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THE UNALASKA GEOTHERMAL EXPLORATION PROJECT

ELECTRICAL POWER GENERATION ANALYSIS - FINAL REPORT

Prepared By:

Republic Geothermal, Inc.

For:

The Alaska Power Authority

April 1984

Prepared for
U.S. Department of Energy
Idaho Operations Office
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EXECUTIVE SUMMARY

The objective of this study was to determine the most cost-effective power cycle for utilizing the Makushin Volcano geothermal resource to generate electricity for the towns of Unalaska and Dutch Harbor. It is anticipated that the geothermal power plant would be intertied with a planned conventional power plant consisting of four 2.5 MW diesel-generators whose commercial operation is due to begin in 1987. Upon its completion in late 1988, the geothermal power plant would primarily fulfill base-load electrical power demand while the diesel-generators would provide peak-load electrical power and emergency power at times when the geothermal power plant would be partially or completely unavailable.

This study compares the technical, environmental, and economic adequacy of five "state-of-the-art" geothermal power conversion processes. Options considered are single- and double-flash steam cycles, binary cycle, hybrid cycle, and total flow cycle.

The power plant designs considered were limited to those capable of being unitized in pre-assembled and pre-tested modules so as to facilitate transportation, erection, and start-up. The size and number of units were determined by an evaluation of commercially available units and by an analysis of the electrical load demands as estimated by Acres American, Inc. for APA. As requested by APA, both "no-bottomfish demand" and "low-bottomfish catch" cases were considered.

Because of the uncertainties in the electrical load forecasts it is recommended herein that the geothermal power plant be developed in phases that are timed to the growth in demand. The first phase of development should consist of two identical 5 MW gross binary units capable of generating a total of 6.7 MW net of electrical power. This plan satisfies the estimated demand for the no-bottom fishing case past the year 2000.

Should bottom fishing take place and electrical load demand increase in accordance with the "low-bottomfish" projections, then a second and third phase would be added to become commercial in early 1993 and 2000 respectively. Each of these two phases would comprise two 5 MW gross binary units identical to those installed in Phase I.

The binary cycle was selected because it is the most economical process in the small unit size considered, it is efficient, it does not incur the risk of freezing during winter months operation and it can be installed quickly, thus adding scheduling flexibility.

INTRODUCTION

The city of Unalaska, a community in the Aleution Island region of southwestern Alaska is expanding and modernizing the electric power systems in the towns of Dutch Harbor and Unalaska. As part of this electrification program, a larger electrical distribution system is being built, an old power house is being refurbished and the installation of four 2.5 MW diesel-generator units is being planned.

Acres American Inc. has been requested by the Alaska Power Authority (APA) to prepare an economic study to determine how to supplement the electricity produced by the diesel-generating system as the system demand grows and thus, minimize reliance on high cost diesel-fired power generation. Because the state of Alaska is attempting to utilize indigenous energy sources located close to population centers, one of the options being considered is the use of geothermal energy.

A significant geothermal resource was discovered in 1983 as a result of the Unalaska geothermal exploration project conducted by Republic Geothermal Inc. for the APA. A small diameter resource confirmation well, Makushin ST-1, was drilled in the flank of the Makushin Volcano which is located within 12 miles of the towns of Unalaska and Dutch Harbor. A short test of the well yielded fluid from that flowed from a three-inch orifice at 47,000 lb/hr with a 16 percent steam flash. Analyses of samples collected during the flow test indicate that the reservoir contains a sodium-chloride type water with a total dissolved solids (TDS) content of approximately 6,000 ppm by weight and that the preflash carbon dioxide content is 217 ppm. At these low concentrations, the dissolved solids and gases are not expected to pose any problems in the conversion cycles.

While more testing is necessary to further characterize and delineate the resource, theoretical calculations predict that a full-scale production well would yield approximately 900,000 lb/hr at a pressure of 57 psia both of which parameters are more than adequate for commercialization.

The study that is described below establishes the best means of generating electricity from the Makushin resource, presents a power generation development scenario based on estimated load forecasts and estimates the cost of commercializing geothermal power on Unalaska. The report addresses all of the tasks listed in the "scope of work" section of Amendment No. 6 to Contract CC-08-2334 as modified by the letter dated February 2, 1984 from the APA.

POWER CONVERSION OPTIONS

The conversion of hydrothermal energy from Makushin-type liquid-dominated geothermal resource into electric power can be accomplished by the following processes:

1. Flash Steam

   In the flash steam process, steam is produced from the geothermal fluid by reducing the pressure of the fluid below the saturated liquid pressure. The steam is then used to directly power a turbine, which in turn drives an electric generator.

2. Binary

   In the binary process, a low boiling point fluid, such as freon or isobutane, is passed through a heat exchanger where it is vaporized by proximity to the geothermal brine. The superheated vapor is then used to power a turbine, which in turn drives an electric generator.

3. Hybrid

   In the hybrid process, part of the geothermal fluid is flashed into steam which is used to drive a steam turbine-generator. The residual fluid is then used to vaporize a low boiling point fluid through a heat exchanger. The superheated vapor produced is then used to power a second turbine-generator.

4. Total Flow

   In the total flow process, all of the geothermal fluid is expanded through a mechanical device which converts both thermal and kinetic energy of the well fluid into shaft work (torque). This shaft work is then used to drive an electric generator.

Numerous commercial power plants using the flash steam process are in operation and several more are under construction in various locations throughout the world. Notable examples of successful geothermal flash steam plants include installations in the Imperial Valley of the United States, New Zealand, Mexico, Japan, The Philippines, and Iceland. It is safe to say that the flash steam process is proven.

One 10 MW geothermal binary plant is presently operating successfully in the Imperial Valley and a number of others are under construction in the United States. While the binary process has not been widely used to date in geothermal applications, the organic fluid Rankine cycle has been used extensively over the years in petrochemical and waste heat recovery plants. The binary process is, therefore, considered to be technologically proven, at least in units in the 0.5 to 5.0 MW size range.

There are no operating geothermal power plants using the hybrid cycle at the present time, however, Republic Geothermal, Inc. is planning to build one soon in the Imperial Valley. The hybrid process is simply the combination of two proven processes (flash steam and binary) for greater conversion efficiency and it is, therefore, considered to be proven as well.

The total flow process, which was developed specifically for geothermal application, comes in technically different options which are in various stages of development. The two best known are the Sprankle helical screw expander and the Biphase rotary separator turbine. The Sprankle expander has been tested extensively on a small scale, and may be ready for commercialization. A full-scale version of the Biphase turbine has been tested successfully in Utah for the last few months and is definately ready for commercialization. The Biphase turbine does not involve significant technical risks and is considered to be state-of-the-art.

Only state-of-the-art processes are being considered for the commercial development of the Unalaska Island resource.

POWER CONVERSION PROCESS DESCRIPTIONS

Flash Steam Process Description

Both single and double flash steam options have been considered in this study.

1. Single Flash Steam Process

   Two-phase geothermal fluid produced by the wells is piped to a steam separator where the steam is separated from the geothermal water.

   The steam is then piped from the separator to a steam turbine-generator where it is expanded to produce electrical power. The exhaust steam from the turbine is then ducted to an extended-surface, air-cooled heat exchanger where its is condensed by rejecting heat to the atmosphere. Noncondensable gases are removed from the condenser by a combination of steam jet ejectors and liquid-ring vacuum pumps. Condensate pumps transfer the warm water from the condenser to an injection surge tank.

   The residual geothermal water flows from the separator into the injection surge tank where it is mixed with the condensate from the steam cycle. The water is then pumped out of the surge tank and injected back into the ground.

   Figure 1 is a schematic flow diagram of the single flash steam process.

2. Double Flash Steam Process

   Two-phase geothermal fluid produced by the wells is piped to a steam separator where the high-pressure steam is separated from the geothermal water. The geothermal water then flows to a flash tank where low-pressure steam is generated by reducing the pressure.

   High- and low-pressure steam from the separator and the flash tank is piped to a dual inlet steam turbine-generator where it is expanded to produce electrical power. The exhaust steam from the turbine is ducted to an extended-surface, air-cooled heat exchanger where it is condensed by rejecting heat to the atmosphere. Noncondensable gases are removed from the condenser by a combination of steam jet ejectors and liquid-ring vacuum pumps. Condensate pumps transfer the warm water from the condenser to an injection surge tank.

   The residual geothermal water is transferred out of the flash tank into the injection surge tank where it is mixed with the condensate from the steam cycle. The water is then pumped out of the surge tank and injected back into the ground by the injection pumps.

   Figure 2 is a schematic flow diagram of the double flash steam process.

FIGURE 1
SINGLE FLASH STEAM PROCESS
SCHEMATIC FLOW DIAGRAM

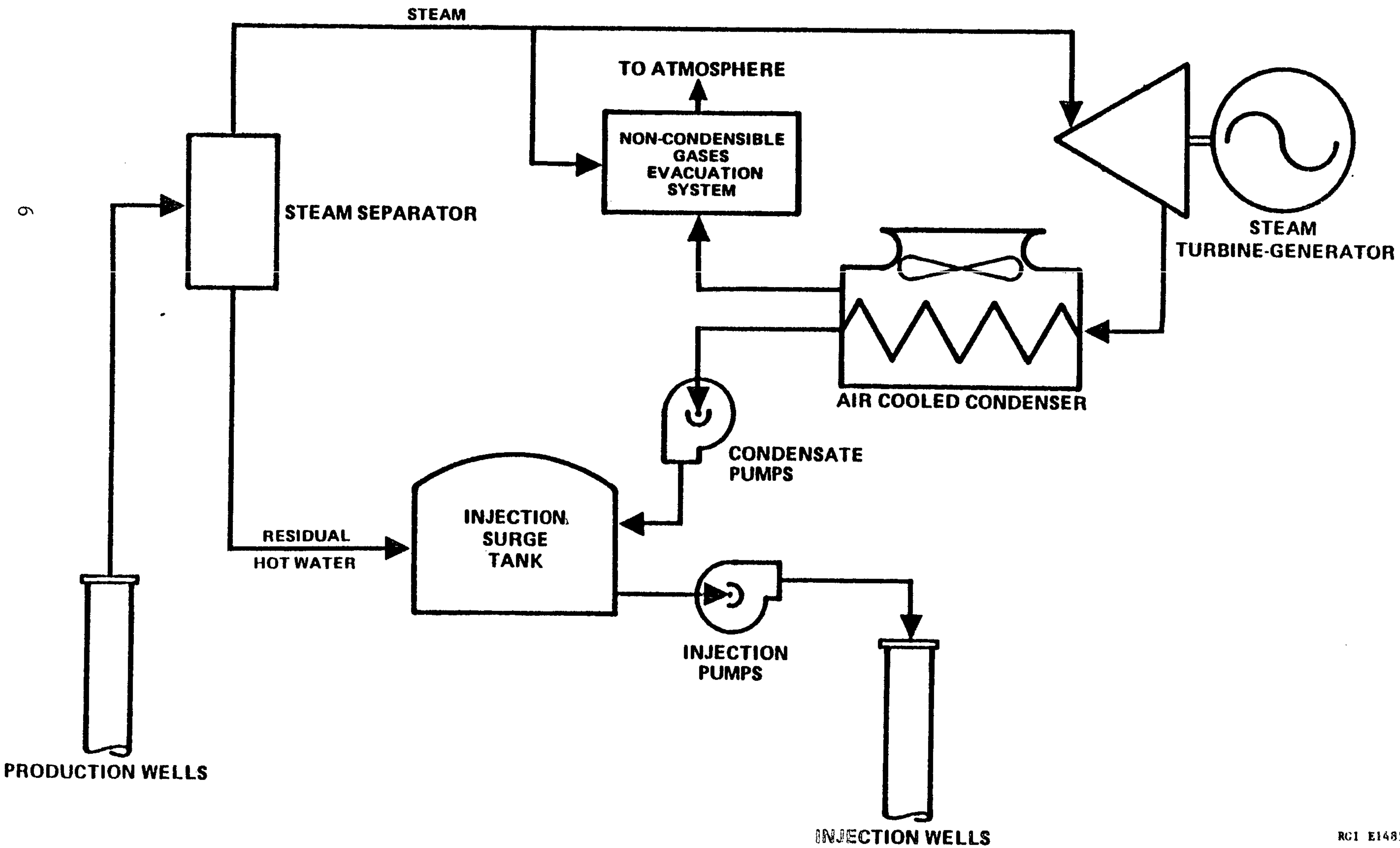

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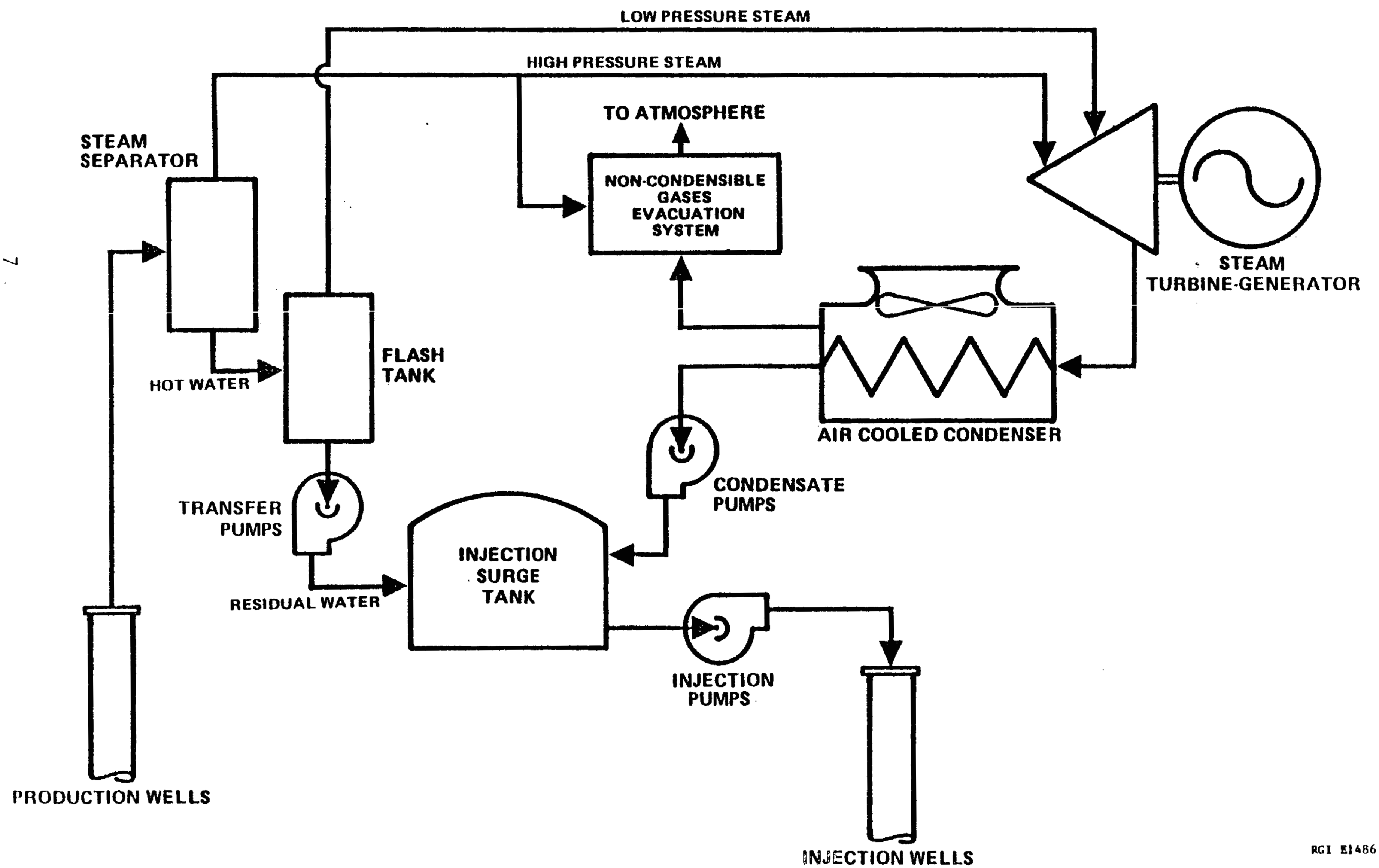
FIGURE 2
DOUBLE FLASH STEAM PROCESS
SCHEMATIC FLOW DIAGRAM



Binary Process Description

Two-phase geothermal fluid produced by wells is piped to a steam separator where the steam is separated from the geothermal water.

The steam and water are piped separately from the separator to a series of shell-and-tube-heat exchangers. The water preheats and evaporates the binary fluid, which can be a hydrocarbon such as isobutane or a fluocarbon such as freon R-114. The steam superheats the binary fluid vapor. The superheated fluid vapor is then piped to a binary turbine-generator where it is expanded to produce electric power.

The exhaust vapor from the turbine is then ducted to an extended-surface, air-cooled heat exchanger where it is condensed by rejecting heat to the atmosphere. Condensate pumps transfer the binary fluid condensate from the condenser back to the binary fluid heat exchangers where the cycle is repeated.

Cooled geothermal water and steam condensate flow from the binary fluid heat exchangers into an injection surge tank. The water is then pumped out of the surge tank and injected back into the ground.

Figure 3 is a schematic flow diagram of the binary process.

Hybrid Process Description

Two-phase geothermal fluid produced by the wells is piped to a steam separator where the steam is separated from the geothermal water.

The steam is piped from the separator to a steam turbine-generator where its is expanded to produce electric power. The exhaust steam from the turbine is directed to an extended-surface, air-cooled heat exchanger where it is condensed by rejecting heat to the atmosphere. Noncondensable gases are removed from the condenser by a combination of steam jet ejectors and liquid-ring vacuum pumps. Condensate pumps transfer the warm water from the condenser to an injection surge tank.

The residual geothermal water flows from the separator to a serie of shell-and-tube heat exchangers where it preheats, evaporates, and superheats the binary fluid, which can be a hydrocarbon such as isobutane or a fluocarbon such as freon R-114. The superheated binary fluid vapor is piped to a binary turbine-generator where it is expanded to produce electric power.

The exhaust vapor from the binary turbine is ducted to a second extended-surface, air-cooled heat exchanger where it is condensed by rejecting heat to the atmosphere. The binary fluid condensate is then transferred by the condensate pumps from the binary fluid condenser back to the binary fluid heat exchangers where the cycle is repeated.

Cooled geothermal water flows from the binary fluid heat exchangers into the injection surge tank and mixes with the condensate from the steam cycle. The water is then pumped out of the surge tank and injected back into the ground.

