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Assessment of Geothermal Resources for Electric Generation in the Pacific Northwest

Draft Issue Paper for the Northwest Power Planning Council

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GEOTHERMAL GENERATION:
A SUMMARY OF FINDINGS

As the electricity surplus in the Pacific Northwest declines, efforts to identify new resources which are available, reliable and cost-effective are intensifying. Geothermal electricity is a promising source of new power which is indigenous to the Northwest and environmentally benign. Geothermal generating technologies have been proven to be reliable and cost effective, with over 200 plants, with a total generating capacity of 5,400 MW on-line in 17 countries. Geothermal plants are routinely built for $1,200 to $1,800 per rated kW with on-site fuel sources. However, for lack of assured fuel supplies (i.e., proven natural steam or hot water reservoirs) and local operating experience, geothermal energy still lacks credibility in the Northwest and cannot at this time be considered to be a viable option to meet future electrical demand.

Northwest power planners need to determine whether geothermal is available and sufficiently reliable to support a large, unfilled power need sometime in the 1990s. The need to replace aging power plants and growing consumer demand will strain existing supplies. New supply has been assumed in recent Council power plans to come from new coal generation. However, environmental and social concerns now challenge the region's ability to site new coal generating facilities.

To become a commercial reality in the 1990s, geothermal energy must first prove itself a credible source of affordable and reliable power. This requires a near-term commitment by Northwest power managers to small confirmation projects. Informed consensus is that equitable power sales contracts for 10 to 25 MW pilot plants on three to five reservoirs, coupled with transmission access, are the most effective form of regional support. Geothermal confirmation must prove the existence and usefulness of commercial-scale reservoirs, and demonstrate compatibility with land use laws, environmental requirements and utility systems. It must also document non-price qualities for consideration in competitive bidding processes. The geothermal industry cannot proceed alone; utilities and power managers must participate to justify the investment needed to obtain the information needed for energy planning and management.

In addition to proving underground reserves, confirmation tests the political feasibility of development by bringing together federal and state oversight, the geothermal industry and the financial community. Both generic and site-specific issues can be identified and mitigation strategies can be developed.

The critical element in reducing Pacific Northwest geothermal uncertainties is not technical research. It is regional acceptance of diversity and limited risks in pursuit of viable new energy sources. Twenty years of earth science and a decade of geothermal resource assessment has identified a significant geothermal potential. The next steps are resource confirmation and development. Many experts believe the Northwest to be geothermal's next and, perhaps, the largest frontier ... subject to market opportunities.

I. GEOTHERMAL AS AN ENERGY RESOURCE

Geothermal resources are the usable heat of the earth. Although possibly the purest definition, this may not be the most useful one. Depending on historical treatment of other natural resources, various federal and state agencies in the United States have adopted specific legal definitions. The federal government and at least one state treat geothermal as a mineral. Several states regard geothermal as water and several others consider it to be *sui generis* (i.e., unique unto itself). (Anderson and Lund, 1987)

These different legal treatments indicate not only the unique qualities of geothermal energy but also an incomplete understanding of geothermal resource potentials. The important and overriding aspect of geothermal resources is that is it the <u>heat</u> contained within both the rock and fluid within the earth; heat which can be extracted to generate electricity.

The Pacific Northwest entered into commercial use of geothermal energy with construction of the Warm Springs Heating District in Boise, Idaho in the early 1890s. However, the resource here and elsewhere in the United States remained more a novelty than a significant energy resource until the 1960s when geothermal energy was first used to produce electricity at The Geysers in northern California.

Interest in geothermal energy grew through the 1970s with passage of the Geothermal Steam Act of 1970 (P.L. 91-581), the Arab Oil Embargo of 1972-74, the development of the Federal geothermal leasing program, and passage of the Federal Geothermal Energy Research, Development and Demonstration Act of 1974 (P.L. 93-410). The U.S. Geological Survey took the lead role in resource identification and published USGS Circulars 726 and 790. (Muffler, 1979) These circulars identified promising areas for leasing by potential resource developers. By the mid-1970s, numerous state and federal programs were in place to assess geothermal resources of the United States and to aggressively encourage exploration and development. (Bloomquist, 1985)

Geothermal interest remained high through the late 1970s and early 1980s due to increasing oil prices, market creation opportunities by the Public Utility Regulatory Policy Act of 1978 (PURPA)(P.L. 95-617), and a second major oil shortage in 1979.

By 1981, major changes began to occur. At the national level, oil prices stabilized and interest in renewable energy waned. In the West, a strong California energy market reflected sustained economic growth and active implementation of PURPA by State regulators. In December 1980, the Pacific Northwest Electrical Power Planning and Conservation Act (P.L. 96-50) created the Northwest Power Planning Council and gave Bonneville Power Administration (BPA) new authority and responsibility for providing most of the region's electrical supplies.

By 1983, projected Northwest power deficits were replaced by forecasts of prolonged surplus and low, stable rates. (NPPC, 1983) The need for exploration vanished, along with the hopes of developers that rising regional electrical prices would create a profitable market for geothermal energy. The Northwest surplus has stalled resource activity for almost a decade, even as exploration and power plant construction have expanded in Nevada and California and throughout the world.

Exploration and Development Trends

Throughout the 1970s, the United States' geothermal industry was characterized by: (GeothermEx, Inc., 1987)

- Continued exploration and drilling of new prospects, under the impetus of rising energy costs and supportive national energy policies.

- The search for hydrothermal systems with fluid temperatures in excess of 200°C (392°F), and especially for vapor-dominated (i.e., steam) systems.

- A clear separation between the developer-supplier of geothermal fuel and the producer of geothermal electricity.

- The desire to build relatively large (greater than 50 MW) geothermal generation facilities.

- The construction of the first pilot plants outside The Geysers in the Imperial Valley of southern California.

As a result of these activities:

- Few new fields were developed, although many attractive prospects were found.

- Exploration and field development were financed almost entirely through USDOE research programs or USGS regional scientific programs and/or equity capital from petroleum companies who dominated private exploration and drilling.

- Utilities designed, built, and owned geothermal generation facilities and purchased steam from field developers.

- Government attitudes and actions were dichotomous. On one hand, incentive programs were offered to geothermal explorers and developers, concurrent with scientific studies. On the other hand, environmental constraints and regulatory delays generated complaints from almost all parties and even caused some companies to leave the industry.

- Debt financing was very difficult to obtain because of the uncertainties over geothermal field life and development risk, and was very expensive when available. This further tended to concentrate control of the industry in the hands of a relatively small number of petroleum companies and investor-owned utilities.

By the early 1980s, several new trends had emerged. (GeothermEx, Inc., 1987) First, and most important, the separation between fuel producer and power generator broke down, as several electrical utilities either acquired leases for exploration or purchased equity in operating geothermal facilities. Engineering contractors and turbine fabricators began to acquire equity positions in development projects. Some began to own and operate power generation facilities. Joint ventures formed as vertically-oriented (i.e., exploration through development to operations) organizations to develop site-specific resources.

Second, for a short time there was a strongly attractive set of government incentives to develop geothermal power. These included the Public Utilities Regulatory Policy Act (PURPA, 1978); the geothermal energy tax credit, percentage depletion allowance on production, and tax write-off of intangible drilling expenses (Energy Tax Act of 1978, P.L. 95-618); accelerated depreciation of capital investment (Windfall Profit Tax Act of 1980, P.L. 96-223); and the Geothermal Loan Guarantee Program. These incentives, however, acted more to spur the development of already discovered properties than to encourage further exploration.

Third, technology was developed or modified, to allow the generation of electricity from low to medium-temperature geothermal fields (120-220°C). The availability of this technology coincided with government incentives, prompting formation of new corporate entities dedicated to geothermal electricity production.

Fourth, transmission-line access to the populous markets increasingly became a severe constraint. During the 1970s, emphasis was on finding resources, assuming that <u>any</u> significant geothermal field would be developed, regardless of location. As project development followed exploration, transmission and market access required utility involvement. Such participation remains a critical issue today.

Commercial scale geothermal generation began in the 1960s at The Geysers because development was relatively simple, economically feasible, and because a major market was nearby. Not until the majority of steam reserves at The Geysers had been committed to specific power plants did work move to the Imperial Valley of southern California and to other promising areas in California, Nevada, and Utah.

Unfortunately, the development surge of the early 1980s did not reach the Pacific Northwest. This was due, in part, to: (a) physical access to promising areas was limited; (b) leasing was slower and more difficult than elsewhere; (c) exploration was more complex and did not lead to immediate discoveries; (d) the major market for geothermal energy, perceived to be in California, was difficult to reach from the Pacific Northwest; and (e) there was no market in the Pacific Northwest because of low energy prices, the forecasted surplus and a sluggish economy.

In the late 1980s, exploration has virtually come to a halt except for a few locations in the Cascade Range province. The principal causes of this are: (a) the desire to commercialize the backlog of discovered fields within the timeframe of California's Standard Offer No. 4 contracts; (b) sharply constrained exploration budgets due to falling energy prices; and (c) uncertainties over the electric power market until the middle or late 1990s ... especially in light of falling fuel prices since 1982, limited transmission-line capacity, emphasis on energy conservation policies, and the expiration or modification of incentive programs.

Given these constraints, it is unlikely that exploration of new prospects in the Pacific Northwest will move ahead unless new incentives and/or access to markets are provided and affirmative policies are adopted by government.

Resource Development Issues

The technology, philosophy and economics of geothermal generation have changed greatly since 1980. (Bloomquist, et al, 1987) From the early 1960s to the late 1970s, the American geothermal industry was, for all practical purposes, a single technology unique to The Geysers. The resource was dry steam at fairly constant temperature and pressure with low amounts of noncondensible gases. Resource companies led exploration for and development of The Geysers' steam field. Pacific Gas and Electric Company (PG&E) was the only utility involved in design, construction and operation of geothermal power plants. Steam was purchased from resource companies at a percentage of the sales price of the electricity.

