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THEORETICAL AND EXPERIMENTAL RESEARCH ON TWO-PHASE FLOW IN GEOTHERMAL WELL BORES

Final Report

By
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MASTER

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U. S. DEPARTMENT OF ENERGY
Geothermal Energy

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Theoretical and Experimental Research on
Two-Phase Flow in Geothermal Well Bores

FINAL REPORT

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I. EXECUTIVE SUMMARY

The Denver Research Institute and Coury & Associates, Inc. have completed an investigation of two-phase flow in geothermal wells. The project consisted of the development of a computer model of the pressure drop in wellbores during two-phase flow and the acquisition of test data from flowing geothermal wells for validation of the model.

A. Objectives

An earlier project performed by these researchers under the sponsorship of the US Department of Energy, Division of Geothermal Energy had demonstrated the feasibility of the concept of modeling two-phase flow pressure drop in geothermal wells. Further, a logging tool was designed, built and used to obtain data that showed good agreement when compared to computer model predictions. These results were sufficiently encouraging to suggest further refinement of the model, and extension of its capabilities and the performance of additional field tests.

The project reported here had several objectives. The first was to acquire further test data from flowing, commercial geothermal wells. The two-phase flow model is envisioned as an instrument to be applied over a wide spectrum of fluid chemistries, reservoir parameters and casing schedules; therefore, actual test data from as great a variety of these conditions as practical would be useful for the validation of model operation. The primary parameters measured during field tests were pressure and temperature, both as a function of well depth. An attempt was made to obtain two other data items - fluid total flowrate, and an indication of fluid phase (gas or liquid) in contact with the downhole probe. A new tool to conduct this additional testing was to be designed and built. A total of five field tests were planned to be run with this new equipment.

Considerable improvement in the two-phase flow pressure drop computer model was a primary objective of the project. To this end, several

modifications were planned. A more detailed treatment of dissolved gases was to be formulated, as was a revision to the dissolved solids subroutine, to properly address the effects of high ionic strength found in solutions where the TDS content is above 3 or 4%. The development of a means to simulate the dissolved methane content of geopressured brines was also included in the task list. Finally, new correlations for two-phase pressure drop calculations that were the result of research at the University of Houston were to be incorporated in the model as an option. This considerably expanded, more sophisticated model was then to be validated by comparison with appropriate field test data obtained with the equipment mentioned previously.

The last and perhaps most important objective of this project was to make a significant effort to transfer to the geothermal industry the technology and analytic techniques developed in the course of the research. Two primary means were envisioned for this process: the preparation and presentation of papers at national meetings describing the project and discussing results of certain aspects; and the development of workshop sessions, where several hours could be devoted to the subject of two-phase flow and the approach designed in this project to predict two-phase pressure drop via the computer model or use of a design handbook based on computer model results. These objectives have been addressed in depth in the research, with results that are described in this report.

B. Accomplishments

A second-generation two-phase flow logging tool was designed, fabricated and field tested. This probe incorporated pressure and improved temperature measurements, as well as a flowmeter and an experimental phase (gas/liquid) sensor. After several modifications to increase operational reliability at elevated temperatures, the flowmeter worked quite well. Where two different devices were tested, insufficient test data was obtained to assess the performance of the phase sensor concept.

Well tests were successfully run in one government-owned and two privately-owned geothermal wells under flow conditions. Extensive negotiations with a number of private geothermal developers resulted in several additional opportunities that could not be realized because of equipment availability problems and scheduling conflicts. However, through a network of personal contacts, additional two-phase flowing pressure/temperature profiles were acquired from two sources. The data were analyzed and used in the computer model validation process.

The two-phase flow computer model was extensively modified. The treatment of dissolved gases was expanded, and a uniform treatment based on Henry's Law was applied to all gases considered. A second dissolved solids subroutine was added, to handle concentrated solution chemistry, where ionic strength becomes a significant influence on dissociation constants and thus impacts the distribution of species in solution. This occurs when the TDS rises above 30,000 to 40,000 parts per million. A subroutine that models the solubility of methane in geopressured brines was also added to the model. Improvements were made in several of the calculational procedures to provide greater speed and accuracy.

A new set of two-phase pressure drop correlations, developed at the University of Houston during a previous contract, were coded and tested in the model. Results with this new correlations set showed the best agreement to date between model predictions and field test data. Overall, the improvements have resulted in a computer model that can be used to effectively model two-phase wellbore flow in most geothermal resources found in the U.S.

As an alternate means of using the results of the two-phase flow computer model, the Geothermal Well Design Handbook has been developed. This document enables an engineer with a pocket calculator to compute wellhead temperature, pressure and flowrates as a function of changing reservoir conditions and well casing schedule. Flowrate over the life of the resource can be maximized by proper design of the wells in two-phase flow. The Comment Issue of the handbook was published during the project and a Final version is now in preparation.

To describe the features of the computer model and to explain the use of the handbook, two workshops were held at the 1978 and 1980 Annual Meetings of the Geothermal Resources Council. Each session was approximately two hours and permitted an in-depth examination of the subject of two-phase flow and its impact on geothermal systems. Other aspects of the project, including tool development and an examination of the features of flashing and pumped flows, were described in a total of four papers presented at various national meetings over the course of the research. This data dissemination is thought to be an important facet of the program goals.

C. Recommendations and Conclusions

The foremost result of this research project is the development of a computer model for the prediction of pressure drop in two-phase flows that has been shown to be accurate when compared to data taken in flowing commercial geothermal wells. The model is recommended for use where the flow from the reservoir into the wellbore is known to be single-phase, and where the activity coefficients for chemical reactions in the brine affecting dissolved gases and solids are near unity. The approach taken to compute activity coefficients, where conditions suggest significant deviation from one, has been shown to be errant in comparison with test data. This area is one where further research could provide an improvement in model performance.

The integration of the two-phase model with models of reservoir behavior and surface plant operation would result in an overall geothermal model that would encompass both thermodynamic and chemical aspects, to accurately predict operating efficiencies and the impact of chemical constituents on the various components of the system. Such a model could be developed from available computer programs in each of the major areas mentioned above, and should be considered.

With the addition of a second technique for the manipulation of the Two-Phase Wellhead Pressure Graph data, the Geothermal Well Design Handbook

has become a very versatile and useful document. Its application is recommended for analysis and well design optimization where the effects of dissolved gases and solids may be neglected, for total dissolved solids less than 5000 parts per million, and for dissolved gas content of less than 0.5% (by weight).

Finally, analyses of the several logs taken in a number of producing geothermal wells have provided valuable information, not only in terms of data for use in validation of the computer model, but also in understanding the nature of two-phase flow in geothermal wells and in determining the composition and properties of the geothermal fluid by measurements in the wellbore itself.

The work reported here takes value mainly when applied to the design of geothermal wells that remain to be drilled. Reading and understanding this document is heartily recommended for those who are responsible for this future development.

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II. IMPROVEMENTS FOR THE DRI TWO-PHASE PROBE

After testing the probe developed for an earlier program for measuring pressure and temperature in the two-phase zone of flowing geothermal wells, it was felt that modifications could be made to improve its performance. Also, the addition of other parameters to those already measured was thought to provide the opportunity for valuable insight into the nature of the two-phase flow phenomenon under study. Thus, an analysis of the possible measurements and their relative merit was undertaken.

Of the physical and chemical parameters examined, three were judged to be of sufficient interest for further investigation. These were pH, density, and total mass flowrate. Inquiries made to manufacturers of pH measurement equipment soon revealed that there was no commercially available hardware in early 1978 that would withstand downhole geothermal conditions. Discussions with several pressure transducer fabricators produced a similar result for differential pressure equipment in a configuration to measure fluid density. In fact, one organization had been funded by DOE to design and build such a unit and was unsuccessful. It was at this point that the alternative, of developing some means to detect flow regime of the two-phase flow, was conceived. Two approaches for such a device were tested, and are described later.

The original DRI probe was designed to measure downhole temperature and pressure, simultaneously and in real time. A platinum RTD (resistance temperature device) is used for the temperature measurement, and the pressure is monitored by an Inconel Bourdon tube which operated a wire wound potentiometer. Two different ranges of absolute pressure measurement are represented in the four transducers purchased: 0 to 500 psia (0 to 34 atm) and 0 to 2000 psia (0 to 136 atm). Both devices are passive resistance elements; no active electronics are placed in the geothermal environment. The tool is designed and built from off-the-shelf components, to minimize cost and maximize reliability.

Operation of the temperature and pressure transducers is in a true four wire configuration. A constant current is maintained across two of the leads, while the potential drop through the sensing element is measured via the other two. There are two important advantages gained in this approach: first, the effect of lead resistance is negated, and second, the change in lead resistance, due to temperature gradients in the wellbore, can also be ignored. When operating the probe on a 5 km (16,000 ft) cable, both of these effects can be significant. For the particular sensors chosen on this design, the lead resistance in the logging cable was at times greater than the resistance of the sensor elements during testing.

The potentials for each of the transducers is monitored with a digital voltmeter (DVM) mounted in the logging rig. When operating on the DOE/Sandia Labs wireline, a digital output from each of the DVM's is fed to a minicomputer along with the logging depth and time of day. Calibrations for both temperature and pressure are stored in memory and resistance values are immediately converted into engineering units and displayed on a CRT, as well as being printed out. The system as described has worked well in several field tests, so the approach taken in designing an improved version was to simply expand the length to accommodate the measurement of additional parameters.

A. Flowmeter

The one parameter which was fairly easily measured with existing equipment was total mass flowrate. This is an important input parameter to the two-phase flow computer model, and must be specified to run simulations of field tests to be used for model validation. Impeller-type spinners have been used in the oil and gas industry for some time, and are available from a number of manufacturers. In tests where facilities to separate the liquid and gas flow streams are not available, a spinner could be used to get an accurate indication of mass flowrate simply by making the measurement at a well depth and pressure sufficient to ensure single-phase (all liquid) flow. This would ease considerably the constraints put on wells which were candidates for two-phase flow testing.

In addition, after conducting a logging operation, the probe could be returned to the single-phase zone for a second measurement to confirm that the well was flowing under steady state conditions.

After consultation with a number of organizations which had purchased and modified commercial flowmeters, DRI ordered a conventional spinner-type unit, model 04-4104-00, from Gearhart-Owens Industries. Per suggestion of the Borehole Geophysics Group of the Water Resources Division, United States Geological Survey, several modifications were made. The ball bearings on which the impeller shaft was supported were replaced by a version with tighter tolerances that had been shown to operate well at geothermal temperatures. The four reed switches, in the standard model, were replaced with a single unit that had shown good performance at elevated temperatures. Mobil jet oil, a high temperature lubricant, was used to lube the bearings in the unit. An adapter to permit mounting of the modified spinner on the front of a two-phase flow pressure/temperature probe was designed and built.

Calibration of the modified spinner was performed at the USGS laboratory facility in Lakewood, Colorado. This was necessary since the standard calibrations produced by Gearhart-Owen for the unit purchased do not include casing diameters typical of geothermal wells (in oil and gas service, flow-meters are usually run inside the tubing string). A problem arose with the USGS facility in that at diameters of 15 cm (6 inches) or greater, the limited pumping capacity resulted in maximum flow velocities of only 1.5 m/min (5 ft per min), well below the levels found in flowing geothermal wells. A decision was made to field calibrate the unit by comparison with orifice-metered or weir-metered flow-rates on the first well tests to be run under this project. Unfortunately, because of sealing problems in the upper body of the tool, the field calibration was not completed due to the limited amount of test time for the new tool.

The electrical output signal of the flowmeter was monitored by measuring the voltage change across a surface resistor caused by the

making and breaking contact of the reed switch. By feeding the flowmeter signal to a ratemeter, the number of pulses (revolutions) in a specified time interval was available in a digital display. Control schematics for the new tool are presented later in this section.

B. Flow Regime Devices

In reviewing the parameters thought to provide insight to the two-phase flow problem, the one that was deemed possible to measure in the geothermal environment was flow regime. In the development of a two-phase flow, there are distinct patterns which can be discerned. These patterns are functions of the relative volumes of liquid and vapor present in the flow at the location under observation, and thus can be detected by measurements of physical properties of the mixture as affected by the phases. Two approaches to the detection of flow regime were developed, and the hardware needed to test both was fabricated and tested, with mixed results.

The Magnetostrictive Device

The basic principle involved in the operation of the first flow regime transducer is that the acoustic impedances of vapor and liquid differ significantly; that is, in proportion to the product of the local density and velocity of sound in the respective media. At 177°C (350°F), for example, the acoustic impedances of water and steam differ by a factor of approximately 500. The concept, then, is to detect the presence of vapor in the fluid flow of a geothermal well by monitoring the acoustic impedance of the fluid passing a source of high frequency sound. While the sonic velocity in the well fluid varies as a function of temperature, pressure and fluid composition, the presence of a vapor regime in the fluid is seen as a step-wise change in the acoustic impedance.

The source of the acoustic energy for the density transducer is a hollow nickel tube 0.63 cm (0.25 inches) in diameter. Magnetization

of the tube sets up compression stresses in the material and produces minute changes in its physical dimensions. By magnetizing the tube with an alternating electromagnetic field, the rod can be made to vibrate, and by matching the frequency of the existing field with the natural resonating frequency of the tube, acoustic energy can be produced and projected into the fluid in a well. Nickel was chosen for the tube material because of its high curie point temperature; it retains good magnetic properties at typical geothermal temperatures.

Figure 11-1 shows the basic configuration of the device developed. The actual configuration is somewhat more complex than that shown, as a result of integrating the device into the well probe and optimizing the geometry and performance of the other transducers in the probe. In addition to the nickel tube, which is sized to resonate at 20,000 hertz (a quarter of the wave length for the fundamental vibrational mode in a tube 12.3 centimeters long), three other basic components may be seen:

- 1) A circular ring magnet, magnetized across the ring diameter, which provides a magnetic bias for the nickel tube and a magnetic field for the "output coil";
- 2) An excitation coil or driving solenoid that maintains the vibration of the tube, and,
- 3) An "output coil" that is fastened to the nickel tube and experiences vibration in the magnetic field, thus producing the signal monitored at the surface.

Under conditions of transition between single and two-phase well flow, the vibrating tube will "see" a decrease in bulk fluid density and an associated decrease in acoustic impedance. Step-wise changes in impedance will produce corresponding changes in the amplitude of vibration monitored at the free end of the tube by the output coil. The changes in voltage produced by the output coil will correspond, in time, with the passage of vapor and liquid regimes past the transducer. Therefore it should be possible to distinguish the slug flow regime, for example,

Figure II-1 Basic Configuration of Magnetostrictive Device.

by noting the voltage level changes due to movement past the probe of a liquid slug trapped between two Taylor bubbles. If a record of the acoustic "signature" at various stations in a two-phase flowing well were made, correlations of these data with flow regime should be feasible.

Just such an approach was used on the first well test attempted under this project. A Hewlett-Packard audio oscillator was used to provide the excitation, and the voltage output of the pickup coil was recorded on a four track, high quality, audio tape with a high performance TEAC tape deck. Unfortunately, most of the data was lost due to the inadvertent positioning of a switch on the audio oscillator which caused the excitation frequency to be an order of magnitude below the natural frequency of the nickel tube.

One log of good data was obtained and analyzed after the field test. New equipment available at DRI made the analysis quick and simple. The data was played back through a Norland model 3001 digital oscilloscope and manipulated via a built-in microprocessor waveform analyzer. Specifically, five second data samples taken from a number of different wellbore elevations were recorded and power spectral densities of these data samples were calculated. The results showed the relative contributions at the dominant frequencies to the total AC signal. Examples of the data are shown in Figures 11-2 through 11-4. As can be seen, there are resonant points at 1, 2 and about 7.5 hertz in each of the spectral density plots. It was hoped that the relative amplitudes at these resonance frequencies would prove indicative of the flow regime encountered; however, sufficient data to perform a true correlation was not available. The potential of the magnetostrictive technique for the identification of two-phase flow regime remains unknown at this time.

Conductivity Device

The other detection scheme for the determination of flow regime was through the measurement of the local conductivity of the fluid in contact

Sensor Output Signal (Lower Trace) and Power Spectral Density Distribution (Upper Trace) for Magnetostrictive Device. Depth at Which Data was Obtained is Shown in Upper Left.

Figure 11-2

Sensor Output Signal (Lower Trace) and Power Spectral Density Distribution (Upper Trace) for Magnetostrictive Device. Depth at Which Data was Obtained is Shown in Upper Left.

Figure 11-3

Sensor Output Signal (Lower Trace) and Power Spectral Density Distribution (Upper Trace) for Magnetostrictive Device. Depth at Which Data was Obtained is Shown in Upper Left.

Figure 11-4

with the tip of the probe. The principle, on which the method is based, is that electrical conductivity of liquid water is much higher than that of steam. Therefore, if a circuit is constructed such that one element is a gap past which the two-phase fluid flows, the signal level will change in proportion to the conductivity of the fluid in contact with the exposed element. In a bubble flow regime, the signal will experience a step-wise change when a steam bubble moves over the conductivity element, an event which will have a short duration but frequent recurrence. For slug flow, the step-wise change should last for several seconds as the Taylor bubble moves past the element.

In the DRI probe, the conductivity sensing element consisted of a 1.6 mm pin (1/16 inch diameter) set in a ceramic insulator of about 6.3 mm (1/4 inch) diameter. The body of the tool formed the ground side of the element, giving an annular arrangement to the gap over which the fluid conductivity was sensed. The minimum size of bubbles sensed by this device was on the order of the diameter of the ceramic insulator, about 6 mm (1/4 inch). The output was detected by monitoring the voltage drop across a series resistor at the surface, with a constant voltage impressed across the entire circuit. The driver voltage was low frequency AC to avoid polarization of liquid water in the single-phase flow region of the wellbore.

The prototype unit was operated during the well test conducted in November of 1979. The output signal from the device was recorded on magnetic tape for later analysis. In addition, a voice track was recorded to provide annotation as well as the excitation signal. For the analysis, the excitation signal was inverted and added to the output signal to remove the AC "carrier" frequency from the output. Here a significant problem was encountered. There appeared to be a phase shift in the response that was variable, and is suspected to be due to the operation of the device through the long leads (4.5 km) in the logging cable. Because of the phase shift and the fact that only limited amounts of data were again available, due to problems associated with other sensors in the probe, no conclusive results were obtained with the conductivity probe.

C. Integration of the Probe Package

In order to operate the logging cable, innovative design of the electronics package was necessary. The mechanical layout to incorporate all the above described elements also required some unique design work. The goal of the design effort was to permit simultaneous operation of the pressure and temperature transducers, along with one of the two available phase sensing devices. The flowmeter was to operate in single-phase flow only, where temperature and pressure measurements are of secondary interest. To allow flowmeter data to be taken, it was necessary to install a relay in the tool itself and to provide proper controls to switch two of the seven cable leads from the phase sensor to the flowmeter and back.

The new tool was arranged as shown in the functional diagram, Figure 11-5. The lowermost element (encountered first by the upward flow) was the flowmeter, followed by an open section where the flow pattern disturbed by the flowmeter body was allowed to "heal" before impacting the nose which housed both the temperature sensor (RTD) and phase sensor (magnetostrictive device or conductivity device). The pressure port was located further up the tool body and was designed to measure static pressure; the transducer was housed inside the tool. Finally, a standard Gearhart-Owens seven conductor cable head was used to mate to the logging cable.

Schematics of the uphole (surface) control box and the tool wiring are shown in Figures 11-6 and 11-7, respectively. Several elements of the system are quite clever and worthy of description. The latching relay, a MIL-SPEC unit designed to operate in the high-temperature environment of a geothermal well, is housed in the lowermost compartment of the tool. In addition to O-ring seals at both ends, there were three other penetrations to this section: two where the temperature RTD and phase sensor were exposed to the fluid, and the third where the single lead for the flowmeter was passed forward. One or more of the sealing surfaces was leaking, and numerous attempts to locate and eliminate the

Figure 11-5. New DRI Probe Functional Diagram.

UP HOLE CONTROL BOX (NEW PROBE)

Figure 11-6

INTERCONNECTING WIRING (NEW PROBE)

Figure 11-7

problem were in vain. Finally, a deep score was found in the inside diameter of the steel tube which forms the tool body for the lower section and provides a sealing surface to the O-rings. A new lower body section was fabricated because the score was too deep to be removed by polishing. The repaired tool has not yet been tested, so it is not known if the leakage problem has been solved. It is suggested that any future designs utilize a double O-ring seal and take advantage of recent improvements in O-ring materials.

III. FIELD TESTS

An integral part of this research project was the logging of flowing geothermal wells to obtain pressure and temperature profiles of the two-phase flow zones under a variety of conditions. Such data is vital in that the validity of the computer model developed is best assessed by comparison with the results of actual field tests. Also, the choice of the most suitable correlation coefficients, from among the options available in the preliminary version of the model, was made by comparison with test data. For these reasons, a series of five tests were planned for the project. Three tests were run, and additional data sets were analyzed, as described later in this section.

A. General Arrangements

In order to maximize the utility of any logging information obtained in the field tests, several criteria were used to screen candidate wells for selection as test sites. These included the known presence of two-phase flow under typical flow conditions, permission for access for testing purposes, some means of total flowrate measurement and completion of the necessary data and liability agreement. The effort involved in meeting these, while satisfying the timing and administrative requirements of the well owner/operator, were indeed gargantuan. DRI held discussions with ten private operators of geothermal wells and also talked with several government organizations. Some of those contacted rejected the concept outright; others remained interested but timing and logistics problems could not be solved. Well tests were run in two privately owned wells and in one well, 6-2, located at the DOE-owned Geothermal Test Facility in the East Mesa KGRA of southern California's Imperial Valley.

One of the administrative elements involved in gaining access to the private wells was the execution of an agreement which delineated responsibilities and liabilities on behalf of both the well owner/operator and DRI. In addition, this document plainly specified that data taken

during the test would not be published without the written consent of the well owner/operator. The data protection clause was essential since most private geothermal companies are not interested in releasing test data to adjacent leaseholders and potential competitors. Use of the confidentiality clause was approved by DOE on the premise that the objective of this research program was not to gather field test data, but rather to produce a predictive computer model whose performance had been verified by comparison with the results of actual two-phase flow measurements made in commercial wells.

The agreement also specified the insurance coverage maintained by DRI for the well tests. In the opinion of the Institute's insurance counsel, most aspects of the testing were covered by the liability policy carried as standard business practice. The costs of fishing for lost logging tools, if such an accident should occur, was not deemed to be covered. Therefore, special arrangements were made to purchase a limited term policy which would specifically cover fishing costs to a total of \$25,000, after which any equipment still lost would be abandoned. These provisions were satisfactory to the two private organizations who provided opportunities for well tests.

DRI was responsible for making all arrangements for equipment support and coordinated all testing. Wireline services were provided by Sandia Labs, who have assembled and maintain a high temperature, seven conductor logging rig with funding by the US Department of Energy. A mast truck, used to erect the riser system and hold the upper sheave during logging operations, was also supplied by Sandia for all three tests. Coury and Associates had an engineer on site to direct the logging operations. Maintenance and repair of the DRI tool and electronics was carried out by a DRI technician. Prior to the start of each test, a general test plan was prepared and distributed to all participants to ensure that the test objectives and proposed operations sequence were understood by all concerned. In addition, DRI conducted a pre-test calibration of all pressure transducers, since the sensing elements of the units on hand have been found to undergo a small but finite amount

of permanent deformation during operation at geothermal temperatures. A dead weight type tester, which is certified by the manufacturer to have an error less than 1/3 of 1%, is used for the calibrations that are repeated over a range of expected temperatures.

B. Geothermal Test Facility Well 6-2

The logging of well 6-2 in the East Mesa KGRA marked the first test of the new DRI tool under this program. The well is part of a complex operated by WESTEC Services for the US Department of Energy. The Geothermal Test Facility is used to test new and innovative equipment concepts for the production of electric power from geothermal fluids. DRI had secured permission to conduct two-phase logging operations in this well as part of its two-phase flow research program. This well was ideal for the initial test since it was known to be only a moderately good producer and had a maximum temperature that was near the lower end of commercial viability, yet would provide conditions of severity sufficient to fully test the operational capabilities of the new tool.

The well had been recently treated to reduce a significant coating of hard scale, several inches thick, which had been built up over a period of years the well had supplied geothermal fluids for equipment tests. A constriction remained, even after treatment, at a level just below the master valve, where the scale had narrowed the inside diameter of the casing to approximately 12 cm (about 4 3/4 inches) diameter with a smooth taper to full diameter at about 15 m (50 ft) depth. This did not present a problem for the new probe, which is only about 9 cm (approx. 3 1/2 inches) wide across the centralizers; however, it is suspected that this scale venturi acted as a throttle when the flow control valve was fully opened. The well was flowed through an 20 cm (8 inch) diameter surface line to an atmospheric flash tank/separator, where the steam fraction was vented to the open air. The liquid portion was run over a V-notch weir to measure the flowrate, and was then dumped into the facility holding pond for later reinjection.

An adapter flange to accommodate the 15 cm (6 inch) riser assembly was bolted to the run of the wellhead tee, above the master valve. A 60 cm (2 ft) stub was threaded into this flange. On top of the stub, a hammer union was threaded to provide an easy break in the riser assembly, for maintenance and repair of the DRI tools. A riser section of approximately 6 m (20 ft) was used to house the tool string when run out of the well, so that the flow could be shut in via the master valve. The riser assembly was topped by a pressure control device to minimize fluid venting under operating conditions. All joints in the riser assembly were made up using a high temperature thread lubricant to facilitate sealing and to prevent seizing of the threads at the elevated temperatures reached during flow.

The tool itself was mated to the cable with a Gearhart-Owen cable head. In testing over the years, the cablehead has been shown to be the component most likely to malfunction under the severe temperature and pressure environment found in a geothermal well. For this particular test, cablehead performance was quite good, most likely because the maximum temperature measured was below 200°C (400°F). About 50 kg (110 lb) of sinker bar are run on the cable to ensure that the tool is not lifted by the geothermal flow. The tool, as an additional precaution, is only 5 cm (2 inches) in diameter to present a minimum cross section to the flow. Centralizers are located near both ends of the tool string to keep the probe centered in the flow and to prevent wedging of the tool in the casing.

Sandia Laboratories supplied two pieces of support equipment as well as five researchers to operate them for the testing. One, a seven-conductor wireline rig has 4.5 km (15,000 ft) of high temperature cable on a hydraulic winch, and is self-contained with a gasoline generator for instrumentation power and a sealed cab to house winch controls and all necessary instrumentation. The other, a mast truck with a 12 m (40 ft) vertical extension boom was used to erect the riser system and to support the upper sheave during logging operations.

Power supplies and data recording equipment for the DRI probe were housed in the wireline rig. A constant current power supply was used in conjunction with two digital voltmeters to monitor the pressure and temperature sensors. The digital outputs of both transducers were fed to a minicomputer that converted the resistance values to engineering units. The results were displayed on a CRT and printed out, as well as stored on a mini disk file. The on-board minicomputer was programmed by Sandia personnel in preparation for the test. A precision audio tape deck was used to record the response of the magnetostrictive device, which was driven by the output of a heavy duty signal generator. Signal from the spinner flowmeter was fed to a digital counter. A written record of the count was taken at periodic intervals.