Figure 4 is a schematic flow diagram of the hybrid process.

FIGURE 3
BINARY PROCESS
SCHEMATIC FLOW DIAGRAM

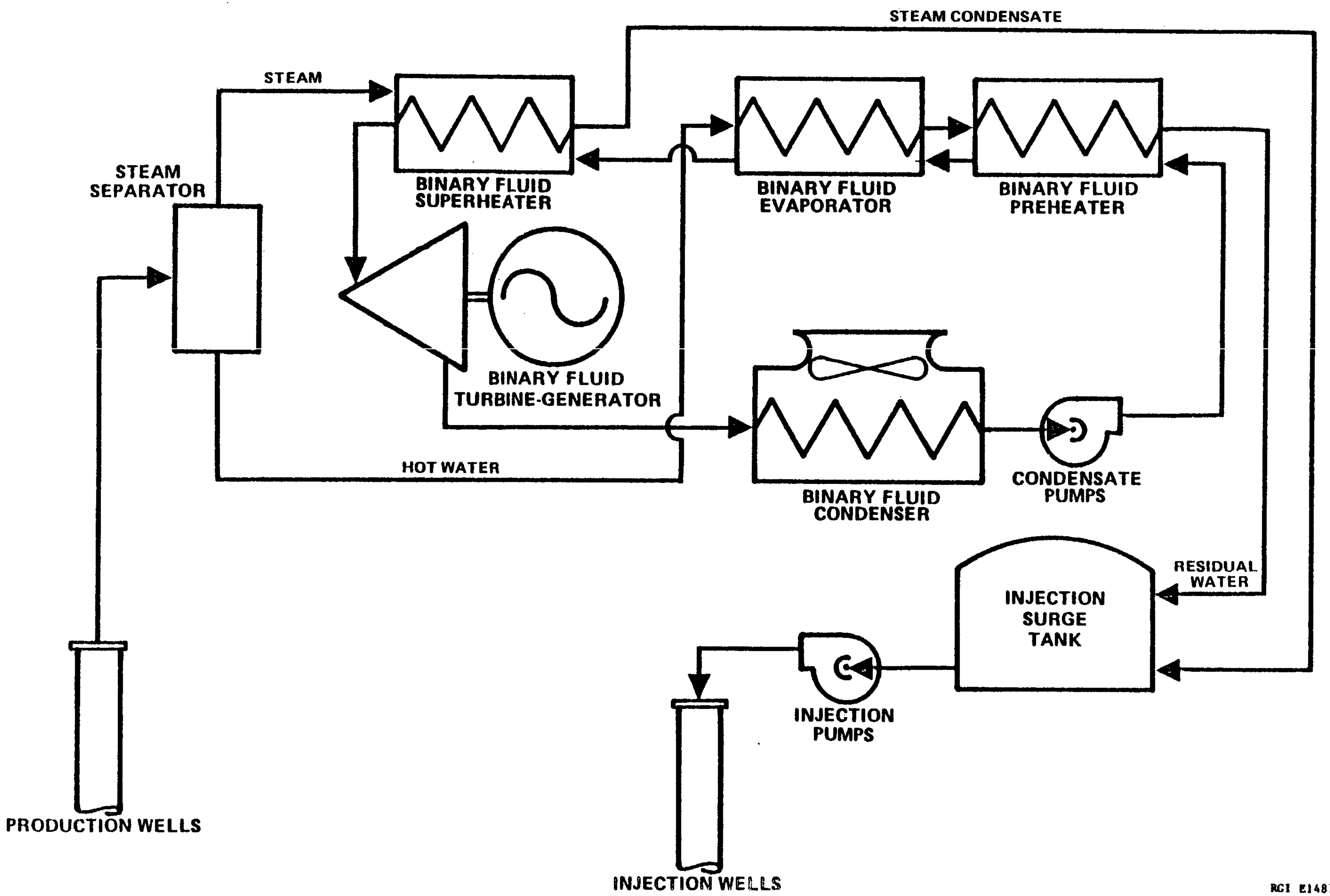
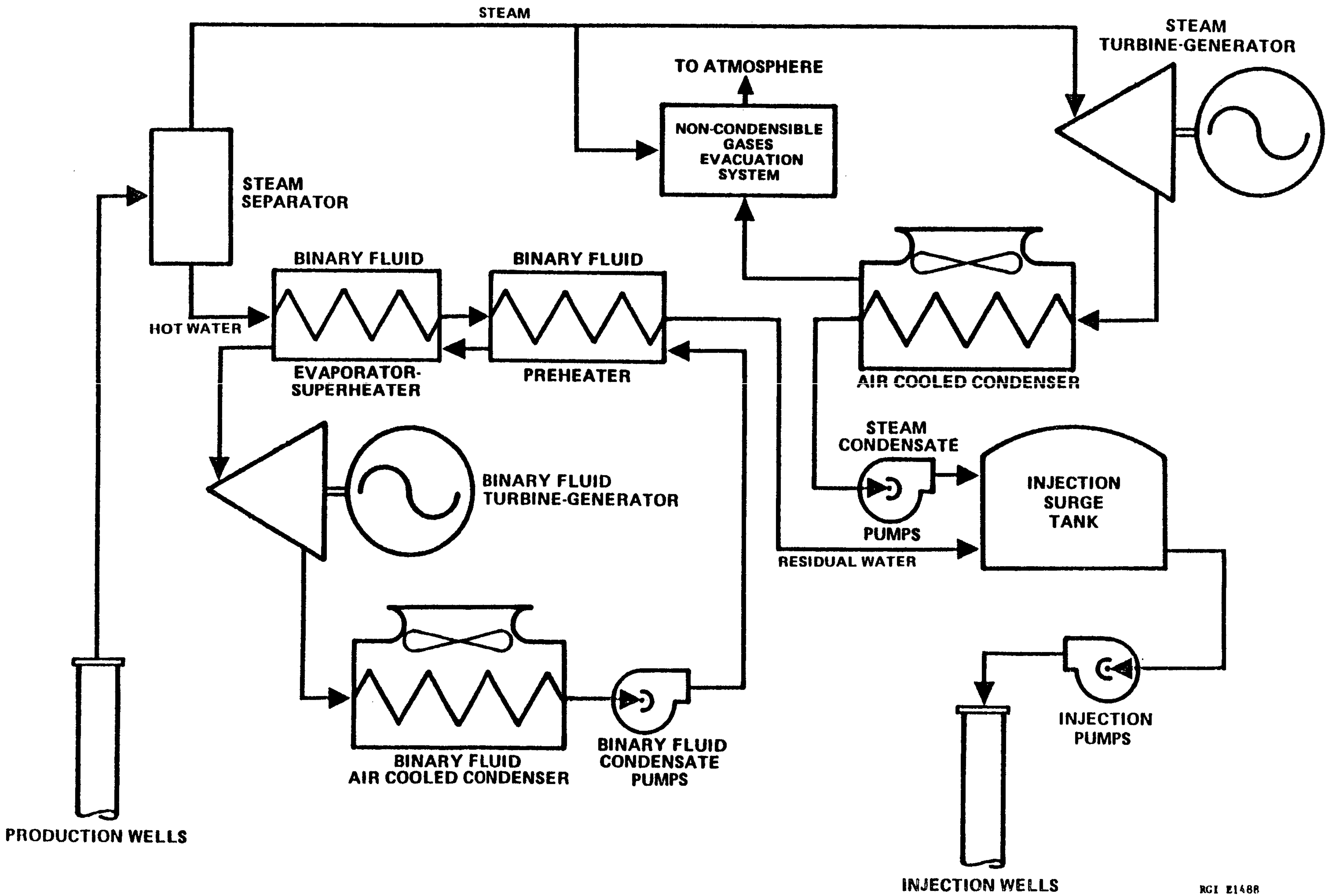


FIGURE 4
HYBRID PROCESS
SCHEMATIC FLOW DIAGRAM



Total Flow Process Description

Two-phase geothermal fluid produced by the wells is piped to a steam separator where the steam is separated from the geothermal water.

The steam is piped from the separator to the high-pressure inlet of a steam-turbine generator. The separated geothermal water is piped to a two-phase nozzle which converts the thermal and pressure energy of the expanded liquid and gas mixture to high efficiency fluid kinetic energy. The two-phase jet is directed tangentially on the inner surface of the rotary separator where steam and water are separated by centrifugal forces. A liquid turbine rotor mounted into the rotary separator converts the kinetic energy of the liquid to shaft power. The turbine shaft is connected to one end of the double-ended electric generator.

The resulting low-pressure steam from the rotary separator is piped to the low-pressure inlet of the steam turbine-generator where it is expanded together with the high-pressure steam to produce electric power. The exhaust steam from the turbine is then ducted to an extended-surface, air-cooled heat exchanger where it is condensed by rejecting heat to the atmosphere. Non-condensable gases are removed from the condenser by a combination of steam jet ejectors and liquid-ring vacuum pumps. Condensate pumps transfer the warm water from the condenser to an injection surge tank.

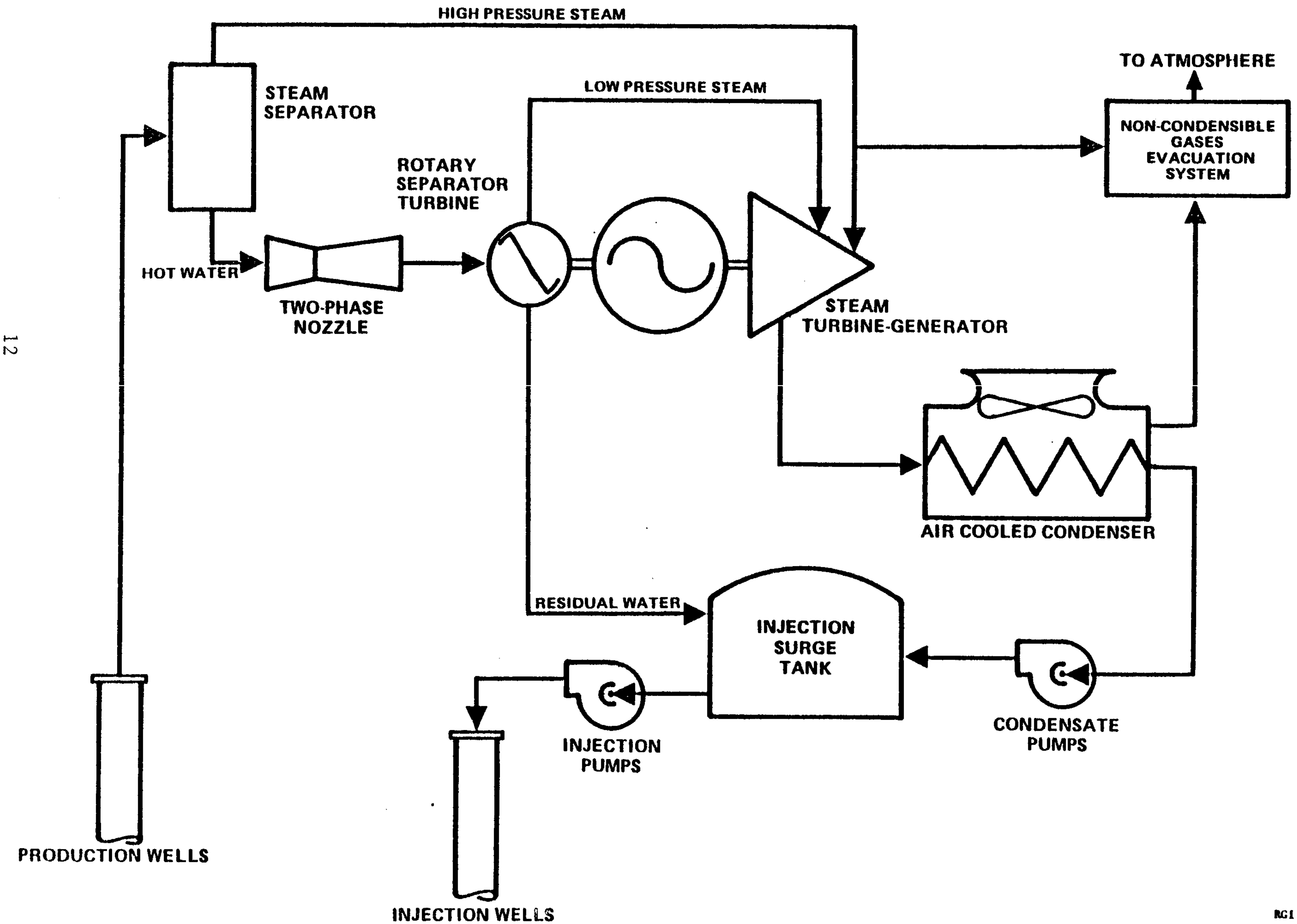
The residual geothermal water from the rotary separator flows into the injection surge tank where it is mixed with the condensate from the steam cycle. The water is then pumped out of the surge tank and injected back into the ground.

Figure 5 is a schematic flow diagram of the total flow process using a Biphase rotary separator.

While the Sprankle helical screw expander may be a viable candidate machine for conversion of geothermal energy by the total flow process, it is not considered in this study due to lack of available test data and to the large physical size required to produce significant power output.

However, should it be used, the geothermal fluid produced by the wells would be piped directly to the positive-displacement device which operates by direct expansion of the two-phase fluid meshing rotors. The fluid entering through a nozzle control valve into a high-pressure pocket is expanded through a pocket that elongates continually as the rotors revolve all the way down to the exhaust port.

FIGURE 5
TOTAL FLOW PROCESS
SCHEMATIC FLOW DIAGRAM



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POWER PLANT CONSTRUCTORS

Geothermal power plants can be designed, engineered, and constructed by Engineering-Construction (E&C) companies or by Equipment Manufacturing Companies.

1. Engineering-Construction

   Typically, E&C companies do not manufacture, but they do specify, select, and purchase the equipment which is integrated into the overall power plant design. Because of their large and diversified staff, E&C companies can select the optimum cycle for the resource as well as optimize and engineer any selected power cycle. While they do not warrant individual pieces of equipment used to construct the plant, they will ensure that the equipment manufacturers do so and will guarantee the overall plant performance and workmanship.

   The following is a short list of E&C companies having geothermal power plant experience.

   a. Large E&C Firms:

      Bechtel Power Corporation
      12400 E. Imperial Highway
      Norwalk, CA 90650
      Phone: (213) 864-6011
      Contact: Joseph A. Falcon

      Fluor Engineers and Constructors, Inc.
      3333 Michelson Drive
      Irvine, CA 92730
      Phone: (714) 975-6839
      Contact: Jake Easton III

      The Ralph M. Parsons Co.
      100 West Walnut St.
      Pasadena, CA 91124
      Phone: (213) 440-2000
      Contact: Roy E. Gaunt

      Gibbs and Hill, Inc.
      226 W. Brokaw Road
      San Jose, CA 95110
      Phone: (408) 280-7091
      Contact: Larry R. Krumland

      Morrison-Knudsen Co., Inc.
      P.O. Box 7808
      Boise, ID 83729
      Phone: (208) 386-5000
      Contact: Frank G. Turpin

b. Small E&C Firms:

The Ben Holt Co.
201 South Lake Ave.
Pasadena, CA 91101
Phone: (213) 684-2541
Contact: Clement B. Giles

Ultrasystems, Inc.
2400 Michelson Drive
Irvine, CA 92715
Phone: (714) 752-7500
Contact: Phillip J. Stevens

2. Equipment Manufacturers

Typically Equipment Manufacturers, generally turbine-generator and/or heat exchanger manufacturers, prepackage power module assemblies incorporating their own equipment into the overall power plant design. Because most equipment manufacturers specialize in one segment of the industry, they can only offer one type of power cycle which may or may not be optimum for the resource. The following is a short list of equipment manufacturing companies that design, engineer, and build geothermal power plants:

a. Equipment Manufacturers for Flash Steam Plants

General Electric Company
1100 Western Ave.
Lynn, MA 01910
Phone: (617) 594-4146
Contact: Howard C. Spears

Fuji Electric Company, Ltd./Nissho Iwai American Corp.
Broadway Plaza, Suite 1900
700 South Flower St.
Los Angeles, CA 90017
Phone: (213) 688-0671
Contact: Mikio (Michael) Ikukawa

Mitsubishi International Corp.
555 South Flower St.
Los Angeles, CA 90071
Phone: (213) 977-3767
Contact: Sam Miyamoto

Toshiba International Corp.
465 California St., Suite 430
San Francisco, CA 94104
Phone: (415) 434-2340
Contact: Hisashi Ohtsuka

b. Equipment Manufacturers for Binary and Hybrid Plants

Ormat Systems Inc.
168 Sendra Ave.
Arcadia, CA 91006
Phone: (213) 445-4202
Contact: H. Ram

Mechanical Technology Inc.
968 Albany-Shaker Road
Latham, NY 12110
Phone: (518) 785-2400
Contact: Thomas E. Williams

Barber-Nichols Engineering
6325 West 55th Avenue
Arvada, CO 80002
Phone: (303) 421-8111
Contact: Kenneth Nichols

c. Equipment Manufacturers for Total Flow Plants

Biphase Energy Systems
2800 Airport Ave.
Santa Monica, CA 90405
Phone: (213) 391-0691
Contact: Donald J. Cerini

Hydrothermal Power Co., Ltd.
P.O. Box 2794
Mission Viejo, CA 92690
Phone: (714) 837-3081
Contact: Roger Spankle

LOAD FORECASTS

The electrical load forecasts for Unalaska and Dutch Harbor have recently been developed as part of a reconnaissance study for the Alaska Power Authority by Acres American Inc. As requested by the Alaska Power Authority, only the "No-Bottomfish Development" case and the "Low-Bottomfish Catch" case are being considered in this study. Figures 6 and 7 show the average and maximum power demand estimated by Acres American Inc. for these two cases.

The average power demand, which is calculated by dividing the annual energy use by 8760 hours, is less than 30 percent of the maximum power demand, indicating possible large seasonal and/or daily demand variations. Discussion with Mr. Jeff Currier of Unalaska Public Utility to clarify this matter seems to disprove this interpretation of the data. While the calculated average power demand appears to be representative of the expected base load demand for the electrical system, he does expect this base load demand to be less than approximately 60 percent of maximum power demand.

In the absence of load duration curves showing daily and seasonal variations in estimated load demand, it is therefore assumed that the electrical system base load demand is the average load demand estimated by Acres and that it is 60 percent of the system peak load demand. Figures 8 and 9 show both base load and peak load demands assumed for the two cases under study.

