Subsurface State of Stress

The subsurface state of stress must be characterized to develop a strategy for directional drilling and to anticipate the direction in which hydraulically induced fractures are likely to grow. Information on the subsurface stress state at Roosevelt Hot Springs is meager. Yusas and Bruhn (1979) attempted to derive the in-situ stress state through analyses of structural fabric and measurement of strain relaxation on granitic core from Well 9-1. However, the results were inconclusive.

The magnitudes of the principal stresses at the average target bottom-hole depth of 12,000 ft (3,700 m) are not known. No hydraulic fracturing or fracture jacking tests have been conducted at the site. Furthermore, the net overburden stress at reservoir depth and the breakdown stress that must be overcome to stimulate hydraulic fracture growth cannot be deduced from available site data. The fracture gradient is site specific. In the absence of data from Roosevelt Hot Springs, we used values of stimulation pressure from the Fenton Hill Project in New Mexico to derive cost estimates for the conceptual fracturing program. Cost sensitivity analyses described in Section 3 bracket the upper and lower limits of expected stimulation pressure.

The direction of the minimum compressive stress, σ_3 , is inferred to be ESE-NNW, based on the direction of natural deviation of the trajectories of Wells 9-1 and 52-21 and the orientation of the most recent faulting.

2.3.5 Fracturing Characteristics of Basement Rocks

Control of hydraulic fracture orientations and radii in the banded and foliated Precambrian gneiss is most likely complicated by the highly variable textural anisotropy and alteration of the rock mass. Additionally, the subsequent fracture growth that is anticipated to result from thermal contraction of the rock mass during system operation might be affected by textural anisotropy. Therefore, the preferred reservoir lithologies are the texturally homogeneous Tertiary granitic rocks (including granodiorite, quartz monzonite, and quartz diorite) that intruded the Precambrian gneiss during emplacement of the Mineral Mountains complex.

Fracture Growth Background. The simplified notion that horizontal stress anisotropy will control fracture growth may not apply. If the rock mass in the reservoir zone is homogeneous both texturally and structurally (i.e., devoid of geologic discontinuities such as joints or sealed fractures), then the rock fracture mechanism (tensile failure) would be controlled by the horizontal stress anisotropy and the resultant fracture would grow vertically. Furthermore, if the rock is chemically unaltered, then porosity would be very low, i.e., close to 1 percent; and permeability to water would be in the range of microdarcies or lower (Brace, Walsh, and Frangos 1968; Katsube and Hume 1987). In this case, most of the water that is injected into the reservoir zone to create a hydraulic fracture network would result in fracture volume with minimal leak-off.

Fracture Growth of Granitic Rocks. However, granitic rocks commonly are jointed; as a result, the simplified notion described above does not adequately describe fracture growth. Hydraulic fracturing of the HDR reservoir at the Rosemanowes project in England and the deep portion of the reservoir at Fenton Hill, New Mexico, resulted in shear stimulation of existing subsurface joint sets (Albright and Pearson 1985; Dreesen et al. 1987; Murphy 1985; Murphy and Fehler 1986; Pine and Batchelor 1984). At Fenton Hill, joint sets with spacings on the order of tens of meters between fracture surfaces controlled the orientation of reservoir fractures by inducing fracture extension at 30° to 60° to vertical along pre-existing joints, enhanced the

creation of multiple fractures, and produced high water loss owing to relatively high joint permeabilities. The influence of geologic discontinuities is expected to be substantial, especially if joint orientations do not coincide with principal stress directions, as modeled by Murphy and Fehler (1986). Section 3.3 presents the results of hydraulic fracture modeling for Roosevelt Hot Springs.

Basis of Well Design Concept. In the absence of either test data on hydraulic fracture orientation and size or geophysical well logs that might contribute information on deep subsurface joint sets, the volumes of fluid and the delivery times required for the creation of large hydraulic fractures were estimated for Roosevelt Hot Springs. Sensitivity estimates for these assumptions were made and are addressed in Section 7.7. Without this critical information about the reservoir target zone, a conceptual reservoir design and a sequence for installation of the injection and production wells were developed that do not rely on predicting the orientation and length of hydraulic fractures. Until sufficient subsurface data are obtained to permit the easing of design constraints without increasing the risk to wellbore integrity or reservoir development, this well pair design and installation strategy will be used. The well design concept is presented in Section 3.5 of this report.

Based on hydraulic fracture operations at Fenton Hill and Rosemanowes, it is anticipated that reservoir fractures will be created by relative shear displacement along existing joints. These fractures will thereby create self-propping fractures of sufficiently large aperture to form low-impedance flow paths for the circulation of water. In the initial stages of operation before commercial production begins and before thermal contraction can reduce flow impedance in the near-wellbore regions, it may be necessary to rework fractures from the production wellbore to stimulate sufficient production flow. Similar stress-unlocking experiments at Fenton Hill successfully reduced the surface injection pressure needed to sustain commercial flow rates (e.g., Dash et al. 1981). Bauxite proppant could be considered if impedance remains excessive.

2.3.6 Drilling Characteristics

Wells 9-1 [total vertical depth = 6,885 ft (2,099 m)] and 52-21 [total vertical depth = 7,500 ft (2,287 m)] both entered crystalline basement rock at depths shallower than 1,000 ft (305 m). Drilling of both wells proceeded without major delays with the exception of one episode of lost circulation in Well 9-1 as it crossed a cataclasite zone from depths 5,790 to 5,810 ft (1,765 to 1,771 m). In Well 9-1, drilling rates in the crystalline basement rock averaged just over 13 ft per hour (4.0 mph) excluding time required to log and set casing. Fourteen drill bits were used, all of which are commercially available.

Progress was slower in Well 52-21, averaging 7 ft per hour (2.1 m/hr) in the igneous basement rock; 21 bits were consumed. No documented explanation is available for the slower progress in Well 52-21.

Drilling of the 12,640 ft (3,854 m) Well 1-26 progressed more quickly than Wells 9-1 and 52-21. However, crystalline basement rock was not encountered until a depth of 10,400 ft (3,170 m). Twenty-six drill bits were used (Shannon et al. 1983). The drilling rate through 3,280 ft (1,000 m) of alluvium averaged 43 ft per hour (13.1 m/hr). The rate through 4,680 ft (1,427 m) of consolidated Tertiary sandstone and Tertiary volcanics averaged 17 ft per hour (5.2 m/hr). Progress through the lowest section of Tertiary conglomerate, quartz monzonite, and Precambrian gneiss averaged 9 ft per hour (2.7 m/hr).

No attempts were made to control the natural wellbore deviations of Wells 9-1 and 52-21. Consequently, drill bits followed the paths of least resistance. Well 9-1 deviates north-northeast, and Well 52-21 deviates southwest, defining a plane that is parallel to the trace of the Opal Mound Fault and perpendicular to the anticipated direction of the minimum compressive stress, σ_3 . These data also strongly suggest that the HDR wellbores will require directional control during drilling to force the deviations east-southeast in the direction of σ_3 and perpendicular to the plane of natural deviation defined by Wells 9-1 and 52-21.

2.3.7 Seismicity

Regional Seismicity. Microearthquake monitoring at Roosevelt Hot Springs and Cove Fort (on the eastern side of the Mineral Mountains) was conducted in 1974 and 1975 to examine the relationship between seismicity and locations of known geothermal resources. The objective of this monitoring was to investigate the feasibility of using patterns of microseismicity to explore for new geothermal resources (Olson and Smith 1976). Twelve portable, high-gain seismographs recorded 163 events in 49 days of magnitude $-0.5 < M_L < 2.8$. Most of the events were characterized as shallow-focus earthquakes less than 10 km (33,000 ft) deep. In order of decreasing activity, they were grouped into three areas:

- o An area of numerous swarms in the Cove Fort vicinity
- o A north-south trend of moderate activity along the western margin of the Milford Valley
- o A trend of minor activity along the western side of the Mineral Mountains, including the Roosevelt Hot Springs KGRA

The earthquake data (Figure 2-12) indicate that the Roosevelt Hot Springs thermal area is only slightly active and at a much lower level than the Cove Fort area.

The unpublished data of Zandt and Nielson show that within the Roosevelt Hot Springs KGRA, the Hot Springs Fault (Negro Mag Fault zone) is seismically active. Localized episodic swarms with Richter magnitudes less than $m_R = 1$ were recorded. Similarly, a baseline seismic survey performed for Phillips Petroleum Company between September 1983 and April 1984 demonstrates that the HDR field at Roosevelt Hot Springs to the west of the Opal Mound Fault has low activity.

Potential for Induced Seismicity. Sudden changes in stress state caused by rapid temperature and pressure changes possibly could give rise to seismic shocks. However, heat extraction from the subsurface using HDR methods is a slow, continuous process. Thus, the changes in the state of stress accompanying HDR exploitation also will be gradual rather than sudden.

Source: Ward et al. (1978)

Figure 2-12 Epicenter Map of Roosevelt Hot Springs – Cove Fort Area

Thermal stress cracking of the reservoir rock is expected to occur at the rock/water interface. These cracks, which are expected to benefit the productivity of the system by increasing the heat-transfer surface area, will be numerous but will initiate one at a time and not as a single, significant failure. The initiation of each crack is expected to generate a microseismic signal that will be detectable only by highly sensitive monitoring instruments. The likelihood of building up an unrelieved stress that could suddenly cause a large-scale earth rupture and thereby generate a significant seismic event is remote. Experience from the operating HDR systems at Fenton Hill and Rosemanowes to date supports these expectations (Armstead and Tester 1987).

In addition to thermally induced stress cracking, potential exists for induced microseismicity as pressurized water permeates into the rock surrounding the reservoir. As water leaks into the formation, microseismicity is expected to occur as the microstructure adjusts to the alteration of stress state. This effect is controlled by the rate of water loss to the formation and the pumping pressure. Siting the heat-exchange reservoir in impermeable rock away from major faults minimizes the potential impact of hydraulic pressurization effects.

While concerns for induced seismicity greatly influence reservoir site selection, an attendant issue is limited water availability. The HDR development plan for Roosevelt Hot Springs is designed to create a closed-loop circulation system with very low water loss to minimize the impact on existing and planned regional water usage while permitting heat extraction from the subsurface.

Apparent induced seismicity at the Rocky Mountain Arsenal in Colorado is often cited as a dramatic case of earthquake activity caused by fluid injection. However, the Roosevelt Hot Springs HDR design is markedly different from the Rocky Mountain Arsenal. The Roosevelt Hot Springs HDR reservoir is designed for low water loss into the surrounding formation. By contrast, the Rocky Mountain Arsenal was designed to use high subsurface permeabilities to ensure high fluid-loss rates for rapid disposal of liquid materials. The Rocky

Mountain Arsenal site is discussed in detail by several authors in a volume edited by Hollister and Weiner (1968).

Onsite measurements of thermally and hydraulically induced microseismic activity at Fenton Hill and Rosemanowes have detected tremors typically in the range of Richter magnitude minus 4 to minus 1, which is 7 to 4 orders of magnitude below the level of human sensitivity (Albright and Pearson 1985; Armstead and Tester 1987). No seismic tremors of significance have yet been detected at either site. The subsurface system design for Roosevelt Hot Springs (see Section 3 of this report) includes costs for an extensive array of monitors for regional and induced seismicity.

2.4 SUBSURFACE TEMPERATURE AND THERMAL ENERGY

Heat flow, electric production potential, and drilling target depths are discussed below.

2.4.1 Heat Flow

The thermal area of interest is located on the western side of the Tertiary granitic pluton that defines the Mineral Mountains, a horst 28 miles (45 km) long and 7.5 miles (12 km) wide. Rhyolitic volcanism that occurred between 0.8 and 0.5 million years ago was a major Pleistocene thermal event that is believed to be significant to the evolution of the heat source driving the Roosevelt Hot Springs KGRA (e.g., Nielson, Evans, and Sibbett 1986; Ross, Nielson, and Moore 1982; Ward et al. 1978).

Delayed P-wave travel times and low-Q S waves that were recorded during microearthquake monitoring of the Cove Fort thermal area suggest the presence of a low-velocity zone beneath the Mineral Mountains. This zone may represent a region of partial melt that exhibits viscous behavior or a region of intense brittle fracturing in hard rock. The vertical and lateral resolution of seismic data are inadequate to delineate the zone (Olson and Smith 1976).

Gravity and magnetic data proved useful in determining the structure and depth of valley fill, but neither detects an igneous intrusive heat source (Crebs and Cook 1976). Heat flow and resistivity data both outline anomalous zones

along systems of faults, but the thermal anomalies probably result from convective circulation of hot brine in the near surface (Sass et al. 1980; Sill and Bodell 1977). Magnetotelluric data show an anomaly over the hydrothermal field that may be interpreted as either a near-surface conductor or a deep conductor (Wannamaker 1978).

Ward et al. (1978) compute the magnitude of the present heat loss at Roosevelt Hot Springs by integrating the heat flux over the areas bounded by the heat-flow contours. The total calculated heat loss is 70 MW. Allowing for contributions from Basin-and-Range heat flow, local hydrologic recharge and discharge, and exothermic clay alteration reactions, the remaining heat loss of 60 MW must be supplied by a deeper source. Using arguments similar to those of Lachenbruch et al. (1976) for the Long Valley Caldera, Ward et al. (1978) estimate that 60 MW heat loss could be supplied by steady-state conduction from a source near the granite solidus with lateral dimensions of the Mineral Mountains pluton at a depth of 4.4 miles (7 km). If the present heat loss has been maintained since rhyolitic emplacement 0.5 million years ago, then resupply of heat to near-surface rocks is implied, possibly from a deep, magmatic source.

2.4.2 Electric Production Potential

The heat loss is considerably smaller than the production potential of the system. Ward et al. (1978) conservatively size the hydrothermal field at 3.9 mi^2 (10 km^2), yielding 300 MWe with 5 MWe wells spaced at 40-acre intervals. Carter and Cook (1978) state that the Tertiary intrusive rock may underlie most of the Milford Valley, and the existence of hot rock at Acord Well 1-26 supports this statement. Based conservatively on the northern, southern, and western limits of existing hot, dry wells at the site, East (1981) calculates a thermal anomaly of 62 mi^2 (160 km^2). This estimate places the HDR prospect at 16 times the size of the hydrothermal field. The region of the participating unit that presently is available to HDR development measures 20 mi^2 (52 km^2). Based on an extrapolation from Ward et al. (1978), this prospect has a potential yield 1,540 MWe.

Using a different approach, Goff and Decker (1982) estimate that there are about 17×10^{18} Joules of conductive thermal energy stored within a technically accessible 27 km^3 prismatic reference volume of rock at Roosevelt Hot Springs. For purposes of comparing several promising resources, the upper surface area of the rectangular reference prisms was assigned a value of 10 km^2 . At Roosevelt Hot Springs, the vertical dimension was derived by taking a 2.3 km height of rock symmetrically distributed vertically about the depth corresponding to $T = 265^\circ\text{C}$ for a thermal gradient of 55° to $60^\circ\text{C}/\text{km}$. The calculation of Goff and Decker (1982) defines the stored thermal energy from the source temperature to a reference temperature of 0°C . Realistically, rock temperatures after drawdown for power generation will be higher than 0°C .

To estimate the electric energy that is available at Roosevelt Hot Springs, we assume the following:

- o The allowable HDR development area within the participating unit is 20 mi^2 (52 km^2).
- o Thermal drawdown could be approximately 100°C , from 265°C to 165°C .
- o There is a 15 percent efficiency in converting thermal power to electrical power.

This approach estimates the thermal equivalent of 160,000 MWe-yr of electrical energy contained within the HDR prospect at Roosevelt Hot Springs. While the expected yield is substantially lower, it is clear that the resource within the participating unit has a potential for supplying several hundred MWe for a period of greater than 30 years.

2.4.3 Drilling Target Depths

The shallowest occurrence of commercially viable HDR temperatures is the most attractive selection for the wellfield site to minimize the costs of the subsurface reservoir installation, including drilling, casing, and fracturing operations. However, this choice must be considered in conjunction with the other site-selection criteria: low fault density, site accessibility, and a

sufficient thickness of Tertiary crystalline rock to support the reservoir development plan.

Data on temperatures and thermal gradients within the Tertiary crystalline basement rock were extrapolated at depth to HDR reservoir temperatures of 250°C to 300°C. From the values in Table 2-1 and the locations given on the map in Figure 2-13, the shallowest projected depth to 300°C occurs in the vicinity of Well 9-1. Figure 2-14 shows the well behaved, linear relationship between temperature and depth that characterizes conductive materials and shows that the thermal gradient at the bottom of Well 9-1 is near 55°C/km. Depths to these temperatures increase northward, westward, and southward from Well 9-1. Commercially viable targets are determined by a combination of temperature, depth, and reservoir development cost.

2.5 HYDROGEOLOGY AND WATER AVAILABILITY

Section 4.1.4 of this report indicates that a 50 MWe HDR facility will require a continuous supply of make-up water approximating 250 lps (3,900 gpm; 6,300 acre-ft/yr) by years 26 through 30. Based on pumping tests in a well located to the north of Roosevelt Hot Springs, Vuataz and Goff (unpublished report) conclude that the shallow aquifer underlying the Milford Valley could sustain flow rates required for HDR development.

Reconnaissance groundwater data reported by Mower (1978) indicate that hydraulic connection between the Roosevelt Hot Springs area and the agriculturally active area to the south in the town of Milford is low. Severe drawdown of the water table near Milford during water-level monitoring over several years ending in the mid-1970s was not seen in water wells in the Roosevelt Hot Springs area, which is located 13 km (8 miles) to the northeast (Mower and Cordova 1974). A survey conducted by the U.S. Geological Survey and the Utah Division of Water Rights between March 1985 and March 1986 also indicates poor connectivity between Roosevelt Hot Springs and Milford; declines of 0 to 10 ft in water levels were recorded near Milford while water levels at Roosevelt Hot Springs rose 0 to 2 ft (Figure 2-15).

Table 2-1

PROJECTED DEPTHS TO 250°C AND 300°C

Well	Total Vertical Depth m (ft)	Grad T, Bottomhole °C/km	Projected Depth(a)	
			250°C m (ft)	300°C m (ft)
OH-5	554.7 (1,820)	41(b)	4,268 (14,002)	5,487 (18,003)
OH-4	536.4 (1,760)	46(b)	3,398 (11,149)	4,485 (14,716)
82-33	1,838.5 (6,032)	41	3,446 (11,306)	4,665 (15,307)
9-1	2,098.4 (6,885)	55(c)	2,444 (8,019)	3,406 (11,174)
		51	2,451 (8,041)	3,431 (11,258)
		56(d)	2,419 (7,938)	3,312 (10,868)
OH-1	706.2 (2,317)	50	3,520 (11,549)	4,520 (14,830)
52-21	2,285.9 (7,500)	35(c)	3,553 (11,659)	4,982 (16,346)
		35	3,553 (11,659)	4,982 (16,346)
		58(d)	3,069 (10,071)	3,932 (12,900)
1-26	3,853.7 (12,644)	54(e)	4,224 (13,860)	5,150 (16,898)

-
- a) If unspecified in column 3, projected depths were calculated from data compiled in Lenzer, Crosby, Berge (1976).
- b) Thermal gradients for Wells OH-4 and OH-5 were based on bottomhole gradients for those wells and values from Well 82-33.
- c) Bechtel analysis of data.
- d) East (1981).
- e) Shannon et al. (1983).

1-26

Figure 2-13 Well Location Map for Data Used to Project Subsurface Temperatures in Table 2-1

Figure 2-14 Temperature Gradient in Well 9-1

From: U.S. Geological Survey and Utah Department of Natural Resources, Division of Water Rights, Water-level-change Map, Number 445

Figure 2-15 Map of Milford Area, Beaver County, Utah: Change of Groundwater Levels, March 1985 to March 1986

Figure 2-16 is a 1972 contour map of the potentiometric surface from Mower and Cordova (1974). This map shows that the general direction of the subsurface hydraulic gradient from the town of Milford is directly to the north toward Beaver Bottoms, which is 21 km (13 miles) to the north. Subsurface recharge of the aquifer at Milford is primarily supplied from the east, south, and west of Milford, but not from the north. The direction of groundwater flow from the proposed HDR water well site at Roosevelt Hot Springs is also toward Beaver Bottoms to the northwest. Since Milford is not in the down-gradient subsurface flowpath from Roosevelt Hot Springs, and because hydrogeologic transmissivity between Roosevelt Hot Springs and Milford is low, pumping operations at Roosevelt Hot Springs for an HDR facility are not expected to affect the water supply in the vicinity of Milford.

Vuataz and Goff (unpublished), Lachenbruch et al. (1976), and Mower and Cordova (1974) give the distribution of concentrations of impurities such as boron and chloride throughout the Milford Valley. Based on these data, Ross, Nielson, and Moore (1982); and Lenzer, Crosby, and Berge (1976) mapped iso-concentration contours. Figure 2-17 is reproduced from Vuataz and Goff (unpublished). Impurity concentrations are highest in the immediate vicinity of the hydrothermal field and indicate that subsurface inflow of geothermal fluids naturally leaking into the groundwater provide up to 60 percent of the local recharge to the aquifer system. Bamford (1978) indicates that elevated levels of Hg, As, Sb, Mn, Cu, Pb, Li, Sr, and other elements have been redistributed and transported in the aquifer by thermal fluids. The proposed wellfield for make-up water lies within the most highly contaminated area of the aquifer. Without treatment, this water may not be suitable for agricultural use. However, this water is suitable for use in the HDR system.

2.6 HDR RESERVOIR DEVELOPMENT RECOMMENDATIONS

Limitations of existing data, recommendations for tests, recommendations for the initial development site, and recommendations for reservoir development are summarized in this section.

Figure 2-16 Potentiometric-Surface Map of Milford Valley Showing Direction of Groundwater Flow from Proposed Water Pumping Field at Roosevelt Hot Springs to Beaver Bottoms

Figure 2-17 Location of Proposed Make-up Water Wellfield
Within Aquifer Region That is Contaminated By
Geothermal Brine

2.6.1 Limitations of Existing Data and Recommendations for Tests

A wealth of valuable data, both published and unpublished, were made available to this project. However, major issues that are important to technical risk mitigation and cost estimates for the subsurface reservoir installation remain unanswered by this geotechnical investigation. These issues are site-specific and concern rock properties in the deep subsurface HDR target zone. We strongly recommend that the next stage of HDR development at Roosevelt Hot Springs should involve drilling and completing one pair of full-depth wells to obtain data on:

- o The persistence of faults at HDR reservoir depths of 7,000 to 16,000 ft (2,100 to 4,900 m), the orientations of faults at depth, and the implications of fault orientations on the state of stress
- o The spacing and orientation of deep subsurface joint sets that may affect hydraulic fracture orientations and size, and the rate of water loss during system operation
- o The orientation of the principal stresses and the magnitude of the rock closure stress that must be exceeded to stimulate hydraulic fracture growth
- o Verification of temperature-at-depth extrapolations calculated from shallower thermal gradients
- o Confirmation that the system operating pressures required to drive fluid circulation in the reservoir are low enough to control water loss and are below pressures that might induce significant earthquakes

The minimum number of borings required to supply the needed data is one pair of injection and production wells. Operations should include drilling the injection well to full depth, casing the well as specified in Section 3 of this report, installing a small number of multilevel hydraulic fractures, drilling and completing the production well to intercept the fractures, and sustaining fluid flow through the subsurface system long enough to answer the technical issues listed above and the additional issues listed at the end of Section 3.

Drilling out and extending the depth of Well 9-1 is not recommended because Well 9-1 deviates 90° to the desired deviation direction. A sidetrack from

the lower section of Well 9-1 would produce a dog leg that is judged to be very difficult technically. Furthermore, since the persistence of the Opal Mount Fault at 11,000 to 12,000 ft (3,300 to 3,700 m) depths is unknown, an ESE sidetrack at 20° to 25° from vertical in Well 9-1 potentially would position subsequent hydraulically created fractures to intersect both the fault and the hydrothermal field. The condition of Well 9-1 is not verified, but it is probably suitable for use as a subsurface seismic monitoring station.

2.6.2 Recommendations for the Initial HDR Development Site

The wellfield site selection criteria are:

- o Absence of faults or low fault density
- o Minimum depth to Tertiary crystalline rocks
- o Minimum depth to target temperature
- o Proximity of available subsurface data
- o Site accessibility
- o Location of planned make-up water wellfield

Based on information presented in the foregoing sections, our recommendation for an initial HDR wellfield site comprises the 5 mi² (13 km²) region that includes Well 9-1. This region is bounded to the north by the Hot Springs Fault (Negro Mag Fault zone), to the east by the western graben fault that defines the Opal Mound horst, to the south by an unnamed fault that trends east-west between Wells 9-1 and OH-1, and to the west by the boundary of the participating unit. The site is outlined in Figure 2-18.

Initial wells should be installed in the eastern portion of this site to take advantage of the shallowest possible occurrences of commercial HDR temperatures.

2.6.3 Recommendations for Reservoir Development

In the absence of site-specific data, we recommend that at least the first wells should be designed to accommodate the broadest possible range of orientations of hydraulic fractures and to mitigate risks to the integrity of

Figure 2-18 Proposed Siting for Initial HDR Wellfield

the wellbore. The wells should be deviated east-southeast since tensile fractures are expected to dip steeply westward in a manner that is consistent with en-echelon down-faulting on the western side of the Mineral Mountains. Based on the near-vertical orientation of Basin-and-Range faults to 7,000 ft (2,100 m) depth, if hydraulic fractures are created by tensile failure in the depth interval from 7,000 to 12,000 ft (2,100 to 3,700 m) corresponding to expected temperatures of 230-300°C in the vicinity of Well 9-1, then these fractures would be steeply oriented. However, hydraulic fractures below 10,000 ft (3,000 m) at Fenton Hill grew in a complicated pattern at inclinations as much as 45° to vertical (Murphy and Fehler 1986; Dresser et al. 1987).

The maximum feasible angle of deviation should be 20° to 25° to accommodate possible near-vertical fractures. Greater deviation angles are not planned based on drilling difficulties experienced at Fenton Hill and at Rosemanowes using 30° to 35° deviation angles. The angle of deviation may be reduced later if information obtained during installation and operation of the initial wells indicates that this involves low risk to reservoir development and operation. Estimated costs for multiple well pairs for the economic analysis assumed that all wells would be deviated.

Section 3

SUBSURFACE SYSTEM DESIGN

3.1 INTRODUCTION

3.1.1 Background

The current HDR concept involves creating a fracture network in hot, impermeable rock through which water is circulated to heat mine the source rock. A design goal for the subsurface, fractured, heat transfer reservoir for Roosevelt Hot Springs is to provide a 30-year output of 50 MWe salable power (i.e., power delivered to the transmission grid). To provide the pumping power for sustaining flow through the subsurface system, net power plant output must be greater than 50 MWe.

Because of the high cost of well drilling and reservoir completion, it is imperative to economically optimize the reservoir and power plant combination to define a technically feasible, commercially competitive design. Consistent with this objective, the subsurface system design involved the following steps in an iterative fashion to screen for an economically viable facility:

- o Reservoir thermal performance modeling was used to identify the ranges of reasonably anticipated thermal drawdown.
- o Cost estimates for well drilling and completion were developed.
- o Thermal-performance modeling results, which included the effects of reservoir depletion, were combined with expected power plant performance to produce an estimate of salable power output as a function of time.
- o For each case considered, a well/reservoir cost estimate, the corresponding projection of salable power output, and appropriate estimates for power plant costs were merged to estimate the levelized cost of electricity.
- o Minimum levelized cost of electricity was used to define an optimum reservoir/power plant combination. To be economically viable, the levelized energy cost from HDR must be competitive with energy from more conventional generating sources, such as coal-fired plants.

3.1.2 Selection of Heat Transfer Model

Several existing models that describe the extraction of heat by the flow of water through fractures in hot granitic rock were considered. The model selected for use is the multiple, parallel fractures model developed by Gringarten, Witherspoon, and Ohnishi (1975). The semi-analytic formulation of the Gringarten model minimizes computing costs thus permitting a large number of parametric-sensitivity studies to be evaluated. In addition, data input requirements are compatible with reasonable extrapolations of available information. Finally, the geometry of flow through numerous fractures used in the Gringarten model agrees favorably with the expected reservoir fracture pattern. The Gringarten model is flexible enough to allow the effects of alternative designs and reservoir performance assumptions to be evaluated by examining upper and lower limits of expected thermal behavior. Numerical formulations, such as the buoyancy-drive model (McFarland 1975) and the jointed-fracture model (Murphy et al. 1980), were not justified for screening purposes considering the uncertainties in the subsurface and the greater computational costs. The model of heat extraction by flow through intensely fractured media (Wunder and Murphy 1978) was modified for use in examining the potential contribution of extreme thermal stress cracking in the narrow zone immediately surrounding the hydraulic fractures. The base case thermal performance was checked against a time-dependent numerical model and showed good agreement (Tester and Ferguson 1987).

3.1.3 Summary of the Subsurface System Design

Later sections discuss more fully the modeling stages, intermediate results, and reservoir design. To help the reader quickly grasp the reservoir concept and identify sections of interest for more intensive study, Table 3-1 summarizes the final results which are used as the base case for economic analysis.

The optimized well pair depletion rate is shown in Figure 3-1. Based on this performance, four initial injection/production well pairs are needed to supply 50 MWe salable output. These initial well pairs will be supplemented by eight additional well pairs as needed to maintain 50 MWe output for 30 years.

Table 3-1

CONCEPTUAL HDR RESERVOIR

<u>Item</u>	<u>Value</u>
Reservoir Selection	
Bottomhole temperature	300°C (572°F)
Average depth to 300°C	3,657 m (12,000 ft)
Injection Well	
Maximum deviation angle	20° to 25°
Cased in deviated interval	yes
Casing diameter in deviated interval	7 in.
Production Well	
Maximum deviation angle	20° to 25°
Cased in deviated interval	no
Open-hole diameter in deviated interval	8-1/2 in.
Fracture Intervals	
Number per well pair	12
Average inclination from vertical	30°
Packer spacing	75 m (250 ft)
Heat transfer area per fracture	100,000 m ² (1,080,000 ft ²)
Aperture	1 mm (0.04 in.)
System Operation	
Flow rate per well pair	120 l/s (1,900 gpm)
Average initial midfield temperature	270°C (518°F)
Injection wellhead pressure	1,500 psi (10.4 MPa)
Water loss per cycle	10%
Reinjection temperature	91°C (196°F)
Make-up water temperature	15°C (59°F)
Reservoir growth	2X
Wellfield Layout (refer Figure 3-12)	
Initial well pairs	4
Later well pair installations	8
Location	T27S, R9W, Sec. 4-9

**Figure 3-1 Salable Power of One
Base Case Well Pair**

Each well pair consists of an injector well, a producer well, and a multilevel, hydraulically fractured network that connects the two wells. The planned sequence for installing a well pair is:

- 1) Drill injector well.
- 2) Create 12-level hydraulic fracture network while microseismically mapping fracture locations.
- 3) Drill producer to intercept microseismically located hydraulic fractures.

