GL02976-8

TREE-1085

TWO-DIMENSIONAL SIMULATION OF THE RAFT RIVER GEOTHERMAL RESERVOIR AND WELLS

WILLIAM C. KETTENACKER

March 1977

EG&G Idaho, Inc.

IDAHO NATIONAL ENGINEERING LABORATORY

ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

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

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22161
Price: Printed Copy $5.50; Microfiche $3.00

TREE-1085

Distributed Under Category:
UC-66A
GE: Resource Development

TWO-DIMENSIONAL SIMULATION OF THE RAFT RIVER GEOTHERMAL RESERVOIR AND WELLS

by

William C. Kettenacker

EG&G IDAHO, INC.

March 1977

PREPARED FOR THE
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
IDAHO OPERATIONS OFFICE
UNDER CONTRACT NO. EY-76-C-07-1570

TABLE OF CONTENTS

LIST OF TABLES

*RRGE #2 - Raft River Geothermal Well No. 2

LIST OF FIGURES

*RRGE #1 - Raft River Geothermal Well No. 1,
RRGE #2 - Raft River Geothermal Well No. 2, etc.

ABSTRACT

Computer models describing both the transient reservoir pressure behavior and the time dependent temperature response of the wells at the Raft River, Idaho, Geothermal Resource have been developed. A horizontal, two-dimensional, finite-difference model for calculating pressure effects was constructed to simulate reservoir performance. Vertical, two-dimensional, finite-difference, axisymmetric models for each of the three existing wells at Raft River were also constructed to describe the transient temperature and hydraulic behavior in the vicinity of the wells. All modeling was done with the use of the thermal hydraulics computer program SINDA-3G. The models are solved simultaneously with one input deck so that reservoir-well interaction may occur. The model predicted results agree favorably with the test data.

1.0 INTRODUCTION

Geothermal energy is quickly becoming an energy alternative in the Western United States. Pacific Gas and Electric Company currently produces 502 MW_e for its customers in Northern California from the Geysers geothermal steam field in the Napa Valley. Residents in Southern California will soon receive some of their electrical power from the San Diego Gas and Electric geothermal power station near the Salton Sea. Several homes in Boise, Idaho are now heated with low temperature hot water from nearby geothermal wells, and there are plans to heat some of the Idaho State office buildings with water from additional wells in that area. Regions in Hawaii, Montana, and Nevada are being studied for possible geothermal energy uses. In other parts of the world geothermal energy has long been established as an energy alternative. Electric power production began in 1904 at the Larderello Field in Italy. Geothermal space heating has been used in Iceland since the 1930's with fifty-one percent of the homes there now heated geothermally. New Zealand, Japan, and Hungary all produce electrical power from geothermal steam. Dwindling supplies and rising costs of fossil fuels are now forcing countries to look at other energy options. Geothermal energy is a viable alternative.

In 1973 Aerojet Nuclear Company, then the prime contractor at the Atomic Energy Commission's National Reactor Testing Station, began preliminary engineering studies in the Raft River Valley in Cassia County of Southern Idaho after the United States Geological Survey (USGS) and the Raft River Rural Electric Cooperative gathered data in the area which showed significant potential for a medium temperature (300°F) developmental geothermal power plant. Currently, EG&G Idaho, Inc., the present prime contractor at the renamed Idaho National Engineering Laboratory

(INEL) for the new Energy Research and Development Administration, is continuing these studies in addition to looking at various other uses of this geothermal energy. Three wells of approximately 5000 feet to 6000 feet in depth have been drilled in the area and flow testing has been taking place for over a year. Figure 1 shows the location of the Raft River Valley and the location of the existing three wells.

The objective of the work covered in this report was to develop the tool or tools necessary for long term predictions of the response of the Raft River geothermal reservoir and wells. A finite-difference computer code was the tool chosen. This code was based on the SINDA-3G[(1)] computer program, an n-dimensional thermal analyzer which utilizes an electrical network (capacitor-conductor) analogy and a lumped parameter (node) representation of the physical system to solve steady-state and transient problems. A thermal code was picked as the program base since its heat transfer capabilities could be used for solving the temperature response phase of the geothermal predictions, while the basic equations solved in its computational scheme are identical with those of the pressure response in a groundwater reservoir.

Application of the developed code will result in long term (30 years) prediction of the pressure response in the Raft River Geothermal Reservoir. Long term temperature response will also be determined in each of the three existing wells and in wells to be added later. These predictions will be useful in forecasting pressure changes in the reservoir and temperature changes in and around the wells so that decisions on future well locations, for both production and injection, can be made. More importantly, the predictions will be helpful in deciding the useful life of the reservoir for energy needs.

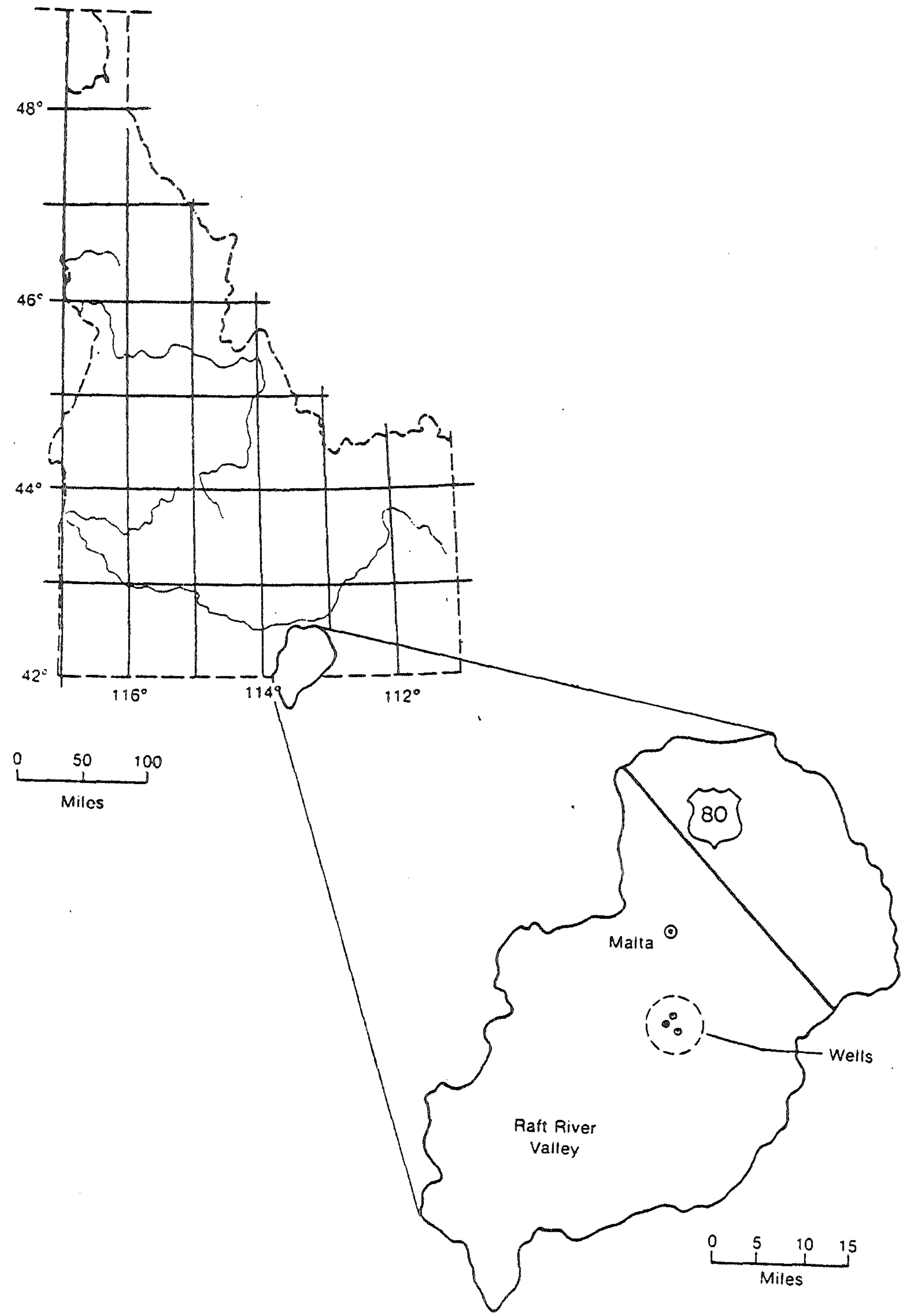


FIGURE 1 - Location Map of Raft River Valley and Geothermal Wells

2.0 PREVIOUS INVESTIGATIONS

Extensive research has been done in the area of groundwater flow and flow through porous media employing analytical techniques[2,3,6] and numerical methods such as finite-difference[4,5,16] and finite-element[7,8,9] schemes. Many applications to geothermal reservoir systems are limited to simplified models[10,11] or analytical procedures[15]. Recent investigations, though, have been directed toward describing the total flow and heat transfer behavior of geothermal reservoirs in general[12,13,14]. Lasseter[13] developed a finite-difference program describing the simultaneous transport of mass and energy by a one- or two-phase fluid in an undisturbed media. Finite-difference and finite-element models for describing energy and mass transfer in porous media with the effect of fluid withdrawal were developed by Witherspoon, et.al.[14] for multiphase systems. Toronyi's[17] finite-difference two-dimensional, two-phase model coupled with a one-dimensional well model appears to be the most complete work to date by including the well as a point sink within the reservoir. Verification of these models has, in most cases, been limited to duplicating the performance of the Wairakei, New Zealand, geothermal reservoir, a liquid dominated two-phase field.

The Raft River geothermal resource has the attribute of being a single phase liquid and, therefore, any tool describing its behavior need not include two-phase effects. Much of the literature cited dealt with the two-phase fluid flow considerations. In addition, all but one (Toronyi) neglected wellbore effects, and even this study lacked injection well considerations. For these reasons, an independent tool was developed based on an existing heat transfer code, SINDA-3G, and including only those parameters deemed important for describing the geothermal resource at Raft River.

3.0 ANALYSIS

The Raft River geothermal reservoir contains a single phase liquid at 296°F to 299°F at a pressure of 2200 psig. Because of this single phase resource and because of the apparent homogeneous and isotropic nature of the geothermal fluid, the development of a computer code describing both the reservoir behavior and the temperature response adjacent to the wells was simplified. An existing finite-difference heat transfer computer code, SINDA-3G, was chosen as the base program for modeling and solving the Raft River geothermal reservoir pressure and temperature response since the basic equations solved by SINDA-3G are identical to those needed to describe single phase flow of a slightly compressible, homogeneous fluid in a porous media.

Two different models were developed: A horizontal two-dimensional reservoir pressure response model and a vertical two-dimensional heat transfer model of each well. The reservoir model was void of heat transfer considerations due to its homogeneous, constant temperature nature. Temperature conditions around the wells during production and injection were handled with the well heat transfer models. Both models were developed to be solved simultaneously by SINDA-3G and interaction between models mainly involved pressure input from the reservoir model to the base of the well model.

3.1 Description of Heat Transfer Computer Program SINDA-3G

The original CINDA computer program, coded in FORTRAN-II and FAP for IBM-7094 computers, was developed primarily for the solution of heat transfer and thermodynamics problems in the aerospace industry. It became a standard industry-wide for many heat transfer and th applications. With the advent of third generation computers, modified (termed CINDA-3G) to run on these improved devices and it is this version that has been adapted for use at the INEL computer facility and termed SINDA-3G.

SINDA-3G employs a lumped parameter approach wherein physical masses are represented by lumped nodes, each having uniform properties and as a result, uniform response. Communication between nodes is accomplished through a conductor network representing resistance to transmission of information between the lumped masses. For the present purpose these conductors have numerous applications such as thermal conductivity resistance, thermal convection resistance in fluid flow, and restriction to pressure communication between nodes.

The concept of network superposition on a lumped parameter representation of a physical system is easily stated by a simultaneous set of partial differential equations of the diffusion type:

$$\frac{\partial T}{\partial t} = \alpha \nabla^2 T + S \qquad (1)$$

where

$$\nabla^2 = \frac{\partial^2}{\partial x^2} + \frac{\partial^2}{\partial y^2} + \frac{\partial^2}{\partial z^2}$$

$$\alpha = \frac{k}{\rho C_p}$$

and

T = Temperature

t = Time

k = Thermal Conductivity

ρ = Density

C_p = Specific Heat

S = Source (of The Type $\frac{u'''}{\rho C_p}$, Where u''' = Internal Generation)

x,y,z = Spatial Cartesian Coordinates

The partial derivative of T with respect to time is approximated by:

$$\frac{\partial T}{\partial t} = \frac{T' - T}{\Delta t} \qquad (2)$$

where the prime indicates the new T value after passage of the Δt time step.

The right side of Equation (1) could be written with the T primed to indicate implicit "backward" differencing or unprimed to indicate explicit "forward" differencing. This can be further illustrated by writing Equation (1) in the general form:

$$\frac{\partial T}{\partial t} = \beta(\alpha\nabla^2 T + S) + (1-\beta)(\alpha'\nabla^2 T' + S') \qquad (3)$$

with $$0 \leq \beta \leq 1$$

Any value of β less than one yields an implicit set of equations which must be solved in a simultaneous manner (more than one unknown exists in each equation). Any value of β equal to or less than one-half yields an unconditionally stable set of equations. The option used in the Raft River model was $\beta = 0$ since this not only guarantees stability but eliminates oscillations (early computer runs using $\beta = 1/2$ experienced undesirable oscillations).

3.2 Raft River Reservoir Model

The flow of a fluid through a porous media may be described by the following partial differential equation[3]:

$$\frac{\partial \gamma}{\partial t} = \alpha_p \nabla^2 \gamma \qquad (4)$$

where $$\alpha_p = \frac{k}{f\beta\mu}$$

γ = Density
t = Time
k = Permeability
f = Porosity
β = Compressibility
μ = Viscosity

The dependence of fluid density upon pressure and compressibility may be stated as follows[3]:

$$\gamma = \gamma_o e^{\beta P} \tag{5}$$

where
γ = Density
γ_o = Density at Original State
e = Natural Logarithm Base
β = Compressibility
P = Pressure

For a slightly compressible, homogeneous fluid flowing in a porous media, Equations (4) and (5) may be combined to give:

$$\frac{\partial P}{\partial t} = \alpha_p \nabla^2 P + S \tag{6}$$

where the symbols are as previously described, and a source term, S, of the type $\frac{Q}{f\beta}$ where Q is a volume flow rate, has been added.

All tests at Raft River indicate that the geothermal resource is a single phase liquid exhibiting constant properties at all three test wells (i.e., homogeneous). Therefore, Equation (6) can be used to describe the pressure response of the Raft River Geothermal Reservoir.

Because of the similarity of Equation (1) and Equation (6), SINDA-3G was used to solve for the transient pressure response of the Raft River Geothermal Reservoir with the SINDA-3G thermal input parameters replaced by the corresponding parameters for fluid flow through porous media. It is evident immediately that T in Equation (1) is replaced by the pressure P in Equation (6). However, a one-to-one correspondence of the other variables is not so straightforward. If one recognizes that k, the thermal conductivity in Equation (1), is the property that indicates the quantity of heat that will flow across a unit area if the temperature gradient is unity, and that k, the permeability in Equation (6), is the property that indicates the flow volume that passes a unit cross section of area under a unit pressure gradient, then these terms are analogous. This is more readily apparent by considering the following two equations:

$$\vec{q} = k\vec{\nabla}T \tag{7}$$

$$\vec{V} = \frac{k}{\mu}\vec{\nabla}P \tag{8}$$

where Equation (7) is Fourier's Law of Heat Conduction and Equation (8) is known as Darcy's Law, the basic equation describing the flow of a homogeneous fluid through a saturated homogeneous porous media. Note that for complete correspondence between Equations (1) and (6), the permeability must be divided by the constant μ, the viscosity. It might appear elementary at this point to equate the remaining variables in Equations (1) and (6) by allowing ρC_p to be replaced by $f\beta$ to achieve similarity. Although this is the case, a more rigorous argument may be stated. The quantity ρC_p is the amount of heat that enters or leaves a unit volume while the substance changes one degree in temperature. The quantity $f\beta$ is the volume of fluid that enters or leaves a unit volume while the volume changes by one unit of pressure. This analogy not only completes the comparison of the properties in Equations (1) and (6), it also defines the value of the source term in Equation (6) in that the source term in Equation (1) is a heat rate input replaced by a fluid volume rate in Equation (6). The two equations, then, are similar, and SINDA-3G can be used to solve Equation (6) with all properties in consistent units. Boundary conditions for the model could include: (1) a no-flow boundary (the same as an adiabatic surface in heat transfer), (2) a constant pressure boundary (the same as specifying constant temperature T), or (3) a flow source boundary (the same as heat addition) or a flow source at an interior point.

The SINDA-3G two-dimensional node-conductor network model of the Raft River Geothermal Reservoir consists of a completely orthogonal mesh with 1400 ft. node spacing. Each node is surrounded by four conductors, i.e., each node is directly affected only by the four nodes surrounding it. Currently the model represents a 15 by 10 mile reservoir and it is believed that this model is large enough to adequately describe the pressure behavior of the field, based on observations of other geothermal resources[18]. Figure 2 shows the area of the Raft River Valley covered by the computer model with the positions of the three wells included. Each well is placed on an existing node in the model. All boundaries are currently of the constant pressure type except the west boundary which is input as a no-flow boundary (adiabatic analogy) to simulate the Bridge Fault that exists in that general area.

The geothermal reservoir thickness is not known but current estimates place it at approximately 500 ft. based on well data from Raft River Geothermal Well No. 1 (RRGE #1) and RRGE #2. Production from RRGE #1 begins at the 3800 ft. depth and production from RRGE #2 begins at the 4200 ft. depth indicating a slight reservoir sloping from south to north. However, pressures at 5000 ft. in each well are 2200 psig. It is for this

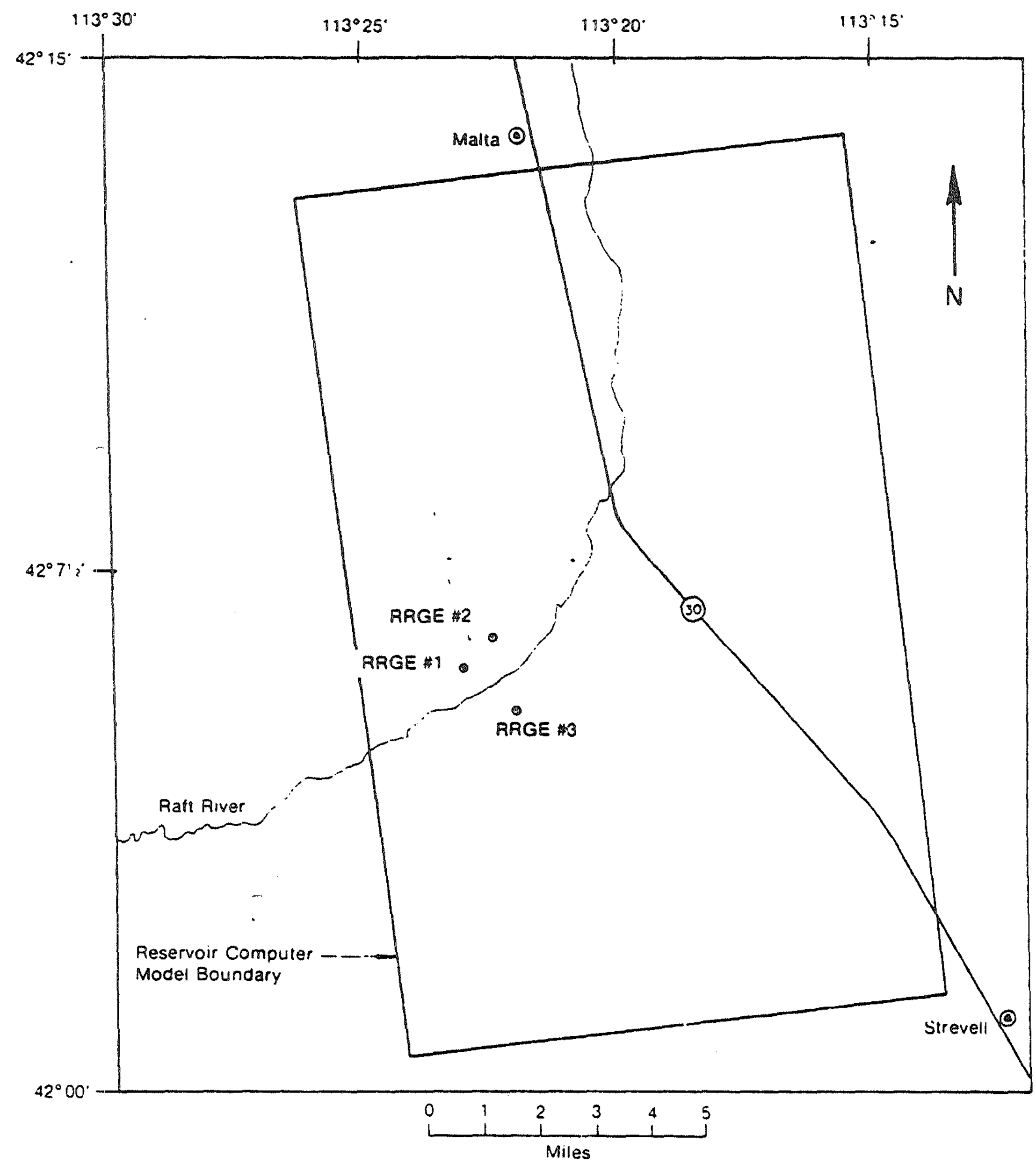


FIGURE 2 - Reservoir Model Coverage

reason, as well as the apparent reservoir homogeneity, that a two-dimensional horizontal reservoir model is justified.

