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FOREWORD

This LBL Report is a copy of a draft* section of a forthcoming book: SOURCEBOOK ON THE PRODUCTION OF ELECTRICITY FROM GEOTHERMAL ENERGY, Prof. Joseph Kestin (Brown University), Principal Investigator.

The SOURCEBOOK (in press) is being produced by Brown University in cooperation with a number of other agencies, laboratories, organizations, and universities with the support of the U.S. Department of Energy, Division of Geothermal, through Contract EY-76-S-02-4051-A002, Mr. Clifton B. McFarland, Program Manager.

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*Final draft submitted to Brown University February 27, 1979.

DEDICATION

This report is dedicated to my lovely wife, Doreen, and sons, Douglas and Scott, who unselfishly allowed me to pursue these challenging personal activities seven days a week over a period of several months.

William L. Pope

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8.2 CONCEPTUAL DESIGN OPTIMIZATION

8.2.1 Introduction

No recent document has appeared with a description of the state-of-the-art of power plant economic design optimization. It is the goal of this chapter, when used with the wealth of information presented in related chapters, to provide the reader sufficient material and interest to appreciate the complexities involved for geothermal power plants and to overcome them.

8.2.1.1 Complexity of Geothermal Power Plant Designs

Because of the inherent complexity of geothermal power plant design calculations, sophisticated computer codes are obviously necessary. System design codes in current use differ considerably in generality, formality, basic structure, fluid property accuracy and treatment, convergence algorithms and criteria (and therefore general accuracy, consistency, and speed), and optimization methodology. These codes have been used in comparative studies of hydrothermal energy conversion systems with a variety of technical and economic assumptions and/or "simplifications." Consequently, economic feasibility consistency has been lacking in previously reported studies of even the simplest geothermal energy conversion systems.

A higher degree of reporting consistency will be necessary if the geothermal community expects private investors to commit funds so that hydrothermal geothermal power can be demonstrated as the viable alternative we all believe it to be.

8.2.1.2 Inconsistencies in Previous Work

New energy technologies develop slowly. Those alternatives on the edge of economic feasibility tend to move faster, because there are fewer obvious technical, environmental, and social impediments. Because of the successful development of geothermal power plants at vapor dominated resources (the GEYSERS in Northern California, for example), hydrothermal geothermal power development obtained the initial industrial and federal stimuli required for rapid growth. However, real progress has been disappointingly slow. Reporting inconsistencies have contributed to a higher than necessary perceived level of risk.

8.2.1.3 Causes of the Inconsistencies

In our view, inconsistencies in the relative thermodynamic and economic performance reported for the simple hydrothermal geothermal energy conversion processes are the result of three factors:

1. differences in degree of system characterization

2. differences in design approach and measures of optimality or goodness

3. differences in economic analysis tools

We will discuss each of these factors briefly as they apply to simple hydrothermal energy conversion processes in order to arrive at a general measure of optimality which can be applied to all types of energy conversion systems.

8.2.1.3.1 Degree of System Characterization

Previous comparative studies of various alternative energy conversion processes for specific hydrothermal resources have frequently been conducted with little or no regard for the producibility of the resource. The "boundary conditions" for various plant types are assumed to be equivalent and the fuel cost is treated as "immaterial"--that is a simple add-on , or "over the fence" price. In some early studies irreversibilities in the heat rejection system have been ignored resulting in overly optimistic brine utilization efficiency expectations.

The various conversion alternatives were "optimized" after making several simplifying assumptions about resource productivity and the best design was the one which provided the electrical energy at the lowest busbar (or load center) energy cost. Depending on the formality of the analysis, reported results differ. Some analyses assume economically unjustified (low) temperature differences in the non-work producing elements of the cycle and either tend toward low specific fuel consumption (high brine utilization efficiency) or optimistic plant capital costs (high cycle efficiency).

As previously mentioned, some analyses assume the unit fuel costs are the same. The thermodynamic availability, productivity, injectivity, and longevity of the resource have a strong influence on the selected plant design and, therefore, the overall optimum system design. The cost of fuel to the plant depends upon the plant load <u>and</u> upon the manner in which the "brine" is produced and disposed. Different surface conversion systems require different wellhead conditions and, therefore, different production and injection scenarios. Because optimum <u>systems</u> are not compared, the selected "optimum" conversion process is questionable. The optimum conversion process for a geothermal power plant <u>is not</u>, in general, the one which utilizes the fuel most effectively. This will be discussed in the next section and quantified with example problems at the end of this report.

8.2.1.3.2 Design Approach-Previous Measures of Goodness

The traditional approach to power plant design has relied heavily on thermodynamics as a measure of economic goodness. This is the result of the large practical experience base which has developed around fossil fueled steam power plants and the fact that the calorific value of the fuel (or heat of combustion) is not significantly different from the available work, $W°$, or exergy, (Ref. 1) of the fuel relative to a chosen dead state. However, the simple economic "rules-of-thumb" applicable to fossil fueled plants are <u>not general</u> and cannot be applied directly to geothermal systems.

For example, in a fossil fired steam power plant either the heating value of the fuel or metalurgical limits determine the <u>maximum</u> cycle temperatures. The low density of steam at the turbine exhaust plus very well established prime mover and heat rejection system technology (<u>and</u>

economics) have determined the minimum cycle temperature. This means that the maximum cycle efficiency or minimum plant cost per unit mass of fuel is fixed for a given type of fossil fuel plant. Consequently, the minimum busbar energy cost system is determined by simply optimizing the fuel utilization.

For the organic fluid (binary) Rankine cycle geothermal power plant, on the other hand, no such simple economic rule applies. For example, if one were to maximize the thermodynamic cycle efficiency to achieve minimum plant cost, the fuel cost would go to infinity. Similarly, if one sought the absolute maximum fuel utilization efficiency, the plant cost would approach infinity as non-work producing temperature steps in the cycle approach zero to minimize cycle irreversibilities. In this case a more general design objective is needed for the system as a whole.

When minimum busbar energy cost is the Design Objective, the optimum geothermal power plant (or total system) design is one in which neither the plant nor the fuel are utilized at peak thermodynamic levels. The minimum busbar cost geothermal power plant design, nevertheless, is not intrinsically different than the minimum busbar cost fossil fueled plant. In both cases state-of-the-art optimality is the result of a complex trade-off between the competing forces of thermodynamics and economics applied to the plant and the fuel. The geothermal power plant simply has fewer constraints or more degrees of freedom. The minimum busbar energy cost geothermal system obviously cannot be determined from thermodynamic considerations alone.

When current economics are applied to optimized plants, we find that the economically achievable fuel utilization efficiency is no better for the all geothermal power plant than it currently is for state-of-the-art fossil fueled plants--i.e. about 40% (Ref. 2).

However, by restricting the geofluid use to sensible heat addition with subsequent reduction of entropy production, higher utilization efficiencies can be achieved. See, for example, the discussion of a hybrid geothermal-fossil fueled plant in Section 4.3 of this SOURCEBOOK.

8.2.1.3.3 Economic Analysis Tools

There should be little disagreement at this point as to what constitutes "goodness". Although thermodynamics will always impose limits to maximum achievable performance, economics always has been and always will be the only universally accepted measure of commercial system optimality.

Unfortunately, for a given level of thermodynamic characterization, an economic optimization requires another dimension of input detail. The quality of this additional input (the cost factors) is frequently open to question. For comparative studies of competing alternatives, economic consistency and relative costs assume added importance. This added degree of complexity has provided much of the stimulus for the development of newer, more sophisticated system design codes which incorporate the latest developments in thermodynamics (Ref. 1), economics, and optimization theory.

In the next section we describe features of some of the promising system design codes under development with DOE/DGE support.

8.2.2 Features of State-of-the-Art Codes

Some of the more sophisticated and generally useful codes are designed with, 1) formal economic and thermodynamic process routines, 2) modular structure, 3) separate, extensive fluid properties routines, 4) detailed process design routines, 5) efficient coding, and 6) multiparameter optimization (MPO) capabilities. The more recent simulators also include 7) simple, user oriented, interactive input features complimented with, 8) data sufficiency/consistency checks performed prior to execution, 9) general thermodynamic logical constraints to avoid computations on unrealistic variable combinations during optimization, 10) easily understood printed thermodynamic and economic output, and 11) flexible, state-of-the-art contour and 3-D plotting capabilities.

8.2.2.1 Ongoing Research

Government and industry are sponsoring research that will provide information on, 1) new process components (heat exchangers, turbines), 2) improved fluid properties (brines, mixtures of light hydrocarbons), 3) scaling behavior of geothermal brines, and 4) reservoir and well flow data compilation and modeling development. A useful geothermal system design code will incorporate this information when it is available.

8.2.2.2 Keeping Abreast

The responsible process designer should become aware and stay abreast of the more general theory (Ref. 1) and the many promising new capabilities made available with recent system software developments, particularly MPO techniques. Not only will MPO techniques most likely guarantee convergence on the global optimum design objective for a system with many independent "optimizable parameters", the new codes with MPO capabilities virtually eliminate the need for the designer to perform subsequent "sensitivity analyses" or parametric studies on each of the optimizable parameters. MPO techniques offer the theoretician an extremely valuable tool to test and/or validate various hypotheses which may be intuitively obvious, but analytically intractible. Examples are presented.

8.2.3 <u>Current Software Limitations</u>

It is equally important that the process designer be exposed to current limitations of the new software. Some of the more important or obvious existing limitations of even the best geothermal power plant design simulators in the open literature are:

1. Reliable subsystem cost and off-design performance characteristics are lacking.

2. Financial routines differ. Built-in "standard" financial assumptions are so different that <u>radically</u> different estimates of "levelized busbar cost" result for the same set of capital cost input data.

3. The plant design routines are coupled only to a zeroth order reservoir simulator, or completely uncoupled.

4. Two-phase production well flow is poorly simulated, if at all.

5. Chemical kinetics are poorly simulated, if at all.

6. Logical conversion system synthesizers for creating configuration or operation alternatives do not exist. The design performance is a direct product of the specified configuration and the chosen mode of operation.

7. Codes, in general, lack adequate documentation.

Items 2 through 5 have been identified and are getting the requisite attention and support from industry and DOE/DGE. In some cases adequate subsystem simulators exist; they just haven't been coupled to the overall plant design simulator. Item 1 is, of course, lacking in generally available codes, but these features are being incorporated by industry as the codes gain industrial acceptance.

Whether or not Item 6 is important depends entirely on the experience and/or creativity of the system designer or synthesizer and errors of ommission are possible. (See, for example, Section 8.2.5.5, Floating Cooling).

Item 7 is a particularly nagging problem. It is not unusual to get "burned" using someone else's routines. Technical and financial limitations, assumptions, approximations, equations solved, convergence criteria satisfied, etc., must be stated in the User Manual. It is the responsibility of the code developer to provide this documentation if general use is anticipated.

We feel that the best way to overcome these current limitations is through vigorous feedback among system and component designers from industry, reservoir engineers, chemists, theoreticians, economists, and system design code developers.

The remainder of this chapter is devoted to a brief description of how these new codes work, and how they have been used for the conceptual design, and economic optimization of various simple energy conversion systems coupled to idealized hydrothermal geothermal resources. A promising, possibly new, optimization algorithm is described, and the results of sample calculations are presented for two basic hydrothermal energy conversion systems.

8.2.4 System Design Selection Criteria

The selection of the "best", or economically most attractive, plant/field design for a known or specified geothermal resource is a multiply iterative process even after the value of the energy conversion to a utility or grid has been estimated for a particular assumed future market. Section 8.1 of this SOURCEBOOK has outlined a method which utilities might use to determine the power requirement, market forces, and grid suitability for pre-conceptual level energy conversion costs.

In this section, a rational computer design optimization method is described which might be used by an architect engineering firm to make reasonable estimates of the resource energy price, determine the best alternative for converting this resource energy into electrical power, and finally establish the most probable busbar energy cost.

8.2.4.1 Utility Perceptions

The best way to describe this method is through the use of Fig. 8.1.1.5.1 (Section 8.1), the SELECTION PROCESS DIAGRAM. The "best" energy conversion alternative as perceived by the utility, or "customer", is defined in Fig. 8.1.1.5.1 as that plant/field design configuration which maximizes the value of the energy conversion, V_C.

8.2.4.2 Constraining the Problem for the Designer

This problem can be posed for the system designer in another way. Given the energy demand, a resource capable of supporting the demand, and minimum values of acceptable rates of return to the producer (estimable but influenced by the producers total market) and the utility (fixed) based on current and projected operating costs and costs of capital, determine the plant/field design configuration which minimizes the busbar (or load center) energy cost, C_E.

It is important to recognize here that, in general, when geothermal power plant conceptual design trade-off studies are being done between various candidate resources, processes, and working fluids, a contract with the producer probably hasn't been signed, so the unit cost of the resource energy is not known. In addition, it is generally not valid to say we can design or compare various plants on the assumption that the unit brine cost (either per unit mass or per unit energy extracted) is the same for all alternative plants.

The cost and number of wells and the productivity and longevity of the resource depend on how the resource is produced and the plant(s) load and, therefore, influence the cost of the brine, or "fuel", to the plant. This "fuel cost" has a significant and predictable influence on the resulting overall Optimum System Design, its busbar energy cost, and the marketability of the power.

This means that in addition to all the financial assumptions that must be made regarding the plant, the method described here requires that similar (and potentially less credible and stationary) financial assumptions be made regarding the field or resource.

This complex problem was addressed by Ben Holt in 1976 and is discussed at length in reference 3. Holt used the cost-of-service approach to arrive at the probable brine cost "in accordance with generally accepted practices in the petroleum industry" and made all the required assumptions regarding exploration costs, well productivity, then current drilling costs, producers minimum required rate of return, depletion and intangible drilling costs, inflation, escalation, etc.

8.2.4.3 Overall System Model - the Design Objective

For screening plant/resource alternatives and subsequent conceptual designs, we assume that Holt's basic system analysis model applies. We price out the brine and the plant costs; establish the minimum or optimum busbar (or load center) energy cost for each plant/field configuration alternative; compare the final results of each alternative; and define as the busbar energy cost, the best of all the alternatives. This is the system Design Objective.

This energy cost along with the predicted cash flow, capacity factor, plant life, estimated off-design daily and seasonal performance capabilities, and environmental impact information is then fed back to the utility (or customer) for comparison with other proposed power plant alternatives.

If all the requirements of the grid are met by the proposed geothermal power plant within the utility's or investor's defined acceptable level of risk or economic uncertainty, and the proposed geothermal plant is the "best" economic and environmental alternative available to the utility, chances are good that the geothermal power plant will be built.

8.2.5 Synthesis of Plant/Field Alternatives

In this section we briefly list some of those factors which will have a relatively strong influence on busbar energy cost in simple hydrothermal energy conversion systems, so they can be used for preliminary screening.

This system preliminary screening discussion must not be taken out of context. We only discuss the simplest hydrothermal energy conversion "cycles" for the purpose of illustrating a common general technique. The cycles discussed here will be limited to the simple, organic fluid (binary) Rankine cycle and the two stage flashed steam (or separating flashed steam) process.

The comparison criteria used in each category will be economics. The conclusions should be intuitively obvious when taken in context, however some degree of controversy is unavoidable. As systems are synthesized and screened, the plant and field capital cost tally must be maintained and periodically upgraded along with the thermodynamic calculations or poor decisions may result. Most useful system simulators provide this capability. Very crude component cost estimates are better than none at all, and no cost optimization can be performed without them.

8.2.5.1 Resource Characteristics

The resource temperature and ambient sink temperature (thermodynamic availability), resource productivity, quality, salinity, non-condensible gas content, and scaling potential will largely determine the number and types of alternative plant designs which need to be considered in the preliminary screening process. Because resource characteristics are too variable and complex to treat in this section alone, the reader is referred to Chapter 2 of this SOURCEBOOK.

8.2.5.2 More Complex Cycles

It is always possible to improve the thermodynamic performance, cycle efficiency, or resource utilization efficiency of the simple conversion systems by adding additional heating and/or cooling stages, and various power recovery devices. This is especially true for subcritical binary cycles. However, the point of diminishing-economic-return is quickly reached as systems get more complex. The cycle efficiency improvement with increasing number of stages is simply the result of increased first-stage temperature. If an alternate working fluid exists with a sufficiently low critical temperature and critical pressure, it is quite possible that a slightly supercritical simple binary cycle with this new fluid would be more cost-effective than the previous subcritical cycle with multiple stages.

8.2.5.3 Candidate Cycle Elimination - Trends

Low temperature hydrothermal resources will generally favor organic fluid (binary) Rankine cycle conversion systems, whereas flashed steam plants will tend to be best for higher temperature resources (Ref. 4). For low to moderate temperature (150°C to 200°C) hydrothermal resources, if the non-condensible gas content in the brine is very high (say greater than roughly 2.0% by weight), conventional, simple flashed steam cycles (condensing) can probably be eliminated in the screening (see Fig. 1 and Ref. 5).

On the other hand, if the resource temperature is very high and the brine is of extremely high salinity (say greater than roughly 50-100,000 ppm) or has a high scaling potential (the Niland area in Southern California, for example), conventional simple binary cycles probably need not be considered.

Furthermore, if the cost of drilling wells (or, more accurately, cost per unit convertible power) is expected to be very high at a particular resource, chances are good that the flashed steam cycles will drop out simply because of the inherently higher brine requirement (and, therefore, increased "fuel" cost) unless the resource temperature is high (say greater than about 200 to 250°C).

However, as might be expected, the screening process will usually not be this simple. For a particular resource to warrant consideration at all, it will probably have relatively low salinity, scaling potential, and non-condensible gas content unless the productivity is unusually high. Furthermore, because the salinity and scaling potential of U.S. hydrothermal reserves appears to increase with increasing resource temperature, it is likely that the temperature of near term technically exploitable candidate resources will be in the low to medium temperature regime (150°C to 250°C) where the energy cost of many hydrothermal conversion alternatives is about the same. This complicates the screening process.

8.2.5.4 Candidate Cycle Simplification - Shortcuts

Nevertheless, there are shortcuts to minimize the complexity of the screening process. For example, if the preliminary screening process has narrowed the selection down to a detailed comparison between, say, a simple

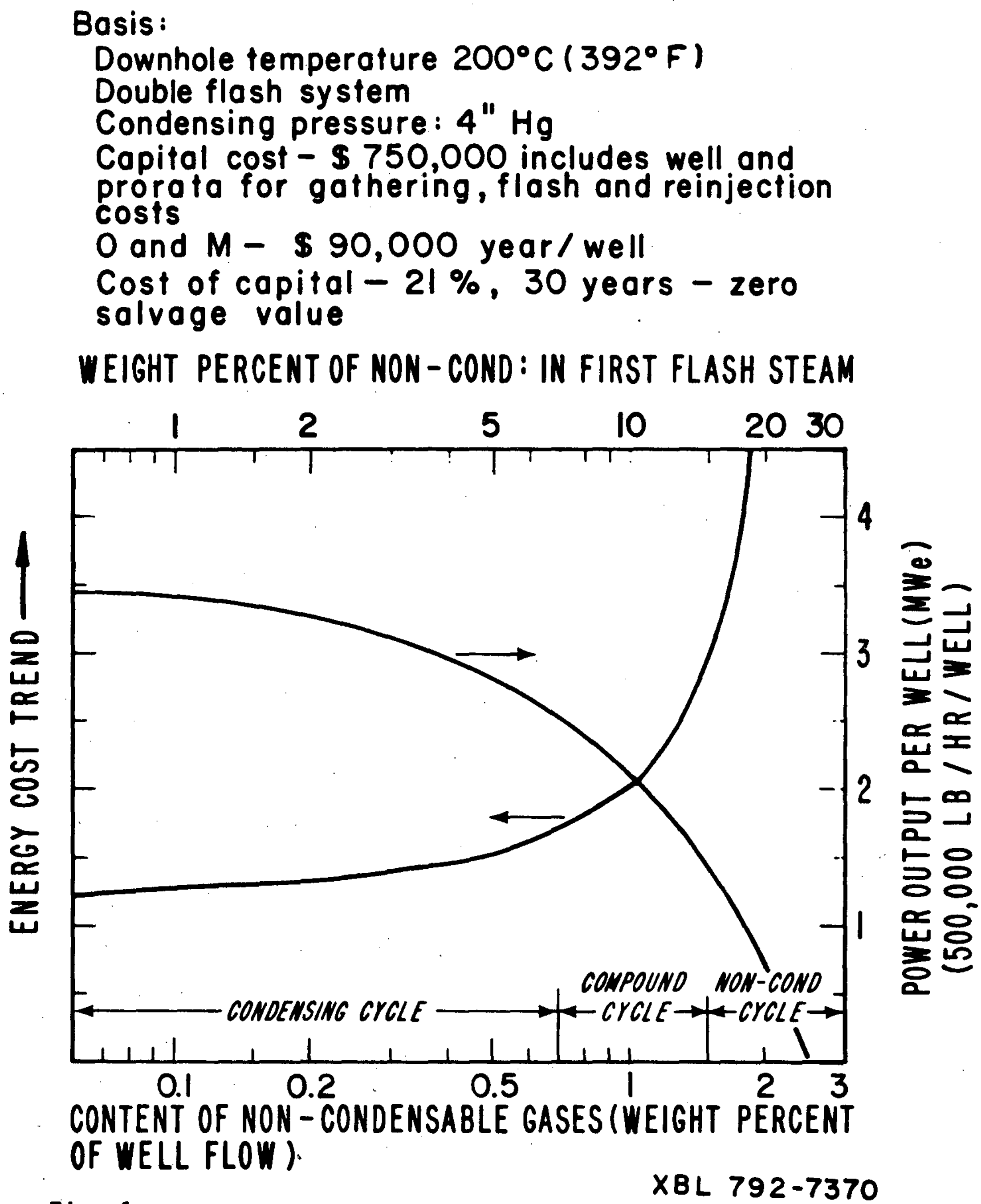

Fig. 1

Influence of non-condensible gases on the per well output power and economics of a condensing flashed steam energy conversion cycle (fixed flow rate per well). It is seen that for a content of non-condensible gases larger than about 1.5 weight percent of total well flow, the net power output per well for a condensing cycle approaches zero and the energy cost approaches infinity. Figure reproduced with energy costs deleted with permission from Ref. 6.

binary cycle and a two-stage flashed steam process; to find the better of the two, one may not need to characterize the influence of non-condensible gas removal in the condenser of the flashed steam process. That is, if the binary cycle is better assuming zero non-condensibles in the flashed steam process, it will be better for any non-condensible gas content (see Fig. 1 and Ref.5) at the same resource.

