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1.0 System Description

A geothermal hydrothermal system consists of a geothermal reservoir, wells, and a power plant. "Hydrothermal" means that the geothermal reservoir contains copious amounts of steam or hot water that can be brought to the surface.

A representative system using a water-cooled flashed-steam power plant is shown in Figure 1. The system includes technical processes to find reservoirs (exploration), to measure and manage reservoirs, and to match power plant designs to the characteristics of reservoirs. The geothermal reservoir contains hot aqueous fluids. The fluids are produced through wells similar to oil wells, and piped to the power plant. Geothermal steam or vaporized secondary working fluids drive a turbine-generator to make electricity. Waste heat is ejected to the atmosphere through condensers and cooling towers. Remnant geothermal liquids, including any excess condensate, are pumped back into the reservoir through injection wells. If present, non-condensible gases are removed from the system by gas ejection equipment and released to the atmosphere after any treatment mandated by emission regulations. Some emission control systems may produce sludges or solids that are disposed of in landfills. The nominal size characterized here is 50 MW_e, the size commonly used by industry for system comparisons. Real-world system sizes range from 0.5 to 180 MW_e.

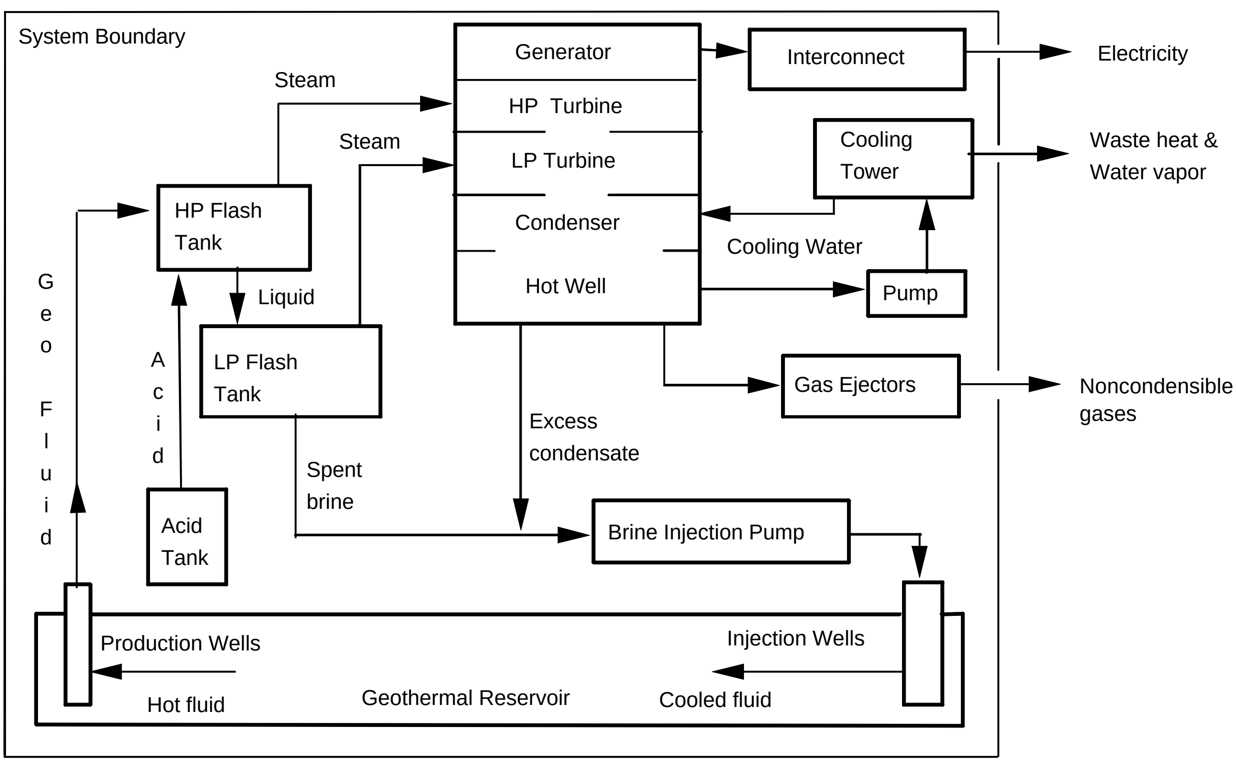

Figure 1. Geothermal hydrothermal electric system with flashed steam power plant schematic.

The technology design, performance, and cost of these systems are markedly affected by the reservoir temperature. In general, the higher the temperature, the lower the cost, because higher temperature fluids contain more available work. To reflect that variation, this Technology Characterization (TC) includes systems useful for high-temperature reservoirs (flashed-steam systems) and for moderate-temperature reservoirs ("binary" systems). Substantial detail about current performance and costs under a wide variety of reservoir conditions and power plant technologies is available from the recent DOE/EPRI Next Generation Geothermal Power Plant (NGGPP) study, from which much of the information in this TC is drawn [1]. Additional general background information on geothermal electric technologies and resources can be found in [2] and [3].

Major Common System Components and Features

a. A geothermal hydrothermal reservoir consisting of hot rock with substantial permeability, and aqueous fluid in situ. The temperature of the fluid ranges from 100°C to 400°C (212°F to 752°F). The fluid may contain substantial amounts of dissolved solids and non-condensible gases (particularly carbon dioxide and hydrogen sulfide).

b. Wells for production and injection of geothermal fluids. These range in total depth from 200 to 3,500 meters at producing U.S. hydrothermal reservoirs. The wells are drilled and completed using technology for deep wells that has been incrementally adapted from oil and gas well technology since the 1960's. The produced fluids range from totally liquid to liquid-vapor mixtures (with two-phase flow at the wellhead). In some systems outside the U.S., the cooled liquid leaving the plant is disposed to the ground surface or streams, rather than injected.

c. An exploration and reservoir confirmation process to identify and characterize the reservoir. This process is usually complex and can add substantial front-end cost to a hydrothermal project. Such costs are usually borne out of developer's equity and can be a large barrier to exploration projects. Those costs are accounted for in this TC but not represented in the system schematics.

d. A reservoir design and management process whose goal is to optimize the production of electricity from the reservoir at least cost over the life of the system. Those costs are accounted for in this TC but not represented in the system schematics.

e. Surface piping that transports fluid between the wells and the power plant equipment.

f. A power plant that converts heat (and other energy) from the geothermal fluid into electricity. Power plants comprise: (a) One or more turbines connected to one or more electric generators. (b) A condenser to convert the vapor exiting from the turbine (water or other working fluid) to a liquid. (c) A heat rejection subsystem to move waste heat from the condenser to the atmosphere. Cooling towers (wet or dry) are used for most systems, but cooling ponds are also used. (d) Electrical controls and conditioning equipment, including the step-up transformer to match the transmission line voltage. (e) An injection pump that pressurizes the spent geothermal liquid from the power plant to return it to the geothermal reservoir through the injection wells. Representative power-conversion (power plant) technologies are described below.

g. Activities and costs related to the operation and maintenance of the system over a typical 30-year useful life of an individual power plant and a 40- to 100-year production life for the reservoir as a whole.