Properties for the existing reservoir computer model are given in Table I[24]. These properties were determined from the long term flow test involving RRGE #1 and RRGE #2 during September and October, 1975, and are based upon a 500 ft. aquifer thickness. The entire model employs these values except those nodes representing the wells and those conductors immediately adjacent to the well nodes. These variations will be discussed in Section 3.5. As previously mentioned, the western boundary represents a no-flow boundary in the model with the remaining boundaries being constant pressure boundaries. This may be modified at a later date as new test data is gathered to show that different types of boundaries exist. The model is driven by placing a source or sink (representing well production or injection, respectively) with the desired strength at a well node and observing the transient pressure response throughout the field. Simultaneous production from two or more wells, production from one well and injection in another, or any other combination placing a source and sink at different well nodes concurrently may be used. If a constant flow rate is not used but the artesian flow rate is desired, the interaction with the well model as described in Section 3.4 must be employed.

3.3 Well Model

A sketch of one of the Raft River Geothermal Wells is shown in Figure 3 and is fairly representative of all three wells. However, slight differences do exist between the wells, such as total depth, casing depth, and in the case of RRGE #3, casing diameter below 1200 ft. Because of these differences, a well model was developed for each well. To simplify the well input parameters, all well models were constructed

TABLE I

Reservoir Model Properties

kH (millidarcy-ft)	2.28×10^{5}
fβH (ft/psi)	1.0×10^{-3}
k (millidarcies)	456.0*
fβ (1/psi)	2.0×10^{-6}*

* k = kH/500 ft, fβ = fβH/500 ft, where H = Aquifer Thickness of 500 ft

TABLE II

Well Model Properties

	k (BTU/hr-ft-^{o}F)	ρ (lbm/ft^{3})	C_p (BTU/lbm-^{o}F)
Cement	0.7	144	0.20
Steel Casing	30.0	490	0.11
Rock (Soil)	1.5	(ρC_p = 50 BTU/ft^{3}-^{o}F)	

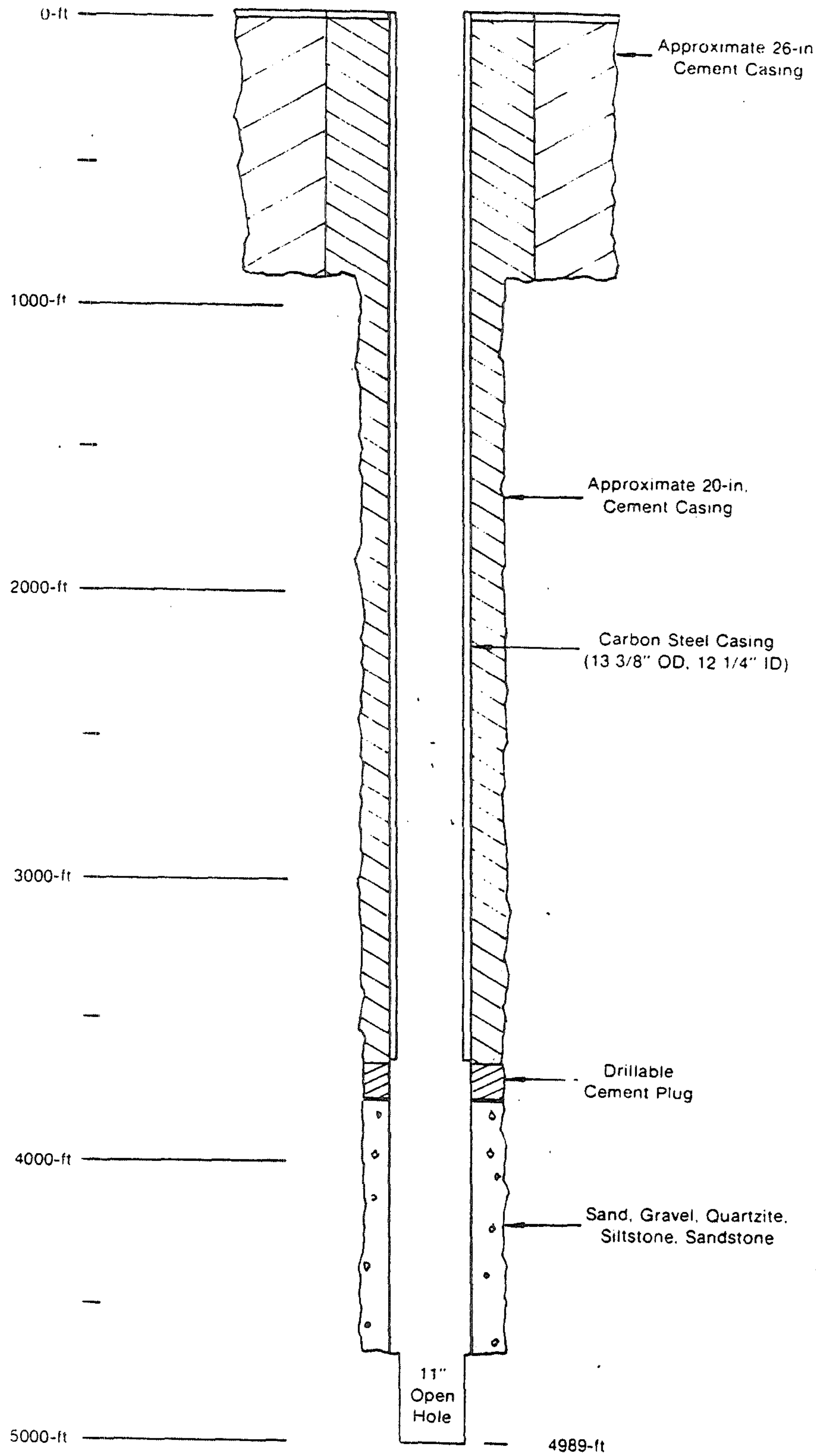


FIGURE 3 - Typical Raft River Geothermal Well

from the common two-dimensional, axisymmetric, node-conductor model shown in Figure 4, with numbers given only for reference. When nodes or conductors were not needed for a particular well model, their properties were input to render them nonexistent. To account for differences in dimensions or materials between the wells, node and conductor values themselves were changed. No vertical conductors were placed in the well models, except along the well axis, because vertical communication away from the wellbore was not considered important. Soil temperatures as a function of depth away from the well are fairly constant all the time.

Input properties for all the well models' conductors and nodes representing the cement and steel casings and the surrounding rock are given in Table II[20]. Water properties only were considered temperature dependent and are given in Table III[20]. These are pure water properties and were employed because of the low amount of contaminants in the reservoir water (∿1000 ppm dissolved solids and ∿39 cc/liter of dissolved gas)[28].

The heat transfer coefficient between the water and casing (and between the water and rock near the bottom of the well) was expressed with the following equation[19]:

$$\frac{h_L D}{k} = 0.023\ (Re)^{0.8}(Pr)^{0.4} \tag{9}$$

where

$$Re = \frac{VD\rho}{\mu}$$

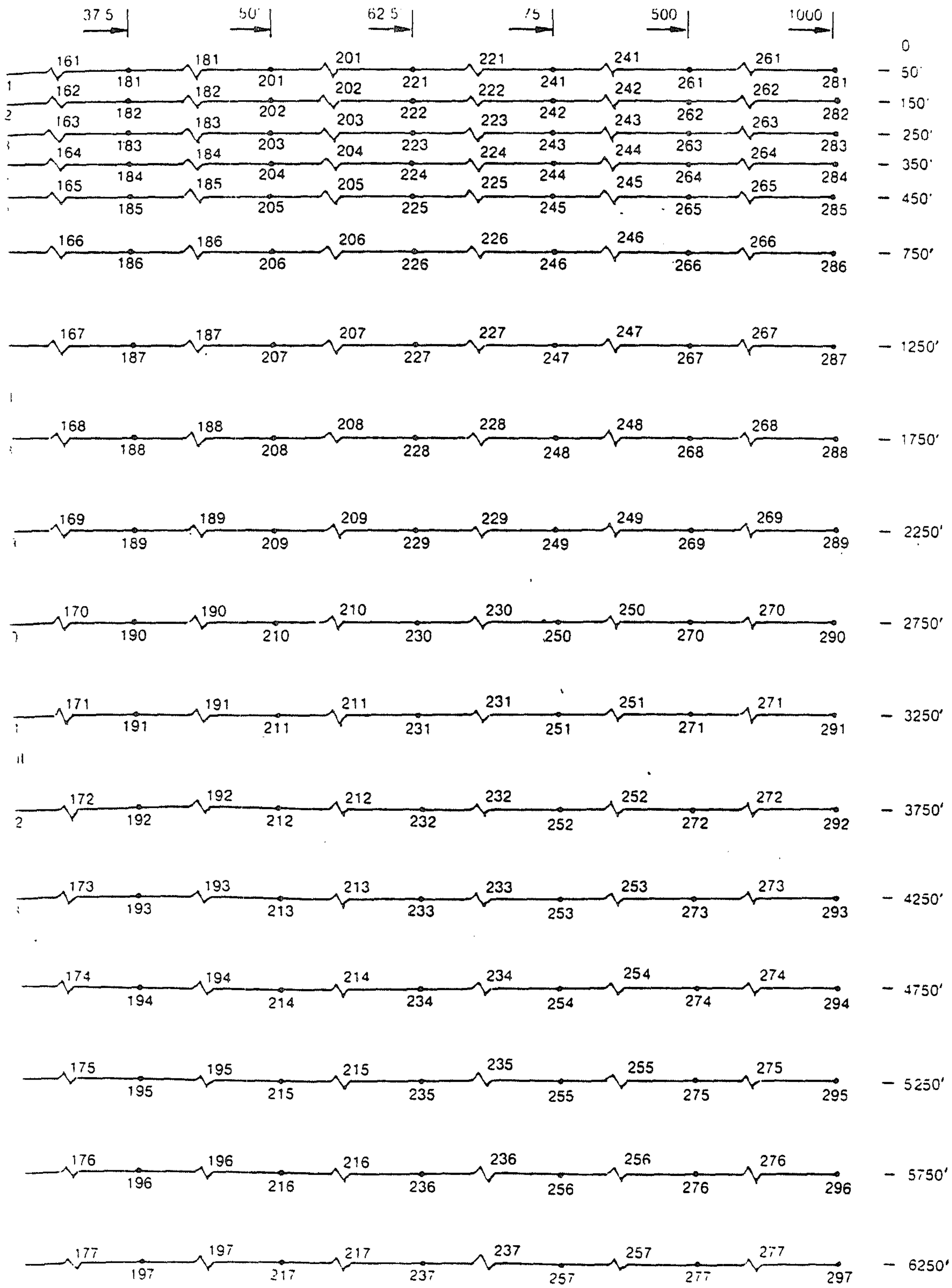
$$Pr = \frac{C_p \mu}{k}$$

and h_L = Surface Heat Transfer Coefficient

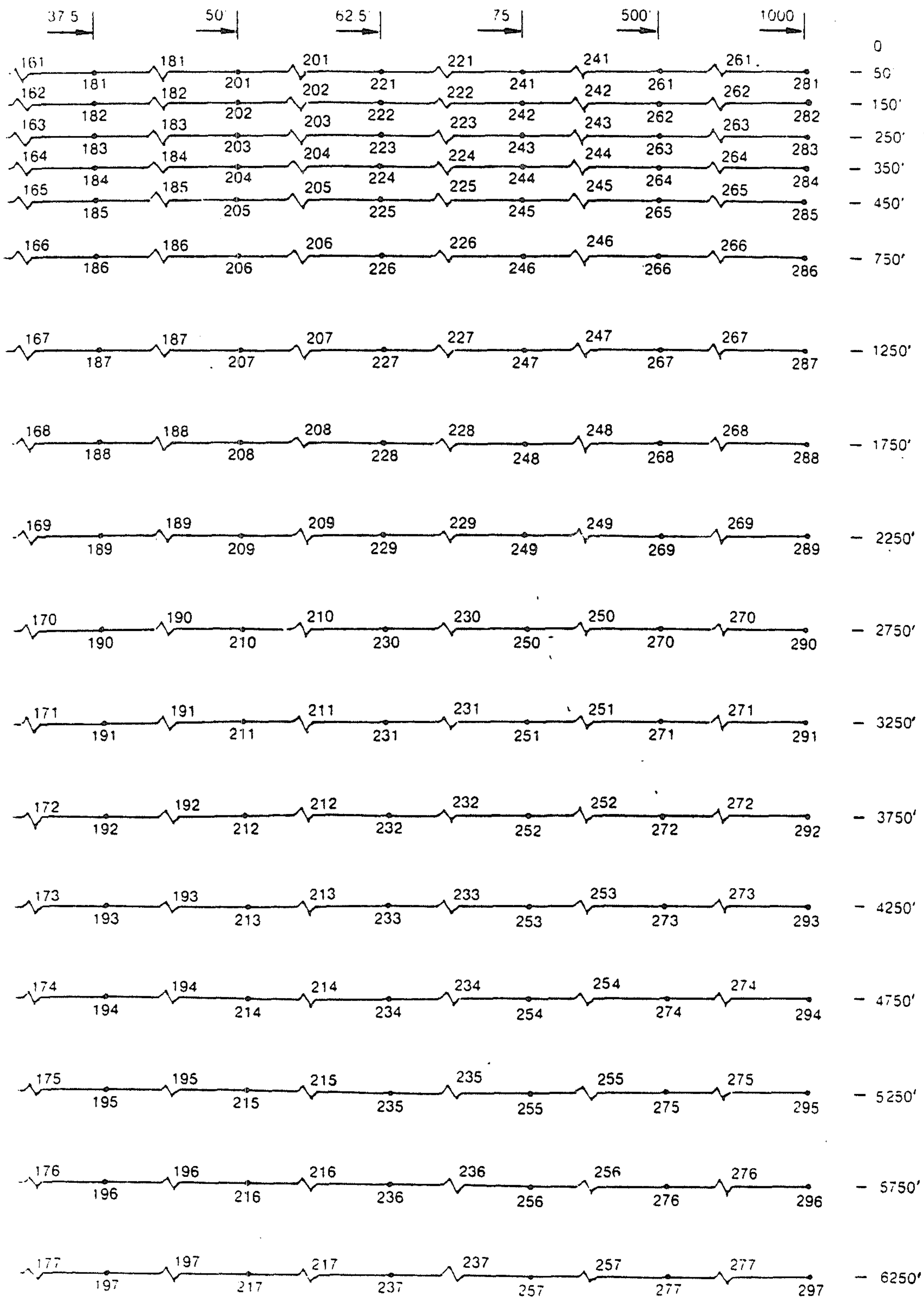
D = Characteristic Length (diameter of well)

k = Thermal Conductivity

V = Fluid Velocity



.ite-Difference Well Model



-Difference Well Model

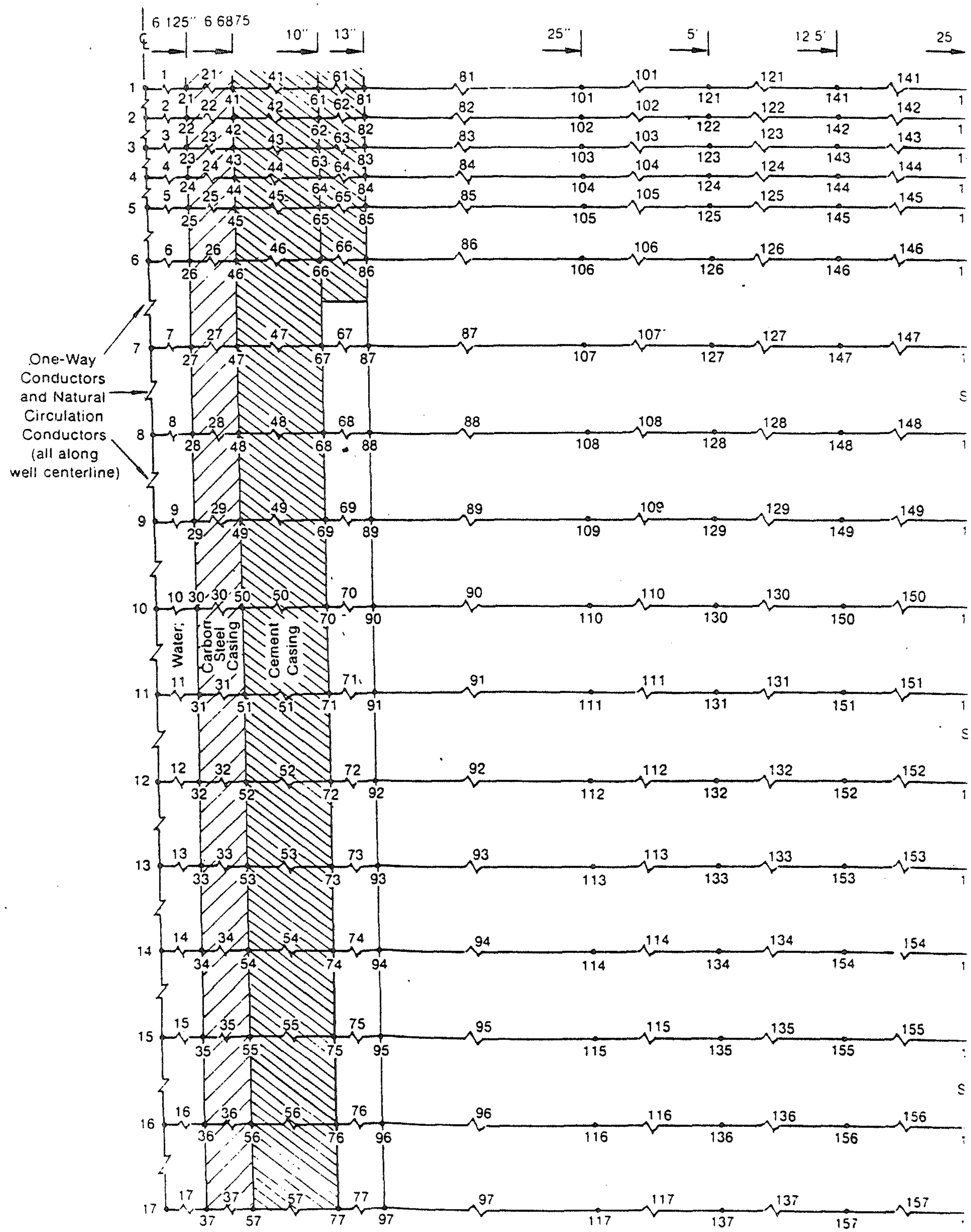


FIGURE 4 - Common Fi

TABLE III

Water Properties

Temperature (^oF)	k ($BTU/hr\text{-}ft\text{-}^oF$)	ρ (lbm/ft^3)	Pr	$\frac{g\beta\rho^2}{\mu^2}$ ($1/^oF\text{-}ft^3$)	μ ($lbm/ft\text{-}hr$)
40	0.325	62.40	11.60	2.3×10^6	3.74
50	0.332	62.40	9.55	8.0×10^6	3.17
60	0.340	62.30	8.03	18.4×10^6	2.74
70	0.347	62.30	6.82	34.6×10^6	2.37
80	0.353	62.20	5.89	56.0×10^6	2.08
90	0.359	62.10	5.13	85.0×10^6	1.85
100	0.364	62.00	4.52	118.0×10^6	1.65
150	0.384	61.20	2.74	440.0×10^6	1.05
200	0.394	60.10	1.88	1.11×10^9	0.74
250	0.396	58.80	1.45	2.14×10^9	0.57
300	0.395	57.30	1.18	4.00×10^9	0.45
350	0.391	55.60	1.02	6.24×10^9	0.38

ρ = Density

μ = Viscosity

C_p = Specific Heat

Equation (9) was chosen from the many available expressions for the heat transfer coefficient because of the desirable characteristic that all properties are evaluated at the bulk fluid temperature. It is based on turbulent flow for various liquids having Prandtl numbers between 0.7 and 120 in tubes for which L/D >60.

One feature of SINDA-3G that lends itself to the application of the well heat transfer models is the one way conductor. These conductors, representing thermal convection resistance in fluid transport, allow a node downstream to be affected only by the upstream node and not by a node further downstream from it. This is particularly useful here for the nodes along the axis of the well, with these one-way conductors used between water nodes and set one way for injection (downflow) studies and reversed when production (upflow) is used.

Natural circulation between the axial water nodes in the well was incorporated to investigate the well temperature distribution during shut-in (no flow). Well temperature recovery after cold water injection or well cooldown following production could be found by including the natural convection conductors along the water nodes. The natural convection heat transfer coefficient used for this was calculated with a modified version of an expression for air in an enclosed space since Nu (Nusselt Number = hL/K) vs GrPr for gases and liquids is well correlated over a wide range of Grashof numbers from 10^{-5} to 10^{7}.[20] This modified version is given in the following equation:[20]

$$\frac{hL}{k} = 0.0481(Gr_b Pr)^{0.37} \tag{10}$$

where $$Gr_b = \frac{g\beta\rho^2 \Delta T L^3}{\mu^2}$$, Properties Evaluated at Bulk Fluid Temperature

h = Total Heat Transfer Coefficient

L = Characteristic Length (distance between nodes)

g = Acceleration of Gravity

β = Compressibility of Water

ΔT = Temperature Difference, and

the remaining variables are as defined in Equation (9). Natural circulation "cells" were set up between nodes with cell height equal to the distance between the adjacent nodes. This convection cell spacing resulted in model predicted shut-in temperature distributions that compared favorably with the data.