Since 1980, "The Geysers Scenario" has rapidly diversified. Steam discoveries elsewhere have different physical or chemical qualities. Nearly all new resources developed in California, Nevada, Utah, Idaho, and Hawaii are hot water instead of steam, with temperatures varying from near boiling (100°C [212°F]) to 260°C (500°F) or above. Water quality varies from several hundred parts-per-million (PPM) total dissolved solids to upwards of 350,000 PPM. The ability to modify established technologies to achieve energy and economic efficiencies with varied fluid qualities has signalled the maturation of geothermal energy as an available and reliable resource, technically proven and economically viable. (Bloomquist, et al., 1987, 1989)

Resource companies continue to explore for and develop resources, but are no longer limited to merely selling steam or brine. Several now construct, own and operate power generating facilities. Utility involvement may be as power brokers or as joint venture participants with non-utility developers. Risk sharing by utilities during exploration and development can gain priority access to new generation, lower "fuel" prices, and privileged insight to new resource potentials. The last value may be the most significant as it reduces planning uncertainties and enhances acquisition strategies and decisions.

Nothing has altered electrical generation so much as the financial structure of new, non-utility power plants. (Geyer, 1989) Commercial, non-recourse financing by risk-taking, profit-oriented developers has introduced new efficiency standards and accountability to plant design, construction, and operation. Geothermal plants of varied designs and ownership are performing throughout the West at availability and output levels not previously seen in the utility industry. (Bloomquist, et al., 1989)

Today's high performance plants are redefining reliability and efficiency in economic as well as engineering terms. Risks and costs unique to geothermal development have forced efficiency gains through innovative designs and practices. (Stone & Webster, 1985, 1988) As a result, geothermal capital costs and construction periods are 30 to 50 percent below published utility costs for other generating resources; availability and capacity factors routinely are in the mid-90 percent range and are 25 to 40 percent above norms of other technologies. (Bloomquist, et al., 1989) Capitalized and dedicated steam fields have stabilized both fuel supply and price while enhancing operations and reducing costs. Whatever the full cost of future power at large, geothermal's life-cycle costs and performance levels assure a competitive position in utility portfolios.

Geothermal energy has grown in the 1980s to a commercial-scale resource which is geographically and technically diverse, compatible with utility operations, and environmentally benign.[1] It has expanded from one reservoir and one technology to over 50 plants successfully using at least 4 technologies on 16 reservoirs in 4 states. (Geyer, 1989) Worldwide, geothermal fuels some 5,400 megawatts of generating capacity. Approximately 2,800 installed megawatts are now operating in the United States (2,344 MW in California as of May 1989) with another 450 MW to begin delivering power by year-end. (Bloomquist, et al., 1989) Construction is expected to drop sharply in 1990 with the sunset of California's Standard Offer No. 4 contracts. The Northwest is viewed by many in government and industry as the next frontier for development.

Most utilities, regulators, financial institutions, and government officials still tend to view geothermal as dominated by production technology problems. (Fenn, 1986) While reservoir and materials engineering challenges do exist, more immediate needs include risk sharing for first-time financial partners, rate sharing for pilot plants on new fields, and greater comfort for banks and utilities with reservoir assessment techniques. In the Northwest, geothermal growth and stature over the next decade will be governed more by institutional factors than by technical hurdles. (Geyer, 1989) This seems unescapable due to lagging regional regulatory experience and the likelihood of environmental and development controversy.

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1. The 230 MWe geothermal complex at Coso, CA, has been described by the <u>California Energy Commission</u> staff in an affirmative ruling as "...will likely set a standard which future similarly situated projects must meet" and "the advances in geothermal technology...should result in the increased development of California geothermal resources."

Geothermal development has two distinct facets: steam or hot water wellfield development and management, and power plant design, construction and operation. While each continues to advance in sophistication and capabilities, this review may accept that both technologies are established and operational. While reservoir discovery and characterization must precede development in the Northwest, no major scientific, materials or engineering breakthroughs are necessary for wellfield or power plant development in the region. (Bloomquist, et al., 1985, 1987, 1989)

New electrical generation projects seldom can compete on a cost-of-energy basis with the embedded costs of existing facilities. However, geothermal's life cycle-costs are highly competitive with those of other <u>new</u> generation options. (Bloomquist, et al., 1989) Given an opportunity to site and build facilities with market access (i.e, both transmission and power sales agreements), successful performance of projects in states with diverse resource characteristics and legislative, environmental and social settings suggests that geothermal can become a major option to meet future generation needs in the Northwest.

Generic Technologies:

Four geothermal power conversion systems are commonly used. These are: (1) dry steam, (2) single-flash, (3) double-flash, and (4) binary cycle power plants. Technology selection is sensitive to fluid form and temperature (i.e., steam, hot water).

Dry steam reservoirs occur only rarely but are the simplest to exploit for electrical generation. This was first done at Lardarello, Italy, in 1904. The United States' geothermal industry began when dry steam was harnessed at The Geysers in 1955. The Geysers remains the only commercial dry steam field in this country. The basic design (Fig. 1-1) involves directing the steam from naturally flowing dry steam wells through a rock catcher, then directly into a turbine. Condensers are used to create a vacuum at the turbine exhaust to increase efficiency. Mechanical draft cooling towers are normally used. Condensate is injected back into the reservoir. The second law of thermodynamics' efficiency of dry steam plants is near 50 percent. (Anderson and Lund, 1987)

Single-flash power plants (Fig. 1-2) are designed for hot water reservoirs above 220°C (425°F). High-temperature reservoir water flows to the surface via wells and is directed into production separators. A lower pressure maintained within the separator allows a portion of the hot water to flash into steam. In most systems, this amounts to about 15 to 20 percent of the water. The flashed steam is directed from the separator, usually through scrubbers, to the

Table 1-1

Resource Conditions and Conversion Processes

Resource	Conversion Process: Direct Steam	Single Flash	Double Flash	Binary
Steam (Similar to The Geysers) 175°C (350°-420°F)	X			
Hot water 277°-216°C (530°-420°F)		X	X	
Hot water 216°-177°C (420°-350°F)		X	X	
Hot water 177°-150°C (350°-300°F)			X	X
Hot water 150°-90°C (300°-177°F)				X

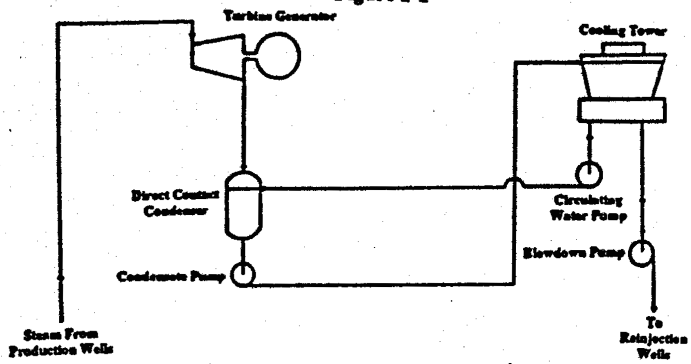
turbine. Liquid from the separator is collected in the water disposal system and disposed of, together with condensate, in injection wells (preferably into the reservoir horizon). The single-flash system utilizes condensers and cooling towers like the dry steam plant. The second law efficiency of a single-flash plant is about 35 percent. (Anderson and Lund, 1987)

Double-flash plants (Fig. 1-3) are essentially the same as single-flash systems, except they incorporate a second-stage separator where the fluid phase from the first-stage separator is flashed again at a lower pressure. This second stream of lower pressure steam is directed into either a later stage of a high-pressure turbine or a a second stage turbine equipped with a larger rotor. Spent fluids and condensate are injected. The system is designed to take maximum advantage of the energy in the geothermal fluid. Double-flash plants are in use throughout the world on hot water reservoirs. Double-flash plants have a second law efficiency of about 40 percent. (Anderson and Lund, 1987)

Binary cycle power plants (Fig. 1-4), also called Rankine cycle plants, consist of two separate fluid loops (hence the name "binary"). The brine loop consists of wells equipped with downhole pumps that circulate production fluids through heat exchangers. Here a portion of the heat is transferred to a "working fluid" such as isobutane or freon. Once the heat has been extracted from the production fluid, it is moved by a pump to an injection well. The working fluid, which is easily vaporized due to its low boiling point, is used to turn the turbine. All binary systems are equipped with a condenser, a working fluid storage tank, and one or more feed pumps. Once condensed, the feed pump moves the working fluid back through the heat exchanger where it is again vaporized, completing the second loop.

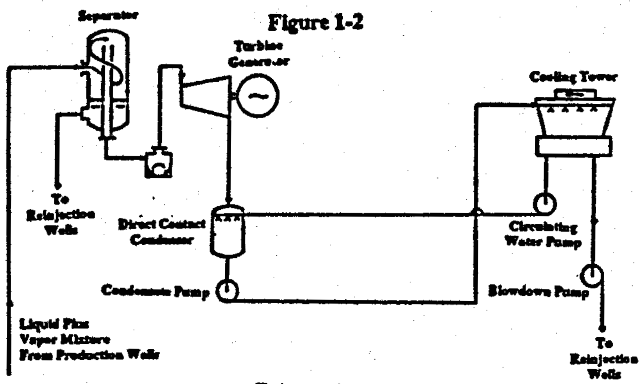
Binary type power plants are best adapted to reservoir temperatures below 193°C (380°F). Above this temperature, it becomes difficult to maintain a fluid phase in the reservoir and heat exchangers cannot withstand the rigors of two-phase flow. The economic threshold

Figure 1-1



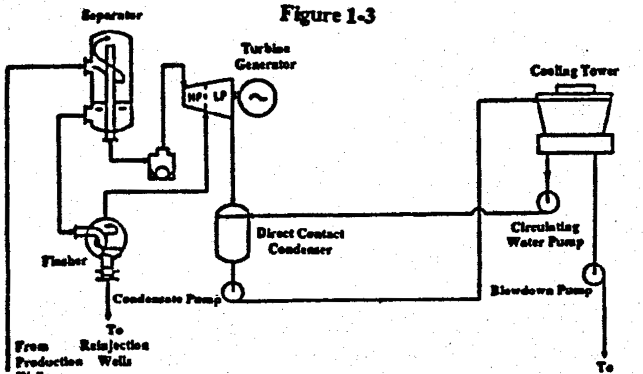
Schematic plan of a geothermal power plant