A problem was encountered with the spinner, in that at the elevated operating temperature, the magnet in the rotor (mounted on a common shaft with the impeller) was not strong enough to consistently cause the reed switch to open; therefore, only random revolutions of the impeller were being counted. When this was realized, operation of the flowmeter was abandoned until a stronger magnet could be installed. Results from the magnetostrictive device were limited because a number of logs were made with an incorrect excitation frequency, examples of the data obtained are shown and discussed in Section II.

Pressure and temperature logs were successfully run at a total of five flowrates. These logs are taken, at approximately 7.6 m (25 feet) per minute, with periodic stops to ensure that the sensing elements do not show a lag from equilibrium conditions. A summary of the data is presented in Table III-1; as can be noted, a wide variety of flowrates were encountered. The pressure and temperature data plotted in the logs is tabulated in the Appendix as Tables A-1 through A-5.

The logs themselves are presented as Figures III-1 through III-5. Several aspects of two-phase flow that are confirmed in the data are of interest. The flash horizon, or the onset of two-phase flow, is marked

TABLE III-1

6-2 EAST MESA WELL TESTS, JULY 1979

<u>Log #</u>	<u>Flowrate*</u> lb/hr	<u>Maximum Depth of Log</u> (Kelly Bushing, Ref)	<u>Maximum Pressure</u>	<u>Maximum Temperature</u>
8	275,500 (34.8 kg/sec)	800 ft (244 m)	342 psia (23.3 atm)	360°F (182 C)
9	192,800 (24.3 kg/sec)	600 ft (183 m)	288 psia (19.6 atm)	359°F (181 C)
16	136,300 (17.2 kg/sec)	800 ft (244 m)	418 psia (28.5 atm)	356°F (180 C)
17	92,300 (11.7 kg/sec)	800 ft (244 m)	437 psia (29.7 atm)	356°F (180 C)
19	260,500 (32.9 kg/sec)	700 ft (213 m)	305 psia (20.6 atm)	359°F (181 C)

Well #6-2 is cased with 7 5/8" to 5456 ft, with 7 5/8" slotted linear to 5957 ft.

*measured at weir, 16.5% added for flash to give listed total.

Pressure and Temperature Log for Test 8

Figure III-1

Pressure and Temperature Log for Test 9

Figure III-2

Pressure and Temperature Log for Test 16

Figure III-3

Pressure and Temperature Log for Test 17

Figure III-4

Pressure and Temperature Log for Test 19

Figure III-5

by a change in both the temperature and pressure gradients. There also appears to be a correlation between the flowrate and the single-phase temperature gradient measured in the flowing well. This would seem logical because the total heat loss is expected to be approximately constant in the steady state high flowrate case. Therefore, if the mass flow was reduced, the temperature drop would have to increase to maintain the constant heat loss rate. The single-phase cooling phenomenon was responsible for the difference in flash temperatures and pressures noted in the data.

The location of the flash is easily defined in the Figures by a change in both the pressure and temperature gradients. In a typical geothermal flow, the single-phase pressure gradient is dominated by the hydrostatic head term, which contributes about 99% of the total; friction makes up the remainder. However, in the two-phase region, the contribution of the hydrostatic term is reduced because of the presence of relatively low density steam bubbles in the fluid. Acceleration and friction terms are the remaining components of the two-phase pressure gradient; their impact on the gradient is very minor until the two-phase flow becomes well developed. Since the hydrostatic term dominates, the pressure gradient is reduced below the single-phase value at the onset of two-phase flow. At the same time, as the bubbles are formed, a significant temperature gradient begins to appear. This is because the sensible heat of the liquid is traded for latent heat of vaporization in the creation of the vapor phase. The onset of two-phase flow, the so-called flash horizon, is therefore attributed to the wellbore depth where both temperature and pressure gradients start to deviate from their constant single-phase values. It is from this point up to the surface where the test data will be compared to the results of a computer simulation of the two-phase flow. Details of this comparison are discussed in part B of this report.

Several operational problems were encountered in the first field test; these included seal failures in the new tool, so that the interior electrical connections were shorted in the presence of moisture, and a loss of the flowmeter impeller in the wellbore. Repairs to the tool were made upon the return to Denver. Overall, because of the quantity and quality of logging data obtained in this field test, it was considered quite successful.

C. Private Well Test #1

After several months of negotiation and execution of a liability/data confidentiality agreement, a test was made of a private well in November of 1979. The well was located in the Imperial Valley of southern California. The DOE/Sandia seven conductor wireline and mast truck were again employed in the logging of this well. These vehicles had been in use prior to this test by Lawrence Berkeley Labs at the Cerro Prieto geothermal field in Mexico, and there was some delay in moving them back across the international border. The customs paperwork delayed their arrival by a day and a half, cutting short the available test time.

The site layout was similar to the previous test. A mating flange was bolted to an isolation valve on the wellhead above the flow tee, and the stub of the riser assembly was threaded into the flange. The riser itself was assembled with a high temperature anti-sieze compound used to coat all threaded joints. Pressure control at the top of the riser assembly is accomplished with the use of a hydraulic packer unit. The new DRI tool was run with two steel sinker bars for a total tool string weight of about 68 kg (150 lb). The Sandia mast truck was used to erect the riser assembly and to hold the upper sheave. The lower sheave was anchored to the wellhead; these steel pulleys were 61 cm (24 inches) in diameter.

The instrumentation setup in the DOE/Sandia wireline van was similar to that developed for the GTF 6-2 test. A constant current power supply was used in conjunction with two digital voltmeters to energize the pressure and temperature sensors in the DRI tool. A slight problem was noted when checking out the operation of the minicomputer. The clock circuit was inoperative, so a section of the BASIC program code was re-written to compensate for the loss. The DRI tool was assembled with a conductivity probe as the phase sensing element; operation of this device was described in Section II. A TEAC precision audio tape recorder was used to record the output and excitation signals for later analysis.

A total of three successful logs were run in this well. The first two were run with the new tool, until a recurring leakage problem in the forward compartment that housed the RTD (temperature) sensor forced use of the back up tool for the final log. Repeated logs, where data was acquired while logging in both upward and downward directions, were made to check the repeatability and stability of the flow. Good agreement was obtained, as shown on the plots of results in Figures III-6 through III-8. In order to maintain the confidentiality of the data, the graphs were made with arbitrary units on all axes. However, the onset of two-phase flow is clearly noted at the change in temperature and pressure gradients, as explained earlier. The logging was done at a probe velocity of 7.6 m/min (25 ft/min).

D. Private Well Test #2

In December of 1980, the third and final well test of this series was run at a private well, also located in the Imperial Valley, an area of intense geothermal development in the past five years. Again a significant effort was expended in negotiating and executing a liability/data confidentiality agreement with the well owner/operator. This well was of interest because it represented a well configuration and fluid chemistry for which no pressure and temperature logs of the two-phase zone were available. Unfortunately, the testing done under the agreement met with only minimal success.

There were two major problem areas in the logging of this well. The first was logistical - due to shipping problems, the equipment needed to perform the logging arrived about a day and a half late, reducing the available test time. In addition, there were several other extensive experiments being conducted at the same time at the test site, and the logging rig and mast truck had to be shoehorned into the vicinity of the wellhead. This slowed the setup time considerably. The second problem area lay in the performance of the logging equipment at the extreme fluid conditions encountered in the well.

Pressure and Temperature Log for Private Test 1

Figure III-6

Pressure and Temperature Log for Private Test 2

Figure III-7

The logging was done with the same wireline layout as that described for the earlier tests. A riser was installed on the wellhead for pressure control, and the original DRI probe that measures pressure and temperature simultaneously and in real time was used. Two sinker bars were employed to assure that the tool string and cable remained taut during logging operations. A depth limitation was placed on the logging by the well owner/operator because of a downhole constriction. This significantly reduced the value of the data in that a record could not be made to the depth where two-phase flow was initiated. Therefore, the computer model could only be compared to that portion of the two-phase flow actually measured. In addition, several fluid parameters had to be estimated because they could not be measured in the single-phase zone.

The cablehead exhibited repeated failures because of the high temperatures encountered in the test well. Repairs were made several times, and included the use of high temperature Krytox grease and potting of the cablehead connector with high temperature-resistant epoxy. As a result of these failures, only a single log was successfully made, that shown in Figure III-9. An arbitrary scale is used to maintain the confidentiality of the data; however the gradients in both temperature and pressure exhibit a stability not seen in earlier logs made under less severe conditions. One would be led to believe that the flow was not flashing were it not for the fact that the measured pressure gradient was about a third of what would be found in a single-phase flow. Detailed analysis of this log has been hampered by difficulties in obtaining supporting data taken during the logging operations by other contractors of the well owner/operator. Estimates and preliminary values have been used as input to the computer model to provide data for comparison purposes.

E. Additional Two-Phase Flow Data

In the spring of 1980, DRI completed a report on another geothermal project for the Nevada Operations Office of DOE. This program used logging results from tests run at the Roosevelt Hot Springs KGRA, Utah along with the DRI/Coury and Associates two-phase flow computer model to predict an

Pressure and Temperature Log for Private Test 4

Figure III-9

optimum casing size for that reservoir. Of particular interest was the comparison of well test data to computer predictions made at high flow rates. The computer results showed pressure gradients that deviated significantly from the measured values. Several possible explanations for such behavior were developed; the most plausible being the fluid flow into the wellbore was two-phase, thereby raising the enthalpy of the incoming fluid. Several runs were made using a "best guess" for the enthalpy, but the problem continued.

This deviation became a topic of study. After consultation with the DOE technical monitor, a decision was made to forego the final two scheduled field tests in favor of further analysis of the two-phase inflow deviation. This decision was made for two reasons: first, the model had shown good agreement with all previous data, and second, the first three field tests had gone considerably over budget due to unanticipated equipment problems and delays during negotiation of access/liability agreements. The agreement of the model with earlier data was highlighted even more by the fact that parametric runs with very similar data to the reservoir conditions at Roosevelt Hot Springs yielded quite reasonable results in terms of the predicted pressure gradients.

A concerted effort was, therefore, made to obtain other temperature/pressure logs from existing wells where two-phase flow was encountered at the reservoir/wellbore interface. Discussions with many developers led to the discovery of two wells on which considerable data was available. These were HGP-A, the first well of the Hawaiian Geothermal Project drilled in the East Rift Zone of Kilauea on the Island of Hawaii, and BR-27, one of the wells at the Broadlands Geothermal Field in New Zealand. The information on the Hawaiian well was obtained from Dr. Bill Chen of the University of Hawaii at Hilo, and the Broadlands data was sent to DRI by Dr. Malcolm Grant of the Department of Scientific and Industrial Research. This data is presented in the Appendix as Tables A-6 through A-14. Comparison of computer model predictions with this information is discussed in Part B of this report.

IV. GEOTHERMAL WELL DESIGN HANDBOOK

One of the goals, throughout the term of the two-phase flow research conducted under this program, has been to publicize the results and analytic techniques developed. Several mechanisms have been utilized: papers have been given at several national meetings and progress reports were prepared. Perhaps the most significant and effective means of disseminating program information has been the publication of the Geothermal Well Design Handbook and its distribution, including explanation, during workshops held at several annual meetings of the Geothermal Resources Council (GRC).

A. Purpose

The Geothermal Well Design Handbook was designed to be a desk top reference that would permit an engineer to quantify the effect of two-phase flow on pressure drop predictions for wells of a chosen design for a given set of reservoir conditions. The handbook incorporates results from the predictive computer model (described in Part II of this report) with a methodology for its application to produce a prediction of the pressure drop in a flowing geothermal well.

The target concept in the preparation of the handbook was to simplify the production and interpretation of results from the two-phase flow computer model. To run the FORTRAN program requires a knowledge of computer use and familiarity with the coding; the handbook was envisioned as more of a "cookbook", where parametric cases previously run with the model would be presented in such a way that no understanding of the model and its sophisticated approach to the pressure drop calculations was necessary. There is a penalty to be paid when such an approach is taken. In this case, a set of simplifying assumptions was made to keep the selection of discrete variables used in the parameterization to a workable number. This means that for some applications the approach taken in the handbook is too simple, and will not yield valid results. Such cases can be easily identified if the assumptions are clearly stated and their impact on the results is noted.

A caution must be noted here, which is that the handbook must be designed such that the results achieved can be interpreted and used properly, since the user is assumed to have no comprehension of the model on which the handbook is based.

The handbook presents a methodology for the prediction of wellbore pressure drop when a set of input variables are known. Alternatively, it can be used to define the effect of changes in the input variables on the predicted pressure drop. This feature can be of value where such parameters as reservoir temperature and pressure or drawdown are not known as precise values, but have been determined to be within some range. This is a so-called sensitivity study used to quantify the impact of individual input parameters on the pressure drop predictions. One result of the use of the predictive computer model, and thus the handbook, has been a means to select an optimum casing size. Application of this technique in a case study at the Roosevelt Hot Springs KGRA in Utah predicted that for a fixed pressure at the wellhead, a 24% increase in flowrate could be achieved by increasing the casing diameter from 24.4 cm (9 5/8 Inches) diameter to 34.0 cm (13 3/8 inches). Of course such a modification to the well design involves changes in costs and their distribution, and must be evaluated on that basis; but without the result of the prediction, there would be no reason to even consider the installation of increased diameter casing.

B. Comment Issue

A draft copy of the handbook was prepared and circulated among internal project personnel as well as to the DOE Technical Project Officer for comments and suggested changes. Several modifications were made and the Comment Issue was published by DRI and released at a workshop which described its use held during the 1978 Annual Meeting of the GRC. Included in the Comment Issue was an evaluation sheet, to encourage user response and comment on the layout, approach and utility of this first version. A limited number of responses were received, and the suggestions were considered in the preparation of the Final Version of the handbook.

The handbook contains all the information necessary for a user with some knowledge of the reservoir and an electronic calculator to find wellhead fluid conditions. Included are graphs of water properties which change with respect to temperature, graphs of computer-calculated two-phase pressure drops for a discrete set of input parameters, and a Well Design Data Sheet that presents the step-by-step algorithm used to complete the computation.

The sequence of calculations used in the handbook is as shown in Figure IV-1: given the fluid conditions at the top of the producing zone, the pressure drop in the fluid as it rises up the wellbore is computed. The well pressure drop calculation is divided into two parts: single-phase and two-phase. The single-phase pressure drop is the sum of two components: elevation pressure drop and pipe friction pressure drop, and an acceleration pressure drop due to the density change that is part of the phase change process. The pressure of the wellhead is then the difference of the production pressure minus the sum of the single-phase and two-phase pressure drops. The procedure used permits calculations to be made by the user without any iteration steps on his part.

In summary, the handbook procedure is as follows:

- Choose values for input parameters, based on user's knowledge of the reservoir and conversion process or end use of resource;
- Evaluate fluid properties from handbook Fluid Properties graphs;
- Compute single-phase pressure drop and location of flash horizon (point of transition to two-phase flow);
- Find wellhead pressure from two-phase pressure graphs;
- Find wellhead temperature from fluid properties (saturation conditions) graph; compute wellhead quality.

It is also possible to use this handbook to evaluate wellhead pressure, temperature and steam quality for wells with changes in diameter.

This is done by thinking of such a well as a series of constant (though different) diameter wells stacked upon each other. The fluid conditions calculated for the top of one constant diameter segment then become the input conditions for the next higher segment in the stack.

Several assumptions were made to simplify the fluid mechanics of the well flow pressure drop calculation. These are as follows:

- Adiabatic wellbore flow (no heat transfer through the well casing)

The thermodynamics of the phase change from liquid water to steam in the flowing fluid are simplified by the first assumption.

- No dissolved solids in the geothermal fluid
- No dissolved gases in the geothermal fluid

The pure water assumptions eliminate chemical interaction considerations from the pressure drop computation: dissolved constituents can serve to change the enthalpy and boiling point of the fluid.

- Single-phase flow in the wellbore at the producing zone

Additional information on the steam quality of the reservoir fluid is needed to perform the handbook process if there is flashing in the reservoir. This information is difficult to estimate, and virtually impossible to measure. The occurrence of phase change in the reservoir was thought to be uncommon. For these reasons, the single-phase inflow assumption was used in the Comment Issue. Further logging and conversation with developers revealed that two-phase inflow is more common than first believed, and this assumption was reconsidered in the Final Version. Without these assumptions, the dimension of the pressure drop calculation becomes unmanageable in a handbook format.

There are five (5) input parameters that must be specified by the user. They are:

- Wellbore diameter - inside diameter of the well casing, given in inches;
- Depth of well to the top of the producing zone, given in feet;
- Total mass flowrate of fluid in the well, in pounds per hour;
- Temperature of the fluid at the top of the producing zone, under flow conditions, given in degrees Fahrenheit. Since a temperature gradient may exist within the producing zone, the value of the bulk fluid temperature at the top of the producing zone may change when shifting from shut-in to flow conditions. A simple approach to the determination of a reasonable value is to assume a uniform contribution throughout the producing zone and therefore to average the expected shut-in temperatures at the top and bottom of the producing zone. If a detailed temperature survey of the producing zone is available, a more accurate temperature can be determined. This input temperature will be referred to as "production temperature" in the text;
- Pressure in the wellbore at the top of the producing zone, under flow conditions, measured in pounds per square inch, absolute. It is important to note that the specified pressure will vary as a function of flowrate because of pressure drop in the formation. This input pressure will be referred to as "production pressure" in the text.

The reservoir parameters (pressure, temperature and flowrate) may be experimental values or reservoir engineering estimates. Several of the user inputs defined above are parameterized in a discrete set to limit the number of two-phase flow wellhead pressure curves that are presented. If it is at all possible for the user to choose his input wellbore diameter,

mass flowrate and production temperature from the values in Table IV-1 the process of finding the corresponding wellhead conditions is simplified considerably. The need for interpolation, and therefore the evaluation of multiple input data sets for a single solution, is then eliminated.

The production temperature of the subject well is specified, so the corresponding saturation pressure (at which boiling is imminent) is known; and the available single-phase pressure drop can be obtained by subtracting this number from the production pressure. Length of the wellbore in single-phase flow can be determined if the single-phase pressure gradient is found. The length of wellbore remaining is in two-phase flow, and the pressure drop in that section is read from computer-generated graphs of length vs. pressure, which form a chapter of the handbook.

The single-phase pressure drop gradient is the sum of two components. Elevation pressure drop per foot is a simple function of water density, and can be found from the Properties Graphs of the handbook. Friction pressure drop per foot of wellbore length contributes only 1% to 5% of the single-phase total. It is a function of fluid properties and velocity and is computed from a modified Moody equation with an electronic pocket calculator. All the needed values for fluid properties can be determined from the Properties Graphs.

The calculation for pressure drop in the two-phase flow zone is complicated; it requires correlations to compute the elevation pressure drop term and friction pressure drop term. These correlations are functions of the physical properties and relative volumes of the steam and liquid water constituents of the fluid. An iterative procedure is necessary to complete the calculation; it is most easily done by a digital computer program.

There are many correlation coefficients for two-phase flow that have been proposed in the technical literature. After consideration of several of the more prominent, those chosen for the first edition of the design handbook are Hughmark for elevation pressure drop and Dukler, Case II, for two-phase friction pressure drop.

TABLE IV-1

Values of Input Parameters Used in Construction
of Two-Phase Wellhead Pressure Graphs

Production Temperature: 300°F, 350°F, 400°F, 450°F
500°F, 550°F, 600°F, 650°F

Mass Flowrate: 200,000 lbs/hr
300,000 lbs/hr
400,000 lbs/hr
500,000 lbs/hr
600,000 lbs/hr
800,000 lbs/hr
1,000,000 lbs/hr
1,200,000 lbs/hr

Wellbore Diameter:

6 inches Outside Diameter = 5.524 inches Inside Diameter
7 5/8 inches OD = 7.125 inches ID
8 5/8 inches OD = 8.097 inches ID
9 5/8 inches OD = 9.063 inches ID
10 3/4 inches OD = 10.192 inches ID
11 3/4 inches OD = 11.15 inches ID
13 3/8 inches OD = 12.715 inches ID
16 inches OD = 15.375 inches ID

A decision was made to run a representative set of input conditions through the computer program and then present the output in graphic form. This method has two advantages: a large volume of data can be presented on a minimum amount of paper, and similar data sets with only one parameter change can be presented on the same graph for comparison purposes.

The two-phase pressure drop graphs are drawn with the y-axis being Wellhead Pressure, rather than pressure drop. This saves on subtraction by the user, and is a much more convenient quantity. An example is found in Figure IV-2.

After the pressure drop procedure is completed, the wellhead pressure is known and the wellhead temperature is consequently fixed due to the saturated nature of the flow. The wellhead temperature is found from the included graph of saturation pressure-temperature relationships. Quality of the geothermal fluid, expressed as a percent by weight of the total flow, is easily computed using conservation of energy and enthalpies of the fluid at the flash horizon and at the wellhead.

Updating of the two-phase pressure drop graphs is simple because of the handbook design. When the computer model is improved (as is expected with the addition of new field test data to the data base), new graphs can be printed and substituted for the originals in the handbook. The procedure used to perform the rest of the calculations remains unchanged.

The graphs presenting the computer model results were prepared by using a computer to plot the output data on a fixed scale for each graph. The plotted points were then joined with a smooth curve by hand. The two-phase pressure drop graphs were then published in two colors. The grid for the graphs was printed in green, and the curves and labeled axis were black. The results were both more pleasing to the eye and easier to use than a single color graph.

The analysis of the output of the handbook is dependent on the use to be made of the geothermal fluid after extraction. A general methodology will be presented here. Since in most cases, some knowledge of the reservoir is available, the depth to the producing zone and the production

Figure IV-1. Design Handbook Utilization Sequence.

Legend

Diameter = 9.063 inches

A: $T_{pr} = 300^{\circ}\text{F}$, $\dot{M} = 500,000 \text{ lb/hr}$	F: $T_{pr} = 400^{\circ}\text{F}$, $\dot{M} = 400,000 \text{ lb/hr}$
B: $T_{pr} = 300^{\circ}\text{F}$, $\dot{M} = 400,000 \text{ lb/hr}$	G: $T_{pr} = 450^{\circ}\text{F}$, $\dot{M} = 500,000 \text{ lb/hr}$
C: $T_{pr} = 350^{\circ}\text{F}$, $\dot{M} = 500,000 \text{ lb/hr}$	H: $T_{pr} = 450^{\circ}\text{F}$, $\dot{M} = 400,000 \text{ lb/hr}$
D: $T_{pr} = 350^{\circ}\text{F}$, $\dot{M} = 400,000 \text{ lb/hr}$	J: $T_{pr} = 500^{\circ}\text{F}$, $\dot{M} = 500,000 \text{ lb/hr}$
E: $T_{pr} = 400^{\circ}\text{F}$, $\dot{M} = 500,000 \text{ lb/hr}$	K: $T_{pr} = 500^{\circ}\text{F}$, $\dot{M} = 400,000 \text{ lb/hr}$

GRAPH LB-4: TWO PHASE WELLHEAD PRESSURE CURVES

Figure IV-2

LB-4

temperature can be fixed. By varying well diameter and mass flowrate inputs, a parametric set of wellhead temperatures, pressures and qualities can be calculated. An estimate of the number and size of wells needed to operate the users' intended process can now be made. With this information, cost comparisons can be calculated for the several cases of diameter and flowrate inputs used. If reservoir characteristics are not well defined, additional cases with changes in depth and temperature can be computed. Economic optimization can be conducted by adding costs for the process itself (as a function of fluid pressure and temperature at the wellhead) to the well costs as computed above.

Long term well operation can also be calculated, if the pressure of the reservoir can be predicted as a function of either time or cumulative production. The method used here depends on production pressure and temperature, so that when standard reservoir engineering techniques are applied, sufficient information can be obtained so that calculation of wellhead pressures and temperatures for future operation is possible.

A final comment on the use of the output should be noted. Because of the simplifying assumptions made and the complex nature of two-phase flow, the wellhead conditions determined via the handbook are approximations. This is why they are called estimates throughout the text. The output data have the most value when used to compare the relative merits of several proposed well configurations and the influence of individual parameters on well performance.

To increase the utility of the data presented in the later chapters of the handbook, an alternate method for analysis of two-phase flow in geothermal wells has been developed. In particular, the new approach allows the user to specify wellhead and reservoir parameters and to find a corresponding mass flowrate. As part of the computational scheme, graphs can be prepared which show the sensitivity of the mass flowrate to any of the input parameters. Such information may be of interest if the values of reservoir or wellhead conditions are known only to fall within some given range.

The key to the method presented here is the use of productivity index (PI), J , as an output of the calculation, rather than an input. The approach splits the available pressure drop, from the equilibrium (or shut-in) reservoir pressure to the chosen wellhead pressure, into wellbore losses and reservoir losses. Wellbore losses are found from the graphs in the handbook and a calculational procedure. The remaining pressure drop is said to take place in the reservoir, equal to a linear function of flowrate. Since the values of this reservoir pressure drop and chosen flowrate are known, the proportionality factor, J , can be computed.

In reality, the productivity index of a reservoir is fixed, but by manipulating the defining equations to permit solution for J , the remaining input parameters may be fixed instead. Thus the calculated productivity index, when compared to the known value, is used as an indication of the validity of the chosen inputs. Choices of other combinations of inputs can also be based on a comparison of values of the calculated and known productivity indices.

When the method has been applied to a number of data sets, the resulting productivity index values can be graphed to show the effect of changes in any of the input parameters. In addition, the results can be further manipulated, either graphically or mathematically, to show the sensitivity of mass flowrate to any of the other inputs. These include depth to production, (assumed) wellhead pressure, reservoir (shut-in) pressure, reservoir temperature, and wellbore diameter. A broad variability in the results can be expected because of the interaction of the inputs on one another for each individual situation. The detailed sequence followed for the alternate approach is shown in Figure IV-3.