In addition to calculating the temperature response in each well, the pressure drop through the well was calculated by incorporating several hydraulic equations into SINDA-3G. Knowing the pressure drop in the well was extremely important for "open" (artesian) flow rate studies. When constant flow rates were used, however, pressure losses were incidental but calculated for reference purposes.

The total pressure drop through a well is a combination of friction, static head, and a term that describes the pressure loss for fluid flowing radially in a porous media toward the well. This last pressure term is incorporated to account for the pressure loss from a distant point from the well where the pressure is known, to the well itself. Since the closest known pressure to any well node is 1400 ft. away (1400 ft. node spacing in reservoir model), the pressure drop from this point to the well must be included.

The frictional losses were combined with the form losses and included in the well model by means of the Darcy-Weisbach Equation[21] as follows;

$$\Delta P_f = (f \frac{L}{D} + k) \frac{\rho V^2}{2g_c} \qquad (11)$$

where ΔP_f = Pressure Drop Due to Friction and Form Losses

f = Darcy-Weisbach Friction Factor

k = Irreversible Form Loss Coefficient

L = Well Length

D = Well Diameter

ρ = Density

V = Fluid Velocity

g_c = Universal Gravitational Constant

with f given by an empirical function for transition flow in commercial pipes[31]:

$$\sqrt{f} = \frac{-1.1513}{\ln\,(.2703(\varepsilon/D) + (2.51/Re\sqrt{f}))} \qquad (12)$$

where ε/D = Relative roughness, and Re as defined in Equation (9).

A form loss k representing pipe casing connections and an entrance contraction at the bottom of the well was used in Equation (11). The ε in Equation (12) had a value corresponding to commercial steel pipe (.00015 ft.) for the well casing and a value of .083 ft. for the soil at the well base. Equations (11) and (12) were applied to the subregions next to each node so that the temperature dependent density could be accounted for by using the node temperature, and the well diameter and roughness changes near the bottom of the well could be included. Note that Equation (12) requires an implicit solution scheme.

The static head pressure drop was obtained by multiplying the temperature dependent density at each node by the length between nodes and adding the results to get the total. The pressure loss through the porous media was found using the following equation:[3]

$$\Delta P_p = \frac{\mu Q \ln(r_e/r_w)}{2\pi k H} \tag{13}$$

where ΔP_p = Pressure Drop Through Porous Media

μ = Viscosity

Q = Flow Rate

r_e = Distance From Effective Well Radius To Distant Point Where Pressure Is Known

r_w = Effective Well Radius

k = Permeability

H = Reservoir Thickness

A total well pressure drop was calculated by summing the individual pressure drops;

$$\Delta P_{total} = \Delta P_f + \Delta P_s + \Delta P_p \tag{14}$$

where ΔP_s = static head pressure drop. The pressure loss due to momentum change was not included in the model since calculations showed it to be extremely small.

Boundary temperatures at the outer edge of each well model (Nodes 281-297 in Figure 4) were obtained from a combination of USGS data[23] and cold shut-in temperature distributions from RRGE #1 and RRGE #2. They represent the undisturbed soil temperatures at depth far removed from the wells (in this case 1000 ft.) and are given in Table IV as the well data. The only other boundary condition necessary for the wells is the atmospheric well head pressure of 12.5 psia.

TABLE IV

RRGE #2 Shut-In (No-Flow) Well Temperature Distribution-Data vs Model

Depth (ft)	RRGE #2 Well Data (°F)	RRGE #2 Well Model Results (°F)
50	55	55.2
150	70	69.6
250	87	85.9
350	101	100.5
450	116	120.8
750	153	153.5
1250	198	196.7
1750	225	224.6
2250	242	241.9
2750	254	253.6
3250	264	263.4
3750	271	270.7
4250	277	276.7
4750	281	280.7
5250	282	282.0
5750	284	283.8
6250	294	293.9

When the transient temperature response of any of the three modeled wells is desired for a particular flow rate, only the well number and flow rate are used as input variables to SINDA-3G. The code then calculates all the heat transfer coefficients and friction factors, and the resulting temperatures and pressure drops are calculated for each time step in the transient. The hydraulics calculations can be solved directly from the input flow rate (converted to velocity for the calculations) since the flow is constant. Artesian flow rates are not so easily handled because the flow rate must be determined from the existing reservoir pressure and the resulting pressure losses in the well. This requires interaction between the reservoir model and well model as discussed in Section 3.4.

The effective well radius defined in Equation (13) is not always the radius of the well casing or radius of the well hole at the bottom. It represents the well radius at the well's production zone and is usually greater than the physical radius due to fracturing or increased permeability that has resulted during drilling. A value was found for this parameter by experimenting with several numbers until the computer code predictions matched the test data, the result being r_w = 2 ft. This is not an uncommon value for wells[18].

3.4 Reservoir-Well Interaction

As described in Sections 3.2 and 3.3, the results of a constant flow rate input, whether injection (source) or production (sink), are that both models operate simultaneously within SINDA-3G and produce well temperature behavior and reservoir pressure behavior independently. When artesian flow rates are desired, however, interaction of the two models must occur to obtain a solution. Artesian flow is driven by the net pressure difference between the reservoir and the well head when the flow valves at the well head are completely open. The resulting flow rate is dependent on the reservoir pressure at the bottom of the well and the total pressure losses through the well. Since well pressure loss is dependent on flow rate, and flow rate is in turn dependent on well pressure loss, an iterative solution is used. Reservoir pressure information and well pressure loss information are needed together to converge on an artesian flow solution.

The initial procedure in finding the artesian flow rate for the current time step is to average the current reservoir pressure around the well, obtained from the reservoir model, and subtract the well head pressure (well model) from this average to obtain a total pressure drop, ΔP_{total}. The next step is to calculate the static head, the friction pressure loss employing the flow rate from the previous iteration (this would be zero on the first iteration per time step), and the term $\frac{\mu \ln(r_e/r_w)}{2\pi kH}$, which is the right hand side of Equation (13) without the flow rate. Then, the sum of the friction loss and static head is subtracted from ΔP_{total}, and this result, divided by $\frac{\mu \ln(r_e/r_w)}{2\pi kH}$, gives a new flow rate Q. If this new flow rate is not within 1% of the flow rate calculated in the previous iteration, then the two flow rates are averaged and the result is used for another iteration. When the flows agree within 1%, the new flow rate Q is used as the flow over the entire time step as the input flow to the well model and the reservoir model. Figure 5 is a flow chart of these steps.

3.5 Model Verification

Verification of the Raft River reservoir pressure and well heat transfer models was made by comparing the computer results with actual test data (see Appendix A for testing procedures). In some instances the computer model input properties were modified, based on early data, and

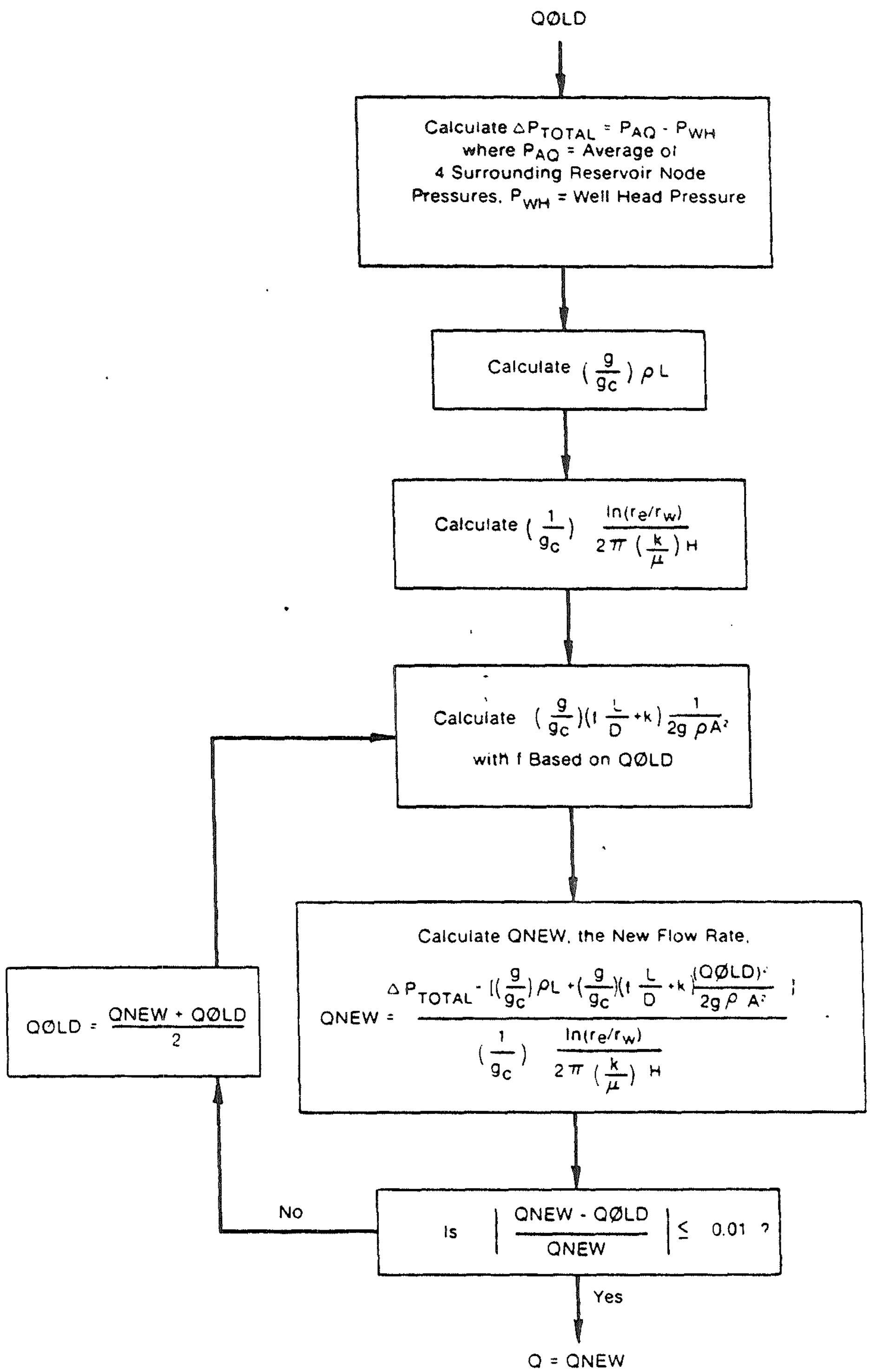


FIGURE 5 - Artesian Flow Rate Calculation Flow Chart

then left untouched for future predictions. In all cases these property changes were made so that the model results would match the early data and, in effect, fine tune the model to account for a recognized reservoir phenomenon not previously incorporated into the node-conductor scheme. This phenomenon will be discussed later. All test data used to verify the model had been taken continuously for a period of three or more days since shorter term test data was often fragmented with periods of flow, then no flow, then flow again, etc. The SINDA-3G models developed here were never intended to predict short transients but were designed for predictions on a long term scale.

Figure 6 shows the drawdown (actual water level decline around the well) in RRGE #1, with flow at RRGE #2, during an actual flow test and compares it with the SINDA-3G reservoir model result. Figure 7 gives the actual RRGE #2 flow rate used for the test and the reservoir model flow rate. This test was run to determine the level of communication between RRGE #1 and RRGE #2.

During the same flow test the drawdown in the flowing well, RRGE #2, was monitored, and the test results and model results appear in Figure 8. Again the test and model flow rates are given in Figure 7. To achieve this good drawdown match, the permeability and porosity values around the flowing well in the reservoir model were modified by changing the conductor values immediately adjacent to the well node and the volume capacity at the node itself. In both cases the values were decreased but represent an accepted well-reservoir occurrence. The permeability and porosity decrease are due to positive skin effect, a marked flow restriction around many wells.[25,26] More specifically, skin effect should be thought of as the result of formation damage adjacent to the wellbore.

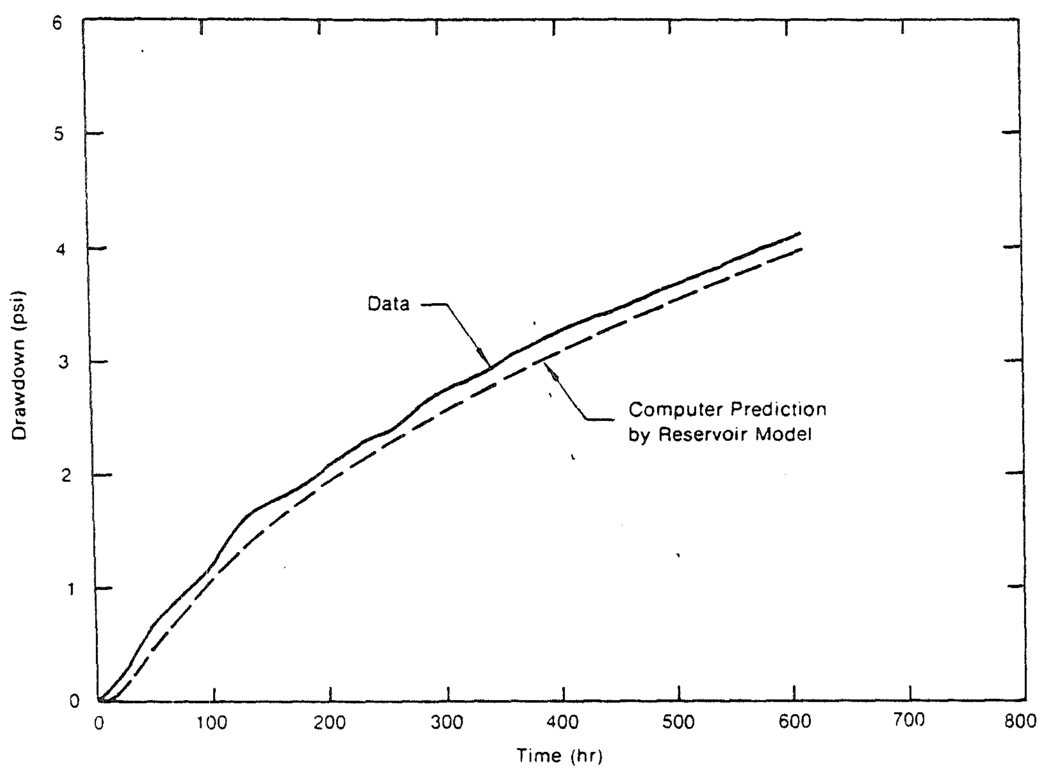


FIGURE 6 - RRGE #1 Drawdown for RRGE #2 Flows Given in Figure 7

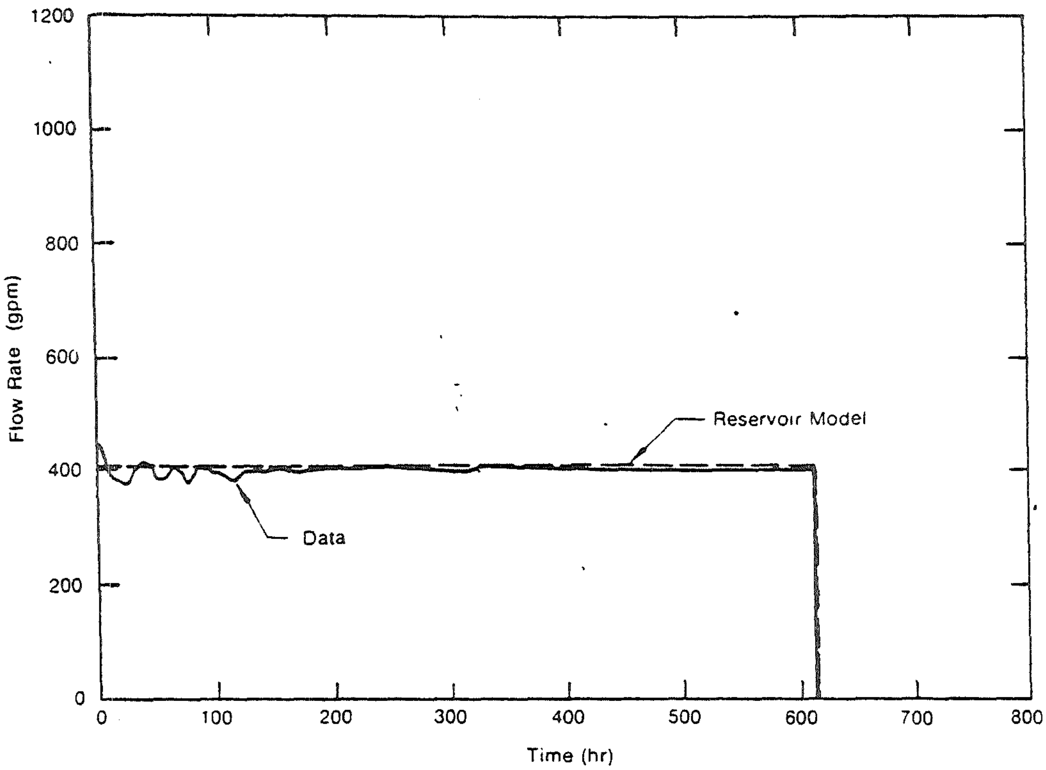


FIGURE 7 - RRGE #2 Flow Rate for September-October, 1975 Test and Flow Rate Used in Reservoir Model

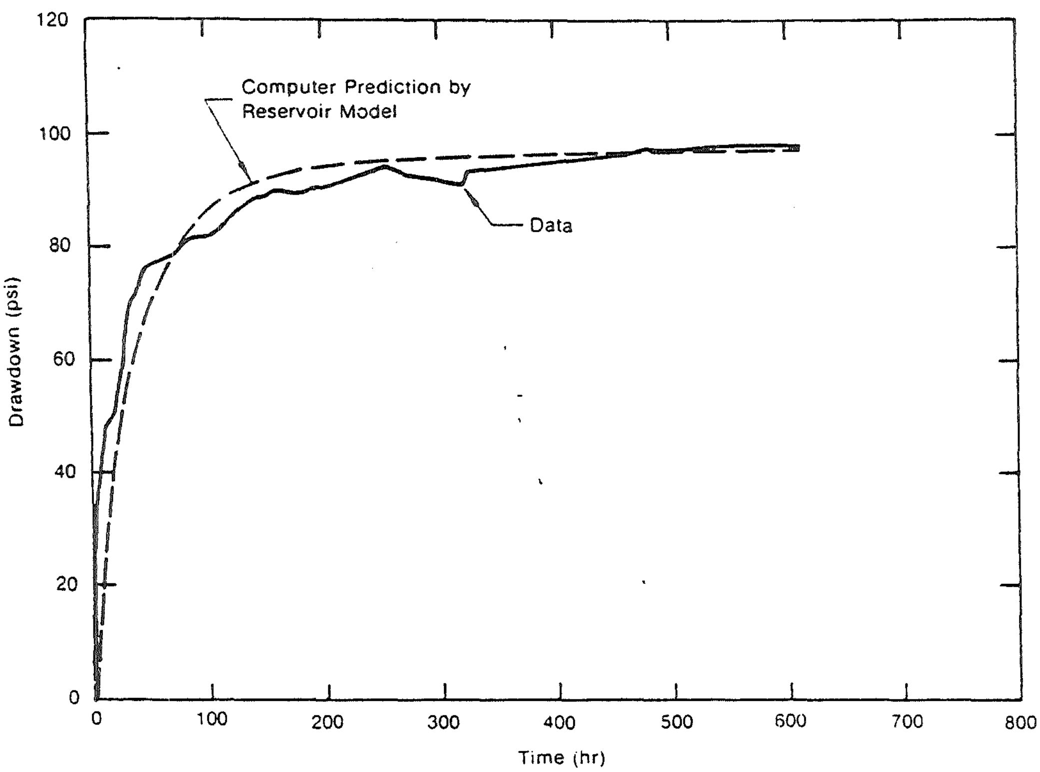


FIGURE 8 - RRGE #2 Drawdown for RRGE #2 Flows Given in Figure 7

Figure 9 shows the data from a pump flow test at RRGE #1, with the drawdown measured at RRGE #1, and the reservoir model comparison. The actual test flow rate and the flow rate used for the reservoir model are presented in Figure 10. For this case the conductors in the model adjacent to the RRGE #1 node and the node volume had to also be decreased to achieve the good match. The justification for doing this is as previously discussed.

The property changes to the reservoir model in and around the well placement nodes were made so that model results would match the test data for each well individually, but were permanently included in the total reservoir model as local irregularities in an otherwise homogeneous reservoir for all future calculations. Their presence in the model does not effect the results of other model predictions as confirmed by Figures 6, 8, and 9. These model results were obtained with the property changes around the two well nodes already incorporated.