Figure 1-2



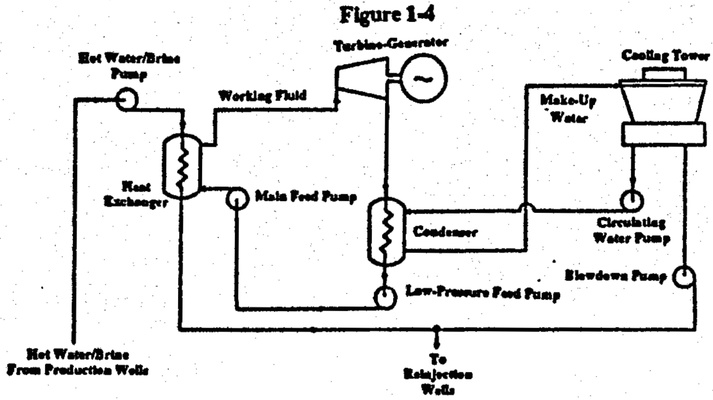
Flash conversion system

Figure 1-3



The double-flash conversion system

Figure 1-4



Binary geothermal power plant

temperature of binary power generation is based on the changing economics of power markets and generation costs. (Anderson & Lund, 1987) Binary plant components are often modular in design and easily lend themselves to factory pre-fabrication. Thus they can usually be installed rapidly at relatively low costs. Binary plants' second law efficiency is lower than for other designs and the internal (parasitic) load for pumps and auxiliary equipment is higher. Despite thermal and economic efficiency penalties, small binary units are suited to wellhead tests or stand-alone installations at low and moderate temperature resources or where environmental factors preclude the use of other technologies.

Factors other than temperature and pressure which help dictate the type of plant to be built include dissolved solids content, the size of the reservoir and environmental compliance requirements. A high percentage of dissolved solids can cause corrosion or scaling and may require special process engineering designs. Full-scale, commercial plants will usually be built on reservoirs of demonstrated capacity. Pilot plants may be sited on newly discovered reservoirs to provide for extended reservoir testing and a cash flow while the reservoir is being developed.

II. GEOTHERMAL RESOURCES OF THE PACIFIC NORTHWEST

From the 1960s until the early 1980s, geothermal exploration in the Pacific Northwest emphasized scientific characterization of the region and development of useful exploration techniques. Access and exploration on federal lands in the Cascade Range lagged behind Basin-and-Range activities where leases were more readily obtained. Emphasis was on finding dry steam fields similar to The Geysers. Prospects were often abandoned when drilling encountered hot water aquifers instead. Exploration was widespread but no discovery of a major geothermal field was made during this period.

This period ended with exploration at a high level of intensity, reflecting higher energy prices, inflationary mentality, numerous Federal incentives for geothermal energy development, (see Chapter I) and the sudden new availability of markets for geothermal energy under terms of PURPA. Private data remained closely held, but useful regional and site specific data entered the public domain through USDOE and USAS sponsored assessment activity, with major emphasis directed to the Klamath Falls, Newberry Volcano and Medicine Lake geothermal areas.

Region-wide leasing and exploration exposed government officials and the public to earth science and natural heat sources. This was hastened by the 1980 eruption of Mt. St. Helens in Washington State. Appreciation grew for Northwest geology and potentials for natural earth heat which might be harnessed. The media and interested citizens used geologic terms more and more.

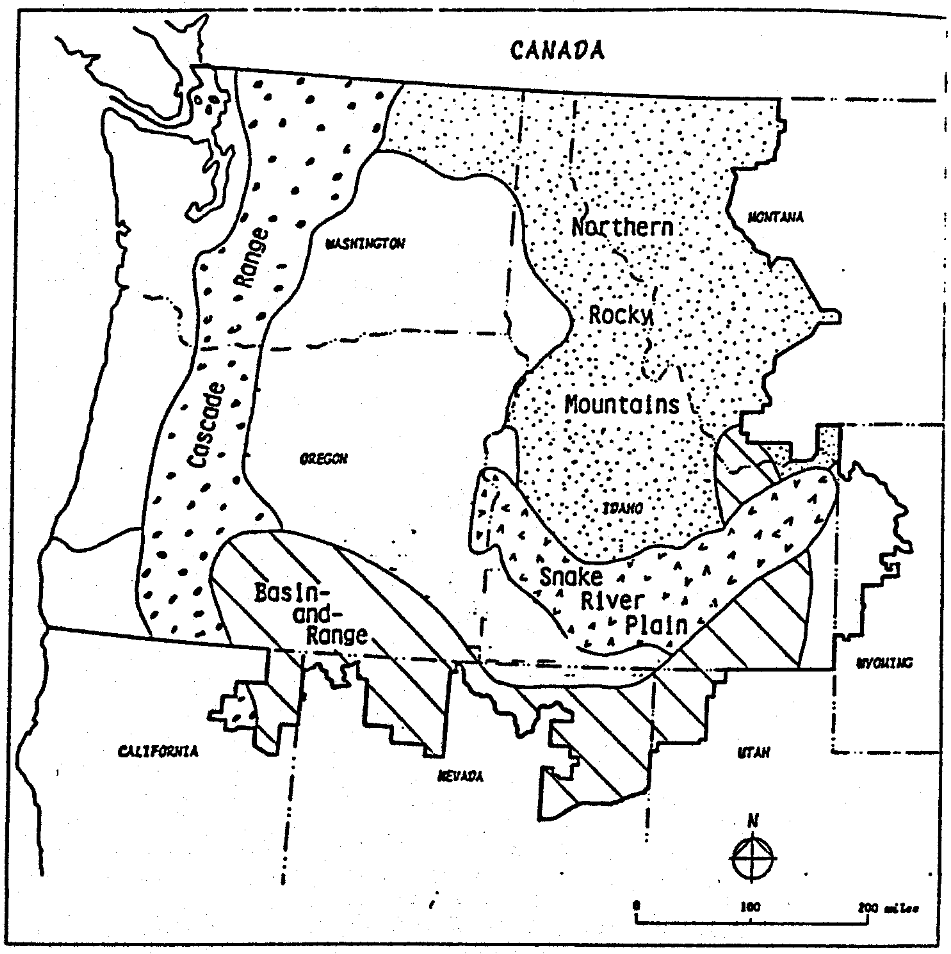
A geologic province is an extensive region of similar geologic structure and history, within which there may be one or more geothermal fields. Different geothermal fields within a single province may share similar physical and chemical characteristics. This is because the primary reason for their very existence (volcanism or extensive deep faults) is similar. (GeothermEx, Inc, 1987)

A geothermal field is a smaller area, ranging from less than one to over 30 square miles in size, from which geothermal energy can be produced for electric power generation. A geothermal field can also be called a geothermal reservoir, although the latter strictly refers to the subsurface system which stores and transmits thermal energy.

Within the Pacific Northwest region are located parts or all of 3 significant geologic provinces. These are: (1) the northern Basin-and-Range, (2) the Cascade Mountain Range, and

(3) the Snake River Plain. The Oregon-Washington lava plateaus, the margin of the Yellowstone region and parts of the northern Rocky Mountains are adjacent regions with geothermal potential.

Figure 2-1



Structural provinces of the Pacific Northwest region

1987, GeothermEx, Inc.

Geothermal conditions in the three principal provinces may be briefly summarized as:

The **Basin-and-Range** province has a general absence of volcanic or intrusive heat sources; high-temperature systems are created by deep fluid circulation along faults in areas of high conductive thermal gradients.

The **Cascade Range** has a long history of volcanism, continuing into the current decade. Eruptions in the 20th Century are recorded for Lassen Peak (1914-1917) and Mt. St.

Helens (1980-present). The most recent volcanic heat sources of this province exist along the eastern margin of the range and at the major volcanic peaks. The latter, however, are largely inaccessible due to inclusion in National Parks, National Monuments or Wilderness Areas.

The origin of the Snake River Plain has been debated among geologists for decades. By prevailing theory, no active magmatic heat source is believed to remain beneath the Plain itself; thermal activity is believed to be remnant from past magmatic influence, which is now manifest to the east at Yellowstone National Park. Moderate temperatures greater than 150°C (300°F) are widespread with none greater than 205°C (400°F) reported by drilling. (GeothermEx, Inc., 1987)

In 1983, the Bonneville Power Administration (BPA) contracted for a detailed regional geothermal assessment, using geothermal expertise from each of the Northwest States and involving industry and advisory groups. (Bloomquist, et al., 1985) The objective of this program was to consolidate and evaluate all geologic, environmental, and legal and institutional information and to apply a uniform methodology to the evaluation and ranking of potential geothermal sites.

To accomplish these tasks, the Four-State Assessment Team identified a total of 1,265 potential geothermal resource sites. All sites were screened to eliminate those which had little or no chance of development because of inadequacies of resource temperature, legal prohibitions against development, or prohibitive economic conditions. Of the original 1,265 sites, 99 were selected for detailed analysis of electrical generation potential and 150 more were studied for direct use (i.e., low temperature) development. A methodology to rank the sites by energy potential, degree of developability and cost of energy was then developed.

Ranking procedures were intended to compare sites relative to each other and to indicate which sites possessed superior, average or inferior development potential and to identify areas requiring work. The best of these sites have been used by the Northwest Power Planning Council to forecast the supply of geothermal energy which could be available to the region over a 20 year planning horizon. The most promising sites have continued to receive industry attention and their selection remains generally valid to date.

Energy costs for electrical generation were based upon estimates by Bechtel National, Inc., citing 32 plants designed or build prior to 1984. (Bechtel National, 1984) Major advances in plant design and costs from 1985 through 1989 have been documented in case studies by BPA, the Washington State Energy Office and the Oregon Department of Energy. (Bloomquist, et al., 1987, 1989) These are used to update cost models. (See Section III: Cost and Operating Characteristics of Geothermal Plants).

The period from 1981 to present has been marked by the end of widespread exploration interest, with sporadic efforts to model geology and discover reservoirs at the most promising Northwest sites. Outside the Northwest, industry attention has focused on development of previously discovered geothermal resources in California, Nevada, and Utah. This raised institutional and market issues to a level of prominence rivaling reservoir engineering and conversion technology. Northwest achievements during this period include issuance of leases on Federal lands and discovery of fluid temperatures of 265°C (510°F) at 940 meters (3,057 feet) at Newberry in a USGS test hole, and fluids well in excess of 205°C (400°F) in several privately drilled holes at Medicine Lake. These sites are potentially attractive for power generation by flash-steam technology. There are no estimates of field reserves.