Flash (Flashed-Steam) Power Plants

The flash plant schematic in Figure 1 was simplified from diagrams of the CalEnergy Company, Inc. (CECI) Salton Sea Unit 2 power plant [4]. Technical descriptions of recently-built flashed-steam power systems can be found in descriptions of the Magma Power Company Salton Sea units [5]; CECI Salton Sea Unit 3 [6,7]; CECI Coso units [8,9]; and GEO East Mesa units [10]. The NGGPP report [1] provides a range of process and cost information.

Equipment present in all or most flashed-steam systems includes:

a. One or two large vessels, flash tanks, wherein part of the geothermal fluid vaporizes ("flashes") into steam at pressures less than the pressure in the reservoir. This steam, typically 18 to 25 percent of the mass of the fluid from the reservoir (for double flash plants), is sent to the high-pressure (HP) and low-pressure (LP) inlets of a turbine or turbines. The amount of steam depends on conditions in the reservoir and the designs of the production wells and power plant. The remaining liquid ("brine") from the second flash tank (75 to 82 percent of mass) is disposed of in the injection wells. The turbine in the dual flash system shown has dual inlets to admit high pressure steam from the first flash tank, and low pressure steam from the second flash tank.

b. Special features related to minimizing the deposition of silicate scale. For the plant depicted in the system diagram (but not at most U.S. flash plants), the geothermal brine contains substantial amounts of dissolved silica, which tends to precipitate upon equipment walls as hard scale if not treated. The ameliorating features may include: (a) Elevation of the conversion cycle's brine exit temperature above that optimal for maximum power production. This tends to keep some of the silica in solution. This is the method of choice when silica problems are small to moderate. (b) A "crystallizer-clarifier" system. This consists of a brine solids clarifier, and a return line from the clarifier that injects silica seeds into the first flash tank. In that case, the flash tanks are called "crystallizers" because the silica seeds prevent the precipitation of amorphous silica on the walls of the vessels and connecting pipes. The liquid from the second crystallizer is sent to a third large vessel, the "clarifier," in which the precipitation, flocculation, and removal of solid silica are completed. (c) A "pH-modification" system (shown in the flash-system schematic in Figure 1). This provides the same functions as the crystallizer-clarifier system by injecting small quantities of acid upstream of the first flash tank to reduce the pH of the geothermal fluid.

c. Gas ejection equipment. At reservoirs where the concentration of noncondensible gases (e.g., CO_2) is high, substantial gas ejection equipment is attached to the condenser. The ejectors are driven by steam or electricity. If hydrogen sulfide in the gases require abatement, H_2S control equipment is attached downstream of the ejectors.

Binary Power Plants

Figure 2 shows a schematic of a geothermal binary power plant [1]. All the geothermal fluid passes through the tube side of the primary heat exchanger and then is pumped back into the reservoir through injection wells. A hydrocarbon working fluid (e.g., isopentane) on the shell side of the primary heat exchanger is vaporized to a high pressure (HP) to drive the turbine-generator. Low pressure vapor from the turbine is liquified in the condenser and re-pressurized by the hydrocarbon pump. Waste heat is ejected to the atmosphere through a condenser and a cooling tower. Makeup water is required for the heat rejection system if wet cooling towers are used, but not if dry cooling towers are used. The binary system characterized here uses dry cooling, but wet cooling could be less expensive where cooling water is available. Most geothermal binary plants are constructed from a number of smaller modules, each having a capacity of 1 to 12 MW_e net.

Technical descriptions of recently-built binary organic Rankine cycle power systems and other systems proposed for moderate-temperature reservoirs can be found in the NGGPP report [1] and others: binary systems [11]; vacuum-flash [12]; ammonia-based cycles [13].

Equipment present in most binary systems includes:

a. Downhole production pumps in the production wells. These keep the geothermal fluid from vaporizing in the wells or in the power plant, and enhance the production well flow rate.

b. A working fluid pump, the "main cycle pump", that pressurizes the low-boiling-temperature liquid working fluid to drive it around the power-conversion loop.

c. A turbine converts energy in the high-temperature high-pressure working fluid vapor to shaft energy. It exhausts low-temperature low-pressure vapor to a condenser.

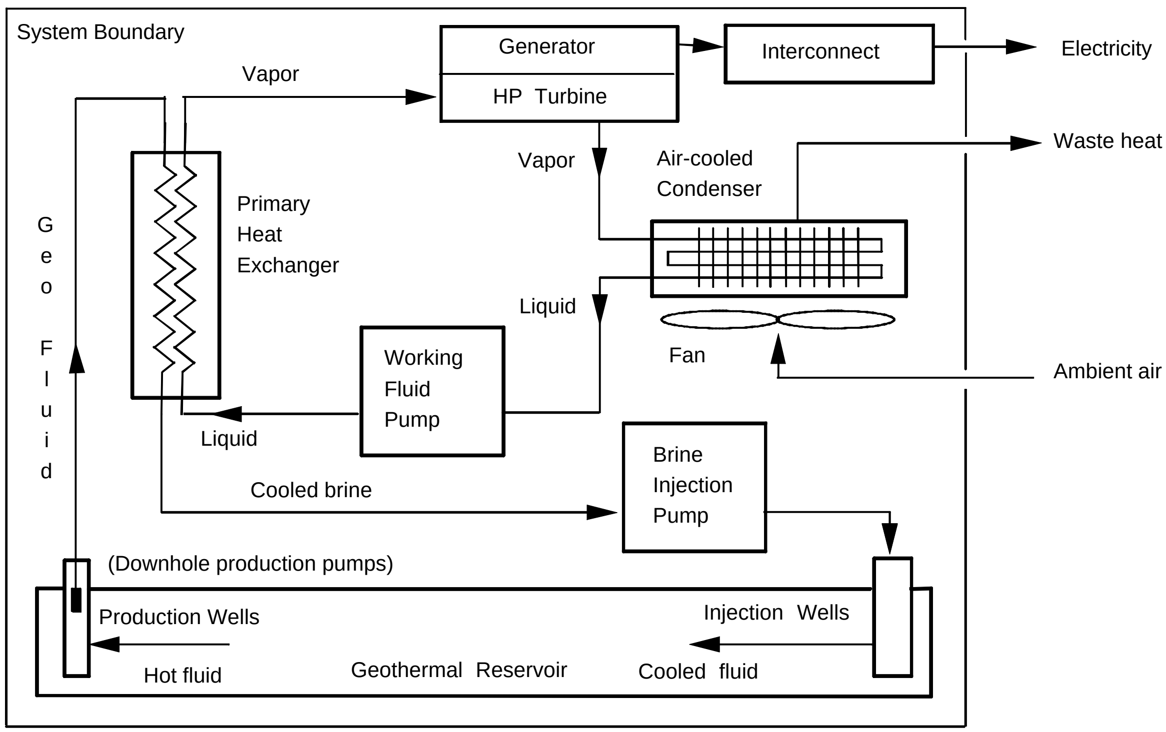

Figure 2. Geothermal hydrothermal electric system with binary power plant schematic.

