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GEOTHERMAL PROGRAMS

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Volume I

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Low-to-Moderate Temperature Hydrothermal Reservoir Engineering Handbook

A Joint-Project Report of
Lawrence Berkeley Laboratory and
The Idaho National Engineering Laboratory

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LOW-TO-MODERATE TEMPERATURE HYDROTHERMAL RESERVOIR ENGINEERING HANDBOOK

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and

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Berkeley, California 94720

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FOREWORD

Low-to-moderate temperature geothermal energy will augment the future energy needs of industrial process heat, space heating, and district heating systems. As an industry in its infancy, geothermal reservoir engineering is unique and different from the technologies of petroleum and ground water reservoir engineering.

This document which provides guidelines to developers and consultants in evaluating reservoir characteristics contains sections on reservoir classification, conceptual modeling, testing during drilling, current theory of testing, test planning and methodology, instrumentation, and a sample computer program. Although the developer will find the entire document useful and informative, sections on test planning and methodology, geochemistry, reservoir monitoring, and the appendixes, containing technical detail, are designed specifically for the consultant. Sections 2 through 6 provide the developer background information needed to monitor the program of reservoir evaluation. As technology improves, this document will be modified. Future sections will depend upon ongoing and completed research in the low-to-moderate temperature geothermal industry.

Metric units are used whenever possible. However, some equations employ constants in English units and some instrumentation and oil field records (i.e., pressure gauges, rig recorders, and well logs) are calibrated or recorded in English units. Therefore, soft-metric and English units are used wherever logical or appropriate. Appendix A provides the reader with information on conversions.

ACKNOWLEDGMENTS

This document has been jointly prepared by EG&G Idaho, Inc., Geosciences Branch, and Lawrence Berkeley Laboratory, Earth Sciences Division for Dr. Leland L. Mink and Susan M. Prestwich of the Idaho Operations Offfice, U.S. Department of Energy. Robert A. Gray, Charles Bufe, and David Lombard of the Department of Energy, Division of Geothermal Energy provided the funding. Key contributors to this document include Dennis Goldman, Larry Hull, Julie Tullis, Steve Mizell, Brent Russell, and Piotr Skiba, all of EG&G Idaho, Inc.; and Calvin Clyde, appointed to EG&G Idaho, Inc. as a faculty participant through the Associated Western Universities. The EG&G Program management was provided by Max R. Dolenc, Susan Spencer, and Susan Petty. Lawrence Berkeley Laboratory contributors include the program manager, Sally Benson, Raymond Solbau, and Ernie Major, and Micheal Wilt.

Subir Sanyal, a private consultant, discussed the overall scope and direction of the document. A critical review of this document, before release, was also provided by: J. K. Balzhiser, Balzhiser/Hubbard and Associates; Calvin Clyde, Utah Water Research Laboratory; Glenn Coury, Coury and Associates; Gary Harvey, TRC Environmental Consultants, Inc.; Charles Morris, Republic Geothermal Inc.; Paul Lineau, Oregon Institute of Technology; John Lund, Oregon Institute of Technology; Derek Freeston, University of Aukland; Richard Pearl, Colorado Geological Survey; John L. Sondergger, Montana Bureau of Mines; Susan Spencer, Morrison and Knudsen; and P. M. Wright, Earth Science Laboratory, University of Utah Research Institute.

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LOW-TO-MODERATE TEMPERATURE HYDROTHERMAL RESERVOIR ENGINEERING HANDBOOK

1. INTRODUCTION

Numerous low- (less than 90°C)-to-moderate temperature (90 to 150°C) geothermal resources occur in many areas of the United States. The number of known geothermal systems increases significantly as the temperature decreases. Geothermal systems occur primarily where the normal geothermal gradient of the earth (30°C/km average) is affected by a positive temperature anomaly. These anomalies are caused by: (a) higher than normal regional heat flow; (b) rocks of low thermal conductivity; (c) higher than normal concentrations of radioactive elements; (d) young magmatic intrusions; and/or (e) hydrothermal circulation.[1]

Low-to-moderate temperature geothermal resources have a wide range of direct-use applications in agriculture and industry. Agricultural uses such as greenhousing, animal husbandry, soil warming, mushroom raising, and biogas generation require the lowest temperature, ranging from 20 to 82°C. Industrial uses such as space heating for homes, offfices, hospitals, and large district heating systems requires temperatures from 45 to 100°C. Industrial processes require temperature up to 150°C with the use of both steam and superheated water. Industrial uses of geothermal fluids also include food processing, crop drying, and multiple use by the forest products industry. Although the unique aspects of each geothermal resource require individual consideration, most development schemes will employ straightforward engineering, using proven technology and existing system components.

The rationale used in developing a low-to-moderate temperature geothermal resource is the same as that used by a hydrologist or petroleum engineer in designing an optimal development scheme for a given water or oil reservoir. Consequently, the geothermal industry depends on two major areas of expertise: hydrology and petroleum engineering.

Hydrologists have applied ground water hydraulics and theory to low-temperature systems (<90°C) that are single phase and liquid and resemble ordinary ground water systems. However, most ground water theory was developed for application to fluids of about 16°C and did not include temperature dependent fluid properties. Problems with ground water theory applications to geothermal systems include those of nonisothermal flow, temperature dependent fluid properties, and proper interpretation of well tests. For well testing, the two most important temperature dependent fluid properties are density and viscosity. Figures 1 and 2 show the value of these parameters from 0 to 150°C.

The petroleum engineering theory was developed for exploitation of hydrocarbon resources. The great depth of some petroleum reserves, gas content of the fluid, and temperature dependent fluid properties make these petroleum reservoirs similar to high-temperature geothermal reservoirs. Because low-to-moderate temperature resources are rarely two-phase steam water mixtures, or have a high gas content, they do not require the sophistication of some of the petroleum techniques developed. Therefore, the reservoir engineering techniques developed for a low-to-moderate temperature geothermal system borrow the most appropriate methods and terminology from hydrology and petroleum engineering. The theories are very similar but the terminology has created a disparity between the petroleum engineering and hydrologic industries when applied to a low-to-moderate temperature resource.

This disparity has created the need for a handbook that will bridge the theories and methodologies of the hydrologic and petroleum engineering fields. This handbook has been prepared for developers with previous experience in one or more of the following: petroleum engineering, ground water hydrology, and/or high-low temperature geothermal systems. In addition, the handbook should provide a useful tool to both consultants and industry personnel. The handbook identifies significant areas of concern, with reference to other

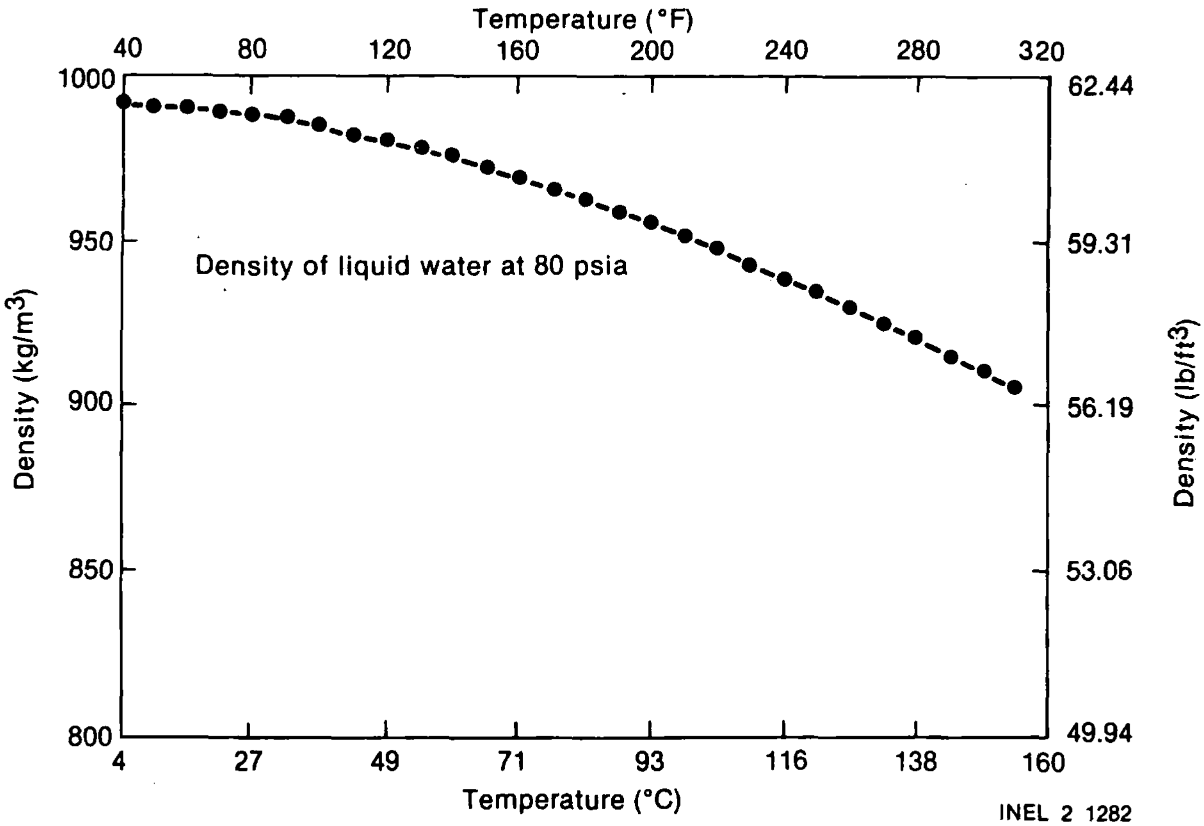

Figure 1. Density of liquid water at 80 psia.

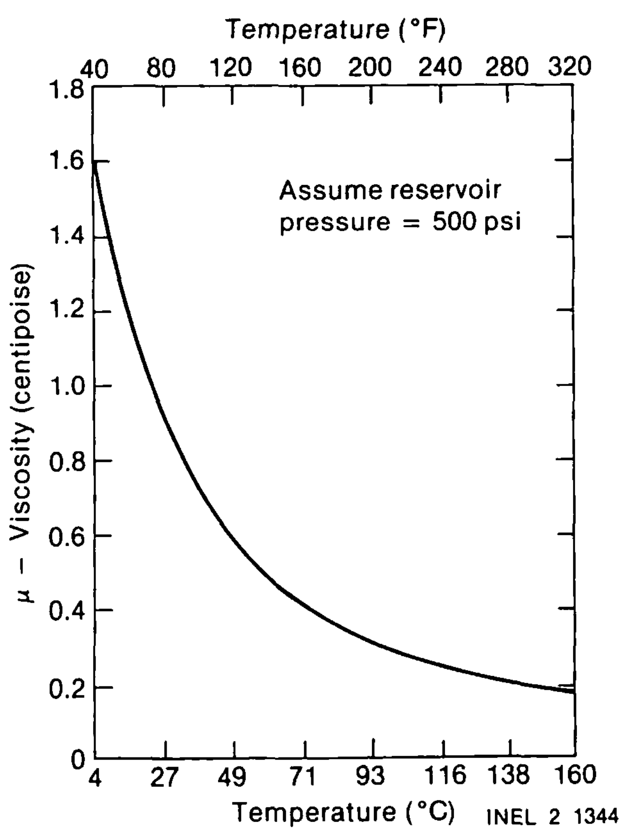

Figure 2. Viscosity of liquid water at 500 psia.

EG&G Idaho, Inc.
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July 14, 1982

Dr. P. M. Wright
UURI
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Salt Lake City, UT 84108

TRANSMITTAL OF RESERVOIR ENGINEERING HANDBOOK - MRD-12-82

Dear Mike:

Enclosed are two copies of the recently published Low-to-Moderate Temperature Hydrothermal Reservoir Engineering Handbook. We wish to thank you for reviewing the draft of this document last winter. We feel your input was most helpful to us in developing an effective document which we believe will assist the geothermal community.

On behalf of Susan Prestwich, DOE-ID, Sally Benson, Lawrence Berkeley Laboratory, and EG&G Idaho, Inc., thanks again for your cooperation and assistance.

Sincerely,

Max

Max R. Dolenc
Hydropower/Geothermal Branch

jd

Enclosures:
As Stated

specific documents for in depth ''how-to'' discussions. The handbook provides an overview of reservoir engineering, basic and applied theory, conceptual modeling, testing during drilling, test planning and methodology, geochemical applications, and reservoir monitoring; it gives the potential developer a firm understanding of the tasks to be performed and the problems that may be anticipated.

2. RESERVOIR CLASSIFICATION

Individual geothermal systems occur in several different geologic environments. These include:

- Areas of recent intrusion and/or extrusion
- Areas where open fractures allow fluid circulation to depth with subsequent heating by the normal geothermal gradient
- Areas where radiogenic heat is trapped in rocks by overlying sediments
- Geopressured areas where hot fluids are confined under high pressures
- Areas where hot rocks exist without adequate natural fluids to transfer the heat (hot dry rock).

Young igneous environments primarily occur in the tectonically active Western United States (Figure 3). These systems provide the majority of known shallow geothermal reservoirs. The Cascade Mountain Range of Washington and Oregon represents a volcanic region caused from heat generated by the converging of plate margins. The Imperial Valley of Southern California is located in a region of crustal extension due to the East Pacific Rise spreading zone. Here the intrusions are emplaced at shallow depth, providing a heat source for the geothermal resource. The Snake River Plain of Idaho and Yellowstone Park represent volcanic areas caused by intraplate melting. Young volcanic regions also occur in some parts of the Basin and Range Province, and in the Rio Grande Rift. The heat source in volcanic belts is provided by the presence of cooling magma.[1]

Deep circulation primarily occurs where the crust of the earth is under tensional stress. The Basin and Range Province and the Rio Grande Rift are extensional environments characterized by active faulting, thick sedimentary basins between young mountain ranges, and occasional sites of active volcanism. The source of heat for this environment comes from higher-than-normal regional heat flow, circulation of fluids to great depths, and igneous intrusions.

Radiogenic heat environments are generally found along the Atlantic Coastal Plain where a thick sedimentary sequence is underlain by granitic rocks. This heat, trapped by rocks with low thermal conductivity, is generated by the decay of U^{238}, Th^{232}, and K^{90} found in high concentrations in granitic intrusions.

Geopressured geothermal reservoirs occur mainly in the Gulf of Mexico where rapid sedimentary loading has trapped the heat under a thick sedimentary blanket. The fluids are under high pressure, usually contain dissolved methane, and are normally 150°C or higher. These reservoirs are not pertinent to a discussion of direct-use application energy resources because of the great diffficulty in developing them; however, waters of low-to-moderate temperatures have been found overlying many geopressured zones.

In this handbook, geothermal systems are classified according to the reservoir characteristics that control fluid flow. These controls are either faults, intergranular permeability, or a combination of both. Fault-controlled systems occur primarily in metamorphic and igneous rocks, but can also occur in sedimentary rocks. Fault control is normally associated with hydrothermal convection systems where cold ground water circulates to depth, heats up, then rises along fractured zones. The heat in these systems is dependent on the regional heat flow, the depth of circulation, and the residence time of water at depth. The permeability of these reservoirs depends on the size and number of fractures in the system, the nature of brecciated material along the fault, and the degree of fracture sealing. Geothermal reservoirs controlled by intergranular permeability normally occur in deep sedimentary basins filled with consolidated or unconsolidated sediments. Ground water from adjacent highlands travels down-dip through the sediments and is heated by the thermal gradient of the earth. Heated water moves upward due to density differences to form geothermal reservoirs within economic exploitation depth. Permeability is controlled by the size and continuity of the pore spaces. Many geothermal reservoirs are controlled by a combination of both faulting and intergranular permeability.

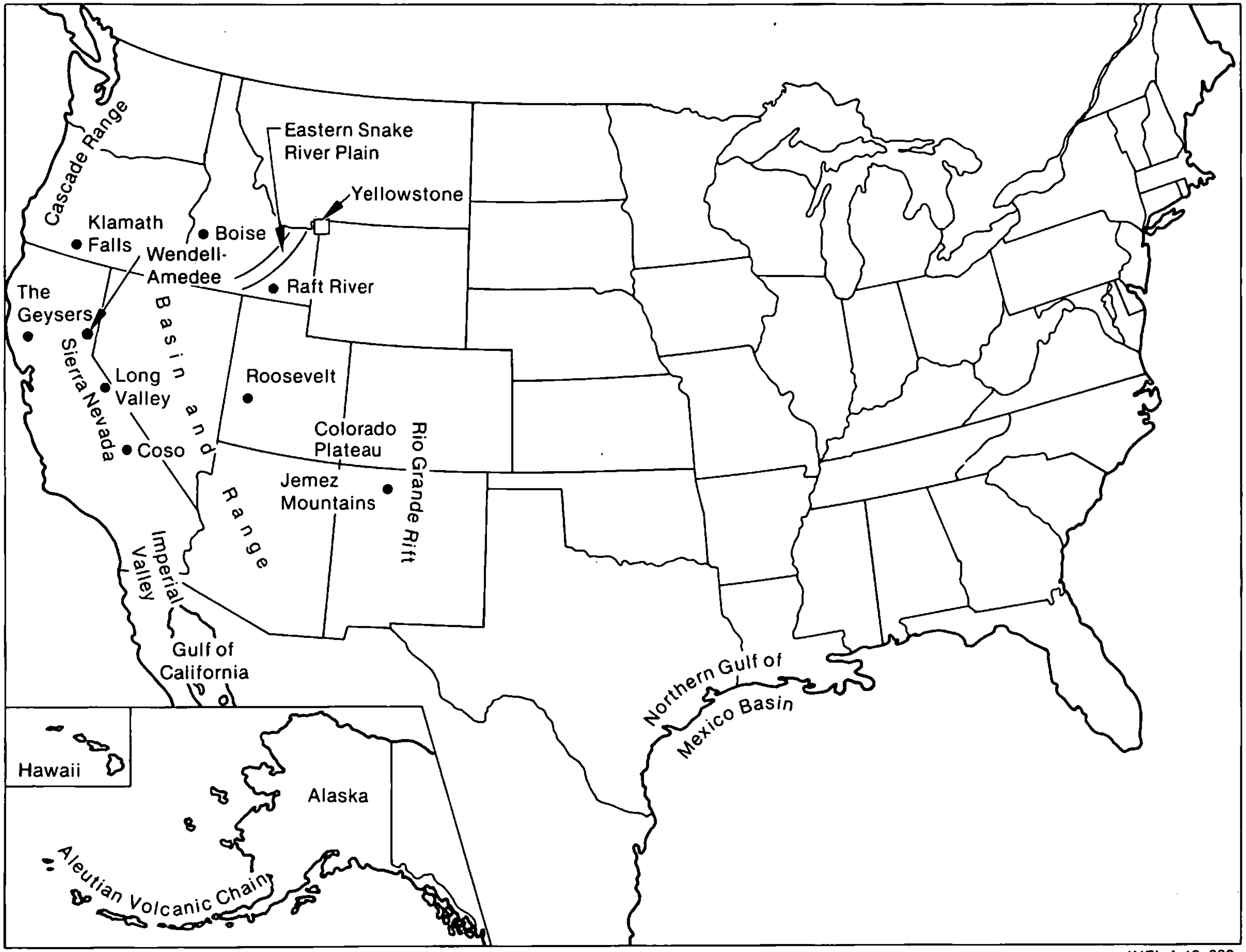

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Figure 3. Map of the United States showing geographic features mentioned in the text and selected geothermal installations.

3. RESERVOIR ENGINEERING

Reservoir engineering can be defined ". . . as the application of scientific principles to the drainage problems arising during the development and production of oil and gas reservoirs. The working tools of the reservoir engineer are subsurface geology, applied mathematics, and the basic laws of physics and chemistry governing the behavior of liquid and vapor phases of crude oil, natural gas, and water."[2]

Reservoir engineering has been developed to a high level of sophistication in both the petroleum and ground water industries. Geothermal reservoir engineering has borrowed heavily from both of these fields. Some features unique to geothermal reservoir engineering include dynamic hydrothermal regimes and non-isothermal temperature distributions.

Reservoir engineering is used to design development strategy, exploitation strategy, and reservoir management programs. The basic problems that should be considered in geothermal reservoir engineering are: pressure, temperature, fracture flow, chemical changes within the thermal reservoir, and hydraulic connection to regional ground water aquifer(s). Specific aspects include: (a) siting production wells and choosing a completion interval; (b) designing well completions; (c) designing and interpreting well tests; (d) selecting the fluid disposal method, i.e., injection or surface disposal; (e) siting injection wells if any; (f) calculating the number of wells needed to supply the required energy; (g) predicting well drawdown; (h) predicting interference effects; (i) predicting the longevity of the resource; and (j) monitoring the exploitation phase.

The reservoir engineer must design a strategy that ensures not only an adequate supply of fluid, but also a fluid temperature that is suffficient for anticipated use. Predicting production temperatures over the life-time of the project is one of the most challenging tasks for the geothermal reservoir engineer.

Reservoir engineering starts during the exploration phase, when geological and geophysical data are collected. A reservoir engineer uses these data to formulate a preliminary conceptual reservoir model by identifying the reservoir type and its approximate size. Drilling data, borehole geophysics, and testing during drilling improve the conceptual model and provide preliminary well and reservoir parameters.

Well testing and test data analysis are important aspects of reservoir engineering that are used to determine the properties of a reservoir system which control the flow of fluids into a well, the migration path of injected fluid, and the natural and induced recharge.

Thus, the reservoir engineer uses all these phases when developing a geothermal resource.

4. CONCEPTUAL MODELING

Conceptual modeling is an important tool at every stage of reservoir evaluation. A conceptual model of the reservoir is envisioned before drilling a well in order to predict what type of rock formations will be penetrated, the expected temperature, and the target depth for the well. After the well has been drilled, a conceptual model is needed to design the well test and interpret well test data. Finally, the conceptual model is used to plan the locations of production and injection wells, optimize production and injection rates, predict the reservoir lifetime, and estimate the total energy available from the hydrothermal system. The conceptual model will evolve and become more refined each time a new piece of information is obtained, analyzed, and integrated into the existing model.

This section describes the types of data required to formulate a working model of a geothermal resource, especially ways of collecting data and integrating them into the model. Examples of different kinds of data gathered in other disciplines are provided for further understanding and conceptualizing the geothermal resource. Since this section is not a definitive work on the subject, references to additional studies are included. The importance of a conceptual model to the design of the well and the interpretation of the well test data are also discussed.

Before drilling any wells the following information can be used to conceptualize the geothermal resource: geothermometry, surface geology, and geophysical surveys. Comparing the geologic setting of the reservoir under investigation to the geology of many known geothermal resource areas can help classify the reservoir. Although every geothermal resource has unique characteristics, the rapid development of many low- and moderate-temperature geothermal resources has provided an adequate data base so that extrapolation of types of phenomena from one system to another is to some extent plausible. The study of similar types of hydrothermal systems should not be overlooked in developing a conceptual model.

Data obtained during drilling provides information on the subsurface characteristics of the hydrothermal system. Drill cuttings and cores can be used to reconstruct the subsurface lithology penetrated by the borehole. Drilling rates provide information on the structural integrity, hardness, and density of the formations penetrated. Loss of circulation fluid while drilling is often a reliable indication of fractures or permeable strata. Drilling mud temperature and mud chemistry are indicators of subsurface temperature and fluid entry into the wellbore.

After drilling a well, a number of borehole geophysical logs are run from which formation porosity and permeability, lithology changes, and formation temperature can be inferred. Well testing is performed to determine the hydrologic and geometric properties of the system. Well tests can also be helpful for inferring subsurface areal temperature distribution.

The effectiveness (i.e., accuracy and refinement) of a conceptual model is dependent on the information that is incorporated into it. The geologic, thermal, geochemical, and structural complexity of the hydrothermal system dictates the amount and type of data required to have a functional and accurate model. For instance, in a system with a near normal geothermal gradient and relatively simple geologic structure, such as the Madison Aquifer, less reconnaissance and exploration effort will be required. On the other hand, in a shallow, highly faulted, complexly fractured volcanic-type system, such as the Klamath Falls known geothermal resource area (KGRA), a substantial amount of exploratory work is necessary to define the hydrothermal system and to predict reservoir performance confidently. The degree of refinement required for an adequate conceptual model depends on the intended use of the resource. If only a small quantity of geothermal fluid is to be extracted from the reservoir compared with the reservoir potential, less exploration and conceptual model development will be required than if the reservoir potential is to be taxed. The model's refinement also depends on the amount of time and effort available to invest in gathering quality data. It should be emphasized that without quality data it is very diffficult to predict confidently the reservoir's behavior during exploitation. Sophisticated methods are now being developed to interpret data from complex geothermal systems. Therefore, every effort should be made to obtain quality data. The following subsections describe what data are important to have, how to process them, how to interpret them, and how the conceptual model can be used to the benefit of the resource developer.

Data Base

Surface Geology. Surface maps are the most readily available piece of information used for delineating geologic features. Information obtained from the surface map will be used for preliminary classification of the hydrothermal system. Geologic mapping has been completed for many areas on a regional or site-specific basis. These maps are available through publications from the U.S. Geological Survey, state geological surveys, and universities.

Aerial photography and landsat imagery interpretation can also be useful tools for delineating major geologic features. They are normally used in conjunction with geologic maps to locate fault lineations, fault intersections, and areas of thermal alteration.

Subsurface Geology. The subsurface geology of an area is usually constructed from data obtained from the examination of drill cuttings, cores, geophysical logs, drillers logs, etc. The drilling rate, circulation fluid record, and drilling fluid temperatures provide data on the physical and thermal properties of the penetrated rock unit. Geophysical logs are also useful tools for identifying subsurface lithologic units and the physical properties of the units. The interpretation of geophysical logs is an important technique in evaluating the subsurface lithology when there are no drill cuttings or cores available. Their use and interpretation are, however, limited depending upon the formation encountered, i.e., porosity and permeability values can be determined from logs run in sedimentary units, but may not always be determined in igneous or metamorphic units. Geophysical logs can be a useful tool for correlating rock units, thermal regimes, and hydrothermal mineralization between wells, and in locating fracture zones in wells.

Many of the low-to-moderate temperature hydrothermal reservoirs in areas with above-normal temperature gradients are associated with faults and fractures. These faults and fractured strata contribute significantly to the permeability of the hydrothermal reservoir; therefore, it is essential to detect their presence and estimate their depth. Among the most useful methods for detecting fractures is the examination of a carefully maintained record of the amount of circulation fluid used. Sudden loss of circulation fluid often indicates that fractures have been penetrated. However, the loss of drill cuttings and circulation fluid is not always indicative of fracture zones. Therefore, all of the subsurface data should be correlated to verify the data interpretation.

Temperature Profiles. Temperature profiles are obtained by measuring wellbore temperatures at a number of depths in the well. Temperature profiles are one of the most useful tools for understanding the hydrothermal system being studied. By carefully examining temperature profiles obtained under a variety of wellbore conditions, producing aquifers can be identified, multiple producing aquifers can be identified, hot water recharge detected, conductive versus convective (hydrothermal circulation) thermal regimes identified, the presence of a caprock and basement rock detected, and the thickness of the hydrothermal reservoir penetrated by the wellbore estimated.

Some caution should be taken when interpreting temperature profiles because circulation of fluid in the wellbore can mask the true formation temperature. An example of this can be seen in Figure 4. The only difference, other than the temperature profiles, between the two wells is the casing schedule. Well YMCA No. 1 is cased to 500 ft (152 m) and well YMCA No. 2 is cased to 980 ft (305 m). By comparing the two profiles obtained in wells 500 ft (152 m) apart with identical lithologic columns, it was determined that water was flowing down the wellbore in the well YMCA No. 1. Cold water entering the wellbore in well YMCA No. 1 at 500 ft (102 m), flowed down the wellbore and enters a second reservoir at 1200 ft (366 m). If the data from well YMCA No. 2 had not been available the temperature profile from well YMCA No. 1 may have been misinterpreted to conclude that the isothermal interval from 500 ft (152 m) to 1200 ft (366 m) was the geothermal aquifer. In reality, the main producing aquifer is in a fractured interval between 1200 (366 m) and 1300 ft (396 m).

Geochemistry. Information about geothermal fields which can be deduced from geochemistry includes: estimated subsurface temperature, location of heat source(s), directions of water movement, source of dissolved solids, sources of recharge, age (possibly), and whether hotter water exists nearby. Contouring maps

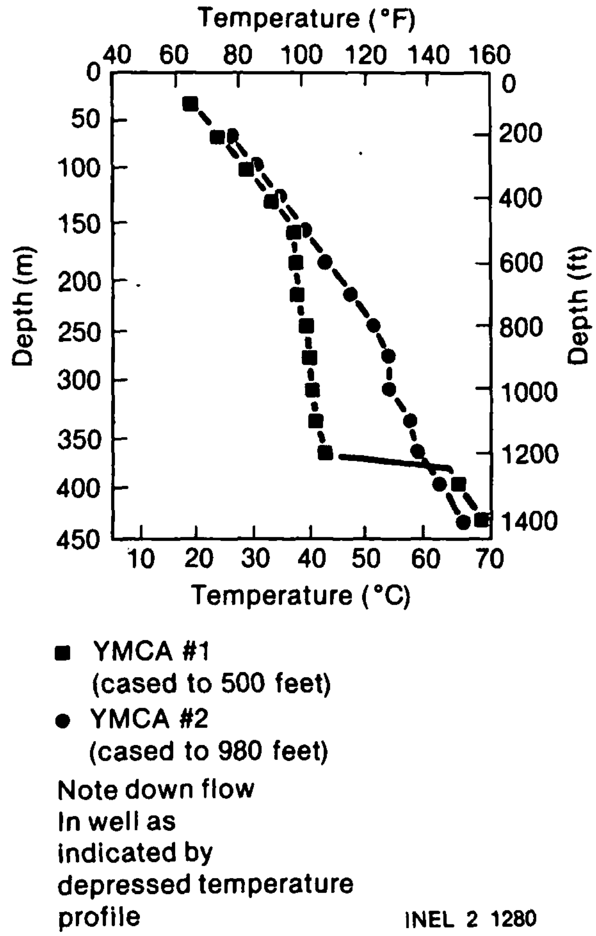

Figure 4. Downflow in well as indicated by depressed temperature profile.

or cross-sectional views of chemical concentrations in a geothermal area can provide insight into water movement and the sources of dissolved salts, heat, and water. Care must be taken, however, to ensure that the data being contoured are from the same hydrogeologic unit. For example, in a geothermal area containing shallow domestic and irrigation wells, intermediate depth wells, and deep geothermal production wells, each depth level must be treated separately. Patterns of contours can indicate directions of water movement. A comparison of contour maps or cross-sections for species whose concentrations are related to temperature (SiO_2) and conservative species (Cl^-) can indicate differences between locations of heat sources and high dissolved solids waters. Spatial variations in water chemistry can be due to mixing of waters from different sources, evaporation, steam loss, precipitation of solid phase, or reactions with aquifer materials. Simple mixing calculations can be used to determine if mixing is responsible for spatial variations.

Stable isotopes in water (hydrogen and oxygen) can be used to determine the source of water. Studies have shown that many geothermal waters are comprised of local meteoric water heated by circulation to depth. Variations in the isotopic composition of recharge water can occur by evaporation before recharge, or by recharge occurring at different elevations. If these variations can be traced through the geothermal system, detailed information on sources of water can be obtained.

Geophysics. Geophysical methods used in the exploration for hydrothermal resources can be categorized in five groups: thermal, seismic, electrical, magnetic, and gravity. These methods can provide valuable exploration data, insofar as they are used to delineate the hydrothermal resource. However, because of the ambiguity inherent in their interpretation, these may or may not be the type of data needed for a conceptual model of the resource.

Thermal methods are among the most direct and commonly used methods for determining the location and size of a geothermal system. Thermal methods include: (a) calculation of the heat flow from the earth using thermal gradient data and thermal conductivity measurements, and (b) evaluation of the measured geothermal gradient. Among other things, these data can indicate the size and shape of the hydrothermal anomaly.

Seismic methods can be passive and active. Passive methods monitor natural earthquake activity to infer anomalous stress states due to possible heat sources, abnormal tectonic activity, and/or abnormal hydrostatic conditions. Detailed microearthquake surveys are also used to delineate active fault zones that may serve as potential ground water conduits. The active methods use the amplitude and velocity variation of seismic waves generated by a controlled source, both compressional (P) and shear (S) waves, to infer the characteristics of the medium in which they are propagated. Active reflection techniques are used to infer the location of discontinuities, layer, thickness, and general structure. Depending upon the size and frequency of the source, reflection techniques can ''look'' as deep as several kilometers and still define fault boundaries and basement structure. Refraction techniques look at the velocity variation of the P-waves to infer layer thickness, fault location, and structural discontinuities. The refraction techniques are not as detailed as the reflection techniques and require larger ''spreads'' and more powerful sources to look at comparable depths. The refraction techniques can also miss structure that the reflection surveys will detect if the velocity variations with depth are not continually increasing. However, the refraction techniques are much cheaper and require less sophisticated post processing.

Electrical and electromagnetic methods are used to estimate the electrical resistivity of the earth. Electrical resistivity is a measure of the earth's ability to conduct electrical current and depends upon the porosity, fluid saturation, temperature and clay content of the rock, and the salinity of the pore fluid. In general, the higher these parameters are, the lower the resistivity of the medium. Since geothermal areas are associated with high subsurface temperatures and saline fluids, they are characterized by anomalously low resistivity. Electrical and electromagnetic surveys performed on the surface are therefore very effective methods for locating buried geothermal systems. The most commonly used of these methods is the d.c. resistivity method. Low frequency electrical current is injected into the ground through a portable generator and earth electrodes. The resulting potential at a site of specified distance away is then measured. By varying the spacing between current and potential electrodes, a variation of voltage with separation and/or location is obtained. This may be corrected for a variation of electrical resistivity with depth, depth soundings, spatial variation at resistivity, or a mapping survey. Electromagnetic methods use a time varying signal source and obtain earth resistivity information from variation at electrical fields with frequency.

Gravity and magnetic surveys are structural methods used to estimate: the thickness of sediments, the depth to the basement, the density or density contrasts of basement rocks, and buried volcanic or intrusive rocks. Magnetic surveys detect the magnetic susceptibility of subsurface rocks. Because hydrothermal alteration reduces the magnetic susceptibility of the subsurface rocks, a negative anomaly may be indicative of a hydrothermal resource.

Well Testing. Well testing is the most common and reliable method for determining the parameters which control flow of fluid through the reservoir. The parameters which affect the ease with which water will flow through the reservoir are the rock permeability (k), the viscosity of the reservoir fluid (μ), the porosity (ϕ), the formation compressibility (c), and the production geometry (height, areal extent, layers, etc.). Knowing these parameters or the groups of parameters kh/μ (transmissivity) and ϕch (storativity), well drawdown, well productivity, and interference effects can be calculated.

Well tests are typically conducted by pumping or artesian flowing a well for a period of time at a constant flow rate. The pressure changes in the production well are observed over time. The change of pressure is analyzed to obtain the physical parameters of the reservoir system. If there are other wells in the area, these too can be monitored for pressure (or water level) changes as a function of time. Often the data from interference wells will provide more accurate reservoir information due to instrumentation and logistical constraints at the production well. If an array of observation wells is available, accurate information about the reservoir size and geometry can be obtained.

Data Preparation

Before the data from all of the various disciplines can be synthesized, it is important to prepare them correctly. There are four basic types of displays by which data can be processed to provide a visual respresentation of the various reservoir characteristics: mapping, profiling, contouring, and cross sections. Depending on the amount and quality of data, it may or may not be worthwhile to do all of the types of processing.

Mapping. Mapping is the least sophisticated and most simple display to prepare. It involves locating observed phenomena or physical features on a cartesian coordinate system that overlies the area under study. This type of representation is used when only a two-dimensional representation of the data is required, i.e., when depth is not considered. Temperatures and chemical data from springs are often mapped with this technique. The representation does not account for the fact that the springs may have circulation at different depths, and thus, differing chemical constituents and temperatures.

Mapping is generally used in the early stages of exploration. For example, the relationship between the recent volcanism and the hydrothermal anomaly at Klamath Falls, Oregon, was examined by radiometric dates obtained on rock samples from in and around the Klamath Falls area. A map showing the location and radiometric age of each sample is shown in Figure 5. The concentric pattern of older dates with distance from the Klamath Falls vicinity may suggest that the anomaly is associated with the most recent volcanism in the area.

Profiling. Profiling consists of looking at data from a single penetration through a vertical section. Profiled data are obtained from wellbore surveys. For instance, by plotting the well lithology versus depth a lithologic profile is obtained; by plotting temperature obtained from a temperature survey versus depth, a temperature profile is obtained.

One example of a lithologic column and temperature profile for a well is shown in Figure 6. This type of temperature profile is typical of temperature profiles in shallow fault-charged reservoirs. A comparison of the lithologic column, the drilling circulation record, and the temperature profile shows that a thermal production interval in the well is between 195 ft (59 m) and 240 ft (73 m).

Contouring. Contouring is used to define the shape and extent of the observed physical phenomena. For instance, temperature contours are used to define the areal and vertical extent of a hydrothermal system and can be used to make rough calculations of the amount of hot fluid in place. One of the most common methods of contouring is to plot isotherms, or isobars, at a given depth below the surface. By comparing contours at several elevations, both an areal and vertical description of the phenomena can be obtained.

In Figure 7 the temperatures at three different depths from the Susanville, California wells are contoured. At the shallowest depth, 150 m below surface elevation (1250 m elevation), the hottest part of the anomaly (inside the 60 degree contour) is centered around the Davis well. With increasing depth the shape of the anomaly is asymmetrically elongated around a northwest trending axis. Using these contours and lithologic data, a production well (Susan 1) was sited next to Suzy 9. As predicted from these contours, the new well, Susan 1, was the hottest well drilled thus far.

Concentrations of chemical species may also be contoured at various depths to determine if and how mixing of different fluids is occurring. Static water levels are contoured to determine the extent and direction of regional ground water flow.

Cross Sections. Cross sections are constructed by correlating or comparing profiles at two or more wells. Multiple cross sections, or cross sections and contours, may be used to get a three-dimensional model of the reservoir. Lithologic data are typically processed this way. Correlations of major geologic features, such as fracture zones, producing aquifers, caprock, and basement rock are obtained by constructing cross sections of the reservoir data. Temperature data are also plotted as cross sections and provide a multidimensional view of the hydrothermal structure. Two cross sections of temperature distribution are shown in Figure 8. This

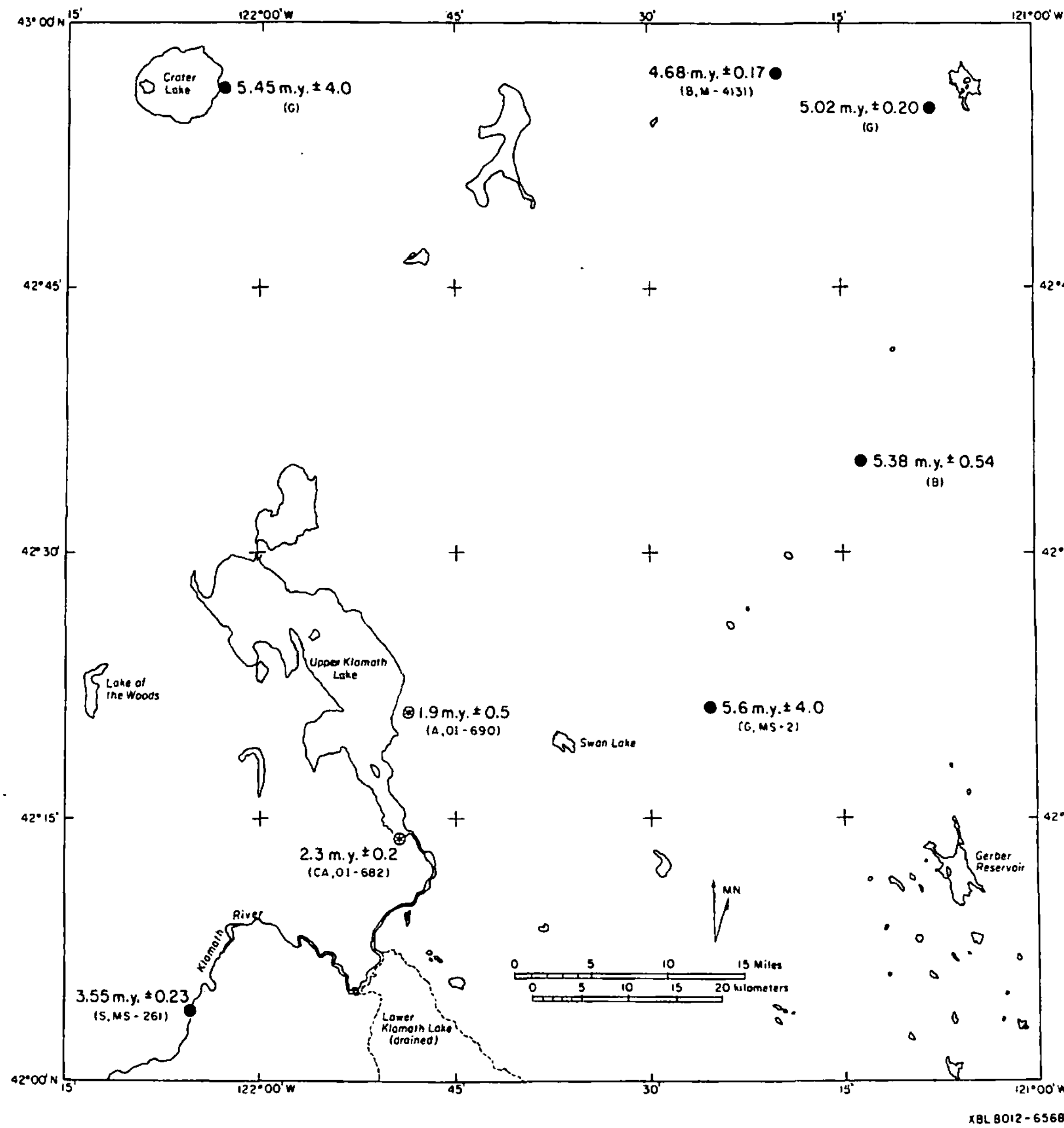

Figure 5. Rock sample locations from Klamath Falls, Oregon.

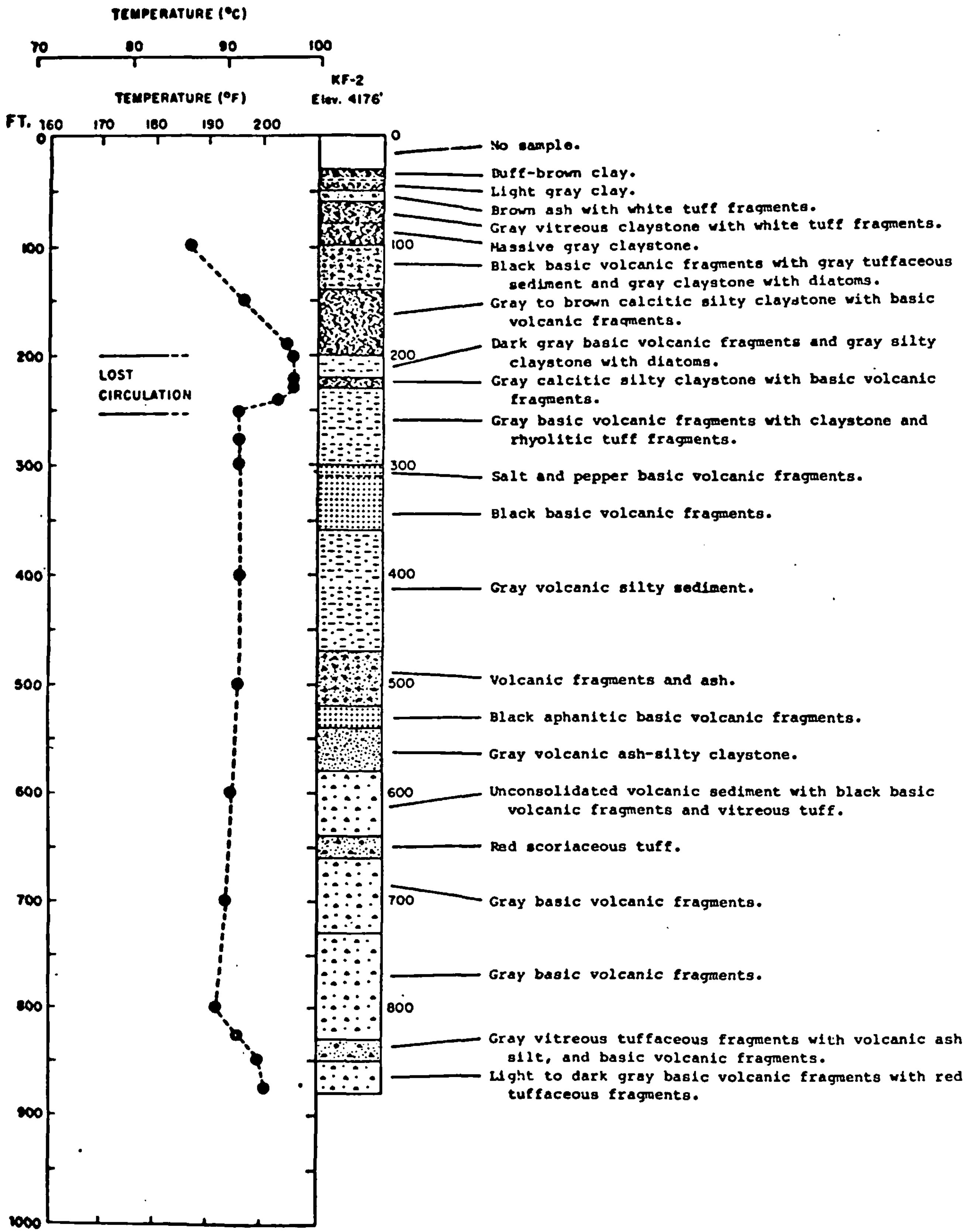

Figure 6. Temperature profile and lithology for Klamath Falls, City Well No. 2.