Other Northwest events of the 1980s, as noted by GeothermEx, Inc. (1987) and others, include:

- Upward re-evaluation of probable reservoir temperature (at an unknown depth) at Klamath Falls to 195°C (383°F) or higher.

- Encouraging temperature and fluid findings in private drillholes at the Alvord Desert, OR. (Anadarko, 1986)

- Abandonment of federal R&D power generation efforts at Raft River in 1982 after only a few months of generation tests at about half the rated 5 MW capacity. Production from wells to 1,850 meters (6,000 ft.) at temperatures under 150°C (300°F) was demonstrated to be technically feasible but commercial feasibility could not be established.

- Abandonment of power generation attempts at Lakeview, Oregon, without having demonstrated the commercial feasibility of the reservoir to support 1 or 2 MW of power. This project suffered from fluid production problems, inadequate disposal mechanism and inability to negotiate a long term power sales agreement.

- Progressively reduced levels of activity at exploration sites in Nevada, eastern Oregon, Idaho, and Montana in response to falling energy prices, shrinking markets for electricity, limited transmission line capacity, cessation of geothermal energy tax credits and other changes in tax law.

- Major public involvement and education efforts in central Oregon, with resulting awareness of geothermal potentials and political initiatives for land use restrictions on geothermal development affecting about 80 percent of the promising lands at Newberry Volcano. (Collins, 1989) These include state Energy Facility Siting Council and USDA, Forest Service declarations of the caldera as "unsuitable for geothermal development" (HJR 31, 1975; Deschutes NF, 1986) and draft federal legislation to create a Newberry Volcanoes National Monument.

- Concerns for protecting the thermal manifestations within the National Park system and opposition to drilling and development in the vicinity of Crater Lake National Park, resulted in federal legislation to protect significant thermal features in National Parks and Monuments. (P.L. 100-443) The passage of this legislation resulted in suspended operations, administrative appeals, and National Park Service-funded scientific studies inside Crater Lake National Park. These raised media and public concern and new uncertainties about future geothermal development near the Park.

- Three USDOE co-funded gradient holes at Newberry and near Mt. Jefferson reached below 4,000 feet but data placed in public records failed to reveal significant temperatures or permeability. A private gradient hole near Breitenbush Hot Springs reached 2,460 meters (8,000 ft.) feet with a 135°C (275°F) aquifer at 760 meters (2,470 ft.) and a maximum temperature of about 170°C (340°F). This hole has been plugged and abandoned.

- Discovery of 265°C (545°F) near 3,000 meters (10,000 ft.) depth at Meager Creek, B.C. (Mt. Garibaldi), provided an important data point in the northern-most part of the Cascade Range and confirms the potential for high temperature discoveries throughout the Cascades.

Over three dozen areas have been drilled to significant temperatures or retained by industry with expressions of interest to proceed, subject to availability of a power sales market.

These activities have prompted the following generalized observations on geothermal resources of the Pacific Northwest:

- Nowhere in the Pacific Northwest region has a commercially exploited high temperature geothermal resource been confirmed to date. The only confirmed resource area (Raft River, ID) has perhaps 5 to 10 MW of proven reserves.

- The commercial generation potential of the Cascade Range is believed (despite limited knowledge about this province) to be larger than that of the Basin-and-Range province, based on the Cascades' young volcanic history and areal extent.

- A large geothermal resource may exist beneath the eastern end of the Snake River Plain; however, almost nothing is known about it. Development access and future exploration is barred by federal legislation due to the proximity of Yellowstone National Park.

- Exploration is much further advanced, and has been significantly more successful, in the Basin-and-Range province than elsewhere in the Pacific Northwest region. Exploration technology is less-well-developed for use in the other provinces.

- The best-known and most developed geothermal fields of the Cascade Range and Basin-and-Range provinces are outside the Pacific Northwest Region, as defined by the Columbia River Basin and adjacent areas served by BPA. These include Medicine Lake, California, and Beowawe, Nevada, both located about 20 miles outside BPA's service boundaries, as well as several of the Basin and Range sites in Nevada and Utah.

- Nothing to date indicates that any of the Northwest resources will have unusual or troublesome geochemistry, or will present unusually difficult resource-related operating conditions. Access and climate may present challenges.

- Environmental and land use constraints on exploration and development are expected to be most severe in the Cascade Range and on parts of the eastern Snake River Plain. There are fewer constraints on development in the Basin-and-Range province.

- Access to geothermal areas will probably be more difficult in the Cascade region than elsewhere in the Pacific Northwest, because of Wilderness and National Park designations, topography and climate, and possibly because of other land use restrictions.

- Because of better developed exploration technology, the results of exploration to date, considerations of land use and access, and despite a probably smaller resource base, confirmation and commercial development is expected to proceed more rapidly in the Basin-and-Range province than elsewhere in the region. However, the remoteness of most of the Basin-and-Range province makes transmission access and interconnection costs critical aspects of confirmation activities.

III. COST AND OPERATING CHARACTERISTICS OF GEOTHERMAL POWER PLANTS

Data Source

To prepare information for the 1990 Northwest Power Plan, resource specialists from Bonneville Power Administration (BPA), Washington State Energy Office (WSEO) and Oregon Department of Energy (ODOE) conducted on-site interviews with active members of the geothermal industry. The objective of these meetings was the obtainment of empirical data and first-hand insight to events associated with exploration, development, financing and utility integration. The findings were often startling. Many were privileged. Company confidential information was shared with the interviewers on the condition that it would not be cited or published. While many findings are shared herein, citation is minimized to respect the sources' desires.

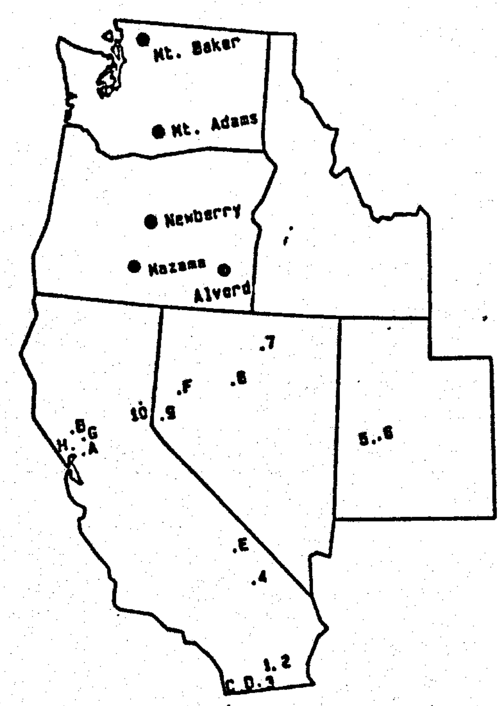
Figure 3-1

New Western States' Geothermal Plants
BPA Project Interviews

<u>1986 Case Studies</u>

A. Oxy #1 (Santa Fe)
B. SMUDGEO #1
C. Heber Binary
D. Heber Flash
E. Mammoth-Pacific
F. Desert Peak
G. CCPA (The Geysers)
H. Bear Canyon

● Primary Northwest Lease Areas



<u>1987-88 Case Studies</u>

1. ORMESA #1/ORMESA #2
2. Salton Sea
3. B.C. McCabe
4. Coso
5. Blundell
6. M.E.I.
7. Beowawe
8. Dixie Valley
9. Steamboat/ Yankee-Caithness
10. Wineagle/Amedee

Table 3-1

Facilities reviewed on-site* and/or in literature included:

		Technology	MW Gross	MW Net
	CCPA	Direct	130	120
*	Santa Fe #1	Direct	88	80
*	SMUDGEO #1	Direct	78	72
	Selected PG&E Units	Direct	55	50
	Bear Canyon	Direct	22	20
	Salton Sea #3	Sgl Flash	54	49.2
*	Blundell #1	Sgl Flash	23.5	20
*	Yankee-Caithness	Sgl Flash	13.5	11
*	Desert Peak	Sgl Flash	10.5	9.5
*	Heber Flash	Dbl Flash	52	47
	GEO East Mesa	Dbl Flash	37	31
*	Coso #1	Dbl Flash	32	28
*	Dixie Valley #1	Dbl Flash	58	50
*	Beowawe #1	Dbl Flash	16.6	15.1
*	Heber Binary	Binary	70	47
*	ORMESA I	Binary	30	24
*	ORMESA II	Binary	20	16
*	B.C. McCabe #1	Binary	12.5	10
*	Mammoth-Pacific	Binary	10	7
*	Steamboat	Binary	8.4	6.8
*	Mother Earth Indus.	Binary	4.4	3.9
*	Amedee #1	Binary	3	2
*	Wineagle #1	Binary	0.66	0.62

Engineering firms were approached for information, subject to client approval. Talks were held with Stone and Webster Engineering Corporation and Barber-Nichols Engineering Company. Utilities interviewed included Sierra Pacific Power Company (Nevada), Imperial Irrigation District (Imperial Valley) and Citizens Power and Light Corporation (national market). Financiers of geothermal projects were visited, including Bankers Trust, Citibank N.A., Swiss Bank Corporation, Credit Suisse, Union Bank of Switzerland and GE Capital Corporation.

