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# SPECIAL FUNCTION INSTRUMENTS FOR BINARY CYCLE GEOTHERMAL POWER PLANTS

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## Abstract

Three special instruments have been designed to support plant operations at the Heber geothermal power plant in Heber, California. All are aids to give operating information which no commercial instruments can provide. The first is a package for determining $CO_2$ breakout conditions for a particular brine. Brine is sampled continuously at either the wellhead or the plant inlet. A temperature-pressure curve is generated which will span all possible operating combinations. That information tells designers or operators what pump pressures must be used to keep the $CO_2$ in solution. A second package unit will detect the presence of ppm levels of isobutane in either brine or water streams. It samples actual flowing brine streams continuously. The function is to alert operators when leaks are occurring in heat exchangers. A final unit senses water in flowing hydrocarbon streams. The sampled streams can be either liquid or vapor. Sensitivity is close to actual solubility limit for water in isobutane. This device warns operators when their hydrocarbon has been contaminated with brine (or cooling water).

## Introduction

Commercial development of producing electricity from geothermal energy depends on solving scaling and corrosion problems. One important scaling species is calcium carbonate (calcite). It forms when carbon dioxide is released from the brine and the brine becomes supersaturated in calcium carbonate. Although the thermodynamics of calcite formation is fairly well understood, no reliable methods exist for predicting when flashing and resulting precipitation will occur in geothermal brines. Pumping costs to keep all the $CO_2$ in solution are not trivial. Generally, pressures are kept some "safe limit" above what is thought necessary to prevent breakout. If actual breakout conditions were known, pumping costs could be held to a minimum and still provide a nonscaling plant. An instrument package has been developed which will experimentally determine breakout conditions for a given well.

General corrosion trends in geothermal plants can be tracked using commercial resistance style probes. Modified linear polarization probes also provide useful information. Neither, however, can reliably predict pitting corrosion. Pits are the most likely failure mode which would result in leaking heat exchanger tubes.

Loss of hydrocarbon into the brine or cooling water streams represents a serious economic penalty. The ability to detect small levels of hydrocarbon in water streams would allow operators to correct problems before they became serious. A special leak detector package has been designed to detect very small leak rates (concentration of hydrocarbon down to < 2 ppm in an aqueous stream).

Consequences of getting water in the hydrocarbon stream could be serious from an operational/safety standpoint. This is unlikely under ordinary operation but very possible during start up and shutdown. Operators must be aware of when/if the hydrocarbon stream is being contaminated.

## Carbon Dioxide Breakout

The equipment is mounted on three skids. One contains the actual breakout equipment. A second contains recording instrumentation. The third supports an air-cooled heat exchanger for cooling circulating cooling water. The entire system is designed to be easily transportable and operable at remote locations. The only additional item required is a power supply to run the cooler and instrumentation. Portable generators are to be used at actual well sites. A flow diagram for the equipment is shown in Figure 1.

During operation brine flows through an inlet heat exchanger (and/or bypass) into an adjustable orifice/sight glass assembly, to a gas collection chamber, then on to an exit heat exchanger. Brine flow is controlled using Valve V-4 at the exit of the gas collection chamber. Brine temperature at the sight glass is varied by changing the bypass rate of hot inlet brine around the first heat exchanger. Valves V-2 and V-6 are used. The adjustable orifice, sight glass assembly is the producer and detector of $CO_2$ breakout from the brine.

For any given temperature of the brine, pressure is dropped across the needle valve until bubbles of $CO_2$ are detected in the sight glass. The bubbles are detected by eye and also by a light source with a photoelectric cell.

Temperatures are measured at points shown using certified Type K thermocouples. Pressures are measured with calibrated pressure transducers. All temperature and pressure readings are sent to a data logging system. The data logger paper tape output serves as the permanent record.

The recorder trace from the photoelectric cell is used as an operational guide to be sure the same bubbling conditions are selected at each temperature/pressure point. Other strip chart recorders monitor temperature and pressure just before and just after flashing. These recorders serve as operational guides only. One additional recorder monitors pressure drop across an orifice. This is the flow indicator and provides the operator visual indication of his desired control point.

