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MEASUREMENT AND CONTROL TECHNIQUES IN GEOTHERMAL POWER PLANTS

J. F. WHITBECK R. H. DART
J. D. MILLER D. R. BREWER

January 1979

EG&G Idaho, Inc.

IDAHO NATIONAL ENGINEERING LABORATORY

DEPARTMENT OF ENERGY

IDAHO OPERATIONS OFFICE UNDER CONTRACT EY-76-C-07-1570

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Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
Price: Printed Copy \$6.00; Microfiche \$3.00

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TREE-1312

Distribution Category:
UC-66C

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J. F. Whitbeck, EG&G Idaho, Inc.

R. H. Dart, EG&G Idaho, Inc.

J. D. Miller, EG&G Idaho, Inc.

D. R. Brewer, Rogers Engineering

EG&G Idaho, Inc.
Idaho Falls, Idaho 83401

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ACKNOWLEDGMENTS

Many people contributed information during preparation of this report. In particular the authors wish to express their gratitude to Chilton Publishing Company for permission to print the material which appears in Figures 10 and 11, and Tables II and V, and to acknowledge the following individuals and companies for their efforts and consultation while preparing this chapter:

Bechtel National Inc.

T. R. Fick, A. N. Rogers, and A. F. Marks

The Ben Holt Co.

Ben Holt, A. J. L. Hutchinson, and Fletcher Leavenworth

Chevron Oil Co.

Al Cooper

Imperial Magma Co.

Tom Hinrichs, Cal Shepherd, and Mike Pierce

Lawrence Livermore Laboratory

Frank Locke

Pacific Gas & Electric Co.

Charlie Franks

Public Service of New Mexico

Art Martinez

Union Oil Co.

A. J. Chasteen, Frank Lemon, and W. B. Blaikie.

Also the authors express their gratitude to Mr. Charlie Franks, P.G.&E. Co., and Mr. Tom Hinrichs, Imperial Magma Co., for their efforts in supplying information which was included in Sections III-2.5 and III-4.3.

ABSTRACT

The information contained in this report provided the background and source material used in preparing the chapter of the Geothermal Source Book on instrumentation, measurement, and control techniques. This source book is being assembled and edited under the direction of Dr. J. Kesten of Brown University. This report presents more complete and detailed information than could be included in the source book chapter and is being published for reference. Included are detailed examples of instrumentation and control techniques currently being used in geothermal power plants. In addition, the basic guidelines and unique characteristics of instrumentation and control in geothermal systems, are presented.

This report addresses the instrumentation and control philosophy and the hardware involved in geothermal electric plants and their supply and injection systems. The intent is to address the unique characteristics of geothermal electric instrumentation and control (I&C) systems. Standard I&C practice is available in the general literature. Sources of information for standard I&C practice are listed in the Appendix.

The information contained in this report presents

- (1) The philosophy of I&C system design
- (2) The development of the system, from power grid considerations through subsystem operation to specific system details
- (3) Component selection and operating considerations.

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MEASUREMENT AND CONTROL TECHNIQUES IN GEOTHERMAL POWER PLANTS

I. INTRODUCTION

Measurement and control techniques in geothermal systems are typical of standard instrumentation and control (I&C) practices used in the process and power industries. This report addresses the methods, systems, guidelines, and hardware unique to geothermal electric facilities. Standard I&C practice is available in the general literature. A selected bibliography is included in the Appendix, listing sources for more information on standard I&C practice.

II. INSTRUMENTATION AND CONTROL SYSTEM DESIGN APPROACH

This Section presents an overview of the design of a geothermal electric I&C system and points out the unique design considerations and options included in the design process.

1. DATA AND CONTROL REQUIREMENTS

The general considerations as to the number and character of panel mounted data channels for use in control, protection, and monitoring are identical to those for any industrial process in that (a) experience gained in operating a pilot or experimental plant is utilized in developing simplified and improved designs for large scale commercial units and (b) technology advances are retrofitted. Both of these trends are typified in the evolution of the Geysers steam plants, as subsequently described. Specific subsystem and plant data requirements for control and protection are described in Section III.

Instrumentation accuracy beyond ordinary process instrumentation standards is justified only for metering applications, where leaseholder or supplier charges are affected, and for experimental plants where binary fluid properties and component performance are of interest.

Response requirements for monitoring and performance evaluation are not stringent, since these channels are of interest in a static or quasistatic sense. Response and sampling rate requirements for control data, monitoring data, and control device actuation are generally not stringent because of the large thermal masses dominating temperature responses. One exception to this rule is the rapid overspeed (less than one second) of the turbogenerator on loss of load. Both thermal and speed responses are illustrated in the simulated transient results given

in Section III. The response of other protective functions and the consequences of a fault should be given consideration in the selection of the trip levels.

2. GEOHERMAL INSTRUMENTATION AND CONTROL DESIGN CONSIDERATIONS

This Section summarizes those unique characteristics of geothermal electric plants which influence the design of the I&C system.

2.1 Well and Plant Distribution

Resource characteristics, plant design, and economics dictate that multiple plants, typically 50 MW(e) each, be placed on a given resource, and that each of those plants be supported by multiple supply and injection wells.

Each well typically requires pressure, temperature, and flow instrumentation and manual or automatic flow control. Each wellhead must communicate in both directions, with the plant or control center, and may require electric power or instrument air. Analog communication, considering the distances involved, requires extensive signal processing and cabling. Signal multiplexing or complete digital systems may therefore be attractive.

Another consequence of the distance between the wells and the plant is the water-hammer hazard for actuated valves in liquid service. Since rapid valve action is generally not required for control or protection, the actuation speed should be made low enough to preclude water-hammer damage.

2.2 Supplier/Plant Interface

Another unique characteristic of geothermal systems is that the supplier and the plant operator are likely to be two separate corporations. Control and communication interfaces must be considered in the I&C system design.

2.3 Operating Point Range

As presented in Section III-1, plant operating parameters change with variations in ambient conditions, increased fouling resistance, and resource degradation. The magnitude of these changes is determined by the type of plant and mode of operation. Using the floating power concept with a liquid binary plant, the "normal" value for an operating parameter may vary significantly. The operator's decision, as to whether operating parameters are within the specified limits, is therefore made significantly more difficult.

2.4 Environmental Constraints

In addition to the basic plant design, the limitations on noise level and emissions affects transient operation and control. Specific influences of hydrogen sulphide emission and noise limitations in transient operation of the steam supply are discussed in Section III.

3. INSTRUMENTATION AND CONTROL SYSTEM DESIGN OPTIONS

This Section describes the options in system design which result from a consideration of the plant status (whether it is a research, pilot, or commercial plant) and of the current trend from analog to digital systems.

3.1 Research Plant

A minimum-cost research plant, which would use existing hardware and would replace the turbine with a throttle valve, could well incorporate local and distributed instrumentation, protection, and control. Since schedule and cost would be the most important factors, particularly for a short term project, the operator would manually provide most of the control and plant protection. The automatic control system would be a correspondingly small portion.

An analog system would typically provide local indicators and strip-chart recorders. A current digital approach would incorporate a data logger at each location. This would provide, with adequate protection from the field environment, a periodically sampled or report-by-exception history.

3.2 Pilot Plant

A more permanent and complex installation would justify a centralized control system with a much greater reliance on automatic control.

The Magmamax pilot plant, described in detail in Section III, incorporates a dedicated signal line for each data and control function, complete analog signal processing, strip-chart recording, remote indicators and an annunciator and scanner warning system. The shutdown chain is triggered by any of a number of system faults or by the operator. Both manual and automatic loops, based on analog circuits, are extensively used for modulated control functions. This plant is an example of a modern analog control system.

A digital system for the same plant would consist of a cathode-ray-tube (CRT) display module, a pushbutton keyboard, a control processor, a printer, and remote stations.

The CRT would provide an automatic visual display of all alarms. In addition it would permit the operator to call up any plant information he might desire. It could provide a more flexible display of information than a strip chart, particularly since the reference for each channel could be computed and moved as a function of varying operating conditions.

The pushbutton keyboard would allow the operator to converse with the power plant system. Through this keyboard he would be able to open or close breakers, raise or lower equipment set points, review monitored breaker positions or metered values, clear alarms, or print information.

The printer would automatically print all alarms and control actions performed by the operator. Display values could be printed on a routine basis or upon operator request.

In addition to the central processor, remote stations gather data and control equipment in their defined area. The remote stations are electrically linked to the central control processor.

The cost of digital systems is now low enough to be an attractive method of powerplant control.

With either type of control system, as long as the system operation is not fully understood, the operator still performs an essential function.

3.3 Commercial Plant

After development of a particular process to commercial status, the design considerations are operator and I&C system costs versus increased plant availability.

Plant operation can be automated to various degrees. In order of increasing plant availability to the grid, four degrees of automation are

- (1) Semiautomatic plants with a roving operator
- (2) Plants connected by an alarm system to a distant control center
- (3) Plants with assigned local operators
- (4) Plants equipped with remote supervisory control and data acquisition, in addition to roving operators.

(1) Semiautomatic Plants with a Roving Operator. In this case the plants would not have full time operators and are unmanned except for sequential visits by a roving operator. This type of operation would be

appropriate for a reduced first cost design for which the power output of an individual unit would be of minor importance to the entire power system and in which the loss of a single plant's output could be tolerated until the downed unit could be brought back on line.

An annunciator system with a "first-in-alarm" capability, is often installed in this type of plant. This type of annunciator is very important in troubleshooting a unit that has been shutdown automatically.

This type of plant also commonly includes an automatic data logging system for selected parameters. This is not a strict requirement, since a roving operator could take readings during his visit, but this feature would allow for important readings to be recorded between the operator visits.

(2) Plants Connected by an Urgent and Ordinary Alarm System to a Distant Control Center. This type of system is a variation of an operation with semiautomatic control and a roving operator, as discussed above. The plant alarms are brought into a central control area, so that an abnormal condition is known immediately and an operator can be dispatched to that plant. This system provides the advantage that the down time of a plant can be reduced or avoided due to immediate knowledge of an abnormal condition.

An urgent alarm is one which requires immediate attention by an operator, such as a unit shutdown. An ordinary alarm is one of a lesser urgency in which a monitored value is out of its normal range and should have the attention of an operator as soon as possible to prevent more serious occurrences including a unit trip.

The Pacific Gas and Electric Company Geysers' installation began operation using the roving operator approach. Recently, however, PG&E has installed a central alarm system to minimize down time.

(3) Plants with Assigned Local Operators. In this case a trained operator would be assigned to each plant at all times. The presence of

trained personnel at the plant during both normal and abnormal conditions will result in a high degree of plant availability. This system normally contains a central control panel with control devices for operating selected plant equipment, data acquisition readouts, and alarms.

(4) Centralized Control of Multiple Plants. Relocation of individual plant control panels to a central control room permits a reduction in the number of operators and a coordination of plant operations. A complete digital system, as previously described would be located in a control area. The control area could be located in a central dispatch center, where operators control a power transmission system and various types of generating plants.

Certain infrequent functional operations, routine maintenance, and component failures would still be attended to by roving operators.

III. INSTRUMENTATION AND CONTROL SYSTEM DEVELOPMENT

This Section describes the development of the I&C system including the basic requirements imposed on a plant by its role in the power grid, the subsystem control requirements, and detail system and performance descriptions for various types of geothermal plants. The discussion covers power range, startup, and upset operation. Supporting systems involved in other less frequent and generally manual operations, such as filling, draining, purging, venting, and blowdown are not discussed. The Section describes the I&C system for steam, flashed steam, flash-binary and liquid-binary power plants. A discussion of auxiliary systems common to different types of plants is presented at the end of this Section.

