# XI

# FACTORS CRITICAL TO ECONOMIC FEASIBILITY

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## ABSTRACT

Geothermal energy development covers a huge range of resource technologies as well as a huge temperature range, and a host of alternative conversion technologies including space heating, district heating, industrial process heating and a number of generating options from dry steam to binary. Because of this, it is impossible to provide a guide and definite method of determining the economics of any given project. Each will be different depending upon the characteristics of the resource and how that resource will be used. It is possible, however, to provide insight into how various resource characteristics and technology choices drive project economics and the author has tried to cover all of the economic factors that are common to all projects.

## INTRODUCTION

The factors that must be considered when assessing the viability of a geothermal project vary from project to project, from conversion technology to conversion technology, and especially from electrical generation to direct use. There are, however, a number of factors common to all projects, although actual cost and impact on project economics will be, to a large extent, de-pendent upon resource characteristics and national or even local political and economic circum-stances.

The economic factors that are common to all projects include: provision of fuel, i.e., the geo-thermal resource; design and construction of the conversion facility and related surface equip-ment, e.g., the electrical generation plant together with required transformers and transmission lines; the generation of revenue; and, of course, financing. The cost of obtaining the required fuel supply, together with the capital cost of the conversion facility, will determine the amount that must be financed. Revenue generated through the sale of electricity, by-products, thermal energy, or product produced, e.g., vegetables, plants, or flowers from a greenhouse, minus the cost of O&M of the fuel supply and conversion facility, must be sufficient to meet or exceed the requirements of the financing package.

## 1. ECONOMIC CONSIDERATIONS

### 1.1. Provision of fuel

For most projects that require a sustained and economically attractive fuel supply, the project sponsor must only contact a supplier and negotiate a long-term supply of natural gas, oil, pro-pane, or coal. To help guarantee low and stable fuel supplies, more and more project sponsors are purchasing gas fields, or oil or coal reserves. For projects that depend upon biomass (wood), fuel can be contracted for from a wood products mill or the mill may even become a partner in the project, providing an even more secure supply. Long-term availability of biomass can be determined from long-term timber holdings within a geographically defined area and/or plans for harvesting as defined by a state or federal land market authority. With municipal solid waste, fuel supply can be assured through local government action requiring that all material be controlled by one authority and delivered to a specific facility for a given time period.

In the case of geothermal resources, however, the fuel cannot be purchased on the open market, legislated into existence, bought from a local utility, or transported over long distances from a remote field.
Whether the steam or hot water is to be provided by the project sponsor, i.e., the steam field and conversion facility are under one ownership, or whether the steam is to be provided by a resource company, the geothermal fuel is only available after extensive exploration, confirmation drilling, and detailed reservoir testing and engineering. Once located, it must be used near the site and must be able to meet the fuel requirements of the project for the lifetime of the project. Even before exploration can begin, however, the project sponsor may incur

significant cost, and a number of extremely important legal, institutional, regulatory, and environmental factors must be fully evaluated and their economic impacts considered.

### 1.2. Obtaining access and regulatory approval

In order to obtain rights to explore for and develop geothermal resources, access must be ob-tained through lease or concession from the surface and subsurface owners. In many countries, the state claims rights to all land and to all mineral and water resources. In other countries, land and subsurface rights can be held in private ownership. Unless the geothermal developer has clear title to both surface and subsurface estates, an agreement for access will have to be entered into with the titleholder of these estates. Such access will normally require a yearly lease fee and eventually royalties upon production. In areas where there is significant competitive interest, competitive bidding may be used to select the developer. Competitive bids can be in the form of cash bonuses or royalty percentages. Royalties can be assessed on energy extracted, electrical or thermal energy sales, or even product sales. Whatever the system, it will have an impact upon project economics and should be carefully considered in terms of overall economic impact. In particular, developers of direct use projects, because of the limited rewards that can be expected, must carefully evaluate how royalties will be calculated. In a number of instances, royalties, if assessed, would comprise up to 50% of annual operating cost, making projects un-economical to pursue.

The second factor that will have an impact on overall project economics is obtaining all regulatory approvals, including the completion of all environmental assessments and the securing of all required permits and licenses, including, if necessary, a water right. Increasing concern for the environment in nearly all countries of the world has resulted in sharply increased cost for preparing the necessary environmental documents. A complete environmental impact statement for any proposed development is now required by federal land management agencies in the United States, and cost for preparation can exceed one million dollars. It is not uncommon to invest up to 40,000 – 60,000 person-hours in completing all necessary environmental documents and obtaining required licenses and permits for a major electrical generation project. Because so many environmental decisions are now contested, a contingency to cover the legal costs related to appeals must be included in any economic analysis; depending upon the issues and the financial and political power of those appealing a decision, the cost of obtaining necessary approvals can easily double. Because most direct-use projects are more limited in scale and, therefore, in environmental impact, these costs may be only a small fraction of the cost incurred by the proposal of a major power generation project. Even such a reduced cost can, however, be significant in relationship to the scale of the project, and the economic impact should not be underes-timated. Unfortunately for the project sponsor, most of the cost related to obtaining access and environmental and regulatory approval must be incurred early in the project, and, in many instances, even before detailed exploration or drilling can begin, and with no clear indication that any of the costs will or can be recovered.

### 1.3. Exploration

Once access has been secured and all necessary regulatory approvals have been obtained, the developer may initiate a detailed exploration program, refining whatever data was initially gathered in the reconnaissance or pre-lease phase of the development process and sequentially employing increasingly sophisticated techniques that will lead to the drilling of one or more exploration wells; hopefully these wells will be capable of sustaining a reservoir testing program, and possibly also serving as preliminary discovery and development wells. Reconnaissance, in all likelihood, included such activities as a literature search, temperature gradient measurements in any existing wells, spring and soil sampling and geochemical analysis, geologic reconnaissance mapping, air-photo interpretation, and, possibly, regional geophysical studies. Costs incurred may range from a low of a few thousand dollars to even $100,000 or more, dependent upon prior work in the area, geological complexity, and, of course, the scale of the proposed project and whether or not the intended use is electrical generation or direct application.