Meaningful results can be achieved only when the brine to this test stand is unflashed. Hence, any wells being tested must be pumped.

Proof of principle tests were done at the inlet to a geothermal power plant rather than a single well. The sampled stream was a composite of four different wells. This location was chosen only because power and tools were convenient.

Results from the test are shown in Figure 2. The smooth curve indicates the data are probably consistent. The same curve shows pressure temperature data for water as a reference point. Also shown are calculated curves. One calculation uses Henry's law constants for $CO_2$ solubility in pure water. It simply treats all of the $CO_2$ in solution as $H_2CO_3$. Disassociation reactions are ignored; so are effects of ionic strength.

The second calculated curve is from a sophisticated chemical equilibrium computer code which was developed specifically for complex solubility calculations. Comparison of theoretical and calculated values shows there is still a need to run experiments. The agreement between CHMTMP and experiment at 77°C is artificial. The code used this as a reference point to set the chemistry of the brine. Deviations between the code and experiment at higher temperatures cannot be completely explained. Experimentally we measured lower breakout pressures than the code predicted. Part of the explanation might be kinetic effects which may not allow immediate bubble formation at equilibrium conditions.

Figure 3 provides more information on the experimental versus computed data. The CHMTMP total pressure line is the total equilibrium pressure in the system including water's vapor pressure. The $CO_2$ partial pressure line is partial pressure of $CO_2$ only. The implication here is that gas bubbles which do form at high temperatures contain significant amounts of water vapor. They are not pure carbon dioxide.

## Water Leaks Into Hydrocarbon Streams

A schematic flow diagram for the instrument is shown in Figure 4. When necessary, the hydrocarbon stream is first cooled to liquefy it. (Some streams which are liquid already, do not pass through a cooler.) The liquid mixture is fed to an expansion chamber where water separates by gravity. A thermocouple at the entrance to the expansion chamber monitors temperature there. A pressure guage at the inlet to the instrument reads system pressure for the instrument. Knowing temperature and pressure of the system, one can determine if the hydrocarbon is liquid or not.

Flow through the instrument is controlled using manual valves. An armored style rotameter with a magnetic follower is the flow indicator. Flow through the system is not critical, but certain ranges are optimal. (Flows greater than 0.2 gpm hydrocarbon but less than 0.7 gpm work quite well.) Higher flow rates (> 1 gpm hydrocarbon) result in reduced separator efficiency. Low flows allow water to collect in the piping and result in a slugging effect at the collector. This complicates interpretation of the information from the instrument.

Hydrocarbon which is sampled from the plant is returned and reused in the plant. It is not vented or sent to a sump. Collected water can be combined with the exit hydrocarbon or sent to a sump. The instrument is not meant to be a clean up device, so no special disposal procedures were developed for the water.

The instrument detects water because it is a much better electrical conductor than liquid hydrocarbon. Water which is separated from the hydrocarbon collects in an annulus formed by a capacitance probe inside a pipe. The capacitance probe shows readings between 0 and 100% as the annulus fills with water. The 100% and 0% points are arbitrary and user adjustable.

Another controller determines the volume of liquid which is dumped when the solenoid valve is opened. The dumped volume is always less than or at most equal to the collected volume. Each open and close cycle on the solenoid valve advances a mechanical counter one count.

A commercially available electronic counter provides interface information for a process computer and operating alarms. The counter accepts a 1 to 5 volt dc pulse input and sends out a 4-20 ma signal proportional to the total number of pulses it receives. The signal is generated by closing of a mechanical relay whenever the solenoid drain valve opens.

Each leak detector connected to the counter uses two totalizers. Total counts give indications of long-term leakage rates. The timed counts track transients which might occur during start up and shutdown of a plant.

If the hydrocarbon does get contaminated during a shutdown, this leak detection system can be used to monitor effectiveness of any clean up procedures, too. As the system gets cleaner, the number of counts per day will decrease to some steady-state point (hopefully zero).

The detector has been operated over a broad range of hydrocarbon flow rates and water concentrations. It will separate water from isobutane down to less than 100 ppm $H_2O$. This is close to the solubility of water in isobutane. Over a wide range of operating conditions the unit recovers 60% of the water entering the system.