FIGURE 6

NO BOTTOMFISH DEVELOPMENT CASE AVERAGE AND MAXIMUM POWER DEMANDS AS ESTIMATED BY ACRES AMERICAN INC.

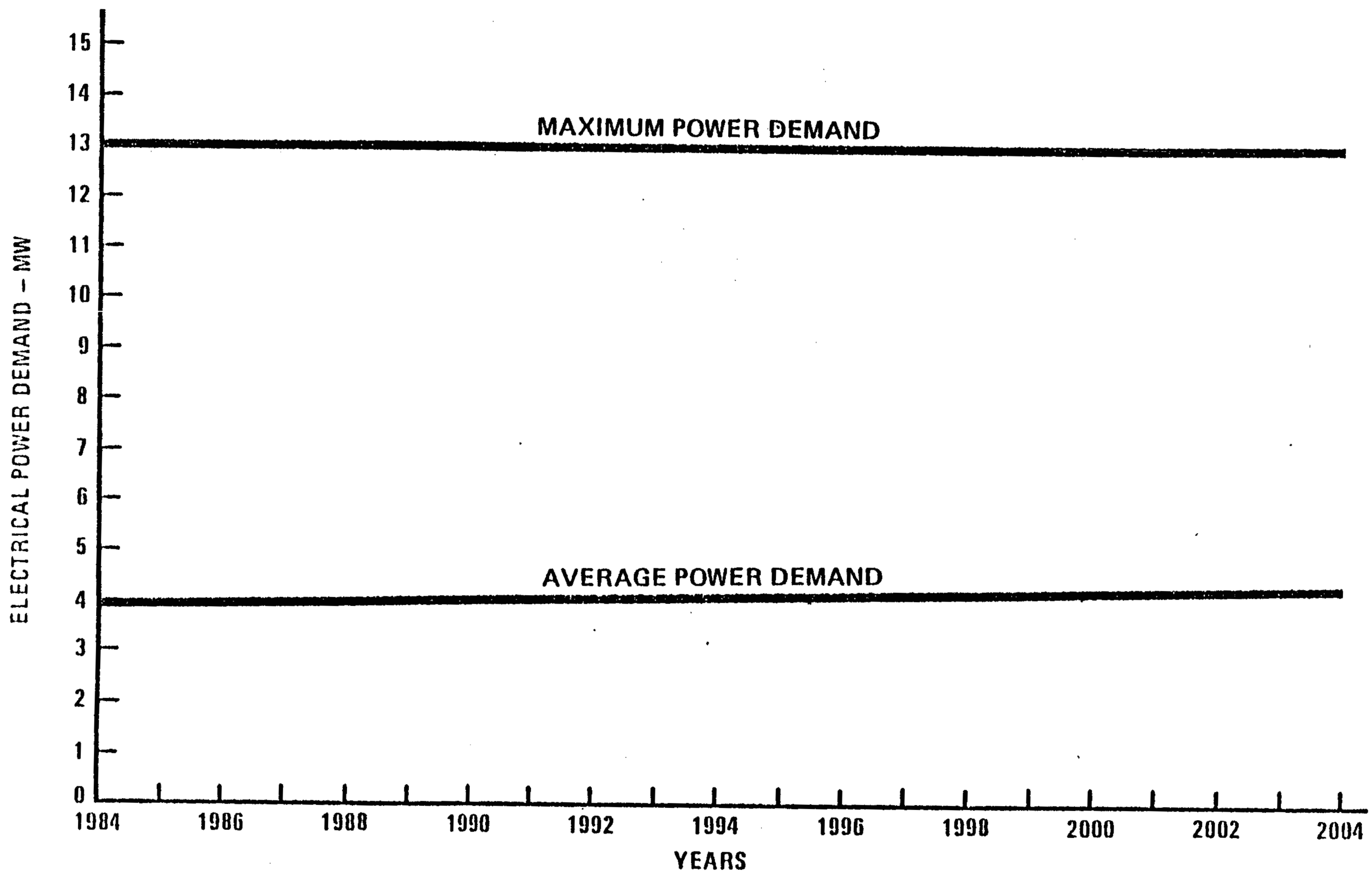

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FIGURE 7

LOW BOTTOM FISH CATCH CASE AVERAGE AND MAXIMUM POWER DEMANDS AS ESTIMATED BY ACRES AMERICAN INC.

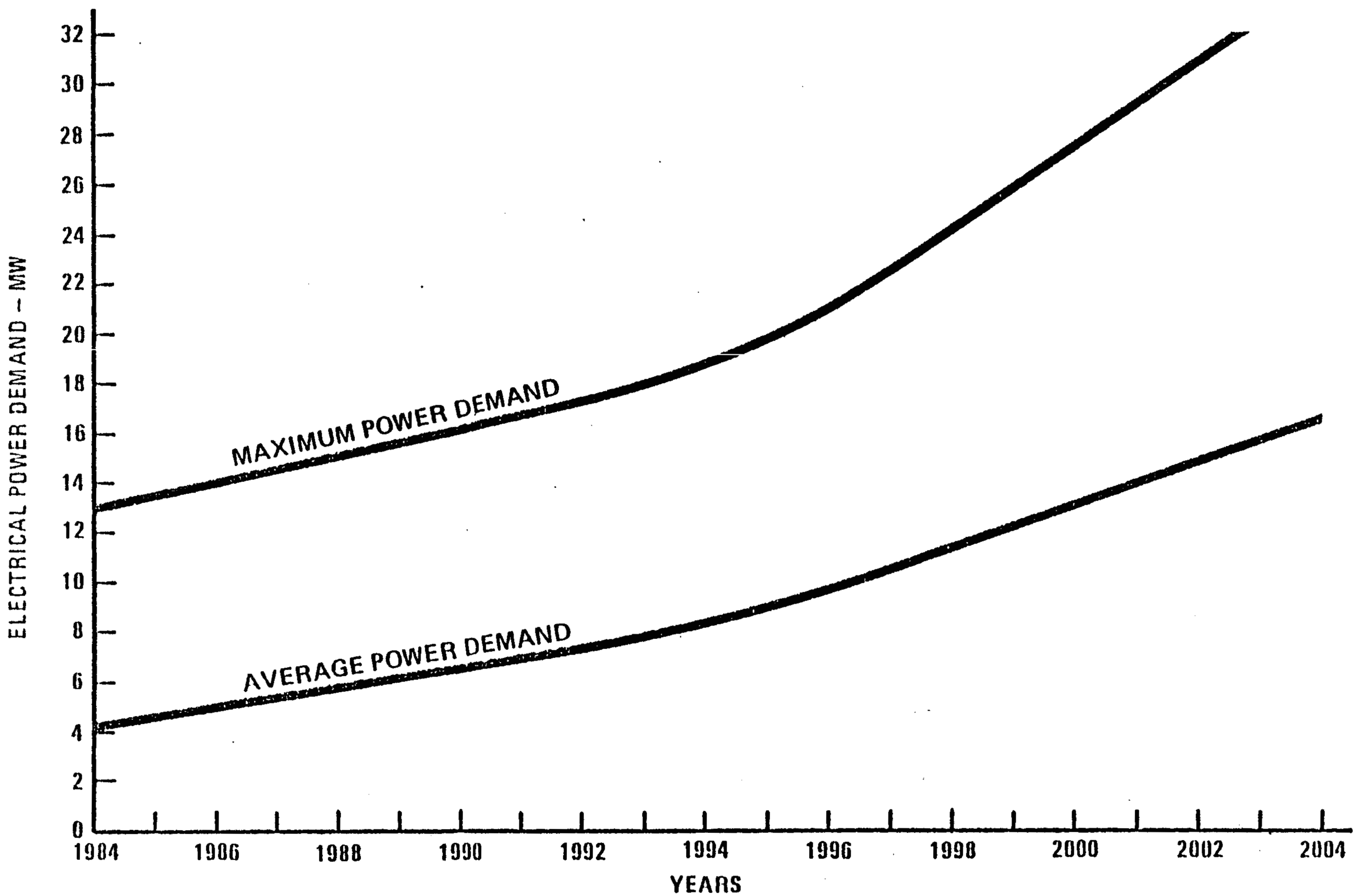

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FIGURE 8

NO BOTTOMFISH DEVELOPMENT CASE ELECTRICAL SYSTEM LOAD DEMANDS

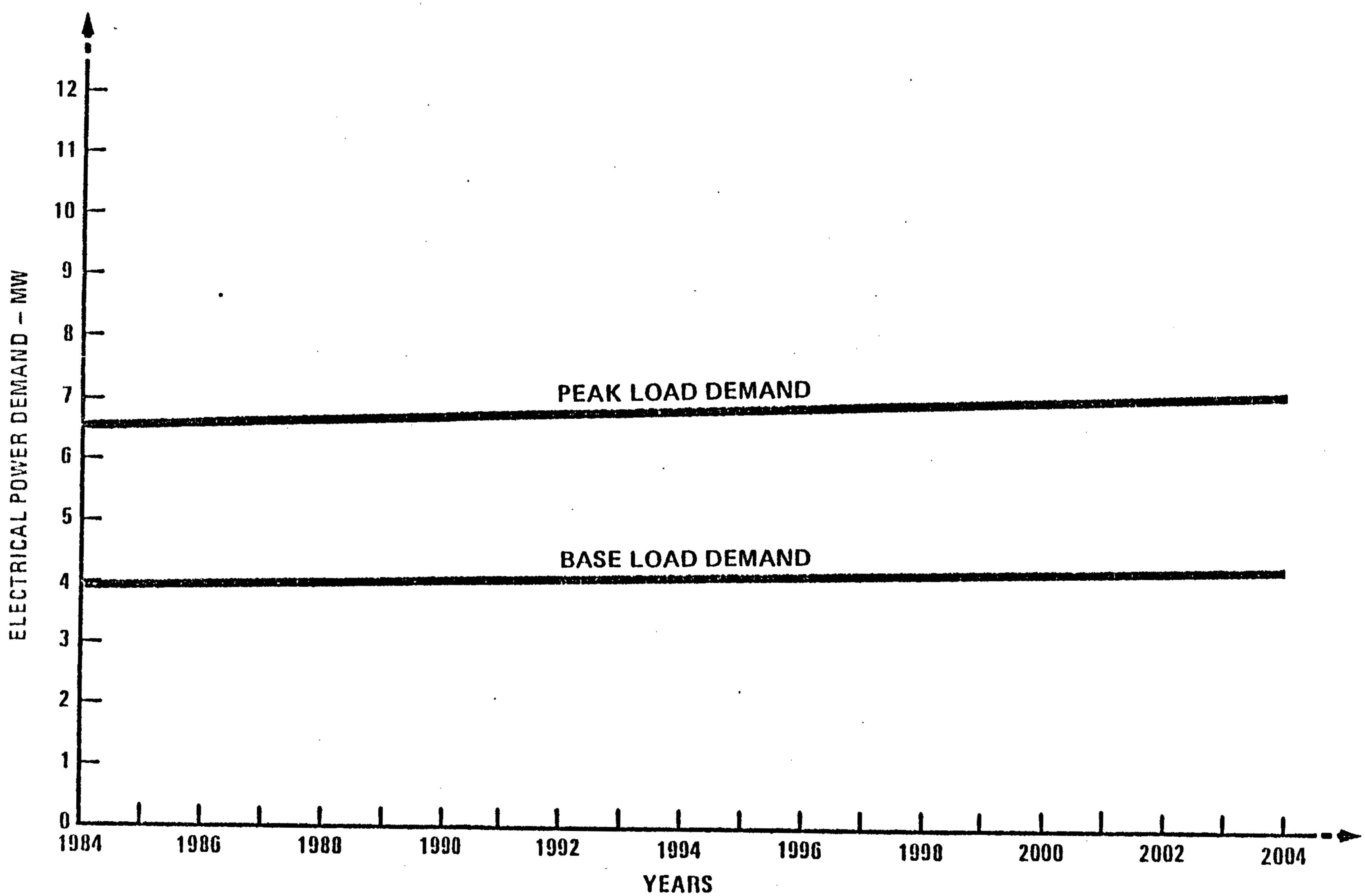

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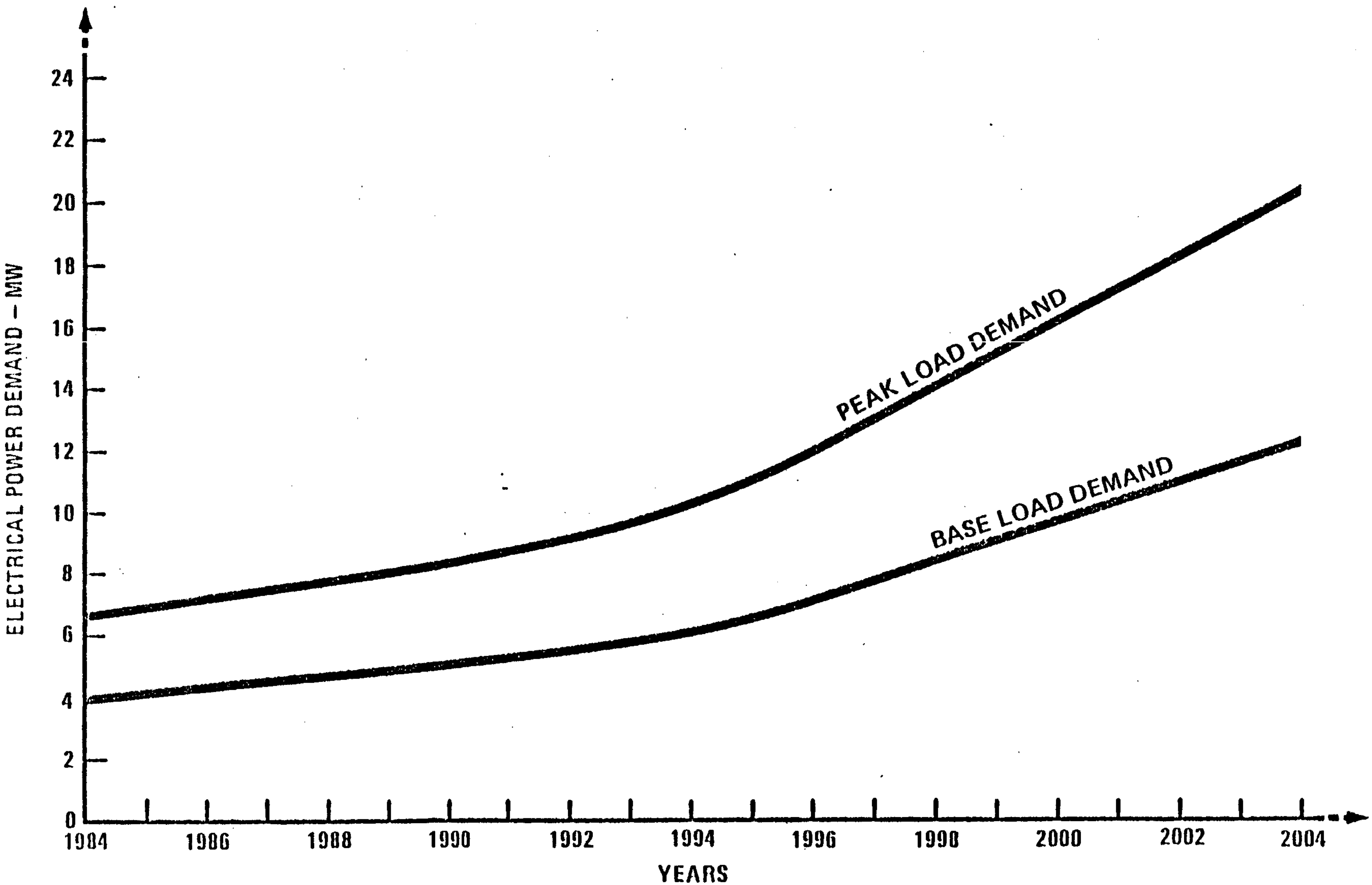
FIGURE 9

LOW BOTTOMFISH CATCH CASE ELECTRICAL SYSTEM LOAD DEMANDS



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UNIT SIZING AND SCHEDULING

It is anticipated that a geothermal power plant would be intertied with a planned conventional power plant to supply the electrical power needs of Unalaska and Dutch Harbor. The conventional power plant will consist of four 2.5 MW diesel generators and is scheduled to begin commercial operation in early 1987. To allow for orderly planning of financing, field development, and power plant/transmission line engineering and construction, the geothermal power plant would be scheduled to begin commercial operation in January 1989. Upon completion, the geothermal power plant would primarily provide base load power while the diesel generators would provide peak load and emergency power should the geothermal power plant be partially or totally disabled.

Due to the remoteness of the geothermal construction site, the difficult site access and the need for high reliability, the geothermal power plant would be unitized. The size, number and phasing schedule of the geothermal units for each of the power conversion processes studied are determined as follows:

1. Unit Sizing

   Economical size of the units is determined by an evaluation of commercially available units. To minimize field erection and start-up operations, only units that can be completely or partially shop-assembled and tested in modules are considered. Modules are sized to be truck-transportable on both main throughfares and unpaved gravel roads.

2. Determination of number of units and commercial operation schedule.

   The Number of units required to meet power demand forecasts and the commercial operation schedule for these units are determined by superimposing the net generating capacity of all units over the estimated power demands. During "normal operation", which is when all installed units are available for power generation, the net generating capacity of the geothermal units will always be kept above the electrical system base load demand. During "emergency operation", which is when the largest installed unit is down for maintenance and the second largest installed unit is down on emergency trip, the net generating capacity of all remaining units will always be kept above the electrical system peak load demand.

In order to meet the electrical system load demands estimated up to the year 2000 for both the "No-Bottomfish Development" and "Low-Bottomfish Catch" cases, a geothermal power plant using any one of the five different power conversion cycles studied could be used to meet the criteria described above.

1. No-Bottomfish Development Case.

    a. Single or double flash steam cycles.

        One 5 MW net unit to be commercial in January 1989 and one 5 MW net unit to be commercial in January 2000.

    b. Binary cycle.

        Two 3.35 MW net units to be commercial in January 1989.

    c. Hybrid cycle.

        Three 3.35 MW net (1 steam and two binary) units to be commercial in January 1989.

    d. Total flow cycle.

        One 5 MW net unit to be commercial in January 1989 and one 5 MW net unit to be commercial in January 2000.