8.2.5.5 The Sink Temperature - Floating Cooling

The lower the source temperature of any thermodynamic energy conversion process, the stronger the influence of the sink temperature (Ref. 1) on process performance. The variability of the sink temperature should be considered when evaluating the performance of organic fluid (binary) Rankine cycles.

If the conceptually optimized, baseloaded binary cycle has a competitive busbar cost of energy for a fixed, extreme (say 1-5%) design wet bulb temperature, the annual average busbar cost of energy in a Floating Cooling mode can be lower. See Fig. 2.

If a market exists for the significant excess power that could be produced by the binary cycle during those daily and seasonal periods when the wet bulb temperature is low, the organic fluid (binary) Rankine cycle operating in the Floating Cooling Mode could be even more attractive. This floating cooling concept is discussed in detail in Ref. 7, 8, 9. A decisive economic evaluation is in Ref 9. (See Chapter 5.)

The floating cooling concept has also been considered for binary cycles with dry cooling towers for areas where cooling water is in short supply. Depending upon how the utility values the excess power available during normally off-peak periods, the computed energy costs can be competitive (Ref. 10). The implementation of floating cooling plants depends now largely on their acceptability, or value, to the grid.

Floating cooling techniques provide no significant improvement in flashed steam plants. In the flashed steam process the turbine exit

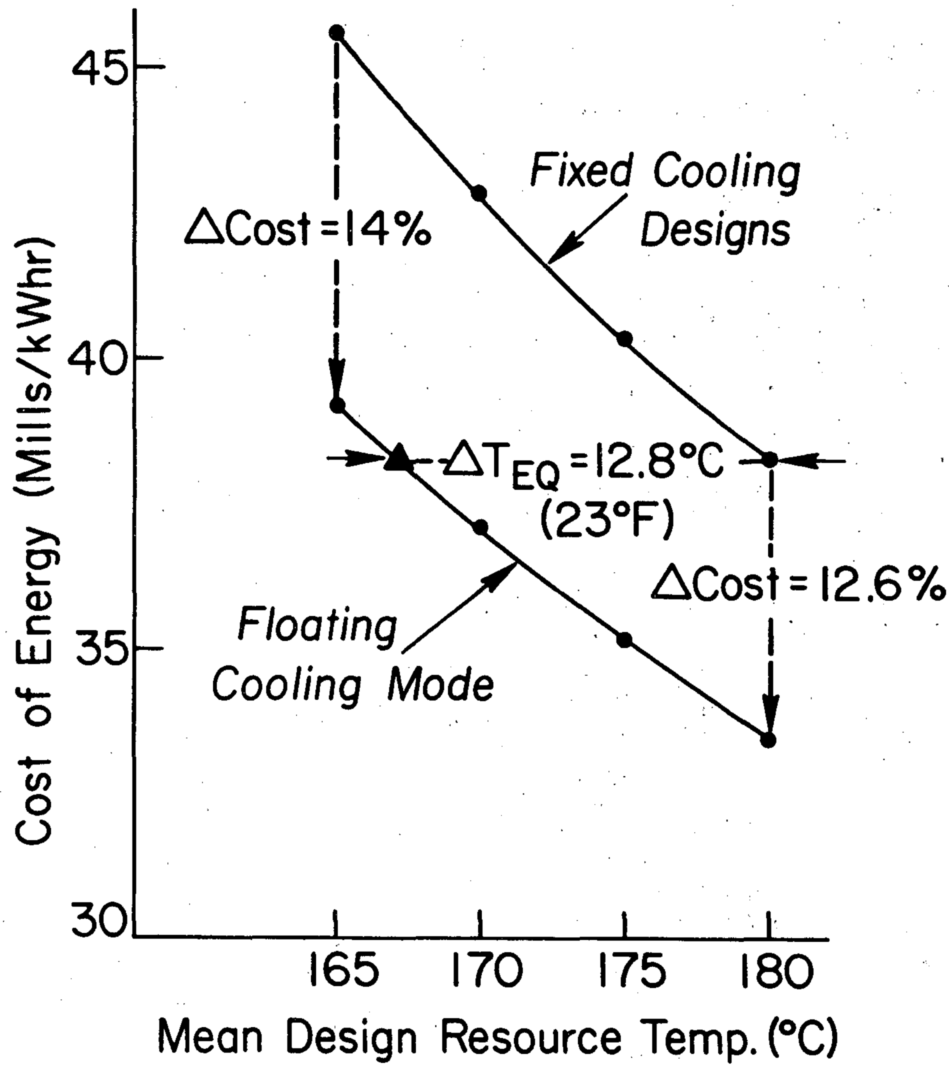

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Fig. 2

Influence of chosen design operating mode of organic fluid (binary) Rankine cycles on the busbar energy cost. In the Floating Cooling Mode, significantly more power can be generated if the condensing temperature is allowed to "float" with daily and seasonal variations of the sink temperature. This plot illustrates the potential reduction of the busbar energy cost for binary cycles designed to deliver 50 MWe (net) at the peak (1%) wet bulb temperature, if off-peak excess power can be sold at the same base rate (Ref. 9).

conditions cannot be changed sufficiently to follow the daily or seasonal wet and dry bulb swings, and thus generate significantly more power, because of specific volume limitations.

8.2.5.6 Cycle State Point Consistency - Assumptions

When considering various candidate cycles for a given resource, the system designer must be careful that exchanger pinch points and other cycle states and boundary conditions are appropriate. However, the foregoing statement <u>does not imply</u> that the plant thermodynamic state parameters should be the same for all cycles, resource temperatures, or working fluids in the pre-screening.

For example, when screening candidate working fluids for binary cycles, the comparison could, of course, be simplified if equal pinch points, condensing temperatures, and cooling tower range or approach were assumed, but the results can be severely biased by this simplification. If the fluids have markedly dissimilar molecular weights or critical properties, erroneous "best fluid" conclusions are quite possible. Economic optimizations using MPO techniques fortunately obviate the need to make many of these simplifying assumptions. This will be discussed later.

8.2.5.7 Configuration Assumptions - When Complexities Might Pay

Similar arguments are important relative to the assumed cycle configuration. Depending on the resource (or wellhead) temperature and the working fluid critical temperature, some simple supercritical binary cycles "optimize out" with considerable superheat in the turbine exhaust, simply because of working fluid, cycle configuration, U factor, and cost input assumptions. If this same cycle were re-optimized with a regenerative exchanger coupling the turbine exhaust and working fluid pre-heat streams, the reduction in cycle heat rejection would increase cycle efficiency, reduce cooling water make-up requirements, and chances are that the busbar cost would be improved. (See Chapter 5). When investigating the regenerative exchanger addition to the simple binary cycle, the tube/shell side fluid stream choice can be important to the cycle (Ref. 11).

8.2.5.8 Cycle Subsystem Assumptions - Overall Heat Transfer Coefficient

Because of otherwise significantly increased complexity and computation time, optimizations of overall geothermal energy conversion systems are generally performed with simplistic, first and second law heat exchanger simulations. The overall heat transfer coefficients are input. Section 4.2.5 of this SOURCEBOOK contains an excellent treatise of the complex considerations involved in arriving at these input overall U factors.

The primary heaters of geothermal binary cycle energy conversion systems are particularly bad actors, by typical exchanger standards, because of radically varying thermodynamic and transport properties and the difficulty of predicting the kinetics of complex brines. Fouling behavior and rates are extremely site specific, and because generally applicable kinetic theories simply do not exist, small scale on-site exchanger tests are usually necessary.

When the results of these on-site tests have been reduced to reasonable estimates of fouling rates, subsystem calculations on the primary heater can be performed. A completely general method for arriving at the optimum cleaning frequency, or optimum design fouling factor, (and therefore U factor) by such a sub-system optimization is described in Ref. 12.

Figure 3 is an example of the relative sensitivity of the total plant heat supply cost, X_{TOT}, to the exchanger pinch point temperature difference, the design cleaning frequency, and the pressure drops for the supercritical primary exchanger array of a proposed 50 MWe (net) isobutane binary cycle power plant on the Heber resource (see Ref. 3). The strong impact of pinch point and fouling factor are obvious and must be anticipated when requesting exchanger quotations.

8.2.5.9 Cost and Financial Assumptions

Another potential designer imposed screening bias exists via subsystem costs. Although little reliable information is published regarding typical

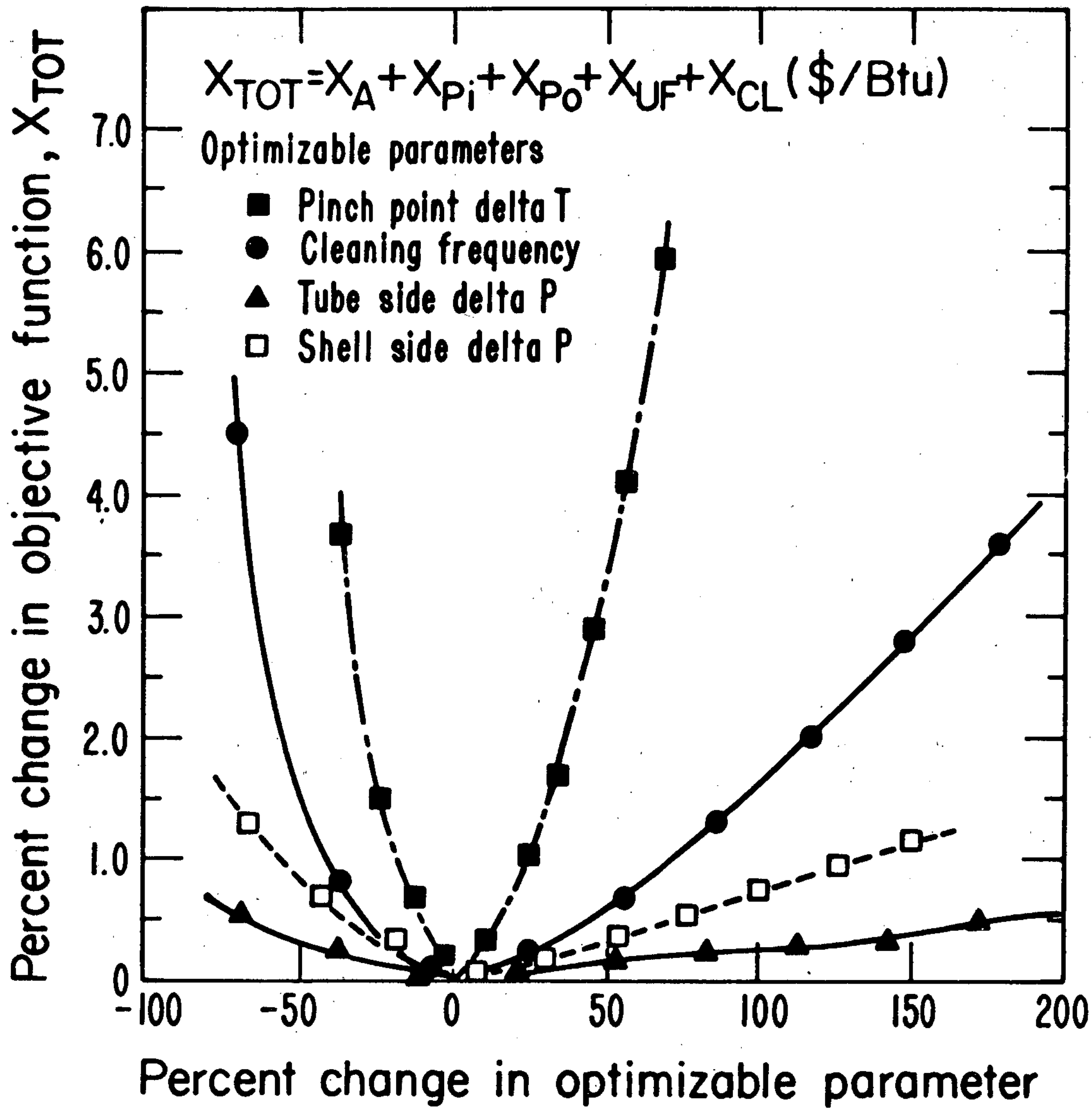

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Fig. 3

Subsystem Considerations. Influence of the sensitivity of the total heat supply cost, X_{TOT}, to various parameters of the design of the primary heat exchanger for a 50 MWe (net), supercritical isobutane binary cycle power plant proposed (Ref. 3) for the Heber resource. At the Optimum Condition, a unique relationship exists between the fouling rate, the design U factor, the design cleaning frequency, and economic factors of the heat supply system (Ref. 12).

subsystem costs, no system cost optimization is possible without a multitude of input assumptions. The economic optimum design is the result of a complex trade-off among the various subsystem thermodynamic irreversibilities and their resulting costs based on these input cost assumptions. The thermodynamic performance of the optimum design is a dependent result of the cost optimization. If the input costs are way out of line, the computed thermodynamic performance at the "optimum cost" will also be unrealistic.

Figure 4 is a dramatic example of how different well cost assumptions (fixed flow rate per well) affect the computed optimum plant state conditions and therefore the thermodynamic performance and busbar cost (Ref. 13). As the well cost increases (increasing fuel cost), the optimum supercritical binary cycle turbine inlet state approaches the transposed critical temperature line (Ref. 14). This will be discussed in more detail in Section 8.2.9.5.

8.2.5.10 Working Fluid Selection for Binary Cycles

Step-by-step methods for the preliminary selection or elimination of possible working fluids for the organic fluid (binary) Rankine process are discussed in detail in Chapters 3 through 6 of Milora and Tester's text (Ref. 15).

Although generally applicable techniques are described--that is minimization of total system irreversibility--this criteria alone introduces thermodynamic biases. It should be also pointed out that the related working fluid selection criterion used (utilization efficiency, η_u) only measures relative fuel cost. In this discussion the system design objective is minimum busbar energy cost.

However, idealized cycle net work calculations can be performed in parallel on the working fluid loop to eliminate the poor thermodynamic performers. If this approach is used, it should be kept in mind that the working fluid specific volume at turbine exhaust conditions and the design overall pressure ratio will influence the size and rotational speed,

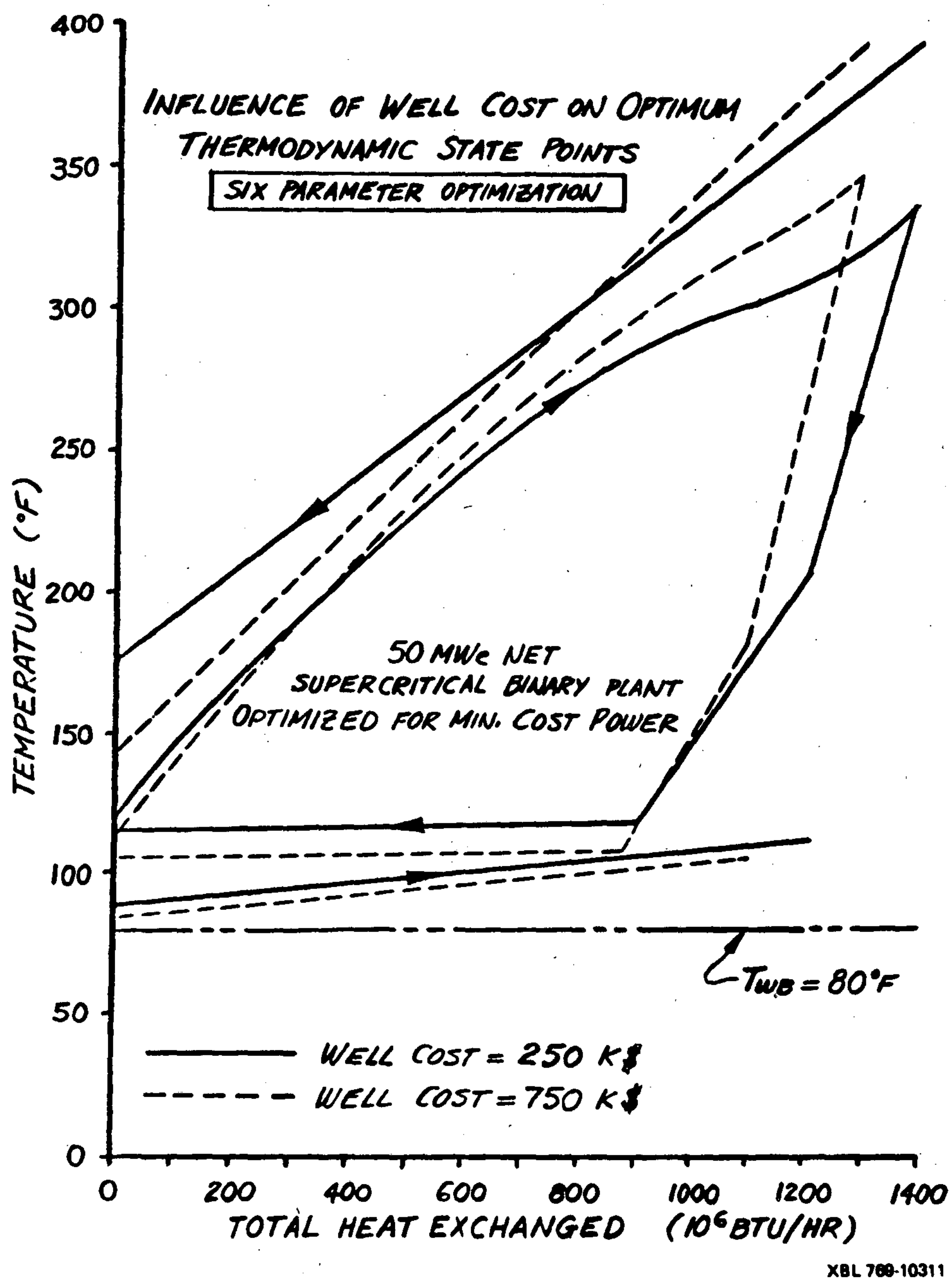

Fig. 4

Influence of well cost on optimum plant thermodynamic state conditions and heat exchange temperature differences for fixed source (wellhead) and sink (wet bulb) temperatures. Both plants are 50 MWe (net) isobutane binary cycles optimized for minimum busbar energy cost (Ref. 13).

and therefore cost, of axial flow expanders. This cost difference for various working fluids can be large. There are, of course, many other economic factors which obviously influence the working fluid choice, and the previous step-by-step list has already introduced too much selection complexity.

If one of the newer cycle simulators is available, it is usually best to defer working fluid final choices until each of the better ones has been cost optimized. This is especially true if multiparameter optimization (MPO) routines exist in the cycle simulator. With MPO techniques, much more decisive working fluid choices can be made, because the many independent cycle state parameters can be cost optimized for each candidate fluid. The choice is then made on system economic grounds.