Figure 11 gives the results of a well model temperature response at a constant flow rate from an initially undisturbed well. No test results are available for this type of transient since the constant monitoring of the wells and the ongoing lab experiments of the geothermal fluid produce a continuous flow of approximately 10 gpm through the wells and keep the wells relatively hot all the time. However, the transient shown in Figure 11 appears reasonable, and the fact that the steady-state temperature of the water exiting the well in the model equals the actual steady-state well head water temperature adds credibility to the well heat transfer model. Further verification is obtained by comparing the shut-in well temperature distribution data with the computer well model prediction, as given in Table IV. The test data in this case was taken during the rare instance of a steady-state undisturbed well.

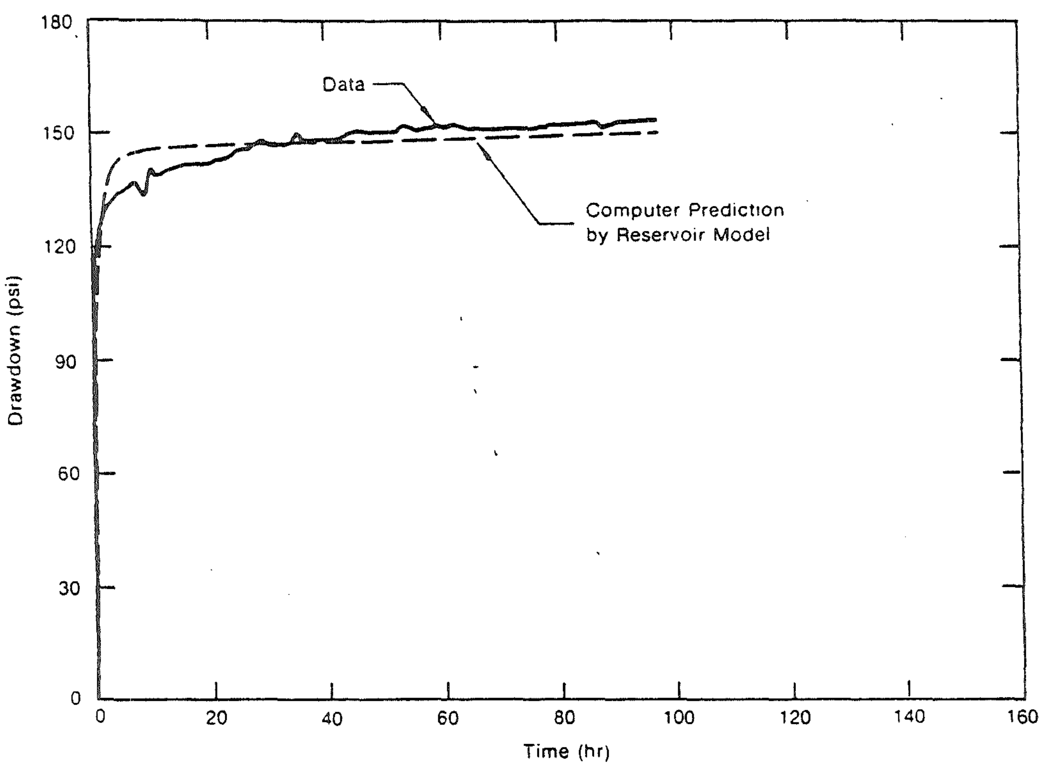


FIGURE 9 - RRGE #1 Drawdown for RRGE #1 Flows Given in Figure 10

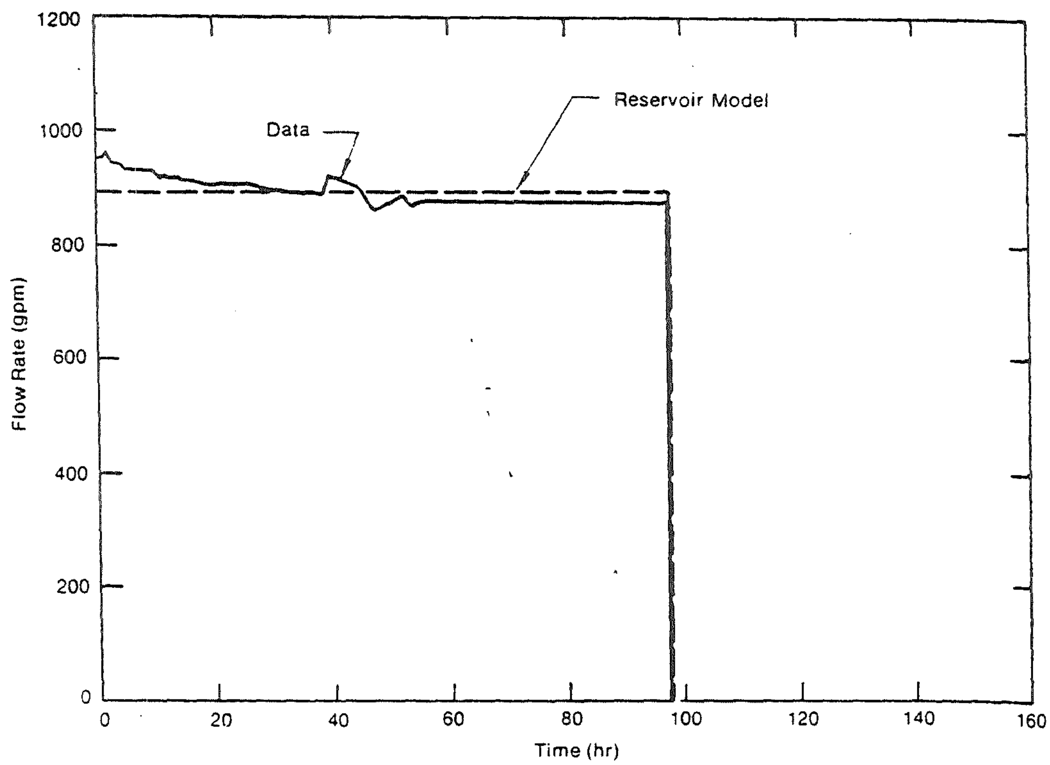


FIGURE 10 - RRGE #1 Flow Rate for February, 1976 Pump Test and Flow Rate Used in Reservoir Model

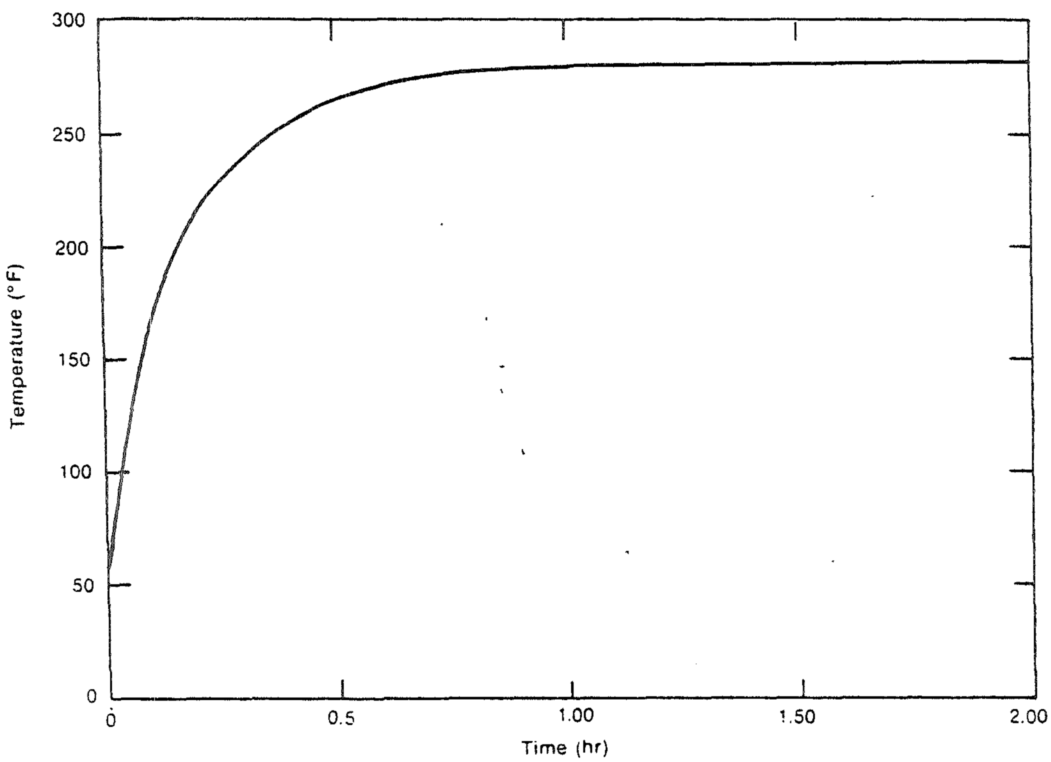


FIGURE 11 - Well Model Predicted Well Head Temperature at RRGE #1
Using a 900 GPM Constant Flow Rate

Artesian flow rate transients, as predicted by the computer reservoir and well models, appear in Figures 12 and 13 for RRGE #1 and RRGE #2, respectively. Again, no good test data is available for comparison since initial flows at the wells often result in flashing at the well head orifice used to determine the flow rate. The computer predictions, however, exhibit the expected early rise in the artesian flow rate as the water temperature in the well increases, and the logical flow rate decrease as the reservoir pressure declines due to flow. The flow then steadies as the reservoir pressure reaches a pseudo-equilibrium and the water temperature in the well is very nearly constant. The artesian flow rate predicted by the model after about 1 hour equals the observed artesian flow rate from the wells in the absence of flashing.

At this point predictions from the computer models developed match all meaningful well data, and it can be assumed that long term predictions made using the model will be accurate. However, the lack of complete definition of reservoir boundary conditions, due in most part to the lack of knowledge concerning underground fault locations and recharge zones, make reservoir pressure response predictions uncertain for transients lasting greater than approximately one year. The longer transients can be greatly effected by these boundary values. Test data is taken on a continuing basis, and this data should, in the near future, give clues as to the nature and extent of the physical boundaries. Incorporation of such information in the model will make longer predictions more credible.

Presently, test data from RRGE #3 is incomplete and comparison with the models has not yet begun. When sufficient data is gathered, the results will be incorporated into the models.

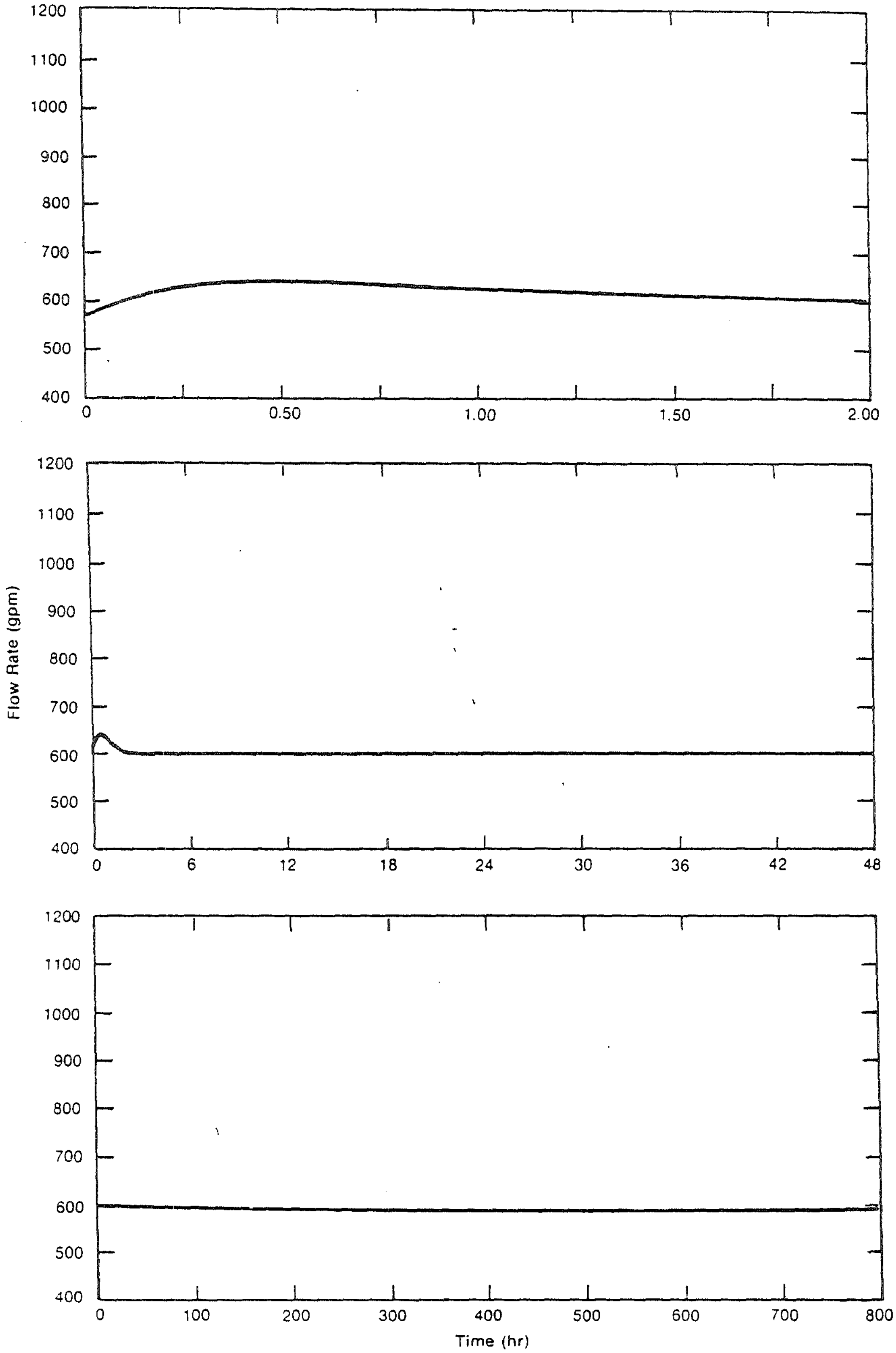


FIGURE 12 - Well-Reservoir Models Predicted Artesian Flow Rate at RRGE #1

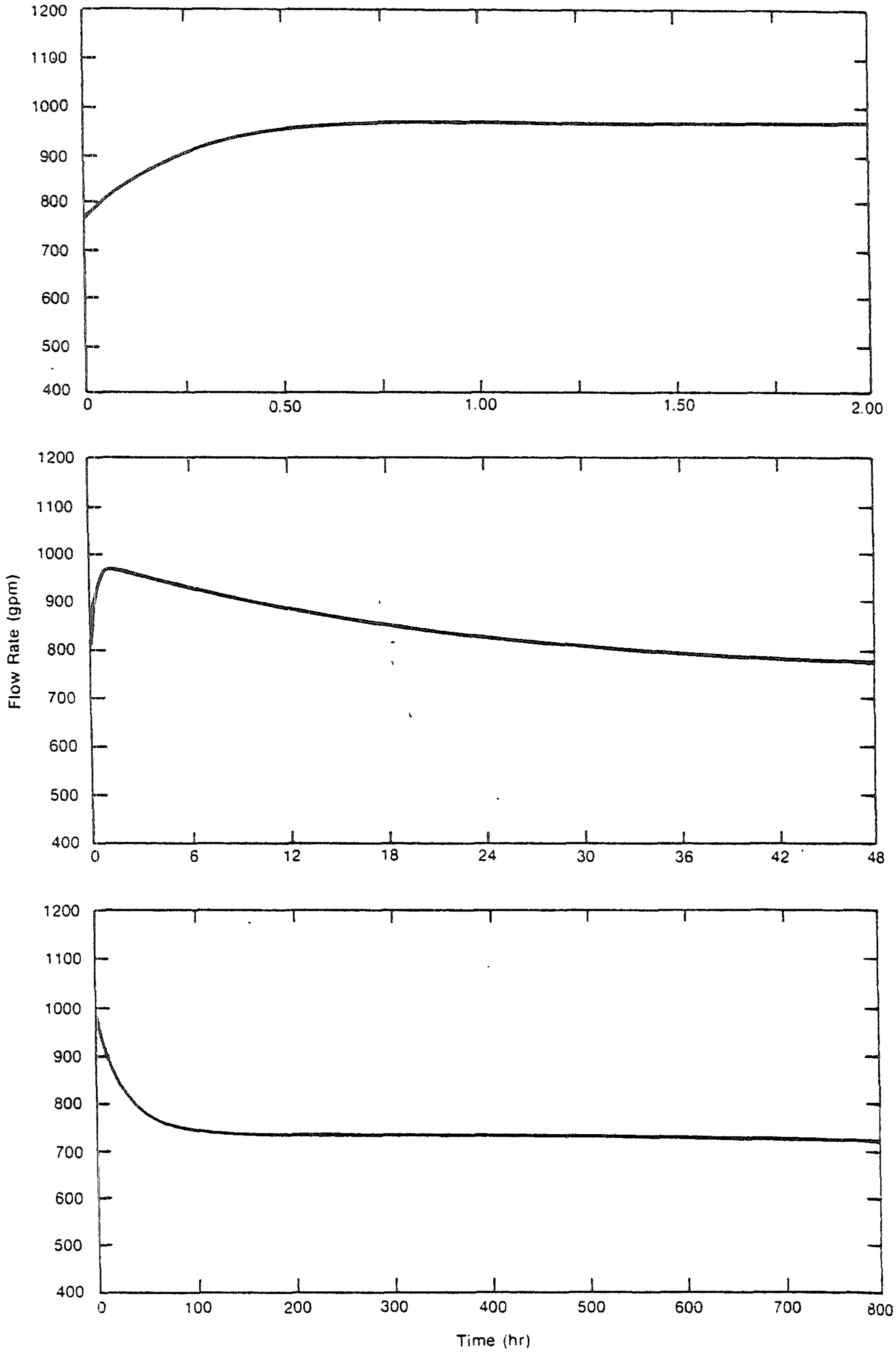


FIGURE 13 - Well-Reservoir Models Predicted Artesian Flow Rate at RRGE #2

4.0 DISCUSSION

The comparison of test data from two wells at Raft River with the results from the computer models of the wells and reservoir is acceptable, as seen in Section 3.5. Property modification in the vicinity of the wells in the reservoir model not only accounts for the good match but further enhances the model performance by including the effect of a physical phenomena that would otherwise not have been included.

Although the current models include the effects of two wells only, the RRGE #3 well model is now being incorporated on SINDA-3G, and data is becoming available for use in further extending the reservoir model. As new wells are drilled, they will also be modeled on SINDA-3G. Their physical location on the reservoir model is limited only by the total number of nodes represented in the reservoir. This limitation could be nullified by increasing the node-conductor reservoir network.

The coarseness of the reservoir model (1400 ft. node spacing) does not affect the model accuracy; only the resolution suffers. A node-conductor model of the reservoir set up with a 50 ft. node spacing to verify this showed no decrease in accuracy. Should better resolution be needed by the positioning of wells at an interval less than 1400 ft., the reservoir model could be changed easily to accomplish the new well spacing. Totally random well positioning could also be handled since SINDA-3G is not restricted to an even array of nodes. The current reservoir model was constructed on a regular node pattern merely to simplify input.

The reservoir node-conductor network was set up with four conductors attached to each node. This in effect allows a particular node to interact with only four adjacent nodes directly. However, because of homogeneity of the actual reservoir, a more intimate node relationship is unnecessary.

Temperature variations between the three existing wells are so slight that the reservoir is considered isothermal. Over the past one and one-half years there have been no temperature changes at the bottom of RRGE #1 and RRGE #2 which could have resulted from cooler recharge water (from run-off, streams, etc.) mixing with the hot reservoir. For these reasons, no heat transfer was incoporated into the reservoir model. At this time, the only foreseeable reservoir temperature changes are those resulting from cold water injection as "used" geothermal water is returned to the reservoir. Its effect on production well temperature should not be felt for many years based on the current conditions and properties at Raft River. A discussion of injection well-production well interaction is given in Appendix D.

A SINDA-3G program listing of the combined reservoir model and well models appears in Appendix B. The user's manual describing model input needed to run the program is contained in Appendix C.

5.0 CONCLUSIONS AND FUTURE WORK

SINDA-3G has proven to be an extremely flexible tool for describing the total response of a single phase geothermal reservoir. It was successfully used for describing the temperature response of the Raft River wells in addition to calculating the reservoir pressure behavior. However, extended long term predictions of the Raft River reservoir, using the computer models, hinges on describing the boundaries. Plans are currently being made to run a series of long term flow tests which would demarcate flow barriers encountered over the flow period. Recharge boundaries are more difficult to determine and may be only estimated from geological data and run-off figures. Studies to determine this are not presently being done but are under consideration for future work.

New wells are being planned at Raft River, especially wells for reinjection, and will be added to the computer models as they are drilled. Codes specifically designed for prediction of injection well-production well communication of the relatively cool water from the injection wells to production wells are to be obtained from the University of California at Berkeley (Lawrence Berkeley Laboratory) in the near future to complement the current reservoir model.

Generally, the long term performance of a geothermal reservoir is not predicted prior to exploitation for energy uses. However, the current Raft River reservoir and well models show great promise in changing this trend and thereby producing valuable information for future energy decisions for this geothermal resource.

REFERENCES

1. Gaski, J. D., and D. R. Lewis, Chrysler Improved Numerical Differential Analyzer, Computer Program Number C-00045, Chrysler Corporation Space Division Technical Note TN-AP-66-15, April 1966.