Once the area of principal interest has been selected, the exploration program can be more in-tensely focused, with the primary objective of siting deep exploration wells. Techniques likely to be employed include detailed geologic mapping, lineament analysis, detailed geochemical analysis, including soil surveys and geochemical analysis of all springs and wells, temperature gradient and/or core drilling, and geophysical surveys, including resistivity, magnetotellurics, gravity, and seismic. Costs increase as the complexity of the techniques and the detail of the surveys become more focused. For large, direct-use projects, costs of $100,000 or more can be incurred. For projects directed toward electrical generation, the cost of this phase of the work can easily exceed several hundred thousand dollars, and may exceed several million dollars.

The final phase in any geothermal exploration program involves the siting, drilling, and testing of deep exploratory wells, and, subsequently, production and injection wells.

## 1.4. Well Drilling

Well cost can vary from a low of a tens of thousands of dollars for small, direct-use projects to several million dollars per well for wells required to access high-temperature resources for electricity generation. Success ratios for exploration wells may be as low as 20% and can not be expected to exceed 60%; however, the risk of dry holes in the exploration phase remains high and can have a significant economic impact. Even in developed fields, 10 to 20% of the wells drilled will be unsuccessful (Baldi, 1990). Drilling cost is typically 30-50% of the total development cost for an electrical generation project and variations in well yield can influence total development cost by some 25%. (Steffanson, 1999.) Prospective developers must anticipate and prepare for the eventuality that despite an investment ranging from a few hundred thousand dollars to several million dollars in lease fees, environmental studies, licenses and permits, and exploration and drilling activities, an economically viable geothermal reservoir may not be discovered.

If, however, drilling is successful, the reservoir must then be tested to determine its magnitude, productivity, and expected longevity. Only after such testing can a determination be made as to the eventual size and design of the generating facility or direct-use application.

## 1.5. Well field development

Well field development for an electricity generation project can last from a few months to several years, depending upon the size and complexity of the project, the speed at which procurement contracts can be let (Koenig, 1995), and the availability of drill rigs. At this stage it also becomes of increasingly critical importance to collect detailed data and to refine the information available on the reservoir. Of course, for most projects this will include both production and injection wells. Many projects experience unnecessary difficulties and delays in financing or in milestone review because of either incomplete or inaccurate data collection, analysis, and/or interpretation (Koenig, 1995). Such difficulties and delays can seriously affect project economics and can have a catastrophic economic impact if delays result in contract forfeiture or if contracts contain a penalty clause tied to milestone completion. Coincidental with well field development will be the construction of well field surface facilities.

Costs associated with both drilling and the construction of well field surface facilities will be affected by the availability of skilled local labor and by geologic and terrain factors. Labor costs can be expected to increase by 8-12% in areas where most of the labor must be brought in or a construction camp erected to provide housing and meals. Terrain and geologic factors can add from 2-5% if special provisions must be made for work on unstable slopes or where extensive cut-and-fill is required for roads, well pads, sumps, etc.

Over half of the total production cost over the lifetime of the project will in fact be expenses associated with the well field. Because of this, it is imperative that wells must be properly maintained and operated to ensure production longevity. But even with proper O&M, many wells will have to be periodically worked over and, for most power generation projects, 50% or more of the wells will likely have to be replaced over the course of the project, adding considerably to the initial well field cost and, of course, to the cost of generating power. For example, if 60% of the wells must be replaced over the economic life of the plant, it would have the effect of increasing the levelized cost of electricity by 15 to 20% (Parker et al., 1985).

For small to medium-sized direct-use projects requiring only one or two production and injec-tion wells, costs will generally be much lower. Because the water chemistry of most geothermal resources that are developed for direct-use applications is of generally higher quality than that available for power production, well life can be expected to be much longer and few, if any, wells will have to be worked over or redrilled during the economic life of the project.

# 2. PROJECT DESIGN AND FACILITY CONSTRUCTION

## 2.1. The power plant

Just as there are numerous geothermal resources throughout the world exhibiting differing temperatures and chemical characteristics, there are numerous power plant designs. These include direct steam, flashed steam, double flashed steam, and binary cycle, each capable of best meeting the specific requirements of a particular reservoir. The selection of the most economically viable power conversion technology can only be accomplished through a thorough evaluation of the differing strengths and weaknesses of various technologies relative to the characteristics of the resource and local circumstances, including environmental and regulatory requirements (e.g., requirements for noncondensable gas emission abatement or fluid injection). Terms of the power sales contract can also have a major influence on power plant design. For example, are there premiums paid for availability during certain times of the year or even times of the day, are there advantages to being able to operate in a load-following manner, or is capacity factor of paramount importance? Another major consideration is the manner in which steam is provided; e.g., is the steam field and the power plant under one ownership or is steam purchased from another party? If purchased, the terms of the steam purchase contract can have a profound impact on economics and, thus, on design. For example, if steam is paid for as a percentage of the selling price of electricity, there is little incentive to achieve high steam use efficiency and a strong incentive to minimize capital cost. On the other hand, if steam is purchased on the basis of dollars per kilogram delivered, then achieving highest possible fuel use efficiency becomes extremely important (Bloomquist and Sifford, 1995). In order to achieve maximum steam use efficiency, some developers have adopted equipment procurement evaluation criteria that penalize offerings for inefficient use of steam and/or electricity at a capitalized rate of X thousand dollars per kilogram of additional steam required and X thousand dollars per kilowatt of parasitic load (Kleinhaus and Prideau, 1985).