## Hydrocarbon Leaks Into Brine or Cooling Water

This leak detector is composed of a gas-liquid separation module and a gas phase composition monitoring instrument. A system schematic is shown in Figure 5.

The leak detector itself samples a process stream continuously. The sampling rate is nominally 0.2 gallons per minute (gpm). The liquid is cooled when necessary; then the pressure is reduced to near ambient so the isobutane will vaporize. Gases are separated from the liquid in an expansion chamber. Gases flow on through a series of water traps and filters, then to a nondispersive infrared (NDIR) analyzer. Liquid is drained out the bottom of a collection tube and sent to an atmospheric sump.

As plant operating conditions change, flow through the leak detector will vary, also. Thus, a control system is used to ensure some liquid is always in the unit but none flows to the gas analyzer. (Small amounts of liquid carry over in the gas stream are expected, but will be removed in the traps and filters.) The level of liquid in the collection tube is sensed by a capacitance probe. Total volume of liquid in the system is determined by settings on a universal transmitter and a setcon controller. These two controllers actuate solenoid valves which admit liquid to the detector or drain liquid out of the collection tube. The controllers operate on the signal from the capacitance probe. An additional controller prevents accidental flooding of the separation chamber. If the liquid level is too high, this controller shuts a valve which stops liquid flow to the separation module. It also opens a second drain valve so the excess liquid can be dumped rapidly. Gas which is released from the brine occupies most of the collection vessel's volume. It is maintained a few psi above ambient by a pressure regulator on a vent line. The slight overpressure is needed to ensure constant flow to the NDIR gas analyzer. The gas analyzer is modified to be highly selective but not specific for isobutane.

A nondispersive infrared analyzer is generally sensitive to all hydrocarbons in a gas stream since it focuses on C-H vibration wavelengths. This modified unit focuses instead on C-C vibrations. That modification desensitizes the unit to methane, which also exists in off-gases from geothermal brines. The unit is about 60 times more sensitive to isobutane than methane. Still, the naturally occurring hydrocarbons in the noncondensible fraction of brines will elicit a small, but non-zero response from the NDIR analyzer.

When geothermal brine is passing through the detector, the volume of gas released will be quite temperature dependent. Higher separator temperatures will give off more carbon dioxide and dilute the isobutane. Conversely at low temperatures, less gas is evolved and the measured isobutane concentration could approach alarm conditions. Therefore, it is recommended the temperature of brine into the separator be controlled to ± 5°F using the built-in heat exchanger.

When cooling water is flowing through the detector, nitrogen carrier gas must be used to sweep any isobutane to the gas analyzer. Since nitrogen is nearly insoluble in water at any temperature (and near ambient pressure), temperature control is not important. Maintaining a constant nitrogen flow is critical, however.

The responses shown in Figures 6 through 8 illustrate traces from the NDIR analyzer while sampling a geothermal brine. (Isobutane was actually being pumped into the brine upstream of the leak detector.) Figure 6 shows a meandering response due to temperature changes in a brine. The temperature affects total volume of gas evolved (primarily the $CO_2$ fraction). This dilutes the isobutane and a lower reading results. (Isobutane is almost 100% in the gas phase at any operating condition for the leak detector.) Figure 7 shows response of the NDIR analyzer as isobutane concentration increases in the brine. The ppm values associated with the gas analyzer response are relative numbers only. They are NOT predictions of responses on the Heber brine. The traces are illustrative of the sensitivity of the leak detector to isobutane. Figure 8 is again illustrative only. It shows the NDIR analyzer response to a sample slug injection of isobutane. It allows operators to verify that the leak detector is indeed operating. The rapid rise and long tail are characteristic of this test.

The leak detector has been operated over the range of 2 to 50 parts per million (ppm) isobutane (liquid) in the liquid stream. The 2 ppm level is near the lower detection limit of the system. Fifty ppm is still well below the saturation limit. Recoveries of injected isobutane ranged between 50 and 70% after temperature compensation.

## Bibliography

Robertus, R. J., D. W. Shannon, and R. G. Sullivan. March 1984. Report on Design Construction and Testing of $CO_2$ Breakout System for Geothermal Brines. PNL-5042, Pacific Northwest Laboratory, Richland, Washington.