2. De Wiest, R. J. M., Flow Through Porous Media, Academic Press Inc., 1969.

3. Muskat, M., The Flow of Homogeneous Fluids Through Porous Media, 1st edition, McGraw-Hill, 1937.

4. Pinder, G. F., and J. D. Bredehoeft, "Application of the Digital Computer for Aquifer Evaluation", in Water Resources Research, Vol. 4, No. 5, October 1968.

5. Goldman, D., "Application of a Mathematical Ground-Water Modeling Technique", M. S. Thesis, The University of Idaho, 1974.

6. Katz, M. L., "Fluid Flow and Heat Transfer in Stratified Systems", Ph.D. Dissertation, The University of Michigan, 1960.

7. Mercer, J. W., Jr., "Finite Element Approach to the Modeling of Hydrothermal Systems", Ph.D. Dissertation, The University of Illinois at Urbana-Champaign, 1973.

8. Witherspoon, P. A., I. Javandel, and S. P. Neuman, "Use of the Finite Element Method in Solving Transient Flow Problems in Aquifer Systems", in The Use of Analog and Digital Computer's in Hydrology, IASH Publication, Vol. 2, No. 81, 1968.

9. Javandel, I., and P. A. Witherspoon, "Application of the Finite Element Method to Transient Flow in Porous Media", in Society of Petroleum Engineers of AIME Journal, 8 (3), September 1968.

10. Donaldson, I. G., "The Simulation of Geothermal Systems with a Simple Convective Model", in Geothermics, Special Issue 2, 1970.

11. Sorey, M. L., "Numerical Modeling of Liquid Geothermal Systems", Ph.D. Dissertation, The University of California at Berkeley, 1975.

12. Mercer, J. W., Jr., and C. Faust, "Geothermal Reservoir Simulation", presented at the Conference on Research for the Development of Geothermal Energy Resources, Pasadena, California, September 1974.

13. Lasseter, T. J., "The Numerical Simulation of Heat and Mass Transfer in Multi-Dimensional Two-Phase Geothermal Reservoirs", A.S.M.E. paper 75-WA/HT-71.

14. Witherspoon, P. A., S. P. Neuman, M. L. Sorey, and M. J. Lippmann, "Modeling Geothermal Systems", Lawrence Berkeley Laboratory paper LBL-3263.

15. Wooding, R. A., "Methods of Solution of the Equations for Convection in Porous Media, with Geothermal Applications", presented at the workshop on Geothermal Reservoir Engineering, Stanford University, December 1975.

16. Narasimhan, T. N., and P. A. Witherspoon, "An Intergrated Finite Difference Method for Analyzing Fluid Flow in Porous Media", Lawrence Berkeley Laboratory paper LBL-3258.

17. Toronyi, R., "Two-Phase, Two-Dimensional Simulation of a Geothermal Reservoir and the Wellbore System", Ph.D. Dissertation, The Pennsylvania State University, 1974.

18. Narasimhan, T. N.*, personal communication, November 11, 1975.

19. McAdams, W. H., Heat Transmission, 3rd edition, McGraw Hill, 1954.

20. Kreith, F., Principles of Heat Transfer, 2nd edition, International Textbook Co., 1965.

21. Streeter, V. L., Fluid Mechanics, 5th edition, McGraw-Hill, 1971.

22. Binder, R. C., Fluid Mechanics, Prentice-Hall, Inc., 1952.

23. Crosthwaite, E. G., "Preliminary Data for Thirty-Four Auger Holes in the Raft River Valley, February 13 - March 8, 1974", United States Geological Survey Open File Data Release, May 10, 1974.

24. Witherspoon, P. A.*, personal communication.

25. Wattenbarger, R. A., and H. J. Ramey, Jr., "An Investigation of Wellbore Storage and Skin Effect in Unsteady Liquid Flow: II. Finite Difference Treatment", in the Society of Petroleum Engineers of AIME Journal, 10(3), September 1970.

26. Ramey, H. J., Jr., "Short-Time Well Test Data Interpretation in the Presence of Skin Effect and Wellbore Storage", in the Journal of Petroleum Technology, 22(1), January 1970.

27. Lauwerier, H. A., "The Transport of Heat in an Oil Layer Caused by the Injection of Hot Fluid", in Applied Scientific Research, Section A, Volume 5, Number 2-3, 1955.

28. "System Specification and Description for the Raft River Thermal Loop Facility", EG&G company report to be published.

29. Bodvarsson, G., "Thermal Problems in the Siting of Reinjection Wells", in Geothermics, Vol. 1, No. 2, 1972.

---

*Currently associated with the University of California at Berkeley and working with the Energy Research and Development Administration through the Lawrence Berkeley Laboratory on various Raft River reservoir engineering studies.

APPENDIX A

Raft River Test Procedures

Almost all tests run at Raft River for the purpose of data acquisition are performed in a different manner with no firm procedures used. This appendix, then, will explain briefly the general guidelines used for testing and the recording of data.

Figure 14 is a schematic of a typical well head piping tree for the Raft River wells. A 3-3/8 in. orifice plate is used to create a pressure drop, measured with a differential pressure gauge, from which the liquid flow rate is calculated. When flashing occurs at the orifice, flow rates cannot be found since calibration of the orifice was based on liquid flow. Flow rate data is taken by hand with flow rates determined from the pressure differential reading using an equation relating flow to pressure drop.

Early well head pressure measurements were made by a Bourdon gauge placed on a nonflow leg of the tree. Data was taken by hand, reading the well head pressure (pressure above atmospheric, psig) directly. At present this pressure is measured by a Paroscientific Digiquartz pressure transducer connected to a constant monitoring Paroscientific digital display.

Pressures in the well are obtained from a Hewlett-Packard Quartz Crystal pressure transducer hooked by cable to a Gearhard-Owens digital readout terminal above ground. This allows constant monitoring while saving the data on strip chart recorders and printed tape. Temperatures are also recorded with a thermocouple attachment on the quartz crystal.

For a typical flow test at Raft River, the well head pressures and pressures in the well vs time for both the flowing well and observation well are recorded. In addition, the well head temperature and flow rate at the flowing well are measured continuously for the test duration.

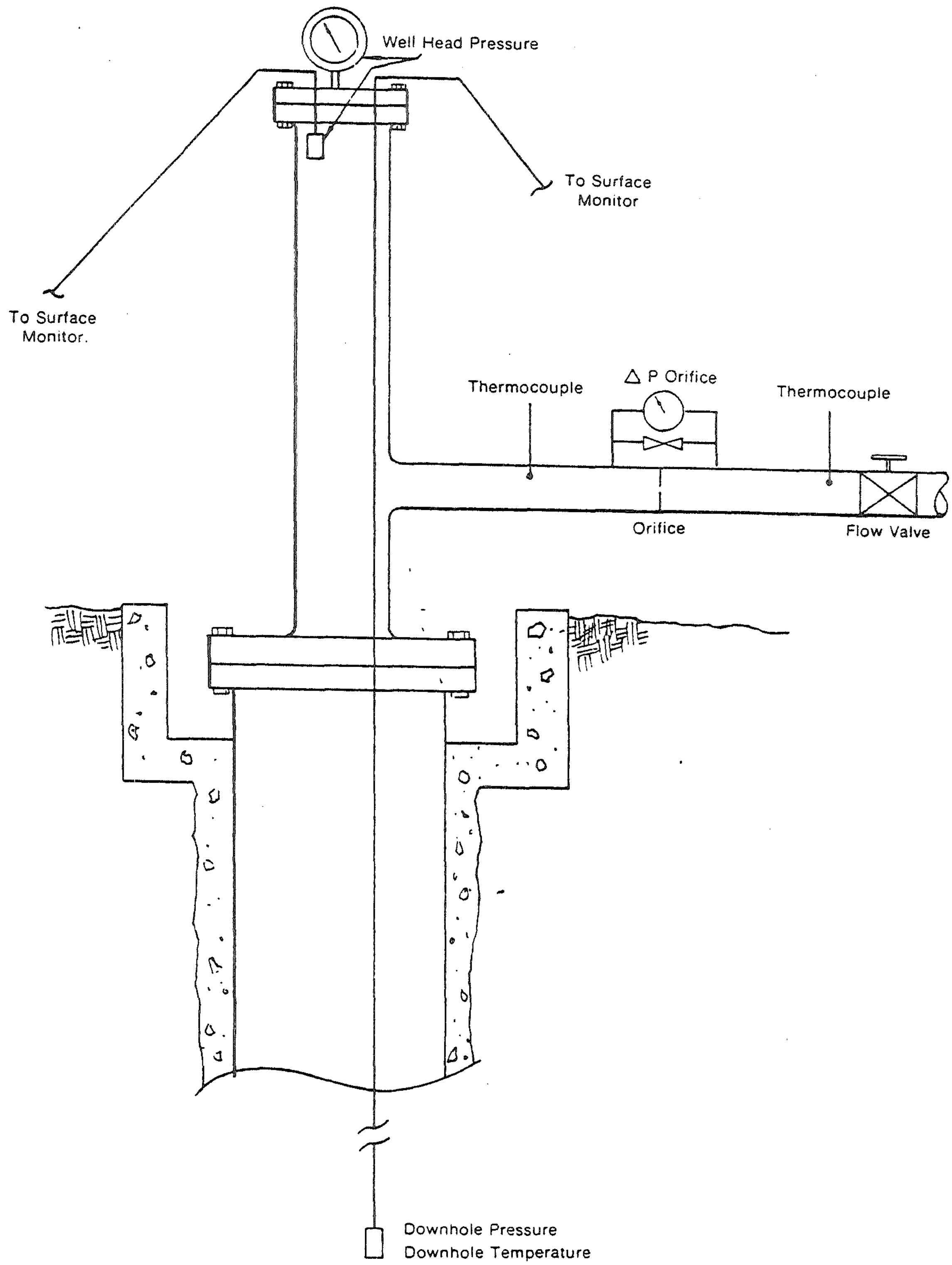


FIGURE 14 - Typical Raft River Geothermal Well Piping Tree and Instrumentation

The flow rate is regulated by a valve, as shown in Figure 14, to any desired flow rate up to the artesian (maximum) flow. Typical examples of test data are explained in Section 3.5 and shown in Figures 6 through 10.

APPENDIX B

Reservoir Model and Well Model
SINDA-3G Program Listing

```
BCD 3THERMAL LPCS
BCD 9 VERTICAL-HORIZONTAL GEOTHERMAL FLOW MODEL
END
BCD 3NODE DATA
REM **** DIFFUSION NODES ****
REM WELL WATER NODES
GEN 01,17,01,300.,1.,1.,1.,1.
REM WELL STEEL CASING NODES
GEN 21,17,01,300.,1.,1.,1.,1.
GEN 41,17,01,300.,1.,1.,1.,1.
REM WELL CONCRETE NODES AT 20 INCHES
GEN 61,17,01,300.,1.,1.,1.,1.
REM WELL CONCRETE NODES AT 26 INCHES
GEN 81,06,01,300.,1.,1.,1.,1.
REM WELL SOIL NODES AT 26 INCHES, BELOW 1000 FT
GEN 87,11,01,300.,1.,1.,1.,1.
REM WELL SOIL NODES AT 50 INCHES
GEN 101,17,01,300.,1.,1.,1.,1.
REM SOIL NODES AT 10 FT (100 FT SPACING)
GEN 121,05,01,300.,2.62E05,1.,1.,1.
REM SOIL NODES AT 10 FT (500 FT SPACING)
GEN 126,12,01,300.,1.31E06,1.,1.,1.
REM SOIL NODES AT 25 FT (100 FT SPACING)
GEN 141,05,01,300.,5.75E06,1.,1.,1.
REM SOIL NODES AT 25 FT (500 FT SPACING)
GEN 146,12,01,300.,2.87E07,1.,1.,1.
REM SOIL NODES AT 50 FT (100 FT SPACING)
GEN 161,05,01,300.,1.03E07,1.,1.,1.
REM SOIL NODES AT 50 FT (500 FT SPACING)
GEN 166,12,01,300.,5.15E07,1.,1.,1.
REM SOIL NODES AT 75 FT (100 FT SPACING)
GEN 181,05,01,300.,1.52E07,1.,1.,1.
REM SOIL NODES AT 75 FT (500 FT SPACING)
GEN 186,12,01,300.,7.61E07,1.,1.,1.
REM SOIL NODES AT 100 FT (100 FT SPACING)
GEN 201,05,01,300.,2.01E07,1.,1.,1.
REM SOIL NODES AT 100 FT (500 FT SPACING)
```

```
GEN 206,12,01,300.,1.01E08,1.,1.,1.
REM SOIL NODES AT 125 FT (100 FT SPACING)
GEN 221,05,01,300.,2.50E07,1.,1.,1.
REM SOIL NODES AT 125 FT (500 FT SPACING)
GEN 226,12,01,300.,1.25E08,1.,1.,1.
REM SOIL NODES AT 150 FT (100 FT SPACING)
GEN 241,05,01,300.,2.99E07,1.,1.,1.
REM SOIL NODES AT 150 FT (500 FT SPACING)
GEN 246,12,01,300.,1.50E08,1.,1.,1.
REM SOIL NODES AT 1000 FT (100 FT SPACING)
GEN 261,05,01,300.,1.56E10,1.,1.,1.
REM SOIL NODES AT 1000 FT (500 FT SPACING)
GEN 266,12,01,300.,7.80E10,1.,1.,1.
REM FIELD NODES (PRESSURES REPLACE TEMPS)-SEE ARRAY 6 FOR PRS.
GEN 2001,280,01,1.,1.,1.,1.,1.
GEN 1001,20,01,316800.,49.583,1.,1.,1.
REM **** BOUNDARY NODES ****
REM WELL SOIL BOUNDARY NODES AT 200 FT DIAMETER
REM SOIL TEMPERATURE AT 50 FT
    -281, 52.,1.
REM SOIL TEMPERATURE AT 150 FT
    -282, 68.,1.
REM SOIL TEMPERATURE AT 250 FT
    -283, 86.,1.
REM SOIL TEMPERATURE AT 350 FT
    -284, 96.,1.
REM SOIL TEMPERATURE AT 450 FT
    -285,105.,1.
REM SOIL TEMPERATURE AT 750 FT
    -286,149.,1.
REM SOIL TEMPERATURE AT 1250 FT
    -287,200.,1.
REM SOIL TEMPERATURE AT 1750 FT
    -288,227.,1.
REM SOIL TEMPERATURE AT 2250 FT
    -289,243.,1.
REM SOIL TEMPERATURE AT 2750 FT
```

```
     -290,254.,1.
 REM SOIL TEMPERATURE AT 3250 FT
     -291,264.,1.
 REM SOIL TEMPERATURE AT 3750 FT
     -292,271.,1.
 REM SOIL TEMPERATURE AT 4250 FT
     -293,277.,1.
 REM SOIL TEMPERATURE AT 4750 FT
     -294,287.,1.
 REM SOIL TEMPERATURE AT 5250 FT
     -295,288.,1.
 REM SOIL TEMPERATURE AT 5750 FT
     -296,290.,1.
 REM SOIL TEMPERATURE AT 6250 FT
     -297,294.,1.
 REM FIELD BOUNDARY CONDITIONS (PRESSURE IN PSFA)
 GEN -1061,44,01,1.,1.,1.,1.,1.
 END
 BCD 3CONDUCTOR DATA
 REM **** CONDUCTORS ****
 REM WELL CONDUCTORS
 REM WATER FILM COEFFICIENTS (WELL)
 GEN 01,17,01,01,01,21,01,1.,1.,1.,1.
 REM STEEL CASING CONDUCTORS (WELL)
 GEN 21,17,01,21,01,41,01,1.,1.,1.,1.
 REM CONCRETE CONDUCTORS, 13.375 IN TO 20 IN (WELL)
 GEN 41,17,01,41,01,61,01,1.,1.,1.,1.
 REM CONCRETE CONDUCTORS, 20 IN TO 26 IN (WELL)
 GEN 61,06,01,61,01,81,01,1.,1.,1.,1.
 REM SOIL CONDUCTORS 20 IN TO 26 IN BELOW 1000 FT (WELL)
 GEN 67,11,01,67,01,87,01,1.,1.,1.,1.
 REM SOIL CONDUCTORS 20 IN TO 50 IN
 GEN 81,17,01,81,01,101,01,1.,1.,1.,1.
 REM SOIL CONDUCTORS 50 IN TO 10 FT
 GEN 101,05,01,101,01,121,01,1076.5,1.,1.,1.
 GEN 106,12,01,106,01,126,01,5382.7,1.,1.,1.
 REM SOIL CONDUCTORS 10 FT TO 25 FT
```

```
GEN 121,05,01,121,01,141,01,1028.6,1.,1.,1.
GEN 126,12,01,126,01,146,01,5142.9,1.,1.,1.
REM SOIL CONDUCTORS 25 FT TO 50 FT
GEN 141,05,01,141,01,161,01,1359.7,1.,1.,1.
GEN 146,12,01,146,01,166,01,6798.5,1.,1.,1.
REM SOIL CONDUCTORS 50 FT TO 75 FT
GEN 161,05,01,161,01,181,01,2324.4,1.,1.,1.
GEN 166,12,01,166,01,186,01,11622.2,1.,1.,1.
REM SOIL CONDUCTORS 75 FT TO 100 FT
GEN 181,05,01,181,01,201,01,3276.1,1.,1.,1.
GEN 186,12,01,186,01,206,01,16380.5,1.,1.,1.
REM SOIL CONDUCTORS 100 FT TO 125 FT
GEN 201,05,01,201,01,221,01,4223.6,1.,1.,1.
GEN 206,12,01,206,01,226,01,21118.2,1.,1.,1.
REM SOIL CONDUCTORS 125 FT TO 150 FT
GEN 221,05,01,221,01,241,01,5169.3,1.,1.,1.
GEN 226,12,01,226,01,246,01,25846.6,1.,1.,1.
REM SOIL CONDUCTORS 150 FT TO 1000 FT
GEN 241,05,01,241,01,261,01,496.80,1.,1.,1.
GEN 246,12,01,246,01,266,01,2484.00,1.,1.,1.
REM SOIL CONDUCTORS 1000 FT TO 2000 FT
GEN 261,05,01,261,01,281,01,1359.7,1.,1.,1.
GEN 266,12,01,266,01,286,01,6798.50,1.,1.,1.
REM AXIAL FLOW CONDUCTORS-UP FLOW (WELL)
    5000,-17,16,1.
    5001,-16,15,1.
    5002,-15,14,1.
    5003,-14,13,1.
    5004,-13,12,1.
    5005,-12,11,1.
    5006,-11,10,1.
    5007,-10,09,1.
    5008,-09,08,1.
    5009,-08,07,1.
    5010,-07,06,1.
    5011,-06,05,1.
    5012,-05,04,1.
```

```
    5013,-04,03,1.
    5014,-03,02,1.
    5015,-02,01,1.
REM AXIAL FLOW CONDUCTORS-DOWN FLOW (WELL)
    6000,-01,02,1.
    6001,-02,03,1.
    6002,-03,04,1.
    6003,-04,05,1.
    6004,-05,06,1.
    6005,-06,07,1.
    6006,-07,08,1.
    6007,-08,09,1.
    6008,-09,10,1.
    6009,-10,11,1.
    6010,-11,12,1.
    6011,-12,13,1.
    6012,-13,14,1.
    6013,-14,15,1.
    6014,-15,16,1.
    6015,-16,17,1.
REM AXIAL FLOW CONDUCTORS-NO FLOW (WELL) -NATURAL CIRCULATION
    7000,01,02,1.
    7001,02,03,1.
    7002,03,04,1.
    7003,04,05,1.
    7004,05,06,1.
    7005,06,07,1.
    7006,07,08,1.
    7007,08,09,1.
    7008,09,10,1.
    7009,10,11,1.
    7010,11,12,1.
    7011,12,13,1.
    7012,13,14,1.
    7013,14,15,1.
    7014,15,16,1.
    7015,16,17,1.
```