2. Low-Bottomfish Catch Case.

    a. Single or double flash steam cycles.

        Two 5 MW net units to be commercial in January 1989, one 5 MW net unit to be commercial in January 1993, and one 5 MW net unit to be commercial in January 1998.

    b. Binary cycle.

        Two 3.35 MW net units to be commercial in January 1989, two 3.35 MW net units to be commercial in January 1993, and two 3.35 MW net units to be commercial in January 2000.

    c. Hybrid cycle.

        Three 3.35 MW net (1 steam and two binary) units to be commercial in January 1989 and three 3.35 MW net units to be commercial in January 1997.

    d. Total flow cycle.

        Two 5 MW net units to be commercial in January 1989, two 5 MW net units to be commercial in January 1993, and two 5 MW net units to be commercial in January 1998.

Figures 10 through 15 show the power generation development schedule, the power generation during normal operation, and the power generation during emergency operation for both the "no bottomfish development" and "low bottomfish catch" cases for an electrical power system with a geothermal power plant using a binary cycle.

FIGURE 10

NO BOTTOMFISH DEVELOPMENT CASE
POWER GENERATION DEVELOPMENT SCHEDULE

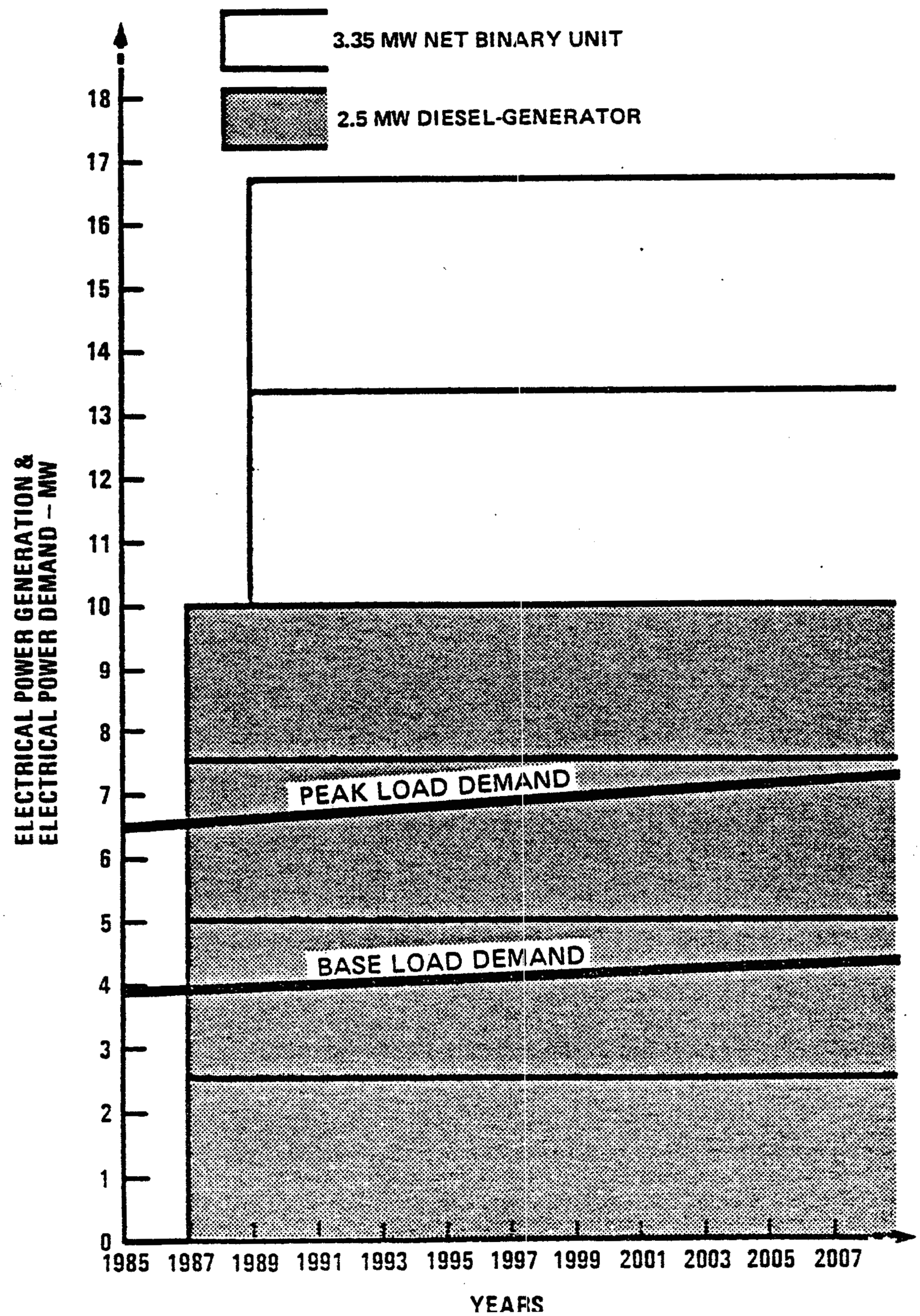

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FIGURE 11

NO BOTTOMFISH DEVELOPMENT CASE
POWER GENERATION–NORMAL OPERATION
ALL UNITS AVAILABLE

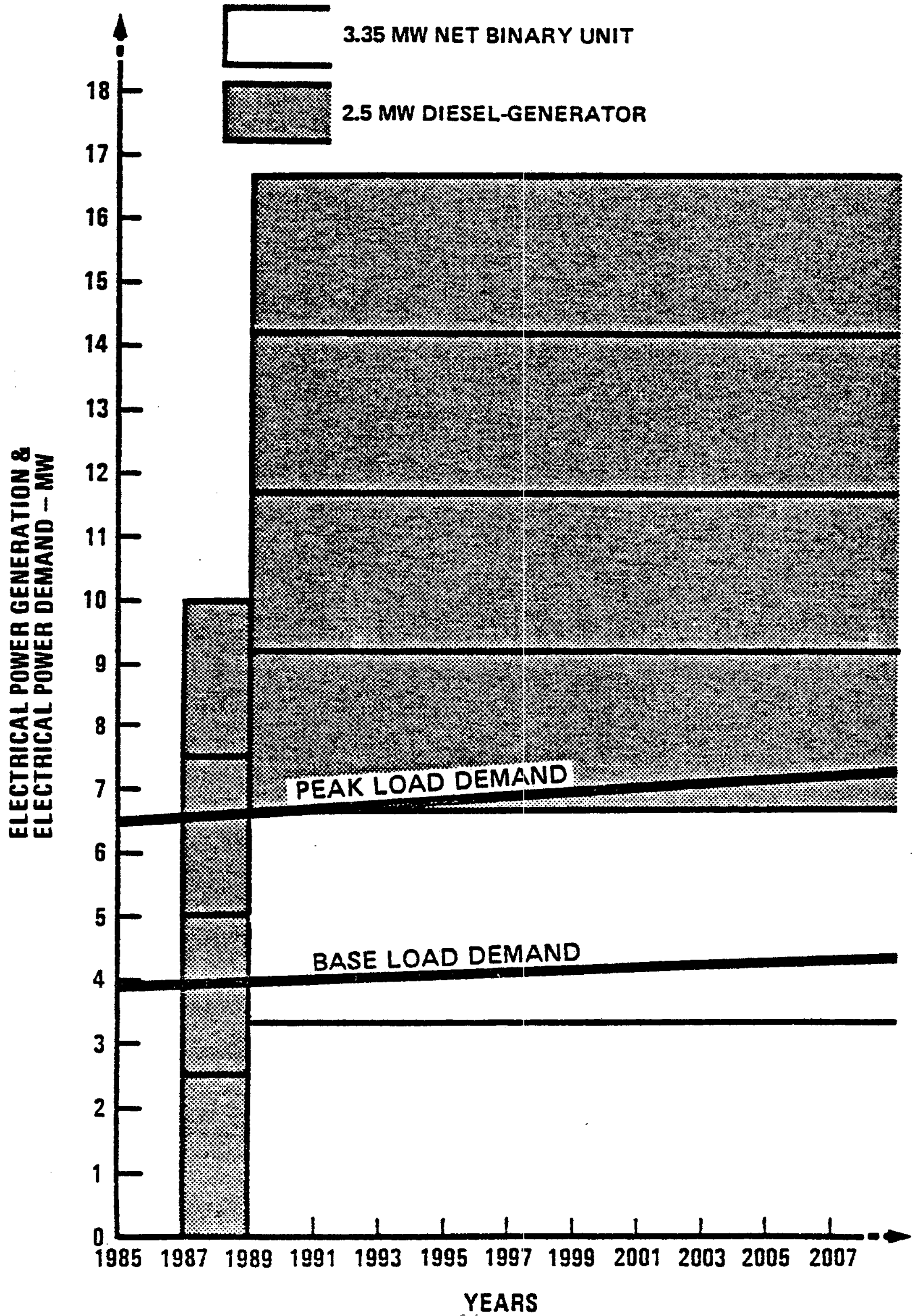

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FIGURE 12

NO BOTTOMFISH DEVELOPMENT CASE POWER GENERATION–EMERGENCY OPERATION LARGEST UNIT DOWN AND SECOND LARGEST UNIT TRIPPED

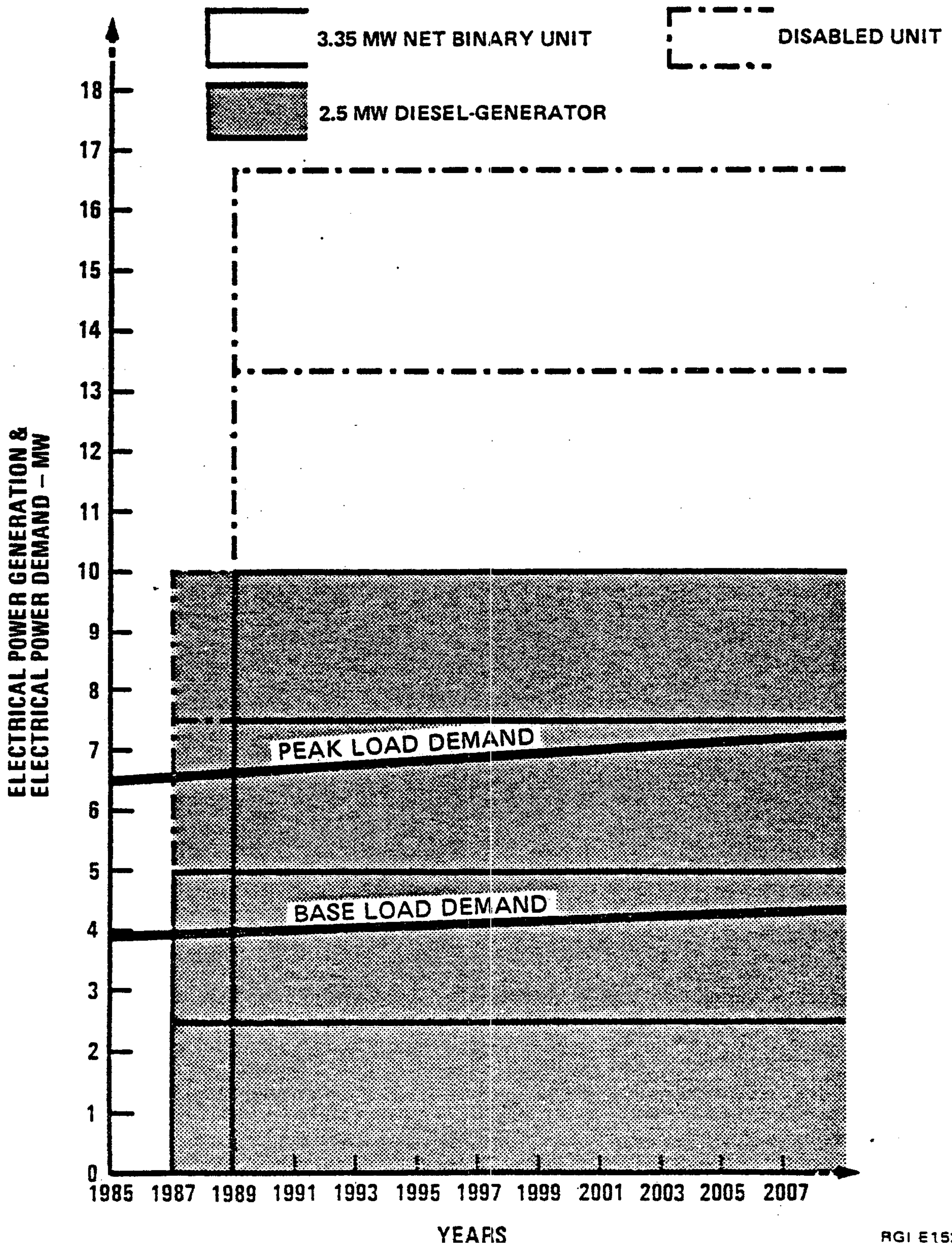

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FIGURE 13

LOW BOTTOMFISH CATCH CASE
POWER GENERATION DEVELOPMENT SCHEDULE

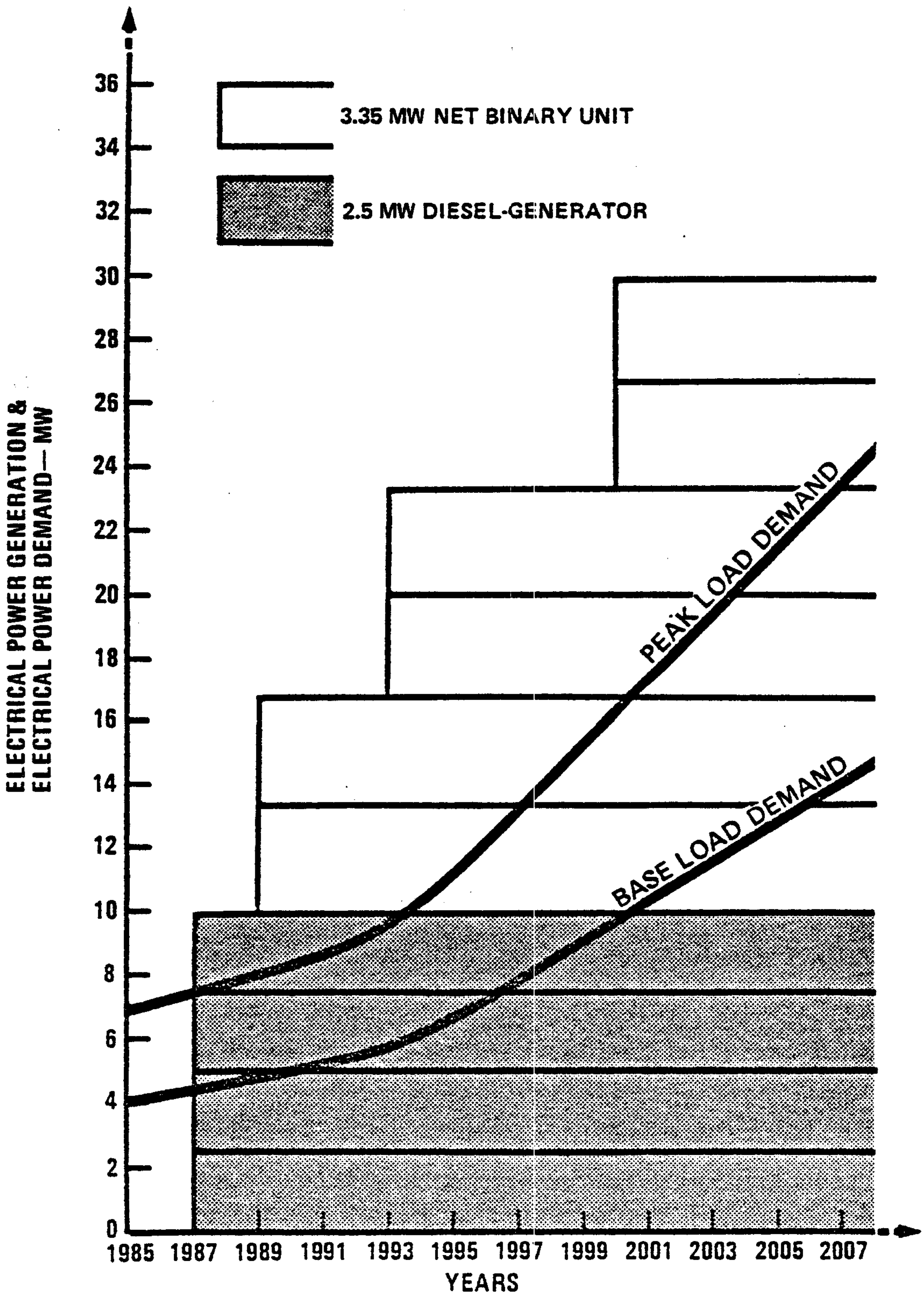

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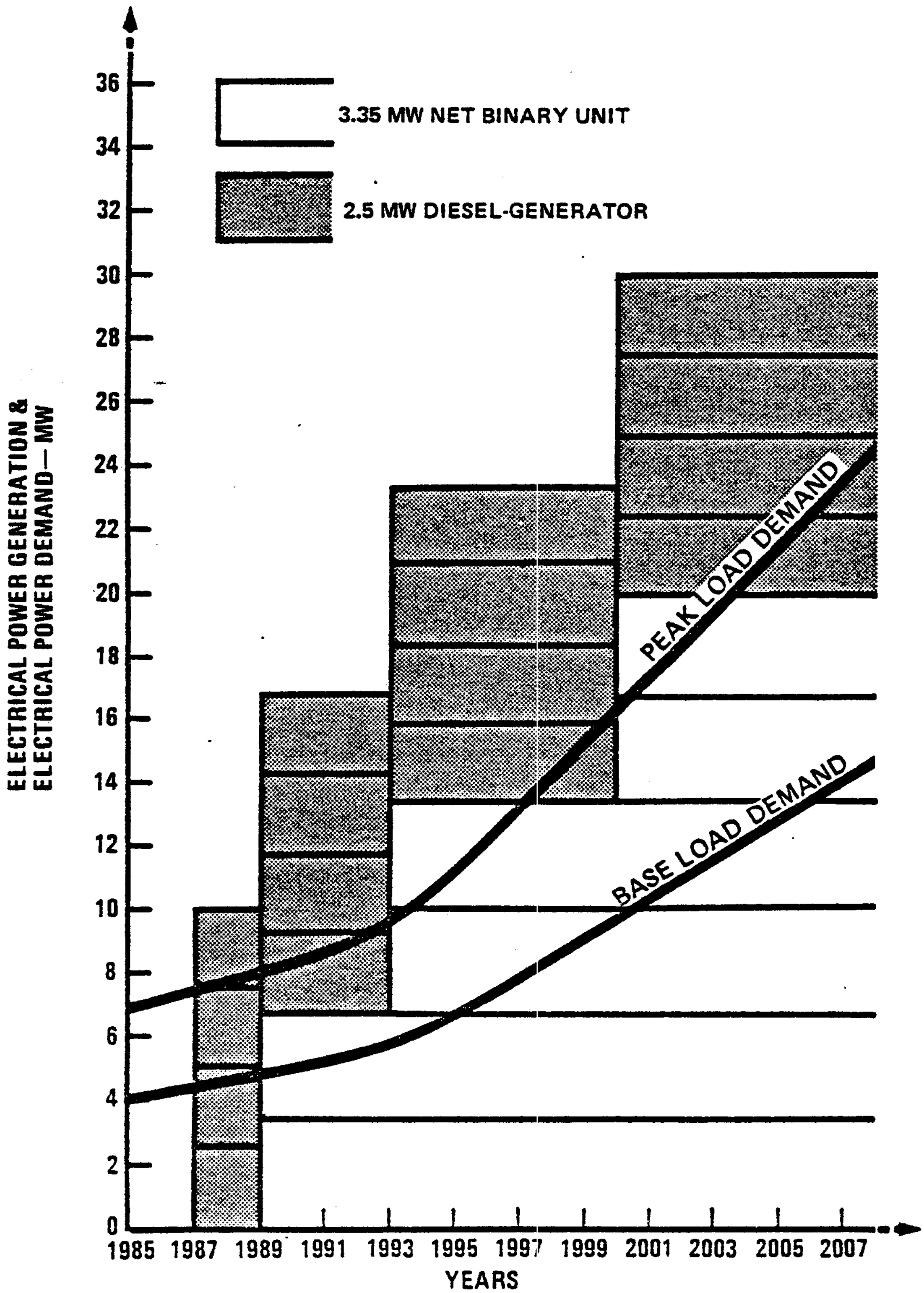
FIGURE 14