Table 3-2

Geothermal Plant Data Matrix

	Santa Fe #1	SMUDGEO #1	Heber Binary	Heber Flash	Mammoth-Pacific	Desert Peak
Size (Gross MW)	96	78	70	52	10	10.5
Size (Net MW)	80	72	47	47	7	9.5
Conversion Tech.	Direct	Direct	Binary	Dual Flash	Binary	RST/Flash
Steam Supplier	Santa Fe	Aminoil	Chevron/Union	Chevron	Mammoth-Pac.	Phillips
Plant Owner	Santa Fe	SMUD	SDG&E et al.	GECC	Mammoth-Pac.	Phillips
Plant Operator	Santa Fe	SMUD	SDG&E et al.	Heber Geo Co.	Mammoth-Pac.	Phillips
Plant Designer	SWEC	SWEC	Fluor Eng.	Gibbs & Hill	Ben Holt Co.	Phillips
Utility Service Area	PG&E	PG&E	IID	IID	SCE	SPPC
Utility Purchaser	PG&E	SMUD	SDG&E	SCE	SCE	SPPC
Plant Financing	Internal	Bonds	Largesse	Internal	Internal	Internal
Plant Features	2 Turbines	#/hr	Scale	2 Steam Trains	Air Cooled	RST
Construction Time	24 mo.	26 mo.	24 mo.	20 mo.	13 mo.	18 mo.
On-Line Date	4/84	12/83	6/85	8/84	11/84	12/85

GECC = General Electric Credit Corp.
IID = Imperial Irrigation District
PG&E = Pacific Gas & Electric
SCE = Southern California-Edison

SDG&E = San Diego Gas & Electric
SMUD = Sacramento Municipal Utility District
SPPC = Sierra Pacific Power Company
SWEC = Stone & Webster Engineering Corp.

	Coso #1	Ormesa #1	Ormesa #2	Wineagle 1	Dixie Valley	Beowawe	Steamboat	MEI Binary	MEI Topping	Blundell
Size (Gross MW)	32	30	20	.660	58	18.8	8.4	2.7	1.7	23.5
Size (Net MW)	28	24	16	.620	50	16.1	6.8	2.2	1.7	20.0
Conversion Tech.	DF	B	B	B	DF	DF	B	DS	SF	
Steam Supplier	CECI/ Cathness			Local Rancher	Oxbow Geothermal	Chevron	GDA	MEI	MEI	Chevron
Plant Owner	CECI	Ormat & Partners	Ormat & Partners	Wineagle Devl. Ltd.	Oxbow Geothermal	Beowawe Geo Power Co.	Far West	MEI	MEI	UP&L
Plant Operator	Cal Energy	Omat	Ormat	Barber-Nichols	Oxbow	Chevron	Ormat	City of	City of Provo	UP&L Provo
Plant Designer		Ormat	Ormat	Barber-Nichols	EBASCO	Crescent Valley Energy Co.	Ormat	Ormat	Barber-	UP&L Nichols
Utility Service Area	SCE/ Navy	IID	IID	CPN	SPPC	SPPC	SPPC	UP&L	UP&L	UP&L
Utility Purchaser	SCE	SCE	SCE	PG & E	SCE	SCE	SPPC	City of	City of Provo	UP&L Provo
Plant Financing	Joint Venture	Ltd. Partnership	Ltd. Partnership	Ltd. Partnership	Equity & Debt	Ltd. Partnership	Partnership	Ltd. Equity	Debt &	Equity
Plant Features	Contract size led to modular plant multiples, i.e., 1st of 9 units	26 units	20 units	Freon working fluid, evaporative cond.	28 mile power line (228)	Dual flash	Air cooled	4 units	Marine turbine	Gas vented
Construction Time	12 months	6 months	10 months	+3 wks	19 months	7 months	13 months	24 months	N/A	28 months
On-line Date	7/87	7/87	3/88	9/85	6/88	12/85		11/87		5/88

The interviews suggest that geothermal development in the Pacific Northwest will build on lessons learned elsewhere and may proceed rapidly. Sponsors of new plants will probably not be engineering firms or utilities as neither group is a risk-taker. Shortly after discovery of resources, primarily in the Cascades, risk-taking resource companies will install small (by commercial standards), modular (i.e., suited to replication) plants. Some projects may fail due to technical, financial or administrative reasons but others will work well.

Once reservoir capability, technical, and economic viability are established, a quick jump will likely be made to larger plants. These can be built almost as fast, involve less capital per kilowatt, have greater reliability, and are eligible for utility acquisition. The best-engineered reservoir/plant complex will offer the highest confidence and be the most attractive. (Gonzalves, 1986)

Northwest political issues must be addressed before resource or technology progress can be realized. Regulatory uncertainty or local controversy preclude affordable financing. No geothermal resource has value until a plant is built on it; requisites include a favorable institutional situation and market mechanisms in place. (Gonzalves, 1986)

Costs Elements

Costs of recently completed are blended below to show what the Northwest may anticipate. The first generation plants may be 10-20 megawatts (MW) gross and 8-17 MW net in size, occupy five-acre sites, have minimal road access and possess high efficiency and reliability but modest design standards. Both the construction season and lead time will be short. Location will likely be in Oregon or Washington, with county rather than state regulation. Commercial modules of 50 MW capacity (plus-or-minus 20 MW) will follow pilot plants of lesser size. Subject to internal and external variables, their capital costs may vary from minus-20 to plus-10 percent of pilot plant costs. While these first plants may range from 5 to 25 MW in size, the larger plants are better able to support infrastructure and recover costs at power prices which are relatively near the market. Smaller pilot plants will reduce total investment but require greater subsidies.

Discussion of geothermal development costs requires notation of included or excluded items. Costs cited below portray the low boundary and mid-range of 1989 industry costs. Total geothermal project costs include (a) siting and licensing, (b) financing and owner's costs during construction; (c) plant construction, including labor, materials, engineering, and management, and start-up; (d) spare parts for the power plant; (e) interconnection with the utility grid, including switchgear and transmission line; and (f) wellfield and steam collection system (i.e., surface pipes).

"As-built" costs cited in interviews and literature include interest during construction but seldom reflect financing fees or owner's costs other than interest. These may be $150 to $200/kW. The following estimates are achievable costs in 1990 dollars.

Table 3-3
($/kW, net)

	Lowest Case	Mid-Range
Siting & Permitting (incl. owner's costs)	$65	$65
Turnkey Construction (mat, lab, e & m, s/u interest & contingency)	1,415	1,655
Interconnection	50	80
Spare Parts Inventory	20	30
Subtotal (Plant)	$1,550 *	$1,830 *
Wellfield & Collection	550	640
Subtotal (plant + field)	2,100 **	2,470 **
Set up & Finance Fees	80	110
Owner's Costs	90	100
Project Total	$2,270	$2,680

* Common reference for plant capital cost.
** Common reference for plant and wellfield.

Costs will vary according to fluid temperatures (and related thermal efficiencies) and the conversion technology used. Power plant and wellfield costs may range from $1,500 to $2,400 on a project basis.

Wellfield capital costs on deep reservoirs average about 35 percent of plant costs. $10 to $12 million, or $550 to $650/kW, would provide four or five production and two injection wells as well as piping and other surface equipment needed to serve a 20 MW plant.

Total direct and indirect costs for a project (plant, financing, general and administrative, capitalized fuel supply and interconnection) could run from $2,200 to $3,000 per net kilowatt. Each 20 MW pilot plant, therefore, represents a $38 to $50 million project.

Siting, permitting and financing will take 14 to 24 months (concurrent with early production drilling and testing), with a construction schedule of 22 to 28 months to follow. Lead time ranges are 36 to 52 months, with 42 months a realistic goal.

Development Considerations

Geothermal resource development is price sensitive. Absent confirmation incentives, economics control the rate but not the feasibility of development. (Gonzalves, 1986) Initiatives are more constrained by institutional factors than by technology or economics. Developer concerns in the Northwest must include public perceptions of resource attractiveness as well as attitudes and awareness levels concerning indirect benefits.

Licensing strategies normally involve developing the wells in lockstep with the permitting process. This is at the heart of resource confirmation and involves the developer's highest risk investment. The field is needed to answer questions of siting, design, etc.; the plant is needed to justify field development. Neither phase is advised to proceed alone.

The design process is driven by the owner's motivation and goals. These can vary significantly. Non-utility developers will design and operate a plant in such a way that a utility might find the plant attractive and wish to buy, own and/or operate it. Proven practices for utilities and non-utilities alike include:

- During design, treat the plant as a discrete entity, regardless of financial or operational relationships to the steam source. If it stands alone and is viable, plant-plus-field ownership structure will only make it better. (Gasf, 1986) Joint ownership and operation of the plant and steam supply yield both economic and operational benefits.

- Design to economic goals; combine utility conservatism with economic efficiencies. Establish clear objectives and decision criteria at the conceptual design phase. Maintain both through-out the design process; monitor for departures. (Fesmire, 1986)

- The design and operations learning curve on a new reservoir is a function of steam analysis. Initially materials and heat balance engineering are the most crucial and variable aspects of design and, therefore, the most significant influence on total costs. (McKay, 1986)

- Ownership goals and regulatory goals should be addressed together. Viability, efficiency, and process optimization answers are often the same.

- The bottom line for any project is net mills per kilowatt-hour. Performance in the early years of a project is critical to risk management and cost recovery. The better the early revenue stream, the greater the cost-effectiveness of the project. The greatest sensitivity of unit costs is the capacity factor in the near term. The effect of reduced availability or capacity factor in out-years is not nearly as significant to present value analysis but remains a key concern to utilities and banks. (Gonzalves, 1986) Practice is to plan for an 80 percent capacity factor, but to design for economic optimization. Most new plants operate in the 90 to 95 percent capacity factor range. .

- Japanese turbines and generators are very high quality units. Start-up problems have been near zero. American penetration of this market is minimal and unlikely to change, as Japan makes GE and Westinghouse designs under license. Japan's domestic turbine market pays most overhead and related costs; the export market is highly valued. Any "Buy American" provisions in a procurement policy will invalidate costs cited. (Stone & Webster, 1988)

Although not universally held, other informed opinions related to project development include:

- If confidence in a strong resource exists, prove the resource with larger plants. Historically, few small units have been economically successful. Mid-size to large units offer the only commensurate reward for a geothermal venture.

- Avoid consortium ownership. Inherent problems with decision authority and procurement policies at Raft River and Heber Binary reduced chances of success.

- Clearly understood administrative and decision structures are essential for sound project design and management. The key criterion for organizational relationships is efficiency; the key criterion for design issues is reliability.

Cost components

Tables 3-4 and 3-5 summarize cost assumptions and elements in the standard format used by the Council.