REM FIELD CONDUCT...

```
REM FIELD CONDUCTORS
REM HORIZONTAL CONDUCTORS (FIELD)
GEN 2001,19,01,2001,01,2002,01,1.,1.,1.,1.
GEN 2021,19,01,2021,01,2022,01,1.,1.,1.,1.
GEN 2041,19,01,2041,01,2042,01,1.,1.,1.,1.
GEN 2061,19,01,2061,01,2062,01,1.,1.,1.,1.
GEN 2081,19,01,2081,01,2082,01,1.,1.,1.,1.
GEN 2101,19,01,2101,01,2102,01,1.,1.,1.,1.
GEN 2121,19,01,2121,01,2122,01,1.,1.,1.,1.
GEN 2141,19,01,2141,01,2142,01,1.,1.,1.,1.
GEN 2161,19,01,2161,01,2162,01,1.,1.,1.,1.
GEN 2181,19,01,2181,01,2182,01,1.,1.,1.,1.
GEN 2201,19,01,2201,01,2202,01,1.,1.,1.,1.
GEN 2221,19,01,2221,01,2222,01,1.,1.,1.,1.
GEN 2241,19,01,2241,01,2242,01,1.,1.,1.,1.
GEN 2261,19,01,2261,01,2262,01,1.,1.,1.,1.
REM VERTICAL CONDUCTORS (FIELD)
GEN 3001,260,01,2001,01,2021,01,1.,1.,1.,1.
REM BOUNDARY CONDUCTORS (FIELD)
GEN 1001,20,01,1001,01,2001,01,1.,1.,1.,1.
GEN 1061,20,01,1061,01,2261,01,1.,1.,1.,1.
GEN 1081,12,01,1081,01,2040,20,1.,1.,1.,1.
GEN 1093,12,01,1093,01,2021,20,1.,1.,1.,1.
END
BCD 3CONSTANTS DATA
    ARLXCA,.0100,DRLXCA,.0100,NLOOP,5000
    1,2                  $RRGE WELL NUMBER FOR THIS RUN
    2,0.                 $AQUIFER PRESSURE
    3,0.                 $
    4,0.                 $WELL HEAD PRESSURE, PSIA
REM SUPPLY K5 ONLY IF INJECTION OR OUTFLOW IS CONSTANT
REM K5 AND ARRAY 7 MUST BE COMPATIBLE WITH K2001 AND K311
    5,415.               $WELL FLOW RATE(GPM), + FOR OUTFLOW
    6,0.                 $PERM (DARCYS) IN REGION OF WELL
    7,0.                 $LN(RE/RW)/(2*PI*AQUIFER THICKNESS) (1/FT)
    8,0.                 $SHUT-IN PRESSURE, PSFA
    9,9.76262E-03        $CHANGES DARCYS TO (FT**4)/LBF-HR AT 300F
```

```
      10,4                $# GRAPHS TO BE PLOTTED (MAX=2*K2000)
      11,0.               $PLOT COUNTER II = 0.
      12,51               $NUMBER OF POINTS TO BE PLOTTED
      20,.0180            $PERM (DARCYS) IN REGION OF WELL #1
 REM  RE=28.56 FT, RW=2 FT, AQ THICKNESS=500 FT  -  WELL #1
      21,.00084634        $LN(RE/RW)/(2*PI*AQUIFER THICKNESS)  1/FT
      22,1.60             $% STORAGE AT WELL #1
      24,.0129            $PERM (DARCYS) IN REGION OF WELL #2
 REM  RE=28.56 FT, RW=2 FT, AQ THICKNESS=500 FT  -  WELL #2
      25,.00084634        $LN(RE/RW)/(2*PI*AQUIFER THICKNESS)  1/FT
      26,57.40            $% STORAGE AT WELL #2
      28,.0129            $PERM (DARCYS) IN REGION OF WELL #3
 REM  RE=28.56 FT, RW=2 FT, AQ THICKNESS=500 FT  -  WELL #3
      29,.00084634        $LN(RE/RW)/(2*PI*AQUIFER THICKNESS)  1/FT
      30,57.40            $% STORAGE AT WELL #3
      101,0.              $WATER FLOW(LBS/HR)
      105,500.            $AQUIFER THICKNESS (FT)
      106,0.              $
      107,0.              $WELL HEAD TEMP(T1) AT BEGINNING OF VAR 1
      108,0.              $TITLE COUNTER = 0.
      109,0.              $
      110,0.              $TIMEN(NEW TIME)  (SEC)
      111,0.              $GRAVITY HEAD PRESSURE DROP  (PSF)
      116,0.              $FRICTION LOSS PRESSURE DROP  (PSF)
      121,0.              $
      126,0.              $PRESSURE DROP DUE TO PORCUS MEDIA TERM
      127,0.              $K7/K6 AT AVERAGE AQUIFER TEMPERATURE
      134,0.              $TOTAL PRESSURE DROP (PSF)
      135,0.              $
      136,0.              $
      141,0.              $TEMPORARY FLOW STORAGE
      153,0.              $
      156,0.              $
      161,0.              $NEW FLOW RATE
      170,0.              $.5(QOLD+QNEW) - USED FOR 'OPENED UP' FLOW
      171,0.              $PRANDTL NUMBER
 REM  IF INJECTION OCCURS, K180 MUST BE INPUT
```

```
     180,100.          $AVERAGE INJECTION WATER TEMPERATURE
REM  IF OUTFLOW IS EXPECTED, THEN K181 MUST BE INPUT
     181,100.          $AVERAGE OUTFLOW WATER TEMP (INITIAL GUESS)
     182,0.            $
     183,0.            $
     201,0.            $
     300,0.            $
     301,0.            $
     302,0.            $
     303,0.            $
REM  CONSTANTS 311-315 ARE INJECTION OR OUTFLOW NODES IN FIELD
     311,2109          $FIRST FLOW NODE, USUALLY = NODE K2001
     312,0             $SECOND FLOW NODE
     313,0             $THIRD FLOW NODE
     314,0             $FOURTH FLOW NODE
     315,0             $FIFTH FLOW NODE
     1000,0.           $DUMMY
REM  K2000=NUMBER OF NODES WHERE DRAWDOWN DATA IS DESIRED(10 MAX)
REM  K2001-K2010 ARE THE NODES WHERE DRAWDOWN DATA IS DESIRED
     2000,2            $NUMBER OF NODES TO FOLLOW (INTEGER)
     2001,2109         $RRGE#K1
     2002,2067         $
     2003,0            $
     2004,0            $
     2005,0            $
     2006,0            $
     2007,0            $
     2008,0            $
     2009,0            $
     2010,0            $
END
BCD  3ARRAY DATA
     1            $AQUIFER BASE NODES - WORKING ARRAY
     SPACE,7,END
     2            $AQUIFER BASE VISCOSITIES - WORKING ARRAY
     SPACE,7,END
     3            $DARCY TERM AT BASE NODES - WORKING ARRAY
```

```
     SPACE,7,END
     4              $WELL HEAD PRESSURE VS. TIME  (PSIA)
      0.,12.5,1.0E10,12.5,END
     5              $SURROUNDING NODES TO INJECTION OR OUTFLOW NODE
     SPACE,4,END
     6              $INITIAL FIELD PRESSURES(PSIA)-344 VALUES
REM  FIRST 280 VALUES ARE DIFFUSION NODE PRESSURES STARTING WITH
REM  2001-2280, LAST 64 VALUES ARE BOUNDARY NODE VALUES STARTING
REM  WITH 1001-1020,1061-1104
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
```



```
      2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200
```

```
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.,2200.
 2200.,2200.,2200.,2200.,END
7                  $INITIAL FLOW RATES IN FIELD(GPM), - FOR OUTFLOW
REM FLOW RATES START WITH NODE 2001-2280, DIFFUSION NODES ONLY
REM THIS IS THE ONLY PLACE WHERE OUTFLOW IS A NEGATIVE VALUE
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0..
 0.,0.,0.,0.,0.,0.,0.,0.,-415.0,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.
 END
8                  $BASE NODE DENSITIES - WORKING ARRAY
SPACE,7,END
20                 $WATER DENSITY (LBM/FT**3)-KREITH
 40.,62.4,50.,62.4,60.,62.3,70.,62.3,80.,62.2,90.,62.1
 100.,62.0,150.,61.2,200.,60.1,250.,58.8,300.,57.3
 350.,55.6,400.,53.6,END
21                 $WATER VISCOSITY (LBM/FT-HR)-KREITH
 40.,3.74,50.,3.17,60.,2.74,70.,2.37,80.,2.08,90.,1.85
 100.,1.65,150.,1.05,200.,.74,250.,.57,300.,.45,350.,.38
 400.,.33,END
22                 $WATER GRASHOF COEFFICIENT (1/F-FT**3)-KREITH
```

```
     90.,85.E6,100.,118.0E6,150.,440.0F6,200.,1.11E9
     40.,2.3E6,50.,8.0E6,60.,18.4E6,70.,34.6F6,80.,56.0F6
     250.,2.14E9,300.,4.0E9,350.,6.24E9,400.,8.95E9,FND
    23             $WATFR PRANDTL NUMBER-KREITH
     40.,11.6,50.,9.55,60.,8.03,70.,6.82,80.,5.89,90.,5.13
     100.,4.52,150.,2.74,200.,1.88,250.,1.45,300.,1.18
     350.,1.02,400.,.927,END
    24             $WATER CONDUCTIVITY (BTU/HR-FT-F)-KREITH
     40.,.325,50.,.332,60.,.340,70.,.347,80.,.353,90.,.359
     100.,.364,150.,.384,200.,.394,250.,.396,300.,.395
     350.,.391,400.,.381,END
REM ARRAYS 51-56 FOR WELL DATA
REM ARRAY 51 IS RRGE #1 NODAL CAPACITOR DATA (WELL ONLY),(BTU/F)
REM 102 VALUES, DIFFUSION NODES ONLY
    51
     4747.,4747.,4747.,4747.,4747.,23737.,23737.,23737.,23737.
     23737.,23737.,23737.,23737.,23737.,1.0,1.0,1.0
     424.,424.,424.,424.,424.,2119.,2119.,2119.,2119.,2119.
     2119.,2174.,2230.,2230.,1.0,1.0,1.0
     424.,424.,424.,424.,424.,2119.,2119.,2119.,2119.,2119.
     2119.,2224.,2330.,2330.,1.0,1.0,1.0
     5500.,5500.,5500.,5500.,5500.,27498.,34956.,34956.,34956.
     34956.,34956.,41347.,47739.,47739.,1.0,1.0,1.0
     8418.,8418.,8418.,8418.,8418.,42088.,50587.,50587.,50587.
     50587.,50587.,50587.,50587.,50587.,1.0,1.0,1.0
     248164.,248164.,248164.,248164.,248164.,1240820.,1240820.
     1240820.,1240820.,1240820.,1240820.,1240820.,1240820.
     1240820.,1.0,1.0,1.0,END
REM ARRAY 52 IS RRGE #1 CONDUCTOR DATA (WELL ONLY),(BTU/HR-F)
REM  85 VALUES
    52
     1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0
     1.0E8,1.0E8,1.0E8
     214538.,214538.,214538.,214538.,214538.,1072690.,1072690.
     1072690.,1072690.,1072690.,1072690.,543425.,1.0,1.0
     1.0E8,1.CE8,1.0E8
     1093.,1093.,1093.,1093.,1093.,5466.,5466.,5466.,5466.,5466.
```

```
      5466.,8589., 11712., 11712., 1.0E8, 1.0E8, 1.0E8
      1676.,1676.,1676.,1676.,1676.,8380.,17961.,17961.,17961.
      17961.,17961.,17961.,17961.,17961.,1.0E8,1.0E8,1.0E8
      1441.,1441.,1441.,1441.,1441.,7205.,7205.,7205.,7205.,7205.
      7205.,7205.,7205.,7205.,1.0E8,1.0E8,1.0E8
      END
REM ARRAY 53 IS RRGE #2 NODAL CAPACITOR DATA (WELL ONLY),(BTU/F)
REM 102 VALUES, DIFFUSION NODES ONLY
     53
      4747.,4747.,4747.,4747.,4747.,23737.,23737.,23737.,23737.
      23737.,23737.,23737.,23737.,23737.,23737.,23737.,23737.
      424.,424.,424.,424.,424.,2119.,2119.,2119.,2119.,2119.
      2119.,2119.,2174.,2230.,2230.,2230.,2230.
      424.,424.,424.,424.,424.,2119.,2119.,2119.,2119.,2119.
      2119.,2119.,2224.,2330.,2330.,2330.,2330.
      5500.,5500.,5500.,5500.,5500.,27498.,34956.,34956.,34956.
      34956.,34956.,34956.,41347.,47739.,47739.,47739.,47739.
      8418.,8418.,8418.,8418.,8418.,42088.,50587.,50587.
      50587.,50587.,50587.,50587.,50587.,50587.,50587.,50587.
      50587.
      248164.,248164.,248164.,248164.,248164.,1240820.,1240820.
      1240820.,1240820.,1240820.,1240820.,1240820.,1240820.
      1240820.,1240820.,1240820.,1240820.,END
REM ARRAY 54 IS RRGE #2 CONDUCTOR DATA (WELL ONLY),(BTU/HR-F)
REM  85 VALUES
     54
      1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0
      1.0,1.0,1.0
      214538.,214538.,214538.,214538.,214538.,1072690.,1072690.
      1072690.,1072690.,1072690.,1072690.,1072690.,543425.
      1.0,1.0,1.0,1.0
      1093.,1093.,1093.,1093.,1093.,5466.,5466.,5466.,5466.
      5466.,5466.,5466.,8589.,11712.,11712.,11712.,11712.
      1676.,1676.,1676.,1676.,1676.,8380.,17961.,17961.,17961.
      17961.,17961.,17961.,17961.,17961.,17961.,17961.,17961.
      1441.,1441.,1441.,1441.,1441.,7205.,7205.,7205.,7205.
      7205.,7205.,7205.,7205.,7205.,7205.,7205.,7205.
```

```
     END
REM ARRAY 55 IS RRGE #3 NODAL CAPACITOR DATA (WELL ONLY),(BTU/F)
REM 102 VALUES, DIFFUSION NODES ONLY
     55
      5034.,5034.,5034.,5034.,5034.,25171.,12588.,12588.,12588.
      12588.,12588.,12588.,12588.,12588.,12588.,1.0,1.0
      290.,290.,290.,290.,290.,1452.,960.,960.,960.,960.,960.
      960.,890.,890.,890.,1.0,1.0
      290.,290.,290.,290.,290.,1452.,6183.,960.,960.,960.,960.
      960.,890.,890.,890.,1.0,1.0
      5500.,8075.,8075.,8075.,8075.,40376.,43279.,55655.,55655.
      55655.,55655.,55655.,59499.,59499.,59499.,1.0,1.0
      8418.,10117.,10117.,10117.,10117.,50587.,50587.,50587.
      50587.,50587.,50587.,50587.,50587.,50587.,50587.,1.0,1.0
      248164.,248164.,248164.,248164.,248164.,1240820.,1240820.
      1240820.,1240820.,1240820.,1240820.,1240820.,1240820.
      1240820.,1240820.,1.0,1.0,END
REM ARRAY 56 IS RRGE #3 CONDUCTOR DATA (WELL ONLY),(BTU/HR-F)
REM 85  VALUES
     56
      1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0,1.0
      1.0,1.0,1.0
      322211.,322211.,322211.,322211.,322211.,1611054.,1240823.
      1240823.,1240823.,1240823.,1240823.,1240823.,62041.,62041.
      62041.,62041.,62041.
      1636.,1636.,1636.,1636.,1636.,8181.,4067.,8129.,8129.,8129.
      8129.,8129.,17420.,17420.,17420.,17420.,17420.
      1111.,2381.,2381.,2381.,2381.,11903.,11903.,6516.,6516.
      6516.,6516.,6516.,6516.,6516.,6516.,6516.,6516.
      1441.,1441.,1441.,1441.,1441.,7206.,7206.,7206.,7206.,7206.
      7206.,7206.,7206.,7206.,7206.,7206.,7206.,END
REM ARRAY 70 CONTAINS FIELD NODE CAPACITORS(FT**5/LBF)-280 VALUES
REM CAPACITORS START WITH NODE 2001-2280, BOUNDARY NODES NOT INCL
     70
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
```

```
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61,13.61
      END
REM ARRAY 71 CONTAINS FIELD CONDUCTORS (FT**5/LBF-HR), 590 VALUES
REM ALL FLD COND'S INCL, START 2001-2279,3001-3260,1001-1104
REM CONDUCTOR VALUES ARE BASED ON 456 MDARCYS, 1400 FT SPACING
     71
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
      2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
```