## 2.2. Cycle Selection

**Direct steam**

Although extremely rare in nature, where available, direct steam will result in the lowest power plant cost. The steam is directed from the wellhead, expanded through the turbine, and condensed or, in certain circumstances, exhausted to the atmosphere. If condensed, the condensate can be used for cooling water make-up and/or injected back into the reservoir.

**Flash steam**

In the case of high-temperature, liquid-dominated resources, a flash steam plant is the most economical choice. The hot water or liquid vapor mixture produced from the wellhead is directed into a separator where the steam is separated from the liquid. The steam is expanded through a turbine and, if condensed, can be used as cooling water or injected, together with the separated brine, back into the reservoir. The brine could, however, be used in another application, such as space or industrial process heating and/or agriculture, in a technique known as cascading.

**Double flash steam**

A double flashed steam cycle differs from a single flash cycle in that the hot brine is passed through successive separators, each at a subsequently lower pressure. The steam is directed to a dual-entry turbine with each steam flow flowing to a different part of the turbine. The advantage is increased overall cycle efficiency and better utilization of the geothermal resource but at an overall increase in cost. The decision as to whether or not a double flash plant is worth the extra cost and complexity can only be made after a thorough economic evaluation based on the cost of developing and maintaining the fuel supply, or cost of purchasing fuel from a resource company, plant costs, and the value of the electricity to be sold.

**Binary**

With a binary cycle, the heat from the geothermal brine is used to vaporize a secondary or working fluid that is then expanded through the turbine, condensed through an air or water cooled condenser, and pumped back to the heat exchanger to be re-vaporized. Binary cycles can more efficiently recover power from a low-temperature (<175 °C) reservoir than can a steam cycle. It should be noted, however, that some research indicates that low temperature flash e.g. < 150° C may be a more economical choice In addition, binary plants may be more easily sited where environmental concerns are paramount and where either gas emissions or cooling tower plumes need to be avoided. Recent developments in adding enhanced evaporative cooling to air condensers can improve summer efficiency of air cooled binary plants by as much as 40%, greatly improving the economics of such operations (Sullivan 2004 Personal Communication). The brine – after passing through the heat exchanger – can be used in other cascaded applications and/or injected back into the reservoir.

**Other design considerations**

In addition to temperature, fluid chemistry is extremely important in cycle selection and power plant design. Many high-temperature resources are highly aggressive brines, with high contents of total dissolved solids (TDS), and bring a host of other problems that affect both design and economics.

A number of techniques have been adopted to recover power from problem brines. Design options include the use of a crystalizer reactor clarifier and pH modification technologies.

The use of either technique can add considerably to capital costs as well as to plant O&M cost. If pH modification is used for scale control, corrosion could also become more severe. Of course, metallurgy of system components thus also becomes crucial and can add significant cost to the plant if more exotic materials such as titanium must be specified.

The use of binary cycles in the presence of high TDS or corrosive brines is limited by the fact that tube-and-shell heat exchangers can easily be fouled or suffer rapid deterioration from corrosion.

The availability of cooling water is also an important consideration in plant design. In a condensing direct steam or flashed steam power plant, the condensate is used for cooling water make-up. The plant can thus take advantage of the low wet bulb temperatures that may be present even though the ambient dry bulb may be quite high. A water-cooled cycle capable of approaching the wet bulb temperature presents a significant advantage, as far as overall power generation is concerned, in comparison to a dry cooled binary cycle that approaches the dry bulb instead of the wet bulb (Campbell, 1995). If, however, limited water is available, it may be used to improve the overall efficiency of a dry-cooled binary plant by injecting a fine spray or mist through the air condenser or percolated through a fibrous material (e.g. fiberglass) that can be used to enclose the sides of the air condenser (Sullivan, 2004 Personal Communication). This could be especially attractive where there is a premium for peak summer power. In an area lacking any source of water for cooling, the optional economic cycle may shift from a binary cycle to a flashed steam cycle (Campbell, 1995). In fact, the terms of the power sales agreement may have a profound influence upon conversion cycle selection, cooling system design, and, eventually, plant operation.

## 2.3. Equipment Selection

**Steam cycle**

The turbine generator set is the most expensive piece of equipment in a steam cycle power plant. For direct steam and single flashed cycles, a single admission steam turbine is appropriate. In turbines up to approximately 30 MW, a single flow turbine is usually selected. However, larger turbines generally incorporate double flow, i.e., the steam is introduced into the middle of the turbine and flows in both directions, thus balancing thrust. Single flow turbines generally exhaust out the top, allowing the condenser to be located to the side and at the same elevation as the turbine, thus minimizing cost. With the double flow turbine, the steam exhausts downward, requiring the turbine to be mounted above the condenser. This arrangement increases capital cost, but that cost is more than justified by the increase in turbine efficiency. Other efficiency considerations include the number of turbine stages, blade length, and whether the plant will operate as a base load unit, will be used for load following, or must be dispatchable. If load following is desirable for either resource or contractual considerations, incorporation of partial-arc admission into the turbine design is critical. Partial-arc admission, as the name implies, allows for steam to enter the turbine through only a portion or 'partial arc' of blades under certain operating conditions, and to enter the turbine through the full arc of blades during other conditions.

Partial-arc admission allows a turbine to be operated at various output levels while maintaining a much higher level of operating efficiency than would be possible if the turbine were controlled through the use of a single throttling valve. In fact, when the plant is operating at the minimum output allowed by the partial-arc arrangement, it will be only 5% less efficient than at full output. This operational flexibility ensures the use of the minimum amount of steam possible for any given level of output. The use of partial-arc admission also allows for plants to be ramped up very quickly, that is, from minimum output to full output in only a few minutes (Bloomquist, 1990). Partial-arc admission can also provide the ability to significantly increase output from a single machine if higher-pressure steam is available. For example, at one plant at The Geysers each of the turbines produces 40 MWe net at 8 bars inlet pressure, while either machine can produce 80 MWe net at 11.6 bars. This arrangement has allowed this particular plant to maintain both capacity and availability in the high 90% range (Bloomquist and Sifford, 1995).