8.2.6 Plant Boundary Assumptions - Coupling to the Reservoir

We have briefly described several groups of variables the designer deals with in the preliminary screening process which influence the selected plant designs and thus the busbar energy cost. To re-iterate, these are listed in Table 1.

TABLE 1

1. Cycle above ground configuration and complexity.
2. Working fluid selection.
3. Brine temperature, salinity, chemistry and non-condensible gases.
4. Thermodynamic state points, pinch point temperature differences, and U factors.
5. Environmental temperatures (i.e. wet and/or dry bulb) and their variations.
6. Subsystem and component cost and efficiency assumptions.
7. System capacity factor or availability.
8. Subsystem life and recurring capital costs.
9. Overall financial considerations.

With those items in Table 1 plus some assumptions about wellhead conditions, well flow rate and cost (or brine cost) we could simply stop here, "optimize" what we have, and report the resulting "busbar energy cost" to the utility. However, these latter assumptions require a much more effective "crystal ball" than those in Table 1, and the results might be of little value. Resource characteristics and detailed well-field design (depth, diameter(s), spacing, cost, and drawdown factor) influence the most economic well flow rate and wellhead conditions. These conditions differ from system to system.

8.2.6.1 Brine Production and Disposal

The thermodynamic availability, productivity, injectivity, and longevity of the resource have a strong influence on the selected plant configuration and the computed busbar energy cost. The cost of the brine (fuel) to the plant depends upon the manner in which the brine is produced (and disposed). Different surface conversion systems usually require different production wellhead conditions and, therefore, different production (and/or injection) design scenarios. The system designer must <u>couple</u> the "plant" to the "resource" in some way to properly characterize these extremely important effects.

8.2.6.2 Injection Pumping

Federal, state, and local restrictions will require that the brine be disposed of in some environmentally acceptable manner. The considerations and implications of several disposal alternatives are discussed extensively in Chapter 9, Environmental Considerations.

In this section we assume that injection pumping <u>is</u> a viable option, and attempt to characterize pumping costs for a simple, <u>idealized</u> subcooled liquid resource. We assume that the reservoir is semi-infinite in areal extent and that break-through considerations, re-charge, and temperature decline are immaterial. We further assume that reservoir flow velocities are low and the reservoir is of uniform permeability and porosity (Darcy's law applies), and is "bounded" above and below by low permeability strata (groundwater pollution not possible). Although we make no attempt to characterize subsidence; gross subsidence affects will <u>probably</u> be mitigated with brine injection.

It should be emphasized that the foregoing assumptions will be gross over-simplifications in many cases. For example, these calculations ignore "interference effects", production well deterioration or "skin effects", and the difference in viscosity between the injected fluid and the bulk resource fluid (see Chapter 2 of this SOURCEBOOK).

Interference effects (between adjacent wells and reservoir boundaries) can be characterized with a more detailed reservoir model. To include skin effects explicitly requires information from each particular reservoir. Because this is an additive series resistance, an implicit simplifying assumption herein is that the production zone skin impedance is included in the drawdown factor (Ref. 46, 47, 48, 49).

The overall effect of these "idealizations" on resource productivity and injectivity, however, is not conservative.

Ideal injection pumping parasitic power (heat loss and well friction ignored) requirements can be estimated for this idealized resource if the well depth, well flow rate, drawdown, shut-in reservoir pressure, and injection pump exit specific volume are known (see Section 2.6 and Ref. 16) and viscosity differences between injected fluid and resource fluid are ignored.

The well depth, reservoir drawdown, and shut-in pressure are highly site specific. The degree to which they're known dictates the accuracy of the injection pumping power estimate. The magnitude of the injection pumping power requirement depends in addition on the resource temperature and the above ground cycle type, or plant exit conditions. Trends are depicted in Fig. 5. With the right combinations of the above, no pumping at all is required; the brine simply flows back into the resource under the influence of gravity. The degree to which the injection pumping power must be known depends not only on its absolute magnitude, but also on the ratio of the plant gross-to-net power output. Production and injection pumping power are not only higher, but also much higher percentages of total parasitic power in simple (pumped) flashed steam plants than in binary cycle plants. Including viscosity terms would reduce the injection pumping power difference somewhat.

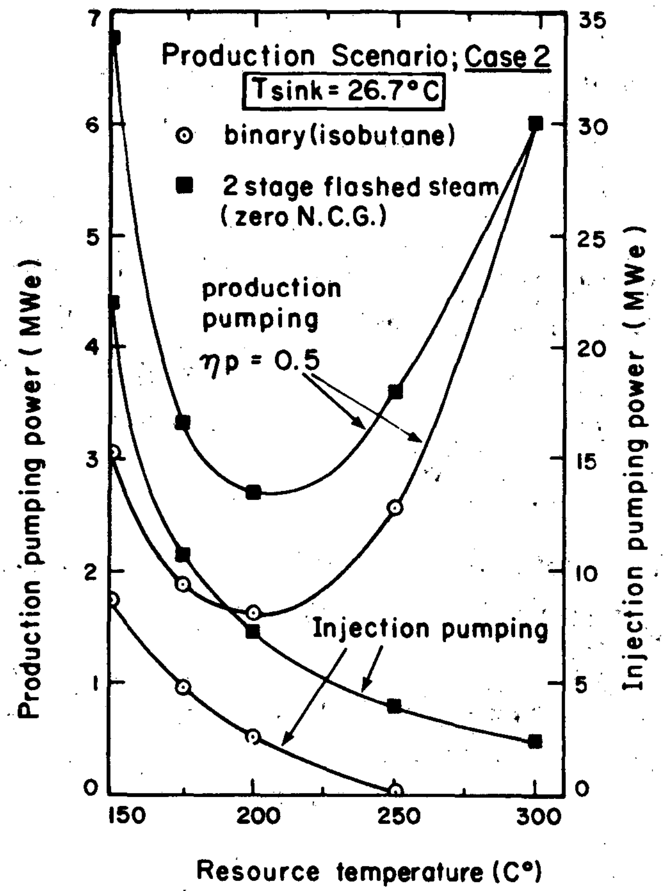

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Fig. 5

Comparison of Production and Injection Power Requirements for Equal Pressure Resources. 50 MWe (net) minimum busbar cost optimized, simple binary (isobutane) and two stage flashed steam plants coupled to idealized (zeroth order) sub-cooled liquid (pure H_2O) hydrothermal resources. All spent fluids injected. The cycles optimized are shown in Fig. 14 and 15. Both plants assume the brine is produced at the wellhead at the saturated liquid state with suitable down-hole, high speed centrifugal pumps shaft driven from the surface. Production well mass flow rate: 81.9 Kg/sec (650,000 lb/hr); injection: 163.8 Kg/sec. Both production and injection wells are assumed frictionless and adiabatic. Production pump adiabatic efficiency: η_p=0.5, K_{DD} = 22.8 KPa/(Kg/sec), H_w = 1830 m.

8.2.6.3 Production Pumping

It is well known that the well flow rate has a significant effect on the brine energy cost and thus the busbar energy cost, Fig. 6. If the normal (self flowing) flash point depth at maximum flow conditions is not too close to the bottom of the well, production pumping can be employed to increase the flow rate. (See Section 2.6.)

Although limited data exists for long term production pumping, there is little doubt that reliable commercial downhole pumps will be developed. Increases of about a factor three in well productivity (compared to free flowing conditions) have been demonstrated (Ref. 17) at the Heber resource (180°C) for binary cycle applications (saturated liquid at the wellhead) with a modest power requirement.

However, for lower <u>or</u> higher resource temperatures, but constant resource pressure, the <u>same</u> drawdown factor, pump adiabatic efficiency, and well depth (different pump depth) this pumping power requirement increases significantly (see Fig. 5). At 300°C the production pump <u>work</u> would be about a factor of six to eight higher to maintain un-flashed conditions at the wellhead.

The high production pumping power requirements at low resource temperatures (Fig. 5) are the result of low brine utilization efficiency (high total flow rate). The high temperature behavior is the result of decreasing flash point depth (high pump head).

Therefore, considering the high cost of wells, the relatively low pumping power requirement in the low-to-medium temperature regime (Fig. 5), the characteristic decay behavior of self-flowing wells (Ref. 16), and the potential for increased scaling with significant two phase flow pressure drop, future <u>binary</u> cycle power plants will probably use some type of downhole production pumps.

8.2.6.4 Should Production Wells for Flashed Steam Plants be Pumped?

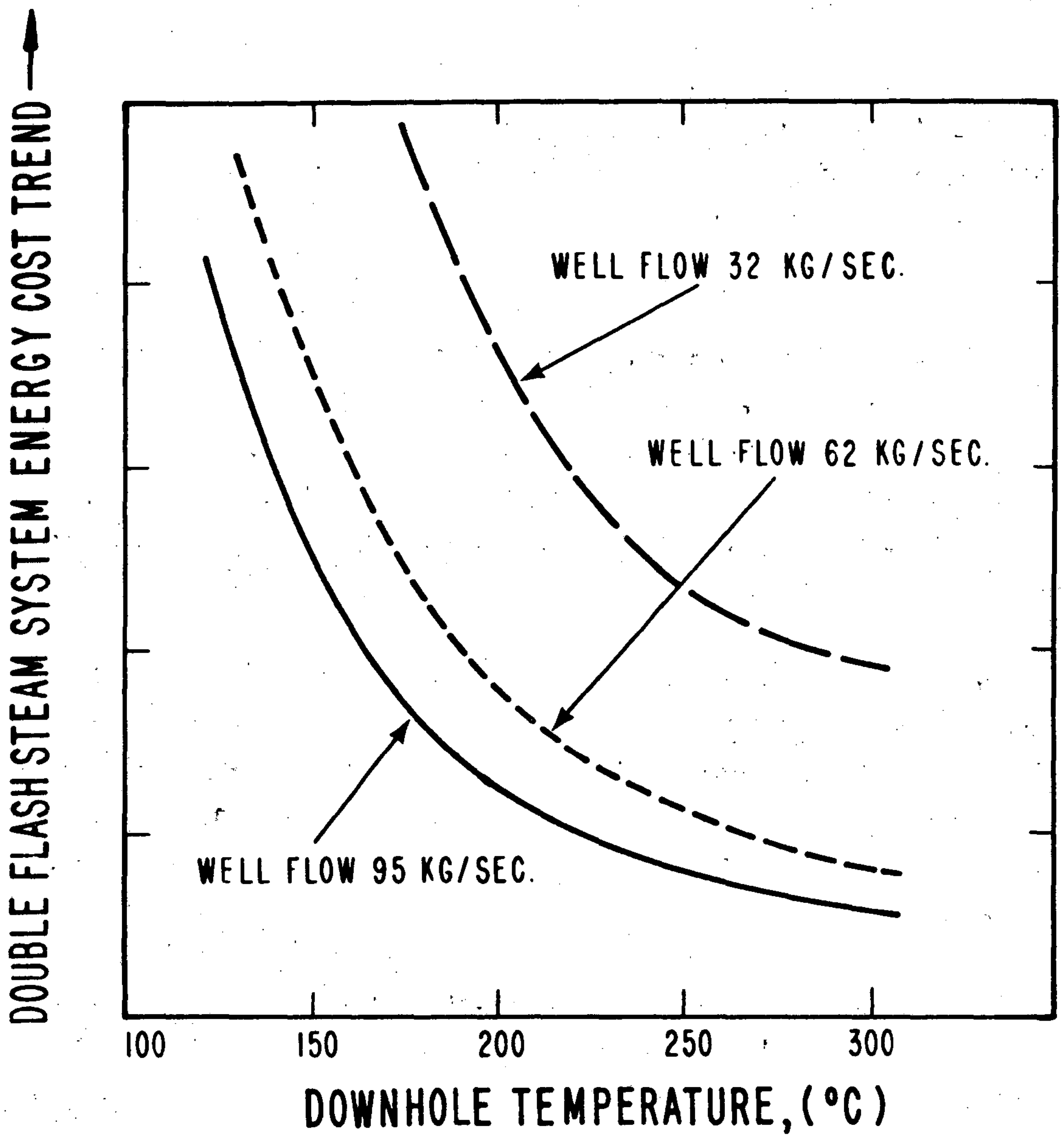

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Fig. 6

Busbar Energy Cost Trends as a function of resource temperature and well flow rate for double flash steam systems (Ref. 6).

For flashed steam power plants, however, brine pumping power requirements are relatively high by comparison. Although it might be necessary to pump the production wells at some resources to avoid serious scaling problems, the penalties can be high (see Fig. 5). For the medium to higher temperature (200°C to 300°C) resources, where flash plants are normally best, if production pumping were required, the economic scales could tip back in favor of the binary cycles because of increased plant size.

Figure 7 illustrates the relative gross electric output power requirement for 50 MWe (net), busbar cost optimized, two stage flashed steam energy conversion systems for two different production scenarios and fixed drawdown factor. For pumped production wells (CASE 2) with saturated liquid wellhead conditions, the plant gross output power requirement (and, therefore capital cost) can be the order of 5% to 15% higher than for free flowing production wells (CASE 1) depending on the resource temperature.

Under normal circumstances, then, preliminary screening calculations would assume the production wells for flashed steam plants are free flowing. (See also Section 2 and Ref. 16).

8.2.7 Influence of Well Design

Perhaps one of the most important reasons for characterizing the entire geothermal system (resource, wells, and plant) at any screening or design stage (conceptual, preliminary, etc.) is the significant effect of the "fuel" cost on the optimum system design.

For flashed steam plants with free flowing production wells, the detail design of the wells has a profound effect on the well mass flow rate, the wellhead conditions, and, therefore, the available energy at the wellhead (Ref. 16). To minimize the number of wells (field capital investment), a mandatory requirement of any well designed free flowing flashed steam production system is that the mass flow rate be at the peak, or near choked, condition.

To do this cost effectively for sub-cooled liquid at the well bottom,

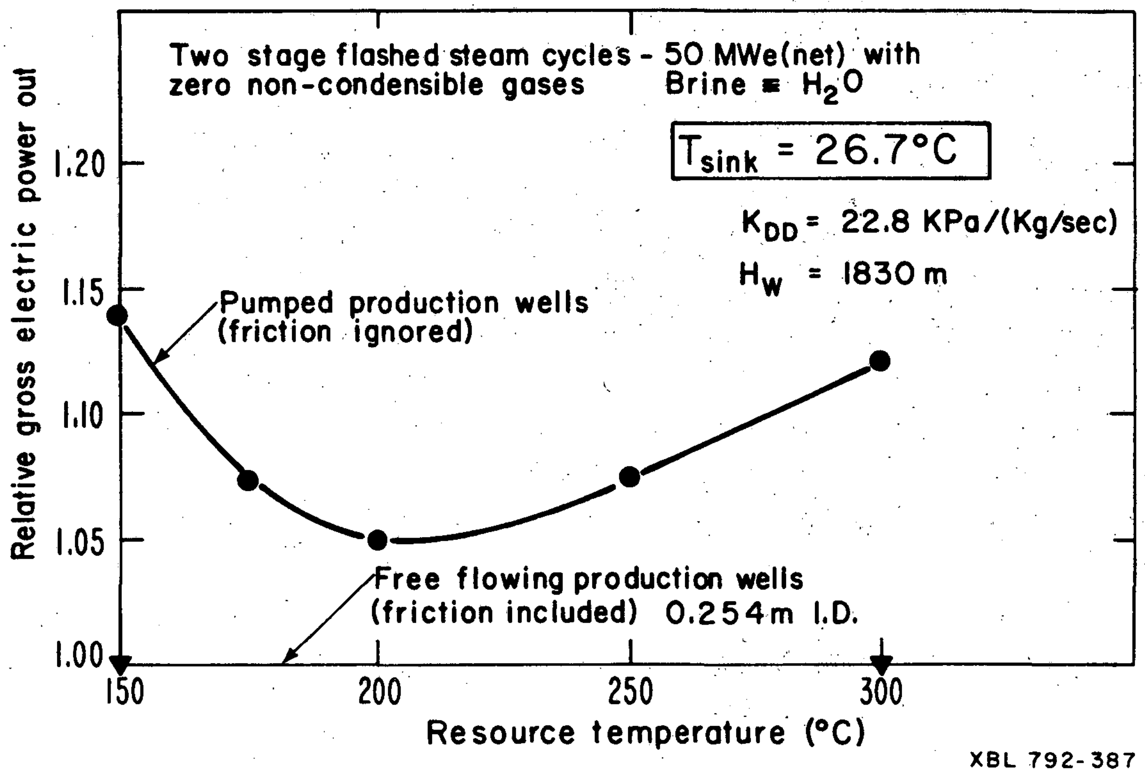

Fig. 7

Relative Gross Electric Output Power for minimum busbar cost optimized, 50 MWe (net) two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of various temperatures but equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber flashed steam Plants), but 0.254 m I.D. production wells were arbitrarily assumed for CASE 1. This analysis assumes the well cost for CASE 1 and CASE 2 are the same.

the wells will usually have at least two liner diameter steps. It is usually desireable that the first liner diameter step, or enlargement, be at the elevation in the well where the "brine" begins to change phase. Above this point velocities increase significantly, and temperature and pressure gradients magnify. Near the top of the well, the two phase mixture "effective velocity" approaches critical conditions where the onset of choking occurs (Ref. 16).

If the well diameter were increased again just below this "choke point", the maximum flow rate attainable would increase for the same wellhead pressure. The second well diameter step, therefore, would logically be placed within a hundred or so meters from the top of the well to achieve the greatest mass flow or availability benefit for a given incremental well capital investment.

Just where these liner steps are placed and the magnitude of the diameter changes are obvious "optimizable parameters" in an overall optimum economic system design for a given resource. It is not at all clear, however, that the existing "art" of geothermal well design has seriously considered the now obviously important thermodynamic (Ref. 16) and economic trade-offs between the free flowing well and flashed steam plant first stage turbine pressure and steam fraction (Ref. 18). All that is needed is a reasonable thermal/hydraulic model of vertical two phase flow, and well costs characterized as a function of depth and diameter (ignoring scaling).

The Elliott homogeneous (zero-slip) vertical two phase flow routines (Ref. 16) are adequate to demonstrate behavioral trends in lieu of more exact solutions which are under development (Ref. 19). A general costing model for wells is under development (Ref. 20). The DOE/DGE funding for the 50 MWe flashed steam Demonstration Plant at Valles Caldera (NM) will bring much valuable well economic data and design technology into the open literature.

8.2.7.1 Approximate Production Well Design Calculations

Until these data become available, idealized calculations can be performed with the available information to illustrate trends. To decisively demonstrate the production well detailed design influence on the total (flashed steam) system busbar energy cost, one would normally have to "step" the well diameter as previously described. However, first order limiting behavior can be determined with a simpler, constant diameter, simulation.

Figure 8 is a simple, first order characterization of the effect of production well inside diameter on the minimum busbar energy cost (and other plant and field parameters) assuming the production well cost is a linear function of diameter. This plot shows that a plus or minus 30% variation in well diameter (also ±30% in well cost) can have a +5.9% to -5.4% effect on the minimum busbar energy cost (+ 11.6% to -13.2% on field capital cost) of two stage flashed steam plants (phase separator first stage) on a 200°C, idealized, sub-cooled liquid hydrothermal resource. This calculation assumes a drawdown factor of 22.8 KPa/(Kg/sec) and depth to the production (and injection) zone of 1830 m (6004 ft.). Note that the optimum production well flow rate increases linearly by 44.1% with a 30% increase in well diameter.

This relatively large influence on busbar energy cost would be even greater if optimum design, stepped diameter wells had been considered over the plus or minus 30% production well cost range.

8.2.8. System Analysis - Computerized Design Optimization

8.2.8.1 Optimization Philosophy

Prior to describing the methodologies used in optimizing the design of a geothermal power plant, it is appropriate to define the role which optimization plays in the overall engineering design process. This topic is best addressed by quoting two experts in the field of applied mathematical optimization theory.