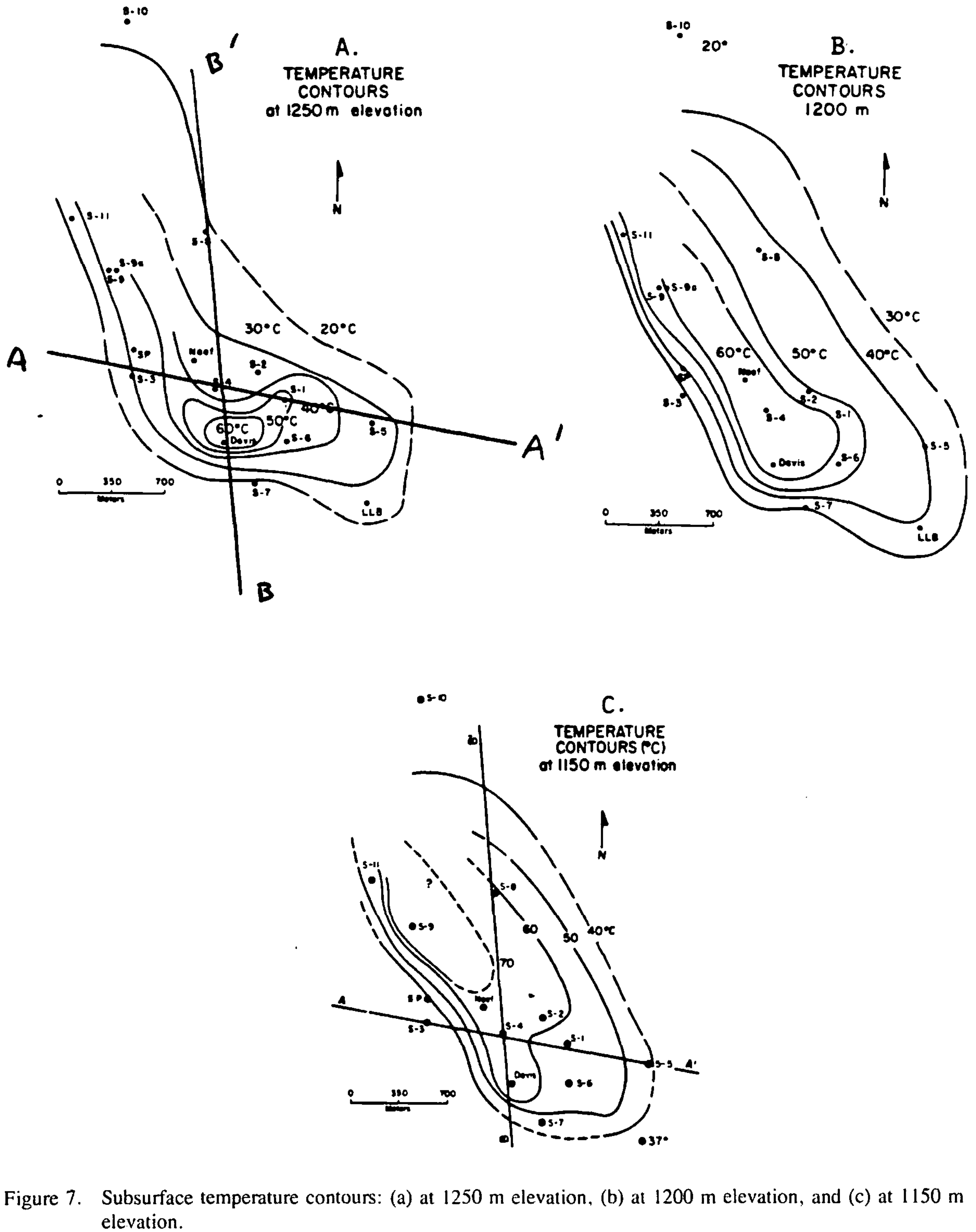

Figure 7. Subsurface temperature contours: (a) at 1250 m elevation, (b) at 1200 m elevation, and (c) at 1150 m elevation.

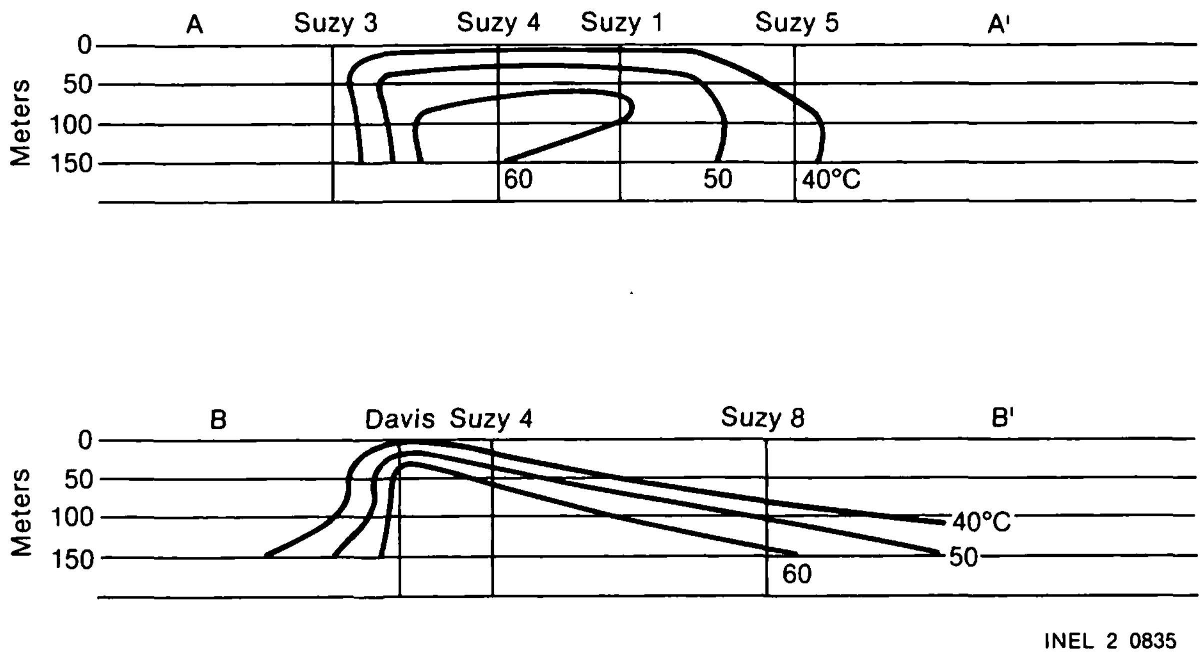

Figure 8. Cross sections of the Susanville hydrothermal anomaly.

type of thermal structure is indicative of upwelling of heated fluids from depth and lateral transport of fluid along permeable beds and fractures. This type of hydrothermal structure is common in shallow geothermal anomalies in the Cascade Range and the Basin and Range Province.

Borehole geophysical logs, such as electrical and nuclear logs, are also correlated on cross sections and are useful indicators of physical properties of the geologic section penetrated by the wellbore.

Graphically representing data in all of the above display forms helps to synthesize subsurface reservoir data with data obtained from surface reconnaissance. The subsurface reconstruction from each discipline should be compared to obtain a coherent conceptual model. Table 1 lists the various ways to process data.

Table 1. Common methods of data preparation

	Map	Profile	Contour	Cross Section
Surface Geological	X	X	—	—
Geochemical	X	X	X	—
Surface Geophysical	—	—	X	X
Hydrologic	X	X	X	—
Lithologic	—	X	—	X
Geophysical Logs	—	X	—	X
Thermal	X	X	X	X

Data Synthesis

The purpose of synthesizing data from each of the disciplines discussed above is to identify the major lithologic, thermal, petrophysical, and structural controls on the hydrothermal system under investigation. The key parameters that govern how a hydrothermal system behaves are: the permeability, storativity, size, and geometry of the production zone(s), the boundary conditions on the producing aquifer such as lateral recharge (hot or cold) caprock and basement rock leakage; regional ground water flow, and thermal distribution in the resource. Hydrothermal reservoirs are often very complex both lithologically and structurally. For this reason it may be diffficult, if not impossible, to identify all of these major features. Nevertheless, an attempt should be made to identify these features because they play a critical role in interpreting well test data, designing the reservoir management program, and providing an overall understanding of the resource.

The first step in synthesizing all of the data is to correlate specific physical, thermal, and lithologic units between wells. If data from only one well are available, correlation between wells will not be possible. However, a thorough evaluation of all of the data from that one well should be performed. The features that identify the production zone, caprock, basement rock, and the physical parameters are discussed below.

Producing Zones. The major production intervals can be identified by numerous features depending on the geologic setting. For instance, in a thick sedimentary sequence, a permeable aquifer will probably occur in a sandstone, and over and underlying impermeable layers will consist of a shale or clay sequence. The temperature profile through such a sequence would consist of several distinct gradients: a convective gradient through the aquifer and a conductive gradient through the underlying boundary layer. An example is shown in Figure 9. In a fractured rock sequence, the production zones (fractures) may be located by fluid entry into the wellbore during drilling, or by loss of circulation fluid into the formation. Production zones in fractured rocks may also be indicated by temperature profiles as was demonstrated in the previous section in Figure 6.

There is no single method of detecting the production zones; however, they can usually be identified by one or more of the following methods:

1. Loss of circulation fluid when drilling through the aquifer
2. A convective thermal gradient as opposed to a conductive gradient
3. Indication of sand zones or high-water-content zones from geophysical logs or cuttings
4. Fluid entry into the wellbore during drilling
5. Fracture zones indicated during drilling
6. Spinner surveys (downhole flow meter).

The properties of the producing aquifer(s) which need to be determined are: transmissivity, storativity, temperature distribution, structure, and geometry.

In general the reservoir transmissivity and storativity can accurately be determined only by well testing. However, before well testing, the type and degree of permeability can be determined by examining items discussed above. The two most common types of permeability are matrix and fracture. Matrix permeability occurs when the fluid flows through porous spaces in the rock. The fluid enters the wellbore from the entire aquifer interval. If the flow in the reservoir is confined mainly to fractures in the rock, then the term fracture permeability is used. In systems with fracture permeability, flow into the well comes only from the fracture, not the matrix of the rock. However, away from the wellbore, fluid may enter the fracture by flowing from the rock matrix into the fracture. The fracture is a conduit for fluid to flow into the wellbore. Many hydrothermal systems are some combination of fracture and matrix permeability and these systems are called dual-porosity systems. In general, hydrothermal systems that occur in volcanic and metamorphic rocks will have a

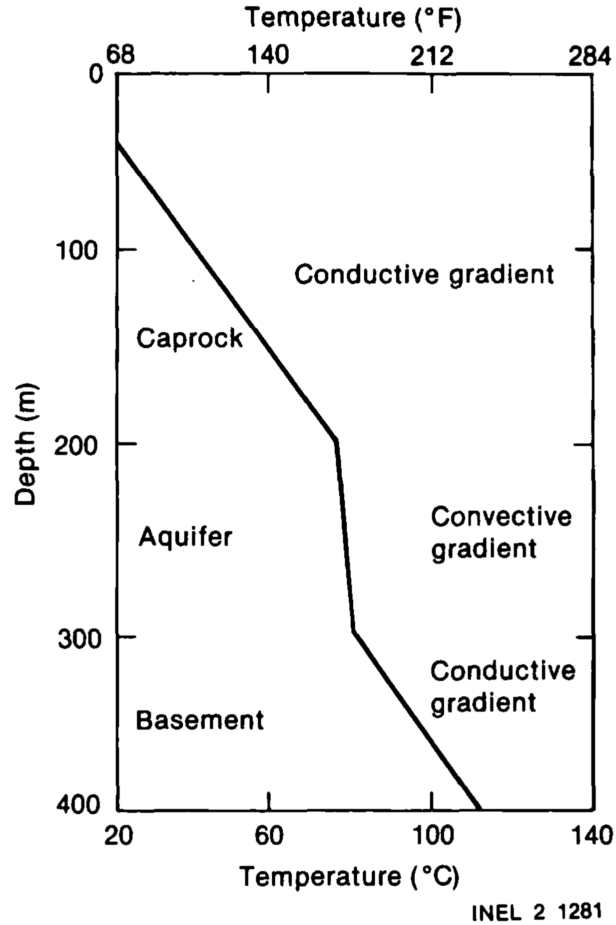

Figure 9. Example of a typical temperature gradient through of sedimentary sequence showing the caprock, aquifer, and basement.

fracture-dominated permeability. Sedimentary formations, except for carbonate systems, will in general have a type of matrix permeability. There are, however, exceptions to this generalization.

The temperature of the producing aquifer may be measured with a downhole temperature probe. It is important to measure the temperature downhole because any measurement taken at the surface may be affected by cooling and mixing as the fluid moves up the wellbore. Except in deep, near-normal geothermal-gradient type reservoirs, the temperature in the producing aquifer will vary spatially. It is important to have measurements of the temperature in the producing aquifer in as many wells as possible because the spatial variation of temperatures in the aquifer is one of the most useful tools for determining where and if hot water recharge is taking place. Temperature contours, at several depths, should be constructed. The interpretation of this is discussed in the previous section.

The important geometric characteristics of a hydrothermal aquifer are the areal extent, height, and shape. The volume of the aquifer (areal extent multiplied by height) is used to make a first-order estimate of the amount of hydrothermal fluids in place. Obviously, data must be available from more than one well to determine the areal extent of the resource. The shape of the hydrothermal aquifer is one of the major clues to understanding the resource. In near-normal geothermal gradient aquifers, it is the size and shape of the permeable (and porous) aquifer that governs the geometry of the hydrothermal system. In Basin and Range and fault-controlled hydrothermal systems it is usually the extent of the thermal anomaly which governs the geometry of the hydrothermal system. It is important to have some idea of the thermal distribution in the producing aquifer because thermal boundaries can be misinterpreted as hydrologic boundaries due to the temperature dependence of fluid viscosity.

Caprock and Basement Properties. The important properties of the confining strata in a hydrothermal system are permeability, continuity, rock type, and temperature. If the caprock or basement rock is permeable, it will supply fluid to the producing aquifer when it is pumped. Even though physical properties of caprock and basement rock are diffficult to determine, proper analysis of well test data can show leakage in caprock or basement rock. This is discussed in the section on well testing. It should be noted that a "true" caprock may not always exist and the resource may be so shallow that the basement characteristics cannot be identified. Caprock and basement rock can be identified by observing one or more of the following items:

1. A conductive thermal gradient as opposed to a convective thermal gradient
2. Delineation of a clay or shale layer from rock cuttings
3. Lack of evidence of fractures during drilling
4. Identification of low water content or shale layers from geophysical logs.

Knowledge of the location and type of confining rock is important because they are used to estimate the thickness of the producing strata and to determine if the wellbore penetrates only part of the hydrothermal aquifer. In this case, partial penetration of the wellbore into the formation, should be considered in the well test analysis.

Boundary Conditions. There are many types of boundary conditions on a hydrothermal aquifer, all of which will affect the results of a well test and reservoir response to sustained production. The aquifer may be infinite, or effectively infinite. The aquifer may be bounded on one side by a linear boundary such as a fault or rapid facies change. The linear boundary may be impermeable to fluid movement, supply a constant flow of hot or cold water into the aquifer, or remain at a constant head. The aquifer may be completely enclosed by impermeable or constant potential boundaries that are square, rectangular, polygonal, or radial. Different types of analysis apply to each of these systems. If the presence of some type of aquifer boundary such as a fault or fracture zone is suspected, the well test should be designed so that it is long enough to determine the hydrologic properties of the boundary. In order to calculate the radius of investigation, the following formula can be used:

$$r = 2\sqrt{\frac{kt}{\phi\mu c}}$$

where

k = permeability (m^2)

t = time (s)

ϕ = porosity

μ = fluid viscosity (Pa•s)

c = total system compressibility $\left(\frac{1}{Pa}\right)$.

In highly fractured and faulted hydrothermal systems, practical experience indicates that it is often difficult to detect the presence and type of reservoir boundaries. This is because the hydrologic systems are so complex that no single phenomena can be isolated and analyzed.

An estimate of the radius of investigation can be obtained even if the parameters are not all precisely known. For example, in a moderately permeable sandstone, the following calculation can be made:

$$k = 100 \text{ md} = 1 \times 10^{-13} \text{ m}^2$$

$$\phi = 20\% \ (.2)$$

$$C_t = 1 \times 10^{-9} \ \frac{1}{\text{Pa}}$$

$$\mu = .3 \text{ cp} = 3 \times 10^{-4} \text{Pa•s} \ .$$

The radius of investigation for a 10-hour test will be:

$$r = 2 \sqrt{\frac{(1 \times 10^{-13}) \ 3.6 \times 10^4}{.2 \times 3 \times 10^{-4} \times 1 \times 10^{-9}}} = 490 \text{ m} \ .$$

For a one week test, the radius of investigation will be:

$$r = 1003 \text{ m} \ .$$

5. TESTING DURING DRILLING

Data collected throughout the drilling operation provide a basis for selecting the well test design and analysis methods to be used in evaluating aquifer characteristics. Mandatory data to be collected during operations include:

- Lithologic logging
- Drilling engineering records
- Geophysical logging
- Transient temperature profiles.

Lithologic Logging

Lithologic logging is an important tool used during drilling and should not be overlooked. Through proper lithologic logging one can identify rock type, formation, and position in the stratigraphic section. If used properly, analysis of the drill cuttings can characterize porosity and hydrothermal alteration, and assist in finding faults and zones of fluid entry. Because of rapid and abrupt changes which occur in faulted and altered rock, composite samples should be taken over no more than 10-foot intervals. Analysis of cuttings should be performed by a qualified geologist familiar with igneous, metamorphic, hydrothermally altered rocks, fault gouge, microbreccia, slickensiding, and mylonite. Unwashed samples should be collected to avoid the loss of fine-grained cuttings.

Drilling Engineering Records

Under ordinary drilling conditions, a number of measurements are made and recorded to assist the drilling engineer in making effective drilling decisions. These drilling parameters include drill rate, rotary speed, pump speed, pump pressure, weight-on-bit, and mud volume totalizers. When parameters are properly employed, decisions can be made on bit changes, borehole deflection, lost circulation, casing sizes and settings, etc.

These data also assist the reservoir engineer in evaluating the subsurface. Although these data are not conclusive, tests during drilling in the typical sense of testing, can assist the reservoir engineer in determining rock strengths and porosity from penetration rate; in identifying hot aquifers from circulation fluid temperature-in, temperature-out; and in assessing fractures and fault zones where lost circulation has occurred. All such information will be of a qualitative nature, to be evaluated further by testing methods of a quantitative nature. Nevertheless, they do identify specific sections in the wellbore that merit further evaluation.

Geophysical Logging

Borehole geophysical logging techniques measure the physical properties of the rock. Coupled with other drilling data, the logging analysis can help in defining porosity, rock type, wellbore size, bulk density, dip of rock strata, fluid temperature, and, to a limited degree, rock fractures.

Commercial logging companies provide the log tool service and deliver a graphical output to the customer. These data should be analyzed with input from other drilling information to provide an interpretation of the wellbore and rock conditions. Conventional analytical techniques for sedimentary rocks cannot be routinely applied to all geothermal resources because of the nature of the rocks encountered (i.e., igneous and metamorphic). Current research efforts are providing interpretive measures for these geothermal environments. Although, it is a fairly expensive service, geophysical logging is a routine tool that should be used for every geothermal well.

Transient Temperature Profiles

The downhole temperature should be measured routinely during the drilling process. Temperature profiles can be performed by a commercial logging company or by a hydrogeologist. Temperature profiles are inexpensive and do not require a long period of time. They can be used to determine cold- and hot-water production zones and loss-of-circulation zones. Temperature logs can provide useful data for determining the depth for setting casing.

The Horner plot method is used to plot transient downhole temperature. The Horner plot is a graph of temperature build-up versus log $\frac{t_k + \Delta t}{\Delta t}$ where t_k is circulation time before shut-in and Δt is buildup time. The static temperature obtained using the conventional Horner plot is lower than the true reservoir temperature.[4] For example, let us assume that prior to running a log suite to set a string of casing, the well was circulated for four hours. Following this circulation period, a series of logs were run and the following times and temperatures observed:

Time (hr)	Temperature (°F)	$\frac{t_k + \Delta t}{\Delta t}$	
0200	Circulation completed	—	
1215	255	14.25/10.25	= 1.39
1500	255	17/13	= 1.31
1630	257	18.5/14.5	= 1.28
1930	260	21.5/17.5	= 1.23
2400	262	26/22	= 1.18

A plot of this data is shown in Figure 10. The estimated static temperature is obtained by an extrapolation of the straight line to a time ratio of unity, which is equal to 272°F. It can be assumed this is probably a lower limit temperature to the true static temperature.

Optional testing methods include:

- Drill-stem tests
- Coring
- Geochemical logging
- Swab and lift tests
- Downhole flow meter tests.

Drill Stem Tests

Drill stem tests (DSTs) are normally conducted in a zone of undetermined potential.[3] The drill stem tool is attached to the drill string and lowered into the zone to be tested. A packer is set to isolate the zone. Formation fluids from the isolated zone flow into the drill pipe. A continuous pressure record is obtained during the

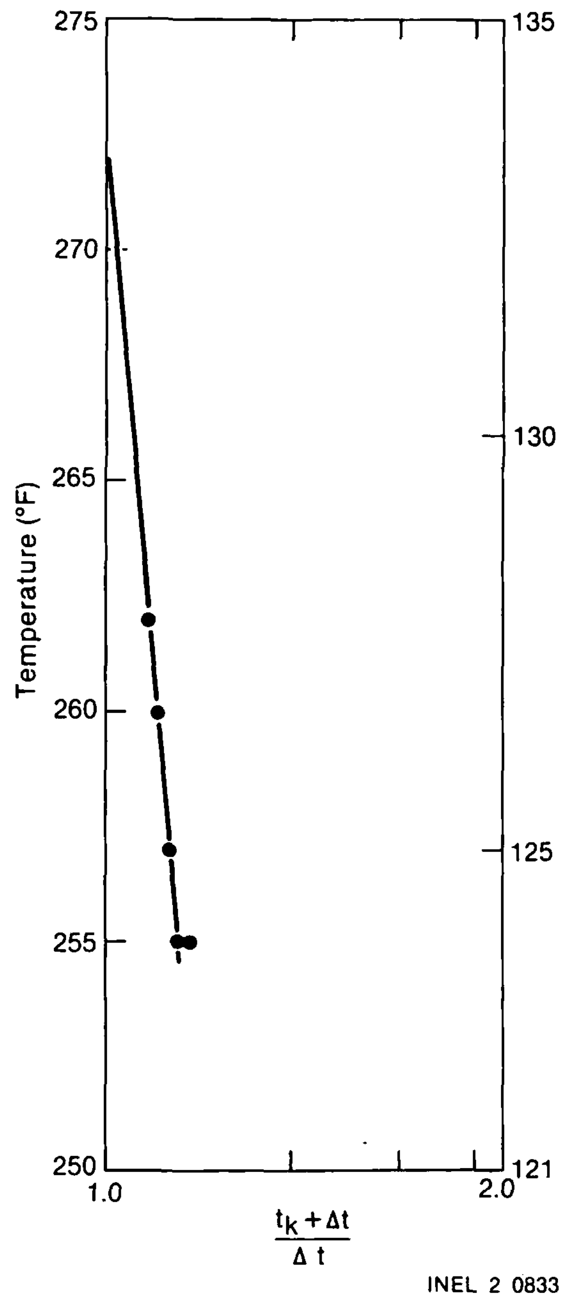

Figure 10. Horner plot of static temperature approximation.

production and shut-in periods. DST data are analyzed to assess preliminary reservoir parameters (i.e., permeability, hydraulic conductivity). At the conclusion of the test, representative fluid samples are collected for further geochemical analysis (refer to Geochemistry Section 8).

An alternative to the drill stem test is a wireline repeat formation test. This test is capable of multiple settings downhole and of retrieving two fluid samples per trip in the hole. The principles governing multiple-level pressure measuring are similar to those of the DST. Wireline testing is attractive because it is fast and less costly than drill stem testing; however, a wireline test is a less accurate method and interpretation of the data is only partially quantitative. Drill stem and wireline formation tests are commonly used in the petroleum industry. Use in geothermal well testing is not expected to be widely applicable due to fractured flow conditions. In a fractured reservoir environment, the data from these kinds of tests may provide erroneous information due to the short flow durations. However, these types of tests may prove valuable in evaluating the results of well stimulation jobs.

Coring

Core drilling allows for the recovery of whole rock samples from a selected interval. Core samples are used to correlate geophysical logging data with rock properties, to perform laboratory permeability tests, and to delineate stratigraphy and lithology profiles. Core drilling is an important tool used in oil and gas exploratory drilling. The high cost of coring is prohibitive for routine use, but may provide useful information for selected intervals in geothermal wells.

An alternative to core drilling is a technique called sidewall coring. This method uses a wireline for collection of the sample. Sidewall coring is quick and inexpensive; however, core samples are small in size and may have limited laboratory use. Sidewall coring will not provide adequate samples in fracture-dominated geothermal systems due to the limited data regarding fracture density, character, and orientation that can be obtained from the small sample.

Geochemical Logging

Geochemical logging can be useful in identifying geothermal production zones during drilling. Geochemical logging procedures are discussed in detail in Section 8.

Swab and Lift Tests

A swab test is used as a method for withdrawing fluid from a borehole. The procedure employs a swab valve attached to a rig sand line. This method provides limited information on well productivity and allows the collection of representative fluid samples. Swabbing and mechanical surging are commonly used methods for the development of a ground water well but may be of limited use to geothermal resources. This is a hazardous technique because of the possibility of high-pressure vapor and gas blow outs.

Airlifting using compressed air or other gases is another mechanism for withdrawing fluids from the hole. This stimulates the well and yields limited information on well productivity. Approximate flow, water level recovery, and temperature data should be collected. Fluid temperatures are affected by the ambient air temperature. A correction should be made for the estimated cooling effect. The accuracy of reservoir characteristics determined from an airlift test may be questionable, since air or gas may give erroneous flow measurements and water level recovery is diffficult to obtain. Nevertheless, geothermal well drillers may employ swabbing and airlifting methods to both develop wells and perform limited well testing.

Downhole Flow Meter Test

Vertical flow of fluids in the borehole can be measured using a downhole flow meter (spinner device). Downhole flow meter tests may be conducted while producing or injecting fluid into a well. The hole should be relatively clean because the instrumentation can be easily plugged by mud or drilling debris. This method is used to indicate production or high permeability zones. The data can be evaluated to determine the amount of fluid entering the borehole from different zones. Used together with a temperature profile, this test may be useful for casing and screen setting decisions.

6. THEORY OF AQUIFER TESTING

Aquifer testing is the correlation of well production at various rates with temporal pressure or water level changes. Inferences may be drawn from such tests about the size and ability of an aquifer or reservoir to transmit and store fluids. Well testing is the only method that provides in situ information about an aquifer or reservoir on a scale meaningful for long-term exploitation of a resource. Despite the fundamental unity in the principles of well testing, the art of well testing has developed in two parallel fields: hydrogeology, following the lead of C. V. Theis[5] and petroleum engineering, following the early contributions of Hurst.[6] Hydrologists have been concerned with determining aquifer constants (transmissivity and storage coeffficient) and interference-type testing of shallow systems. Petroleum engineers, on the other hand, have been concerned with interpretation of production/injection testing of deep systems. High-temperature geothermal well testing (usually steam flows) has followed the petroleum engineering lead. Low-to-moderate temperature geothermal well testing (usually hot water flows) requires adaptations from both the ground water and petroleum fields.

The equations developed for various aquifer and well conditions provide tools for analyzing data from many different hydrogeologic conditions. However, the simplifying assumptions used to develop the solutions are usually only partially satisfied. In addition, many of the solutions result in curves of similar shape, and thus are not unique to one flow system. Consequently, careful site evaluation and well test design by a qualified petroleum reservoir engineer or hydrogeologist are essential to ensure the success of planned testing.

Essential Elements of Well Tests

Geothermal well testing usually consists of operating the well with a controlled flow rate and measuring three variables (flow rate, water level or pressure, and fluid temperature) as time passes, while other parameters (distance, r, to the observation wells, permeability, reservoir dimensions, and storage capacity) remain constant. The flow rate, water level or pressure, and time are the primary data required for test analysis. Temperature measurements provide data for corrections for temperature effects related to changes in fluid density and viscosity. Fluid chemistry, geology, geophysics, and well construction data are also important parameters in test data interpretation.

Basic Equations

Well testing analysis methods are based on the basic equations of flow through porous media presented below. The symbols used first are those usually found in the water-well literature. The same equations are repeated in the symbols of petroleum engineering references.

Darcy's Law

Darcy[7] observed from experiments on apparatus similar to that illustrated in Figure 11 that the speed of laminar flow of water through sand is proportional to the hydraulic gradient. He expressed this concept by the following equation now known as Darcy's law:

$$q_s = \frac{Q}{A} = -K \frac{\Delta h}{\Delta \ell} = -K \frac{dh}{d\ell}$$

or

$$Q = KiA \tag{1}$$

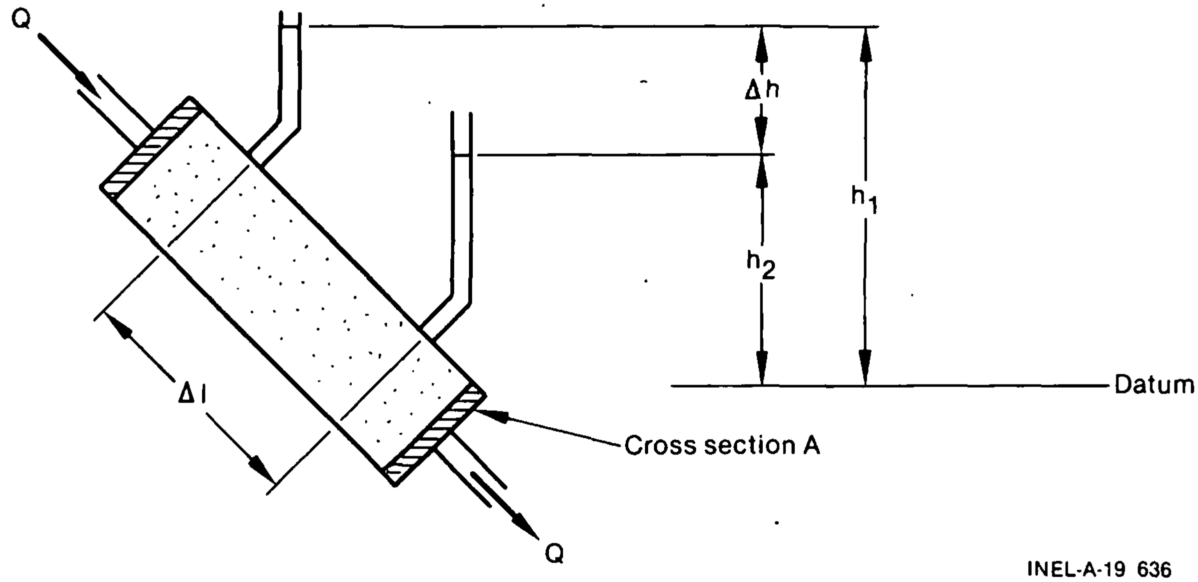

Figure 11. Laminar flow speed measurement apparatus.

where

q_s = specific discharge (L/T)

Q = flow rate (L^3/T)

A = cross-sectional area (L^2)

K = hydraulic conductivity (L/T)

h = hydraulic head (L)

ℓ = length (L)

i = $\frac{dh}{d\ell}$ = hydraulic gradient (L/L)

and the minus sign indicates a loss of potential in the direction of flow. If the porosity, ϕ, is known, an estimate of the velocity of flow is given by

$$v = \frac{q_s}{\phi} = \frac{-K}{\phi}\frac{dh}{d\ell} \quad (2)$$

The hydraulic conductivity, K, depends on both the properties of the porous medium and the properties of the fluid. Often it is advantageous to separate these effects and define a permeability that depends only on the medium such that

$$K = \frac{k\rho g}{\mu} \quad (3)$$

where

k = intrinsic permeability (L^2)

ρ = mass density (M/L^3)

g = acceleration of gravity (L/T^2)

γ = ρg = weight density (F/L^3) or (M/L^2T^2)

μ = dynamic viscosity (FT/L^2)

p = pressure (F/L^2)

$\frac{dp}{d\ell}$ = pressure gradient (F/L)

then

$$q_s = \frac{Q}{A} = \frac{-k\gamma}{\mu}\frac{dh}{d\ell}$$

or

$$Q = \frac{-k\gamma A}{\mu}\frac{dh}{d\ell} \qquad (4)$$

and in petroleum symbols

$$q_s = \frac{Q}{A} = \frac{-k}{\mu}\frac{dp}{d\ell}$$

or

$$Q = \frac{-kA}{\mu}\frac{dp}{d\ell} \; . \qquad (5)$$

Darcy's equation is valid only for laminar flow conditions. Thus, in fractured rock, coarse unconsolidated material, or formations with large solution openings, the equation may not represent the flow.

Steady-State Well Equation. Based on Darcy's work, Thiem[8] developed an equation for steady (equilibrium) flow toward a well as shown in Figure 12. He assumed that:

- The aquifer is horizontal, homogeneous, and isotropic
- The well is fully penetrating
- The steady flow is maintained long enough so that the zone of influence is no longer expanding with time.

The simple continuity concept of equal flow through adjacent concentric cylinders gives the equation

$$Q = 2\pi Kbr\frac{dh}{dr} \; . \qquad (6)$$

where

b = formation (aquifer) thickness (L)

h = height from the botton of the formation to the piezometric surface at the point indicated by the subscript (L)

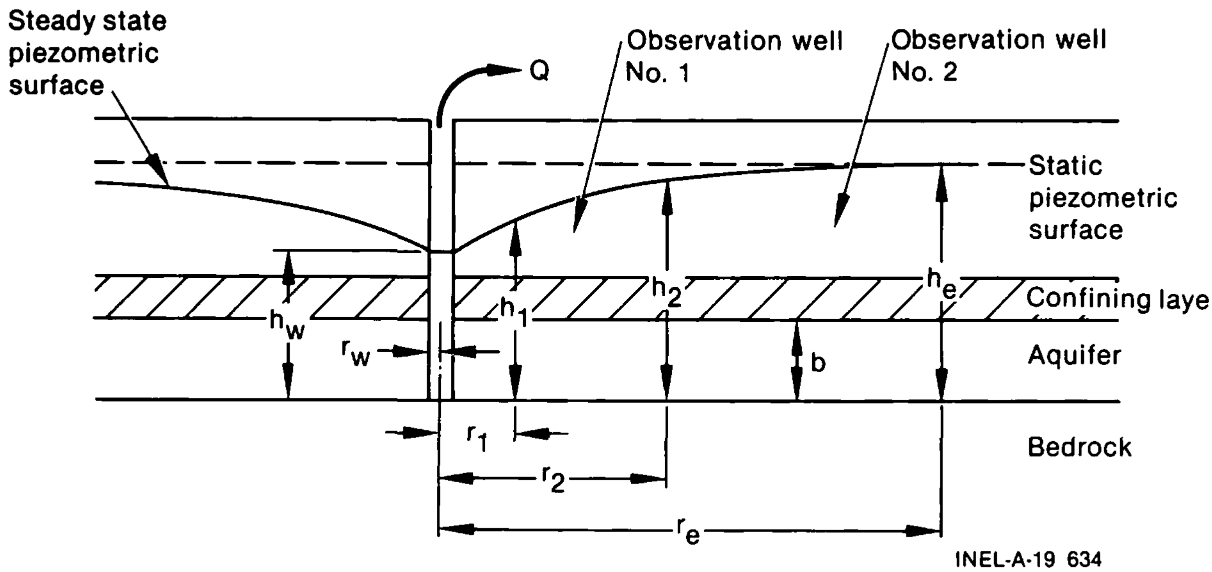

Figure 12. Steady flow toward a well.

r_w = radius of well (L)

r_1, r_2 = radial distance from production well to observation wells 1 and 2 (L)

r_e = radius of influence of the well (L).

When integrated between the two observation wells in an unconfined aquifer

$$Q = \frac{\pi K \left(h_2^2 - h_1^2\right)}{\ell n \, (r_2/r_1)}$$

or

$$K = \frac{Q \;\ell n \, (r_2/r_1)}{\pi \left(h_2^2 - h_1^2\right)} \tag{7}$$

or in a confined aquifer

$$Q = \frac{2\pi K b \, (h_2 - h_1)}{\ell n \, (r_2/r_1)}$$

or

$$K = \frac{Q \,\ell n \, (r_2/r_1)}{2\pi b \, (h_2 - h_1)} \quad . \tag{8}$$

When the limits of integration are the production well and the radius of influence, the equation for a confined aquifer is

$$Q = \frac{2\pi Kb\,(h_e - h_w)}{\ell n\,(r_e/r_w)}$$

or

$$K = \frac{Q\ \ell n\,(r_e/r_w)}{2\pi b\,(h_e - h_w)} \qquad (9)$$

In petroleum symbols, Equation (9) is

$$q = \frac{0.00708\ kb\,(p_e - p_w)}{B\mu\ \ln\,(r_e/r_w)}$$

$$k = \frac{qB\mu\ \ell n\,(r_e/r_w)}{0.00708\ b\,(p_e - p_w)} \qquad (10)$$

where

q = flow rate (STB/day)

k = intrinsic permeability (md)

p_e = external pressure (psi)

p_w = bottom hole pressure (psi)

B = formation volume factor (RB/STB)

μ = viscosity (cp).

General Differential Equation. Jacob[9] developed a formal, classical development of the general differential equation for transient flow through a saturated, homogeneous, isotropic porous medium. A more complete development is given by Jacob.[10] Freeze and Cherry[11] summarize the development of the equation and the contributions of others to its development. The equation in three dimensions is known as the diffusion equation and is:

$$\frac{\partial^2 h}{\partial x^2} + \frac{\partial^2 h}{\partial y^2} + \frac{\partial^2 h}{\partial z^2} = \frac{S_s}{K}\frac{\partial h}{\partial t} \qquad (11)$$

where

S_s = specific storage (1/L)

and the other symbols are as given earlier.

For flow toward a well in a horizontal aquifer of thickness, b, in cylindrical coordinates, the equation becomes:

$$\frac{\partial^2 h}{\partial r^2} + \frac{1}{r}\frac{\partial h}{\partial r} = \frac{S}{T}\frac{\partial h}{\partial t} \tag{12}$$

where

$T = Kb$ = transmissivity (L^2/T)

and

$S = S_s b$ = storage coeffficient (dimensionless).

Any compatible system of units can be used in the equation without introduction of constants. For example, if h and r are in meters and t is in days, the transmissivity, T, is in meters squared per day.

In petroleum symbols and units the equation is:

$$\frac{\partial^2 p}{\partial r^2} + \frac{1}{r}\frac{\partial p}{\partial r} = \frac{1}{C}\frac{\phi \mu c_t}{k}\frac{\partial p}{\partial t} \tag{13}$$

where

C = constant depending on units used

c_t = system total compressibility (L^2/F).

With μ in Centipoise, c_t in 1/psi, k in millidarcy, p in psi, r in feet, and t in hours, then C = 0.0002637.

Solution of the General Equation. Theis[5] found a solution of Equation (12) for a steady flow rate, Q, from the well subject to appropriate boundary and initial conditions. The solution, in terms of drawdown, applies to constant discharge from a fully penetrating well in a confined, homogeneous, isotropic aquifer of infinite areal extent with no vertical leakage

$$s = h_o - h(r,t) = \frac{Q}{4\pi T}\int_u^{\infty} \frac{e^{-u}}{u}\,du = \frac{Q\,W(u)}{4\pi T} \tag{14}$$

where

$u = \frac{r^2 S}{4Tt}$ = well function argument

s = drawdown at any radius, r, at time, t (L)

h_o = initial height of piezometric surface above the bottom of the formation (L)

h = height of piezometric surface at r and t (L). (15)

The integral term is known as the well function, W(u), and is available in tabular and graphical form in most ground water literature such as Reference 11. It is represented to any desired degree of accuracy by an infinite series as follows

$$W(u) = \left(-0.5772 - \ell n\, u + u - \frac{u^2}{2 \cdot 2!} + \frac{u^3}{3 \cdot 3!} - \frac{u^4}{4 \cdot 4!} + \ldots\right). \tag{16}$$

Unsteady State Radial Flow in Isotropic Nonleaky Artesian Aquifer with Fully Penetrating Wells and Constant Discharge Conditions

Analysis in Water Well Terms. Consider Equations (14) and (15) and rewrite them as:

$$\ell n\ s = \ell n \left(\frac{Q}{4\pi T}\right) + \ell n\ W(u) \text{ and } \ell n\ t = \ell n \left(\frac{r^2 S}{4T}\right) + \ell n \frac{1}{u}\ .$$

This suggests a graphical curve matching technique for analyzing pumping test data. If Q is held constant during the test, then $Q/4\pi T$ and $r^2S/4T$ are constants and the relationship between ℓn s and ℓn W(u) is similar to the relationship between ℓn t and ℓn 1/u. When each pair of variables are plotted on the same scale of two different sheets of log-log paper, the resulting curves are similar and are merely displaced horizontally and/or vertically from each other depending on the values of the two constants.

The method proceeds as follows and is illustrated in Figure 13:

1. A reverse type curve, 1/u (abscissa) versus W(u) (ordinate) is plotted on log-log paper.

2. The pumping test data, t (abscissa) versus s (ordinate) are plotted on another sheet of the same paper.

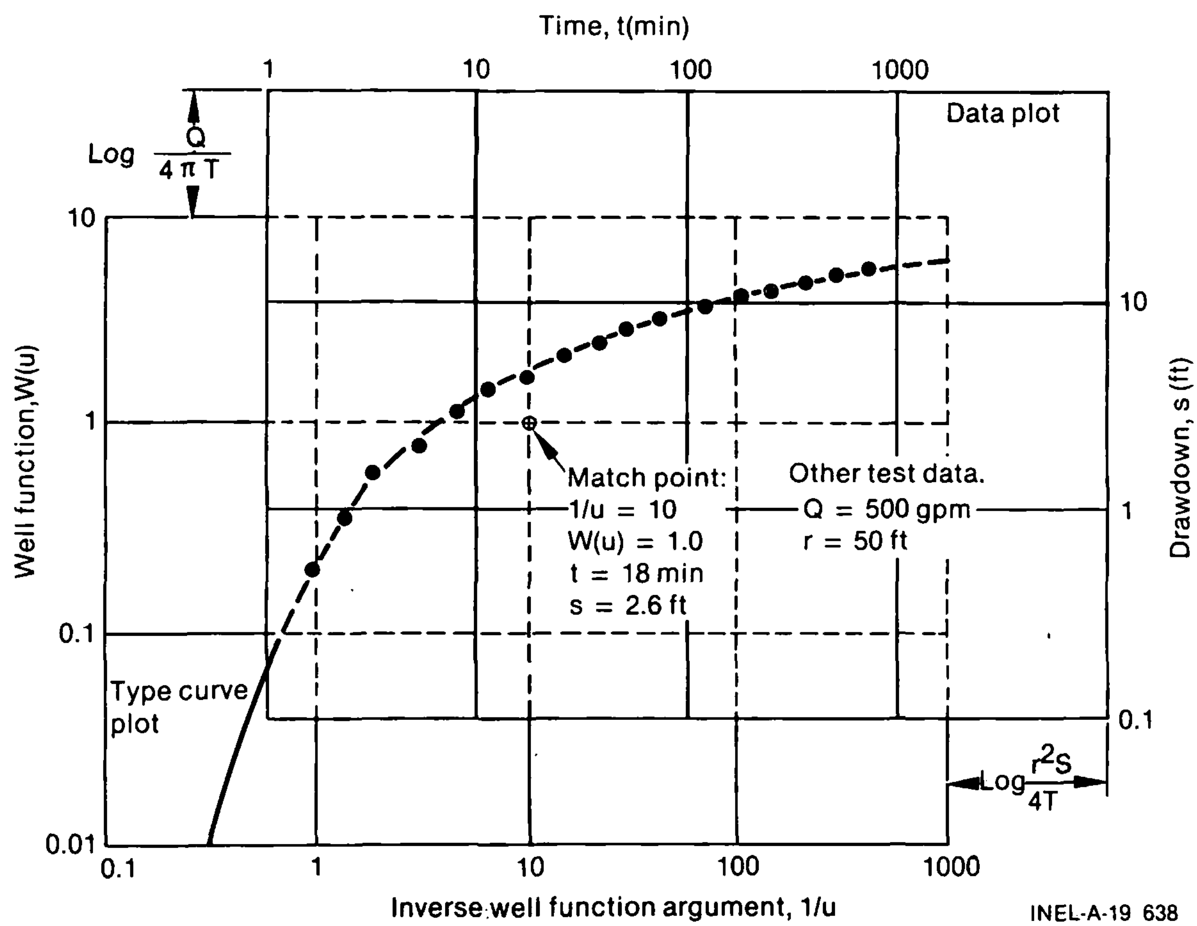

Figure 13. Superimposed curves for aquifer constants.

3. The two plots are superimposed on a light table. The two curves are translated vertically and horizontally, keeping the axes parallel at all times, until the best match of the test data with the type curve is obtained.

4. Then a convenient match point near the type curve is selected and the values of the four variables, t, s, 1/u, W(u) are recorded.

5. Using Equations (14) and (15), the unknown values of the formation coeffficients are calculated from:

$$T = \frac{Q\,W(u)}{4\pi s} \quad \text{and} \quad S = \frac{4tT}{r^2(1/u)} \,.$$

An alternative is to plot the type curve u versus W(u) and the field data s versus (r^2/t) both on log-log paper. The curves are superimposed, match point coordinates are recorded and the aquifer constants calculated as before.

Analysis in Petroleum Engineering Terms. The petroleum engineering approach has been to plot families of dimensionless curves and to fit the well test data to these. Dimensionless time, radius and pressure are defined as:

$$t_D = \frac{0.0002637\,kt}{\phi\mu c_t\, r_w^2}\,, \text{ and } r_D = \frac{r}{r_w}$$

then

$$p_D = f\,(t_D, r_D, C_D, \text{geometry}) \tag{18}$$

where

C_D = dimensionless wellbore storage factor.

If only the effects of dimensionless time and radius are considered, then

$$p_D = f(t_D, r_D) = -1/2\ \text{Ei}\left(\frac{-r_D^2}{4t_D}\right) \tag{19}$$

where

$$\text{Ei}\,(-x) = -\int_x^\infty \frac{e^{-u}}{u}\,du \,.$$

The solution of Equation (13) is

$$\Delta p = 141.2\,\frac{qB\mu}{kb}\,f(t_D, r_D) \tag{20}$$

where

Δp = $p_i - p\,(t,r)$

p_i = initial reservoir pressure (psi)

$p\ (t,r)$ = reservoir pressure at r and t (psi)

B = formation volume factor (RB/STB)

q = flow rate (STB/D).

Expansion of Equations (19) and (20), and rearrangement of terms shows it to be identical to the water well Equations (14) and (15).

The petroleum method is to plot test pressure, Δp, (ordinate) versus test time, Δt, on log-log paper and to superimpose the plot on a type curve for the value of r_D. A match point is chosen and values of $(\Delta p)_m$, $(\Delta t)_m$, $(p_D)_m$, and $(t_D)_m$ and noted.

Then

$$k = 141.2 \frac{qB\mu}{b} \frac{(P_D)_m}{(\Delta p)_m}$$

and

$$\phi c_t = \frac{0.0002637k}{\mu r_w^2} \frac{(\Delta t)_m}{(t_D)_m} \quad (21)$$

Thus, the two methods are seen to be the same in principle.