3.2 RESERVOIR HEAT EXTRACTION MODELING

3.2.1 Assumptions

Use of the modified Gringarten semi-analytical multiple-fractures model assumes that the hydraulically created fractures are parallel, equidistant, of uniform aperture, and of equal surface area (Gringarten, Witherspoon, and Ohnishi 1975). The reservoir rock mass is assumed to have constant thermal

conductivity and a constant product of density and heat capacity. Initial temperature in the rock mass is treated as an average, uniform midfield value calculated from the thermal gradient. Flow of water in the fractures is assumed to be laminar and constant. Heat transfer in the rock is treated as conduction normal to the fracture surfaces. Large rectangular fractures are assumed with uniform 1-dimensional flow across the fracture faces as an idealized but convenient method for quantitatively introducing finite thermal drawdown into the model.

Table 3-2 summarizes the general model assumptions and the ranges of assumptions that were made regarding site-specific and design-specific conditions.

3.2.2 Stage I Modeling

Stage I modeling consisted of initial parametric sensitivity studies with three, five, and eight fractures per well pair. Fracture spacing was for thermally noninteracting distances [greater than 25 m (80 ft)]. The reservoir was assumed to undergo no thermal growth during operation. Data that were generated include:

- o Average temperature at the fracture outlet as a function of time and flow rate
- o Outlet water enthalpy as a function of time and flow rate
- o Net salable power output as a function of time and flow rate

Early results clearly emphasized the commercial importance of creating large heat transfer area (fracture surface) per well pair and maximizing the target temperature consistent with technical constraints and cost considerations.

Effect of Fracture Area on Salable Power Output. Figure 3-2 shows the strong dependence of salable power on fracture area, and it illustrates the desirability of maximizing the effective fracture area per well pair. A well pair with $2.4 \times 10^6 \text{ m}^2$ ($25.8 \times 10^6 \text{ ft}^2$) of fracture area ($300,000 \text{ m}^2 \times 8$ fractures) shows minimal drawdown yet maintains high power output over 30 years. Volumes of fractured rock in excess of $100 \times 10^6 \text{ m}^3$ were created

Table 3-2

SITE-SPECIFIC AND DESIGN-SPECIFIC MODEL INPUT INFORMATION

<u>Description</u>	<u>Value</u>	<u>Justification</u>
Rock Characteristics		
Thermal gradient	55°C/km (0.03°F/ft)	Temperature logs, of
Maximum bottomhole temperature	300°C, 250°C (572°F, 482°F)	Wells 9-1 and 1-26 measured in conductive basement rock
Rock thermal conductivity	6.2×10^{-3} cal/cm-s-°C (1.5 Btu/ft-hr-°F)	Published values for granitic rocks, Clark (1966)
Rock density	2.65 g/cm ³ (165 lb/ft ³)	
Rock specific heat	0.25 cal/g-°C (0.25 Btu/lb-°F)	
Wells		
Wellbore maximum deviation angle	20° - 25°	Expectation of steeply inclined hydraulic fractures; based on Fenton Hill and Rosemanowes experience
Injection wellbore diameter, cased	7 in.	Injector well cased to lower risk of multilevel hydraulic fracture installation
Production wellbore diameter, uncased	8.5 in.	
Fractures		
Aperture	1 mm (0.04 in.)	Fenton Hill and Rosemanowes data for self-propped fractures
Heat transfer area per fracture	50,000 - 300,000/m ² (0.54 - 3.2 x 10 ⁶ ft ²)	GDK fracture design and Fenton Hill and Rosemanowes data
Packer spacing	25 - 100 m (80 - 330 ft)	Fracture pressure control, site-specific joint spacing
Average inclination	vertical, 30°	Fenton Hill and Rosemanowes data
Number per well pair	3 - 32	Well depth, thermal gradient, site-specific lithology
Reservoir thermal growth	0, 2X	Fenton Hill and Rosemanowes data
System Operation		
Water loss per cycle	10%	Fenton Hill and Rosemanowes data
Power plant return temperature	115°C, 66°C (239°F, 151°F)	Double-flash and binary plant designs
Make-up water temperature	15°C (59°F)	Assumed aquifer temperature
Flow rate per fracture	2 - 30 l/s (32 - 475 gpm, 1,080 - 16,270 bpd)	Fenton Hill and Rosemanowes data

Model conditions: 1 well pair
 8 parallel fractures at 50 m (164 ft) spacing
 Fractures inclined at 30° to vertical
 300°C (572°F) bottomhole temperature
 6 l/s (95 gpm, 2.3 bpm) flow rate per fracture
 No restimulation, no fracture growth
 Areas are the average per fracture

Figure 3-2 Effect of Fracture Area on Salable Power Output

at both Fenton Hill and Rosemanowes. However, the maximum effective fracture areas that have been successfully interconnected in research systems to date in the redrilled Fenton Hill Phase II reservoir ($58,000 \text{ m}^2$ in a preliminary analysis) and the initial and redrilled Rosemanowes Phase II reservoirs ($279,000 \text{ m}^2$ and $41,000 \text{ m}^2$, respectively) (calculated from Robinson and Tester 1984 and Armstead and Tester 1987) suggest that a feasible size for commercial design fractures at Roosevelt Hot Springs is near $100,000 \text{ m}^2$ ($1.1 \times 10^6 \text{ ft}^2$). Given this apparent limitation in fracture size, the approach to maximizing fracture surface area per well pair focuses on the installation of fractures averaging $100,000 \text{ m}^2$ ($1.1 \times 10^6 \text{ ft}^2$) at several locations along the lower, deviated length of the injector wellbore. Section 3.3 shows that $100,000 \text{ m}^2$ is conservative based on recommended methods to restrict the length of the wellbore fracture-stimulation intervals and to use of microseismically mapped locations of the hydraulically stimulated fractures to optimize the trajectory of the production well through the fracture zone.

Technical justification for the feasibility of installing multiple, discretely created fractures per well pair was extrapolated from examples of multilevel hydraulic fracturing in the petroleum industry. The primary risks associated with installing large, multilevel HDR hydraulic fractures are:

- o Ensuring a continuous, strong cement bond between the casing and formation
- o Minimizing thermal-stress cycling in the wellbore during hydraulic fracturing operations
- o Minimizing the potential for wellbore breakout
- o Providing a manageable amount of fluid leak-off in the reservoir
- o Inducing sufficient shear displacement to create a low-impedance connection with high sweep efficiency and large effective heat transfer area

Flow Rate, Power Output, and Pumping Losses. Figure 3-3 shows that low flow rates during plant operation promise excellent thermal drawdown performance with temperatures remaining approximately constant over 30 years, but the

A. Thermal Drawdown

B. Salable Power Outlet

Model conditions: 1 well pair
 8 parallel fractures at 50 m (164 ft) spacing
 Fractures inclined at 30° to vertical
 $100,000 \text{ m}^2$ ($1.1 \times 10^6 \text{ ft}^2$) area per fracture
 270°C (518°F) midfield temperature corresponding
 to 300°C (572°F) bottomhole temperature

Figure 3-3 Examples of Thermal Modeling Results

power output is low. At low flow rates, a large number of well pairs would be required at considerable cost. Conversely, high flow rates project high initial power output but deplete the reservoir rapidly, indicating that frequent addition of new fractures or new well pairs would be required over the lifetime of the planned facility. The flow rate for the base case well pair was selected by optimizing the economics (i.e., lowest levelized revenue requirements) of the power plant/reservoir combination.

The calculation of net power plant output was based on the two-stage flash process described in Section 4. For each target bottomhole temperature considered, the flash temperatures for the two stages were selected to produce the maximum electrical energy per unit mass of hot water for the initial hot water production temperature.

Net plant electric power output was adjusted for the pumping power needed to sustain flow through the subsurface system. This parasitic pumping loss can be a significant burden on salable power output depending on fracture flow impedance, the number of fractures, and the total flow rate. Because site-specific data are lacking, a value of 1,500 psi (10 MPa) at the injection wellhead was used to estimate the pumping losses. Use of this wellhead pressure was based on pressures required for the Fenton Hill Phase I and reworked Phase II reservoirs.

Bottomhole Temperature Effect on Salable Power Output. At temperatures above 250°C (482°F), perforation equipment is unproven and signal-conductor cables for high temperature diagnostic well-logging tools are likely to fail. However, a comparison of well pair output for bottomhole temperatures of 300°C (572°F) and 250°C (482°F) demonstrates a significant increase in salable power for 300°C (572°F) (see Figure 3-4). Furthermore, an appropriately designed fracture initiation procedure that cools the wellbore can greatly mitigate limitations imposed by higher temperatures. These issues are addressed by the well design and completions strategy in Section 3.5. The selection of 300°C (572°F) rather than 250°C (482°F) as the target bottomhole temperature is expected to pose no significant risks to the drilling or casing programs.

Model conditions: 1 well pair
 8 parallel fractures at 75 m (250 ft) spacing
 200,000 m² per fracture
 Fractures inclined at 30° from vertical
 6 l/s (95 gpm, 2.3 bpm) flow rate per fracture

Figure 3-4 Effect of Bottomhole Temperature on Well Pair Salable Power Output

3.2.3 Stage II Modeling

Stage II modeling focused on defining a benchmark design well pair and wellfield. At this stage, reservoir modeling was highly interactive with economic optimization and power plant design tasks. The objective was to design a technically feasible 50 MWe conceptual wellfield for which the cost of power is competitive with coal. All modeling included the effects of water loss rate and the costs of pumping to overcome reservoir flow impedance.

Stage II modeling of well pair performance involved fine-tuning plausible ranges of combinations of the following parameters:

- o Target temperature/depth
- o Number of fracture intervals
- o Fracture size
- o Flow rate per fracture
- o Fracture spacing
- o Fracture inclination

Thermal drawdown and salable electric power output were estimated for the range of conditions summarized in Table 3-3.

Table 3-3
RANGE OF CONDITIONS FOR ESTIMATES

<u>Item</u>	<u>Value</u>
Fractures	
Area	100,000 m ² (1.1 x 10 ⁶ ft ²)
Number per well pair	8, 12, 16
Orientation	vertical, 30°
Reservoir	
Flow rate per fracture	2, 4, 6, 10, 12 l/s (32, 63, 95, 160, 190 gpm)
Bottomhole temperature	300°C, 250°C (572°F, 482°F)
Return water temperature	115°C (239°F)
Percent make-up water at 15°C	10%
Thermal growth of reservoir	none

Summary graphs of selected Stage II reservoir modeling are presented in Figures 3-5 and 3-6. Figure 3-5 demonstrates that negligible economic benefit is gained by attempting to space fractures within thermally interactive distances of less than 50 m. Furthermore, the cost of electric energy does not increase significantly as a result of the less uniform temperature drawdown inherent in using 70 m (230 ft) or 75 m (250 ft) rather than 60 m (200 ft). The minimum distance between packers must allow ample wellbore length for fracture growth up the wellbore without compromising wellbore integrity for subsequent fracture intervals. Also, the pack-off volume must be sufficient to permit close regulation of fluid pressure. Initially, the minimum spacing should be 250 ft (75 m) to ensure that these two criteria are met. Later onsite experience may demonstrate that packer spacings can be reduced. Depending on the length of the perforated zone within each fracture pack-off interval, the spacing of hydraulically induced fractures depends largely on the site-specific spacing and orientation of existing joints or fractures as discussed in Section 2.3.5.

The greater salable power resulting from inclined hydraulic fractures (Figure 3-6) is due to the higher midfield temperature that accompanies the reduction in vertical extent of the fractures. Fracture inclination is site- and depth-specific depending on existing joint and in-situ stress conditions; it is not a controllable design variable. Based on experience from the Phase I and II reservoirs at Fenton Hill, the deepest fractures at Roosevelt Hot Springs in a well of 3,170 m (12,000 ft) total vertical depth are expected to be inclined as much as 45° and to steepen at shallower depths, becoming nearly vertical at about 1,800 m (6,000 ft).

Since the multiple-fractures reservoir model of Gringarten, Witherspoon, and Ohnishi (1975) treats only parallel fractures, an average inclination of 30° from vertical was assumed. Variations in inclination from 20° to 30° produce only minor differences in predicted reservoir performance. Although the assumption of inclined fractures is a simplification, the parametric effect of inclination on drawdown was introduced by this method to study its importance on the economics.

A. Salable Power Output

B. Levelized Energy Costs
(Economic Screening Results)

Model conditions: 16 fractures per well pair
 300°C (572°F) bottomhole temperature
 30° from vertical fracture inclination
 Constant flow rate per fracture

Figure 3-5 Effect of Fracture Spacing

A. Salable Power Output

B. Levelized Energy Costs
(Economic Screening Results)

Figure 3-6 Effect of Fracture Inclination

If fracture spacing is constant, then incremental increases in the number of fractures per wellbore show a diminishing return (Figure 3-6B) because of the lower average temperature of each additional fracture at the upper end of the wellbore. Therefore, the optimal number of fractures per wellbore determined from economic analysis may not be the maximum number that will physically fit along the deviated interval.

Economic screening of Stage II results show that even if no reservoir growth results from thermal-stress cracking (discussed in Section 3.2.4), several well designs imply costs of energy that approach levels competitive with coal (50 to 60 mills/kWh for screening purposes). The most competitive strategies involve designs for 300°C (572°F) bottomhole temperature, 12 or 16 fractures per well pair flowing 10 to 12 l/s (160 to 190 gpm, 5,470 to 6,480 bpd) per fracture, with a small number of well pairs required initially to provide 50 MWe net salable power. Staged installations of additional well pairs will maintain the salable system output close to 50 MWe over 30 years.

3.2.4 Stage III Modeling

Stage III modeling anticipates an increase in thermal performance resulting from reservoir growth due to thermal-stress cracking and sustained hydraulic pressurization. This sort of reservoir growth, based on data from Fenton Hill and Rosemanowes, is expected to produce significant increases of the effective heat transfer area starting soon after a well pair begins operation.

Reservoir Growth and Heat Extraction from Granitic Rock. Tester et al. (1986), Armstead and Tester (1987), and Dash, Murphy, and Cremer (1981) cite data for reservoir growth that are summarized in Table 3-4. These and additional data from the Phase I Rosemanowes reservoir suggest that reservoir growth is a generic characteristic of heat extraction from granitic rocks. Figure 3-7, reproduced from Robinson and Tester (1984), shows a power law correlation between reservoir modal volume measured with geochemical tracers and the effective heat transfer area estimated from model-calculated thermal drawdown behavior. Modal volume does not necessarily correlate with heat transfer area; however, the results to date are compelling. Modal volume is

Table 3-4

COMPARISON OF HDR RESERVOIR GROWTH CHARACTERISTICS

Item	Fenton Hill				Rosemanowes
	Phase I, Segments			Redrilled	Redrilled
	2	3	5	Phase II	Phase II
Initial fracture area, m ²	7,000	7,000	38,000	58,000	41,000
Final fracture area, m ²	18,000	13,000	50,000	70,000	135,000
Operating period, hr	1,800	552	6,864	744	12,480
Production flow rate, kg/s	7-16	7-16	6-8	12-14	12-24
Initial rock temp., °C	175	135	156	232	80
Final water temp., °C	85	98.5	149	232	74

Areas of Fenton Hill redrilled Phase II and Rosemanowes redrilled Phase II reservoirs determined from Figure 3-7 using modal volumes given in Figure 15.4 of Armstead and Tester (1987).

Source: Robinson and Tester (1984)

Figure 3-7 Effective Heat Transfer Surface Area Versus Modal Volume

measurable in field tests; effective heat area must be calculated using a reservoir simulation model.

An examination of the two largest reservoirs in Table 3-4 yields the following. From the modal volume increase, the redrilled Rosemanowes Phase II reservoir increased in area to more than three times its initial size in 520 days, and Fenton Hill Phase II increased an estimated 21 percent of its initial fracture area (determined from modal volumes given in Armstead and Tester 1987) in 31 days of continuous operation at commercial flow rates. No thermal drawdown was observed in the Fenton Hill redrilled Phase II reservoir. These results indicate that significant enhancement of heat transfer area can be expected within a few months of initial operation, and they suggest that the HDR reservoir at Roosevelt Hot Springs could grow to perhaps two to three times its initial size in a year.

Since the reservoir model of Gringarten, Witherspoon, and Ohnishi (1975) does not permit a time-dependent change in effective heat transfer surface area, an early increase was simulated by assuming instantaneous reservoir growth.

The growth induced by sustained hydraulic pressurization should primarily extend fracture area in the planes of the initial hydraulic fractures; thermally induced tensile fractures - shrinkage cracks - should occur most densely in regions of highest flow rate and heat transfer growing normal to the hydraulic fracture faces in low-impedance flow zones. Based on data from Rosemanowes and all Fenton Hill systems, a value of two times (2X) the initial area was assumed for the effective heat transfer area after nearly instantaneous (compared to a 30-year plant life) thermal and hydraulic growth.

This growth was modeled as a fracture of double width - constant height - constant aperture; and alternatively as constant width - double height - constant aperture, with the results predicting nearly equal salable power at any given time.

A multiple-fracture, numerical reservoir simulator (Tester and Ferguson 1987) was used to compare with the results of the Gringarten models. For three

alternative benchmark cases, including the conceptual design case, numerical results closely agree with the solutions obtained with the Gringarten model.

Economic Optimization of Reservoir Model. Economic optimization of the reservoir model that includes thermal growth was performed for several strategies of staged well pair installations. Figure 3-8 summarizes the most favorable cost-of-power results for 8, 12, and 16 fractures per wellbore for 250°C (482°F) and 300°C (572°F) bottomhole temperatures. Results demonstrate that costs are competitive with coal (50 to 60 mills/kWh for screening purposes) only for 300°C (572°F) bottomhole temperature and with some contribution by reservoir thermal growth. There is a substantial reduction of levelized energy cost associated with 12 rather than 8 fractures per well pair; however, levelized energy costs for 16 fractures show only minor reduction compared to 12 fractures. If the maximum bottomhole temperature is 250°C (482°C) rather than 300°C (572°C), only 8 fractures will fit in the average design wellbore at the Roosevelt Hot Springs HDR prospect designated in Section 2.6.2. This restriction is specific to the Roosevelt Hot Springs site where the extrapolated subsurface location of cataclastic zones and a westward deepening to the upper surface of the crystalline basement rock limit the maximum number of fracture intervals per wellbore.

3.3 DESIGN OF FRACTURES TO PRODUCE LARGE HEAT TRANSFER AREAS

3.3.1 Impact of Hydraulic Fracturing on Heat Transfer Area

In addition to accounting for thermal growth of the reservoir, Stage III modeling reassessed the expected size of installed hydraulic fractures.

The Phase II reservoir at Rosemanowes was created by a series of 10 injections totalling 630,000 bbl (26×10^6 gal, $100,000 \text{ m}^3$) over 2 months. The cumulative microseismic volume was $400 \times 10^6 \text{ m}^3$ ($4.3 \times 10^9 \text{ ft}^3$), and the modal volume as measured with tracers was 2,500 to $3,500 \text{ m}^3$ (88,000 to $123,500 \text{ ft}^3$). The effective heat transfer area was conservatively estimated at $270,000 \text{ m}^2$ ($2.9 \times 10^6 \text{ ft}^2$) using Figure 3-7 (based on tabulated data from Armstead and Tester 1987). However, excessive water loss rates near 50 percent and high flow impedance required a sidetrack and redrilling,

Figure 3-8 Effect of Number of Fracture Intervals without and with Thermal Fracture Growth

thereby reducing the effective reservoir size. The redrilled modal volume measured 153 m^3 ($5,400 \text{ ft}^3$) - only 6 percent of the previously measured modal volume. A conservative estimate of the redrilled effective heat transfer area is $41,000 \text{ m}^2$ ($441,000 \text{ ft}^2$).

Although the size of the installed fracture network at Rosemanowes was many times greater than the area that was accessed by redrilling, operations data from Rosemanowes and Fenton Hill indicate that this is desirable. At Rosemanowes, in 1 year of continuous operation at commercial flow rates of 12 to 24 l/s (190 to 380 gpm, 6,500 to 13,000 bpd), the rate of water loss dropped from 25 to 15 percent, and flow impedance decreased to 0.5 GPa-s/m^3 , accompanying the increase in effective heat transfer area.

Recent re-evaluation by Los Alamos National Laboratory of microseismic data collected at Fenton Hill during the massive hydraulic fracture operations indicate that as many as five sets of subparallel, complexly interconnected fracture surfaces were produced by the massive hydraulic fracture of the Phase II reservoir (Dreesen et al. 1987). Hydraulic fracturing operations created a microseismically active volume of $108 \times 10^6 \text{ m}^3$ ($3.81 \times 10^9 \text{ ft}^3$) using 133,000 bbl of water ($5.6 \times 10^6 \text{ gal}$, $21,000 \text{ m}^3$) delivered at an average rate of 38 bpm (1,600 gpm, $0.10 \text{ m}^3/\text{s}$). Because hydraulic connection between the predrilled wellbores was not achieved, this reservoir also required a wellbore sidetrack and redrilling. The modal volume of the redrilled system measured 270 m^3 ($2,900 \text{ ft}^3$), which conservatively corresponds to an effective heat transfer area of $58,000 \text{ m}^2$ ($623,000 \text{ ft}^2$).

Similarly, the research results obtained at Rosemanowes and Fenton Hill imply that a reasonable range for the expected installed size of one hydraulically created fracture interval at Roosevelt Hot Springs may be larger than $40,000 \text{ m}^2$ ($430,600 \text{ ft}^2$) but smaller than $270,000 \text{ m}^2$ ($2,900,000 \text{ ft}^2$).

3.3.2 Hydraulic Fracturing Program for Roosevelt Hot Springs

An important consideration in designing the hydraulic fracturing program for Roosevelt Hot Springs is that the total surface area of installed fractures should be significantly larger than the effective heat transfer area. Based

on this approach, each hydraulic fracture interval at Roosevelt Hot Springs will be created with 71,400 bbl (3×10^6 gal, $11,400 \text{ m}^3$) of fluid delivered at 60 bbl/min (2,520 gpm, $0.16 \text{ m}^3/\text{s}$). The effective heat transfer area is the fraction of low impedance fracture area that is swept by the flow of water between the wellbores. During operation, the average fracture aperture increases by thermal contraction of the rock mass, thereby increasing the sweep area. Thermal stress cracking and sustained hydraulic pressurization are expected to further increase the effective heat transfer area.

Base Case Effective Heat Transfer Area. The base case selection of $100,000 \text{ m}^2$ ($1.1 \times 10^6 \text{ ft}^2$) as the installed effective heat transfer area was exceeded in the Rosemanowes Phase II initial installation (estimated by Robinson and Tester 1987) and has been approached in operating systems at Fenton Hill and Rosemanowes. Significant refinements in the strategy for installing the reservoir suggest that the base case heat transfer area is reasonable. Indeed, the following factors may lead to even larger accessible heat transfer areas:

- o Recommended high-strength casing program, which is described in Section 3.5
- o Restricted length of each multilevel wellbore stimulation zone (75 m, 250 ft)
- o Fluid delivery rate (60 bpm, $0.16 \text{ m}^3/\text{s}$)
- o Design downhole fracturing pressure (13,000 psi, 90 MPa)
- o Volume of fracturing fluid per 75 m (250 ft) wellbore interval (3×10^6 gal, 71,400 bbl, $11,400 \text{ m}^3$)
- o Strategy of targeting the production well through the optimum trajectory to intersect the microseismically mapped fracture zones

Creating Largest Possible Effective Heat Transfer Area. The design objective at Roosevelt Hot Springs is to create the largest possible effective heat transfer area that also has manageable water loss and flow impedance. Radial and bilinear formulations of the Geertsma and de Klerk (GDK 1969) analytical

model for vertical planar fracture design were used to estimate the volume and the delivery rate of fluid that are required to produce the design fractures. Fluid volumes and injection rates were used to estimate costs of the conceptual fracture program.

Fresh, intact granite has low fluid leak-off because porosity and permeability are low (see Section 2). In this case, GDK predicts that large fluid volumes of 24 to 71×10^3 bbl (1 to 3×10^6 gal, 3.8 to 11.4×10^6 l) delivered at 40 to 80 bpm (1.8 to 3.5×10^3 gpm, 106 to 212 l/s) will produce enormous fractures of 2.5 to 6.7×10^6 m² (27 to 72×10^6 ft²). If propped, even the aperture at half the radius (1.7 mm, 0.07 in.) is large enough in all cases to have low flow impedance (see Appendix A).

Sensitivity of the design fracture size to fluid volume, injection rate, reservoir leak-off coefficient, and rock elastic moduli was evaluated. Results are given in Appendix A. Modeling results demonstrate that fracture size is insensitive to shear modulus but depends strongly on the formation leak-off coefficient and the volume of injected fluid.

In granitic rocks, high leak-off coefficients generally indicate altered and/or jointed rock. Hydraulic fracture growth was strongly influenced by subsurface joint sets at both the Rosemanowes reservoir and the deep reservoir at Fenton Hill. The principal effects of joint sets are to limit the radial growth of fractures and to induce volumetric growth by shear slippage. If a shear slip mechanism is significant at Roosevelt Hot Springs, the single-fracture simulation of GDK is not strictly applicable. However, studying the effects of fluid leakoff on the resultant fracture radius provides a simple method of evaluating the extent to which fluid flow away from the primary fracture might limit the radial growth of the fracture and thereby reduce the wellbore spacing. However, if multiple-fracture shear stimulation occurs, the GDK term "leakoff coefficient" is appropriate since much of the leakoff fluid goes to stimulating additional, interconnected, en-echelon fractures.

The occurrence of shear stimulation at both Rosemanowes and Fenton Hill created multiple, self-propped fractures with widely varying dip angles. Multiple joint stimulation by shear slippage was modeled by Murphy (1985) who found that the failure mechanism depends on the degree of misalignment of the principal stresses with the joint orientations and on the level of anisotropy of the horizontal principal stresses. Expectations at Roosevelt Hot Springs are uncertain because no data are available on the spacings and orientations of deep subsurface joints in the HDR prospect. Because of this uncertainty, the conceptual well pair design for Roosevelt Hot Spring accommodates large ranges of fracture azimuth, dip, and radius as well as the possible creation of multiple fractures per fracture interval.

3.4 CONCEPTUAL WELL PAIR

Figure 3-9 presents two examples of staged well pair installation strategies and the relative HDR system component costs for the results of Stage III economic screening. Figure 3-9B shows that the total levelized cost of energy with 250°C (482°F) bottomhole temperature is more than 40 percent higher than with 300°C (572°F) bottomhole temperature. Assuming that reservoir growth occurs, costs of power are favorable for 12 or 16 fracture intervals per wellbore with 300°C (572°F) bottomhole temperature. The minimal cost-benefit advantage of a 16-fracture well (see Figure 3-8) does not appear to justify the technical risk to the wellbore incurred by installing four additional fracture intervals. Therefore, the base case conceptual injection well has 12 fracture intervals. Table 3-5 summarizes the conceptual well pair characteristics.

3.5 WELL DESIGN AND COMPLETIONS PROGRAM

3.5.1 Drilling and Completions Strategy

Although it is a direct result of experience gained from the Fenton Hill program, the strategy for drilling and completing well pairs at Roosevelt Hot Springs is a major departure from the experimental procedure used at Fenton Hill. To accommodate the widest possible range of hydraulic fracture orientations, the program comprises the sequence: drill injection well, install and map fractures, drill production well. The major steps in the this program are:

300 °C target temperature
 12 fracture intervals
 100,000 m² per fracture interval, 2X fracture growth
 4 well pairs initially, 8 additional well pairs

Total levelized cost	42 mills/kWh	(Screening results)
Wellfield	20 mills/kWh	(48 % of total)
	Initial wells	50 % of wellfield costs
	O&M	16 % of wellfield costs
	Redrilling	34 % of wellfield costs
Power Plant	22 mills/kWh	(52 % of total)
	Capital	76 % of power plant costs
	O&M	24 % of power plant costs

(A)

Figure 3-9 Total Levelized Energy Costs for Staged Well Pair Installation Strategies to Maintain 50 MWe Net Salable Power Over 30 Years

250 °C target temperature

8 fracture intervals

(8 fracture intervals at 75 m spacing is the maximum for 250°C target temperature at Roosevelt Hot Springs)

100,000 m² per fracture interval, 2X fracture growth

9 well pairs initially, 12 additional well pairs

Total levelized cost	60 mills/kWh	(Screening results)
Wellfield	34 mills/kWh	(57 % of total)
	Initial wells	62 % of wellfield costs
	O&M	11 % of wellfield costs
	Redrilling	27 % of wellfield costs
Power Plant	26 mills/kWh	(43 % of total)
	Capital	76 % of power plant costs
	O&M	24 % of power plant costs

(B)

Figure 3-9 (Cont'd)

Table 3-5
CONCEPTUAL WELL PAIR

<u>Item</u>	<u>Characteristic</u>
Reservoir lithology	Tertiary granitic basement
Wellbore inclination from vertical	20° - 25°
Direction of wellbore deviation	ESE
Number of fracture intervals	12
Expected fracture inclination	45° - 0°
Average fracture inclination from vertical	30°
Initial heat transfer area per fracture	100,000 m ² (1.0 x 10 ⁶ ft ²)
Fracture spacing along wellbore	75 m (250 ft)
Fracture aperture	1 mm (0.04 in.)
Constant, laminar flow rate per fracture	10 l/s (160 gpm, 5,500 bpd)
Bottomhole temperature	300°C (572°F)
Average depth to 300°C	3,657 m (12,000 ft)
Temperature gradient	55°C/km (0.03°F/ft)
Initial production wellhead temperature	270°C (518°F)
Injection wellhead pressure	1,500 psi (10 MPa)
Water loss per cycle	10%
Fracture size after thermal growth	200,000 m ² (2.2 x 10 ⁶ ft ²)
Total effective heat transfer area after thermal growth	2.4 x 10 ⁶ m ² (26 x 10 ⁶ ft ²)

1. Drill injection well, coring at top and bottom of reservoir interval.
2. Log to highest temperature possible to locate open fracture zones.
3. Perform small-scale openhole hydraulic fracturing test in shallowest reservoir zone using seismic monitors. Determine breakdown stress of rock or joint stimulation pressure; locate fracture.
4. Case and cement injection well.
5. Extend depth of injection well 100 to 200 ft (30 to 60 m).
6. Run 7 in. tubing from the top of the 7 in. liner to the surface.
7. Fracture the openhole interval below the 7 in. liner. This obviates the need for perforating the deepest fracture interval and substantially cools the wellbore for subsequent cased-hole fracture operations. Use microseismic monitors to map subsurface fracture. Do not flow-back the fracture. Allow pressure to decay to about 3,000 psi (21 MPa) at the wellhead.
8. Set cast iron casing cement retainer near base of 7 in. liner. Perforate 20 to 80 ft (6 to 25 m), depending on spacing of natural joints at Roosevelt Hot Springs. Fracture and monitor. Do not flow back, but allow pressure to decay to 3,000 psi (21 MPa).
9. Repeat Step 8 through the 12th fracture interval.
10. Drill production well approximately parallel to injection well to intercept uppermost fracture zone. Remove packer from injector to flow test hydraulic fracture. Rework fracture from production well if necessary.
11. Extend production well to intercept next fracture. Flow test. Restimulate if necessary.
12. Repeat Step 10 through deepest fracture interval.