"The concept of optimization is now well-rooted as a principle underlying the analysis of many complex decision problems. It offers a certain degree of philosophical elegance that is hard to dispute, and it often

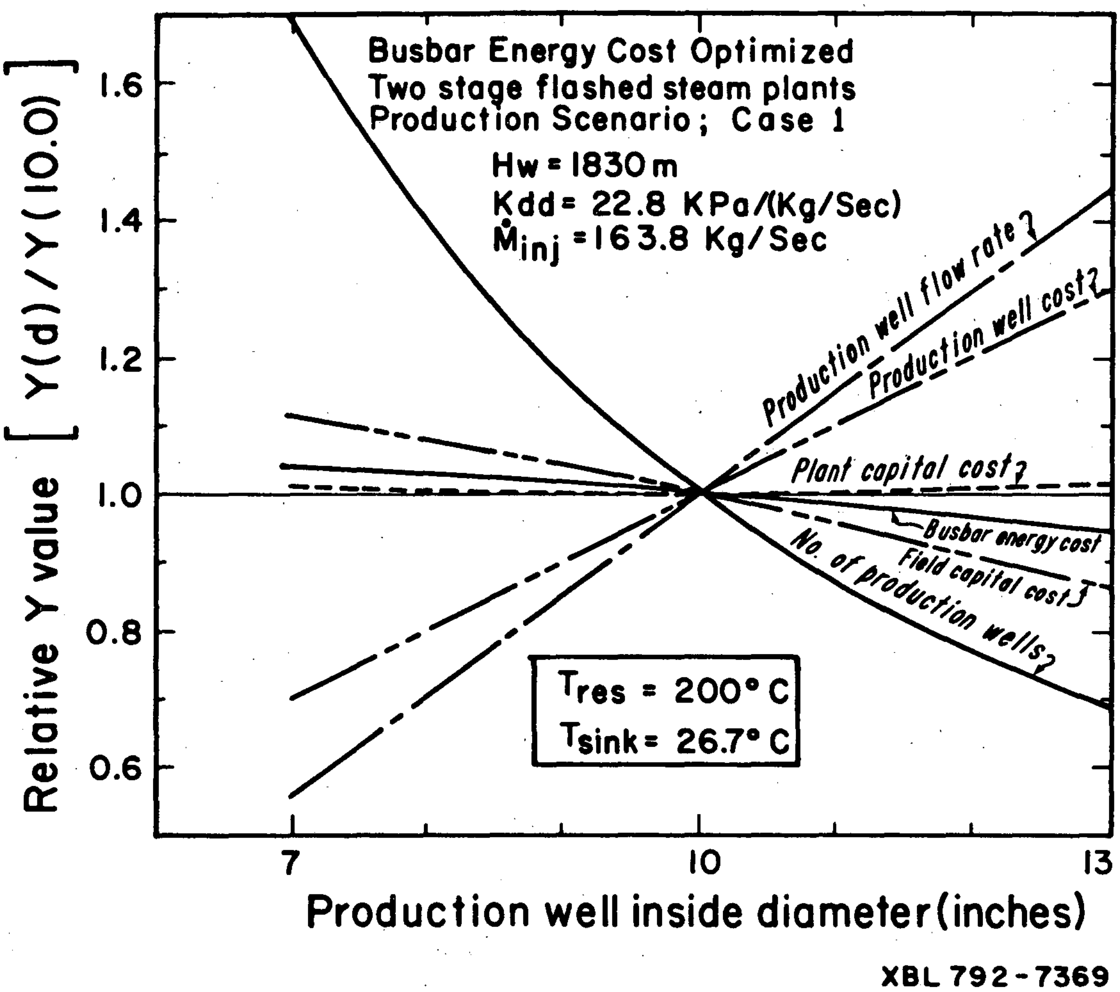

Fig. 8

Approximate influence of production well inside diameter on optimum production well flow rate, number of production wells, and various costs for two stage separating flashed steam plants on idealized, 200°C, hydrothermal resource. Production well cost assumed to be linear function of well inside diameter (300K$/well for 10 inch production well). All injection wells (single phase) assumed to cost 300K$. All other costs normalized to EPRI ER-301 (Ref. 3).

offers an indispensible degree of operational simplicity. Using this optimization philosophy, one approaches a complex decision problem involving the selection of values for a number of interrelated variables, by focusing attention on a <u>single objective</u> designed to quantify performance and measure the quality of the decision. This one objective is maximized or minimized subject to the constraints that may limit the selection of decision variable values." (Ref. 21) When one or more of the constraints or the objective function is non-linear, the problem is a non-linear programming problem.

"Optimization is important in all fields in which a measure of goodness exists. It is especially important in engineering, economics, and operations research. In a sense, all research and development is directed toward an optimal solution. Optimization should be the final of three steps. The first step is describing the system and the second is defining an objective function as a measure of goodness." (Ref. 22).

"It is, of course, a rare situation in which it is possible to fully represent all the complexities of variable interactions, constraints, and appropriate objectives when faced with a complex decision problem. Thus, as with all quantitative techniques of analysis, a particular optimization formulation should only be regarded as an approximation. Skill in modeling to capture the essential elements of a problem, and good judgment in the interpretation of results are required to obtain meaningful conclusions. Optimization, then, should be regarded as a tool of conceptualization and analysis rather than as a principle yielding the philosophically-correct solution. Skill and good judgment, with respect to problem formulation and interpretation of results, is enhanced through concrete practical experience and a thorough understanding of relevant theory." (Ref. 21).

"The chemical industry is among the leaders in using optimization techniques, although much of the reporting is company confidential. Problems in optimization occur in plant and equipment design and process control. It would be difficult to find a technical or economic area in the chemical industry in which optimization is not used. There are a number of reasons why engineers are interested in optimization. An important one is that intensive competition in the chemical process industry makes it necessary that equipment and systems operate at peak performance." (Ref. 22).

8.2.8.2 Algorithms

The thermodynamic and cost criteria which are selected as objective functions in geothermal plant design optimization problems are highly non-linear, complex functions of the system's optimizable design parameters. The nature of these functional relationships will determine the optimization method, also known as an "algorithm", which is most suitable for the solution of the particular problem at hand. The design objective may be a "well-behaved" smooth continuous function of the system design parameters, in which case a gradient or Newton optimization algorithm will consistently converge upon the global optimum objective.

It is more likely, however, that the objective function will vary in a discrete, piece-wise continuous manner with respect to changes in the design parameters. For example, the cost of field development to a resource company is a "quantized", step-function of the number of wells drilled. A gradient or Newton optimization method can not adequately deal with these non-smooth "step-like" characteristics in the search for the global optimum design point. A direct search "stepping method", such as the "Simplex" algorithm is highly successful in dealing with these quantized functions. Both the continuous and discrete functional forms are encountered in the modelling and design of geothermal power plants.

Numerous non-linear optimization codes are commercially available to the design engineer (ref. 23). These codes tend to specialize in solving problems of a particular functional form. The MINUITS (Ref. 24) package of mathematical optimization routines, developed by the math and computing group at the CERN Laboratory in Geneva, Switzerland, has capabilities for solving both the continuous and the discrete type of problems discussed previously. MINUITS features the Davidon, Fletcher, Powell (Refs. 25, 26) gradient method for optimizing continuous functions and the simplex algorithm of Nelder and Mead (Ref. 27) for optimizing functions of a quantized nature. The MINUITS package has, therefore, been selected for incorporation into the LBL developed GEOTHM code. MINUITS has consistently demonstrated its versatility and computational efficiency in dealing with the broad class of geothermal system design problems encountered by the LBL Cycle Studies Group (Refs. 12, 28, 29, 30, 31), some of which are described in the remainder of this chapter.

8.2.9 Optimization Using the LBL Developed GEOTHM Code

8.2.9.1 Cycle Characterization

The thermodynamic performance of a simple binary cycle can be completely specified (Ref. 13) by six thermodynamic state parameters as shown in Fig. 9 if component efficiencies are constant and small parasitic losses such as pressure drops in the heat exchangers and pipes are fixed or ignored. To use the optimization techniques described in reference 24, the user specifies some overall process Objective Function (i.e. minimum busbar cost, minimum capital cost, maximum brine thermodynamic yield, etc.) and selects some or all of the system independent thermodynamic state parameters as Optimizable Parameters (Ref. 32).

Multiparameter optimization with GEOTHM and possibly other similar codes proceeds as depicted in Fig. 10. In addition to specifying first guesses to the optimizable parameters, these un-constrained, non-linear MPO codes usually require specifications of upper and lower limits to each of the optimizable parameters, and maximum allowable step sizes. These limits are functional constraints which can influence the selected optimum design either on the path toward the solution or at the final solution and they must, therefore, be chosen very carefully. These are briefly discussed in Ref. 24. With the first few cycles through the optimizer, the objective function and its numerical derivatives with respect to each of the optimizable parameters are computed. Using this information, the optimizer makes

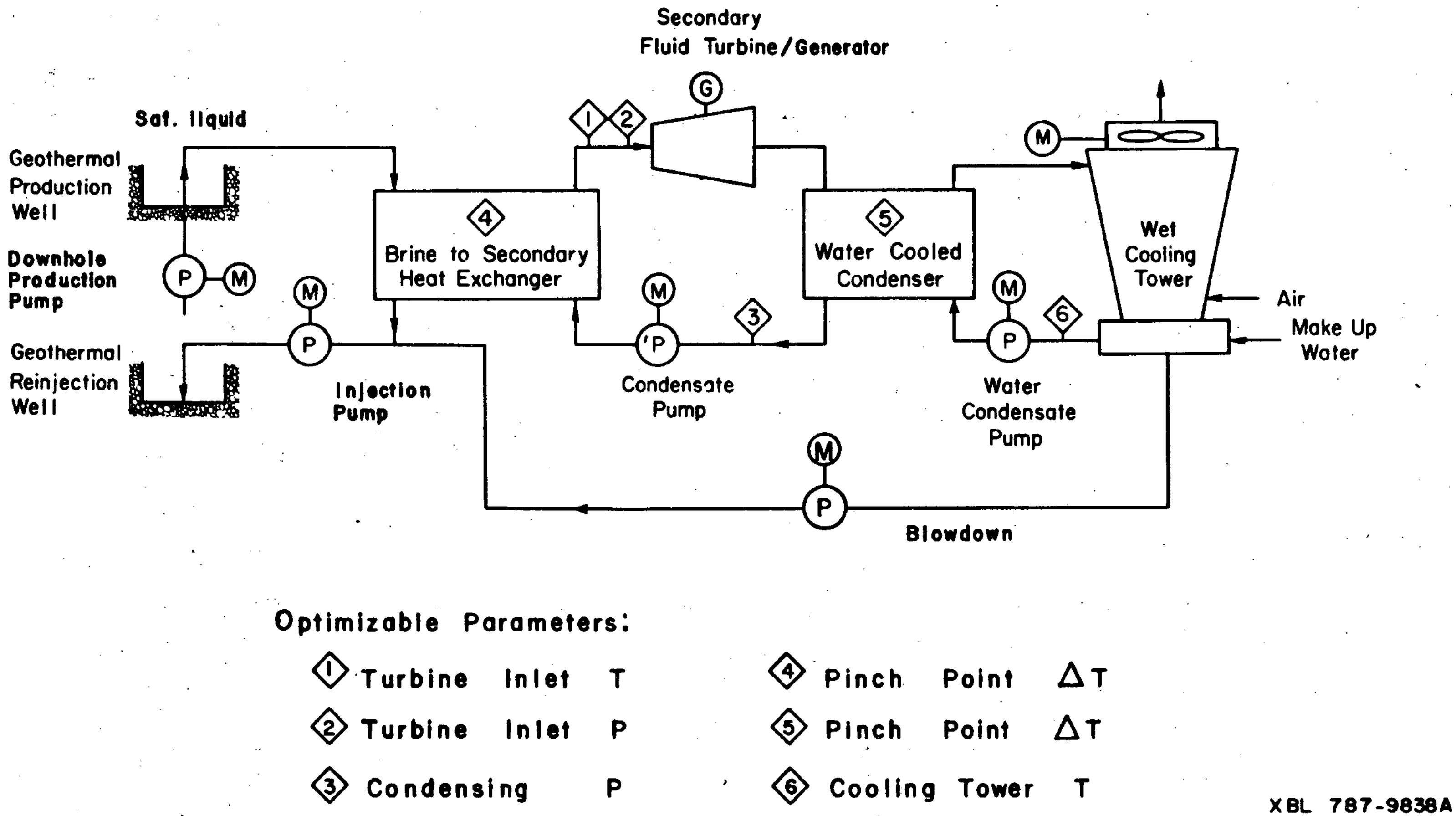

Fig. 9

Simplified schematic of a simple organic fluid (binary) Rankine cycle without regenerative heat exchange. The six optimizable parameters completely characterize the thermodynamic performance of the plant.

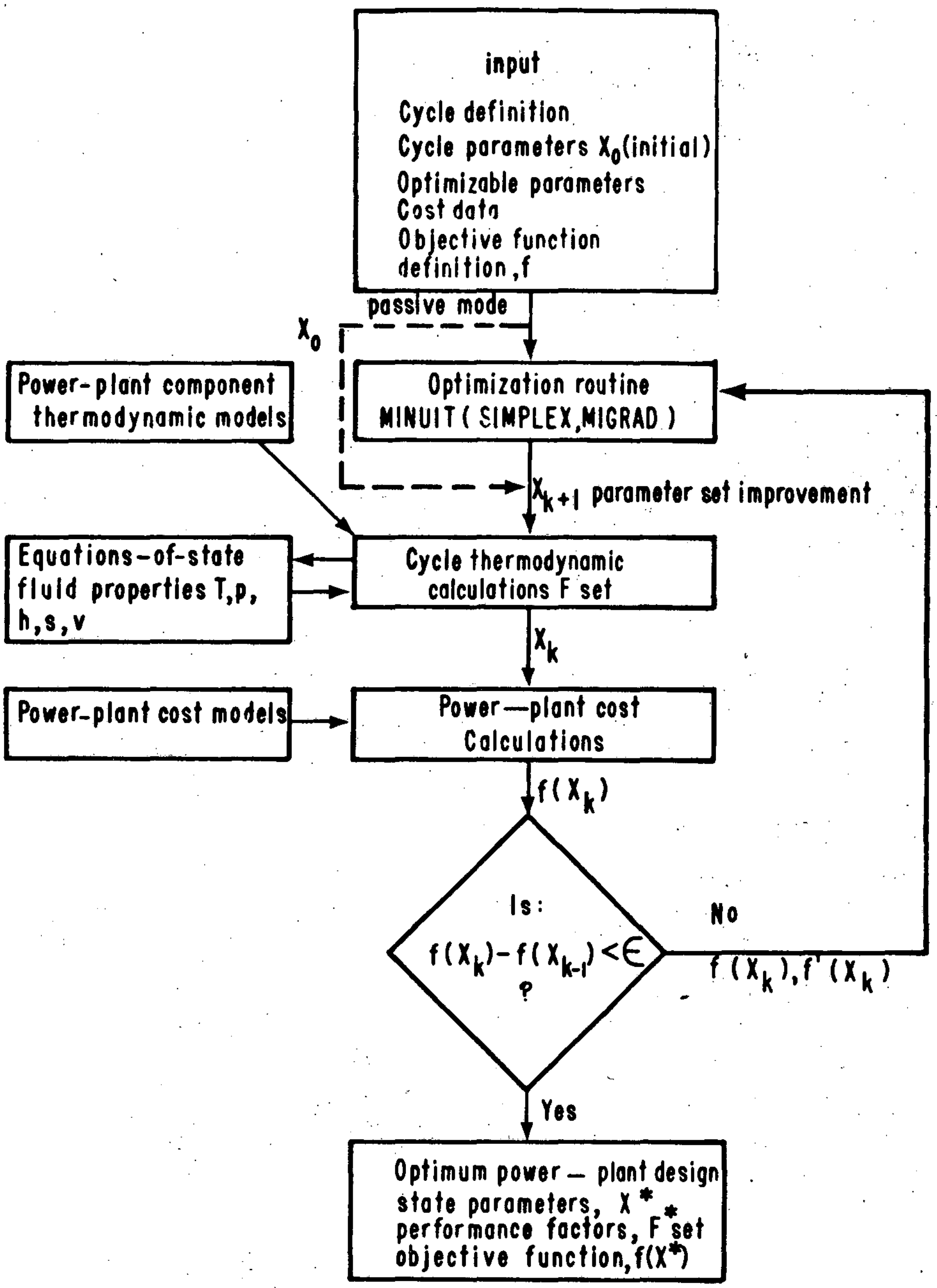

Fig. 10 XBL 792-7368

Simplified logic block diagram illustrating calculations in the Design Optimization Mode of the LBL developed process simulator, GEOTHM. The MIGRAD routines of the CERN developed MINUIT optimization program (Ref. 24) are most effective for a continuous Objective Function, whereas the SIMPLEX routines have been found to be best suited for discontinuous, step functions.

new choices for the optimizable parameters to converge finally on the optimum design.

8.2.9.2 Convergence Criteria - Computer Generated Noise

The value of the objective function is influenced by convergence criteria used in the solution of thermodynamic process and fluid property equations which require iterative numercial solution techniques. These techniques utilize information from numercial derivatives, df=f(x)-f(x-del) where del is some user-specified step-size, to converge within some user-specified error tolerance (called an 'epsilon') of the exact solution. The design and optimization of the geothermal plant proceeds as a hierarchy of nested, interacting, numerically iterative calculations. This hierarchy is organized from top to bottom "levels" as follows: optimizer (objective function) ⟶ plant (net power balance) ⟶ thermodynamic processes (heat and mass balances) ⟶ fluid properties (state equations).

The design of a heat exchanger to achieve a specified pinch point temperature difference illustrates the interaction between thermodynamic process and fluid property calculations. The exchanger heat balance calculations are performed iteratively in order to converge upon the desired pinch condition. Each heat balance iteration, however, depends upon a number of fluid property calculations, each of which is also performed iteratively.

When convergence criteria are too slack, a high level of uncertainty is introduced into the calculations. This uncertainty appears as 'random noise' or 'bumpiness' superimposed upon the overall envelope of the design surface (see Figure 2 in Ref. 28). If the level of this computer-generated noise is of a sufficient magnitude, it can prevent global convergence by the optimizer because the noise itself acts as numerous local minimum traps. It is therefore necessary to 'tighten' the convergence criteria until the noise level is non-interfering. In the structure of the hierarchy of numerical calculations, it is essential to tighten the epsilons on all levels and to maintain their relative ranking.

8.2.9.3 Visualizing the Design Surface

In the course of the optimization sequence described in Figure 10, the optimizer literally searches along a 'design surface' for the global optimum plant design. This mathematical surface in an n+1 dimensional Euclidean space is composed of points corresponding to all the plant designs made possible from different combinations of the n optimizable parameters.

In order to visualize this surface, it is necessary the fix the values of all but two of these optimizable parameters and then to plot the objective function, e.g. busbar cost, for different combinations of these two parameters. This is shown in Figure 11 where the busbar cost is plotted as a function of the turbine inlet temperature and pressure. Prior to producing this contour plot, the global minimum cost design (point L is the point of minimum elevation on the design surface) was found by the GEOTHM optimization code. Then, four of the six optimizable parameters were fixed at their respective optimum values. Finally, a series of 900 passive designs (30x30) with variable turbine inlet temperature and pressure were used to generate the busbar energy cost data.

These design surface 'visualizations' are extremely useful for understanding the functional relationships among the optimizable parameters and the objective function. For example, for the plant designs in Figure 11, the fuel is costed on a $/BTU basis and the busbar cost is therefore seen to be a smooth, continuous function of the optimizable parameters. These plots also provide intuitive insight about the optimization sequence and about any potential difficulties which can prevent successful global convergence.