The petroleum engineers have carried the method further to include other important factors. A more general solutaion of Equation (13) to include the wellbore storage, geometry, and "skin" effects is:

$$\Delta p = 141.2 \frac{qB\mu}{kb} [f\ (t_D, r_D, C_D, \text{geometry}) + s_s] \quad (22)$$

$$C_D = \frac{5.6146\ C}{2\pi\phi c_t b r_w^2} \quad (23)$$

where

C = wellbore storage constant (bbl/psi)

$$C = \frac{\Delta v}{\Delta p} = V_w c$$

and

Δv = change in volume of fluid in wellbore at wellbore conditions (bbℓ)

Δp = change in bottom-hole pressure (psi)

V_w = total wellbore volume (bbℓ)

c = compressibility of the fluid in the wellbore at wellbore conditions (1/psi)

s_s = skin effect, which is a dimensionless pressure drop assumed to occur at the wellbore face (r_D = 1) as a result of wellbore damage or improvement. Positive skin effect is due to damage of the wellbore by the drilling process, plugging by mud, etc. Negative skin effect would be an improvement through development of the well, fracturing, reaming, etc.

A variety of type curves including the effects of wellbore storage, reservoir geometry, and skin effects have been developed and many of these are given in Earlougher.[3] Skilled use of these curves, where appropriate, allows more information to be extracted from the test data than through use of the simple exponential integral type curve alone. The additional data come from the parameters identifying the various type curves and make possible the computation of wellbore storage and skin effect coeffficients, in addition to the permeability and formation storage coeffficients already discussed.

Approximate "Straight-Line" Test Methods

The structure of the infinite series in Equation (16) provides a simple test procedure when the value of u is small. As suggested by Cooper and Jacob,[12] all the terms in the series except the first two can be neglected when $u < 0.01$. Then:

$$s = \frac{Q}{4\pi T}\left(-0.5772 - \ln\frac{r^2S}{4Tt}\right) = \frac{2.3Q}{4\pi T}\log\frac{2.25\,Tt}{r^2S} \; . \tag{24}$$

For most pumping tests, all parameters except t are constant. Thus s will plot as a straight line with log t. The slope of the straight line is seen to be the drawdown over one log cycle, Δs, or

$$\Delta s = \frac{2.3Q}{4\pi T}$$

and

$$T = \frac{2.3Q}{4\pi\Delta s} \; . \tag{25}$$

By extrapolating the straight line to the point where $s = 0$, the intercept, t_0, on the time axis can be determined. Then:

$$0 = \frac{2.3Q}{4\pi T}\log\frac{2.25\,Tt_0}{r^2S}$$

or

$$1 = \frac{2.25\,Tt_0}{r^2S}$$

and

$$S = \frac{2.25\,Tt_0}{r^2} \; . \tag{26}$$

Thus, by plotting s and t on semilog paper, and by noting Δs and t_0, simple calculations give the aquifer constants. If data from more than three observation wells are available at one time, a distance-drawdown plot can be made of s versus log r; Δs and r_0 can be noted. Then:

$$T = \frac{2.3Q}{2\pi\Delta s}$$

and

$$S = \frac{2.25\ Tt}{r_0^2}\ . \qquad (27)$$

Similarly, if drawdowns in several wells are available over a period of time, plot s versus lot (t/r^2). Record the drawdown over one cycle, Δs, and the intercept $(t/r^2)_0$. Then:

$$T = \frac{2.3Q}{4\pi\Delta s}$$

and

$$S = 2.25\ T\ (t/r^2)_0\ . \qquad (27a)$$

The three straight-line approximate methods are illustrated in Figure 14.

A similar straight-line approximate method is commonly used in petroleum engineering. The flowing bottom hole pressure, pwf, in psi (ordinate) is plotted against log t in hours (abscissa). At early times the wellbore storage makes the plot nonlinear, but this is followed by a straight line portion of the plot. The slope, m, in psi/cycle and the intercept, P/hr (where log t = 0 or t = 1), on the straight line are recorded. Then:

$$k = \frac{-\ 162.6\ qB\mu}{mb}$$

and

$$s_s = 1.1513\ \left[\frac{(p_{1hr} - p_i)}{m} - \log\left(\frac{k}{\phi\ uc_t\ r_w^2}\right) + 3.2275\right].$$

For the observation well the skin effect is zero, then the reservoir porosity-compressibility product may be calculated using the equation:

$$\phi c_t = \frac{k}{r^2\mu}\ \text{antilog}\left(\frac{P_i - P_{1hr}}{m} - 3.2275\right).$$

Recovery Tests

Analysis in Water-Well Terms. When a pumping test is discontinued after a period of production, data taken during the recovery period can also be used to determine formation constants. Conditions during the recovery period are represented by imagining that production continues from the well while at the same time an injection well at the same location replaces the fluid produced by the well. The net flow rate is zero and the imaginary injection well can be visualized as representing the recharging fluid coming into the cone of depression from the surrounding area. The drawdown at any point and at any time can be computed by adding the effects of the pumping and the injection as shown in Figure 15.

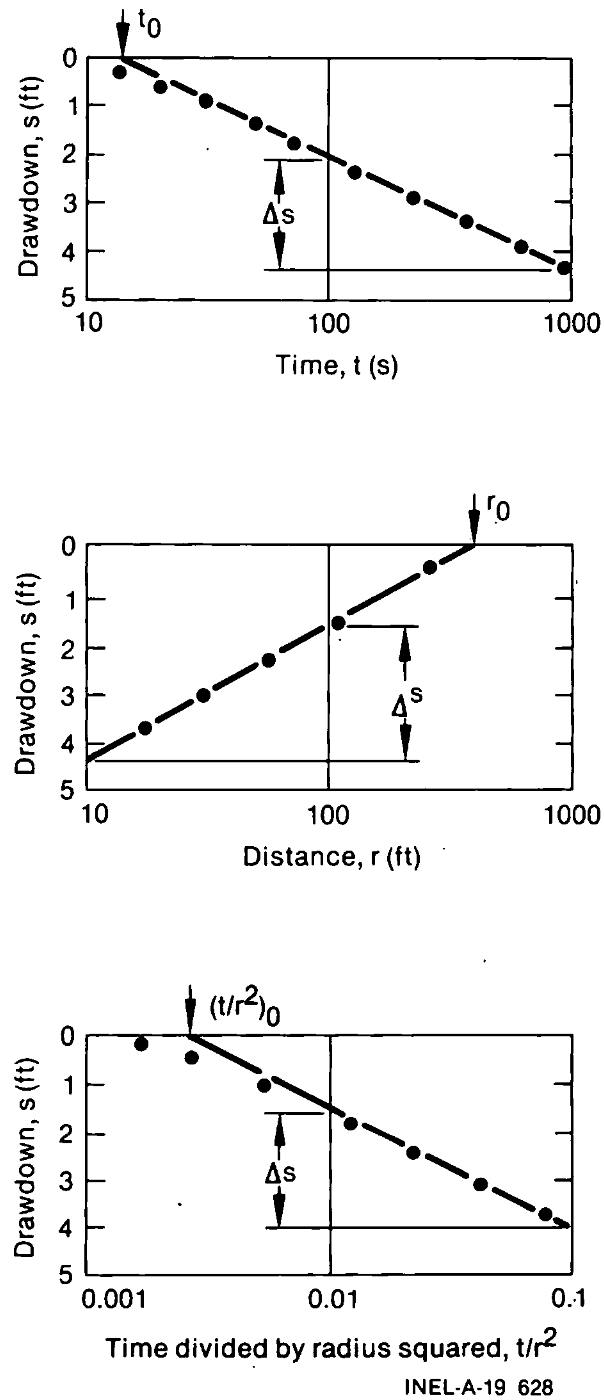

Figure 14. Straight line approximate methods.

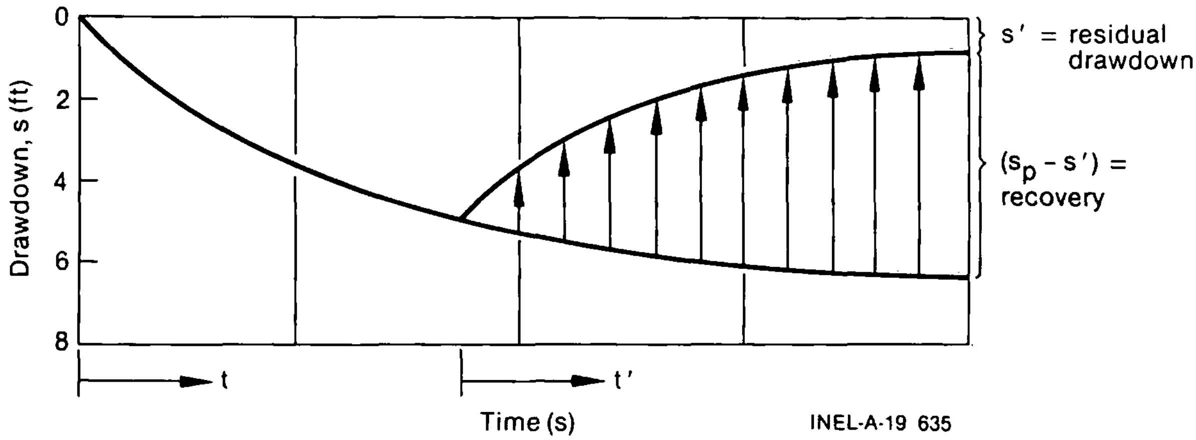

Figure 15. Drawdown computation.

In terms of well functions, the residual or remaining drawdown

$$s' = \frac{Q}{4\pi T} \int_u^\infty \frac{e^{-u}}{u}\, du - \int_{u'}^\infty \frac{e^{-u'}}{u'}\, du' \qquad (28)$$

where

$$u = \frac{r^2 S}{4Tt}$$

$$u' = \frac{r^2 S}{4Tt'}$$

and

t = time since pumping began

t' = time since shutoff.

Once t' becomes large, $u' < 0.01$ and the well function can be represented by the first two terms of the infinite series

$$s' = \frac{2.3Q}{4\pi T} \log \frac{t}{t'} \qquad (29)$$

and a plot of s' versus $\log t/t'$ is a straight line. If $\Delta s'$ is the drawdown over log cycle, then

$$T = \frac{2.3Q}{4\pi \Delta s'} \qquad (30)$$

When concurrent data from one or more observation wells are available, the storativity, S, can be estimated from

$$S = \frac{2.25\ T\ t'/r^2}{\log^{-1} [(s_p - s')/\Delta(s_p - s')]} \qquad (31)$$

where

s_p	=	pumping period drawdown projected to t′
s′	=	residual drawdown at t′
$\Delta(s_p - s')$	=	change in recovery over one log cycle
$(s_p - s')$	=	recovery at t′.

Horner Method

Analysis in Petroleum Engineering Terms. The Horner method is used to analyze pressure buildup data. The method has been used extensively in both the geothermal and petroleum industries. The technique is based on superposition of the exponential integral solution. The derivation is as follows:

$\Delta P_{\text{well shut in}} = \Delta P_{\text{due to the well flowing for a time } \Delta t + t \text{ at a rate of } +q}$

$+ \Delta P_{\text{due to a well flowing at a rate of } -q \text{ for a period of time } \Delta t}$.

By adding the flow rates at any time the appropriate conditions are modeled:

time $<t$ flow rate $= +q$

time $>t$ flow rate $= +q - q = 0$.

The pressure drop due to a well flowing at $+q$ for a time of $t + \Delta t$ can be expressed:

$$\Delta P_{(t+\Delta t)} = \frac{\mu q}{4\pi kh} \ln\left(\frac{\gamma\phi\mu c r_w^2}{4k(t+\Delta t)}\right)$$

and similarly,

$$\Delta P(\Delta t) = \frac{-\mu q}{4\pi kh} \ln\left(\frac{\gamma\phi\mu c r_w^2}{4k\Delta t}\right).$$

Adding these together:

$$P_i - P_{\text{well shutin}} = \frac{q\mu}{4\pi kh} \ln\left(\frac{t+\Delta t}{\Delta t}\right).$$

In standard petroleum engineering units

$$P_i - P_{\text{well shutin}} = 162.6\, q \frac{\mu B}{kh} \log \frac{t+\Delta t}{\Delta t} .$$

This equation forms the basis for the Horner method. As can be seen from the equation, when $(t + \Delta t/\Delta t)$ and $P_{\text{well shutin}}$ are plotted on semilog paper, the data should plot as a straight line with the slope $= \dfrac{162.6\, q\mu B}{kh}$.

Therefore:

$$\frac{kh}{\mu} = \frac{162.6\, q\, B}{\text{slope}}$$

The skin value can be calculated as discussed in the previous section:

$$S = 1.151 \left[\frac{P_{1\text{ hour}} - P_{\text{flowing}}}{\text{slope}} - \log \frac{k}{\phi \mu c r_w^2} + 3.23 \right]$$

In order to estimate the skin value an independent estimate of ϕch must be available. In the petroleum industry, this is usually obtained by testing cores in the laboratory. For geothermal reservoirs this is best estimated from the analysis of interference test data.

Analysis of Unsteady State Radial Flow in Isotropic Nonleaky Artesian Aquifer with Fully Penetrating Wells and Constant Drawdown Conditions

Analysis in Water-Well Terms — Curve Matching Techniques. For a flowing artesian well, it may be simpler to test the well with a constant drawdown and a varying flow rate than with the methods, already discussed, that require a constant discharge and variable drawdown. Under geothermal conditions, the well would need to be preheated by flowing at a low rate before the test so that thermal effects on pressure at the well will be largely eliminated. Jacob and Lohman[13] found the solution to the general equation for these conditions as follows:

$$Q = 2\pi T s_w G(\alpha)$$

where

$$\alpha = \frac{Tt}{S r_w^2}$$

and

$$G(\alpha) = \frac{4\alpha}{\pi} \int_0^\infty x e^{-\alpha x^2} \left[\frac{\pi}{2} + \tan^{-1} \left(\frac{Y_0(x)}{J_0(x)} \right) \right] dx \qquad (32)$$

where

$J_0(x)$ = zero order Bessel function of the first kind

$Y_0(x)$ = zero order Bessel function of the second kind.

The function $G(\alpha)$ is available in Jacob and Lohman[13] or Walton.[14]

A curve matching technique is used for the well test. Values of Q/s_w (ordinate) are plotted against t/r_w^2 (abscissa) on log paper (or plot Q versus t). This well test plot is superimposed over the type curve $G(\alpha)$ (ordinate) versus α (abscissa). A match point is chosen and the aquifer constants determined from

$$T = \frac{Q}{2\pi s_w G(\alpha)}$$

and

$$S = \frac{Tt}{\alpha r_w^2} \quad . \tag{33}$$

Analysis in Water-Well Terms — Straight Line Approximations. Jacob and Lohman[13] observed that the function $G(\alpha)$ can be approximated closely by $2/W(u)$ for all except very small values of t. The approximation of $W(u)$ by the first two terms of the infinite series in Equation (16) has already been noted. Thus, it can be expected that (s_w/Q) versus log (t/r_w^2) will plot as a straight line since by substitution in Equation (32),

$$Q = \frac{4\pi T s_w}{2.3 \log \left(\dfrac{2.25\ Tt}{r_w^2 S}\right)}$$

or

$$\frac{s_w}{Q} = \frac{2.3 \log}{4\pi T} \left(\frac{2.25\ Tt}{r_w^2 S}\right) \quad . \tag{34}$$

The test data are plotted as (s_w/Q) (ordinate) against log (t/r_w^2) (abscissa), where Q is the average discharge during a timed interval in the test (L^3/T). A straight line is fitted to the data and the slope (the change in $\Delta(s_w/Q)$ over log cycle) and the intercept (the value of t/r_w^2 at $s_w/Q = 0$) are noted. Then

$$T = \frac{2.3}{4\pi\Delta(s_w/Q)}$$

and

$$S = 2.25\ T \left(t/r_w^2\right)_0 \tag{35}$$

$$S = \frac{2.25\ Tt/r_w^2}{\log^{-1}\left[\dfrac{(s_w/Q)}{\Delta(s_w/Q)}\right]} \quad . \tag{36}$$

If the intercept is diffficult to obtain because of the distant extrapolation required, the S may be determined from Equation 36

where

s_w/Q = value taken near the middle of the straight line plot

and

$\Delta(s_w/Q)$ = change in the value over one log cycle.

Analysis in Petroleum Engineering Terms. The constant-pressure flow testing has been described by Earlougher[3] in petroleum terminology. For the curve matching technique, the test data are plotted as flow rate (q) in STB/D (ordinate) against time (t) in hours (abscissa) on log-log paper. The data are superimposed over the type curve, q_D (t_D), on the same type of log-log paper as given by Earlougher.[3] Once the best superposition has been found, the coordinates of a match point are recorded. Then:

$$k = \frac{141.2\ B\mu}{(p_i - p_{wf})^b} \left(\frac{q_m}{(q_D)_m}\right)$$

and

$$(\phi\ c_t b) = 0.0002637 \quad \frac{kb}{\mu r_w^2} \left[\frac{t_m}{(t_D)_m}\right] . \qquad (37)$$

A zero skin factor is assumed in the type curve, and P_{wf} = flowing bottom hole pressure (psi).

A straight-line method has also been developed which is within 2% when $t_D \geq 5000$. A skin factor is included in the formulation. In the method l/q is plotted versus log t and a straight line is fitted to the data. The straight line slope, m_q, and the intercept at t = 1 hour, $(1/q)_{1\ hr}$ are recorded. Then:

$$k = \frac{162.6\ B\mu}{m_q\ (p_i - p_{wf})^b}$$

and

$$S_s = 1.1513 \left[\frac{(1/q)_{1\ hr}}{m_q} - \log\left(\frac{k}{\phi\mu c_t r_w^2}\right) + 3.2275\right] . \qquad (38)$$

Well Losses

The total drawdown, s, during a test of a production well is made up of some or all of the following parts:

s_f = formation loss due to the laminar flow through the aquifer towards the well

s_w = well loss due to turbulent or near turbulent flow through the developed zone and/or the gravel pack and the well screen

s_p = additional formation loss due to the effects of partial penetration of the well into the aquifer

s_d = additional drawdown in cases of dewatering a portion of the aquifer

s_b = drawdown due to barrier boundaries of the aquifer

s_r = buildup due to recharge boundaries of the aquifer

s_T = apparent drawdown or buildup due to temperature effects.

Stated as an equation

$$s = s_f + s_w + s_p + s_d + s_b + s_r \pm s_T . \qquad (39)$$

Step Drawdown Tests for Well Losses

In many wells where there are no effects due to partial penetration or dewatering, the test may not go on long enough to be affected by boundaries and temperature effects may be negligible due to preheating. Thus, only the first two terms of the equation remain.

In laminar flow the drawdown is related linearly to the flow rate, Q, while in turbulent flow it is related to some power of Q near 2 as suggested by Cooper and Jacob:[12]

$$s = s_f + s_w = C_fQ + C_wQ^n . \tag{40}$$

Rorabaugh[15] developed a graphical procedure whereby C_f, C_w, and n are evaluated from a step drawdown test. The procedure is to pump the well at a selected Q until s changes little with time; then Q is immediately increased and s is measured after the same time interval as used for the first step; and the process is repeated for four or five values. No recovery of the well is allowed between different pumping rates. Equation (40) can be rewritten as:

$$\frac{s}{Q} - C_f = C_wQ^{n-1}$$

or

$$\log\left(\frac{s}{Q} - C_f\right) = \log C_w + (n - 1)\log Q . \tag{41}$$

Thus $(s/Q - C_f)$ versus Q on log-log paper will plot as a straight line with a slope of $(n - 1)$ and an intercept C_w where $(s/Q - C_f) = 1$. Such a plot cannot be constructed, however, since C_f is not known. The procedure is to assume different values of C_f and plot a series of lines until a value of C_f is formed that makes the plot a straight line, as illustrated in Figure 16 which is taken from Bouwer.[16]

In the example, $C_f = 0.004$ gives a straight line whose slope is $n - 1 = 1.3$ and thus $n = 2.3$. In actual tests n may be as high as 3.5 but is usually near 2. The value of C_w can be determined by extrapolating the straight line to where $(s/Q - C_f) = 1$ or, alternatively, known values of C_f, n, s, and Q can be substituted into Equation (41).

Once the constants in Equation (41) are known, estimates can be made of the drawdown, s, for different (increased) values of flow rate, Q.

In petroleum parlance, the step drawdown test is called the "flow after flow" test.

Pulse Tests

If the well is allowed to recover for a time between increasing flow rate steps, the procedure is known as a pulse test. In petroleum terms, this test is called the "modified isochronal flow test." A "pulse test" in petroleum engineering is a multiple well test in which flow rate pulses of constant rate with equal shut-in periods in between are produced and the resulting pressure changes are recorded in a nearby observation well.[3]

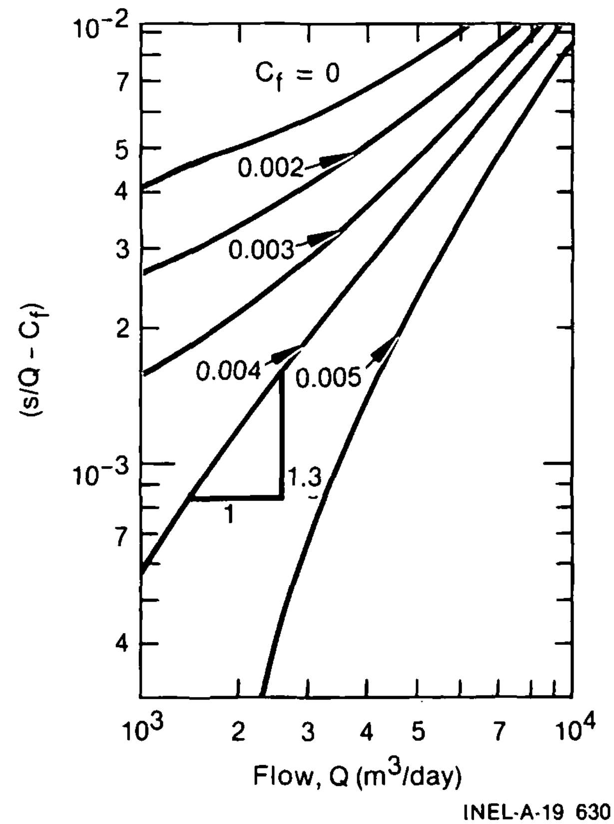

Figure 16. A plot to determine C_f.

Superposition of Solutions Applied to Multiple Wells and Multiple Rates

The drawdown at any point in a confined aquifer with more than one well is the sum of the drawdowns that would occur from each well individually. This is so because Equation (12) is linear (that is, there are no cross terms of the form $(\partial h/\partial r)$ $(\partial h/\partial t)$. Thus, in terms of well functions, one can write for a system of n wells, each with different flow rates:

$$s = \frac{1}{4\pi T} \sum_{i=1}^{n} Q_i \, W \left(\frac{r_i^2 S}{4Tt_i} \right)$$

$$i = 1, 2, 3, \ldots n \qquad (42)$$

where

s = drawdown at a selected location

r_i = distance from the selected location to the i^{th} well

and

t_i = time since pumping began at the well whose flow rate is Q_i.

A negative flow rate can be used to represent injection of fluid at a well. The equation also defines the interference of wells with each other.

This principle can also be applied to multiple flow rates at one well as given by Bear[17] and illustrated in Figure 17. For these conditions

$$s = \frac{1}{4\pi T} \sum_{j=1}^{m} (Q_j - Q_{j-1}) W \left[\frac{r^2 S}{4T(t - t_{j-1})} \right] \qquad j = 1, 2, 3, \ldots\ldots m \tag{43}$$

where

Q_0 = 0 at $t \leq 0$

s = drawdown at a given point a distance r from the well at time t

t_j = time since pumping began at rate Q_j

and

index j identifies the pumping period.

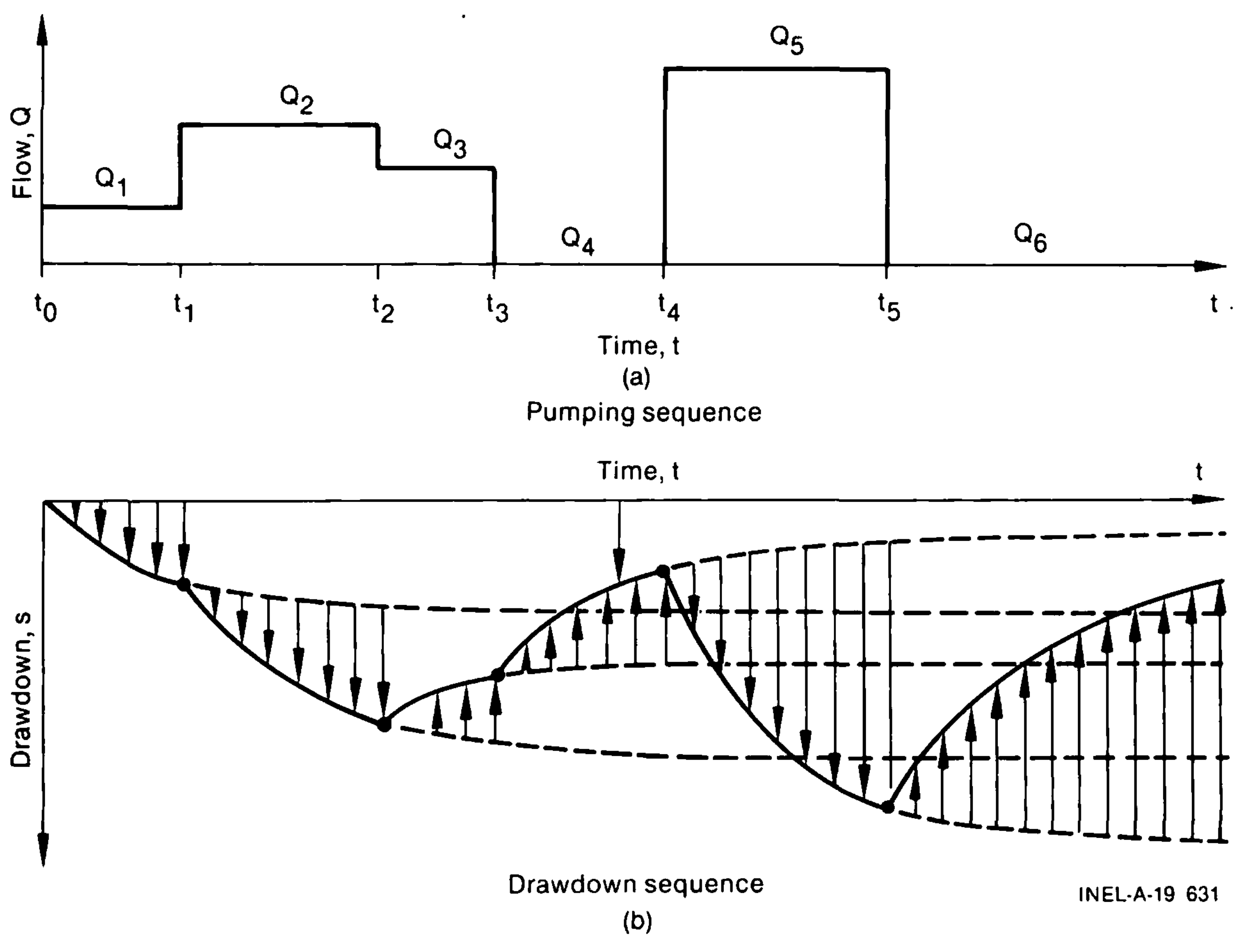

Figure 17. Multiple pumping rates.

The Effect of Fluid Density on Water Level and Wellhead Pressure Measurements

If it is not possible to obtain downhole pressure transient data, the free water level in a well (or the wellhead pressure) must be used for all pressure transient measurements. When the static level or wellhead pressure is used for pressure transient calculations, it is important to understand the effects of changes in density of the fluid filling the wellbore. The density of the fluid in the wellbore is dependent on the temperature and salinity of the fluid. Since the salinity will probably remain relatively constant throughout the test, only the change in density due to temperature will be considered. The density of water as a function of temperature is plotted in Figure 1.

If static water level (SWL) is the water level in the wellbore, the reservoir pressure can be calculated as follows:

$$P_{res} = \int_0^{H - SWL} \rho g \, dz + P_{wellhead}$$

where

SWL = static water level (m)

ρ = fluid density (kg/m^3)

g = gravitational constant (m/s^2)

z = depth (z = 0 reservoir)

H = length of the wellbore (m)

P_{res} = reservoir pressure (Pa).

If the density of the fluid along the entire length of the wellbore is known, then the integral can be evaluated and the reservoir pressure determined. Several examples are given below.

Example 1

What will the SWL be if the temperature of the wellbore changes from a 50°C isothermal profile to a 100°C isothermal profile?

$$P_{res} = \int_0^{H - SWL(50°C)} \rho g \, dz = \int_0^{H - SWL(100°C)} \rho g \, dz \ .$$

If ρ is only a function of temperature, and the temperature is constant, then it is trivial to evaluate the integral

$$P_{res} = \rho(50°C)g\ (H - SWL_{50°C}) = \rho(100°C)g\ (H - SWL_{100°C}) \ .$$

To convert P_{res} from psi to Pa, multiply by 6895 Pa/psi.

The difference in static water level can be calculated for several well depths (h).

P_{res} (psia)	H (m)	$SWL_{50°C}$ (m)	$SWL_{100°C}$ (m)
120	100	13.82	10.73
600	500	69.14	53.65
1200	1000	138.3	107.3
2400	2000	276.6	214.6

Example 2

What will the approximate SWL be in a well with a linear temperature gradient (with 50°C at the SWL and 150°C at the reservoir) compared with a hot wellbore at 150°?

$$P_{res} = \int_0^{H - SWL} \rho g \, dz$$

$$\rho(T) \approx 980 - 0.75\,(T - 50°C)$$

$$T(z) \approx 150 - 100\frac{z}{H}$$

$$\text{so: } \rho(z) \approx 980 - 75 \quad 1 - \frac{z}{H}$$

$$P_{res} = \int_0^{H - SWL} \left[980 - 75\left(1 - \frac{z}{H}\right) gdz\right]$$

P_{res} (psia)	H (m)	$SWL_{Linear\ Gradient}$ (m)	$SWL_{150°C}$ (m)
120	100	9.75	6.7
600	500	50.3	33.4
1200	1000	100.6	66.8
2400	2000	201.2	133.7

As can be seen from the two examples presented above, the temperature of the fluid has a large effect on the SWL. When the temperature changes as a function of depth in the wellbore, it is diffficult to separate this phenomena from true pressure changes in the reservoir. This phenomena is particularly important to understand in the interpretation of pressure build-up data because the wellbore quickly starts to cool when the well is shut-in. The effects of the density changes in the wellbore fluid on the measured pressure response can be eliminated in two ways: by using downhole pressure instrumentation, or by using a wellbore code to calculate the temperature of the fluid in the wellbore.

As can be seen from the two examples, the density changes of the fluid will have the most pronounced effect on deep wellbores. For a wellbore length of less than than 100 m, these changes may not be significant. However, for a deep well (500 to 2000 m), even small temperature changes will dramatically affect the SWL or wellhead pressure.

7. TEST PLANNING AND METHODOLOGY

Preliminary Test Preparation and Design

Before planning a test the developer and his hydrogeologic/reservoir engineering consultant should review the local, state, and federal regulations for fluid production and disposal. These regulations are available through individual state geothermal resource teams, the state water resource or oil and gas department, the U.S. Geological Survey, or the Environmental Protection Agency. Special permits to produce and dispose geothermal fluids may be required. Therefore, any limitations or restrictions must be considered before designing the test. Certain restrictions (i.e., discharge of geothermal fluids to lined ponds only) will raise the cost of testing and limit test duration and/or test discharge rates which could result in inappropriate or inadequate data. The restrictions will probably depend on the water quality, the temperature of the thermal fluid, and/or the compatibility with local water resources. Some eastern states, such as New Jersey, require all geothermal fluid, including any testing fluid, to be discharged into an injection well. Thus, testing of any production or test well will require the additional cost of an injection well.

After the developer or consultant has evaluated and made allowances for testing regulations they need to determine the end use of the well, i.e., whether it will be a production or a test/monitor well. They then need to determine whether the reservoir is intergranular permeable, fracture-controlled, or has dual porosity. If the type of reservoir is unknown, it should be treated as a fracture flow case.

The first design decision to be made is whether to test produce the well using a pump or by natural artesian flow. This decision will be clear cut if artesian conditions are not present. An air lift or nitrogen lift test is not recommended for geothermal resources because flow rate control is at best diffficult. For a production well test, the anticipated end-use method of producing the geothermal fluid should be used. However, for test wells, the less expensive method of artesian flow testing is recommended. If a moderate temperature resource is being tested, the additional factor of flashing (boiling) at the wellhead or orifice must be considered. At temperatures greater than approximately 100°F, suffficient pressure must be maintained across a fluid discharge measuring device to prevent flashing, otherwise expensive two-phase measurement equipment will be necessary. If the well is to be artesian flow tested, an additional possibility must be considered, i.e., can the well be completely shut-in? If the well cannot be shut-in, the capability of flow rate regulation is necessary. In all cases the consultant should determine the testing parameters and be sure that all relevant data can be obtained and pertinent variables controlled.

Test Pump. If a pump is required, the consultant must select the pump, determine the pump elevation setting, and evaluate the pump limitations. A combustion-engine-driven pump is recommended for testing as this will allow for a wide range of discharge rates. An additional reason for using a test pump rather than the intended production pump is the potential damage to the pump by the corrosive nature of early postdevelopment discharge fluids. The estimated pump setting depth should be developed from the data collected during the drilling and development process. It is better to set the pump deep rather than run a test at too low a flow rate or for too short a time, or to be forced to pull the pump out and set it deeper.

There are technical problems with off-the-shelf, water well type pumps even at low temperatures. The main problems are in lubrication of moving parts, cooling of motors and moving parts, and differential expansion. Information from several brand name pump distributors suggests that warranties on submersible pump motors will not be honored at temperatures above 37.8°C. Vertical turbine pumps can be used for extended periods of time in geothermal fluids if care is taken to account for differential thermal expansion and lubrication. In addition, the corrosive nature of the geothermal fluid must be considered in selecting pump materials.

Test Instrumentation. After anticipated drawdown, temperature, and flow rates have been estimated, instrumentation suitable to measure those parameters should be chosen. The recommended accuracy and resolution of the data limits or restricts the instruments that should be used. Most off-the-shelf, low-cost pressure gauges are not suffficiently accurate or do not have suffficient resolution. On the other hand, it may be uneconomical for the developer of a low-temperature resource to use the sophisticated and expensive surface or downhole instrumentation used in moderate- to high-temperature geothermal developments. One alternative for low-temperature resources is that the producing well be supplied with a continuous bubbler tube in conjunction with moderate-cost surface gauges that at least meet the resolution requirements. This will reduce early-time thermal effects and result in accurate relative change of pressure or water level. It is also recommended that fluid discharge temperature data be obtained continuously or at least on the same measurement schedule as pressure and discharge rate. It is also necessary to consider the thermal effects on the instrument operation. Economical instrumentation, due to the required accuracy and resolution and due to thermal problems, is currently a problem in low-temperature geothermal development. Additional cost-effective instrumentation needs to be developed.

Appendix C lists a variety of instruments employed in low-to-moderate temperature systems. A brief discussion of accuracy and resolution is also available for reference.

Test Parameters. General statements on test parameters are diffficult to make, because the test design depends on the information needed. The general recommendations provided here should be applied with extreme caution, and used only after the end use of the well and the purpose of the test has been determined.

The test parameters that need to be addressed at this time are a function of the test type, discharge rate, the duration of the test, and fluid temperature. The ''test type'' refers to the standard procedural well tests in the petroleum and ground water industries, i.e., step test, pulse test, constant-discharge variable-head test, etc. The recommended method and limits will depend not only on the decision path taken during test preparation and test design, but also on the dollar investment of the project. It is assumed for this document that the testing of moderate-temperature resources will be expensive.

Recommendations of test parameters for low-temperature cases are presented in Table 2.

Recommendations of test parameters for moderate-temperature cases are presented in Table 3. There is less divergence from standard ground water or petroleum testing procedures, because downhole instrumentation is subjected to minimal temperature change and eliminates the problems created by borehole density effects. Moderate-temperature cases that do not use downhole pressure/temperature instrumentation should follow the recommendations for low-temperature resources.

Testing Methods. Testing methods may be categorized according to the following:

1. Discharge or injection rate:

    a. Constant rate flow tests (variable drawdown)

    b. Multiple flow rate tests

    c. Variable flow rate tests (constant drawdown).

2. Flow duration:

    a. Step tests

    b. Pulse tests

    c. Short-term tests

    d. Long-term tests

Table 2. Recommended test parameters for low-temperature hydrothermal systems

	Test Well								Production Well							
	Intergranular Permeable				Fractured or Unknown				Intergranular Permeable				Fractured or Unknown			
		Flow				Flow				Flow				Flow		
Test Parameters	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control	Pump	Shut-In	Rate Control	No Rate Control
Type Test(s)	B CD R — —	B CD R — —	B CD R — —	B — — — CH	B CD R — —	B CD R — —	B CD R — —	B — — — CH	B Pr CD R —	B Pr CD R —	B Pr CD R —	B — — — CH	B Pr CD R —	B Pr CD R —	B Pr CD R —	B — — — CH
Flow Rate	RD	RD	RD	—	MP	MP	MP	—	RD	RD	RD	—	E	E	E	—
Minimum duration (days)	2-4	2-4	2-4	30+	3-7	3-7	3-7	30+	5-10	5-10	5-10	30+	10-20	10-20	10-20	30+

Legend
- B = Borehole temperature log (if possible)
- CD = Constant-discharge variable-head
- PR = Pulse and recovery
- R = Recovery
- E = End-use requirements
- MP = Maximum practical
- RD = Reduced discharge rate
- CH = Constant head, variable discharge

Data Requirements[a]

	Resolution	Accuracy
Pressure	1.0 psi	±1% F.S.
Temperature	±0.5°C	±1°C
Flow	±0.5% F.S.	±1% F.S.

a. See Reference 18.

Table 3. Recommended test parameters for moderate-temperature hydrothermal resources

	Test Well		Production Well	
Test Parameter	Intergranular Permeable	Fracture Control	Intergranular Permeable	Fracture Control
Type test(s)	StD R —	StD R —	S or P StD R	S or P StD R
Flow rate	RD	MP	RD	E
Minimum duration (days)	0.3-3	3-7	3-7	10-20

Assumes use of downhole instrumentation in production zone

Legend			
S or P	=	Step test or pulse test	
StD	=	Acceptable standard for testing	
	=	groundwater or petroleum resources	
R	=	Recovery	
RD	=	Reduced discharge rate	
MP	=	Maximum practical discharge rate	
E	=	End use requirements discharge rate	

Data Requirements (Lamers, 1974)

	Resolution	Accuracy
Pressure	1.0 psi	±1% F.S.
Temperature	±0.5°C	±1°C
Flow	±0.5% F.S.	±1% F.S.

3. Test geometry:

   a. Single well test

   b. Multiple-well production

4. Well tests with observation wells

5. Injection testing

6. Recovery tests.

Constant Rate Flow Tests — Constant rate flow tests are commonly used in both ground water and petroleum industries and are highly recommended for low-to-moderate temperature geothermal well testing. In the constant rate flow test, the desired pumping rate has to be obtained as fast as possible and maintained throughout the test duration. The flow rate is carefully monitored and adjusted if changes are observed. Pumping rates for a constant rate flow test should be carefully designed to provide enough flexibility for these adjustments. Drawdown and temperature data are collected according to a time schedule designed specifically for each test. An advantage to the constant rate flow test method is that analysis techniques are well developed.

Multiple-Flow Rate Tests — Multiple-flow rate tests are used to estimate well losses, specific capacity, well productivity, skin effects, and reservoir parameters. This type of test is commonly conducted before testing at constant rates to aid in subsequent test planning.

Variable Flow Rate Tests — The hydraulic properties of a reservoir can be determined from a well test in which the discharge rate varies with time and the drawdown remains constant.[19] The change in discharge rate is plotted against the logarithm of time. This type of test is most effective for an artesian flowing well. Thermal changes may cause problems in maintaining a constant head. This type of test is not normally used for testing geothermal wells.

Step Tests — A step test consists of an abrupt increase or decrease in the fluid discharge rate with no recovery allowed between steps. Each pumping rate is continued at a constant flow until the well approaches a steady flow condition, after which the discharge rate is abruptly increased or decreased to the next level. Each step interval may last from 30 minutes to four hours. This procedure is continued for several discharge rates. This type of testing is most useful in geothermal wells in which downhole instrumentation, i.e., downhole pressure bombs and temperature probes are used to collect data. This is because some time is required after each discharge change before the surface temperature becomes stable and temperature effects can be neglected.

Pulse Tests — Pulse tests are conducted at increasing or decreasing discharge rates with recovery allowed between each pulse interval. Data are collected for the pumping and recovery portions of each rate. Each pulse interval may last from one hour to several days. In geothermal well testing, longer pulses are recommended to provide enough time so that early recovery data with thermal effects will not have to be used. Pulse testing is not commonly used in the ground water industry. The petroleum industry uses this type of test to determine reservoir anisotropy.

Short- and Long-Term Tests — Duration of a test in terms of "long or short" is a relative measure; however, these terms are commonly used in practice. A test conducted for less than three days should be considered short-term. A long-term test is commonly conducted for more than three days with no defined maximum time limit. Tests of long duration are recommended more often in geothermal aquifer testing than in ground water or petroleum well testing. This recommendation is based on the following factors: the hydrogeology and geologic structure of a geothermal reservoir is often complex; reservoir volumes are so large that long production periods are needed to produce significant pressure responses; and there is no alternative method to predict resource temperature changes.

Single- and Multiple-Well Tests — Classification of tests by geometry includes single well tests and multiple-well tests. The multiple-well production test is more complex, and more diffficult to evaluate than single-well production tests. A single-well production test may be needed prior to the multiple well test to provide a basis for comparison. The multiple-well production test should provide information about both interference effects between wells and aquifer properties. In general, less precise reservoir data are obtained from multiple-production well tests due to reservoir heterogeneity.

Well Tests with Observation Wells — Generally, there is little difference between test procedures with or without observation wells. Tests with observation wells provide a more complete data base for evaluating aquifers. These data are average values for a large area of the reservoir. Whenever practical, the use of observation wells is recommended.

Injection Testing — Injection testing may be accomplished by injecting fluids from a body of surface water or a production well. The following factors should be considered when choosing the injection interval:

1. Interference and cooling effect on a production zone

2. Environmental impact of the injected fluid on a potable ground water aquifer

3. Cost of the injection well.

Data on injection rate, wellhead temperature, and wellhead or downhole pressure are collected from the injection well. Injection test data are analyzed by the same methods as the previously discussed test data. Because disposal of the geothermal fluid by injection is often necessary, injection testing may be used frequently in geothermal fields. However, care should be taken to prevent damage to the formation due to clay swelling or fluid incompatibility. Injection testing, as a means of determining reservoir parameters, is not recommended in sedimentary formations.

Recovery or Fall-Off Testing — A recovery or fall-off test should follow all production or injection tests. Measurements of pressure or head recovery begin immediately after pumping or injection is stopped. Theoretically, the recovery phase should last as long as the production/injection phase. If surface instrumentation is used for a geothermal well, time-dependent fluid-density effects will limit the usefulness of early-time data. An advantage in analyzing recovery data is that major fluctuations in discharge have minimal effect. It should be stressed that recovery data are as important as production data and often are of better quality. This is one of the most common test methods used by the oil and gas industry.

Reservoir Parameters

The following well and reservoir parameters, determined by analyzing test data, are given in order of increasing complexity:

1. Specific capacity and well effficiency
2. Aquifer transmissivity (T) and storativity (S)
3. Skin factor and wellbore storage
4. Well-loss constant
5. Aquifer permeability (k), or thickness-permeability product (kh) and porosity-compressibility-thickness product (ϕcth).

Definitions of Key Parameters.

Specific Capacity and Well Efficiency — The specific capacity (productivity index) of a well is its yield per unit of drawdown at a specific time and is a practical number characterizing a given well. Generally, high specific capacity indicates high aquifer transmissivity. Correlation between specific capacity and transmissivity can be made;[20] however, it is not recommended for final aquifer evaluations. The higher the specific capacity, the better the well. A good geothermal well may have a productivity index as high as 50 gpm/psi drawdown.

Well effficiency is the ratio of the theoretical drawdown in the formation to the actual drawdown measured in a pumped well including well losses. Specific capacity and well effficiency are well parameters widely used in ground water well-testing methods.

The ratio of the rate of production to the pressure drawdown at midpoint of the producing interval is called the productivity index. The productivity index is a term used in the petroleum industry and is equivalent to the term specific capacity used in the water well industry. The index measures the well's potential to produce.

Aquifer Transmissivity (T) and Storativity (S) — Transmissivity is a term used in the ground water industry to characterize the ability of the aquifer to transmit a fluid. The transmissivity (T) is a number indicating the rate at which fluid flows through a unit width of the aquifer under a unit hydraulic gradient. Although, transmissivity characterizes a property of the aquifer, it is also a property of the transmissivity fluid.

Storativity is the ground water term used to express the storage capacity of an aquifer. The storativity (S) is a number indicating the volume of water released from or taken into storage per unit surface area of the aquifer per unit change in head. Storativity (S) is dimensionless.

Skin Factor and Wellbore Storage — The skin factor is a petroleum term which is represented by a steady-state pressure drop of the well face in addition to the normal transient pressure drop in the reservoir.[3] The skin factor increases or decreases the pressure change of the well, depending on the flow rate of the well. Wellbore storage affects the short-time transient pressure behavior in the test well. The skin factor and wellbore storage both affect the early-time portion of the data. These effects can be accounted for in test analysis.

Well-Loss Constant — The well-loss constant characterizes the losses due to the well screen plus the gravel pack or developed area near the well and can be evaluated from a step test or several pulse tests. A properly developed well has a well-loss constant less than 5 sec^2/ft^5.[20]

Aquifer Permeability, Thickness-Permeability Product and Porosity-Compressibility Thickness Product — Aquifer permeability (k) or the absolute permeability of the rock,[2] is a property of the rock and not of the fluid which flows through it. The unit of permeability used in the petroleum industry is the Darcy unit. A rock of one Darcy permeability will allow a fluid of one centipoise viscosity to move at a velocity of one centimeter per second under a pressure gradient of one atmosphere per centimeter.[2]

The thickness-permeability product (kh) is a term characterizing the fluid transmitting ability of the aquifer. The thickness-permeability product is a petroleum industry term which is somewhat similar to the term transmissivity used in the ground water industry. The difference is that the transmissivity characterizes fluid transmitting aquifer properties for a fluid, and thickness-permeability product is independent of the fluid.

The porosity-compressibility-thickness product ($\phi c_t h$) is a term used in the petroleum industry that is equivalent to the term storativity used in the ground water industry. The unit used for the porosity-compressibility-thickness product is in ft/psi.

Analyzing Test Data.