Use of this technique is demonstrated in Table IV-2, where several data sets that have been compiled from typical US reservoir parameters were used as inputs. The resulting productivity index values are plotted on Figure IV-4 as the lowermost curve. Two other data sets, at different fixed wellhead pressures, are also shown for comparison. The effect of

Figure IV-3. Design Handbook Alternate Utilization Sequence

Table IV-2

Two-Phase Flowrate Determination Worksheet

Step No.	Activity		Result			
			Case A	Case B	Case C	Case D
1	Specify Inputs:					
	Wellbore Depth to Reservoir	L	4000	4000	4000	4000
	Wellhead Pressure	P _{wh}	120	120	120	120
	Shut-In Reservoir Pressure	P _o	1750	1750	1750	1750
	Choose Reservoir From Temperature	T _{pr}	400°F	400°F	400°F	400°F
	Para- Casing					
	metric Diameter	D	9 5/8	9 5/8	9 5/8	9 5/8
2	Date Set Mass Flow-	M	300000	500,000	600,000	800,000
	(p. 6) rate					
	Find Length of Two-Phase Zone from Appropriate Graph Corresponding to (see p. 31 for Index)	P _{wh}	970	840	765	620
	Find Length of Single-Phase Zone: L _{1p} = L - L _{2p}		3030	3160	3235	3380
	Calculate Single-Phase Gradient $\left(\frac{\Delta P}{\Delta L}\right)_{1p}$		.3738	.3761	.3777	.3816
	From Eq. below					
	$\Delta P_{1p} = L_{1p} \cdot \left(\frac{\Delta P}{\Delta L}\right)_{1p}$		1133	1188	1222	1290
6	P _{2p} = P _{sat} from Properties Graph P-4, p.35		247	247	247	247
	J = $\dot{M} / [P_o - (P_{2p} + \Delta P_{1p})]$		811	1581	2135	3756

Single-Phase Gradient Equation:

$$\left(\frac{\Delta P}{\Delta L}\right)_{1p} = \left(\frac{\Delta P}{\Delta L}\right)_{\text{elev}} [1 + (4.8377 \times 10^{-4}) \left(\frac{f \dot{M}^2}{\rho^2 D^5}\right)]$$

where f is Moody Friction Factor, ρ is fluid density and $\left(\frac{\Delta P}{\Delta L}\right)_{\text{elev}}$ is the gravity head in psi/ft.

Page References are to Comment Issue Handbook

Figure IV-4. Graphic Presentation of Worksheet Results.

PI on the mass flowrate that can be sustained under the input conditions is easily seen on the plot. The shape of the curve also gives an indication of the impact of an increase in PI that can be caused by artificial stimulation as well as the effect of any decrease in PI that could occur if scaling is initiated in the reservoir or may be due to skin effect from drilling and completion practices.

The data in Figure IV-4 becomes even more useful if it can be replotted. The smooth curves drawn through the plotted data points is intersected by a vertical (constant PI) line, at the known value of the case under study. These intersection points are then replotted as shown in Figure IV-5, where mass flowrate is now shown as a function of wellhead pressure. Two additional curves are shown for higher and lower PI's than the 1450 chosen for the typical well.

This alternate approach to the use of the handbook data can be used to quantify the effect of changes in any of the input parameters by applying the technique demonstrated above. The most important limitation to the use of this approach is tied to the assumption of a linear relationship between mass flowrate and reservoir pressure drop, whose ratio is expressed as the productivity index. In cases where this linear relationship is thought not to hold, such as when two-phase flow occurs in the reservoir, the alternate approach should not be applied.

C. Final Version of the Handbook

As noted earlier, comments and suggestions on the initial published version of the handbook were solicited, and several of the evaluation sheets were returned. Most comments asked that some means be developed to fix the wellhead pressure and calculate the mass flowrate, a request that is answered in the alternate approach. Others commended and condemned the use of traditional units in the handbook. A page of conversions to standard metric units is being compiled for use in the final version. One additional significant change will be made in the handbook: several users have noted that the plot of heat of vaporization shown as a function

Figure IV-5. Replot of Worksheet Results to Show Mass Flowrate Dependence on Wellhead Pressure.

of temperature was incorrectly drawn. This Properties Graph has been redone and the proper version will be inserted in future copies.

A Final Version of the handbook is now in preparation and will be submitted to DOE for publication. The alternate approach will be incorporated to increase the utility of the handbook. A new set of two-phase flow pressure drop curves will be included. These have been revised because the new holdup and pressure drop correlations developed by Dukler have been programmed into the model and seem to show a better match with the field test data taken to date.

Numerous inquiries about the status of the handbook has resulted in the compilation of a distribution list, which is being maintained at DRI and will be submitted with the camera-ready copy.

V. TWO-PHASE FLOW WORKSHOPS

An important aspect of the two-phase flow research reported here has been the presentation, at several national meetings, of the concept of two-phase flow accompanied by an explanation of its application to geothermal systems and a description of the research program undertaken by DRI and Coury and Associates. Workshops on this topic were presented at the 1978 and 1980 Annual Meetings of the Geothermal Resources Council. Each workshop was about two hours in length and included presentations on three tasks of the project: a review of the principles of two-phase flow, a description of the approach and features of the DRI/Coury and Associates Two-Phase Flow computer model and a tutorial on the use of the Geothermal Well Design Handbook. In addition, papers on the design and test of the pressure/temperature logging probe and the use of the handbook were published in the GRC Transactions. A summary paper of the two-phase flow research was presented at the 1980 ASME Energy Technology Conference and Exhibition in New Orleans, LA.

A. First Handbook Workshop

The 1978 GRC Annual meeting was held at the Hilo Lagoon Hotel in Hawaii, and 25 attendees registered for the DRI/Coury and Associates Two-Phase Flow Workshop. There were nine no-shows, leaving a total of 16 persons plus a couple drop-ins at the session. The first item on the agenda was a general description of the concept of two-phase flow presented by Dr. Glenn Coury. The physical phenomenon was discussed and the generally accepted succession of flow regimes for vertical systems was explained. This was followed by an outline of the DRI/Coury and Associates research program which highlighted both the experimental field tests and computer model development work.

The objective, approach and operating characteristics of the computer model (under development at the time) were then presented. Arrangements were made to have at the workshop a remote computer terminal on which example cases brought by the attendees could be run through the model.

Since this was a remote job entry to a time share system, the results were delayed by about four hours, and an informal discussion of results in a group setting was cancelled in favor of short individual conferences to assist in interpretation of the model output.

The remainder of the workshop was devoted to the introduction of the Geothermal Well Design Handbook. A draft version of the handbook had been presented to DOE/DGE about six months before the workshop and several suggested changes were made in what was entitled the Comment Issue. A total of 80 copies were printed and inserted in loose-leaf binders to permit easy access. Due to a problem with the production of computer generated data graphs, only two samples of the 64 Two-Phase Wellhead Pressure Graphs were included in the handbook distributed at the Workshop; the others were mailed later to participants.

A presentation on the layout and use of the handbook was made by Mr. James Butz of DRI. The reason for preparation and assumptions made in the handbook were noted, and a sample calculation was presented step by step to describe its use. Additional manipulation of the handbook results through interpolation was also discussed. This was followed by a question and answer session to clarify any remaining doubts or misunderstandings.

B. Final Workshop

A second workshop was held at the 1980 GRC Annual Meeting in Salt Lake City for the use of handbook data and to present additional data on a study of pumped and two-phase flow produced geothermal wells. There were 35 persons registered, about 30 of whom attended along with several drop-ins. Since a majority of this audience had not attended the earlier workshop, the background materials on the nature of two-phase flows and their impact on geothermal systems were repeated.

There was considerable interest among the group in several of the concepts which prompted some spirited discussion and contributions from

the participants. This exchange reflected a significant increase in awareness of the importance of two-phase flow in the design and development of geothermal resources. The discussion comments came from two sources: academic researchers, who have begun to explore the physics and chemistry of two-phase flow, and industry people, who have become concerned over the effects of two-phase flow as the initial flashing brine plants in the US enter the construction phase. Both groups were supplied with new and challenging questions as well as some useful answers on the topic of two-phase flow.

The Geothermal Well Design Handbook was the subject of a presentation that paralleled that of the earlier workshop. A description of the handbook covered the objective, layout, assumptions, methodology and finished with the step by step solution of an example problem. This was followed with an explanation of an alternate approach to the use of the handbook data, presented in the handbook as a family of curves plotted on 64 graphs. This data was generated by the two-phase flow computer model, using as inputs a discrete set of well and reservoir parameters thought to span the range of values for most commercially feasible resources in the US.

The alternate approach allows for considerable versatility in the use of the data from the two-phase wellhead pressure graphs. Through the application of this method, the user can define the effect on mass flowrate of the following variables: wellhead operating pressure, wellbore depth, casing diameter, reservoir temperature, equilibrium (shut-in) reservoir pressure, and Productivity Index. This can be of significant value when decisions on well spacing, design and number must be made with a limited amount of reservoir data. By quantifying the impact on mass flowrate over the expected range of reservoir parameters an economic optimization of the field development can be set up and solved mathematically. There are limitations to the use of this technique, the most important being the assumption of a linear relationship between mass flowrate and drawdown. A detailed description of the alternate approach is contained in Section IV of this report.

The final presentation covered results of a comparison of pumped and naturally flashing geothermal production wells. A paper on this topic prepared for the 1979 GRC Annual Meeting had generated some controversy in that several of the assumptions made in the calculations were misunderstood. The workshop served as an ideal vehicle for clarifying and expanding on the earlier paper, since considerably more time was devoted to the results and analysis of the task. Details of the investigation are presented in Part B of this report.

VI. EQUILIBRIUM GEOCHEMISTRY OF GASES DISSOLVED IN GEOTHERMAL BRINES

A literature search was conducted to establish equilibrium constants for the solution of certain gases commonly found in geothermal waters.

The reactions considered were

- 1) $O_2^v \rightleftharpoons O_2^l$
- 2) $N_2^v \rightleftharpoons N_2^l$
- 3) $H_2^v \rightleftharpoons H_2^l$
- 4) $CH_4^v \rightleftharpoons CH_4^l$
- 5) $H_2S^v \rightleftharpoons H_2S^l$
- 6) $H_2S^l \rightleftharpoons H^+ + HS^-$
- 7) $HS^- \rightleftharpoons H^+ + S^{2-}$
- 8) $NH_3^v \rightleftharpoons NH_3^l$
- 9) $NH_4^+ \rightleftharpoons NH_3 + H^+$
- 10) $CO_2^v + H_2O^l \rightleftharpoons H_2CO_3^l$
- 11) $H_2CO_3^l \rightleftharpoons H^+ + HCO_3^-$
- 12) $HCO_3^- \rightleftharpoons H^+ + CO_3^{2-}$
- 13) $CaCO_3 \rightleftharpoons Ca^{++} + CO_3^{2-}$
- 14) $H_2O^l \rightleftharpoons H^+ + OH^-$

In order to characterize the geochemistry of geothermal fluids realistically, the effect of dissolved gases on aqueous equilibria must be considered. To this end, a literature search for thermodynamic equilibrium constants, generally in the form of Henry's Law constants, for gas reactions important to geothermal fluids (Ellis, 1977) has been carried out. These reactions have been divided into several groups; the "inert" gas reactions involving O_2 , N_2 , H_2 and CH_4 , the carbonate-carbon dioxide reactions involving CO_2 , H_2CO_3 , HCO_3^- and CO_3^{2-} , the hydrogen sulfide reactions involving H_2S , HS^- and S^{2-} , and the ammonia reactions involving NH_3 and NH_4^+ .

In general, two treatments are necessary; that involving non-ionizing Henry's Law gases and that involving highly soluble or dissociating gases.

A. Henry's Law Gases

Henry's Law constants, expressed in atmospheres per mole fraction, were garnered from the work of Himmelblau (1960) for the diatomic gases and non-geopressured methane. In this work, the logarithm of the Henry's Law constants are expressed as a function of temperature using the fitted equation:

$$A(\log H)^2 + B\left(\frac{1}{T}\right)^2 + C(\log \bar{H})\left(\frac{1}{T}\right) + D(\log \bar{H}) + E\left(\frac{1}{T}\right) - 1 = 0$$

where $\bar{H} = H \times 10^{-4}$ and $\left(\frac{1}{T}\right) = \left(\frac{1}{T}\right) 10^3$; H in atm/mole fract. and T°K

The coefficients for each of the various gases are listed in Appendix I. Himmelblau's paper represents a compilation of data from several sources which describe experimental results over various temperature ranges. Attempts to extrapolate fitted curves beyond the range of data may give questionable results. Temperature ranges over which the curves are considered valid are also listed in Table VI-1. For each of these gases, only the simple solution reaction is considered in the overall modeling process.

B. Reactive Gases

Systems requiring the second treatment include the carbonate-carbon dioxide reactions, hydrogen sulfide reactions and ammonia reactions. These gases all speciate in solution and hence, do not obey Henry's Law when only simple solution is considered. In these cases, equilibrium constants for the total set of reactions, rather than a single vapor to liquid reaction, were fitted as a first or second order function of temperature.

TABLE VI-1

EQUILIBRIUM CONSTANTS FOR HENRY'S LAW GAS REACTIONS

	Temperature Range of fit (°C)
1) $O_2^v \rightleftharpoons O_2^l$	0° - 343°
2) $N_2^v \rightleftharpoons N_2^l$	0° - 316°
3) $H_2^v \rightleftharpoons H_2^l$	66° - 332°
4) $CH_4^v \rightleftharpoons CH_4^l$	25° - 171°

Data for these reactions fitted by:

$$A(\log \bar{H})^2 + B(1/\bar{T})^2 + C(\log \bar{H})(1/\bar{T}) + D(\log \bar{H}) + E(1/\bar{T}) = 0$$

where $\bar{H} = H \times 10^{-4}$ (Henry's Law Constant)

and $(1/\bar{T}) = (1/T) \times 10^3$ (°K)

Correlation Coefficients

<u>Gas</u>	<u>A</u>	<u>B</u>	<u>C</u>	<u>D</u>	<u>E</u>
O_2	-0.0005943	-0.1470	-0.0512	-0.1076	0.8447
N_2	-0.1021	-0.1482	-0.01900	-0.03741	0.8510
H_2	-0.1233	-0.1366	0.02155	-0.2368	0.8249
CH_4	-0.1173	-0.1247	-0.07629	0.1959	0.7413

The carbonate-carbon dioxide, hydrogen sulfide, and dissociation of water equilibrium constants (Table VI-2) were selected from Helgeson (1969). Values of Log K(T) listed in this reference were generally computed using data, when available, fitted to the expression

$$\begin{aligned} \log K(T) = & \frac{\Delta S_c^0(T_r)}{2303 KT} [T_r - T - \frac{\theta}{\omega} (1 - \exp [\exp(b + aT) - c + (T - T_r)/\theta])] \\ & - \frac{\Delta H_r^0(T_r)}{2.303 RT} + \frac{\Delta S_r^0(T_r)}{2.303 R} + \frac{\alpha'}{2.303R} (\ln T/T_r - 1 + T_r/T) + \\ & + \frac{\beta'(T-T_r)^2}{4.606RT} + \frac{\lambda'}{4.606RT} (T^3/3 - T_r^3/3 - T_r^3T + T_r^3) \end{aligned} \quad (1)$$

where θ , ω , a , b and c are temperature independent constants characteristic of the solvent, $\Delta S_e^0(T_r)$ is the electrostatic entropy of dissociation at the temperature of reference (T_r) and α' , β' , and λ' are temperature independent coefficients characteristic of the reaction (3). α' , β' , and λ' were evaluated at low temperatures where log K information was already available. When few experimental values were available the reaction dependent terms were dropped from the equation.

In extracting the Log K(T)'s from Helgeson (1969), it is not apparent whether the values presented are the original data points to which equation (1) was fit or are only the values resulting from the fit of equation (1) to the original data. The latter was assumed to be the case, since the data were always presented at even intervals of temperature. That being the case, it was thought that fitting yet a second curve to the already fitted data was wholly justified. However, the fits in general were so good, that it was decided to keep the simpler fit as a first approximation.

In the case of the carbonate-carbon dioxide system, the following reactions were considered.

TABLE VI-2

EQUILIBRIUM CONSTANTS FOR NON-HENRY'S LAW GAS REACTIONS

Carbonate-carbon dioxide reactions

	T°C							
log Keq	25°	50°	60°	100°	150°	200°	250°	300°
K ₁	- 1.46	- 1.70	- 1.78	- 1.97	- 2.07	- 2.06	- 1.98	- 1.83
K ₂	- 6.35	- 6.31	- 6.32	- 6.45	- 6.73	- 7.08	- 7.63	- 8.86
K ₃	-10.32	-10.17	-10.15	-10.16	-10.29	-10.68	-11.43	-13.38
K ₄	- 8.37	- 8.62	- 8.74	- 9.39	-10.25	-11.37	-12.72	-14.10

Fitted Equations:

$$K_1 = -1.3181 - 0.008442T + 0.00002277T^2$$

$$K_2 = -6.507 + 0.00574T - 0.00004396T^2$$

$$K_3 = -10.744 + 0.01500T - 0.0000770T^2$$

$$K_4 = -8.092 - 0.009034T - 0.00003698T^2$$

Hydrogen sulfide reactions

TABLE IV-2 (Continued)

	T°C							
log K(T)	25°	50°	60°	100°	150°	200°	250°	300°
K ₅	- 0.99	- 1.20	- 1.26	- 1.43	- 1.52	- 1.54	- 1.52	- 1.46
K ₆	- 6.99	- 6.77	- 6.72	6.63	6.72	6.96	7.35	8.06
K ₇	-13.90	-13.13	-12.84	-11.78	-10.62	- 9.57	- 8.61	- 7.72

Fitted Equations:

$$K_5 = -0.8866 - 0.006678T + 0.00001619T^2$$

$$K_6 = -7.1571 + 0.009238T - 0.00004069T^2$$

$$K_7 = -14.194 + 0.022366T$$

Dissociation of water

	T°C							
log K(T)	25°	50°	60°	100°	150°	200°	250°	300°
K _w	-14.0	-13.27	-13.03	-12.26	-11.64	-11.27	-11.13	-11.39

$$K_w = -14.6264 + 0.029527T - 0.00006254T^2$$

Ammonia reactions

TABLE IV-2 (Continued)

<u>Temp. °C</u>	<u>Corrected Volatility (ppm^v/ppm^l)</u>
147	9.67
172	8.80
201	6.94
245	5.19
254	4.76
292	3.42
326	2.63
149	9.75
175	8.51
203	7.07
245	5.08
266	4.47
289	3.77
318	3.05
147	9.98
206	6.67
260	4.44
317	3.05

Fitted Equation:

$$K_d^9 = 22.6 - 0.10486T + 0.0001371T^2$$

$$10) \quad \text{NH}_4^+ \rightleftharpoons \text{NH}_3 + \text{H}^+ : K_{10} = \frac{10^{-\text{pH}} (\alpha_{\text{NH}_3})}{\alpha_{\text{NH}_4}}$$

	<u>T°C</u>								
<u>log K(T)</u>	<u>25°</u>	<u>50°</u>	<u>75°</u>	<u>100°</u>	<u>125°</u>	<u>150°</u>	<u>200°</u>	<u>250°</u>	<u>300°</u>
K ₁₀	-9.25	-8.56	-7.95	-7.41	-6.94	-6.54	-5.73	-5.05	-4.29

Fitted Equation:

$$K_{10} = -9.7887 + 0.02559T - 0.00002508T^2$$

in addition to the solution reaction of calcite

where $K_4 = K_\alpha = (\alpha_{\text{Ca}^{++}})(\alpha_{\text{CO}_3^{2-}})$, an activity product.

Reactions 1-4 could be fit to a minimum 97% confidence level using a simple second order dependence on temperature.

The hydrogen-sulfide system consists of the following set of equations:

$\log K(T)$'s for reactions 5 and 6 were fitted to a 97% percent confidence level again using a simple second order dependence on temperature while reaction 7 was fitted to a straight line with a confidence level of 99.4%.

The dissociation of water:

was fitted to a second order temperature dependence with a confidence limit of 99.8%.

Information on the solubility of ammonia has been taken from Jones (1968). Jones's results are couched in terms of distribution constants rather than equilibrium constants. These K_d 's have been corrected for the percentage of ionized ammonia in solution, hence any calculation of the concentration of NH_3 in the liquid phase refers only to un-ionized ammonia.

$$9) \quad \text{NH}_3^{\text{l}} \rightleftharpoons \text{NH}_3^{\text{v}} \quad K_d^9 = \frac{\text{ppm}_{\text{NH}_3}^{\text{v}}}{\text{ppm}_{\text{NH}_3}^{\text{l}}}$$

(un-ionized
at eqbm.)

Should it become necessary to use total ammonia rather than un-ionized NH_3 , the amount of total ammonia can be split into ionized and un-ionized proportions by considering the following reaction:

$$10) \quad \text{NH}_4^+ \rightleftharpoons \text{NH}_3 + \text{H}^+ \quad K_{10} = \frac{10^{-\text{pH}} (\alpha_{\text{NH}_3})}{\alpha_{\text{NH}_4^+}}$$

where NH_3 is assumed to be total measured ammonia in the liquid phase. The amount of un-ionized ammonia can be recalculated once the amount of NH_4^+ in solution is known. The amount of NH_3 in the vapor phase can then be calculated using equation (9).

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I. INTRODUCTION

The work discussed in Part B includes the continued development of a mathematical model, the comparison of model predictions with data, and the use of the model in a few specific studies.

The mathematical model is for the simulation of single- and two-phase fluid flow in geothermal wells. The technical effort described in Part B is a continuation of one begun by the University of Denver and Coury and Associates, Inc. in a previous contract. Due to the continuing nature of this work, the reader is referred to the final technical report of the previous DOE contract, No. DE-AC02-TTET28359, for a detailed discussion of the nature of two-phase flow and for a discussion of benefits resulting from development of a mathematical model for the two-phase flow process. Only a brief discussion of these two items is included here for the purpose of orienting the reader to the present work effort.

The nature of two-phase flow is complex in that several factors interact to determine flow rate and pressure drops--factors which are not present in single-phase flow. This complexity complicates the design problem of predicting the expected rate of production given the fluid properties, wellhead pressure, and wellbore diameter and of making economically attractive selections of line size and surface pressure.

A meaningful model of the two-phase flow process permits study and understanding of the process necessary for good definition and solution of the design problem. Models evolve with time as feedback from testing of early models is used in developing rationale for better descriptive models and as part of this in the identification of technical areas for meaningful research programs. Eventually, with further development, the model can become a valued predictive tool in the simulation of well conditions. The continued development of the model is a focus of the current contract.

In the previously mentioned contract, a mathematical model was developed for simulating single-phase and two-phase flow of pure water in geothermal wells. The model was used for a parametric study of the effects of temperature, flow, and casing diameters on wellhead conditions--for the case of pure water. The results of this study were compiled in the Geothermal Well Design Handbook (Denver Research Institute, 1978). In the

current contract, the mathematical model was further developed to include the effects of dissolved solids and dissolved gases. Another extension of the model permits the simulation of geopressured methane wells. In an effort to more accurately predict pressure drops, new holdup correlations from the University of Houston were incorporated into the model and compared to correlations previously used. After these refinements and extensions, the model results were compared to several sets of well test data which included both low and high salinity data. The model was also used in a parametric study of the effects of complex brines on well conditions. A separate study comparing pumped flow to flashing flow used model predictions for the flashing flow case.

The rest of Part B is included in three sections and two appendices. Section II includes three subsections which address the development of the model. The first, II-A, discusses the approach taken to include the effects of dissolved solids and dissolved gases. The second subsection, II-B, further discusses modeling of dissolved gases for the special case of geopressured methane. The third subsection, II-C, covers the approach taken to include recent two-phase flow holdup correlations into the model. Section III covers testing and validation of the model. In the first subsection, III-A, the new University of Houston holdup correlations are compared against the Hughmark correlation, which was previously used in the model. Subsection III-B presents and discusses the comparison of model predictions to several sets of well test data. In Subsection III-C, a parametric study of the effect of complex brines on well conditions is presented. The final subsection, III-D, summarizes the results of the validation tests and studies. Section IV discusses Coury and Associates' participation in two workshops, and presents the results of a study analyzing pumped and flashing flow that were presented at the most recent workshop. Four appendices are included. Appendix B contains a flow chart of the two-phase flow computer model, and Appendix C gives directions for the use of the computer model. Appendices D and E both have to do with pumped versus flashing flow studies that Coury and Associates has made. Appendix D contains a published article, the contents of which were presented at the 1979 Geothermal Resources Council meeting. Appendix E includes part of a handout provided at a 1980 Geothermal Resources Council meeting workshop on two-phase flow.

II. APPROACH TO MODEL DEVELOPMENT

In Section II, three extensions of the mathematical model are discussed. Section II-A covers the approach taken in modeling the effects of dissolved solids and dissolved gases on well conditions. More specifically, it discusses the important considerations of the modeling effort and the search for a suitable computer code for the prediction of activity coefficients for dissolved species. As this particular task was completed in 1979, the discussion does not include more recent information on code development and availability.

Section II-B describes the approach taken to model geopressured methane. It describes equations that calculate the solubility concentrations of methane in water and aqueous sodium chloride solutions up to 25 weight percent, temperatures up to 360°C (680°F), and pressures up to 20,000 psia. The range of conditions for which these equations are valid exceed those expected for geopressured methane applications and the accuracy is well within the requirements of this task. Section II-C discusses work done in the evaluation of recent two-phase flow holdup correlations resulting from theoretical and experimental studies at the University of Houston.

A. Dissolved Salts and Gases

The flow characteristics of geothermal wells are affected in several ways by dissolved chemicals. Dissolved salts change the density and viscosity of the liquid, thereby affecting all three components of pressure loss: frictional, gravitational, and acceleration losses. In addition, the temperature-pressure saturation curve is displaced and the enthalpy of the liquid changes, thereby changing both the temperature at which flashing occurs and the quantity of vapor formed for a given reduction in pressure. Finally, dissolved gases are released as pressure decreases during flow up the well, so that two-phase flow is initiated lower in the well than would be the case for pure water.

These factors must be well understood in order to adequately predict the pressure-flow relationships for a given well, whether the production method is by natural flashing two-phase flow or by pumping with submerged pumps. The most difficult to predict of the various effects of dissolved chemicals is the rate of release of gases, yet this parameter is of particular importance. For pumped wells, the depth of installation of pumps

and the pressure head developed by the pump depend strongly on the bubble point of the brine. For natural flow, the length of the two-phase zone and the total mass flow rate of the vapor phase depend on the behavior of the dissolved gases. In addition, the formation of precipitates is largely influenced by the brine pH, which becomes more basic as acid gases are released by flashing.

The prediction of gas release requires the knowledge of several parameters, none of which are well known. These include the bottomhole composition and temperature of the brine, the equilibrium constants governing the various reactions that can occur and the effect of temperature on the value of the constants, the activity of the various chemical species as affected by temperature and ionic strength of the brine, and the rate at which the various reactions approach equilibrium. For the present study, it was assumed that the downhole composition was known, and that chemical equilibrium existed throughout the well. With respect to the latter assumption, equilibrium implies a limiting, worst case calculation with respect to both pressure drop and scaling.

A great deal of effort has been devoted by several researchers to both the development of models for predicting equilibrium coefficients and the activity of dissolved species, and for the development of computer codes to make the complex predictive calculations. These works have been reviewed and discussions have been held with the researchers. For various reasons, all of the existing computer programs that have been uncovered either were not well suited to the needs of this two-phase flow study, or were not available to Coury and Associates. It appeared that the most applicable was the program called WATEQ developed by the U. S. Geological Survey (Truesdell et al., 1973) which requires considerable modification to be compatible with the calculational requirements. This report presents a brief review of the status of several computer codes, and describes the modifications that were made to WATEQ.

In brief, WATEQ needed to be revised to accomplish two new sets of calculations. First, the change in equilibrium pH of the brine solution must be determined after each increment of flashing within the wells; the program as written, however, requires that the pH be known and specified. Second, the composition of the vapor phase after release of gases from the liquid phase and the new liquid phase equilibrium composition

after release of gases must be calculated; the original program calculates the distribution of species only within the liquid phase. Algorithms have been developed for these revisions and have been incorporated into the computer program.