2.0 System Application, Benefits, and Impacts

Application: Traditionally, geothermal systems have been perceived to compete with other baseload generation systems. Currently, geothermal electric systems compete most directly with gas-fired turbines and cogeneration systems in California, and coal and natural gas plants in Nevada. However, recent experiments have shown that some geothermal power plants (e.g., the dry steam plants at The Geysers) can be cycled to follow system load in the intermediate-baseload area of the utility time-demand curve [14], thereby increasing their value in certain applications. It is likely that load-following would be more difficult to do at flash and binary plants than at dry steam plants. Current contract capacity factors are on the order of 80 percent. Experienced capacity factors for many currently operating plants are on the order of 100 percent or higher (see discussion in Section 4.2)

Benefits: Typical plant sizes are 5 to 50 MW_e net. Once the geothermal reservoir is confirmed, system construction time is on the order of a year or less. O&M costs are low compared to fossil-fueled systems because there are no "fuel" costs other than those for the O&M of the field wells and pipes. With appropriate emission control equipment, geothermal-generated electricity provides an environmentally attractive alternative to baseload gas, oil, coal, and nuclear-fueled electricity. Some in the U.S. geothermal industry have recently indicated interest in using relatively small geothermal power plants (from 50 kW to 2,000 kW) to supply off-grid or "mini-grid" power in a number of remote places that are favored with geothermal resources.

Economic Conditions: The recent surge in competition from low-cost electricity from natural gas has broad implications for the economic competitiveness of geothermal electric systems. Approximately 900 MW_e of geothermal hydrothermal systems were installed in the western U.S. between 1980 and 1990. However, since about 1990, the advent of cheaper electricity from natural-gas fueled systems and low load growth rates have slowed the pace of U.S. domestic geothermal installation to nearly zero. (One 40 MW_e plant was installed at the Salton Sea, California reservoir in 1996, under a high-price-of-power contract that originated in the early 1980's.)

In 1990, geothermal power developers expected to be able to compete easily against 6 to 7¢/kWh power in 1996. But by about 1993, the developers found themselves competing (not very successfully) against 2.5 to 3.5¢/kWh power in western states. However, it was expected that the currently strong overseas markets for these systems, especially in the Philippines and Indonesia, would continue to provide a strong experiential base for ongoing technology improvements. With the large recent decreases in the cost of geothermal flash power plants, U.S. technology for using higher-temperature geothermal resources may be able to again compete for new electricity demand. (See “Special Note on Power Plant Costs,” page 3-20, for more details.)

Impacts: All emissions stated in Table 1 are for flashed-steam plants [7]. Emissions for binary plants are essentially nil because the geothermal fluid is never exposed to the atmosphere. The zero value for sludge assumes use of "pH modification" technology at locations where silica scaling would otherwise be high. By comparison, sludge at 6 kg/MWh has been cited for the previously-used crystallizer/clarifier technology, circa 1985-90 [15].

Table 1. Environmental impacts of geothermal flashed steam plant.

Indicator		Base Year					
Name	Units	1997	2000	2005	2010	2020	2030
Gaseous							
- Carbon Dioxide	kg/MWh	45	45	45	45	45	45
- Hydrogen Sulfide	kg/MWh	0.015	0.015	0.015	0.015	0.015	0.015
Liquid	kg/MWh	0	0	0	0	0	0
Solid							
- Sludge	kg/MWh	0	0	0	0	0	0

Note: Emissions for binary plants are essentially nil because the fulid is never exposed to the atmosphere.

3.0 Technology Assumptions and Issues

Geothermal (hydrothermal) electric technology is commercially available. The systems characterized here reflect ordinary conditions and technology for representative high-temperature (232°C/450°F) and moderate-temperature (166°C/330°F) hydrothermal reservoirs in the United States. Technologies for exploration, drilling, and reservoir analysis and management are essentially the same for the two types of systems. These systems represent conditions and technology that are similar to a High-Temperature system at Dixie Valley, NV (using dual-flash conversion technology today) and a Moderate Temperature system at Steamboat Hot Springs, NV (using Organic Rankine Cycle, i.e., “binary,” technology today). The conditions and technologies selected for this TC broadly represent many aspects of commercial technologies for producing electricity from these resources [1].

Substantial room for improvement exists in most aspects of this technology, including both the fluid-production (exploration, wells, and reservoir management) and electricity-conversion (power plant) components. The cost of deep geothermal wells is expected to decline by about 20 percent in 5 to 10 years, mainly through improvements in drill bits. The cost of conversion technologies (power plants) should continue to decrease substantially over the next 5 to 15 years for lower-temperature systems (binary-like), but may not decrease much for higher-temperature (flash) systems because of recent very large reductions in the cost of those systems. The current main thrusts for reducing power plant costs are: (a) substantial changes in the basic conversion cycle designs used in the plants, including the addition of "topping" cycles and "bottoming" cycles, improved working fluids, and the use of various hybrid cycles that merge the best features of flash and binary plants (e.g., see [1]); (b) urgent efforts on the part of owners of geothermal power systems to reduce O&M costs, especially by reducing the number of staff employed at each system and site, in anticipation of marked reduction in revenues when prices fall under certain contracts [16]; and (c) gradual reduction in complex instrumentation and controls as engineers learn what is safe to omit.

These improvements are expected to be relatively continual over the next 20 years, due to the combined effects of: (a) industry experience and learning from designing and installing these systems where they continue to be economic and (b) continuing R&D by the U.S., Japan, Italy, and other nations. In the U.S., the R&D effort is led by the Office of Geothermal Technologies, Office of Utility Technologies, Department of Energy, which has supported an active geothermal R&D program since 1974.

As detailed more in Section 4.0, it is believed that continued R&D would be valuable on many fronts, including: (a) development of geophysical methods to detect fluid-filled permeable fractures during exploration and siting of production wells; (b) substantial decreases in the cost of drilling geothermal wells; (c) moderate decreases in the cost of power plants, and moderate increases in the conversion effectiveness of plants sited on lower-temperature reservoirs; and (d) continuing decreases in the operation and maintenance costs of wells, field equipment, and power plants.

General Methodology

Sources: Most of the performance and cost estimates for the 1997 technology has been drawn from the EPRI 1996 "Next Generation Geothermal Power Plants" (NGGPP) study [1]. Starting from the NGGPP estimates, this TC adds performance and cost factors to exploration and reservoir management processes to represent geothermal "field" technologies more accurately.

Scope: This TC includes both Flash Steam and "Binary" conversion systems because: (a) those technologies cover the temperature range at geothermal reservoirs currently under production; (b) they share many subcomponents, especially all aspects of finding, producing, and injecting geothermal fluids; (c) they serve the same markets; and (d) the distinctions of when to use them and what other conversion subsystem designs might modify or replace them are beginning to blur.

Process and Status: Industry and laboratory experts were interviewed to formulate the estimates of how these technologies will be improved over time. Processes to obtain such inputs have been active since 1989, when the Department of Energy Technology Characterization process was initiated. The estimates provided here are based on continuing updates of assessments conducted for OGT in 1990 and 1993 [17]. Polling of experts was renewed in 1997 because of large changes in some aspects of system designs and component costs.

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4.0 Performance and Cost

Tables 2 and 3 summarize the performance and cost indicators for the geothermal hydrothermal electricity systems being characterized in this report.

4.1 Evolution Overview

There is not a peer-reviewed literature on how much geothermal electric technology is likely to improve over time. However, there are published indicators that suggest hydrothermal-electric technology is immature and is frequently being improved along a number of fronts.