Evaluating Early-Time Data — Data which are not thermally affected are evaluated according to standard petroleum and ground water techniques.[3,14] However, all of the techniques are not applicable. The methods recommended in Table 4 are general categories of techniques which should be applied. The specific techniques applicable to each category will depend on the quantity and quality of the reservoir test data plus other geologic and hydrologic inferences gathered during the exploration and drilling phases. These specific techniques are described by Walton,[14] Earlougher[3] and others conversant in the ground water and petroleum fields.

Early-time data emphasized in the ground water and petroleum industries are often not as useful in analyzing low-temperature geothermal production wells due to thermal and density changes effecting surface data. These problems can be eliminated by collecting downhole data.

The recovery data may also be affected by time-dependent thermal changes if downhole data is not used. The thermal effect increases with time from the start of recovery. This means that early-time recovery data is important and late-time data becomes hard to analyze.

Analyzing Fracture Flow — Fracture flow analysis has been discussed by numerous authors, i.e., Warren and Root, Papadopulos, Rofail, Gringarten, Streltsova, Dugiud, and Aquilera.[21-28] Most analytical methods assume either a single fracture for production or a block response. The solutions are for the most part not analytical or field oriented, but computer model comparisons. Field analyses of fractured systems have conventionally relied on anisotropic analysis of intergranular permeable systems. The assumption that fracture flow averaged over a large enough area, acts like an intergranular permeable system, is not unreasonable.[29] However, this approach suggests that early-time data may not be useful.

Evaluating Reservoir Parameters — A critical part of well test analysis is evaluation of reservoir parameters. The theoretical background and essential elements of well test analysis were presented in Section 6. This section presents several methods developed by the ground water and petroleum industries that are commonly used in the geothermal industry as well.

Table 4. Recommended test analysis methods for low-temperature hydrothermal development

Type Well	Test Type	Considerations	Recommended Methods: Intergranular Permeability	Recommended Methods: Fracture Controlled
Production	Pulse	Transient density skin effects or well loss wellbore storage boundaries	Graphical[a] (straight line)	Graphical[a] (straight line)
	Drawdown	Transient density	Graphical[a] (type curve or straight line)	Graphical[a] (type curve or straight line)
	Recovery	Same		
		Same	Transient and semisteady state (straight line)	Graphical[a] (straight line)
Observation	Drawdown and recovery	Anisotropy, boundaries	Transient and semisteady state (type curve)	Anisotropic and fracture methods (type curve)

a. Use of Q/s_{10} technique.

Evaluating Graphical Methods of Test Data — Graphical methods are commonly used in the water well and petroleum industries. One such method is the type-curve matching method.

Type Curves — The graphical methods of superposition provide one way of evaluating reservoir parameters. The type-curve matching analysis method may be used for drawdown, buildup, interference, and constant pressure testing. The method should be applied where downhole data are being obtained since early-time thermal effects will impact surface readings. Type curves are obtained by plotting selected values of W(u) versus u on a logarithmic graph paper.[5] For constant flow during a test W(u) is related to u in the same manner as drawdown is related to the r^2/t or l/t. Therefore, if the recorded values of drawdown are plotted on a logarithmic scale against r^2/t or 1/t on a similar logarithmic scale, the raw data curve should be similar in shape to the type curve. However, the two curves may be displaced both vertically and horizontally.

The type-curve-matching method used in the petroleum industry is similar to that used in the water well industry. Data are typically plotted in terms of logarithm pressure change versus logarithm test time. The type curve is in units of dimensionless pressure versus dimensionless time.

Standard type curves are developed for various aquifer geometries and conditions such as wellbore storage and skin effects. The type curve evaluation technique is widely used in water well industry and to some extent the petroleum industry. Use of type curves for geothermal well testing analysis is limited when using uphole data because of time-dependent thermal effects.

Straight-Line Solutions — The straight-line solution is another graphical method for aquifer test analysis when considering semisteady-state conditions. Typically, time is plotted on the logarithmic scale versus drawdown, which is plotted on a linear scale. The data points should ideally form a straight line.[12] The slope of water level change over one log cycle of time is needed to calculate reservoir parameters.

Recovery data should be analyzed using the ratio of time from start of pumping and time from start of recovery plotted on the logarithmic scales. Reservoir parameters are calculated using the same equation as for a drawdown plot.

If more than one observation well is used for data collection, a distance-drawdown plot may be used for test analysis.[8] Distance is plotted in the logarithmic scale and drawdown on the linear scale.

The straight-line plot is recommended for geothermal well testing. However, it must be remembered that time-dependent thermal effects on the water level data may significantly influence the plot. For example, an increase in water temperature may have an effect similar to a recharge boundary and a decrease in temperature during shut-in may appear similar to a barrier boundary.

Monitoring Observation Wells (Interference Tests)

Any well or spring within a 1 to 5 km radius of the producing well that is potentially connected hydraulically with the geothermal reservoir should be monitored during testing. The geology and construction of any observation wells should be evaluated. It will be necessary to determine the elevation of a measuring point relative to the producing well, and the use schedule of the observation well, if appropriate. Pressure measurement and the instrumentation for the observation wells should follow water well standards and practices.

There should be no diffficulties with thermal conditions at observation wells, unless the well is flowing and cannot be shut-in. If a well or spring is flowing, discharge, temperature and water quality measurements should be obtained.

If there are any wells or springs within a 1 to 5 km radius of the production well which cannot be shut-in for the test duration, it will be necessary to determine if there will be any potential hydraulic interference problems. If there are, discharge should be regulated during and after the test. If this is not possible, then at least a record of production from the observation well should be kept.

Fluid Disposal

The technical aspects of fluid disposal must be considered. This may mean calculating the fill rate of a pond to determine if the test can run for the projected duration at the desired discharge rate. It may mean determining the anticipated thermal or water quality change in a stream at the desired discharge rate. The disposal must consider the waste heat in addition to the water quality.

Because elevated temperatures increase solution kinetics and mineral solubility, geothermal waters tend to be higher in dissolved solids than surrounding ground waters. Thermal waters can also have high concentrations of particular dissolved species that may cause special disposal problems, such as arsenic, mercury, boron, or fluoride. Environmental regulations generally prohibit the disposal of efffluents into surface streams where the efffluent will degrade the quality. Table 5 lists the dissolved species most likely to be present in troublesome quantities in geothermal fluids. Water samples should be collected and analyzed for these species to evaluate the potential for disposal problems. In addition to chemical aspects, thermal pollution from disposing fluids also must be controlled.

Test Procedures

Before beginning the actual reservoir test, it is necessary to meet all the facility requirements. This may mean installing power for a pump, instruments, or lighting. It would also mean obtaining permission to monitor a well on private land or constructing access roads. The pump, production well instrumentation, and the observation well instrumentation should be installed at this time. Any technicians or professionals who will be involved with the test should be trained in the operation of the pump and testing instrumentation. In addition, the field staff should understand the anticipated data responses during the test.

Table 5. Dissolved species found in geothermal waters

Total dissolved solids	Boron
Chloride	Arsenic
Sulfate	Sulfide
pH	Carbon dioxide
Fluoride	Mercury

The reservoir test begins with obtaining background data on all the wells and springs to be monitored (historic water levels, temperature, chemistry data). These data will be used to determine short- and long-term trends in order to correct the test data for these trends. The required duration of background monitoring will vary according to the site. It is recommended that the minimum duration be at least equal to the duration of the intended reservoir test.

The next step is to determine if suffficient field support has been employed for the reservoir test. The required number of people will depend on the disposal method, the number of monitor wells and springs, the distance or travel time between monitor wells and springs, and the type of instrumentation at each monitoring site. It will be desirable to have more assistance during the early-time rapid measurements of the production and recovery portion of any test. If there is insuffficient field assistance, then additional help should be employed and properly trained.

A static or nonproducing borehole temperature log of the production well should be run at or before this time. It may be preferable for technical and economic reasons to run this log before setting a pump. The log should be recorded while entering the well (logging down) to minimize any thermal disturbance (mixing) within the well. Finally, the data will be used for calculating time-dependent changes in fluid density and early-time thermal borehole storage effects in the producing well. A temperature log obtained after drilling was completed may be used, if the time between drilling and testing was less than three to five days. Otherwise, a new temperature log is recommended.

Preheating of the wellbore should be considered before the start of testing if pressure or water-level information during the test is to be obtained in any portion of the well that sees a temperature change. The well or spring should be preheated by producing at 10 to 20% of the intended testing discharge rate. The preheating lessens the time-dependent density changes during the test, and usually does not cause problems with the latter analysis.[30] The preheat procedure should continue until the discharge temperature is constant.

A step rate or pulse test should be run in order to determine the optimal flow rate for a long-term test and the productivity index. A standard water well step test and analysis may be run if the pressure or water level data do not have time-dependent density changes (downhole data). A step test is not recommended if downhole data are not available due to probable thermal changes at the differing discharge rates. The variable thermal conditions and the short duration of most step tests make comparison and analysis impractical. At least two pulse steps are recommended, one at a higher rate and one at a lower rate than the intended end-use production rate. The highest rate should be run first to aid in preheating the borehole. The duration of each pulse and recovery will depend on the time required to reach thermal equilibrium at the wellhead and obtain suffficient analyzable pressure or water level data. This may be on the order of four to eight hours per pulse. If a step test is run, one to four hours may be required, since the wellbore should be stabilized by the inital high rate step test.

The discharge rate for the long-duration test will depend on the well type, reservoir type, drilling data, etc. and the pulse test data. The end-use required rate be used for all fracture-controlled type springs or wells. The end-use rate is recommended due to the low reliability of standard extrapolation techniques in fractured rock reservoirs.[31] A higher than end-use rate is not recommended, as extrapolation of temperature for the lower rate is not reliable. If there is no specified end use requirement, the test should be conducted at the maximum possible rate. A reduced discharge rate (less than the end-use production rate) can be used for intergranular permeable reservoirs.

The recommended test duration for low-to-moderate temperature geothermal resources is somewhat longer than a standard cold-water aquifer or petroleum test to allow for stabilization of early-time thermal effects. Also, the test duration for fracture flow cases should be somewhat longer than intergranular permeable cases due to problems in the analysis and projection of reservoir longevity. In general, the longer the test, the more reliable the data.

After concluding the production phase of a test, it is important to obtain recovery data level/pressure at the production well and at all monitor wells and discharge rates at all springs. The duration of the recovery portion of a test will depend on the type of instruments used and/or the rate of cooling in the production well. In the water well and petroleum fields, one would expect the recovery portion of a test to run approximately the same duration as the production portion. In low-to-moderate temperature geothermal systems, the recovery portion of a test (considering the production well only) will be of shorter duration. This is a result of thermal effects. The recovery data at a production well is especially useful if the discharge rate during the test was somewhat erratic or had several step changes. The evaluation technique assumes a constant discharge rate by averaging the discharge during the production. Recovery data are also useful for a monitor well to confirm that a water level/pressure response was due solely to the test and not part of a short- or long-duration background trend.

8. GEOCHEMISTRY

Geochemical information on geothermal fields both supplements hydrologic information and provides additional data. For instance, chemical logging during drilling can indicate the presence of cold and hot aquifers and aids in the placement of casing. Subsurface temperature can be estimated with chemical geothermometers. Isotopic composition variations in water can be used to determine sources of water, the occurrence of boiling in the reservoir, or the amount of interaction between water and wall-rock. The chemical composition of the water may foretell of problems with corrosion or scaling, or may indicate environmental problems from specific dissolved species. The scope of this section is to provide information available from geochemical studies and to briefly describe the geochemical methods involved.

Chemical geothermometers may be used to estimate aquifer temperatures in wells weeks or months before underground temperatures return to normal after drilling. Flow testing may speed the temperature recovery in the production zone, but interferes with obtaining information about predrilling temperatures elsewhere in the well. Also, extensive flow testing immediately after the termination of drilling is not always possible because of fluid disposal problems or delayed delivery of test equipment. Production and collection of a small amount of fluid at the wellhead or from a downhole water sampler, however, may be all that is necessary to provide a good indication of the aquifer temperature.

Where well design requires interruption of production of a geothermal well to run a temperature log, geochemical temperatures may be monitored. Logging wells is also a relatively slow process, and a temperature survey of a field with several production wells could take many days or weeks. Monitoring temperatures of waters supplying drillholes can be accomplished using the silica content of water where calculated temperatures and downhole measured temperatures are in close agreement. Water samples can be collected without interrupting production. Mahon[32] has shown that the silica concentration in the water entering wells decreases at Wairakei, New Zealand, in response to decreasing temperatures in the aquifer.

By producing a well at various flow rates, the contribution to total discharge from multiple aquifers may vary. If different aquifers have different chemical compositions, and different pressures or transmissivities, the chemical composition of the discharge fluid would change as the production rate was varied. Collection of water samples during a step drawdown tests could be analyzed to detect production from different aquifers.

The following subsections present a brief overview of some of the geochemical methods that can be used in low-to-moderate temperature geothermal reservoirs.

Chemical Logging

The growth of the geothermal industry has created a need for techniques that can be used during drilling operations to determine the depth at which to complete a well, depth for casing placement, and the best method for well development. Techniques developed by the petroleum industry, such as geophysical logging, lithologic logging, and core drilling, can be useful. However, little development has been oriented toward the specific conditions encountered during geothermal exploration and well drilling. Chemical logging[33] is one of the methods developed at the Raft River KGRA for geothermal applications.

Chemical logging can indicate the depth and relative flow of geothermal aquifers penetrated during drilling. The method involves periodic collection of drilling fluid for chemical analysis while drilling is in progress. A chemical log is prepared by plotting the concentrations of the analyzed chemical species, or their ratios, versus drill string depth. The resulting log is a profile of chemical changes taking place in the drill fluid during the drilling operation. Changes in the chemical composition of drilling fluids indicate the entrance of formation waters into the wellbore. Changes in particular species indicate the presence of geothermal water.

Changes in the chemical composition of the drilling fluid result from mixing the fluid with water from aquifers penetrated by the drill string. Figure 18 is a cross-sectional view of a drill string that has penetrated several water-bearing strata. Drilling fluid is pumped through the drill stem and bit and returns to the surface between the drill stem and the wall of the borehole carrying the drill cuttings with it. When a water-bearing stratum is penetrated, it contributes water to the drilling fluid, diluting the fluid and causing variations in its chemical composition. Generally, after the drill string passes through the water-bearing stratum, the drilling mud or sediments in the drill water form a mud cake on the walls of the borehole, sealing off the aquifer. If the flow from the stratum is too great and the stratum is not sealed by the mud cake, the incoming water will produce a permanent change in the background chemical composition of the drilling fluid. The chemical log determines the change in chemical composition of the drilling fluid as each aquifer is penetrated; it also determines the separation of this change from the chemical background contributed by the drilling fluid.

Interpretation of chemical logs is complicated by a number of factors, the most important of which are the effects of drilling mud on the composition of drilling fluids. Drilling muds absorb much of the free hydrogen ion in the solution raising the pH, and consequently the alkalinity. Other cations will also be affected by ion exchange reactions, but anions will be relatively unaffected. Problems arising from this will not seriously interfere with the chemical logging technique because the plot with depth will show changes relative to the background, which are more important than the absolute values of species. Instances when the drilling fluid is changed, for example when drilling mud is replaced by mud-free water, will make comparisons between different parts of the hole diffficult, if not impossible.

Sampling Procedure

The procedure is to collect samples of the drill return fluid at specified depth intervals. Drill fluid is pumped from the mud pit, through the drill string, and returns up the borehole between the borehole walls and the drill stem. Drilling fluid samples are collected where the drill-return fluid enters the mud pit. Samples of 4 to 5 L should be collected to ensure an adequate sample size when drilling mud is being used. Frequently, water is used as a drilling fluid in geothermal wells, in which case only 1-L samples need be collected.

Sampling frequency depends on the detail desired in the chemical log, and the proximity of the hole to the geothermal resource. Also, changes in drilling rate or other changes in drilling indicate that a sample should be collected. Sample frequency may vary from once every 100 m in the upper portion of the hole, to as often as every 5 to 10 m when proximity to the geothermal resource is anticipated. Sampling depths must be corrected for lag time or travel time in the wellbore. This information can usually be supplied by personnel compiling the mud log.

Drilling mud, cuttings, and other residues are separated from the water sample by centrifuging or filtering. In many cases, centrifuging will not settle gelatinous suspensions of drilling mud. Filtering with a coarse filter in a funnel, and a flask with side tube connected to a hand-operated vacuum pump is readily adapted to field filtration of samples.

Chemical species that will provide the most information when drilling in an area must be determined by comparing chemical analyses of cold-water aquifers, drilling fluid make-up water, and the geothermal resource. Those constituents that show the greatest differences in concentration among these water sources would be the best species to use in constructing the chemical log. Constituents that might commonly be expected to show large differences between geothermal and other waters are silica, fluoride, magnesium, chloride, specific conductance, and alkalinity. Also useful are ratios of constituents. Ratios may produce an even more sensitive log if the two species in the ratio show opposite behavior in the background water and in geothermal water.

By compiling the chemical log in the field, during drilling, the chemical log will have its greatest utility in locating geothermal zones as they are penetrated. During development at Raft River, the most useful log was

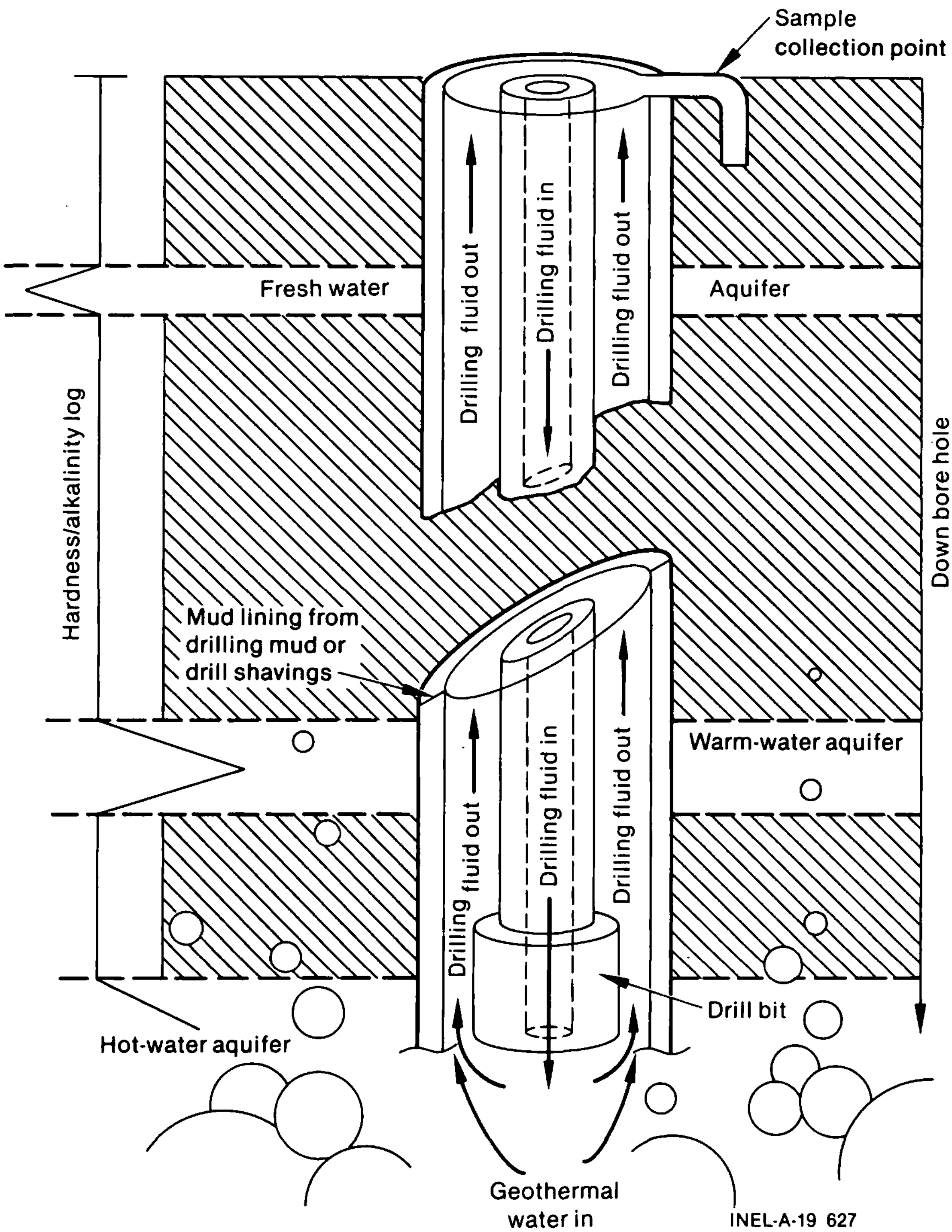

Figure 18. Changes in drilling fluid composition by fluid from a geothermal aquifer.

found to be the hardness-alkalinity ratio log. Both hardness and alkalinity can be measured very easily in the field by colorometric titration. Thus, information gained from this chemical log will be immediately available for decision-making during drilling.

Raft River Example. The concept of chemical logging originated during drilling of exploratory well RRGE-3 at the Raft River KGRA, and was developed and refined during drilling of production wells RRGP-4 and RRGP-5 and injection well RRGI-6. At Raft River, shallow drilling used mud as a drilling fluid. Once casing was set, further drilling used geothermal water as the drilling fluid to prevent possible damage to the formation from the mud. Because geothermal water was used as the drilling fluid, only small chemical differences were anticipated between drilling fluid and any geothermal aquifers that were penetrated. Chemical constituents that would best differentiate between geothermal waters and cold waters, at Raft River, are hardness, alkalinity, fluoride, chloride, and total dissolved solids.

Figure 19 shows the chemical log collected during the drilling of well RRGP-5. The log shows sharp changes in the chemical composition of the drill fluid at 488 m. At this depth, the alkalinity and hardness increase and fluoride and silica concentrations decrease. This would be a typical change in chemical composition when fresh water dilutes the drilling water. The relative constancy in chloride ion concentration and conductivity indicate, however, that the fresh-water aquifer had fairly high dissolved solids, probably from intrusion of geothermal water. The production zone of a geothermal aquifer was penetrated at 1280 m. Because the drill fluid was geothermal water similar to that in the aquifer, only small changes were observed in the drill fluid chemical composition. There was a small increase in SiO_2 concentration and a small decrease in conductivity. The decrease in alkalinity was the only large change detected at this depth.

The hardness/alkalinity log is shown in Figure 20. Evaluation of the hardness/alkalinity log reveals a sharp change in the ratio at a depth of 1220 m. This increase in the hardness/alkalinity ratio was observed until the drill string reached a depth of 1280 m, where a flow of hot water with an estimated rate of 68 L/s was observed. Geothermal water from the 1280 m depth washed away the chemical profile of the well for the remainder of drilling. The lower part of this borehole was lost when a concrete plug was set at 1051 m depth to install the well casing. After the well was cased and reentry was made with the drill string, the concrete plug could not be drilled through. Sidetrack drilling was initiated at the top of the plug, but the second leg either did not penetrate the high-flow zone penetrated in the first leg or the fractures were sealed with concrete. The second leg is shown as Leg B in Figure 20. and indicates the penetration of a narrow, hot-water-bearing aquifer, which flowed at about 13 L/s with a maximum temperature of 123°C.

The hardness/alkalinity ratio log (Figure 20) also showed that as the drill approached a geothermal zone, the ratio increased before the zone was reached, with the resulting chemical log displaced uphole relative to the temperature log. The uphole displacement varied between 16 and 120 m for the wells tested, and appears to be a function of the permeability or fracturing of material above the geothermal aquifer. Additional confirmation of the value of chemical logging was demonstrated during the drilling of RRGI-6. Comparison of the hardness/alkalinity ratio to the temperature log for RRGI-6 revealed similarities as shown in Figure 21 . The hardness/alkalinity log is displaced about 60 m uphole relative to the temperature log. This characteristic of the hardness/alkalinity ratio, of anticipating geothermal aquifers, combined with the information on the permeability of stratum already penetrated, furnished by the mud logger, could be used to determine the depth at which to set the well casing.

Figure 22 shows the hardness/alkalinity chemical log collected during the redrilling of well RRGP-4 with the object of converting an injection well into a production well. Sidetrack drilling started at 565 m to a total depth of 1650 m for Leg A. To improve resolution, samples were taken at 15 m intervals with additional samples collected at 8 m intervals where the driller detected structural changes. To make the chemical log more useful as a predictive tool, the hardness/alkalinity chemical log was kept current with the drilling progress. The object was to anticipate any significant temperature changes before the drill string reached a production zone.

An upper geothermal zone was penetrated by the drill between 700 and 870 m, with the hardness/alkalinity ratio increasing sharply through this area. In this upper portion of the hole, drilling mud was being

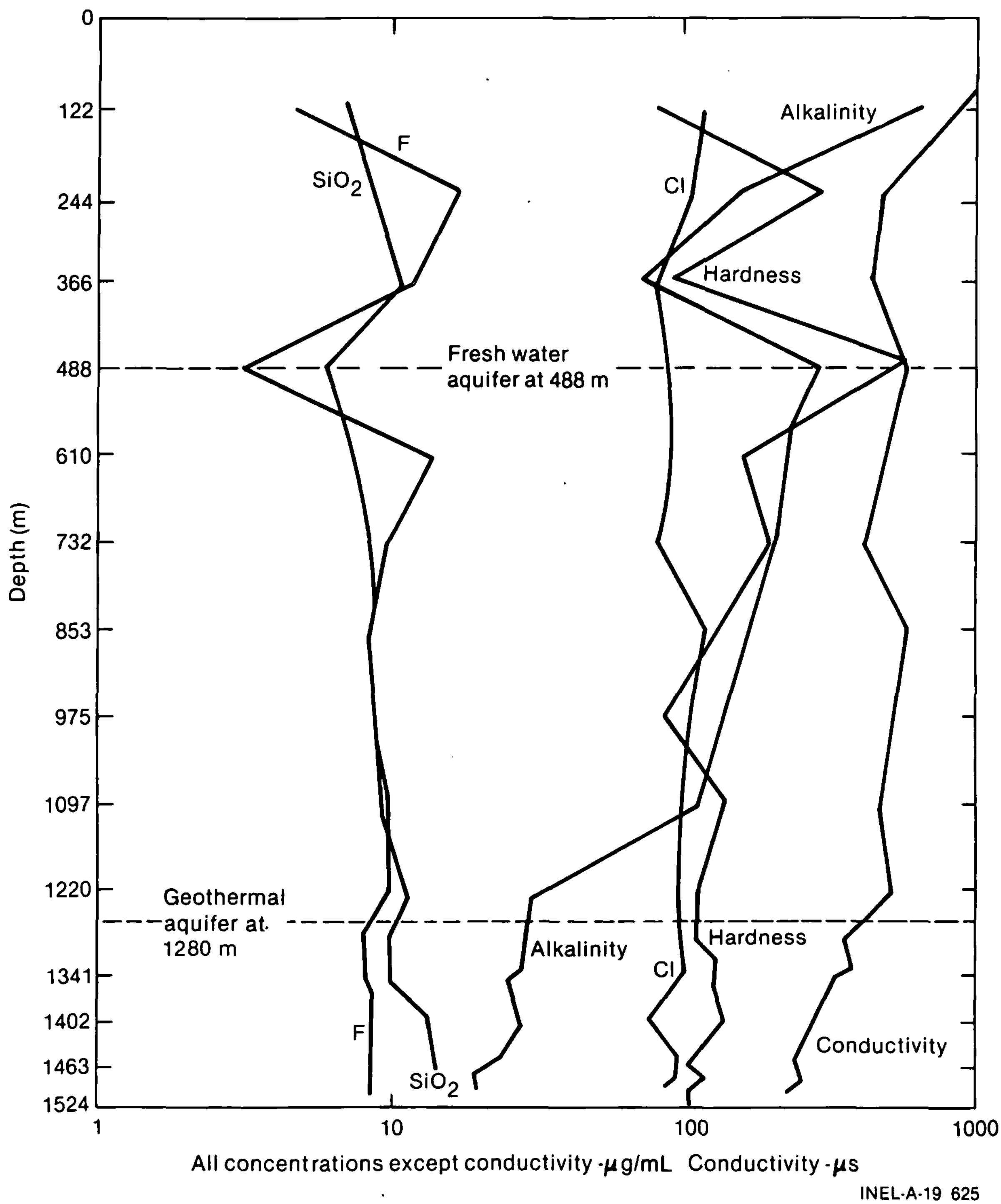

Figure 19. Chemical log of all analyzed chemical species for Well RRGP-5.

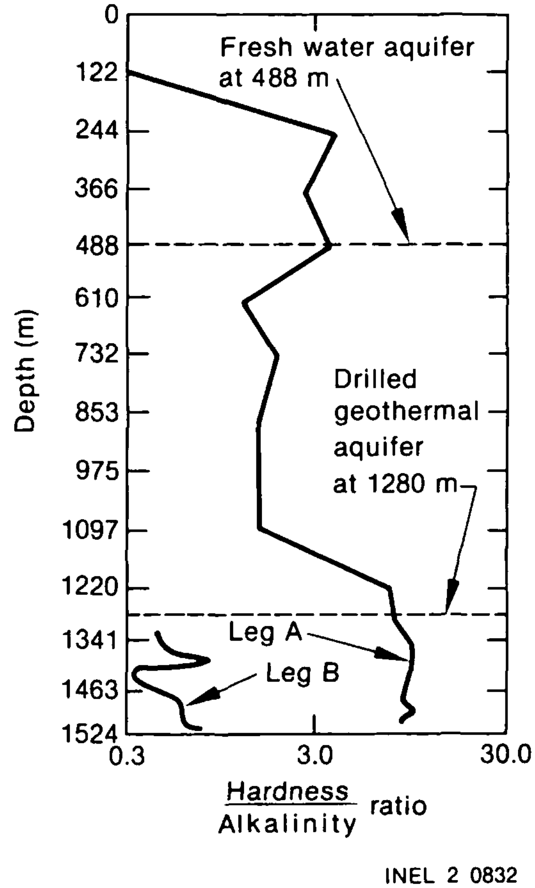

Figure 20. Hardness/alkalinity chemical log for Well RRGP-5.

used in the drilling fluid. Although the background chemical composition of the fluid was much different because of the presence of the drilling mud, the change in the ratio is still quite apparent. After casing the upper hole to a depth of 1070 m, the background hardness/alkalinity ratio changed significantly. Comparison of the chemical and lithologic logs of the upper portion of the wellbore shows that the section having high hardness/alkalinity ratios corresponds to a sandstone layer. Geophysical logging confirmed that this sandstone layer is an aquifer. At a depth of 1520 m, the driller noticed a decrease in drilling rate when the drill bit encountered a hard stratum about 10 m before penetration of a narrow, low-producing, hot-water zone. The hardness/alkalinity ratio began to increase about the time the drill reached the hard stratum, and continued to increase as the zone was penetrated. The ratio decreased after the drill passed through the producing zone. This same sequence was repeated at 1580 m. The combined flow of the two producing zones was about 2.25 L/s, with water temperatures above the boiling point.

Corrosion and Scale-Forming Species in Moderate Temperature Geothermal Brines

Geothermal brines, in general, represent an environment that is very corrosive and contains high concentrations of scale-forming species. This subsection provides general guidelines for proper selection of material and scale control techniques to nontechnical individuals that are involved in geothermal applications. Additional information can be obtained from Casper and Pinchback.[34] These guidelines presented here will apply to any geothermal area but should not be used in lieu of professional advice.

Corrosion. The predominate factors affecting corrosion in moderate temperature brines are temperature, brine chemistry, fluid velocity, and the specific material in contact with the brine. Specific chemical species associated with corrosion are:

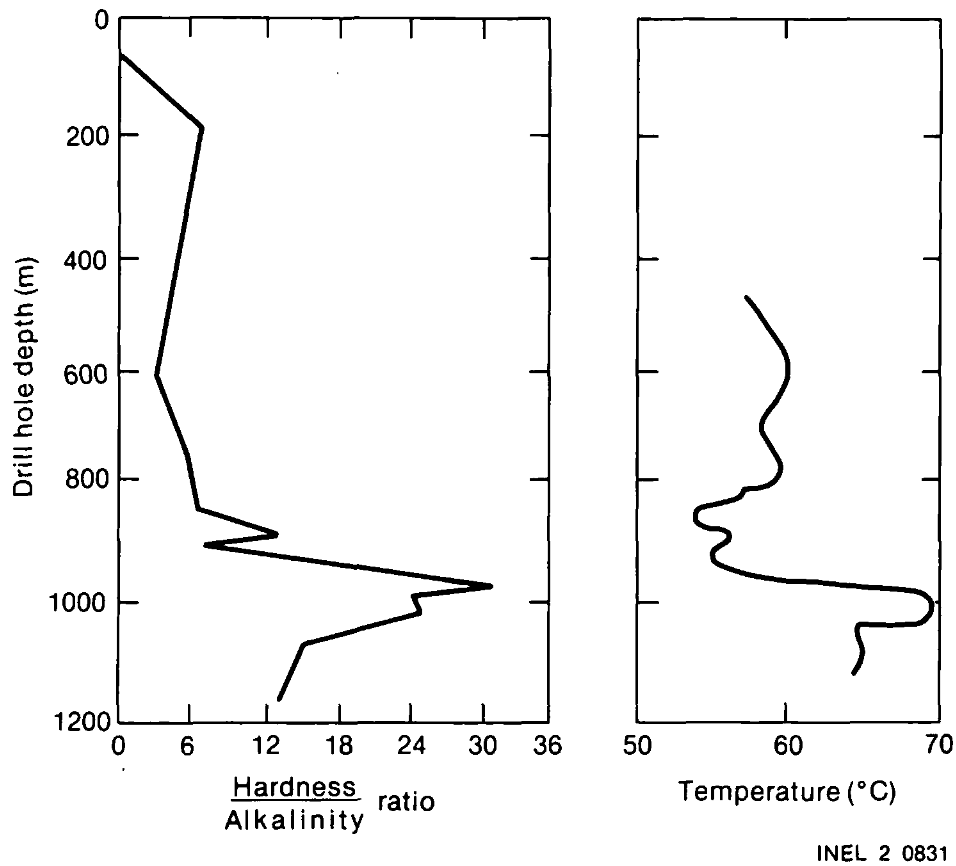

Figure 21. Hardness/alkalinity chemical log and temperature log for Well RRGI-6.

- Oxygen
- Hydrogen ion (pH)
- Chloride ion
- Hydrogen sulfide
- Carbon dioxide
- Ammonia
- Sulfate ion.

The presence of boron and heavy metals such as copper, mercury, tin, etc., will also affect the corrosion rates of different materials. The specific corrosive effect of each of the materials listed above will vary with the material selected. When two or more of the above species are present, the corrosion rate may be significantly greater than the additive corrosion rates associated with the individual species.

Scaling. The predominant factors affecting scale deposition in pipes are brine chemistry, change in temperature, change in pressure, fluid velocity, and the material in contract with the brine. The specific chemical species associated with scale deposition are:

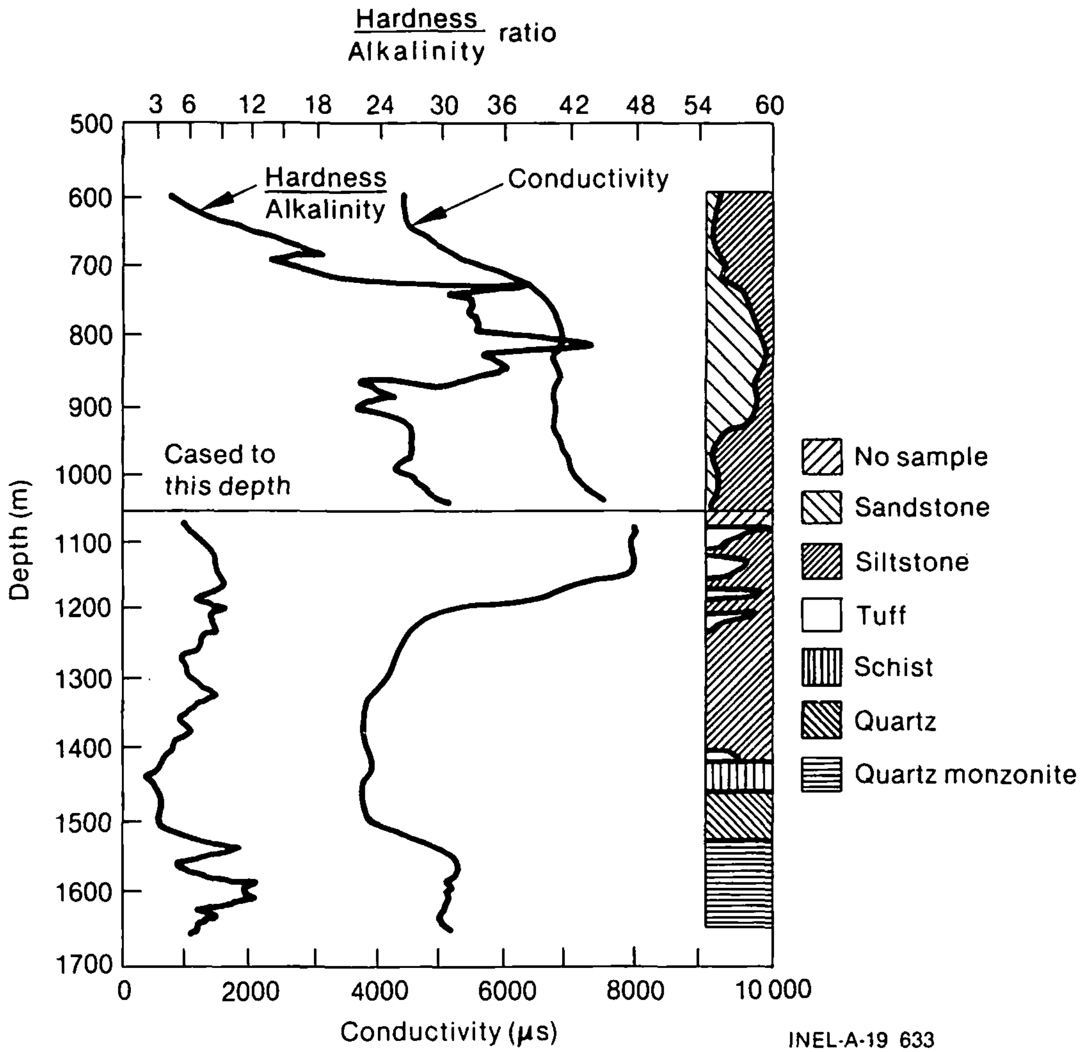

Figure 22. Hardness/alkalinity chemical log for Well RRGP-4A.

- Silica
- Hardness—recorded as calcium hardness and magnesium hardness
- Hydrogen ion (pH)
- Alkalinity—recorded as total and methyl orange alkalinity
- Sulfate ion
- Fluoride ion.

Corrosion products will also affect scale deposition.

Material Selection. Since scale and corrosion are not mutually exclusive, material should be selected with both in mind. There are a large number of materials to select from, ranging from plastics to carbon steels to exotic alloys.

Plastics — Plastic pipes are relatively free from both scaling and corrosion problems. They may be excellent for transporting fluids from wellhead to process areas, but may not be used where transfer of heat is required. Plastic pipes are available in many different forms and price ranges. Restrictions on their use are those of operating temperature and pressure. The higher the temperature, the lower the operating pressure must be.

Carbon Steel — Carbon steels are readily available and are the most inexpensive kind of metal piping. Carbon steel can be used both as transportation and heat transfer material provided adequate corrosion allowance is made. It may not be used if oxygen is present in the brine or if the pH is below six, as this will result in greatly increased corrosion rates and iron scale deposition.

Copper and Copper Alloys — The use of copper and its alloys represents an approximately three-fold increase in material cost and may be required when oxygen is present. Copper has excellent heat transfer properties but should not be used if the pH is below six, as corrosion rates significantly increase with lowering pH, i.e., more acidic water. Copper may not be used if ammonia or sulfide is present.

Stainless Steels — Stainless steels should not be used in brines as the high chloride concentration may result in early failure of components.

Other Materials — There are many other alloys on the market, such as nickel alloys, chrome-moly alloys, titanium, cobalt, etc. The use of these materials should be made after consultation with a corrosion expert, as they are very expensive.

The following are basic guidelines for selecting materials for a geothermal application.

1. Obtain a water sample of the brine and analyze it for the species listed in the Corrosion and Scaling subsections above. The sample should be unflashed and taken by a reputable firm. If the sample is flashed, the noncondensable gasses such as oxygen, carbon dioxide, hydrogen sulfide, and ammonia will flash, resulting in an inaccurate analysis.

2. Select, tentatively, a material based on the analysis. This selection should be confirmed with a professional corrosion engineer.

3. Determine optimum velocity for the given material. As velocity increases, erosion-corrosion increases dramatically while scale deposition decreases; hence the optimum for the given material.

4. Review the system with a water treatment specialist after the material has been selected. The primary considerations are the analysis at the wellhead and the temperature and pressure drops across the system. Temperature is the largest single factor in the solubility of many chemical species. If a large temperature drop occurs across a system, many chemical species may become supersaturated and deposit a scale. Also if pressure drops occur across the system, i.e., across valves, elbows, carbon dioxide may flash, resulting in calcite deposition. This may be eliminated by maintaining pressure across the entire system.

Chemical Geothermometers

Chemical geothermometers are probably the most recognized contribution of geochemistry to the development of geothermal fields. Application to low- and moderate-temperature reservoirs requires careful assessment of the techniques, as many of the assumptions involved in development of geothermometers are based on high-temperature reservoirs. Geothermometers do not stand alone and must be viewed in the geologic and hydrologic context of the field.

There are five basic assumptions that must be met for the geothermometry techniques to be valid. These are:[35]

1. Chemical concentrations are determined by water-rock interactions

2. There is an excess of all reactants

3. Water and rock are in equilibrium at reservoir temperature

4. After leaving the reservoir, water does not reequilibrate with rocks

5. Either no mixing occurs with cooler, shallower water, or the mixing can be quantified.

The geochemist must test the validity of these assumptions after he has considered the hydrology, geology, and mineralogy of the reservoir. Water produced from deep wells offers advantages for sampling in that flow up the wellbore can limit external alterations of water chemistry.

Geothermometers most applicable to low- and moderate-temperature reservoirs are the silica and sodium-potassium-calcium (Na-K-Ca) geothermometers. The Na/K geothermometer is generally limited to reservoirs with temperatures over 180°C. Even with the other two geothermometers, however, results at temperatures below 150°C tend to be less consistent than at higher temperatures. This problem is due in part to kinetic effects and the broad range of mineralogic compositions found in lower-temperature reservoirs.

Silica Geothermometer. The silica geothermometer is based on the theoretical solubility curves of various silica phases, and is applicable to the temperature range from 0 to 250°C.[36,37] The range of temperatures over which the technique works best is from 150 to 225°C. The first consideration in applying this geothermometer is to collect and preserve the sample properly. As waters cool, silica polymerizes and may precipitate. Polymerization can interfere with analysis when colorimetric techniques are used. Water samples, especially if water temperatures are over 140°C, should be diluted as much as 5 to 10 times to prevent polymerization and precipitation.

Silica solubility can be controlled by a number of silica phases, including quartz, chalcedony, and amorphous silica. Equations for calculating estimated reservoir temperatures assuming control of SiO_2 concentrations by these silica phases are:

$$\text{Quartz } t(°C) = \frac{1309}{5.19 - \log C} - 273.15$$

$$\text{Chalcedony } t(°C) = \frac{1032}{4.69 - \log C} - 273.15$$

$$\text{Amorphous silica } t(°C) = \frac{731}{4.52 - \log C} - 273.15$$

Silica concentration, C, is in mg/kg as SiO_2, and the calculated temperature is in degrees centigrade.

In freshly drilled boreholes, in basaltic terrains, or in areas with chert in sediments, quartz may not be the phase controlling silica solubility. If the assumptions of geothermometers are valid for a site, and the proper controlling phase can be determined, the silica geothermometer seems to give the best reservoir temperature estimates.

Na-K-Ca Geothermometer. This geothermometer is based on an ion exchange equilibrium among feldspars controlling the concentrations of sodium, potassium, and calcium.[38] The following equation for calculating temperature is empirical, but feldspar control is assumed.

$$t(^\circ C) = \frac{1647}{\log (Na/k) + \beta [\log (Ca/Na) + 2.06] + 2.47} - 273.15$$

$t < 100^\circ C, \beta = 4/3$

$t \geq 100^\circ C, \beta = 1/3$

Na, K, Ca concentrations in mg/kg.

In geothermal systems where calcium concentrations are significantly affected by gypsum or calcite solubility, calculated temperatures may not be valid. Loss of calcium by mineral precipitation will produce anomalously high temperatures. For waters that are fairly high in magnesium, an empirical correction to the Na-K-Ca geothermometer has been proposed by Fournier and Potter.[39]

Glenwood Springs Example. The situation at Glenwood Springs, Colorado is an example of the equivocality of geothermometers in low-temperature reservoirs. At Glenwood Springs, the temperatures of seven springs, which range in discharge from a fraction of a liter per second to over 125 L/s, are remarkably similar and suggest a fairly uniform reservoir at about 50°C (mean = 48.9°C, standard deviation = 2.7°C).[40] Quartz geothermometer calculations give closely grouped, although much higher temperatures for the springs, averaging 79.7°C with a standard deviation of 2.2°C. Estimates using the Na-K-Ca (Mg corrected) geothermometer give a much broader range of temperatures, averaging 85.1°C with a standard deviation of 15.5°C. An analysis of the mineralogy of the geothermal reservoir, however, indicates that these geothermometers may not be valid in this case.

There is extensive evidence of the presence of evaporites in the limestone reservoir, mainly gypsum or anhydrite. Thermodynamic calculations show the springs to be supersaturated with calcite, which may, therefore, be precipitating in the subsurface. Lowering of calcium concentrations by calcite precipitation would raise the temperature predicted by Na-K-Ca geothermometer. The wide range in geothermometer temperatures would reflect the variability in calcite precipitation.

Sediments in the reservoir contain chert, which is much more soluble than quartz. Calculations of reservoir temperature using the chalcedony geothermometer give temperature estimates that average 48.6°C with a standard deviation of 2.4°C.

The potential questionability of the quartz and Na-K-Ca geothermometers, and evaluation of mineralogy, spring discharge, measured temperatures, and chalcedony geothermometer suggests that the reservoir temperature is closer to 50°C than 80°C. This difference can mean the success or failure of a low-temperature project. Drilling in the Glenwood Springs area during the fall of 1981 found 52°C water in the Leadville Limestone at a depth of 174 m.[41]

Isotopic Composition of Water

Oxygen and hydrogen isotopes in water can be used to indicate sources of geothermal fluids, as evidence for mixing of thermal waters with shallow, cool waters, and to give qualitative estimates of the extent of reaction between water and rock. The most significant contribution of isotopes to the hydrology of geothermal systems was demonstrating that significant quantities of geothermal waters are derived from meteoric sources. Truesdell and Hulston[42] present an in-depth analysis of isotope methods in geothermal systems, from which this section is excerpted.