Review of Existing Computer Codes and Property Correlations

Brine property correlations--In addition to chemical equilibrium calculations, the transport properties of high saline brines at high temperatures must be determined in order to accurately determine the hydrodynamic aspects of flashing flow up production wells. The most important properties are the brine density, the saturation temperature-pressure relationship, and brine specific heat and heat of vaporization. Of secondary importance are brine viscosity and surface tension. Of several references on this subject (Elliot, 1975; Pool, 1964; Miller, 1978; Burnham, 1969; Liu, 1972; Rariden, 1971; and Dittman, 1977), the most useful for the purpose of this modeling effort are the references by Elliot and Pool. These correlations have been modified to be compatible with the calculational procedures required for the two-phase flow analysis, and have been incorporated into the program.

Computer codes for chemical equilibrium--General discussion--Computer codes for the calculation of brine equilibrium have been developed by several organizations, including the U. S. Geological Survey, the University of California at Berkeley, the Lawrence Livermore Laboratory, the Los Alamos Scientific Laboratory, and Battelle Northwest Laboratory. Other code developments taking place by private companies are proprietary. In addition, Coury and Associates have developed a simplified code for rapid determination of vapor-liquid equilibrium, the distribution of species in the aqueous phase, and the equilibrium point at which calcium carbonate would precipitate. This simplified code is applicable to flashing systems for dilute brines, where the activity coefficient may be assumed equal to unity with reasonable accuracy. It is based primarily on equilibrium coefficients from Helgeson (Helgeson, 1967).

As the brine becomes more concentrated, the simplifying assumption that the activity coefficient is equal to one becomes more and more in error. The activity coefficient can be estimated by means of the

Debye-Hückel theory, as a function of solution ionic strength and temperature. This calculation is an iterative one since the ionic strength is, itself, a function of the activity coefficient, in that the degree of ionization of several species is affected by their activity.

The iterative procedure required for the calculation of species activity is of special practical significance when a chemical equilibrium code is being considered for use as part of the two-phase flow computer program. The hydrodynamic calculations for two-phase are in themselves long. Adding chemical equilibrium to these calculations increases the run time considerably because of four levels of complexity in the calculating scheme, two of them applying to simple brines with activity coefficients of unity, as described below. As the brine flashes continuously up the well, both the quantity and composition of each phase change continuously. The chemistry of the liquid phase is strongly dependent upon both the liquid pH and the partial pressure of carbon dioxide in the vapor phase. In order to determine these values, a double iteration is required. First, the values for both the CO₂ vapor pressure and the liquid pH are assumed, and the corresponding equilibrium composition is determined. Several trials are required until the correct pH is achieved, and then the assumed vapor pressure of CO₂ is checked to see if it is correct. If not, the assumed vapor pressure is changed and the pH trials are repeated. This entire procedure is repeated at several critical points along the flow path of the well as flashing progresses. A computer code developed by Coury and Associates was designed to handle this case for simple brines.

When the assumption of an activity of unity must be discarded for more concentrated brines, the third level of complexity is introduced. Another level of trial and error calculations, to determine the activity as a function of ionic strength, is introduced as was described above. The fourth level of complexity is due to the large number of species that is present in some geothermal brines. This requires that a large number of possible chemical combinations must be considered. Most of the computer programs that have been written for the determination of chemical equilibrium have been oriented towards a good understanding of basic geochemical phenomena. Accordingly, their goal is to consider as many chemical combinations as is practical, and the computer running time tends to be long.

Description of chemical equilibrium codes--In this section, a brief description is given of several chemical equilibrium codes that have been analyzed, and of their status as related to the needs of this study on flashing brine production wells. A code called EQUILB (Shannon et al., 1977, and Shannon et al., 1978) as of 1979 was under development by the Battelle Pacific Northwest Laboratories as part of a study being undertaken for the Electric Power Research Institute. This program was originally based upon the data and code of Helgeson (Helgeson et al., 1970), but was modified to include Bureau of Standards data and to reduce running time and memory storage requirements. The program is set up to handle seven gaseous species and over 100 each of aqueous species and precipitates. Additional species are being added to the program capabilities. Several problems make the code unsuitable for the present need. Primarily, it is not yet available for use and the date of availability is uncertain. Also, it requires a large amount of computer time, ranging from more than one to over forty seconds per case. The approach to determining the vapor pressure of dissolved gases and the pH of the liquid phase are much different from that now in use in the Coury and Associates program, and extensive changes would be required to make the codes compatible.

Several code development efforts are at various stages of completion at the Lawrence Livermore Laboratory. A low temperature code called MINICULE has been developed (Jackson, 1979) which appears to be potentially very useful. As of 1979, a high temperature data base was being developed for the code. A simplified code (Jackson, 1977) was also under development which is limited in its scope. The number of chemical combinations considered in this reference is less than in most programs but is well suited to the needs of the two-phase flow computer program. Activity and equilibrium coefficients are taken directly from Helgeson (Helgeson, 1967) which had to be extrapolated for solution concentrations greater than a molality of three. A primary simplification that should greatly reduce computation time is the assumption that liquid phase pH is controlled only by the carbon dioxide equilibrium. This assumption reduces the accuracy of calculations, however, when significant quantities of other buffering species are present. This code appears to be generally in working condition but is not yet completed or available for general use at this time--1979.

Another brine equilibrium model was developed earlier at the Lawrence Livermore Laboratory (Miller et al., 1977a, and Miller et al., 1977b) for ERDA (now the Department of Energy). This code is based on the modification made by C. Herrick, of the Los Alamos Scientific Laboratory, to the original Helgeson code (Helgeson et al., 1970). The fundamental purpose of the original code was to determine the solution chemistry that results from dissolving rock in water or in dilute electrolytes, and it is not well suited to the calculations for flashing brine. The code is long and slow in running, and not really applicable to addition as a subroutine to an already long program. It cannot be used for gas phase calculations.

The U. S. Geological Survey has also been active in the development of geochemical equilibrium codes for various purposes. The SOLMNEQ code (Kharaka et al., 1973) is suitable for high temperature calculations but not for vapor phase determinations. It tends to be a long running program, in part because of the tabular search routine to find equilibrium coefficients as a function of temperature, that would have to be done at every step in the iterative procedure described above. The primary problem that this code presents with respect to the two-phase flow program is the fact that it is written in the PL-1 language for use in the conversational mode. Conversion of the program would require a considerable effort.

Another U. S. Geological Survey code, MIX2 (Plummer et al., 1975) does not consider the full range of chemicals important to the two-phase study. The primary missing constituents are sulfides, ammonia, and silica. In addition, it is designed to handle specific liquid phase problems involving mixing of two solutions. Some parts of the code may be useful for later applications; for example, the mass balance convergence technique is said to be several times faster than that of other codes.

The WATEQ code also developed by the U. S. Geological Survey (Truesdell et al., 1973) appears well suited to the needs of the two-phase flow study, because the revisions needed, as were previously discussed, are relatively straightforward. The code has been used with apparent satisfaction at elevated temperatures to analyze brine-rock interaction (Dickson, 1979), and has been used previously by Coury

and Associates and coworkers with ambient temperature waters (Hounslaw et al., 1978). The code can then be incorporated as a subroutine into the primary two-phase flow program. It would be called upon when brine concentrations were high enough to justify the calculation of actual activity coefficients. Otherwise, the simplified code developed by Coury and Associates, for activity coefficients of unity, would be used. The WATEQ code considers a total of 115 aqueous species and 193 possible reactions. The basic calculational procedure, as described briefly below, needed to be only slightly modified.

The water analysis is read in and ion concentrations are converted to molality. All values of equilibrium constants are recalculated to the temperature of interest using the van't Hoff equation, unless experimental data are available. A cation-anion balance is calculated. If the charge balance is satisfactory, oxidation-reduction data, including electron activity and Eh, are calculated. As a final preparatory calculation, the Debye-Hückel solvent constants are corrected for temperature. During the next phase of computation, single-ion activity coefficients are calculated using the Davies equation or the Debye-Hückel approximation. With these, the activities of all possible aqueous species can then be computed. The distribution of these species is then calculated by means of a chemical model (Garrels et al., 1962), which uses analytical concentrations, experimental solution equilibrium constants, mass balance equations, and the measured pH. This distribution is presented in the form of a table which contains the concentrations, in mg/l and molality, the activities, and the activity coefficients of all possible aqueous species. In the final phase of the calculation, saturation data are computed. Ion activity products for all possible reactions are calculated and compared with the temperature-corrected equilibrium constants. This information is, again, presented in a table containing ion activity products, equilibrium constants, the ratio of these two values, and the logarithms of all of these, and also the ΔG of reaction. In this way, one can readily determine which reactions are controlling the water composition, and which reactions are impossible under equilibrium conditions.

In addition to the various codes that have been prepared to calculate brine equilibrium compositions, several other references related

to geothermal brine chemistry and interactions have been reviewed (including Owen, 1975; National Academy of Sciences, 1978; EPA, 1976; U. S. Geological Survey, 1976; Williams et al., 1978; and Jackson, 1976). These references have been of general usefulness in determining what chemistry problems are of particular concern and what data requirements and calculation procedures are required.

Summary--To summarize briefly, the interaction between rocks, brines, and gases is a complex problem with interest and applications in many areas, including mineralogy, production of geothermal wells, injection of geothermal fluids and makeup water, and groundwater reactions. Several studies have been made in these areas and, in particular, several computer codes have been written to make the many calculations required to characterize such situations. The codes have been written for various purposes. Consequently, they vary both in the complexity of their design, which affects both the running time for calculations, and the ease of adaptation of the codes to other uses, and the language and computer for which they were written. At the time of this work, April 1979, the most suitable for adaptation to the two-phase flow program is the WATEQ code. The required modifications of WATEQ have been made and the model has been implemented into the two-phase flow program.

B. Geopressured Methane

Currently, there is considerable interest in investigating the potentials for recovering large amounts of methane that exist in geopressured geothermal reservoirs. In these reservoirs, the methane is dissolved in geothermal brines which have a primary salt constituent of sodium chloride with salt concentrations up to 25% by weight. The pressures in geopressured reservoirs are much greater than the static head pressure and may be as high as 20,000 psia with reservoir temperatures approaching 600°F. In order to accurately predict the potential of these reservoirs and determine the optimum production methods, the solubility of methane in water and aqueous sodium chloride solutions at these reservoir conditions must be known.

A literature search was performed to obtain correlations that could be used to define the solubility of methane in water and NaCl brine solutions with salt concentrations, temperatures, and pressures that are

expected to exist in geopressured reservoirs. Information on the solubility of methane in pure water is readily available; however, information on the solubility of methane in NaCl brine solutions is limited. References (Haas, 1978; Price, 1978; Bonham, 1978; Culberson, 1951; and Sultanov, 1972) were reviewed and, of these sources, Haas was the only source that included information on the solubility of methane in NaCl brine solutions.

This reference, a U. S. Geological Survey Open File Report by John L. Haas, Jr., presented empirical equations based on a comprehensive compilation of data on the solubility of methane in pure water and NaCl brine solutions. The data used in this reference were obtained from the following sources:

Culberson, O. L., and J. J. McKetta, Jr., 1951, Phase Equilibria in Hydrocarbon-Water Systems

Duffy, J. R., N. O. Smith, and Bartholomey Nagy, 1961, Solubility of Natural Gases in Aqueous Solutions

O'Sullivan, T. D., and N. O. Smith, 1970, The Solubility and Partial Molar Volume of Nitrogen and Methane in Water and in Aqueous Sodium Chloride from 50°C to 125°C and 100 to 600 atm

Sultanov, R. G., V. G. Skripka, and A. Yu. Namiot, 1972, Solubility of Methane in Water at High Temperatures and Pressures

The information presented in Haas (Haas, 1978) regarding the solubility of methane in pure water (Culberson, 1951, and Sultanov, 1972) and in NaCl solutions (Duffy, 1961, and O'Sullivan, 1970) appears to be the best available at this time. References (Culberson, 1951, and Sultanov, 1972) were reviewed for this task and were also cited as references in other documents reviewed for this task (Price, 1978, and Bonham, 1978). The Haas (Haas, 1978) reference covers the full range of temperature, pressure, and sodium chloride concentrations that are expected to exist in geopressured reservoirs. Due to the comprehensive nature of this reference, it is the basis for the completion of this task.

Equations for methane solubility concentrations in water and NaCl brine solutions are presented in the next section of this report. The equations for methane solubility concentrations in pure water are valid from 77°F to 680°F and up to 10,000 psia with a precision of 5%. These

equations can be extrapolated up to 20,000 psia with an expected precision of about 10%. When applying the equations for salt solutions, the above precisions will deteriorate up to an additional 23% for salt solutions of 25 weight percent NaCl. The additional precision deterioration for 5 weight percent NaCl is only 4%. The equations are considered to be valid up to 25 weight percent NaCl. These pressures, temperatures, and salt concentrations meet or exceed the conditions expected to be found in actual geopressured-methane applications. These equations are based on the best available information at this time and the precisions are considered to be suitable for the purposes of this task.

Equations

The following equations for determining the dissolved methane concentrations in pure water and aqueous NaCl solutions are based on information presented in the Haas (Haas, 1978) reference.

Methane and pure water--The following equations are used to determine the solubility of methane in water with no dissolved salt.

$$P_{\text{Total}} = P_{\text{H}_2\text{O}} + P_{\text{CH}_4} \quad (1)$$

$$\text{LOG}_{10} P_{\text{CH}_4} = \text{LOG}_{10} X_{\text{CH}_4} - a - b X_{\text{CH}_4} \quad (2)$$

$$a = -3.4384 \times 10^2 T^{-2} + 29.940 T^{-1} - 3.4661 \\ + 1.6339 \times 10^{-5} T^2 - 1.2409 \times 10^{-8} T^3 \quad (3)$$

$$b = 40.393 T^{-1} - 4.0466 + 2.8505 \times 10^{-2} T \\ - 7.0893 \times 10^{-5} T^2 + 6.1429 \times 10^{-8} T^3 \quad (4)$$

where P_{Total} = total system pressure, atmospheres

$P_{\text{H}_2\text{O}}$ = saturation pressure of water @ temperature T, atmospheres

P_{CH_4} = partial pressure of methane, atmospheres

X_{CH_4} = molal concentration of methane expressed in moles of CH_4 per kg of H_2O

T = temperature, $^{\circ}C$

Methane and aqueous solutions of sodium chloride--The following equation is used to determine the solubility of methane in aqueous solutions of sodium chloride.

$$\text{LOG}_{10} Y_{CH_4} = \text{LOG}_{10} X_{CH_4} - A I \quad (5)$$

where Y_{CH_4} = molal concentration of methane in aqueous sodium chloride solution expressed in moles CH_4 per kg of brine

X_{CH_4} = molal concentration of methane in pure water at the same pressure and temperature as Y_{CH_4} ; determined by equations 1 through 4

A = Sechenov constant, recommended value is 0.11 (Haas, 1978)

I = ionic strength of NaCl/ H_2O solution which is equal to the molality of NaCl (molality is defined as number of moles of NaCl per kg of water)

Parameter limits--The preceding equations are valid within the following parameter ranges:

Temperature: $25^{\circ}C$ to $360^{\circ}C$ ($77^{\circ}F$ to $680^{\circ}F$)

Pressure: 0 to 20,000 psia

NaCl concentration in water: 0 to 25 weight percent

Precisions--The precision of X_{CH_4} is 5% between $25^{\circ}C$ and $360^{\circ}C$ ($77^{\circ}F$ and $680^{\circ}F$) and up to 10,000 psia. The precision of X_{CH_4} is 10% from 10,000 to 20,000 psia within the same temperature range. The precision of Y_{CH_4} is downgraded from the corresponding X_{CH_4} value in the following manner. The following amounts are added to the X_{CH_4} precisions to obtain the Y_{CH_4} precision for various concentrations of salt.

<u>Weight Percent NaCl</u>	<u>Percent Amount Added to X_{CH_4}</u>	
	<u>Precision to Obtain Y_{CH_4}</u>	<u>Precision</u>
5		4
10		8
15		13
20		18
25		23

C. Holdup Correlations

In October 1979, the University of Houston, with A. E. Dukler as principal investigator, completed a final report for Denver Research Institute entitled "Two-Phase Flow in Geothermal Energy Sources." This work was done under a subcontract to DOE Contract No. E(11-15-2729). As part of this work, Dukler and coworkers developed new theoretical and empirical bases for determination of flow regime and for calculation of holdup values. Experimental data were taken for an air-water system at 25°C.

Previous to this study, Coury and Associates compared various holdup correlations and determined that the Hughmark holdup correlation (Hughmark, 1962) provided the best overall match between computer model predictions and well test data. Thus, this present task was restricted to comparison of the new University of Houston holdup correlations with this Hughmark correlation. The Hughmark correlation is a single relation used for all flow regimes. It requires a value for the two-phase flow frictional pressure drop. The Dukler Case II relation (Dukler, 1964) is used for this purpose. The previously used approach to calculating the holdup is herein referred to as the Hughmark/Dukler approach. Flow regime has been determined by a relation due to Taitel (Taitel, 1976). This determination has no effect on other calculations including that of holdup.

The University of Houston work provides a new means of determining the flow regime and the holdup. The holdup is calculated from relations that apply only to the specific flow regime. The reader is referred to the University of Houston report for specific equations and other technical details. The Dukler Case II relation is again used to calculate the two-phase flow frictional pressure drop.

Since the remainder of this study of holdup correlations involves the testing of the University of Houston relations, the discussion is continued in Section III, which addresses the testing and validation of the two-phase flow model.

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III. MODEL TESTING AND VALIDATION

In this section, three separate studies are reported. Two of these test some or several aspects of the model against available data and the third predicts the effects of some model parameters on well conditions. They provide indications of the sophistication and quality of the current model. Likewise, they all give insight into aspects of the model that might benefit from further extension or refinement.

Section III-A deals with the testing of new University of Houston holdup correlations. The holdup is directly involved in the calculation of two-phase pressure drop. With the assumption of thermodynamic equilibrium, determination of pressure at a point sets the temperature. Thus, the holdup plays an important role in the determination of pressure and temperature profiles in the well including the wellhead values.

In Section III-B, predictions of the two-phase flow model are compared with several sets of well test data for both low and high salinity brines. Comparisons are made of the temperature and pressure profiles which include flash and wellhead conditions.

Section III-C presents a study of the effects of complex brine chemistry on well conditions. Specifically, the NaCl and CO₂ contents of the bottomhole brine are varied over a wide range of values. The resultant temperature and pressure profiles, and wellhead conditions are compared to each other and with the results obtained from simulation of the pure water case.

A. University of Houston Flow Regime and Holdup Correlations

This discussion follows directly from that of Section II-C and includes a direct comparison of flow regime and holdup correlations for arbitrary sets of operating conditions and a comparison of the full two-phase flow model predictions using each group of correlations. These predictions are also compared with well test data. The specific comparison is between the previously favored Hughmark correlation for holdup and the new University of Houston holdup correlations. In using the new University of Houston holdup correlations, the flow regime is first calculated from newly developed correlations. The specific holdup correlation used depends on the flow regime. Previously, an approach due to Taitel had been used to determine flow regime.

The holdup calculation via the Hughmark correlation, however, is the same for all flow regimes.

Comparison of Flow Regime and Holdup Correlations

A computer program was written to directly compare both flow regime and holdup values using the Taitel-Hughmark/Dukler and the new University of Houston approaches. The input data were physical properties of air and water at 25°C, and various combinations of superficial liquid and gas velocities. The region of operating velocities covered corresponds to the experimental runs and theoretical results presented in the University of Houston report. A flow regime map presented by the University of Houston group corresponding to this range of operating conditions is given in the Taitel reference (Taitel, 1980). A similar diagram is shown in Figure III-1. The flow regime is defined when values of both the liquid and gas superficial velocities are set. The published flow regime map provided a means of checking the flow regime predictions resulting from our programming of the report correlations with those obtained by Dukler's group. The flow regime calculations were the same. Table III-1 contains flow regime and holdup information resulting from the computer program for both the University of Houston approach and the Taitel-Hughmark/Dukler approach. Based on these and similar results from other comparisons made, the following statements can be made:

1. The flow regimes predicted by the Taitel correlations, column 3, and the new University of Houston correlations, column 4, are substantially different. The new correlation gives fewer bubble flow regimes and more annular flow regimes than the Taitel approach does--in fact, the Taitel approach did not identify any annular flow regimes.
2. The differences between the holdup values calculated from the Hughmark/Dukler approach, column 5, and the new University of Houston approach, column 6, were less striking. In the slug and churn regions as defined by the new University of Houston approach, in column 4, the Hughmark/Dukler values were generally lower than the University of Houston values. In the bubble and annular regions, they were slightly higher.
3. There were computational problems associated with use of the new University of Houston holdup correlations. The first problem occurs in the region of high liquid superficial velocity churn flow. The University of Houston approach to calculate churn flow holdup is to take an

- (1) = Region of first computational problem
(2) = Region of second computational problem

Figure III-1. Flow Regime Map

TABLE III-1. FLOW REGIME AND HOLDUP COMPARISON
FOR AIR-WATER SYSTEM AT 25°C

(1) Liquid Superficial Velocity (ft/sec)	(2) Gas Superficial Velocity (ft/sec)	(3) Flow Regime*		(6) Liquid Holdup			(7)
		Taitel	UH	Hughmark	UH	Slug	
0.0164	0.137	1	2	0.660	0.750		
0.0328		1	2	0.700	0.760		
0.1640		1	2	0.810	0.810		
0.3280		1	2	0.860	0.850		
1.6400		1	2	0.950	0.950		Same as UH
3.2800		1	2	0.970	0.970		
16.4000		1	1	0.993	0.992		
32.8000		1	1	0.997	0.996		
0.0164	0.683	2	2	0.280	0.430		
0.0328		2	2	0.320	0.440		
0.1640		2	2	0.450	0.500		
0.3280		2	2	0.540	0.560		Same as UH
1.6400		1	2	0.780	0.780		
3.2800		1	2	0.870	0.870		
16.4000		1	1	0.968	0.962		
32.8000		1	1	0.983	0.980		
0.0164	1.370	3	2	0.240	0.32		
0.0328		3	2	0.260	0.33		
0.1640		2	2	0.320	0.38		
0.3280		2	2	0.390	0.43		Same as UH
1.6400		2	2	0.650	0.66		
3.2800		1	3	0.780	0.77		
16.4000		1	1	0.939	0.93		
32.8000		1	1	0.967	0.96		
0.0164	6.830	3	3	0.17	0.21	0.20	
0.0328		3	3	0.18	0.21	0.21	
0.1640		3	3	0.21	0.23	0.22	
0.3280		3	3	0.23	0.26	0.24	
1.6400		2	3	0.36	0.46**	0.35	
3.2800		2	3	0.46	0.70**	0.45	
16.4000		1	1	0.76	0.71	0.71	
32.8000		1	1	0.86	0.83	0.83	
0.0164	13.700	3	3	0.13	0.18	0.19	
0.0328		3	3	0.14	0.18	0.19	
0.1640		3	3	0.17	0.21	0.19	
0.3280		3	3	0.18	0.23	0.20	
1.6400		3	3	0.26	0.42**	0.27	
3.2800		2	3	0.34	0.65**	0.34	
16.4000		2	1	0.63	0.55	0.55	
32.8000		1	1	0.75	0.70	0.70	

TABLE III-1. FLOW REGIME AND HOLDUP COMPARISON
FOR AIR-WATER SYSTEM AT 25°C (continued)

(1) Liquid Superficial Velocity (ft/sec)	(2) Gas Superficial Velocity (ft/sec)	(3) Flow Regime*		(6) Liquid Holdup		
		(4) Taitel	(4) UH	(5) Hughmark	(6) UH	(7) Slug
0.0164	68.300	3	4	0.032	0.016	0.17
0.0328		3	4	0.050	0.024	0.17
0.1640		3	4	0.081	0.055	0.17
0.3280		3	4	0.092	0.079	0.17
1.6400		3	4	0.130	0.180 ⁺	0.19
3.2800		3	4	0.150	0.530 ⁺	0.21
16.4000		2	4	0.290	0.400 ⁺	0.33
32.8000		2	4	0.410	0.480 ⁺	0.44
0.0164	137.000	3	4	0.00012	0.0079	0.17
0.0328		3	4	0.00024	0.0120	0.17
0.1640		3	4	0.03700	0.0330	0.17
0.3280		3	4	0.05100	0.0510	0.17
1.6400		3	4	0.08100	0.2300 ⁺	0.18
3.2800		3	4	0.09900	0.3200 ⁺	0.19
16.4000		3	4	0.19000	0.2500 ⁺	0.26
32.8000		2	4	0.27000	0.3200 ⁺	0.33

*Flow regime symbols: 1 = bubble; 2 = slug; 3 = churn; 4 = annular.

**First computational problem, see text.

+Second computational problem, see text.

average of the slug and annular holdup values for the flow regime transition boundaries at the same value of liquid superficial velocity. The slug value is not defined for the region in question, as evident from Figure III-1. Use of the bubble holdup value in place of the slug value for the averaging process results in the high values shown in column 6. The second computational problem occurs in annular flow at high values of liquid superficial velocity. Calculation of the annular holdup is an iterative process which makes use of values of functions previously published (Dukler, 1960). The high values of liquid superficial velocity are beyond the range in which these functions have been calculated and published. Extrapolation procedures are unsuccessful in leading to reasonable values for the holdup. In column 6 of Table III-1, the unreasonable holdup values corresponding to both of these computational problems are noted. Similar computational problems were evident when the University of Houston approach was incorporated into the two-phase flow computer model and the model was used to predict wellbore conditions.

Column 7 contains values of holdup for slug, churn and annular flows, as defined in column 4. The values are calculated from the slug flow correlation for holdup. The bubble flow correlation is used for the bubble flow holdup calculation. The slug holdup values for churn flow are between the values given by the University of Houston approach and the Hughmark/Dukler approach. Furthermore, for low values of superficial liquid velocity, they are close to the University of Houston values; and for the high values of superficial liquid velocity, corresponding to the computational problem, they are very close to the Hughmark/Dukler values. The slug model gives unreasonably high holdup values for annular flow.

Based on these results, to avoid the computational problems resulting in questionable holdup values, yet to maintain the essential nature of the new University of Houston holdup correlations, the following approach to calculating holdup was taken:

<u>University of Houston (UH)</u> <u>Flow Regime</u>	<u>Holdup</u> <u>Correlation Used</u>
Bubble	UH bubble
Slug	UH slug
Churn	UH slug
Annular	Hughmark/Dukler

The flow regimes are as identified by University of Houston correlations.

In the writing that follows, this approach to determining holdup is referred to as the new composite approach.