The estimated evolution of these systems assumes gradual improvements over time of many subsystems and components of the 1997 technology. Table 4 describes how some of the estimates of the cost of future technology were derived. Costs in that table are in 1997 dollars. The values in Table 4 reflect only some of the expected changes in technology, and then only for the high-temperature (flashed-steam) system, and not binary or other technologies.

Expected technology improvements and their sources, in brief, are:

- Average cost per well: Mid-term: Improved diamond compact bits, and control of mud circulation. Long-term: Costs drop markedly through radical improvements in drilling technology now being pursued for oil, gas, and geothermal wells. Cost savings for shallow wells will be smaller than for deep wells.

- Wildcat exploration success rate: The current value here implies that, on average, five deep wells need to be drilled to discover a new geothermal power-capable field. In the near-term (e.g., 10 years), most improvements will come from improved interpretations of local geology, in cross-comparison to geologies in other geothermal fields. In the long-term, sophisticated improvements in geophysical methods will make drilling targets (large water-filled fractures) relatively visible.

- Flow per production well: Combined impacts of better completions and improved reservoir engineering. Improved completions will reduce formation damage near the wellbore. Improved reservoir engineering will increase the degree to which the wellbore penetrates large-scale permeability.

- Field O&M cost: The 1990's effects of power sales contracts, i.e., lower payments for energy, established under PURPA (the Public Utilities Regulatory Policies Act of 1978) are now driving geothermal operators to identify cost-savings opportunities in plant O&M manpower. Also a result of improved chemistry and materials, but smaller effects than for power-plant O&M.

Table 2. Performance and cost indicators for a geothermal high-temperature system ("flashed-steam" technology).

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	47.9		47.9		47.9		47.9		47.9		47.9	
Performance													
Levelized Capacity Factor	%	89	5	92	5	93	5	95	5	96	5	97	5
Annual Energy Production	GWh/year	390		403		407		416		420		425	
Power Plant Net Effectiveness	Wh/kg fluid	26.4	*	27.5		28.8		29.0		29.0		29.0	
Average Flow/Well	1000 kg/hr	304	*	322		342		368		402		435	
Average Cost/Well	$1000	1,639	*	1,557		1,311		1,229		983		820	
Capital Cost													
Wildcat Exploration	$/kW	46	10	44	+11/-10	32	+13/-10	25	+14/-10	17	+17/-10	12	+20/-10
Site Confirmation, Well Costs		100	†	93		76		69		53		43	
Site Confirmation, Soft Costs		18		17		16		16		15		13	
Siting & Licenses		64		64		64		64		64		64	
Land (@ $5000/ha)‡		1		1		1		1		1		1	
Producing Wells & Spares		255	15#	224		174		154		115		90	
Dry Production Wells		64	5#	53		38		31		22		15	
Injection Wells		110	5#	96		74		64		47		37	
Field Piping		47	10	41		36		32		28		23	
Production Pumps		0		0		0		0		0		0	
Power Plant		629	10	629		629		629		629		629	
Owner's Costs		109	10	109		109		109		109		109	
Total Overnight Capital Cost		1,444	--	1,372		1,250		1,194		1,100		1,036	
Operations and Maintenance Cost													
Field, General O&M & Rework	$/kW-yr	32.40	10	29.00	+11/-10	25.50	+13/-10	23.60	+14/-10	21.70	+17/-10	20.90	+20/-10
Makeup Wells		12.20		11.60		10.40		8.10		6.10		4.00	
Relocate Injection Wells		2.70		2.60		2.30		1.60		1.10		0.50	
Power Plant O&M		49.10		43.90		36.60		33.00		29.30		29.30	
Total Operating Costs		96.40		87.10		74.80		66.30		58.20		54.70	

Notes for Tables 2 and 3:

Plant construction period is assumed to require 0.8-1.5 years.

Column sums and totals may differ because of rounding.

* Values depend highly on reservoir temperature, geology, and hydrology.

† The generic uncertainty factors (+10/-10, +11/-10, etc.) are explained in Section 4.2.

‡ Assumes desert land. Would be higher in agricultural areas.

\# Uncertainty is for cost per unit well.

Table 3. Performance and cost indicators for a geothermal moderate-temperature system ("binary" technology).

INDICATOR NAME	UNITS	Base Case 1996		2000		2005		2010		2020		2030	
			+/- %		+/- %		+/- %		+/- %		+/- %		+/- %
Plant Size	MW	50.0	-	50.0		50.0		50.0		50.0		50.0	
Performance													
Levelized Capacity Factor	%	89	5	92	5	93	5	95	5	96	5	97	5
Annual Energy Production	GWh/Year	390		403		407		416		420		425	
Power Plant Net Effectiveness	Wh/kg fluid	11.6	*	11.8		12.2		12.8		13.3		13.9	
Average Flow/Well	1000 kg/hr	317	*	337		356		383		419		454	
Average Cost/Well	$1000	492	*	467		443		418		393		344	
Capital Cost													
Wildcat Exploration	$/kW	21	10	20	+11/-10	16	+13/-10	13	+14/-10	10	+17/-10	4	+20/-10
Site Confirmation, Well Costs		29	†	27		24		22		20		17	
Site Confirmation, Soft Costs		17		17		16		15		14		12	
Siting & Licenses		64		64		64		64		64		64	
Land (@ $5000/ha)‡		1		1		1		1		1		1	
Producing Wells & Spares		148	15#	131		115		98		82		65	
Dry Production Wells		26	15#	21		18		14		11		8	
Injection Wells		69	15#	61		53		45		37		29	
Field Piping		35		31		27		23		19		15	
Production Pumps		46		43		40		36		32		29	
Power Plant		1,545		1,468		1,391		1,313		1,236		1,159	
Owner's Costs		109		109		109		109		109		109	
Total Overnight Capital Cost		2,112		1,994		1,875		1,754		1,637		1,512	
Operations and Maintenance Cost													
Field, General O&M & Rework	$/kW-yr	28.80	10	25.60	+11/-10	22.30	+13/-10	20.50	+14/-10	18.80	+17/-10	18.40	+20/-10
Makeup Wells		7.10		6.70		6.00		4.70		3.60		2.30	
Relocate Injection Wells		1.70		1.60		1.40		0.80		0.30		0.10	
Power Plant O&M		49.80		44.60		37.20		33.40		29.70		29.70	
Total Operating Costs		87.40		78.50		66.80		59.50		52.40		50.50	

Notes: See notes at the bottom of Table 2.

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Table 4. Representative major technology improvements expected for flashed-steam system.

Technology Factor or Indicator	Units	1997 value	Performance or Cost Multiplier (relative to 1997 value)			
			2005	2010	2020	2030
a. Average cost per well	$K	1,639	.80	.75	.60	.50
b. Wildcat dry hole ratio	ratio	0.80	.95	.90	.80	.70
c. Flow per production well	1000 kg/hr	304	1.12	1.20	1.30	1.40
d. Field O&M cost	$/kW/yr	24	.75	.68	.62	.62
e. Power plant capital cost	$/kW	629	1.00	1.00	1.00	1.00
f. Plant net effectiveness	Wh/kg	26.4	1.09	1.10	1.10	1.10
g. Plant O&M cost	$/kW/yr	49	.75	.67	.60	0.50
h. Reservoir pressure decline:	%/yr	6	.85	.66	.40	.33

- Power plant capital cost: Expected to remain flat after mid-1990's large decreases in costs due to world-wide competition among suppliers.