Table 3-4

Power Plant Summary
Cost and Performance Data
(Least Cost Case)

Type of Plant	Geothermal
Primary Fuel	Natural Steam: direct, flashed or binary
Alternate Fuel	N/A
On-site Fuel Inventory	Indefinite; Long term reserves in the steam/hot water field
Rated Capacity	50 MW units; 5,000"+"MW potential
Heat Rate	16 pounds steam/kWh net @ about 580 Btu/pound
Equiv. Annual Availability	90%
Seasonality	N/A
Siting and Licensing Time	14 to 24 months; average 18
License Shelf Life	5 years
Construction Time	36 months for 50 MW Unit; 28 months for 25 MW Unit; 16 months for 10 MW Unit
Siting and Licensing Cost	$65/kW net, incl. owner's costs over 18 months
Siting/Licensing Hold Cost	$13/kW/yr ($13/kW x 5 yr = $65/kWyr per yr siting/licensing cost; steam reserves hold without cost)
Construction Cost	$1,550/kW net, plant $550/kW net,wellfield (add 20% to each for binary)
Fixed O&M Cost 3% of	$45/kW for plant; $17/kW for wellfield (based on capital cost)
Variable O&M Cost (includes fuel)	3 mills/kWh, if capitalized 20 mills/kWh, if purchased. (add 3 mills to each for binary)
Decommissioning Costs	$80/kW to restore/plug & abandon
Operating Life	30 years

Table 3-5

Cost Components

	Lowest Case	Mid-Range Case
1. Acquisition Program Administrative Costs	N/A	N/A
a) Independent variable of the acquiring utility; outside the scope of this study.		
2. Siting and Licensing Costs		
a) Land Options:	Federal lease	Federal lease
b) Easements and right-of-way acquisition	Federal lease	Federal lease
c) Owner's costs during siting and licensing	$40/kW net	$40/kW net
d) Geotechnical Surveys	$10/kW net	$10/kW net
e) Environmental Impact Statement	$15/kW net	$15/kW net
3.* Financing costs	$80/kW net	$100/kW net
4. Construction Costs		
a) Land acquisition	2.c; federal lease	2.c; federal lease
b) Site utilities and services	$25/kW net	$25/kW net
c) Construction process		
1. materials	$625/kW net	$725/kW net
2. labor	$600/kW net	$700/kW net
3. engineering & management	$140/kW net	$200/kW net
4. Preproduction (start up)	$25/kW net	$30 kW net
d) Contingency allowance	(incl. in 4a,b) 6% capital cost	(incl. in 4a,b) 6% capital cost
e) Owner's costs during construction	$90/kW net	$100/kW net
f) Switchyard	$10/kW net	$10/kW net
g) Transmission interconnect to the grid (subject to distance; $110k/mi. for 115 kV line w/ 150 MW capacity)	$40/kW net	$70 kW net
h) Spare parts inventory	$20/kW net	$30 kW net
i) Royalties	4.a., 4.b.	
j) Socioeconomic impact mitigation	N/A	
k) Preproduction (start-up) costs	3.c.4.	
l) Sales Tax (where applicable)	N/A	
5. Fuel Costs		
a) Fixed fuel delivery costs (if wellfield capitalized at $550/kW net and annual O&M is 3.5% of capital cost)	14 mills/kWh	15 mills/kWh
b) Variable fuel (commodity costs, if bought)	$1.25/1,000 lbs. steam @16 lbs/kWh= 20 mills/kWh	$1.45/1,000 lbs. steam @18 lbs/kWh= 26 mills/kWh
6. Operating and Maintenance costs		
a) Fixed operating and maintenance costs (calculate @ 3.5% of capital costs)	$45/kW-yr	$53/kW-yr
b) Variable operating and maintenance costs	5.a.	5.a
c) Consumables	$10/kW-yr	$10/kW-yr
d) By-product credit	N/A	N/A
e) Interim capital replacement (for operation throughout the expected operating life)	$2 MM every 5 yrs:wellfield	$2 MM every 5

* Modified NPPC input format: new entry

IV. ENVIRONMENTAL EFFECTS OF GEOTHERMAL GENERATION

The Geothermal Steam Act of 1970 (P.L. 91-581) was the first major federal legislation to be enacted after the passage of the National Environmental Protection Act (NEPA). The regulations for NEPA and the federal geothermal program were drafted concurrently by the same federal departments and agencies. (Bloomquist, 1986) Subsequent legislation has maintained the most contemporary of standards for geothermal administration. Industry sensitivity to the environment has contributed to geothermal's consistently high safety record and its characterization as environmentally benign. Geothermal's effects on the social environment include localized impacts on land use patterns; sustained tax revenues to the public sector from a modest land base; economic diversity for rural areas in which geothermal resources typically exist; a history of safe operations; adherence to contemporary regulatory statutes with public involvement and support; and a high rate of successful development once decisions to proceed are made. In agricultural, recreational and suburban settings, geothermal plants have consistently proven to be "good neighbors." (Geyer, 1989)

Power planning holds few issues as complex or controversial as the challenge to safeguard the environment. The lull in construction of new capacity to replace aging plants or to service growing demand will result in a "catch up" period as regional surplus ends. (Kyle, 1988) Siting and permitting of new plants or transmission lines to import power will face regulatory and community scrutiny. All proposals will face two tests. The first will be for popular support as an energy source. The second will be for compliance with environmental standards for emissions, land use and off-site effects. Geothermal attributes of availability, reliability and minimum environmental effects will qualify it as a viable regional resource.

Of all the alternative energy sources other than conservation, geothermal is the most mature, ready-to-use technology. (Condy, 1989) Due to its characteristics of on-site fuel with few emissions or by-products, geothermal's attractiveness can only increase as environmental regulations tighten.

Most discussion of environmental effects concerns emissions from operating plants. Standards tend to be quantitative and lend themselves to mitigation by special treatments. Geothermal plants often achieve mitigation by avoidance of undesirable conditions through innovative designs or processes. (Tucker, 1982; Kleinhans, 1985)

Current scientific opinion and federal legislation is aimed at reducing gaseous emissions which affect atmospheric dynamics or global climate trends. Whatever the ultimate findings of the "greenhouse" debate, policies aimed at reducing emissions from fossil fuel combustion are assured. Utility operations will be affected in at least two ways: availability of fossil fuel generation will be reduced and cost-of-energy will increase due to new mitigation requirements. Potentially a "carbon tax" may be imposed on use of certain fuels. (EPA, 1989)

Carbon monoxide (CO), carbon dioxide (CO2), nitrogen oxides (NOx) and hazardous or toxic wastes are the emissions of concern from utility plants. These will be the emissions which constrain future energy resource choices. Alternative energy sources such as geothermal are able to supply "clean" electrical power without the production of NOx or appreciable quantities of CO, CO2 or hazardous waste. (McClain, 1989)

Tables 4-1 through 4-3 illustrate current levels of emissions at 60 percent (approximately 35 units) of this nation's operating geothermal plants. These data include the most widely-used technology (i.e., The Geysers) and the most recently certified technology approved by the State of California (Coso flash-plant complex, California Energy Company, Inc., aka CECI).

Table 4-1

Comparison of Carbon Dioxide Emissions
From Direct Combustion in Power Plant Operations

Power Plant Fuel Source	CO_2 Emissions per MWe lb carbon/hr per MWe(e)	Percentage of Methane %
Methane	282	100
Ethane	324	115
Propane	341	121
Butane	351	124
Gasoline	395	140
Diesel Oil	412	146
Fuel Oil #6	418	148
Bituminous Coal	497	176
Subbituminous Coal	529	188
Geothermal		
The Geysers (a)	21.9	7.77
PG&E Unit #20 (b)	21.9	7.77
Coso CECI	0.327	0.116

Table 4-2

Comparison of Controlled Power Plant Sulfur Emissions
of Fossil Fuel Fired and Geothermal Plants

Power Plant	Hydrogen Sulfide Emission per Megawatt lb/hr MWe (g)	Sulfur Oxides per Megawatt lb/hr MWe (g)
The Geysers (a)	0.2420	0.455(h)
PG&E Unit #20 (b)	0.0920	0.173(h)
CECI Coso (c)	0.0662	0.124(h)
Coal (e)	----	12.0
Oil (f)	----	10.6

NOTES
(a) Average of The Geysers' 24 geothermal power plants currently operating with a combined output of 1,773 MWe;

(b) PG&E Unit #20 with an output of 113 MWe;

(c) Average of the 9 CECI Coso units with a combined estimated output of 225 MWe;

(d) USEPA conversions were used in the calculation: 250 MM Btu/h heat input is equal to 29 MWi heat input, or 25 MWe output, or 200,000 lb steam/h output.

(e) Tennessee Valley Authority 12/13/86, USEPA #KY-0007B, 200 MMBtu/hr boiler (20 MWe equivalent)

(f) Georgia-Pacific Corp., USEPA #OH-0094, 118 MMBtu/hr boiler (30.9 MWe equivalent);

(g) Following USEPA conversions were used in the calculations:
250 MMBtu/hr heat input is equal to 29 MWi heat input, or 25 MWe output, or 200,000 lb steam/hr output;

(h) H_2S as SO_2 after 18 to 30 hours (Weres, 1977)

Table 4-3

Lake County, CA Geothermal Hazardous Waste by Type
Hazardous Waste Generation in Tons per Net Megawatt(a)

Waste Description	PG&E Units 13 & 16 1988: 243 Net MWe	DWR Bottle Rock 53 Net MWe
Stretford H2s Abatement (b)	1.94	38.0
Waste Oil and Solvent	0.033	0.038
Contaminated Debris	0.453	0.132
Contaminated Water	0.070	none listed

NOTES
(a) Indicative of types and amounts of waste from large-scale, commercial geothermal facilities;

(b) Stretford system is standard H2S application for dry steam as found at The Geysers. May not be representative of fluids or treatment elsewhere.