1. PLANT OPERATING MODES AND PARAMETERS

This Section details those aspects of plant operation which are common to all plant cycles. The principal modes of operation, defined as power range, startup and upset are discussed.

1.1 Power Range Operation

The most fundamental classification to be considered is that of the plant's role in the power grid, i.e., base load at or near plant capacity, or load-following in which generation matches the transient variation of power demand.

In most cases the geothermal plant output represents a small portion of the capacity of a large power grid. Cost and operational considerations would require that such geothermal plants be operated in the base load condition. Load following would be required if the geothermal plant were isolated with its own load network.

Load control is usually accomplished by modulating the vapor flow (steam or binary-fluid vapor) through the turbine, by moving a governor valve or other variable admission device at the turbine inlet. Partial closing of this valve reduces the turbine inlet pressure and flow rate. An additional control element is generally employed to control the pressure in the vapor generator or steam main, as described below.

In the base load application the turbogenerator speed is dictated by the grid system, and an operator changes the load demand to match the power output to the power setpoint. Maximum plant output is provided by a setpoint which equals or exceeds the current capability. The generating capability is determined by the design plant output less curtailments (reductions due to equipment out of service, such as a pump not in service).

In the load-following application, where the plant exists alone or has a significant effect on the overall load generation, the system frequency must be maintained by moving the throttle valve to control the turbogenerator speed.

The maximum net power of a geothermal plant would, in general, decline with the cooling and depletion of the resource. Some binary designs, notably the EPRI/SDGE Heber Plant, accommodate a cooling resource by changing the composition of the binary fluid. Power required for resource pumping would increase appreciably if the flowrate of the geothermal fluid were increased to offset the temperature decrease of the resource. Additional wells may also be necessary.

Maximum plant output also varies with the changes in condenser pressure caused by ambient temperature changes. The variation is relatively minor in a steam plant, because the condenser pressure is limited by the capability of the noncondensable gas removal system. As the temperature of the cooling water decreases, a lower condenser pressure is established.

The ability of the noncondensable gas removal system to remove the gases at a lower pressure is quite limited. The gases remaining in the condenser exert their partial pressure therefore limiting the condenser pressure. A binary plant is not subject to the same limitation, however, and the resulting power variation can be substantial as shown subsequently for the Raft River pilot power plant.

Both classes of plants show a reduction in power output as fouling deposits accumulate. The steam plants lose power due to pipeline, turbine, and condenser fouling. The binary plants lose power principally due to heat exchanger fouling. The common transient power variation due to this is represented by a sawtooth curve; the power declines to a minimum as the fouling builds up then peaks to a maximum after shutdown and cleaning.

1.2 Startup Operation

This is the most challenging of all phases of operation because of the number of subsystems simultaneously exercised, the off-design operating levels of the various components, and the wide ranging transient conditions.

The most obvious of the hazards is that of thermal stress. Components throughout the geothermal system are subject to design limitations on heatup rate. Wells generally require a slow increase in flow. The speed with which a well can be put on line depends upon the temperature of the geothermal fluid at the wellhead and the temperature of the resource, and is determined by temperature change limitations of the well pump (particularly a shaft-driven pump) or the transmission systems.

Generally each of the liquid loops, such as the brine, working fluid, and coolant, incorporates a pump which has a limited range of flow-to-speed ratios for sustained operation. The slow transit through the low flow range generally requires additional complications such as a variable-speed electric or turbine drive or, for fixed-speed drives, a bypass flow-control loop.

Turbine startup is not subject to the same temperature gradient limitations as in fossil or nuclear plants, because of the substantially lower vapor temperatures. The control hardware and operating procedures are, however, similar. The acceleration to near synchronous speed is accomplished with the generator unloaded and with the governor or steam chest valves full open, to provide full admission for even heating and loading. A relatively small vapor flow is controlled by the speed controller and a separate throttle valve prior to synchronization. When the throttle valve is full open, control is transferred to the governor valve. Connection to the grid results in fixed-speed operation, as dictated by the grid frequency. The speed controller and the governor valve provide load control as the load is increased to the desired level.

Plant operation during turbine startup is detailed for each type of plant in the Sections which describe the individual plant types.

1.3 Upset Operation

An upset condition is defined as an abnormal operating condition sensed by one or more of the plant protective devices or by an operator. Where system response to an upset does not depend on an operator reaction, it is accomplished by logic implemented in the plant protective system. That logic is, of course, developed by a consideration of the consequences of various upsets.

Upsets may result in the system responding by: curtailment, turbine shutdown, or total shutdown.

A curtailment is a reduction in system output due to the failure of one of a set of parallel devices such as pumps and cooling tower fans. The device is shutdown by automatic or operator response and plant operation continues at a reduced power output.

A turbine shutdown is dictated by a turbogenerator or line fault which requires separation from the grid and cessation of turbine operation. The remainder of the plant can continue operating if the fault can be cleared quickly and if the vapor can bypass the turbine, or, if in a steam plant, the vapor can be vented. This allows rapid resumption of power generation.

Turbine-only shutdown with continued plant operation requires external power for auxiliaries unless an immediate resumption of generation at the station-auxiliary level can be accomplished. This is common on conventional power plants in Europe, because of limited tie-line capability, and is of interest for U.S. geothermal plants with high parasitic losses.

The plant must be totally shutdown if the fault is local and serious, if external faults persist, or if turbine-only shutdown is not possible.

A critical upset condition in any power system is the loss of generator load due to separation from the grid. Vapor flow to the turbine must be stopped quickly to limit the resultant turbine overspeed. In Westinghouse's large-turbine design, for example, the turbine valves at the main steam inlet to the turbine are closed in 0.10 to 0.15 second by venting the actuator oil and allowing rapid spring-driven closure.

A simulation of a turbine trip with vapor bypass is described for the Raft River binary plant below.

1.4 Bypass Operation

Plant operation and control, in power range, startup, and upset operation, may be improved by the addition of geothermal-supply or turbine bypasses. Bypassing geothermal fluid around the plant permits independent startup and testing of the supply system. Bypassing vapor around the turbine allows starting and operating the plant without

requiring turbine startup. The turbine can be started subject only to its own requirements. The load can be controlled without disturbing plant operation by simply diverting excess flow around the turbine. It allows continued plant operation in the event of a turbine trip, so that normal operation can be quickly restored if the problem was external to the plant. Bypass operations are discussed in each of the specific plant presentations which follow.

2. STEAM PLANT OPERATION AND CONTROL

2.1 Configuration

A plant producing electricity from a geothermal steam resource, as shown in Figure 1, incorporates four main process streams: steam, coolant, condensate, and noncondensable gas. The figure represents an early Geysers design without hydrogen sulphide abatement. Modifications for H_2S abatement are addressed in the following discussion.

Steam flows from the producing wells through the supply lines, scrubber, separator, turbine, and condenser. The coolant stream is brought to a direct-contact condenser, and the mixed condensate-coolant stream is pumped to the cooling tower. Excess coolant is pumped from the cooling tower and injected into the ground. Noncondensable gases, including H_2S , are drawn from the condenser through two stages of steam-jet ejectors. The relatively dry noncondensables, are treated to remove the objectionable gases including H_2S , then vented. The condensate from the ejectors is returned to the injection well. This process requires that the complete flow of coolant and condensate be treated for gas removal.

By changing to a surface condenser and treating the noncondensable gas stream with the Stretford process 90% of the H_2S is removed from the stream. Since only the condensate leaves the condenser with dissolved

Fig. 1 Typical steam plant.

H₂S, the amount of water which must be treated is vastly decreased. Further abatement, to approximately 95%, is possible by treating the condensate before it reaches the cooling tower.

2.2 Steam Supply System

Before a geothermal power plant can be started, the wells must be started and brought up to the normal flow of clean steam. During this period the steam flows through automatic pressure-control valves to the atmosphere. When the plant is brought up to load the pressure control valves will automatically close and the steam flow is directed to the turbine. The automatic pressure-control valves are backed up by pressure-relief valves designed to handle well flow if the control valves fail to open. If the plant is to be shutdown for a long period of time, the wells will be manually shut off. When the plant is ready to restart, the wells will be gradually brought up to the design flowrate, and vented which clears them of debris.

The initial Geysers design responded to the flow reduction resulting from a turbine trip, by venting through pressure-control valves. If the outage continued for several hours, cross-connections with other supply lines were used to divert the flow to other plants. A more recent plant design, Unit 15, incorporates the capability of a 20% reduction in well flow, in order to reduce noise and H₂S emission without damaging the supply wells by a rapid shutin. Normal supply system shutdowns require over four hours to prevent well damage.

Even though significant condenser fouling occurs the time interval between shutdowns is dictated by the fouling of the turbine by particulates. This interval is determined by how efficiently the particulate scrubbers remove particulate.

A plant that is fed dry steam from the wells is not usually endangered by excessive moisture in the steam. The condensate that forms in the pipelines is drained off by steam traps. An in-line moisture separator

is installed in the steam pipeline from the wells before the line enters the turbine building; it collects condensate that may be coming through the pipeline.

2.3 Coolant and Condensate

Coolant flows from the cooling tower basin to the condenser by gravity or by pumping. The coolant condenses the vapor from the turbine and is returned to the cooling tower.

In a direct contact condenser, the condensate plus the total flow of cooling water must be pumped from the condenser basin to the cooling tower to maintain a constant level in the condenser basin. If the condenser is of the surface type, only the condensate must be pumped out to maintain the level. In both cases it is important to maintain the condenser level within limits. A high level will reduce the condenser efficiency, while a low level will cavitate the condensate pump.

The normal method of controlling condenser basin level is by throttling a flow-control valve, in the discharge line of the coolant pumps, with a signal from the level controller. In some designs a bypass valve permits return of the condensate-pump discharge back to the condenser basin to control level or to prevent pump overheating during low flow conditions.

The portion of the condensate that is not used as make-up in the cooling tower will overflow from the cooling-tower basin as blowdown into a collecting pond. To prevent this from causing stream or surface pollution, it is normally returned to the aquifer via injection wells. The wells are located so that the cool return water will not thermally degrade the producing geothermal wells. The operation of the injection pump is controlled by a level controller in the pond. When the steam condensate is insufficient or unavailable for make up it may be necessary to add surface water to the tower basin.

Cooling tower operation is discussed in Section III-5.2.

2.4 Noncondensable Gas System

The absolute pressure in the condenser is determined by the capability of the noncondensable gas removal system and by the heat-transfer capability of the cooling system.

Before turbine startup, the noncondensable gas removal system is started to evacuate air from the condenser and produce the low absolute pressure required to operate the turbine at design conditions. When the turbine is operating and steam is flowing into the condenser, the vacuum is controlled by equipment capability to remove gases which exert their partial pressure in the condenser.

The system shown in Figure 1 requires a level controller to control the condensate discharge level of the steam condenser.

2.5 Geysers Steam Plants

This section presents a summary of the control configuration for Geysers Unit 11, which has two 55 MW turbines and a single generator. Both turbine-exhaust flows to a single low level direct contact condenser. This is the common configuration of most of the Geysers plants. The later units, currently under construction, will have surface type condensers.