- Plant net effectiveness: Improved due to better matching to reservoir conditions.

- Plant O&M cost: Similar to impacts in field O&M costs, above. Also expect continuingly higher degrees of automation in operation of power plants.

- Rate of reservoir pressure decline: The 6% decline per year set for Base Case (1997) technologies is higher than expected for fields developed at a reasonable pace. While this level of decline would require adding enough makeup wells to double the number of production wells by about year 20, its impacts on levelized costs and on the present value of reduced production in the final years are very small.

For hydrothermal electric systems as a whole, the estimated time to final commercial maturity is estimated to be 30 to 40 years. The time to maturity for major subcomponents is estimated as follows:

- Reservoir exploration and analysis technologies: 30 to 40 years. Substantial improvements in geophysical sensors and data inversion processing can be expected to occur over a long interval [18]. Also, advances in computer modeling of geochemical systems and rock-water interactions will provide substantial new information about underground conditions and long-term production processes [19].

- Conventional drilling technology: 10 to 20 years. The pace here will depend mainly on the pace of hydrothermal commercial development during the next 10 years, and the degree to which the 500-fold larger market for equipment for drilling oil and gas wells in harder rock at higher temperature improves technologies that then will spill over to improve geothermal operations [20].

- Advanced drilling technology: 20 to 30 years. Systems studies are in progress for drilling technologies that could substantially reduce the costs of both removing rock and maintaining the integrity of the wellbore during drilling and production (i.e., alternatives to conventional casing). Such systems would be applicable to geothermal drilling under adverse conditions [21,22].

- Power plant technology: 10 to 20 years. Flash power plant technology is substantially mature, but analyses indicate that a number of cost-effective modifications of designs are possible [4,23]. Binary power plant technology is somewhat less mature [24,25].

4.2 Performance and Cost Discussion

The cost estimates in Tables 2 and 3 are in 1997 dollars. Capital costs are stated in dollars per kilowatt on an overnight construction basis. Costs not included specifically in Tables 2 and 3 are royalties to the owner of the geothermal resource at a (typical) rate of 10% of the fluid-production-related capitalized and O&M costs.

No single technology used in geothermal electric systems is immune to improvement through industry experience and basic and applied R&D. However, the most noticeable and measurable technology improvements that continue to produce large cost reductions will be in geothermal wells and in power plants.

The temporal pace of improvement in Tables 2 and 3 is similar to that used in the 1991 National Energy Strategy Current Policy Base Case. It generally assumes continued funding of the DOE Geothermal Research Program at the constant dollar budget levels of 1995-1997 to about 2010, plus an average 10 to 15 percent industry-experience-based learning curve effect through the year 2030.

Capital Cost of Systems: Anecdotal information has suggested that U.S. industry had wrung about 20 percent out of flash-system costs in the 1985 to 1990 period, and about 30 percent out of binary-system costs in the same interval. This rough quantification has been essentially verified by the statement by Elovic [26] that Ormat, Inc., managed to cut about 32 percent from the costs of its organic Rankine cycle (ORC) binary systems in the eight years between 1986 and 1994. Much of that improvement was attributed to changes in equipment design that lowered manufacturing costs.

Similar specific quantitative statements cannot be made for process- or manufacturability-related changes in geothermal flash electric power systems. It appears that the cost (in nominal dollars) estimated for Salton Sea power systems in the NGGPP study (estimates made in late 1993 [1]) is not much different from that stated for such plants when built in 1985 to 1987 [27]. This would represent improvements in cost effectiveness (after inflation) on a number of fronts, but especially the replacement of crystallizer-clarifier technology (at about $17 million per 40 MW power plant in 1985) by pH-modification technology for silicate scaling control (at only a few million dollars per plant).

Note: Power plant costs appear to have changed greatly in the past three years. Geothermal power plant capital costs could be substantially different from the estimates in this TC if there are moderate changes in the pace of power plant construction (in U.S. or abroad) or currency exchange rates. (See "Special Note on Power Plant Costs," page 3-20, for more details.)

The cost of purchased land is estimated to be $5,000 per ha for 10 ha, assuming desert land. Land costs in agricultural areas could be higher. This land accommodates the power plant, drilling pads (wellhead areas), and piping runs between wells and the plant. Power plant capital cost includes $15/kW for the final line transformer.

Cost of Wells: It is difficult to track the "modal" or average cost of geothermal wells, because the cost depends markedly on well depth, the geology being drilled, the sequence of the well among all wells drilled in a field, the expertise of the drilling crew, and on the fact that relatively few geothermal wells are drilled each year. The prices of geothermal well component materials and services fluctuate with the demand for nearly identical components for oil and gas drilling. Those costs became extremely high (escalated rapidly) in the late 1970's and early 1980's, but de-escalated substantially in the mid-1980's as the world price of oil dropped dramatically.

Current R&D at Sandia National Laboratories promises to reduce the cost of drilling deep geothermal wells by 20 percent within the next 5 to 10 years [28]. Percentage cost reductions will be less for relatively shallow wells, such as those for the moderate-temperature case characterized here, since a higher fraction of the cost of those wells is in cement and casing whose costs are relatively inelastic with respect to improvement in drilling technology.

In the long run, say by about 2020, costs are expected to reach as little as 50% of current costs through radical improvements in drilling technologies, such as those being pursued by the National Advanced Drilling and Excavation Technologies (NADET) R&D program originated by the Department of Energy and now managed by the Massachusetts Institute of Technology [29].

Other Reductions in Field Costs: Other improvements of field technology will arise from a number of fronts. None of the fronts are easy to either quantify or predict. Some of the expected improvements are: (a) improved siting of production wells, through better means of interpreting geophysical data to detect permeable zones in reservoirs. This will result in increased success per attempted well, and increased average production flow per well; (b) less drilling damage to the wellbore, on average, from drilling operations per se, also increasing flow rates slightly; and (c) improved positioning and selection of injection wells, leading to fewer abandoned wells.

Exploration Costs: Two modes of "exploration" are included here: wildcat exploratory drilling and power plant siting after wildcat drilling. (a) Wildcat drilling includes regional assessments that culminate in the first deep well(s) being drilled in a geothermal "prospect" area. Wildcat wells usually encounter heat at depth, but encounter economic amounts of fluid and permeability only about 20 percent of the time in the U.S. (b) Exploration for plant siting occurs at reservoirs, prospects that have already been proven by wildcat drilling or subsequent additional drilling and production. This exploration, as well as production well siting in general, has the advantage over wildcat siting and drilling of information from nearby existing wells. So the likelihood of success is much higher, typically 80 to 95 percent.

Many of the enhanced geophysical methods that are expected to improve siting of production wells will also be applied to the siting of exploration wells. Many believe that a key path to improvements here is better understanding of the fractures and faults that define much of the permeability and boundaries of geothermal reservoirs [30,31]. Also, drilling costs for geothermal exploration will continue to decline, especially as more and more "slim holes" of about 10 cm diameter, costing about half that of 30 cm production-diameter wells, are used for wildcat drilling [32,33].