Stable Isotopes. During the evaporation of sea water, lighter isotopes of water (oxygen-16, hydrogen) can escape into the vapor phase more readily than the heavier oxygen-18 and deuterium. As this water vapor forms precipitation, the heavier isotopes condense first, resulting in progressively lighter precipitation during movement toward the poles, inland over land masses, and to higher elevations. The average annual precipitation at any location will have a fairly constant isotopic composition reflecting its elevation, latitude, and distance from the ocean.

Oxygen and hydrogen isotopic compositions of precipitation are related by the equation:.

$$18\ \delta D = 8\ \delta\ ^{18}0 + 10$$

where δ is the difference in parts per thousand ($^0/00$) between a water sample and a standard water known as "standard mean ocean water" (SMOW). Ground waters in an area frequently display the same relation between oxygen and hydrogen isotopes as precipitation. Surface and ground waters that have undergone evaporation fall to the right of the meteoric water line (Figure 22) along lines with slopes of about five. The deuterium isotopic composition can be used as a label reflecting the recharge area and history of a water sample.

The isotopic composition of many high-temperature geothermal waters is related to that of local meteoric water, but indicates a change in oxygen isotopic composition (Figure 23) from exchange between reservoir rocks and hot waters. Because few rock-forming minerals contain very much hydrogen, a concurrent change in hydrogen does not occur. The magnitude of the oxygen isotope shift depends on the original isotopic compositions of water and rock, mineralogy and texture of rocks, temperature, water/rock ratio, and time of contact. Systems with maximum temperatures below 150°C, moderate water/rock ratios, and igneous rocks with original δ^{18} 0 values near +50/00 may show little or no isotopic shift. Most low- and moderate-temperature reservoirs would, therefore, be expected to show little or no isotope shift.

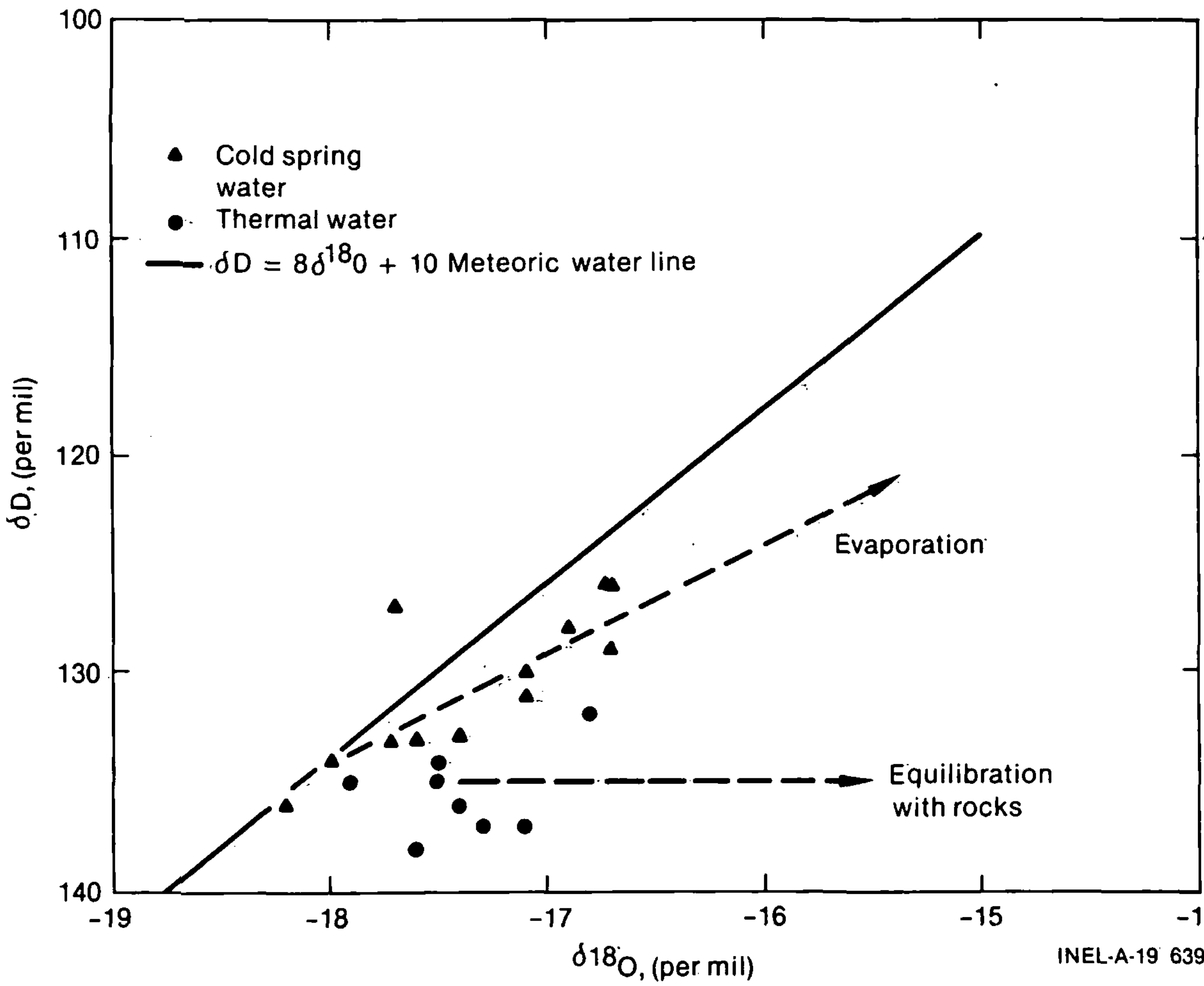

Figure 23. Oxygen-18 and deuterium compositions of hot and cold ground waters from the Raft River KGRA.

Mixing with shallow, cooler ground waters commonly occurs in the upper portions of geothermal systems, which may be feeding thermal springs. Isotopic compositions combined with dissolved salt contents may be used to demonstrate this mixing. Correlations between the isotopes of oxygen or hydrogen and dissolved salts would be expected where shallow waters were lower in salt content and isotopically different than thermal waters.

Tritium. Tritium is a radioactive isotope of hydrogen with a half life of 12.3 years, and is produced naturally by cosmic rays. Atmospheric testing of nuclear weapons between 1954 and 1965 produced a 100-fold increase in peak tritium levels in the northern hemisphere. The current detection level for tritium allows dating of waters up to 60 years old. Most measurements of deep thermal waters show no significant tritium, indicating that waters are greater than 60 years old. Measurable tritium in thermal wells and springs probably indicates the mixing of deep thermal waters with recent, shallow ground water.

9. RESERVOIR MONITORING

Reservoir analysis is not complete when the end-use production of a thermal well or well field begins. It is necessary to monitor the hydrologic system(s) to confirm initial predictions; to anticipate and plan for any geochemical changes in pressure and temperature of the resource; and to obtain a larger data base for confirming the reservoir conceptual model. Confirmation of the conceptual model can be used to evaluate reservoir capacity, recharge, and the potential for future expansion.

Monitoring of a well or well field includes pressure monitoring, temperature monitoring, and geochemical sampling of production/injection wells, observation wells, and springs. Observation wells may include fully or partially penetrating wells designed to monitor reservoir response and any deep or shallow existing irrigation or domestic wells. Monitoring also includes discharge/recharge rates for all wells and springs, and geochemical sampling and temperature changes in a disposal stream or pond.

It is essential that monitoring be accomplished throughout the life of any development to ensure economical use and predict potential environmental hazards.

Pressure Monitoring

The completion of a geothermal well and the start of production from the reservoir should signal the beginning of a regularly scheduled, permanent program of pressure monitoring of the following:

1. The producing aquifer or reservoir formation
2. The confining strata above the reservoir
3. The unconfined aquifer above the confining layer (springs)
4. The production and injection wells.

The pressure measurements will usually be done with surface instruments, i.e., pressure gauges installed at the well head. If the well is not under pressure, a bubbler tube must be installed so that the depth to the water level in the well can be conveniently determined. In a few wells on some occasions, downhole pressure may be needed.

The Producing Aquifer or Reservoir Formation. The pressure in all available observation wells open to the geothermal reservoir should be recorded each month. A few important observation wells may be read weekly if there is a need to indicate shorter-term fluctuations of pressure.

The Confining Strata Above the Aquifer. Some observation wells may have been completed in the confining layers above the reservoir. The water level in these also should be observed at least monthly to show the pressure conditions in the confining layer and to give indications of interference problems.

The Unconfined Aquifer Above the Confining Layer(s). Some observation wells (and local water wells) may be open to the unconfined aquifer near the surface. The water level in these wells and also any nearby springs gives a measure of the water table elevation and should be recorded at least monthly. These data, along with the pressure measurements described above, can give an indication of the gradient causing vertical leakage through the confining layer(s) as well as evidence of well interference problems.

Production and Injection Wells. These wells are the most important in the field and should be monitored most often. In fact, a continuous watch of pressure in production and injection wells is probably needed for the operational control of reservoir production. A permanent daily record should be kept of the pressure, temperature, production and injection rates.

Temperature Monitoring

Temperature monitoring should include discharge/recharge measurements at the surface and where feasible, downhole measurements. Surface measurements are inexpensive and easy to obtain. It is recommended that surface temperatures be obtained whenever a pressure measurement is obtained at a production/injection well. At nearby observation wells, springs, or discharge rivers or ponds, it may be suffficient to obtain surface discharge temperature (where appropriate) on a weekly schedule. Downhole temperature data are usually more expensive and may be impractical if a pump is in a well. If downhole data can be collected, it is recommended that measurements be taken at a minimum of every ten feet to total well depth at least biannually.

Confirmation of Reservoir Conceptual Model

As data are gathered from reservoir monitoring, it is necessary to assimilate them into initial projections and note any deviations from these projections. This assimilation is critical for verifying the conceptual model of the reservoir system, which logically ties into not only reservoir longevity, capacity and recharge, but also chemical changes, water level changes, and a group of potential environmental impacts.

Verification of the conceptual model would provide an early-warning system to a developer to modify or correct potential problems before they are encountered. In addition, reservoir monitoring allows the system to be expanded based upon a confirmed conceptual model, provides confidence to investors in reservoir development, and enhances further development of this technology.

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Low-to-Moderate Temperature Hydrothermal Reservoir Engineering Handbook

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APPENDIX A
UNITS AND CONVERSIONS

APPENDIX A

UNITS AND CONVERSIONS[a]

Units

	Metric	English
Pressure	Pa	psia
Temperature	°C	°F
Flow	m^3/s or l/s	gpm
Compressibility	1/Pa	1/psi
Length	m (Meter)	ft
Permeability	m^2	mD
Static water level	m	ft
Viscosity	Pa•sec	cP

a. Abstracted from the Invitational Well Testing Symposium, Berkeley, California, 1977.

TABLE A-1. Permeability

ρ_w = 1 viscosity = 1 centipoise

	cm^2	m^2	ft^2	Darcy	cm/s	ft/s	ft/year	$L/s \cdot m^2$	gpd(U.S.)/ft^2 (Meinzer)	Ebhlm
cm^2	1	10^{-4}	1.076×10^{-3}	1.014×10^{8}	9.804×10^{4}	3.216×10^{3}	1.015×10^{11}	8.698×10^{5}	1.845×10^{9}	0.9
m^2	10^{4}	1	1.076×10^{1}	1.014×10^{12}	9.804×10^{8}	3.216×10^{7}	1.015×10^{15}	8.697×10^{9}	1.845×10^{13}	0.8
ft^2	9.294×10^{2}	9.294×10^{-2}	1	9.417×10^{10}	9.109×10^{7}	2.988×10^{6}	9.430×10^{13}	8.080×10^{8}	1.714×10^{12}	0.7
Darcy	9.862×10^{-9}	9.862×10^{-13}	1.062×10^{-11}	1	9.66×10^{-4}	3.173×10^{-5}	1.001×10^{3}	8.58×10^{-3}	1.82×10^{1}	0.6
cm/s	1.020×10^{-5}	1.020×10^{-9}	1.097×10^{-8}	1.035×10^{3}	1	3.281×10^{-2}	1.035×10^{6}	9.985×10^{0}	2.118×10^{4}	0.5
ft/s	3.109×10^{-4}	3.109×10^{-8}	3.347×10^{-7}	3.152×10^{4}	3.048×10^{1}	1	3.156×10^{7}	2.704×10^{2}	5.736×10^{5}	0.4
ft/year	9.852×10^{-12}	9.852×10^{-16}	1.060×10^{-14}	9.990×10^{-4}	9.662×10^{-7}	3.169×10^{-8}	1	8.570×10^{-6}	1.818×10^{-2}	0.3
$L/s \cdot m^2$	1.150×10^{-6}	1.150×10^{-10}	1.238×10^{-9}	1.166×10^{2}	1.001×10^{-1}	3.698×10^{-3}	1.167×10^{5}	1	2.121×10^{3}	0.2
gpd(U.S.)/ft^2 (Meinzer)	5.420×10^{-10}	5.420×10^{-14}	5.834×10^{-13}	5.494×10^{-2}	4.721×10^{-5}	1.743×10^{-6}	5.500×10^{1}	4.714×10^{-4}	1	0.1
Ebhlm	0.9	0.8	0.7	0.6	0.5	0.4	0.3	0.2	0.1	1

TABLE A-2. Compressibility (Lt^2/M)

	m^2/N $(Pa)^{-1}$	m^2/kgf	$in.^2$ lbf $(psi)^{-1}$	$Bars^{-1}$	Atm^{-1}	(ft of water)$^{-1}$ at 68°F	(m of water)$^{-1}$ at 68°F
m^2/N $(Pa)^{-1}$	1	9.807	6.897×10^{3}	10^{5}	1.0133×10^{5}	2.984×10^{3}	9.794×10^{3}
m^2/kgf	1.020×10^{-1}	1	7.031×10^{2}	1.0197×10^{4}	1.0332×10^{4}	3.042×10^{2}	9.980×10^{2}
$in.^2/lbf$ $(psi)^{-1}$	1.450×10^{-4}	1.4223×10^{-3}	1	14.504	14.696	0.4327	1.419
$Bars^{-1}$	10^{-5}	9.8068×10^{-5}	6.895×10^{-2}	1	1.01325	2.984×10^{-2}	9.790×10^{-2}
Atm^{-1}	9.8692×10^{-6}	9.6787×10^{-5}	6.805×10^{-2}	0.98692	1	2.945×10^{-2}	9.662×10^{-2}
(ft of water)$^{-1}$ at 68°F	3.351×10^{-4}	3.287×10^{-3}	2.311	33.512	33.956	1	3.281
(m of water)$^{-1}$ at 68°F	1.021×10^{-4}	1.002×10^{-3}	0.7044	10.214	10.349	0.3048	1

Table A-3. Temperature °C to °F

°C	°F	°C	°F	°C	°F	°C	°F	°C	°F
0	32	100	212	200	392	300	572	400	752
5	41	105	221	205	401	305	581	405	761
10	50	110	230	210	410	310	590	410	770
15	59	115	239	215	419	315	599	415	779
20	68	120	248	220	428	320	608	420	788
25	77	125	257	225	437	325	617	425	797
30	86	130	266	230	446	330	626	430	806
35	95	135	275	235	455	335	635	435	815
40	104	140	284	240	464	340	644	440	824
45	113	145	293	245	473	345	653	445	833
50	122	150	302	250	482	350	662	450	842
55	131	155	311	255	491	355	671	455	851
60	140	160	320	260	500	360	680	460	860
65	149	165	329	265	509	365	689	465	869
70	158	170	338	270	518	370	698	470	878
75	167	175	347	275	527	375	707	475	887
80	176	180	356	280	536	380	716	480	896
85	185	185	365	285	545	385	725	485	905
90	194	190	374	290	554	390	734	490	914
95	203	195	383	295	563	395	743	495	923

Table A-4. Volume (L^3)

	m^3	L	bbl	gal (U.S.)	gal (Imp.)	ft^3
m^3	1	10^3	6.289	2.642×10^2	2.20×10^2	35.315
L	10^{-3}	1	6.289×10^{-3}	0.2642	0.220	3.5315×10^{-2}
bbl	0.1590	1.590×10^2	1	42.0	34.97	5.6146
gal (U.S.)	3.7854×10^{-3}	3.7854	2.381×10^{-2}	1	0.8327	0.13368
gal (Imp.)	4.546×10^{-3}	4.546	2.860×10^{-2}	1.2009	1	0.16054
ft^3	2.832×10^{-2}	28.32	0.178	7.481	6.229	1

TABLE A-5. Flow rate
(L^3/t or M/t)

	m^3/s	L/min	bbl/day	gal/min (U.S.)	gal/min (Imp.)	ft^3/s	klb/h (ρ_w = 1.0)	klb/h (ρ_w = 0.9)
m^3/s	1	6×10^4	5.434×10^5	1.585×10^4	1.320×10^4	35.315	7.94×10^3	7.15×10^3
L/min	1.667×10^{-5}	1	9.058	0.2642	0.220	5.885×10^{-4}	1.32×10^{-1}	1.19×10^{-1}
bbl/day 6.498×10^5		1.840×10^{-6} 1.46×10^{-2}	1.31×10^{-2}	1.10×10^{-1}	1	2.917×10^{-2}	2.428×10^{-2}	
gal/min (U.S.)	6.31×10^{-5}	3.785	34.28	1	0.8327	2.2280×10^{-3}	0.50	0.45
gal/min (Imp.)	7.58×10^{-5}	4.546	41.19	1.2009	1	2.676×10^{-3}	0.601	0.541
ft^3/s	2.8317×10^{-2}	1.699×10^3	1.539×10^4	4.488×10^2	3.737×10^2	1	2.25×10^2	2.03×10^2
klb/h ρ_w = 1.0	1.26×10^{-4}	7.56	68.5	2.00	1.66	4.45×10^{-3}	1	0.900
klb/h ρ_w = 0.9	1.40×10^{-4}	8.42	76.2	2.22	1.85	4.93×10^{-3}	1.11	1

TABLE A-6. Pressure
(M/Lt^2)

	N/m^2 (Pa)	kgf/m^2	lbf/in^2 (psi)	Bars	Atm	ft of water (at 68°F)	m of water (at 68°F)
N/m^2 (Pa)	1	1.020×10^{-1}	1.450×10^{-4}	10^{-5}	9.8692×10^{-6}	3.351×10^{-4}	1.021×10^{-4}
kgf/m^2	9.804	1	1.4223×10^{-3}	9.806×10^{-5}	9.6787×10^{-5}	3.287×10^{-3}	1.002×10^{-3}
$lbf/in.^2$ (psi)	6.895×10^{3}	7.031×10^{2}	1	6.895×10^{-2}	6.805×10^{-2}	2.311	0.7042
Bars	10^{5}	1.0197×10^{4}	14.504	1	0.98692	35.512	10.214
Atm	1.0133×10^{5}	1.0332×10^{4}	14.696	1.01325	1	33.956	10.349
ft of water (at 68°F)	2.984×10^{3}	3.042×10^{2}	0.4328	2.984×10^{-2}	2.945×10^{-2}	1	0.3048
m of water (at 68°F)	9.794×10^{3}	9.980×10^{2}	1.419	9.790×10^{-2}	9.662×10^{-2}	3.281	1

TABLE A-7. Viscosity (Dynamic)

Pa•s	$lbf \cdot s/in.^2$	$lbf \cdot s/ft^2$	$kgf \cdot s/m^2$	lbm/ft•s	$dyne \cdot s/cm^2$	cP	lbm/ft•h
Pa•s	6.894 757 E+03	4.788 026 E+01	9.806 650 E+00	1.488 164 E+00	1.0 E-01	1.0 E-03	4.133 789 E-04

TABLE A-8. Viscosity (Kinematic)

m^2/s	ft^2/s	in.^{2}/s	m^2/h	cm^2/s	ft^2/h	cSt
m^2/s	9.290 304 E+04	6.451 6 E+02	2.777 778 E+02	1.0 E+02	2.580 64 E+01	1

TABLE A-9. Diffusivity

m^2/s	ft^2/s	cm^2/s	ft^2/h
m^2/s	9.290 304 E+04	1.0 E+02	2.580 64 E+01

TABLE A-10. Thermal Conductivity

W/m·K	cal/s·cm^2·°C/cm	Btu/h·ft^2·°F/ft	kcal/h·m^2·°C/m	Btu/h·ft^2·°F/in.	cal/h·cm^2·°C/cm
W/m·K	4.184 E+02	1.730 735 E+00	1.162 222 E+00	1.442 279 E-01	1.162 222 E-01

TABLE A-11. Density (Liquids)

kg/m	lbm/gal (U.K.)	lbm/gal (Imp.)	lbm/ft	g/cm
kg/m^3	1.198 264 E+02	9.977 633 E+01	1.601 846 E+01	1.0 E+03
	1.198 264 E-01	9.977 633 E-02	1.601 846 E-02	1

TABLE A-12. Specific heat capacity (Mass basis)

J/kg·K	kW·h/kg·°C	Btu/lbm·°F	kcal/kg·°C
J/Kg·K	3.6 E+03	4.186 8 E+00	4.184 E+00

TABLE A-13. Enthalpy calorific value (Mass basis)

J/kg	Btu/lbm	cal/g	cal/lbm
J/kg	2.326 000 E-03	4.184 E+00	9.224 141 E+00
	2.325 000 E+00		
	6.461 112 E-04		

APPENDIX B
GLOSSARY OF TERMS

APPENDIX B

GLOSSARY OF TERMS[a]

ANISOTROPY: Term used to denote the dependence of properties such as permeability on spacial orientation. Anisotropy is usually expressed as a tensor. When the principal axes are perpendicular to each other, the material is said to be orthotropic.

AQUICLUDE (GW)[b]: A body of saturated but relatively impermeable material that does not yield appreciable amounts of water to wells. Characterized by very low "leakance" (the ratio of vertical hydraulic conductivity to thickness) and very low rates of yield from compressible storage.

AQUIFER SYSTEM (GW): A heterogeneous body consisting of two or more permeable beds separated at least locally by aquitards that impede groundwater movement but do not greatly affect the regional hydraulic continuity of the system.

AQUITARD (GW): A bed with low permeability that impedes groundwater movement and does not yield water freely to wells, but which may transmit water between aquifers and may constitute an important storage unit. Leakance values vary over a wide range. When low, an aquitard may function as a boundary to an aquifer flow system.

AREA OF INFLUENCE (GW): Defined by Meinzer to be the land area of the same horizontal extent as the portion of the potentiometric surface that is perceptibly lowered due to withdrawal of water by a production well.

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a. Adapted from the Invitational Well Testing Symposium, Berkeley, California, 1977.

b. Terms commonly used in hydrogeology.

BANK STORAGE (GW): The change in storage in an aquifer resulting from a change in stage of an adjacent surface water body especially in alluvial deposits adjacent to surface streams.

BAROMETRIC EFFICIENCY OF A WELL: The ratio of water-level changes in the well to the water-level changes in a water barometer.

BOUNDARY PRESSURE (PE)[c]: Pressure at boundary of drainage area.

CAPILLARY FRINGE (GW): A zone whose lower part is completely saturated, but with water under less than atmospheric pressure. May range in thickness from a small fraction of an inch in gravel to more than 5 ft in silt.

COEFFICIENT OF PERMEABILITY (GW): See "Hydraulic Conductivity."

COEFFICIENT OF SPECIFIC STORAGE (GW): See "Specific Storage."

COEFFICIENT OF STORAGE (GW): See "Storage Coefficient."

COEFFICIENT OF TRANSMISSIBILITY (GW): See "Transmissivity."

COMMINGLED SYSTEMS (PE): Two-layered or multiple layer reservoirs with communication taking place between layers, either through the wellbore alone or directly across the layer interface.
(cf: multiaquifer well)

COMPACTION (GW): Decrease in volume of sediments, as a result of compressive stress, usually resulting from continued deposition. Also called "one-dimensional consolidation."

---

c. Terms commonly used in petroleum engineering.

COMPACTION, RESIDUAL (GW): The difference between (a) the amount of compaction that will occur ultimately for a given increase in applied stress, once steady-state pore pressures are achieved, and (b) that which has occurred as of a specified time.

COMPRESSIBILITY, TOTAL SYSTEM (PE): A term representing the combined compressibility of all the elements in an aquifer system. Accounts for the compressibilities of the oil phase, water phase, gas phase, and of the rock formation itself, according to the relative fraction of the total system volume occupied by each.

CONDITION RATIO (PE): Also called flow efficiency, indicates approximate fraction of a well's undamaged producing capacity. Ratio of actual productivity index to the productivity index if there were no skin (ideal conditions).

CONFINING BED (GW): A body of relatively impermeable material stratigraphically adjacent to one or more aquifers. Can be either an "aquitard" or an "aquiclude."

CONSOLIDATION (GW): See "Compaction."

CONSTANT DRAWDOWN TEST (GW): also known as constant pressure test in petroleum engineering. A test in which flow rate is gradually varied in time to maintain a constant drawdown (or constant pressure) in the producing well.

CONSTANT PRESSURE TESTING (PE): Also known as constant drawdown test in groundwater hydrology. Involves recording change in flow rate with time while bottom-hole pressure is held constant.

CRITICAL FLOW (PE): occurs in high-permeability zones; the rate of flow into the drill pipe is independent of drawdown during a drill-stem test.

CRITICAL FLOW PROVER (PE): Device that measures flow rate of a gas through an orifice under critical conditions (velocity is constant at a maximum value despite downstream pressure variations).

DAMAGE FACTOR: A measure of wellbore damage obtained by subtracting the condition ratio from 1.

DAMAGE RATIO (PE): Inverse of condition ratio. Indicates wellbore condition.

DELAYED DRAINAGE (GW): Term used to identify the slow release of water from the unsaturated zone in an unconfined aquifer.

DELIVERABILITY TESTING OF OIL WELLS (PE): Determines capability of a well to deliver against a specific flow bottom-hole pressure. Two main types: (a) flow-after-flow test; flowing pressure is recorded for three or more successive flow rates. Each flow rate is held constant until pressure has stabilized. (b) modified isochronal flow test; used for systems where stabilization time is too long for flow-after-flow test. For each flow rate, the well is shut-in after pressure transience is recorded, but before stabilization occurs. At each step the final flowing pressure and then the final shut-in pressure are observed. At the final flow rate, the well is allowed to produce until the pressure stabilizes, and this pressure is recorded.

DIMENSIONLESS PRESSURE (PE): A dimensionless solution to the diffusivity equation. Directly proportional to physical pressure, where the scaling factor is dependent on flow rate and reservoir properties. Usually denoted by $P_D = \frac{2\pi k H \Delta P}{q\mu}$.

DIMENSIONLESS TIME (PE): A scaled version of real time. Scaling factor depends on reservoir properties and distance to point of observation $t = \frac{kt}{\phi \mu c r^2}$, where k is intrinsic permeability; t is time; ϕ is porosity; μ is viscosity; c is total compressibility; r is distance to point of observation.

DRAWDOWN (GW): Difference in water level (or pressure) between the static condition and that at any given instant during discharge.

DRAWDOWN TESTING (PE): Involves recording the drop in bottom-hole pressure when a shut-in production well is switched to production at constant flow rate.

DRILL STEM TESTING--DST (PE): Used in testing uncompleted wells. An arrangement of packers seals off the interval to be tested, allowing a pressure to be built up as formation fluid flows into the drill stem and surface-actuated valves are closed. Pressure changes are observed by a pressure gauge located in the test interval. See "Single Packer Test," "Straddle Packer Test."

DYNAMIC PRESSURE (PE): The pressure at a given time and location in a reservoir during a period of transient pressure distribution, such as during a build-up or drawdown test.

EFFECTIVE WELL RADIUS (GW): The radius of an imaginary cylinder centered at the wellbore in which the permeability is much higher than in the reservoir. In a gravel-packed well it often denotes the probable radius of the gravel pack.

EQUIVALENT INJECTION TIME (PE): In a fall-off test on an injection well where the injection rate before shut-in varies, the equivalent injection time is the length of time it would have taken to inject the same volume of fluid at a constant flow rate as was injected at a variable flow rate since the last pressure equalization.

EXCESS PORE PRESSURE (GW): Transient pore pressure at any point in an aquitard or aquiclude in excess of the pressure that would exist under steady-flow condition.

EXPANSION, SPECIFIC (GW): The increase in thickness of deposits per unit decrease in applied stress.

EXPANSION, SPECIFIC UNIT: The expansion (increase in volume) of deposits, per unit thickness, per unit decrease in applied stress.

EXPONENTIAL INTEGRAL (PE): See "Theis Solution."

FALLOFF TESTING (PE): Involves shutting in an injection well and observing the decrease in bottom-hole pressure with time.

FALSE PRESSURE (PE): Obtained by extrapolating the straight-line section of a Horner plot of pressure build-up data to infinite shut-in time. Approximates average reservoir pressure in an infinite system and can be used to estimate average drainage region pressure in a bounded system.

FIVE-SPOT PATTERN (PE): An arrangement of production and injection wells with four production wells at the corners of a square and one injection well in the center.

FLOW-AFTER-FLOW TESTING (PE): See "Deliverability Testing of Oil Wells."

FLOW EFFICIENCY (PE): See "Condition Ratio."

FLUID POTENTIAL (GW): The mechanical energy per unit mass of a fluid at any given point in space and time with respect to an arbitrary state and datum.

FORMATION VOLUME FACTOR (PE): A factor to account for changes in volume in each phase upon transition from reservoir to standard surface conditions. The ratio of the volume at reservoir conditions to the volume at standard surface conditions.

GROUND WATER, PERCHED (GW): Confined ground water separated from an underlying body of ground water by an unsaturated zone. It is held up by a "perching bed" of low permeability, and its water table is a "perched water table."

HEAD, STATIC (GW): The height (above a datum) of a column of water that can be supported by the static pressure at a given point. The sum of the "elevation head" and the "pressure head." See "Head, Total."

HEAD, TOTAL (GW): The sum of three components: (a) "elevation head," which is the elevation of the point above a datum; (b) "pressure head," the height of a column of static water that can be supported by the static pressure at the point; (c) "velocity head," the height the kinetic energy of the liquid is capable of lifting the liquid.

HORNER PLOT (PE): A plot of pressure build-up versus log $\frac{t + \Delta t}{t}$ where t is time since production and Δt is time since shut-in. A similar plot was proposed in ground water hydrology by Theis to analyze recovery data.

HYDRAULIC CONDUCTIVITY (K) (GW): Has dimensions of length per unit time. A medium has a hydraulic conductivity of unit length per unit time if it will transmit in unit time a unit volume of groundwater at the prevailing viscosity through a cross section of unit area, measured at right angles to the direction of flow, under a hydraulic gradient of unit change in head through unit length of flow. Replaces the term "coefficient of permeability."

HYDRAULIC CONDUCTIVITY, EFFECTIVE (GW): The rate of flow of water through a porous medium that contains more than one fluid.

HYDRAULIC DIFFUSIVITY (GW): The ratio between hydraulic conductivity and specific storage.

HYDRAULIC GRADIENT (GW): The change in static head per unit of distance in a given direction.

HYDROCOMPACTION (GW): The process of volume decrease and density increase that occurs when moisture-deficient deposits are wetted for the first time.

IMAGE METHOD (METHOD OF IMAGES) (PE): The technique of using image wells to generate no-flow and constant pressure boundaries in an infinite system.

IMAGE WELL (GW): An imaginary well which effectively produces the same drawdown (or recovery) as a linear boundary limiting the aquifer. See "Image Method."

INFLOW PERFORMANCE RELATIONSHIP (PE): Used to predict a well's deliverability when deliverability test data are not available. A relationship between flow rate, bottom-hole pressure, average reservoir pressure, and a productivity index.

INFLUENCE REGION (PE): The region surrounding a well or wells whose properties influence transient tests performed on those wells. (Not to be confused with Meinzer's "area of influence.")

INJECTIVITY TESTING OR INJECTION WELL TESTING (PE): Pressure transient testing during injection into a well. Bottom-hole pressure is recorded while injection rate is held constant.

INTERFERENCE TESTING (PE): A multiple-well transient test which involves the production of an active well (injection) and observing the resulting pressure changes in an observation well.

INTERPOROSITY FLOW PARAMETER (PE): A dimensionless property of a fractured system. Dependent on the well radius, a matrix-to-fracture geometric factor, and the ratio of the formation matrix permeability to the effective fracture permeability.

ISOCHRONAL TESTING (PE): See "Deliverability Testing of Oil Wells."

JACOB'S METHOD (GW): Also known as asymptotic solution. Involves a semi-logarithmic plot of drawdown as a function of the log of time.

LEAKANCE (GW): The ratio of vertical hydraulic conductivity to thickness of the aquiclude.

LEAKY AQUIFER (GW): An aquifer into which overlying and/or underlying aquitards discharge water as the potentiometric head in the aquifer is lowered.

MEINZER UNIT (GW): A unit of hydraulic conductivity defined as the flow of water in gallons per day through a cross-sectional area of 1 ft^2 under a hydraulic gradient of 1 at a temperature of 60°F.

MOBILITY (PE): The ratio of absolute permeability to viscosity.

MOBILITY RATIO: The ratio of the mobility of the injected fluid to that of the in situ fluid.

MULTI-AQUIFER WELL (GW): A well which is screened to produce fluids from multiple aquifers which are separated by zones of low permeability. (cf: "commingled systems")

MULTIFLOW EVALUATOR (PE): A tool used in drill stem testing which allows unlimited sequences of production and shut-in. Includes a fluid chamber to recover an uncontaminated formation-fluid sample under pressure at the end of the flow period.

MULTIPLE RATE TESTING (PE): Tests involving a variable flow-rate. Testing at a series of constant flow rates, or testing at constant bottom-hole pressure with continuously changing flow rate.

ORTHOTROPY (GW): See "anisotropy."

PERMEABILITY, EFFECTIVE (GW): See "Hydraulic Conductivity, Effective."

PERMEABILITY, INTRINSIC: Same as "Permeability." Term adopted by U.S. Geological Survey to indicate a property of the medium alone, independent of the fluid properties. Has dimensions of L^2. Also called "Absolute Permeability."

PIEZOMETRIC SURFACE (GW): See "Potentiometric Surface."

POROSITY (GW): The property of a rock or soil of containing interstices. Expressed as the ratio of the volume of interstices to the total volume.

POROSITY, DUAL: The porosity of the rock having substantial primary and secondary porosity.

POROSITY, EFFECTIVE (GW): Refers to the amount of interconnected pore space available for fluid transmission. Expressed as the percentage of total volume occupied by interconnecting interstices.

POROSITY, PRIMARY (GW): Refers to the original interstices created when a rock or soil was formed in its present state.

POROSITY, SECONDARY (GW): Refers to the porosity created by fractures, openings along planes of bedding and solution cavities. Occur mostly in consolidated rocks having low primary porosity.

POTENTIOMETRIC SURFACE: A surface which represents the static head. An imaginary surface connecting points to which water would rise in tightly cased wells from a specified surface or stratum in the aquifer.

PRESSURE, AVERAGE RESERVOIR: The pressure a reservoir would attain if all wells were shut in for infinite time, assuming no natural influx of fluid.

PRESSURE BUILDUP TESTING (PE): Involves shutting in a producing well and analyzing the resultant pressure buildup curve for reservoir properties and wellbore condition

PRESSURE, INITIAL RESERVOIR (PE): Stabilized pressure of a shut-in well.

PRESSURE, INTERWELL (PE): The pressure halfway between an injection well and a production well. Sometimes used to approximate average reservoir pressure.

PRODUCTIVITY INDEX (PE): Also known as the specific capacity of a well. Denotes the productivity of a well per unit drawdown.

PSEUDO SKIN FACTOR (PE): The apparent skin factor in a well which has no true physical damage (or improvement) but is not drilled completely through the formation thickness or is only partially completed, thus appearing damaged.

PSEUDO STEADY STATE (PE): A transient flow regime in which the rate of pressure change with time is constant at all points in the reservoir.

PULSE TESTING (PE): A multiple-well transient test, in which flow rate pulses are produced in an active well and the resulting pressure changes are recorded in an observation well. Provides reservoir information for the region around and between the two wells. (Because of the shorter time intervals, the influence region for a pulse test is less than that for an interference test, and thus information is gained about a smaller portion of the reservoir.)

RADIUS OF DRAINAGE (PE): Defines a circular system around a well in which a pseudo steady state pressure distribution exists.

RECOVERY TEST (GW): Also known as build-up test in petroleum engineering. Denotes a test which involves the measurement of recovery in a well after the well is shut in following a known period of production.

RELATIVE PERMEABILITY (PE): Also called effective permeability in ground water hydrology. Denotes the permeability of the porous medium to a particular fluid when more than one fluid is present.

RESIDUAL DRAWDOWN (GW): During recovery, the difference between the static water level and the water level at any instant during recovery.

SAFE YIELD (GW): Given a variety of meanings, but originally defined (by Meinzer) as the rate at which ground water can be withdrawn year after year from a given aquifer system without depleting the supply to the point where withdrawal at this rate is no longer economically feasible.

SEEPAGE FACE (GW): For a well piercing an unconfined aquifer, seepage face denotes that segment of the well screen over which the total head equals elevation above datum and water flows from the aquifer into the well.

SEEPAGE FORCE: See "Stress, Seepage."

SHAPE FACTOR (PE): A geometric factor, characteristic of the reservoir shape and well location.

SLUG METHOD (GW): Used to determine transmissivity of an aquifer. A known volume or "slug" of water is suddenly injected into or removed from a well and the decline or recovery of the water level is measured at closely spaced time intervals during the ensuing minute or two.

SINGLE-PACKER TEST (PE): A drill stem test utilizing one packer in which fluid flows through the perforated anchor pipe into the drill string.

SKIN (PE): A zone of decreased permeability near the wellbore created by drilling and completion practices.

SKIN FACTOR (PE): A constant which relates the pressure drop across the skin to the dimensionless rate of flow. A measure of wellbore damage.

SPECIFIC CAPACITY (GW): The rate of discharge of water from a well divided by the drawdown of water level within the well. Varies slowly with duration of discharge. Also called productivity index in petroleum engineering.

SPECIFIC DISCHARGE or SPECIFIC FLUX (GW): The rate of discharge of ground water per unit area measured at right angles to the direction of flow.

SPECIFIC RETENTION (GW): The ratio of the volume of water a saturated rock or soil will retain against the pull of gravity to its own volume.

SPECIFIC STORAGE (GW): The volume of water released from or taken into storage per unit volume of the porous medium per unit change in head.

SPECIFIC YIELD (GW): The water yielded by water-bearing material by gravity drainage, as occurs when the water table declines. The ratio of the volume of water a saturated rock or soil will yield by gravity to its own volume.

STABILIZATION TIME (PE): The time corresponding to the start of the pseudo steady state period.

STATIC WATER LEVEL (GW): The static position of the potentiometric surface in a well prior to the commencement of discharge. (See also initial reservoir pressure in petroleum engineering.)

STEADY STATE: Pressure is constant at all points in the reservoir.

STEP DRAWDOWN TEST (GW): Also known as productivity index test or step-rate test in petroleum engineering. Involves producing a well at different rates for predetermined periods of time and monitoring drawdown.

STEP-RATE TESTING (PE): A multiple-rate injection well test in which fluid is injected at a series of increasing rates, each rate lasting an equal amount of time. Injection pressure at the end of each rate is plotted versus injection rate.

STORAGE COEFFICIENT: The volume of water an aquifer releases from or takes into storage per unit surface area of the aquifer per unit change in head.

STRADDLE-PACKER TEST (PE): A drill stem test in which the tested interval lies between two packers.

STRESS: APPLIED: The downward stress imposed at the aquifer boundary by (a) the weight (per unit area) of sediments and moisture above the water table, (b) the submerged weight of the saturated sediments overlying the boundary, and (c) the net seepage stress due to flow within the saturated sediments above the boundary.

STRESS, EFFECTIVE: Stress that is borne by and transmitted through the grain to grain contacts of a deposit. The effective stress at a point in an aquifer differs from the applied stress at the aquifer boundary by the submerged weight (per unit area) of the intervening sediments and the net seepage stress due to flow within the intervening sediments.

STRESS, SEEPAGE: Stress created by the seepage force, which is transferred from the water to the porous medium by viscous friction. Seepage force is exerted in direction of flow.

SUBSIDENCE: Sinking or settlement of the land surfaces, due to any of several processes, but most importantly due to artificial withdrawal of subsurface fluids.

TEMPERATURE, PSEUDOCRITICAL (PE): For a mixture of gases, calculated from the relative amounts and critical temperatures of the components.

TEMPERATURE, PSEUDOREDUCED (PE): The ratio of the temperature of interest to the pseudocritical temperature.

THEIM EQUATION (GW): Represents steady-state radial flow solution to a well in the center of a circular, homogeneous, horizontal aquifer with prescribed potential at the circular boundary.

THEIS SOLUTION (GW): Represents the solution to a continuous line source in a homogeneous, horizontal, infinite, isotropic aquifer. (Also known as exponential intergral in petroleum engineering.)

TIDAL EFFICIENCY: A measure of the response of the water level in a well to changes in ocean level. Equal to the barometric efficiency subtracted from 1.

TRANSIENT TESTING: The study of pressure variation with time in an active well (production or injection) under a variety of conditions and possible operating procedures.

TRANSMISSIVITY (T), (GW): The rate at which water of the prevailing kinematic viscosity is transmitted through a unit width of the aquifer under a unit hydraulic grandient.

TWO-RATE TESTING (PE): A multiple-rate test on a production well using only two different flow rates.

TWO-ZONE SYSTEMS: See "Composite Systems."

u (GW): Dimensionless quantity related to the reciprocal of dimensionless time, t_D, used in petroleum engineering.

$$u = \frac{r^2 s}{4Tt} = \frac{1}{4t_D}$$

UNCONFINED AQUIFER (GW): Also called water table aquifer. An aquifer which contains a water table, at which it is in direct contact with the atmosphere.

UNIFORM-FLUX FRACTURE (PE): One in which fluid enters at a uniform flow rate per unit area. A first approximation to the behavior of a vertically fractured well.

VERTICAL PULSE TESTING (PE): Used to determine vertical permeability of a formation. Fluid is injected in pulses above a packer, escapes the wellbore through flow perforations and reenters below the packer through observation perforations where pressure changes are observed with a pressure gauge.

VOID RATIO (GW): The ratio of the volume of the interstices in a rock or soil to the volume of its mineral particles.

WATER DRIVE RESERVOIRS (PE): Reservoirs in direct communication with an active aquifer.

WELLBORE STORAGE (PE): Fluid stored in the wellbore above reservoir level. Usually occurs when a production well is shut-in without packers used to maintain fluid level. Affects pressure build-up data at early time as fluid continues to flow into the wellbore after shut-in.

WELL FUNCTION OF u (GW): Equal to twice the value of P_D, dimensionless pressure, which denotes the value of the exponential integral.

WELL LOSSES (GW): Denotes drawdowns at the well in excess of the theoretical capability of the reservoir. Such well losses may be due to poor development of the well, excessive entrance velocities and casing damages due to skin, scaling, or corrosion.

WIRELINE FORMATION TESTING (PE): A tool is lowered into the well on a logging cable. The mechanism establishes communication with formation fluid and measures pressure response. Slightly more qualitative than a DST.

APPENDIX C
INSTRUMENTATION

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INSTRUMENTATION

Requirements

Before the appropriate type of instrument can be selected, the developer or consultant must calculate the anticipated pressure changes, flow rates, temperatures, and time resolution requirements. Methods for doing this have been discussed in Volume I. The importance of correctly anticipating these parameters is that the instrument chosen must have accuracy and precision far greater than the expected changes. For instance, when measuring pressure changes in an observation well with an expected 1 psi maximum of pressure change, then the instrument should have a resolution of at least 0.1 psi. On the other hand, in a production well there will be a relatively large pressure change and therefore only require 1 psi resolution. Instruments with a wide range of precision and accuracy are available. In general, the finer the resolution and greater the accuracy, the more expensive the instrument. However, advances in the development and availability of these instruments is lowering the cost of the high precision gauges.

An often overlooked area in test planning is the time element. If pressure changes take place very rapidily the recording equipment and/or personnel may not be suitable to record the data at a sufficiently small time interval. In general, in fractured or highly permeable aquifers the pressure changes will take place very quickly and be of a smaller magnitude than in a moderate or low intergranular permeability system. In almost every case it is valuable to have continuous recording devices with accurately synchronized clocks for measuring and recording each parameter of the test. This minimizes operator error, missed events, ambiguity in the data, and simplifies data analysis and interpretation.

Before any meaningful analysis of the data can be obtained, data of good quality is essential; it can be obtained from careful test planning, control, execution, and adequate instrumentation. Knowing how to use downhole pressure transducers to obtain pressure transient data is important. In principle, downhole data will always provide more reliable data insofar as the effects of temperature changes in the wellbore become unimportant. However, the use of downhole instrumentation may not always be possible or cost effective. For instance, if the production well is being pumped, it may not be possible to use a downhole tool because of the difficulty in setting the tools and the pump. Alternatively, the budget allocation for testing may prohibit the use of downhole tools. In general, the deeper the well or the hotter the well, the more important it is to use downhole instrumentation. If the well is over 100°C and sufficient wellhead pressure cannot be maintained, the water will start to flash (boil) in the wellbore. In this event, wellhead data or water level data will be useless for pressure transient testing and productivity calculations. For this case, downhole data is essential. If good quality production well data cannot be obtained, it is recommended that every effort be made to conduct a simultaneous production and interference test. Instrumentation for interference testing is readily available and, in general, easy to install and maintain.

In the following sections, subdivided by the test parameter to be measured, a variety of instruments will be discussed. Relevant to the discussion is the definition of accuracy and resolution. Accuracy is a measure of how closely a measured parameter compares to the correct value, as determined by the Bureau of Standards. The accuracy of an instrument is a function of its calibration, hysteresis, drift, repeatability and resolution. The resolution of an instrument is a function of sensitivity of the transducer to the parameter being measured, and the smallest quantity that can be observed and measured when using the instrument. For instance, a thermistor may have infinite resolution to temperature changes, but the ohm-meter being used to read the resistance may only have a resolution of five ohms; thus, the meter, not the probe controls the resolution of the instrument. The resolution or accuracy of a measured system is only as good as the worst component. For geothermal applications, the resolution of a pressure gauge is often the more significant measure of the quality (or suitability) of a gauge. However, for temperature and flow rate measurements, accuracy is a more important requirement.

The following pages list some of the instruments currently available, their assets and drawbacks, and the types of instruments most suitable for a variety of applications. In addition to the detailed discussions, Tables C-1 through C-3 at the end of this subsection, summarize many of the performance characteristics of temperature and pressure sensors as defined in Reference C-1.

Flow Measurement

1. Weirs and flumes

Accuracy: ±10%

Range: 1 gpm to any maximum.

Advantages: Very inexpensive, can be home-built. Construction details and formulas are contained in several engineering handbooks.

Disadvantages: Cannot be used if the temperature is greater than 100°C. Also, cannot be installed in a pressurized pipeline and cannot be connected to a continuous recording device very easily.

Suppliers: F. B. Leopold Company and BIF Industries.