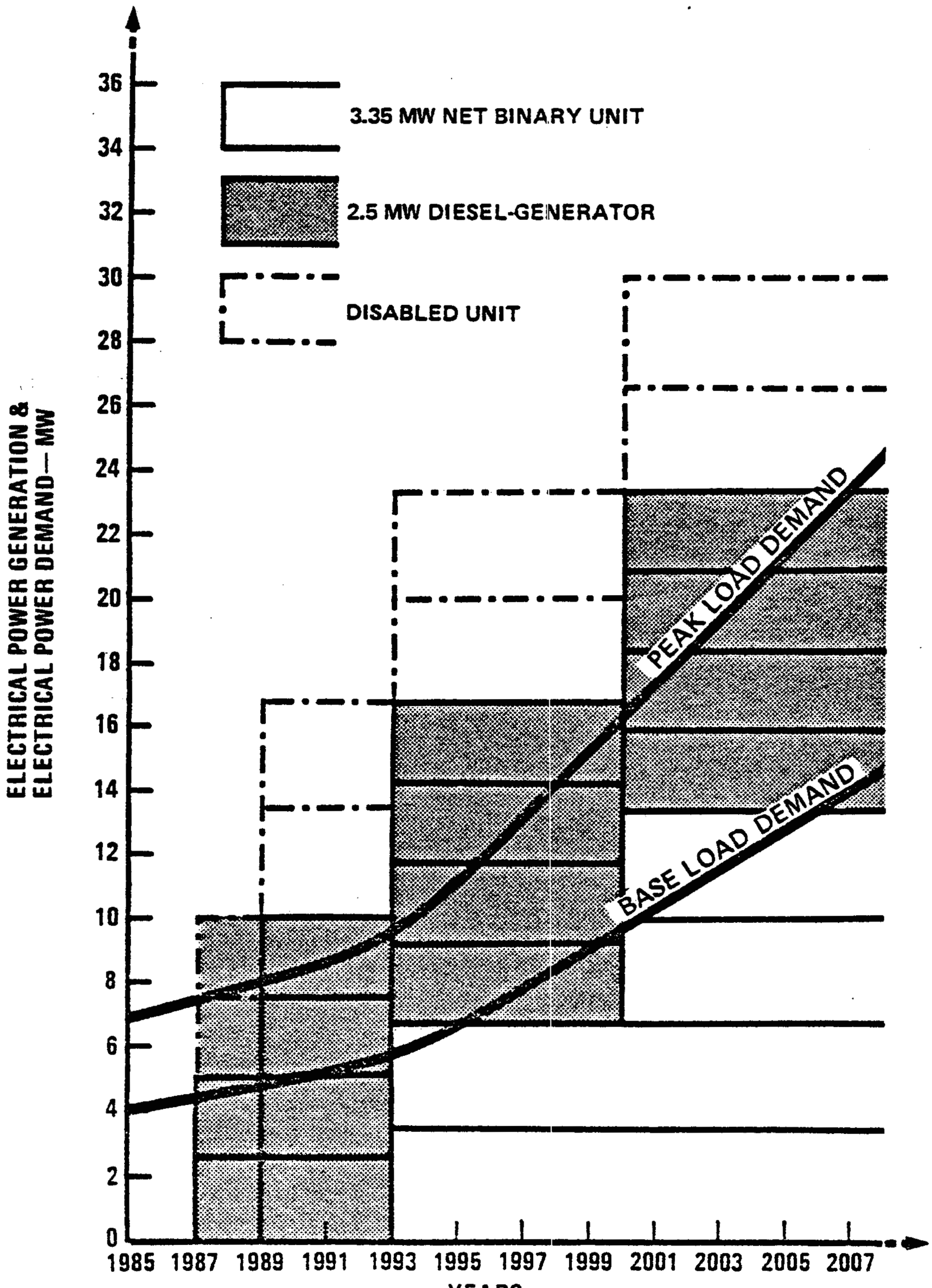
LOW BOTTOMFISH CATCH CASE
POWER GENERATION–NORMAL OPERATION
ALL UNITS AVAILABLE



RGI E1529

FIGURE 15

LOW BOTTOMFISH CATCH CASE POWER GENERATION-EMERGENCY OPERATION LARGEST UNIT DOWN FOR MAINTENANCE AND SECOND LARGEST UNIT TRIPPED



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GEOTHERMAL POWER DEVELOPMENT TECHNICAL CHARACTERISITICS

The technical characteristics of each geothermal power development alternative considered for both the "No-Bottomfish Demand" and Low-Bottomfish Catch" cases are shown on Tables 1 and 2. Each power development alternative includes both the power plant and the associated field development. The basis used in developing the power development technical matrices is defined below:

1. The electrical power generation capacity of each alternate power plant is determined by matching economically sized units to the power load demands estimated beyond the year 2000 for the electrical system, as described in the previous section "Unit Sizing and Scheduling."

2. Due to the low average dry-bulb temperature of the air on Unalaska Island, a direct dry cooling system is incorporated into all alternative cycles. In a dry cooling system the heat to be rejected from the power cycle is transferred through the walls of an air-cooled heat exchanger directly to the ambient air stream. Use of this system allows for 100 percent geothermal fluid reinjection and eliminates the need for an outside source of water.

3. Customarily a power plant is designed for a constant output that can be assured year-around, as determined by the capacity of the heat rejection system at reasonable worst-case conditions. Alternatively, a power plant can be designed to allow for a power output that will vary as the capacity of the waste heat rejection system is affected by ambient conditions. This variable output concept is termed "floating" power.

   The thermodynamic properties of steam are not compatible with the variable output mode creating excessive in costs and efficiencies. Therefore, all steam flash alternatives are designed for a constant output mode based on a 50°F dry-bulb ambient temperature.

   The thermodynamic properties of organic hydrocarbons or fluocarbons do allow turbines to operate over a wide range of back pressure with only minor reductions of peak efficiencies; therefore, all binary alternatives have been designed for a floating output mode based on an average 30°F dry bulb ambient temperature.

4. As described in the "Unit Sizing and Scheduling" section, each power plant unit is comprised of completely or partially shop-assembled and tested modules. This modular approach facilitates field erection and start-up as well as transportation. It has been assumed that modules would be barged from the mainland to Driftwood Bay where they would be unloaded and trucked to the construction site.

TABLE 1

NO-BOTTOMFISH DEVELOPMENT CASE
GEOTHERMAL POWER DEVELOPMENT TECHNCIAL MATRIX

	Single Flash Steam Plant	Double Flash Steam Plant	Binary Plant	Hybrid Plant	Total Flow Plant
Power Plant Gross Power Generation Capacity	11.2 MW	11.5 MW	10 MW	14 MW	11.5 MW
Power Plant Net Power Generation Capacity	10 MW	10 MW	6.7 MW	10 MW	10 MW
Power Plant Heat Rejection Type	Dry Cooling	Dry Cooling	Dry Cooling	Dry Cooling	Dry Cooling
Power Plant Design Ambient Temperature	50°F	50°F	30°F	50°F(steam unit) 30°F(binary units)	50°F
Power Plant Construction Type	Modular	Modular	Modular	Modular	Modular
Shop Assembly	Maximum	Maximum	Maximum	Maximum	Maximum
Field Construction	Minimum	Minimum	Minimum	Minimum	Minimum
Transportation	Barge & Truck	Barge & Truck	Barge & Truck	Barge & Truck	Barge & Truck
Power Plant Operation	Constant Output	Constant Output	Floating Output	Floating Output	Constant Output
Number of Power Generation Units	2	2	2	3 (1 steam + 2 binary)	2
Largest Module	Turbine-Generator Sets	Turbine-Generator Sets	Heat Exchangers	Heat Exchangers and Steam Turbine-Generator Sets	Turbine-Generator Sets
Weight of Heaviest Module	130,000 lb	145,000 lb	120,000 lb	120,000 lb	213,000 lb
Maximum Net Power Generation Potential of Average Production Well	4.35 MW	5.5 MW	6.1 MW	6.75 MW	5.8 MW
Minimum Geothermal Fluid FLow Required per Net kw of Power Generation	206.9 lb/hr	163.6 lb/hr	143.4 lb/hr	133.3 lb/hr	155.2 lb/hr
Minimum Total Geothermal Fluid Flow Required andCorresponding Wellhead Pressure	2,069,000 lb/hr at 57 psia	1,636,000 lb/hr at 57 psia	961,000 lb/hr at 59 psia	1,333,000 lb/hr at 57 psia	1,552,000 lb/hr at 57 psia
Minimum Number of Production Wells Required	2.3	1.82	1.1	1.48	1.72
Number of Production Wells Provided	3	2	2	2	2
Average Flow per Production Well	690,000 lb/hr	815,000 lb/hr	365,000 lb/hr	665,000 lb/hr	775,000 lb/hr
Production Wellhead Pressure	75 psia	65 psia	96 psia	77 psia	68 psia
Production Wellhead Temperature	308°F	298°F	325°F	309°F	301°F
Percent Reinjection	100%	100%	100%	100%	100%
Minimum Number of Injection Wells Required	1.15	.91	.53	.74	.86
Number of Injection Wells Provided	2	1	1	1	1
Average Flow per Injection Well	1,035,000 lb/hr	1,636,000 lb/hr	961,000 lb/hr	1,333,000 lb/hr	1,552,000 lb/hr
Injection Wellhead Pressure	Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric
Injection Wellhead Temperature	260°F	200°F	170°F	170°F	200°F
Waste Discharge to Atmosphere	476 lb/hr Noncondensable Gases	376 lb/hr Noncondensable Gases	221 lb/hr Noncondensable Gases	307 lb/hr Noncondensable Gases	357 lb/hr Noncondensable Gases
Expected Reliability	High	High	High	High	High
Expected Substainable Capacity Factor	85%	85%	85%	85%	85%

TABLE 2

LOW-BOTTOMFISH CATCH CASE
GEOTHERMAL POWER DEVELOPMENT TECHINCIAL MATRIX

	Single Flash Steam Plant	Double Flash Steam Plant	Binary Plant	Hybrid Plant	Total Flow Plant
Power Plant Gross Power Generation Capacity	22.4 MW	23 MW	30 MW	28 MW	23 MW
Power Plant Net Power Generation Capacity	20 MW	20 MW	20 MW	20 MW	20 MW
Power Plant Heat Rejection Type	Dry Cooling	Dry Cooling	Dry Cooling	Dry Cooling	Dry Cooling
Power Plant Design Ambient Temperature	50°F	50°F	30°F	50°F(steam unit) 30°F (binary unit)	50°F
Power Plant Construction Type	Modular	Modular	Modular	Modular	Modular
Shop Assembly	Maximum	Maximum	Maximum	Maximum	Maximum
Field Construction	Minimum	Minimum	Minimum	Minimum	Minimum
Transportation	Barge & Truck	Barge & Truck	Barge & Truck	Barge & Truck	Barge & Truck
Power Plant Operation	Constant Output	Constant Output	Floating Output	Floating Output	Constant Output
Number of Power Generation Units	4	4	6	6(2 steam + 4 binary)	4
Largest Module	Turbine-Generator Sets	Turbine-Generator Sets	Heat Exchangers	Heat Exchangers and Steam Turbine-Generator Sets	Turbine-Generator Sets
Weight of Heaviest Module	130,000 lb	145,000 lb	120,000 lb	120,000 lb	213,000 lb
Maximum Net Power Generation Potential of Average Production Well	4.35 MW	5.5 MW	6.1 MW	6.75 MW	5.8 MW
Minimum Geothermal Fluid Flow Required per Net kw of Power Generation	206.9 lb/hr	163.6 lb/hr	143.4 lb/hr	133.3 lb/hr	155.2 lb/hr
Minimum Total Geothermal Fluid Flow Required and Corresponding Wellhead Pressure	4,138,000 lb/hr at 57 psia	3,272,000 lb/hr at 57 psia	2,883,000 lb/hr at 59 psia	2,666,000 lb/hr at 57 psia	3,104,000 lb/hr at 57 psia
Minimum Number of Production Wells Required	4.6	3.64	3.3	2.96	3.45
Number of Production Wells Provided	5 + 1 standby	4 + 1 standby	4 + 1 standby	3 + 1 standby	4 +1 standby
Average Flow per Production Well	825,000 lb/hr	815,000 lb/hr	595,000 lb/hr	890,000 lb/hr	775,000 lb/hr
Production Wellhead Pressure	64 psia	65 psia	82 psia	58 psia	68 psia
Production Wellhead Temperature	297°F	298°F	314°F	291°F	301°F
Percent Reinjection	100%	100%	100%	100%	100%
Minimum Number of Injection Wells Required	2.3	1.82	1.6	1.48	1.72
Number of Injection Wells Provided	3 + 1 standby	2 +1 standby	2 +1 standby	2 +1 standby	2 + 1 standby
Average Flow per Injection Well	1,379,000 lb/hr	1,636,000 lb/hr	1,442,000 lb/hr	1,333,000 lb/hr	1,552,000 lb/hr
Injection Wellhead Pressure	Atmospheric	Atmospheric	Atmospheric	Atmospheric	Atmospheric
Injection Wellhead Temperature	260°F	200°F	170°F	170°F	200°F
Waste Discharge to Atmosphere	952 lb/hr Noncondensable Gases	752 lb/hr Noncondensable Gases	663 lb/hr Noncondensable Gases	614 lb/hr Noncondensable Gases	714 lb/hr Noncondensable Gases
Expected Reliability	High	High	High	High	High
Expected Sustainable Capacity Factor	85%	85%	85%	85%	85%

5. The maximum net power generation potential of an average production well, the minimum geothermal fluid flow required per net kw of power generation, the minimum total geothermal fluid flow required and the minimum number of production wells required are derived from curves shown in Figures 16 through 20 where the wellhead pressure vs flow rate curve for a commercial well with 13-3/8 inch casing is cross-plotted with electricity generation curve for the various power cycles studied. To stay within safe operating conditions, the well flow and wellhead pressure have been limited to 900,000 lb/hr and 57 psia respectively.

6. The average flow per production well, the production wellhead pressure and the production wellhead temperature are derived from the number of operating production wells provided. No-bottomfish development case power development does not include any dedicated spare production well as it cannot be economically justified. However, the "low-bottomfish catch" case power development does include one dedicated spare production well.

7. The number of injection wells required is based on the assumption that one injection well will be able to dispose of 1,800,000 lb/hr of cooled geothermal fluid at atmospheric wellhead pressure.

8. The average flow per injection well is derived from the number of operating injection wells provided. No-bottomfish development case power development does not include any dedicated spare injection well as it cannot be justified economically. However, the "low-bottomfish catch" case power development does include one dedicated spare injection well.

9. Waste discharge to atmospheric assumes total removal of the non-condensable gases contained in the geothermal fluid. Analysis of gas samples collected during the Makushin ST-1 test indicate, that very low initial concentrations of noncondensable gases (approximately .023 percent by weight) can be expected. The gases are predominantly CO_2(94%), plus H_2(5%), with traces of H_2S, NH_3, H_2, Ar, CH_4, and He. They should therefore, not pose any problems in the conversion cycles and can be directly discharged to atmosphere.

10. The composition of liquids produced from the Makushin Resource is given in the Unalaska Geothermal Exploration Project Phase II Final Report. The geothermal fluid, averaging approximately 6,000 ppm total dissolved solids (TDS), is not expected to be corrosive or to pose any scaling problems, thus allowing for use of standard construction materials. Because of the benign nature of the fluid, filtration is not expected to be required prior to reinjection of the spent fluid.