The steam, condensate, coolant, and noncondensable flow configuration is shown in Figure 2. From the wells, steam flows into the plant through a motor operated valve. A parallel pressure equalizing valve is used for warming the lines and the turbines. The flow is then split into two paths, each with a strainer, stop valve and swing check valve. One of the stop valves is paralleled by a 10-inch motor operated valve to admit steam for initial turbine acceleration. Auxiliary steam, for the gas ejectors, is taken from the other line. The two lines are reconnected in a header which supplies steam to each turbine. Each turbine entry line has a butterfly control valve. The steam is expanded through the turbines and the exhaust flows to the main condenser. Auxiliary steam to the first and second stage gas ejectors is provided through a motor operated valve and a pressure control valve.

Fig. 2 Geysers Unit 11 control schematic.

Cooling water to the inter- and after-condensers is modulated by temperature control valves. Liquid level in the after condenser is controlled by modulating the coolant return to the main condenser. Coolant flows from the cooling tower basin to the main condenser by gravity and vacuum drag. A flow control valve regulates the flowrate according to condenser pressure. During the initial portion of a startup the relatively high condenser pressure blocks the flow to the top of the condenser. During this period coolant flow is directed through a startup line and level control valve. The startup line is located at a lower elevation on the main condenser. When the condenser pressure has reached 14 to 15 inches of mercury the startup-line valve is closed. The coolant flow is directed to the top of the condenser and level control is switched to the recirculation line from the pump discharge header to the condenser hotwell.

The four condensate pumps are started in sequence. Each pump-discharge valve controls pump-discharge pressure during startup and is then opened fully. Backflow through a stopped pump is prevented by closing the discharge valve. A separate line from the pump discharge header to the cooling tower basin is used to start up the unit when freezing conditions prevail. Excess condensate overflows the cooling tower basin and proceeds via a weir to a settling basin for ultimate reinjection.

3. FLASH STEAM PLANT OPERATION AND CONTROL

3.1 Configuration

A flash steam plant differs from a direct steam plant in that a liquid or two-phase fluid flows or is pumped to the plant, where the vapor is created in a series of flash tanks. The steam supply to the turbine is cleaner than that of a direct-steam cycle. The brine discharge is more saline and has a higher rate of flow, than the condensate discharged from the direct steam plant.

As in the direct steam plant, vapor can be bypassed around the turbine during turbine startup or turbine trip operation. In contrast with the direct steam plant, however, the flash steam plant can bypass the liquid supply directly to the injection system during plant startup.

The operation of control of turbine, condenser, cooling tower, and noncondensable gas system is basically the same as for the direct steam cycle, and they will not be discussed further.

3.2 Steam Supply System

The discussion which follows is initially directed towards a design without brine or turbine bypasses. Discussion of bypass system operation is deferred to the end of Section III.

Figure 3 illustrates a typical two-stage flash supply system without bypasses.

A mixture of hot liquid brine and steam flows from each well through a control valve to the first-stage separator (flash drum). The pressure in the drum is normally controlled at primary steam pressure by operation of inlet-control valve PCV-1A. Steam flow through the flash drum and thence to the turbine is controlled by the turbine-throttle valve. If the first-stage flash drum pressure cannot be controlled by the inlet-control valve PCV-1A, the vent control valve PCV-1B will open to release steam to the atmosphere. If PCV-1B cannot control pressure at a level that is safe for the flasher, the pressure-safety valve PSV-1 will open to release additional steam.

The liquid level in the first-stage flash drum must be maintained at a level that will prevent both steam flow into the liquid line and liquid flow into the steam line. A level control sensor in the flash drum, controls level-control valve LCV-1A, which allows liquid brine to flow into the second-stage flash drum. If the flow rate to the second-stage flash drum is not sufficient, the level in the first-stage flash drum will rise, and the controller will then open drain-valve LCV-1B, which allows liquid brine to flow to the collection pond.

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Fig. 3 Dual flash steam system.

The steam pressure in the second-stage flash drum is controlled by releasing steam to atmosphere when the pressure exceeds that required at the turbine-throttle valve. A pressure-safety valve protects the flash drum from excessive pressure should the pressure control system fail. It may be necessary to close the low pressure turbine-stop valve if the flash drum pressure becomes subatmospheric. The liquid level in the second-stage flash drum must also be controlled to prevent steam flow into the liquid disposal line and liquid brine to flow in the steam line. Level controller LIC-2 operates valve LCV-2, which allows excess brine to be pumped to the injection well.

Startup of the wells requires a period of time during which automatic pressure-control valves at the well head allow the liquid to flash into steam. The steam is vented to the atmosphere and the excess brine flows into a pond. After the well operation becomes stable, the liquid brine and steam flow is gradually shifted to the high-pressure steam flash drum. The excess brine from the high-pressure flash drum flows to the low-pressure flash drum. Steam is vented to the atmosphere from both flash drums by automatic pressure-control valves. When the plant is brought up to load, the pressure-control valves will automatically close and all steam flows to the turbine. The automatic pressure-control valves are backed up by pressure-relief valves designed to handle well flow if the control valves fail to open.

If the plant is to be shut down for a long period of time, the wells would be shut off manually. When the plant is ready to re-start, the wells will be gradually brought up to flow to clear them of debris, and to control the heating rate of the well and of the piping system. With shorter shutdowns, the pressure-control valves at the wellhead, vent steam as in well startup.

Plant startup for a system with a brine bypass would involve the manual or programmed closure of a flow-control valve in the bypass line, with brine admission to the first-stage flash drum modified by the first-stage pressure controller. Turbine startup would involve increasing

the turbine-inlet flow while maintaining flash drum pressures by controlling turbine-bypass flows. By opening the turbine bypass valves, turbine trip could be accommodated without shutting the plant down or venting to the atmosphere.

A flash steam system is vulnerable to excessive moisture being fed into the turbine. To guard against this, the turbine is tripped, due to a signal from a level sensor when the liquid level gets to the critical level in any of the flash drums. Other alarms which may be provided on each flash drum are: high or low level flash drum pressure and high or low flash drum level.

4. BINARY PLANT OPERATION AND CONTROL

4.1 Design and Operational Considerations

Figure 4 illustrates a typical binary plant concept, where an intermediate working fluid is vaporized, expanded through a turbine, condensed, and pumped back through the loop, in a closed cycle. The geothermal fluid is used to heat the secondary working fluid.

One requirement of binary systems is multiple heat exchangers. Various types of heat exchangers can be used. The direct-contact heat exchanger is one type currently being studied. Many different surface heat exchanger configurations have been studied. The significant distinction from a controls standpoint is the boiler temperature relative to the critical point of the binary fluid. Figure 4 illustrates a subcritical boiler, in which the liquid level may be measured and controlled by the feed control, matching the feed supply to the rate of vapor generation. A supercritical boiler, of course, has no liquid level; the feed control could be based on boiler exit temperature.

The binary fluid boiler pressure, in the variation shown in the Figure 4, is controlled by slaving the turbine-bypass valve to the turbine-governor valve, in order to provide a constant total vapor flow

Fig. 4 Liquid binary system.

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as the load varies. Boiler pressure control may also be accomplished by driving the turbine-bypass valve from a separate boiler-pressure controller or by modulating the geothermal fluid flowrate. Geothermal fluid control is discussed separately in the sections describing the flash-binary and liquid-binary systems.

As shown in the figure, the working fluid head rise is provided by a motor-driven pump. The bypass-flow control loop provides for satisfactory pump operation and a more constant head rise in the startup range. Another common arrangement incorporates a motor-driven boost pump and a turbine-driven main feed pump. Feed control would be provided by modulating the flow of vapor to the main feed pump turbine.

Surface type condenser and cooling tower operation are similar to the operation in other types of geothermal plants previously discussed.

4.2 Flash Binary Systems

Figure 5 shows a flash brine replacement for the supply system portion of the previous configuration. The control of the flash binary supply system is similar to the flash steam plant control presented previously. The liquid level and pressure is maintained in the first flash drum. The liquid level is maintained in the second flash drum. During low flow and startup condition the brine is flashed at the wellhead, the vapor is vented to the atmosphere, and the liquid is pumped to the injection well.

4.3 Liquid Binary Systems

4.3.1 General Design Considerations. Figure 4 is typical of a liquid brine system. This type of binary system uses the geothermal fluid in liquid state, throughout the system, by making certain the pressure is above the vapor pressure. It is also necessary, for brines with high carbon dioxide content, to keep pressures high enough to prevent outgassing and the resulting deposition of calcium carbonate in piping and equipment. Figure 4 shows the use of a pressure controller

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Fig. 5 Flash binary system.

and a control valve at the injection wellhead to maintain the pressure on the geothermal fluid. Pumps are typically provided at the supply wells, at the plant, and at the injection wells.

Figure 4 shows an arrangement which provides brine inlet temperature control and a constant brine flow rate. It also provides a slow heatup rate to minimize heat exchanger thermal stresses.

The three control valves are driven by a single controller providing a constant flow resistance while replacing some of the hot incoming brine with an equal amount of colder plant exit brine. The supply and injection system is started and brought to full flow with valves A and B open and valve C closed. The brine boost pump is started and the design flow rate is established through the heat exchangers while recirculating cold geothermal fluid through valve B. The controller adjusts valves A, B, and C, to provide a mixed brine temperature, matching a demand which is ramped upwards to the resource temperature. This gradually closes valves A and B and opens valve C until the bypasses are closed and all of the brine flows directly through the heat exchangers.

A much simpler arrangement may be used if heat exchanger startup limitations can be met by flow modulation. Valve B and the recirculation line can be eliminated, valve A is driven to provide the required bypass and valve C is driven to provide the required heat exchanger flow.

4.3.2 Raft River Dual Boiling Plant. The Raft River 5 MW plant in southern Idaho has been chosen to illustrate binary system performance because the data is available from the dynamic simulation used to develop the plant controls and operating procedures. The information and considerations are typical of what might be developed for any binary plant control system design.

(1) **Configuration.** Figure 6 illustrates the configuration of this plant. This plant is a variation of the liquid binary system discussed previously. The plant is intended to demonstrate the technical feasibility

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Fig. 6 Raft River dual boiler binary plant.

of a dual-boiling system utilizing isobutane as a working fluid for power generation from a medium temperature (290°F) geothermal fluid.

The plant will operate in the base load, and power variations due to changing operating conditions will be accepted by the grid. Turbine throttling and bypass allow transient load reduction without adjustment of brine or coolant loops.

The brine loop consists of three supply wells (for simplicity, the figure shows only one) with check valves at the junctions with the main supply line. An artesian bypass at each well permits thermal conditioning (controlled heatup rate) of the complete brine system. Pumped geothermal fluid flow is established by starting the well pump and opening the manual control valve. Subsequent adjustment of well flow is also accomplished manually.

Temperature control during startup is provided at the plant by the boost pump and the ganged three-valve arrangement discussed earlier. A hand balancing valve is provided in the flow path through the heat exchangers, to adjust for variations in heat exchanger performance and in fouling resistance.

This startup procedure requires considerable external power to drive the pumps, until the turbogenerator begins producing power. Peak external power requirements could be reduced by starting the plant after a single supply well is established. This would require additional hardware to drive an additional balancing valve that would match the recirculation pressure drop to the bypass pressure drop, in order to permit the three valve system to operate at a suitable pressure distribution for the lower brine flowrate.