2. Known-Volume container or weighing tank and stopwatch

Accuracy: ±20%.

Range: Limited only by the scales, container or tank, and the flow control apparatus.

Advantages:	Very inexpensive.
Disadvantages:	Cannot be connected to a continuous recorder. The person measuring the flow can get burned.

3. Differential pressure meters (orifice meters, nozzles, Pitot tubes, Venturi tubes, and low-pressure loss tubes)

Accuracy:	±10%.
Range:	Pitot tubes--<1 to >30 ft/sec. Others--0.1 to 30 ft/sec. Depends on orifice and pipeline size.
Advantages:	Most pump companies and drillers use these methods and are comfortable and familiar with them. They are most easily connected to continuous recording devices; therefore, these methods are very suitable for most applications.
Disadvantages:	Scaling or flashing across the orifice can create undetected inaccuracy in the measurements.
Cost:	Costs vary widely with the type of element and also with line size and pressure rating; less than $100 for an orifice plate to several thousand dollars for a venturi or one of the patented flow tubes. Installed cost also varies greatly with line size and pressure rating except for the pitot tube which is installed in a boss on the pipe wall.
Readout and Recording Equipment:	A method must be provided to measure the pressure difference, and if desired, convert that to flow rate. In some cases, ΔP can be measured with a homemade manometer made from clear plastic tubing and a yard

stick, or a commercial manometer. At high line pressures, a ΔP gauge or transmitter with output indicator may be required. In either case the measured ΔP is then used to calculate flow rate. If direct flow reading is required, a pressure gauge scale (nonlinear) can be calibrated in flow units or a transmitter output can be converted electronically to a direct flow indication or output proportional to flow for recording or display. Cost of equipment to provide transmitting, recording, and indication could range from $2,000 to $3,000 or more, depending on the grade or quality of equipment.

Partial List of Suppliers: Pitot Tubes--Foxboro Corp., Meriam Instrument Co., Rosemount Engineering, Deitrich Standard, Taylor Instrument Co. Orifice Plates, Venturi tubes and nozzles--Daniel Industries, Inc., Badger Meter, Meriam Instrument Co., Fischer & Porter Co., Foxboro Corp., Tech Tube Corp.

4. Turbine Flow Meters

Accuracy: $\pm 5\%$.

Range: Depends on impeller and pipe diameter 0.1 to 50 ft/s.

Cost: Relatively expensive; several hundred dollars to several thousand depending on size and features.

Output: Output signal of most transmitters is a frequency proportional to volumetric flow rate that can be fed directly to a compatible flow rate indicator meter.

Advantages: Good accuracy, repeatability, and linearity. Wide ranges. Can be installed in-line or on a probe through the pipe wall.

Disadvantages: Can be degraded by other than clean fluids. Relatively high cost.

Partial List of Suppliers: Daniel Industries, Flow Technology, Inc., Foxboro Corp., Brooks Instruments, Fischer & Porter, and Electronic Flow-Meters.

5. Others

There are many other types of meters available that could be investigated if those listed above are not suitable. The following types would be in that category:

Acoustic/ultrasonic--no obstruction, thus no pressure loss. The clamp-on Doppler eliminates scaling and corrosion problems.

Magnetic--No obstruction in the line thus no pressure loss. Somewhat pressure and temperature limited by liner material. Relatively insensitive to dirty fluids.

Vortex--Good accuracy--subject to scaling.

Wellhead and Differential Pressure Measurement

1. In addition to the transducers in the preceding table, the following instruments are available:

   a. Manometers: Measure pressure or differential pressure.

      Accuracy: ±1% of span for most. ±0.1% for precision types.

      Range: Minimum span is 0.15" H_2O, maximum span 60 psig.

Design pressure:	Up to 6,000 psig.
Design temperature:	Function of seal fluid, usually ambient.
Advantages:	Relatively low cost. Availability.
Disadvantages:	Difficulty connecting to a recording device, not sufficiently rugged for field testing.
Cost:	Ranges from a few dollars for the simple units to approximately $1,000 for the more sophisticated and precise.
Partial List of Suppliers:	Meriam Instrument Co., Bailey Meter Co., and Foxboro Corp.

b. Mechanical pressure gauges bourdon tube

Accuracy:	Between ±0.1% and ±5% of span.
Range:	From 10 in. H_2O to 100,000 psig.
Advantages:	Readily available and replaceable. Most drillers and pump operators have them.
Disadvantages:	Difficult to connect to recording devices.
Cost:	From $20 to thousands depending on dial size and accuracy.
Partial List of Suppliers:	Ashcroft, Foxboro Corp., Robert Shaw Controls, Heise (Dresser) Wallace and Tiernan Inc., ITT Barton.

c. Electronic pressure and differential pressure transmitters, capacitors, strain gauges, piezoelectric semiconductors (piezoresistive), potentiometers. (Process grade field instrumentation.)

Accuracy:	0.1% to 1% of calibrated span.
Range:	A few inches of water to several thousand psig.
Advantages:	Easily connected to continuous recording devices. Usually these devices are fairly reliable.
Disadvantages:	High cost and lead time for replacement.
Cost:	$750 to $2,000 depending on accuracy and pressure.
Partial List of Suppliers:	ITT Barton, Fisher Controls, Foxboro Corp., Honeywell, Taylor Instrument Co., Rosemount, Bailey Meter Co.

Temperature

Temperature gauges should be placed in thermal wells near the wellhead on the discharge line.

1. Mercury Thermometer

Accuracy: Depends on range 0.1 to 1°C.

Advantages: Readily available. Very accurate if small enough range.

Disadvantages: Cannot be connected to a recording device.

2. Electronic gauges

There are a wide variety of electronic gauges available. Tables C-1 and C-2 summarize the many varieties and manufacturers. Most of the available transducers are suitable for wellhead temperature measurements. One advantage of electronic gauges is that they can be easily connected to readout and recording devices. Calibration and recalibration of these gauges will ensure their repeated accuracy.

Downhole Instrumentation

Downhole Temperature Measurement

Tables C-1 through C-3 compare the performance of various sensors. For simple downhole temperature measurement a max-reading thermometer can be lowered into the well on a line. If more than maximum temperature is required, i.e., temperature versus depth or a continuous indication, a thermocouple, RTD or thermistor can be lowered into the well on a conductor line and temperature measured on the surface with a portable bridge, potentiometer or the temperature can be recorded if desired. Small reels or winches with conductor lines are available at reasonable cost. For more precise and detailed temperature logs, it may be more suitable to rent the equipment or hire a well logging service. Downhole tools can be purchased outright but the cost is usually prohibitive. The "Kuster" temperature tool incorporates a downhole recorder and can be run on a wire line. A logging service's charge will include costs/foot of depth, a flat service charge, and other charges depending on well condition, location, etc. The charges to log a 5,000-ft. deep cased hole could be several thousand dollars.

The following companies rent equipment or provide service as noted:

Schlumberger Well Services--Service

Dresser Atlas--Service

Birdwell--Service

Kuster Company--Tool Rental and Sale

Gearhart Owen Industries--Tool rental, sales, and service

Halliburton Services--Service

Sperry-Sun--Tool rental, sales, and service

Downhole Pressure Measurement

1. Bubbler Tube. Perhaps the simplest and least expensive method to measure downhole pressure and water level is the bubbler tube. A crude but sometimes appropriate arrangement consists of a tire pump and a gauge connected to a small pipe or tube suspended in the well. Accuracy of the bubbler tube in well measurement applications can vary widely depending on the equipment, temperature effects, and operating techniques. In ordinary tank level measurement accuracies of ±1% can be achieved.

2. Downhole Capillary Tube. This consists of a small tube suspended in the well with a pressure coupling chamber at the bottom and a precision pressure transducer on the surface. The tube is filled with inert gas or a synthetic fluid. Sperry-Sun Inc., supplies such a system.

3. Electronic Pressure Transducers. Table C-3 compares the performance of several transducers suitable for downhole measurements. As in the case of downhole temperature measurements, the tools can be rented, purchased, or the services can be hired. The table lists suppliers, some of which will rent tools. The same companies listed as renting temperature tools or providing logging service will also provide pressure tools and service at similar costs. In the following section, an instrument incorporating a Paro-scientific digiquartz transducer is discussed.

Downhole Flow Measurement

Most of the downhole flow meters use a variation of the turbine discussed previously. As with downhole pressure and temperature measurement the tools and/or service are available for rent or hire. Most of the companies listed above will provide flow measurement tools or service.

Water Level Measurement

1. Bubbler Tube. The bubbler is usable in subsurface water level or artesian wells. Several companies supply systems and equipment for ordinary tank level measurements which may be suitable for well measurements. Cost would be on the order of several hundred dollars. Some of the companies are: Fisher Governor Co., Meriam Instrument Co., Petrometer Corp., and Uehling Instrument Co.

2. Tape and Float. This method can be used on wells with water levels below the surface. They can be suspended by hand and the distance measured, or wound on a drum with provisions for continuous recording of level. Several companies make the latter unit which is well suited for monitoring well water level at depths up to 30(ft. Cost is approximately $1,000. Partial list of suppliers: Leopold & Stevens and Keck Instrument Inc.

3. Others. This would include the conductivity probes, which can be fouled by oil, etc., the chalked tape, and other float and changing resistance type systems.

Approximate Cost: $50 to $100 for 100 ft of chalk tape.
$300 to $800 for an electric tape.
$500 for a conductivity probe and meter.

Partial List of Suppliers:

Lufkin and Roe Instrument: chalk tape.
Sepa-Air Inc.: electric tape.
Springs Instruments: conductivity probe.

TABLE C-1. Manufacturers of temperature sensors reviewed

	Electrical Sensing			Passive Indicating	
Manufacturer/Supplier	Resistance Temperature Detectors (RTDs)	Thermistors	Thermocouples	Maximum Indicating Sensors	Bi-Metallic Stem Thermometers
ARi Industries	X	--	X	--	--
Barber-Coleman Co.	X	X	X	--	--
Big Three Industries	--	--	--	X thermochemical	--
Brooklin Thermometer	--	--	--	X glass/bi-metallic	--
Celesco Transducer Products	X	X	X	--	--
C. S. Gordon Co.	--	--	X	--	--
Fenwal Electronics	--	X	--	--	--
Fischer & Porter Co.	X	--	X	--	--
Foxboro Co.	X	--	X	--	--
Hi-Cal Engineering	X	--	X	--	--
ITT-Barton	X	--	--	--	--
Markal Co.	--	--	--	X thermochemical	--
Matthey Bishop, Inc.	X	--	--	--	--
Minco Products, Inc.	X	--	X	--	--
Rosemont, Inc.	X	--	--	--	--
Semco, Inc.	X	--	X	--	--
Spectro Systems, Inc.	--	--	--	X metal pellets	--
Sybron-Taylor Corp.	X	--	X	X glass	X
Thermometrics, Inc.	--	X	--	--	--
Victory Engineering	--	X	--	--	--
W. Wahl Corp.	X	X	X	X thermochemical and bi-metallic dial	X
Weed Instrument Co.	X	--	--	--	--
W. H. Keseler Co., Inc.	--	--	--	X glass	--
Weston Instruments	--	--	--	--	X
Yellow Springs Instruments	X	X	--	--	--
Omega Engineering	X	X	X	--	--

TABLE C-2.[a] Performance comparison of some commercial pressure transducers

No.	Manufacturer and (Model)	Sensor Technique	Accuracy (overall) (% FS)	Resolution (% FS)	Stability and Drift	Max °F	Coefficient	Maximum Pressure Range(s) (psia)	Size	Comments
1.	Hewlett Packard, (2811B)	Diaphragm with oscillating quartz crystal	0.025%	Infinite (0.01 psi typ)	0.01%/yr	300	?	11,000	1-7/16" dia. by 40" long	Accepted standard for precision downhole oil/gas well testing. Temp correction to ±1°C recorded.
2.	Mensor, (Digital Quartz manometer)	Fused quartz helical bourdon tube w/optical sensor and electronic nulling	<0.2%	0.0005%	0 @ 3 mos (0.01%/yr)	122	0.0004%/°C	1,000	11" by 10" by 8-1/2"	System temp control/ compensation to ±2°C to achieve performance quoted. Also makes unit like #3 below.
3.	Heise (Dresser), (Digiquartz)	C bourdon tube and servo force balance	0.05%	0.005%	NA	125	Very small, 0.1% PS over range	10,000	4-3/8" by 6" by 16"	Sperry-Sun sells for use with their 'tube' pressure transmission system.
4.	Paroscientific, (Digiquartz)	Bellows linked to vibrating quartz bar	0.1%	<0.1%	0.1%/yr	225	0.004%/°F	5,000	1.15" dia. by 3-1/4"	Hi temp @ pressure (530°F @ 10,000 psi) unit currently under joint development with Sandia Labs--will have high temp electronics.
5.	Sundstrand Data Controls, Inc., (Developmental)	Bellow linked via quartz structure w/force-balance and capacitor feedback	0.11%	0.004%	0.1%/yr ?	176	NA	500	1-5/8" dia. by 2"	Mfg claims higher pressure (5K-10K) unit is developable, basic sensor capable of higher temperature
6.	Setra Systems, (204/205)	Diaphragm w/capacitor plate displacement	0.11%	<0.01%	0.05%/yr ?	250	0.004%/°F	10,000	1-3/4" dia.	Basic sensor w/o integral electronics capable of much higher temperature.
7A.	Heise (Dresser), (#CMM16)	C bourdon tube linked to dial and potentiometer	0.1%	0.01%	0.02%/yr	125	0	10,000	17-3/8" dia. by 3-1/4"	16" by 660 dial readout, electrical output also provided.
7B.	Mensor, (2792)			0.01%	0.02%/yr	125	0	10,000	17-3/8" dia. by 3-1/4"	Can operate up to 250°F w/external compensation.
8.	Robinson-Halpern, (144)	Helical bourdon tube linked to differential transformer	0.1%	<0.01%	NA	165	0.1%/°F	10,000	6" by 6" by 4-1/4"	--

TABLE C-2.[a] (continued)

No.	Manufacturer and (Model)	Sensor Technique	Accuracy (overall) (% FS)	Resolution (% FS)	Stability and Drift	Max °F	Coefficient	Maximum Pressure Range(s) (psia)	Size	Comments
9.	Bell & Howell, (CEC-1000)	Diaphragm w/thin film strain gage (sputtered)	0.15%	<0.01%	0.1%/yr	600+	0.005%/°F	10,000	1" dia. by 2-/2"	Mfgr claims higher accuracy and temp performance available
10.	Bell & Howell, (CEC-4-361)	Diaphragm w/unbonded wire strain gage	<0.2%	<0.05%	0.5%/yr	700	0.1%/°F	5,000	1-1/4" dia. by 2-1/2"	Fragile and slow temp response time (mfgr feels thin film will replace).
11.	Kaman Sciences, (KP-1911)	Diaphragm with eddy current variable impedance coil	0.25%	0.1%	NA	1000	0.1%/°F	5,000	5/8" dia. by 1-1/2"	--
12.	Sparton South-west, (890 HT)	C bourdon tube with wire potentiometer	1%	0.3%	NA	600+	0.1%/°F	10,000	1" dia. by 2-1/2"	--
13.	Celesco, (P2)	Diaphragm w/variable reluctance transducer	1%	0.1%	0.5%/yr	250	0.2%/°F	10,000	1-1/4" dia.	Mgfr has built high temp (600°F) unit w/derated accuracy (∼1-1/4%).
14.	Data Instruments, (MPA 1000)	Diaphragm w/bonded semiconductor strain gage	0.25%	<0.05%	0.5%/yr	250	0.001%/°F	5,000	1-1/4" dia. by 2-1/2"	--
15.	Vernitech	C bourdon tube with film potentiometer	0.7%	<0.05%	0.5%/yr	185	0.01%/°F	10,000	2-1/2" dia. by 2"	--

a. See Reference C-1.

TABLE C-3. Performance comparison of geothermal process temperature sensors

Performance Parameter	Resistance Temperature Detectors (RTDs)	Thermistors	Thermocouples	Bi-Metallic Thermometer	Thermochemical and Physical Melt Indicators	Bulb-Bourdon Tube (thermal fluid filled)
Temperature range	-260 to 900°C	-100 to 400°C	-270 to 2000°C	-60 to 450°C	38 to 1649°C labels (38 to 600°C)	0 to 340°C
Accuracy	0.01% (<0.1°C)	1%	0.1%	1% (0.5% available)	1% (0.3% available)	1%
Sensitivity (signal level)	Good: +0.5%/°C (<0.1V/°C with bridge)	High: -5%/°C -0.5% linearized (<0.5 V/°C with bridge)	Very low, 1%/°C	Depends on dial size, etc.	NA	0.5% of F.S.
Linearity	Excellent: 1%	Poor: 10-20% Linearized: 2%	Poor: 10-25%	1%	NA	1%
Stability	Excellent	Poor	Excellent	Good	NA	Fair
Interchangeability	Excellent	Good	Poor	NA	NA	NA
Size	Medium: >1/8" diam. by >1/4" long	Very small	Small	1" to 5" dial. stem dia. >1/8"	Typically >1/8"	Very large
Time constant	0.2 to 10 s	0.05 to 10 s	0.1 to 4 s	10 to 30 s	1 s	Long
Cost	$25 to $1000	$2 to $300	$1 to $50		$0.50 to $7	High
Comments	Best overall	Narrow span (typically <105°C)	Requires reference temp. junction	Can be configured w/maximum registering dial. Used in Kuster 'bomb' type high temp		Used in GRC 'bomb' type high temp logging tool (span limited ~150°C). Kuster also makes system rated for 260°C.

REFERENCE

C-1. M. D. Lamers, Measurement Requirements and Methods for Geothermal Reservoir System Parameters (An Appraisal), LBL-9090, GREMP-6, 1979.

APPENDIX D
FABRICATION OF INSTRUMENTS

APPENDIX D

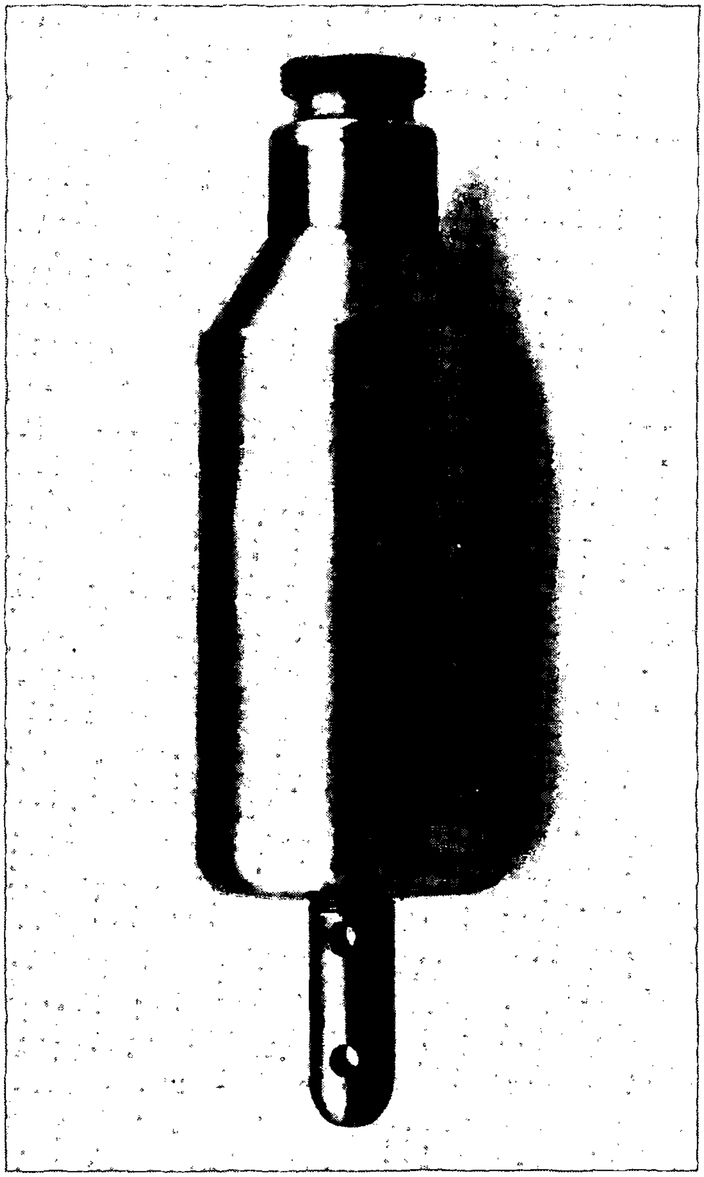
FABRICATION OF INSTRUMENTS

The cost of commercially available downhole instrumentation is often prohibitive. For this reason, and to obtain the highest quality data possible, the Earth Sciences group at Lawrence Berkeley Laboratory has developed a suite of downhole instruments for low-to-moderate temperature geothermal well testing. Three components of a downhole instrument package are described here: a downhole pressure temperature tool, a multiconductor cablehead, and a line driver for transmitting the pressure tool signal. A fourth instrument, a float type water level detector is also discussed. The complete engineering drawings for these instruments are available in Reference D-1.

Downhole Pressure and Temperature Instrument

The Paroscientific 400 psi and 900 psi digiquartz pressure transducers have been used for many years in measuring precise changes in wellhead pressures, pressure differentials across orifice plates and also in conjunction with "Perk" tubes and Sperry Sun downhole pressure chambers. In order to obtain precise pressure data during interference testing and accurate downhole pressure data, the Lawrence Berkeley Laboratory Reservoir Engineering group decided to incorporated the digiquartz pressure transducer in a downhole pressure temperature package which can be used in artesian and non-artesian wells. The maximum operating temperature of the tool is 107°C.

The downhole instrument package incorporates the Paroscientific 400 psi model 2400-A or 900 psi model 2900-A digiquartz pressure transducer (Figures D-1, D-2, and D-3). The transducer is shock-mounted inside the instrument package and connected to the pressure port with a stainless steel capillary tubing filled with Dow Corning f.s. 1265 fluid. The pressure device, when interfaced with the Paroscientific model 600 digiquartz computer and the Hewlett Packard 5150A thermal printer, can record pressure data at intervals of 1 second to 2 hours. The combination pressure-temperature housing is constructed from 316 stainless steel and has an outside diameter of 2.75 in. and a length of 9.5 in.



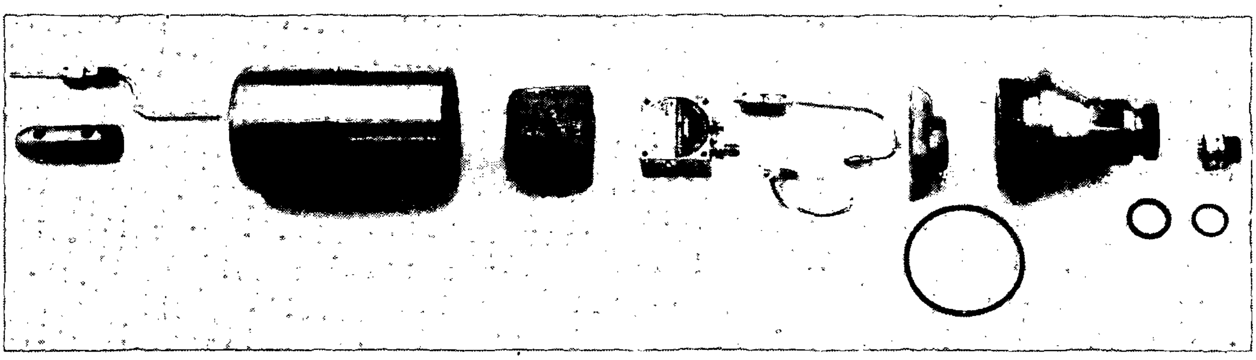


Figure D-1. Downhole instrument package.

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	1	18B4433	HOUSING
	2	18B4442	THERMISTOR GUARD
	3	18B4453	HOUSING CAP
	4	18B4462	THERMISTOR LEAD CONDUIT
	5	18B4472	THERMISTOR WELL
	6	18B4482	PRESSURE TRANSFER TUBE ASSEMBLY
	7	18B4492	CONNECTOR, MODIFIED BURNDY 10 PIN
	REF	18B4563	CABLE HEAD
	A		QUARTZ PRESSURE TRANSDUCER ASSEMBLY
	B		FOAMED URETHANE SHOCK ABSORBER
	C		—
	D		1/8" TUBE TO 1/8" FPT ADAPTER, SWAGELOK SS-200-1-2.
	E		'O' RING, VITON, PARKER SIZE 2-144 (2 1/2 I.D. x 3/32 SECTION)
	F		'O' RING, VITON, PARKER SIZE 2-017 (11/16 I.D. x 1/16 SECTION)
	G		'O' RING, VITON, PARKER SIZE 2-177 (13/16 I.D. x 3/32 SECTION)

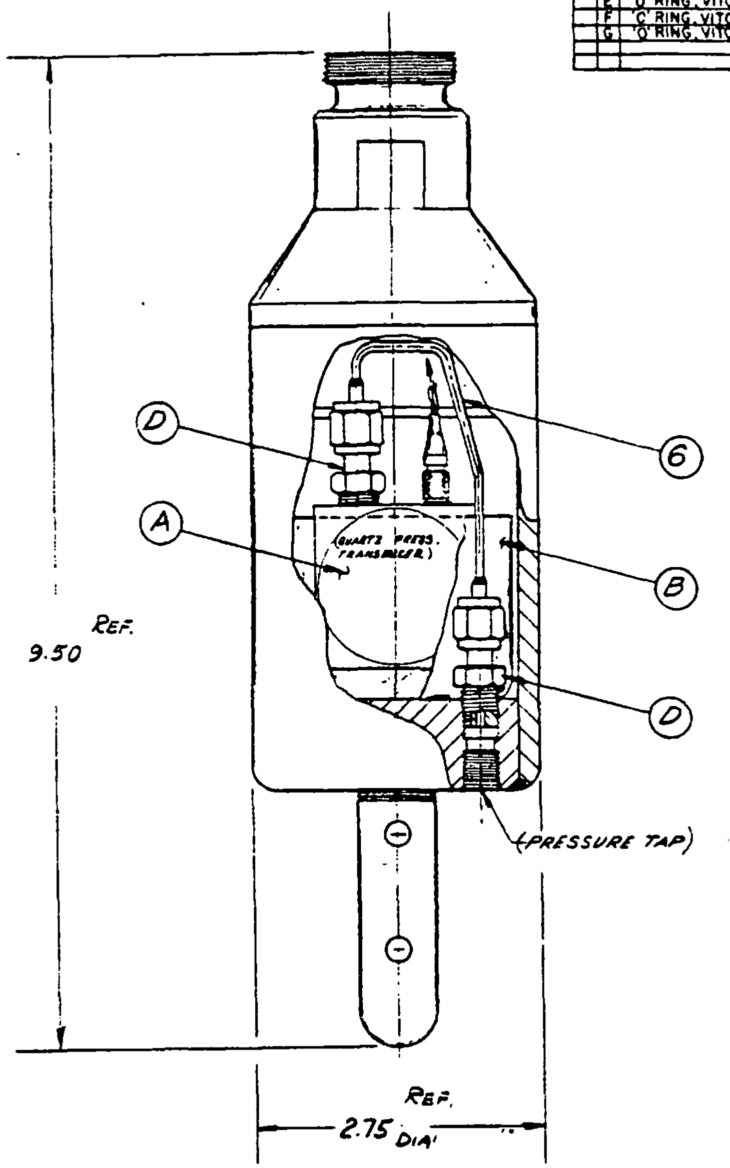

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Figure D-2. Downhole pressure and temperature instrument.

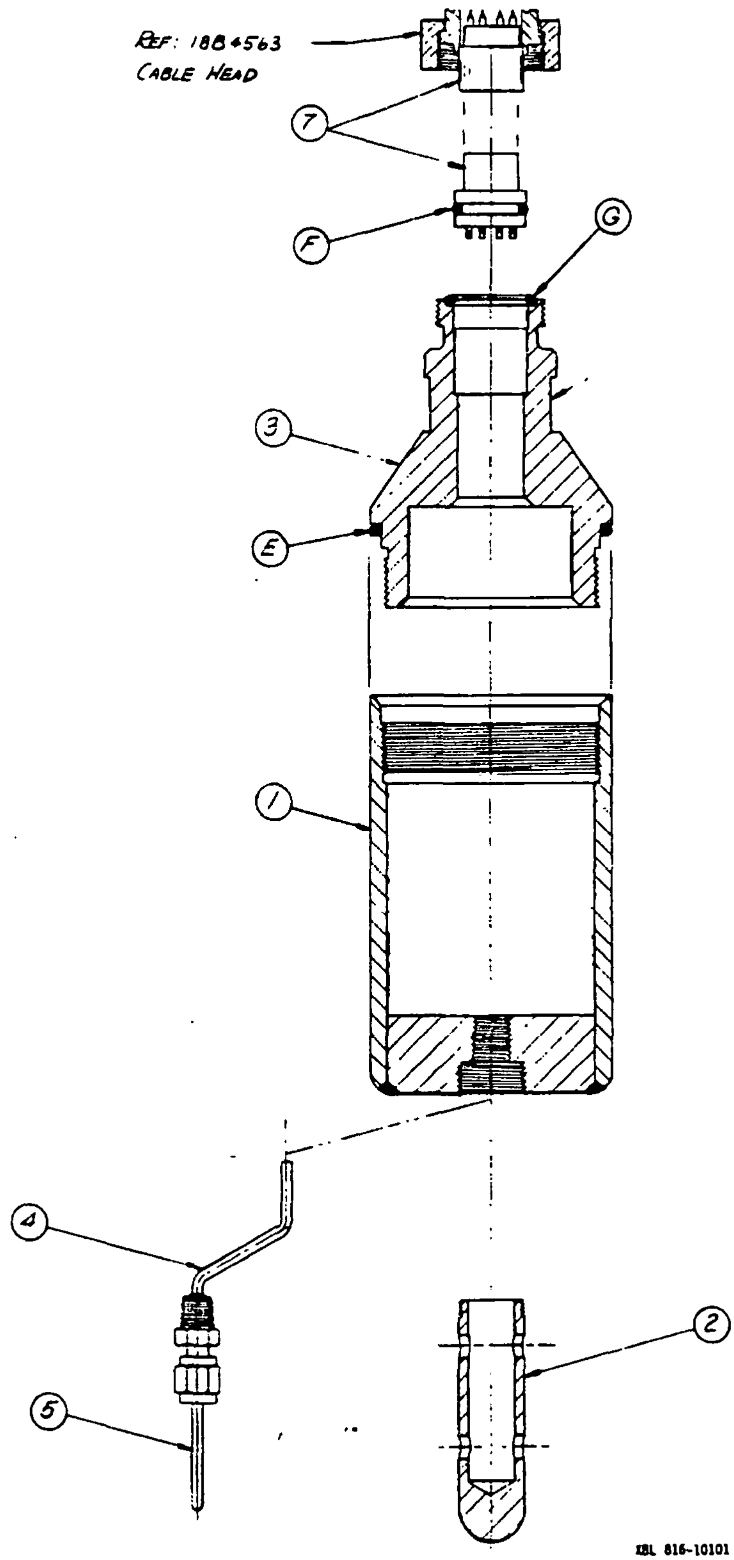

Figure D-3. Downhole pressure and temperature instrument continued.

The combination pressure-temperature chambers are lowered into the well on armored four-conductor cable. The cable is connected to the tool by a designed cablehead, but can also be run with a conventional multi-conductor cablehead. The temperature sensing element is a YSI 44011 100,000 ohm at 25°C thermistor, isolated from the well fluid by 1/8 in. outside diameter stainless steel tubing with a 0.010 in. wall thickness. The thermistor has a resolution of ±.2°C (including thermistor interchangeability) and a response time of approximately 1 second in liquids. The resistance of the thermistor, which is temperature dependent, is read at the surface and converted to temperature.

The system has been field tested at Klamath Falls, Oregon; Susanville, California; and Cerro Prieto, Mexico.

Geothermal Multiconductor Cablehead

A cablehead is a connector used to mechanically and electrically attach the armored logging cable to a downhole instrumentation package. Commercially available cableheads perform properly in noncorrosive environments, but when subjected to the corrosive brines and the elevated temperatures found in geothermal wells, the corrosive brine will eventually enter the cablehead. This will short the electrical connectors and cause the armored steel strands to corrode. Loss of data and eventual loss of instrument package downhole can result.

The geothermal group at the Lawrence Berkeley Laboratory has designed an inexpensive multiconductor cablehead (Figure D-4). The body is machined from stainless steel with a length of 9 in. and a 1.5 in. diameter. It has an overshoot provision for retrieval should the instrument package be lost downhole. The cable is mechanically attached within the cablehead by letting a brass cone force the unbraided cable strands against the walls of an internally tapered sleeve. The cablehead incorporates an epoxy pressure seal. The high temperature epoxy used has excellent corrosion, chemical and solvent resistant properties. The epoxy is rated for continuous operation at temperatures up to 600°F. The epoxy seal is formed by pouring the epoxy mix around the electrical conductors inside the specially machined

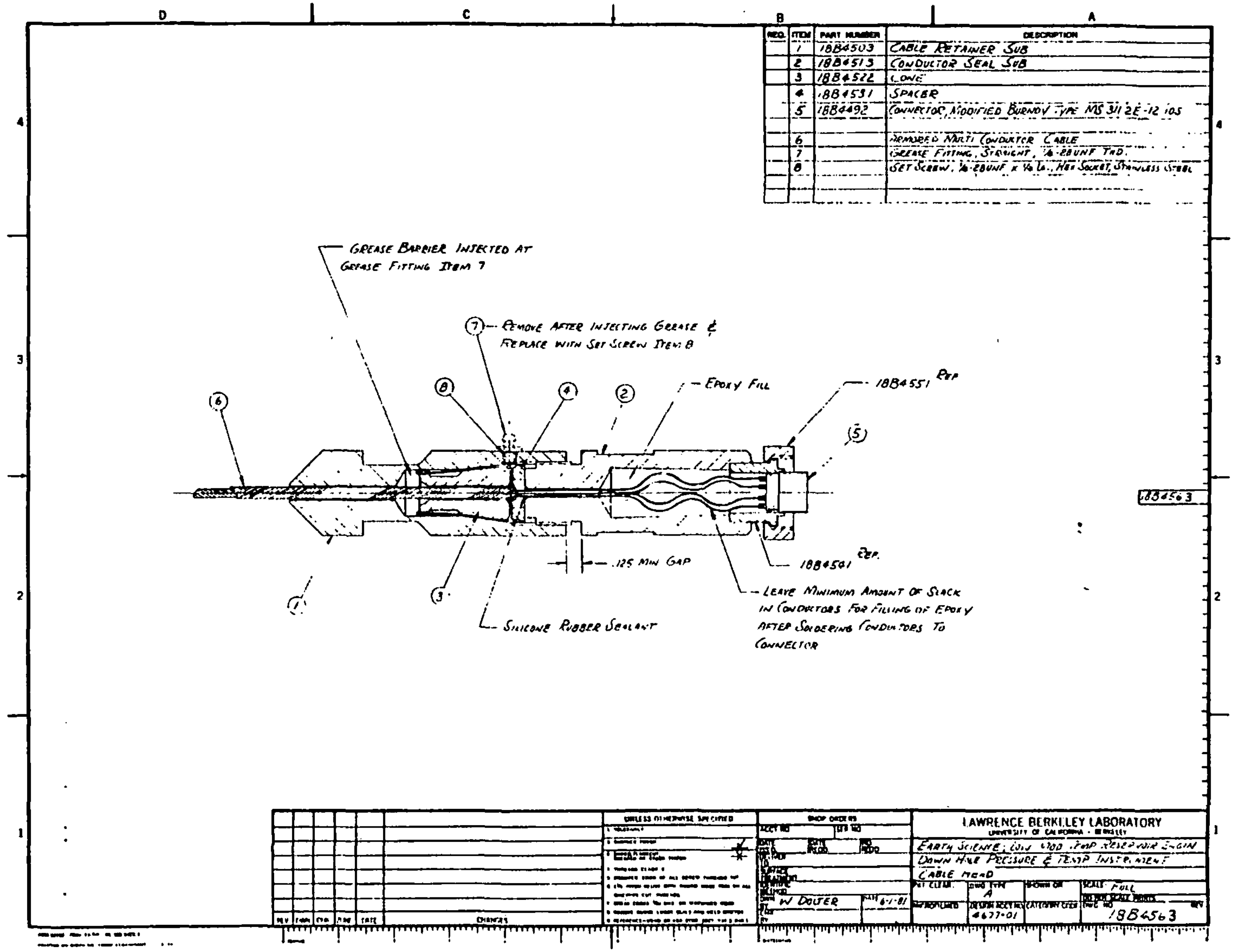

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Figure D-4. Multiconductor cablehead.

tapered cablehead cavity. The insulation on the conductors has been previously etched to ensure maximum adhesion of the epoxy. Should it become necessary, the epoxy seal can be easily removed with the aid of an electric drill. The cable can then be reheaded and a new seal poured in place. This can be carried out even under field conditions.

The cablehead also incorporates a grease barrier. A high temperature grease is pumped through a removable zerk fitting and fills void spaces within the cablehead assembly. This procedure keeps the often very corrosive, well bore fluid from entering the cablehead assembly. This eliminates the frequent reheading of the cable due to strand corrosion. The connection of cablehead to instrument package is made with a threaded fastener incorporating an "O" ring seal, and multi-conductor electrical connector.

Line Drivers

When using a Paroscientific pressure transducer it is often desirable to transmit the signal from the measurement location to a central data acquisition location. This allows for accurate clock synchronization and continuous observation of the instrument function. Because the transducer has a limited range in transmitting its frequency output, it is necessary to amplify the signal before it is relayed to the central data acquisition location.

The Field Systems Group at Lawrence Berkeley Laboratory designed an inexpensive line driver that detects, amplifies, and transmits the frequency signal from the transducer. The line driver provides power to the transducer from a 12 V automatic battery and transmits the output signal to a central location on an inexpensive twisted two-conductor wire.

The line driver is housed in a small instrument enclosure. The electronic circuit uses inexpensive commercially available components. A schematic of how the line driver is used in conjunction with the pressure tool is shown in Figure D-5.

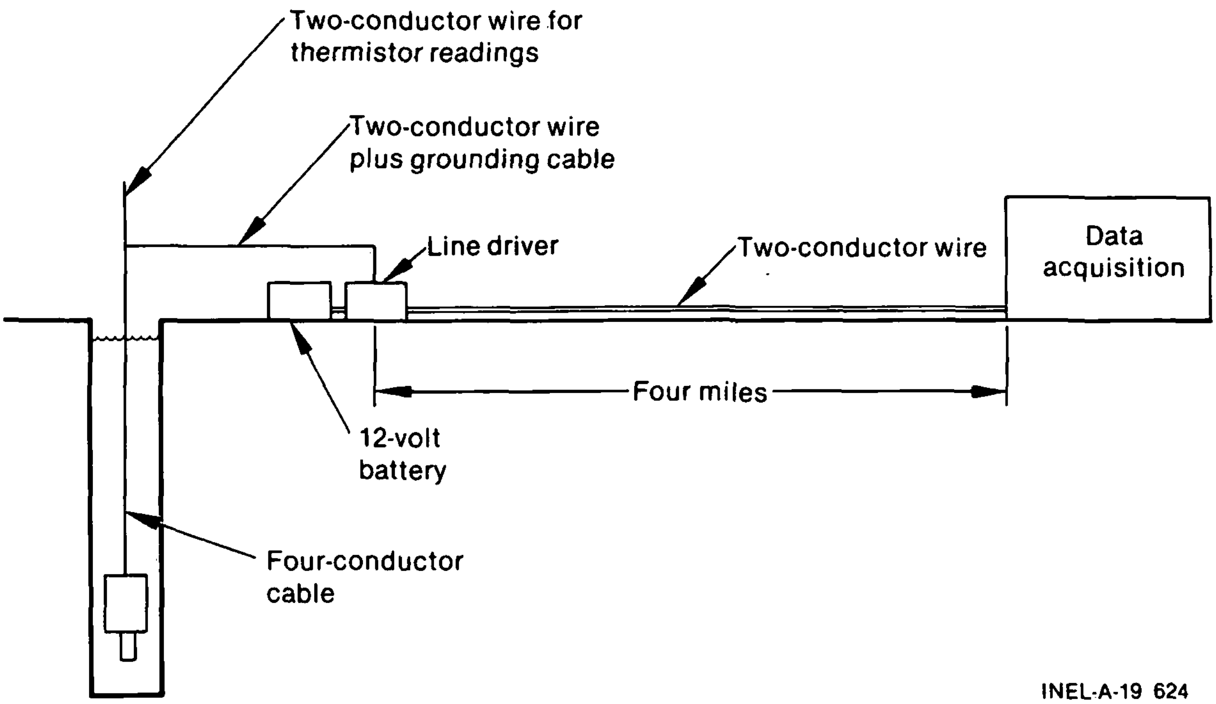

Figure D-5. Schematic of a line driver used in conjunction with the pressure tool.

Water Level Indicator

Description

Fluid level indicators, as used in well testing, are portable instruments used to detect the water level in the wellbore. The most commonly used type of probe is a conductivity-type gauge. The weighted probe attached to a two conductor cable is run down a well. When the probe contacts the water an electrical circuit is completed and the current flow is measured at the surface. When used in cold water wells, such a probe performs adequately; but for hot wells it is often unreliable. Because a conductivity-type gauge relies solely on the conductivity of the downhole fluid to complete the electrical circuit, erroneous readings may result due to heavy steam layers, spill over from pumps, and casing leaks. Nonconductive fluids floating on the water surface, such as liquid paraffin or oil, can also cause erroneous readings.

By replacing a conventional conductivity-type probe with a GEMS model LS-1700 liquid-level switch, these problems can be avoided. In the GEMS unit a magnet-equipped float rises with the fluid level and closes a reed switch encased in the unit's central stem. An electrical circuit is completed and the current is detected at the surface. The assembly drawing for this unit is shown in Figure D-6. It is easily fabricated and the instructions to do so follow.

Fabrication

The assembly and fabrication drawings are as shown. The GEMS liquid-level switch (model LS-1700) is inexpensive and readily available. The parts surrounding the unit, Parts 3 and 4 (see assembly drawing) should be made of a nonmagnetic material to avoid interference with the operation of the probe.

1. Insert the GEMS liquid level switch into the fabricated housing (Items 3 and 4) letting the leads and threaded portion of the GEMS unit protrude through the hole (Item 4). Slip the hose fitting (Item 2) over the leads.

2. Fill the hose fitting with silicon rubber sealant and screw it securely to the GEMS unit.

3. Insert the two-conductor cable with the conductivity type probe removed through a one-foot section of appropriately-sized heat shrink tubing.

4. Solder the leads from the GEMS Unit to the leads of the two-conductor cable approximately two inches beyond the end of the hose fitting. Cover the solder joint, the cable, and the end of the hose fitting with silicon rubber sealant.

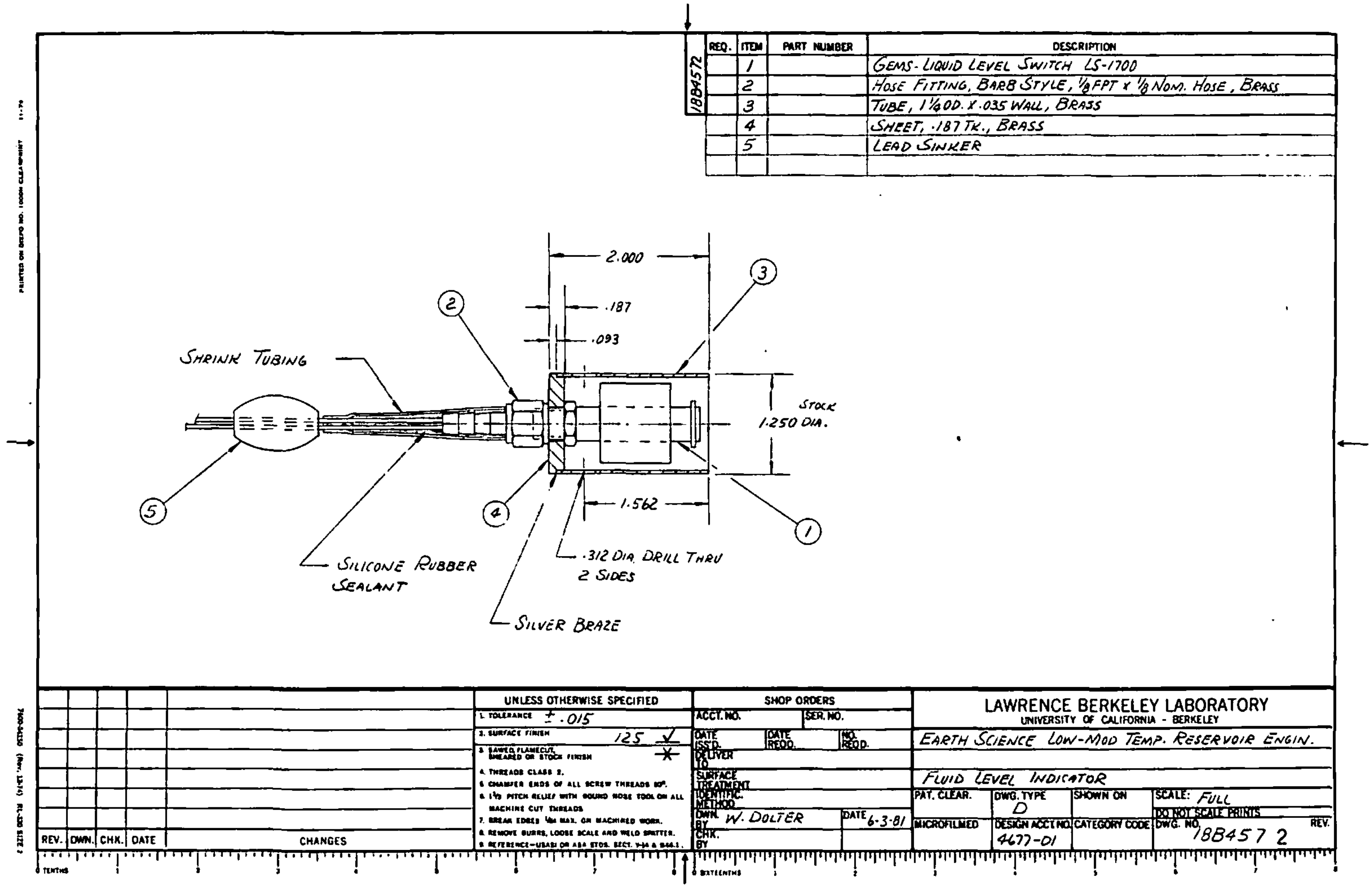

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Figure D-6. Fluid level indicator.

5. Slip the shrink tubing over the cable solder joint and hose fitting. Heat the shrink tubing until it fits snugly on the cable. Do not use the probe until the silicon rubber sealant has set.