FIGURE 16

POTENTIAL NET POWER GENERATION OF AVERAGE PRODUCTION WELL WHEN USING SINGLE FLASH STEAM CYCLE

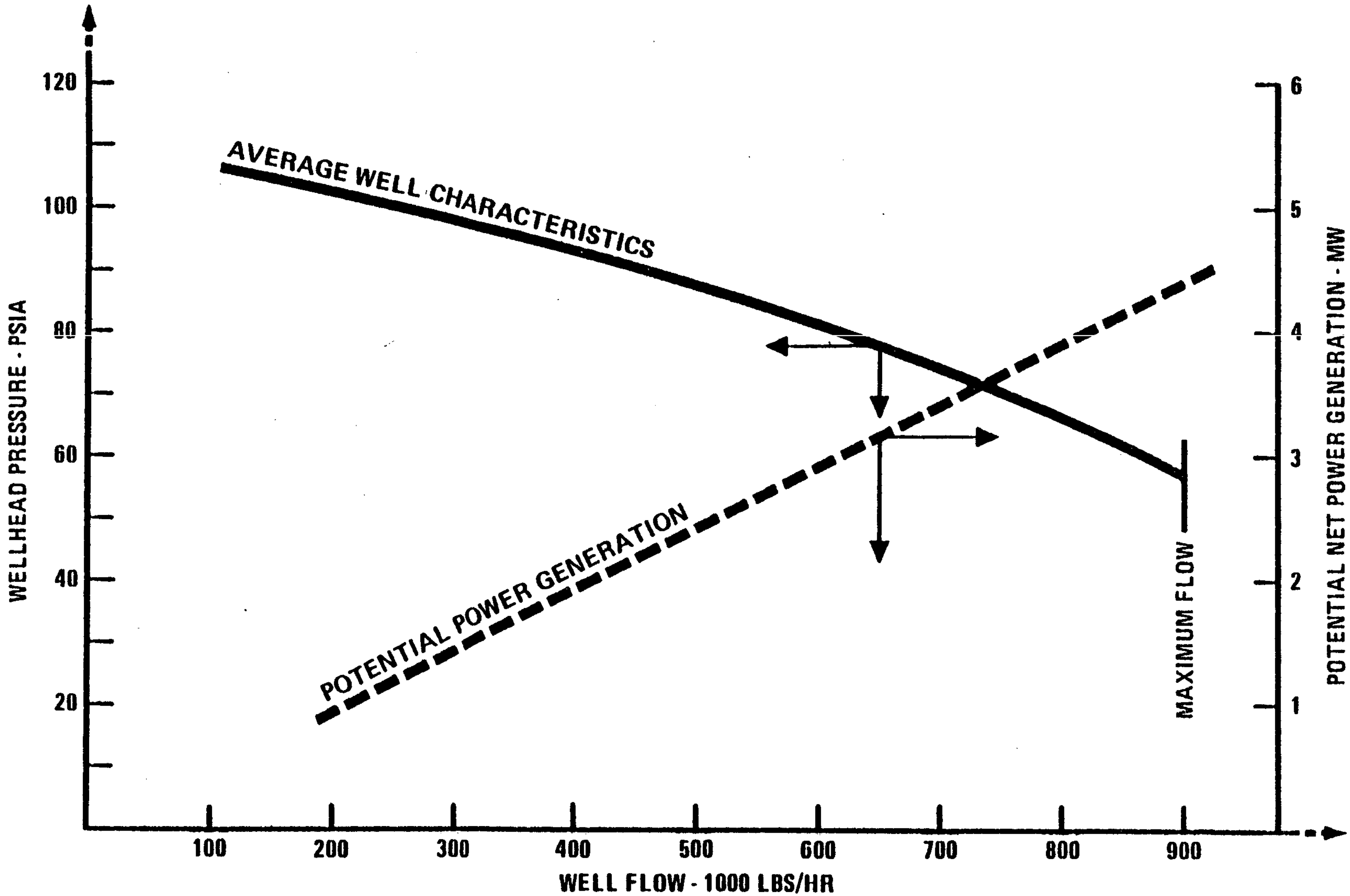

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FIGURE 17

POTENTIAL NET POWER GENERATION OF AVERAGE PRODUCTION WELL WHEN USING DOUBLE FLASH STEAM CYCLE

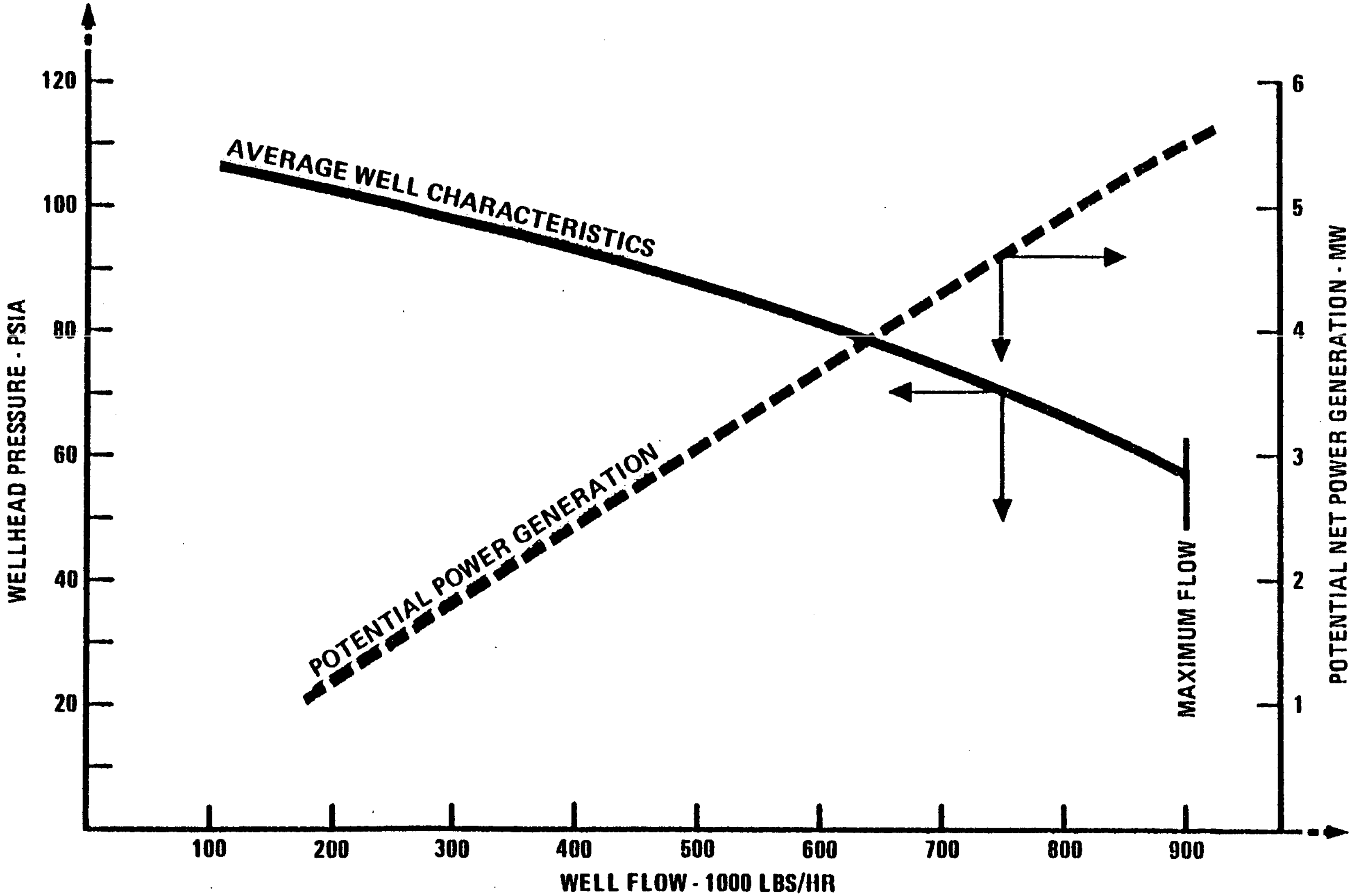

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FIGURE 18

POTENTIAL NET POWER GENERATION OF AVERAGE PRODUCTION WELL WHEN USING BINARY CYCLE

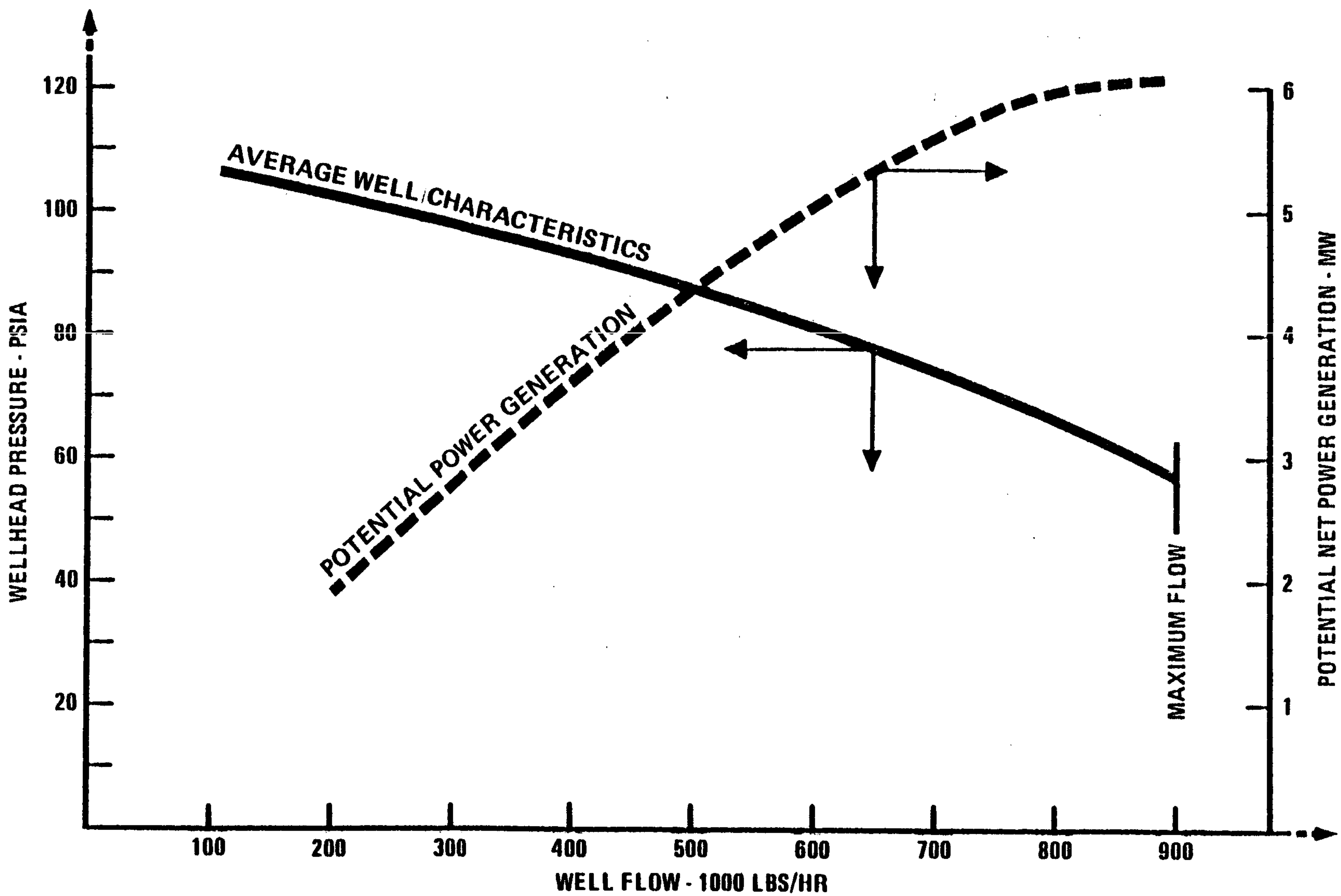

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FIGURE 19

POTENTIAL NET POWER GENERATION OF AVERAGE PRODUCTION WELL WHEN USING HYBRID CYCLE

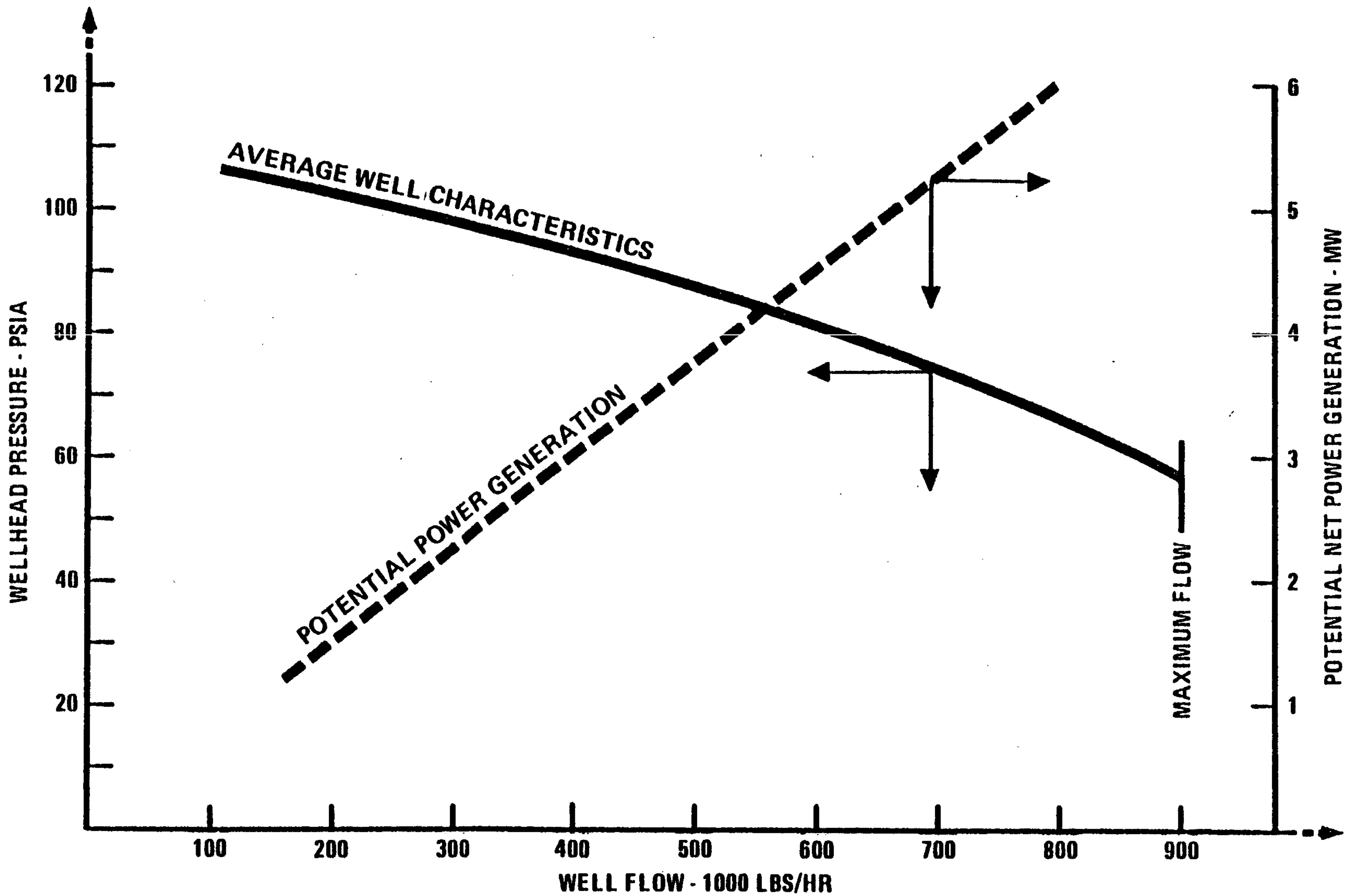

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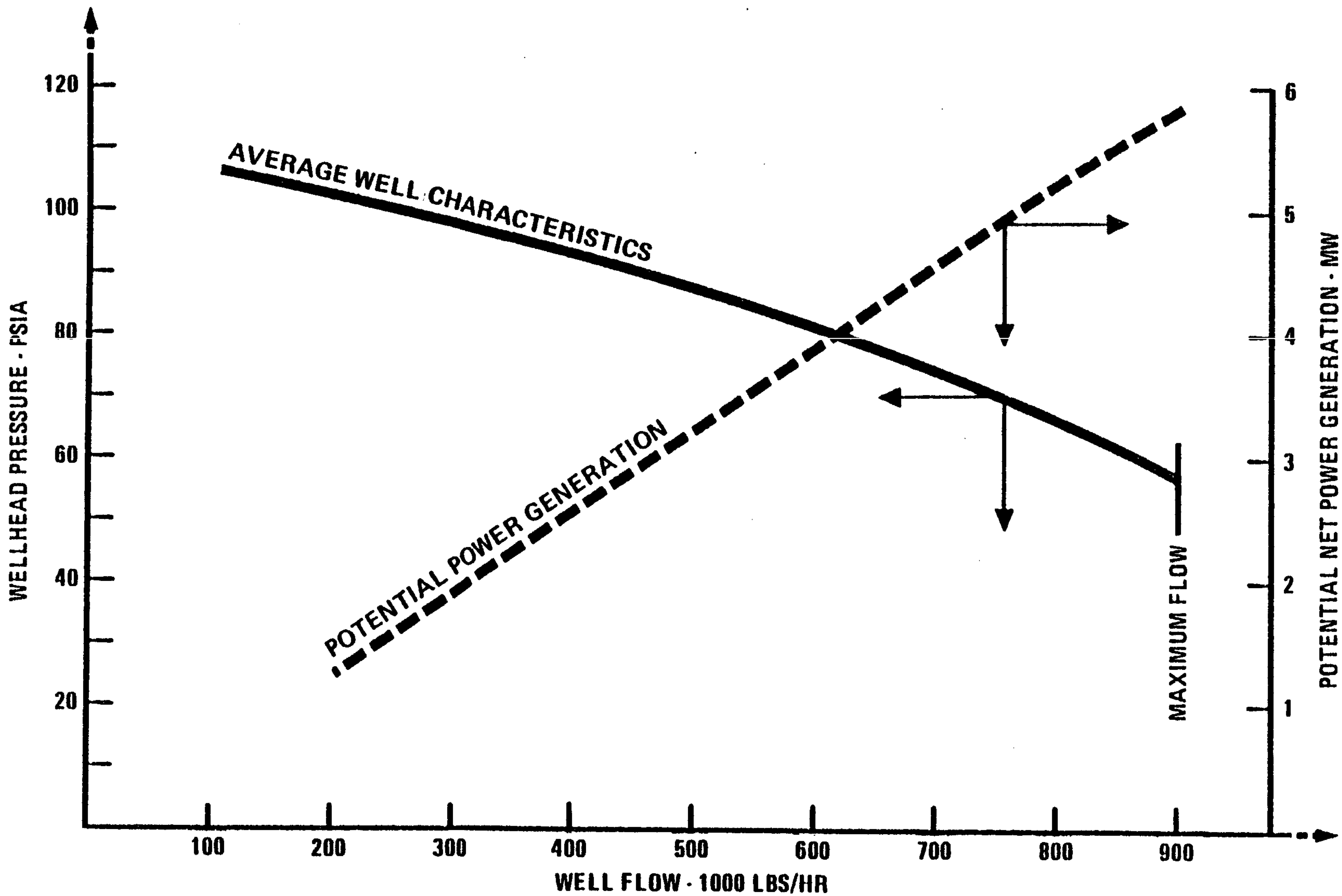
FIGURE 20

POTENTIAL NET POWER GENERATION OF AVERAGE PRODUCTION WELL WHEN USING TOTAL FLOW CYCLE



AGI E 1562

11. All alternative power plants on Makushin Volcano are assumed to be enclosed and include the following three main prefabricated buildings:

   a. A power building; housing the power generation equipment.

   b. A control building; housing the control room, switch gear, and laboratory.

   c. A maintenance building; housing the maintenance shop, the warehouse for storage of spare parts, and the living quarters for the crew.