$CO_2$ BREAKOUT TEST SYSTEM

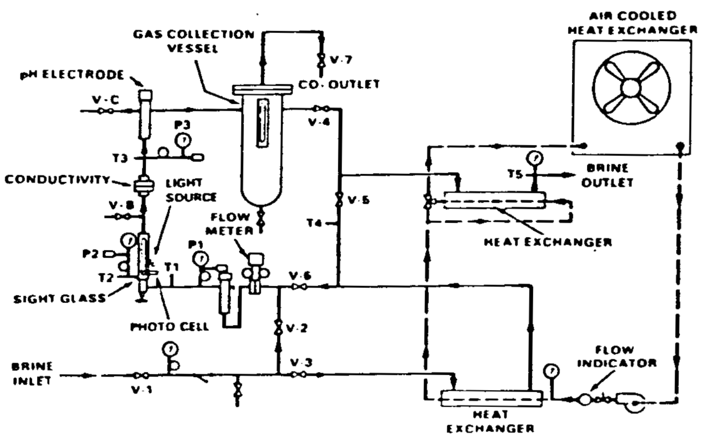


Figure 1 Flow Diagram

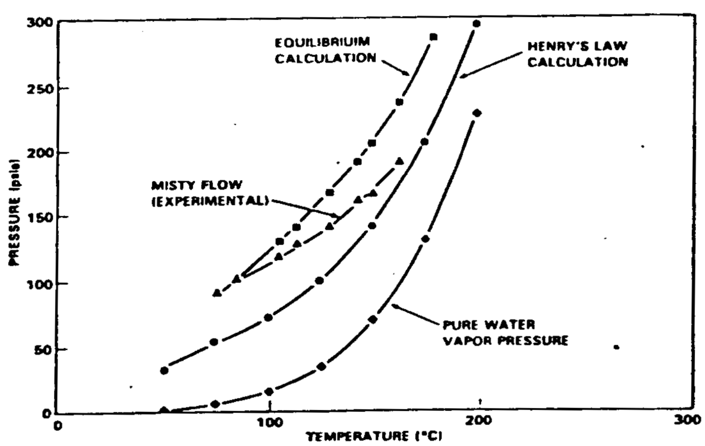


Figure 2 Calculated vs Experimental $CO_2$ Breakout Curves

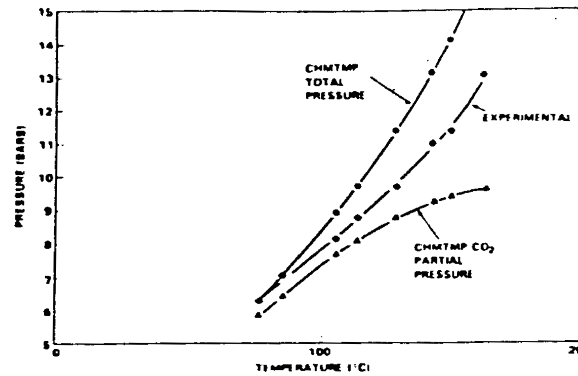


Figure 3 Equilibrium Predictions

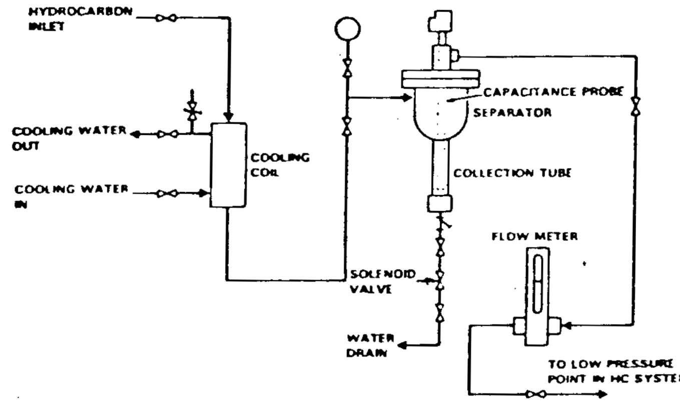


Figure 4 Water Leak Detector