8.2.9.4 Local Minimum Trap

If a local minimum exists on the design surface which lies along the path taken by the optimizer, i.e. between the user-specified starting point and the global minimum, it is possible to converge upon the local minimum and be unable to 'escape'. Just such a local minimum exists on the busbar

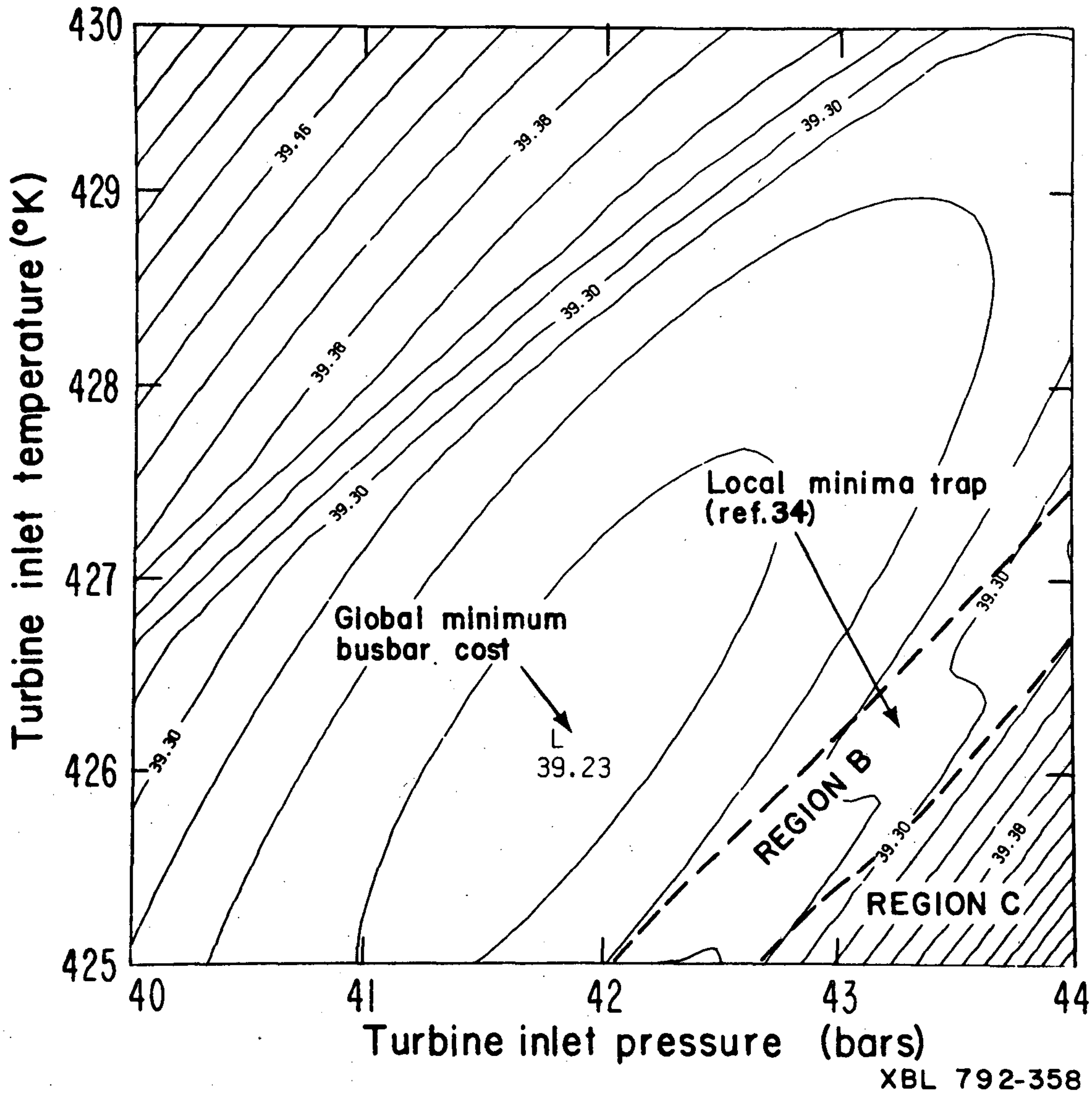

Fig. 11

Busbar energy cost design surface on turbine inlet coordinates for a 50 MWe (net) isobutane binary cycle power plant with 180°C, saturated liquid production wellhead conditions and 26.7°C wet bulb temperature. The global optimum was originally found after many previous optimization runs without apriori knowledge of the existence of the local minimum in Region B. This local minimum can prevent convergence at the global minimum.

energy cost design surface of a typical supercritical Rankine cycle geothermal power plant. This local minimum is shown as Region B in Figure 11. It corresponds to a region of the thermodynamic P-h diagram of the working fluid where the turbine inlet temperature and pressure are in the vicinity of the critical point.

This local minimum can be a computational nuisance. In the first place, this local minimum 'Valley' resides in the immediate vicinity of the global optimum design point. Secondly, the value of the objective function at the local minimum is of nearly the same magnitude as the global minimum. These factors might not be apparent without a plot of the design surface such as Figure 11.

8.2.9.5 The Transposed Critical Temperature

Intrigued by the existence of the pronounced, sharp local minima on the busbar energy cost design surface, and the inability to explain it away as computer generated noise, Pope (Ref. 14) noted that the locus of points representing the turbine inlet state on P-h coordinates for thermodynamic yield ($P_{net}/\dot{m}_b$) optimized supercritical binary cycle plants (near infinite plant cost) intersect the working fluid "domes" at very near the critical point and roughly follow a constant specific volume line.

After plotting the transposed critical temperature (TPCT) line on the same P-h coordinates (which, of course, also originates at the critical point and very nearly follows a constant volume line), Pope postulated that if field or fuel costs clearly dominated, the turbine inlet state for busbar cost optimized supercritical binary systems should fall on the TPCT line.

Five isobutane test cases were run at 3 different resource temperatures: 150°C, 175°C, and 200°C with the well (or fuel) cost increased from "normal" levels by factors of 100 and 1000. All cases converged with the optimum cycle turbine inlet state on the TPCT line except the 200°C resource temperature case where the optimizer chose a lower pressure design point. This behavior is predictable considering the near-exponential maximum specific heat fall-off with departure from the critical point.

This specific heat capacity, C_p, behavior is illustrated for isobutane in the 3-D plot, Fig. 12, using data calculated from the equation of state of Ref. 33. All pure fluids behave, more or less, the same way. In fact the contuor plot for a light hydrocarbon mixture--specifically 80% isobutane, 20% isopentane--is "virtually" the same using the mixture equation of state from Ref. 33. We have not definitely established that the local busbar cost minima band found by Pines (Ref. 34) is caused by the fluid specific heat behavior at the transposed critical temperature. Another related possibility should be investigated. If we were to compute the primary heater U factor on a local zone basis (Ref. 12) and account for real fluid behavior with an Eckert Number (Ref. 52) the local cost minimum in Fig. 11 might "disappear."

8.2.9.6 Potential Applications

Considering the fact that there are probably several emerging energy conversion technologies which fall into or near the "fuel cost dominated" regime (i.e. "collector costs" for terrestrial or orbiting solar power plants), further investigation of working fluid TPCT behavior appears warranted.

For geothermal binary cycles, it appears that TPCT behavior could be very useful in working fluid screening and selection. For example, if a working fluid (pure fluid or mixture) could be found for a particular resource temperature such that when all the subsystem costs and thermodynamic irreversibilities are in balance the optimum turbine inlet state fell on or near the TPCT line, the local cost minimum (ostensibly caused by the TPCT) would be coincident with the "global" minimum and a very well defined minimum busbar cost system would result.

8.2.10 Thermodynamic Optimization as a Prelude to Cost Optimization

Soon after the supercritical Rankine cycle local minimum trap was found by Pines (Ref. 34), Doyle found that an algorithm exists which appears to avoid it. Doyle's method (Ref. 35) has been tested on simple geothermal binary cycles with 3 different working fluids (isobutane,

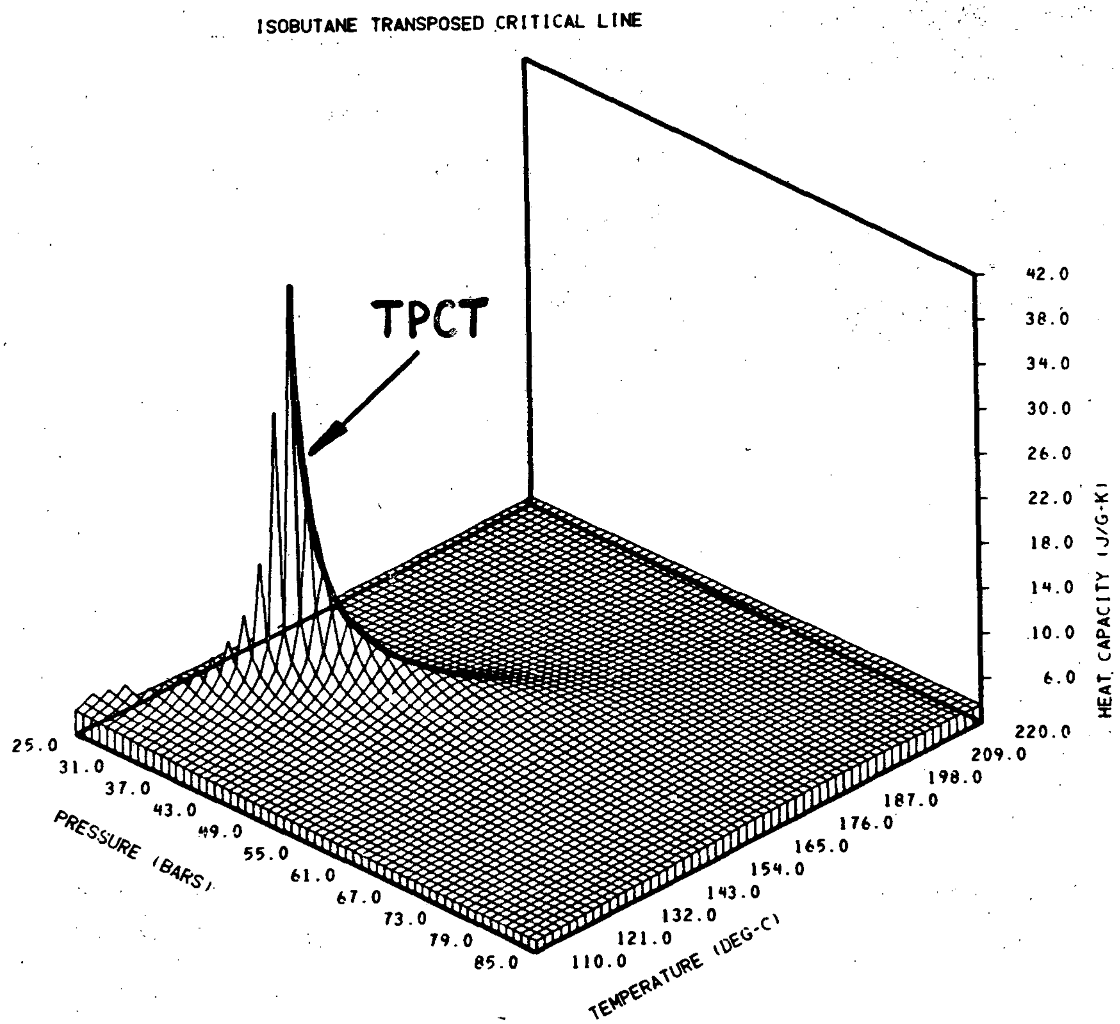

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Fig. 12

3-D plot of the heat capacity at constant pressure for isobutane as a function of temperature and pressure. In the supercritical region the maximum specific heat occurs at different temperatures along a given isobar. These temperatures form a locus of points called the transposed critical temperature line.

isopentane, and propane) for resource temperatures of 150, 175, 200, 250, and 300°C (fifteen different test cases).

After considerable frustration attempting to cost optimize these cycles without a systematic method for selecting the first guess numerical value, maximum step size, and upper and lower limits for the six variables in a simple binary cycle, Doyle tried a cost optimization using the selected cycle states from a previous thermodynamic optimization (a "yield," $P_{net}/\dot{m}_b$, maximization) as a first guess. The results were very encouraging.

Doyle tested this algorithm, now called "yield as a first guess" (YAFG), and it consistently worked on the 15 cases previously cited. He later reasoned that on a contour plot of the cost objective function, there should exist a point of maximum thermodynamic performance on any iso-cost contour, C_j. Extending this idea further, one can theorize that a path of maximum thermodynamic performance (POMTEP) exists between the Global Thermodynamic Optimum (where plant costs approach infinity) and the Global Cost Optimum. This will be investigated and discussed in Ref. 35.

In Figure 13 we've plotted the path of two variables (the turbine inlet temperature and pressure) for a GEOTHM optimization routine (MIGRAD, Ref. 24) as the convergence sequence proceeds from the thermodynamic optimum brine yield, $(P_{net}/\dot{m}_b)$opt, to the global busbar cost optimum. Keep in mind this is simply the projection of the path in three dimensions as the optimizer moves in seven dimensional space. Fortuitously, the path taken by the optimizer routine is remote from the local minima previously noted and the YAFG algorithm has avoided the potential trap.

The YAFG algorithm has also been used with excellent results in the optimization of two stage flashed steam cycles for the five resource temperatures cited. Although the flashed steam cycles were easier to optimize (4 optimizable parameters for the simple cases studied) and do not have the binary cycle local minima trap, the YAFG algorithm seems to work consistently.

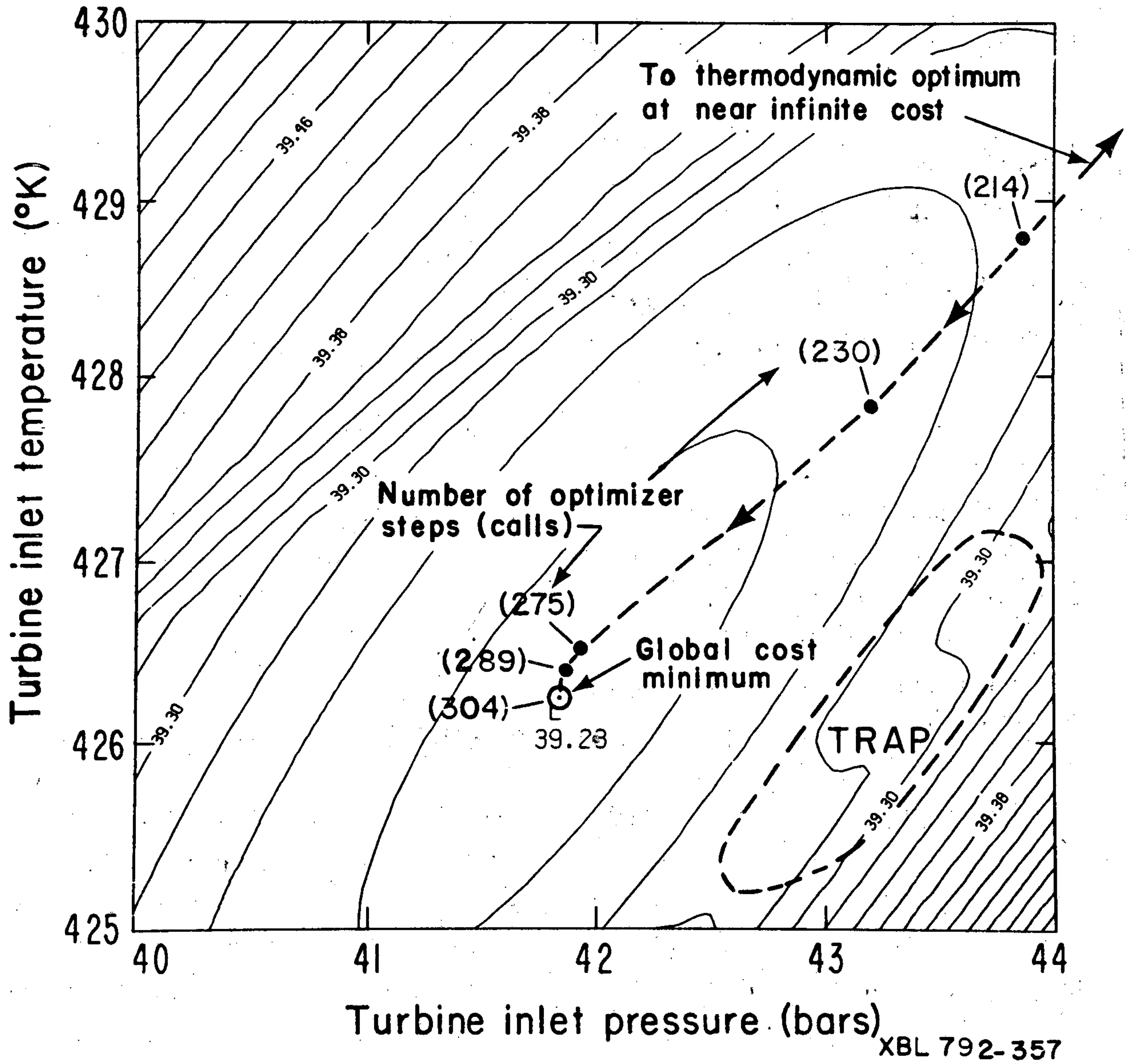

Fig. 13

Reproduction of Fig. 11 illustrating the path the optimizer followed in varying the turbine inlet temperature and pressure (along with the four other optimizable parameters) using the optimum thermodynamic brine yield as the first guess to the global cost optimum, YAFG (Ref. 35). The local minima trap has been avoided. The YAFG method converged on the global cost optimum in one optimization run.

8.2.11 GEOTHM Example Problems

8.2.11.1 Introduction

In this section we define two basic hydrothermal energy conversion systems. In the next section we present the results of conceptual design optimizations performed with the Lawrence Berkeley Laboratory developed computer program, GEOTHM (Ref.36, 37, 38). In these example problem optimizations, we will address geothermal power plant design methodology in the following areas:

1. The relationships between thermodynamics and economics as selection criteria for optimal plant design.

2. The capability of MPO techniques will be exploited in performing the complex trade-offs between thermodynamics and costs with a minimum of bias.

3. For the specific results obtained, a first-order attempt to rank the cycles and fluids considered on the basis of economic merit for a range of resource temperatures.

In order to address these design topics, the following computer modelling scenario has been devised. Three binary cycles, isobutane, isopentane, and propane (Figure 15) and two dual stage flash steam cycles, free-flowing and pumped production wells (Figure 14) will be optimized on separate bases of thermodynamics (specific net energy) and economics (busbar energy cost) for a range of resource temperatures.

That the scope of these studies is restricted to the aforementioned working fluids and cycle configurations is purely an arbitrary decision by the author to establish a baseline for the study of the above topics. In reality, other cycle configurations and working fluids, e.g. single stage flashed steam or flash/binary hybrid cycles, may be just as appropriate. More general studies proposed in Ref. 13 will explore thermodynamic and economic trade-offs for a broader class of design alternatives and resource parameters.

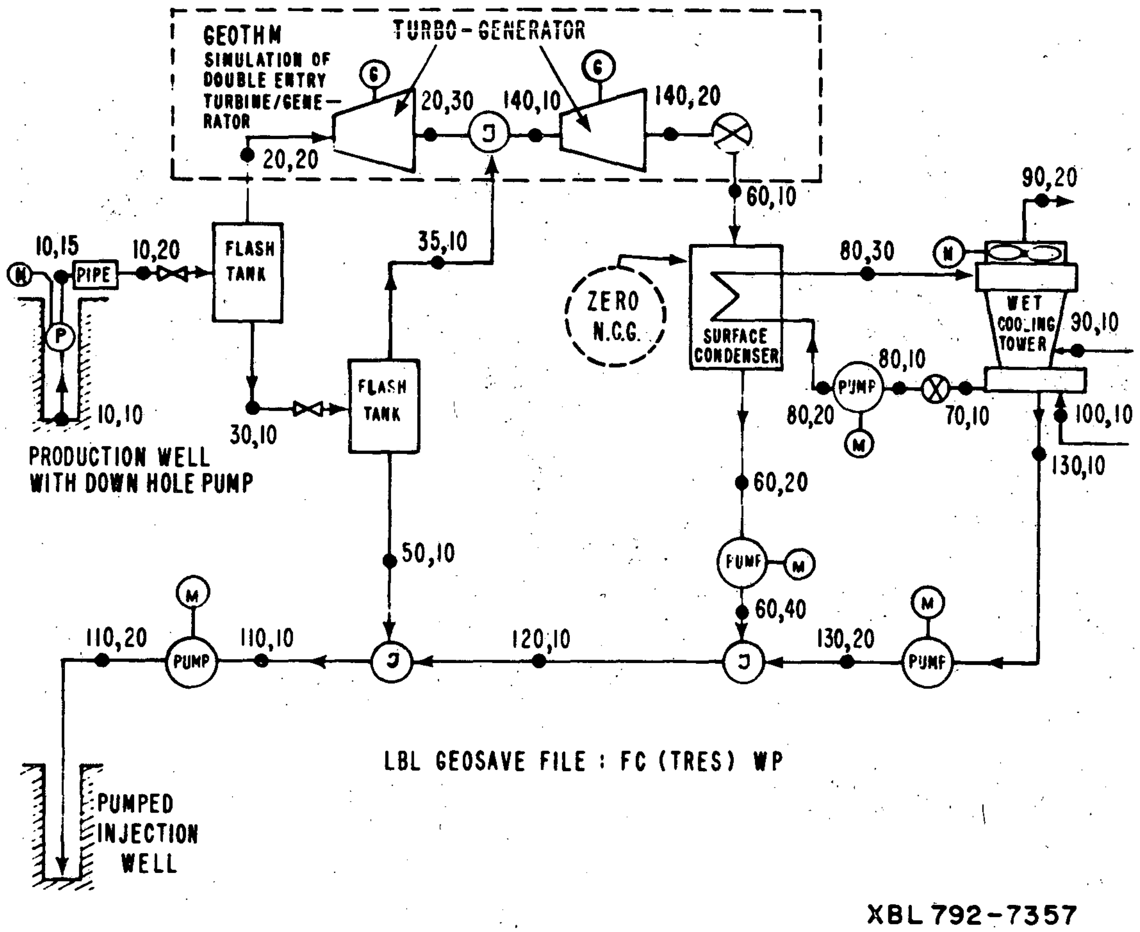

Fig. 14

Simple two stage flashed steam system (pumped production wells) or separating flashed steam system (free flowing two-phase production wells) as specified for GEOTHM. The state point numbering system follows GEOTHM input conventions (Ref. 37). Optimizable parameters are listed in Table 3. All brine (simulated by H_2O) and cooling tower blowdown are reinjected and all parasitic loads are included in the design. The turbine back pressure is fixed at 4" Hg and zero non-condensible gases are assumed. The simulator inserts an expansion valve in place of the injection pump if plant exit and resource conditions permit.