In an urgent upset condition, the bypass line provides a rapid and redundant means of stopping heat input to the working fluid loop. Since the majority of the brine piping is low cost asbestos-cement with a limited capability for rapid temperature change, the injection line

cannot accept the sudden change from normal plant exit brine at 150°F to supply brine at 290°F. The three way valve is therefore sequenced to divert the flow to the pond, and the injection and supply pumps are shut down when the exit brine temperature rapidly changes.

Each of two injection wells has a control valve at the pump discharge to automatically maintain the pump inlet pressure above the outgassing level.

The working fluid loop uses isobutane and a configuration identical to that shown in Figure 4 except for the parallel high and low pressure paths, which were provided to increase cycle efficiency, and the preheater bypass lines. These bypass lines are manually controlled to prevent flashing at the boiler inlets, to compensate for heat exchanger over-performance, and to adjust for variations in fouling.

The boiler feed valves are, relative to the basic configuration discussed earlier, moved downstream to the boiler inlets. This provides individual boiler level control. While this increases the vapor pressure at the control valves it ensures that cavitation will occur in these valves. The pressure drops are relatively small and cavitation resistant valve trims are provided to minimize erosion.

The coolant loop provides a constant cooling water flowrate and an isobutane condensing pressure varying with the ambient temperature. Cooling tower basin level is controlled by varying the treated brine makeup flow.

(2) Simulation. Transient simulation of the plant and the supply and injection system was accomplished using two specifically developed codes.

The thermohydraulic system behavior, neglecting acoustic phenomena, was simulated using the Time and Frequency (TAF) problem solver code^[1] and a CDC 7600 computer. The acoustic behavior was studied using the

C5MP Code^[2]. The following discussion presents some of the analysis generated using the TAF code.

The TAF mathematical model of the system incorporates the following:

- (1) Approximations to Starling's^[3] data for isobutane properties
- (2) Estimated or vendor data for pump, turbine, and cooling tower characteristics
- (3) Detailed lumped parameter models of the condenser and the heat exchanger
- (4) Flow equilibrium throughout the various process loops
- (5) Mass and energy balances for uniform two-phase control volumes for the isobutane spaces in the boilers and the condenser,
- (6) Proportional plus integral mode controllers.

The model accepts variable inputs for brine inlet and exit conditions, pump speeds, fouling, ambient conditions, trim valve positions, and controller demands.

Table I summarizes the effect of ambient air conditions and fouling on plant performance. The three data points represent the hot, median, and cold conditions. Ambient temperature, exceeds the value of the hot condition 1% of the time, and goes below the cold condition 1% of the time. A discontinuous curve must be used to connect the data at the three points, because the tower air flow is reduced from 2255 to 1500 cfm at the cold condition. This was done to keep the cold water leaving the cooling tower at least 39°F to prevent icing at the worst location.

TABLE I

RAFT RIVER PLANT STATIC PERFORMANCE

Wet Bulb °F	Dry Bulb °F	Foul % Design	Low Bypass %	High Bypass %	Cond Press psia	Low Boil Press psia	High Boil Press psia	Cond Temp °F	[a]	Low Boil Temp °F	High Boil Temp °F	Low Subcool Margin °F	High Subcool Margin °F	Brine Exit Temp °F	Cold Coolant Temp °F	Hot Coolant Temp °F	Evap Flow lb/sec	Tot Iso Flow lb/sec	Net Power MW(e)
<u>Effect of Preheater Bypass</u>																			
65	92	DES	10	0	74.8	196.7	364.1	100.8		175.2	233.8	5.3	5.3	149.7	73.2	93.0	38.1	245.5	2.46
			15	0	74.6	193.7	363.2	100.6		174.0	233.5	7.4	5.7	150.2	73.2	92.9	37.9	243.8	2.42
<u>Effect of Ambient and Fouling</u>																			
65	92	DES	10	0	74.8	196.7	364.1	100.8		175.2	233.8	5.3	5.3	149.7	73.2	93.0	38.1	245.5	2.46
		10%			73.1	196.2	395.0	99.3		175.0	242.2	8.0	8.8	140.5	73.4	94.3	39.7	258.1	2.96
38.4	47	DES	10	0	54.5	192.3	362.8	80.2		173.4	233.4	8.0	5.8	140.7	50.9	71.8	26.2	243.6	3.34
		10%			53.3	192.5	394.3	78.8		173.4	242.0	10.2	9.0	130.8	51.2	73.4	27.8	256.6	3.87
8	8	DES	10	0	44.7	190.2	362.2	68.8		172.5	233.2	9.6	6.1	135.8	38.6	60.1	19.9	242.4	3.82
		10%			43.8	190.7	393.9	67.8		172.7	241.9	11.3	9.2	125.7	39.4	62.2	21.4	255.7	4.37

[a] Saturation temperature: leaving condition is 4°F lower

Standard ConditionsDesign fouling - Brine 0.0015 hr-ft²-°F/Btu

Working fluid 0.0005

Coolant 0.001

Brine inlet 289.6 lb/sec @ 290°F

Makeup temp 75°F

Coolant flow 1869 lb/sec

The low-temperature preheater bypasses 10% of the total flow, and the high preheater bypass is closed. These settings yield inlet conditions at both boilers which are 5.3°F subcooled at the critical conditions of "hot" ambient temperature and design (maximum) fouling. As shown in the table, power output is relatively insensitive to preheater bypass.

The effect of reduced ambient temperature is to: lower condenser temperature and pressure, lower coolant temperature, lower brine exit temperature, lower evaporation rate, increase the low preheater subcooling, and increase the net power output.

Reduced fouling increases high boiler pressure and temperature, increases subcooling, increases isobutane flow rate, increases net power, and appreciably decreases brine exit temperature.

The maximum range of plant power output, considering 1% temperature extremes and fouling of 10 and 100% of the design value, is 1.91 MW(e), or 78.0% of the minimum power. The advantages of allowing the power output to vary with the ambient conditions are clear.

It should be noted, in summary, that the controls operating over the above range of full power operation are

- (1) High and low pressure boiler feed controls
- (2) Turbine power-boiler pressure control
- (3) Cooling tower basin level control
- (4) Injection pump inlet pressure control
- (5) Building heating/cooling and freeze protection control valves
- (6) Manual stepping of cooling tower fan speed (full, half, zero) and direction under icing conditions.

Further description of cooling tower control is given in Section III-5.2.

(3) Plant Startup. As described earlier, the supply and injection system is brought to full flow and the temperature is stabilized by using the plant bypass. The isobutane loop startup is initiated by successive purges with water and nitrogen. The loop is then completely filled with subcooled isobutane. The isobutane pumps are started and circulation continues until the pump work has heated the fluid to 130°F and any remaining water has been removed by a dryer. The loop is then drained to the required inventory of isobutane.

The brine boost pumps are started and the brine temperature controller is enabled with an initial demand of 130°F, thereby providing a small brine supply to the plant with the nearly open recirculation and bypass valves reducing the mixed plant inlet temperature to 130°F.

The turbine inlet-bypass valve combinations are manually controlled, with the bypass valves initially closed, and turbine flow blocked by the stop valves. The isobutane recirculation-flow control and the boiler level controls are enabled, and the isobutane pumps restarted. The cooling tower basin level control is then enabled, and the fans and the coolant pumps are started. The brine temperature demand is then ramped to 290°F.

Figure 7 shows the results of a quasistatic mapping study made to determine the turbine-bypass valve sequencing during the heatup to full operating conditions. The objective was to maintain a subcooled condition at the boiler inlets, and to minimize the change in sensitivity of brine recirculation flow to brine mixed temperature over the entire startup. Both preheater bypasses were set at 15%. The high pressure preheater-bypass is necessary at the cold end of the startup; it will be shut off after startup is complete. The data is for all heat transfer surfaces fouled to 10% of the design maximum. Different bypass settings would be required if fouling were more severe.

NOTE: The selected bypass valve schedule (C_v a linear function of brine temperature) is shown as the dashed lines. The solid lines represent constant C_v values for bypass valves as indicated.

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Fig. 7 Raft River startup mapping.

Figure 7 shows the high pressure and low pressure boiler inlet subcooling and the brine recirculation flow as functions of mixed brine temperature for several turbine-bypass-valve flow coefficients. The high and low pressure bypass-valve coefficients are made equal for the purposes of this study.

The data show that the subcooling at both boiler inlets varies inversely with the bypass-valve flow coefficient as the brine temperature increased. A linear (with mixed brine temperature) bypass valve sequencing with a very small initial value was selected for simplicity. The resulting subcooling and brine recirculation flow is shown by the dotted lines. The minimum subcooling values were 5.0 and 5.5°F for the high and low pressure boiler inlets, respectively. The ratio of recirculation-flow change to mixed-brine-temperature change varied by a factor of 3.0 over the complete startup range.

The turbine would be started at the completion of the plant startup, when the turbine-bypass valves are fully open, the slaved turbine-inlet valves are fully closed, and the turbine-stop valves are closed. The stop valves would be opened, the turbine speed control enabled, and the speed demand ramped up to the design level. The generator would be put on line, control transferred to the load control mode, and the load demand ramped to the desired plant output.

(4) Upset Operation. Figures 8a through 8c shows the simulation of a turbine trip at full power. The loss of the generator was simulated (conservatively) by stepping the generator torque to zero at 1.0 second. After a 0.2 second dead time, the turbine-stop valves (both stages) were closed in 0.5 second and the turbine bypass valves opened in 5.0 seconds.

Figure 8a shows the turbine speed increase from 8000 to 8800 revolutions per minute and the subsequent decay. Figures 8a through 8c show the perturbation in liquid levels in the boilers and condenser, which is due to blocking the vapor flow until the bypasses open fully and the feed

Fig. 8a Turbine trip response -- valve position, speed, and torque.

Fig. 8b Turbine trip response -- pressure, level, and subcooling margin.

Fig. 8c Turbine trip response -- temperature and flowrate.

controls return to the design condition. Except for a 7.0 psi pressure rise in the high boiler, a 3.0 psi rise in the low boiler, and a 7.0 psi drop in the condenser, the system is relatively undisturbed.

While the flow and pressure disturbances could be eliminated by providing bypass-valve speeds equal to those of the turbine stop valves, the transient response illustrated above is considered acceptable.

4.3.3 Magmamax Dual Binary Plant. The Magmamax system is presented because of the interesting control aspects of the dual binary cycle, the particular design options chosen, and to show the detailed I&C design for a plant currently being constructed.

- (1) Configuration. As shown in Figure 9, the design incorporates
 - (a) A liquid brine system with a flow modulation plant bypass
 - (b) A supercritical isobutane loop, with a turbine driven feed pump, a tandem synchronous turbogenerator, and recuperation to a separate propane loop
 - (c) A lower temperature propane loop with an induction turbogenerator, and
 - (d) A spray pond cooling system with extensive management of cooling capability.

Another unique feature of both isobutane and propane loops is the use of heat exchanger bypass flow to cool the turbine bypass flow, and thereby reducing condenser thermal shock.

Fig. 9 Magmamax dual binary control schematic.

(2) Geothermal Brine Circuit. The heat source for the Magmamax power plant is geothermal brine supplied by deepwell pumps from three separate wells. Since these wells are quite far apart (as much as 1/2 mile), and since the equipment yard and the heat exchange equipment is remote from these well sites, the geothermal brine is piped from each well to a common point where it is manifolded, and brought to the plant as a single combined flow. Each of these individual well lines contains a sand separator for removing any particulate matter which may flow from the well. Valves VB1, VB2, and VB3 are production well shutoff valves, actuated locally to shut off well flow and stop the well pump in the event of pipeline rupture. These valves may also be used to manually adjust well supply quantity and will be used for well balancing purposes.