Power Plant Capital Costs: Power plant costs should continue to decrease for two primary reasons: (a) There will be improved conversion cycle designs that produce more electricity from each pound of geothermal fluid, and (b) There will be gradual reduction in the amount and number of instruments, controls, secondary valves, and safety systems as designers learn over time what can be excluded safely. But flash plant costs may stay flat over time because the large cost reductions experienced recently may have brought flash plant costs to near or below their long-term economic equilibrium point. (See “Special Note on Power Plant Costs,” page 3-20, for more details.)

There are topping devices (e.g., Rotoflow turbine [4] and Rotary Separator turbine [34]) that extract extra power from very-high-temperature fluids, hybridized main cycles that extract extra power from moderate-temperature fluids (e.g., Kalina cycle [35] and Ormat "combined cycle" [36]), and bottoming cycles (e.g., vacuum-flash cycle [12]) being proposed and/or installed. Moreover, there is continued attention to how to simplify these plants to their bare essentials.

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Operation & Maintenance Costs: Annual O&M costs will decrease markedly for many sites, especially those within the U.S., and perhaps abroad. Until recently, the general employment rate for U.S. geothermal power plants was about one full time equivalent staff per MW of capacity. That is three to five times the rate for coal plants. With many of the U.S. power sales contracts for these power plants reaching and nearing the date for reversion of price of electricity to low avoided costs of power, the geothermal industry is working very hard to reduce the labor costs of operations [16]. Pacific Gas and Electric has cut its labor pool at The Geysers significantly [37], but that is due in part to retirement of some of PG&E's capacity there. No extensive statistics for changes in O&M expenditures for U.S. liquid-dominated geothermal power systems seem to be available publicly, but such information continues to be sought.

Since most of the operating costs of geothermal electric systems are fixed, no variable operating costs are shown in Table 1. In technical reports prior to the late 1980's a high variable operating cost for geothermal power plants is often shown; this is because those plants, often utility-owned and especially at The Geysers field, purchased steam or brine from a separate field-operating firm on an amount-consumed basis.

Capacity Factors: The availability and capacity factors of geothermal power systems tend to be much higher than the other baseload systems to which they are traditionally compared, coal and nuclear. This is because geothermal systems are intrinsically much simpler than the others. System availability factors (the percentage a year in which the system is capable of delivering its rated power) are historically very high, typically 95 percent or better [38].

Actual annual capacity factors equal to or greater than 100 percent have been reported. This is due to two trends in geothermal power plant design: (a) Generator ratings: Electric generators for geothermal service are usually ordered with an assumed power factor (a technical parameter of alternating current systems) of 0.85: for a gross generator rating of 50,000 kW, a generator sized at 58,800 kVa would be ordered. The generator ratings and costs in the NGGPP study [1] were set on this basis [39]. However, the real loads that these generators serve tend to have power factors of about 0.98-0.99. In those circumstances, the generator produces substantially more than 50 MWh of real energy per hour. Manufacturers' ratings sometimes show this effect [40,41]. (b) Redundant equipment: One (dry steam) plant at The Geysers was designed with redundant turbines and generators, to ensure a capacity factor of essentially 100 percent; the economics of doing so were favorable in the mid-1980's [42,43]. This approach could be used at flashed-steam and binary plants whenever economics warrant it.

"Capacity factor" is usually defined based on nameplate rating (i.e., capacity factor = kWh output/year ÷ ((nameplate kW) X 8,760 hours/year)). Therefore, the reported capacity factor of these plants can reach 108 to 112 percent if their annual availability is 98 percent. It is also worth noting that many contemporary geothermal power sales contracts set a "contract" capacity factor at 80 percent. If production falls below the contract capacity factor, the plant receives no capacity payments for a designated period, e.g., three months. That 80 percent value is sometimes cited as the typical geothermal actual capacity factor, but that is rarely the case.

The levelized capacity factors in Tables 2 and 3 reflect effects of decreased system output late in project life, e.g., in years 25-30, as it becomes uneconomic to replace production wells whose outputs might be declining. Such events are expected to be ameliorated by continuing improvements in reservoir management technologies.

Expected Economic Life: The 30-year life is the common U.S. design life for geothermal power plants. Pacific Gas & Electric's initial systems at The Geysers did operate for that life span. The effective life of geothermal production wells is usually shorter than that, and that has been taken into account in the costing here. The life of geothermal hydrothermal reservoirs can be much greater than 30 years, depending on how much capacity is installed. For example, The Geysers reservoir first produced power in 1960, and is expected to continue to operate until at least 2015. Reservoirs can be depleted in less than 30 years if too much capacity is installed. The life of reservoirs is generally improved by injection of fluid back into the producing formations.

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Construction Period: The construction period is typically reported as about 0.8 to 1.5 years. This period is that for erecting new capacity on a reservoir already discovered through exploration and fairly well characterized as to its production potential. Those prior activities, exploration and reservoir confirmation, can require 3 to 8 years of development work before installation of a first power plant on a reservoir [44]. (See Table 8, below, for allocation of capital costs over years before start up.)

Basis and Interpretation of Estimates

This section provides information regarding some of the starting assumptions for the two technology cases, and provides information needed to use the cost and performance estimates in Tables 2 and 3 to derive estimates of the cost of electricity from geothermal systems.

Sources of Estimates and Assumptions: Most of the information used for characterization of the 1997 baseline technologies here comes from a 1995 study of current and "Next Generation Geothermal Power Plant" (NGGPP) designs. Conducted by CE Holt, a respected geothermal power system design and A&E firm, this is the first comprehensive set of cost estimates for U.S. geothermal power plants placed in the public domain in about 15 years [1].

Until that report, the level of detail of publicly-available information about the performance and cost of U.S. commercial geothermal electric systems was generally low. This is due in large part to the fact that almost all geothermal capacity built in the U.S. since 1985 was built under PURPA contracts. That shifted almost all geothermal power plant design and development from the Investor Owned Utility (IOU) domain to the Independent Power Producer (IPP) domain. IOU's have to report construction and operation costs, while IPP's do not. In addition, competition among IPP's intensified and contributed to a reduced flow of performance and cost information into the open literature, after about 1982. Until 1996, most of the detailed geothermal electric cost information published since 1982 came from systems installed in Italy, Mexico, the Philippines, and Japan.

This "geothermal information gap" was especially unfortunate because the 1981-1990 decade saw the development in the U.S. of two new major geothermal conversion schemes for liquid-dominated reservoirs: about 620 MW_e of flash plants and about 140 MW_e of binary plants [45]. The experience with these plants will define important aspects of geothermal electric technology for much of the next decade, but the technical details on the effectiveness of design tradeoffs and varied managerial approaches are largely not public and likely to remain so. The publication of the NGGPP study has now largely remedied this situation with respect to the performance and cost of geothermal power plants built, and to be built, in the U.S. However, details on the cost of geothermal wells and O&M costs in general are still mostly held closely in the private domain.

Three groups of changes were made to estimates from the NGGPP study, to make the results more reflective of "typical" geothermal hydrothermal reservoirs in the U.S.