Major advantages of this reservoir installation strategy are:

- o Fracturing is through reliable casing packers.
- o Fracturing through large-diameter tubing with low friction loss minimizes the cost of hydraulic horsepower, obviates the need for friction reducers, and because the surface injection pressure is reduced, reduces surface safety hazard.

- o Time-consuming flow-back of the fractures is not required. Also, wellbore-damaging thermal cycling that is associated with flow-back is eliminated.
- o Since this program calls for sequential installation of fractures after drilling and casing the injection well is completed, the installation program requires only a single wellbore cooldown, minimizing mechanical risk that would result from repeated thermal cycling of the well.
- o Perforating will be done after the wellbore is cooled by the preceding hydraulic fracture installation. Following the method of Ramey (1962), a bottomhole temperature of 23°C (73°F) was calculated at the end of the first, openhole hydraulic fracture installation. The temperature will remain below 150°C (300°F) for a few days, or water can be circulated at 1.3 bpm (55 gpm, 3.4 l/s) to hold the bottomhole temperature at 150°C (300°F) for an extended time. The circulation rate can be increased slowly to further cool the wellbore.

3.5.2 Well Description

Although multilevel completion programs are common in the petroleum industry, they have not been demonstrated in an HDR application. Many of the well pair design features are incorporated to minimize the technical risks.

The injection well is cased to within 30 to 60 m (100 to 200 ft) of total deviated depth to allow use of casing packers while installing the fractures. The production well is uncased along the deviated length.

In the deviated section of the injection well, the fracture program requires 1,030 m (3,400 ft) of cased wellbore length. This includes length for 11 fractures above the openhole fracture at 75 m (250 ft) spacings, plus an allowance of 25 percent for unusable intervals (open joints and fractures, cataclastic zones, and cement gaps). An additional 60 m (200 ft) is required for the spacing between the injection and the production wellbores.

Wellbore deviation will be maintained at less than 25° to reduce the risk of cement gaps, to reduce wear on tubular goods, and to reduce the time required to log and fish. For a wellbore deviation angle of 20° from vertical, this implies that an average 3,657 m (12,000 ft) injection well at Roosevelt Hot Springs must complete the deviation turn by a depth of 2,591 m (8,500 ft).

The deviated length of wellbore is drilled with an 8-1/2 in. bit to total depth. The 7 in. casing is placed and cemented to total depth in the injection well, and drilling extends the wellbore an additional 30 to 60 m (100 to 200 ft). The wall thickness of the 7 in. casing is specified to withstand both internal and external hydraulic fracturing pressures to minimize the possibility of casing collapse.

Within the Roosevelt Hot Springs HDR prospect (see Figure 2-21), the depth to 300°C (572°F) is expected to vary from 3,334 m (10,940 ft) near the eastern border of the prospect to 4,267 m (14,000 ft) at the western margin. For the shallowest injection well, the deviation turn must be completed by a vertical depth of 2,255 m (7,400 ft).

The deviated section of the production wellbore will approximately parallel the injection wellbore at a displacement parallel to the fractures of 250 m to 500 m (820 ft to 1,640 ft) above the injection well. The production well design has an 8-1/2 in. open-hole diameter throughout the deviated length. Figures 3-10 and 3-11 summarize the wellbore and casing configurations.

3.5.3 Completions Program

The major risks associated with a 12-level completion program in an HDR application are:

- o Mechanical damage to the wellbore if repeated thermal cycling occurs
- o Casing collapse if external fracturing pressures exceed casing strength
- o Extensive fracturing and leakage along the wellbore if the cement bond between the casing and the formation is poor as a result of either cement gaps or rapid cement degradation
- o Risks associated with setting casing packers and perforating in a deviated interval

The key objective of casing the injector wellbore throughout the fracture interval is to take advantage of the greater reliability of metal-seal casing

Figure 3-10 Depths and Spacing of Injection-Production Well Pair

Figure 3-11 Casing and Open-Hole Diameter/Depth Configurations for Injection and Production Wells

packers as compared to open-hole packers. The use of commercially available, pressure-retaining packer assemblies should permit successful completion of the aggressive, sequential, 12-level fracture program with a single episode of wellbore cooling, thereby minimizing damage to the wellbore that might be caused by repeated thermal cycling. In addition, because drilling of the injection well will proceed uninterrupted by hydraulic fracturing operations, drill rig time and cost are minimized. Also, by using the drill rig as the work-over rig during completion operations, mobilization/demobilization costs are reduced, a traditional work-over rig becomes unnecessary, and the drill rig charges drop to standby costs.

Although high-strength geothermal cements are unproven for sustaining multilevel fracture operations, Unocal's experience in the highly corrosive, hot environment in the Imperial Valley, California, is encouraging. Casing and class G cement with 40 percent silica have withstood temperatures in excess of 290°C (554°F) for a continuous period of 6-1/2 years in the Brawley geothermal field (Shen 1987). The proposed HDR application requires that the cement retain its strength and bonding in a low-corrosion environment only through the duration of the fracture program.

Based on the fracture design results from the GDK model (Geertsma and de Klerk 1969) and data from Fenton Hill, the conceptual fracture program will require 71,000 bbl (3 million gallons) of fluid at 60 barrels per minute (2,520 gpm, 160 lps) for each fracture interval. The total time for fracturing 12 intervals is 30 days.

Since the fluid delivery tube for the fracture operations will be the 7 in. diameter casing, no friction reducer is required. The specified fracturing fluid is water, with up to 100,000 gallons (2,380 bbl) of viscosifier to be pushed through immediately following reservoir breakdown to force fracture growth away from the wellbore. Based on data from Fenton Hill, surface delivery pressure is not anticipated to exceed 7,000 psi (48 MPa).

3.5.4 Well Pair Cost Estimates

An average cost per well pair with 12 fracture intervals is estimated to be \$10.1 million. This figure includes site preparation, fracture pond, rig operations (drilling, coring, crews), geophysical well logs, test hydraulic fractures, casing and cement program, fracture programs, wellhead fixtures, and well design. Detailed cost estimates for drilling and casing are presented in Appendix B. Table 3-6 summarizes well pair cost estimates. In addition to using conservative design assumptions, especially for the hydrofracturing program, these cost estimates provide about 15 percent contingency for costs that probably will be experienced but cannot presently be identified. As a point of reference, the average costs in 1987 dollars for drilling and casing 12,000 ft depth oil wells and gas wells in Utah are \$1.038 million and \$1.949 million, respectively (McClintock 1987).

3.5.5 Seismic Monitoring

Regional seismic monitoring and microseismic monitoring of hydraulic fractures are briefly discussed below. More detailed cost estimates are shown in Appendix C.

Regional Seismic Monitoring. A nine-station regional network comprising five near-surface vertical geophones, one near-surface 3-component geophone, and one downhole vertical geophone is required. The estimated initial cost for this system is \$195,000 with annual O&M costs, including quarterly reports, of \$95,000. Costs include all geophysical equipment, labor, direct costs at the site, and computer processing time.

Microseismic Monitoring of Hydraulic Fractures. In addition to the regional-network equipment, determination of the volume and orientation of hydraulically induced fractures requires three local high-frequency receiver stations, which will be repositioned for each well pair. Events generated by hydraulic fracturing will be located by triangulation from borehole and near-surface deployed receivers. Borehole clamping receivers will be stationed below the sedimentary column, coupled to the granitic basement complex. Well 9-1 and additional observation/exploration holes that are

Table 3-6

SUMMARY OF COSTS FOR DRILLING AND COMPLETING ONE WELL PAIR
12 Fracture Intervals
(\$1987)

Fracture Fluid/Interval Pumping Rate	2 Million Gallons			3 Million Gallons		
	40 bpm	60 bpm	80 bpm	40 bpm	60 bpm	80 bpm
Pumping Services	1,474,000	1,544,000	1,744,000	2,096,000	2,216,000	2,517,000
Wireline Services	184,000	170,000	176,000	194,000	180,000	184,000
Subtotal	1,658,000	1,714,000	1,920,000	2,290,000	2,396,000	2,701,000
15% Contingency	249,000	257,000	288,000	344,000	359,000	405,000
Subtotal	1,907,000	1,971,000	2,208,000	2,634,000	2,755,000	3,106,000
Drilling and Casing (Two wells)	6,718,000	6,718,000	6,718,000	6,718,000	6,718,000	6,718,000
Microseismic Mapping	119,000	119,000	119,000	119,000	119,000	119,000
Subtotal	8,744,000	8,808,000	9,045,000	9,471,000	9,592,000	9,943,000
Management Fee	437,000	440,000	452,000	474,000	480,000	497,000
Total	9,181,000	9,248,000	9,497,000	9,945,000	10,072,000	10,440,000

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recommended as a part of the next phase of detailed site evaluation and testing will be used as geophone stations. A hodographic technique will be used to check triangulation results. The estimated total cost for this phase of monitoring is \$477,000 for the four initial well pairs.

3.6 CONCEPTUAL WELLFIELD DESIGN

The conceptual well pair installation strategy is based on results of the reservoir performance modeling and economic screening. Reservoir restimulation by the addition of new fractures in existing wellbores is not expected to be a practical solution to long-term thermal drawdown. Initial fractures will be spaced as closely as reasonable in the injector wellbores, and fractures will be installed from deepest to shallowest. Thus, although a length of wellbore may remain that could be used for later addition of fractures, remaining space will be at the shallowest and coolest portion of the reservoir where temperatures may not warrant commercial development. The primary method for coping with well pair depletion will be the addition of new well pairs to maintain salable power output near 50 MWe for 30 years.

The base case design wellfield consists of four initial well pairs with eight additional well pairs staged at 3- to 4-year intervals to maintain salable power near 50 MWe for 30 years.

Denser initial wellfield configurations, e.g., 5-spot, were not considered for the base case because too little is presently known about these layouts for HDR applications. If later results of microseismic monitoring and thermal-drawdown modeling demonstrate that effective heat transfer surfaces are growing during operation in a direction away from the flow path between the injection and production wells, then denser injector-producer well arrays should be evaluated. If increases in sweep area occur as expected during operation of the reservoir, then later installation of a second production well is a promising method of maintaining reservoir output at about one-quarter the cost of a new well pair.

Spacing between wellheads for each injector-producer pair is specified at 60 m (200 ft) to accommodate all the rig equipment. The close spacing minimizes rig moving costs.

As shown in Figure 3-12, the four initial well pairs will be installed in a single row parallel to the Opal Mound Fault. The distance between well pairs will be large enough that fracture systems in adjacent well pairs will not interact. This spacing will be confirmed by the results of microseismic monitoring but is set tentatively at 500 m (1,640 ft). Later well pair installations will run parallel but offset to the initial row, with rows spaced at 762 m (2,500 ft).

3.7 REQUIREMENTS FOR ADDITIONAL DATA

Results of reservoir modeling and economic screening demonstrate that commercial success of an HDR system critically depends on the long-term thermal performance of the subsurface reservoir and, therefore, on the ability to create a large heat transfer area. Although all assumptions used in the models appear reasonable and conservative based on currently available information, the following have not been confirmed by actual tests at either Fenton Hill or Rosemanowes:

- o Long-term thermal drawdown characteristics at commercial flow rates
- o Effective growth rate, with time, of a commercially sized reservoir
- o Feasibility of large-scale, multilevel fracturing
- o Long-term water-loss rate
- o Long-term flow impedance
- o Geochemical scaling and carbon dioxide production
- o Long-term induced seismicity

Short-term testing at both existing HDR sites suggests that the relationship between volumetric fracture growth (measured by microseismic monitoring, geochemical tracer analysis, and flow tests) and the increase in effective

Figure 3-12 Conceptual Wellfield Layout

heat-transfer surface area is generic for heat extraction from hot dry granitic reservoir rocks (refer to Figure 3-7). However, because HDR technology is young, test verification of reservoir performance should be completed at Roosevelt Hot Springs prior to commitment for a commercial facility.

Drilling and testing of an injection/production well pair at Roosevelt Hot Springs would provide the following needed data on the technical feasibility of completing multilevel installation of hydraulic fractures with large surface areas:

- o Large-scale hydraulic fracture tests will indicate the approximate maximum achievable fracture surface areas, the hydraulic fracture orientation (and the subsurface failure mechanism and stress field orientation), and a suitable pack-off interval spacing.
- o Closed-loop, long-term flow tests through the hydraulically created reservoir will permit evaluation of the thermal performance, the system water-loss, flow impedance, injection pressure, any need to control silica scaling in the near wellbore region of the reservoir, and any need to reduce flow through low-impedance fracture zones to remedy short-circuiting.
- o The microseismic monitoring system for remote sensing of fracture growth can at that time be optimized for the lithologic, geostructural, and environmental conditions at Roosevelt Hot Springs.
- o Well installation and completion operations will confirm drilling conditions, cement performance during multistage fracturing, and the fracture installation procedure.

In short, to generate the data required to adequately support design and performance estimates for a 50 MWe commercial facility, one test HDR well pair must be installed and continuously operated at Roosevelt Hot Springs.

These results should be augmented by drilling three or four deep geologic observation holes distributed throughout the HDR prospect area to verify depth/temperature extrapolations, stratigraphy, and fault and joint density, as well as to provide subsurface seismic monitoring stations for later use.

Section 4

SURFACE FACILITIES

The surface facilities include all the systems and equipment needed to operate the HDR underground reservoir and to produce electric power. These include the equipment for distributing and injecting water into the man-made reservoir via the injection wells, gathering the heated water from the production wells and transporting it to a central location, converting the thermal energy into electric energy, and transmitting the electricity to a utility system grid for distribution to the utility customers. A process flow schematic is shown in Figure 4-1, and Figure 4-2 shows a plot plan for the centrally located wellfield facilities and the power plant.

For discussion in this section, the surface facilities are designated as either wellfield or power plant: the wellfield includes the facilities that directly affect operation of the fractured reservoir, and the power plant includes the facilities that convert thermal energy into electricity. Specifically, the surface facilities and their functions may be grouped as follows:

- o Wellfield

- The injection system distributes water to the injection wellheads with enough pressure to circulate the needed flow rate through the fractured reservoir.
- The gathering system collects the heated water from the production wellheads and transports it to a centralized location for flashing to produce steam.
- The flash system flashes part of the hot water to steam for use in the power plant and transports the steam to the power plant. The rationale for selecting the flash process is given in Section 4.2.1.
- The make-up water supply furnishes the water needed for operation of both the wellfield and the power plant of the HDR power generation facility.

Figure 4-1 Process Flow Schematic

Figure 4-2 HDR Facility Plot Plan

o Power Plant

- The energy conversion system extracts thermal energy from the steam and produces electric energy.
- The cooling system dissipates thermal energy that cannot be converted to electricity.
- The transmission system delivers the electric power to the utility system grid.

This section describes the design of these systems for a 50 MWe HDR power generation facility at Roosevelt Hot Springs and then presents the estimated costs for these systems. The approach used for installed spare capacity is the same as that used for highly reliable geothermal power plants and wellfields which commonly experience availability greater than 90 percent.

4.1 WELLFIELD SURFACE FACILITIES

Wellfield surface facilities include the injection system, the gathering system, the flash system, and the make-up water supply.

4.1.1 Injection System

The injection system distributes water to the injection wellheads with enough pressure to circulate the needed flow rate through the fractured reservoir. It consists of an injection water storage tank, a set of booster and injection pumps, and distribution piping to deliver the water to the injection wellheads.

Injection Water Storage Tank. This tank, which provides 850,000 gallons (3,220,000 liters) surge capacity in the injection system, allows the make-up water to be mixed with the water leaving the low pressure flash vessels as shown in Figure 4-1. It is a round concrete tank, approximately 110 ft (34 m) in diameter, and 15 ft (5 m) tall. The internal pressure is atmospheric; however, the tank has an insulated roof to minimize heat loss and evaporation. Nominal liquid fill is to the 10 ft (3 m) level allowing operation for 30 minutes at maximum well flow rate with 12 injection wells operating, as expected near the end of a 30-year plant life. The injection water storage tank is separate from the pond for storing water used for hydraulic fracturing (frac pond).

Make-up water from the freshwater wells is introduced into the injection water storage tank for mixing with the liquid from the low-pressure flash vessel. The liquid from the low-pressure flash is hotter than the boiling temperature at atmospheric pressure, and part of it would flash upon release into the tank if precautions are not taken to prevent it. Therefore, the hot water is introduced via a submerged sparger to ensure contact with cooler water and thus prevent steam from flashing.

Injection Pumps. The injection pumps deliver the water at a pressure in excess of 1,500 psi (10 MPa) to a manifold for distribution to the injection wells. Three 50 percent capacity pumps are installed to provide reliability by allowing operation with any two pumps while the third is out of service for maintenance. The injection pumps are horizontally split case pumps with direct drive electric motors; each motor is rated at 4,000 hp and operates at 3,600 rpm.

Booster Pumps. The booster pumps provide sufficient net positive suction head to ensure proper operation of the main injection pumps. Three 50 percent capacity pumps are installed to provide reliability. The booster pumps are radially split case machines with direct drive electric motors; each motor is rated at 400 hp and operates at 3,600 rpm.

Distribution Piping. The distribution piping delivers the water to the injection wellheads from a manifold at the outlet of the injection pumps. This piping is carbon steel, Schedule 120 for the 1,500 psi (10 MPa) pressure, with insulation to protect personnel and to minimize heat loss from the water in transit to the injection wells. The distribution piping is installed above ground on concrete supports. One 10 in. diameter line is needed to accommodate the flow rate of water to each injection well. Based on a preliminary layout of the HDR well system, 6,000 ft (1,830 m) of piping was estimated as the initial requirement with 24,000 ft (7,300 m) additional piping added as new well pairs are drilled and connected over the lifetime of the plant.

Scaling Control. The HDR experiments at Fenton Hill and Rosemanowes plus the operating experience for the hydrothermal plant at Roosevelt Hot Springs indicate that the two most likely scale forming materials are calcium carbonate and silica.

Weak alteration expected in the crystalline basement rock at the target temperatures (see Section 2.3.3, Lithology) indicates that calcium carbonate is not likely to be abundant in the reservoir rock. Therefore, carbonate scaling is not expected to be significant for the HDR wells or surface facilities. Furthermore, the expected scarcity of carbonate in the reservoir rock indicates that carbon dioxide concentration is likely to be low in the steam flashed from the hot water heated by the HDR reservoir. By contrast, calcium carbonate is common in the naturally fractured, highly altered rock comprising the hydrothermal reservoir at Roosevelt Hot Springs, and carbonate scaling must be cleaned frequently from the hydrothermal wells.

Even though carbonate scaling is not expected to cause significant operating problems, silica scaling control will probably be needed. One interpretation of results from the tests at Fenton Hill (Tester and Albright 1979) indicates that the water flowing from the HDR production wells could become saturated with dissolved silica within a few weeks after beginning operation. Cooling and concentration in the flash system could cause silica supersaturation in the injection water unless some appropriate remedial treatment is employed. This supersaturated water could cause silica deposition in the fractured reservoir which could reduce the output and possibly even plug the reservoir eventually. Appendix D addresses this problem and some possible remedies; it concludes that dilution with a small amount of additional make-up water is the best way to ensure that the injection water is unlikely to cause silica deposition in the reservoir. This treatment would require only a small amount of make-up water (25 gpm or 1.6 l/s) in addition to that needed to replace the assumed reservoir loss and the cooling tower make-up. In fact, if the reservoir leakage is even slightly greater than the amount experienced during the Fenton Hill tests, silica control would be accomplished by adding no more make-up water than that needed to replace the reservoir leakage plus cooling

tower make-up. On the other hand, if reservoir leakage is so low that silica-rich water needs to be withdrawn from the injection/production circuit and make-up water needs to be added to control silica, the water withdrawn could be injected into a shallow well for disposal. Costs for this form of silica control are included in the capital and operating costs for the make-up water supply.

4.1.2 Gathering System

The gathering system transports the hot water from the production wellheads to the centrally located flash system. The piping is carbon steel, Schedule 120 for the 1,000 psi (6.9 MPa) pressure needed to ensure single, liquid phase flow from the production wells to the flash system to minimize scaling in the wellbore. One 10 in. diameter line serves each production well, and the lines are covered with 2 in. (5 cm) of aluminum-jacketed calcium silicate insulation to minimize heat loss from the hot water produced by the HDR reservoir. The gathering system piping is installed above ground on concrete supports. As for the distribution piping, 6,000 ft (1,830 m) of piping was estimated as the initial requirement with 24,000 ft (7,300 m) added as new well pairs are drilled and connected over the lifetime of the plant.

4.1.3 Flash System

The flash system converts part of the hot water to steam for use in the power plant and transports the steam to the power plant. The flash pressures selected for this design provide optimum energy conversion (i.e., maximum electric energy per unit mass of hot water) for water from new HDR reservoirs. However, as the reservoir temperature declines, these flash pressures would provide performance that is slightly below optimum. Since the energy conversion (kWh/lb) is a weak function of flash pressure, the performance deterioration would be minimal. Nevertheless, some opportunity exists for improving long term performance by optimizing the flash pressures considering the expected reservoir temperature decline with time.

High Pressure Flash Vessels. The hot water from each production well flows to a high pressure flash vessel where the pressure is reduced, flashing part of the water to steam. The high pressure flash vessels are bottom-outlet cyclone

separators that have been used successfully for liquid-dominated geothermal power plants. Steam from the high pressure flash vessels is collected into a single steam header that leads to the power plant. The liquid from the high pressure flash vessels flows to the low pressure flash vessels to produce additional steam at lower pressure.

As the temperature of the hot water from a production well declines with the age of the well, less high pressure steam is produced. As the high pressure steam production approaches zero, the water flow from the production well is diverted to the low pressure flash vessel, bypassing the high pressure flash vessel completely. In this way, useful low pressure steam can be produced for several years even though newer wells must be relied upon to produce high pressure steam.

Preliminary specifications for the high pressure flash vessels include a working pressure of 225 psia (1.55 MPa), a temperature of 392°F (200°C), an inlet water flow equal to 1,710 gpm (108 l/s), and a maximum steam flow of 131,000 lb/hr (16 kg/s).

Low Pressure Flash Vessels. The liquid from each high pressure flash vessel flows to a low pressure flash vessel. There the pressure is reduced further and part of the remaining water flashes to low pressure steam for use in the power plant turbine. The low pressure flash vessels are bottom-outlet cyclone separators with a design fundamentally similar to that of the high pressure vessels. However, low pressure vessels are larger than high pressure vessels to accommodate lower density steam. Steam from the low pressure flash vessels is collected into one low-pressure steam line that leads to the power plant. The liquid water from the low pressure flash vessels flows to the injection water storage tank for recirculation through the HDR reservoir.

Preliminary specifications for the low pressure flash vessels include a working pressure of 31 psia (0.21 MPa), a temperature of 253°F (123°C), an inlet water flow equal to 1,200 gpm (76 l/s), and a maximum steam flow of 78,000 lb/hr (10 kg/s).

Steam Piping. The high pressure and low pressure steam piping from manifolds downstream of the flash vessels are carbon steel lines installed above ground on concrete supports. These lines are covered with 2 in. (5 cm) of aluminum-jacketed calcium silicate to minimize heat loss. Each of the steam lines is approximately 300 ft (90 m) long.

4.1.4 Make-Up Water Supply

The make-up water supply furnishes water needed to replace the water lost due to reservoir leakage, silica control, and evaporation in the power plant cooling tower. In addition to supplying this water for normal plant operation, the make-up water supply system furnishes the water needed for to hydraulically fracture the HDR reservoir as well pairs are completed.

When the plant begins operation, the water consumption is estimated as 2,400 gpm (150 l/s, 3,900 acre-ft/year) assuming 10 percent reservoir leakage as indicated in Table 3-2. This rate is expected to increase to 3,900 gpm (250 l/s, 6,300 acre-ft/year) as HDR well pairs are added to sustain 50 MWe salable power output.

Within the production unit, water wells with an average depth of 700 ft (210 m) are expected to produce an average of 300 gpm (20 l/s, 485 acre-ft/yr) based on data from Mower and Cordova (1974). Therefore, 13 wells are needed to produce the 3,900 gpm (250 l/s, 6,300 acre-ft/year) eventually required for plant operation. These wells are located in Sections 6 and 7 (T27S, R9W) with rows 2,000 ft (600 m) apart and wells spaced at 1,000 ft (300 m) intervals within the rows. Due to the sparsity of data and the highly variable thickness and permeability of alluvial deposits in the Roosevelt-Milford Valley area, a test hole program should be completed to properly locate the make-up water wells.

The well water from the shallow aquifer is pumped to the injection water storage tank where it mixes with the warm water from the low pressure flash vessels. Based on available chemical analyses of the water, no requirement

for water treatment before injection is anticipated. Alternate piping is also provided to divert part or all of the well water to a holding pond for hydraulic fracturing (frac pond).

4.2 POWER PLANT

The power plant receives steam from the wellfield and uses it to produce electricity. Broadly speaking, an energy conversion system changes thermal energy to electric energy, rejecting heat in the process. The electric energy is then transmitted to the utility system grid in the area for use by the utility system customers. The fundamental design of the power plant for the HDR application at Roosevelt Hot Springs is similar to that for a geothermal plant of equal capacity for a liquid-dominated hydrothermal resource.

4.2.1 Energy Conversion System

Process Selection. Energy conversion processes considered include single-stage flash, two-stage flash, and binary. The two-stage flash process was selected for this HDR application for the following reasons:

- o Two-stage flash requires 20 to 30 percent less hot water than single flash.
- o Several two-stage flash plants of approximately 50 MWe net capacity are in commercial service while the binary plants of this capacity are not yet commercially proven.
- o Flash plants require significantly less capital investment than binary for equal net power capacity.
- o For the relatively high hot water temperatures expected in this application, the estimated energy conversion efficiency is greater for two-stage flash than for binary (see Appendix E).

System Description. Steam is admitted to the turbine at two different pressures as shown in Figure 4-1. The flash pressures were selected to produce maximum electric energy per unit mass of hot water for the initial production temperature; this results in equal temperature drop per stage. The high pressure steam expands part way through the turbine where it mixes with the low pressure inlet steam. The combined stream then expands through the remainder of the turbine stages and exhausts to the condenser at a design

pressure of 4 in. Hg (1.9 psia, 0.013 MPa) (i.e., 125°F, 52°C). Optimum condenser pressure may actually be somewhat lower; a tradeoff study comparing performance improvement with additional cost of the cooling system should be conducted during preliminary or final design.

Heat given up by the condensing steam is absorbed by the circulating water from the cooling tower. Condensate from the hotwell of the surface condenser is pumped into the circulating water system as make-up water for the cooling tower. All condenser components, including the tubes, are of type 304L stainless steel to resist corrosion from the mixture of water, air, carbon dioxide, and traces of other potentially corrosive gases, such as hydrogen sulfide. A contact condenser is usually a bit less expensive and should be evaluated in later design stages; however, for this initial investigation, the cost difference is not pivotal. The surface condenser could also provide high quality water for use in pump seal flush systems.

Although the amount of noncondensable gas (primarily carbon dioxide) with the steam is expected to be low, there will be at least a small amount, and there will be some air inleakage. Steam-operated ejectors remove the noncondensable gases from the condenser to permit condensation at subatmospheric pressure and thereby gain efficiency resulting from low turbine exhaust pressure.

The turbine and the generator are direct-coupled to operate at 3,600 rpm and produce 60 Hz, three-phase power at 13.8 kV. For salable power generation of 50 MWe, the power plant is rated at 70 MWe net. The difference between the net and the salable power is the amount of power needed to operate the wellfield, primarily the injection pumps, with the maximum number of HDR well pairs in service late in the 30-year life of the plant. With 70 MWe net capacity, the power plant has a gross power rating of 74 MWe.

4.2.2 Cooling System

Process Selection. Both a wet cooling tower and a dry cooling tower were considered. The wet tower was selected because of lower cost and greater plant output during summer daytime operation.

The main disadvantage of using a wet cooling tower is the water consumption. Approximately 1,400 gpm (90 l/s) of make-up water is evaporated in operating the cooling tower. If use of water from the shallow aquifer becomes a crucial impediment to HDR development at Roosevelt Hot Springs, switching to a dry cooling system should be evaluated. Dry cooling could eliminate the water used in the cooling tower although make-up water would still be needed to replace losses in the reservoir and to control silica scaling potential.

System Description. The cooling tower is a five-cell mechanical induced-draft unit of wood construction with polyvinyl chloride plastic fill. A cooling tower basin collects water running down the tower fill and directs it to the circulating water pump intake structure. Two half-capacity circulating water pumps are provided to supply cooled water to the condenser; this two-pump configuration allows part-load operation in case one pump must be shut down for maintenance. The circulating water piping between the pumps and the condenser is made of fiberglass reinforced plastic to resist corrosion from the circulating water that may contain carbon dioxide; it is installed below grade. The cooling water was assumed to require no significant water treatment; this is the case for geothermal power plants currently in operation.