The brine is supplied from the wells at 360°F and about 200 psia, in order that it might be pumped to the plant without flashing and without releasing any of its dissolved gases. Flow quantity from each well will be measured (probably near the wellhead) and a remote indication of these flows will be required. At the plant, the geothermal brine is pressurized by the booster pump to 270 psia to prevent flashing in the heat exchanger field. The total plant flow passes through valve VB4 into the heat exchanger field (HXF) when the plant is in full operation. Valve VB4 is a two-position isolation valve which is used to protect the heat exchanger in the HXF from rapid thermal changes at startup. It will be controlled by HXF leaving water temperature, and is bypassed by a small orifice for HXF warmup. It would open only after enough hot brine had been bled through the field to raise its temperature to a preset value.

Valve VB8 is a small bleed valve. It bypasses VB7 to provide warmup flow control and it is controlled by a preset flow rate ramp-up. Valve VB7 is the main flow control valve for the HXF, and is controlled by flow rate, ΔT , or isobutane knockout drum temperature, depending on whether control is in the start, intermediate, or run mode. Valve VB9

is the HXF flow bypass valve. This valve is pressure controlled to keep the circuit above saturation pressure, and would bypass the plant circuit during startup, and during load fluctuation transients.

The heat exchanger field consists of eleven long-tube true counterflow heat exchangers. Ten of these are piped in a series-parallel arrangement used to preheat, boil, and superheat the isobutane working fluid. Each of these exchangers is 18 inches in diameter, with 70 foot-long tubes. Isobutane flows in the tubes, and geothermal brine flows in the shell. The eleventh shell is a shorter exchanger used to boil and superheat the dual fluid cycle (DFC) propane working fluid after it has been heated by the main turbine exhaust. Valves VB5 and VB6 are used to control the brine flow through this propane boiler-superheater. Design throughput time for the water side of the HXF is about two minutes, and design pressure drop is about 153 psi. At the HXF exit, cooled brine flows to the injection pump where it is pressurized and sent to the injection wells. Valves VB10 and VB11 are the shutoff valves for the injection well piping, being controlled in a manner similar to VB1, VB2, and VB3.

(3) Isobutane Circuit. The isobutane flow circuit is not unlike that of a conventional steam power cycle, but uses the hydrocarbon as its working fluid. Isobutane liquid entering at a nominal 93°F is heated during its series travel through six of the 10 counterflow heat exchangers in the HXF. It then splits into two parallel flows, each flowing through a boiler and a superheater before passing into the knockout drum at 345°F and 500 psia. Design isobutane flow is 1.03×10^6 pounds per hour. After passing through the knockout drum, the gas passes through a trip valve and then through the main turbine control valve VII. This valve is controlled by a speed-load controller, the speed signal comes from a magnetic pickup on the main turbine gear reducer output shaft and the load signal provided by devices sensing generator electrical output. Several modes of operation of the turbine-control valve are required. At startup, and prior to synchronization, manual speed control will be used to bring the turbine to idle speed. After reaching idle speed, the turbine acceleration will be controlled through automatic ramp-up by the governor. Once synchronization is

accomplished, the generator speed is set by the grid line frequency, and valve VI1 will be used to control only the load. Normally, this valve will be wide open and the plant will be running at full capacity, since it is only a pilot operation. When it is necessary to reduce the plant output, a means of setting and controlling VI1 is required.

The main turbine starting bypass valve, VI8, is used to bypass gas around the main turbine to the condenser during the startup sequence and during any load change stabilization periods. This valve would be under knockout drum pressure control, and would be closed during normal operation. The bypass desuperheater valve, VI9, would be modulated during periods of bypass flow to provide liquid for cooling this bypass gas, since the condensers should not be subjected to temperatures as high as may be encountered in the main turbine supply flow.

The main turbine is a YORK 3338 tandem design with dual three-stage units, each unit exhausting into the shell side of the isobutane recuperator. The turbine drives an Allis-Chalmers 10,500 KW, 1200 rpm synchronous generator through a General Electric reduction gear, at a turbine speed of 6391 rpm. Extraction gas from the main turbine flows through a flow measuring device (FI2) and then through the boiler feed pump-turbine control-valve, VI2, to the boiler feed pump-turbine (BFPT). The BFPT is a YORK 226 two-stage turbine driving a, United Centrifugal Pump, three-stage horizontal centrifugal pump through a Western reduction gear. VI2 is controlled by a governor, which senses both speed and knockout drum pressure. The speed signal comes from a magnetic pickup on the BFPT gear reducer. The BFPT speed will be varied during operation, to control liquid flow to the HXF. A pressure controller, sensing boiler feed pump (BFP) discharge pressure, will override the knockout drum pressure signal. The extraction flow control VI7 will normally be closed during operation, but would be controlled by a flow controller, and would open if extraction flow was throttled by VI2 to the point where it began to affect main turbine output. A pressure controller sensing extraction line-pressure will override this flow signal to maintain the proper

interstage pressure. The operational control of VI7 must be flexible enough to allow future resetting and "tuning," since this valve will probably be used mainly for improving the plant power output. Its control mode will depend upon the operational efficiencies of some of the other plant equipment.

Exhaust gas from the generator and feed pump turbines flows through the recuperator, where it gives up some of its heat to the dual fluid cycle (DFC) by heating and starting liquid propane to boil from the DFC boiler feed pump. The isobutane exhaust gas passes from the recuperator to the two isobutane condensers, where the power plant's waste heat is rejected to the cooling water circuit. This isobutane liquid then passes to the receiver, where it is picked up by the two condensate booster pumps and passed on to the BFP. The BFP then pressurizes the working fluid to HFX pressure. Valves VI3 and VI4 are the BFP throttle and bypass valves. These valves assist the BFPT governor, in controlling the flow of working fluid to the HFX, and prevent the BFP from being throttled to shutoff. The BFPT startup valve, VI6, will be used to supply BFPT gas during startup, and would also supply BFPT gas under any condition where extraction flow was insufficient. The knockout drum-blowdown-valve, VI5, under primary control of knockout drum-level, is used to return any liquid carryover from the HXF to the receiver. VI5 would be in use mainly during the warmup and startup sequences.

(4) Propane Circuit. The propane flow circuit is very similar in configuration to the isobutane circuit, providing a "bottoming cycle" to extract additional heat from the geothermal brine and also reduce the amount of heat rejected to the atmosphere through the cooling water circuit.

Propane liquid, entering at a nominal 77°F is heated and partially boiled in the tube side of the isobutane recuperator, extracting heat from the isobutane turbine exhaust. It then passes into the propane boiler-superheater where boiling is completed and the gas is heated to 205°F and 460 psia. This second stage of heating is provided by geothermal

brine, which passes through the shell side of the boiler-superheater after leaving the isobutane boilers. The brine then flows on to the isobutane heaters. Design propane flow is 274,400 pounds per hour. From the boiler-superheater, propane gas passes through the knockout drum, through a trip valve, and then through VP1, (DFC Turbine control valve). This valve is controlled by a governor, the speed signal being provided by a magnetic pickup on the turbine and the load signal provided by devices sensing generator electric output. The turbine also contains variable inlet nozzles that are share-controlled by the governor. The modes of operation of the DFC turbine control are similar to those outlined for the main turbine, but are set up to handle an induction generator load.

Valve VP2 (DFC turbine bypass valve) is controlled by propane knockout drum pressure. This valve would be used during propane circuit startup to provide turbine bypass; it would assist in flow circuit stabilization during any rapid load changes and it would provide the capability to "tune" the "bottoming" cycle for optimum dual cycle operation. Valve VP4 (propane knockout drum blowdown valve) is controlled by a level controller and is used to return any liquid carryover from the heating vessels to the propane receiver. This valve would be subject to the same override considerations during the startup mode that the isobutane knockout drum blowdown valve control experiences. Valve VP5 (DFC turbine bypass desuperheater valve) is controlled by bypass line gas temperature and protects the propane condensers from excessively high inlet temperatures during bypass periods.

Gas from the turbine exhaust flows to the propane condenser, where it is cooled and condensed by the cooling water system. This liquid drains to the receiver, where it is taken by the motor-driven condensate pump and passed on to the motor-driven boiler feed pump. Valve VP3 (propane BFP throttle valve) is controlled by knockout drum temperature, and is bypassed by a flow orifice to prevent the condensate and boiler feed pumps from overheating by going to shutoff.

(5) Cooling Water Circuit. The cooling water circuit for the Magmamax power plant is similar to a standard spray pond system, but has some unique improvements. The sprays are of the jet spray type, and are not atomized to the extent that they are in conventional spray ponds. These jet sprays utilize a gravity fall to provide controlled stream breakup to optimum drop size. The spray headers are directional-controlled to provide operation counterflow with the wind direction for optimum cooling. Spray cooling is only accomplished during off-peak periods when the atmospheric cooling conditions are the most favorable.

The deep storage pond is the reservoir from which a 25,000 gpm vertical wet-pit type turbine pump circulates water to the condensers. This pump is mounted on a specially-designed tower in the pond. The submerged portion of the tower contains a device which allows the pump suction to draw water from the bottom (30 feet deep) or from the surface of the pond. This two-position selector valve is operated by a manually actuated gear motor mounted above the water surface. Valve position is dependent upon plant power output requirements and water temperatures. Water flows from the circulating pump through the tube side of the propane condenser (single pass), and then it splits, half flowing through the tube side of each of the two isobutane condensers. These condensers each discharge to separate day storage pond-spray header combinations.

The 12,500 gpm flows pass directly into day storage ponds during a nominal 8-hour peak load period (daytime), when the air wet bulb temperature is the highest. This allows the plant to operate with the least amount of parasitic power requirements, since none of the spray pumps are operated during this period, and the circulating pump is drawing from the deep, cold water in the main pond. During this 8-hour period the water level in the day storage ponds rises about 5 feet. At the end of this period, valves VW1, 2, 3, and 4 (horizontal spray pump suction valves) are opened, and valves VW5 and 6 (day storage pond fill valves) are closed. The horizontal spray pumps are started and jet-spray cooling is begun. Valves VW7, 8, 9, and 10 (spray pond bypass valves) are used

to adjust spray header supply pressure, with full pressure being used when wind velocities are low, and the pressure being reduced as wind velocities increase. These valves would modulate to minimize drift and maximize cooling. Spray orientation would also be controlled on this basis. In the meantime, vertical wet-pipe pumps in the day storage ponds would begin to transfer water by jet sprays from these ponds. All spray-cooled water would be collected by the cooling stream surface and would flow into the deep storage pond.

It is expected that all water system valves (including those required for the makeup and blowdown circuits) would be operated from the control panel, but would be manually actuated. Position spray header pressure and pond level indications would be used to establish the proper operating profile. Automatic control of these functions could be added at a later date.

5. AUXILIARY SYSTEMS

5.1 Heat Rejection System

The techniques for rejecting heat to the surroundings are, of course, those in common practice in the power industry. The options are: once-through-cooling, evaporative cooling in either a spray pond or cooling tower, and dry air cooling. The choice depends on availability, environmental, and economic considerations. Controls for the heat rejection system can include, coolant and air flowrate control as required. These are generally manual controls. In the case of evaporative cooling a control loop is required to modulate the makeup flow to maintain a basin level.