- Change 1: The High Temperature system is that from Dixie Valley, Nevada. The initial reservoir temperature is 232°C (450°F). Dual flash technology is assumed for the 1997 system. Well depth is 3,050 m (10,000 ft). The field costs here were raised about 50 percent from those reported in the NGGPP study, by reducing the assumed flow per production and injection wells by one third. That was done to get the field capital costs to be about 30 percent of the total capital costs, which is the more-or-less modal case for flashed steam systems analyzed in the NGGPP study. Note that in some cases today, flash-binary hybrid power plants are being used at relatively high-temperature reservoirs. We assume that this may be the beginning of a trend, but stay with double-flash plants as our 1997 baseline technology for these reservoirs.

- Change 2: The Moderate Temperature system is based at a 166°C (330°F) reservoir. Well depth is about 305 m (1,000 ft). The system assumes a partially-optimized Organic Rankine Cycle (ORC) conversion technology, using mixed working fluids, for the 1997 system. In the NGGPP study, this system was designed for an estimated reservoir at Vale, Oregon. Even though no working system exists at Vale, or is likely to in the near future, the Vale estimate was selected for use here because the initial resource temperature in that NGGPP case is a temperature for which there are working cost estimates from other sources. A reservoir with similar characteristics, but less expensive wells, is that at Steamboat Springs, Nevada, where a modest amount of ORC capacity is operating. Well costs were changed to approximately $450,000 per well in 1993 dollars, estimated by an industry engineer familiar with drilling at Steamboat. So the Moderate Temperature system here is a composite of Steamboat Hills and Vale.

- Change 3: Certain costs were added or modified:

  a. Wildcat exploration costs. Costs were added (see Table 7, equation FA) to account for "wildcat" exploration that accomplishes the initial discovery of hot fluid in a geothermal reservoir. The exploration included in the NGGPP cost estimates covered only the costs to confirm that a new power plant can be supported at a new site in a reservoir that has already been discovered.

  b. Impacts of reservoir management. Effects of reservoir pressure decline were added, using simple models not documented here. The base cases assume 6 percent decline in pressure per year. Makeup production wells are added during the middle years of project life, and system output allowed to decline in the last years. The effects of this are (1) added costs for makeup wells and (2) calculation of the appropriate levelized capacity factor that includes effects of production decline. In addition, costs were added to account for a certain number of injection wells that are drilled ("relocated") after production begins to reduce cooling of productive zones.

  c. Financing costs. The financing costs estimated in the NGGPP report were removed from the costs shown here. Finance costs are included in the estimate of COE in Chapter 7.

Special Note on Power Plant Costs: Geothermal flashed-steam power plants now cost about 40% less than four years ago (the NGGPP cost estimates were completed mid-1993). This applies not just to major equipment, but also to engineering services and plant construction. This is due to factors whose effects are difficult to quantify and differentiate, including: (1) intense competition in the electric equipment and power plant construction industry; (2) fluctuations in currency exchange rates; and (3) some simplifications and improvements in the designs of geothermal flash power plants.

Geothermal flash plants that cost $1,100 to $1,200 per kW in early 1994, now (in early 1997) cost about $600 to $800 per kW. It is believed that the same degree of cost change has not occurred for binary plants, due to a lack of competition in that segment of the geothermal market.

This general status of intense competition across the electric power industry, world-wide, was noted recently in Independent Energy magazine [46]. "Competition has driven down the price of new power plants -- as much as 40 percent in the last six years. A major reason for this is fierce competition among suppliers." The article states that only about 50 percent of world power-plant manufacturing capacity was being used in early 1997.

This Technology Characterization takes those effects into account by:

After the adjustment, that cost was set at $575 per kW, which was then escalated to $629 in 1997 dollars. (There are at least four firms making flash turbo-generator units, and many plant construction firms.)

- The NGGPP estimate for the cost of the binary power plant was not changed, except for converting to 1997 dollars. (There is only one company that is very active in the manufacture and construction of binary power plants.)

Given these large recent variations in costs, the users of this Technology Characterization are urged to be cautious in applying the numerical values herein to real world situations without consulting engineering firms with substantial experience in estimating costs for geothermal power systems.

Cost Deviation Estimates: The error range ascribed to the base year (1997) estimates, for capital and O&M costs, is set at +/-10 percent to reflect best estimates of the general accuracy of the information on which the cost estimates are based. The upper bound set for the error range is assumed to grow linearly by an additional 10 percentage points between 2000 and 2030 to reflect the uncertainties associated with R&D forecasts.

Note that these cost estimates internally account for one of two other dominant sources of uncertainty:

Cost Contingency: The construction cost contingency is about 15 percent for field-related costs and 10 percent for power plant-related costs.

Reservoir Uncertainties: Uncertainties in measurements on reservoir properties can add on the order of 15 to 25 percent to the levelized cost of delivered electricity. The estimates provided in this TC are not quantified with respect to such uncertainties; it is believed that the present estimates represent something akin to an "industry's expected case."

These "measurement" uncertainties and the costs that are occasioned by them are subject to reduction through research and industry experience, and the scenario evaluated here estimates that such reductions will occur over time. Specifying and improving the quantification of these uncertainties is a continuing research priority.

Factors for Estimating Cost of Electricity: Costs of energy are not shown in this chapter. Such costs are shown and documented in Chapter 7 of this report. The reader should note that most U.S. geothermal electric systems installed in recent years have been owned by independent power producers (IPPs) rather than investor-owned utilities (IOUs). It is also the case that when IOUs have owned geothermal power plants in the U.S., they have almost always turned to a geothermal specialty company to develop and operate the field (wells and pipes). When this is the case, different tax write-offs apply to the field operation and the power plant operation.

Certain specialized factors are required for correct analysis of the economics of the field components of the system, e.g., fluid royalties, intangible drilling expenses, and depletion allowances. The values assumed for these factors are:

- Life for Federal Income Tax: Five years.

- Renewable Energy Tax Credit: This is 10 percent of capital cost of the system, up to but not including transmission equipment (Section 48 of Federal Tax Code). The basis for depreciation must be reduced by 50 percent of the credit taken.

- Expensing of Intangible Fraction of Well Costs: This study assumes the intangible fraction is 100 percent for exploration wells and 70 percent for production-related wells.

- Percentage Depletion Allowance: 15 percent per year of field-related revenues (fraction of annual revenues attributable to field-specific investments, operating costs, and profits). In any year, percentage depletion may not exceed 50 percent of taxable income. If the field part of the project shows an annual loss, cost depletion may be taken.

- Geothermal Fluid Royalty Payments: The rates for royalties on Federal geothermal properties are a reasonable basis for estimating typical royalty costs. Federal royalties for liquid-dominated reservoirs are 10 percent annually of [project gross revenues minus power plant-related costs and returns to capital]. This is roughly equivalent to 10 percent of annual field-related costs and returns.

- Given the breadth of some of these incentives, Federal and state income tax calculations need to adhere to provisions for Alternative Minimum Tax.

Working Model for Cost Estimation: The estimates of project costs in Tables 2 and 3 are derived from more-fundamental estimates than shown in those tables. The primary technical estimates used are shown in Tables 5 (variables) and 6 (constants). Tables 7 and 8 document the formulas needed to derive capital and O&M costs, and system performance (levelized capacity factor and output.) Table 8 includes a column that documents the temporal pattern of expenditures. Note especially that wildcat exploration precedes other project costs by a considerable period. All costs in these tables are in 1997 dollars.