Two major categories of condensers are used with steam cycles: the surface condenser and the direct contact condenser. In a surface condenser, the cooling water is circulated through the inside of heat transfer tubes with steam condensing on the outside of the tubes. In contrast, in a direct contact condenser the cooling water is sprayed into the condenser where it directly contacts the steam from the turbine discharge. The primary advantage of the surface condenser is that contamination of the cooling water with constituents of the wellhead steam is avoided - an important factor where hydrogen sulfide abatement is required (Campbell, 1995). The direct contact condenser, however, is less expensive and is less prone to maintenance problems, and would thus be the most economical choice if hydrogen sulfide is not a problem.

The selection of direct contact or surface condenser will also have an impact on pumps and pumping requirements, i.e., parasitic power requirements. In a surface condenser, the condensate from the condenser is collected in a hot well and a condensate pump is required to pump this condensate from a vacuum of about 0.098 bars up to the top of the cooling tower. The other major pumps required for surface condenser operation are the cooling water pumps, located at the base of the cooling tower, and used to circulate cooling water through the tubes of the condenser and back to the cooling tower.

Because the condenser itself is at a vacuum, no pump is required in a direct contact condenser to move cooling water from the cooling tower basin into the condenser. However, a pump is required to pump cooling water and the condensate back into the cooling tower. Because of the usually high content of carbon dioxide and other contaminates in a direct contact condenser, stainless steel pumps are normally specified to resist corrosion.

Noncondensable gases must be removed from the condenser in a steam cycle in order to reduce backpressure and optimize steam use efficiency. Noncondensable gas removal, however, results in a significant parasitic load either in terms of steam used in jet ejectors or electricity used to power compression or vacuum pumps. Steam jet ejectors have by far the lowest capital cost but are relatively inefficient in comparison to liquid-ring vacuum pumps or mechanical compression. A commonly used arrangement employs one or two steam jet ejectors in series followed by a liquid-ring vacuum pump, thus taking advantage of the low capital cost of the initial stage with the higher efficiency final stage.

If the noncondensable gas contains concentrations of hydrogen sulfide that require removal, a number of options are available, including liquid reduction-oxidation using an iron chelate solution such as is employed in the Dow Sulferox process, and the Wheelabrator Lo-Cat process. The Stretford process is another option that has been successfully used with geothermal power generation. Inclusion of hydrogen sulfide abatement can increase the capital cost of a steam cycle plant by 10% or more, and will also result in an ongoing increased cost for O&M.

The cooling tower design can also have a major impact on capital cost, O&M, and cycle effi-ciency. The most commonly used cooling tower designs include cross-flow, cross-flow with high efficiency fills, and counter-flow. The counter-flow tower yields more efficient heat transfer and greater depression of water temperature than the cross-flow design. The high efficiency fill not only increases efficiency at a lower cost than conventional towers, but also the tower can be shorter, thus resulting in a lower parasite load for pumping cooling water to the top of the tower. On the downside, high-efficiency fills have a tendency to become clogged and cooling water chemistry must be carefully controlled. Biocides are generally added to minimize algae and other biological growth, and corrosion inhibitors are added to protect the system (Campbell, 1995). Although dry cooling towers (see Binary cycle below) can be used with steam systems, efficiency considerations will generally discourage their use.

## 2.4. Binary cycle

Selection of the right working fluid is the most critical design decision in the development of a binary cycle power plant. The selection must achieve a good match between the heating curve of the working fluid and the cooling curve of the geothermal heat source. The cooling curve of liquid brine is a relatively straight line, whereas a two-phase flow of liquid and vapor will give a curve of a different shape. Working fluids used in binary plants fall into three broad categories: light hydrocarbons, ammonia, and freons. The light hydrocarbons include butane, propane, isopentane, isobutane, and even hydrocarbon mixtures designed to find the most efficient match of working fluid to resource. In terms of freons, R11 and R22 have both been successfully used with low-temperature resources. In the Kalina cycle an ammonia water mixture is used and the ratio of ammonia to water can be varied depending upon the temperature of the geothermal fluid in order to maximize efficiency.

The light hydrocarbons have the disadvantage of being highly flammable, requiring installation of fire control equipment. The use of R11 has been banned because of its adverse impact on the ozone layer, and R22 will be phased out over the next several years. However, more environmentally friendly replacements are now available, and work is now being directed toward the development of other even more efficient and environmentally acceptable replacements. There is increasing interest in ammonia as a working fluid and a number of demonstration applications are already planned or on line.

Because the heat content of the geothermal resource is transferred in the binary cycle to the working fluid, the heat exchanger becomes an additional critical equipment component, and can account for a significant capital cost increase over that of a steam cycle plant. The heat exchanger is generally of shell-and-tube design with the geothermal brine pumped through the tubes and the working fluid on the shell side. Because of the heating curve, counter-current flow is desired and achieved by laying out the heat exchangers in series with single-pass flow on both shell-and-tube sides. Material selection is critical to avoid problems of both corrosion and erosion of the heat transfer tubing. For most applications, carbon steel is acceptable if oxygen can be kept out of the system, and has the lowest capital cost. The cost of the heat exchanger can escalate rapidly if stainless steel or even titanium is required. The use of a direct contact heat exchanger would reduce capital cost and limit the problems associated with erosion and corrosion of the heat exchanger tubing. However, problems associated with contamination of the working fluid by corrosive constituents in the brine and noncondensable gases can result in serious problems downstream in the turbine and condenser. Loss of working fluid to the spent brine is less of a problem, but must still be taken into account by including recovery equipment.