Excess condensate not evaporated in the cooling tower is returned to the wellfield injection water storage tank for reservoir injection. The excess condensate was assumed to be fit for injection into the reservoir with no significant treatment required; solids separators used to protect the injection pumps will remove the larger solid particles that may enter the water via the cooling tower.

4.2.3 Balance of Plant

Electrical. The plant uses a 4,160 volt three-phase bus to power large motors, a 480 volt three-phase bus to power small motors, and a 240/120 volt single-phase panel for small loads.

The main transformer in the switchyard boosts the 13.8 kV generator output to 138 kV to connect with the existing transmission line in the area. It also serves to reduce offsite power to 13.8 kV to furnish power for auxiliary loads when the generator is not operating.

Turbine Building. The turbine building houses the turbine-generator, the condenser and related mechanical equipment, the electrical switchgear, and the power plant control room, shop, warehouse, and administrative offices. It is a rectangular, structural steel building of braced steel frame construction with plan dimensions approximately 75 ft (23 m) wide by 150 ft (46 m) long. The lowest level is at grade, and the top of the roof is approximately 65 ft (20 m) above grade. The steel roof framing and side walls are covered with insulated, corrugated metal siding and roofing.

The turbine-generator is supported on a massive reinforced concrete pedestal and is installed at the operating floor level at approximately the mid-height of the building.

The turbine building also encloses a bridge crane serving the full length of the building to facilitate maintenance work, especially for periodic turbine disassembly, inspection, and rework.

Auxiliary Systems. A single, compressed air system is provided for both instrument air and service air used in the power plant. The compressed air is supplied by two compressors equipped with coolers and a drier.

Three fire pumps are provided - two main pumps and one jockey pump. One of the main pumps is electric motor driven, and the other is driven by a diesel engine to ensure fire pump service. The jockey pump maintains the pressure in the firewater system; it is electric motor driven.

Other auxiliary systems include the heating-ventilating-air-conditioning, potable water supply, and sewage treatment systems. Office space, access roads, and parking typical of a geothermal power plant with similar capacity are provided.

4.2.4 Transmission Line

A 138 kV line from the power plant connects to an existing 138 kV Utah Power and Light Company (UP&L) line approximately four miles (6 km) from the HDR plant. In addition, approximately 14 miles (22 km) of the existing line would be upgraded to carry the additional power in the UP&L system.

4.3 COST ESTIMATES

This section describes the cost estimating methods and summarizes the capital and the operating and maintenance (O&M) cost estimates for the wellfield surface facilities and the power plant. All these cost estimates are for 1987 price levels.

4.3.1 Wellfield Surface Facilities

Wellfield Capital and Preproduction Costs. Capital costs for the wellfield surface facilities were derived by starting with estimates from previous Bechtel studies where the costs were estimated from material and labor quantity estimates. Adjustments were applied to the previous estimates to account for specific requirements and quantities for a HDR facility at Roosevelt Hot Springs.

Exceptions to this procedure are the pumps, the injection water storage tank, and the make-up water supply. For the wellfield booster and injection pumps, budget estimates for the pumps and motors were furnished by a pump vendor; costs for the foundations, piping, motor controls, and installation labor were added to obtain the installed costs. For the injection water storage tank, the material quantities for concrete were estimated and then multiplied by a unit rate that includes both the materials and the installation costs. For the make-up water supply, quantities and costs were estimated from a conceptual description of the water wellfield and a preliminary wellfield layout, including the collection and conveyance pipeline to deliver the make-up water to the plant location.

Additional lease costs were considered to be zero since the leases have already been acquired for geothermal rights. Likewise, land use rights are included with the existing geothermal leases.

Preproduction costs for the wellfield were estimated by summing estimates for baseline seismic monitoring (\$480,000), permitting (\$400,000 for one-half the estimated total permitting costs), and water rights acquisition (\$200,000). Water rights acquisition was estimated as an initial payment equal to one year of payments for make-up water as described below under the heading "Wellfield O&M Costs."

Capital cost estimates for the initial wellfield surface facilities are summarized in Table 4-1; the total for these facilities is \$9.3 million. Interest during construction (IDC) for the surface facilities amounts to \$2.61 million. The estimate in Table 4-1 does not provide for any costs associated with drilling and completing the injection and production wells; these costs are addressed in the discussion of costs for the subsurface system in Section 3. Likewise, it does not provide for the surface facilities needed to add injection and production wells later in the life of the HDR plant; these are part of the tangible costs for drilling and connecting new wells addressed in Section 7.

Wellfield O&M Costs. The variable O&M cost for use of make-up water was estimated as being equal to the irrigation pumping cost in the Milford area. Although all the water rights in the area are appropriated, about 11,000 acre-ft of the total of 55,000 acre-ft has not been used in recent years. In the absence of other estimating methods, the value of water to the holders of water appropriations was equated to the irrigation pumping costs. The actual cost may be lower or higher, depending on the results of the negotiations for the water rights. Additional costs for pumping the make-up water are included in the pumping power costs for the injection pumping, which are treated separately in Section 7.

Wellfield annual fixed O&M costs were estimated using a procedure outlined by the Electric Power Research Institute (EPRI) (1986). This procedure addresses operating labor, maintenance costs, and overhead charges. Although this procedure is not specific to HDR wellfields, it is expected to yield a realistic result that can be used in economic analyses of an HDR project.

Table 4-1

INITIAL CAPITAL COSTS - WELLFIELD SURFACE FACILITIES
(\$ millions, 1987)

<u>Facility</u>	<u>Cost</u>
Injection system	
Injection water storage tank	0.18
Pumps	1.42
Distribution piping	<u>0.95</u>
Total injection system costs	2.55
Gathering system	0.95
Flash system	1.60
Make-up water supply	<u>4.20</u>
Subtotal of tangible surface facilities	9.30
Capitalized interest	2.61
Preproduction costs	<u>1.08</u>
Total	12.99

Since the injection pumping costs are relatively large and vary from year to year depending on how many HDR well pairs are in service, they are treated separately in the economic analyses in Section 7.

The wellfield O&M costs, except for the pumping costs, are summarized in Table 4-2. The total fixed O&M costs are estimated to be \$1.35 million per year, and the variable cost to purchase the needed make-up water is 0.45 mill/kWh.

4.3.2 Power Plant

Power Plant Capital and Preproduction Costs. The capital costs for the power plant, excluding the transmission line, were based on a power-law correlation of capital cost for a two-stage flash plant as a function of net capacity from Bechtel (1985). This correlation includes costs for removing low to moderate amounts of noncondensable gas, but it does not include hydrogen sulfide abatement systems. The cost estimate derived from this correlation was adjusted for inflation to bring the estimate to 1987 price levels yielding the following equation:

$$\text{Power Plant Cost in \$ Millions} = 2.86 \times (\text{Net Capacity})^{0.699}$$

The capital costs for the transmission line were estimated from information provided by UP&L (Peterson 1986). The estimated costs amount to \$560,000 for a 4-mile (6-kilometer) line from the plant to the nearest transmission line plus \$700,000 for upgrading 14 miles (22 kilometers) of existing line.

A method recommended by EPRI (1986) was used for estimating most of the power plant preproduction costs (\$1.5 million). One-half the estimated total permitting costs (\$400,000) was added as the power plant owner's share of the permitting expenses.

The estimated capital and preproduction costs for the power plant are summarized in Table 4-3. The total power plant capital requirement is \$68.9 million, which includes a \$10.5 million estimated allowance for funds during construction (AFDC).

Table 4-2

WELLFIELD OPERATING AND MAINTENANCE COSTS

<u>Fixed O&M (\$ millions/year)</u>	<u>Cost</u>
Operating labor	0.72
Maintenance labor	0.15
Maintenance material	0.22
Overhead charges	<u>0.26</u>
Total annual wellfield fixed O&M costs	1.35
<u>Variable O&M (mills/kWh)</u>	
Power - see Section 6	
Consumables	0.00
Make-up water acquisition	<u>0.45</u>
Total wellfield variable O&M cost ^(a)	0.45

(a) Except pumping power

Table 4-3

CAPITAL COSTS FOR THE POWER PLANT
(\$ millions, 1987)

<u>Item</u>	<u>Cost</u>
Power plant (excluding transmission line)	55.2
Transmission line	1.3
AFDC	10.5
Preproduction costs	<u>1.9</u>
Total	68.9

Power Plant O&M Costs. Power plant annual O&M costs were estimated using a procedure outlined in EPRI (1986). This procedure addresses the fixed O&M costs associated with operating labor, maintenance, and overhead.

Variable O&M costs for the power plant are negligible since the economic analyses in Section 7 are based on net power output (i.e., plant power consumption is already taken into account).

The power plant O&M costs are summarized in Table 4-4; these costs total \$2.26 million per year.

Table 4-4

**POWER PLANT OPERATING AND MAINTENANCE COSTS
(\$ millions/year)**

<u>Fixed O&M</u>	<u>Cost</u>
Operating labor	0.79
Maintenance labor	0.44
Maintenance material	0.66
Overhead charges	<u>0.37</u>
Total annual power plant O&M costs	2.26

Section 5

ENVIRONMENTAL, SOCIOECONOMIC, AND PERMITTING ISSUES

5.1 INTRODUCTION

This section presents an analysis of the environmental and socioeconomic effects and the permitting requirements of a commercial 50 MWe HDR power plant at Roosevelt Hot Springs. The objectives of this analysis are to:

- o Identify any major environmental or socioeconomic issues or potential constraints to project development
- o Determine major permitting requirements
- o Identify major cost or schedule impacts associated with permit acquisition

Data for this analysis were obtained from published reports, confidential reports owned by Chevron Resources Company, and discussions with representatives from Chevron, Utah Power and Light, and federal and state agencies. No onsite data were gathered specifically for this analysis. In addition, estimates of potential emissions are approximate only; to acquire the necessary permits and approvals to proceed with the facility, detail design information should be used to prepare emission estimates.

In this section, the potential environmental and socioeconomic considerations are discussed first, followed by permitting requirements. In general, there are no major environmental or permitting constraints to developing a power plant or to conducting the required industrial experiments to demonstrate that the HDR technology is ready for development.

The most important consideration for development is obtaining sufficient water appropriations since all groundwater in the Milford Valley area is appropriated. No attempt was made to discuss water appropriations with the current owners; therefore, no evaluation of the ability to obtain sufficient resources can be made. However, in 1985, appropriation owners used only

44,000 acre-ft of a total of 55,000 acre-ft available per year. If rights to unused appropriations can be negotiated, this would be more than sufficient to supply the 6,300 acre-ft per year required for a 50 MWe HDR facility.

There are no apparent constraints to permitting the facility. The major permits will likely be air quality (PSD) and solid waste permits. The critical path for permitting is likely to be the air quality permit which may require 1 year of monitoring and could require up to an additional year after submittal for the permit to be issued.

5.2 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The potential environmental and socioeconomic impacts from construction and operation of a 50 MWe HDR power plant at Roosevelt Hot Springs are expected to be minor. The major impact during construction, the socioeconomic effects of in-migration of the construction work force, will be temporary and generally beneficial to the local economy. During operation, the environmental impacts will be relatively small since there will be low levels of air emissions, no point source water effluents, and little solid or hazardous waste. The following is an evaluation of the environmental and socioeconomic effects of facility development.

5.2.1 Air Quality

The Roosevelt Hot Springs Known Geothermal Resource Area (KGRA) is in an area designated as a Class II Region by the Environmental Protection Agency (EPA). This designation means that pollution levels for the primary air pollutants (suspended particulates, sulfur oxides [SO_x], oxides of nitrogen [NO_x], ozone [O₃], and carbon monoxide [CO]) are below federal secondary standards (see Table 5-1).

To permit the Blundell Geothermal Power Plant and associated steam supply wells from the Roosevelt Hot Springs hydrothermal resource, Phillips Petroleum Company (the resource operator at the time) conducted a 1-year baseline study of air quality and meteorology, from October 1977 to November 1978. This

Table 5-1

NATIONAL AMBIENT AIR QUALITY STANDARDS

Pollutant	Standards ($\mu\text{g}/\text{m}^3$)		PSD Increments ($\mu\text{g}/\text{m}^3$)		
	Primary	Secondary	Class I	Class II	Class III
Sulfur oxides					
Annual	80(a)	-	2	20	40
24 hours	365(b)	-	5	91	182
3 hours	-	1300(b) (0.5 ppm)	25	512	700
Particulates					
Annual	50	50	5	19	37
24 hours	150(b)	150(b)	10	37	75
Carbon monoxide					
8 hours	10(b)	(c)	-	-	-
1 hour	40(b)	(c)	-	-	-
Ozone					
1 hour	235(d)	(c)	-	-	-
Nitrogen oxides					
Annual	100(a)	(c)	-	-	-
Hydrogen sulfide	(e)	(e)	(e)	(e)	(e)

(a) Not to be exceeded

(b) Not to be exceeded more than once a year

(c) Same as primary

(d) Not to be exceeded more than three times in 3 years

(e) No ambient H_2S standards, federal or state of Utah

study, designed to fulfill permitting requirements, was supplemented by sampling conducted by the EPA in the Milford area during the same period. Hydrogen sulfide (H_2S), visibility, sulfur dioxide, and nitrogen dioxide were monitored continuously for 1 year; total suspended particulates (TSP) were sampled every sixth day for 24 hours. In addition, ammonia (NH_4) and radon were periodically sampled. Data on methane (CH_4) and carbon monoxide were monitored by the EPA. Based on the results from these monitoring activities, it was shown that ambient concentrations of air pollutants prior to construction and operation of the Blundell plant were below established federal and state standards (Phillips Petroleum Company 1979).

Table 5-2 shows potential air emissions from the proposed facility. Particulates and noncondensable gases are the only pollutants of any significance. During construction and drilling operations, particulates in the form of fugitive dust were not quantified, but would be controlled by watering-down or compacting areas of high use and revegetating exposed areas as soon as possible. Suspended particulates in the form of airborne soil particles in the cooling tower drift were not quantified but are not considered to be significant.

Noncondensable gases from the power plant are estimated to be about 0.1 to 0.5 percent of the total high pressure steam flow based on current assumptions of formation solubilities. Carbon dioxide would constitute most of this gas, with trace amounts of hydrogen sulfide (possibly 0.5 to 2.5 lb/hr or 0.2 to 1.1 kg/hr) which would be dissolved from the reservoir formation during circulation. This level of hydrogen sulfide emission is below the established Occupational Safety and Health Act (OSHA) standards and would therefore not be a problem. Should conditions in the formation result in concentrations of hydrogen sulfide that exceed these standards, an abatement system for hydrogen sulfide could be added. Site-specific data on dissolution rates for noncondensable gases are an important part of the fluid chemistry sampling program to be carried out during the proposed industrial HDR experiment.

Table 5-2

POTENTIAL AIR EMISSIONS

<u>Source</u>	<u>Air Emissions</u>	<u>Estimated Quantities</u>
Construction activity	Fugitive dust Diesel exhaust	Not quantified - low Not quantified - low
Drilling operations	Fugitive dust Diesel exhaust	Not quantified - low Not quantified - low
High pressure steam	Noncondensable gases CO ₂ H ₂ S	0.1-0.5% ^(a) <500-2500 lb/hr 0.5-2.5 lb/hr ^(b)
Cooling tower drift	Suspended particulates - airborne soil particles	Not quantified - low

(a) High pressure steam flow.

(b) Assumes the reservoir formation contributes soluble hydrogen sulfide (H₂S) to the circulating fluid.

5.2.2 Water Quality

As presently designed, there will be no point source discharges of water effluents into navigable waters from constructing or operating a HDR power plant at Roosevelt Hot Springs. The only potential sources of pollutants would be from:

- o Non-point source seepage around the mud sumps used for drilling mud
- o Run-off during construction and during the drilling of injection and production wells throughout the life of the facility

To avoid potential contamination of groundwater, the mud sumps will be compacted to the degree necessary to prevent seepage. Potential run-off from cleared construction areas would contain eroded soil particles and trace amounts of hydrocarbons from the operation of diesel generators and vehicles. This potential source of pollutants can be controlled by applying erosion-control measures and by installing catchments around the sites of drilling and construction activity.

The circulating water withdrawn for silica control will be injected into a disposal well. This waste stream is discussed in Section 5.2.4.

5.2.3 Water Resources

The water requirement for operating a 50 MWe HDR power plant will increase during its 30-year life from 3,900 acre-ft per year (initially with four well pairs supplying the steam requirement) to a maximum of 6,300 acre-ft per year (with all 12 well pairs) during the last 3 years of operation. The required water would be obtained by withdrawing groundwater from wells in the vicinity of the site. However, the groundwater appropriations for the Milford Valley area are fully allocated. To obtain water resources for the facility, the developer will have to acquire appropriations from current holders of water allocations.

According to the Utah Division of Water Rights, Office of Appropriations, and the Utah State Energy Office (Burks 1987), water rights in Utah are deemed to be a form of property and can be traded, bought, and sold by water users. Legal title to water rights can be acquired by negotiation and transfer of ownership of the water right between a willing seller and a willing buyer. To change use of the water right, an application must be filed with the State Engineer of the Utah Division of Water Rights. The State Engineer will issue a public notice and allow a 30-day period for interested parties to file a protest. The State Engineer may hold a hearing and may require additional information before making a decision. The process of changing the designated water use of acquired water rights may take 3 to 4 months.

The Beaver River (approximately 8 to 10 miles [12.8 to 16 kilometers] south and southwest of the Roosevelt Hot Springs KGRA) is the only dependable surface water in the Milford Valley. The Rocky Ford Dam controls the flow of the Beaver River and creates the Minersville Reservoir (approximately 9 miles [14.4 kilometers] to the south of the Roosevelt Hot Springs KGRA). Water from Minersville Reservoir is diverted for irrigation in the southeastern part of the Milford valley. From 1931-1985, the average annual discharge of the

Beaver River at Rocky Ford Dam was 29,700 acre-ft. The maximum was 127,000 acre-ft in 1983, and the minimum was 9,150 acre-ft in 1960. In 1985, discharge from the Beaver River was 57,100 acre-ft.

Groundwater withdrawn by pumped irrigation wells provides most of the irrigation water in the Milford Valley area. The unconsolidated materials underlying the Milford area contain the principal groundwater reservoir. The decreed groundwater appropriations are 55,658 acre-ft. In 1985, withdrawal of water was about 44,000 acre-ft, 42,000 of which were used for irrigation; 800 acre-ft were for public water supply; and 250 acre-ft were for domestic use and livestock watering.

The aquifers in the area near the Roosevelt Hot Springs KGRA have been shown to contain levels of arsenic, boron, fluoride, and iron that exceed maximum levels for irrigation water established by the EPA (Vuataz and Goff 1984; Utah Department of Natural Resources 1986). In addition, the movement of groundwater in this region of the Milford Valley is toward the northwest, i.e., away from the southeastern area of high irrigation use (see Figure 2-16, Section 2). Therefore, if a developer of the HDR project acquired water rights from other users, it would likely be possible to change the beneficial water use for those rights from irrigation to industrial uses. However, because this is a feasibility study, no attempt was made to discuss water appropriations with current owners; therefore, no evaluation of the ability to obtain sufficient water rights can be made at this time.

5.2.4 Solid and Hazardous Waste

Relatively small amounts of solid and hazardous wastes are expected from construction and operation of the facility. Because the generation, transport, and disposal of waste is carefully regulated, a Waste Management Plan should be written to provide a framework for compliance and control of wastes. The primary concern is whether a waste is or could become classified as "hazardous waste."

The Utah Waste Management Rules (Utah Department of Health 1986) list 786 specific and generic compounds that are deemed hazardous. In addition, a

waste will be classified as hazardous if it exhibits characteristics defined as:

- o Corrosive
- o Ignitable
- o Reactive
- o Toxic

For toxic characteristics, maximum concentrations of contaminants (by Extraction Procedure [EP] toxicity test) have been established for arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver, and several organic compounds (pesticides).

By these standards, several waste streams may potentially contain toxic levels of heavy metals and may, therefore, be classified as hazardous. Table 5-3 shows waste streams from facility construction or operation and their potential classification. These waste streams can be managed to avoid such classification entirely or to reduce the volume of waste to eliminate the requirement of disposal as hazardous waste. Table 5-4 lists hazardous waste disposal sites in the region that would accept toxic wastes generated by construction and operation of the project.

Drilling muds would be disposed of by allowing them to dry in the mud sump (with compacted lining) and burying them. To avoid the classification of the muds as hazardous waste, the mud additives should be tested prior to use to be sure that heavy metals concentrations are below toxic thresholds. If necessary, alternative additives should be identified. If the mud additives have unavoidably high levels of heavy metals, the muds must be disposed of as hazardous wastes at an EPA approved Class 1 disposal site.

Similarly, drilling cuttings would be disposed of by allowing them to dry in the lined mud sump with the drilling mud. It is possible that heavy metals

Table 5-3
SOLID WASTE STREAMS

<u>Source</u>	<u>Constituents</u>	<u>Classification</u>
Drilling mud	Heavy metals	Potentially hazardous
Drilling cuttings	Dissolved constituents from formation - potential heavy metals	Potentially hazardous
Water withdrawn for silica control	Make-up water constituents, i.e., boron, arsenic, etc. from groundwater Minerals dissolved from reservoir formation	Potentially hazardous
Cooling tower sludge	Soil particles, make-up water constituents, i.e., boron, arsenic, etc.	Potentially hazardous

Table 5-4
HAZARDOUS WASTE DISPOSAL SITES NEAR ROOSEVELT HOT SPRINGS

USPCI
Grassy Mountain, Utah
(801) 266-3908

Casmalia Resources
NTU Road
Casmalia, CA 93429
(805) 937-8449

Chemical Waste Management
35251 Old Skyline Road
Kettleman City, CA 93239
(209) 386-9711
(714) 970-7971 (S. California Office)

contained in the drilling cuttings may be present in sufficiently high concentrations or may be sufficiently soluble to classify the waste as hazardous. The presence of heavy metals in the drilling cuttings would depend on site-specific characteristics of the formation itself and are not possible to predict at this time. Such information will be an important part of the formation sampling program during the proposed industrial HDR experiment. Should the cuttings be classified as hazardous, they would be disposed of at an approved Class I disposal site.

Water withdrawn for silica control will be disposed of into an appropriately permitted well. This water would contain the constituents of the groundwater resource which supplies the make-up water as well as minerals dissolved from the reservoir formation. If the groundwater resource contains heavy metals, these constituents may become concentrated by evaporation or by dissolution of the same constituents from the reservoir. Should the concentrations of heavy metals exceed the threshold for classification as hazardous waste, the waste would have to be disposed of in an appropriately permitted hazardous waste disposal well or an approved Class I disposal site.

Cooling tower sludge is the residue left from insoluble constituents in the circulating water. This waste would contain primarily airborne soil particles which could contain heavy metals. The volume of this waste is expected to be small, and, if it is classified as hazardous, the waste could be disposed of at an approved hazardous waste disposal site.

If the drilling muds, drilling cuttings, and/or water withdrawn for silica control are classified as hazardous, the potential costs for reducing the liquid volume and for disposing of this waste at an approved Class I disposal site could be significant.

5.2.5 Seismicity

Geology and local seismicity are discussed in detail in Section 2. The drilling, hydraulic fracturing, and production of HDR wells to supply steam for a 50 MWe HDR power plant at Roosevelt Hot Springs would produce microseismic events. These events are expected to be four to seven orders of

magnitude (extrapolated Richter scale) below the threshold for human detection, although they may be detected by sensitive instrumentation. The potential for induced seismicity, discussed in detail in Section 2.3.7, is considered to be negligible because of site selection (away from known faults), reservoir design, and operating conditions. In the experiments conducted at Fenton Hill and at Rosemanowes, no seismic tremors of significance have been detected as a result of hydraulic fracturing or circulating water.

5.2.6 Biological Resources

Information on biological resources was derived primarily from the environmental baseline study prepared for Phillips Petroleum Company (Phillips Petroleum Company 1979) and from an environmental analysis prepared by the U. S. Department of Interior (1976) as part of the permitting program for the steam supply wells for the Blundell power plant.

The Roosevelt Hot Springs KGRA is located along the eastern edge of the Escalante Valley Desert on the west slope of the Mineral Mountains. The climate is considered arid to semi-arid, and is characterized by low humidity and relatively low precipitation. Average annual rainfall is less than 9 in. (23 cm). The elevation of the Roosevelt Hot Springs KGRA ranges from 5,100 ft (1,554 m) near the western boundary to almost 7,800 ft (2,377 m) in the southeastern portion of the KGRA on the slopes of the Mineral Mountains. Average monthly temperatures range from a low of 25.7°F (-4°C) in January to a high of 74.3°F (24°C) in July. Recorded extremes range from -34°F (-37°C) to a high of 105°F (41°C). The growing season is from about mid-April to late September.

The vegetation and wildlife of the Roosevelt Hot Springs KGRA is similar to that found in much of the Great Basin. Table 5-5 lists the vegetation types and sub-types found in the KGRA and the approximate acreage for each.

Much of the native vegetation and wildlife habitat within the KGRA has been disturbed primarily by livestock grazing, but also by burning, chaining, and other activities. Current management practices by the BLM, which manages

Table 5-5
VEGETATION TYPES

<u>Vegetation Type</u>	<u>Approximate Acres</u> ^(a)
Mountain Shrub	558
Juniper-Pinyon	6,568
Northern Desert Shrub	
Sagebrush	14,505
Sagebrush-Wash	1,990
Disturbed	
Burn	497
Chained	2,270

Source: Philips Petroleum Company (1979)

(a) 1 acre = 0.405 hectare

grazing allotments, are oriented toward range recovery of the three BLM grazing allotments that extend over the KGRA. Recently, the BLM has placed significant portions of the allotted Animal Unit Months in the KGRA in suspended non-use.

The five vegetation types found to occur throughout the KGRA support 53 mammal species, 81 bird species, plus 18 species of reptiles and amphibians. Diversity and abundance of wildlife species vary significantly by functional group. Species of small mammals, raptors, reptiles, and nongame birds are relatively diverse. However, big game, medium-sized mammals (furbearers, large carnivores, etc.), waterfowl, and upland game are not well represented and have relatively low densities. The factors which appear to limit species diversity include limited cover, lack of permanent surface water resources on or near the site, competition with domestic livestock, and habitat loss due to chaining, fencing, and other human-made causes.

The construction and operation of a 50 MWe HDR power plant at Roosevelt Hot Springs would:

- o Result in the permanent loss of about 40 acres (16.2 hectares) of land for the power plant; injection, gathering, and flash systems; and associated access and transmission corridors
- o Temporarily disturb approximately 72 acres (29.2 hectares) for the 24 HDR reservoir injection and production wells (assumes about 3 acres will be cleared for each drill pad)

Additionally, about 12 acres (4.9 hectares), would be cleared for an estimated four injection wells for disposal of wastes, and about 13 acres (5.3 hectares) (1 acre [0.405 hectare] each) would be cleared for the water supply wells.

The loss of 40 acres (16.2 hectares) of habitat is not expected to significantly affect the wildlife populations that inhabit or winter in the area. Most of the wildlife would move into an adjacent undisturbed area. There are hundreds of acres of similar habitat within the KGRA adjacent to disturbed areas, and thousands of acres of similar habitat in the surrounding Escalante Valley Desert.

The areas cleared for drill pads would be restored by reshaping the surface and revegetating with an appropriate mixture of cover species. The greatest amount of disturbance would occur at the beginning of the project when the initial reservoir well pairs, disposal injection wells, and water supply wells are drilled (43 acres [17.4 hectares] disturbed). As additional HDR reservoir well pairs are needed, the remaining disturbance would occur periodically, when about 6 acres (2.4 hectares) at a time would be cleared.

The noise and disturbance of construction, drilling, and power plant operations will cause wildlife to avoid such areas. However, the important winter habitat ranges for deer and upland game in the area are quite large and therefore not critical.

5.2.7 Threatened or Endangered Species

Results of the studies conducted in 1977-1978 suggest that there are no threatened or endangered plant or animal species known to occur in the KGRA

(Philips Petroleum Company 1979). The bald eagle is the only endangered species observed in the KGRA during the investigation. No bald eagle nests or nesting activities were observed.

With regard to rare species or species of unique or scientific interest, there exist two clones of the relic hybrid oak, Quercus x pauciloba, located south of the KGRA boundary. These trees occur at elevations of 6,200 and 6,800 ft (1,890 and 2,073 m) and mark the southernmost limit of relic hybrids in the Great Basin (Phillips Petroleum 1979). These clones are important because they provide data concerning past climates as they relate to present climatic conditions. The only possible cause of potential disturbance to these trees from development of a 50 MWe HDR power project is the transmission line corridor; transmission lines could easily be routed to avoid these specimen trees.

5.2.8 Socioeconomic Resources

The Roosevelt Hot Springs KGRA is located in Beaver County (population: 5,100) in Southwestern Utah. There are no large cities or metropolitan areas within the county. The major towns of the area are Beaver, Milford, and Minersville. Table 5-6 shows the population of these towns and their proximity to the HDR power plant site.

The total nonagricultural work force employed in Beaver County is 2,080 (Utah Department of Employment Security 1987). Table 5-7 shows nonagricultural employment by major industrial sector. As shown in the table, the major industrial sectors are (in order of decreasing employment): government, trade, transportation and communication, and services. The unemployment rate in Beaver County was 6.9 percent in November 1987.

Average per capita income in Beaver County in 1986 was \$7,169 per year, 66.7 percent of the state average of \$10,746 per year. Gross taxable sales for Beaver County in the second quarter of 1987 were \$5.268 million.

In general, Beaver County is characterized by low levels of economic activity, primarily centered around agriculture, tourism, and trade. The estimated

Table 5-6

POPULATION OF TOWNS IN BEAVER COUNTY

<u>Town</u>	<u>Population</u>	<u>Proximity to Site (miles)</u>
Beaver	2,100	8(a)
Milford	1,280	18
Minersville	740	21

Source: July 1986 U. S. Census Bureau

(a) 1 mile = 1.6 kilometers

Table 5-7

EMPLOYMENT BY MAJOR INDUSTRIAL SECTOR

<u>Industrial Sector</u>	<u>Number of Employees</u>
Mining	2
Finance	31
Manufacturing	34
Construction	48
Services	183
Transportation and communication	216
Trade	330
Government	419

Source: Utah Department of Employment Security 1987

construction work force for a 50 MWe HDR power plant at Roosevelt Hot Springs is a peak of 50 people for the drilling operations and a peak of 150 for the power plant. Some of this work force would be recruited from the local labor pool, but most would immigrate to work on the project. During the 3 years required for construction, the workers will likely reside in the area. Most would be single-status construction workers or drillers.