Source 4-1 to 4-3: (McClain, 1989)

Geothermal's acceptability in the political and regulatory environment is demonstrated best in the state of California. Policies and strategies for mitigating "greenhouse" gas emissions while promoting electrification for economic growth recognize the advantages of non-fossil fuel technologies such as geothermal. To the extent that regulatory bodies consider emissions and environmental effects in the economic balancing test to justify need for new power generation (as does the California Energy Commission), the comparative operating characteristics of geothermal energy speak for themselves. (McClain, 1989)

V. PROSPECTS FOR DEVELOPMENT IN THE PACIFIC NORTHWEST

BPA's Four State Geothermal Study (Bloomquist, et al., 1985) and other assessments have identified several areas in the Pacific Northwest with potential for geothermal development. Many have been validated by the geothermal industry's payments for land and resource rights (leases) and exploration investments. The more active and promising sites are summarized in Tables 5-1 and 5-2. The existence of other unidentified prospects must also be assumed.

These areas can be classified as primary and secondary targets for high-enthalpy (i.e., high heat/pressure/energy) fluids, suitable for flash-steam power generation, or primary and secondary targets for medium-enthalpy fluids, suitable for binary cycle or total flow power generation. (GeothermEx, Inc. 1987) However, no Northwest area has sufficient data to conclude definitively that geothermal resources exist in commercial quantities; that resources are of the described enthalpy; or that commercial development is feasible.

Before geothermal energy can be added with confidence to the resource portfolio, pre-commercial scale confirmation activities are essential. Pilot projects are needed to reduce planning uncertainties and define risks associated with subsequent commercial development. Tasks involve resource discovery and characterization, exercise of environmental and regulatory processes, and creation of technical and logistical support for power plant and wellfield operation.

Risks of geothermal confirmation and development can be divided into 5 major components, relating to (a) the geothermal resource, (b) development of the reservoir, (c) the market and related economics, (d) regulatory activities, and (e) acts of God (DOE, 1981; Sanyal, 1985). Risks affecting commercial availability, reliability and costs are best defined and mitigated through practical experience and understanding. Resource confirmation, rather than research or development, accurately describes geothermal's status in the Northwest.

The pioneering nature of reservoir confirmation makes it very difficult to quantify the risks. Risk quantification will reduce power planning uncertainties, improve resource decisions and define local development issues. Industry confirmation strategies attempt to contain risk and recover costs through power production. It is inappropriate for the Northwest Power Planning Council or utilities to evaluate confirmation work at new sites solely in terms of cost-of-energy from the first plant. Tests of cost effectiveness, relative to system or marginal costs, are better suited to subsequent, commercial-scale development facilities.

The body of scientific evidence pointing to large, durable geothermal resources (Fitterman, et al., 1988; Muffler, 1979), coupled with a shrinking power surplus and geothermal's compatibility with utility systems and the environment, suggests an untapped Northwest resource with high strategic, economic and environmental values. Until market opportunities arise to justify continued investment by the geothermal industry, the prospects for Northwest geothermal development will continue to languish. (Geyer, 1987)

Requisites for Confirmation

Steps can be taken to encourage private companies to conduct the expensive and time-consuming work of confirming major (i.e., greater than 50 MW for 20 to 30 years) geothermal resources in the Northwest. GeothermEx, Inc., an international geothermal consulting firm, proposed the following policies as important (in descending order) to advancement of regional geothermal confirmation.

- Provision of guaranteed access to electrical utility markets at an attractive price for electricity through:

  Reservation of some portion of the anticipated electric power demand after 1990 for geothermal energy.

  Provision of levelized electricity prices that offer initial price supports above competing modes of generation.

  Reservation of electric-power transmission capacity, and/or construction of new transmission lines, to carry geothermal electricity to markets.

- Provision of financial assistance to developers through:

  Provision of geothermal energy tax credits or advantages.

  Access to tax-free borrowing authority to reduce interest rates.

  Provision of government geothermal loan guarantees to reduce borrowing costs.

  Government cost-sharing during confirmation in drilling, well testing, reservoir analysis, environmental mitigation, and related matters.

Establishment of a geothermal risk insurance pool at reasonable rates.

- Provision of governmental technical assistance in specific situations regarding regional data collection, environmental monitoring and public works.

Through some combination of these measures, confirmation of at least one major resource could be achieved in three to five years (i.e., by 1994). Lacking development incentives, it remains uncertain whether any confirmation will occur prior to Northwest need for power. Thus geothermal will not be an option to meet future need unless a decision to purchase or build is made.

There appear to be sufficient leased lands available and capable exploration companies to exploit them. The more attractive the confirmation incentives, the broader the likely industry response. To minimize collective risks, concurrent work at several sites is warranted. These should not be viewed as competitive activities but rather as a broad regional confirmation program of resource potentials.

Participant responsibilities (and associated risks) should be assigned to those best able to understand them and, therefore, best able to perform at least cost and with the greatest likelihood of success. (Glenday, 1988) Incentive programs should be result-oriented rather than tied to process oversight. Council, BPA and utility roles should concentrate on monitoring performance results rather than administrative procedures. (GeothermEx, 1987) Federal and state cost sharing and technical support may be best directed toward off-site activities that are subject to variable costs or administrative delays (e.g., financial risk sharing; siting, permitting or environmental reviews; fluid analysis or reservoir modeling; impact mitigation studies; etc.).

Lastly, government and utility commitment to confirmation should be long-term (5 years) and resolute, rather than subject to availability of personnel, funds or other contingencies. The scope of confirmation programs should be clearly defined, along with decision points, performance standards and bases for compensation of industry participants. Once initiated, administrative oversight should be minimal.

Requisites for Development

Commercial development differs from confirmation in scale, timing, roles, rewards and underlying participant motives. The number of resources built will depend on the realism of supply estimates and prevailing social attitudes. Obligations for assured service and construction lead time requirements may dominate cost in resource evaluation criteria. Flexibility and diversity of the resource portfolio may drive selection criteria. (Geyer, 1989) Constraints must be assumed but may be factors not yet recognized.

After attainable conservation and efficiency improvements to the existing power system are realized, new generation will be needed. Concerns about today's energy technologies hasten the search for alternatives with greater safety and lower total costs. Geothermal's potential size, compatibility with the existing hydro-thermal system, environmental attributes, internal fuel cycle and flexible lead time all justify better insight to its availability.

Several lessons have been learned about construction of new generating facilities. The need for risk management is primary; performance accountability is equally imperative. Utilities, project promoters, non-utility developers, fuel supply companies, independent plant operators, private and commercial financiers and political supporters have formed alliances to create new geothermal power plants with higher technical, operational, economic and financial efficiencies than previously imagined possible in the utility industry. (Stone & Webster, 1986, 1988) No one party, utility or developer, is sufficiently expert in all areas to (a) assure timely and successful start up of new facilities, or (b) shoulder the full burden of responsibility for failure. (Carse, 1988)

The Northwest is unmapped territory for most new geothermal generation developers and financiers. (Kyle, 1988) Regional regulatory and energy market uncertainties are obstacles to project financing. Few developers see opportunities for constructive involvement with regional power entities. This may be a problem for major energy resource development at the region's time of need. Initiatives to encourage small geothermal plants can foster the relationships, experience and insights which will bring about new power. This would benefit both the Northwest and the geothermal industry.

"Optioning" or Scheduling of Development

Once geothermal reservoirs are confirmed and the opportunity to site and build plants is demonstrated, transition from limited scale confirmation activities to larger, commercial development occurs. Timing is critical to avoid premature spending, even while assuring energy availability when needed. Recent Council Power Plans refer to this as resource "optioning" or "resource banking." (NPPC, 1986)

Geothermal development is capital intensive, especially at first. Early reservoir testing and development requires investment beyond the needs of the first plant. Interconnection with utility grids requires transmission lines "up front". Initial financing and construction risks are greatest; costs are accordingly higher.

Geothermal wellfields and plants are typically developed in modular or incremental stages. Each site is unique. Understanding of reservoir behavior comes with operating experience. Risks decline, operating efficiencies improve and incentives to develop the reservoir increase. Accrued experience is also the ultimate inducement for participation by banks and utilities.

"Step out" development of a reservoir tends to re-use effective designs and materials. Incremental development costs decline, as do unit costs of electricity produced. At this point, least-cost competition with other resources becomes appropriate and of "Optioning" by utilities or power managers to influence the number of plants built becomes feasible.

The financial structure and revenue requirements of each project are unique, as are the motives of developers. Attempts to forecast "option" terms or costs must note that once initial costs are recaptured, an opportunity cost must be offered in addition to the expense of maintaining but not exercising development rights. While development of a producing reservoir can be deferred and even enhanced with time, negotiated rights of control lack precedent. Compensation for these rights may include non-financial support to developers such as endorsement of site or permit applications, enhanced transmission access or construction loan guarantees when permitted-but-deferred plants are built.

The time line of modular development on a major reservoir involves several years. Increases of up to 100 MW per year or more at each reservoir are possible. (Geyer, 1988) As development typically follows market demand, proven but untapped reserves represent a "banked resource" without direct social cost. Development can normally be hastened through power pricing.

Even in the absence of "options" to schedule development, modular geothermal development would likely serve local loads through sponsoring or purchasing local utilities. Utility-led development often reflects existing or imminent local need. Project financing for non-utility development requires a power sales agreement to assure debt service. Either case precludes untimely or imprudent development and avoids need for construction schedule control through "options."

Competitive Bid Qualifications

As regulators and utilities devise mechanisms to justify commitments to new resources, competitive bidding and acquisition criteria are being used to set prices and structure the market. To compete commercially after confirmation, geothermal generation must demonstrate load following and utility dispatch capabilities. These can be achieved either through operational and control strategies or through joint-bidding with another more flexible resource. Geothermal's base load character complements the Northwest's hydroelectric system but its decentralized locations may impact utility operating schemes. Developer-utility cooperation will be required.

Regional geothermal confirmation should address effective presentation of attributes in competitive bidding processes, with attention to both price and non-price factors.

Geothermal Supply Curves

Supply curves are a traditional economic tool used to depict the amount of a product available across a range of prices. (NPPC, 1986) Table 5-1 describes the most promising Northwest geothermal sites and their estimated potential capacity and energy, up to an assumed maximum of 500 MW.[2] Computations for some sites greatly exceed this amount but, in general, more and better data yield smaller and more reliable estimates. This list illustrates the variety of sites with significant promise but limited data.