Another major cost that is specific to the binary cycle is the number of pumps required and the significant parasitic load they place on the plant. Because the binary cycle operates much more efficiently if brine from a liquid-dominated reservoir can be maintained as a single-phase flow through the heat exchanger, production well pumps are used. Standard production pumps are multi-stage, vertical turbine pumps driven by a motor at the surface. Downhole pumps could be an attractive and economical alternative, and recent advances could soon result in commercially available downhole pumps. But the high temperature of the geothermal brine has so far limited their applications. Improvements in vertical shaft turbine pumps now make multi-year runs between servicing possible and have significantly improved operational economics and reduced downtime.

The second major requirement for pumps stems from the need to pump the working fluid through the heat exchangers and to the turbine inlet. The pumps are usually multi-stage, vertical canned pumps. Multiple stages are used to achieve the required turbine pressure. In addition to the additional capital cost attributable to the need for production and/or working fluid circulating pumps, pumping requirements result in a parasitic load of 10 to 15% of the power that is generated, a significant reduction in the amount of power that is available for sale.

Power is generated in the binary cycle using either a radial inflow or axial flow turbine. The radial inflow turbine can achieve efficiencies as high as 90% and is usually the preferred option.

Once expanded through the turbine, the working fluid must be condensed before being returned to the heat exchanger in a continuous cycle. To date, a majority of binary cycle plants have employed air-cooled condensers. In the air-cooled condenser, the condensing working fluid is directed through the heat transfer tubes and air forced across the tubes to remove the heat. The air-cooled condenser can be extremely large and expensive both to build and to operate.

A water-cooled system is an alternative and can provide significantly increased efficiency under certain operating conditions. The water-cooled system, however, does have a number of drawbacks. The most critical of these is probably the fact that the binary cycle does not in itself generate a source of cooling water so that an external source of cooling water is required. If an external source can be obtained, an evaluation must be made of capital and operating costs vs. electrical output. The combined cost of the condenser, cooling towers, and cooling water pumps of the water-cooled system will be less than the cost of the air coolers of the air-cooled system. However, the cost of water, chemicals, and disposal of blow-down, coupled with the parasitic load associated with cooling tower pumps and fans, can exceed the cost of operating the air-cooled condenser. Other advantages of the air-cooled option are avoidance of the cooling tower plumes and cooling tower emissions, factors that are often critical to obtaining the necessary permits and meeting regulatory mandates. The best of both systems may be the hybrid based on the use of air coolers but with injection of a water mist into the airflow of the air cooler or the spraying of water onto fibrous material, e.g. fiberglass, used to enclose the walls of the cooling tower. Alternatively the water can be percolated through the fiberglass fill. This can significantly increase cycle efficiency and output during peak demand periods in a summer peaking area. Testing at a facility in California which began in 2001 has resulted in a 25+% to as high as 40% increase in power output during certain climatic conditions (Sullivan, 2004).

### 2.5. Power plant construction

A number of factors related to power plant construction can have a significant influence on project economics, including geologic conditions, terrain, accessibility, labor force, economies of scale, and site or factory assembly of major components.

Geologic conditions and terrain, e.g. slope stability and need for extensive cut-and-fill, can be expected to increase the cost of construction by 2 - 5%. The need to build or reinforce roads to carry heavy equipment will also be affected by both geologic conditions and terrain factors and can be a significant cost.

The availability of an adequate and skilled labor force can also impact construction cost. If the site is located in a rural area with little or no skilled construction labor force, most construction personnel will have to be brought to the site and, in fact, depending upon the commuting distance, a construction camp may have to be established to provide living quarters and meals for the workers (Sifford et al., 1985).

Economics of scale will often favor the larger power plant; however, a number of factors can virtually eliminate the initial capital cost advantage and may provide operational characteristics that greatly increase both plant availability and capacity factors. The most important of these are modular design and factory assembly of major components. Modular design will often allow for factory assembly of major components, virtually eliminating most weather-related delays, minimizing the need to upgrade roads to carry extremely heavy pieces of equipment, and helping to ensure more consistent and higher quality workmanship, possible because of the controlled environment where the work is taking place. Modular design may also allow for staged start-up of generation, providing for a revenue stream much earlier than with the larger, site-erected plant, and minimizing interest during construction. For example, a 110-MWe power plant, made up of two 55-MWe turbine generators at The Geysers has a normal construction period of three years. Modular plants of approximately 25 MWe and less can often be on-line within one year of the start of construction with subsequent modular plants coming on-line at 6- to 12-month intervals. The generation of considerable revenue during the construction period more than offsets any advantage that economy of scale may provide. In addition, the ability to bring units on-line sequentially often is a major benefit in being able to better track load growth of the utility. However, within the size range of most modular constructions, e.g., less than 25 MWe, economy of scale does apply. For example, it would be more cost effective to erect five 5-MWe modules rather than ten 2.5-MWe modules.

## 3.0. DIRECT USE

A discussion of project design and facility construction relative to direct-use projects is much more difficult than the previous discussion relating to power generation. A direct use project may be supplying the needs of a greenhouse or aquaculture complex, a dehydration plant, an industrial facility, or a district energy system supplying multiple commercial, industrial, and even residential customers. (Note: Individual systems to heat and/or cool a single residence or greenhouse, or projects directed toward balneology, are not considered.)

The uses mentioned above, however, share a number of design considerations and even some equipment components, all having a bearing on the economics of the project. All are highly dependent upon resource characteristics, including temperature and flow, hydrostatic head, drawdown, and fluid chemistry. The characteristics of the resource will dictate not only the type of project that can be developed, but also the scale of the project and the metallurgy of the components selected. Direct use projects must be located near enough to the resource site to allow for economic transport of the geothermal fluids from the wells. For very large district energy systems, however, this distance may be several tens of kilometers. If the well(s) does not flow artesian, well pumps will be required and, at resource temperatures at which most direct use projects operate, either line shaft or downhole pumps may be used. Because of variations in flow requirements to meet seasonal loads, inclusion of variable speed drives should be considered in order to minimize electrical costs.