The influx of this labor force would cause an increase in demand for local services. The addition of family status construction workers would place an additional requirement on schools and other family services. These additional demands would be temporary, lasting as long as major construction is ongoing, i.e., a period of about 3 years.

However, during this period these workers would also add local income and would increase the county tax base. The temporary increase in employment, local income, sales, taxes, and other economic activity would be beneficial to the economy of the community.

The estimated work force required to operate the steam production facilities, ongoing drilling operations, and power plant would be about 25 employees. This work force would be primarily permanent family status, some of whom would be recruited from the local labor pool. These workers will contribute to local income, sales, taxes, and other economic activity. Increased taxes should offset the need for increased school and other community services.

5.2.9 Archaeological Resources

Archaeological investigations of the Roosevelt Hot Springs KGRA area were conducted in 1975 and 1977 (Thomson 1975 and 1977). These were performed for Phillips Petroleum Company in conjunction with permitting requirements to develop steam production wells for the Blundell power plant (U.S. Department of Interior 1976).

The Roosevelt Hot Springs KGRA is located on the east bench of the Escalante Valley and shows evidence of "intense long-term human activity," possibly as long as 10,000 years (Thompson 1975). This activity is due to the presence of

two important resources: obsidian in the lower Mineral Mountains and water resources in the Beaver River drainage.

However, in the 1975 and 1977 investigations of this area, no middens or cultural debris were discovered. Flakes and small cores are present throughout the area and are found in greater concentrations where obsidian resources are abundant. One such site was found near one of 16 well sites investigated for Phillips in 1977.

Potentially disturbed areas associated with construction and operation of a 50 MWe HDR power plant at Roosevelt Hot Springs would require site-specific investigations to determine whether significant archaeological sites exist. Two factors suggest that significant archaeological resources at the HDR site would be unlikely:

- o There were no significant sites found on the nearby hydrothermal area previously investigated.
- o The HDR site is even further from permanent water resources of the Beaver River drainage than is the hydrothermal resource.

Should an archaeological investigation reveal a potential midden or cultural debris at a well site or on the site of the power plant facilities, appropriate mitigation measures would be worked out with the Utah Division of State History and the Federal Department of Interior.

5.3 PERMITTING REQUIREMENTS

Permitting requirements for a 50 MWe HDR power plant at Roosevelt Hot Springs will be similar to those required for the 20 MWe Blundell geothermal power plant, which was brought on line in 1984, is owned and operated by Utah Power & Light Company, and is powered by geothermal steam supplied by Intermountain Geothermal Company. In general, with the exception of water supply, permitting requirements will not restrict development. The most important environmental concern is obtaining sufficient water appropriations for operating the facility for the industrial experiments and for full facility development.

In this section, major federal and state permits that likely will be required for construction and operation of a 50 MWe HDR power plant are listed by permitting categories, such as land use, air resources, water resources, solid waste, etc. Table 5-8 lists the major permits required for both the power plant and the industrial experiments recommended in Section 6.2 and the estimated time required to acquire each permit. Most of the information provided is summarized from the Utah Environmental and Land Use Permits and Approvals Manual issued by the Environmental Law Committee of the Utah State Bar in November 1985. These data were updated or supplemented by communications with the permitting agencies.

5.3.1 Land Use

Federal Permits

Permitting Agency: Bureau of Land Management

Permit: Exploration Permit

The licensee or designated operator must submit an application for "exploration operations" on lands covered by his geothermal lease. The application must provide information requested in 43 CFR Part 3209.

Permit: Designation of Geothermal Operator

Authorizes an operator other than the lessee or licensee to conduct operations including well operations, research and demonstration projects, or facility operation.

Permit: Plan of Utilization for a Federal Geothermal Lease

The licensee or designated operator must submit a Plan of Utilization (POU) prior to starting site preparation, road construction, or facility construction. The POU is required to engage in any site investigations. The information provided in the POU must comply with requirements of 43 CFR Part 3262.4-1.

Permit: Utilization Permit for a Federal Geothermal Lease

The permit authorizes a licensee or designated operator to utilize geothermal resources and develop plant facilities, well production facilities, research and demonstration facilities, and related activities. The application must contain information required by 43 CFR Part 3264.2-1.

Table 5-8

MAJOR FEDERAL AND STATE PERMITS^(a)

<u>Permit</u>	<u>Required For Power Plant</u>	<u>Indust. Exper.</u>	<u>Lead Time^(b)</u>
Land Use			
Plan of Utilization	X	X	6-12 mo
Plan of Operation	X	X	6-12 mo
Geothermal Drilling Permit	X	X	6-12 mo
License to Construct a Geothermal Power Plant	X		6-12 mo
Construction Permit for Geothermal Power Plant	X	X ^(c)	6-12 mo
Approval of a Temperature Gradient Well	X	X	30-90 days
Air Resources			
Permit to Construct or Modify a Source of Air Pollution in a PSD Area	X	X ^(d)	1-2 years
Water Resources - Quality			
NPDES	Not Required		
Underground Injection Control	X	X	30-90 days
Water Resources - Appropriations			
Cert. of Appropriation of Water	Not Required		
Application for Water Use Change	X	X	3-6 mo
Application to Appropriate Water for Geothermal Purposes	X	X	3-6 mo
Solid and Hazardous Waste			
Hazardous Waste Permit	X	X	3-6 mo

(a) Only permits requiring significant lead time for preparation of the application and for processing and agency approval are listed.

(b) Lead time includes time required for baseline data gathering, preparation of the application, and agency review and approval.

(c) Required only if the industrial experiments include power production.

(d) Required only if the industrial experiments include power production; however, agency review will be necessary for any site activity even if a permit is not required.

Permit: Plan of Operations on a Federal Geothermal Lease

The licensee or designated operator must submit a Plan of Operations (POO) to conduct well operations, construct new production facilities, or alter existing production facilities. The information provided must comply with requirements contained in 43 CFR Part 3262.4. The POO is reviewed jointly by BLM, USGS, and other federal and state agencies. The plan must include information on the potential environmental effects of the proposed activities.

Permit: Geothermal Drilling Permit

This permit authorizes a licensee or designated operator to drill, redrill, deepen, or plug-back a well. The application must include information required by 43 CFR Part 3264.2. The permit application must be accompanied by a POO if none has been filed.

Permit: License to Construct Geothermal Electric Generat. Plant

This permit is required for use of surface lands under a federal geothermal lease to construct a plant for generating electric power from geothermal resources. The application must comply with requirements set forth in 43 CFR Part 3250. A license is not required for a research and development project of 20 MW or less and with a maximum life of 5 years from the date the facility becomes operational. A license is not required to test an individual well for electric power generation so long as it is not for transmission or sale of more than 10 MW. The applicant must be a U.S. citizen as defined in 43 CFR Part 3250 and must furnish and maintain a \$100,000 bond (surety or personal). The term of the license is 30 years; annual rental of \$100 per acre is charged and is subject to readjustment every tenth year.

Permit: Construction Permit for Geothermal Power Plant

This permit authorizes the licensee or designated operator to construct a geothermal power generating facility on lands held under federal geothermal lease. This permit is required for research and development projects and for facilities for testing individual well production even though these activities do not require a License to Construct (above). The information required must comply with 43 CFR Part 3260.

Permit: Right-of-Way Across BLM Lands

This permit is required for pipelines, access roads, transmission lines, or any other right-of-way across lands administered by the BLM.

State Permits

Permitting Agency: Utah Division of Water Rights

Permit: Approval of a Temperature Gradient Well

Approval of the State Engineer is required to drill any well on lands within the state of Utah for the purpose of testing and measuring subsurface temperatures and conductive heat flow. The well must be drilled by a bonded driller holding a Well Driller's Permit from the State Engineer, in accordance with Rule 8-2 of the Utah Geothermal Regulations.

Permit: Plan of Operations for Geothermal Drilling

The Utah Geothermal Regulations require an approved P00 prior to drilling an exploratory or production well or wells for geothermal resources on any lands within the state of Utah. In addition, prior to drilling, redrilling, deepening, permanently altering the casing of or abandoning any well, a notice of intent must be filed with the Division.

Permitting Agency: Utah Division of State Lands and Forestry

Permit: Right-of Way Across State Lands

This permit is required for rights-of-way on, through, or over any state lands for pipelines, access roads, communication lines, transmission lines, and other similar uses.

5.3.2 Air Resources

Federal Permits. The Clean Air Act provides for delegation of permitting authority to the state upon approval of a State Implementation Plan (SIP). The state of Utah has received that approval and, with the exception of actions on Indian lands, has authority over issuing permits for facilities located in Prevention of Significant Deterioration (PSD) areas and nonattainment areas. The Utah Air Conservation Committee is the state permitting agency for air quality permits.

The proposed site for the HDR facility is located in the Utah Intrastate Air Quality Control Region (AQCR), designated by the Environmental Protection Agency (EPA) as a Class II attainment area. This means that ambient concentrations of regulated primary air pollutants are below the limits established by the National Ambient Air Quality Standards (NAAQS) (see Table 5-1).

State Permits

Permitting Agency: Utah Air Conservation Committee

Permit: Construct or Modify Source of Air Pollution in PSD Area

Required for construction of a major new stationary source of air pollution in a Prevention of Significant Deterioration (PSD) area. "Major" is defined as a source emitting more than 100 tons per year (91,000 kg/yr) of any of the primary pollutants (particulates, sulfur dioxides (SO_x), nitrous oxides (NO_x), carbon monoxide (CO), ozone, or volatile organics) or over 250 tons per year (227,000 kg/yr) for other pollutants. A new facility must not emit more than the allowable PSD increment above baseline concentrations. In addition, there are emission standards established for certain industrial categories by the EPA. An electrical generating station is one of the regulated industrial categories; therefore, the proposed project would have to comply with the New Source Performance Standards (NSPS) for this type of facility.

To obtain the permit, the applicant must supply information on the project design and construction, construction schedule, air pollution control equipment and procedures, estimated potential emission levels, and evidence that best available control technology has been applied. The agency may require ambient air quality monitoring data for a period of 1 year, and based on these data, may require demonstration (through modeling) that the PSD air quality increment will not be exceeded. The agency may also require a commitment to conduct post-construction monitoring.

The agency is required to notify the applicant of any deficiencies within 30 days of submittal. Once an application is complete, the agency is required to act within 1 year. Public notification and a hearing are requirements for processing the approval.

Permit: Construct or Modify Sources of Hazardous Air Pollutants

This permit is required for the construction or modification of a stationary source of hazardous air pollutants for which standards have been established. At present, there are no potential emissions from the proposed facility which would be classified as hazardous. However, because hazardous substance regulations are changing, and new substances are being added, the standards should be reviewed as the time for permitting the facility nears.

5.3.3 Water Resources

Water Quality - Federal Permits. The Federal Water Pollution Control Act (FWPCA) provides for delegation of permitting authority to the state upon approval of the state plan. The state of Utah is currently in the process of obtaining approval. By the time the proposed project is ready for permitting, the state will have completed this process, and the permitting authority for the National Pollution Discharge Elimination System (NPDES) will have shifted from the EPA to the state Bureau of Water Pollution Control.

Water Quality - State Permits. Since it is proposed to recycle all circulating water in the HDR reservoir and to inject water that is removed from the cycle for silica control, there should be no requirement for an NPDES permit. However, the project will be reviewed by the permitting agency to ensure that the permit is not required. Therefore, the NPDES permit requirements are briefly outlined.

Permitting Agency: Utah Bureau of Water Pollution Control

Permit: National Pollution Discharge Elimination System (NPDES)

This permit is required for point source discharges into navigable waters. "Point source" is defined as a discernible, confined and discrete conveyance from which pollutants are or may be discharged into navigable waters. "Navigable waters" are defined as virtually every body of water used or potentially used by industries engaged in interstate commerce.

The operator must submit the application no later than 180 days prior to the date discharge will start. The application must be signed by a principal corporate officer or principal. The application must contain information on the project design, potential pollutants in the discharge stream, dispersion/dilution in the receiving waters, and utilization of best practical control technology (BPCT).

The agency will determine the effluent limitations, a schedule of compliance, and other conditions when a permit determination is made. These conditions are based on the industry effluent limitations and on water quality standards for the receiving waters. Water quality standards are established by the State Water Quality Plan and are based on designations of allowable uses of specific bodies of water and minimum water quality standards for such designated uses.

Permitting Agency: Utah Division of Environmental Health

Permit: Underground Injection Control

All underground injection wells are regulated by this permit. There are five classes of injection wells:

- o Class I. Wells used by generators of hazardous waste
- o Class II. Wells for injection of fluids for the recovery of natural gas or oil or for the storage of hydrocarbons
- o Class III. Wells used for extraction of minerals or energy
- o Class IV. Wells used by generators of hazardous or radioactive waste to inject the waste into or above a formation which is a source of drinking water and contains a potable water well within 0.25 mile (400 m) from the injection well
- o Class V. All injection wells not included in Classes I through IV including wells associated with production of geothermal energy

Class I, III, IV, and V wells are under the jurisdiction of the Division of Environmental Health; Class II wells are administered by the Division of Oil, Gas and Mining. The applicant must demonstrate that the injection well will not result in the movement of fluids into underground sources of drinking water. The proposed injection wells for generation of HDR energy would be Class V wells; these wells would be cased to a depth several thousand feet below any local aquifers that are potential sources of drinking water. The injection well used for the disposal of water removed from circulation for silica control would be appropriately permitted.

Permitting Agency: Utah Board of Oil, Gas and Mining

Permit: Underground Disposal of Water Associated with Oil and Gas Drilling

Depending on how the agency classifies HDR technology, this permit:

- May be required for disposal of water withdrawn from circulation for silica control
- Is required for underground disposal of salt water, brackish water, or other water unfit for domestic, livestock, or other general uses

The permit requires that the injection well must be cased and cemented and that the casing be tested prior to use of the disposal well. In addition, the source and the estimated daily minimum and maximum amount of water to be injected must be provided in the permit application.

Water Appropriations - Federal Permits

Permitting Agency: Bureau of Land Management

Permit: Permit to Drill a Water Well on BLM Land

This permit is required for drilling of water wells on federal lands managed by the Bureau of Land Management. This permit is required for exploratory as well as production wells.

Water Appropriations - State Permits

Permitting Agency: Utah Division of Water Rights

Permit: Certificate of Appropriation of Water

This permit is required to acquire the right to use any water that is unappropriated in the state of Utah. The applicant must show that there is sufficient unappropriated water and that the water will be used for a beneficial purpose. At present, since all water in the Milford Valley is appropriated, this permit would not be necessary. To obtain water rights, the developer will have to acquire sufficient appropriations from those already held in the Milford area.

Permit: Application to Appropriate Water for Geothermal Purposes

This permit is required to drill a well or wells for the production of geothermal resources or for injection wells. This permit is authorized by the Utah Geothermal Regulations (Rule 2-3-1) which regulate steam and hydrothermal geothermal development. Because HDR technology does not utilize geothermal fluids, it does not appear that this permit would be necessary. However, the state regulatory agency has not reviewed the regulations with regard to their applicability to HDR technology.

5.3.4 Solid Waste

Federal and State Permits. The Resource Conservation and Recovery Act (RCRA) provides for delegation of permitting authority to the state. The state of Utah has received authorization to take over permitting authority subject to implementation of recent federal amendments to the RCRA. Because of the

current overlap in permitting authority, federal and state permits are described together.

**Permitting Agencies: Environmental Protection Agency (federal)
Utah Bureau of Solid Waste (state)**

Permit: Hazardous Waste Permit

This permit is required of any person who owns, generates, or disposes of hazardous wastes. Permit applications require information on the processes, design capability, and the hazardous waste to be handled, and on the ability to meet technical standards promulgated under the Resource Conservation and Recovery Act of 1976, Section 3004 (42 USC 6901-6987 and 40 CFR Parts 260-265 and 122-124).

Noncompliance could result in civil penalties of up to \$25,000 per day. Knowingly transporting or disposing of hazardous waste without a permit, or making false statements or representations could result in criminal penalties of up to \$50,000 per day or up to 5 years imprisonment or both.

The applicant must show that he has a program in place to reduce the volume or quantity and the toxicity of the waste and must propose methods of waste treatment that are currently available and that minimize present and future threat to human health and the environment.

Permit: Federal Notification for Hazardous Waste Activity

Within 90 days after the EPA publishes regulations defining a substance as a hazardous waste, notification must be filed with the EPA by anyone conducting hazardous waste activity (owns, generates, treats, stores, transports or disposes of hazardous waste). Generators or transporters of hazardous waste must obtain an EPA Identification Number. This request is processed through the state Bureau of Solid Waste.

Permitting Agency: Utah Department of Health, Solid and Hazardous Waste Committee

Permit: Approval for Disposal of Solid Wastes

This permit is required for disposal of solid waste. Similar to the Federal Hazardous Waste Permit, the operator must submit design plans and other information on disposal activities.

Permit: State Notification for Hazardous Waste Activity

Similar to the Federal Notification for Hazardous Waste Activity, the operator must file a notification to the Executive Secretary of the Solid and Hazardous Waste Committee of the State Department of Health, for the generation, treatment, storage, disposal, or transportation of hazardous waste. The operator must also obtain an EPA Identification Number.

Permit: Hazardous Waste Plan Approval

This permit is required prior to constructing, modifying, or operating any facility or site which will generate, treat, store, or dispose of hazardous wastes. Failure to comply with the submittal requirements or the approved plan could result in a civil penalty of \$10,000 per day. Knowing violation could result in a penalty of \$15,000 per day and a Class A misdemeanor.

5.3.5 Archaeological Resources

A 50 MWe HDR power plant at Roosevelt Hot Springs will require a site-specific investigation of cultural and archaeological resources. To obtain information on the existence of any archaeological resources on or near the proposed development site and access corridors, certain permits would be required for excavation. These permits, described below, would be required of either the developer or the consultant conducting the site investigations.

Federal Permits

Permitting Agency: Secretary of the Interior

Permit: Permit to Conduct Archaeological Excavation or Exploration on Federal Lands

This permit is required for the examination of ruins, the excavation of archaeological sites, or the gathering of objects of antiquity on lands administered by the U. S. Department of the Interior. The permit may be granted to a university, reputable museum, or recognized scientific or educational institution. The application must describe the proposed site and the work to be performed, the dates for conducting the work, and information on the potential objects to be excavated.

State Permits

Permitting Agency: Utah Division of State History

Permit: Permit to Explore, Excavate, or Remove Archaeological or Paleontological Remains

This permit is required to explore or excavate prehistoric ruins, pictographs, hieroglyphics, or any other deposit of archaeological or paleontological significance on either state or federal lands. As a condition of the permit, the Historical Preservation Officer may require that a portion of the antiquities discovered remain the property of the state.

Section 6

DEVELOPMENT PLAN

6.1 INTRODUCTION

This section presents a phased development plan to carry a commercial HDR project at Roosevelt Hot Springs through construction and startup. It describes the elements needed for the venture project and presents a schedule for accomplishing the activities needed to bring the project to the stage where it is generating commercial amounts of power from the HDR resource.

Commercial success of an HDR system depends on the ability to create several large fractures in each injection well and on the long-term thermal performance of the subsurface reservoir. Although the estimates of expected performance used in this study appear plausible from the short-term tests at Fenton Hill and Rosemanowes, the following crucial aspects of reservoir thermal performance have not been demonstrated conclusively:

- o Total effective heat transfer area that can be created by hydraulic fracturing using a multilevel pack-off approach
- o Rate of growth of the effective heat transfer area after production begins
- o Long-term thermal drawdown characteristics
- o Ability to control flow through multiple fractures

Therefore, a test verification of both the drilling/completion concept and the reservoir performance is needed prior to installation of a commercial facility.

Completing such a test should provide information needed for project preliminary design. This design step in turn should furnish reliable cost estimates for realistic evaluation of the project economics.

Assuming that the economic projections based on these more reliable cost and performance estimates are favorable, a venture group can be formed; project

financing can be arranged; a power sales agreement can be negotiated; and environmental permits can be obtained.

The remaining major steps to commercial realization are the detail design, construction, and startup of the wellfield and power plant. Each of these steps is discussed in more detail below. Figure 6-1 presents a schedule for their completion.

6.2 INDUSTRIAL HDR EXPERIMENT

A satisfactory experiment to obtain the needed HDR well and reservoir information involves:

- o Drilling and casing a full-depth, full-bore injection well
- o Fracturing a number of intervals while mapping the microseismic events to target a production well. (Four to six fracture intervals may be sufficient for a test compared to twelve fracture intervals envisioned for a commercial well pair.)
- o Drilling a full-depth, full-bore production well
- o Flowing the well pair for about 2 years at a rate somewhat greater than commercial optimum to project long-term thermal performance

This test would be accompanied by other related activities, such as acquiring water rights and testing water-wells, carrying out HDR reservoir numerical thermal modeling, acquiring and interpreting additional geologic and geophysical data, drilling exploration and observation wells, and obtaining necessary permits. These activities either support the HDR reservoir test directly or reduce the risks associated with commercial development.

As shown in Figure 6-1, this industrial HDR experiment phase is expected to require approximately 5 years, from 1988 through 1992. The critical path in this part of the overall project schedule is drilling and completing the injection well, fracturing the reservoir, drilling the production well, and testing the well pair for 2 years. This sequence of activities requires 3-1/2 years; the injection well and the production well must be drilled and completed sequentially (requiring about 1-1/2 years for the onsite work for

Year	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996
Industrial HDR Experiment										
Drill and test a pair of test injection and production wells	X	~~XXXX~~	~~XXXX~~	~~XXXX~~	~~XXXX~~	~~XXX~~				
Secure water rights for 50 MWe HDR power facility		X	XXXX	XXX						
Drill and test two water wells				X	XXX					
Develop a numerical model to simulate, evaluate, and predict reservoir performance		X	XXXX	XXXX	XXXX	XXX				
Perform additional geology and geophysical evaluation		X	XXXX	X						
Drill exploration and observation wells		X	XXXX	XXXX	XXX					
Secure permits		XX								
Project Preliminary Design						XX				
Venture Formation						XX	~~XXX~~			
Negotiate power sales agreement						XX	XX			
Prepare permitting plan and submit initial applications						XX	XX			
Financing							XX	XX		
Final Design and Construction										
Wellfield										
Design and drill HDR injection and production wells								XX	XXXX	XX
Design and construct injection, gathering, and flash systems								XX	XXXX	XXX
Drill water wells and install pumps								XXXX	XXXX	
Construct make-up water pipeline								XX	XX	
Secure permits							XX	XX		
Power Plant										
Develop detail design for power plant							~~XX~~	XXXX	XXXX	XX
Construct power plant								~~XXXX~~	~~XXXX~~	~~XXX~~
Perform power plant startup										~~XX~~
Secure permits							XXXX			
— Critical Path										

Figure 6-1 HDR Project Schedule

the two test wells), and that is to be followed by a 2-year test. Thus, there are limited opportunities to significantly accelerate the activities on the critical path.

The cost of drilling and completing full-depth, full-bore wells and performing the prolonged testing (compared to most geothermal wells) required to provide performance data for the infant HDR technology is necessarily greater than a commercial geothermal resource developer can be expected to bear. Although estimating the costs for the test program was not addressed in depth, the funds required can be expected to be two to four times the \$10 million cost of an injection/production well pair. Because these experiments are critical steps proving the economic and technical feasibility of the technology, federal funding will be needed to advance HDR technology with this industrial HDR experiment at Roosevelt Hot Springs. Other parties, such as the State of Utah Energy Office, the resource lease holder, and contractors may costshare part of this test although no specific commitments have been made to date.

6.2.1 Test Injection and Production Wells

The data to be obtained from drilling and testing a pair of full-depth, full-bore wells are crucial to determining the economic feasibility of an HDR project.

The drilling and multilevel fracturing of an injection well and the targeted drilling of a production well involves no new technology. However, these activities have never been carried out in granitic rock at temperatures approaching 300°C (572°F), and they do involve vigorous application of existing fracturing techniques. Drilling and completing the test well pair should confirm the feasibility of this approach to create a reservoir.

A flow test lasting about 2 years will permit the thermal performance of the reservoir to be evaluated. This test will furnish actual reservoir data to determine whether the thermal performance meets requirements for commercial operation considering the costs of reservoir creation.

The industrial HDR experiment will provide valuable site-specific data that are significant to the economic projections. These data include more reliable estimates of hydraulic fracturing costs, a more accurate estimate of the pumping power required to circulate water through the reservoir, and information about the amount of water loss due to leakage from the reservoir.

About 6 months prior to the start of drilling for the HDR injection well, a network of seismic instrumentation should be installed to monitor the background earthquake activity. This network would be left in place and operated during the entire test and construction to alert the operators in the event of any increase in local seismic activity.

6.2.2 Water Supply

A water supply of approximately 450 gpm (730 acre-ft per year) is needed during the test period for operating the HDR test well pair; for a 50 MWe power plant, 3,900 gpm (6,300 acre-ft per year) will be needed for commercial operation. Therefore, water rights should be obtained, and at least two water wells should be drilled and tested during preparation for the HDR well test. In addition to supplying water for testing the HDR well pair, this will provide a realistic assessment of the cost and availability of the water required for commercial operation.

6.2.3 Numerical Model

Analytical reservoir computer models are not adequate for the more realistic predictions needed for commercial reservoir management. A numerical model should be developed and applied to provide needed reservoir management information. During the industrial HDR experiment, the model can be validated, refined, and used to evaluate the test results. Use of an improved reservoir model should reduce the risk involved in predicting the performance of the commercial well pairs.

6.2.4 Additional Geology and Geophysical Evaluation

To reduce the probability of reservoir installation problems, some additional geophysical surveys and evaluations should be conducted to enhance knowledge

of the geology in the HDR area. Most of the geophysical measurements to date have been centered on the hydrothermal area of the Roosevelt Hot Springs geothermal resource. Improved knowledge of the geology and the attendant improvement in expected hydraulic fracturing success should reduce the economic risk of the HDR project. Detailed seismic reflection and possibly refraction profiling within the planned HDR wellfield area should focus on locating fractures and lithologic contacts, and highlighting specific locations for detailed evaluation by exploratory drilling.

6.2.5 Exploration and Observation Wells

Presently, the lithology, temperature gradient, and other drilling and fracturing conditions expected for each HDR well must be inferred from depth-extrapolated geologic data. The well drilling and completion cost estimates as well as the probability of hydraulic fracturing success can be improved by drilling three or four full-depth (to 300°C) exploration and seismic observation wells throughout the area planned for the HDR wellfield. This should significantly reduce the economic risk associated with wellfield development by verifying deep thermal gradients, depth of the upper granodiorite contact, and the absence of open faults at the locations of planned HDR wells.

6.2.6 Permits

To conduct the industrial HDR experiment, permits are required as described in Section 5.

6.3 PROJECT PRELIMINARY DESIGN

Once the results of the industrial HDR experiment are available, a preliminary design of the HDR project at Roosevelt Hot Springs will be prepared to estimate costs and performance using more accurate and complete data than are presently available. This preliminary design should address all the facilities needed for the HDR project - HDR wells and reservoir, wellfield surface facilities (including the make-up water supply), the power plant, and any needed electrical transmission lines.

The cost and performance estimates resulting from this preliminary design form the basis for economic projections and permitting needed in the next two activities - venture formation and financing.

6.4 VENTURE FORMATION

Although informal discussions with potential venture participants should precede the start date indicated in Figure 6-1 for this phase, venture formation activity is expected to intensify once the preliminary design results are available for evaluation.

If the overall economics of the prospective HDR facility are sufficiently attractive to justify development, participants need to devise a business plan to carry out the project. The plan should provide for mutually beneficial ownership, financing, and commercial arrangements. As a part of the venture formation, binding agreements should be negotiated and signed among the following active participants:

- o Resource developer. The group of companies constituting the Roosevelt Hot Springs Unit, with Intermountain Geothermal Company as the operator, presently owns the resource rights in the area considered for the HDR facility. This group or a successor (that could be formed expressly for the HDR development) would be likely to participate as the resource developer. Specific commitments at today's early stage of development are premature. However, as results from the industrial HDR experiment show increasing potential, resource developer participation would be increasingly likely. Although for the first-of-a-kind plant, incentives greater than typical return on investment may be required. These might be in the form of state and/or federal tax incentives, low cost loans, energy subsidies, or other governmental participation.
- o Power plant owner. UP&L owns and operates the nearby 20 MWe geothermal plant using hydrothermal energy, and the HDR resource is within the UP&L service area. Therefore, UP&L should be considered as a possible power plant owner - similar to the arrangement for using the hydrothermal resource. However, in the event it is impractical for UP&L to participate in this role, other possibilities include one or more municipal utilities in Utah, the resource developer, a non-utility third party, or an out-of-state utility.

- o Power purchaser. If the power plant owner is not a utility, a purchaser for the electric power must be involved. Possibilities include UP&L, one or more municipal utilities in Utah, or an out-of-state utility.
- o Wheeling utility. If UP&L does not own the power plant and does not purchase the power, UP&L would probably be requested to use its transmission facilities to wheel the power to reach the ultimate electricity consumer. In that case, a wheeling agreement with UP&L would be negotiated.

During the venture formation phase, a permitting plan should be prepared as described in Section 5. As appropriate, initial applications should be filed during this phase to ensure timely receipt of necessary permits.

With formal agreements in place defining the roles and commitments of the active participants, the next phase is to secure financing for the non-equity investments needed for the project as discussed in Section 6.5.

6.5 FINANCING

In the course of developing the formal agreements among the HDR venture participants, needs for debt financing may be identified. Although discussions with possible lenders may begin prior to signing the venture formation documents, specific discussions are expected to intensify once the active participants agree on their various roles. Generally, the contract documents, such as the sales agreements, performance guaranties, and environmental permit applications, resulting from formal venture formation are needed to secure commitments from lenders.