Comparison of Hughmark/Dukler and Composite Approaches Using Pure Water Well Data

Runs discussed in this section correspond to runs included in the Geothermal Well Design Handbook (Denver Research Institute, 1979). The fluid is assumed to be pure water. The effects of dissolved gases and salts have not been included. Several well conditions result in the University of Houston flow regime correlations giving mostly annular flow regimes. For these wells, the holdup values calculated by the composite approach thus result mostly from the Hughmark correlation. In these cases, there is very little difference between the use of the Hughmark/Dukler approach and the composite approach which uses the Hughmark correlation for the annular flow regime. For these cases of predominantly annular flow and thus use of the Hughmark holdup correlation, the liquid holdup values for annular flow are many times in the range of 30% to 50%--much higher than values usually considered representative of annular flow. This result raises some question as to the applicability of the University of Houston flow regime predictions. The original work by University of Houston is with air-water systems at 25°C. Perhaps the results can not be simply extrapolated to geothermal conditions.

In cases where the flow to diameter ratio is low and thus of lower superficial velocities, the annular flow regime is not the predominant one, and the composite and Hughmark/Dukler approaches for calculating holdup give quite different results.

Comparison of Hughmark/Dukler and Composite Approaches Using Complex Brine Well Data

Figure III-2 shows the pressure and temperature profiles plotted from a set of well test data along with predicted profiles resulting from the computer model. Predicted profiles are shown from use of both the Hughmark/Dukler and the composite approaches. The composite approach results are seen to give better agreement with the well test data for both the pressure and temperature profiles. This has been found to be the case in nearly all such comparison runs.

Figure III-2. Comparison of Simulation Model Results with Well Test Data

Summary

New correlations for the calculation of flow regime and holdup were compared to the correlations previously used in the two-phase flow computer model. A direct comparison of flow regimes and holdup values for given flow conditions revealed some differences and also some computational problems associated with use of the new holdup correlations. The approach taken as a result of these comparisons was to use parts of both the old and new holdup correlations such that the resulting holdup values were consistent with the new holdup correlation but which avoided the computational problems. This composite approach was implemented on the old holdup correlation with the new composite holdup correlations. Based on these results, the new composite holdup correlations are being used in all subsequent work.

B. Comparison of Field Test Data with Computer Model Results

The objective of the work which is summarized in this section was to obtain and analyze field test data, and to compare the data to the predictions generated with the two-phase flow computer model. In this way, by the direct comparison of the model and the real system, the predictive capability of the current model can be judged and areas for future model improvement may be identified. The well test data is first discussed and summarized. The approach taken to generate model results corresponding to the test data is then presented. Finally, the comparison of test data and model predictions is presented in both tabulated and graphical form.

Well Test Data Summary

Coury and Associates, Inc., in conjunction with Denver Research Institute, performed nine well logs at three geothermal wells in the Imperial Valley from July 1979 to September 1980. These well tests were performed with permission from the operator of the test wells, Republic Geothermal, Inc., MCR, and Westec. Ten additional well logs were obtained from three geothermal wells. The additional well log data was supplied to us by the University of Hawaii for the HGP-14 well in Hawaii, by the Department of Scientific and Industrial Research for the BR-27 well in New Zealand, and by a confidential source for

a high-salinity well in the Imperial Valley. A short synopsis of each well test is given in Table III-2.

The 19 well logs differ in the type, quantity, and quality of the information given. The well logs may be grouped according to whether initial flashing of the geothermal fluid occurs in the reservoir or in the wellbore, and whether the well fluid is of low or high salinity. Further, some of the wells specify a gas content and some do not. On this basis, Table III-3 shows the grouping of the various well logs. The table also indicates that not all of these well logs were analyzed. The fifth run of the East Mesa tests is quite similar to the first and was not analyzed. The third run of the Imperial Valley data did not include a temperature profile and was not analyzed. The last two sets of data on the Hawaiian well are questionable and were not analyzed. Thus, as reflected in Table III-3, ten logs were analyzed for initial flashing in the wellbore and five for initial flashing in the formation.

At present, the computer model for two-phase flow does not allow for the case of two-phase flow in the formation. However, as described later, an approach was devised to allow for some comparison of the model with this type of data.

The well test data may include several of the following items:

- Flowing temperature profile (from test section bottom to the wellhead)
- Flowing pressure profile log (from test section bottom to the wellhead)
- Flow rates
- Total dissolved solids (TDS)
- Total dissolved gas
- Specific breakdown of TDS and dissolved gas
- Enthalpies

The casing schedule must also be specified.

The minimum set of test data necessary to run the computer model includes the bottomhole temperature and pressure, the casing schedule, and the bottomhole flow rate. Bottomhole here means bottom of the test

TABLE III-2, WELL TEST SYNOPSIS

<u>Date of Well Test</u>	<u>Location of Well Test; Operator</u>	<u>Description</u>
July 16-21, 1979	East Mesa Well #6-2, Holtville, CA; WESTEC	Five successful well logs were obtained. The well logs were completed to a depth of 2000 feet. Down-hole temperatures of 360°F were found.
November 28-30, 1979	Republic Well	Three successful logs were obtained. Chemical analyses were obtained from Don Michels of Republic Geothermal. The data are proprietary and have been coded.
December 14, 1980	MCR Well	One log was obtained for this high salinity well. The information was incomplete for dissolved gases content, dissolved solids content, and liquid-vapor split at the wellhead separator. The data are proprietary and have been coded.
February, March, April 1981	Imperial Valley Well	Three pressure and two temperature profiles for this high salinity well were provided. The data are proprietary and the specific location is thus not identified.
October 5, 1976	Well BR-27, New Zealand	Data were obtained from Malcolm A. Grant, Department of Scientific and Industrial Research. The three well logs encompass depths up to 3012 feet at pressure and temperature of 955 psig and 525°F, respectively.
January 1978	HGP-A, Hawaii	Data were obtained from Dr. Bill H. Chen, University of Hawaii. The four well logs encompass depths to 6300 feet, and pressure and temperature up to 760 psig and 520°F, respectively.

TABLE III-3. WELL LOG CLASSIFICATION

		Initial Flash Location							
		In Wellbore		a	b	In Formation		a	b
Salinity level	Low	East Mesa 6-2*	5	4	Hawaii	4	2		
		Republic* (no gas content given)	3	3	New Zealand (gas content given)	3	3		
High		MCR*	1	1					
		Imperial Valley (range of gas content given)	3	2					

Notes: * = wells logged under this contract

a = number of logs available

b = number of logs simulated

low salinity = <5,000 ppm TDS

high salinity = >20,000 ppm TDS

section which should be in the single-phase zone for the present model. In order to offer a comparison of the test data with model predictions, it is necessary to have other conditions in the wellbore or at the wellhead specified. Usually, temperature and pressure profiles are available and provide for this.

There is a problem with obtaining reliable data for the above parameters. This is due in part to the harsh environment which affects the reliability and accuracy of wellhead equipment, the logging tool, and the sampling and analytical procedures used for obtaining dissolved gas and solids content of the fluid. There is frequently considerable scatter in the temperature and pressure data which complicates definition of the profiles. Further, some of the parameters are not directly measured. The bottomhole solids composition must be deduced from samples taken at the wellhead or on subsequently flashed brine. The dissolved gases may be estimated from the flashed brine composition, and the vapor-liquid split when vapor and liquid separation is done at the wellhead site. The bottomhole flow rate may be estimated from measurement of the liquid flow rate after a surface flash tank or gas-liquid separation tank, along with the assumption of no heat loss through the wellbore casing and knowledge of the separation temperature and bottomhole temperature. These indirect estimates introduce error into the data.

Figure III-3b shows typical temperature versus depth data. The single-phase zone is characterized by a straight line with some degree of slope away from vertical due to heat loss from the single-phase fluid through the wellbore casing. Once flashing begins, the slope of this curve begins to deviate more and more from the vertical before it steadies or even reverses this behavior. Figure III-3a shows a typical pressure profile. The change in slope upon flashing is much less. The temperature profile can be used to estimate the flash point in the well. This is indicated in Figure III-3b as the point at which the data begin deviating from the straight line.

Information may also be obtained by combining the temperature and pressure profiles into a temperature-pressure curve. Except for the presence of dissolved gases and solids, this curve should be identical to one obtained from steam table values. Figure III-4a shows a pure water pressure-temperature curve along with some typical data.

Figure III-3. Pressure and Temperature Profiles

Figure III-4. Pressure-Temperature Diagram, Pure Water Curve

The single-phase zone is distinguished by the deviation from the saturated liquid-vapor conditions given by the curve. As shown in Figure III-4b, the presence of dissolved gases moves the data to one side of the pure water curve and dissolved solids to the other side. The solids effect is simply the boiling point elevation effect where, at a given pressure, the boiling temperature is higher. The gas effect is due to the partial pressure of the gas in addition to that of water defining the total vapor pressure or saturation pressure at a given temperature.

For the data analyzed, the gas effect seems to be the predominant effect with some exceptions near the wellhead where, due to extensive flashing, the liquid contains only small amounts of dissolved gases. Thus, most data lie to the left of the saturated steam curve and a plot of well test data against the saturated steam curve may be used as an indication of the validity of the data. The last two data sets of the Hawaiian well tests previously mentioned were questionable from this standpoint. Attempts to generate computer results with any similarity to these sets of data were not successful and these runs were subsequently dropped from further analysis. The 19 well test data sets are summarized in Tables III-4a, III-4b, and III-4c.

Approaches for Generating Model Results

This section discusses the procedures developed for generating the model results and comparing them with the well test data. Different procedures were developed for the two cases of flashing in the formation and initial flashing in the wellbore. The case of initial flashing in the wellbore is discussed first. The model input parameters are:

- Bottom log depth
- Bottom log temperature
- Bottom log pressure
- Bottom log single-phase liquid flow rate
- Casing schedule
- Bottom log dissolved solids
- Bottom log dissolved gases

TABLE III-4a. WELL LOG INFORMATION SUMMARY--WELLS WITH INITIAL FLASHING IN THE WELLBORE

No. Date	EAST MESA WELL 6-2					REPUBLIC WELL*		
	1 7/18/79	2 7/18/79	3 7/20/79	4 7/20/79	5 ^a 7/21/79	1 11/28/79	2 11/30/79	3 11/30/79
Identification	62-8	62-9	62-16	62-17	62-19	--	--	
Well depth, ft	5,100	5,100	5,100	5,100	5,100	1,000	1,000	1,000
Flow rate, lb/hr	232,820	160,088	111,487	75,876	220,425	0.845	1.143	1.059
Wellhead conditions:								
T, °F	325	335	343	340	324	0.900	0.869	0.866
P, psia	114.7	129.7	147.7	157.7	114.7	0.521	0.483	0.473
Bottom log conditions:								
T, °F	360	359	355.6	356.8	359.7	1.000	1.007	1.008
P, psia	416	276	405	444.7	292.3	3.205	2.738	2.776
D, ft	1,010	600	800	850	700	100	100	100
Flash point ^b :								
T, °F	359.4	358.5	355.1	354.6	-- ^a	0.991	0.998	1.002
P, psia	225	213	320	270	--	1.505	1.267	1.238
D, ft	550	450	575	400	--	43.75	50.00	50.00
Dissolved gas, ppm	--	--	--	--	--	--	--	--
Dissolved solids, ppm	3,915	3,915	3,915	3,915	3,915	3,215	3,215	3,215
Well casing:								
Diameter, ID, in.	6.969	6.969	6.969	6.969	6.969	12.52	12.52	12.52
D, ft	5,100	5,100	5,100	5,100	5,100	154.88	154.88	154.88
Diameter, ID, in.	--	--	--	--	--	7.921	7.921	7.921
D, ft	--	--	--	--	--	745.38	745.38	745.38
Diameter, ID, in.	--	--	--	--	--	5.921	5.921	5.921
D, ft	--	--	--	--	--	1,000	1,000	1,000

*Due to proprietary nature, most information is coded.

^aCase never simulated due to its similarity to Case 1.

^bObtained from plots of temperature versus depth and pressure versus depth.

TABLE III-4b. WELL LOG INFORMATION SUMMARY--WELLS WITH INITIAL FLASHING IN THE WELLBORE

No.	IMPERIAL VALLEY WELL*			MCR WELL*
	1	2	3 ^a	1
Well depth	129.6	129.6	129.6	617.6
Flow rate	1.00	1.607	2.464	1.071
Well conditions:				
Temperature	.887	.845	-- ^a	0.927
Pressure	.239	.203	.109	0.6 to 0.667
Bottom log conditions:				
Temperature	1.018	1.016	1.016	1.004
Pressure	1.732	1.393	.746	1.195
Depth				100
Flash point:				
Temperature	.893 to 1.00	1.014	-- ^a	Data is entirely in two-phase flow region
Pressure	.979 to 1.151	.918 to 1.012	--	
Depth	53.75 to 65	70 to 75	--	
Dissolved gas, ppm	5,000 to 9,000 CO ₂			~20,000 CO ₂
Dissolved solids, ppm	(>100,000)	(>100,000)	(>100,000)	(>100,000)
Well casing:				
Diameter, ID, in.	8.835	8.835	8.835	8.625

*Due to proprietary nature, information is coded or deleted.

^aCase not simulated--no temperature profile available.

TABLE III-4c. WELL LOG INFORMATION SUMMARY--WELLS WITH FLASHING IN FORMATION

No.	HAWAII WELL				NEW ZEALAND WELL		
	1	2	3 ^a	4 ^a	1	2	3
Date	1/78	1/78	1/78	1/78	10/5/76	3/2/77	8/10/77
Well depth, ft	6,400	6,400	6,400	6,400	3,813	3,813	3,813
Flow rate, lb/hr	76,000	84,000	93,000	101,000	97,000	83,800	81,600
Top log conditions:							
T, °F	440	390	330	295	495	466	469
P, psia	379.7	254.7	104.7	74.7	679.7	555.7	588.7
D, ft	0	0	0	0	1,806	0	402
Enthalpy, Btu/lb:							
Based on P	827.6	843.2	869.0	850.6	--	--	--
Based on T	825.2	840.5	868.4	849.2	563.6	563.6	551.5
Quality, %	52	57	64	64	--	--	--
Bottom log conditions:							
T, °F	520	470	425	400	525	--	509
P, psia	774.7	509.7	304.7	264.7	969.7	835.7	844.7
D, ft	6,300	6,300	6,300	6,300	3,012	2,509	2,509
Dissolved gas, ppm	2,100	2,100	2,100	2,100	36,360	22,000	27,020
Composition, %	60.4 CO ₂	21.7 H ₂ S	17.3 O ₂	6.9 H ₂	Mostly CO ₂		
Dissolved solids, ppm	1,268.4	455.7	363.3	12.6	Not given		
Well casing:							
Diameter, ID, in.	8.755	8.755	8.755	8.755	8.625	8.625	8.625
D, ft	2,260	2,260	2,260	2,260	1,812	1,812	1,812
Diameter, ID, in.	6.366	6.366	6.366	6.366	6.625	6.625	6.625
D, ft	6,300	6,300	6,300	6,300	3,813	3,813	3,813

^aCases not simulated due to questionable data.

Specification of the first five parameters is required for simulation of a pure water situation. Specification of the dissolved solids and gases allows for simulation of complex brines.

The simulation results are temperature and pressure profiles which extend from the bottom depth in the single-phase region to the wellhead which is at two-phase flow conditions. The information includes temperature and pressure at the flash point and at the wellhead. Compositions of the phases and liquid phase pH are also determined along the flow path. Comparison of model results with the test data are in the form of a comparison of the temperature and pressure profiles, which includes the flash depth and conditions, and wellhead conditions.

As is evident in the well log temperature profile shown in Figure III-3b, the temperature linearly decreases in the liquid single-phase region due to heat losses across the casing wall. The mathematical model does not allow for these heat losses in either the single-phase or two-phase zone, and thus predicts constant temperature in the single-phase region.

A means of comparing the model results with the test data which recognizes and allows for the single-phase heat loss is to match conditions at the flash point depth rather than at the bottom log depth. In this approach, the temperature input to the mathematical model is not the bottom log temperature but the flash temperature. Both approaches are illustrated in Figures III-5a and III-5b.

The flash conditions are determined from plots of the temperature and pressure profiles as previously discussed in the well test data section. Quantitative definition of the flash conditions, however, depends on the shape of the temperature profile and the degree of scatter present in the data. Where there is a lengthy straight line portion and also significant curvature in the temperature profile along with little scatter in the data, the flash conditions may be defined with high confidence. In all cases, a restricted range of depths and temperatures may be defined which cover the flash conditions. With the well depth and bottomhole flow and pressure set, there are three parameters which may be varied to locate the model's flash depth. These are the dissolved gas content, the dissolved solids content, and the flash temperature. The temperature has only a minor effect and the dissolved

a) Conditions matched at bottom log

b) Conditions matched at flash point

Figure III-5. Matching of Well Log and Model Predictions

salts are important only at higher salinities where activity coefficient values depart from unity. Thus, in most cases, it is the gas content that is varied to match the model flash depth with that determined from the test data. Values for the dissolved gas content and dissolved solids content may be specified in the well test data, in which case their values are varied within reasonable limits about the specified test values for determination of the flash depth. Between the definition of flash conditions as determined by the temperature profile and the restrictions placed on model parameters by their specification in the well test data, the manipulation of model parameters to achieve fit of model to data amounts to a fine tuning operation. Any resulting changes in parameter values are likely within experimental error of the test data.

There is no single indicator of goodness of fit of model results with the test data. Matching of the two-phase zone temperature and pressure profiles and the wellhead conditions are the indicators used in this work. The goodness of fit for the profile is qualitative and judged by the graphics of the results. Matching of the wellhead conditions is quantitative. The best general profile fit does not necessarily imply the best fit of wellhead conditions. The entire procedure used to obtain the best fit of model results to the well test data for the case of initial flashing in the wellbore is summarized in Table III-5.

For the case where flashing occurs in the producing formation, a somewhat different approach is needed in applying the model. As previously mentioned, the mathematical model used does not cover this case. In this situation, the well logs contain only two-phase flow data. Again, the approach taken is to match the model temperature at the bottom two-phase flow log depth with that of the well test data. In the previous case, this corresponds to the beginning of the two-phase flow zone at the flash point where vapor is first appearing. Now it is a point of significant vapor flow in the two-phase flow region. In order to do this, an "equivalent" well is modeled which has both single- and two-phase flow, and which gives the above match of conditions in the two-phase flow region. The pressure drop and flashing which occur in the formation for the real well take place in the model well within the wellbore at hypothetical depths below the formation depth.

TABLE III-5. PROCEDURE USED IN ANALYSIS AND MODELING
OF WELL TEST DATA--INITIAL FLASHING IN WELLBORE CASE

BASIS	<p>Available data:</p> <ol style="list-style-type: none"> 1. Temperature and pressure profiles extending through the two-phase region into the all liquid region 2. Flow rates from flash tanks or gas-liquid separation tanks 3. Casing schedule 4. Sometimes: approximate chemical composition--TDS and gas content--from surface measurements
COMMENTS	<ol style="list-style-type: none"> 1. Heat loss through well casing is taken into account only for single-phase region 2. Isenthalpic flash assumed in calculation of bottomhole flow rate
APPROACH	<ol style="list-style-type: none"> 1. Reduce the well test data to the following graphs: <ol style="list-style-type: none"> A. Temperature versus depth B. Pressure versus depth C. Pressure versus temperature 2. If data appear reasonable on pressure versus temperature graph, continue. 3. Determine range of reasonable flash depth and temperature values from the temperature versus depth graph. 4. Determine flash pressure from pressure versus depth graph. 5. Using bottom log pressure, estimated flash temperature, flow rate, casing schedule and dissolved solids content, run model and vary dissolved CO₂ content until flash depth is approximated. 6. With estimates of a reasonable range of values for dissolved CO₂ content, flash temperatures, and dissolved solids content, make some fine-tuning model runs varying these parameter values.

TABLE III-5. PROCEDURE USED IN ANALYSIS AND MODELING
OF WELL TEST DATA--INITIAL FLASHING IN WELLBORE CASE (continued)

7. Plot temperature versus depth information and compare against well test data. Compare wellhead temperature and pressure against well test data.
8. Choose best set of parameter values and plot the results of:
 - temperature versus depth
 - pressure versus depth
9. Tabulate results.

In these sets of well test data, estimates are given of dissolved gas and dissolved solids content, and these values are used in the model. The pseudo-bottomhole temperature, pressure, and depth are parameters as well as the casing diameter up to the log bottom depth which may be varied to provide the match of conditions. Use is also made of the measured wellhead enthalpies. If the well flow is considered to be adiabatic, and thus heat losses through the wellbore negligible, then the enthalpy is the same throughout the well. The saturation condition for all liquid flow allowing for the dissolved gases and solids may be determined. This corresponds to the initial flash condition for the pseudo-well. A pressure slightly in excess of the flash pressure is chosen to guarantee a single-phase zone. The bottomhole temperature is chosen as the saturation temperature. The bottomhole pressure, depth, and diameter are varied in a systematic way until the bottom log temperature is matched. The steps followed in obtaining the best fit of model results to well test data for the case of flashing in the formation are summarized in Table III-6.

Presentation and Discussion of Results

The results of the model simulations are presented in both tabular and graphical form. The temperature and pressure profiles are compared with the test data in Figures III-6 through III-20 with one figure for each of the 15 simulated tests. Tables III-7a, III-7b, and III-7c compare the top log, flash point, and bottom log conditions of the model results with the test data.

East Mesa well logs--The comparisons of model results with the four sets of test data for this low salinity well were quite good as shown in Figures III-6 to III-9 and in Table III-7a. The worst comparison was at the highest flow rate of Case 4 where the wellhead condition was off by 7°F. This case also has the greatest difference between the predicted and test data temperature profiles. Note in Table III-7a that the dissolved gas quantities used in the simulations varied from 1900 ppm in Case 2 to 4325 ppm in Case 4, with Cases 3 and 4 having considerably higher amounts than Cases 1 and 2. In Cases 3 and 4, the well had been shut-in prior to testing and the increase in CO₂ predicted with the model was qualitatively verified by people at the East Mesa test site. The

TABLE III-6. PROCEDURE USED IN ANALYSIS AND MODELING
OF WELL TEST DATA--FLASHING IN FORMATION CASE

BASIS	<p>Available data:</p> <ol style="list-style-type: none"> 1. Temperature and pressure profiles for two-phase flow 2. Flow rates 3. Wellhead enthalpy 4. Casing schedule 5. Dissolved gas composition
COMMENTS	<ol style="list-style-type: none"> 1. Heat losses not accounted for 2. Isenthalpic process assumed in calculation of pseudo-single-phase temperature
APPROACH	<ol style="list-style-type: none"> 1. Reduce the well test data to the following graphs: <ol style="list-style-type: none"> A. Temperature versus depth B. Pressure versus depth C. Pressure versus temperature 2. If data appear reasonable, continue. 3. From given wellhead enthalpy, liquid-vapor split and wellhead temperature, calculate saturated liquid temperature and pressure for case of all liquid. 4. Assume pseudo-bottomhole pressure slightly in excess of calculated pressure. 5. Assume an arbitrary pseudo-well depth greater than the actual well depth. 6. Assume arbitrary casing diameter for the length between the actual depth and the pseudo-well depth. 7. Vary the pseudo-bottomhole pressure, depth, and casing diameter until model temperature in two-phase zone match well test data at the bottom log depth. 8. Plot the results of : <p style="margin-left: 40px;">temperature versus depth pressure versus depth</p> 9. Tabulate results.

Figure III- 6. Model Versus Test Data, East Mesa Well, Case 1

Figure III-7.. Model Versus Test Data, East Mesa Well, Case 2

Figure III- 8. Model Versus Test Data, East Mesa Well, Case 3

Figure III- 9. Model Versus Test Data, East Mesa Well, Case 4

TABLE III-7a. SUMMARY--MODEL RESULTS COMPARED TO WELL TEST DATA

No.	EAST MESA WELL 6-2				REPUBLIC WELL*		
	1	2	3	4	1	2	3
Wellhead conditions:							
T, °F	325	335	343	340	0.900	0.869	0.866
P, psia	114.7	129.7	147.7	157.7	0.521	0.483	0.473
Bottom log conditions:							
T, °F	360	359	355.6	356.8	1.000	1.007	1.008
P, psia	416	276	405	445	3.205	2.738	2.776
D, ft	1,010	600	800	850	100	100	100
Flash point:							
T, °F	359.4	358.5	355.1	354.7	0.991	0.998	1.002
P, psia	225	213	320	270	1.505	1.267	1.238
D, ft	550	450	575	400	43.75	50.00	50.00
Dissolved gas, ppm	--	--	--	--	--	--	--
Dissolved solids, ppm	3,915	3,915	3,915	3,915	3,215	3,215	3,215
C&A MODEL				GE02PRT			
Wellhead conditions:							
T, °F	333.0	334.4	345.4	346.9	0.914	0.871	0.872
P, psia	110.3	112.2	144.0	145.2	0.587	0.465	0.466
Bottom log conditions:							
T, °F	359.7	358.5	355.0	354.7	0.991	0.998	1.002
P, psia	416	276	405.5	445	3.205	2.738	2.776
D, ft	1,010	600	800	850	100	100	100
Flash point:							
T, °F	359.7	358.5	355.0	354.7	0.991	0.998	1.002
P, psia	238.5	218.3	318.4	271	1.511	1.256	1.257
D, ft	551	450.7	574.8	399.9	43.75	50.08	50.08
Dissolved gas, ppm	2,320	1,900	4,325	3,408	2,050	1,300	1,270
Dissolved solids, ppm	4,069	4,069	4,069	4,069	2,776	2,776	2,776

*Due to proprietary nature, most information is coded.

flash depths indicated by the test data temperature profiles do not follow the trend expected with flow rate. This suggests some other operable factor besides the flow rate--such as the dissolved gas content. It is of interest to note the differences between the descending and ascending well test data shown in most of these figures. The differences are perhaps greatest at the highest flow rate of Case 1.

Republic well log--Figures III-10 to III-12 and Table III-7a show very close agreement between model and data. The data for the Republic well is proprietary, and thus the results have been coded. The worst comparison is with Case 1 which has the lowest flow rate. The difference in descending and ascending test logs seem greatest again at the highest flow rate--Case 2.

Hawaii well logs--Although the temperature and pressure ranges are seen to be much larger than those for the previous wells and the wells have flashing in the formation, the general trends of the data are predicted reasonably well by the model. This is seen in Figures III-13 and III-14. The wellhead quality predicted by the model is in close agreement with that given. This may be seen in Table III-7b. The Hawaii well has production from two zones--one at bottomhole and one at about 4300-foot depth. This was not accounted for in the model simulation.

New Zealand well logs--The three cases simulated are shown in Figures III-15, III-16, and III-17. Tabulated results are given in Table III-7b. This well has flashing in the formation and substantial dissolved CO₂ gas. No values for dissolved solids were given. The Case 1 test data shown in Figure III-15 are questionable. They do not extend to the wellhead and have unusual profiles for both temperature and pressure. The comparison of model with test data for Cases 2 and 3 are much better as shown in Figures III-16 and III-17.