Piping from the well(s) to the application site will be dependent upon temperature, pressure, and distance. Insulated pipe may or may not be required, and will depend on distance and whether or not some temperature loss is acceptable. The pipes may be constructed above ground, but local regulations may require burial.

Another major design consideration is whether or not the heating system should be based on meeting the peak heat demand entirely with geothermal or whether the system should rely on a fossil fuel (oil, propane, natural gas, or even coal) boiler for peaking and/or backup. In many instances, a strategy where the geothermal system is designed for 'base load only' operation may be the most economical. For both greenhouse applications and district energy systems, designing the geothermal system to meet 50 - 70% of the peak heating load will still allow the geothermal system to meet 90 - 95% or more of the annual heating requirement in most climatic zones.

This is because a system that is designed to meet peak-heating load only operates a few hours of the year under those conditions. For example, if a district energy system is to meet peak demand solely with geothermal, the number of wells will have to be doubled and the size of the distribution piping increased by approximately 30% to accommodate the requirement for increased flow. Another strong argument for meeting peak demand with a non-geothermal system is the need for back up for both greenhouse applications and for district energy systems. And although back up can be provided through the use of standby wells and back-up generators to run pumps, a fossil fuel system may be the most secure alternative and also the most cost effective. Whether or not to include fossil fuel peaking for an aquaculture or industrial application will depend upon the particular requirements of the application.

In addition to giving careful design consideration to the selection of the most appropriate and economical heating system, similar consideration should also be given to the provision of cooling. For most greenhouse operations, cooling can be provided through a combination of shading and the use of evaporative coolers.

However, if a more sophisticated cooling system is required, or there is a need for refrigeration, absorption cooling may be an option worth evaluating. New advances in double and even triple-pass absorption equipment allow for a coefficient of performance (COP) significantly above 1 to be obtained, and even at geothermal resource temperatures as low as 80 - 100°C, absorption cooling may be the answer to meeting the needs of both greenhouse operators and providers of district energy service. Binary turbine driven refrigeration machines may also deserve careful consideration.

### 3.1. Equipment selection

Most if not all systems will require the inclusion of a heat exchanger to separate the geothermal fluids from the in-building or process heating circulating loop because of the potential for corrosion and scaling associated with most geothermal fluids. Both plate-and-frame and shell-and-tube heat exchangers have been successfully employed in such applications. Despite higher cost, however, a number of factors tend to favor the plate-and-frame exchanger. Approach temperatures across the plate-and-frame exchanger are somewhat better at 3° to 6° C vs. 8° to 11° C for shell-and-tube. Another major consideration in the selection of a plate-and-frame heat exchanger is the ability to easily add plates in order to expand the heat exchanger capacity, and the fact that the exchanger can be easily opened for cleaning. (NOTE: This is not true for brazed plate-and-frame exchangers.) Materials include various grades of stainless steel and titanium.

Selection of the piping material is especially important in applications that have extremely long pipe runs such as is common to all district energy systems. If the geothermal fluid is to be circulated through the distribution-piping network, material selection and even carrier-pipe wall thickness become crucial decisions. For example, in the case where geothermal fluids are circulated, thin-walled, pre-insulated district heating pipe, so common to most district energy systems in Europe, may not be appropriate. If, however, the heat is transferred to a secondary fluid that is circulated in a closed loop, and where addition of corrosion inhibitors is practical, the thin-walled, pre-insulated pipe is probably a logical choice. Other points to consider include the choice between metallic and nonmetallic pipes and whether flexible pipes should be used. Flexible piping is only available in the smaller size ranges, but the decrease in cost associated with its installation may make providing heat to areas with relatively low heat load density economically viable. If nonmetallic piping is selected, care must be taken to ensure that it has an oxygen barrier or that areas served with nonmetallic pipes are separated by a heat exchanger from areas served with metallic pipes. If this is not done, severe corrosion problems may occur in the metallic pipe portions of the system due to oxygen infiltration.

Other system components and design considerations are very application-dependent. The reader is referred to the Geothermal Direct-Use Engineering and Design Guidebook published by the Oregon Institute of Technology in Klamath Falls, Oregon (see listing at: htpp://geoheat.oit.edu).

### 3.2. Project construction

For greenhouses and aquaculture projects, construction of the geothermal portion of the project is usually a very minor part of the entire project, and consists primarily of wells, pumps, heat exchangers, peaking and/or backup equipment, piping, and controls. However, with a district energy system, the thermal energy transmission and distribution piping system will comprise 60% or more of the total construction budget. District energy systems may include multiple heat exchanges and peaking or back-up stations, thermal storage tanks, and extensive control systems. In the majority of district energy applications, the geothermal fluid is most often used to heat a secondary fluid that is circulated to meet customer needs. In some cases, however, the geothermal fluid is circulated directly to each customer, where the heat exchange takes place. The principal cost during construction is related to pipe lines and includes excavation, back filling, and repaving, if necessary. The installation of the piping system can run from an equivalent of $300 US per meter to as high as $9000 US per meter in highly developed urban areas. A major problem for most developers of district energy systems is that the transmission piping must be sized to meet the needs of the system at full build-out although revenue will increase only slowly as the system expands and as the customer base increases. This dilemma is by far the most important economic consideration in determining the feasibility of introducing geothermal district energy service into an existing community. The use of computer models for determining the economic viability of constructing a new district energy system or expanding an already existing system is now available. For one such model see HEATMAP© GEO, which can be found at http://www.energy.wsu.edu/software/heatmap/. In a new community or a new area of a community, much of the cost of constructing the distribution system can be shared with the developers of other utility services, including sewer, water, and electricity.