The project schedule in Figure 6-1 shows completion of the financing phase before start of construction. However, prior project experience indicates that construction may be started using equity funds or construction loans before long-term loan arrangements are completed.

6.6 FINAL DESIGN AND CONSTRUCTION

The critical path for final design and construction is the schedule for power plant design and construction. Power plant construction is expected to

require approximately 3 years, with intensive design work starting about 6 months before start of construction. The wellfield drilling and construction can be fitted to the power plant schedule.

6.6.1 Wellfield

Injection and Production Wells. Each of the commercial HDR well pairs is expected to require about 1 year to complete. Figure 6-1 shows four well pairs being drilled and completed using two drill rigs for a total time of 2 years. This part of the wellfield development must be completed in time to furnish hot water to perform startup operations for the power plant.

Injection, Gathering, and Flash Systems. These wellfield surface facilities must be completed in time to furnish steam to the power plant for testing and startup. Figure 6-1 shows that this part of the construction will take 2-1/4 years to complete; however, the construction activities are sufficiently independent that several crews could work simultaneously and reduce this time appreciably. A more rapid schedule may be considered as an optional approach. The important point in this part of the construction is the completion date; the wellfield must be sufficiently complete to furnish steam to the power plant during startup.

Water Wells. The water wells drilled for the industrial HDR experiment can be used to furnish water for the drilling operations associated with the commercial HDR wells. However, greater quantities of water are needed for the hydraulic fracturing operations. The first commercial hydraulic fracturing operation is scheduled for mid-1995; therefore, a sufficient number of water wells must be completed by the second quarter of 1995 to furnish water for this operation.

Nine of the total of thirteen water wells should be completed by early 1996 to supply water for HDR well testing and facility startup. These nine water wells are sufficient for initial facility operations; therefore, drilling of the remaining water wells could be deferred until later in the life of the plant, as additional HDR wells are drilled.

Make-Up Water Pipeline. The pipeline from the water wells to the vicinity of the HDR wells should be installed in time to furnish water for hydraulic fracturing the first commercial HDR well in mid-1995.

Permits. To do the drilling and construction for the wellfield, permits are required as described in Section 5. Stipulations in the permits may require establishing monitoring stations for certain sensitive parameters if any are identified by the permitting agencies.

6.6.2 Power Plant

The schedule for power plant design and construction is dominated by the time required to specify, obtain, install, and start up the turbine-generator unit. Other activities are coordinated with these considerations.

Detail Design. The early detail design activities address the specifications for large items, such as the turbine-generator, condenser, and cooling tower owing to the procurement lead times for these items. The civil-structural design should also start reasonably early to prepare for the first site work.

Power plant design usually takes a fast-track approach with construction starting before design completion. Once construction begins, design and construction proceed simultaneously until the plant is nearly complete. The schedule shown in Figure 6-1 is based on concurrent design and construction activities.

Construction. The earliest construction activities involve site preparation and the installation of civil-structural items, such as turbine pedestal and cooling tower basin, to prepare for orderly installation of the major mechanical items - turbine-generator, condenser, and cooling tower. The critical path runs from installation of the turbine pedestal, to erection of the turbine-generator, through to completion of testing and startup.

Permits. To construct the power plant, permits are required as described in Section 5. As for the wellfield permits, stipulations in the permits may

require the establishment of monitoring stations for certain sensitive parameters if any are identified by the permitting agencies.

6.7 OVERALL SCHEDULE

The schedule in Figure 6-1 indicates that about 10 years would be required for the needed testing through design and construction, with 1997 being the first full year of commercial operation. This schedule is a deliberate one. Some of the activities could be accelerated a bit and others could be overlapped rather than sequential. On the whole, it may be possible to accelerate the total schedule 1 to 2 years, if necessary.

Section 7

ECONOMIC AND RISK ASSESSMENT

The primary objectives of the economic and risk assessment are to establish the cost of electricity generation from an HDR project at Roosevelt Hot Springs and to investigate the commercial viability of developing this HDR resource. Sensitivity and risk analyses were also conducted to determine the sensitivity to the main cost components and technical uncertainties that would affect the cost of energy production.

7.1 METHODS OF ANALYSIS

The costs of steam and electricity production were developed on a levelized basis to project a constant level of revenue required to recover all expenses incurred in constructing and operating a facility over its economic lifetime.

7.1.1 Ownership Arrangement

In calculating the production costs, the following ownership arrangement was adopted to reflect the expected venture formation and the corresponding costs of capital:

- o The HDR wellfield would be developed and operated by a non-utility resource developer.
- o The power plant would be owned and operated by UP&L since the HDR resource under consideration is within its service area.

7.1.2 Economic Analysis Model

An economic analysis model was designed to provide two types of information about an HDR power project. First, it projects revenue requirements, which is the principal criterion used by the utility industry to compare generation alternatives. Second, the model forecasts the wellfield financing requirements, net income, and cash flow. Financing requirements and income projections assist resource developers in estimating the impact of such a

project on their financial plans and financial accounting statements. Cash flow results can be used to identify situations where expected returns are sufficient to attract investment.

7.1.3 Revenue Requirements Estimates

The methodology used to forecast revenue requirements is based on the regulatory principal that revenue should be set to ensure that a utility earns a "fair return" on assets. This is usually equivalent to the ratio of its operating income to its rate base. Operating income is the difference between a utility's reported revenue and operating expenses, which include operating and maintenance costs, book depreciation and amortization, property taxes and insurance, income taxes, and fuel cost. For an HDR project, the fuel cost is the cost of steam. The rate base is the sum of the capital costs including an allowance for funds used during construction less accumulated depreciation and deferred income taxes. The allowed return is usually equal to the utility's weighted cost of debt and equity capital.

To estimate annual revenue requirements, the elements of revenue requirements were grouped into three principal components:

- o Carrying (fixed) charges, which include debt and equity return plus depreciation and taxes
- o Operating costs, which consist of fixed and variable operating and maintenance costs
- o Cost of steam

Estimating revenue requirements for an HDR power project involves developing year-by-year forecasts and levelized costs for carrying charges, operating costs, and steam costs and then adding them to arrive at total revenue requirements.

The cost of steam for the economic evaluation of the HDR technology may be different from that used in the wellfield financial analysis. The cost of steam used for economic evaluation of the HDR technology reflects an assumed rate of return to a resource developer, normalized to a per kWh basis. By

contrast, the cost of steam used for wellfield financial analysis reflects expected energy payments by the operator of the power plant to the resource developer.

Revenue requirements were developed on both a current dollar and constant dollar basis. However, to avoid confusion, only the constant dollar results are reported here except for Section 7.6, which treats current (nominal) dollars. The advantage of this approach is that the results can be directly compared with present-day production costs. The least error prone procedure for estimating constant dollar revenue requirements is to first project annual revenue requirements in current (inflated) dollars and then deflate the current dollar results to the desired base year using the anticipated inflation rate. Discounting and levelization calculations are performed in the same manner as for current dollar analysis except that a constant dollar discount rate and constant dollar annuity factors are used.

The wellfield financial analysis, on the other hand, was performed in current dollars that reflect the actual year a project of this kind would be commercially available. As stated in Section 6, an HDR power project at Roosevelt Hot Springs is projected to be commercially available in 1997.

7.2 ECONOMIC PARAMETERS AND ASSUMPTIONS

Table 7-1 shows the economic parameters used in the economic analysis for the power plant and the wellfield.

Table 7-1

ECONOMIC PARAMETERS

<u>Parameter</u>	<u>Value</u>
State and federal tax rate, %	37.0
Property tax and insurance rate, %	1.5
General inflation rate, %	4.0
Escalation rate for construction costs, %	3.0 to 1997 4.0 thereafter
Escalation rate for O&M expenses, %	4.0
Investment tax credits, %	0.0
Facilities economic life, yr	30
Facilities tax life, yr	15

The income tax rate is a combined state and federal tax rate and is approximately 37 percent in the state of Utah.

The property tax and insurance rate is the ratio of the anticipated expenditures for property taxes and insurance to the accumulated plant and owner's costs.

To conform with the federal tax law enacted in 1986, investment tax credits are taken as zero on capital cost items.

The depreciation schedules in the economic analysis use the revised Accelerated Capital Recovery System (ACRS) in the Economic Recovery Tax Act (1981). Under ACRS, the cost of investments in this type of depreciable property are recovered on an accelerated basis (150 percent declining balance method) with no allowance for inflation.

For the wellfield, 80 percent of intangible drilling costs is expensed in the year incurred, and the remaining 20 percent is amortized over a 3-year period following the year the costs are incurred.

Resource depletion costs are recovered using the percentage depletion method. Under this method, 15 percent of the resource developer's gross income from the HDR property is allowed as a deduction in any taxable year not to exceed 50 percent of the net income from the HDR wellfield property.

Table 7-2 presents the assumed capital structures of the resource developer and the power plant owner.

Table 7-2
CAPITAL STRUCTURE OF THE HDR PROJECT
VENTURE PARTICIPANTS

<u>Item</u>	<u>Resource Developer</u>	<u>Power Plant</u>
Debt ratio, %	30.0	48.7
Preferred stock, %	-	5.6
Common stock, %	70.0	45.7
Return on debt, %	9.5	9.5
Return on preferred, %	-	8.1
Return on common, %	18.0	15.0

These capital structures reflect typical debt and equity terms for investor-owned utilities and resource developers. The resulting weighted cost of capital for the utility is 12.0 percent, and the corresponding real discount rate is 7.7 percent. For the resource developer, the weighted cost of capital is 15.5 percent, and the corresponding real discount rate is 11.0 percent. The 18 percent return on the resource developer's equity is assumed for the risks involved in the resource development component of this HDR project.

7.3 COST OF ELECTRICITY PRODUCTION

Tables 7-3 through 7-5 show the base case data used to estimate the cost of electricity generation for an HDR project at Roosevelt Hot Springs. Table 7-6 and Figure 7-1 summarize the levelized cost of steam production and the cost of electricity. Based on the economic parameters and assumptions in Section 7.2, the levelized cost of steam production in constant 1987 dollars is 28.2 mills/kWh, and the total cost of electricity generation from an HDR project is 49.8 mills/kWh.

Figure 7-2 shows how the cost of electricity production from an HDR power project compares to the cost for other power options that are commercially available in the state of Utah. The capital and operating costs used in evaluating these alternative power technologies represent conceptual level estimates from Bechtel's database. These cost estimates are summarized in Appendices F and G. The fuel cost for the coal-fired technologies is \$1.50/MM Btu. This comparison of revenue requirements suggests that an HDR project could produce electric energy at a cost that is competitive with that of new coal-fired plants with flue gas desulfurization systems (100 to 200 MW) and circulating fluidized bed fossil plants (150 MW).

The levelized cost of electricity production from a 50 MWe hydrothermal power plant at Roosevelt Hot Springs, on the other hand, is approximately 17 mills/kWh lower than for HDR; this difference is due primarily to lower drilling and completion costs for a hydrothermal power plant and to higher plant output capacity needed to supply pumping power for HDR wellfield operation. With this economic advantage, the hydrothermal resource at Roosevelt Hot Springs will probably be developed there before aggressive commercialization of HDR. Estimates of the hydrothermal resource at

Table 7-3

BASE CASE WELLFIELD INITIAL AND O&M COSTS**INITIAL CAPITAL COSTS (1987 \$ millions)**

Surface Facilities	9.30	
Tangible well costs	4.36(a)	
Total Tangible Wellfield Costs		13.66
Capitalized Interest		2.66
Total Wellfield Investment		16.32
Preproduction Costs		1.08
Initial Materials		0
Lease Costs (Already acquired for hydrothermal)		0
Land (Acquired with hydrothermal leases - no additional cost)		0
Total Initial Capital Costs		17.4
INTANGIBLE DRILLING COSTS (1987 \$ millions)		35.22(a)

OPERATING AND MAINTENANCE COSTS

Fixed O&M Costs (1987 \$ millions per year)	1.35
Variable O&M Costs	
Make-Up Water Acquisition (mills/kWh)	0.45
Geothermal Resource Royalties	10 % of wellfield gross receipts
Electrical Power (Varies year by year - see Table 7-4)	

(a) The total of tangible and intangible drilling costs is \$39.58 million. This is \$700,000 less than four times the \$10.07 cost of a typical well pair given in Table 3-6. The difference results from adjustments to mobilization costs and to repeated use of a single frac pond.

Table 7-4

**BASE CASE POWER PRODUCTION AND CONSUMPTION
AND REDRILLING COSTS BY YEAR**

Year	Net Power Output (MWe)	Pumping Power (MWe)	Salable Power (MWe)	Redrilling Costs (1987 \$ millions)	
				Tangible (a)	Intangible
1997	54.4	6.2	48.2	0	0
1998	53.7	6.2	47.5	0	0
1999	51.6	6.3	45.3	0	0
2000	57.8	7.8	50.0	2.68	8.91
2001	57.9	7.9	50.0	0	0
2002	55.8	8.0	47.8	0	0
2003	59.5	9.5	50.0	2.68	8.91
2004	59.6	9.6	50.0	0	0
2005	58.8	9.7	49.2	0	0
2006	55.2	9.7	45.5	0	0
2007	61.2	11.2	50.0	2.68	8.91
2008	61.3	11.3	50.0	0	0
2009	58.5	11.4	47.1	0	0
2010	62.9	12.9	50.0	2.68	8.91
2011	63.0	13.0	50.0	0	0
2012	61.5	13.1	48.4	0	0
2013	64.6	14.6	50.0	2.68	8.91
2014	64.7	14.7	50.0	0	0
2015	64.3	14.7	49.6	0	0
2016	61.2	14.8	46.4	0	0
2017	66.3	16.3	50.0	2.68	8.91
2018	66.4	16.4	50.0	0	0
2019	65.8	16.5	49.4	0	0
2020	62.8	16.5	46.3	0	0
2021	68.0	18.0	50.0	2.68	8.91
2022	68.1	18.1	50.0	0	0
2023	68.2	18.2	50.0	0	0
2024	64.8	18.2	46.6	0	0
2025	69.8	19.8	50.0	2.68	8.91
2026	69.9	19.9	50.0	0	0

(a) Includes cost of additional surface facilities

Table 7-5

BASE CASE POWER PLANT COSTS**CAPITAL COSTS (1987 \$ millions)**

Plant Costs (a)	55.2	
Transmission Line	1.3	
Total Power Plant Costs		56.5
Allowance for Funds Used During Construction (AFDC)		10.5
Royalties		0
Preproduction Costs		1.9
Inventory Capital		0
Initial Materials		0
Land (Acquired with hydrothermal leases - no additional cost)		0
Total Capital		68.9

OPERATING AND MAINTENANCE COSTS

Fixed O&M (1987 \$ millions per year)	2.26
Variable O&M (mills/kWh)	0

(a) Process capital, general facilities, engineering costs, project contingency, and process contingency.

Table 7-6

LEVELIZED COST OF STEAM AND ELECTRICITY PRODUCTION

WELLFIELD

Reservoir		
Carrying Charges (a)	4.1 mills/kWh	
Operating and Maintenance	8.1	
Expensed Drilling Costs	7.3	
Reservoir Subtotal		19.5

Redrilling		
Carrying Charges	2.2	
Expensed Drilling	3.7	
Redrilling Subtotal		5.9

Royalties		2.8

Wellfield Total		28.2

POWER PLANT

Carrying Charges	16.7	
Operating and Maintenance	4.9	

Power Plant Total		21.6

Total Levelized Cost (a)		49.8 mills/kWh

(a) Constant 1987 dollars

Figure 7-1 Levelized Cost of Steam and Electricity Production

Figure 7-2 Cost of Electricity Production

Roosevelt Hot Springs indicate that the addition of one to four 50 MWe plants could make use of the maximum capacity. Therefore, the hydrothermal resource is likely to be fully committed by the time HDR testing can be completed and a commercial HDR plant can be built. After the hydrothermal resource is totally committed, HDR could provide a competitively priced electric generation option in the future.

7.4 SENSITIVITY ANALYSES

A number of sensitivity analyses were performed to determine the impact of variations in the cost estimates of components. We evaluated the impact of a reasonable range of variation from the base case assumptions with respect to the following major factors:

- o Intangible and tangible drilling costs
- o Capital cost of wellfield surface facilities
- o Wellfield fixed O&M cost
- o Capacity factor
- o Return on equity - wellfield
- o Power plant capital cost
- o Power plant O&M cost

For each of the cost components, variations of +25 percent were used to test the sensitivity of revenue requirements to uncertainties in the estimated costs. The +25 percent variations were selected arbitrarily to test sensitivity. They are arbitrary variations selected to identify the cost components having the greatest influence on project economics; they are not estimates of uncertainty. In future evaluations, once the most influential cost components are identified, we can assign higher priority to achieving cost reductions by design modifications, develop accurate cost estimates, and devise risk management strategies for these components. Less influential cost components can be addressed later.

Likewise, arbitrary increments were assigned to capacity factor and to return on wellfield equity to test the sensitivity of project economics to these two

variables. Again, these are not estimates, projections, or predictions; they are arbitrarily chosen increments to test economic sensitivity.

The results of the sensitivity analyses of steam and electricity production costs are shown in Table 7-7. When the major cost components of the wellfield facilities are individually varied by 25 percent in both directions from the base case estimates, steam production cost changes by a maximum of 4.1 mills/kWh from the base case figure of 28.2 mills/kWh. This maximum deviation is for the intangible drilling costs; it could also represent sensitivity to the possibility that drilling may not be completely successful.

The impact of a 5 percent change in the capacity factor results in a deviation of approximately 3 mills/kWh from the base case estimate. A 2 percentage point change in the assumed return on equity for the wellfield implies a change of approximately 2 mills/kWh in the revenue requirements.

The effect of a 25 percent variation in power plant capital cost is significant, with a deviation of about 4.6 mills/kWh from the base case. However, the effect of a 25 percent variation in power plant O&M cost is relatively minor, with a maximum deviation of 1.3 mills/kWh.

In general, these results indicate that the sensitivity to changes in any one of these factors is moderate; therefore, steam and electricity costs are not highly sensitive to variations in any single cost component.

7.5 ALTERNATIVE POWER PLANT AND WELLFIELD OWNERSHIP

The cost of electricity production for an HDR power project is heavily dependent on the assumed capital structure. For example, if UP&L were to develop the HDR resource and operate the power plant, the revenue requirements for electricity production would decrease from 49.8 to 45.4 mills/kWh in constant 1987 dollars.

Table 7-7

SENSITIVITY OF REVENUE REQUIREMENTS TO COST COMPONENTS

Cost Component	Base Case	Sensitivity Test	Cost of Steam (mills/kWh) (a)	Power Plant Costs (mills/kWh) (a)	Total (mills/kWh) (a)
Base Case	-	-	28.2	21.6	49.8
Intangible drilling cost	\$35.16 million	-25% to +25%	24.2 to 32.3	21.6	45.8 to 53.9
Tangible drilling cost	\$4.36 million	-25% to +25%	27.6 to 28.8	21.6	49.2 to 50.4
Wellfield surface facilities	\$9.30 million	-25% to +25%	26.8 to 29.6	21.6	48.4 to 51.2
Wellfield fixed O&M	\$1.35 million/yr	-25% to +25%	27.3 to 29.1	21.6	48.9 to 50.7
Capacity factor	90%	85% to 95%	29.9 to 26.7	22.9 to 20.5	52.8 to 47.2
Return on equity-wellfield	18%	16% to 20%	26.4 to 30.2	21.6	48.0 to 51.8
Power plant capital cost	\$56.5 million	-25% to +25%	28.2	17.0 to 26.0	45.2 to 54.2
Power plant fixed O&M	\$2.3 million/yr	-25% to +25%	28.2	20.4 to 22.9	48.6 to 51.1

(a) Constant 1987 dollars

Another ownership arrangement could involve a resource developer as a sole owner and operator of an HDR project and local municipality, such as Utah Association of Municipal Power Systems (UAMPS), as purchaser of plant electrical output. Based on an assumed return on equity of 18 percent, the total cost of production is 58.8 mills/kWh, 9.0 mills/kWh higher than the base case. This total cost of production figure, however, is very sensitive to the developer's assumed return on equity. A 2 percentage point variation in the developer's assumed return on equity would result in a deviation of 5.6 mills/kWh. Hence, at an assumed return of 15 percent, the levelized cost of electricity production would be 53.0 mills/kWh, which is approximately what UAMPS currently pays Intermountain Power Project for electricity.

7.6 WELLFIELD FINANCIAL ANALYSIS

The revenue requirements approach is used in Sections 7.1 through 7.5 to investigate whether electric energy from an HDR power plant at Roosevelt Hot Springs could be cost competitive with other electric generation sources. In this section, the cash flow/internal rate of return approach is used for wellfield financial analysis to begin evaluating an HDR project at Roosevelt Hot Springs from a resource developer's perspective.

The revenue requirements approach (used in Sections 7.1 through 7.5) and the cash flow/internal rate of return approach (used in this section) are two different ways of evaluating a project based on different perceptions of the selling price for the product (steam in this case). The revenue requirements approach estimates a required selling price that is needed to earn a prescribed rate of return on equity. By contrast, the cash flow/internal rate of return approach starts with a selling price for the product and estimates the revenues, expenses, net cash flows, and internal rate of return (i.e., the discount rate to yield zero for the net present value of positive and negative cash flows). The revenue requirements approach is used extensively by the regulated electric utility industry where selling price is set by the regulators to yield an allowed return on equity. However, the cash flow/internal rate of return approach is commonly used by unregulated resource developers where the selling price for a product (oil, natural gas, coal, gold, aluminum, etc.) is set by market conditions without regard for

production costs. Because the product of an HDR wellfield is steam that can be used by a dedicated power plant, neither approach is adequate for use by a regulated utility and an unregulated resource developer. This section presents some sample results using the cash flow/internal rate of return approach to supplement the revenue requirements results discussed in Sections 7.1 through 7.5.

As mentioned in Section 7.1, the economic analysis model was also designed to provide preliminary financial statements including the projected cash flow and internal rate of return for the HDR resource.

Tables 7-8 and 7-9 present sample financial statements of revenue, expenses, and cash flow based on a steam price of 28 mills/kWh in 1987 dollars escalated to the year indicated.

Several steam prices ranging from 15 to 30 mills/kWh (in 1987 dollars) were considered to establish a relationship between steam prices and internal rate of return for the resource developer as illustrated in Figure 7-3. The lower end of this price range approximates the energy payment to qualifying facilities by Utah utilities under currently available PURPA agreements. The energy price offered by UP&L to qualifying facilities and small power producers was recently reduced from 21 to 13 mills/kWh due to lower avoided fuel costs. The high end of this price range reflects the levelized cost of production based on revenue requirements as established in Section 7.3.

Although Figure 7-3 was generated by calculating the internal rate of return anticipated for various steam prices, it can be used to estimate the steam price needed for a specified internal rate of return. For example, the allowed rate of return on common stock for an investor-owned electric utility company is typically about 15 percent. This value, which is appropriate for relatively low risk utility company investment, probably represents a lower limit for internal rate of return expected by resource developers. Figure 7-3 indicates that for a 15 percent internal rate of return, the steam price must be approximately 29 mills/kWh (in 1987 dollars). Thus, a steam price of 29 mills/kWh (in 1987 dollars) probably represents a minimal incentive for

Table 7-8

PRO FORMA STATEMENT OF REVENUES AND EXPENSES — 28 MILLS/kWh (IN 1987 \$) FOR STEAM
(Current \$ Millions)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Revenues from sales				17.8	18.2	18.2	21.2	22.1	22.2	24.6	25.6	26.3	25.7	29.6	30.8	30.6
Operating expenses																
Variable O&M				2.3	2.4	2.5	3.2	3.4	3.5	4.3	4.5	4.8	4.9	5.9	6.2	6.5
Fixed O&M				2.0	2.1	2.2	2.2	2.3	2.4	2.5	2.6	2.7	2.8	3.0	3.1	3.2
Royalties 10%				1.8	1.8	1.8	2.1	2.2	2.2	2.5	2.6	2.6	2.6	3.0	3.1	3.1
Subtotal				6.1	6.3	6.5	7.6	7.9	8.2	9.3	9.7	10.1	10.3	11.8	12.3	12.7
Operating income				11.7	11.9	11.7	13.7	14.2	14.0	15.3	15.9	16.2	15.3	17.8	18.5	17.9
Other expenses																
Depreciation				2.3	2.1	1.9	1.8	1.7	1.5	1.7	1.7	1.7	1.7	2.0	2.0	2.0
Amortization				3.2	3.2	3.2	0.9	0.9	0.9	1.0	1.0	1.0	0.0	1.2	1.2	1.2
Property tax & ins				0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Intangible drilling	10.4	14.3	11.0	0.0	0.0	0.0	10.8	0.0	0.0	12.1	0.0	0.0	0.0	14.2	0.0	0.0
Subtotal	10.4	14.3	11.0	5.8	5.5	5.3	13.8	2.9	2.7	15.1	3.0	3.0	2.0	17.6	3.5	3.5
EBIT	(10.4)	(14.3)	(11.0)	5.9	6.4	6.4	(0.2)	11.3	11.3	0.1	12.9	13.2	13.3	0.2	15.0	14.4
Interest				0.6	0.5	0.4	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.1
Taxable income before depletion allowance	(10.4)	(14.3)	(11.0)	5.3	5.9	6.0	(0.4)	11.1	11.2	0.1	12.7	13.0	13.2	0.1	14.9	14.3
Depletion allowance	0.0	0.0	0.0	2.7	2.7	2.7	0.0	3.3	3.3	0.0	3.8	3.9	3.9	0.1	4.6	4.6
Taxable income	(10.4)	(14.3)	(11.0)	2.7	3.2	3.3	(0.4)	7.8	7.9	0.0	8.9	9.1	9.4	0.1	10.2	9.7
Taxes @ 37%	(3.8)	(5.3)	(4.1)	1.0	1.2	1.2	(0.1)	2.9	2.9	0.0	3.3	3.4	3.5	0.0	3.8	3.6
Net income	(6.5)	(9.0)	(6.9)	1.7	2.0	2.1	(0.2)	4.9	5.0	0.0	5.6	5.7	5.9	0.0	6.4	6.1

Table 7-8 (Cont'd)

PRO FORMA STATEMENT OF REVENUES AND EXPENSES – 28 MILLS/kWh (IN 1987 \$) FOR STEAM
(Current \$ Millions)

	2010.	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Revenues from sales	34.2	35.6	36.2	39.5	41.2	42.6	42.1	47.5	49.4	51.0	50.6	57.0	59.3	61.8	61.1	68.4	71.2
Operating expenses																	
Variable O&M	7.6	7.9	8.3	9.6	10.0	10.4	10.9	12.4	13.0	13.6	14.1	16.0	16.7	17.5	18.1	20.5	21.4
Fixed O&M	3.3	3.5	3.6	3.7	3.9	4.0	4.2	4.4	4.6	4.7	4.9	5.1	5.3	5.5	5.8	6.0	6.2
Royalties 10%	3.4	3.6	3.6	4.0	4.1	4.3	4.2	4.7	4.9	5.1	5.1	5.7	5.9	6.2	6.1	6.8	7.1
Subtotal	14.3	15.0	15.5	17.3	18.0	18.7	19.3	21.6	22.5	23.4	24.1	26.8	28.0	29.2	30.0	33.3	34.8
Operating income	19.9	20.7	20.7	22.3	23.2	23.8	22.8	25.9	26.9	27.5	26.5	30.1	31.3	32.6	31.1	35.1	36.5
Other expenses																	
Depreciation	2.3	2.3	1.0	1.4	1.4	1.4	1.4	2.2	2.2	2.2	2.2	3.8	3.8	3.8	3.8	9.2	9.2
Amortization	1.3	1.3	1.3	1.5	1.5	1.5	0.0	1.7	1.7	1.7	0.0	2.0	2.0	2.0	0.0	2.4	2.4
Property tax & ins	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Intangible drilling	16.0	0.0	0.0	17.9	0.0	0.0	0.0	21.0	0.0	0.0	0.0	24.6	0.0	0.0	0.0	28.7	0.0
Subtotal	19.9	4.0	2.6	21.2	3.2	3.2	1.7	25.3	4.3	4.3	2.5	30.7	6.1	6.1	4.1	40.6	11.9
EBIT	0.0	16.7	18.1	1.1	19.9	20.6	21.1	0.6	22.7	23.3	24.0	(0.5)	25.2	26.5	27.0	(5.5)	24.6
Interest	0.1	0.2	0.2	0.1	0.3	0.2	0.1	0.1	0.3	0.2	0.1	0.1	0.3	0.2	0.2	0.1	0.4
Taxable income before depletion allowance	(0.1)	16.5	17.9	1.0	19.7	20.4	21.0	0.6	22.4	23.1	23.8	(0.6)	24.9	26.3	26.8	(5.6)	24.2
Depletion allowance	0.0	5.3	5.4	0.5	6.2	6.4	6.3	0.3	7.4	7.6	7.6	0.0	8.9	9.3	9.2	0.0	10.7
Taxable income	0.0	11.2	12.5	0.5	13.5	14.0	14.7	0.3	15.0	15.4	16.2	(0.6)	16.0	17.0	17.7	(5.6)	13.5
Taxes @ 37%	0.0	4.1	4.6	0.2	5.0	5.2	5.4	0.1	5.5	5.7	6.0	(0.2)	5.9	6.3	6.5	(2.1)	5.0
Net income	0.0	7.0	7.9	0.3	8.5	8.8	9.2	0.2	9.4	9.7	10.2	(0.4)	10.1	10.7	11.1	(3.5)	8.5

Table 7-9

CASH FLOW ANALYSIS — 28 MILLS/kWH (IN 1987 \$) FOR STEAM
(Current \$ Millions)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Net income	(6.5)	(9.0)	(6.9)	1.7	2.0	2.1	(0.2)	4.9	5.0	0.0	5.6	5.7	5.9	0.0	6.4	6.1
Non cash expenditures																
Depreciation				2.3	2.1	1.9	1.8	1.7	1.5	1.7	1.7	1.7	1.7	2.0	2.0	2.0
Amortization				3.2	3.2	3.2	0.9	0.9	0.9	1.0	1.0	1.0	0.0	1.2	1.2	1.2
Depletion allowance				2.7	2.7	2.7	0.0	3.3	3.3	0.0	3.8	3.9	3.9	0.1	4.6	4.6
Subtotal	0.0	0.0	0.0	8.1	8.0	7.8	2.7	5.9	5.7	2.8	6.6	6.7	5.6	3.2	7.8	7.8
Repayment of principal				1.3	1.3	1.3	1.3	1.5	0.2	0.2	0.5	0.5	0.3	0.3	0.6	0.3
Cash from operations	(6.5)	(9.0)	(6.9)	8.5	8.7	8.6	1.2	9.3	10.5	2.5	11.6	11.9	11.2	3.0	13.6	13.6
Intangible drilling amortized	2.6	3.6	2.8	0.0	0.0	0.0	2.7	0.0	0.0	3.0	0.0	0.0	0.0	3.5	0.0	0.0
Equity outlays	3.8	5.2	4.0	0.0	0.0	0.0	2.8	0.0	0.0	3.2	0.0	0.0	0.0	3.7	0.0	0.0
Net cash flow	(12.9)	(17.8)	(13.7)	8.5	8.7	8.6	(4.3)	9.3	10.5	(3.7)	11.6	11.9	11.2	(4.3)	13.6	13.6
Internal rate of return = 14.3																
First year of operation 1997																

Table 7-9 (Cont'd)

CASH FLOW ANALYSIS – 28 MILLS/kWH (IN 1987 \$) FOR STEAM
(Current \$ Millions)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Net income	0.0	7.0	7.9	0.3	8.5	8.8	9.2	0.2	9.4	9.7	10.2	(0.4)	10.1	10.7	11.1	(3.5)	8.5
Non cash expenditures																	
Depreciation	2.3	2.3	1.0	1.4	1.4	1.4	1.4	2.2	2.2	2.2	2.2	3.8	3.8	3.8	3.8	9.2	9.2
Amortization	1.3	1.3	1.3	1.5	1.5	1.5	0.0	1.7	1.7	1.7	0.0	2.0	2.0	2.0	0.0	2.4	2.4
Depletion allowance	0.0	5.3	5.4	0.5	6.2	6.4	6.3	0.3	7.4	7.6	7.6	0.0	8.9	9.3	9.2	0.0	10.7
Subtotal	3.6	9.0	7.7	3.4	9.1	9.3	7.8	4.3	11.4	11.6	9.8	5.8	14.7	15.1	12.9	11.6	22.2
Repayment of principal	0.3	0.7	0.7	0.4	0.8	0.8	0.4	0.4	0.9	0.5	0.5	0.5	1.0	0.6	0.6	0.6	3.8
Cash from operations	3.3	15.4	14.9	3.4	16.8	17.4	16.6	4.0	20.0	20.9	19.6	5.0	23.8	25.2	23.5	7.5	27.0
Intangible drilling amortized	4.0	0.0	0.0	4.5	0.0	0.0	0.0	5.2	0.0	0.0	0.0	6.1	0.0	0.0	0.0	7.2	0.0
Equity outlays	4.2	0.0	0.0	4.7	0.0	0.0	0.0	5.5	0.0	0.0	0.0	6.5	0.0	0.0	0.0	7.6	0.0
Net cash flow	(4.9)	15.4	14.9	(5.8)	16.8	17.4	16.6	(6.7)	20.0	20.9	19.6	(7.6)	23.8	25.2	23.5	(7.3)	27.0

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Figure 7-3 Internal Rate of Return for HDR Resource Developer

installing and operating an HDR wellfield at Roosevelt Hot Springs.