Imperial Valley well log--The two sets of test data shown in Figures III-18 and III-19 are from a high salinity well with a total dissolved solids content of 116,000 ppm by weight. There are also from 5000 to 9000 ppm of dissolved CO₂ gas. Although the pressure profiles are fairly well

Figure III-10. Model Versus Test Data, Republic Well, Case 1

Figure III-11. Model Versus Test Data, Republic Well, Case 2

Figure III-12. Model Versus Test Data, Republic Well, Case 3

Figure III-13. Model Versus Test Data, Hawaii Well, Case 1

Figure III-14. Model Versus Test Data, Hawaii Well, Case 2

TABLE III-7b. SUMMARY--MODEL RESULTS COMPARED TO WELL TEST DATA

	HAWAII WELL		NEW ZEALAND WELL		
No.	1	2	1	2	3
Top log conditions:					
T, °F	440	390	495	466	469
P, psia	379.7	254.7	679.7	555.7	588.7
D, ft	0	0	1,806	0	402
Bottom log conditions:					
T, °F	520	470	525	--	509
P, psia	774.7	509.7	969.7	835.7	844.7
D, ft	6,300	6,300	3,012	2,509	2,509
Wellhead quality	52.0	57.0		Not given	
Dissolved gas, ppm	2,100: 60.4% CO ₂ , 21.7% H ₂ S, 17.3% O ₂ , 6.9% H ₂		36,360 CO ₂	22,000 CO ₂	27,020 CO ₂
Dissolved solids, ppm	1,268.4	455.7		Not given	
C&A MODEL	GE02PRT				
Top log conditions:					
T, °F	451.6	340.1	506.5	461.9	467.2
P, psia	429.2	117.9	817.8	501.2	538.8
D, ft	0	0	1,812	0	461.7
Bottom log conditions:					
T, °F	520	470.3	525.4	513.7	509
P, psia	812.5	516.2	997.2	835.7	825.2
D, ft	6,300	6,300	3,012	2,509	2,509
Wellhead quality	52.0	60.7	18.0	18.3	17.8
Dissolved gas, ppm	Same as in Test Data		36,082	22,000	26,960
Dissolved solids, ppm	4,614	4,614	4,450	4,450	4,450

Figure III-15. Model Versus Test Data, New Zealand Well, Case 1

Figure III-16. Model Versus Test Data, New Zealand Well, Case 2

Figure III-17. Model Versus Test Data, New Zealand Well, Case 3

Figure III-18. Model Versus Test Data, Imperial Valley Well, Case 1

Figure III-19. Model Versus Test Data, Imperial Valley Well, Case 2

predicted by the model, the temperature profiles differ substantially. Relative to the test data, the model predicts a much steeper temperature profile for some distance above the flash depth and then a more gradual temperature gradient nearer the wellhead. In Section III-C of this report, this same model behavior is discussed and attributed to high values of the activity coefficient predicted for the $\text{CO}_2(\text{aq})$ species. Equivalently, this may be referred to as high values for the Henry's Law constant for CO_2 . Available empirical data suggests that the Henry's Law values predicted by the model at high temperatures and high salinity are high by a factor of about 4. In Figure III-19, these model results are referenced as the $\gamma_{ij} \neq 1$ case with the symbol γ_{ij} representing an activity coefficient. Also shown are results for a simulation where the activity coefficient values are set at unity. The results are much closer to the test data and support the argument that the Henry's Law constant for CO_2 at high temperature and high salinity is in error. Some tabulated results of the comparison of model predictions with data are given in Table III-4c.

MCR well log--The data from this well were incomplete, thus complicating any comparison of model results with the data. The data shown in Figure III-20 are entirely in the two-phase zone. Only approximate information was obtained for dissolved gas content, dissolved solids content, and vapor liquid split at the surface separator where the liquid flow rate was measured. Further, no bottomhole conditions were available. Assumptions and calculations that could be made were made and used as input for the model. The salinity of the well and the dissolved gas content are very high such that no simulation could be made with the model calculating activity coefficient values. The value calculated for the Henry's Law constant for CO_2 was much higher than that suggested by available empirical data, the result being extremely high and unreasonable values for downhole saturation pressures. The model results shown in Figure III-20 are for the case of $\gamma_{ij} = 1$. Data for this well are coded due to its proprietary nature.

Figure III-20. Model Versus Test Data, MCR Well

TABLE III-7c. SUMMARY--MODEL RESULTS COMPARED TO WELL TEST DATA

	IMPERIAL VALLEY WELL*		MCR WELL
No.	1	2	1
Wellhead conditions:			
Temperature	.887	.845	0.927
Pressure	.239	.203	0.6 to 0.667
Bottom log conditions:			
Temperature	1.018	1.016	1.004
Pressure	1.732	1.393	1.195
Depth	100	100	100
Flash point:			
Temperature	.893 to 1.000	1.014	Data is entirely in the two-phase flow region ~20,000 CO ₂
Pressure	.979 to 1.161	.918 to 1.012	
Depth	53.75 to 65	70 to 75	
Dissolved gas, ppm	5,000 to 9,000 CO ₂		
<u>C&A MODEL</u>	<u>GEO2PRT</u>		<u>VCGEOSYS</u>
Wellhead conditions:			
Temperature	.847	.763	0.922
Pressure	.187	.115	0.614
Bottom log conditions:			
Temperature	1.000	1.012	1.018
Pressure	1.732	1.393	0.990
Depth	100	100	100
Flash point:			
Temperature	1.000	1.012	1.250
Pressure	1.010	.910	2.849
Depth	53.47	72.11	369.7
Dissolved gas, ppm	3,000	2,400	22,000

*Due to proprietary nature, information is coded or deleted.

C. Complex Brine Study

The objective of this study was to determine, by means of the two-phase flow computer model, the effect of dissolved gases and solids on the prediction of geothermal well conditions. Dissolved salts and gases affect the physical and thermodynamic properties of the brine including the various chemical reaction equilibriums. These items help determine, along with well parameters and operating conditions, the temperature and pressure profiles of the simulated well fluid including the flash and wellhead conditions. To help elicit the nature of these relationships, the study involved two variables: the amount of sodium ion, and the amount of carbon dioxide in the bottomhole brine. Negatively charged chloride ions were assumed present to help balance the positive charge of the sodium ions. The chemical system was thus:

A set of well parameter values and operating conditions was assumed which resembles conditions found in high salinity Imperial Valley geothermal wells. These were:

Bottomhole temperature	= 500°F
Bottomhole pressure	= 2,500 psia
Depth of well	= 8,000 ft
Casing	= 8.835-in ID
Flow rate	= 250,000 lb/hr

Several computer runs were made at various values of Na and CO₂ content. The model results are presented in tabular and graphical form and are discussed with particular reference to the pure water case which corresponds to zero Na and CO₂ content.

Complex Brine

The term "complex brine" is taken to mean brine which contains both dissolved solids and dissolved gases. The solids and gases affect physical properties such as viscosity and density. This in turn affects the fluid mechanical behavior of the fluid such as causing changes in the static head and frictional pressure losses. The solids and gases also affect thermodynamic properties of the fluid causing deviation from the

pure water saturation conditions that are tabulated in steam tables. In addition to these effects, the solids and gases cause changes in chemical reactions as best reflected in the departure of activity coefficient values from unity. This directly affects dissolution, dissociation, and other chemical reactions that define the vapor-liquid equilibrium that is assumed to exist. In pure water, none of these effects is present and pure water is thus used as a reference case with which to compare the various effects.

Several different solids and gases may be present in geothermal brines. In general, the effect of each solid and gas is different in magnitude from that of another solid or gas. The magnitude of the effect of a given dissolved solid is determined by its molecular weight, its charge, the number of moles of the solid present, and the equilibrium constants for any reactions the dissolved solids participate in. The magnitude of the effect of a given dissolved gas is determined by its molecular weight, number of moles present, and its equilibrium constant values. The effects of gases and solids are not independent as the amount and types of solids determine the ionic strength of the liquid phase which in turn, by the model used, determines the values of activity coefficients. They in turn may be considered to change the effective value of the equilibrium constants which define the vapor-liquid equilibrium. Since the effects of each solid and gas are different, it is important, when simulating a specific geothermal well situation, to include the various solids and gases. A dramatic illustration of this is the case of hydrogen, which has a Henry's Law constant of about 100 times that of CO_2 . This means that each ppm of H_2 in the liquid will generate 100 times the partial pressure that each ppm of CO_2 will.

To provide a meaningful yet manageable scope for this preliminary investigative study, attention is restricted to the dissolved solids Na^+ and Cl^- , and the dissolved gas CO_2 . These species are the dominant solid and gaseous species present in most geothermal brines. The input variables to the model are the weight concentrations of Na^+ and CO_2 at the bottomhole of the well. The Cl^- concentration necessary to provide charge balance for the system is calculated in the model.

The chemical system modeled includes the species:

The gas phase is made up of CO_2 and H_2O . The liquid phase contains Na^+ , Cl^- , H_2O , $\text{CO}_2(\text{aq})$, and the dissociation products of H_2O and $\text{CO}_2(\text{aq})$: H^+ , OH^- , HCO_3^- , and CO_3^{2-} .

Description of Model Runs and Comparisons Made

While the magnitude of the effects of changes of complex brine chemistry on well conditions may be somewhat different at different values of flow rate, temperature, pressure, and casing schedule, this is considered to be of secondary importance to determination of the nature of the effects themselves. Thus, the present study focuses on the effects predicted for a typical well design under conditions found in the Imperial Valley.

The constant well conditions used in the runs were:

Bottomhole temperature	= 500°F
Bottomhole pressure	= 2,500 psia
Depth of well	= 8,000 ft
Casing	= 8.835-in ID
Flow rate	= 250,000 lb/hr

Table III-8 lists 22 runs made for this study. The values of Na and CO_2 for each run are listed in columns 2 and 3. The next six columns list some model results. Runs 1 through 15 were listed in order of increasing values of the predicted wellhead temperature and pressure as shown in columns 4 and 5. Columns 6 through 9 list values of flash depth, length of single-phase zone, flash pressure, and percent vapor at wellhead. The results given in columns 4 through 9 are further presented in various figures which follow. Listed between runs 9 and 10 is a pure water run marked PW. This run and runs 1 through 15 were made with the computer model calculating values of activity coefficients for the various species. This results in nonunity values for the activity coefficients and in subsequent figures, tables, and text, these runs are sometimes designated by the symbol $\gamma_{ij} \neq 1$, where γ_{ij} represents an

TABLE III-3. MODEL RUNS AND RESULTS

Run No.	Na (ppm)	CO ₂ (ppm)	Wellhead Temperature (°F)	Wellhead Pressure (psia)	Flash Depth (ft)	Length Single-Phase Zone (ft)	Flash Pressure (psia)	Wellhead Vapor (%)	Symbol
1	50,000	0	361.6	141.3	3,156	4,844	628.1	11.49	⊖
2	40,000	0	375.3	171.7	3,073	4,927	640.9	11.32	▼
3	50,000	5,000	385.4	193.1	7,267	733	2,216.6	10.20	▲
4	30,000	0	385.9	199.7	2,983	5,017	653.1	11.39	◆
5	20,000	0	395.5	223.0	2,887	5,113	664.4	11.62	•
6	10,000	0	406.1	261.7	2,782	5,218	674.2	11.73	○
7	40,000	10,000	407.8	263.2	7,989	11	2,495.7	9.53	◊
8	30,000	10,000	411.7	280.4	6,082	1,918	1,793.9	10.01	•
9	20,000	10,000	412.5	287.6	4,985	3,015	1,417.4	10.86	■
PW	0	0	414.6	291.0	2,662	5,338	680.9	11.95	*
10	10,000	10,000	420.0	317.1	4,291	3,709	1,202.3	11.10	◊
11	20,000	20,000	429.0	362.8	7,192	808	2,209.9	10.13	•
12	10,000	20,000	432.9	382.3	5,859	2,141	1,751.0	10.54	◊
13	0	20,000	435.4	395.0	4,984	3,016	1,472.2	11.11	•
14	10,000	30,000	441.5	442.7	7,490	510	2,321.5	10.47	+
15	0	40,000	451.0	520.6	7,445	555	2,311.0	10.80	x
16	0	0	414.6	291.0	2,662	5,338	680.9	11.95	
17	50,000	0	361.5	141.2	3,155	4,845	627.8	11.50	
18	0	40,000	445.4	484.7	5,675	2,325	1,707.7	11.55	x
19	50,000	5,000	370.9	161.8	3,523	4,477	769.7	11.21	▲
20	20,000	20,000	419.1	322.7	4,365	3,635	1,194.7	11.12	•
21	40,000	10,000	391.0	215.7	3,807	4,193	918.1	10.92	◊

activity coefficient. Runs 16 through 21 were runs made at six previously run sets of Na and CO₂ values; however, the activity coefficient values were all set at unity. These runs have been designated by the symbol $\gamma_{ij} = 1$.

The effects of Na and CO₂ bottomhole content and of activity coefficient values, $\gamma_{ij} \neq 1$ versus $\gamma_{ij} = 1$, are made evident through comparison of the temperature and pressure values that occur in the wellbore. This includes conditions at the flash point and wellhead, the general profiles of temperature and pressure versus depth, and pressure versus temperature diagrams. In addition, comparisons are made of the depth at which flashing occurs, the length of the single-phase zone and the percent vapor at the wellhead.

Figure III-21 shows the saturation pressure or flash pressure of the 500°F brine as a function of the CO₂ and Na content expressed in parts per million (ppm) by weight. The CO₂ content varies from zero to 30,000 ppm, or 3 weight percent. The Na values range from zero to 60,000 ppm. With the accompanying chloride, this is approximately from zero to 152,400 ppm total dissolved solids (TDS), or 15 weight percent TDS. The solid lines represent the results where the model calculates values of activity coefficients. The dotted line represents the results where the activity coefficient values are restricted to unity. Several points are of interest:

- For the case of unity activity coefficients ($\gamma_{ij} = 1$), there is little effect due to the solids. The effect present is the boiling point elevation of the saturation condition.
- The CO₂ effect for $\gamma_{ij} = 1$ case is simply the increased total pressure at 500°F due to the presence of the CO₂ gas which exerts its partial pressure in addition to that of water to define the system saturation pressure.

When the activity coefficients are calculated, they are found to differ significantly from unity. For the system in question, this results in higher partial pressures of CO₂ at a given temperature, Na and CO₂ level. The effect is dramatic as shown by the solid lines in Figure III-21. It may be seen that:

Figure III-21. Saturation Pressure as Function of Na and CO₂ at 500°F; Effect of Activity Coefficients

- The effects of Na are now quite significant along with the effect of CO₂ content itself.
- The zero Na line has shifted. This is due to the presence of various CO₂ species in the brine which are themselves dissolved solids.

The test conditions state a bottomhole pressure of 2,500 psia. From Figure III-21, it may be seen that the saturation pressure easily exceeds this bottomhole pressure where Na is present in quantities above 60,000 ppm at low CO₂ levels, and above 10,000 ppm at high CO₂ levels. This is better illustrated in Figure III-22 where the solid curve represents a locus of points corresponding to a saturation pressure of 2,500 psia. Higher saturation pressures occur above this line. When the saturation pressure exceeds the bottomhole pressure, flashing of the brine occurs. For a well with the 2,500-psia bottomhole pressure, a higher saturation pressure would correspond to the case of flashing in the formation--the entire wellbore flow being in two-phase flow. To avoid assuming a particular and arbitrary reservoir model which would give a value for the fraction of vapor at the bottomhole location and permit wellbore calculations to proceed, the model runs were restricted to those giving some single-phase flow in the wellbore, thus to those conditions below the solid line in Figure III-22. The conditions and identification numbers of the runs listed in Table III-8 are shown in Figure III-22.

Presentation of Model Results

The results of the model runs are given in several figures. Figures III-23 through III-29 show various results for runs 1 through 15 where values of activity coefficients were calculated. Figures III-30 and III-31 show selected results from runs 16 and 21 where the values of activity coefficients are taken as unity. The effect of bottomhole brine Na and CO₂ content on the flash or saturation pressure has been discussed in the previous subsection with use of Figure III-21. The flash point in a well, the location where in moving up a well the decreasing fluid pressure first equals the saturation pressure, thus depends heavily on Na and CO₂. Accordingly, the length of the single-phase and two-phase zones varies with Na and CO₂. Figure III-23 shows the length of the single-phase zone as a function of Na and CO₂. The range of values at zero CO₂ content reflect the effect of Na on liquid density and viscosity

Figure III-22. 2500 psia Saturation Pressure as Function of Na and CO₂; Conditions and Identification Number of Runs Made

Figure III-23. Length of Single-Phase Zone as a Function of Na and CO₂

and thereby on the static head and frictional pressure drops. The pure water condition is marked on the figure.

Figures III-24 and III-26 present the temperatures and pressures as a function of depth. The heavy dark line in the center of the curves corresponds to pure water conditions--zero Na and zero CO_2 . The run numbers, 1 through 15 and PW for pure water, are marked at both ends of the curves. The model used in these simulations does not account for heat losses through the well casing. Thus, the temperature remains at 500°F from bottomhole up to the flash point. The vertical line of depths at 500°F represents the various flash depths. The horizontal line of temperatures at zero depth represents the wellhead temperatures. Runs 1 through 9, those with wellhead temperatures lower than the pure water case, are mostly of low CO_2 and high Na; whereas runs 10 through 15 with wellhead temperatures higher than the pure water run are of high CO_2 and low Na. It is of interest to note these same runs on Figure III-22. Wellhead temperature increases as both Na is decreased and CO_2 is increased. This is shown more explicitly in Figure III-25.

For the cases of no CO_2 , runs 1, 2, 4, 5, 6, and PW, the temperature versus depth gradient in Figure III-24 changes abruptly at the flash point. As the CO_2 content is increased or the Na level is increased, the flash depth increases--or equivalently, the single-phase zone decreases as was shown in Figure III-23. Also, as the CO_2 content is increased, the temperature-depth gradient changes less abruptly upon flashing.

Figure III-26 is a companion graph to Figure III-24 showing the pressure versus depth profiles. The run numbers are again designated both at the wellhead or zero depth location and at the flash point location. The effect of CO_2 upon flash depth is again apparent. Since the fluid is considered to be at equilibrium, the wellhead conditions are at saturation and, thus the ranking of the runs according to wellhead pressure follows that due to wellhead temperature. The wellhead pressures are explicitly shown as a function of Na and CO_2 in Figure III-27.

Figure III-28 shows the percent vapor at the wellhead as a function of Na and CO_2 content of the bottomhole brine. The pure water case gives the highest value of percent vapor of any of the runs. CO_2 and Na both decrease the percent vapor at the wellhead. The range of

Figure III-24. Temperature Versus Depth Profiles

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Figure III-25. Wellhead Temperature as Function of Na and CO₂

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Figure III-26. Pressure Versus Depth Profiles

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Figure III-27. Wellhead Pressure as Function of Na and CO₂

Figure III-28. Wellhead Vapor as Function of Na and CO₂

the effect is from a pure water case of 11.8% to low value of 9.53% in run 7. Relative to the pure water case, run 7 has about 20% less vapor and is at a lower wellhead temperature. This represents a lower energy content of the wellhead fluid.

Figure III-29 is a pressure versus temperature diagram showing the saturation conditions that occur during the flashing process in the wellbore. The heavy line represents the pure water case as determined using steam table values. Four other curves are shown, corresponding to runs 1, 3, 13, and 15. Runs 13 and 15 are entirely to the left and above the pure water curve. Both runs have zero Na with run 15 having 40,000 ppm CO_2 , and run 13 having 20,000 ppm CO_2 . As the flashing process takes place moving up the well, the temperature decreases. The initial vapor is primarily CO_2 . As flashing proceeds up the well, the ratio of water to CO_2 in the new vapor increases dramatically. Eventually, the vapor phase contains much of the original CO_2 but even greater amounts of water such that the vapor is mostly water vapor. The liquid has low amounts of CO_2 in it and the system behaves much like a pure water one. The saturation curve begins to approach that of pure water. To the right of the pure water curve is the curve for run 1 which had 50,000 ppm Na and zero CO_2 . The curve is displaced from the pure water curve by an amount corresponding to the boiling point elevation due to the Na. Of particular interest is the result from run 3. With bottomhole brine conditions of 50,000 ppm Na and 5,000 ppm CO_2 , the curve starts above and to the left of the pure water curve. As CO_2 and H_2O evolve upon flashing, the liquid becomes more like a 50,000 ppm Na brine and the vapor becomes mostly water vapor. The curve crosses the pure water curve and approaches quite close to the curve from run 1 which represented a brine of 50,000 ppm Na and no CO_2 .

Figures III-30 and III-31 illustrate the effect of the activity coefficients on the model results. Figures III-30 and III-31 show sets of two runs each where one run is made with the unity activity coefficient values. The corresponding runs with nonunity values for the activity coefficients are runs previously described. The run numbers are shown on the graph. In all cases, the runs with $\gamma_{ij} = 1$ give lower values of wellhead temperature and pressure, and lower flash depths. This last result is anticipated from Figure III-21. Table III-9 tabulates the changes in wellhead conditions and flash depth for the runs in question.

Figure III-29. Saturation Pressure Versus Saturation Temperature

Figure III-30. Temperature Versus Depth Profiles; Effect of Activity Coefficients

Figure III-31. Pressure Versus Depth Profiles; Effect of Activity Coefficients

TABLE III-9. COMPARISON OF FOUR SETS OF RUNS; EFFECT OF ACTIVITY COEFFICIENTS

<u>Run Number</u>	<u>γ_{ij}</u>	<u>Na (ppm)</u>	<u>CO₂ (ppm)</u>	<u>Wellhead Temperature (°F)</u>	<u>Wellhead Pressure (psia)</u>	<u>Wellhead Vapor (%)</u>	<u>Flash Depth (ft)</u>
3	$\neq 1$	50,000	5,000	385.4	193.1	10.20	7,267
19	$= 1$			370.9	161.8	11.21	3,523
7	$\neq 1$	40,000	10,000	407.8	263.2	9.53	7,989
21	$= 1$			391.0	215.7	10.92	3,807
PW	--	0	0	414.6	291.0	11.95	2,662
11	$\neq 1$	20,000	20,000	429.0	362.8	10.13	7,192
20	$= 1$			419.1	322.7	11.12	4,365
15	$\neq 1$	0	40,000	451.0	520.6	10.80	7,445
18	$= 1$			445.4	484.7	11.55	5,675

The differences between the pure water curve and the four runs with $\gamma_{ij} = 1$ represent the effect of Na and CO₂ on physical and thermodynamic properties with the equilibrium constants being the same. The difference between the $\gamma_{ij} = 1$ and $\gamma_{ij} \neq 1$ curves represent the effect of the Na and CO₂ on the equilibrium constants. All of these effects are seen as significant, with the effect of nonunity activity coefficients appearing comparable to that of the changes in physical and other thermodynamic properties.

Discussion of Results

The bases for this study are the particular two-phase flow model used, the variables studied, the ranges of values of these variables studied, and the other well parameters and operating conditions chosen. The results of the study just presented strictly apply only to the system studied as defined by its bases. The results may, however, have implications for systems other than the specific one studied--the results may allow for some generalization.

Over the range of Na and CO₂ values studied, it is evident from the results presented that both Na and CO₂ can significantly affect wellbore conditions. Results were obtained for the following, which were greater and less than the corresponding items for the pure water run.

- Temperature versus depth profiles
- Pressure versus depth profiles
- Pressure versus temperature curves
- Wellhead temperatures
- Wellhead pressures

The pure water case seems to be an intermediate case in the comparison of these items. For two other items, however, this was not the situation. For both the length of the single-phase zone and the percent vapor at the wellhead, the pure water case gave the largest values obtained.

Some general trends were observed:

Wellhead temperature and pressure

- The wellhead temperature decreases with increasing Na and increases with increasing CO₂.

- Since the wellhead pressure is in equilibrium with the wellhead temperature, for the model used, it follows the same trends.
- For the runs made, those with Na greater than CO_2 have wellhead temperature and pressures lower than that of the pure water case; those with Na equal to CO_2 or less than CO_2 have wellhead temperature and pressures greater than that of the pure water case.
- The use of activity coefficients with values of unity decreased wellhead temperatures and pressures, and decreased the flash depth.

General shape of temperature versus depth profiles

- The runs with zero CO_2 have an immediate abrupt change in temperature gradient from the initial infinite slope vertical line below the flash point to the nearly constant final gradient line above the flash point. The final gradient decreases--and thus the change is more abrupt--with increasing Na.
- When CO_2 is present, the change in temperature gradient is much more gradual above the flash point. The final roughly constant gradient decreases with both increases in Na and CO_2 --thus the change from initial to final gradient is sharper with increasing Na and increasing CO_2 .

Length of single-phase zone

- The length of the single-phase zone decreases with both increasing Na and increasing CO_2 content.

Percent vapor at wellhead

- The percent vapor at the wellhead decreases with increasing CO_2 ; and for CO_2 contents above 2,500 ppm, it decreases with increasing Na. This qualification concerning Na and depicted in Figure III-28 needs additional study to determine if it is meaningful.

The magnitude of effect of nonunity activity coefficients on saturation pressure and more specifically on CO_2 partial pressure, as reflected in Figure III-21, was surprising. Further study showed that the effect was mostly due to the effective value of the Henry's Law constant changing with Na content. The model predicts a value of the constant, a factor of 7, greater at 60,000 ppm Na than at zero Na. The authors have recently become aware of empirical data for the $\text{NaCl-CO}_2\text{-H}_2\text{O}$ system which provides values for the Henry's Law constant as a function of NaCl content. The data show the constant doubling in value as the Na value increases from zero to 60,000 ppm. The implications are that the

model used for prediction of activity coefficients--and which was tested against available data at low temperatures--may give erroneous values at high temperatures. It was stated at the end of the previous subsection that the effects on well conditions due to changing equilibrium constants appeared comparable to that due to changing physical and other thermodynamic properties. The implications of the empirical data found are that the effects due to changing equilibrium constants are less than those due to the changing physical and other thermodynamic properties. If this were the case, the effects of Na and CO₂ on well conditions would still be significant and the trends presented would still be expected to apply.

D. Summary of Testing and Validation Work

In total, the current results are good and a direction for improving the results has been identified. The two-phase flow model has been through two separate evaluations of holdup correlations since 1978. As discussed in Sections II-C and III-A, the second evaluation has resulted in the use of a composite approach for the holdup. This approach uses recent correlations from University of Houston research for some of the flow regimes and the Hughmark/Dukler correlation for the annular flow regime. The results presented in Section III-A and those from the previous evaluation of other holdup correlations suggest that, with this approach, the model is using the best available holdup correlations. This is an important result, for the holdup correlations are critical in the determination of the pressure and temperature profiles of the well.

Using this new composite approach for holdup calculations, Section III-B demonstrated the close agreement between well test data and the two-phase flow model for low salinity data. Surprisingly, good results were also obtained for low salinity data where flashing takes place in the producing formation--a situation that the current model can not directly simulate as it requires a region of single-phase flow. The high salinity well test simulations coupled with the results of Section III-C suggest a current shortcoming of the model. The model predicts much higher partial pressures for a given amount of dissolved CO₂ gas than are suggested by

empirical data--for the specified case of high temperature and high salinity. Preliminary indications are that much closer agreement of model predictions to well test data will be obtained if this lone item is addressed and corrected. The choice between use of empirical data or predictive programs for activity coefficients, such as is currently used in the two-phase flow model, is straightforward. Empirical data exists only for simple systems such as dissolved CO_2 gas and NaCl in aqueous solutions. Similar data does not exist for more complex solutions such as found in the Hawaii well where the dissolved gas consists of 60.4% CO_2 , 21.7% H_2S , 17.3% O_2 , and 6.9% H_2 . As mentioned in Section III-C, gases present in relatively minor amounts, such as H_2 above, can have surprisingly large effects due to large values of Henry's Law constants. Since CO_2 is usually the prime dissolved gas found in geothermal systems, a modification of the activity coefficient prediction program to force agreement with available empirical data seems fruitful.