GEOTHERMAL POWER DEVELOPMENT COST COMPARISONS

The capital costs required to develop geothermal power using each of the alternative processes considered for both "No-Bottomfish Demand" and "Low-Bottomfish Catch" cases are shown on Tables 3 and 4. Each power development alternative includes power plant costs and associated major field development costs. Costs for infrastructure items, such as road and transmission line, are not included as they are identical for all alternatives. All costs are in 1983 dollars and do not include escalation and interest during construction.

Power plant costs are limited to the costs of the power generation units and are broken down as follows:

1. Power plant engineering and fabrication costs which include engineering, shop fabrication and testing of power modules, prefabrication of auxiliary systems and transportation to Driftwood Bay.

2. Power plant construction costs which include transportation from Driftwood Bay to jobsite, construction camp, construction labor, and construction management. Construction costs at the Unalaska site are estimated to be four times the construction costs at a site in the continental United States.

Associated field development costs are limited to the following major items:

1. Production well costs which include drilling, completion, and short testing of all production wells to be provided to supply the geothermal fluid flow required by the power plant.

2. Injection well costs which include drilling, completion, and short testing of all injection wells to be provided to dispose of the residual geothermal fluid flow from the power plant.

3. Production pipeline costs which include engineering and construction of insulated pipeline between production wells and power plant.

4. Injection pipeline costs which include engineering and construction of noninsulated pipeline between power plant and injection wells. Costs include injection pumps as required.

Figures 21, 22, and 23 were developed to show the total installed cost and the installed cost per kw of a geothermal power plant, using each alternative process considered, based on power generation unit size. To illustrate the impact of the high construction costs estimated for the Island of Unalaska, we have shown both the installed costs at a hypothetical site in the "lower 48" United States and the costs at the site on Unalaska Island.

It is notable that the cost per installed kw of geothermal power decreases substantially as the power generation unit size increases, particularly for flash steam plants.

TABLE 3

NO-BOTTOMFISH DEVELOPMENT CASE
GEOTHERMAL POWER DEVELOPMENT CAPITAL COSTS MATRIX
ALL COSTS IN THOUSANDS OF 1983 DOLLARS

	Single Flash Steam Plant	Double Flash Steam Plant	Binary Plant	Hybrid Plant	Total Flow Plant
Power Plant Net Generating Capacity	10 MW	10 MW	6.7 MW	10 MW	10 MW
Number of Power Generation Units	2	2	2	3	2
Power Plant Engineering and Fabrication Costs	14,820	17,000	8,590	14,520	18,720
Power Plant Construction Costs	21,800	24,800	11,440	20,080	27,200
Subtotal Installed Power Plant Costs	36,620	41,800	20,030	34,600	45,920
Number of Production Wells Provided	3	2	2	2	2
Number of Injection Wells Provided	2	1	1	1	1
Production Well Costs	8,151	6,099	6,099	6,099	6,099
Injection Well Costs	3,200	1,600	1,600	1,600	1,600
Production Pipeline Costs	1,445	963	963	963	963
Injection Pipeline Costs	900	680	453	453	680
Subtotal Field Development Costs	13,696	9,342	9,115	9,115	9,342
Total Geothermal Power Development Costs	50,316	51,142	29,145	43,715	55,262
Cost Per MW of Net Power Generated	5,031.6	5,114.2	4,350	4,371.5	5,526.2

TABLE 4

LOW-BOTTOMFISH DEVELOPMENT CASE
GEOTHERMAL POWER DEVELOPMENT CAPITAL COSTS MATRIX
ALL COSTS IN THOUSANDS OF 1983 DOLLARS

	Single Flash Steam Plant	Double Flash Steam Plant	Binary Plant	Hybrid Plant	Total Flow Plant
Power Plant Net Generating Capacity	20 MW	20 MW	20 MW	20 MW	20 MW
Number of Power Generation Units	4	4	6	6	4
Power Plant Engineering and Fabrication Costs	28,160	32,300	25,770	29,040	37,440
Power Plant Construction Costs	41,420	47,120	34,320	40,160	54,400
Subtotal Installed Power Plant Costs	69,580	79,420	60,090	69,200	91,840
Number of Production Wells Provided	6	5	5	4	5
Number of Injection Wells Provided	4	3	3	3	3
Production Well Costs	14,907	12,555	12,555	10,503	12,555
Injection Well Costs	6,400	4,800	4,800	4,800	4,800
Production Pipeline Costs	2,701	2,251	2,251	1,801	2,251
Injection Pipeline Costs	2,718	2,038	1,359	1,359	2,038
Subtotal Field Development Costs	26,726	21,644	20,965	18,463	21,644
Total Geothermal Power Development Costs	96,306	101,064	81,055	87,663	113,484
Cost Per MW of Net Power Generated	4,815.3	5,053.2	4,052.8	4,383.2	5,675.2

FIGURE 21

GEOTHERMAL POWER PLANT
TOTAL INSTALLED COST vs. POWER PLANT UNIT SIZE

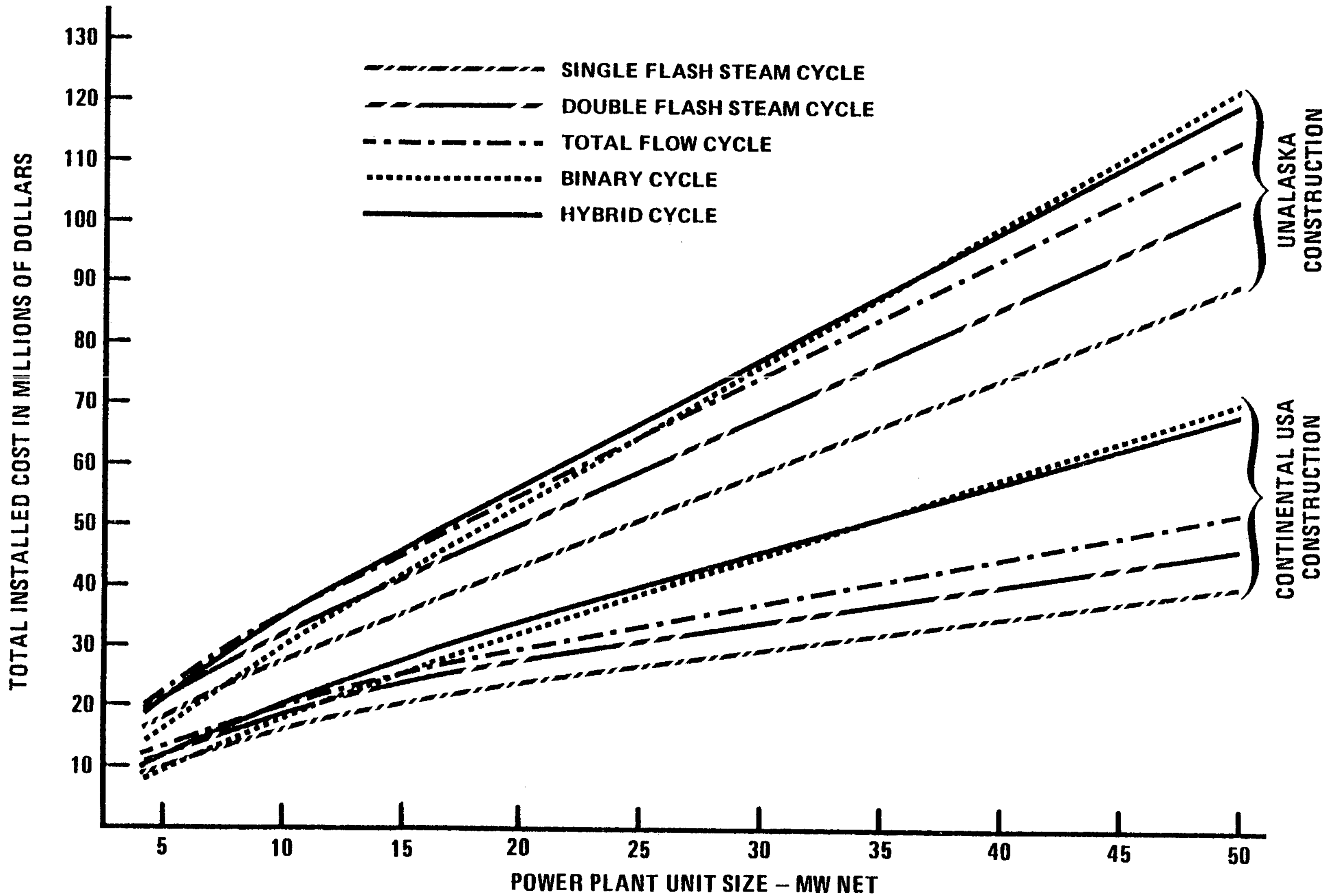


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FIGURE 22

GEOTHERMAL POWER PLANT INSTALLED COST PER KW vs. POWER PLANT UNIT SIZE BASED ON CONTINENTAL USA CONSTRUCTION

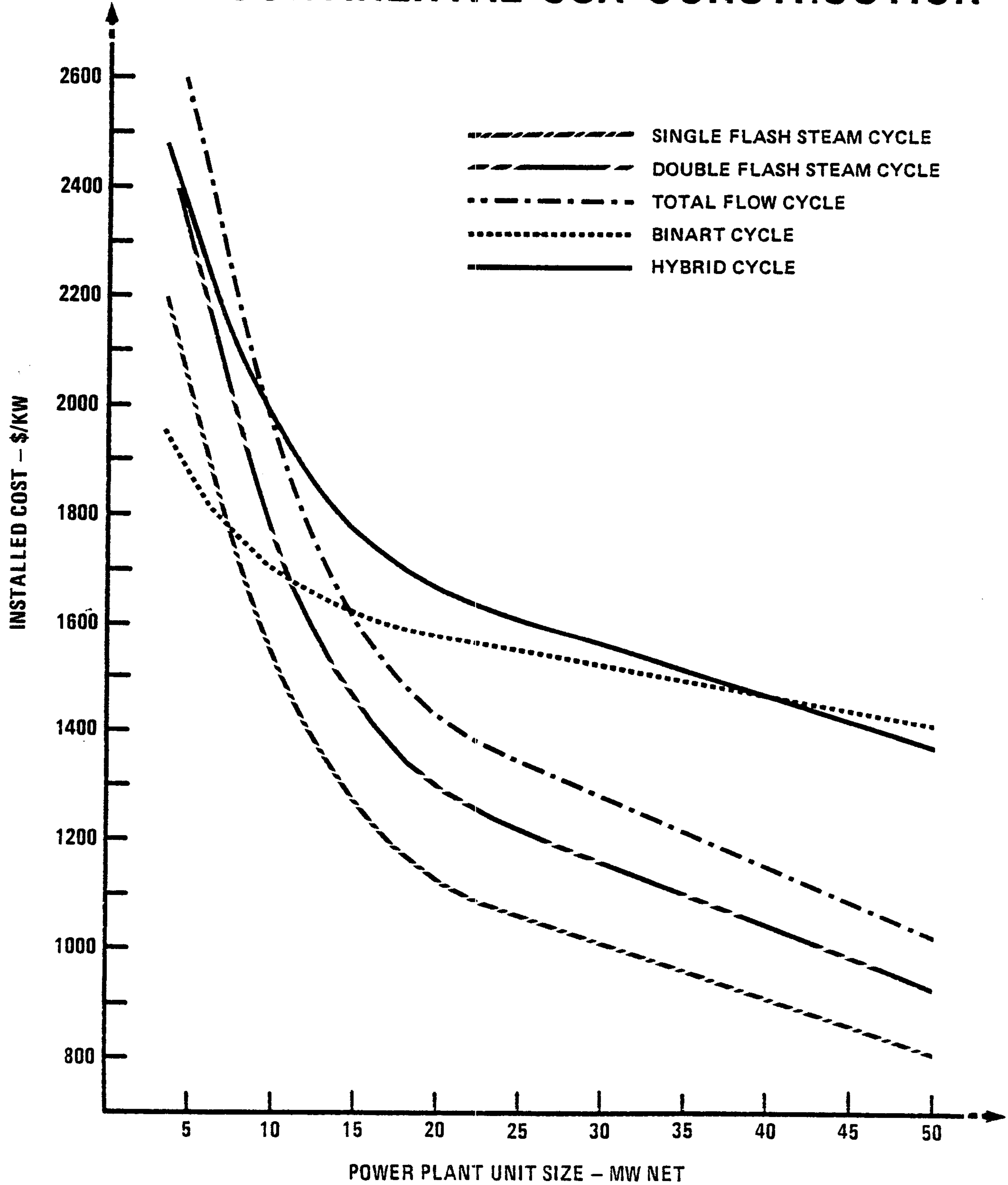
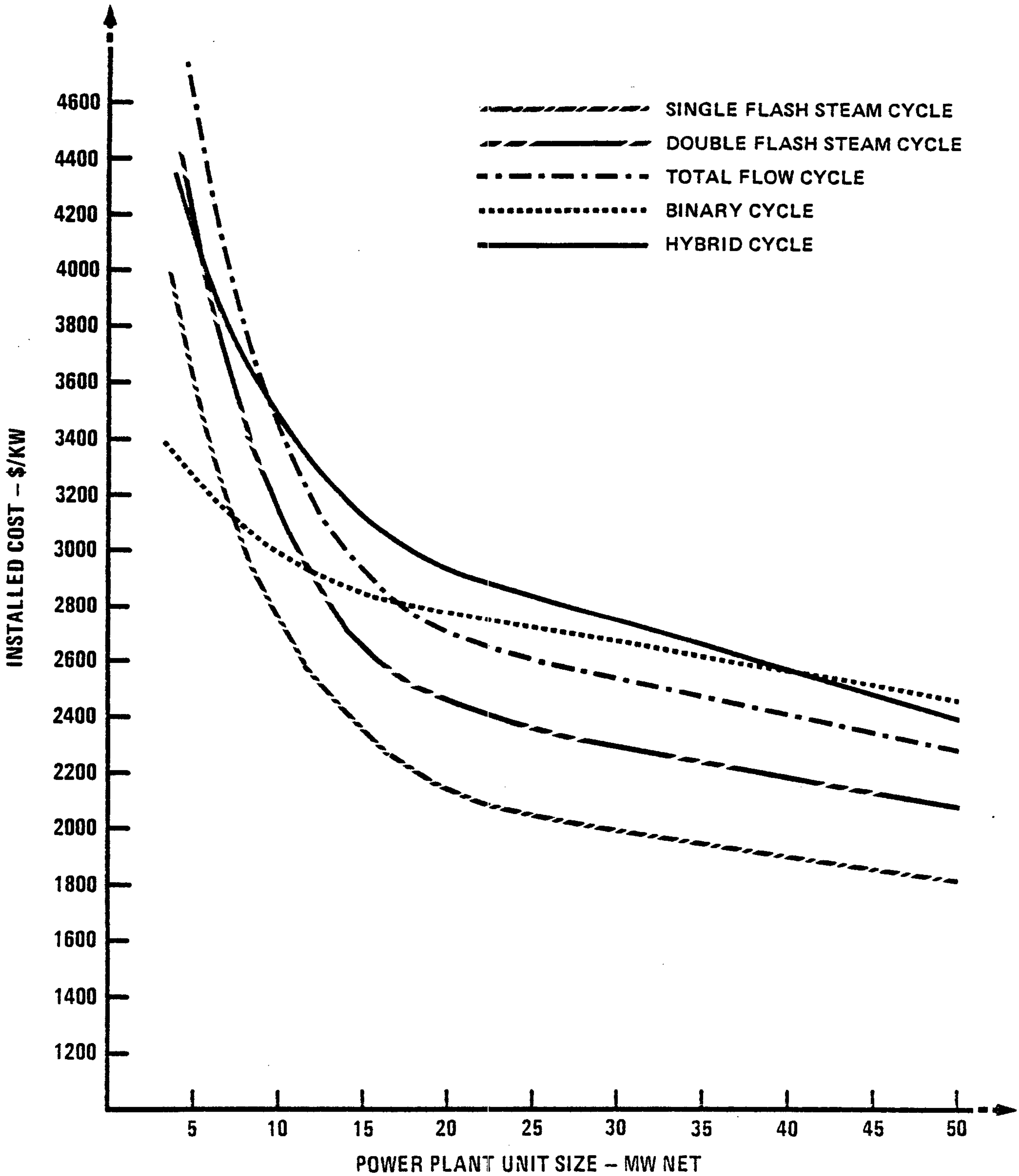


FIGURE 23

GEOTHERMAL POWER PLANT INSTALLED COST PER KW vs. POWER PLANT UNIT SIZE BASED ON UNALASKA CONSTRUCTION



POSITIVE AND NEGATIVE ASPECTS OF EACH TYPE OF POWER PLANT CONSIDERED

1. Single Flash Steam Plant

   a. Positive Aspects

      i. Uses proven and reliable process to generate electrical power.

      ii. Simple plant with few components.

      iii. Easily operated and maintained.

   b. Negative Aspects

      i. Requires more geothermal fluid flow and therefore more wells than all other alternative plants due to a very low brine utilization factor.

      ii. Requires careful monitoring during winter months operation to prevent freezing of steam condensate.

      iii. Not cost competitive in the small unit size contemplated.

2. Double Flash Steam Plant

   a. Positive Aspects

      i. Uses proven and reliable process to generate electrical power.

      ii. Simple plants with few components.

      iii. Easily operated and maintained.

   b. Negative Aspects

      i. Requires careful monitoring during winter months operation to prevent freezing of steam condensate.

      ii. Not cost competitive in the small unit size contemplated.