Cold weather operation requires special attention for an evaporative cooling system. Cooling towers can be damaged by icing, which tends to occur on the windward louvers. To prevent this, a minimum bulk fluid temperature of 37 to 40°F must be maintained, by reducing fan speed or reversing fan direction, to allow the warm water introduced at the top of the tower to cascade over the exposed surface rather than the internal

portions of the tower. A significant amount of operator attention is required to attain these low coolant temperatures with a typical multi-cell tower.

The Magmamax spray pond system discussed in Section III-4.3 is of interest because it provides an effective management of cooling resources. It provides and stores water produced in the cooler parts of the day. This cooler water is used to maximize plant output during the peak load demand period daily.

5.2 Auxiliary Cooling System

Cooling water is required for cooling a variety of auxiliary equipment within the plant. This includes the inter- and after-condensers of a noncondensable gas removal system, the generator cooling medium, the Tube oil, the air compressors, and the plant air conditioning system.

The intercondenser and aftercondenser require cooling water to condense the vapor carryover from the condenser and the steam from the steam-jet gas ejectors. In most systems this flow is set manually, since the amount of steam to be condensed is relatively constant and independent of load.

The lube oil temperature must be controlled in order to hold the oil viscosity in the proper range. This is usually done in a shell and tube heat exchanger. Since geothermal condensate tends to include finely suspended solids, it is desirable to pass the cooling water through the tube side of a shell and tube heat exchanger, at a constant velocity sufficient to minimize deposition of solids in the tubes. To maintain heat transfer capability, the tubes may be rodded out if they start to become plugged. A bypass around the exchanger is used to control the oil flow rate through the exchanger and to maintain the desired temperature of the total flow of oil.

The generator is normally cooled by the flow of a gas through its windings. This gas will be either air or hydrogen, depending mainly on

generator size. The gas is cooled by circulating cooling water through tubes mounted in the generator gas cooling stream. The cooling water flow is set manually, to maintain proper temperatures within the generator when it is at full load.

The air compressors and the air conditioning system require cooling water. Therefore, a closed fresh water cooling system is used. It consists of circulating pumps, piping, heat exchanger, surge tank, and treated water. The fresh water is cooled by cooling tower water which flows through the tube side of the heat exchanger at constant velocity, while the flow of the treated water is controlled to maintain the temperature of the system.

5.3 Heating System

The geothermal supply may also be required to provide space heating and freeze protection. The geothermal fluid flow through these systems should be thermostatically controlled.

5.4 Miscellaneous Auxiliary Systems

Subsystems for filling, draining, purging, venting, blowdown, flare, instrument, and plant air, in-house power, and other minor subsystems are not discussed in this chapter because they are common to standard process practice.

IV. INSTRUMENTATION SYSTEM

Most measurement systems include three subsystems: detector-transducer, signal conditioning, and action or results. The detector-transducer subsystem is generally a measurement element which detects the physical variable and transforms this into a mechanical or electrical signal. The signal conditioning subsystem modifies the direct measurement element signal by amplification, filtering, or other modifications so that the output can be used by the action or results subsystem. The action or results subsystem indicates, stores, records, controls, or acts on the physical variable being measured.

The detector-transducer subsystem or measurement element is the primary concern of the following Section. The remainder of the measurement system is common to any process system and is adequately covered by the many texts on instrumentation and controls.

The specification and selection of measurement elements for use in geothermal systems requires a knowledge of the operating range and location of measurements. The expected end use of the measurement and the necessary accuracy must also be known. This information is generally the result of process control studies and test or experiment plans.

The various types of control systems have been examined in the previous sections. Each control system requires certain types, range, and location of measurements. With this information the particular instruments to accomplish the desired results can be selected.

The following discussion of primary measurement elements addresses three aspects of this topic

- (1) The service considerations common to all geothermal measurement elements

(2) The accuracies, ranges, and responses available for each type of measurement device

(3) And the applicable codes and standards in measurement systems.

1. GENERAL SERVICE CONSIDERATIONS

The selection of measurement elements for use in geothermal systems must consider fluid temperature, corrosion, deposition, and operating environment. This Section discusses each of these considerations as they apply uniquely to geothermal systems.

1.1 Fluid Temperature

An instrument selected for use in a geothermal system must be compatible with the operating temperature range. The operating temperature may range from a low ambient temperature to the maximum temperature of the resource. The materials of construction must be able to withstand these temperature extremes.

The accuracy and reliability of some instrument elements is affected by a temperature variation. This inaccuracy may be unacceptable for certain critical measurement. Instruments which would be unaffected by the temperature variation are available, and could very well be necessary for certain applications.

1.2 Corrosion

Geothermal fluids are generally corrosive. Therefore, when a measurement device is in direct contact with the geothermal fluid, the selection of materials is very important.

A typical Bourdon-tube pressure gauge, for example, has a brass bourdon and is connected to the system with a brass nipple. A geothermal fluid which contains hydrogen sulfide (H_2S) is very corrosive to copper

and copper alloys; a more suitable material, such as austenitic stainless steel, may therefore be necessary.

Corrosion due to dissolved oxygen, pH, or chloride ions is also common to some geothermal fluids. A materials test program is often necessary to determine the type and severity of corrosion a particular geothermal fluid will have. The results of tests should be used when selecting measurement devices. In a binary system, measurement devices must also be compatible with the system's secondary fluid.

1.3 Deposition

Most geothermal fluids tend to form deposits. Measurement devices in direct contact with the geothermal fluid may become plugged and inoperable due to deposition. Deposition is caused by a pressure drop across a device, a disturbance of the fluid flow or an area of stagnant fluid. Most devices commonly used are subject to one or more of these conditions. Particular attention must therefore be given to the type of device used. A method often used to reduce the severity of the problem is to avoid direct contact with the geothermal fluid by using a diaphragm seal between the element and the geothermal fluid.

Deposition may also affect the accuracy and response of an element with time. A deposit formation on a thermowell, for instance, has resistance to heat transfer and causes inaccurate measurements. When this happens the instrument should be taken out of service and cleaned.

1.4 Operating Environment

The problems associated with the environment in which measurement devices are expected to operate are due to ambient temperatures and corrosive gases. Geothermal systems are typically located outside, exposed to the ambient environment. Measurement devices should be able to withstand variations in ambient conditions without damage or inaccurate performance. In some locations there is a freezing problem. In these locations the geothermal fluid should not be stagnant without some type

of heating. In other locations extreme heat may cause malfunctions or inaccuracies. Both of these conditions should be considered when selecting and installing a measurement device.

Hydrogen sulfide (H_2S) in the environment is both corrosive and flammable. Copper and copper alloys are particularly susceptible to corrosive attack by hydrogen sulfide. Copper containing devices can be enclosed in an airtight environment, or the use of copper can be avoided entirely.

Other gases commonly associated with geothermal systems, particularly binary systems, can be corrosive or flammable. Appropriate measures, such as the installation of explosion proof enclosures, must be taken to avoid problems and hazards.

2. MEASUREMENT ELEMENTS

The following Section reviews the common types of measurement elements in commercial use. A discussion of actual operating experience in geothermal systems is included for each type of measurement.

2.1 Pressure Measurement

Pressure is one of the most important of the measured and controlled process variables. Most commercial pressure elements use mechanical devices such as Bourdon tubes, diaphragms, or bellows as the basic detector elements. These elements deflect under pressure. This deflection moves a pointer, in the case of a gauge, or creates an electrical signal, in the case of a transducer.

A pictorial summary of the method of operation of various pressure-measurement elements is shown in Figure 10^[4]. The normal pressure and temperature range, accuracy, and other characteristics of commercially available pressure-measurement elements are listed in Table II^[5].

Fig. 10 Pressure monitoring elements.

TABLE II

CHARACTERISTICS OF PRESSURE MEASUREMENT DEVICES

	Gauges			Transducers										
	Bourdon	Diaphragm	Bellows	Strain Gauges					Reluctive	Capacitive	Potentiometer	Linear Variable Diff. Trans. (LVDT)	Force Balance	Piezoelectric
Pressure Range	12 psi to 100K psi 150K psi	15" H ₂ O to 15 psi	0.5 to 30 psi	0.5 psi thru 10K psi	5 psi thru 10K psi	15 psi thru 5K psi	3" H ₂ O thru 10K psi	5 psi thru 10K psi	1" H ₂ O thru 10K psi	.01 thru 200 psi	5 psi thru 10K psi	30-10K psi	1 psi thru 5K psi	0.1 psi thru 10K psi
Temperature Range	-40°F to +375°F Error depend. on const.	-40°F to 375°F Error depends on const.	-40°F to +375°F Error depends on construction	-320°F to +600°F (0.005%/°F over limited compensated range)	-65°F to +250°F (0.005%/°F over limited compensated range)	-320°F to +525°F (0.005%/°F over limited compensated range)	-65°F to +30,000°F (0.01%/°F over limited compensated range)	-65°F to 30,000°F (0.01%/°F over limited compensated range)	-320°F to +600°F (0.02%/°F over limited compensated range)	0°F to 165°F Requires temperature control	-65°F to +300°F non-linear 0.01%/°F	0°F to 165°F	40°F to 165°F 0.01%/°F	-450°F to +400°F 0.01%/°F
Accuracy	±0.1% to ±5 FS Depend on gauge	±0.1% to ±3% FS Depend on gauge	±1% to 3% FS	0.25%	0.5%	0.25%	±0.01% to ±0.35%	0.25%	0.5%	0.05%	1%	0.5%	0.05%	1%
Output Level	Not applicable	Not applicable	Not applicable	Low level 4 mV/V	Low level 3 mV/V	3 mV/V	Medium to high level 3 mV/V to 20 mV/V	Medium to high level 3 mV/V to 20 mV/V	40 mV/V	Hi level (5V) Freq./bridge	Hi level	Hi level (5V) Phase Demod/bridge	Hi level (5V) with servo	Medium level with amp.
Excitation	Not applicable	Not applicable	Not applicable	10 Vac-dc	10 Vac-dc	10 Vac-dc	10-28 Vdc	10 Vac-dc	ac special	ac-dc special	ac-dc regulated	ac special	ac line power	dc amp and self gen. ac
Shock and Vibration Sensitivity	Fair to good	Poor	Fair to good	Good	Very good	Very good	Excellent	Very good	Very good	Poor to good	Poor	Poor	Fair to good	Excellent
Frequency Response	Not available	Not available	Not available	0 Hz to >2 KHz	0 Hz to >1 KHz	0 Hz to >1 KHz	0 Hz to >100 KHz	0 Hz to >70 KHz	0 Hz to >1 KHz	0 Hz to >100 Hz	0 Hz thru >50 Hz	>100 Hz	0 Hz to <5 Hz	1 Hz to >100 KHz
Life or Calibration Shift With Use	10 ⁷ cycles Depend on const. and press. range	10 ⁴ cycles Depend. on const. and press. range	10 ⁴ cycles Depend on const. and press. range	<0.5% cal. shift after 10 ⁴ cycles	>10 ⁴ cycles	>10 ⁴ cycles with <0.25% cal. shift	<0.25% calibration shift after 10 ⁴ cycles	<0.5% calibration shift after 10 ⁴ cycles	>10 ⁴ cycles	>10 ⁴ cycles with <0.05% cal. shift	<10 ⁴ cycles	>10 ⁴ cycle	>10 ⁴ cycles with <0.5% cal. shift	Unmeas. use effects
Advantages	Low cost; field replaceable; variety of mat. for media and range	Variety of materials for media and range; field replaceable; large force	Compact, accurate; field replaceable	Accepts uni-directional and bi-directional pres. meas; ac or dc excitation	Temp. effects small and linear; ac or dc excitation; rugged construction	Excellent thermal zero and sensitivity shift; ac or dc excitation	Small size, high nat. freq; steady and dynamic Reliability	Small size, high nat. freq; steady and dynamic	High output (40 mV/V excitation); rugged construction; over pressure capability	Low mass; excellent freq. response; dynamic and static meas; output countable without A/D converter	Low cost; small size; high output without amplification	Available in rotary form; not affected by mech. overload	High accuracy; high output; stable; wide ranges	High freq. resp; self gen. signal; small size; rugged const.
Disadvantages	Slow response; large sensor volume sen. to shock and vibration	Limited cap.; position sensitive in low ranges	Limited material; may be position sensitive	low signal level (4 mV/V)	Low signal level (3 mV/V); limited temp. range; mod. natural freq.	Low natural level; low signal level. 3 mV/V	Suscept. to handling prob.; more temp. sens. than most trans.; Elec. output only	Suscept. to handling problems. More temp. sens. than most trans.	Sensor requires ac excitation; susceptible to stray magnetic fields; ac carrier systems require balanced line for data transmission	Requires short leads from sensor; high impedance output; temp. sensitive; needs extra electronics to produce useable output	Tend. to short life due to mech. wear; noise increases with wear	Some prob. maintaining linear move. of core proport. to pressure change. Will develop mech. wear	Large size; shock and vibration sensitive; low freq. resp.	Temp. sensitive; req. amplifier and spec cabling between device and amp; slow recovery to shock and overpressure