Realistically, a higher steam price and/or additional incentives are likely to be required, especially for the first-of-a-kind plant with higher than normal risks.

7.7 RISK ASSESSMENT

In the design of the base case HDR facility, the following were identified as prominent performance characteristics that cannot be confidently predicted at present:

- o Well pair productivity (i.e., effective heat transfer area per HDR well pair)
- o Well pair depletion rate (i.e., long-term thermal performance)

- o Reservoir leakage
- o Injection pumping losses

This section summarizes the potential economic impact of these technical risk areas. This is done by evaluating the effect on revenue requirements of variations of these characteristics from the values used in the design of the base case facility.

7.7.1 Well Pair Productivity

The base case design assumes the following two conditions:

- o The effective heat transfer area produced per fracture interval is $100,000 \text{ m}^2$ ($1,080,000 \text{ ft}^2$) initially.
- o The effective heat transfer area doubles within the first year of operation (2X growth of heat transfer area).

As discussed in Section 3.3, both of these design assumptions appear reasonable and probably conservative. Well pair productivity after early growth of the heat transfer area is determined by the product of these two effects (i.e., the effective heat transfer area per fracture interval after a year). The product used for the base case design is $200,000 \text{ m}^2$ ($2,160,000 \text{ ft}^2$) per fracture interval. Based on indications to date from Fenton Hill and Rosemanowes and on the aggressive hydraulic fracturing program in Section 3 for the reservoir conceptual design, productivity is likely to be equivalent to heat transfer area in excess of $400,000 \text{ m}^2$ ($4,320,000 \text{ ft}^2$) per fracture interval after a year of operation. Effective heat transfer area of this size or greater could improve project economics markedly.

For $400,000 \text{ m}^2$ ($4,320,000 \text{ ft}^2$) of effective heat transfer area per fracture interval, the revenue requirement decreases from 49.8 to 39.7 mills/kWh as shown in Figure 7-4 and Table 7-10. This would considerably increase the margin between HDR electricity production cost and the costs for coal generation. Such an increased margin could provide for transmission costs to a tie-point to better compete with coal, serve as a buffer against possible adverse project cost experience, and provide additional incentive for risk-taking by the resource developer. There is a caveat: Although this

Figure 7-4 Energy Cost Effect of Reservoir Productivity

level of reservoir productivity is possible based on reasonable extrapolations of results from Fenton Hill and Rosemanowes, it needs to be thoroughly demonstrated by actual test results before basing investment decisions on it.

On the other hand, lower reservoir productivity could severely damage the project economic performance. If the heat transfer area per fracture interval after a year were $100,000 \text{ m}^2$ ($1,080,000 \text{ ft}^2$), the revenue requirements would be increased 16.5 mills/kWh, from 49.8 to 66.3 mills/kWh. Since the cost of coal-generated electric energy is about 52 mills/kWh, the higher revenue requirement implies that an HDR facility with this assumed low well pair productivity could not compete with coal.

Well pair productivity is pivotal with respect to project economics. The economic projections implied by the base case may be too pessimistic if greater effective heat transfer area can be created; however, lower productivity could be economically damaging for a commercial project.

Table 7-10

EFFECTS OF WELL PRODUCTIVITY ON REVENUE REQUIREMENTS

Item	Number of Initial Well Pairs	Number of Additional Well Pairs	Wellfield Revenue Requirement (a) (mills/kWh)	Power Plant Revenue Requirement (a) (mills/kWh)	Total Revenue Requirement (a) (mills/kWh)	Difference from Base Case (mills/kWh)
Base Case 100,000 sq m per Fracture Interval 2X Growth within One Year	4	8	28.2	21.6	49.8	-
200,000 sq m per Fracture Interval 2X Growth within One Year	2	4	18.2	21.5	39.7	-10.1
100,000 sq m per Fracture Interval No Growth During Operation	7	16	44.5	21.8	66.3	16.5

(a) Constant 1987 dollars

Additional testing is needed to demonstrate high enough productivity for prudent investment in a commercial facility. Until productivity data from additional testing are available, reservoir performance and project economics cannot be adequately evaluated.

7.7.2 Well Pair Depletion Rate

Since no long-term HDR flow tests have been conducted to date, the well depletion rate has not yet been demonstrated; it can only be estimated by reservoir modeling.

More rapid depletion could occur. For example, if short-circuiting (where water flows predominantly through a small number of fractures rather than more or less equally through each) cannot be controlled by the means available, it could cause the water temperature at the production wellhead to decrease more rapidly than estimated from reservoir modeling. The lower water temperature would reduce the power output that can be derived from operating the reservoir.

Slower depletion could occur if the fracture surface is larger than expected or if growth of the heat transfer area continues during the life of the reservoir. Either effect would allow mining heat from a larger rock mass, offsetting the temperature reduction that would normally be expected.

To evaluate the economic effect of more rapid or slower reservoir depletion, the output of each well pair was assumed to decrease twice as fast or one-half as fast as predicted by the modeling results. The initial output of a well pair is equal to that for the base case. Thus, the same number of well pairs is required initially, but the number of additional wells is greater for more rapid depletion and smaller for slower depletion. For both of these cases, the number and timing of additional wells to produce 50 MWe salable power (+0, -5 MWe) were determined, and the costs of the revised number of wells were incorporated.

In addition, the capacity of the power plant was adjusted for the revised pumping requirement, and the costs were adjusted accordingly. This method for handling the power plant costs assumes that the depletion rate can be determined by experiment before the commercial HDR facility is designed.

The revenue requirements per kWh of electric energy were estimated using the same computer model and economic parameters as for the base case.

Table 7-11 compares these two cases of well pair depletion rate with the base case. Depletion at twice the rate predicted by modeling increases the revenue requirements from 49.8 to 58.9 mills/kWh or slightly more than 9 mills/kWh. An increase of this assumed magnitude could seriously jeopardize the economic viability of the project; therefore, prudence demands that a realistic estimate of the depletion rate needs to be obtained from actual reservoir operation before committing to development of a commercial HDR project.

Depletion at one-half the rate predicted by modeling decreases the revenue requirements by 5.0 mills/kWh from 49.8 to 44.8 mills/kWh. If it were to occur, this assumed improvement in reservoir performance could significantly improve project economics.

7.7.3 Reservoir Leakage

The rate of water loss from the reservoir is site-specific, dependent on the reservoir rock characteristics. For this study, the leakage is assumed to equal the approximately 10 percent (of the injection water) rate experienced during tests at Fenton Hill because site-specific data needed to quantify reservoir leakage are not presently available for the Roosevelt Hot Springs site.

The economic effect of the reservoir leakage rate was investigated by assuming that the leakage is one-half and double the 10 percent rate used for the base case. The number of make-up water wells was estimated for each of these hypothetical cases; and the capital costs, variable costs for purchasing the water, and the pumping power requirements were adjusted accordingly.

The revenue requirements per kWh of electric energy were estimated using the same computer model and economic parameters as for the base case.

Table 7-12 compares these two cases for reservoir leakage with the base case. Doubling the water loss increases the revenue requirements by 1.7 mills/kWh from 49.8 to 51.5 mills/kWh. To mitigate this risk, a realistic estimate of reservoir leakage needs to be established by a site-specific test.

Table 7-11

EFFECTS OF WELL PAIR DEPLETION RATE ON REVENUE REQUIREMENTS

Item	Number of Initial Well Pairs	Number of Additional Well Pairs	Power Plant Net Capacity (MWe)	Wellfield Revenue Requirement (a) (mills/kWh)	Power Plant Revenue Requirement (a) (mills/kWh)	Total Revenue Requirement (a) (mills/kWh)	Difference from Base Case (mills/kWh)
Base Case	4	8	70	28.2	21.6	49.8	-
7-26 More Rapid Depletion (Twice as fast as for Base Case)	4	14	79	35.7	23.2	58.9	9.1
Slower Depletion (One-half as fast as for Base Case)	4	4	63	23.8	21.0	44.8	-5.0

(a) Constant 1987 dollars

Table 7-12

EFFECTS OF RESERVOIR LEAKAGE ON REVENUE REQUIREMENTS

<u>Item</u>	<u>Number of Additional Water Wells</u>	<u>Wellfield Revenue Requirement (a) (mills/kWh)</u>	<u>Power Plant Revenue Requirement (a) (mills/kWh)</u>	<u>Total Revenue Requirement (a) (mills/kWh)</u>	<u>Difference from Base Case (mills/kWh)</u>
Base Case (10 percent reservoir leakage)	13	28.2	21.6	49.8	—
Greater Reservoir Leakage (20 percent reservoir leakage)	21	29.9	21.6	51.5	1.7
Lower Reservoir Leakage (5 percent reservoir leakage)	10	27.9	21.6	49.5	-0.3

(a) Constant 1987 dollars

If reservoir leakage is reduced to one-half the rate assumed for the base case, the revenue requirements would decrease by 0.3 mills/kWh, from 49.8 to 49.5 mills/kWh. This possible improvement alone is not likely to be pivotal. Indeed, control of silica scaling potential may require make-up water of 10 percent or slightly greater (see Appendix D).

7.7.4 Injection Pumping Losses

The injection pumping power, which is proportional to the injection wellhead pressure, required to circulate the necessary flow of water through the HDR reservoir cannot be accurately determined at present. Since the pumping power may be large (10 to 30 percent of the plant net output for the base case as the number of well pairs is increased from four to twelve) and subject to considerable uncertainty, there is reason for concern about the effect of injection pumping power requirements on the economics of an HDR power facility.

The economic effect of pumping power was investigated by assuming that the injection wellhead pressure is 500 psi greater or less than the 1500 psi used for the base case. For each of these alternative cases, the number of initial HDR well pairs, the number and timing of additional wells to produce 50 MWe salable power (+0, -5 MWe), and the pumping power were determined. Then the wellfield capital and operating costs were revised accordingly. The net capacity and cost of the power plant were also adjusted for the revised pumping requirement; this assumes that the injection pressure and pumping power are determined by experiment before the commercial HDR facility is designed.

The revenue requirements per kWh of electric energy were estimated using the same computer model and economic parameters as for the base case.

Table 7-13 compares these two cases for higher and lower injection pressure with the base case. There is less than 3 mills/kWh difference between the revenue requirements for these two injection pressures and the revenue requirements for the base case; therefore, the economic effect of higher or lower pumping power losses is moderate. Nevertheless, the required injection pressure should be determined from a site-specific test to mitigate this potential risk and to guide pump selection for a commercial project.

Table 7-13

EFFECTS OF INJECTION PUMPING LOSSES ON REVENUE REQUIREMENTS

Item	Number of Initial Well Pairs	Number of Additional Well Pairs	Power Plant Net Capacity (MWe)	Wellfield Revenue Requirement (a) (mills/kWh)	Power Plant Revenue Requirement (a) (mills/kWh)	Total Revenue Requirement (a) (mills/kWh)	Difference from Base Case (mills/kWh)
Base Case (1500 psi injection pressure)	4	8	70	28.2	21.6	49.8	-
Greater Injection Pumping Losses (2000 psi injection pressure)	4	8	78	30.2	22.3	52.5	2.7
Lower Injection Pumping Losses (1000 psi injection pressure)	4	6	61	26.8	21.3	48.1	-1.7

(a) Constant 1987 dollars

7.7.5 Conclusions

Well pair productivity and depletion rate are key performance variables that have pronounced effects on project economics. In both cases, performance is likely to be better than for the base case, and economic projections could be more advantageous. However, this better performance must be demonstrated. Likewise, if actual performance in either aspect is poorer than for the base case, serious economic consequences could result. Testing that develops solid data for evaluating productivity and depletion rate is imperative before commitment for a commercial project.

Reservoir leakage and injection pumping losses could significantly affect project economics, but, compared to well pair productivity and depletion rate, they are lower order effects. Site-specific testing to determine the values of these two variables and to mitigate the associated risks is recommended.

Section 8

CONCLUSIONS AND RECOMMENDATIONS

This section presents the conclusions derived from the investigation and states some recommendations concerning the HDR technology in general and the potential HDR project at Roosevelt Hot Springs in particular.

8.1 CONCLUSIONS

Conclusions regarding the geotechnical evaluation, the subsurface system design, surface facilities, environmental and socioeconomic issues, the development plan, the economic and risk assessment, and general issues are summarized below.

8.1.1 Geotechnical Evaluation

The Roosevelt Hot Springs area appears to be well suited for installation and operation of an HDR power facility with the most promising region being the 5-square-mile area bounded to the north by the Hot Springs Fault (Negro Mag Fault zone), to the east by the western graben fault that defines the Opal Mound horst, to the south by an unnamed fault that trends east-west between Wells 9-1 and OH-1, and to the west by the boundary of the participating unit. The shallowest occurrence of possibly commercial HDR temperatures is in the eastern portion of this region.

Although a wealth of data were available for this study, major issues that are important to technical risk mitigation and cost estimates remain unanswered. These concern rock properties in the deep subsurface HDR target zone. Specifically, site-specific data are needed for the following:

- o Persistence of faults at HDR reservoir depths
- o Orientation of faults at HDR reservoir depths
- o Orientation of the principal stresses at depth
- o Magnitude of closure stress and pressure that must be exceeded to stimulate hydraulic fracture growth

- o Spacing and orientation of deep subsurface joint sets that may affect hydraulic fracture orientations and size, and the rate of water loss
- o Temperatures at depth
- o Confirmation that pressures needed to drive fluid circulation are low enough to control water loss and pumping costs

Hydraulic fractures at HDR reservoir depths [7,000 to 12,000 ft (2,130 to 3,660 m)] are expected to be near vertical; this expectation results from the near-vertical orientation of Basin-and-Range faults at the site to 7,000 ft (2,130 m) depth. However, the possible existence of low-angle joint sets may lead to lower-angle fractures.

Existing Well 9-1 is probably suitable for use as a subsurface seismic monitoring station, but it does not appear to be suited for fracturing tests because of its proximity to the hydrothermal field and the direction of its deviation.

If water rights can be obtained to do so, make-up water could be produced from the shallow aquifer underlying the site without significantly affecting the underground water near Milford.

8.1.2 Subsurface System Design

Creating a large heat transfer area (fracture surface) per injection well and maximizing the target temperature consistent with technical constraints and cost considerations are important to commercial viability of an HDR reservoir.

A promising approach to accomplishing these two goals consists of the following principal steps:

- o Drill and case an injection well
- o Hydraulically fracture multiple intervals (12 intervals is optimum for conditions at Roosevelt Hot Springs) using casing packers and perforated wellbore intervals
- o Drill a production well targeting the fractures

This approach uses present-day equipment and techniques throughout.

In developing the subsurface system design, three major areas of uncertainty were identified. The ability to:

- o Accurately predict the size and location of fractures created
- o Create multiple fractured zones in a single well bore
- o Predict long-term thermal performance of the reservoir

Preliminary information from Fenton Hill and Rosemanowes were used as a basis for the design. However, there is considerable uncertainty about the expected reservoir performance, and, in the absence of better experimental evidence, conservative assumptions were used for the base case design.

Initial salable power production of 12 MWe, declining to 2 MWe after 30 years of production, results from one HDR injection/production well pair with 12 fracture intervals, $100,000 \text{ m}^2$ ($1,080,000 \text{ ft}^2$) effective heat transfer area per fracture interval, doubling of fracture growth within the first year of plant operation, target temperature of 300°C (572°F), and economically optimized flow rate of 10 l/s (160 gpm) per fracture interval. For a power plant to produce 50 MWe of salable power (+0, -5 MWe), four injection/production well pairs would be needed initially, and eight additional well pairs would be drilled over a 30-year plant life to make up for declining well production. These characteristics were adopted as the average values for a base case injection/production well pair used for economic analysis.

The initial size and expected growth of the effective heat transfer per fracture interval are reasonable and possibly even conservative based on preliminary information from Fenton Hill and Rosemanowes, but they have not been fully demonstrated.

Average cost per HDR injection/production well pair is estimated to be \$10.1 million for conditions at Roosevelt Hot Springs with average depth of 12,000 ft (3,660 m). This cost includes site preparation, rig operations,

casing/cementing, hydraulic fracturing, and wellhead fixtures. This cost estimate is summarized in Table 8-1.

Table 8-1

AVERAGE COST PER HDR INJECTION/PRODUCTION WELL PAIR
(\$ million, 1987)

<u>Item</u>	<u>Cost</u>
Pumping services	2.2
Wireline services	<u>0.2</u>
Subtotal	2.4
15% contingency	<u>0.4</u>
Subtotal	2.8
Drilling and casing (two wells)	6.7
Microseismic mapping	<u>0.1</u>
Subtotal	9.6
Management fee	<u>0.5</u>
Total	10.1

The proposed approach for coping with well pair depletion is the addition of new well pairs to maintain electrical output near the 50 MWe rating for salable power. Restimulation by fracturing additional intervals in existing wells may not be feasible due to lower temperatures in the remaining wellbore intervals. However, as the size and location of the fractures become better understood and more reliably located, other restimulation methods, such as drilling additional production wells, may be identified as cost-effective methods to increase production.

Two important site-specific operating characteristics, reservoir leakage and pressure at the injection wellhead, were based on test conditions at Fenton Hill and Rosemanowes since the required data for Roosevelt Hot Springs are not available at present. In addition, performance estimates assume uniform flow

distribution among the fracture intervals; this in turn assumes that, if needed, the methods currently used in oil field waterflood operations for restricting flow in particular intervals will produce reasonably uniform flow.

8.1.3 Surface Facilities

The wellfield surface facilities include an injection water storage tank, a centrally located set of booster and injection pumps, an injection pipeline system, a pipeline system to gather the hot water, a centrally located flash system to produce steam for the power plant, and a make-up water supply consisting of water wells and a pipeline to the injection water storage tank.

The two-stage flash process was selected for the power plant, and evaporative cooling was chosen for the heat rejection process. Therefore, the fundamental design of the power plant is similar to that for a geothermal plant of equal capacity for a liquid-dominated hydrothermal resource. The two-stage flash process was selected over a binary process because flash plants are proven in commercial service, they cost less, and their energy conversion efficiency is greater for the relatively high water temperatures expected in this application. Cost estimates for the surface facilities are summarized in Table 8-2.

Table 8-2

COST ESTIMATES FOR SURFACE FACILITIES (1987 \$)

<u>Item</u>	<u>Value</u>
Wellfield capital costs for surface facilities, \$ million	9.3
Wellfield O&M costs	
Fixed O&M, \$ million/yr	1.35
Variable O&M, mills/kWh(a)	0.45
Power plant capital costs, \$ million	55.2
Power plant O&M costs, \$ million/yr	2.26

(a) Not including pumping costs

The total costs for a 50 MWe HDR facility at Roosevelt Hot Springs are estimated as \$53 million for the wellfield and \$69 million for the power plant. In addition, wellfield costs of \$2.7 million for tangibles and \$8.9 million intangible drilling costs will be required every 3 or 4 years to install new well pairs to make up for reservoir depletion.

8.1.4 Environmental and Socioeconomic Issues

There are no apparent environmental or permitting constraints to developing a 50 MWe power plant at Roosevelt Hot Springs or to conducting an industrial HDR experiment to demonstrate that HDR technology is ready for development.

The most important environmental consideration for development is obtaining the water needed to operate the facility. All groundwater in the Milford Valley area is appropriated; however, if rights to unused appropriations can be acquired, these unused amounts are more than enough to supply the water needed to operate a 50 MWe HDR power plant facility.

The potential environmental and socioeconomic impacts from construction and operation of a 50 MWe HDR power plant at Roosevelt Hot Springs are expected to be minor. The major impact during construction, the socioeconomic effects caused by in-migration of the construction work force, will be temporary and generally beneficial to the local economy. During operation, the environmental impacts will be relatively small since there will be low levels of air emissions, no point source water effluents, and little solid or hazardous waste.

There are no apparent constraints to permitting the facility. The major permits will likely be air quality (PSD) and solid waste permits. The critical path for permitting is likely to be the air quality permit which may require 1 year of monitoring and could require up to an additional year after submittal for the permit to be issued.

8.1.5 Development Plan

The major elements of the development plan for an HDR power facility at Roosevelt Hot Springs are the following:

- o Industrial HDR experiment
- o Project preliminary design
- o Venture formation
- o Financing
- o Final design and construction

Because the industrial HDR experiments are likely to require about 5 years (1988 through 1992) to produce reliable data needed for design, evaluation, and commitments, a deliberate schedule for completion of a 50 MWe facility projects 1997 as the initial date for generating commercial electric power. If desirable, this might be accelerated by a year or possibly two.

To a commercial geothermal resource developer, the technical risks associated with HDR technology and the high cost of the industrial HDR experiment to obtain the needed data are prohibitive. Drilling and completion of full-depth, full-bore wells, demonstration of multiple fracture technology, and prolonged thermal drawdown experiments are required to develop a sufficient information base for commercial development. Therefore, federal funding is needed to advance HDR technology with these industrial HDR experiments at Roosevelt Hot Springs. Other parties, such as the state of Utah and the resource developer, may participate in cost sharing of these tests although no specific commitments have been made to date.

8.1.6 Economic and Risk Assessment

The constant dollar (1987) revenue requirements for the base case facility (which assumes that a non-utility resource developer produces and sells steam to a power plant that is owned and operated by an investor-owned utility) are summarized as follows:

	<u>Mills/kWh</u>
Wellfield	28.2
Power Plant	<u>21.6</u>
Total	49.8

This assumes an 18 percent return on equity for the resource developer and a 15 percent return on equity for the power plant owner.

In the assessment of risk, sensitivity analyses were performed on a number of variables. The results suggest that the revenue requirements are not highly sensitive to any single cost component. However, technically and economically, resource risk is by far the greatest uncertainty. Well pair productivity and depletion rate are the key performance variables that significantly affect project economics.

8.1.7 General Issues

Even with the reasonable and possibly conservative base case assumptions used for the reservoir performance, the revenue requirement for HDR at Roosevelt Hot Springs is competitive with a new coal-fired power plant in Utah (at 52 to 53 mills/kWh). This promising result is dependent to a large degree on the ability to create a sufficiently large fractured area per well pair to justify the cost of installing the wells.

Ownership scenarios other than the base case produce slightly varied results. However, none of the currently envisioned scenarios would produce a sufficiently high return on equity for a PURPA qualifying facility. The recently revised energy price of 13 mills/kWh reflects the present demand/supply situation in Utah and is too low to provide a revenue stream conducive to development.

However, the Utah Associated Municipal Power Systems (UAMPS) has suggested that they would be interested in the 49 to 53 mills/kWh (in 1987 dollars) range in the time frame considered for this HDR project (1997).

The industrial HDR experiment suggested in the development plan will be designed to advance the understanding of resource development and performance. These data will greatly reduce the resource risk associated with design and construction of a first-of-a-kind commercial application of HDR technology. However, even with these data, the resource risk for this first

project will be high. Because the risk is high and the earnings expectation is moderate, it is reasonable to expect that, for the development to proceed, some additional incentives and/or limitation of resource risk will be required. These may include government participation in the venture (the fossil program is presently developing ground rules for U.S. DOE participation in first-of-a-kind ventures), tax incentives, insurance, and multiple industry participation.

8.2 RECOMMENDATIONS

The results of the economic analysis using reasonable and possibly conservative assumptions and present-day drilling/completion technology show HDR technology to be competitive with new coal-fired power generation. These results are so promising that a site-specific industrial HDR experiment at Roosevelt Hot Springs is highly recommended. This experiment would demonstrate:

- o The ability to:
  - Create multiple intervals with large fractures
  - Predict the size, orientation, and location of the fractures created
  - Target and drill through the multiple fractures to access the maximum feasible heat transfer area
- o The long-term thermal performance of a commercial-sized reservoir created for heat mining

Site-specific information for further developing a commercial first-of-a-kind project would also be gathered and would include data on:

- o Temperature/depth profiles
- o Reservoir leakage
- o Injection pressure
- o Persistence and orientation of faults at HDR reservoir depths
- o Spacing and orientation of deep subsurface joint sets
- o Magnitude of closure stress and pressure needed to stimulate fractures

These data will enable optimization of the subsurface design and construction to mitigate technical and economic risks and to improve project economics.

The technical uncertainties of HDR technology currently prevent industry-funded resource development even though installation of an HDR facility appears to require nothing more than aggressive application of existing drilling, fracturing, and seismic monitoring technology. Furthermore, the electric energy market for the foreseeable future does not provide enough economic incentive for a private developer to invest in HDR energy technology development. Therefore, federal support for funding the industrial HDR experiment is recommended. Cost sharing by others, including industry participants and the state of Utah, is also recommended; however these sources can be expected to provide only a small fraction of the funding required.

Further, if the industrial HDR experiment verifies the technical and economic projections, a commercial-size first-of-a-kind power plant project is recommended. To attract private industry participation in this first-of-a-kind project, the resource risk needs to be mitigated and economic incentives need to be provided by some combination of federal government participation in the venture (for example, a federal cooperative agreement), tax incentives, insurance, and multiple industry participation.