5.0 Land, Water, and Critical Materials Requirements

Land: The land use stated, 10 ha (10 hectare; 25 acres) for a 50 MW_e plant, is that for direct occupancy for the power plant and surface disturbances due to wells and pipelines. Roads are not included in the estimate. The total well field area for the reference 50 MW_e flash plant is on the order of 160 ha (400 acres). These are estimates made from general information, and apply to either flash and or binary systems.

Water: Water use for the reference dual flash plant is essentially nil because all of the cooling tower makeup comes from steam condensate, while still allowing the plant to meet typical requirements to reinject at least 80 percent of the geothermal fluids produced. Because the binary plant characterized here is air cooled, it consumes no cooling water.

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Table 5. Basic estimates of system characteristics.

ID	Item	Units	Base Year Value	
			Flash	Binary
I. Capital Cost and Initial Performance:				
eA	Power plant, capital cost	$M	30.124	77.256
eB	Power plant net effectiveness	Wh/kg fluid	26.41	11.60
eC	Average cost per production well	$M	1.639	0.492
eD	Wildcat exploration probability of success	ratio	0.20	0.20
eE	Wildcat non-drilling costs per unit	$M	0.546	0.546
eF	Years wildcat cost carried to plant start up date	years	6	6
eG	Site confirmation, soft cost	$M	0.874	0.874
eH	Production well probability of success*	ratio	0.80	0.85
eI	Number of injectors per producer †	ratio	0.5	0.5
eJ	Initial average flow per producer	1000 kg/hr	304.5	317.4
eK	Impact on flow of better completions ‡	ratio	1.00	1.00
eL	Impact on flow of better reservoir engineering ‡	ratio	1.00	1.00
eM	Cost, per downhole production pump #	$M	0.0	0.154
eN	Gathering system cost, per active production well	$M	0.212	0.080
II. Operating Performance and Costs:				
eQ	Power plant, general O&M cost	$M/year	2.350	2.490
eR	Field general O&M cost	$M/year	1.172	1.224
eS	Well general rework cost	$M/year	0.382	0.218
eT	Field pressure decline	% per year	6	6
eU	Fraction of injectors relocated early in project	ratio	0.25	0.25
III. System Output				
eY	Nominal capacity factor	%	92	92
eZ	Capacity levelization factor **	%	97	97

Notes:

* "Producer well probability of success" is the logical inverse of "producer well dry hole fraction." The latter term is more commonly used in the U.S. industry.

† Synonyms: producer -- production well; injector -- injection well.

‡ Initially 1.00, but expected to increase with improved technology.

\# Downhole production pumps are used at binary systems only. Cost per pump (@ producers and spares).

** Used to account for certain effects of reservoir pressure and well flow rate decline.

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Table 6. Fixed assumptions (constants, base year value).

ID Code	Item	Units	Flash	Binary
cA	System net size	MW	47.9	50.0
cB	Number of 50 MW plants over which to spread wildcat costs	integer	5	5
cC	Cost multiplier for first site test well	ratio	1.67	1.67
cD	Cost multiplier for second site test well	ratio	1.25	1.25
cE	Siting & Licenses	$/kW	64	64
cF	Land	$/kW	1	1

Table 7. Formulas for intermediate values.

Formula, Name	Units	Formula
FA, Wildcat exploration cost	$M	FA = (eC + eE) * (1/(eD)) * (1/cB) 'Regional cost; spread over five power plants.
FB, Confirmation well cost	$M	FB = (cC + cD) * eC 'Two wells, at decreasing cost per well.
FC, Flow per producer	kg/hr	FC = eJ * eK * eL 'Improves due to better completions and reservoir engineering.
FD, No. active producers needed	number *	FD = ((cA * 1000)/eB)/FC + 0.5 + 1.0 'Plant flow need divided by flow per producer, plus one spare.
FE, No. of initial dry producers	number	FE = FD * (1/eH - 1) 'Accounts for dry holes in production drilling
FF, No. of initial injectors	number	FF = FD * eJ
FG, Producers, initial cost	$M	FG = FD * eC
FH, Dry holes, initial cost	$M	FH = FE * eC 'Attempted producers that failed
FI, Injectors, initial cost	$M	FI = FF * eC
FJ,Production pumps, initial cost	$M	FJ = eM * FD 'Unit cost times active producers plus spares
FK, O&M cost to capitalize and operate makeup wells	$M/year	From detailed model and tables. 'One effect of {eT}
FL, O&M cost to relocate injector wells	$M/year	From detailed model and tables. 'Effect of {eU}
FM, Levelized system output	kWh per year	FL = 8760 * (eY * eZ / 1E4) 'Levelized system output

* Value is not rounded (the 0.5 factor compensates) to avoid algebraic discontinuities (step functions) that are difficult to interpret in screening and policy studies. Planner of a real project would round well counts up to the nearest integer. The 1.0 factor provides for one spare producer.

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Table 8. Final values of costs, and temporal pattern of outlays.

Line, Formula or Source	Item	Base Year Value (1997$ in 1997)		Annual Spend Pattern [*]	Tax Aspects [†]
		Flash	Binary		
Capital costs (Units: $/net kW, overnight costs)					
1, FA	Wildcat exploration cost	45.63	20.76	-6 100 [‡]	idc = 100
2, cE	Siting & licenses	64.00	64.00	-3 100	idc = 0 cd = 100
3, cF	Land (purchased)	1.00	1.00	-3 100	idc = 0 dep = 0
4, FB	Site confirmation, well costs	99.92	28.72	-3 100	idc = 100
5, eC	Site confirmation, soft costs	18.25	17.48	-3 100	idc = 50
6, FE	Producing wells, initial	255.15	148.30	Standard [#]	idc = 70
7, FD	Dry producers, initial	63.79	26.17	Standard	idc = 100
8, FG	Injection wells, initial	110.46	69.23	Standard	idc = 70
9, FF	Field piping, initial	47.29	35.29	Standard	idc = 0
10, FJ	Production pumps, initial cost	0.00	46.50	Standard	idc = 0
11, eA	Power plant	628.89	1,545.12	Standard	idc = 0
12,	Owner's costs	109.27	109.27	Standard	idc = 0
O&M Expenses (Units: $/net kW, first year)					
13, eR	Field, general O&M	24.46	24.48	O&M	
14, eS	Wells, rework cost	7.98	4.37	O&M	
15, FK	Field, makeup producers	12.22	7.09	O&M	
16, FL	Field, relocated injectors	2.73	1.71	O&M	
17, eQ	Power plant, O&M cost	49.06	49.78	O&M	
Performance (Units: kWh per year)					
18, FM	System levelized output	7,817	7,817	NA	

Notes:

[*] "6 100" means: 100 percent of the funds are spent in year 6 before startup. (The year immediately before the date of startup is counted as "year 1 before startup."

[†] Tax aspects: -idc: Fraction expensed as intangible drilling cost (remaining fraction is depreciated). -cd: Depletable fraction on which cost depletion may be taken. -dep: Depreciable fraction (land is not depreciable)

[‡] The "6 year" delay shown here is a variable. See item eF in Table 5. This study estimates 6 years for 1997 - 2000, 5 years for 2005-2020, and 4 years for 2030 for all technologies.

[#] "Standard" spend pattern is 33% in year 2 and 67% in year 1 before startup.

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