The most significant problem which affects pressure measurement in geothermal systems is deposition. A Bourdon-tube pressure gauge made of appropriate materials functions well in geothermal service until the passageway becomes plugged by deposits. This problem has been partially solved by using a seal element between the geothermal fluid and the gauge; however, the accuracy of the gauge is degraded with time due to the deposition on the seal element. This same approach, of isolating the gauge or element from the geothermal fluid, has been used successfully with other types of pressure-measurement elements.

Because fluids in a pressure element are mostly stagnant another area of concern in some locations is the possibility that the geothermal may freeze. This can be resolved by heat tracing.

The problem of material selection for all elements in direct contact with the geothermal fluid is common to all types of measurement devices. The appropriate materials can be determined from the results of a testing program.

In other plant systems, such as in the secondary fluid or the cooling water, the elements and accessory equipment must withstand the operating environment. This includes small amounts of hydrogen sulfide (H_2S) which is very corrosive to copper and copper alloys.

In binary systems with flammable secondary fluids, the instrument enclosures must be of the appropriate class as defined by the National Fire Protection Association.

2.2 Temperature Measurement

The measurement and control of temperature within a geothermal system is of primary concern. Heat exchange, heat balances, turbine-generator and supply system operation, and many other functions depend on the measurement and control of temperature.

Most commercial temperature-measuring elements detect the change in heat-affected physical properties like thermal expansion, radiation, or electrical properties. These properties change with a change in temperature. This difference is measured, and correlated to a temperature change.

The accuracy, response, range, and relative cost of commercially available temperature-measurement elements, is shown in Table III.

2.3 Flow Measurement

The measurement and control of fluid flow is important to the safe and efficient operation of a geothermal system. In some cases (as at the plant inlet from the supply system, if this is the basis of payment for the supply), extreme precision is called for; in other instances only crude measurements are necessary.

Flow measurement is generally an inferred measuring of another variable such as pressure, pressure drop, velocity, flow disturbance, or other properties, which change with a change in flowrate. Flowrate is most commonly indicated by head loss or differential pressure measurement. Three common devices - orifice plate, flow nozzle, and venturi tube - cause a differential pressure by a flow obstruction. This differential is measured by a pressure or differential pressure gauge, and the flowrate can be derived from this measurement. Table IV summarizes the characteristics of head-loss flow-measurement elements.

Many other types of flow-measurement elements are available, and they have possible application in geothermal service. A pictorial review of the principles of operation is given in Figure 11^[6]. A summary of flowmeter characteristics is shown in Table V^[7].

TABLE III

CHARACTERISTICS OF TEMPERATURE MEASUREMENT ELEMENTS

	Liquid-in-glass thermometer	Fluid Expansion Thermometer	Bimetallic Strip	Electric Resistance Thermometer	Thermistor	Thermocouples Type E	Thermocouples Type J	Thermocouples Type K	Thermocouples Type T
Temperature Range (°F)	-200 to 600	-150 to 1000	-100 to 1000	-300 to 1800	-150 to 600	-300 to 1600	-300 to 1400	-300 to 2300	-300 to 700
Approximate Accuracy (% of reading)	± 1	± 2	± 1	± 0.1	± 0.2	± 0.5	± 0.75	± 0.75	± 0.375
Output Type	Mechanical	Mechanical	Mechanical	Resistance Change	Resistance Change	Electric Current	Electric Current	Electric Current	Electric Current
Transient Response	Poor	Poor	Poor	Fair to good	Very Good	Good	Good	Good	Good
Shock and Vibration Sensitivity	Good	Good	Good	Fair	Fair	Fair to Good	Fair to Good	Fair to Good	Fair to Good
Cost	Low	Low	Low	Readout Rather Expensive	Readout Rather Expensive	Low	Low	Low	Low
Advantages	Low Cost Dependable	Low Cost Rugged	Reliable for indust. measurement	Most accurate of all methods very stable	Fast response small ΔT	Highest Emf	Recommended for reducing atm	Resists oxidation	Linear Sensitivity for moist atm.
Disadvantages	Poor Response	Lacks accuracy poor response	Lacks stability	Additional readout required	Small range	Protect from sulfur	Protect from oxygen, moisture, sulfur	Low resist to reducing atm	Temperature limited protect from acid

TABLE IV

HEAD LOSS OR DIFFERENTIAL PRESSURE FLOW MEASUREMENT

Device	Fluid Types	Head Loss (% Produced)	Accuracy (% Max.)	Required Upstream Piping (Pipe Dia.)	Viscosity Effect	Relative Cost	Advantages	Disadvantages
<u>Orifice</u>							<u>Orifice</u>	
Concentric	Liquid, gas, or steam	50-90	± 1	10-30	Large	Low	1. Lowest cost	1. High head loss
Eccentric	Liquid-vapor mixtures	60-100	± 2	10-30	Large	Low	2. Easily installed or replaced	2. Traps suspended solids
Segmented	Liquid	60-100	± 2.5	10-30	Large	Low	3. Well established coefficient	3. Low capacity
Quadrant	Liquid	40-80	± 1	20-50	Small	Medium	4. Continued reliability	4. Requires flanges
<u>Flow Nozzle</u>	Liquid, gas, or steam	30-70	± 1.5	10-30	Small	Medium to high	<u>Flow Nozzle</u>	
							1. Can be used w/o flanges	1. Higher cost than orifice
							2. Lower cost than Venturi	2. Higher head loss than Venturi
							3. Lower head loss than orifice	3. Installation is critical
<u>Venturi Tube</u>	liquid, gas, or steam	10-20	± 1	10-20	Very large	High	<u>Venturi Tube</u>	
							1. Lowest head loss	1. Highest cost
								2. Largest and heaviest
							3. Shortest upstream piping required	
							4. Does not obstruct flow of suspended solids	
							5. Does not require pipe flanges	
							6. Well established coefficient

Fig. 1a Orifice plate
Source: Singer

Fig. 1b Orifice plate installed Source: Singer

Fig. 1c Venturi tube
Source: Singer

Fig. 10 Rotameter

Fig. 2a Trapezoidal weir

Fig. 2c V-Notch weir

Fig. 2b Parshall flume

Fig. 3 Turbine Source: Liptak

Fig. 4 Magnetic
Source: Fischer & Porter

Fig. 5a Vortex precession
Source: Fischer & Porter/Singer

Fig. 5b Vortex shedding
Source: Neptune/Eastech

Fig. 6 Mass Source: Singer

Fig. 7 Positive displacement
Source: Singer

Fig. 8 Sonic/Ultrasonic
Source: Mapco

Fig. 9a Fluidic

Source: Moore Products

Fig. 11 Flow monitoring elements.

TABLE V

CHARACTERISTICS OF FLOWMETER ELEMENTS

	Rotameter	Diff. Pressure with orifice, Flow Tube, etc.	Turbine	Magnetic	Wires & Flumes	Forced Vortex	Hot Vortex Meter	Mass (Ang. Momentum)	Positive Displacement	Ultrasonic Thru Wall Transducers	Ultrasonic Clamp On Type	Fluidic
Service	Liquids or Gases	Liquids or Gases	Liquids or Gases	Electrically Conductive Liquids or Solvents	Liquids in Open Channels	Gases	Liquids or Gases	Liquids or Gases	Liquids or Gases	Liquids Sonically Conductive	Liquids Sonically Conductive	Liquids or Gases
Flow Limits	Liquids 0.1 cc/min. to 150 gpm	0.1 cc/min. to any desired max. flow	1-10000 gpm	0.1-100,000 gpm -0.3 FPS	50 gpm to any desired max. flow	---	10-1400 gpm	2000-300,000 PPH	0.1-3000 gpm 1 in.	0.1-100,000 -0.1 FPS	1-100,000 -0.1 FPS	1-1000 gpm
	Gases as Air Equip. metered at STP	50 cc/min. to 500 SCFH	50 cc/min. to any desired max. flow	---	---	---	1-2000 actual ft ³ /min.	250-80,000 PPH	---	---	---	0-8000 SCFH
Scale or Signal Characteristic	Linear or Logarithmic	Square Root	Linear	Linear	3/2 power or 5/2 power for V notch weir	Linear	Linear	Linear	Linear	Linear	Linear	Linear
Flow Range- ability,	no adjusting the span	4:1	10:1 to 15:1	10:1	20:1	10:1 to 25:1	8:1 to 15:1	10:1	10:1	25:1	25:1	10:1
	with adjusting the span Max. Usable Min.	no adjustment	12:1 (with same flow element)	15:1	100:1	100:1	25:1	15:1	---	100:1	---	---
Accuracy including Dead-band Hysteresis Non-linearity	± 2% of max. (uncalibrated) to ± 1% of rate (calibrated)	± 1% of max. (uncalibrated) including transmitter	± 1% of rate (± 1% of rate excluding non-linearity)	± 1% of rate	Approximately 5% of rate	1% of rate	± 1% to ± 2% of rate	± 1% Rate	± 1% rate	± 1% rate	± 1% rate	± 1% max.
Factory Flow Calibrated	Optional	Not for orifice tubes - 2" optional for other elements	Always	Always	No	Always	Always	Always	Always	Usually	No	Always
Display Only (unpowered)	Yes, glass or metal tube	Yes	No	No	Yes	No	No	No	Yes Totalization	No	No	No
Transmission Types	Anal. Pres. Anal. Elect.	Anal. Pres. Anal. Elect.	Anal. Elect. Dig. Pulse Rate	Anal. Elect. Dig. Pulse Rate	Anal. Pres. Anal. Elect.	Anal. Elect. Dig. Pulse Rate	Anal. Elect. Dig. Pulse Rate	Anal. Elect. Digital Pulse	Anal. Elect. Digital Pulse	Anal. Elect. Digital Pulse	Anal. Elect. Digital Pulse	Anal. Elect. Dig. Pulse Rate
Electrical Classification	Available as Intrinsically Safe	Available either as Class I, Group C & D, Div. 1 or Intrinsically Safe	Class I, Group C & D Div. 1 Class II, Group B, C & D Div. II	Class I, Group B, C & D Div. II or Class I, Group C & D Div. I with purge	Available as Intrinsically Safe	Class I, Group C & D, Div. I	Class I, Group C & D, Div. I or Intrinsically Safe	Class I Group C & D Div. 1	Class I Group C & D Div. 1	Class I Group C & D Div. 2	Class I Group C & D Div. 2	Class I Group D Div. 1
Relative Installed Cost	Local Display, Low Transmitters, 2" - Low 2" - Med.	Local Display, Med. Transmitters Low to Med.	Med	Med to High	Low to Med.	Med. to High (with P&I Compensation High)	Low to Med.	High	Med-High	Med-High	Low	Med.
Viscosity Effect	Good immunity to viscosity except in very small meters	Fairly good immunity for orifice plates, less immunity for Venturi or Flow Tube	Fairly good immunity	No effect of viscosity on accuracy	Normally not used on viscous liquids	Good immunity to viscosity of glasses	Fair immunity to viscosity Viscosity can increase the minimum flow	Immune to Viscosity	Fair immunity to viscosity	Good immunity on large tubes	Good immunity on large tubes	Viscosity sets Lower Flow Limit
Max. Overall Press. Loss (typically)	3-30 H ₂ O	10-200 H ₂ O	30-120 H ₂ O	Negligible if meter is not size	3-15 H ₂ O for Parshall Flumes 10-40 H ₂ O for Weirs	10-500 H ₂ O	3-150 H ₂ O	110-130 H ₂ O	140-300 H ₂ O Liquid	Negligible	Negligible	120 H ₂ O
Other Important Considerations	Moisture of tube, Noel, fittings Float-actuator limits for gas	Moisture of element and OP sensor Freezing Gases, ρ max. must be less than 2% of dia. press.	Moisture of meter and bearings Pulse voltage Type bearings, normally ceramic	Moisture of lens and electrodes Vacuum possibility of damage to Teflon lines	Moisture of float Freezing possibility Sufficient gradient for low flow conditions	Moisture of float Freezing possibility Pressure and temperature compensation	Moisture of meter and O-Ring (316 SS only) No slurries	Clean Fluids only Meter Driven Parts may Req. Maint. Program	Relatively Clean Fluids Mech. wear Requires periodical proving	Relatively Clean Liquids Sensitive to Low Reynolds numbers Flow profile sensitive	Sensitive to Low Reynolds No., some to Face mat'l & internal surface cond.	Clean Low Viscosity Fluid Req'd Var. Install Recommended
Effect of Installation Piping	Negligible	Per ASME STD5	Per ISA RP31.1	Negligible	Straight Upstream Conduit Req'd	Straight Piping Req'd	Straight Piping req'd	Not Critical	Negligible	Critical for Single Beam Range for 4 Beam	Critical	Straight Piping Req'd