Table 5-2 presents estimates of levelized nominal cost per kWh for projects with capital costs ranging from $1,600 to $2,400 per net kilowatt over 20 and 30 year service lives, as sponsored by non-utility developers (QF/IPP), investor owned utilities (IOU) and publicly owned utilities (POU). Variables include ownership, costs and financial life. Each model has been computed twice, using the Council's same financial assumptions. Financial analysis was performed by Citizens Power and Light Corporation, Boston, MA. The first applied the Council's fixed charge rates to capital and O&M costs. The second was a full revenue requirements analysis of project life. Levelized nominal costs for the two methods are consistently within 5 percent.

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2. All costs reflect a 1990 base year and other financial assumptions of the Council. Data from section III, Cost and Operating Characteristics for Geothermal Plants, are portrayed in ranges of capital costs for geothermal facilities.

Table 5-3 is a probability distribution of capacity available across the range of development costs. Only preliminary engineering proposals at specific sites can refine estimates.

Table 5-1

Promising Northwest Geothermal Sites

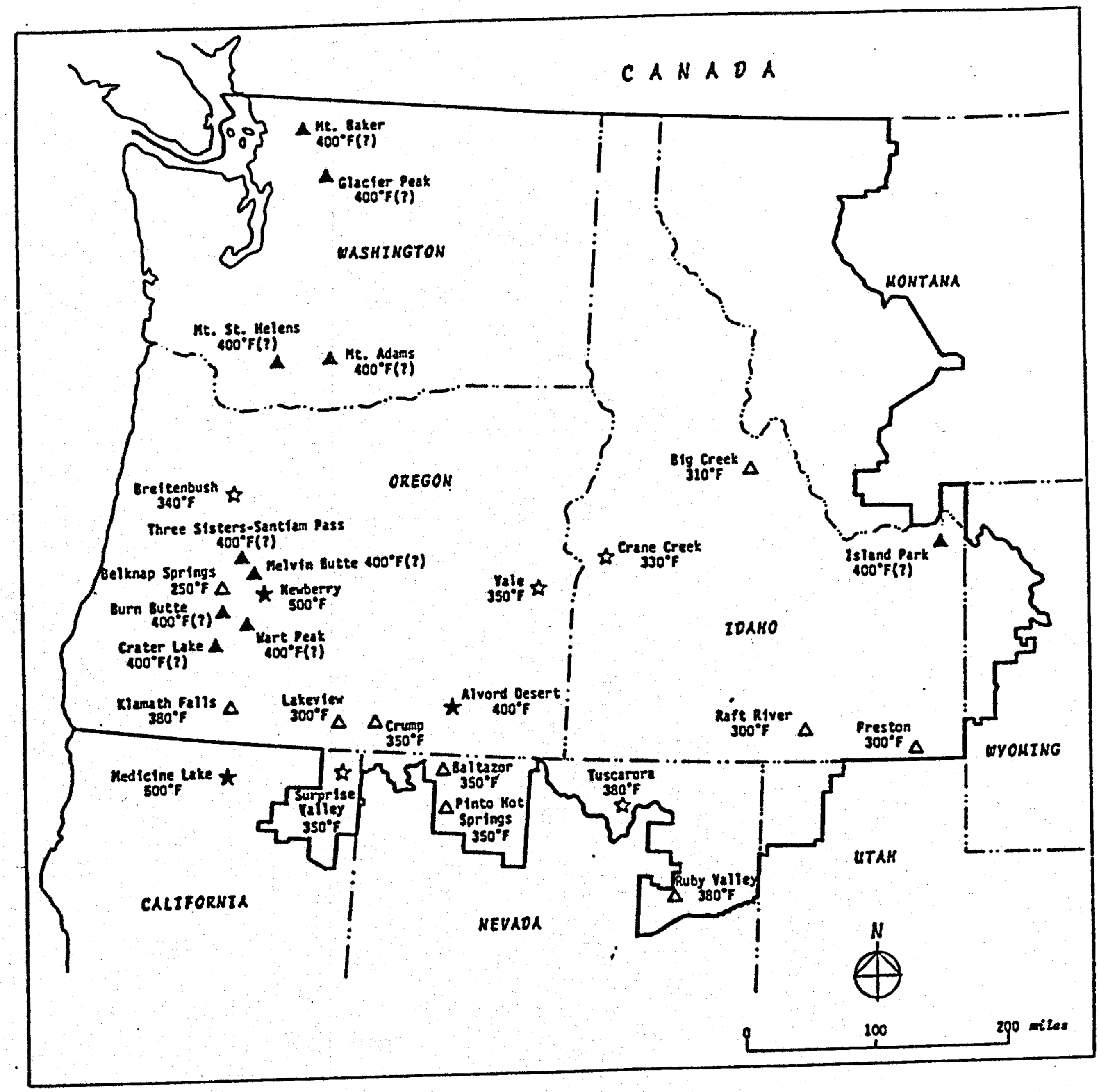
Resource Potentials		Geologic Province	Data Quality	Pot. Capacity (MWe)	Pot. Energy (MWa)
HIGH POTENTIAL for HIGH ENTHALPY fluids		Geologic	Data	Pot.	Pot.
Newberry Volcano, OR	*	Cascades	High	311+	250+
Alvord Desert, OR		Basin & Rng	Med.	118	95
Medicine Lake, CA		Cascades	High	n/a	n/a
HIGH POTENTIAL for MEDIUM ENTHALPY Fluids					
Surprise Valley, CA		Basin & Rng	High	25	20
Vale, OR		Basin & Rng	Med.	163	130
Cove-Crane Cr., ID	*	Basin & Rng	Med.	224	179
MODERATE POTENTIAL for HIGH ENTHALPY Fluids					
Crater Lake, OR		Cascades	Med.	500	400
Cappy-Burn Butte, OR	*	Cascades	Low	473	378
Glass Buttes, OR	*	Cascades	Low	348	278
Wart Peak Caldera, OR	*	Cascades	Low	145	116
Melvin-3 Creek Butte, OR	*	Cascades	Low	500	400
Bearwallow Butte, OR	*	Cascades	Low	500	400
Mt. Baker, WA		Cascades	Low	500	400
Mt. Adams, WA		Cascades	Low	500	400
MODERATE POTENTIAL for MEDIUM ENTHALPY Fluids					
Klamath Falls, OR	*	Basin & Rng	High	200	160
Klamath Hills area, OR	*	Basin & Rng	Med.	300	240
Lakeview, OR		Basin & Rng	Med.	10	8
Crump, OR		Basin & Rng	Med.	79	63
Raft River, ID	*	Basin & Rng	High	15	12
Big Creek, ID	*	Basin & Rng	Med.	29	23

* Top sites from 1985 Four State Study noted in 1986 Power Plan.
+ Reduced 80% from 1986 Power Plan due to land use restrictions.

Source: Four-State Geothermal Study and GeothermEx, Inc.

Thirty additional locations were identified in the 1985 "Four State Geothermal Study" as having "good" or "average" development potential for more than 1 MW of capacity. These remain valid but lack recently expressed interest by industry. Together, these are estimated to have 163 MW of potential capacity and 130 MWa of energy at levelized costs from 5.0 to 9.8 cents per kWh.

Figure 5-1



Potential for the development of geothermal resources in the Pacific Northwest.

1987, GeothermEx, Inc.

Table 5-2

Levelized Nominal Cost
mills/kWh

	Capital Cost per kW, net						
	----Low Case----		--------Likely Case--------			----High Case----	
	$1,600	$1,800	$2,000	$2,200	$2,400		
30 Year Life							
QF/IPP	55	59	65	69	75	84	89
IOU	57	63	67	73	78	81	87
POU	44	49	51	54	59	61	65
20 Year Life							
QF/IPP	55	61	66	70	76	85	89
IOU	56	62	66	73	78	81	87
POU	44	48	52	56	59	62	65

Source: Citizens Power & Light, Corp., per NPPC Financial Assumptions and Costs.

Table 5-3

Capital Cost Distribution
Northwest Plant and Wellfield Development

	Capital Cost	Estimated Energy (MWa)	Levelized Nominal Cost (mills/kWh)*
< 15MW Plant Shallow Wells Good Access	< $1,600	50 MW	40 to 50
< 15MW Plant Deep Wells Good Access	$1,600	100 MW	44 to 57
15-50MW Plant Shallow Wells Good Access	$1,800	250 MW	49 to 59
15-50MW Plant Deep Wells Good Access	$2,000	400 MW	51 to 67
15-50MW Plant Deep Wells Good Access	$2,200	800 MW	54 to 69
> 50 MW Plant Deep Wells Remote	$2,400	1,000 MW	59 to 78
>50 MW Plant Deep Wells Good Access	$2,600	1,000+ MW	61 to 84
>50 MW Plant Deep Wells Remote	$2,800	1,000+ MW	65 to 89

* Subject to sponsorship, technology, temperature, and terms of financing.

Conclusion

Review of achievements and costs at geothermal power plants throughout the western United States and of geothermal potentials and history in the Pacific Northwest finds geothermal energy possible, practical and desirable in the region's energy future. A body of scientific evidence supports the local existence of geothermal resources. Operating plants demonstrate geothermal electricity's technical and economic feasibility. Regulatory approvals endorse its social and environmental merits. Safe, reliable operating histories in diverse settings testify to geothermal's "good fit" with utility operations and "good neighbor" reputation.

No Northwest area has sufficient data to conclude that geothermal resources exist in commercial quantities; that resources are of the described heat content and usefulness; or that commercial development is feasible at a specific site. Before geothermal energy can be added with confidence to the regional resource portfolio, pre-commercial scale confirmation activities are essential. Pilot projects are needed to reduce planning uncertainties and define risks associated with subsequent commercial development. Through assurance of a market and limited incentives, confirmation of at least one major resource can be achieved in three to five years. Lacking development incentives, it remains uncertain whether any confirmation will occur prior to regional need for power and when decision to buy or build additional generating capacity must be made. If this occurs, a potential major option will not be available to meet needs. Industry cannot proceed without regional confirmation initiatives and utility participation.

Geothermal electricity merits inclusion, or at least serious consideration, in the regional energy portfolio. Assured availability of geothermal and other promising resources by time of need requires aggressive confirmation of regional potentials. Geothermal energy availability by the mid-1990s coincides well with regional demand.

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