## 4. REVENUE GENERATION

For power generation projects, the power sales contract establishes the legal framework for revenue generation. For direct use projects, however, the revenue stream to support the project may well come from the sale of a product, e.g., flowers, plants, or vegetables from a greenhouse project, fish or shellfish from an aquaculture project, value-added service, e.g., dehydration in an industrial process, or thermal energy sales for a district energy project. Combined heat and power (CHP) may be an attractive consideration. With CHP, the heat available in the spent brine or condensate is used in a direct use application, e.g. district heating, thus providing another revenue stream. Considerable interest in so-called co-production is increasing rapidly as a means of improving the economics of geothermal power generation by providing an additional revenue stream. Co-production involves the extraction of valuable by-products for the geothermal brine before re-injection. These by-products may include zinc, manganese, lithium and silica – all with relatively high market value.

### 4.1. Electrical generation

Ultimately, the economic viability of a particular power generation project will depend upon its ability to generate revenue, and revenue can only be generated from power sales. Such sales must be equal to or exceed that required to purchase or maintain the fuel supply, to cover debt service related to capital purchases, and to cover operation and maintenance of the facility. The output from the plant, and hence the source of revenue generated, will be highly dependent upon how well the plant is maintained, how it is operated, and the ability to take maximum advantage of incentives to produce at certain times or under certain conditions. For example, a plant selling into a summer peaking service area must be able to provide maximum possible output when a premium is being paid for output.

With the increase in the number of geothermal power plants by private sector developers, O&M has assumed even greater importance. Competition means that margins for profit are slimmer, making O&M costs all the more critical. Because most power sales contracts are output-based, and because geothermal generation costs are predominantly fixed as opposed to variable, the unit cost of geothermal power decreases rapidly as the capacity factor increases, i.e., maximum operation yields maximum return to the owner. For example, as the plant capacity factor increases from 50 to 90%, the levelized cost of producing electricity could be expected to decrease by nearly 50% (Parker et al., 1985).

A number of innovative approaches have been adopted to ensure the highest possible capacity factor and thus maximum revenue to the plant owner. The most common of these is the use of redundant or back-up equipment, including spare wells, cooling water pumps, noncondensable gas removal equipment, and the use of multiple turbine generation sets. The presence of redundant equipment allows for routine or even forced maintenance to be accomplished without taking the plant off line or at least the entire facility off line. The use of multiple modular turbine generators is a prime example of a strategy to achieve maximum capacity factor. In many instances, the steam or brine can be routed from the downed unit to other operating units capable of operating at slightly over design, thus providing the possibility of covering the entire load of the unit that is out of service.

One of the most innovative uses of this philosophy was first demonstrated at the Santa Fe plant in The Geysers geothermal field. Due to Santa Fe's common ownership of the plant and well field, regulatory restrictions, and contractual incentives, it was highly desirable to obtain highest allowable capacity and availability for maximum revenue generation with minimum per unit fuel use and production cost. Maximum capacity was ensured through the use of two, two-flow turbines, each capable of producing the maximum regulatory allowable 80 MWe. The use of two turbine generator sets allows for more frequent refurbishing of the turbine blades to maintain performance at or near design value without significant loss of revenue during down time and without the need to maintain two spare rotors. Higher efficiency was also ensured through the selection of a turbine design that incorporated partial arc admission and the capability to slide to 50% overpressure. The use of the partial-arc admission resulted in reduced throttling losses under normal operating conditions (two-turbine operation, each at 40 MWe net output) and improved single turbine operation, i.e., 80 MWe net output.

At eight bars throttle pressure at (or near) the first valve point, the larger valve is fully open and the smaller valve is fully closed. Under these operating conditions, each machine produces 40 MWe of net output. When only a single turbine generator is operable, the small valve is operated at 11.6 bars throttle pressure, and one turbine can produce approximately 80 MWe net (McKay and Tucker, 1985). According to the design engineers, Stone and Webster, the cost of the second turbine generator would be covered by an additional two weeks of operation per year, approximately equal to the time required for routine maintenance. ( Efficiency is further enhanced through the use of a large, multi-pressure condenser that guarantees a low average condenser pressure, and condenser bypass that allows full steam flow through the condenser of the operating unit, as well as the use of the entire cooling tower so that design back-pressure can be maintained during single turbine operation (McKay and Tucker, 1985). Through such innovative approaches, not only is maximum capacity and potential for revenue generation ensured, but efficient use of steam is also achieved.

Revenue can also be affected by plant availability, dispatchability, and load-following capability. Many power purchase contracts provide incentive payments for: availability, i.e., the ability to generate at certain levels or during certain peak demand periods; dispatchability, i.e., the ability to go off-line or curtail production when the power is unneeded; or load-following capability, i.e., the ability to match power output to the need for power of the receiving utility. Availability, much like plant capacity factor, can be achieved through the highest possible flexibility and reliability in plant operation, and, as with capacity, is often achieved through the use of redundant equipment. However, possibly as important in terms of revenue generation is the ability of the plant to quickly come on-line after a forced outage, after being tripped off-line, or upon request of the utility to curtail production. In many areas, being tripped off-line means shutting in wells to avoid unabated hydrogen sulfide emission and a lengthy restart because major components have to be brought up to temperature slowly. The use of a turbine by-pass and computerized well field control can individually or, ideally, together minimize both these effects and help maximize on-line availability. By being able to route the steam flow past the turbine and directly into the condenser, it is possible to remove the noncondensable gases, and any hydrogen sulfide can be removed and treated in the hydrogen sulfide abatement system. Without the turbine by-pass, the wells would have to be shut in or vented to the atmosphere, and it could take up to several hours to bring the wells and plant back to full production. In its first full year of operation, Santa Fe Geothermal, one of the first plants to use the turbine by-pass, achieved a capacity factor of 98.6% of its 80 MWe operating permit and had an availability of 99.9% (Fesmire, 1985).