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IV. WORKSHOP PRESENTATIONS

Workshops were conducted as part of the annual meetings of the Geothermal Resources Council in July 1978 and September 1980. The intent of the workshops was to familiarize the geothermal community with the two-phase flow project and to learn of any needs that could be resolved by adaptations of the product. The workshops were run on an informal basis and consisted of presentations, discussions, solution of sample problems by individual workshop participants, and solution of particular and often proprietary problems by each participant who desired to do so, often with Coury and Associates' assistance. The intent was to allow each participant to develop insight into the problems and design needs related to two-phase flow in geothermal production wells.

The particular objectives of the two workshops included the following:

- Present background material on the hydrodynamic aspects of two-phase flow, the state of current knowledge and design capabilities, the impact of two-phase flow on the design of geothermal wells, and on the sensitivity of production well performance to design errors.
- Review the objectives and status of the DOE project for well design in two-phase flow, and solicit suggestions on how the project could best serve particular interests.
- Explain the utilization of the computer program and allow interested individuals to use the program to analyze their own particular production problems.
- Explain the utilization of the User's Manual for rapid estimations of well design.
- Review the procedures developed for determining when pumping of a production well, to produce all liquid at the surface, would be more economical than allowing the well to flow naturally in a flashing flow regime.
- Present rules of thumb to indicate when pumping should be seriously considered.

The primary suggestions that were received for making the program more useful to industry related to its use during the testing and aquifer evaluation that take place early in the development of a geothermal field.

During this period, the wells are generally run infrequently and are not produced at full flow rates over long time periods. Essential steady-state between fluid in the wellbore and the formation is not achieved until after several days of operation. Thus, during early testing, heat loss from the wellbore could be excessive, and this could cause a change in the production rates of steam and brine from the values predicted by means of the program. During this test period, the analysis of the reservoir requires that the temperature and pressure at the bottom of the well be known. In order to determine these downhole conditions on the basis of wellhead parameters, the program must be modified to account for the heat loss described above. This requires, in addition, that the program also be slightly modified to make calculations while progressing down the well, from wellhead to bottomhole. This would accomplish two purposes: it would make it easier for the reservoir engineer to use the program during reservoir analysis, and it would make it possible to incorporate more accurately the effect of dissolved gas and salts on the well performance. The incorporation of brine chemistry into the well program requires a downward calculational approach because accurate analyses of downhole brine chemistry are not always available and are probably never available during the reservoir testing program; on the other hand, accurate analyses of wellhead steam and brine can be attained and utilized in the calculational procedures.

It was also suggested that the unsteady state terms in the hydraulic equations should be incorporated into the program to allow a better simulation of well performance during startup. Coury and Associates has found, however, that the rate of change of hydrodynamic parameters, even during startup, is too small to have an appreciable effect on the steady-state results. An accurate simulation can be obtained by making several runs with the steady-state program, where each run reflects the pseudo-steady boundary conditions over different time periods. A small modification to the program could be made so that these boundary condition changes are made automatically, rather than requiring a continuous manual interface with the computer. This change would make it easier for the user to convert test measurements at the wellhead to the downhole conditions needed to evaluate reservoir performance. In addition to the discussions and hands-on workshop activities described above, each participant was furnished with a packet of materials that summarized the presentations. Some of these are discussed in the next section.

Pumped Versus Flashing Flow

In each of the workshops, Coury and Associates presented results from studies of pumped and two-phase flow production. The objectives specifically were:

- To develop the methodology with which to evaluate pumped flow and flashing flow for specific reservoir and well conditions and surface applications.
- To stress the importance and necessity of evaluating each case from a site-specific system approach, avoiding the dangers of generalization.
- To discuss various factors which need to be considered in making such evaluations.
- In general, to transmit knowledge and to have an interactive discussion on pumped flow.

The first workshop presentation on this subject is summarized in a Geothermal Resources Council Transaction publication, which is reproduced as Appendix D.

The second workshop had an additional objective:

- To illustrate the methodology by discussing two specific examples--one which favored pumped flow and one which favored flashing flow.

The outline for the discussion and supporting figures and table are included in Appendix E. The effects of temperature, productivity index, casing diameter, flow rate, pump setting depth, and setting pressure for the particular system considered are reflected in the graphical results given.

Appendices D and E are self-explanatory. The results presented need to be taken within the context defined by the objectives previously stated. The studies demonstrate the methodology by which specific pumped versus flashing flow situations may be evaluated.

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APPENDIX A

Tables A-1 through A-14

Table A-1

Geothermal Component Test Facility
Well 6-2 Log 8
July, 1979

Depth feet		Temperature °F		Pressure PSIA
DEPTH	RTEMP	TEMP	RPRESS	PRESS
796	170.25	359.998	787.5	342.347
779	170.25	359.998	773	336.044
761	170.25	359.998	754.5	328.003
744	170.25	359.998	736.5	320.179
717	170.2	359.758	714.5	310.653
700	170.2	359.758	696	302.746
602	170.2	359.758	681.5	296.549
664	170.2	359.758	663.5	288.855
638	170.15	359.517	638	277.98
620	170.15	359.517	623	271.569
602	170.15	359.517	608.5	265.366
584	170.15	359.517	590.5	257.533
557	170.1	359.277	568.5	247.866
541	170.1	359.277	550	239.717
521	170.1	359.277	532	231.789
499	170.05	359.036	510	222.118
477	170	358.796	489	212.915
462	169.95	358.555	477	207.895
439	169.9	358.315	455	198.765
417	169.8	357.834	437	191.311
402	169.75	357.594	426	186.751
380	169.65	357.113	411	180.539
357	169.5	356.391	393	173.09
342	169.4	355.91	389	171.451
319	169.2	354.949	371	164.007
297	169	353.907	360	159.329
283	168.85	353.265	352.5	156.075
258	168.55	351.823	341.5	151.304
242	168.3	350.62	334	148.046
218	168	349.185	323	143.243
201	167.75	347.992	315.5	139.976
177	167.35	346.085	304.5	135.201
160	167.1	344.893	297.5	132.168
144	166.85	343.701	290	128.921
119	166.4	341.555	279	124.184
103	166.15	340.362	271.5	120.951
78	165.75	338.455	264	117.755
60	165.4	336.786	256.5	114.556

Log 8 (Continued)

Depth feet		Temperature °F		Pressure PSIA
78	165.6	337.74	259.5	115.822
97	165.95	339.409	266.5	118.806
124	166.4	341.555	270.5	120.464
142	166.65	342.747	277.5	123.481
160	166.95	344.177	285	126.712
178	167.2	345.37	292	129.739
204	167.6	347.277	299.5	132.967
222	167.85	348.469	306.5	136.006
240	168.15	349.9	314	139.263
257	168.35	350.861	321.5	142.544
284	168.7	352.544	332.5	147.334
301	168.9	353.506	343.5	152.125
319	169.05	354.227	351	155.381
336	169.25	355.189	362	160.149
363	169.45	356.151	376.5	166.236
380	169.55	356.632	387.5	170.789
398	169.7	357.353	402.5	176.99
424	169.8	357.834	420.5	184.449
442	169.85	358.074	435	190.464
459	169.95	358.555	450	196.67
477	170	358.796	464.5	202.682
504	170.05	359.036	490	213.333
521	170.1	359.277	505	219.897
539	170.1	359.277	519.5	226.283
557	170.15	359.517	538	234.411
583	170.15	359.517	567	247.183
601	170.15	359.517	582	253.789
619	170.2	359.758	596.5	260.152
636	170.2	359.758	614.5	267.912
663	170.2	359.758	637	277.529
681	170.2	359.758	651.5	283.726
699	170.25	359.998	669.5	291.395
722	170.25	359.998	691.5	300.797
740	170.25	359.998	706	306.994
758	170.25	359.998	724.5	314.962
776	170.25	359.998	739	321.266
794	170.3	360.239	757.5	329.277

Geothermal Component Test Facility
Well 6-2 Log 9 July, 1979

Table A-2

Depth feet	Temperature °F		Pressure PSIA	
DEPTH	RTEMP	TEMP	RPRESS	PRESS
500	170	358.796	575.5	250.993
479	170	358.796	560.5	244.385
458	169.95	358.555	539	234.934
438	169.95	358.555	520.5	226.783
417	169.9	358.315	502.5	218.872
397	169.85	358.074	484	210.839
377	169.8	357.834	466	203.371
356	169.75	357.594	451	197.148
336	169.65	357.113	433	189.692
316	169.55	356.632	418.5	183.688
296	169.45	356.151	403.5	177.473
275	169.3	355.429	389	171.477
265	169.2	354.949	385.5	170.045
244	169.05	354.227	371	164.043
224	168.85	353.265	360	159.361
204	168.65	352.304	348.5	154.359
183	168.4	351.101	341.5	151.328
163	168.15	349.9	327	144.985
143	167.9	348.708	323	143.255
123	167.6	347.277	315.5	139.996
102	167.3	345.846	304.5	135.208
82	167	344.416	293.5	130.43
62	166.7	342.985	286	127.194
57	166.5	342.031	282	125.478
76	166.8	343.462	285.5	126.958
96	167.15	345.131	293	130.186
116	167.45	346.562	299.5	132.991
136	167.7	347.754	307.5	136.467
157	168	349.185	314.5	139.503
177	168.25	350.30	322	142.774
197	168.5	351.582	333	147.58
218	168.75	352.784	344	152.368
238	168.95	353.746	355	157.151
258	169.15	354.708	369.5	163.394
279	169.3	355.429	379	167.313
299	169.45	356.151	399	175.6
319	169.55	356.632	406.5	178.695
340	169.65	357.113	424.5	186.155
360	169.75	357.594	439	192.157
381	169.8	357.834	457.5	199.836
401	169.85	358.074	476	207.513
422	169.9	358.315	494	215.132
442	169.95	358.555	512.5	223.259
462	170	358.796	534.5	232.931
483	170	358.796	552.5	240.861
503	170	358.796	574.5	250.552
524	170	358.796	589.5	257.16
544	170.05	359.036	611	266.485
564	170.05	359.036	629.5	274.394
585	170.05	359.036	647.5	282.089
600	170.05	359.036	662.5	288.502

Table A-3
Geothermal Component Test Facility
Well 6-2 Log 16
July, 1979

Depth feet		Temperature °F		Pressure PSIA
DEPTH	RTEMP	TEMP	RPRESS	PRESS
800	169.5	355.625	983.5	418.042
785	169.5	355.625	971	412.843
757	169.5	355.625	947	403.053
741	169.45	355.385	929	395.739
723	169.45	355.385	917.5	391.054
698	169.4	355.144	888.5	379.246
685	169.45	355.385	881	376.184
664	169.4	355.144	859	367.222
644	169.4	355.144	837.5	358.317
623	169.4	355.144	819	350.497
602	169.35	354.904	797.5	341.422
599	169.4	355.144	790	338.237
577	169.35	354.904	775.5	332.128
557	169.35	354.904	753.5	322.835
536	169.3	354.663	739	316.773
516	169.3	354.663	717	307.689
500	169.3	354.663	702.5	301.718
477	169.3	354.663	682	293.277
457	169.25	354.423	658.5	283.623
444	169.25	354.423	647.5	279.093
424	169.25	354.423	629.5	271.679
404	169.25	354.423	611	264.046
400	169.2	354.183	607.5	262.614
380	169.2	354.183	589.5	255.135
360	169.2	354.183	571	247.447
340	169.15	353.942	549	238.327
320	169.15	353.942	531.5	231.055
300	169.1	353.702	508.5	221.524
276	169.05	353.462	486.5	212.441
255	169	353.221	468	204.563
241	169	353.221	450	196.864
217	168.9	352.74	432	189.193
200	168.8	352.26	417	182.794
184	168.65	351.538	406	178.107
163	168.65	351.538	391.5	171.885
138	168.45	350.577	373	163.957
118	168.3	349.857	362	159.371
100	168.1	348.904	348	153.656
84	167.9	347.95	340.5	150.628
60	167.6	346.52	325.5	144.548
40	167.35	345.329	314.5	140.108

Table A-4

Geothermal Component Test Facility
Well 6-2 Log 17
July, 1979

Depth feet	Temperature °F		Pressure PSIA	
DEPTH	RTEMP	TEMP	RPRESS	PRESS
600	169.25	354.423	838.5	358.742
578	169.25	354.423	827	353.892
558	169.25	354.423	806	345.034
537	169.2	354.183	788	337.459
516	169.2	354.183	766.5	328.397
500	169.25	354.423	745	319.305
476	169.25	354.423	730.5	313.204
455	169.2	354.183	708.5	304.244
435	169.2	354.183	690	296.623
415	169.15	353.942	668.5	287.79
400	169.15	353.942	650.5	280.373
381	169.15	353.942	638	275.222
360	169.1	353.702	621	268.237
340	169.05	353.462	597	258.312
320	169.05	353.462	577.5	250.212
300	169	353.221	552.5	239.849
280	169	353.221	537	233.411
259	168.95	352.981	519	225.96
239	168.9	352.74	500.5	218.303
218	168.8	352.26	479.5	209.573
198	168.7	351.779	464	202.972
179	168.65	351.530	446	195.260
150	168.55	351.058	431.5	189.075
144	168.5	350.817	417	182.859
124	168.35	350.096	402	176.438
100	168.25	349.619	380	167
75	168.05	348.665	369.5	162.546
60	167.9	347.95	354.5	156.4
80	168.05	348.665	354.5	156.353

Log 17 (Continued)

Depth feet		Temperature °F		Pressure PSIA
100	168.2	349.38	369	162.293
124	168.35	350.096	391	171.706
144	168.5	350.817	402	176.414
165	168.6	351.298	423.5	185.627
175	168.65	351.538	431	188.833
200	168.75	352.019	453	198.237
217	168.8	352.26	467.5	204.432
238	168.9	352.74	489.5	213.753
258	169	353.221	504	219.705
278	169.05	353.462	526.5	229.026
300	169.1	353.702	551.5	239.388
320	169.1	353.702	566	245.413
340	169.15	353.942	584.5	253.078
360	169.2	354.183	606	261.991
381	169.2	354.183	624.5	269.64
400	169.25	354.423	643	277.239
421	169.25	354.423	664.5	286.094
441	169.25	354.423	682.5	293.508
462	169.3	354.663	708	303.983
483	169.3	354.663	726.5	311.601
503	169.35	354.904	745	319.245
524	169.35	354.904	765.5	327.904
545	169.4	355.144	785	336.124
555	169.4	355.144	793.5	339.717
576	169.4	355.144	814	348.383
596	169.45	355.385	836	357.682
617	169.5	355.625	851.5	364.166
637	169.5	355.625	874.5	373.531
658	169.55	355.865	892.5	380.853
679	169.55	355.865	916	390.417
700	169.6	356.106	932	396.912
720	169.6	356.106	956.5	406.877
740	169.6	356.106	971	412.793
761	169.65	356.346	987.5	419.630
781	169.7	356.587	1011	429.483
801	169.7	356.587	1029.5	437.255

Table A- 5

Geothermal Component Test Facility
Well 6-2 Log 19
July, 1979

Depth feet	Temperature °F		Pressure PSIA	
DEPTH	RTEMP	TEMP	RPRESS	PRESS
700	170.3	359.471	712	305.07
683	170.3	359.471	694	297.692
663	170.25	359.231	672	288.698
643	170.25	359.231	650.5	279.883
623	170.2	358.99	632	272.318
600	170.25	359.231	607	261.994
576	170.2	358.99	585	252.847
556	170.2	358.99	563.5	243.888
535	170.15	358.75	548.5	237.661
515	170.15	358.75	526.5	228.495
500	170.1	358.51	512	222.479
484	170.1	358.51	494	215.009
461	170	358.029	468.5	204.36
445	170	358.029	454	198.214
425	169.9	357.548	435.5	190.403
400	169.8	357.067	417.5	182.789
380	169.7	356.587	403	176.648
360	169.55	355.865	392	171.992
338	169.35	354.904	375	164.760
318	169.2	354.183	366.5	161.191
300	168.95	352.981	355	156.456
299	168.95	352.981	351.5	155.012
276	168.7	351.779	340.5	150.479
255	168.4	350.337	333	147.388
239	168.2	349.38	322	142.893
225	167.9	347.95	314.5	139.907
199	167.5	346.044	300	134.082
179	167.2	344.614	296	132.551
159	166.9	343.184	285	120.146
141	166.6	341.754	277.5	125.186
136	166.5	341.277	274	123.791
116	166.15	339.609	266.5	120.861

Log 19 (Continued)

Depth feet		Temperature °F		Pressure PSIA
100	165.85	338.179	259	117.916
84	165.6	336.988	256.5	117.001
59	165.1	334.604	244	112.134
83	165.6	336.988	256	116.797
100	165.9	338.418	258	117.484
118	166.1	339.371	262	119.037
135	166.4	340.801	265.5	120.344
155	166.75	342.469	273	123.276
182	167.15	344.376	284	127.634
202	167.45	345.806	291.5	130.601
223	167.75	347.235	298.5	133.368
239	167.9	347.95	302.5	134.959
259	168.3	349.857	313.5	139.348
278	168.55	351.058	325	144.084
298	168.75	352.019	332	146.971
322	168.95	352.981	346.5	152.95
343	169.25	354.423	354	156.036
363	169.35	354.904	368.5	162.011
383	169.6	356.106	376	165.18
403	169.7	356.587	394.5	173.036
424	169.75	356.827	408.5	178.977
444	169.95	357.788	423.5	185.3
464	169.95	357.788	438	191.448
484	170	358.029	456	199.062
500	170.4	359.952	472.5	205.882

Table A-6
Summary of Well Conditions
Well HGP-A, East Rift Zone, Hawaii

Total Depth: 6400 feet

Casing Schedule:

0 to 2260 ft.	9 5/8 in. diameter N-80, 43.5 lb/ft., 8.755 in ID
2260 to T.D.	7 in. diameter liner K-55, 23 lb/ft., 6.366 in ID set in 8 1/2 in. hole

Production Zones:

Upper: at about 4300 ft.
Lower: near well bottom

Dissolved Gas Content:

2100 ppm measured at 180°C
composition 60.4% CO₂

21.7% H₂S

17.3% N₂

0.6% H₂

Flowrate Measurement Technique:

James Method

Information Source: Dr. Bill H. Chen
University of Hawaii at Hilo
P. O. Box 1357
Hilo, Hawaii 96720
(808) 961-9367

Table A-7

HGP-A Well Temperature/Pressure Profiles for January 1978 Tests

Total Mass Flow Rate = 76,000 lb/hr, Quality = 52%

<u>Well Head Pressure</u>	<u>Depth</u>	<u>Pressure</u>	<u>Temperature</u>
375 psig	0 ft	365 psig	440
	500	380	450
	1000	405	455
	1300	420	455
	1500	430	460
	2100	450	465
	2500	480	470
	3000	505	480
	3500	550	480
	4000	575	485
	4300	600	490
	4500	620	495
	5000	650	495
	5500	695	505
	5750	710	510
	6000	735	515
	6300	760	520

Enthalpy based on wellhead temperature = 827.6 BTU/lbm

Enthalpy based on wellhead pressure (365 psig) = 827.2 BTU/lbm

Table A-8

HGP-A Well Temperature/Pressure Profiles for January 1978 Tests

Total Mass Flow Rate = 84,000 lb/hr, Quality = 57%

<u>Well Head Pressure</u>	<u>Depth</u>	<u>Pressure</u>	<u>Temperature</u>
237 psig	0 ft	220 psig	390°F
	500	230	395
	1000	240	400
	1300	250	405
	1500	255	410
	2100	270	415
	2500	290	420
	3000	310	425
	3500	335	435
	4000	360	440
	4300	370	445
	4500	380	445
	5000	410	450
	5500	450	460
	5750	460	460
	6000	475	465
	6300	495	470

Enthalpy based on wellhead temperature = 840.5 BTU/lbm

Enthalpy based on wellhead pressure (220 psig) = 843.2 BTU/lbm

Table A-9

HGP-A Well Temperature/Pressure Profiles for January 1978 Tests

Total Mass Flow Rate = 93,000 lb/hr, Quality = 64%

<u>Well Head Pressure</u>	<u>Depth</u>	<u>Pressure</u>	<u>Temperature</u>
100 psig	0 ft	90 psig	330°F
	410	95	340
	1000	95	345
	1300	100	345
	1500	100	350
	2100	110	360
	2500	125	355
	3000	155	375
	3500	180	390
	4000	205	395
	4300	220	400
	4500	225	405
	5000	235	410
	5500	255	410
	5750	265	415
	6000	280	420
	6300	290	425

Enthalpy based on wellhead temperature = 868.4 BTU/lbm

Enthalpy based on wellhead pressure (90 psig) = 869.0 BTU/lbm

Table A-10

HGP-A Well Temperature/Pressure Profiles for January 1978 Tests

Total Mass Flow Rate = 101,000 lb/hr Quality = 64%

<u>Well Head Pressure</u>	<u>Depth</u>	<u>Pressure</u>	<u>Temperature</u>
51 psig	0 ft	50 psig	295°F
	500	60	310
	1000	70	315
	1300	75	320
	1500	80	320
	2100	85	330
	2500	110	340
	3000	125	355
	3500	135	365
	4000	160	375
	4300	180	380
	4500	185	380
	5000	210	390
	5500	220	395
	5750	230	400
	6000	245	400
	6300	250	400

Enthalpy based upon wellhead temperature = 849.2 BTU/lbm

Enthalpy based upon wellhead pressure (50 psig) = 850.6 BTU/lbm

Table A-11
Summary of Well Conditions

Well BR27, New Zealand, Broadlands Geothermal Field

Casing Schedule:

20 inches to 124 feet

16 inches from surface to 463 feet

11.75 inches from surface to 1007 feet

8.625 inches from surface to 1812 feet

6.625 slotted liner from 1812 to 3813 feet

Contact:

Malcolm A. Grant
Dept. of Scientific and Industrial Research
Applied Mathematics Division
P. O. Box 1335
Wellington
New Zealand
Telephone 727-855

Flow Rate and Enthalpy Measurement Technique

"Lip Pressure and weir method" used to calculate mass flow and enthalpy

Lip pressures measured on a 6 inch (152 mm) discharge pipe at the
silencer inlet.

Water flows measured over a rectangular weir in an open channel
near the silencer outlet.

Wellhead pressure was raised in steps by throttling the 7.9 inch (200 mm)
by-pass valve. Mass, enthalpy, water, steam, and heat values were cal-
culated and plotted against wellhead pressure.

Total Depth: 3813 feet

Dissolved Gas Content:

ranges between 2.2% and 3.6% of total mass flow rate, or 1,760 lb./hr.
to 3,500 lb./hr. dissolved gas is mostly CO₂

Production at 2270 ft.

Undisturbed temperature is about 260°C (500°F).

Test data indicates two-phase flow in reservoir.

Table A-12
Temperature/Pressure Profiles
New Zealand
Well Broadlands BR27
(10/5/76)

<u>Wellhead Pressure</u>	<u>Depth</u>	<u>Temperature</u>	<u>Pressure</u>
540 psig	1806 feet	495°F	665 psig
	2007	496	687
	2208	498	709
	2408	507	762
	2610	514	829
	2811	520	897
	3012	525	955

Enthalpy = 1310 J/g = 563.6 Btu/lb.

Mass Flow Rate = 44 metric tons/hr. = 97,000 lb./hr.

Gas Flow Rate = 1.60 metric tons/hr. (mostly CO₂) = 3,500 lb./hr.

Gas Flow Rate as percent of mass flow = 3.636%

Table A-13
New Zealand
Well Broadlands BR27
(3/2/77)

<u>Wellhead Pressure</u>	<u>Depth</u>	<u>Temperature</u>	<u>Pressure</u>
547 psig	0 feet	466°F	541 psig
	402	471	571
	803	476	600
	1204	481	636
	1605	484	669
	2007	-	710
	2208	-	731
	2408	-	787
	2509	-	821

Enthalpy = 1310 J/g = 563.6 Btu/lb.

Mass Flow Rate = 38 metric tons/hr. = 83,800 lb./hr.

Table A-14

New Zealand
Well Broadlands BR27
(8/10/77)

<u>Wellhead Pressure</u>	<u>Depth</u>	<u>Temperature</u>	<u>Pressure</u>
546 psig	402 feet	469°F	574 psig
	803	477	609
	1204	484	642
	1605	487	677
	2007	493	720
	2208	496	749
	2408	505	796
	2509	509	830

Enthalpy = 1282 J/g = 551.5 Btu/lb.

Mass Flow Rate = 37 metric tons/hr. = 81,600 lb./hr.

Gas Flow Rate = 1.0 metric tons/hr. = 2,200 lb./hr.

Gas Flow rate as percent of mass flow rate = 2.702%

APPENDIX B

MAIN PROGRAM AND SUBROUTINE FUNCTIONS AND INTERACTIONS

Table B1 depicts how the two-phase flow computer model main program and subroutines interact. With the exception of the initial reading of the problem data, which occurs in MAIN, all calculations and output are directed from LEADER. There are three levels of subroutines which perform the indicated tasks listed for LEADER. Calculations in the two-phase flow region proceed segment-by-segment up the well until the top of the well is reached. Each segment involves iteration on pH, and partial pressure and steps 4 to 7 are repeated for each segment.

TABLE B1. MAIN PROGRAM AND SUBROUTINE FUNCTIONS AND INTERACTIONS

↓
LEADER (cont'd)

5. Calculate pressure loss gradients and determine segment length
 - A. Calculate pressure loss due to acceleration
 - B. Calculate pressure loss due to elevation changes and friction

GOPHER
Organizes hydrodynamic calculations

1. Determine flow regime

REGIME

Determine flow regime

2. Calculate holdup

HOLDUP

Determine holdup for bubble, slug and churn flow regimes

OR

HUGHMK

Determine holdup for annular flow regime

3. Calculate frictional pressure loss

DUKLER

Determine frictional pressure gradient in two-phase flow

6. Summarize results for segment and prepare output

RITE

Write output for each segment

7. Determine if top of well has been reached; if not, repeat step 4 on; if yes, prepare summary of calculations, and stop

RITSUM

Write summary sheet for the design

TABLE E1. MAIN PROGRAM AND SUBROUTINE FUNCTIONS AND INTERACTIONS (continued)

APPENDIX C

INPUT DATA REQUIRED FOR COMPUTER PROGRAM

Table C1 shows the input data required to run the two-phase flow computer program. Data on lines 00010 and 00030 are for identification purposes only. In line 00050, the steam-water fluid system is specified and the next four numbers describe whether a single run or parametric sets of runs are to be made, what holdup correlation to use, what friction factor correlation to use, and whether nonunity activity coefficients should be calculated. Line 00061 gives a convergence coefficient value that influences the rate of convergence of the iterative vapor-liquid equilibrium calculations. Line 00070 contains the bottomhole well data for depth, diameter, temperature, pressure, liquid flow rate, and gas flow rate. The last three numbers set the number of different diameters in the well, indicate whether dissolved gases are to be specified, and indicate whether dissolved salts are to be specified. Line 00090 contains parameters for CO₂ injection. The four numbers tell whether CO₂ injection is to be considered, give the injection rate, give the injection depth, and give the outer diameter of the injection tube. Line 00101 lists any other diameters present and line 00103 gives the corresponding depth of any diameter changes. Line 00110 gives the amounts of dissolved gases present and line 00130 gives the amounts of dissolved salts present.