6. Add split-type lead weights to the cable to facilitate running the probe down a well.

Use

The unit described here can be substituted on the end of a conventional conductivity-type water-level indicator. When the fluid level is reached, a current will be detected on the current-detecting instrument at the surface. If an entire water level detector is to be constructed, a suitable substitute for the surface readout is an ohmmeter. When the fluid level is reached by the probe, the ohmmeter will indicate that a circuit has been closed.

REFERENCE

D-1. Recently Developed Well Test Instrumentation for Low-to-Moderate Temperature Hydrothermal Reservoirs, LBL-13260.

APPENDIX E

VARFLOW PROGRAM USER'S GUIDE

APPENDIX E

VARFLOW PROGRAM USER'S GUIDE

Before a well test is conducted, you should calculate the anicipated drawdown at each of the wells to be monitored during the test. If a single well is being flowed at a constant rate, the drawdown can easily be calculated from the equations in Section 6 of Volume I. However, if two or more wells are flowing and/or you are also reinjecting the produced brine, the calculations are more complicated. Also, if the flow rate from the well is not held at a constant rate, the calculations are more complex. The following computer program can be used to calculate the anticipated pressure response at up to 10 wells, due to the flow rate of up to 10 production and/or injection wells.

Program Description

VARFLOW calculates pressure changes in response to fluid production/injection from/into an idealized reservoir system. The program is set up to calculate pressure changes at up to ten observation wells. These observation wells may be interference monitoring wells or production wells. The reservoir description is as follows:

1. The reservoir is of infinite areal extent, or bounded on one side by a linear constant potential or barrier boundary.

2. The reservoir is completely saturated with a slightly compressible single phase fluid.

3. The reservoir is isothermal.

4. The reservoir is horizontal and has a constant thickness, H.

5. The flow of fluid in the reservoir is described by Darcy's law.

6. The reservoir is homogeneous and bounded above and below by imper meable layers.

7. The reservoir permeability can be anisotropic in a horizontal plane (x-y anisotropy) or isotropic.

The flow into or from a fully penetrating well is uniformly distributed over the length of the well. The well is modeled as a line source. However, a skin effect, indicative of wellbore condition can be included in the analysis.

Flow rates from up to ten wells can vary arbitrarily. Flow rates are modeled by superposition of consecutive "production pulses." Within any "production pulse" the flow rate may be constant or vary linearly. Figure E-1 demonstrates the construction and definition of a "production pulse." With this scheme for modeling flow rates, any variable flow rate history can be represented to the desired accuracy by a series of sequential straight-line segments, each of the appropriate duration and inclination.

Basic Equations

Variable Flow Rate

In an isotropic reservoir, which complies with the description discussed above, pressure changes caused by production/injection from a single well with a variable flow rate can be calculated from Equation (E-1).

$$\Delta P(t) = \frac{\mu}{4\pi kH} \int_{\tau_n}^{\tau_{n+1}} \frac{q(\tau)}{t - \tau} \exp\left[\frac{-r^2}{4\eta(t - \tau)}\right] d\tau \qquad \text{(E-1)}$$

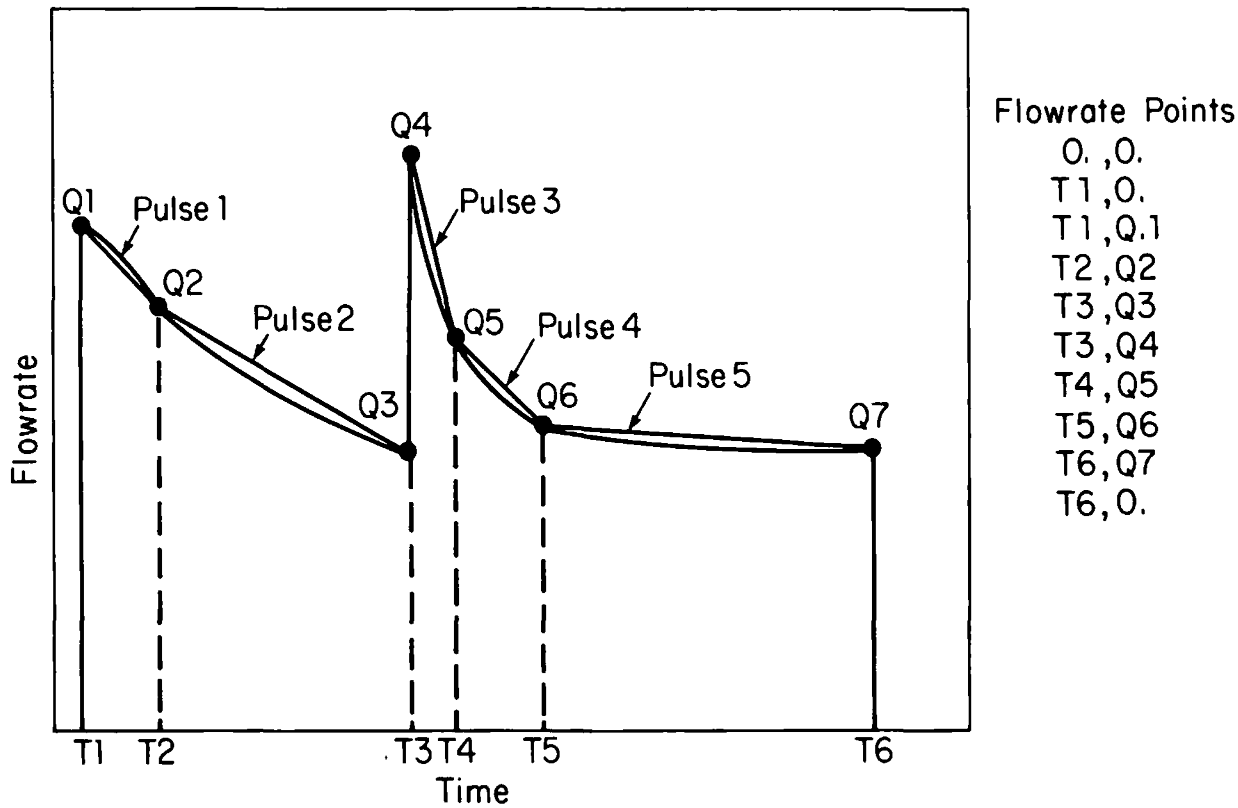

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Figure E-1. Representation of a production pulse.

where

$\Delta P(t)$ = pressure change at time t due to the flow rate $q(\tau)$ for $\tau_n < t < \tau_n + 1$

μ = dynamic viscosity of the fluid

k = permeability

H = reservoir thickness

τ_n = time at which the flow starts

τ_{n+1} = time at which the flow stops

$q(\tau)$ = volumetric flow rate at time τ

r = distance between the observation well and the production/injection well

η = the hydraulic diffusivity $(k/\phi\mu c)$

ϕ = storage coefficient = $c_r\ (1 - \phi) + c_f\ \phi$.

Then, if $q(\tau)$ expressed as

$$q_n(\tau) = A_n + B\ (\tau - \tau_n) \tag{E-2}$$

where

$q_n(\tau)$ = the flow rate at time τ which is within production pulse n

A_n = the flow rate at the beginning of production pulse k

B = the slope of the production pulse

$= (A_{n+1} - A_n) \,/\, (\tau_{n+1} - \tau_n)$

τ_n = the time at which production pulse n begins

and it:

$$u_n = \frac{\mu\phi c r^2}{4k(t - \tau_n)}$$

$$u_{n+1} = \frac{\mu\phi c r^2}{4k(t - \tau_{n+1})}$$

$$w(u) = \int_u^\infty \frac{\exp(-y)}{y}\, dy$$

N = the total number of production pulses which begin prior to time τ,

then, the pressure response is calculated by Equation (E-3).[E-2, E-3]

$$\Delta P(t) = \frac{\mu}{4\pi kH} \sum_{n=1}^{N} \Bigg\{ [A_n + B_n (t - \tau_n)(1 + u_n)] [w(u_n) - w(u_{n+1})] - B_n [(t - \tau_n) \exp(-u_n) - (t - \tau_{n+1}) \exp(-u_{n+1})] \Bigg\} \quad . \qquad \text{(E-3)}$$

The pressure response, caused by production/injection from more than one well is calculated by summing the response due to each production/injection well.

Anisotropy. If the reservoir is anisotropic then the equations are modified in the following manner. If that the principal axes of anisotropy are at 90 degrees to each other and that the x and y axes are chosen to be the principal axes (see Figure E-2) the Equation (E-1) is rewritten as Equation (E-4).[E-4]

$$\Delta P(t) = \frac{1}{4\pi} \left(\frac{\mu}{kH}\right)_e \int_{\tau_n}^{\tau_{n+1}} \frac{q(\tau)}{t - \tau} \exp\left(\frac{-r^2}{4\eta_\theta (t - \tau)}\right) d\tau \qquad \text{(E-4)}$$

where

$(kH/\mu)_e$ = effective transmissivity

$= \sqrt{(kH/\mu)_x \cdot (kH/\mu)_y}$

and

$$\eta_\theta = \frac{(kH/\mu)_\theta}{\phi c H}$$

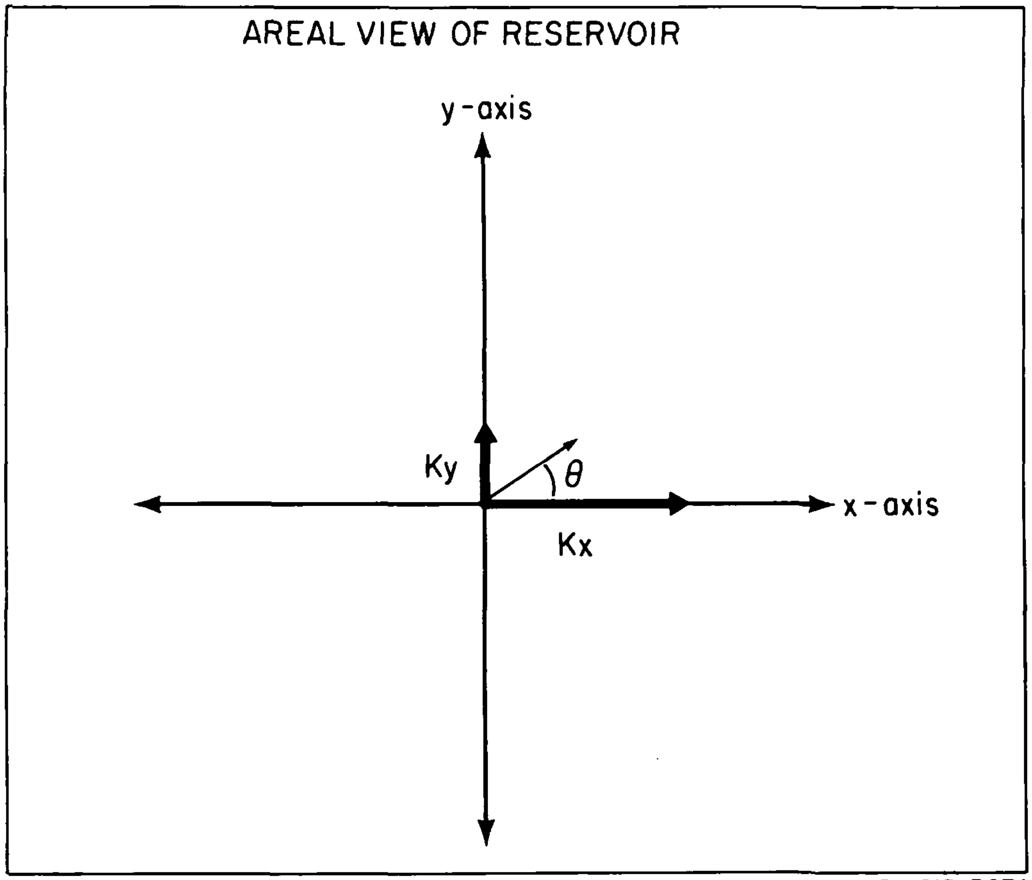

Figure E-2. Anisotropy representation.

$$(kH/\mu)_\theta = \frac{(kH/\mu)_x}{\cos^2\theta + \frac{(kH/\mu)_x}{(kH/\mu)_y}\sin^2\theta} .$$

Theta is defined as the angle between the line adjoining the observation well and the production/injection well as measured counter-clockwise from a line parallel to the x-axis. (See Figure E-2). Since both $(kH/\mu)_e$ and η_θ are constants for any single production-observation well pair, the integral in Equation (E-4) may be evaluated analogously to the integral in Equation (E-1). In addition, because the reservoir is still homogeneous, regardless of the anisotropy, superposition of pressure responses, from each production well, is allowable.

Hydrologic Boundaries

A single fully penetrating linear hydrologic boundary can be modeled using the method of images.[E-5] Briefly stated, a boundary may be modeled as a line of bilateral symmetry about which image wells are arrayed in one-to-one symmetric correspondence with the real production/injection wells. Figure E-3 shows the image well locations for a case with two production wells and a barrier boundary. A barrier boundary is modeled by using image wells which have flow rates which are identical to the production/injection well counterparts. A constant potential boundary (leaky boundary) is modeled using image wells which have flow rates that are identical in magnitude but opposite in sign to the production/injection well counterparts. The image wells contribute an additional pressure response at each observation well.

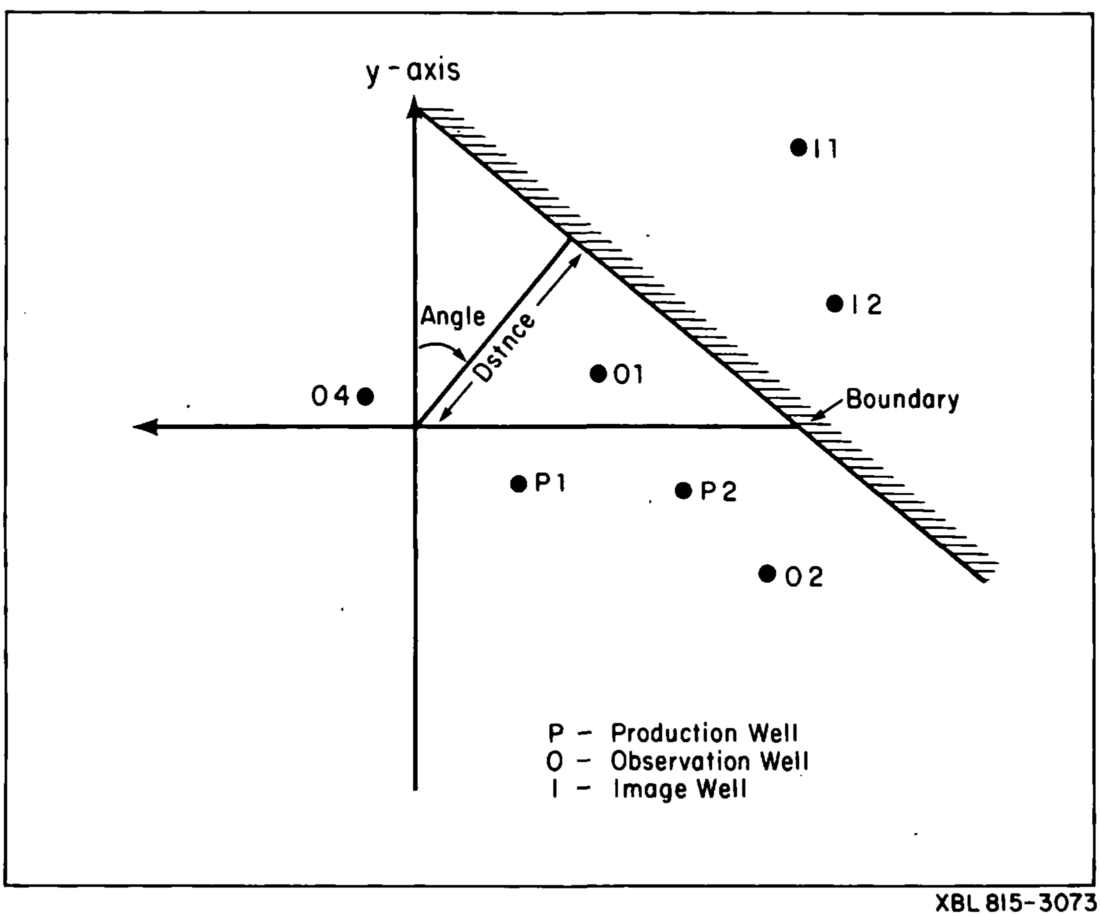

Figure E-3. Boundary location scheme.

Skin Effect

The calculated pressure response at a production well may also include the effects of a zone of enhancement or damage around a wellbore. The pres sure change is calculated using the steady-state pressure change as defined below in Equation (E-5).[E-6]

$$\Delta P_{skin}(t) = s \frac{q(t)\mu}{2\pi kH} \qquad \text{(E-5)}$$

where

$q(t)$ = the instantaneous value of the flowrate at time t

s = the skin value

$\Delta P(t)_{skin}$ = the pressure change due to the skin at time t.

A damaged wellbore is indicated by a positive skin value and an enhanced wellbore is indicated by a negative skin value. When the reservoir is anisotropic, kH/μ is replaced by $(kH/\mu)_e$.

Program Input

Input Data Categories

Run Parameters and Problem Description. To run the program, the following information must be specified:

Variable name	Description
IHH	The number of observation wells in this run. (default 0) (maximum 10)

Variable name	Description
JJ	The number of production wells in this run. (default 0) (maximum 10)
IDIMEN	A flag to indicate that the data are not being input in S.I. units. (0 default--data are input in S.I. units) (1 set flag--data are not in S.I. units) See the following section for a description of the conversion factors.
NTIMES	The number of times at which pressure changes will be calculated. (default 0) (maximum 100)
RKHUX	The transmissivity $(kh/\mu)_x$ in the x-direction.
NOTE:	The x-axis is always a principal direction of anisotropy, and the second axis is at 90 degree to it, in the y direction. (default value 0.0) (default units $m^3/Pa \cdot s$)
RKHUY	The transmissivity $(kh/\mu)_y$ in the y-direction. (default value 0.0) (default units $m^3/Pa \cdot s$)
PCH	The storativity (ϕch). (default value 0.0) (default units m/Pa)

Variable name	Description
ANGLE	The azimuth to the boundary (see Figure E-3) measured clockwise from the positive y-axis.
DSTNCE	The perpendicular distance to the boundary from the origin of the coordinate system. (default value 0.0) (default units m)
BOUND	If the effects of a boundary are to be included, then the type of boundary, either barrier or constant potential, is input as an alphanumeric variable; either 10HBARRIER, or or 10HLEAKY,. which must be specified

Unit Conversion Factors. All parameter inputs are converted to S.I. units for internal calculation. At the termination of the calculation they are all converted back to the original input units. The conversion factor data required are listed below.

If IDIMEN was set to 1, the following information must be supplied. If IDIMEN is equal to 0, this data card is eliminated altogether.

Variable name	Description
PAPRESS	Number of pascals per pressure input unit.
CMSFLOW	Number of m^3/s per flow rate input unit.
SECTIME	Number of seconds per time input unit.

Variable name	Description
MLENGTH	Number of meters per length unit.
PASVISC	Number of pascal•seconds (Pa•s) per viscosity input unit.
SMPERM	Number of m^2 per permeability input unit.

Observation Well Locations and Specifications. The observation wells may be located at any position as specified by a set of x-y coordinates in a cartesian coordinate system. The following is a list of the specifications required for each observation well(I):

Variable	Description
NAME(I)	An alphanumeric name for the well. (default--blank)
OX(I)	The x-coordinate of the well. (default 0.) (default units m)
OY(I)	The y-coordinate of the well. (default 0.) (default units m)
YSTART(I)	The initial pressure at the well prior to any production or injection. (default units Pa)
LOBS(I)	A number (as read) that indicates that this observation well(I) is also production well LOBS(I). (Default 0 indicates the well is an interference monitoring well.)

Variable	Description
SKIN(I)	If the well(I) is also production well LOBS(I) the well may be assigned a non-zero skin value. (default 0. no skin)

Production Well Specifications and Flow Rate. To input a flow rate schedule, the data must be put in the format of pairs of flow rate points such that the flow rate is specified at the beginning and the end of a production pulse. Then, the flow rate, at all times, between the beginning and end of a production pulse, is known from Equation (E-3). The flow rate record will then consist of consecutive production pulses arranged in chronological order. If there is a step change from one flow rate to another, this is represented by two sequential production pulses, and must be input as such (see Sample Problem 1).

The following is a list of the specifications for each production well(J):

Variable	Description
PNAME(J)	An alphanumeric name for production well (J). (default value--BLANK)
PX(J)	The x-coordinate, in cartesian coordinates of production well(J). (default value 0.0) (default units m)
PY(J)	The y-coordinate, in cartesian coordinates, of production well(J). (default value 0.0) (default units m)

Variable	Description
KKJ(J)	The number of flow rate points for production well (J). (default value 0)
[TQ(K,J), AQ(K,J)]	The flow rate data points for well(J) which are of the form (time, flow rate). Up to 100 points per well are allowed. (default [0.0, 0.0]) (default units [s, m^3/s]) (K = 1, KKJ(J))

<u>Times at Which Pressures Are To Be Calculated</u>. Up to 100 different times can be specified at which pressure changes will be calculated:

Variable	Description
TIMES (L)	The times at which pressure calculations will be made up to 100 points. (default value 0.0) (default units, s)

INPUT DATA FORMAT

PROBLEM DESCRIPTION AND UNIT CONVERSION FACTORS

-----

1 CARD - Title card (8A10)
alphanumeric to 80 characters

1 CARD - IHH, II, IDIMEN, NTIMES (4I10)

If IDIMEN Is set equal to 1 on CARD 2

THEN INCLUDE

1 CARD - PAPRESS, CMSFLOW, SECTIME, RLENGTH, PASVISC, SMPERM (6E10.4)

OTHERWISE

1 CARD - RKHUX, RKHUY, PCH, ANGLE, DSTNCE, BOUND (5E10.4, A10)

OBSERVATION WELL DATA

IIH CARDS - NAME(I), OX(I), OY(I), YSTART(I),
LOBS(I), SKIN(I), etc.
(I = 1, IIH) (A10, 2F10.2, E10.4, I10, F10.2)

Repeat for each observation well.

PRODUCTION WELL DATA

JJ SETS OF CARDS - PNAME(J), PX(J), PY(J), KKJ(J) (A10, 2F10.2, I10)

TQ (1, J) , AQ (1, J) (2E10.4)
• •
• •
• •
• •
TQ (KKJ(J),J) AQ (KKJ(J), J)

Repeat this set of cards for each production well.

TIMES FOR CALCULATIONS OF PRESSURE CHANGES

TIMES(1), TIMES(2), TIMES(3),.....TIMES(8) (8E10.4)

Put eight per card - repeat until amount specified by NTIMES on CARD 2.

Sample Problems

Four sample problems are discussed in which the various capabilities of the program are demonstrated. Data decks and outputs are provided for each problem.

Sample Problem

No Anisotropy--Variable Flow Rate (Step-Wise)

In this problem a single production well is produced at a step wise variable flow rate and four observation wells monitor the pressure response. The observation wells are located symmetrically around the observation well (Figure E-4). Since there is no x-y reservoir anisotropy, the pressure drop at each of the observation wells should be identical. The flow rate from the production well is shown in Figure E-5. As is shown, there are three consecutive "production" pulses, the first two lasting 1000 minutes each, and the third lasting 2000 minutes.

The data deck for Sample 1 is shown in Figure E-6. The first card (card 1) gives the title information for the problem. The second card indicates that there are four observation wells (column 10, 1 production well (column 20), the IDIMEN flag is set (column 30) and the pressure changes will be calculated at 56 times (columns 30-40). On card three, the unit conversion factors are shown. The following table shows the units used for each quantity and the conversion factor to S.I. units.

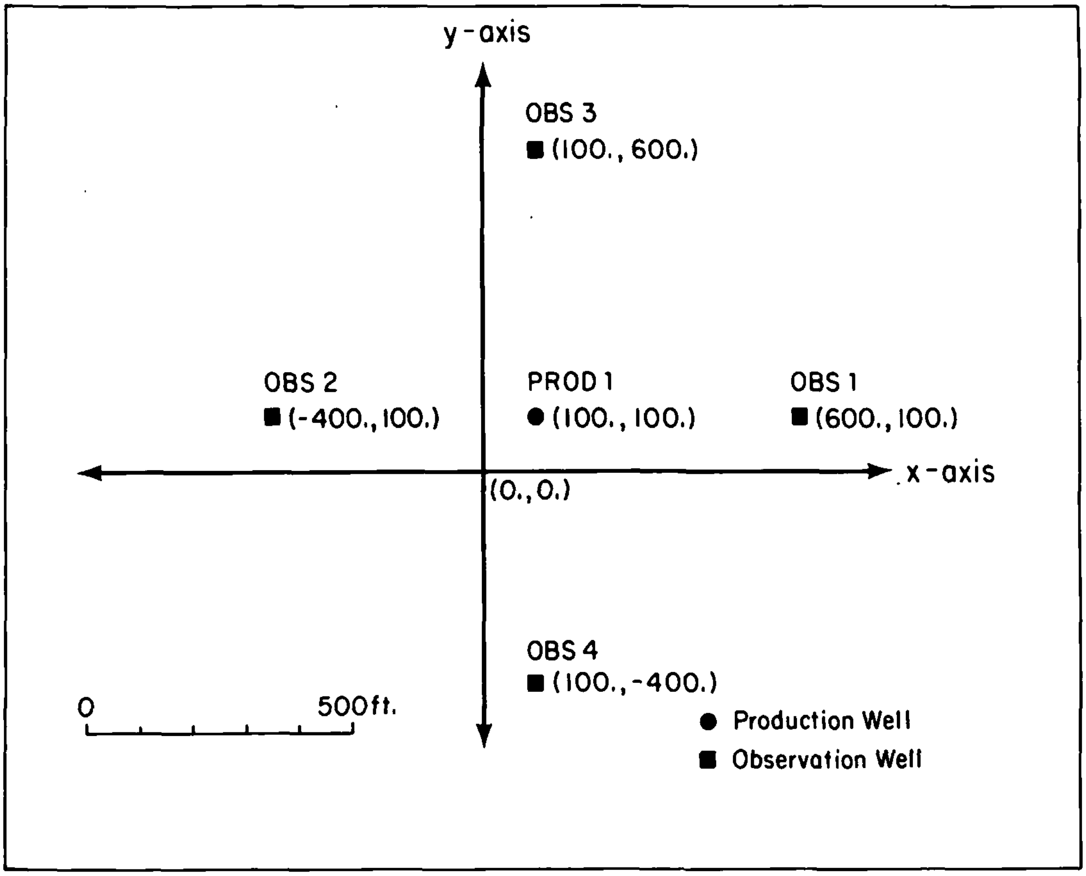

Figure E-4. Location scheme, in cartesian coordinates, for the production well and observation wells for Sample Problem 1.

Quantity	Unit	Conversion factor
Pressure	Psia	6895
Flow rate	Gal/min	6.31×10^{-5}
Time	Hours	3600
Length	Feet	0.3048
Viscosity	Centipoise	1×10^{-3}
Permeability	Millidarcies	9.862 x 10-16

It is important to note that once a time or distance unit is chosen, it must be used consistently throughout the input deck. For instance, when the flow rate is input, the time units must be the same as the time units used for the specification of times at which pressure calculations will be made.

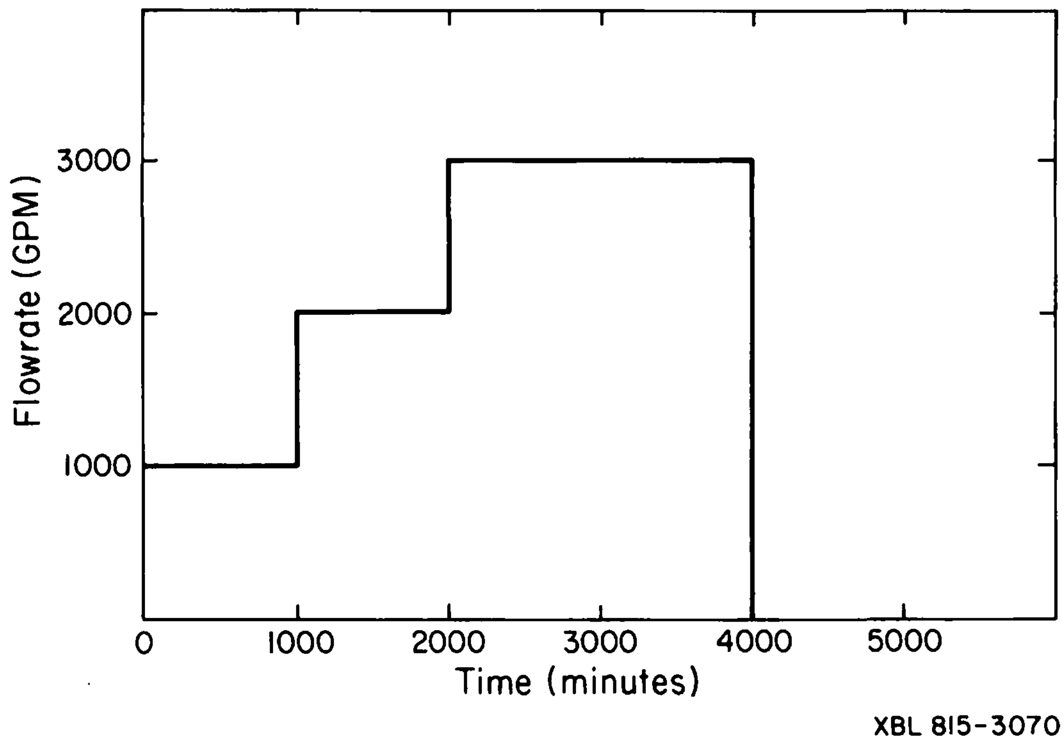

Figure E-5. Variable flow rate schedule for the production well in Sample Problem 1.

Card 4 lists the information about the x and y direction transmissivity and the reservoir storativity. For this problem, since there is no anisotropy, both the x-direction and y-direction transmissivity are equal and set to 150,000 md-ft/cp. The storativity for this problem is set equal to 2×10^{-3} ft/psi.

Cards 5 through 8 list the alphanumeric names for each observation well (columns 1-10), the (x,y) coordinates of each well (columns 11-20 and 21-30 respectively) and the initial reservoir pressure for each well (columns 31-40). The coordinates of each well are shown in Figure E-4.

Cards 9 through 15 contain all of the relevant information about the production well. On card 9, the alphanumeric name of the production well (column 1-10), the coordinates of the production well (columns 11-20, 21-30) and the number of flow rate points (columns 31-40, format I10) are input. For this problem six flow rate points are used to model the step-wise variable flow rate shown in Figure E-5. Note the construction of three "production pulses" to represent the flow rate.

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PROBLEM SAMPLE PROBLEM 1

DATA ENTRY FORMS

PAGE 1

CARD	1–10	11–20	21–30	31–40	41–50	51–60	61–70	71–80
1	NO ANISOTROPY-VARIABLE RATE							
2	4	1	1	56				
3	6.895E+03	6.31 E-05	3600.	.3048	1.0 E-03	9.862E-16		
4	150000.	150000.	.002					
5	OBS 1	600.	100.	0.				
6	OBS 2	-400.	100.	0.				
7	OBS 3	100.	600.	0.				
8	OBS 4	100.	-400.	0.				
9	PROD 1	100.	100.	6				
10	0.	1000.						
11	1000.	1000.						
12	1000.	2000.						
13	2000.	2000.						
14	2000.	3000.						
15	4000.	3000.						
16	1.	2.	3.	4.	5.	6.	7.	9.
17	10.	20.	30.	40.	50.	60.	70.	80.
18	100.	101.	102.	103.	104.	105.	106.	107.
19	109.	110.	120.	130.	140.	150.	160.	170.
20	180.	200.	200.	201.	203.	204.	205.	206.
21	207.	208.	209.	210.	220.	230.	240.	250.
22	260.	270.	280.	300.	320.	340.	360.	380.

RL-2145-1

Figure E-6. Input deck for Sample Problem 1.

Cards 16 through 22 specify times at which pressure calculations, at each of the four observation wells, will be calculated. For this problem, pressures will be calculated at 1 hour, 2 hours, 3 hours, etc. to 380 hours. The units for the times specified here are input on card 3. If 3.6×10^3s had not been specified, the default units would have been used, implying that pressures would be calculated at 1 s, 2 s, 3 s, etc., to 380 s.

The output for this problem is shown in Figure E-7. As can be seen, the pressure drop at each well is identical, because each well is equidistant from the production well (500 ft). The next sample problem will show a similar problem but one in which there is extreme x-y anisotropy.

```
 NO ANISOTROPY-VARIABLE FLOWRATE


NUMBER OF OBSERVATION WELLS          4
NUMBER OF PRODUCTION WELLS           1
NUMBER OF TIMES AT WHICH PRESSURES WILL BE CALCULATED            56


                    CONVERSION FACTORS
                    ==================

        PRESSURE UNIT PER PASCAL                                .6895E+04
        FLOWRATE UNIT PER CUBIC METER PER SECOND                .6310E-04
        TIME UNIT PER SECOND                                      3600.00
        LENGTH PER METER                                              .30
        VISCOSITY PER PASCAL-SECOND                              .100E-02
        PERMEABILITY PER SQUARE METER                           .9862E-15


   PARAMETER VALUES
   ================
   X-AXIS TRANSIMISSIVITY = .1500E+06
   Y-AXIS TRANSMISSIVITY = .1500E+06
   STORATIVITY = .2000E-02


OBSERVATION WELL NUMBER     1
   WELL OBS   1    COORDINATES (    600.00,     100.00)
   INITIAL PRESSURE=0.


OBSERVATION WELL NUMBER     2
   WELL OBS 2      COORDINATES (   -400.00,     100.00)
   INITIAL PRESSURE=0.
```

Figure E-7. Output for Sample Problem 1.

```
OBSERVATION WELL NUMBER      3
   WELL OBS 3      COORDINATES (     100.00,     600.00)
   INITIAL PRESSURE=-.0


OBSERVATION WELL NUMBER      4
   WELL OBS 4      COORDINATES (     100.00,    -400.00)
   INITIAL PRESSURE=-.0


PRODUCTION WELL NUMBER            1
   PROD 1       COORDINATES (     100.00,     100.00)
   NUMBER OF FLOWRATE POINTS=     6

                   TIME              FLOWRATE


                 0.                  .1000E+04
                  .1000E+03          .1000E+04
                  .1000E+03          .2000E+04
                  .2000E+03          .2000E+04
                  .2000E+03          .3000E+04
                  .4000E+03          .3000E+04


DISTANCES BETWEEN OBSERVATION WELLS AND PRODUCTION WELLS



          OBS    1       OBS 2         OBS 3         OBS 4
PROD 1          500.00        500.00        500.00         500.00


         TIME    OBS    1       OBS 2         OBS 3         OBS 4
          1.00   -.1715E+00   -.1715E+00   -.1715E+00   -.1715E+00
          2.00   -.1433E+01   -.1433E+01   -.1433E+01   -.1433E+01
          3.00   -.3238E+01   -.3238E+01   -.3238E+01   -.3238E+01
          4.00   -.5102E+01   -.5102E+01   -.5102E+01   -.5102E+01
          5.00   -.6878E+01   -.6878E+01   -.6878E+01   -.6878E+01


          6.00   -.8531E+01   -.8531E+01   -.8531E+01   -.8531E+01
          7.00   -.1006E+02   -.1006E+02   -.1006E+02   -.1006E+02
          9.00   -.1278E+02   -.1278E+02   -.1278E+02   -.1278E+02
         10.00   -.1400E+02   -.1400E+02   -.1400E+02   -.1400E+02
         20.00   -.2292E+02   -.2292E+02   -.2292E+02   -.2292E+02


         30.00   -.2867E+02   -.2867E+02   -.2867E+02   -.2867E+02
         40.00   -.3291E+02   -.3291E+02   -.3291E+02   -.3291E+02
         50.00   -.3627E+02   -.3627E+02   -.3627E+02   -.3627E+02
         60.00   -.3905E+02   -.3905E+02   -.3905E+02   -.3905E+02
         70.00   -.4142E+02   -.4142E+02   -.4142E+02   -.4142E+02
```

Figure E-7. (continued).

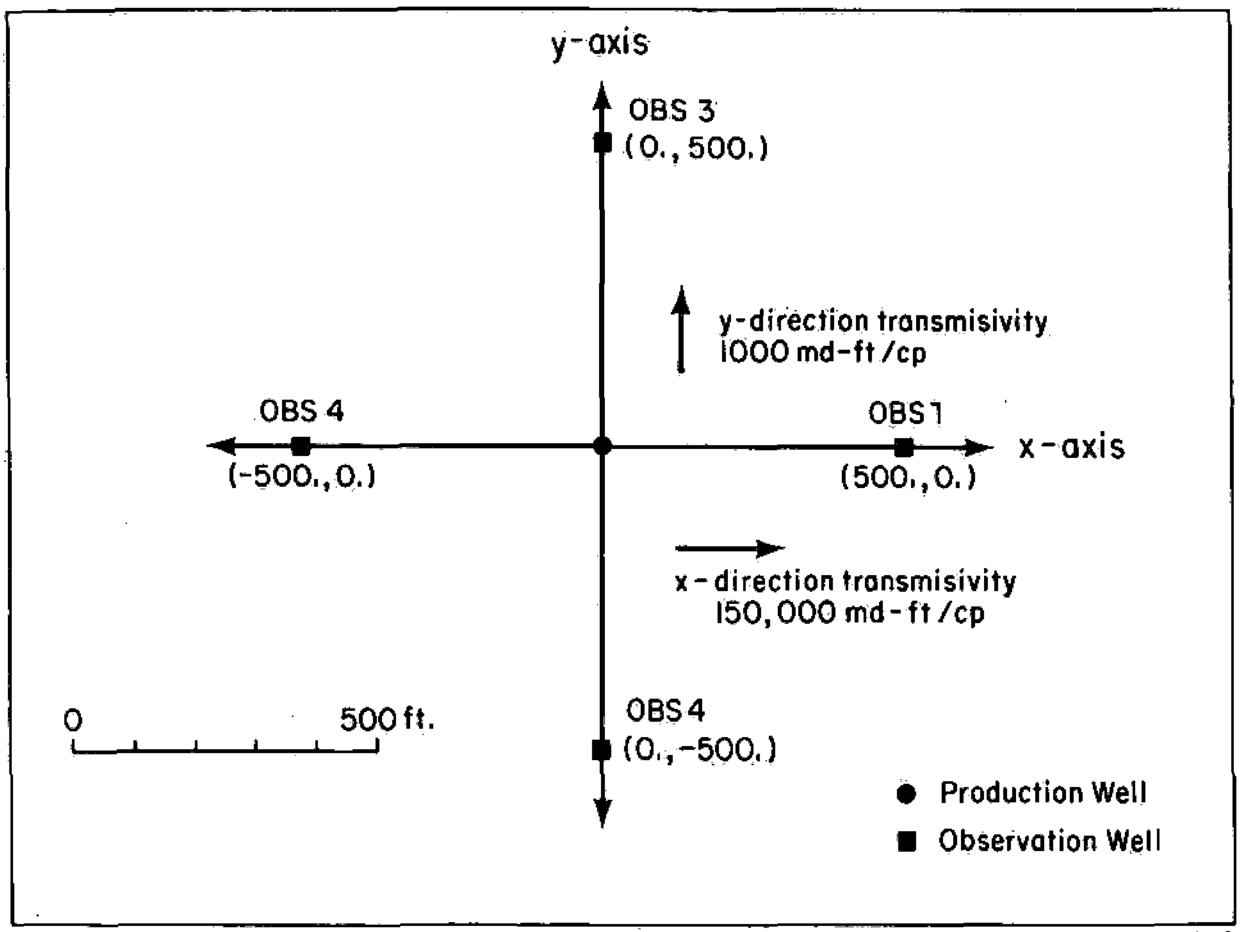
TIME	OBS 1	OBS 2	OBS 3	OBS 4
80.00	-.4349E+02	-.4349E+02	-.4349E+02	-.4349E+02
100.00	-.4697E+02	-.4697E+02	-.4697E+02	-.4697E+02
101.00	-.4729E+02	-.4729E+02	-.4729E+02	-.4729E+02
102.00	-.4871E+02	-.4871E+02	-.4871E+02	-.4871E+02
103.00	-.5067E+02	-.5067E+02	-.5067E+02	-.5067E+02
104.00	-.5268E+02	-.5268E+02	-.5268E+02	-.5268E+02
105.00	-.5461E+02	-.5461E+02	-.5461E+02	-.5461E+02
106.00	-.5641E+02	-.5641E+02	-.5641E+02	-.5641E+02
107.00	-.5809E+02	-.5809E+02	-.5809E+02	-.5809E+02
109.00	-.6110E+02	-.6110E+02	-.6110E+02	-.6110E+02
110.00	-.6246E+02	-.6246E+02	-.6246E+02	-.6246E+02
120.00	-.7275E+02	-.7275E+02	-.7275E+02	-.7275E+02
130.00	-.7976E+02	-.7976E+02	-.7976E+02	-.7976E+02
140.00	-.8517E+02	-.8517E+02	-.8517E+02	-.8517E+02
150.00	-.8962E+02	-.8962E+02	-.8962E+02	-.8962E+02
160.00	-.9342E+02	-.9342E+02	-.9342E+02	-.9342E+02
170.00	-.9675E+02	-.9675E+02	-.9675E+02	-.9675E+02
180.00	-.9973E+02	-.9973E+02	-.9973E+02	-.9973E+02
200.00	-.1049E+03	-.1049E+03	-.1049E+03	-.1049E+03
201.00	-.1053E+03	-.1053E+03	-.1053E+03	-.1053E+03
202.00	-.1068E+03	-.1068E+03	-.1068E+03	-.1068E+03
203.00	-.1088E+03	-.1088E+03	-.1088E+03	-.1088E+03
204.00	-.1109E+03	-.1109E+03	-.1109E+03	-.1109E+03
205.00	-.1129E+03	-.1129E+03	-.1129E+03	-.1129E+03
206.00	-.1148E+03	-.1148E+03	-.1148E+03	-.1148E+03
207.00	-.1165E+03	-.1165E+03	-.1165E+03	-.1165E+03
208.00	-.1182E+03	-.1182E+03	-.1182E+03	-.1182E+03
209.00	-.1197E+03	-.1197E+03	-.1197E+03	-.1197E+03
210.00	-.1211E+03	-.1211E+03	-.1211E+03	-.1211E+03
220.00	-.1322E+03	-.1322E+03	-.1322E+03	-.1322E+03
230.00	-.1399E+03	-.1399E+03	-.1399E+03	-.1399E+03
240.00	-.1460E+03	-.1460E+03	-.1460E+03	-.1460E+03
250.00	-.1511E+03	-.1511E+03	-.1511E+03	-.1511E+03
260.00	-.1555E+03	-.1555E+03	-.1555E+03	-.1555E+03
270.00	-.1594E+03	-.1594E+03	-.1594E+03	-.1594E+03
280.00	-.1630E+03	-.1630E+03	-.1630E+03	-.1630E+03
300.00	-.1693E+03	-.1693E+03	-.1693E+03	-.1693E+03
320.00	-.1747E+03	-.1747E+03	-.1747E+03	-.1747E+03
340.00	-.1794E+03	-.1794E+03	-.1794E+03	-.1794E+03
360.00	-.1838E+03	-.1838E+03	-.1838E+03	-.1838E+03
380.00	-.1877E+03	-.1877E+03	-.1877E+03	-.1877E+03

Figure E-7. (continued).

Sample Problem 2

Verification of Anisotropy. In Sample Problem 2 a well in an anisotropic reservoir is produced at a constant flow rate of 1000 GPM for a period of 5000 hours. Four observation wells, located symmetrically about the production well, along the major axes of anisotropy, are used to observe the pressure changes. For this problem, the x-axis permeability was chosen to be 150 times larger than the permeability in the y-direction. Thus, transmissivity values of 150,000 md•ft/cp and 1000 md•ft/cp were used. Figure E-8 shows the well location scheme and the representation of the reservoir anisotropy.

The data deck for Sample Problem 2 is shown in Figure E-9. The first three cards are the same as they are in Sample Problem 1. On card 4 the x-direction transmissivity (column 1-10) is set to 150,000 md•ft/cp, and



XBL 815-3072

Figure E-8. Well location scheme for Sample Problems 2 and 3.

```
    VERIFICATION OF ANISOTROPY
         04            1            1            56
6.895 E+03 6.310E-05   3.6E+03   .3048       1.0   E-03 9.862E-16
150000.    1000.      .002        00.         0000.
OBS   1     500.       0.          0.                      0         0.
OBS  2    -500.       0.          0.
OBS  3     000.          500.
OBS  4     000.         -500.
PROD 1       0.          0.                    2
0.         1000.
5000.      1000.
1.         2.         3.          4.          5.          6.          7.          9.
10.        20.        30.         40.         50.         60.         70.         80.
100.       101.       102.        103.        104.        105.        106.        107.
109.       110.       120.        130.        140.        150.        160.        170.
180.       200.       201.        202.        203.        204.        205.        206.
207.       208.       209.        210.        220.        230.        240.        250.
260.       270.       280.        300.        320.        340.        360.        380.
```

Figure E-9. Input deck for Sample Problem 2.

the y-direction transmissivity is set to 1000 md*ft/cp. As in Problem 1, the storativity, ϕch, is set to 0.002 ft/psi. The remaining part of the data deck is similar to that in Problem 1, except that only one production pulse or two flow rate points are required to model the flow rate.

The output for Sample Problem 2 is shown in Figure E-10. Note the effect of the extreme anisotropy on the reservoir pressure response.

Sample Problem 3

Verification of Anisotropy--Boundary Problem. Sample Problem 3 is identical to Problem 2 except that there is a barrier boundary in the reservoir 1000 ft from the production well, in a direction perpendicular to the x-axis. Figure E-11 shows the well locations and the boundary location scheme. Note that the alpha is measured clockwise from the positive y-axis.