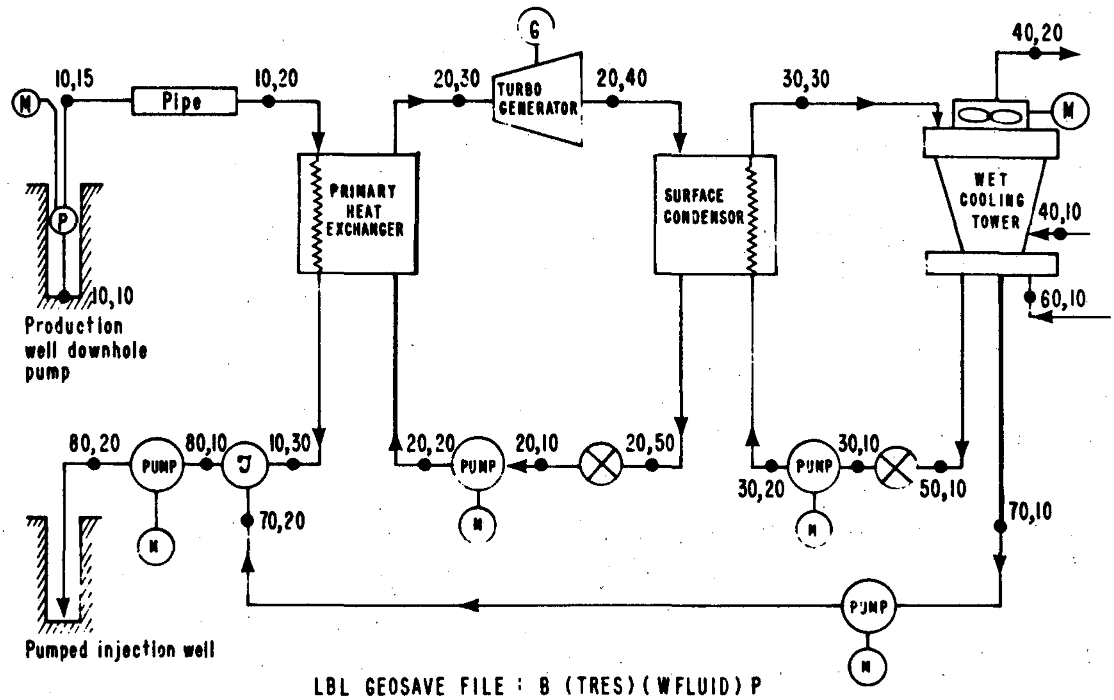

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Fig. 15

Simple organic fluid (binary) Rankine cycle (without regenerative heat exchange) with pumped production wells as specified for GEOTHM. These systems were cost optimized for three different light hydrocarbon secondary working fluids. Optimizable parameters are listed in Table 3. All brine (simulated by H_2O) and cooling tower blowdown are reinjected and all parasitic loads are included in the design. The simulator inserts an expansion valve in place of the reinjection pump if plant exit and resource conditions permit.

8.2.11.2 Basic Cycles Considered

The two basic cycles characterized are:

1) Simple two stage flashed steam cycle and separating flashed steam cycle (Fig. 14).
2) Simple organic fluid (binary) Rankine cycle (Fig. 15).

8.2.11.3 General Assumptions

Both cycles assume that the "brine" is pure H_2O. In the flashed steam system the condensing pressure is fixed at 4.0 in. H_g (we do not have a detailed process routine in the GEOTHM code to adequately characterize steam turbine efficiency for a range of back pressure conditions) and the non-condensible gas content is zero.

Both cycles assume that the hydrothermal resource is in the subcooled liquid state with resource pressure characterized by the hydrostatic head of ground water (saturated liquid at the ambient wet bulb temperature) at the production/injection well depth, H_w; the "zeroth order" reservoir model previously mentioned (Section 8.2.6.2).

The well depth (to the production and injection zones) is constant at 1830 m (6004 ft) for all resource temperatures considered (150°C to 300°C), so these sample problem results "represent" resources over a range of average geothermal gradients.

In all cases, the production <u>and</u> injection zone drawdown factor, K_{DD}, (inverse of the "Productivity Index") is assumed to be 22.8 KPa/(Kg/sec). This drawdown was measured at I.I.D. #1 (Ref. 39) in the Niland area, of the Salton Sea KGRA, but is considered about average for "good producers" in the Imperial Valley of California (Ref. 40).

8.2.11.4 Production Scenarios

Two different production scenarios are assumed in these studies. These are:

Case 1:	Production Wells	Injection Wells
(a) flash	free flowing	pumped
(b) binary	pumped	pumped
Case 2:		
(c) flash	pumped	pumped
(d) binary	pumped	pumped (same as (b))

In all cases except Case 1(a) the well flow is simulated as single phase, frictionless, and adiabatic with the production wellhead state maintained at the saturated liquid condition by suitable downhole high speed, multistage centrifugal pumps shaft driven from the surface by electric motors. The downhole pump adiabatic efficiency assumed was conservative: $\eta_p = 0.5$ (Ref. 17).

For Case 1(a), the flashed steam cycle with free flowing production wells, we calculated the production wellhead conditions and optimum well flow rate using the simple Elliot (Ref. 16) homogeneous (zero slip) adiabatic, vertical two phase flow approximations described in Section 2.6. We used the "zeroth order" reservoir model and drawdown factors (described above), assumed an average "friction factor" of .008 (Ref. 16), and a constant well inside diameter of 0.254 m (10.0 inches).

The assumptions and vertical two-phase flow approximations for Case 1(a) are admittedly crude. We have, however, connected the plant to the "resource" to investigate the implications of two general production scenarios for two simple but basically different optimized surface conversion systems over a broad range of resource temperatures (or geothermal gradients) for three typical working fluid candidates, "typical" resource drawdown conditions, and "average" well depths (resource pressures).

8.2.11.5 Subsystem Assumptions

For all cases presented the following input assumptions apply except as noted above:

Table 2 - Subsystem Assumptions

Parameter	Binary Cycle	Flashed Steam
Drawdown Factor, K_{DD}(KPa/(Kg/sec))	22.8	22.8
Well Depth (m)	1830.	1830.
Well Cost (drilled and cased) (K $)	300.0	300.0
Net Cycle Power output(MWe)	50.0	50.0
Plant Capacity Factor	0.85	0.85
Design wet bulb temp (°C)	26.7	26.7 (80°F)
Expander Type	Radial Inflow	Double Entry, axial inflow
Expander Adiabatic Efficiency (constant)	0.85	0.70 high pressure stages 0.65 low pressure stages
Generator Efficiency	0.98	0.98
Motor Efficiencies (all)	0.95	0.95
Pump Efficiencies (all)	0.80	0.80
Overall Heat Transfer Coefficients ($W/m^2 {}^\circ K$)		
Supercritical Primary H.X.	1514.	--
Subcritical Primary H.X.		
. Pre-heating	1514.	--
. Boiling	1514.	--
. Superheating	1514.	--
Condensing	567.	3240.
Desuperheating	238.	--

8.2.11.6 Costing Assumptions - Financial Factors - Normalization

Prior to performing any cost optimizations, we carefully normalized all subsystem costs and direct and indirect cost factors to those in Ref. 3 in the following manner.

First we modeled the identical cycle configurations as those in Ref. 3 for the same source and sink conditions using the GEOTHM code and verified the mass flow rates and subsystem power requirements for the same stated subsystem efficiencies, working fluids, cycle state conditions, and pinch points.

Then we normalized all the subsystem cost factors (see Ref. 37) to achieve the same purchased costs as those in Ref. 3. We then determined the values of the direct and indirect cost factors (see Ref. 15, Chapter 6) which were necessary for the plant and field to achieve equal installed capital costs and O and M expenses as those stated in Ref. 3.

Finally we determined the required "effective fixed charge rates" which, when applied to the plant and field capital costs for the initial capital investment or <u>beginning-of-life</u> configuration, achieved the same plant and field annual expenses and busbar costs as those in Ref. 3. The preferred method of doing all this is described in Chapter 7 of this SOURCEBOOK, Economic Considerations.

These tedious, but effective, cost normalization procedures were necessary for two reasons. First of all, general formal subsystem costing routines do not exist in the LBL GEOTHM code; adjustable cost coefficients must be normalized (Ref. 37) <u>by the user</u> to vendors quotes or other data on a case-by-case basis depending on the rating, quality, materials, and type of subsystem(s) assumed.

Secondly, formal financial routines do not currently exist in the GEOTHM code which would allow the user to explicitly specify such things as 1) rate of return, 2) debt/equity ratio, 3) inflation rate, etc. These routines are currently being developed for GEOTHM, but will not be operational until approximately April 1979 (Ref. 41).

Because of the subsystem cost and financial factor normalization technique we used, all those cost, financial factor, plant life, well replacement, and subsystem life assumptions stated in Ref. 3 also apply for the example problem results presented herein.

8.2.11.7 Modified Assumptions

However, after the cost normalizations to Ref. 3 (Heber Plants) were performed, we modified some of the assumptions of Ref. 3 to put all these 50 MWe (net) plants on a consistent basis. Four modifications were made:

(1) Inclusion of production and injection parasitic power
(2) Number of "spare" production wells
(3) Equal cooling tower make-up water temperature
(4) Cooling tower blowdown injection

For example:

(1) In Ref. 3, the production and injection pumping systems were detailed and costed, but these parasitic power requirements were not included in the cases presented. We include all parasitic power requirements as shown in Figs. 14 and 15.

(2) It may be noted that the total brine flow rate and number of production wells specified in Ref. 3 for the base case binary cycle (Heber) allows for one extra production well (ostensibly a "spare" for well or downhole pump maintainence) whereas the Heber two stage flashed steam plant does not.

We assume one spare production well (and pump if applicable) for all plants.

(3) It may also be noted that the cooling tower make-up water temperature for the Heber Binary Cycle of Ref. 3 was 90°F, whereas the Heber flashed steam plant assumed 85°F. For the

single 80°F (26.7°C) wet bulb temperature cases presented here, we assume the cooling tower make-up water is available at 90°F (32.2°C) for all plants.

(4) We assume the cooling tower blowdown is injected with the spent brine and calculate the number of wells and power required to accomplish this.

8.2.11.8 Optimizable Parameters

Table 3 lists the thermodynamic state parameters which were treated as "optimizable parameters" for the two simple cycle configurations of this study.

Table 3 - Optimizable Parameters

A. Binary Cycle (saturated liquid wellhead conditions):
1. Turbine inlet pressure
2. Turbine inlet temperature
3. Condenser pressure
4. Primary heat exchanger pinch point delta T
5. Condenser pinch point delta T
6. Cooling tower approach to wet bulb

B. Two Stage Flashed Steam (Zero non-condensible gases, 4.0 in Hg turbine back pressure):

(1) Production Scenario; CASE 1 (two-phase wellhead conditions)
1. Production flow rate per well
2. Second stage flasher pressure
3. Condenser pinch point delta T
4. Cooling tower approach to wet bulb

(2) Production Scenario; CASE 2 (saturated liquid wellhead conditions)
1. First stage flasher pressure
2. Second stage flasher pressure
3. Condenser pinch point delta T
4. Cooling tower approach to wet bulb

8.2.12 Example Problem Results

8.2.12.1 Highlights

The results of the example problems can be summarized briefly as follows:

1. Any single thermodynamic or cost category other than minimum busbar energy cost is a misleading criterion in an attempt to rank the relative economic goodness of various conversion systems for a common resource. These stand-alone categories include wellhead utilization efficiency, brine specific net energy, plant capital cost, and field capital cost.

2. The relative economic ranking between flashed steam and binary cycle plants shifts significantly when production pumping requirements are considered in the sizing of the flashed steam plant. Pumping the production wells in the flashed steam plant displays this alternative in a relatively unfavorable manner (Ref. 3).

8.2.12.2 Discussion

Because thermodynamics alone is frequently used as a measure of competing geothermal process "goodness", it is appropriate that we discuss the significance of this selection criterion first. In Figure 16 we have plotted the maximum wellhead "brine" utilization efficiency as a function of resource temperature for the two simple hydrothermal energy conversion processes described previously in Figures 14 and 15. The wellhead utilization efficiency is simply the ratio of the useful work of the energy conversion process to the maximum available work (i. e. if the "brine" were expanded isentropically from the wellhead state to the sink (wet bulb) temperature). Each of the points on this plot represent cycles which have been thermodynamically optimized (see Section 8.2.9.1) with system maximum specific net energy, or brine "yield", ($P_{net}/\dot{m}_b$) as the objective function. For this optimization, the pinch point (<u>not</u> the mean) temperature differences of all non-work producing elements of the cycle

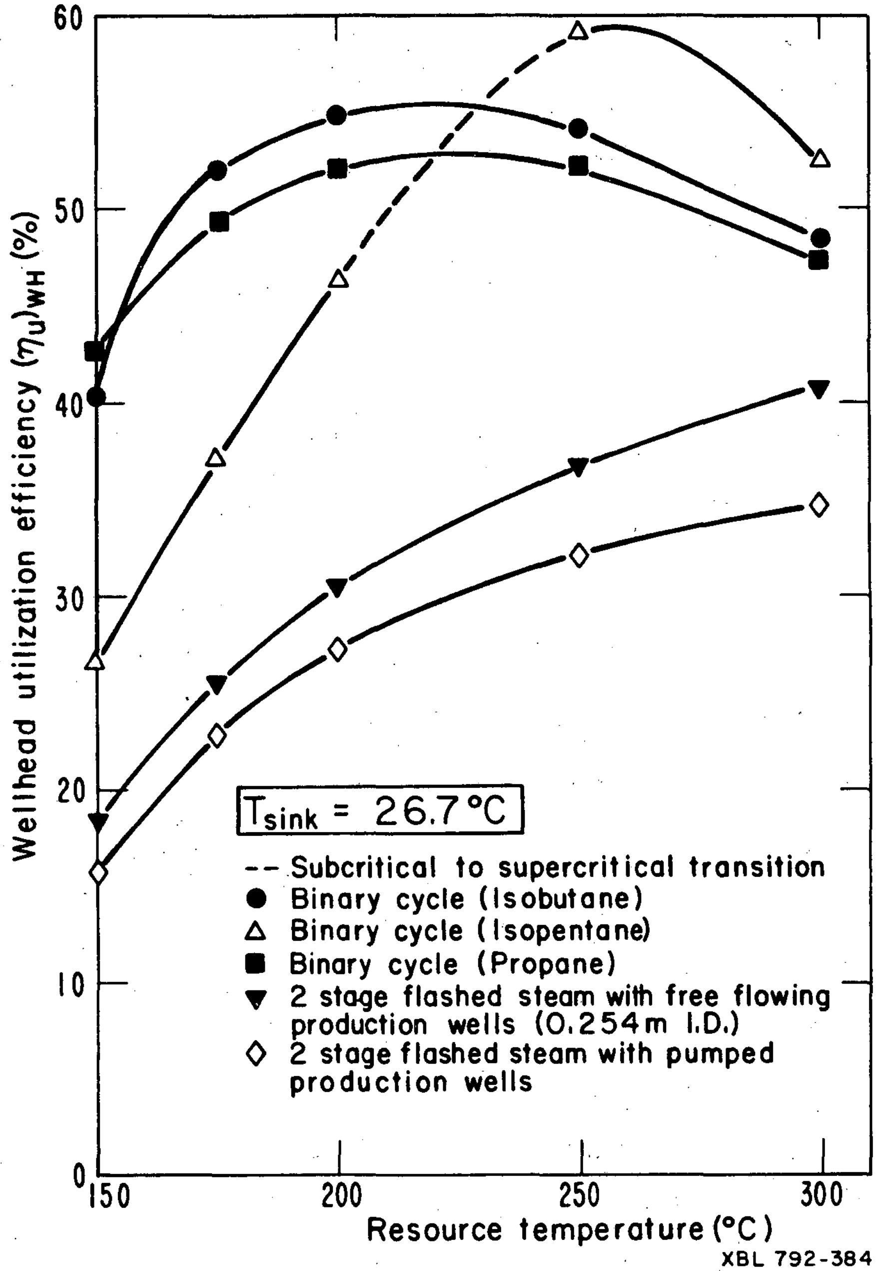

Fig. 16

Wellhead Utilization Efficiency for maximum thermodynamic brine yield optimized, 50 MWe (net) simple binary and two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production and injection wells are frictionless and adiabatic except the free flowing flashed steam, where friction is included. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. ALL COSTS IMMATERIAL.

were zeroed whereas the remaining independent system thermodynamic state parameters (see Table 3) were optimized. In each case all sub-system parasitic power has been considered including the heat rejection system and fluid production and injection systems. All costs for this thermodynamic optimization are immaterial.

The first point we wish to make regarding Figure 16 is that our maximum theoretically achievable utilization efficiencies are, in general, lower than those reported in Ref. 15. There are three principle reasons for this:

1. Degree of system characterization.

2. The utilization efficiency defined here is based on the sink temperature as the dead state (Ref. 1), not the condensing or "heat rejection temperature".

3. Our turbine inlet state and condensing pressures have been determined using the MPO capabilities of GEOTHM thus minimizing potential biasing assumptions. An exception is that we assumed a constant (4.0 in H_g) condensing pressure for all the flashed steam calculations.

The second point regarding Figure 16 is that with brine utilization efficiency at the optimum thermodynamic condition as the selection criterion, a relative "goodness ranking" between cycles and working fluids is clearly implied. We will later show that this relative goodness is not only a poor indication of relative busbar cost between cycles, but also a poor indicator of relative economic goodness between various working fluids in a binary cycle.

The third point regarding Figure 16 is that the wellhead utilization efficiency for the free flowing flashed steam process (phase separator as a first stage) is in all cases higher than for the two stage flash steam process with pumped production wells (saturated liquid wellhead conditions) for the same resource temperature.

We will return to Figure 16 later to illustrate additional differences when minimum busbar energy cost is the objective function.

In Figure 17 we have plotted the maximum wellhead "brine" utilization efficiency for the cycles and fluids previously discussed, but in this case, all points plotted represent designs which have been optimized with minimum busbar energy cost as the design objective (see Table 3). For cost optimized designs the economically achievable resource utilization efficiency is the result of a complex trade-off between minimizing sub-system irreversibilities and minimizing sub-system costs.

The first point illustrated in Figure 17 is that economically achievable brine utilization efficiencies are significantly lower than in Figure 16 and Ref. 15. This has also been pointed out by Starling (Ref. 42). The main reason for the reductions from Figure 16 values is increased system entropy production introduced in the heat exchange portions of the cycle as practical pinch points are adopted. The utilization efficiency reduction is less for the flashed steam cycles (at lower temperatures) because we have fixed the condensing pressure at "practical levels" (4.0 in H_g) for both the thermodynamic and the cost optimization (see Section 8.2.11.3).

The second feature discernable from Figure 17 is that isopentane no longer stands out at temperatures above say 230°C (Fig. 16) when utilization efficiency at optimum busbar energy cost is the selection criterion.