Specification of the above data is sufficient to run the computer model. Segment length is determined internally and corresponds to the length required to attain a specified segment pressure drop. This pressure drop may be held constant; usually, however, it is allowed to vary such that smaller values are used in regions where conditions change rapidly and larger values are used in regions where little change is occurring.

TABLE C1. INPUT DATA FOR TWO-PHASE FLOW COMPUTER PROGRAM

```

***** ***** TOP OF DATA *****
00010 10-14-81      GEO2PRT / MIKE      CORY AND ASSOCIATES
00020 --DATE-- --PROGRAM--ENGINEER-- --COMPANY--
00030 COMPLEX BRINE STUDY      RUN L-1      8.45AM
00040 -----PROBLEM DESCRIPTION-----
00050 STEA 0 5 3 0 DESN CARD 1
00060 STEA X Y Z W DESN CARD 1      PROBLEM DATA LAYOUT LINE
00061 1.00
00062 ***** CONVERGENCE COEFFICIENT *****
00070 7000.0 9.06 400.0 2152.0 300000. 0.0 2 1 1
00080 *DEPTH* DIAM* TEMP* *PRES* **#/HR.** #/HR.* *DDGGSS WELLDATA LAYOUT LINE
00090 0 20000. 3900. 3.63
00100 ** *RATE** *DEPTH *DIA** CO2 INJECTION DATA: K1CO2,CO2INJ,CO2DD,CO2DIA
00101 12.57
00102 *****/*****/*****/*****/ DIAMETER CHANGES
00103 3000.
00104 *****/*****/*****/*****/ DEPTHS OF DIAMETER CHANGES
00110 4500.. 100. 50.
00120 **CO2** *H2S** *NH3** *N2** *H2** *CH4** IGAS VALUES
00130 14500. 0.0 00000. 00.0 00000.0 000. 000. 000. 0.
00140 * NA+ ** MG++ ** CA++ ** BA++ ** CL- ** SO4---** HCO3---** CO3---**SI02-*
00150 999 ABOVE LINE ITEMS ARE ISALT VALUES 999

```

APPENDIX D

A TECHNICAL EVALUATION OF PUMPING VS. NATURALLY FLASHING GEOTHERMAL WELL PRODUCTION

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ABSTRACT

A study has been completed which demonstrates that, for parameters and conditions typical of current state-of-the-art geothermal electrical power generation, there is a very high probability that pumping will reduce the production capabilities of an otherwise naturally flashing two-phase flow well. The effect of pumping is shown to be primarily dependent on reservoir temperature and reservoir productivity. Pumping becomes less favorable as temperature increases and productivity index decreases. The parametric models used in this evaluation include reservoir temperatures of 335°F and 400°F, and productivity indices of 1000 and 3000 LB/HR/PSI. The results of the analysis show pumped wells generally having reduced electrical power production capabilities when compared with unpumped flashing wells with the same reservoir conditions. The results also indicate that at very low temperatures and high reservoir productivities pumping may increase the net production capabilities.

The analysis performed was based on geothermal reservoir conditions assumed to be typical of resources capable of being produced through naturally flashing two-phase flow wells. The well diameters, pump design capabilities and limitations, and two-stage flash turbine generator facility were based on typical state-of-the-art designs and process parameters. The naturally flashing well calculations were based on advanced two-phase flow geothermal well modeling techniques.

BACKGROUND

In many geothermal locations with temperatures high enough for practical direct electrical power generation, conditions exist such that geothermal wells are capable of producing unassisted as flashing two-phase flow wells. In these situations, the temperatures are usually well over 300°F; however, the pressure due to hydraulic head in the reservoir is sufficient to maintain single-phase liquid in the reservoir and lower portions of producing wells. As this liquid phase geothermal water is forced up a producing well, the combination of frictional losses in the formation and well and the reduction in hydraulic head in the well causes a drop in pressure sufficient enough to allow flashing to occur part way up the well. Two-

phase flow (vapor-liquid) then exists from the flash point in the well to the wellhead.

The flow rate of a flashing well is limited by the complex flow mechanics of the two-phase system. Also, some flashing geothermal wells have potential scaling problems due to precipitants, such as calcium carbonate, that are produced as flashing occurs. Currently, there is considerable interest in pumping these otherwise naturally flashing wells in an attempt to possibly increase the flow rate of the wells and, also, to possibly prevent scaling from occurring in the wells by maintaining liquid flow in the well. The current commercially available pumps have significant design limitations in setting depths and pump power. Since the pump power and setting depth requirements in a given pumped well increase with flow (as will be explained later) the flow rate of a pumped well is limited by these parameters. Also, the pump itself is consuming power, thus, in effect, reducing the net power output of a well. The ultimate justification in pumping a well in this situation can only be determined by a complete economic analysis taking into consideration such factors as the effect on the net well power production capability due to pumping; the total economic effect of scale prevention (if scaling is a potential problem); and the capital, maintenance, and operating cost of the pump.

OBJECTIVES AND RESULTS SUMMARY

The objective of this study was to compare the overall electrical power production capabilities of pumped and unpumped wells with reservoir parameters typical for this application. The results of this study were that pumping generally reduced the overall electrical power production capabilities when compared with allowing the wells to produce as unassisted flashing wells. These results are based on design limitations of current commercially available pumps and particular parametric models which are assumed to be typical for this geothermal application. The results may be slightly different with other reservoir parameters; however, the implications derived from this analysis indicate that pumping may very possibly reduce the power production capabilities in most situations with higher temperatures and lower productivity indices. These results demonstrate the importance of performing complete economic and

technical analyses when considering pumping a well in this situation.

MODEL PARAMETERS AND ASSUMPTIONS

The reservoir parameters selected for this analysis are based on data obtained from the East Mesa area in Southern California (1). These parameters are assumed to be representative of typical geothermal resources that would be suitable for this application. Two temperatures were examined in the analysis. The lower temperature, 335°F, is somewhat lower than what normally would be expected for this application (350°F is considered a marginal low temperature for practical electrical power generation) and represents a worst case low temperature. The higher temperature examined, 400°F, is a more reasonable temperature for this application. The two productivity index values examined, 1000 and 3000 LB/HR/PSI, define a reasonable range for geothermal reservoirs. The productivity index is a measure of the flow rate that can be obtained for a given frictional pressure drop in the reservoir. The production zone depths and characteristics are listed below. A three-diameter stepped well was selected as the well model. These diameters and step elevations are typical of current practice. The pump was assumed to be a surface electric driven vertical turbine line shaft pump. This was selected over a submersible pump since currently available submersible pumps cannot be used at these temperatures. The pump design parameters and limitations are listed below. These limitations are representative of current commercially available pumps. The turbine-generator facility was based on a two-stage flash system. In order to simplify the analysis, the conditions of the second-stage flash tank and the condenser were selected based on values shown to be optimum through the operating experience of similar facilities. The first-stage flash conditions for the pumped wells were optimized based on well temperature. The first-stage flash conditions for the unpumped wells were assumed to be the same as wellhead conditions, with the first-stage flash actually occurring in the well. The wellhead pressure of the pumped wells was assumed to be saturation pressure. Other important assumptions are listed below. The system model is simplified in many respects from that of an actual geothermal generation facility in order to simplify the analysis. However, these simplifying assumptions are consistent for both the unpumped and pumped wells and should not affect the objectives of this analysis, which is to compare the net power-producing capabilities of pumped and unpumped wells.

Well Design:

	I.D.	Depth
Surface casing	15.124 IN.	0-1500 FT
Intermediate liner	10.880 IN.	1500-5550 FT
Production liner	7.921 IN.	5550-7000 FT

Pump:

Design - vertical turbine line shaft pump with electric motor drive on surface.
Pump Column O.D. - 10.75 IN

Pump Column I.D. - 10.02 IN
Shaft Tube O.D. - 3.50 IN
Net Positive Suction Head - 50 FT
(Pump suction located 50 FT below top of liquid in well)
Pump Efficiency - 75%
Motor Efficiency - 90%
Drive Shaft Power Loss - 0.023 HP/FT
Wellhead Pressure - Saturation Pressure

Reservoir:

Temperature - 335°F and 400°F
Productivity Index - 1000 LB/HR/PSI and 3000 LB/HR/PSI
Production Zone - Uniform production between 6000 and 7000 FT with static head datum at 6100 FT
Reservoir Static Pressure - 2570 PSIA

Surface Facility:

Design - Two-stage flash turbine-generator facility
First-Stage Conditions
Unpumped wells - same as wellhead conditions (first-stage flash occurs in well)
335°F pumped well - 280°F and 49 PSIA*
400°F pumped well - 310°F and 78 PSIA*
Second-Stage Conditions - 228°F and 20 PSIA**
Condenser Conditions - 110°F and 1.28 PSIA**
Turbine-Generator Efficiency - 82%

Assumptions:

- Constant enthalpy throttling
- Adiabatic system (well and surface equipment)
- Constant entropy expansion in turbine
- Negligible surface friction losses
- No dissolved solids or gases
- Pipe and well absolute roughness of .00015 FT.

* Optimized based on well temperatures and specified second-stage and condenser conditions.

**Based on current state-of-the-art practice.

ANALYSIS

Pumped Well

The flow in the pumped well is all single-phase liquid from the reservoir to the wellhead since the pressure in the well is maintained above saturation pressure. Therefore, the pressure drop calculations are straightforward and are based on conventional, well-known single-phase flow correlations. The pump suction must be located 50 feet below the top of the liquid in the well in order to provide the assumed required net positive suction head of 50 feet. The pump suction depth and top of liquid depth are determined by calculating the frictional and hydraulic head pressure differentials up to these elevations. The pressure at the top of the liquid is the saturation pressure at the reservoir temperature. Since the frictional pressure drop increases with flow, the required pump suction depth will increase as flow increases.

Also, the saturation pressure increases with temperature; thus, for a given flow rate, the required pump suction depth will increase as the reservoir temperature increases. The productivity index (P.I.) also affects the required pump suction depth. As the P.I. decreases, implying greater friction losses in the reservoir, the required pump suction depth increases. The pump power requirements are also calculated using conventional, well-known relationships involving frictional and hydraulic head pressure drops, fluid flow rates, and pump efficiencies and mechanical losses. The flow inside the pump column is annular flow; therefore, the frictional losses are calculated using the hydraulic radius. The pump power requirements increase as the flow rate increases and the required setting depth increases. For a given set of reservoir parameters, the flow rate of the pumped well is limited by either the setting depth requirement or the power requirement, which are about 1,200 feet and 1,000 H.P., respectively, based on limitations of current commercially available pumps. The pumped well calculations define pump power and pump setting depth as a function of flow rate and reservoir conditions. Limiting flow rates are determined based on the pump depth and power limitations.

Unpumped Well

The analysis of the unpumped flashing well is much more complicated since this involves two-phase flow analysis. Coury and Associates has developed a computer program based on state-of-the-art correlations and calculational techniques for two-phase flow (vapor liquid) systems. This unique computer program accurately models the pressure, temperature, and vapor-liquid ratio changes that occur as the two-phase fluid flows up the well. Conventional single-phase liquid frictional and hydraulic head loss calculational techniques are used to model the pressure drops in the reservoir and the single-phase liquid portion of the well in order to determine the flash elevation in the well. The flash elevation is defined as the point in which the liquid pressure is equal to the saturation pressure at the reservoir temperature. This computer program requires extensive iterative runs in order to get precise solutions; therefore, in this analysis previously run sets of parametric computer runs were used to determine the wellhead conditions for various reservoir temperatures, productivity indices, and well flow rates. The results of these parametric computer runs are shown in graph form in reference 2. The parametric computer runs indicate flow rate limitations for given reservoir temperatures and productivities. These limiting flows are based on a complicated phenomenon which indicates that the energy losses in the two-phase system, such as acceleration losses, are in balance with the driving forces; therefore, no additional flow can be obtained. The wellhead conditions and flow rate limitations are obtained by interpolation of the parametric computer runs. Due to the nature of the interpolation of these parametric runs, the indicated limits are very conservative and the actual flow rates may be greater by as much as 100,000 to 200,000 lb/hr.

Turbine Generator Facility

A complete mass flow and energy balance is performed through the two-stage flash turbine facility using basic thermodynamic principals to determine the total electrical power output of the generator based on the calculated wellhead conditions and flow rates. For the unpumped flashing well, the first stage conditions are assumed to be the same as the wellhead. For the pumped well, the first-stage flash tank conditions are optimized to give maximum electrical power output per unit mass flow based on reservoir temperatures and other fixed parameters. The required pump power is subtracted from the generator output to obtain the net electrical power produced from the pumped wells.

RESULTS

Figures 1 and 2 show the calculated pump depth and pump power requirements as functions of well flow rate, reservoir temperature, and productivity. The limiting values are also indicated in these figures.

Table 1 shows the calculated limiting flow rates for both the pumped and unpumped wells for reservoir temperatures of 335°F and 400°F, and productivities of 1000 and 3000 LB/HR/PSI. The net electrical power production capabilities corresponding to these flow rates are also shown as well as the pump depth and pump power requirements and the single phase-two phase transition depth (flash depth) for the flashing well. The limiting values of pump power and pump setting depth for the pumped well are noted. As previously discussed, the actual flow rates of the unpumped flashing wells may exceed the indicated values by as much as 100,000 to 200,000 lb/hr with a proportional increase in net electrical power production capabilities.

Figure 3 depicts the limiting flow rates and maximum net electrical power production capabilities of the pumped and unpumped wells as functions of reservoir temperature and productivity.

The results of the calculations show the unpumped flashing well to have greater electrical power production capabilities than the pumped well for all cases except the low temperature (335°F), high productivity (3000 LB/HR/PSI) case where the production capabilities are very close. Since the unpumped well flow limitations are very conservative, it is very likely that the unpumped well may actually have greater production capabilities for this case also. The results indicate that the unpumped flashing wells become more favorable as temperature increases and reservoir productivity decreases. At very low temperatures and high productivities, pumped wells may have higher production capabilities than unpumped wells; however, 335°F is already very low for this application based on past experience.

One significant assumption that should be mentioned here is the simplifying assumption of no dissolved gases in the geothermal resource. Including dissolved gases in the analysis would tend

to increase the required pump setting depth, thus also increasing the pump power requirements for a given set of conditions. Dissolved gases normally exist in geothermal waters, and the pumped well cases will actually be less favorable than what is shown here when the gas content is significant.

This analysis is based on a particular set of reservoir parameters which is assumed to be typical; however, reservoir parameters may vary considerably, thus indicating the need for analysis for particular applications. Also, some wells have potential scaling problems which might necessitate pumping in order to prevent flashing. The results of this study indicate the necessity

of performing a detailed technical and economic analysis for each application where pumping is being considered.

REFERENCES

1. Campbell, T. A., 1978, Analysis of Geothermal Well Pumping, Geothermal Resources Council Transactions, Volume 2, July 1978.
2. Coury and Associates, Inc., and Denver Research Institute, 1979, Geothermal Well Design Handbook, Department of Energy Contract No. EY-76-02-2729*000.

Figure 1. Pump Depth Vs. Well Flow Rate

Figure 2. Pump HP Vs. Well Flow Rate

Note: Unpumped flashing wells may produce up to 100,000 to 200,000 LB/HR in addition to flow rates shown in Table 1 and Figure 3 with proportional increase in electrical power production. 400°F-3000 LB/HR P.I. unpumped well exceeded limits of parametric two-phase flow calculations; therefore, production limit of this well is unknown.

Table 1. Well Production Capabilities

Reservoir Temperature	Productivity Index	Pumped Well				Unpumped Flashing Well		
		Limiting Flow Rate	Net Power Produced	Pump Power	Pump Depth	Limiting Flow Rate	Net Power Produced	Flash Depth
°F	LB/HR/PSI	LB/HR	K.W.	H.P. (K.W.)	FEET	LB/HR	K.W.	FEET
335	1000	519,252	2526	526 (392)	1200**	475,000	3399	1108.7
335	3000	1,120,519	5551	1000 (746)**	938	810,000	5476	601.8
400	1000	468,032	4278	516 (385)	1200**	800,000	7892	2060.4
400	3000	991,613	9134	1000 (746)**	933	1,200,000	11,726	1043.7

* After subtracting pump power
 ** Limiting values

APPENDIX E

COURY and ASSOCIATES, INC.

CONSULTING ENGINEERS
GEOTHERMAL PRODUCTION AND UTILIZATION
WATER : REUSE, DESALTING, DISPOSAL
H₂S CONTROL • ALCOHOL PRODUCTION

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WORKSHOP

TWO-PHASE FLOW IN GEOTHERMAL WELLS

PART III

A Comparison Study of Natural Flashing Two-Phase Flow Production Versus Pumped Single-Phase Production of Geothermal Wells

By Glenn E. Coury and Robert A. Babione, Coury and Associates

Workshop Conducted September 10, 1980, at the 1980 Annual Meeting of the
Geothermal Resources Council
Salt Lake City, Utah

Workshop Conducted By:
Coury and Associates, Inc.
Glenn E. Coury
Robert A. Babione

and

Denver Research Institute
James Butz

DISCUSSION OUTLINE

- I. Introduction
 - A. Background Discussion
 - B. Objectives of Study
 - 1. Limited to production comparison
 - 2. Demonstration of methodology for using two-phase flow computer model for specific cases
 - 3. Demonstration of general parametric behavior
 - C. Brief Discussion of Paper Presented at the Geothermal Resources Council 1979 Annual Meeting in Reno, Nevada: "A Technical Evaluation of Pumping Vs. Naturally Flashing Geothermal Well Production." By Robert A. Babione and Glenn E. Coury of Coury and Associates, Inc.
 - D. Necessary Considerations for a Total Economic and Technical System Evaluation
 - 1. Significance of this study--Important first step
 - 2. Other considerations--scaling, binary vs. flashed steam systems, surface piping and well diameter economics, etc.
 - E. Overview of New Material to be Discussed in This Workshop Session
- II. Presentation and Discussion of Comparison Study
 - A. Important Parameters Defined
 - 1. Reservoir parameters
 - 2. Pumped well parameters
 - 3. Flashing well parameters
 - B. Calculation Methods
 - 1. Use of computer model and handbook in comparing pumping vs. flashing well production
 - 2. Equations for pumped well
 - 3. Model of two-stage flash power plant
 - C. Discussion of Parametric Behavior
 - 1. Presentation of abbreviated parametric study results
 - D. Discussion of Two Specific Examples
 - E. Discussion of Current and Future Pump Technology
 - 1. Specific effects of current limitations
 - 2. Effects of anticipated improvements
- III. Open Discussion

OBJECTIVES OF COMPARISON STUDY OF FLASHING TWO-PHASE
FLOW VS. PUMPED FLOW GEOTHERMAL WELL PRODUCTION

- LIMITED TO PRODUCTION COMPARISON (DOES NOT INCLUDE TOTAL ECONOMIC EVALUATION)
- DEMONSTRATION OF METHODOLOGY FOR USING TWO-PHASE FLOW COMPUTER MODEL FOR SPECIFIC CASES
- DEMONSTRATION OF GENERAL PARAMETRIC BEHAVIOR

PUMPED WELL CALCULATIONS

INPUT INFORMATION:

- SAME AS FOR FLASHING WELL PLUS PUMP DISCHARGE GEOMETRY.

HAND CALCULATIONS:

- BUBBLE PRESSURE OF BRINE (AS FUNCTION OF TEMPERATURE AND DISSOLVED GAS OVER PRESSURE).
- WELL PRESSURE AT PRODUCTION DEPTH.
- BUBBLE PRESSURE DEPTH (AS FUNCTION OF FLUID STATIC HEAD AND FRICTION LOSS AT GIVEN FLOW RATE, TEMPERATURE, SALT CONTENT, WELL DIAMETER, ETC.).
- PUMP SUCTION DEPTH (AS FUNCTION OF BUBBLE PRESSURE DEPTH AND NPSH REQUIREMENTS).
- PUMP SUCTION PRESSURE (AS FUNCTION OF PUMP DEPTH AND STATIC HEAD AND FRICTION PRESSURE GRADIENTS).
- PUMP DISCHARGE PRESSURE (AS FUNCTION OF FLUID STATIC HEAD AND FRICTION PRESSURE GRADIENTS AT GIVEN FLOW RATE, TEMPERATURE, SALT CONTENT, PUMP DISCHARGE GEOMETRY, ETC.).
- PUMP SHAFT POWER (AS FUNCTION OF PUMP SUCTION AND DISCHARGE PRESSURES, FLOW RATE, AND LINE SHAFT FRICTION IF SURFACE DRIVEN PUMP IS USED).
- THE RESULTS OF THE ABOVE CALCULATIONS WILL PROVIDE PUMP POWER AND PUMP SETTING DEPTH VS. FLOW RATE AND THE MAXIMUM WELL FLOW IF LIMITS FOR PUMP POWER AND SETTING DEPTH ARE KNOWN.

FLASHING WELL CALCULATIONS

INPUT INFORMATION:

- WELL FLOW RATE
- WELL DIAMETER
- PRODUCTION DEPTH
- RESERVOIR TEMPERATURE
- RESERVOIR PRESSURE
- RESERVOIR PRODUCTIVITY INDEX
- DISSOLVED GAS CONCENTRATIONS
- DISSOLVED SALT CONCENTRATIONS

HAND CALCULATIONS:

- WELL PRESSURE AT PRODUCTION DEPTH (AS FUNCTION OF RESERVOIR PRESSURE, PRODUCTIVITY INDEX, AND FLOW RATE)

COMPUTER MODEL OUTPUT:

- WELLHEAD PRESSURE VS. FLOW RATE
- MAXIMUM WELL FLOW

NOTE: HANDBOOK CAN BE USED IF THE DISSOLVED GAS AND DISSOLVED SALT CONCENTRATIONS ARE NEGLIGIBLE.

TWO-STAGE FLASH TURBINE GENERATOR FACILITY MODEL

OPTIMUM FLASH CONDITIONS
FOR A
TWO-STAGE FLASH SYSTEM

ASSUMPTIONS: CONDENSER TEMPERATURE = 110°F
MINIMUM SECOND-STAGE TEMPERATURE = 220°F

CASE 1 -- RESERVOIR TEMPERATURE = 550°F :

$$T_1 = 403^{\circ}\text{F} \quad P_1 = 256 \text{ PSIA}$$

$$T_2 = 257^{\circ}\text{F} \quad P_2 = 147 \text{ PSIA}$$

NET STEAM ENERGY TO TURBINE = 26.48 BTU/LBM BRINE

CASE 2 -- RESERVOIR TEMPERATURE = 400°F :

$$T_1 = 310^{\circ}\text{F} \quad P_1 = 78 \text{ PSIA}$$

$$T_2 = 220^{\circ}\text{F} \quad P_2 = 17 \text{ PSIA}$$

NET STEAM ENERGY TO TURBINE = 11.45 BTU/LBM BRINE

CASE 3 -- RESERVOIR TEMPERATURE = 300°F :

$$T_1 = 260^{\circ}\text{F} \quad P_1 = 36 \text{ PSIA}$$

$$T_2 = 220^{\circ}\text{F} \quad P_2 = 17 \text{ PSIA}$$

NET STEAM ENERGY TO TURBINE = 4.327 BTU/LBM BRINE

E13
 13 3/8" CASING V.S. 9 5/8" CASING

$$PR = PSH \text{ }^{E14} \text{ Vs. } PR = PSH - 200 \text{ PSI}$$

EXAMPLE NO. 1

RESERVOIR TEMPERATURE = 300°F

PRODUCTIVITY INDEX = 3000 LB_m/HR/PSI

PUMPED CASE:

- ASSUME PUMP SETTING DEPTH LIMIT = 3,000 FT
- ASSUME PUMP POWER LIMIT = 1000 HP
- WELLHEAD PRESSURE = 77 PSIA
- FIRST-STAGE FLASH PRESSURE = 36 PSIA
- PUMP FLOW > 1,000,000 LB_m/HR (ASSUME = 1,000,000 LB_m/HR FOR THIS EXAMPLE)
- STEAM POWER TO TURBINE = 4,330,000 BTU/HR (BASED ON 4.33 BTU/LB IN BRINE)
- ELECTRIC POWER OUT = 951 KW (BASED ON ASSUMED T/G EFFICIENCY OF 75%)
- PUMP SHAFT POWER = 497 HP

FLASHING WELL CASE:

- ASSUME WELLHEAD PRESSURE TO BE 20 PSI OVER FIRST STAGE FLASH PRESSURE-WELLHEAD PRESSURE = 56 PSIA
- FLOW RATE = 300,000 LB_m/HR
- STEAM POWER TO TURBINE = 1,299,000 BTU/HR (BASED ON 4.33 BTU/LB_m BRINE)
- ELECTRIC POWER OUT = 285 KW (BASED ON ASSUMED T/G EFFICIENCY OF 75%)

EXAMPLE NO. 2

RESERVOIR TEMPERATURE = 550°F

PRODUCTIVITY INDEX = 1000 LBM/HR/PSI

PUMPED CASE:

- ASSUME PUMP SETTING DEPTH LIMIT = 3,000 FT
- ASSUME PUMP POWER LIMIT = 1,000 HP
- WELLHEAD PRESSURE = 1056 PSIA
- FIRST STAGE FLASH PRESSURE = 256 PSIA
- PUMP FLOW = 360,000 LBM/HR (BASED ON BOTH LIMITS)
- STEAM POWER TO TURBINE = 9,540,000 BTU/HR (BASED ON 26.5 BTU/LBM BRINE)
- ELECTRIC POWER OUT = 2095 KW (BASED ON ASSUMED T/G EFFICIENCY OF 75%)
- PUMP SHAFT POWER = 1000 HP

FLASHING WELL CASE:

- WELLHEAD PRESSURE AT 1,000,000 LBM/HR IS 345 PSIA. THIS GIVES A WELLHEAD TO FIRST STAGE FLASH PRESSURE DIFFERENTIAL OF 89 PSIA
- FLOW RATE $> 1,000,000$ LBM/HR (ASSUME = 1,000,000 LBM/HR FOR THIS EXAMPLE)
- STEAM POWER TO TURBINE = 26,500,000 BTU/HR (BASED ON 26.5 BTU/LBM BRINE)
- ELECTRIC POWER OUT = 5819 KW (BASED ON ASSUMED T/G EFFICIENCY OF 75%)