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Appendix A
HYDRAULIC FRACTURE DESIGN RESULTS

Appendix A

HYDRAULIC FRACTURE DESIGN RESULTS

GDK Radial Fracture Propagation:

$$C = \frac{\% \eta}{2XR^2} \sqrt{t}$$

x = 0.25   = 1 cp   w = 3 1/2 in   G = 2.4 x 10¹⁰ N/m²

Run	Flow Rate	Volume	Leakoff	C	Program Thermfrac Results		
					Fracture Radius	Maximum Aperture	Aperture at 1/2 Radius
CT-K1	40 bpm	1x10 ⁶ gal	0%	0	895 m	2.8 mm	2.0 mm
K2	60	1x10 ⁶ gal	0%	0	856	3.1	2.2
K3	80	1x10 ⁶ gal	0%	0	829	3.3	2.3
K4	40	2x10 ⁶ gal	0%	0	1218	3.1	2.2
K5	60	2x10 ⁶ gal	0%	0	1165	3.3	2.4
K6	80	2x10 ⁶ gal	0%	0	1128	3.6	2.5
K7	40	3x10 ⁶ gal	0%	0	1459	3.2	2.3
K8	60	3x10 ⁶ gal	0%	0	1394	3.5	2.5
K9	80	3x10 ⁶ gal	0%	0	1351	3.7	2.6
CT-L1	40	1x10 ⁶ gal	25%	1.46 x 10 ⁶ m/√s	740	2.7	1.9
2	60	1x10 ⁶ gal	25%	1.95 x 10 ⁶	707	2.9	2.1
3	80	1x10 ⁶ gal	25%	2.40 x 10 ⁶	685	3.1	2.2
4	40	2x10 ⁶ gal	25%	2.40 x 10 ⁶	1007	2.9	2.1
5	60	2x10 ⁶ gal	25%	2.40 x 10 ⁶	963	3.2	2.2
6	80	2x10 ⁶ gal	25%	2.40 x 10 ⁶	932	3.4	2.4
7	40	3x10 ⁶ gal	25%	2.40 x 10 ⁶	1206	3.0	2.1
8	60	3x10 ⁶ gal	25%	2.40 x 10 ⁶	1152	3.3	2.4
9	80	3x10 ⁶ gal	25%	2.40 x 10 ⁶	1116	3.5	2.5
CT-M1	40	1x10 ⁶ gal	50%	6.72 x 10 ⁶	487	2.4	1.7
2	60	1x10 ⁶ gal	50%	6.72 x 10 ⁶	466	2.7	1.9
3	80	1x10 ⁶ gal	50%	6.72 x 10 ⁶	451	2.8	2.0
4	40	2x10 ⁶ gal	50%	6.72 x 10 ⁶	663	2.6	1.8
5	60	2x10 ⁶ gal	50%	6.72 x 10 ⁶	634	2.9	2.0
6	80	2x10 ⁶ gal	50%	6.72 x 10 ⁶	614	3.1	2.2
7	40	3x10 ⁶ gal	50%	6.72 x 10 ⁶	794	2.7	1.9
8	60	3x10 ⁶ gal	50%	6.72 x 10 ⁶	759	3.0	2.1
9	80	3x10 ⁶ gal	50%	6.72 x 10 ⁶	735	3.2	2.3

Appendix B

WELL PAIR DRILLING AND CASING COSTS

Appendix B

SHEET 1

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
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B-1

SHEET 2

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
					HDR INJECTION WELL (12,466')			HDR PRODUCTION WELL (11,425')				
				OPERATION	DAYS		COST	SUBTOTALS	DAYS		COST	SUBTOTALS
1												
2												
3												
38												
39		2.5	DRILL 17 1/2"		5		\$37,500		5		\$37,500	
40			HOLE TO 1500'									
41												
42												
43		2.6	RUN GEOPHYSICAL		1		\$7,500		1		\$7,500	
44			LOGS									
45												
46		2.7	RUN & CEMENT		3		\$22,500		3		\$22,500	
47			1500' OF 13 3/8"									
48			68LB/FT L-80									
49			BTC CASING, WOC									
50			INSTALL BOPE									
51												
52		2.8	DRILL 12 1/4"HOLE		33		\$247,500		26		\$195,000 (TO 5,451')	
53			TO 8,635'									
54												
55		2.9	RUN GEOPHYSICAL LOGS		2		\$15,000		2		\$15,000	
56												
57		2.10	RUN & CEMENT 8500'		7		\$52,500		4		\$30,000	
58			9 5/8"CASING, WOC									
59			CBL, BOPE									
60												
61		2.11	DRILL 8 1/2" HOLE TO		26		\$195,000		24		\$180,000	
62			12,400' MD,									
63												
64												
65												
66												
67		2.12	GEOPHYSICAL LOGGING		3		\$22,500		3		\$22,500	
68												
69		2.13	CORING (3-30' CORES)		3		\$22,500				0	
70												
71												

B-2

HDR WELL COST ESTIMATES

[illegible]

SHEET 4

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2												
3												
				OPERATION	DAYS	COST	SUBTOTALS			DAYS	COST	SUBTOTALS
106												
107			3.1.5	4,065'-7", 35 LB/FT		\$127,275					\$0	
108				S-95, SP. THD. \$31.31/FT								
109												
110			3.1.6	LINER HANGER WITH		\$10,000					\$0	
111				HI-TEMP SEALS								
112												
113			3.1.7	CASING INSPECTION		\$14,900					\$10,500	
114				@ \$1.05/FT								
115												
116				SUBTOTAL FOR 3.1 CASING			\$589,436					\$337,339
117												
118		3.2		CASING HARDWARE								
119												
120			3.2.1	20" CASING SHOE		\$3,200					\$3,200	
121				20" FLOAT COLLAR								
122				12-20" CENTRALIZERS								
123												
124			3.2.2	13 3/8" CASING SHOE		\$4,200					\$4,200	
125				13 3/8" FLOAT COLLAR								
126				15- 13 3/8" CENTRALIZERS								
127												
128			3.2.3	9 5/8" CASING SHOE		\$8,300					\$8,300	
129				9 5/8" FLOAT COLLAR								
130				50-9 5/8" CENTRALIZERS								
131				2-STAGE COLLAR								
132												
133			3.2.4	7" LINER SHOE		\$1,200					\$0	
134				7" FLOAT COLLAR								
135				15-7" CENTRALIZERS								
136												
137												
138				SUBTOTAL FOR 3.2 CASING HARDWARE			\$16,900					\$15,700
139												

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SHEET 5

[illegible]

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
					HDR INJECTION WELL (12,466')				HDR PRODUCTION WELL (11,425')			
				OPERATION	DAYS	COST	SUBTOTALS		DAYS	COST	SUBTOTALS	
174												
175		3.5	WELLHEAD									
176												
177												
178												
179			3.5.1	3,000 PSI CASING HEAD		\$65,000				\$65,000		
180				10"VALVE, 4"SWAB VALVE								
181				&ACCESSORIES								
182												
183			3.5.2	7" FRAC VALVE(10K PSI)		\$60,000				\$0		
184				7" TBG HD. 10K PSI								
185				(EST. ONLY)								
186												
187				SUBTOTAL FOR 3.5 WELLHEAD			\$125,000				\$65,000	
188												
189		3.6	MUD AND CHEMICALS									
190												
191			3.6.1	MUD (\$1500/DAY)	103		\$154,500		82		\$123,000	
192												
193		3.7	SHOCK SUBS @ \$ 240/DAY		45		\$10,800		45		\$10,800	
194												
195		3.8	DRILLING JARS @ \$240/DAY		0							
196												
197		3.9	TUBING									
198			LONE STAR PRICE BOOK									
199			PLUS HYDRIL THDS.									
200												
201			3.9.1	8,300'-7', 35 LB/FT		\$259,873						
202				S-96, HYDRIL WEDGE								
203												
204			3.9.2	HI-TEMP SEALS & 30'PBR		\$45,000						
205												
206			3.9.3	INSPECTION @ \$1.05/FT		\$8,715						
207			SUBTOTAL FOR TUBING				\$313,588					

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SHEET 7

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
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B-7

SHEET 8

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
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242												
243												
244												
245												
246												
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3.13.2 AT 1500'

CBL	\$6,500	\$6,500
ELECTRIC	\$4,700	\$4,700
COMP DENSITY	\$4,100	
COMP NEUTRON/GR	\$4,600	
COMP SONIC/CALIPER/WAVEFORM	\$4,800	
COMPUTERIZED ANAL., MILEAGE,	\$2,700	
AND SERVICE CHARGE		

3.13.3 AT 8,635'

CBL	\$13,500	\$11,000
ELECTRIC	\$8,900	\$7,400
COMP DENSITY	\$8,900	
COMP NEUTRON/GR	\$9,600	
COMP SONIC/CALIPER/WAVEFORM	\$7,000	
COMPUTERIZED ANAL., MILEAGE,	\$4,000	
AND SERVICE CHARGE		

3.13.4 AT 12,400'

CBL	\$7,300	
ELECTRIC	\$11,560	\$13,067
COMP DENSITY	\$11,560	
COMP NEUTRON/GR	\$13,800	
COMP SONIC/CALIPER/WAVEFORM	\$15,400	
COMPUTERIZED ANAL., MILEAGE,	\$6,900	
AND SERVICE CHARGE		

3.13.5 CASING INSPECTION
9 5/8"

\$3,550	\$3,550

SUBTOTAL FOR 3.13 ELECTRIC LOGGING \$152,370 \$49,217

HDR WELL COST ESTIMATES

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HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
					HDR INJECTION WELL (12,466')			HDR PRODUCTION WELL (11,425')				
				OPERATION	DAYS	COST	SUBTOTALS	DAYS	COST	SUBTOTALS		
310												
311			3.18.4	DIRECTIONAL	4 RUNS	\$72,000					\$72,000	
312				DRILLING								
313												
314			3.18.5	INSPECTION AND REPAIRS								
315				INCLUDED IN 3.18.4								
316												
317			3.18.6	TRUCKING		\$2,000						
318												
319			3.18.7	STEERING TOOLS		\$64,000					\$16,000	
320												
321				SUBTOTAL FOR 3.18 DIRECTIONAL			\$167,400					\$117,400
322												
323		3.19		DRILL PIPE INSPECTION & REPAIR								
324												
325			3.19.1	INSPECTION		\$17,500			\$17,500			
326												
327			3.19.2	REPAIRS		\$50,000			\$50,000			
328												
329			3.19.3	TRUCKING		\$6,000			\$6,000			
330												
331				SUBTOTAL FOR 3.19 DRILL PIPE INSP.& REPAIR			\$73,500					\$73,500
332												
333		3.20		DRILL PIPE REPLACEMENT			\$15,000					\$7,500
334				3000'-5", 19.50LB/FT @ \$5/FT								
335												
336		3.21		ROTATING HEAD RUBBERS	12		\$6,600					\$5,500
337				@\$550/EA								
338												
339		3.22		20" BOPE, HYDRIL			\$3,900					\$3,900
340				DOUBLE GATES, SPOOLS, RING GASKETS								
341				10 DAY MIN.								
342												
343				FREIGHT			\$1,200					\$0

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SHEET 11

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
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SHEET 12

HDR WELL COST ESTIMATES

	A	B	C	D	E	F	G	H	I	J	K	L
1												
2				OPERATION		DAYS	COST	SUBTOTALS		DAYS	COST	SUBTOTALS
3												
378												
379				3.28 MISCELLANEOUS SERVICES								
380												
381				3.28.1 TELEPHONE @\$70/DAY				\$11,200		98		\$6,860
382												
383				3.28.2 POTABLE WATER @\$21/DAY				\$3,360		98		\$2,058
384												
385				3.28.3 SANITARY @\$21/DAY				\$3,360		98		\$2,058
386												
387				3.28.4 TRAILER RENTAL				\$4,189				\$2,000
388												
389				3.28.5 SEPTIC TANK				\$3,300				
390												
391				3.28.6 OFFICE MACHINES				\$3,300				\$3,300
392												
393				3.29 ADDITIONAL EQUIPMENT								
394												
395				3.29.1 PIT LEVEL & FLOW		120		\$8,640		98		\$7,056
396				SHOW @\$72/DAY								
397												
398				3.29.2 MUD COOLOER				\$20,000				\$0
399												
400				3.29.3 MUD CLEANER		120		\$60,000				\$40,000
401				@ \$500/DAY								
402												
403												
404												
405				SUBTOTAL FOR DRILLING AND CASING ONLY				\$3,863,913				\$2,243,424
406												
407				ALLOWANCE FOR STATE TAXES AND OMISSIONS (10%)				\$386,391				\$224,342
408												
409												
410				TOTAL ESTIMATED COST LESS FRACTURING OPERATIONS				\$4,250,304				\$2,467,766
411												

Appendix C
COSTS OF SEISMIC MONITORING

Appendix C

COSTS OF SEISMIC MONITORING

C.1 REGIONAL SEISMIC MONITORING

Initial Costs

<u>Equipment</u>	<u>Cost</u>
5 1-channel stations consisting of 1 Hz geophone, radiotelemetry, solar-panel power, housing	\$ 40,265
1 4-channel station: downhole 1 Hz vertical, surface 2 Hz 3-component, radiotelemetry, multiplexed transmitter and receiver, solar panel, housing near Well 9-1	\$ 18,600
1 9-channel recorder station	\$ 62,400
<u>Labor</u>	
Baseline survey	\$ 24,800
System startup for long-term monitoring	\$ 35,200
<u>Other Direct Costs</u>	
Travel/expenses	\$ 10,800
Backhoe	\$ 2,000
Total Initial Cost	\$195,065

Operation and Maintenance, Annual

<u>Labor:</u> System maintenance, quarterly reports, data processing, data analysis	\$ 72,000
Travel/expenses	\$ 5,800
Computer: 200 hr @ \$85/hr	\$ 17,000
Total Annual O&M	\$ 94,800

C.2 MICROSEISMIC MONITORING OF HYDRAULIC FRACTURES

Hydraulic Fracturing Operations: Fracture Volume and Orientation Determination

<u>Equipment</u> (in addition to regional array)	<u>Cost</u>
3 additional recorder channels	\$ 8,000
3 single-channel, high-frequency geophones with telemetry capability	\$ 24,000
<u>Labor</u>	
Hydraulic fracturing operations: calibration, 2 test fractures plus 48 initial reservoir fractures, data analysis	\$110,000
<u>Other Direct Costs</u>	
Travel/Expenses	\$ 21,500
Computer: 500 hr @ \$135/hr connect/CPU average, 50 fractures	\$ 67,500
Backhoe	\$ 5,000
Total Hydraulic Fracturing Operations	\$236,500

Appendix D
SILICA CONTROL

Appendix D

SILICA CONTROL

The possibility of plugging the reservoir with silica deposited from the injected water is the most likely operating problem associated with dissolution of minerals in the reservoir rock. The low pressure flash vessels and liquid piping may also experience some scaling; however, these surface facilities can be taken apart and cleaned periodically to cope with scale. By contrast, silica scale in the reservoir could result in permanently reduced permeability with attendant reduced flow and lower production. The most effective means of avoiding silica deposition in the reservoir is to ensure that the silica content of the injected water does not exceed amorphous silica solubility; water that is supersaturated may cause plugging problems (Henley 1983).

Time plots from a 75-day test at Fenton Hill (Tester and Albright 1979) show that silica concentration in the hot water at the production wellhead was approaching equilibrium with respect to quartz. This indicates that saturation with respect to quartz should also be expected for the higher temperature hot water at Roosevelt Hot Springs unless an appropriate measure is taken to control the concentration. This approach to equilibrium is slow (an apparent first-order lag with a time constant of 25 days for conditions during the Fenton Hill testing), but it could cause a problem for a facility that operates continuously.

Figure D-1 shows the silica concentration states for the liquid stream assuming 100 percent saturation with respect to quartz at the production wellhead. Hot water from the production wellhead (State 1) is flashed successively to lower temperatures and higher concentrations (States 3 and 5) in the high pressure and low pressure flash processes. The numbers designating the states are the same as those shown in the process flow schematic of Figure D-2. Addition of make-up water to replace the flashed steam and the reservoir leakage reduces both the temperature and concentration

State	Description
1	Hot water at production wellhead assuming saturation with quartz
3	Water leaving high pressure flash vessel
5	Water leaving low pressure flash vessel
7	Water at injection wellhead
7b	Water leaving heat exchangers of binary cycle

Figure D-1 Silica Concentration for Saturated Water at the Production Wellhead

Figure D-2 Process Flow Schematic

to State 7; however, the water at State 7 is supersaturated with silica and thus unsatisfactory for injection because of concern about plugging the reservoir with silica deposits.

The possibility of using a binary process to avoid this situation was considered; however, the binary process does not remedy the potential problem associated with silica supersaturation. The cooling during a binary process is represented by a horizontal line in Figure D-1 from State 1 to lower temperatures in the supersaturation region, such as State 7b. The water would be supersaturated unless the injection temperature is maintained higher than about 130°C (266°F). If that is done, the thermal efficiency of the binary cycle is reduced intolerably.

Likewise, a single flash process was considered. It does not remedy the silica supersaturation either. Furthermore, it requires 20 to 30 percent more hot water to produce the same amount of electric energy.

Figure D-3 illustrates an appropriate measure for controlling the silica in the injection water stream. The concentration at the injection wellhead (State 7) can be maintained at any specified level by limiting the concentration at the production wellhead (State 1). Physically this is done by withdrawing silica-rich water before injection and providing additional make-up water which has a very low silica concentration.

The amount of additional make-up water required is small compared to the design value of 10 percent (of the injection water flow rate) reservoir leakage. According to calculations based on data for Fenton Hill (Tester and Albright 1979), limiting silica concentration to saturation with amorphous silica at the injection wellhead requires about 0.1 percent make-up water in addition to the 10 percent leakage rate experienced at Fenton Hill. Lower silica concentration (e.g., if needed to avoid scaling flash vessels) could be maintained at the injection wellhead by withdrawing more silica-rich water and adding more make-up water. For a 50 MWe plant at Roosevelt Hot Springs, the 0.1 percent additional make-up water is equivalent to less than 25 gpm with all HDR wells operating late in a 30-year plant life. That rate is incidental

State	Description
1	Hot water at production wellhead
3	Water leaving high pressure flash vessel
5	Water leaving low pressure flash vessel
7	Water at injection wellhead

Figure D-3 Silica Concentration for Saturated Water at the Injection Wellhead

compared to the 3,900 gpm required for replenishing the water losses from the reservoir and making up for the water used by the cooling tower. The low rate of dilution water required to control the silica concentration is a direct result of the long time constant associated with the process of approaching silica saturation at the production wellhead (i.e., quartz is not really very soluble in water).

If the reservoir leakage is slightly greater than the rate experienced at Fenton Hill, disposal of the silica-rich water occurs spontaneously as water loss from the reservoir. On the other hand, if the reservoir leakage is lower, the water withdrawn from the circuit to control silica would be injected into a shallow well in the vicinity of the power plant; underground flow of the withdrawn water would return it to the aquifer from which it originated.

Since water loss from the reservoir is a site-specific characteristic that is not yet known for Roosevelt Hot Springs, the estimates here of additional make-up water and water for disposal are approximations based on data from Fenton Hill testing. Site-specific data are needed to make more accurate estimates.

REFERENCES

- Henley, R. W. 1983. "pH and silica scaling control in geothermal field development," Geothermics, Vol. 12, No. 4, pp. 307-321.
- Tester, J. W. and Albright, J. N. eds. 1979. Hot dry rock energy extraction field test: 75 days of operation of a prototype reservoir at Fenton Hill, Segment 2 of Phase I. Informal Report, Los Alamos Scientific Laboratory, LA-7771-MS, April.

Appendix E

COMPARISON OF PERFORMANCE FOR FLASH AND BINARY SYSTEMS

Appendix E

COMPARISON OF PERFORMANCE FOR FLASH AND BINARY SYSTEMS

The most likely binary cycles for the relatively high water temperatures expected for the HDR application at Roosevelt Hot Springs (about 270°C at the production well head) are isopentane (subcritical cycle), cyclopentane (subcritical cycle), and isobutane (supercritical cycle).

Figures E-1 through E-10 (and Tables E-1 through E-10) compare the expected performance of these binary cycles with the expected output from a two-stage flash plant. In every case, the two-stage flash process would be expected to produce a greater net electrical plant output at the expected temperatures.

These results do not account for the power needed to drive the pumps to circulate water through the reservoir; however, since that power requirement is not subject to accurate estimation presently, it should not be the decisive factor.

A two-stage flashed steam process is the best choice as the baseline plant for an HDR facility at Roosevelt Hot Springs for the following reasons:

- o Two-stage flash requires 20 to 30 percent less hot water than single flash.
- o Several two-stage flash plants of approximately 50 MWe net capacity are in commercial service while the first binary plant of this capacity is in an evaluation stage but is not yet commercially proven.
- o Flash plants require significantly less capital investment than binary for equal net power capacity (binary would cost 1.5 to 2 times as much per net kW).
- o For the relatively high hot water temperatures expected at Roosevelt Hot Springs, the energy conversion performance is expected to be better than for a binary cycle.

Figure E-1 Isopentane Subcritical Cycle with 300° F (149° C) Evaporator Design Temperature

Figure E-2 Isopentane Subcritical Cycle with 250° F (121° C) Evaporator Design Temperature

Figure E-3 Isopentane Subcritical Cycle with 200° F (93° C) Evaporator Design Temperature

Figure E-4 Isopentane Subcritical Cycle with 150° F (66° C) Evaporator Design Temperature

Figure E-5 Cyclopentane Subcritical Cycle with 400° F (204° C) Evaporator Design Temperature

Figure E-6 Cyclopentane Subcritical Cycle with 375° F (191° C) Evaporator Design Temperature

Figure E-7 Cyclopentane Subcritical Cycle with 350° F (177° C) Evaporator Design Temperature

Figure E-8 Cyclopentane Subcritical Cycle with 325° F (163° C) Evaporator Design Temperature

Figure E-9 Cyclopentane Subcritical Cycle with 300° F (149° C) Evaporator Design Temperature

Figure E-10 Isobutane Supercritical Cycle with Turbine Inlet at 320° F (160° C) and 600 psia (41 bar)

Table E-1

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-1

Binary Working Fluid--Isopentane (Subcritical Cycle)

Hot Water Temperature, F	570	530	490	450	440	430	410	390	370
Hot Water Temperature, C	299	277	254	232	227	221	210	199	188
Evaporator Temperature, F	300	300	300	300	300	300	300	300	300
Evaporator Temperature, C	149	149	149	149	149	149	149	149	149
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	150	150	150	170	200	225	250
Outlet Water Temperature, C	66	66	66	66	66	77	93	107	121
Binary Cycle Condenser Pressure, psia	25	25	25	25	25	25	25	25	25
Binary Cycle Condenser Pressure, MPa	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Binary Cycle Condenser Temperature, F	116	116	116	116	116	116	116	116	116
Binary Cycle Condenser Temperature, C	47	47	47	47	47	47	47	47	47

Table E-2

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-2

Binary Working Fluid--Isopentane (Subcritical Cycle)

Hot Water Temperature, F	570	530	490	450	440	430	410	390	370	330	320
Hot Water Temperature, C	299	277	254	232	227	221	210	199	188	166	160
Evaporator Temperature, F	250	250	250	250	250	250	250	250	250	250	250
Evaporator Temperature, C	121	121	121	121	121	121	121	121	121	121	121
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	150	150	150	150	155	175	195	220	230
Outlet Water Temperature, C	66	66	66	66	66	66	68	79	91	104	110
Binary Cycle Condenser Pressure, psia	25	25	25	25	25	25	25	25	25	25	25
Binary Cycle Condenser Pressure, MPa	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Binary Cycle Condenser Temperature, F	116	116	116	116	116	116	116	116	116	116	116
Binary Cycle Condenser Temperature, C	47	47	47	47	47	47	47	47	47	47	47

Table E-3

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-3

Binary Working Fluid--Isopentane (Subcritical Cycle)

Hot Water Temperature, F	570	530	490	450	440	430	410	390	370	330	300	270
Hot Water Temperature, C	299	277	254	232	227	221	210	199	188	166	149	132
Evaporator Temperature, F	200	200	200	200	200	200	200	200	200	200	200	200
Evaporator Temperature, C	93	93	93	93	93	93	93	93	93	93	93	93
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	150	150	150	150	150	150	150	170	180	200
Outlet Water Temperature, C	66	66	66	66	66	66	66	66	66	77	82	93
Binary Cycle Condenser Pressure, psia	25	25	25	25	25	25	25	25	25	25	25	25
Binary Cycle Condenser Pressure, MPa	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Binary Cycle Condenser Temperature, F	116	116	116	116	116	116	116	116	116	116	116	116
Binary Cycle Condenser Temperature, C	47	47	47	47	47	47	47	47	47	47	47	47

Table E-4

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-4

Binary Working Fluid--Isopentane (Subcritical Cycle)

Hot Water Temperature, F	570	530	490	450	440	430	410	390	370	330	300	260	220
Hot Water Temperature, C	299	277	254	232	227	221	210	199	188	166	149	127	104
Evaporator Temperature, F	150	150	150	150	150	150	150	150	150	150	150	150	150
Evaporator Temperature, C	66	66	66	66	66	66	66	66	66	66	66	66	66
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	150	150	150	150	150	150	150	150	150	155	160
Outlet Water Temperature, C	66	66	66	66	66	66	66	66	66	66	66	68	71
Binary Cycle Condenser Pressure, psia	25	25	25	25	25	25	25	25	25	25	25	25	25
Binary Cycle Condenser Pressure, MPa	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Binary Cycle Condenser Temperature, F	116	116	116	116	116	116	116	116	116	116	116	116	116
Binary Cycle Condenser Temperature, C	47	47	47	47	47	47	47	47	47	47	47	47	47

Table E-5

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-5

Binary Working Fluid--Cyclopentane (Subcritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450
Hot Water Temperature, C	299	288	274	260	246	232
Evaporator Temperature, F	400	400	400	400	400	400
Evaporator Temperature, C	204	204	204	204	204	204
Pinch Point Temperature Difference, F	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11
Outlet Water Temperature, F	155	175	195	240	290	335
Outlet Water Temperature, C	68	79	91	116	143	168
Binary Cycle Condenser Pressure, psia	13	13	13	13	13	13
Binary Cycle Condenser Pressure, MPa	0.09	0.09	0.09	0.09	0.09	0.09
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46

Table E-6

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-6

Binary Working Fluid--Cyclopentane (Subcritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450	425
Hot Water Temperature, C	299	288	274	260	246	232	218
Evaporator Temperature, F	375	375	375	375	375	375	375
Evaporator Temperature, C	191	191	191	191	191	191	191
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	165	185	215	255	295	335
Outlet Water Temperature, C	66	74	85	102	124	146	168
Binary Cycle Condenser Pressure, psia	13	13	13	13	13	13	13
Binary Cycle Condenser Pressure, MPa	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46	46

Table E-7

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-7

Binary Working Fluid--Cyclopentane (Subcritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450	425	400
Hot Water Temperature, C	299	288	274	260	246	232	218	204
Evaporator Temperature, F	350	350	350	350	350	350	350	350
Evaporator Temperature, C	177	177	177	177	177	177	177	177
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	155	175	205	235	265	290	320
Outlet Water Temperature, C	66	68	79	96	113	129	143	160
Binary Cycle Condenser Pressure, psia	13	13	13	13	13	13	13	13
Binary Cycle Condenser Pressure, MPa	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46	46	46

Table E-8

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-8

Binary Working Fluid--Cyclopentane (Subcritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450	425	400	375
Hot Water Temperature, C	299	288	274	260	246	232	218	204	191
Evaporator Temperature, F	325	325	325	325	325	325	325	325	325
Evaporator Temperature, C	163	163	163	163	163	163	163	163	163
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	165	185	210	230	260	280	305
Outlet Water Temperature, C	66	66	74	85	99	110	127	138	152
Binary Cycle Condenser Pressure, psia	13	13	13	13	13	13	13	13	13
Binary Cycle Condenser Pressure, MPa	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46	46	46	46

Table E-9

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-9

Binary Working Fluid--Cyclopentane (Subcritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450	425	400	375	350
Hot Water Temperature, C	299	288	274	260	246	232	218	204	191	177
Evaporator Temperature, F	300	300	300	300	300	300	300	300	300	300
Evaporator Temperature, C	149	149	149	149	149	149	149	149	149	149
Pinch Point Temperature Difference, F	20	20	20	20	20	20	20	20	20	20
Pinch Point Temperature Difference, C	11	11	11	11	11	11	11	11	11	11
Outlet Water Temperature, F	150	150	155	170	190	210	230	250	270	290
Outlet Water Temperature, C	66	66	68	77	88	99	110	121	132	143
Binary Cycle Condenser Pressure, psia	13	13	13	13	13	13	13	13	13	13
Binary Cycle Condenser Pressure, MPa	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46	46	46	46	46

Table E-10

DESIGN CONDITIONS FOR BINARY CYCLE IN FIGURE E-10

Binary Working Fluid--Isobutane (Supercritical Cycle)

Hot Water Temperature, F	570	550	525	500	475	450	425	400	375	350
Hot Water Temperature, C	299	288	274	260	246	232	218	204	191	177
Turbine Inlet Temperature, F	320	320	320	320	320	320	320	320	320	320
Turbine Inlet Temperature, C	160	160	160	160	160	160	160	160	160	160
Turbine Inlet Pressure, psia	600	600	600	600	600	600	600	600	600	600
Turbine Inlet Pressure, MPa	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14	4.14
Outlet Water Temperature, F	150	150	150	150	150	150	150	150	150	175
Outlet Water Temperature, C	66	66	66	66	66	66	66	66	66	79
Binary Cycle Condenser Pressure, psia	90	90	90	90	90	90	90	90	90	90
Binary Cycle Condenser Pressure, MPa	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Binary Cycle Condenser Temperature, F	115	115	115	115	115	115	115	115	115	115
Binary Cycle Condenser Temperature, C	46	46	46	46	46	46	46	46	46	46

Appendix F

ESTIMATED COSTS FOR 50 MWe HYDROTHERMAL PLANT AT ROOSEVELT HOT SPRINGS

Appendix F

ESTIMATED COSTS FOR 50 MWe HYDROTHERMAL PLANT AT ROOSEVELT HOT SPRINGS

WELLFIELD

Gathering system (millions \$1987)	5.10	
Reinjection system	2.79	
Tangible well costs	3.00	
Total tangible wellfield costs	<u>10.89</u>	
Capitalized interest (interest during construction)	3.05	
Total wellfield investment	<u>13.94</u>	
Permitting	0.40	
Total Capital for Wellfield	<u>14.34</u>	
Intangible Drilling (initial wellfield)	7.00	
Fixed Operating and Maintenance Costs (millions \$/year)		
Operating labor	0.72	
Maintenance labor	0.13	
Maintenance material	0.19	
Overhead charges	0.25	
Total fixed O&M for wellfield		1.29
Variable Operating and Maintenance Costs (mills/kWh)	0	

Restimulation and Redrilling Costs   One new well is to be drilled each five years with tangible cost of \$1.79 million and intangible cost of \$0.88 million

POWER PLANT

Capital Costs (millions \$1987)	
Power plant	43.60
Transmission line	1.26
Total plant cost	<u>44.90</u>
AFDC	8.30
Total Plant Investment	<u>53.20</u>
Preproduction Costs	1.90
Total Power Plant Capital	<u>55.10</u>
Operating and Maintenance Costs	
Fixed O&M (millions \$/year)	
Operating labor	0.79
Maintenance labor	0.35
Maintenance materials	0.52
Overhead charges	0.34
Total fixed O&M costs for power plant	<u>2.00</u>
Variable O&M (mills/kWh)	0

F-1

Appendix G
POWER TECHNOLOGIES COST DATA

Appendix G

POWER TECHNOLOGIES COST DATA

Technology	PCF/FGD	PCF/FGD	CFB
Year of Cost Estimate	1987	1987	1987
Location of Design Site	Four Corners	Four Corners	Four Corners
Plant Size	200 MW	100 MW	150 MW
Plant Capacity Factor	65.0%	65.0%	65.0%
Plant Efficiency	34.1%	31.0%	32.8%
Plant Cost (Million \$)	252.1	139.8	184.2
Owner's Cost (Million \$)	37.5	20.8	29.3
Construction Schedule	4 yrs	4 yrs	4 yrs
Fixed O&M (Million \$)	3.8/yr	2.1/yr	3.2/yr
Variable O&M (Million \$)	2.7/yr	1.4/yr	2.5/yr