As previously stated, the most common method of flowrate measurement uses an orifice plate and differential pressure gauge. This is also true in geothermal systems. Operating experience has shown that in some cases, depending on the brine chemistry and location, orifice plates will trap scale and build up a scale deposit upstream. This causes inaccurate readings and will eventually plug the hole. Another problem is that the orifice plate is damaged by erosion from particulates. In most brines, however, and under most service considerations an orifice plate will give reliable and accurate flowrate measurement. It must frequently be checked to determine if the edges are rounded or the diameter changed, due to erosion or scale formation.

Another method which has been used with some success is a pitot tube; however, this requires very clean service and ideal conditions. Other methods which are in use include ultrasonic, vortex, magnetic, and turbine meters. Each of these can be given consideration when the conditions, accuracy, pressure drop, or scale formation will not allow using a less expensive device.

2.4 Level Measurement

The measurement and control of liquid level is frequently a primary control element in a geothermal system. Typical applications in a geothermal system are separator level, condenser level, and cooling tower level.

The measurement of liquid level can be a direct or inferred measurement. The methods commonly used are as follows:

Direct methods

- (1) Gauge glass
- (2) Ball float

- (3) Electric conductivity electrode
- (4) Light, sonic, or ultrasonic beams

Inferred methods

- (1) Pressure gauge
- (2) Differential pressure
- (3) Physical or electrical property change
- (4) Radiation
- (5) Displacement transmitter
- (6) Bubbler or purge.

The characteristics of these types of liquid level measurement elements are summarized in Table VI.

Level-measurement elements in contact with the geothermal fluid have two common problems: corrosion and deposition. Therefore, a measurement element which is disabled by either of these, such as a ball float, gauge glasses, or electrodes, must use a method to resolve this. In some cases this is not possible, as in any type of float device, the float will collect deposits and the accuracy of measurement will be degraded. In these cases sonic, ultrasonic, or pressure gauges can sometimes be used. In other "clean-water" applications, such as in cooling water or condensate, float devices may perform satisfactorily.

In some cases two different types of measurement may be used, one for continuous monitoring and the other for high or low level switches.

TABLE VI

CHARACTERISTICS OF LEVEL MEASUREMENT ELEMENTS

	Mechanism	Components	Principle of Operation	Advantages	Disadvantages
Gauge glass	Hydrostatic	Transparent tube connected to vessel	Gauge acts as a manometer showing level	Simple, inexpensive, accurate	Slow response, limited pressure, visual reading, deposition
Ball float	Float	Internal or external float with mechanical or pneumatic	Float moves up and down, with level with motion transmitted	Simple, inexpensive, direct mechanical action	Narrow range, corrosion or deposition, must be in contact with process fluid
Conductivity electrode	Electronic	Electrodes with switches and detecting relays	Conducting liquid completes a circuit when level reaches electrode	Simple, inexpensive, unlimited range, accurate switch	Deposition, corrosion, viscous fluids
Light, sonic, ultrasonic beams	Electronic	Transmitter and receiver, transducer, power supply	Beam sent from transmitter is reflected to receiver, timing is measured	Relatively small, no moving parts, out of process fluid, continuous level monitor, accurate	Expensive, calibration required for viscosity, temperature, density, salinity
Pressure gauge	Hydrostatic	Pressure gauge and other standard instrument components	Measured hydrostatic head due to liquid level	Simple, inexpensive, standard equipment, unlimited range	Deposition, corrosion, density sensitive, temperature sensitive
Differential pressure	Hydrostatic	Differential pressure gauge, transducer, pneumatic system	Level hydrostatic head causes a differential pressure from top to bottom of vessel	Simple, inexpensive, standard equipment, unlimited range	Deposition, corrosion, temperature, pressure, and density limited calibration, cleaning.
Property Change	Viscosity, thermal, or electrical property	Device to measure a change in the property of the gas vs the liquid	When the phase changes at the liquid level the measured property also changes	Varies with the type of measurement	Depends on known properties, deposition, corrosion, must in contact with process fluid
Radiation	Radiation attenuation	Source, detector, transducer, amplifier, power supply	Change in level varies the quantity and intensity of radiation from source to detector	Accurate, out of process fluid, large range	Expensive, safety precautions,
Displacement transmitter	Float	Float, sealing bellows, beam, pneumatic or electric system	Level change varies the buoyant force opposed by pneumatic feedback system	Sensitive, mechanical movement, continuous measurement	Narrow range, corrosion deposition, density and viscosity sensitive
Bubbler or purge	Hydrostatic	Pressure, gauge, purge gas supply, regulator	Purge gas pressure balances that of the level hydrostatic head	Unlimited range, simple, inexpensive, no moving parts	Purge gas mixes with process fluid, corrosion deposition, density sensitive

2.5 Quality Measurement

The most widely used methods to measure quality are the sodium tracer, electrical conductivity, throttling calorimeter, and gravimetric.

The throttling calorimeter determines the quality directly, whereas the other methods infer the quality from measuring the solid content of the steam. The most accurate method for continuous measurement is the sodium tracer method. Conductivity methods are useful within a limited range. The throttling calorimeter is not suitable for small quantities of carry-over. Gravimetric methods require large samples and do not detect carry-over peaks.

Other methods sometimes used are: capacitance measurement, piezo-electric, various wave-absorption methods; however, these are not in common operational use.

2.6 Water Chemistry Monitors

Water chemistry monitoring, in both the geothermal brine and the cooling water systems, is limited to measurement of pH and conductivity. In some cases corrosivity and total dissolved solids are inferred from other measurements.

These types of instruments are commercially available, and their use in geothermal service does not involve unique problems. However, as previously discussed, corrosion, deposition, and temperature, should be given consideration when selecting an instrument.

2.7 Combustible Mixture Monitors

Combustible mixture monitors are necessary in a binary system using a flammable secondary fluid, and where concentrations of hydrogen sulphide (H_2S) or other gases are possible. Measurement of combustible gases is important for detecting process leaks and for ensuring that their concentrations are within safe limits, below the lower explosive limit.

The most common method used for measuring combustible gas mixtures employs self-heated "hot wire" detectors of a high-temperature material such as platinum. These are mounted in a Wheatstone bridge circuit. The hot wire causes a combustible mixture to burn. The combustion of the mixture causes a temperature rise which results in a resistance imbalance. When the bridge is brought to a balance it indicates the concentration of combustibles.

Other methods include infrared absorbtion, thermoconductivity, and oxidation.

2.8 Additional Measurements

Other measurements that may be required include geophysical monitoring, seismic monitoring, air quality monitoring, and weather measurements. Devices for these measurements are available and in common use. The application, installation, and operation of these instruments should follow the manufacturers' suggested methods.

3. INSTALLATION REQUIREMENTS

3.1 Codes and Standards

The following codes and standards should be followed when selecting, installing, and operating measurement and control systems

- (1) American Society of Mechanical Engineers (ASME), Boiler and Pressure Vessel Code, Section VIII, Div. 1
- (2) Occupational Safety and Health Administration (OSHA) Regulations
- (3) National Electric Code
- (4) ASME Power Test Codes

- (5) ASME flow metering and other measurement standards
- (6) American National Standards Institute (ANSI) standards
- (7) Institute of Electric and Electronic Engineers (IEEE) standards for instrumentation
- (8) Instrument Society of America (ISA) Standards and Practices Manual
- (9) National Electric Manufacturers Association (NEMA) standards for electrical equipment
- (10) National Fire Protection Association (NFPA) standards.

3.2 Guidelines and Standard Practices

In addition to the applicable codes and standards previously discussed, this section addresses those items which are used as general guidelines for installation of measurement devices in geothermal systems.

The maintainability of a measurement device is of particular concern in geothermal systems. This is due to the potential for corrosion or deposition. The relative ease of maintenance of a particular device is considered in the process of selection and should be followed during installation of the device. Isolation valves should be provided for devices such as pressure gauges, for example, which can become plugged by deposition. Also, bypasses are normally provided where a device is in the full process stream.

In areas critical to the operation, redundant instrumentation may be necessary. In general, areas of stagnation should be avoided. This will reduce the possibility of plugging and freezing.

The location of a device should be carefully selected to ensure that the desired process variable-measurement is actually being measured.

For example, a pH meter in the cooling water system should be located at a point of complete mixed condition, not in areas of concentration cells.

Piping runs for instrumentation should be as short as possible, to avoid damage due to thermal expansion.

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1. The purpose of this document is to provide information regarding the activities of the [redacted] in the [redacted] area.

2. The [redacted] has been observed in the [redacted] area, and it is believed that it is engaged in [redacted] activities.

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APPENDIX
SELECTED BIBLIOGRAPHY

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