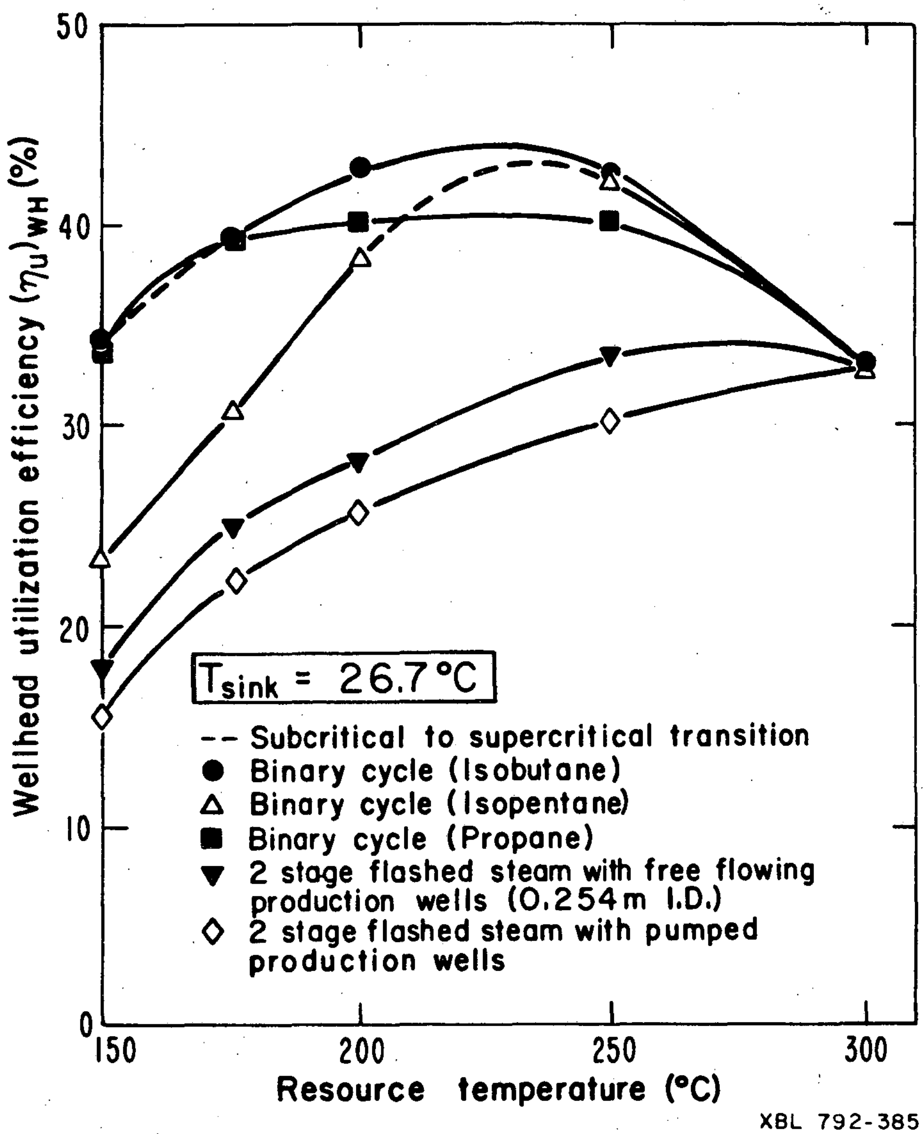

Fig. 17

Wellhead Utilization Efficiency for minimum busbar cost optimized, 50 MWe (net) simple binary and two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production and injection wells are frictionless and adiabatic except the free flowing flashed steam, where friction is included. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). Equal expander unit costs ($/KWgross) were assumed for all binary fluids. See Sec. 8.2.11 for other assumptions.

It is interesting to note that all cycles "converge" upon virtually the same wellhead utilization efficiency at 300°C. This is explained in the footnote below.≠

Figure 18, fortunately, sorts out the previous confusion from using thermodynamic criteria alone for selecting conversion system and working fluid alternatives. In Figure 18 we've plotted the relative busbar energy cost (binary/flash) as a function of resource temperature for production scenario, Case 1(a) and 1(b). This plot indicates that not only is isopentane the best binary cycle working fluid (of the selected 3) for resource temperatures above about 230°C (Fig. 16), it is the best binary cycle choice for all average resource temperatures above about 180°C. This is consistent with Starling's (Ref. 43) conclusion that the optimum working fluid (mixture) molecular weight increases with increasing resource temperature. According to these results, the isopentane binary cycle will be competitive with free flowing separating flashed steam cycles for resource temperatures up to roughly 270°C. This must be qualified by the figure caption statement; assuming the unit cost of first generation radial inflow geothermal expanders will be "about the same" (Ref. 44). Rough comparative

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≠The two hydrothermal energy conversion systems considered will approach the same specific net energy at some high resource temperature (ostensibly about 300°C) for cost optimized designs because of asymtotic thermodynamic performance trends indicated by binary cycles (see Fig. 24). With the high maximum well flow rates we've assumed (81.8 Kg/sec for all pumped production wells and 163.8 Kg/sec for all injection wells) the total number of wells required for all cases at 300°C is small (7-8). We've used a quantized field cost model to characterize discrete well costs. Therefore, for example, given the choice of either accepting a quantum field capital cost increase of about $600,000 due to adding a well or adjusting the plant optimizable parameters to achieve a lower busbar cost with a smaller than $600,000 increase in plant cost, the optimizer chooses the latter in all cases at 300°C. This forces the specific net energy (and therefore utilization efficiency) from being nearly equal for the pumped well cases to being exactly equal (± 0.11%) at 300°C. The free flowing flashed steam specific net energy is only 2.6% lower than the rest at a production well flow rate of 148 Kg/sec.

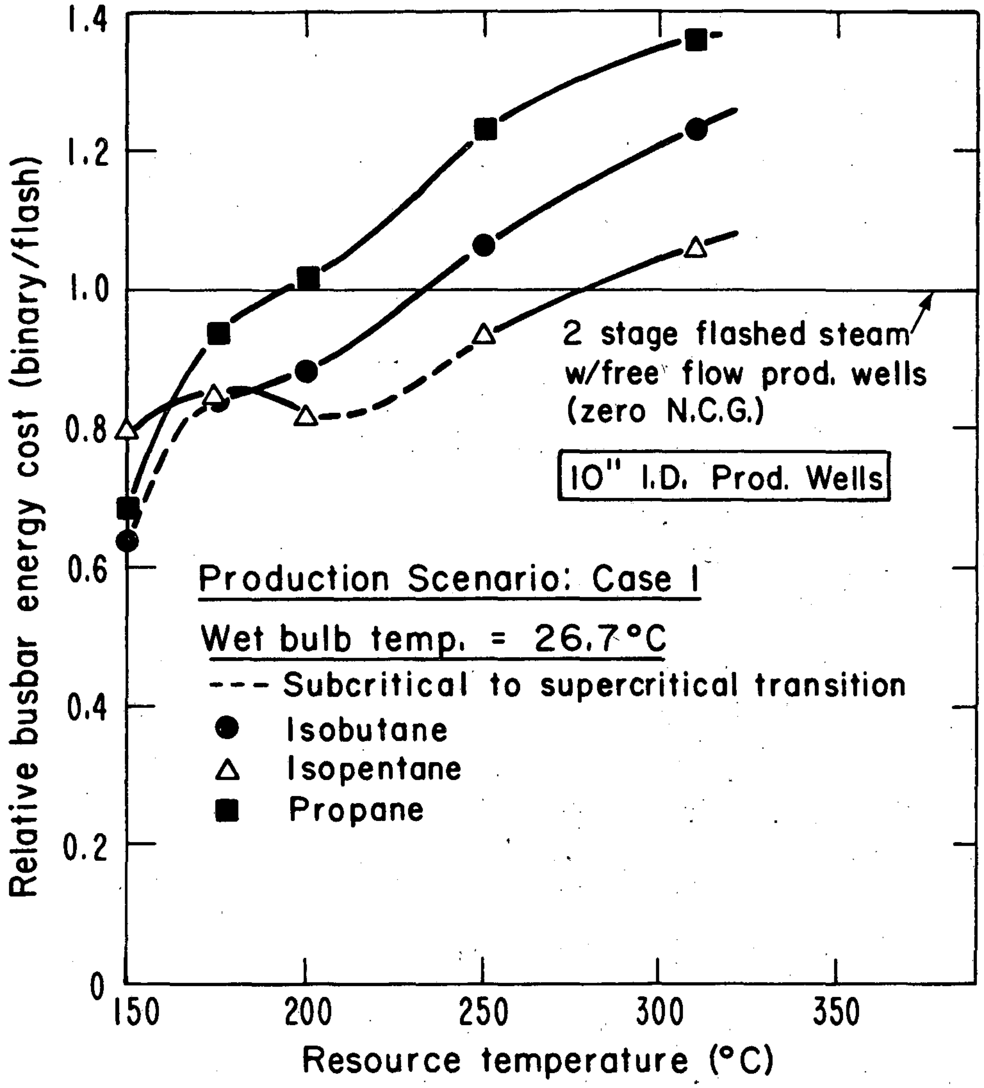

Fig. 18

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Relative Busbar Energy Cost for minimum busbar cost optimized, 50 MWe (net) simple binary and two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production scenario; CASE 1. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). The 10" I.D. constant diameter production wells were arbitrarily assumed at no increase in cost over EPRI ER-301 assumptions. Equal expander unit costs ($/KWgross) were assumed for all binary fluids. See Sec. 8.2.11 for other assumptions. Note: 300°C data points have been incorrectly plotted.

calculations of axial flow expander unit costs (Ref.15, Section 6.4) for these fluids do not support the foregoing assumption. Those rough calculations suggest the differences in binary cycle economic performance would be less than that indicated in Fig. 17.

Figure 19 is similar to Fig. 18 in all details except here the flashed steam process assumes pumped production wells with saturated liquid wellhead conditions, and a constant production well mass flow rate at all resource temperatures.

The main difference noticeable between Figures 18 and 19 is that binary cycle relative economic goodness is displayed more favorably when the flashed steam cycles assume pumped production wells (CASE 2) as in Fig. 19. This potential system designer bias has been pointed out by Elliott (Ref. 45), was alluded to previously in Section 8.2.6.4 and illustrated in Fig. 7.

The degree of difference between flashed steam plants with pumped and unpumped production wells is influenced by various free flowing production well design and cost assumptions described previously in Section 8.2.7, and the resulting parasitic power influence on plant and field size.

Figure 20 illustrates that the manner in which fuel "costs" are evaluated can be important if various conversion systems are compared with fuel cost as a simple additive "over-the-fence" price. All data points on this plot were computed from the final results of minimum busbar energy cost optimized plants with the fuel cost determined by the "cost-of-service" approach described in Section 8.2.4.2. We simply offer this plot " in evidence" for a currently unresolved issue.

Fig. 21 shows computed relative plant capital costs (binary/flash) for 50 MWe (net) minimum busbar cost optimized designs assuming production scenario; CASE 2 (pumped production wells with saturated liquid wellhead

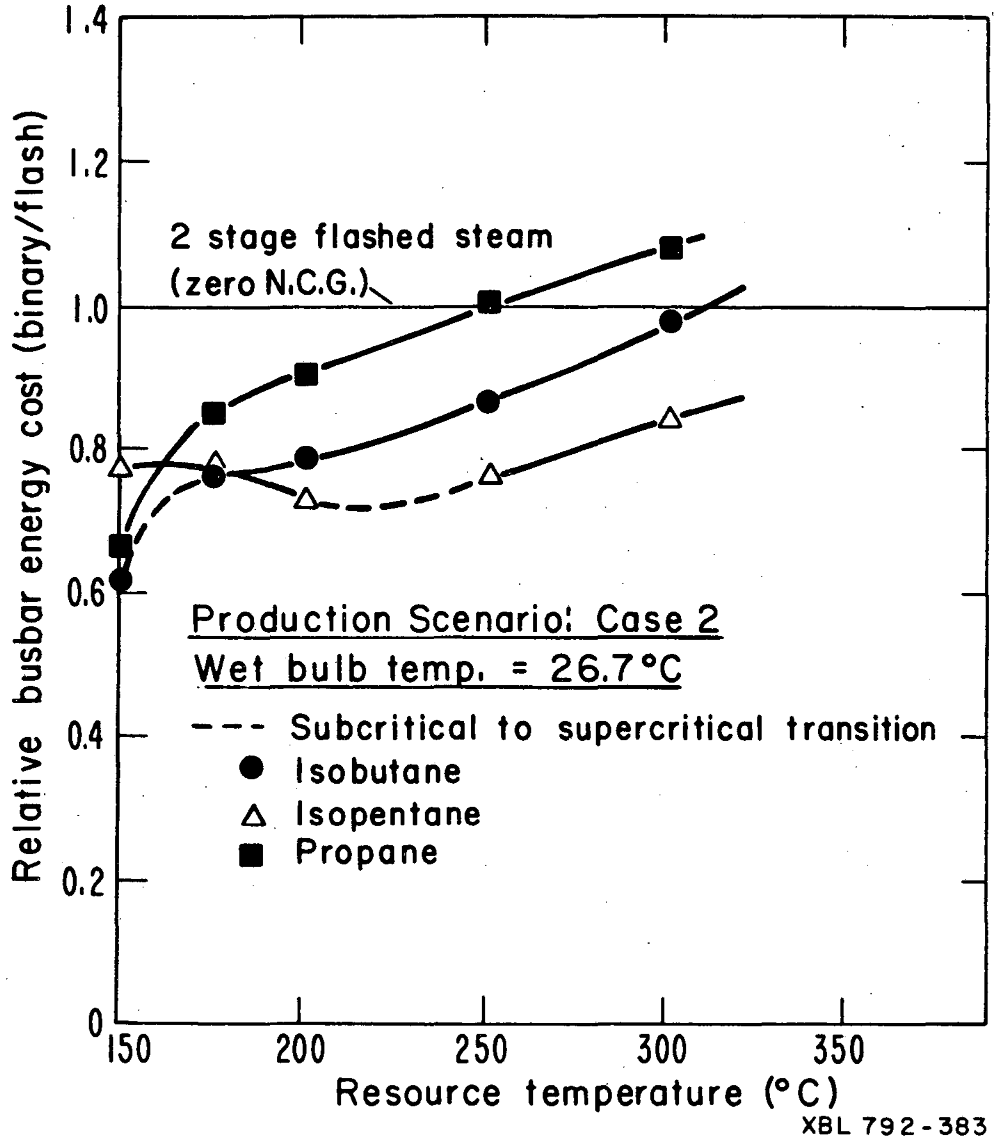

Fig. 19

Relative Busbar Energy Cost for minimum busbar cost optimized, 50 MWe (net) simple binary and two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production scenario; CASE 2. K_{DD} = 22.8 KPa/(Kg/sec), H_w = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). Equal expander unit costs ($/KWgross) were assumed for all binary fluids. See Sec. 8.2.11 other assumptions.

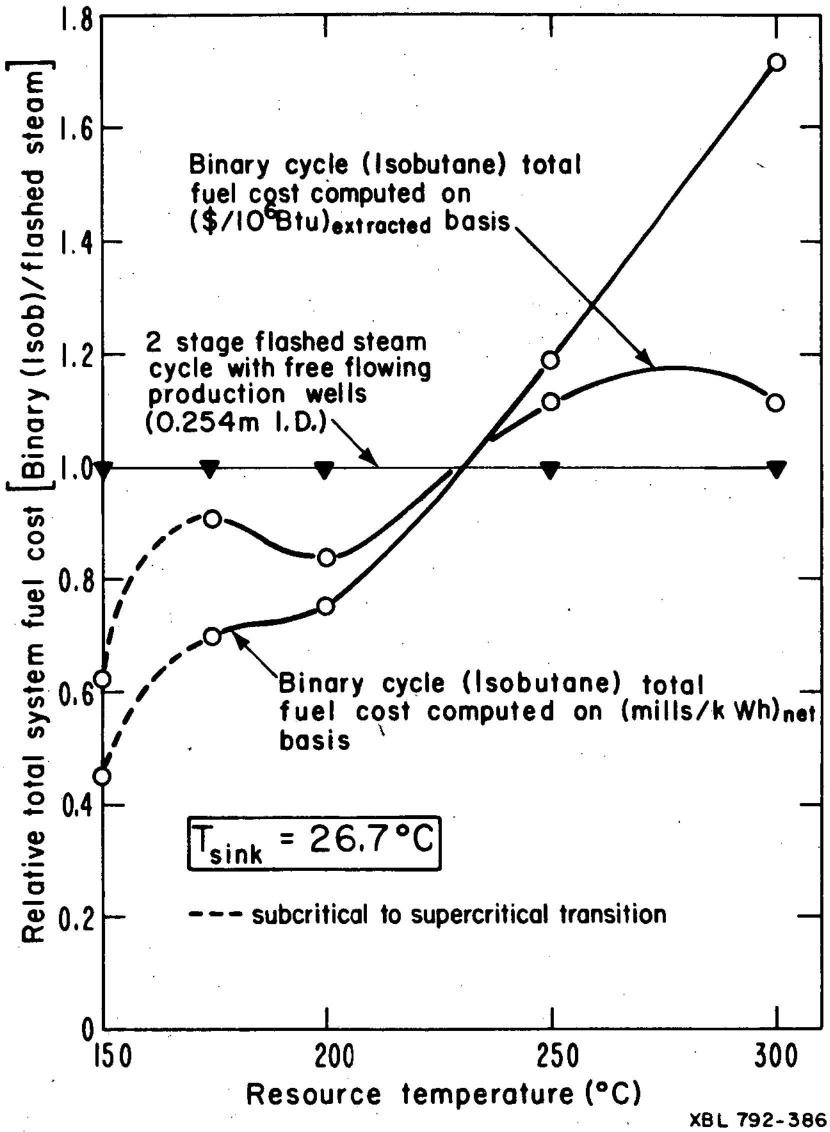

Fig. 20

Relative Total System "Fuel" Cost (annualized field capital and O&M expenses and annual cost of brine, cooling water, and treatment chemicals) for minimum busbar cost optimized, 50 MWe (net) simple binary (isobutane) and two stage flashed steam (free flowing production wells) energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig.14 and Fig.15. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants), but 0.245 m I.D. production wells arbitrarily assumed for flashed steam plants. See Sec. 8.2.11 for other assumptions.

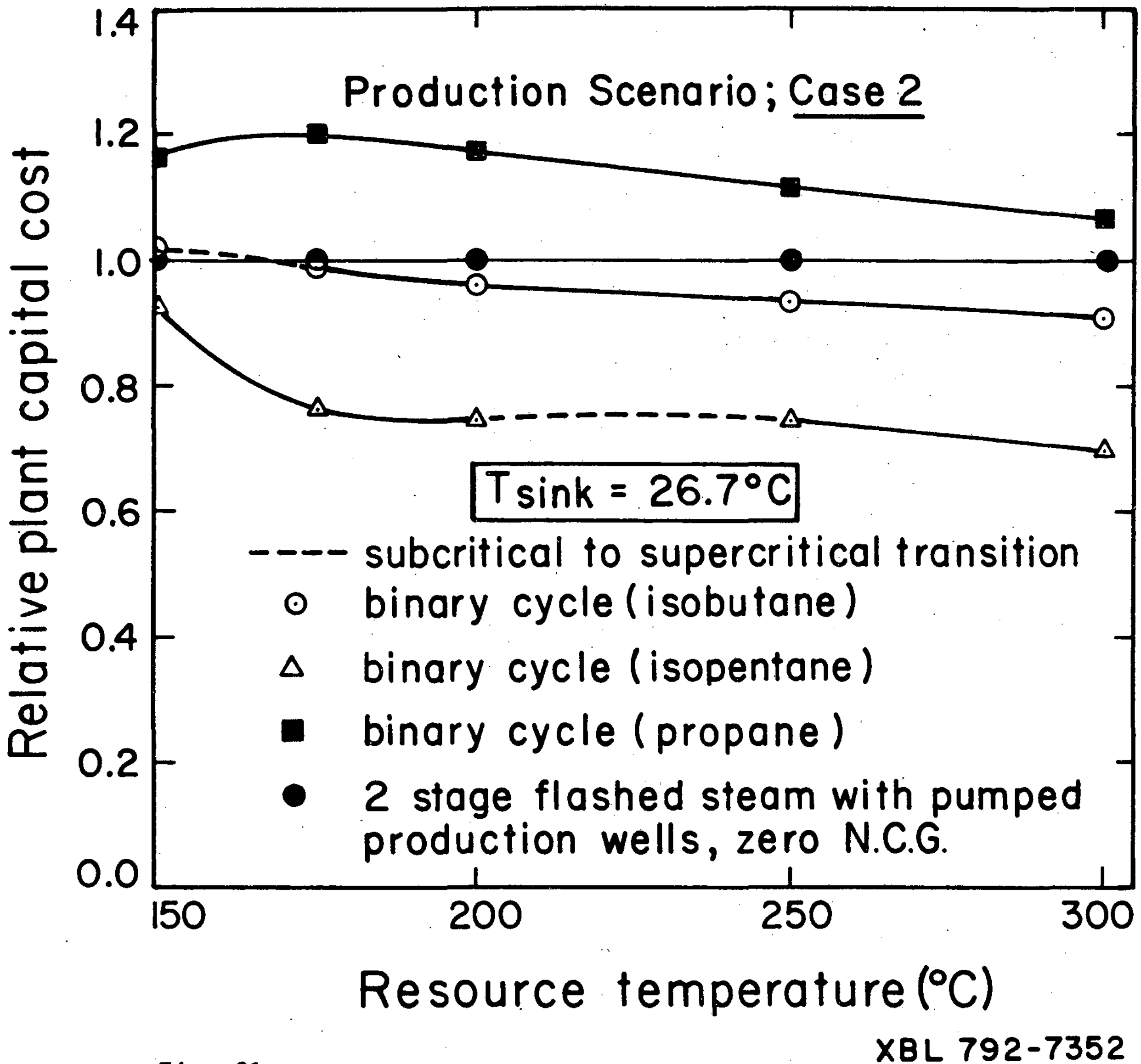

Fig. 21

Relative plant capital cost for minimum busbar cost optimized, 50 MWe (net) simple binary and two stage flashed steam (Case 2) energy conversion systems coupled to idealized, sub-cooled liquid, hydrothermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production scenario; CASE 2. K_{DD} = 22.8 KPa/(Kg/sec), H_w = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). Equal expander unit costs ($/KW gross) were assumed for all binary cycles, see Sec. 8.2.11 for other assumptions. Reinjection pump capital costs are included as plant capital costs.

conditions in all cases). It can be noted from this plot that plant capital cost differences alone are also a poor indicator of relative busbar energy cost (see Fig. 19).