The data deck (Figure E-12) for this problem is identical to the data deck in Problem 2 except for card 4. Columns 1-10 and 11-20 contain the reservoir transmissivity information and columns 21-30 contain the storativity data. Alpha, the angle seen in Figure E-11, is input in columns 31-40 and DSTNCE, the distance from the origin to the perpendicular of the boundary, is input in columns 41-50. The type of boundary is indicated alphanumerically in columns 51-60. Note that the type, either BARRIER or LEAKY must begin in column 51.

```
VERIFICATION OF ANISOTROPY

NUMBER OF OBSERVATION WELLS              4
NUMBER OF PRODUCTION WELLS               1
NUMBER OF TIMES AT WHICH PRESSURES WILL BE CALCULATED        56

                     CONVERSION FACTORS
                     ==================

      PRESSURE UNIT PER PASCAL                           .6895E+04
      FLOWRATE UNIT PER CUBIC METER PER SECOND           .6310E-04
      TIME UNIT PER SECOND                                3600.00
      LENGTH PER METER                                        .30
      VISCOSITY PER PASCAL-SECOND                         .100E-02
      PERMEABILITY PER SQUARE METER                      .9862E-15

   PARAMETER VALUES
   ================
   X-AXIS TRANSIMISSIVITY = .1500E+06
   Y-AXIS TRANSMISSIVITY = .1000E+04
   STORATIVITY = .2000E-02

 OBSERVATION WELL NUMBER       1
    WELL OBS  1      COORDINATES (    500.00,       0.  )
    INITIAL PRESSURE=0.

 OBSERVATION WELL NUMBER       2
    WELL OBS 2       COORDINATES (   -500.00,       0.  )
    INITIAL PRESSURE=0.

 OBSERVATION WELL NUMBER       3
    WELL OBS 3       COORDINATES (      0.   ,    500.00)
    INITIAL PRESSURE=-.0

 OBSERVATION WELL NUMBER       4
    WELL OBS 4       COORDINATES (      0.   ,   -500.00)
    INITIAL PRESSURE=-.0

  PRODUCTION WELL NUMBER          1
     PROD 1        COORDINATES (      0.  ,       0.  )
     NUMBER OF FLOWRATE POINTS=    2

                       TIME             FLOWRATE

                        0.              .1000E+04
                     .5000E+04          .1000E+04

   DISTANCES BETWEEN OBSERVATION WELLS AND PRODUCTION WELLS

              OBS  1      OBS 2       OBS 3       OBS 4
  PROD 1      500.00      500.00      500.00      500.00
```

Figure E-10. Output for Sample Problem 2.

TIME	OBS 1	OBS 2	OBS 3	OBS 4
1.00	-.2101E+01	-.2101E+01	-.3917-206	-.3917-206
2.00	-.1755E+02	-.1755E+02	-.8058-103	-.8058-103
3.00	-.3966E+02	-.3966E+02	-.2625E-68	-.2625E-68
4.00	-.6251E+02	-.6249E+02	-.5152E-51	-.5152E-51
5.00	-.8435E+02	-.8424E+02	-.1286E-40	-.1286E-40
6.00	-.1048E+03	-.1045E+03	-.1136E-33	-.1136E-33
7.00	-.1239E+03	-.1232E+03	-.1064E-28	-.1064E-28
9.00	-.1587E+03	-.1566E+03	-.4742E-22	-.4742E-22
10.00	-.1746E+03	-.1715E+03	-.1026E-19	-.1026E-19
20.00	-.3029E+03	-.2815E+03	-.4294E-09	-.4294E-09
30.00	-.3935E+03	-.3553E+03	-.1870E-05	-.1870E-05
40.00	-.4754E+03	-.4131E+03	-.1373E-03	-.1373E-03
50.00	-.5399E+03	-.4618E+03	-.1916E-02	-.1916E-02
60.00	-.5954E+03	-.5043E+03	-.1151E-01	-.1151E-01
70.00	-.6441E+03	-.5424E+03	-.4241E-01	-.4241E-01
80.00	-.6875E+03	-.5769E+03	-.1147E+00	-.1147E+00
100.00	-.7522E+03	-.6377E+03	-.4767E+00	-.4767E+00
101.00	-.7655E+03	-.6405E+03	-.5048E+00	-.5048E+00
102.00	-.7689E+03	-.6433E+03	-.5341E+00	-.5341E+00
103.00	-.7722E+03	-.6461E+03	-.5644E+00	-.5644E+00
104.00	-.7755E+03	-.6488E+03	-.5959E+00	-.5959E+00
105.00	-.7788E+03	-.6515E+03	-.6286E+00	-.6286E+00
106.00	-.7821E+03	-.6542E+03	-.6624E+00	-.6624E+00
107.00	-.7853E+03	-.6569E+03	-.6975E+00	-.6975E+00
109.00	-.7917E+03	-.6623E+03	-.7712E+00	-.7712E+00
110.00	-.7943E+03	-.6649E+03	-.8098E+00	-.8098E+00
120.00	-.8250E+03	-.6903E+03	-.1267E+01	-.1267E+01
130.00	-.8530E+03	-.7141E+03	-.1861E+01	-.1861E+01
140.00	-.8792E+03	-.7366E+03	-.2597E+01	-.2597E+01
150.00	-.9038E+03	-.7579E+03	-.3480E+01	-.3480E+01
160.00	-.9269E+03	-.7780E+03	-.4509E+01	-.4509E+01
170.00	-.9483E+03	-.7972E+03	-.5683E+01	-.5683E+01
180.00	-.9695E+03	-.8155E+03	-.6997E+01	-.6997E+01
200.00	-.1008E+04	-.8496E+03	-.1002E+02	-.1002E+02
201.00	-.1010E+04	-.8514E+03	-.1019E+02	-.1019E+02
202.00	-.1012E+04	-.8530E+03	-.1035E+02	-.1035E+02
203.00	-.1013E+04	-.8546E+03	-.1052E+02	-.1052E+02
204.00	-.1015E+04	-.8563E+03	-.1069E+02	-.1069E+02
205.00	-.1017E+04	-.8579E+03	-.1086E+02	-.1086E+02
206.00	-.1019E+04	-.8595E+03	-.1103E+02	-.1103E+02

Figure E-10. (continued)..

TIME	OBS 1	OBS 2	OBS 3	OBS 4
207.00	-.7160E+03	-.7160E+03	-.6501E+01	-.6501E+01
208.00	-.7169E+03	-.7169E+03	-.6598E+01	-.6598E+01
209.00	-.7178E+03	-.7178E+03	-.6695E+01	-.6695E+01
210.00	-.7188E+03	-.7188E+03	-.6793E+01	-.6793E+01
220.00	-.7278E+03	-.7278E+03	-.7806E+01	-.7806E+01
230.00	-.7365E+03	-.7365E+03	-.8874E+01	-.8874E+01
240.00	-.7448E+03	-.7448E+03	-.9992E+01	-.9992E+01
250.00	-.7528E+03	-.7528E+03	-.1116E+02	-.1116E+02
260.00	-.7604E+03	-.7604E+03	-.1236E+02	-.1236E+02
270.00	-.7678E+03	-.7678E+03	-.1361E+02	-.1361E+02
280.00	-.7749E+03	-.7749E+03	-.1489E+02	-.1489E+02
300.00	-.7884E+03	-.7884E+03	-.1755E+02	-.1755E+02
320.00	-.8011E+03	-.8011E+03	-.2031E+02	-.2031E+02
340.00	-.8129E+03	-.8129E+03	-.2316E+02	-.2316E+02
360.00	-.8241E+03	-.8241E+03	-.2607E+02	-.2607E+02
380.00	-.8348E+03	-.8348E+03	-.2904E+02	-.2904E+02

Figure E-10. (continued).

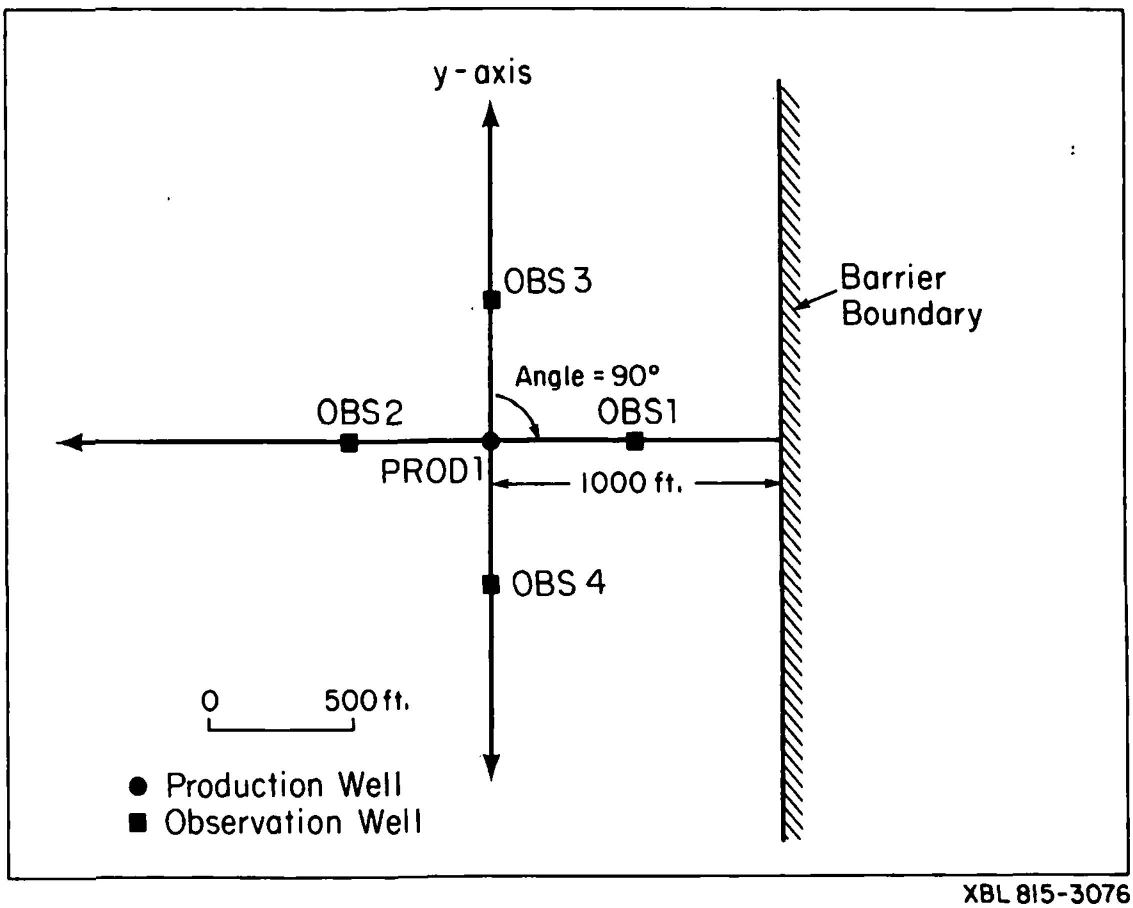


Figure E-11. Boundary location scheme for Sample Problem 3.

```
     VERIFICATION OF ANISOTROPY-RUN TO COMPARE WITH BOUNDARY
            04              1              1          56
6.895 E+03 6.310E-05    3.6E+03   .3048      1.0   E-03 9.862E-16
150000.    1000.      .002       90.        1000.       BARRIER
OBS   1     500.      0.         0.                   0       0.
OBS 2      -500.      0.         0.
OBS 3       000.         500.
OBS 4       000.        -500.
PROD 1        0.         0.                    2
0.         1000.
5000.      1000.
1.         2.         3.         4.         5.         6.         7.         9.
10.        20.        30.        40.        50.        60.        70.        80.
100.       101.       102.       103.       104.       105.       106.       107.
109.       110.       120.       130.       140.       150.       160.       170.
180.       200.       201.       202.       203.       204.       205.       206.
207.       208.       209.       210.       220.       230.       240.       250.
260.       270.       280.       300.       320.       340.       360.       380.
```

Figure E-12. Input deck for Sample Problem 3.

The output for the Sample Problem 3 is shown in Figure E-13.

Sample Problem 4

Verification of Anisotropy--Run to Compare with Boundary. Sample Problem 4 demonstrates how the algorithm in VARFLOW accounts for the effects of a barrier or constant potential boundary in the pressure calculations. In this calculation the existence of a boundary is not specified, however, a well which would be the image well for the calculation in Sample Problem 3 is explicitly included in the calculation. The well locations for the observation wells, the production well and the "image" production well are shown in Figure E-14.

The input deck (Figure E-15) for the problem is similar to the data decks in problems 2 and 3. Note that on Card 2, Column 20, it is specified that there are two production wells for this problem. The production data and production well specifications for the second production well, PROD2, are on Cards 12-14. Note that the production rate for PROD2 is identical to that of PROD1.

The output for this problem is shown in Figure E-16. Note that the pressure response is identical to the pressure response in Problem 3.

```
VERIFICATION OF ANISOTROPY-RUN TO COMPARE WITH BOUNDARY

  NUMBER OF OBSERVATION WELLS           4
  NUMBER OF PRODUCTION WELLS            1
  NUMBER OF TIMES AT WHICH PRESSURES WILL BE CALCULATED       56

                      CONVERSION FACTORS
                      ==================

           PRESSURE UNIT PER PASCAL                       .6895E+04
           FLOWRATE UNIT PER CUBIC METER PER SECOND       .6310E-04
           TIME UNIT PER SECOND                            3600.00
           LENGTH PER METER                                    .30
           VISCOSITY PER PASCAL-SECOND                     .100E-02
           PERMEABILITY PER SQUARE METER                  .9862E-15

     PARAMETER VALUES
     ================
     X-AXIS TRANSIMISSIVITY = .1500E+06
     Y-AXIS TRANSMISSIVITY = .1000E+04
     STORATIVITY = .2000E-02

  THERE IS A BARRIER   BOUNDARY AT AN ANGLE OF      90.00 DEGREES AND A DISTANCE OF    1000.00

  OBSERVATION WELL NUMBER      1
     WELL OBS   1     COORDINATES (     500.00,       0.  )
     INITIAL PRESSURE=0.

  OBSERVATION WELL NUMBER      2
     WELL OBS 2       COORDINATES (    -500.00,       0.  )
     INITIAL PRESSURE=0.

  OBSERVATION WELL NUMBER      3
     WELL OBS 3       COORDINATES (       0.  ,     500.00)
     INITIAL PRESSURE=-.0

  OBSERVATION WELL NUMBER      4
     WELL OBS 4       COORDINATES (       0.  ,    -500.00)
     INITIAL PRESSURE=-.0

  PRODUCTION WELL NUMBER              1
     PROD 1      COORDINATES (      0.  ,       0.  )
     NUMBER OF FLOWRATE POINTS=     2

                          TIME          FLOWRATE

                       0.               .1000E+04
                        .5000E+04       .1000E+04

  DISTANCES BETWEEN OBSERVATION WELLS AND PRODUCTION WELLS

             OBS   1       OBS 2         OBS 3         OBS 4
  PROD 1         500.00        500.00        500.00        500.00
```

Figure E-13. Output for Sample Problem 3.

TIME	OBS 1	OBS 2	OBS 3	OBS 4
1.00	-.2101E+01	-.2101E+01	-.3917-206	-.3917-206
2.00	-.1755E+02	-.1755E+02	-.8058-103	-.8058-103
3.00	-.3966E+02	-.3966E+02	-.2625E-68	-.2625E-68
4.00	-.6251E+02	-.6249E+02	-.5152E-51	-.5152E-51
5.00	-.8435E+02	-.8424E+02	-.1286E-40	-.1286E-40
6.00	-.1043E+03	-.1045E+03	-.1136E-33	-.1136E-33
7.00	-.1239E+03	-.1232E+03	-.1064E-28	-.1064E-28
9.00	-.1587E+03	-.1566E+03	-.4742E-22	-.4742E-22
10.00	-.1746E+03	-.1715E+03	-.1025E-19	-.1025E-19
20.00	-.3029E+03	-.2915E+03	-.4294E-09	-.4294E-09
30.00	-.3935E+03	-.3553E+03	-.1870E-05	-.1870E-05
40.00	-.4754E+03	-.4131E+03	-.1373E-03	-.1373E-03
50.00	-.5399E+03	-.4618E+03	-.1916E-02	-.1916E-02
60.00	-.5954E+03	-.5043E+03	-.1151E-01	-.1151E-01
70.00	-.6441E+03	-.5424E+03	-.4241E-01	-.4241E-01
80.00	-.6875E+03	-.5769E+03	-.1147E+00	-.1147E+00
100.00	-.7622E+03	-.6377E+03	-.4767E+00	-.4767E+00
101.00	-.7655E+03	-.6405E+03	-.5048E+00	-.5048E+00
102.00	-.7689E+03	-.6433E+03	-.5341E+00	-.5341E+00
103.00	-.7722E+03	-.6461E+03	-.5644E+00	-.5644E+00
104.00	-.7755E+03	-.6488E+03	-.5959E+00	-.5959E+00
105.00	-.7788E+03	-.6515E+03	-.6286E+00	-.6286E+00
106.00	-.7821E+03	-.6542E+03	-.6624E+00	-.6624E+00
107.00	-.7853E+03	-.6569E+03	-.6975E+00	-.6975E+00
109.00	-.7917E+03	-.6623E+03	-.7712E+00	-.7712E+00
110.00	-.7949E+03	-.6649E+03	-.8098E+00	-.8098E+00
120.00	-.8250E+03	-.6903E+03	-.1267E+01	-.1267E+01
130.00	-.8530E+03	-.7141E+03	-.1861E+01	-.1861E+01
140.00	-.8792E+03	-.7366E+03	-.2597E+01	-.2597E+01
150.00	-.9038E+03	-.7579E+03	-.3480E+01	-.3480E+01
160.00	-.9269E+03	-.7780E+03	-.4509E+01	-.4509E+01
170.00	-.9488E+03	-.7972E+03	-.5683E+01	-.5683E+01
180.00	-.9695E+03	-.8155E+03	-.6997E+01	-.6997E+01
200.00	-.1008E+04	-.8496E+03	-.1002E+02	-.1002E+02
201.00	-.1010E+04	-.8514E+03	-.1019E+02	-.1019E+02
202.00	-.1012E+04	-.8530E+03	-.1035E+02	-.1035E+02
203.00	-.1013E+04	-.8546E+03	-.1052E+02	-.1052E+02
204.00	-.1015E+04	-.8563E+03	-.1069E+02	-.1069E+02
205.00	-.1017E+04	-.8579E+03	-.1086E+02	-.1086E+02
206.00	-.1019E+04	-.8595E+03	-.1103E+02	-.1103E+02

Figure E-13. (continued).

TIME	OBS 1	OBS 2	OBS 3	OBS 4
207.00	-.1021E+04	-.8611E+03	-.1120E+02	-.1120E+02
208.00	-.1022E+04	-.8627E+03	-.1137E+02	-.1137E+02
209.00	-.1024E+04	-.8642E+03	-.1155E+02	-.1155E+02
210.00	-.1026E+04	-.8658E+03	-.1172E+02	-.1172E+02
220.00	-.1043E+04	-.8813E+03	-.1354E+02	-.1354E+02
230.00	-.1059E+04	-.8961E+03	-.1546E+02	-.1546E+02
240.00	-.1075E+04	-.9104E+03	-.1747E+02	-.1747E+02
250.00	-.1090E+04	-.9243E+03	-.1959E+02	-.1959E+02
260.00	-.1105E+04	-.9376E+03	-.2178E+02	-.2178E+02
270.00	-.1119E+04	-.9505E+03	-.2406E+02	-.2406E+02
280.00	-.1133E+04	-.9630E+03	-.2641E+02	-.2641E+02
300.00	-.1158E+04	-.9869E+03	-.3129E+02	-.3129E+02
320.00	-.1183E+04	-.1009E+04	-.3640E+02	-.3640E+02
340.00	-.1206E+04	-.1031E+04	-.4169E+02	-.4169E+02
360.00	-.1227E+04	-.1051E+04	-.4712E+02	-.4712E+02
390.00	-.1243E+04	-.1070E+04	-.5268E+02	-.5268E+02

Figure E-13. (continued).

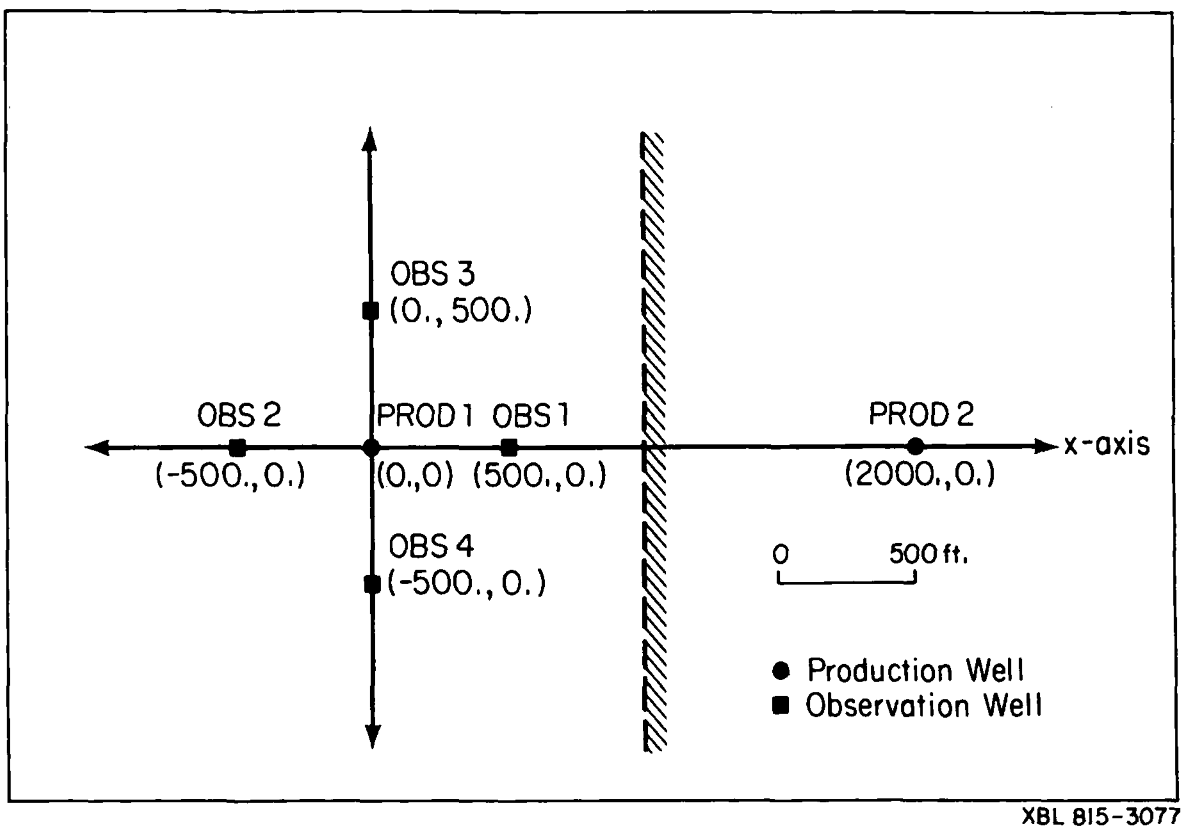


Figure E-14. Observation well locations, production well location, and "image" well location for Sample Problem 4.

```
     VERIFICATION OF ANISOTROPY-RUN TO COMPARE WITH BOUNDARY
           04                 2           1          56
 6.895 E+03 6.310E-05   3.6E+03   .3048     1.0  E-03 9.862E-16
 150000.   1000.      .002       0.                0.
 OBS   1      500.    0.         0.                     0        0.
 OBS 2     -500.     0.         0.
 OBS 3      000.        500.
 OBS 4      000.       -500.
 PROD 1       0.        0.                 2
 0.         1000.
 5000.      1000.
 PROD 2     2000.       0.                 2
 0.         1000.
 5000.      1000.
 1.         2.         3.         4.         5.         6.         7.         9.
 10.        20.        30.        40.        50.        60.        70.        80.
 100.       101.       102.       103.       104.       105.       106.       107.
 109.       110.       120.       130.       140.       150.       160.       170.
 180.       200.       201.       202.       203.       204.       205.       206.
 207.       208.       209.       210.       220.       230.       240.       250.
 260.       270.       280.       300.       320.       340.       360.       380.
```

Figure E-15. Input deck for Sample Problem 4.

```
    VERIFICATION OF ANISOTROPY-RUN TO COMPARE WITH BOUNDARY


   NUMBER OF OBSERVATION WELLS               4
   NUMBER OF PRODUCTION WELLS                2
   NUMBER OF TIMES AT WHICH PRESSURES WILL BE CALCULATED         56


                       CONVERSION FACTORS
                       ==================

          PRESSURE UNIT PER PASCAL                                .6895E+04
          FLOWRATE UNIT PER CUBIC METER PER SECOND                .6310E-04
          TIME UNIT PER SECOND                                     3600.00
          LENGTH PER METER                                            .30
          VISCOSITY PER PASCAL-SECOND                              .100E-02
          PERMEABILITY PER SQUARE METER                           .9862E-15


      PARAMETER VALUES
      ================
      X-AXIS TRANSIMISSIVITY = .1500E+06
      Y-AXIS TRANSMISSIVITY = .1000E+04
      STORATIVITY = .2000E-02


   OBSERVATION WELL NUMBER      1
      WELL OBS   1     COORDINATES (     500.00,       0.   )
      INITIAL PRESSURE=0.
```

Figure E-16. Output for Sample Problem 4.

```
OBSERVATION WELL NUMBER       2
   WELL OBS 2       COORDINATES (    -500.00,        0.   )
   INITIAL PRESSURE=0.


OBSERVATION WELL NUMBER       3
   WELL OBS 3       COORDINATES (       0.   ,     500.00)
   INITIAL PRESSURE=-.0


OBSERVATION WELL NUMBER       4
   WELL OBS 4       COORDINATES (       0.   ,    -500.00)
   INITIAL PRESSURE=-.0


  PRODUCTION WELL NUMBER              1
     PROD 1       COORDINATES (       0.   ,        0.   )
     NUMBER OF FLOWRATE POINTS=     2

                          TIME           FLOWRATE


                       0.                .1000E+04
                        .5000E+04        .1000E+04


  PRODUCTION WELL NUMBER              2
     PROD 2       COORDINATES (    2000.00,        0.   )
     NUMBER OF FLOWRATE POINTS=     2

                          TIME           FLOWRATE

                       0.                .1000E+04
                        .5000E+04        .1000E+04


  DISTANCES BETWEEN OBSERVATION WELLS AND PRODUCTION WELLS

              OBS    1        OBS 2         OBS 3         OBS 4
  PROD 1         500.00        500.00        500.00        500.00
  PROD 2        1500.00       2500.00       2061.55       2061.55
```

Figure E-16. (continued).

TIME	OBS 1	OBS 2	OBS 3	OBS 4
1.00	-.2101E+01	-.2101E+01	-.3917-206	-.3917-206
2.00	-.1755E+02	-.1755E+02	-.8058-103	-.8058-103
3.00	-.3966E+02	-.3966E+02	-.2625E-68	-.2625E-68
4.00	-.6249E+02	-.6249E+02	-.5152E-51	-.5152E-51
5.00	-.8424E+02	-.8424E+02	-.1286E-40	-.1286E-40
6.00	-.1045E+03	-.1045E+03	-.1135E-33	-.1135E-33
7.00	-.1232E+03	-.1232E+03	-.1063E-28	-.1063E-28
9.00	-.1566E+03	-.1566E+03	-.4727E-22	-.4727E-22
10.00	-.1715E+03	-.1715E+03	-.1020E-19	-.1020E-19
20.00	-.2807E+03	-.2807E+03	-.4004E-09	-.4004E-09
30.00	-.3512E+03	-.3512E+03	-.1601E-05	-.1601E-05
40.00	-.4031E+03	-.4031E+03	-.1092E-03	-.1092E-03
50.00	-.4442E+03	-.4442E+03	-.1440E-02	-.1440E-02
60.00	-.4783E+03	-.4783E+03	-.8268E-02	-.8268E-02
70.00	-.5073E+03	-.5073E+03	-.2939E-01	-.2939E-01
80.00	-.5326E+03	-.5326E+03	-.7720E-01	-.7720E-01
100.00	-.5752E+03	-.5752E+03	-.3071E+00	-.3071E+00
101.00	-.5771E+03	-.5771E+03	-.3246E+00	-.3246E+00
102.00	-.5790E+03	-.5790E+03	-.3428E+00	-.3428E+00
103.00	-.5809E+03	-.5809E+03	-.3617E+00	-.3617E+00
104.00	-.5828E+03	-.5828E+03	-.3812E+00	-.3812E+00
105.00	-.5846E+03	-.5846E+03	-.4014E+00	-.4014E+00
106.00	-.5864E+03	-.5864E+03	-.4223E+00	-.4223E+00
107.00	-.5882E+03	-.5882E+03	-.4439E+00	-.4439E+00
109.00	-.5918E+03	-.5918E+03	-.4893E+00	-.4893E+00
110.00	-.5935E+03	-.5935E+03	-.5130E+00	-.5130E+00
120.00	-.6103E+03	-.6103E+03	-.7912E+00	-.7912E+00
130.00	-.6257E+03	-.6257E+03	-.1147E+01	-.1147E+01
140.00	-.6400E+03	-.6400E+03	-.1583E+01	-.1583E+01
150.00	-.6534E+03	-.6534E+03	-.2101E+01	-.2101E+01
160.00	-.6659E+03	-.6659E+03	-.2699E+01	-.2699E+01
170.00	-.6777E+03	-.6777E+03	-.3375E+01	-.3375E+01
180.00	-.6888E+03	-.6888E+03	-.4126E+01	-.4126E+01
200.00	-.7093E+03	-.7093E+03	-.5840E+01	-.5840E+01
201.00	-.7102E+03	-.7102E+03	-.5932E+01	-.5932E+01
202.00	-.7112E+03	-.7112E+03	-.6026E+01	-.6026E+01
203.00	-.7122E+03	-.7122E+03	-.6119E+01	-.6119E+01
204.00	-.7131E+03	-.7131E+03	-.6214E+01	-.6214E+01
205.00	-.7141E+03	-.7141E+03	-.6309E+01	-.6309E+01
206.00	-.7150E+03	-.7150E+03	-.6405E+01	-.6405E+01

Figure E-16. (continued).

TIME	OBS 1	OBS 2	OBS 3	OBS 4
207.00	-.1021E+04	-.8611E+03	-.1120E+02	-.1120E+02
208.00	-.1022E+04	-.8627E+03	-.1137E+02	-.1137E+02
209.00	-.1024E+04	-.8642E+03	-.1155E+02	-.1155E+02
210.00	-.1026E+04	-.8658E+03	-.1172E+02	-.1172E+02
220.00	-.1043E+04	-.8813E+03	-.1354E+02	-.1354E+02
230.00	-.1059E+04	-.8961E+03	-.1546E+02	-.1546E+02
240.00	-.1075E+04	-.9104E+03	-.1747E+02	-.1747E+02
250.00	-.1090E+04	-.9243E+03	-.1959E+02	-.1959E+02
260.00	-.1105E+04	-.9376E+03	-.2178E+02	-.2178E+02
270.00	-.1119E+04	-.9505E+03	-.2406E+02	-.2406E+02
280.00	-.1133E+04	-.9630E+03	-.2641E+02	-.2641E+02
300.00	-.1158E+04	-.9869E+03	-.3129E+02	-.3129E+02
320.00	-.1183E+04	-.1009E+04	-.3640E+02	-.3640E+02
340.00	-.1206E+04	-.1031E+04	-.4169E+02	-.4169E+02
360.00	-.1227E+04	-.1051E+04	-.4712E+02	-.4712E+02
380.00	-.1248E+04	-.1070E+04	-.5268E+02	-.5268E+02

Figure E-16. (continued).

```
                        **PROGRAM VARFLOW(INPUT,OUTPUT,TAPE1,TAPE2)**

 1.    000000B          PROGRAM VARFLOW(INPUT,OUTPUT,TAPE1,TAPE2)
                  C
                  CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
                  C
                  C     THIS PROGRAM CALCULTES DRAWDOWN IN AN ANISOTROPIC,HOMOGENEOUS,
                  C     CONSTANT THICKNESS POROUS MEDIUM. THERE CAN BE UP TO 10
                  C     PRODUCTION WELLS AND TEN OBSERVATION WELLS. FLOWRATES
                  C     CAN BE VARIABLE. THE PROGRAM CAN ALSO INCLUDE DRAWDOWN DUE TO
                  C     SKIN EFFECTS AND A SINGLE LINEAR RESERVOIR BOUNDARY (BARRIER
                  C     OR CONSTANT POTENTIAL).
                  C
 2.    002205B          DIMENSION X(3),TITLE(8),YSTART(10),LOBS(10),KKJ(10),ROY(10),
                       $SKIN(10),R(10,10),TIMES(100),RI2(10,10),UX(10),UY(10),ROX(10),
                       $PX(10),PY(10),AQ(100,10),TQ(100,10),BQ(100,10),YCALC(100,10)
                       $,NAME(10),PNAME(10),RPX(10),RPY(10),RIPX(10),RIPY(10)
 3.    002205B          COMMON /SUB/ PI
 4.    002205B          DATA ((KKJ(J),J=1,10),L)/11*0/
 5.    002205B          DATA (PI,PAPRESS,CMSFLOW,SECTIME,RLENGTH,SMPERM,PASVISC)
                       &/3.141592654,6*1.0/
                  CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
                  C           READ IN ALL OF THE PROBLEM PARAMETERS AND FLOW RATE DATA
                  C           PRINT OUT ALL OF THE ABOVE
 6.    002205B
 7.    002205B          READ 100,(TITLE(I),I=1,8)
 8.    013012B   100    FORMAT(8A10)
 9.    013012B          PRINT 200, (TITLE(I),I=1,8)
10.    013021B   200    FORMAT(1H1,2X,8A10)
11.    013021B          READ 101,IHH,JJ,IDIMEN,NTIMES
12.    013030B   101    FORMAT(4I10)
13.    013030B          PRINT 201,IHH,JJ,NTIMES
14.    013036B   201    FORMAT(//,*  NUMBER OF OBSERVATION WELLS*,I10,
                       $/,*  NUMBER OF PRODUCTION WELLS *,I10,
                       $/,*  NUMBER OF TIMES AT WHICH PRESSURES WILL BE CALCULATED*,I10)
15.    013036B          IF(IDIMEN  .EQ.    0)GO TO 10
16.    013037B          READ 102,PAPRESS,CMSFLOW,SECTIME,RLENGTH,PASVISC,SMPERM
17.    013050B   102    FORMAT(6E10.4)
18.    013050B   10     PRINT 202,PAPRESS,CMSFLOW,SECTIME,RLENGTH,PASVISC,SMPERM
19.    013061B   202    FORMAT(//,20X,*CONVERSION FACTORS*,/,20X,18(1H=),/,
                       $/,10X,*PRESSURE UNIT PER PASCAL*,21X,E10.4,/,10X,
                       $*FLOWRATE UNIT PER CUBIC METER PER SECOND*,5XE10.4,/,10X,
                       $*TIME UNIT PER SECOND*,25XF10.2,/,10X,*LENGTH PER METER*,29XF10.2,
                       $/,10X,*VISCOSITY PER PASCAL-SECOND*,18XE10.3,/,10X,
                       $*PERMEABILITY PER SQUARE METER*,16XE10.4)
```

Figure E-17. VARFLOW Program sample.

```
013061B        READ 103,RKHUX,RKHUY,PCH,ANGLE,DSTNCE,BOUND
013072B   103  FORMAT(5E10.4,A10)
013072B        PRINT 203,RKHUX,RKHUY,PCH
013100B   203  FORMAT(//,5X,*PARAMETER VALUES*,/,5X,16(1H*),/,
              $5X,*X-AXIS TRANSIMISSIVITY =*,E10.4,/,5X,
              $*Y-AXIS TRANSMISSIVITY =*,E10.4,/,5X,*STORATIVITY =*,E10.4)
013100B        IF(BOUND  .NE.   10H            )PRINT 204,BOUND,ANGLE,DSTNCE
013110B   204  FORMAT(/,2X,*THERE IS A *,A10,*BOUNDARY AT AN ANGLE OF *,F10.2,
              $* DEGREES AND A DISTANCE OF *,F10.2)
013110B        DO 1000 I=1,IHH
013112B        READ 105, NAME(I),OX(I),OY(I),YSTART(I),LOBS(I),SKIN(I)
013132B        PRINT 205,I,NAME(I),OX(I),OY(I),YSTART(I)
013146B  1000  IF(LOBS(I)  .GT.  0)PRINT 206,LOBS(I),SKIN(I)
013161B   205  FORMAT(//,*  OBSERVATION WELL NUMBER *,I5,/,5X,*WELL *,A10,
              $* COORDINATES (*F10.2,*,*F10.2,*)*,/,5X,*INITIAL PRESSURE=*,E10.4)
013161B   206  FORMAT(5X,*THIS OBSERVATION WELL IS ALSO PRODUCTION WELL NUMBER*
              $,I10,/,5X,*IT HAS A SKIN VALUE OF*,F10.2)
013161B   105  FORMAT(A10,2F10.2,E10.4,I10,F10.2)
013161B        DO 1020 J=1,JJ
013163B        READ 106, PNAME(J),PX(J),PY(J),KKJ(J)
013177B        PRINT 207,J,PNAME(J),PX(J),PY(J),KKJ(J)
013213B        DO 1020 IJ=1,KKJ(J)
013216B        READ 107, TQ(IJ,J),AQ(IJ,J)
013231B  1020  PRINT 208,TQ(IJ,J),AQ(IJ,J)
013245B   207  FORMAT(//,*  PRODUCTION WELL NUMBER *,I10,/,5X,A10,
              $2X,*COORDINATES (*,F10.2,*,*,F10.2,*)*,2X,/,5X,
              $*NUMBER OF FLOWRATE POINTS=*,I5,//,23X,*TIME*,9X,*FLOWRATE*,//)
013245B   106  FORMAT(A10,2F10.2,I10)
013245B   107  FORMAT(2E10.4)
013245B   208  FORMAT(20X,E10.4,5X,E10.4)
013245B   108  FORMAT(8E10.4)
013245B        DO 1030 I=1,NTIMES,8
013247B  1030  READ 108, (TIMES(K),K=I,I+7)
         C
         CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
         C      SET UP THE PROBLEM
         C
         C      CALCULATE THE GRADIENTS FOR THE FLOW RATE DATA
013262B        DO 1050 I=1,JJ
013264B        DO 1050 IJ=1,KKJ(I)-1
013270B        IF( ABS(TQ(IJ+1,I)-TQ(IJ,I)) .EQ. 0. ) GO TO 1050
013277B        BQ(IJ,I)=(AQ(IJ+1,I)-AQ(IJ,I))/(TQ(IJ+1,I)-TQ(IJ,I))
013307B  1050  CONTINUE
         C
         C      CALCULATE RADIAL DISTANCES BETWEEN THE OBSERVATION WELLS
         C      AND THE PRODUCTION WELLS
013314B        DO 1070 IH=1,IHH
013316B        DO 1070 J=1,JJ
013321B  1070  R(IH,J)=SQRT((PX(J)-OX(IH))**2. + (PY(J)-OY(IH))**2.)
013343B        PRINT 211,(NAME(I),I=1,IHH)
013353B   211  FORMAT(//,*  DISTANCES BETWEEN OBSERVATION WELLS AND PRODUCTION*
              $,* WELLS*,//,12X,10(A10,2X),//)
013353B        DO 1080 I=1,JJ
013355B  1080  PRINT 210, PNAME(I),(R(IH,I),IH=1,IHH)
013374B   210  FORMAT(2X,A10,10(F10.2,2X))
         C
         CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
         C       CALCULATE THE PARAMETERS
013374B         RKHUE=SQRT(RKHUX*RKHUY)
013400B        X(1)=CMSFLOW*PASVISC/4./PI/RKHUE/SMPERM/RLENGTH/PAPRESS
013406B        ALPHA=ANGLE*PI/180.
013410B        IF(BOUND    .EQ. 10H                )GO TO 40
         CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
         C      CALCULATE THE COORDINATES OF THE IMAGE WELLS
013412B        DO 1090 IH=1,IHH
013414B        ROX(IH)=OX(IH)*SIN(ALPHA)+OY(IH)*COS(ALPHA)
013424B        ROY(IH)=OY(IH)*SIN(ALPHA)-OX(IH)*COS(ALPHA)
013434B  1090  IF(BOUND  .EQ.10HLEAKY          )L=1
013443B    40  DO 2001 IH=1,IHH
013446B        DO 2002 N=1,NTIMES
013451B        YCALC(N,IH)=YSTART(IH)
013454B        DO 2000 J=1,JJ
```

Figure E-17. (continued).

```
VARFLOW                        **PROGRAM VARFLOW(INPUT,OUTPUT,TAPE1,TAPE2)**

  71.   0134608        CALL RKHUNF(RKHUX,RKHUY,OX(IH),OY(IH),PX(J),PY(J),RKHUN)
  72.   0134678        RKHUN=X(1)*RKHUE/RKHUN
  73.   0134718        X(2)=R(IH,J)*R(IH,J)*(RLENGTH**3.)*PI*PCH*RKHUN/CMSFLOW/SECTIME
  74.   0135028        IF( BOUND  .EQ. 10H              )GO TO 50
  75.   0135058        RPX(J)=PX(J)*SIN(ALPHA)+PY(J)*COS(ALPHA)
  76.   0135158        RPY(J)=PY(J)*SIN(ALPHA)-PX(J)*COS(ALPHA)
  77.   0135258        RIPY(J)=RPY(J)
  78.   0135268        RIPX(J)=2.*DSTNCE-RPX(J)
                 CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
                 C     CALCULATE THE DISTANCE BETWEEN THE IMAGE WELLS AND THE OBSERVATION
                 C     WELLS
  79.   0135308        RI2(IH,J)=(ROX(IH)-RIPX(J))**2.  + (ROY(IH)-RIPY(J))**2.
  80.   0135368        CALL COOR(RIPX(J),RIPY(J),XI,YI,ANGLE)
  81.   0135448        CALL RKHUNF(RKHUX,RKHUY,OX(IH),OY(IH),XI,YI,RKHUN)
  82.   0135508        RKHUN=X(1)*RKHUE/RKHUN
  83.   0135528        X(3)=RI2(IH,J)*(RLENGTH**3.)*PI*PCH*RKHUN/CMSFLOW/SECTIME
  84.   0135618        NNW=3
  85.   0135628  50    IF(BOUND  .EQ. 10H                    )NNW=2
                 C
                 CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
                 C     MAIN CALCULATION LOOP
  86.   0135668        TR=TIMES(N)
  87.   0135678        FII=0.
  88.   0135708        DO 1100 I=2,NNW
  89.   0135728        FI=0.0
  90.   0135728        DO 1110 KJ=1,KKJ(J)-1
  91.   0135778        IF(ABS(TQ(KJ+1,J)-TQ(KJ,J)).LT.1.E-5) GO TO 1110
  92.   0136068        TN=TR-TQ(KJ,J)
  93.   0136138        TN1=TR-TQ(KJ+1,J)
  94.   0136168        IF(TN.LE.0.) GO TO 1100
  95.   0136218        IF(TN1.LE.0.0) GO TO 80
  96.   0136238        FI=(AQ(KJ,J)+BQ(KJ,J)*(TN+X(I)))*(EI(-X(I),TN1)-EI(-X(I),TN))
                      $-BQ(KJ,J)*(TN*EXP(-X(I)/TN)-TN1*EXP(-X(I)/TN1))+FI
  97.   0136648  1110  CONTINUE
  98.   0136678        GO TO 90
  99.   0136708  80    FI=-(AQ(KJ,J)+BQ(KJ,J)*(TN+X(I)))*EI(-X(I),TN)
                      A-BQ(KJ,J)*TN*EXP(-X(I)/TN)+FI
 100.   0137148  90    IF(L.EQ.1.AND.I.GT.2)FI=-FI
 101.   0137238  1100  FII=FII+FI
 102.   0137278        IF(LOBS(IH).NE.J) GO TO 70
 103.   0137318        FII=(FII+2.*SKIN(IH)*(AQ(KJ,J)+BQ(KJ,J)*TN))
 104.   0137428  70    F=FII*X(1)
 105.   0137448  2000  YCALC(N,IH)=YCALC(N,IH)=F
 106.   0137528  2002  CONTINUE
 107.   0137548  2001  CONTINUE
                 C
                 CCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCCC
                 C
                 C     PRINT OUT RESULTS OF THE CALCULATION
 108.   0137578        PRINT 118,(NAME(I),I=1,IHH)
 109.   0137708        N=0
 110.   0137708        IN=0
 111.   0137708        DO 1120 I=1,NTIMES
 112.   0137738        PRINT 119,TIMES(I),(YCALC(I,IH),IH=1,IHH)
 113.   0140128        N=N+1
 114.   0140138        IF(N   .NE.   5)GO TO 1120
 115.   0140148        PRINT 120
 116.   0140208        IN=IN+1
 117.   0140218        N=0
 118.   0140218        IF(IN   .NE.   8)GO TO 1120
 119.   0140238        PRINT 118,(NAME(M),M=1,IHH)
 120.   0140348        IN=0
 121.   0140348  1120  CONTINUE
 122.   0140378  118   FORMAT(1H1,//,5X,*    TIME    *,10(A10,2X),/,5X,130(1H=),//)
 123.   0140378  119   FORMAT(3X,F10.2,2X,10(E10.4,2X))
 124.   0140378  120   FORMAT(/)
 125.   0140378        STOP
 126.   0140408        END

EI                             **FUNCTION EI(X,T)**

   1.   0000008        FUNCTION EI(X,T)
   2.   0000008        A=-X/T
```

Figure E-17. (continued).

```
VARFLOW                          **PROGRAM VARFLOW(INPUT,OUTPUT,TAPE1,TAPE2)**

  000002B         IF(A.GT.10.0) GO TO 20
  000005B         ET=-ALOG(A)-.5772156649
  000010B         TERM=1.0
  000011B         DO 10 J=1,100
  000014B         TERM=-TERM*A/J
  000016B         ET=ET-TERM/J
  000021B         IF(ABS(TERM/J/ET).LT.1.E-8)  GO TO 12
  000021B      10 CONTINUE
  000030B      12 ET=-ET
  000032B         RETURN
  000034B      20 ET=-EXP(-A)/A*(1.0-1.0/A+2.0/A**2-6.0/A**3)
  000046B         RETURN
  000051B         END
```

```
RKHUNF                           **SUBROUTINE RKHUNF(RKHUX,RKHUY,OXD,OYD,PXD,PYD,RKHUN)**

  000000B         SUBROUTINE RKHUNF(RKHUX,RKHUY,OXD,OYD,PXD,PYD,RKHUN)
  000000B         COMMON /SUB/ PI
  000000B         YD=OYD-PYD
  000001B         XD=OXD-PXD
  000003B         THETA=ATAN2(YD,XD)
  000006B         PRINT 99,THETA
  000013B   99    FORMAT(5X,*THETA=*,F10.2)
  000013B         RKHUN=RKHUX/((COS(THETA)**2.) + RKHUX*(SIN(THETA)**2.)/RKHUY)
  000024B         PRINT 100,RKHUN
  000031B   100   FORMAT(5X,*RKHUN=*,F10.2)
  000031B         RETURN
  000033B         END
```

```
COOR                             **SUBROUTINE COOR(RIPXD,RIPYD,XI,YI,ANGLE)**

  000000B         SUBROUTINE COOR(RIPXD,RIPYD,XI,YI,ANGLE)
  000000B         COMMON /SUB/ PI
  000000B         ANG=90.-ANGLE
  000001B         ANG=ANG*PI/180.
  000003B         XI=RIPXD*COS(ANG)+RIPYD*SIN(ANG)
  000012B         YI=RIPYD*COS(ANG)-RIPXD*SIN(ANG)
  000021B         RETURN
  000024B         END
```

Figure E-17. (continued).

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APPENDIX F
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