2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226

```
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226,2.226
2.226,2.226,2.226,2.226,2.226,2.226
.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373
.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373,.5373
.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113
.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113
.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113
.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113,.1113
.1113,.1113,.1113,.1113,END
REM THE FOLLOWING ARRAYS ARE USED FOR HYDRAULICS CALCULATIONS
90            $TEMPERATURE(F) - WORKING ARRAY
SPACE,17,END
91            $ROUGHNESS (FT) - WORKING ARRAY
SPACE,17,END
92            $LOSS COEFFICIENT-OUTFLOW-INITIAL
.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,.2,END
93            $LENGTH (FT)
100.,100.,100.,100.,100.,500.,500.,500.,500.,500.,500.,500.
500.,500.,500.,500.,500.,END
94            $AREA (FT**2) - WORKING ARRAY
SPACE,17,END
95            $DIAMETER(IN) - WORKING ARRAY
SPACE,17,END
96            $DIA/AREA(1/FT) - WORKING ARRAY
SPACE,17,END
97            $ROUGHNESS/(3.7*DIA) - WORKING ARRAY
SPACE,17,END
98            $(-0.5)/ALOG10(A97) - WORKING ARRAY
SPACE,17,END
99            $L/D  - WORKING ARRAY
```

```
SPACE,17,END
100           $PRESSURE DROP - WORKING ARRAY
SPACE,17,END
101           $DENSITY (LBM/FT**3) - WORKING ARRAY
SPACE,17,END
102           $NATURAL CIRCULATION HEAD (LBS/FT**2) - W'K'G AR
SPACE,17,END
103           $FRICTION COEFFICIENT (F*L/D) - WORKING ARRAY
SPACE,17,END
104           $LOSS COEFFICIENT FOR REVERSE FLOW-INITIAL
 0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,0.,END
105           $2*G*A*A (FT**5/HR**2) - WORKING ARRAY
SPACE,17,END
191           $ROUGHNESS-EPSILON (MICROINCHES) WELL #1
1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.
1800.,1800.,1000000.,1000000.,.0001,.0001,.0001,END
201           $TITLES
RRGE,FND#,TSEC,GPM,FRIC,HEAD,PERM,DPT,AQPR,END
291           $ROUGHNESS-EPSILON (MICROINCHES) WELL #2
1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.
1800.,1800.,1800.,1000000.,1000000.,1000000.,1000000.,END
300           $TITLES
K301,K302,K303,END
391           $ROUGHNESS-EPSILON (MICROINCHES) WELL #3
1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.,1800.
1800.,1800.,1000000.,1000000.,1000000.,.0001,.0001,END
505           $ABSCISSA(TIME) VALUES
 SPACE,800,END
515           $ORDINATE(FLOW RATE) VALUES
 SPACE,800,END
525           $ORDINATE(TEMPERATURE) VALUES
 SPACE,800,END
 535          $ORDINATE(DRAWDOWN) VALUES-NODE K2001
 SPACE,800,END
 536          $ORDINATE(DRAWDOWN) VALUES-NODE K2002
 SPACE,800,END
 537          $ORDINATE(DRAWDOWN) VALUES-NODE K2003
```

```
          SPACE,800,END
          538          $ORDINATE(DRAWDOWN) VALUES-NODE K2004
          SPACE,800,END
          539          $ORDINATE(DRAWDOWN) VALUES-NODE K2005
          SPACE,800,END
          540          $ORDINATE(DRAWDOWN) VALUES-NODE K2006
          SPACE,800,END
          541          $ORDINATE(DRAWDOWN) VALUES-NODE K2007
          SPACE,800,END
          542          $ORDINATE(DRAWDOWN) VALUES-NODE K2008
          SPACE,800,END
          543          $ORDINATE(DRAWDOWN) VALUES-NODE K2009
          SPACE,800,END
          544          $ORDINATE(DRAWDOWN) VALUES-NODE K2010
          SPACE,800,END
          600          $COMMON ORDINATE WORKING ARRAY
          SPACE,800,END
          2000         $CONTAINS NODE NUMBERS K2001-K2010
           SPACE,10,END
          3000         $INITIAL PRESSURES, NODES K2001-K2010
           SPACE,10,END
          5000         $DRAWDOWN, NODES K2001-K2010
           SPACE,10,END
      END
      BCD 3EXECUTION
      REM ********************** EXECUTION **************************
F           DIMENSION X(5000)
F           DIMENSION TITLE(10),XLABEL(10),YLABEL(10),APLOT(500)
F           DIMENSION OPLOT(500),MESAGE(20)
F           NDIM=5000
F           NTH=0
F           CALL ECHO
      REM SET UP WELL ARRAYS AND CONSTANTS FOR HYDRAULIC CALCULATIONS
            STFSEP(K1,ITEST)             $CHECK WELL FOR THIS ANALYSIS
F           GO TO (10,20,30),ITEST
F   10      CONTINUE
            STFSQS(12.25,12,A95+1)       $WELL #1 DIAMETERS TO 4000 FT
```

```
          STFSQS(13.375,5,A95+13)       $WELL #1 DIAMETERS BELOW 4000 FT
          SHFTV(102,A51+1,C1)           $WELL #1 NODE CAPACITANCES
          SHFTV(85, A52+1,G1)           $WELL #1 CONDUCTORS
          STFSEP(0.,G5002,G6013,G7013)$WELL #1 CUT-OFF (NODES 14-15)
          SHFTV(17,A191+1,A91+1)        $WELL #1 ROUGHNESS
          STFSEP(K20,K6)                $PERM IN REGION OF WELL #1
          STFSEP(K21,K7)                $PERM TERM IN REGION OF WELL #1
F         GO TO 100
F    20   CONTINUE
          STFSQS(12.25,13,A95+1)        $WELL #2 DIAMETERS TO 4500 FT
          STFSQS(13.375,4,A95+14)       $WELL #2 DIAMETERS BELOW 4500 FT
          SHFTV(102,A53+1,C1)           $WELL #2 NODE CAPACITANCES
          SHFTV(85, A54+1,G1)           $WELL #2 CONDUCTORS
          SHFTV(17,A291+1,A91+1)        $WELL #2 ROUGHNESS
          STFSEP(K24, K6)               $PERM IN REGION OF WELL #2
          STFSEP(K25, K7)               $PERM TERM IN REGION OF WELL #2
F         GO TO 100
F    30   CONTINUE
          STFSQS(12.615,6,A95+1)        $WELL #3 DIAMETERS TO 1000 FT
          STFSQS(8.921,11,A95+7)        $WELL #3 DIAMETERS BELOW 1000 FT
          SHFTV(102,A55+1,C1)           $WELL #3 NODE CAPACITANCES
          SHFTV(85, A56+1,G1)           $WELL #3 CONDUCTORS
          STFSEP(0.,G5001,G6014,G7014)$WELL #3 CUT-OFF (NODES 15-16)
          SHFTV(17,A391+1,A91+1)        $WELL #3 ROUGHNESS
          STFSEP(K28, K6)               $PERM IN REGION OF WELL #3
          STFSEP(K29, K7)               $PERM TERM IN REGION OF WELL #3
F   100   CONTINUE
          MPYARY(17,A95+1,A95+1,A94+1)$D**2 (IN**2)
          ARYMPY(17,A94+1,3.142,A94+1)$PI*(D**2)
          ARYDIV(17,A94+1, 576.,A94+1)$PI*(D**2)/(4*144)  (FT**2)
          DIVARY(17,A95+1,A94+1,A96+1)$(D)/(PI*(D**2)/(4*144))(IN/SQFT)
          ARYDIV(17,A96+1,  12.,A96+1)$D/A  (1/FT)
          ARYMPY(17,A91+1,1.E-6,A97+1)$EPSILON TO INCHES
          ARYDIV(17,A97+1,  3.7,A97+1)$EPSILON/3.7  (INCHES)
          DIVARY(17,A97+1,A95+1,A97+1)$EPSILON/(D*3.7)-DIMENSIONLESS
          LOGTAR(17,A97+1,A98+1)        $LOG10(EP/(D*3.7))
          ARINDV(17,A98+1, -.5 ,A98+1)$-.5/LOG10(EP/(D*3.7))
```

```
               DIVARY(17,A93+1,A95+1,A99+1)$L/D  (FT/IN)
               ARYMPY(17,A99+1,   12.,A99+1)$L/D -DIMENSIONLESS
               ARYPLS(17,A99+1)             $ALL L/D ARE POSITIVE
               DIVARY(17,A93+1,A94+1,A100+1)$L/A  (1/FT)
               ARYPLS(17,A100+1)            $ALL L/A POSITIVE
               SUMARY(17,A100+1,K121)       $SUMMATION OF L/A
               SCALE(2.3962E-9,K121,K121)   $(L/A)/(32.2*3600**2)  (HR/FT)**2
               MPYARY(17,A94+1,A94+1,A105+1)$(AREA**2)      (FT**4)
               ARYDIV(17,A105+1,1.1981E-9,A105+1)$(A**2)/(1/2G) G(FT/HR**2)
           REM SET INITIAL FLOW CONDUCTORS
               STFSEP(K5,STEST)             $CHECK INITIAL FLOW
F              IF(STEST) 1,2,2
           REM INJECTION WATER CONDUCTOR ASSIGNMENT
F      1       CONTINUE
               DIDEGI(K180,A20,TTEST)       $LOOK-UP DENSITY-INJECTION WATER
               MLTPLY(K5,.1337,60.,TTEST,K101)$GPM TO LBS/HR
               STFSEP(K101,K141,RTEST)      $RTEST,K141 = LBS/HR
               MLTPLY(RTEST,-1.,RTEST)      $RTEST NOW POSITIVE
               ARYMPY(16,G6000,RTEST,G6000)$SET CONDUCTORS = FLOW RATE
               STFSQS(  0.0,16,G5000)       $SET CONDUCTORS = 0.0
F              GO TO 3
           REM OUTFLOW WATER CONDUCTOR ASSIGNMENTS
F      2       CONTINUE
               DIDEGI  (T1,A20,TTEST)       $LOOK-UP DENSITY-OUTFLOW WATER
               MLTPLY(K5,.1337,60.,TTEST,K101)$GPM TO LBS/HR
               STFSEP(K101,K141,RTEST)      $RTEST,K141 = LBS/HR
               ARYMPY(16,G5000,RTEST,G5000)$SET CONDUCTORS = FLOW RATE
               STFSQS(   0.,16,G6000)       $SET CONDUCTORS = 0.0
F      3       CONTINUE
           REM PUT BOUNDARY SOIL TEMPS INTO OTHER NODES AS INITIAL GUESS
               STFSEP(T281,T1,T21,T41,T61,T81,T101,T121,T141,T161,T181,T201
                     T221,T241,T261)
               STFSEP(T282,T2,T22,T42,T62,T82,T102,T122,T142,T162,T182,T202
                     T222,T242,T262)
               STFSEP(T283,T3,T23,T43,T63,T83,T103,T123,T143,T163,T183,T203
                     T223,T243,T263)
               STFSEP(T284,T4,T24,T44,T64,T84,T104,T124,T144,T164,T184,T204
```

```
          T224,T244,T264)
     STFSEP(T285,T5,T25,T45,T65,T85,T105,T125,T145,T165,T185,T205
          T225,T245,T265)
     STFSEP(T286,T6,T26,T46,T66,T86,T106,T126,T146,T166,T186,T206
          T226,T246,T266)
     STFSEP(T287,T7,T27,T47,T67,T87,T107,T127,T147,T167,T187,T207
          T227,T247,T267)
     STFSEP(T288,T8,T28,T48,T68,T88,T108,T128,T148,T168,T188,T208
          T228,T248,T268)
     STFSEP(T289,T9,T29,T49,T69,T89,T109,T129,T149,T169,T189,T209
          T229,T249,T269)
     STFSEP(T290,T10,T30,T50,T70,T90,T110,T130,T150,T170,T190
          T210,T230,T250,T270)
     STFSEP(T291,T11,T31,T51,T71,T91,T111,T131,T151,T171,T191
          T211,T231,T251,T271)
     STFSEP(T292,T12,T32,T52,T72,T92,T112,T132,T152,T172,T192
          T212,T232,T252,T272)
     STFSEP(T293,T13,T33,T53,T73,T93,T113,T133,T153,T173,T193
          T213,T233,T253,T273)
     STFSEP(T294,T14,T34,T54,T74,T94,T114,T134,T154,T174,T194
          T214,T234,T254,T274)
     STFSEP(T295,T15,T35,T55,T75,T95,T115,T135,T155,T175,T195
          T215,T235,T255,T275)
     STFSEP(T296,T16,T36,T56,T76,T96,T116,T136,T156,T176,T196
          T216,T236,T256,T276)
     STFSEP(T297,T17,T37,T57,T77,T97,T117,T137,T157,T177,T197
          T217,T237,T257,T277)
     SHFTV(280, A70+1,   C2001)  $SET FIELD NODE CAPACITORS
     SHFTV(590, A71+1,    G2001) $SET FIELD CONDUCTORS
REM WELL#1 AT NODE 2067
     MLTPLY(K20,K9,K105,RTEST)
     STFSEP(RTEST,G2066,G2067,G3047,G3067) $CNGE COND TO K20 PERM
     DIVIDE(K22,100.,K22)
     MLTPLY(C2067,K22,C2067)      $NODE 2067 CAP TO K22%
REM WELL#2 AT NODE 2109
     MLTPLY(K24,K9,K105,RTEST)
     STFSEP(RTEST,G2108,G2109,G3089,G3109) $CNGE COND TO K24 PERM
```

```
         CIVIDE(K26,100.,K26)
         MLTPLY(C2109,K26,C2109)       $NODE 2109 CAP TO K26%
     REM WELL#3 AT NODE 2123
         MLTPLY(K28,K9,K105,RTEST)
         STFSEP(RTEST,G2122,G2123,G3103,G3123) $CNGE COND TO K28 PERM
         DIVIDE(K30,100.,K30)
         MLTPLY(C2123,K30,C2123)       $NODE 2123 CAP TO K30%
         ARYMPY(344,A6+1,144.,A6+1)   $FIELD PRESSURES TO PSFA
         SHFTV(280,A6+1,T2001)        $SET FLD DIFFUSION NODE PRESSURES
         SHFTV(44,A6+281,T1061)       $SET FLD BOUNDARY NODE PRESSURES
     REM PULL OUT INITIAL FIELD PRESSURES OF NODES K2001-K2010, AND
     REM STORE IN ARRAY A3000
         STFSEP(K2000,ITEST)
         BLDARY(A2000+1,K2001,K2002,K2003,K2004,K2005,K2006,K2007
                        K2008,K2009,K2010)
F        DO 3050 I=1,ITEST
F        JTEST=I
         ARYSTO(JTEST,KTEST,A2000+1)
         SUBFIX(KTEST,2001,KTEST)
         ADDFIX(1,KTEST,KTEST)
         ARYSTO(KTEST,RTEST,T2001)
         STOARY(JTEST,RTEST,A3000+1)
F3050    CONTINUE
     REM CONVERT PERMEABILITY(DARCYS) TO  FT**4/LBF-HR
         MLTPLY(K6,K9,             K6)
         ARYDIV(17,A95+1, 12.,      A95+1) $CHANGE DIAMETER TO FEET
         ARYMPY(280,A7+1,8.022, A7+1)      $CHANGE FLD SOURCES TO FT3/HR
     REM * * * * TIME STEP AND/OR SOLUTION SCHEME * * * *
         SCALE(1.0,DTIMEI,1.0,OUTPUT,1.0
              TIMEND,1.0)
         CNBACK
         SCALE(1.0,DTIMEI,24.,OUTPUT,24.
              TIMEND,624.)
         CNBACK
     REM * * * * * * * * * * * * * * * * * * * * * * * * * * * * * *
```

```
          STFSEP(K10,MTEST)
          FLOAT(MTEST,STEST)
F         IF(STEST.GE.1.0) GO TO 50
F         GO TO 12
F   50    CONTINUE
F         DO 4 I=1,MTEST
F         READ 22, TITL
F         READ 22, XLABEL
F         READ 22, YLABEL
F   22    FORMAT(10A4)
F         READ 6, XMIN,XSTEP,XMAX,YMIN,YSTEP,YMAX
F    6    FORMAT(6F10.2)
F         READ 13, MESAGE
F   13    FORMAT(20A4)
          STFSEP(K12,ITEST)
F         IF(I.EQ.1) GO TO 101
F         IF(I.EQ.2) GO TO 102
F         IF(I.EQ.3) GO TO 103
F         IF(I.EQ.4) GO TO 104
F         IF(I.EQ.5) GO TO 105
F         IF(I.EQ.6) GO TO 106
F         IF(I.EQ.7) GO TO 107
F         IF(I.EQ.8) GO TO 108
F         IF(I.EQ.9) GO TO 109
F         IF(I.EQ.10)GO TO 110
F         IF(I.EQ.11)GO TO 111
F         IF(I.EQ.12)GO TO 112
F  101    CONTINUE
          SHFTV(ITEST,A535+1,A600+1)
F         GO TO 150
F  102    CONTINUE
          SHFTV(ITEST,A525+1,A600+1)
F         GO TO 150
F  103    CONTINUE
          SHFTV(ITEST,A515+1,A600+1)
F         GO TO 150
F  104    CONTINUE
```

```
              SHFTV(ITEST,A536+1,A600+1)
F             GO TO 150
F 105         CONTINUE
              SHFTV(ITEST,A537+1,A600+1)
F             GO TO 150
F 106         CONTINUF
              SHFTV(ITEST,A538+1,A600+1)
F             GO TO 150
F 107         CONTINUE
              SHFTV(ITEST,A539+1,A600+1)
F             GO TO 150
F 108         CONTINUE
              SHFTV(ITEST,A540+1,A600+1)
F             GO TO 150
F 109         CONTINUE
              SHFTV(ITEST,A541+1,A600+1)
F             GO TO 150
F 110         CONTINUE
              SHFTV(ITEST,A542+1,A600+1)
F             GO TO 150
F 111         CONTINUE
              SHFTV(ITEST,A543+1,A600+1)
F             GO TO 150
F 112         CONTINUE
              SHFTV(ITEST,A544+1,A600+1)
F 150         CONTINUE
F             N=ITEST
F             DO 14 J=1,N
F             JTEST=J
              ARYSTO(JTEST,RTEST,A600+1)        $ORDINATES
F             OPLOT(J)=RTEST
              ARYSTO(JTEST,STEST,A505+1)        $ABCISSA
F             APLOT(J)=STEST
F  14         CONTINUE
F             WRITE(9) TITL,XLABEL,YLABEL,XMIN,XSTEP,XMAX,YMIN,YSTEP,YMAX,N
F     *,APLOT,OPLOT,I,MESAGE,MTEST
F   4         CONTINUE
```

```
F   12       CONTINUE
        END
        BCD 3VARIABLES 1
        REM ********************** VARIABLES 1 ************************
             STFSEP(K5,                  STEST) $PUT FLOW GPM INTO STEST
             STFSEP(T1,K107)                    $K107=NEWEST WELL HD TEMP
F            IF(STEST.LE.0.0) GO TO 49
             D1DEG1(K107,A20,TTEST)             $DENSITY LOCK-UP
             MLTPLY(K5,.1337,60.,TTEST,K101)    $FLOW RATE TO LBS/HR
             STFSEP(K101,K141)                  $K141=K101=FLOW RATE, LBS/HR
F   49       CONTINUE
F            IF(STEST.GE.0.0) GO TO 51
             STFSEP(K180,T1)                    $FIX T1 TO INJECTION TEMP
             STFSEP(K180,K107)                  $K107=K180=INJECTION TEMP
             D1DEG1(K107,A20,TTEST)             $DENSITY LOOK-UP
             MLTPLY(K5,.1337,60.,TTEST,K101)    $FLOW RATE TO LBS/HR
             STFSEP(K101,K141)                  $K141=K101=FLOW RATE, LBS/HR
F   51       CONTINUE
        REM PUT IN INITIAL SOURCE TERMS INTO FIELD NODES
             SHFTV (280,A7+1,  Q2001)           $PUT SOURCES IN AS Q'S
F            IF(DTIMEU.LE.0.0) GO TO 750
        REM IF CONSTANT INJECTION OR OUTFLOW GIVEN,SKIP HYDRAULIC CALCS
F            IF(STEST) 750,50,750
F   50       CONTINUE
        REM *** CALCULATE WATER FLOW RATE GIVEN DELTA P ***
             STFSEP(    K101,             K141) $K141=OLD FLOW RATE(LBS/HR)
             STFSEP(      0,             ITEST) $ITEST INITIALIZED TO ZERO
             STFSEP(     1.0,            K1000) $K1000 SET TO 1.0, VAR1 ENTRY
F  700       CONTINUE
             D1DEG1(TIMEN,   A4,            K4) $WELL HEAD PR AT NEWEST TIME
             MLTPLY(K4,     144.,           K4) $WELL HEAD PRESSURE IN PSFA
        REM CALC PE AT 1400 FT FROM FOUR SURROUNDING NODES OF K311
             STFSEP(K2001,RTEST)
             ADDFIX(1,RTEST,STEST)
             SUBFIX(RTEST,1,TTEST)
             ADDFIX(20,RTEST,UTEST)
             SUBFIX(RTEST,20,VTEST)
```



```
        BLDARY(A5+1,STEST,TTEST,UTEST,VTEST)
```

```
          BLDARY(A5+1,STEST,TTEST,UTEST,VTEST)
F         DO 52 I=1,4
F         JTEST=I
          ARYSTO(JTEST,KTEST,A5+1)
          SUBFIX(KTEST,2001,KTEST)
          ADDFIX(1,KTEST,KTEST)
          ARYSTO(KTEST,RTEST,T2001)
          STOARY(JTEST,RTEST,A5+1)
F   52    CONTINUE
          SUMARY(4,    A5+1,       RTEST) $SUM SURROUNDING NODE PRESS'S
      REM DIVIDE SUM OF SURROUNDING NODE PRESSURES BY 4.0 TO AVERAGE
F         RTEST = RTEST/4.
          STFSEP(   RTEST,             K2) $PUT AVE PR IN K2(AQ PRESS)
      REM FIND WELL PRESSURE (PW)
          SUBFIX(K311, 2001, JTEST)
          ADDFIX(1, JTEST, JTEST)
          ARYSTO(JTEST,  RTEST,  T2001)
      REM CALC AQ PRESSURE AT RE=28.56 FT
          SUB(K2, RTEST, K2)
          MLTPLY(.402,  K2,  K2)
          ADD(K2,  RTEST,  K2)
          SUB(K2,       K4,          K134) $K134=AQ PR-WELL HEAD PR
      REM INCREMENT ITEST
F         ITEST=ITEST + 1
      REM *** SKIP TO HYDRAULIC CONSTANTS CALCULATIONS ***
F         CALL LOSS
          SUB(K134,K111,K116,          K109) $K109=DELP-(HEAD+FRICTION)
          DIVIDE(K109,   K127,         K161) $K161=NEW FLOW RATE (LBS/HR)
      REM COMPARE QOLD(K141) WITH QNEW(K161) WHERE Q=FLOW RATE(LBS/HR)
          SUB(K141,  K161,           RTEST) $RTEST=QOLD(K141)-QNEW(K161)
          DIVIDE(RTEST,  K161,       RTEST) $RTEST=RTEST/QNEW(K161)
          SETPLS(                    RTEST) $RTEST=ABS(RTEST)
          FLOAT(ITEST,                K109) $K109=ITEST.
          PRINT(K109,   K141,         K161) $PRINT ITERATION,QOLD,QNEW
          ADD(K141,K161,K170)               $K141+K161
          DIVIDE(K170,2.,K170)              $(K141+K161)/2.
          STFSEP( K161,               K141) $PUT QNEW INTO FLOW RATE
```

```
      REM ITERATION ALLOWED FOR 50 STEPS ONLY
F             IF(ITEST.GE.50)   GO TO 2
F             IF(RTEST.GE.0.010) GO TO 1
F             GO TO 2
F     1       CONTINUE
              STFSEP(K170,K141)
      REM IF FLOWS ARE NOT WITHIN 1.%, GO BACK TO 700 AND START AGAIN
      REM WITH NEW GUESS=(QOLD+QNEW)/2.
F             GO TO 700
F     2       CONTINUE
      REM THE FOLLOWING OPERATIONS PUT NEW WELL FLOW INTO FLOW ARRAY 7
              SUBFIX(K311, 2001,           JTEST)
              ADDFIX(1,      JTEST,        JTEST)
              DIDEG1(T1,    A20,           UTEST) $DENSITY AT WELL HEAD
              DIVIDE(K141,  UTEST,         VTEST) $VTEST=FLOW RATE (F**3/HR)
              MLTPLY(-1.,VTEST,VTEST)             $OUTFLOW IS - FOR FIELD
              STOARY(JTEST, VTEST,Q2001)          $PUT NEW FLOW INTO FIELD
              STFSEP(0.0,                 K1000) $ENTER 'LOSS' BY VAR2 NEXT
F   750       CONTINUE
      REM SET FLOW CONDUCTORS
              STFSEP(K141,                RTEST) $RTEST=FLOW RATE (LBS/HR)
      REM UPFLOW OR DOWNFLOW TEST
F             IF(RTEST) 5,6,6
      REM DOWNFLOW (INJECTION)
F     5       CONTINUE
              MLTPLY(RTEST, -1.0,         RTEST) $RTEST POSITIVE
              STFSQS(RTEST, 16,           G6000) $SET DOWNFLOW AXIAL COND'S
              STFSQS(0.0,   16,           G5000) $SET UPFLOW COND = 0.0
F             GO TO 7
      REM UPFLOW (PRODUCTION)
F     6       CONTINUE
              STFSQS(RTEST, 16,           G5000) $SET UPFLOW AXIAL COND'S
              STFSQS( 0.0,  16,           G6000) $SET DOWNFLOW COND = 0.0
F     7       CONTINUE
      REM RESET WELL CUT-OFF AXIAL CONDUCTORS
              STFSEP(K1,ITEST)
F             GO TO (713,714,716),ITEST
```

```
F 713       CONTINUE
            STFSEP(0.0,G5002,G6013,  G7013) $WELL #1 CUT-OFF
F           GO TO 715
F 714       CONTINUE
F           GO TO 715
F 716       CONTINUE
            STFSEP(0.0,G5001,G6014,  G7014) $WELL #3 CUT-OFF
F 715       CONTINUE
            STFSEP(K141,                K101) $K101 = FLOW RATE (LBS/HR)
        REM CALCULATE WATER FILM COEFFICIENT
            STFSEP(K101,               RTEST) $RTEST = FLOW RATE (LBS/HR)
F           RTEST=ABS(RTEST)
        REM FIND WATER FILM COEFFICIENT BASED ON AT LEAST TURBULENT FLOW
F           IF(RTEST.LE.1000.) RTEST=1000.
        REM A FLOW RATE OF APPROX 1000 LBS/HR CORRESPONDS TO A REYNOLDS
        REM NUMBER OF ABOUT 2000 (FOR T=250F, D=13INCHES)
            EXPNTL(   .8, RTEST,        K106) $K106=(RTEST)**.8
        REM DETERMINE HEAT TRANSFER COEFFICIENT
            MLTPLY(K106, .02036,        K106) $K106=.02036*(RTEST)**.8
        REM THE NEXT THREE CALCS SET HORIZONTAL WELL CONDUCTORS = H*A
            ARYMPY(17,A95+1,3.1416,      G01) $PI*DIAMETER (FT)
            MPYARY(17,G01,A93+1,         G01) $PI*DIAMETER*LENGTH=AREA
            ARYMPY(17,G01, K106,         G01) $CONDUCTORS= H*A
        REM THE FOLLOWING CALCS SET UNCASED WELL CONDUCTORS
            STFSEP(K1,MTEST)
F           GO TO (731,732,740),MTEST
F 731       CONTINUE
            STFSEP(G13,G33)
            STFSEP(G14,G34)
F           GO TO 733
F 732       CONTINUE
            STFSEP(G14,G34)
            STFSEP(G15,G35)
            STFSEP(G16,G36)
            STFSEP(G17,G37)
F           GO TO 733
F 740       CONTINUE
```

```
F 733         CONTINUE
          REM CALCULATE NATURAL CIRCULATION IN WELL-HORIZONTAL PLATE MODEL
F             DO 100 ITEST=1,16
              ARYSTO(ITEST,RTEST,          T1) $RTEST=TOP TEMP
              ARYSTO(ITEST,STEST,          T2) $STEST=BOTTOM TEMP
          REM AVERAGE TEMPERATURE = TTEST
F             TTEST=(RTEST+STEST)/2.
              DIDEG1(TTEST,A22,          K109) $GRASHOF COEFFICIENT LOOKUP
              DIDEG1(TTEST,A23,          K171) $PRANDTL NUMBER LOOKUP
              DIDEG1(TTEST,A24,         UTEST) $WATER CONDUCTIVITY LOOKUP
          REM FIND DELTA T = TTEST
F             TTEST=ABS(RTEST - STEST)
              ARYSTO(ITEST,VTEST,       A93+1) $VTEST=APPLICABLE LENGTH(FT)
          REM NOTE: DISTANCE BETWEEN NODES 5 AND 6 (WELL) IS 300 FT
F             IF(ITEST.EQ.5) VTEST = 300.
              MLTPLY(VTEST,VTEST,VTEST,RTEST) $RTEST= L**3.
              MLTPLY(K109,K171,RTEST,   RTEST) $RTEST=GR*PR*L**3.
              MLTPLY(RTEST,TTEST,       TTEST) $TTEST=GR*PR*L**3.*DELTA T
              EXPNTL(.37,  TTEST,       TTEST) $TTEST=TTEST**.37
              MLTPLY(TTEST,.0481,UTEST,UTEST) $UTEST=.0481*K*TTEST
              DIVIDE(1.,VTEST,          VTEST) $VTEST= 1/L
              MLTPLY(VTEST,UTEST,       UTEST) $UTEST =UTEST/L = H
              ARYSTO(ITEST, RTEST,      A94+1) $RTEST=APPLICABLE AREA(FT**2)
              MLTPLY(RTEST, UTEST,      UTEST) $UTEST=H*A
              STOARY(ITEST,UTEST,       G7000) $G7000=NAT CIRCULATION COND
F 100         CONTINUE
F   3         CONTINUE
              STFSEP(K1,MTEST)
F             GO TO (734,735,737),MTEST
F 734         CONTINUE
              STFSEP(0.0,G5002,G6013,G7013)    $WELL#1 CUT-OFF
F             GO TO 736
F 735         CONTINUE
F             GO TO 736
F 737         CONTINUE
              STFSEP(0.0,G5001,G6014,G7014)    $WELL#3 CUT-OFF
F 736         CONTINUE
```

```
          STFSEP(K5,STEST)
F         IF(STEST.FQ.0.) GO TO 4999
F         GO TO 5000
F4999     CONTINUE
          DIDEGI(K107,A20,          TTEST) $LOOKUP DENSITY
          MLTPLY(TTEST,.1337,  60.,TTEST) $TTEST=RHO*.1337*60.
      REM GPM
          DIVIDE(K141,  TTEST,      K141) $CHANGE FLOW RATE TO GPM
      REM FRIC
          DIVIDE(K116,  144.,       K116) $CHANGE FRICTION TO PSI
      REM HEAD
          DIVIDE(K111,  144.,       K111) $CHANGE GRAVITY HEAD TO PSI
      REM PERM
          DIVIDE(K126,  144.,       K126) $CHANGF DARCY TERM TO PSI
      REM DPT
          DIVIDE(K134,  144.,       K134) $CHANGE TOTAL PR DROP TO PSI
      REM AQPR
          DIVIDE(K2,    144.,         K2) $CHANGF AQ PR TO PSI
      REM PRINT RRGE,FND#,TSEC,GPM,FRIC,HEAD,PERM,DPT,AQPR
          FLOAT(K1,K1)
          FLOAT(K311,K311)
          PRINTL(A201+1,K1,K311,K110,K141,K116,K111,K126,K134,K2)
          FIX(K311,K311)
          FIX(K1,K1)
          ADDFIX(K11,1,K11)
          STFSEP(K11,JTEST)
          STFSEP(K12,ITEST)
F         IF(JTEST.LE.ITEST) GO TO 4000
F         TIMEND=TIMEN
F4000     CONTINUE
          DIVIDE(K110,3600.,K110)
          STORMA(JTEST,K110, A505+1,K141,A515+1,T1,A525+1
                A5000+1,A535+1,A5000+2,A536+1,A5000+3,A537+1
                A5000+4,A538+1,A5000+5,A539+1,A5000+6,A540+1
                A5000+7,A541+1,A5000+8,A542+1,A5000+9,A543+1
                A5000+10,A544+1)
      REM CHANGE FLOW RATE(K141) BACK TO LBS/HR
```

```
          MLTPLY(K141,  TTEST,       K141) $K141=GPM*.1337*RHO*60.
      REM CHANGE ALL PRESSURE DROPS BACK TO PSF
          SCALE(144.,K116,K116,K111,K111,K126,K126,K134,K134,K2,K2)
      REM CHANGE TIME (K110) BACK TO SECONDS
          MLTPLY(K110,3600.,K110)
F5000     CONTINUE
      END
      BCD 3VARIABLES 2
      REM ********************** VARIABLES 2 ************************
          STFSEP( K101, K141)            $K141 = K101   FLOW RATE
F         ENTRY LOSS
      REM ************ CALCULATE CURRENT HYDRAULIC CONSTANTS *********
          SHFTV(17, T1, A90+1)           $PUT WELL TEMPS INTO ARRAY 90
      REM CALCULATE GRAVITY HEAD TERM (CALC FROM APPROX BTM OF CASING)
          D1DG1I(17,A90+1,A20,A101+1) $DENSITY LOOK-UP
          MPYARY(17,A101+1,A93+1,A102+1) $RHO * L
          STFSEP(K1,MTEST)                 $MTEST = WELL NUMBER
F         GO TO (11,21,31),MTEST
F   11    CONTINUE
      REM SUMMATION(RHO*L), WELL #1
          MLTPLY(.75,A102+14,A102+14)
          SUMARY(14,A102+1,K111)
          DIVIDE(A102+14,.75,A102+14)
F         GO TO 41
F   21    CONTINUE
      REM SUMMATION(RHO*L), WELL #2
          SUMARY(13,A102+1,K111)
F         GO TO 41
F   31    CONTINUE
      REM SUMMATION(RHO*L), WELL #3
          SUMARY(13,A102+1,K111)
F   41    CONTINUE
      REM CALCULATE PERMEABILITY TERM
          D1DG1I(17,A90+1,A21,A100+1)      $VISCOSITY LOOK-UP
F         GO TO(12,22,24),MTEST
F   12    CONTINUE
      REM WELL #1 PERMEABILITY TERM (AVE) ALONG BASE,SCALED FROM 300F
```

```
      MLTPLY(K141,  TTEST,       K141) $K141=GPM*.1337*RHO*60.
  REM CHANGE ALL PRESSURE DROPS BACK TO PSF
      SCALE(144.,K116,K116,K111,K111,K126,K126,K134,K134,K2,K2)
  REM CHANGE TIME (K110) BACK TO SECONDS
      MLTPLY(K110,3600.,K110)
F5000 CONTINUE
  END
  BCD 3VARIABLES 2
  REM *********************** VARIABLES 2 ************************
      STFSEP( K101, K141)           $K141 = K101  FLOW RATE
F     ENTRY LOSS
  REM ************ CALCULATE CURRENT HYDRAULIC CONSTANTS *********
      SHFTV(17, T1, A90+1)          $PUT WELL TEMPS INTO ARRAY 90
  REM CALCULATE GRAVITY HEAD TERM (CALC FROM APPROX BTM OF CASING)
      D1DG1I(17,A90+1,A20,A101+1) $DENSITY LOOK-UP
      MPYARY(17,A101+1,A93+1,A102+1) $RHO * L
      STFSEP(K1,MTEST)               $MTEST = WELL NUMBER
F     GO TO (11,21,31),MTEST
F  11 CONTINUE
  REM SUMMATION(RHO*L), WELL #1
      MLTPLY(.75,A102+14,A102+14)
      SUMARY(14,A102+1,K111)
      DIVIDE(A102+14,.75,A102+14)
F     GO TO 41
F  21 CONTINUE
  REM SUMMATION(RHO*L), WELL #2
      SUMARY(13,A102+1,K111)
F     GO TO 41
F  31 CONTINUE
  REM SUMMATION(RHO*L), WELL #3
      SUMARY(13,A102+1,K111)
F  41 CONTINUE
  REM CALCULATE PERMEABILITY TERM
      D1DG1I(17,A90+1,A21,A100+1)    $VISCOSITY LOOK-UP
F     GO TO(12,22,24),MTEST
F  12 CONTINUE
  REM WELL #1 PERMEABILITY TERM (AVE) ALONG BASE,SCALED FROM 300F
```