Other factors that can affect revenue generation include plant dispatchability and load-following ability. Although the commonly held philosophy is that geothermal power plants, because of the ratio of fixed to variable costs, must operate in a base load manner, utility requirements and/or reservoir concerns may require that the plant be operated in a load-following or dispatchable manner. Reservoir depletion at both The Geysers and Larderello has forced load following, and some utility contracts provide incentives for dispatchability that more than offset any loss of revenue while the plant is operated below design capacity.

A number of plant features, including partial-arc admission, turbine by-pass, and computerized well field operation, all mentioned before, help maximize revenue generation during load-following operation. The Italians have also found that remote operation can play a significant role in meeting the demands of load-following operation while at the same time significantly reducing labor costs, costs that become increasingly important when a plant or plants are operated below design capacity. It is also important to note that availability takes on increasing importance when operated in a load-following mode inasmuch as severe economic penalties may be imposed if the plant is not available when needed.

The direct link between revenue generation, plant availability, and capacity also places greater emphasis on O&M. Plant operation costs and on-line performance are under increasing scrutiny by purchasing utilities, direct electrical service customers, and those who provide financing. Indeed, because investors and financiers are typically more conservative than developers, an experienced, big name company able to provide both O&M has strong appeal to backers, and that appeal translates directly into slightly lower financing costs, which are a major economic consideration. It is extremely important that the O&M provider or in-house staff be retained at an early stage in the development process and provide review and input into plant design, participate in plant construction, start-up, and conduct system checks. The contractor or plant staff should also be capable of and required to perform a post-hoc analysis of all significant events, including root cause analyses for future planning (Independent Power, 1989).

The increase in partnerships developing projects also highlights another O&M trend: affiliates of financiers and/or partners are often highly competent facility operators. A vested interest in plant performance provides a motivating influence to the O&M provider. Such motivation, in turn, provides security to financiers.

Other incentives to peak performance, however, do exist. A bonus for good operation, tied with a penalty for not meeting minimum performance requirements, helps ensure optimum performance, guarantees achieving output to match contractual requirements, and generates maximum revenue and profit. But good O&M goes beyond maximizing current profits, to an efficient use of the reservoir in order to prolong life and assure supply. Smart developers also know that a good performance record will be critical to obtaining both future power sales agreements and financing for future plants at attractive rates.

### 4.2. Co-Production

Co-production, i.e. the production of silica and other marketable products from geothermal brines, is rapidly becoming not only a very viable source of additional revenue for power plant owners, but a key technique for improving power plant economics by reducing operation and miantenance costs. The removal of silica may allow additional geothermal energy extraction in bottoming cycles or additional uses of low-grade heat that are presently prohibited due to problems associated with scaling.

Precipitated silica has a relatively high market value (1-10 US dollars per kilogram) for such uses as waste and odor control, or as an additive in paper, paint and rubber (Borcier, 2002, Personal Communication, Borcier, et al., 2001). Initial estimates from Salton Sea geothermal fields places the market value of extracted silica at 84 million US dollars a year.

Silica removal also opens the door to the downstream extraction of, for example, zinc (ZN), manganese (MN), and lithium (LI), all with relatively high market values. The first commercial facility for the recovery of zinc from geothermal brine was built in the Salton Sea geothermal area of southern California in 2000. The facility is designed to produce 30,000 metric tonnes of 99.99% pure zinc annually at a value of approxinmately 50 million US dollars (Clutter, 2000).

Silica removal has the additional benefit of helping to minimize reinjection problems and, in one case in California, could allow use of the spent brine as the source of cooling water needed to improve summer power plant performance. Initial studies indicate that power plant efficiency of an air-cooled binary plant could be increased by 25+% through the use of spray cooling (Sullivan 2004, Personal Communication).

### 4.3. Direct Use

Most large-scale direct use projects tend to fall into three broad categories: provision of district energy;

industrial processes, including dehydration; and agriculture, including greenhouses and aquaculture. In all except the provision of district energy, revenue is generated from the sale of a product, such as potted plants from a greenhouse, or from a value-added service rendered, e.g., the drying of onions in a dehydration plant.

Ultimately, in both cases, revenue generated and economic viability are totally dependent upon the value and marketability of the end product. Long-term contracts for sale of these products are almost never available. Geothermal may be the most economic form of energy for any given application, and may even provide certain other benefits such as fuel price stability or constant heat, but the economic viability of the project will seldom be driven by the cost of developing and/or operating and maintaining the geothermal source. The geothermal resource developer must therefore not only have a thorough appreciation of the costs involved in developing and operating a geothermal project in an economical manner, but must fully understand what factors ultimately determine the economic viability of the products produced.

With district energy, on the other hand, revenue is generated solely from the sale of thermal energy in the form of either hot water or chilled water. Long-term sales contracts to customers are the norm, and most contracts call for both capacity (fixed) payment and variable payment components. The capacity or fixed portion of the payment is based upon the capital invested, including wells, heat exchangers, thermal storage units, back up or peaking boilers, and the transmission and distribution network. The variable portion of the amount charged relates to O&M, including personal cost, cost for fossil fuels used in the back up and/or peaking boilers, and re-drilling of wells. In most systems, charges are based on usage, metered either as flow or thermal demand, i.e., kW/hour. Some systems, however, use a fixed orifice and charges are based upon the orifice size.
Because weather conditions will, to a large extent, determine thermal energy usage by residential and commercial customers, it is extremely important that rates are structured in such a way as to ensure that revenue is always able to cover both fixed and variable costs.

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