Fig. 22 is a similar plot of computed relative field capital costs for Production Scenario; CASE 2. As with all previous singular thermodynamic or cost ranking "evaluators", relative field capital cost (proportional to number of wells or brine mass flow) does not properly rank relative busbar energy cost (see Fig. 19).

Therefore, if one were to compare geothermal energy conversion system alternatives by any of the foregoing "intuitively valid" criterion other than minimum busbar energy cost, inconsistencies in reported results will develop. We feel the foregoing discussion adequately demonstrates the validity of statements made in the beginning of this section (see 8.2.1.1).

However, the degree of credibility of the system analysis can be measured by the individual and agregate subsystem characterizations. We would be the first to admit to gross over simplification in many of the process routines currently in the GEOTHM code and used in this study.

We regard this study as simply a first in-house attempt to connect the "resource" to the plant. Dr. Elliott's well routines have allowed this, providing a "first order" characterization of a very complex total system. It is appropriate at this point to present the wellhead conditions computed for the "optimized" flashed steam plants of this study.

Figure 23 shows computed optimum wellhead state, flash point depth, and wellhead flow rate for 50 MWe (net) minimum busbar cost optimized separating flashed steam power plants (Fig. 14) for Production Scenario CASE 1 (free flowing wells). This plot shows the degree of geothermal well characterization currently possible using the Elliott free flowing well routines (Ref. 16) for a constant diameter well. It can be seen here that optimum wellhead pressures begin to increase rapidly at about 180°C, whereas steam fraction rate increases do not significantly change until about 250°C (assuming adiabatic flow conditions).

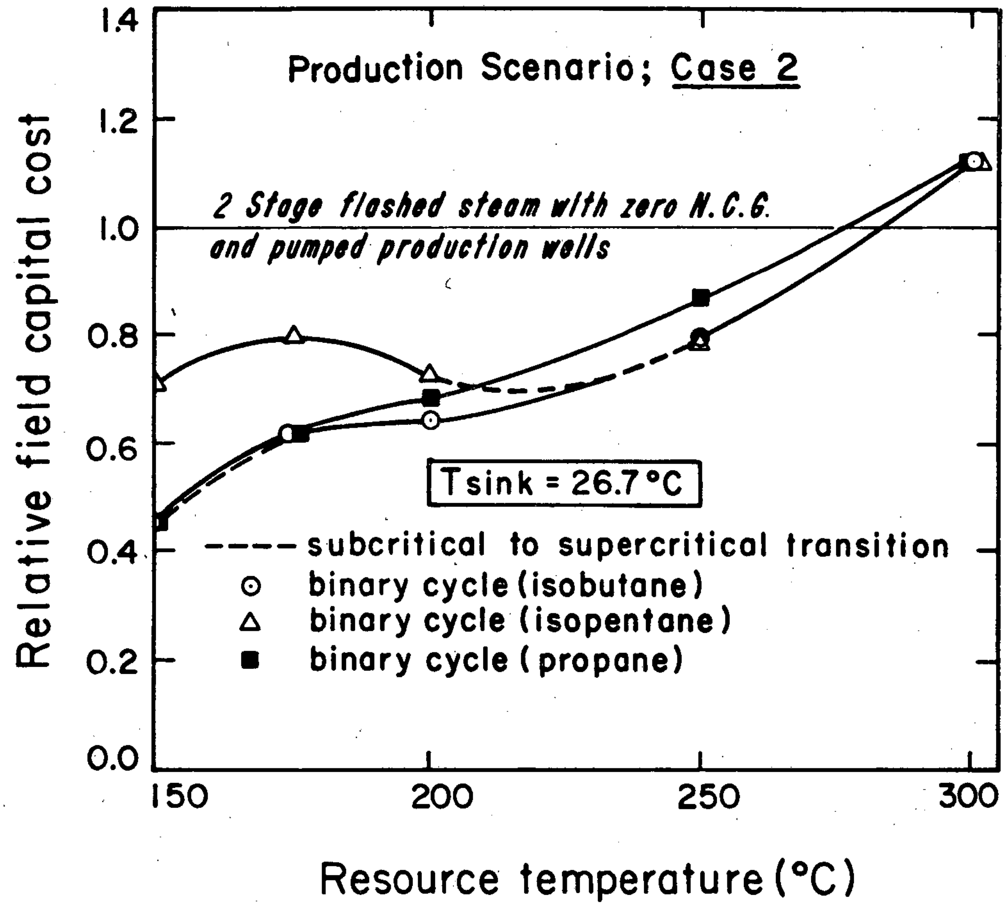

Fig. 22

Relative field capital cost for minimum busbar cost optimized, 50 MWe (net) simple binary and two stage flashed steam energy conversion systems coupled to idealized, sub-cooled liquid, hydorthermal resources of equal pressure. All spent fluids injected. The cycles optimized are shown in Fig. 14 and Fig. 15. Production scenario; CASE 2. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m. All costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). Equal expander unit costs ($/KW gross) were assumed for all binary cycles. See Sec. 8.2.11 for other assumptions.

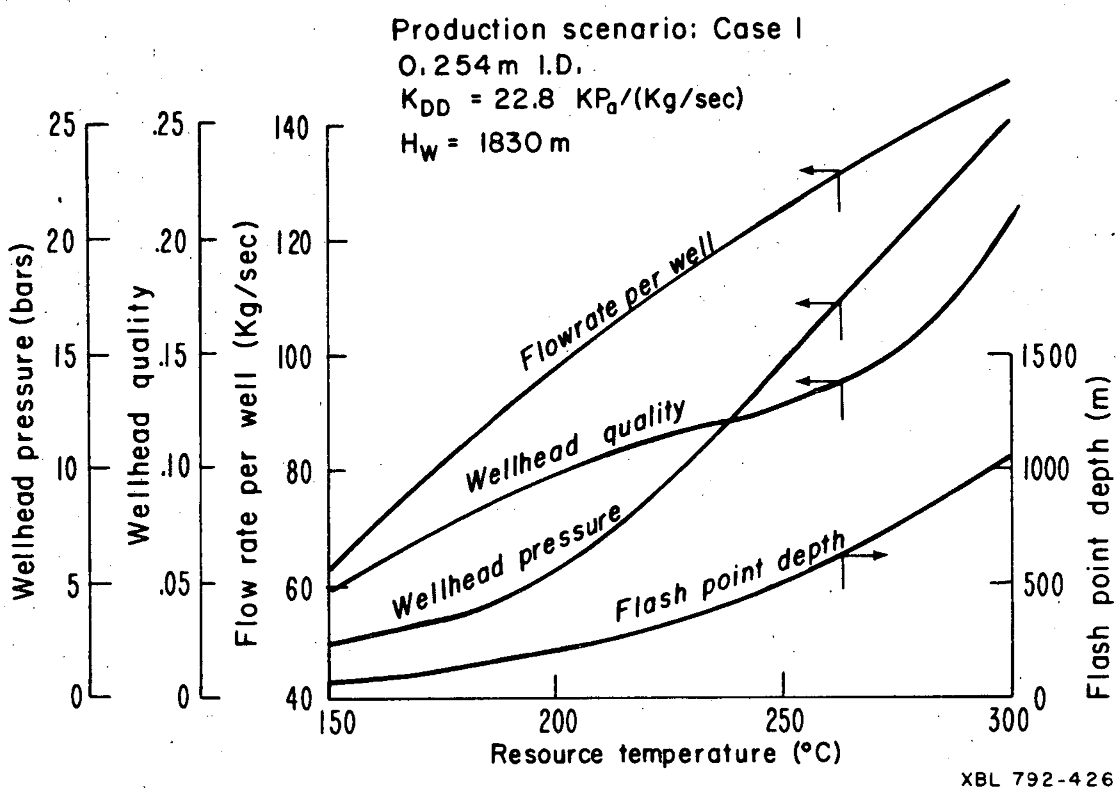

Fig. 23

Calculated optimum wellhead state conditions, flash point depth, and mass flow rate for equal pressure, sub-cooled reservoirs. Two stage flashed steam plant for production scenario; CASE 1. System optimized for minimum busbar energy cost is shown in Fig. 14. Assumes "zeroth order" reservoir model and approximate vertical two phase flow routines described by Elliott (Ref. 16). Well heat transfer ignored. H_W = 1830 m, 0.254 m I.D., K_{DD} = 22.8 KPa/(Kg/sec).

The high optimum wellhead pressures computed here are symptomatic of our "degree of characterization" of steam turbine costs which are very elementary at this time. With more realistic expander cost models, the computed optimum wellhead pressures would obviously go down.

Fig. 24 is the final plot of this section. In this plot we have superimposed the results of our calculations for two binary cycle working fluids and the free flowing flashed steam cycle over the known thermodynamic performance of two existing geothermal power plants and the Total Flow process studied extensively by the Lawrence Livermore Laboratory (see Section 4.4 of this SOURCEBOOK).

It can be seen here, that the separating flashed steam process does not utilize the "brine" as effectively as the existing, more efficient, three stage Wairakei plant. A reverse order of performance, however, could be inferred using the early thermodynamic performance data from optimized plants in Ref. 15. We feel the relative thermodynamic performance shown in Fig. 24 lends a reasonable degree of credibility to all the GEOTHM optimized designs included in this report.

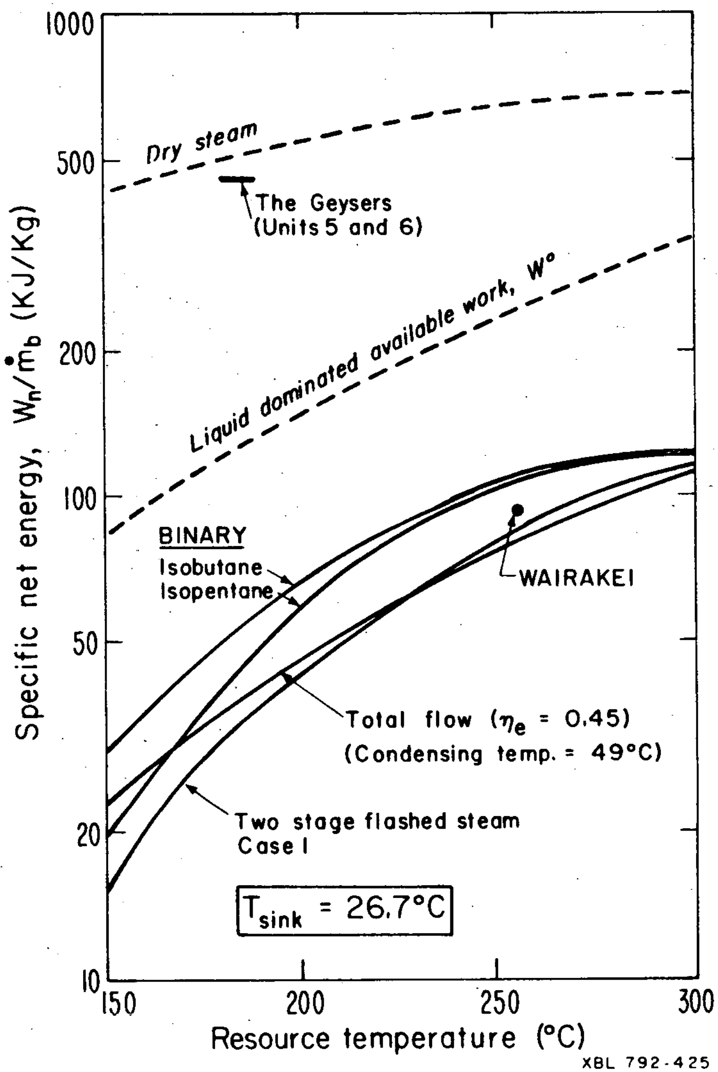

Fig. 24

Specific Net Electric Energy for various geothermal energy conversion systems.

- Detail specifications and performance of the GEYSERS plants are contained in Ref. 50.
- The WAIRAKEI energy conversion cycle has been described as "a multi-pressure, separated-steam, double flash plant". Spent fluids are not injected. (See Ref. 51 for details).
- The TOTAL FLOW curve was plotted from data in Fig. 4-2 of Chapter 4, Section 4.4 (LLL calculations assuming pure H_2O, zero N.C.G., 10% parasitics) after converting to an expander adiabatic efficiency of 45%.
- The BINARY curves and the TWO STAGE FLASHED STEAM curve are the calculated performance of busbar energy cost optimized cycles coupled to idealized, subcooled liquid (pure H_2O), hydrothermal resources of equal pressure. Costs and financial assumptions were normalized to EPRI ER-301 (Heber Plants). All spent fluids injected. Production and injection wells are frictionless and adiabatic except flashed steam production wells (0.254 m I.D.), where friction is included and N.C.G. ignored. K_{DD} = 22.8 KPa/(Kg/sec), H_W = 1830 m.

8.2.13 Summary and Conclusions

Our perception of the state-of-the-art of hydrothermal geothermal energy conversion system design has been presented. We have introduced features of developing conceptual design aids and described current software limitations. We have suggested that some previously reported geothermal studies have been inconsistent and therefore contributed to an unnecessarily high level of investor's perceived risk.

Example problems for the simplest energy conversion systems have been used to demonstrate the inherent complexity of geothermal system design using even the most sophisticated techniques and have uncovered several possible reasons for the reported inconsistencies. We have repeatedly stressed the importance of coupling the energy conversion process to the geothermal reservoir, and illustrated that valuable new insights into the problem can be achieved with even a primitive level of geothermal well characterization.

We also have shown that it is not possible to isolate any single facet of the geothermal system design process, e.g. subsystem thermodynamic performance or economic performance to determine absolute or relative goodness, without biasing the optimality of the systems as a whole. We have demonstrated, however, that minimum busbar energy cost is a consistent measure of commercial feasibility for geothermal systems as with any other established conversion technology.

The importance of thermodynamic optimizations stressed by Kestin, nevertheless, have been acknowledged: "It is.... recognized that the economic optimum in given circumstances is not coincident with the thermodynamic optimum.... However, past experience shows that the latter contains valuable indications for the former and constitutes an indispensable first step." (Ref. 1). We concur and have been able to expand on the significance of this statement. Thermodynamic optimization is the most reasonable first step to the problem solution. Use of the maximum specific net energy as a first guess to the cost optimization has been found to consistently converge on the global cost optimum. Thus a link between thermodynamics and economics has been established. This link is possibly unique, because it ties the optimum thermodynamic solution to the optimum economic solution. There is reason to believe that the optimization algorithm used here for geothermal power plants can be applied to other similar systems as well.

Perhaps the weakest existing link we've found in the geothermal system conceptual design process is the degree of system characterization--the connection between the plant and the reservoir. Studies which ignore the mutual interaction between the plant, the reservoir, and the wells cannot possibly portray the true economic life (and therefore feasibility) of hydrothermal systems as a whole. Even the relative rank between candidate conversion alternatives can only be crudely approximated.

Plant design technology is relatively well established (Refs. 3, 11, 53, 54, 55), except, possibly, in the areas of scale control, or mitigation, and corrosion. The state-of-the-art of resource identification, assessment, and characterization has developed impressively in recent years (Ref. 56). Geothermal reservoir engineering and well analysis techniques utilize state-of-the-art instrumentation, computer techniques, and theory of flow in porous media (Refs. 46, 47, 48, 49). Studies are under way which will do much to improve our understanding of flow regimes and thermodynamics in vertical two-phase flow (Ref. 19). Detailed economic design information for wells (Ref. 20) is forthcoming. Brine modification techniques (Ref. 57) have been developed for hyper-saline brines, but the scaling behavior (chemical kinetics) of complex low salinity brines in geothermal wells must be better simulated (Ref. 58) and included in the well flow-economic models to make rational future system decisions. Finally, we have shown in these studies that existing multiparameter optimization techniques have achieved a level of maturity such that they can be applied to geothermal systems on an industrial scale to perform the complex system economic trade-offs with a minimum of bias.

However, until the above major subsystem variables are coupled into an overall system thermodynamic-economic model, the true economic sensitivity of each on the others will remain unknown and potential system improvements may be overlooked. This overall system model could reduce reporting inconsistencies and, therefore, the level of risk portrayed to the geothermal investor.

8.2.14 Notation

C_E	busbar (or load center) energy cost
C_j	iso-cost contour on the busbar energy cost design surface
C_p	specific heat capacity at constant pressure, J/(g°K)
d	well diameter, in
df	numerical derivitive of the function f
del	step-size used in numerical derivitive calculations
$f(X_k)$	objective function evaluated at X_k
$f'(X_k)$	first partial derivatives of the objective function with respect to each of the optimizable parameters, evaluated at X_k
$f(X^*)$	value of objective function evaluated at the optimum set of optimizable parameters X^*
F*	set of performance factors, evaluated at the optimum condition
G	electrical generator in Figs. 9, 14, 15
h	enthalpy, J/g
Hw	well depth, m
I.D.	production well inside diameter, in, m
I.I.D	Imperial Irrigation District
K_{DD}	drawdown factor, kPa/(kg/sec)
KGRA	known geothermal resource area, a legal definition
M	electrical motor in Figs. 9, 14, 15
$\dot{m}_b$	brine mass flow rate, kg/sec
MPO	multiparameter optimization
n	number of optimizable parameters

N.C.G.	noncondensible gases
O and M	operation and maintenance
p	pressure, bars
P	power, megawatts (MWe)
POMTEP	path of maximum thermodynamic performance
s	entropy, J/(g°K)
ΔT	temperature difference, C°, K°
ΔT_{EQ}	equivalent temperature difference, C°
T	temperature, °C, °K
TPCT	transposed critical temperature
T_{RES}	resource temperature, °C, °K
T_{SINK}	sink temperature, °C
T_{WB}	wet bulb temperature, °F, °C
U	overall heat transfer coefficient, W/m^2°K
v	specific volume, cm^3/g
V_C	value of energy conversion
W^o	available work or exergy (Ref. 1), kJ/kg
X_0	initial vector of optimizable parameters
X_{k+1}	improved vector of optimizable parameters
X_k	kth value of vector of optimizable parameters
X^*	solution vector
X_A	heat exchanger annual capital investment, $/BTU
X_{CL}	annual cost of exchanger cleaning, $/BTU
X_{P_i}	annual cost of tube-side pumping power, $/BTU
X_{P_0}	annual cost of shell-side pumping power, $/BTU

X_{TOT}	total annual heat supply cost, \$/BTU
X_{UF}	annual brine cost, \$/BTU
Y	variable in Fig. 8
YAFG	(thermodynamic) Yield As First Guess (to a global cost optimum)
ε	some arbitrarily small number
η_p	pump adiabatic efficienty, %
η_u	utilization efficiency, %
$(\eta_u)_{WH}$	wellhead utilization efficiency, %

<u>Subscripts</u>

e	expander
inj	injection
n	net
opt	optimum value of any function

8.2.15 References

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