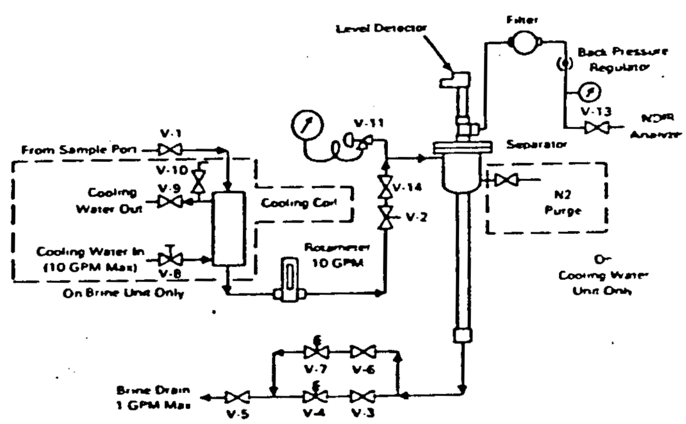


Figure 5 Hydrocarbon Leak Detector

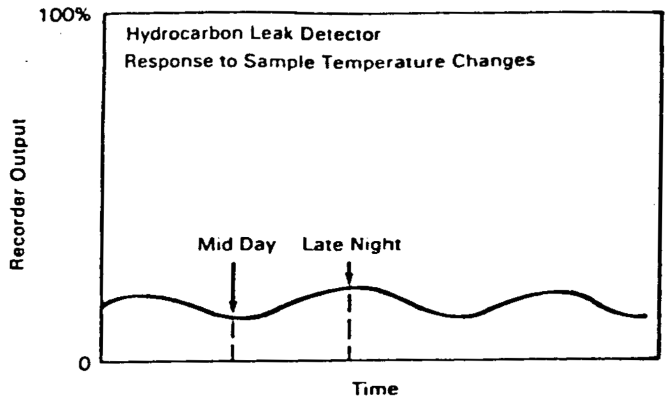


Figure 6 NDIR Trace at Quasi-Steady State

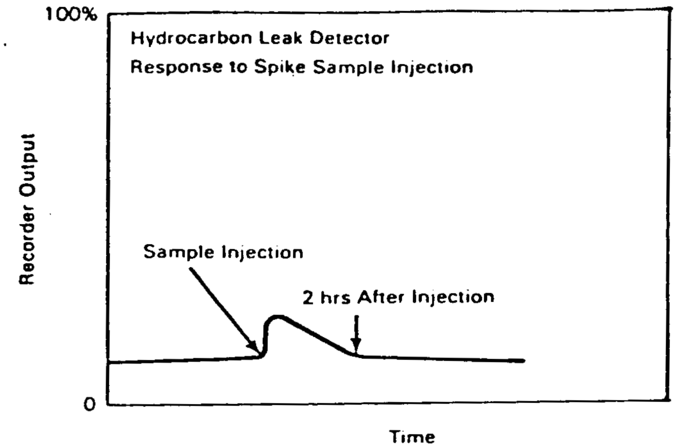


Figure 8 Response to Operational Check

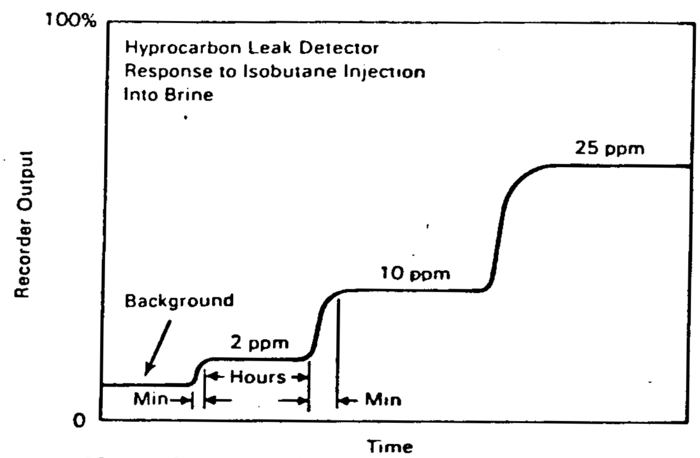


Figure 7 Sensivity to Isobutane Injection