3. Binary Plant

   a. Positive Aspects

      i. High brine utilization factor.

      ii. Does not run the risk of freezing during winter months operation due to the low freezing point of the working fluid.

iii. Lowest cost in the small unit size contemplated.

iv. Can be easily modularized.

b. Negative Aspects

i. Uses less proven process than flash steam process.

ii. Some working fluids may pose potential fire or environmental hazards if they should leak to the atmosphere.

iii. Requires a large number of components increasing the operation and maintenance costs.

4. Hybrid Power Plant

a. Positive Aspects

i. Highest brine utilization factor.

ii. Combines the advantages of both steam flash and binary processes.

b. Negative Aspects

i. To be efficient and economical, must be developed in a minimum of 10 MW increments which provides for large excess capacity up front.

ii. Combines the disadvantages of both flash steam and binary processes.

5. Total Flow Plant

a. Positive Aspects

i. High brine utilization factor.

b. Negative Aspects

i. Uses the least proven of all studied processes.

ii. Requires careful monitoring during winter months operation to prevent freezing of steam condensate.

iii. Not cost competitive in the small unit size contemplated.

POWER CONVERSION PROCESS RECOMMENDATION

Considering the positive and negative aspects of each cycle considered as discussed previously, the binary cycle is recommended as the best power conversion process to generate electricity from the Makushin resource for the following reasons:

1. It is the most economical process for the small estimated base load demand (5 to 20 MW) of the electrical system.

2. It is an efficient power conversion process requiring relatively small field development to support the power plant.

3. While it has not been as widely used as the flash steam process, it is easily developed in small units thus, adding reliability to the overall plant.

4. It can be fabricated in small, shop assembled and tested modules that can be easily transported and installed.

5. It can be easily automated to require minimal operating supervision.

6. It does not incur a risk of freezing during winter months operation.

7. It can be installed quickly, adding scheduling flexibility if power demand increases faster than expected.

BINARY SYSTEM DEVELOPMENT COSTS

The economic feasibility of developing the Makushin geothermal resource for electrical power generation will be assessed by ACRES American, Inc. as requested by the Alaska Power Authority. To permit this assessment, Republic Geothermal, Inc. has prepared the following tables showing the capital cost estimate and the operation and maintenance cost estimate for the 10 MW and the 30 MW scenario. All cost estimates are based on the use of the recommended binary cycle for power generation.

1. Table 5 - Capital cost estimate for the development of a 10 MW gross (6.7. MW net) geothermal power plant.

2. Table 6 - Capital cost estimate for the development of a 30 MW gross (20 MW net) geothermal power plant with all the wells drilled during the first phase of plant development.

3. Table 7 - Capital cost estimate for the development of a 30 MW gross (20 MW net) geothermal power plant with the wells drilled as needed in each phase of plant development.

4. Table 8 - Operation and maintenance cost estimate for a 10 MW gross (6.7 MW net) geothermal plant development.

5. Table 9 - Operation and maintenance cost estimate for a 30 MW gross (20 MW net) geothermal plant development.

An analysis of the costs of drilling all wells required for the 30 MW gross power plant upon construction of the initial phase, instead of drilling the wells as each increment is constructed shows the following:

If all wells are drilled in the initial phase of development (as shown on Table 6), the total development costs are $202,316,000. This requires a total capacity investment of $101,158,000 having a 1983 present valkue of $45,984,000 if discounted back at a factor of 10.5% per year.

If the wells are drilled as each increment is constructed (as shown on Table 7), the total development costs are $220,334,000. This requires a total equity investment of $110,172,000 having a 1983 present value of $46,201,000 if discounted back at a factor or 10.5% per year.

Assuming that the amortization of the debt starts upon completion of each phase of construction, a high penalty would be paid if all wells are drilled up front, as the debt service will be substantially higher. Based on this, and because of the uncertainties in electrical demand growth, it is recommended that the wells be drilled as each increment is developed, thus minimizing the risks to the existing consumer base.

TABLE 5

NO-BOTTOMFISHING DEVELOPMENT CASE
UNALASKA 10 MW GROSS (6.7 MW NET) BINARY POWER PLANT
DEVELOPMENT COSTS IN THOUSANDS OF DOLLARS

	1985	1986	1987	1988	Total Costs
Field Development Costs (1983)					
Production Wells (2)	3,747	2,352	0	0	6,099
Injection Well (1)	1,600	0	0	0	1,600
Well Testing	521	236	0	0	757
Direct Operation & Maintenance	513	526	426	734	2,199
Home Office	475	600	400	525	2,000
Start-Up	0	0	0	210	210
Subtotal Field Costs	6,856	3,714	826	1,469	12,865
Power Plant Costs (1983)					
Power Plant Eng. & Const.	0	2,504	10,516	7,010	20,030
Production Pipeline	0	0	963	0	963
Injection Pipeline	0	0	0	453	453
Spare Parts	0	0	0	200	200
Consulting & Coordination	162	200	200	238	800
Start-Up	0	0	0	400	400
Insurance	0	0	130	130	260
Subtotal Power Plant Costs	162	2,704	11,809	8,431	23,106
Other Costs (1983)					
Road Construction	0	5,146	0	0	5,146
Transmission Line	0	0	0	6,405	6,405
Subtotal Other Costs	0	5,146	0	6,405	11,551
TOTAL COSTS (1983)	7,018	11,564	12,635	16,305	47,522
Escalation	1,017	2,602	3,927	6,564	14,110
TOTAL ESCALATED COSTS	8,035	14,166	16,562	22,869	61,632
Interest Expenses	259	978	2,018	3,399	6,654
TOTAL DEVELOPMENT COSTS	8,294	15,144	18,580	26,268	68,286
Equity	4,147	7,572	9,290	13,134	34,143
Debt	4,147	7,572	9,290	13,134	34,143
TOTAL USE OF FUNDS	8,294	15,144	18,580	26,268	68,286

TABLE 6

LOW-BOTTOMFISH CATCH CASE
UNALASKA 30 MW GROSS (20 MW NET) BINARY POWER PLANT
DEVELOPMENT COSTS IN THOUSANDS OF DOLLARS
ALL WELLS DRILLED IN FIRST PHASE OF POWER PLANT DEVELOPMENT

	1985	1986	1987	1988	Total Costs First Phase	1991	1992	Total Costs Second Phase	1998	1999	Total Costs Third Phase	Total Costs All Phases
Field Development Costs (1983)												
Production Wells (5)	3,747	4,404	4,404	0	12,555	0	0	0	0	0	0	12,555
Injection Wells (3)	1,600	1,600	1,600	0	4,800	0	0	0	0	0	0	4,800
Well Testing	521	354	354	0	1,229	0	0	0	0	0	0	1,229
Direct Operation & Maint.	513	526	526	734	2,299	426	734	1,160	426	734	1,160	4,619
Home Office	475	600	600	525	2,200	400	525	925	400	525	925	4,050
Start-Up	0	0	0	210	210	0	150	150	0	100	100	460
Subtotal Field Costs	6,856	7,484	7,484	1,469	23,293	826	1,409	2,235	826	1,359	2,185	27,713
Power Plant Costs (1983)												
Power Plant Eng. & Const.	0	2,504	10,516	7,010	20,030	10,015	10,015	20,030	10,015	10,015	20,030	60,090
Production Pipeline	0	0	963	0	963	963	0	963	325	0	325	2,251
Injection Pipeline	0	0	0	453	453	0	453	453	0	453	453	1,359
Spare Parts	0	0	0	200	200	0	200	200	0	200	200	600
Consulting & Coordination	162	200	200	238	800	200	200	400	200	200	400	1,600
Start-Up	0	0	0	400	400	0	200	200	0	150	150	750
Insurance	0	0	130	130	260	0	130	130	0	130	130	520
Subtotal Power Plant Costs	162	2,704	11,809	8,431	23,106	11,178	11,198	22,376	10,540	11,148	21,688	67,170
Other Costs (1983)												
Road Construction	0	5,146	0	0	5,146	0	0	0	0	0	0	5,146
Transmission Line	0	0	0	6,405	6,405	0	0	0	0	0	0	6,405
Subtotal Other Costs	0	5,146	0	6,405	11,551	0	0	0	0	0	0	11,551
TOTAL COSTS (1983)	7,018	15,334	19,293	16,305	57,950	12,004	12,607	24,611	11,366	12,507	28,873	106,434
Escalation	1,017	3,451	5,997	6,564	17,029	8,621	10,570	19,191	19,993	24,416	44,409	80,629
TOTAL ESCALATED COSTS	8,035	18,785	25,290	22,869	74,979	20,625	23,177	43,802	31,359	36,923	68,282	187,063
Interest Expenses	259	1,125	2,598	4,295	8,277	655	2,091	2,746	997	3,233	4,230	15,253
TOTAL DEVELOPMENT COSTS	8,294	19,910	27,888	27,164	83,256	21,280	25,268	46,548	32,356	40,156	75,512	202,316
Equity	4,147	9,955	13,944	13,582	41,628	10,640	12,634	23,274	16,178	20,078	36,256	101,158
Debt	4,147	9,955	13,944	13,582	41,628	10,640	12,634	23,274	16,178	20,078	36,256	101,158
TOTAL USE OF FUNDS	8,294	19,910	27,888	27,164	83,256	21,280	25,268	46,548	32,356	40,156	72,512	202,316

TABLE 7

LOW-BOTTOMFISH CATCH CASE
UNALASKA 30 MW GROSS (20 MW NET) BINARY POWER PLANT
DEVELOPMENT COSTS IN THOUSANDS OF DOLLARS
WELLS DRILLED AS NEEDED IN EACH PHASE OF POWER PLANT DEVELOPMENT

	1985	1986	1987	1988	Total Costs First Phase	1991	1992	Total Costs Second Phase	1998	1999	Total Costs Third Phase	Total Costs All Phases
Field Development Costs (1983)												
Production Wells (5)	3,747	2,352	0	0	6,099	5,799	0	5,799	3,747	0	3,747	15,645
Injection Wells (3)	1,600	0	0	0	1,600	1,600	0	1,600	1,600	0	1,600	4,800
Well Testing	521	236	0	0	757	354	0	354	236	0	236	1,347
Direct Operation & Maint.	513	526	426	734	2,199	526	734	1,260	526	734	1,260	4,719
Home Office	475	600	400	525	2,000	600	525	1,125	600	525	1,125	4,250
Start-Up	0	0	0	210	210	0	150	150	0	100	100	460
Subtotal Field Costs	6,856	3,714	826	1,469	12,865	8,879	1,409	10,288	6,709	1,359	8,068	31,221
Power Plant Costs (1983)												
Power Plant Eng. & Const.	0	2,504	10,516	7,010	20,030	10,015	10,015	20,030	10,015	10,015	20,030	60,090
Production Pipeline	0	0	963	0	963	963	0	963	325	0	325	2,251
Injection Pipeline	0	0	0	453	453	0	453	453	0	453	453	1,359
Spare Parts	0	0	0	200	200	0	200	200	0	200	200	600
Consulting & Coordination	162	200	200	238	800	200	200	400	200	200	400	1,600
Start-Up	0	0	0	400	400	0	200	200	0	150	150	750
Insurance	0	0	130	130	260	0	130	130	0	130	130	520
Subtotal Power Plant Costs	162	2,704	11,809	8,431	23,106	11,178	11,198	22,376	10,540	11,148	21,688	67,170
Other Costs (1983)												
Road Construction	0	5,146	0	0	5,146	0	0	0	0	0	0	5,146
Transmission Line	0	0	0	6,405	6,405	0	0	0	0	0	0	6,405
Subtotal Other Costs	0	5,146	0	6,405	11,551	0	0	0	0	0	0	11,551
TOTAL COSTS (1983)	7,018	11,564	12,635	16,305	47,522	20,057	12,607	32,664	17,249	12,507	29,756	109,942
Escalation	1,017	2,602	3,927	6,564	14,110	14,405	10,570	24,975	30,342	24,416	54,758	93,843
TOTAL ESCALATED COSTS	8,035	14,166	16,562	22,869	61,632	34,462	23,177	57,639	47,591	36,923	84,514	203,785
Interest Expenses	259	978	2,018	3,399	6,654	1,096	2,999	4,095	1,513	4,297	5,810	16,559
TOTAL DEVELOPMENT COSTS	8,294	15,144	18,580	26,268	68,286	35,558	26,176	61,734	49,104	41,220	90,324	220,344
Equity	4,147	7,572	9,290	13,134	34,143	17,779	13,088	30,867	24,552	20,610	45,162	110,172
Debt	4,147	7,572	9,290	13,134	34,143	17,779	13,088	30,867	24,552	20,610	45,162	110,172
TOTAL USE OF FUNDS	8,294	15,144	18,580	26,268	68,286	35,558	26,176	61,734	49,104	41,220	90,324	220,344

TABLE 8

NO-BOTTOMFISHING DEVELOPMENT CASE
UNALASKA 10 MW GROSS (6.7 MW NET) BINARY POWER PLANT
COMBINED PLANT AND FIELD ANNUAL OPERATION
AND MAINTENANCE COSTS

(Thousands of 1983 Dollars)

Administration	85
Operation and Maintenance Labor	580
Contract Maintenance	350
Well Reconditioning	75
Outside Consulting	150
Power Plant Insurance	100
Miscellaneous	460
TOTAL ANNUAL COST	1,800

TABLE 9

LOW-BOTTOMFISH CATCH CASE
UNALASKA 30 MW GROSS (20 MW NET) BINARY POWER PLANT
COMBINED PLANT AND FIELD ANNUAL OPERATION
AND MAINTENANCE COSTS

(Thousands of 1983 Dollars)

Administration	170
Operating and Maintenance Labor	790
Contract Maintenance	650
Well Reconditioning	225
Outside Consulting	150
Power Plant Insurance	300
Miscellaneous	550
TOTAL ANNUAL COST	2,835

A. Capital Costs

Capital cost estimates show the field development costs, power plant construction costs, and other necessary costs in 1983 dollars for each alternative. Addition of these costs gives a total development cost in 1983 dollars. To this total, escalation and interest during construction are added to give a total capital cost required for the development of each alternative.

1. Field Development Costs

The field development costs include production well drilling and completion, injection well drilling and completion, well testing necessary to prove productivity and injectivity, direct field operation and maintenance during development, home office support and services, and field operation and maintenance during power plant start-up.

Ten MW gross field development includes two production wells and one injection well. This provides for almost a full spare production well when the plant is operated at full capacity and ensures adequate power generation in the unlikely event of the catastrophic failure of a production well. The injection well provides approximately 40 percent more capacity than necessary to reinject the total fluid required to run the power plant at full capacity. In the very unlikely event of a catastrophic failure, it is assumed that temporary disposal of the spent brine on the ground would be permissible.

Thirty MW gross field development includes five production wells and three injection wells, which provides for one spare production well and one spare injection well.

2. Power Plant Costs

Power plant costs include engineering and construction of the binary units, engineering and construction of the production pipeline, engineering and construction of the injection pipeline, spare parts, consulting services and coordination support, start-up including operator training, and fire and casualty insurance during construction.

10 MW gross power plant construction is assumed to take place during spring and summer months (April to October) of the first year of construction and continuously from April to end of construction of second year of construction.

First phase of 30 MW gross power plant construction (20 MW gross) is assumed to take place as described above. Second and third phases will take place continuously, starting in April of the first year until completion at the end of the second year.

Power plant engineering and construction costs are based on a turnkey type proposal offered by the Ben Holt Co. for a binary plant similar to one being built in the Sierra Nevada of California. Construction costs are multiplied by a factor of four to reflect the high construction cost expected on Unalaska. Construction field costs include manual labor, nonmanual labor, indirect field costs and construction management.

3. Other Costs

Other costs include the construction of a road from Driftwood Bay to the power plant site and the construction of a 34.5 kv transmission line from the power plant site to a substation in Dutch Harbor.

The road construction estimate is based on a Dames and Moore study prepared for Republic Geothermal, Inc. and Alaska Power Authority in February 1, 1983. It includes existing road grading, repair and gravel surfacing; new road construction including culverts and major canyon crossing; and mobilization and demobilization. To ensure that the road is ready to receive major equipment as it is unloaded from the barge, road construction is scheduled for the summer months of the year prior to actual field construction of the first 10 MW gross power plant.

The transmission line estimate is based on burial of the cable approximately 30" underground from the power plant site to Broad Bay and then going underwater to Dutch Harbor. The estimate includes a substation to be located in Dutch Harbor that will tie the power plant to the distribution system. It also includes a 30 percent contingency to account for the uncertainties about the underwater portion of the line which has to be buried in the ocean floor.

4. Escalation

Escalation is based on an annual inflation rate of seven percent.

5. Interest Expenses

Interest expenses represent the interest to be paid during construction based in a debt to equity ration of one and on an interest rate of 12 percent per year.

B. Operation and Maintenance Costs

Operation and maintenance (O&M) costs estimates show the total annual cost in 1983 dollars to operate and maintain the overall geothermal development.

O&M costs assume that operation and maintenance labor as well as administration personnel are shared by both power plant and field.

O&M costs do not include any royalty payment on the resource utilized during commercial operation or any taxes on the power plant or field.

CONCLUSIONS

On the strength of this study, the following conclusions can be drawn:

1. The Makushin geothermal resource can be utilized to generate electrical power for the towns of Unalaska and Dutch Harbor.

2. Due to its high development costs, geothermal power is best suited to meet baseload demand of the electrical system.

3. The binary cycle is the preferred power conversion process to generate electricity from the Makushin geothermal resource.

4. A 10 MW gross (6.7 MW net) geothermal power development would satisfy the electrical load demand estimated by Acres American, Inc. for the "no-bottomfishing" case past the year 2000. Preferred development would consist of two identical 5 MW gross binary units together with two production and one injection wells.

5. A 10 MW gross geothermal power development could be commercial by January 1989 and would cost a total of $68,286,000.

6. A 30 MW gross (20 MW net) geothermal power development would satisfy the electrical load demand estimated by Acres, America, Inc. for the "low-bottomfish catch" case past the year 2000. It is recommended that such a power plant be developed in three phases timed to the growth in demand. The first phase of development would consist of two identical 5 MW gross binary units together with two production and one injection wells and would become commercial in January 1989. The second phase of development would consist of duplicating the initial phase and would become commercial in January 1993. The third phase of development would consist of two additional binary units identical to the units provided in phases 1 and 2 together with one production and one injection wells and would start commercial operation in January 2000.

7. A 30 MW gross geothermal power development as outlined above would cost a total of $220,344,000.