REM THIS IS USEFUL ...

```
      REM THIS IS USEFUL MAINLY FOR INJECTION FLOW
          BLDARY(A1+1,T14,T34,T54,T74,T94,T114,T134) $WELL1 BASE NODES
F   40    CONTINUE
          DIDGII(7,A1+1,A21,A2+1)       $BASE NODE VISCOSITIES
          DIDGII(7,A1+1,A20,A8+1)       $BASE NODE DENSITIES
          ARYMPY(7,A2+1,K7,A3+1)        $(LN(RE/RW)/(2*PI*B))*VISCOSITY
          DIVARY(7,A3+1,A8+1,A3+1)      $(LN(RE/RW)/(2*PI*B*RHO))*VISC
          ARYDIV(7,A3+1,K6,A3+1)        $DIVIDE A3 BY PERMEABILITY
          ARYDIV(7,A3+1,0.45,A3+1)      $DIV A3 BY VISC AT 300F(HR/FT**2)
          SUMARY(7,A3+1,K127)           $SUM TERMS
          DIVIDE(K127,7.,K127)          $DIV SUM BY 7. TO AVE(HR/FT**2)
F         GO TO 32
F   22    CONTINUE
      REM WELL #2 PERMEABILITY TERM (AVE) ALONG BASE,SCALED FROM 300F
      REM THIS CALCULATION USEFUL MAINLY FOR INJECTION FLOW
          BLDARY(A1+1,T16,T36,T56,T76,T96,T116,T136) $WELL2 BASE NODES
F         GO TO 40
F   24    CONTINUE
      REM WELL #3 PERMEABILITY TERM (AVE) ALONG BASE,SCALED FROM 300F
      REM THIS CALCULATION USEFUL MAINLY FOR INJECTION FLOW
          BLDARY(A1+1,T15,T35,T55,T75,T95,T115,T135) $WELL3 BASE NODES
F         GO TO 40
F   32    CONTINUE
      REM CALCULATE REYNOLDS NUMBER
          DIVARY(17, A96+1,A100+1,A103+1) $A103=(D/A)/VISC.
          MPYARY(17,A101+1,A105+1,A101+1) $A101= (RHO)*2*G*A**2
          MLTPLY(K127,K141,K126)$K126=K127*FLOW RATE=PERM PR DROP
      REM CALCULATE FRICTION TERM
          ARYMPY(17,A103+1,  K141,A100+1) $A100=((D/A)/VISC)*FLOW RATE
F         DO 810 KTEST=1,17
      REM TEST FOR TURBULENT FLOW
          ARYSTO(  KTEST, RTEST, A100+1) $RTEST=A100+KTEST(DV)
      REM TURBULENT FLOW TEST
F         IF(ABS(RTEST)-2000.)779,779,760
      REM CALCULATE FRICTION FACTORS
      REM TURBULENT FLOW FRICTION FACTOR
F  760    CONTINUE
```

```
          ARYSTO(    KTEST, STEST,  A97+1) $STEST=EPS/(D*3.7)
          ARYSTO(    KTEST, TTEST,  A98+1) $TTEST=-.5/(LOG10(STEST))
F 770     UTEST=-0.5/ALOG10(STEST+2.51/(ABS(RTEST)*TTEST))
F         VTEST=ABS(TTEST/UTEST-1.0)
F         IF(VTEST-.0005)776,776,775
F 775     CONTINUE
F         TTEST=UTEST
F         GO TO 770
F 776     VTEST=UTEST*UTEST
F         GO TO 780
F 779     CONTINUE
      REM LAMINAR FLOW FRICTION FACTOR
F         IF(RTEST.EQ.0.0) RTEST=0.1
F         VTEST=64.0/ABS(RTEST)
F 780     CONTINUE
      REM CALCULATE LOSS TERMS & PRESSURE DROPS
          ARYSTO(    KTEST, STEST,  A99+1) $STEST=A99+KTEST =(L/D)
          MLTPLY(    VTEST, STEST,  VTEST) $VTEST=(L/D)*F
F         IF(RTEST)801,802,802
F 801     CONTINUE
      REM PULL INITIAL LOSSES FROM ARRAY - IF ANY EXIST
          ARYSTO(     KTEST, STEST,A104+1)
F         GO TO 803
F 802     CONTINUE
          ARYSTO(     KTEST, STEST, A92+1)
F 803     CONTINUE
          ADD    (    VTEST, STEST, VTEST) $VTEST=F*(L/D)+INITIAL LOSS
          STOARY(     KTEST, VTEST,A100+1) $STORE LOSS COEFFICIENTS
F 810     CONTINUE
          DIVARY(17,A100+1,A101+1,A100+1) $A100=F*(L/D)/(2*G*RHO*A**2)
          ARYMPY(17,A100+1,  K141,A100+1) $A100=A100*FLOW RATE(LBS/HR)
          ARYPLS(17,               A100+1) $ALL A100 POSITIVE
          ARYMPY(17,A100+1,  K141,A100+1) $A100=A100*(FLOW RATE)**2
F         GO TO (13,23,25),MTEST
F  13     CONTINUE
          MLTPLY(.75,A100+14,A100+14)
          SUMARY(14,A100+1,         K116) $SUM LOSSES,      WELL #1
```

```
          DIVIDE(A100+14,.75,A100+14)
F         GO TC 33
F   23    CONTINUE
          SUMARY(13,A100+1,         K116) $SUM LOSSES,      WELL #2
F         GC TC 33
F   25    CONTINUE
          SUMARY(13,A100+1,         K116) $SUM LOSSES,      WELL #3
F   33    CONTINUE
          STFSEP(K1000,            RTEST)
F         IF(RTEST.LE.0.0)GO TO 815
F         RETURN
F  815    CONTINUE
          MLTPLY(  K136, K121,      K156) $K156=(L/(A*G))*DW
          ADD(K111,K116,K126,K156,  K134) $K134=SUM OF PRESSURE DROPS
      END
      BCD 3CUTPUT CALLS
      REM ************************** OUTPUT ****************************
      REM MAKE SURE THERE IS NO PRESSURE BUILD-UP IN AQUIFER IF THERE
      REM ARE NC INJECTION WELLS
F         DO 6011 I=1,280
F         ITEST=I
          ARYSTC(ITEST,RTEST,A7+1)
F         IF(RTEST.GT.0.) GO TC 6020
F6011     CONTINUE
F         DO 6012 I=1,280
F         ITEST = I
          ARYSTC(ITEST,STEST,T2001)
F         DELTA=316800.-STEST
F         IF(DELTA) 6015,6012,6012
F6015     STEST = 316800.
          STOARY(ITEST,STEST,T2001)
F6012     CCNTINUE
F6020     CONTINUE
      REM CALCULATE DRAWDOWN CF NODES K2001-K2010
          STFSEP(K2000,ITEST)
F         DO 5050 I=1,ITEST
F         JTEST=I
```

```
              ARYSTO(JTEST,KTEST,A2000+1)
              SUBFIX(KTEST,2001,KTEST)
              ADDFIX(1,KTEST,KTEST)
              ARYSTO(KTEST,RTEST,T2001)
              ARYSTC(JTEST,STEST,A3000+1)
              SUB(STEST,RTEST,TTEST)
              STOARY(JTEST,TTEST,A5000+1)       $DRAWDOWN(PSF) IN A5000
F5050         CONTINUE
              ARYDIV(10,A5000+1,144.,A5000+1) $DRAWDOWN TO PSI
              STFSEP(K108,STEST)
F             IF(STEST.GE.1.0) GO TO 4003
F4001         PRINT 4002
F4002         FORMAT(1H1, '****************************** RAFT RIVER GEOTHE
F     2RMAL FIELD AND WELL MODEL ******************************      ',///
F     1       /,'  RRGE = WELL NUMBER USED IN THIS ANALYSIS',
F     2       /,'  FND# = HORIZONTAL FIELD NODE NUMBER LOCATION OF WELL',
F     3       /,'  TSEC = TIME IN SECONDS',
F     4       /,'  GPM  = FLOW RATE INTO OR OUT OF WELL IN GALLONS PER MINU
F     5TE ',/,'  FRIC = PRESSURE DROP DUE TO FRICTION LOSSES IN WELL (PSI
F     6) ', /,'  HEAD = PRESSURE DROP DUE TO GRAVITY HEAD (PSI)',
F     7       /,'  PERM = PRESSURE DROP DUE TO RADIAL FLOW THROUGH POROUS M
F     8EDIA (PSI) ',/,'  DPT  = TOTAL PRESSURE DROP (PSI)',
F     9       /,'  AQPR = AQUIFER PRESSURE (PSIA) = AVERAGE OF FOUR SURROUN
F     1DING NODES',
F     2       ////,' TIME GIVEN AT BEGINNING OF EACH PRINTOUT IS IN HOURS',
F     3////)
F4003         CONTINUE
              TOPLIN
              TPRINT
F             PRINT 4004
F4004         FORMAT(///)
              MLTPLY(TIMEN,   3600.,    K110) $CHANGE TIME TO SEC    (TSEC)
              STFSEP(K5,STEST)
F             IF(STEST.EQ.0.) GO TO 4005
              DIDEG1(K107,A20,          TTEST) $LOOKUP DENSITY
              MLTPLY(TTEST,.1337,  60.,TTEST) $TTEST=RHO*.1337*60.
              DIVIDE(K141,  TTEST,      K141) $CHANGE FLOW RATE TO GPM
```

```
          DIVIDE(K116,  144.,        K116) $CHANGE FRICTION TO PSI
          DIVIDE(K111,  144.,        K111) $CHANGE GRAVITY HEAD TO PSI
          DIVIDE(K126,  144.,        K126) $CHANGE DARCY TERM TO PSI
          DIVIDE(K134,  144.,        K134) $CHANGE TOTAL PR DRCP TC PSI
          DIVIDE(K2,    144.,          K2) $CHANGE AQ PR TO PSI
      REM PRINT RRGE,FND#,TSEC,GPM,FRIC,HEAD,FERM,DPT,AQPR
          FLCAT(K1,K1)
          FLOAT(K311,K311)
          PRINTL(A201+1,K1,K311,K110,K141,K116,K111,K126,K134,K2)
          FIX(K311,K311)
          FIX(K1,K1)
          ADDFIX(K11,1,K11)
          STFSEP(K11,JTEST)
          STFSEP(K12,ITEST)
F         IF(JTEST.LE.ITEST) GO TO 4000
F         TIMEND=TIMEN
F4000     CONTINUE
          STORMA(JTEST,TIMEN,A505+1,K141,A515+1,T1,A525+1
                A5000+1,A535+1,A5000+2,A536+1,A5000+3,A537+1
                A5000+4,A538+1,A5000+5,A539+1,A5000+6,A540+1
                A5000+7,A541+1,A5000+8,A542+1,A5000+9,A543+1
                A5000+10,A544+1)
      REM CHANGE FLOW RATE(K141) BACK TC LBS/HR
          MLTPLY(K141,  TTEST,       K141) $K141=GPM*.1337*RHO*60.
      REM CHANGE ALL PRESSURE DROPS BACK TO PSF
          SCALE(144.,K116,K116,K111,K111,K126,K126,K134,K134,K2,K2)
F4005     CONTINUE
          ADD(1.0,K108,K108)
      END
      BCD 3END CF DATA
```

APPENDIX C

User's Manual

To use the two computer models, both incorporated in a single SINDA-3G input deck, the user should have at least an understanding of the SINDA-3G basics. The use of the models is described herein.

CONSTANT 1- Place here the well for which heat transfer calculations will be performed and temperature response obtained, e.g., for RRGE #1 place a 1 here, for RRGE #2 place a 2 here, etc. (Integer)

CONSTANT 5- Flow rate (gpm) for the well defined by CONSTANT 1. Use a positive value for outflow (production) and a negative value for injection. A zero here will cause artesian flow rate to be calculated. (Real)

CONSTANT 10- Total number of transient parameters to be saved on Tape 9 for future reference or plotting as defined below:

1 parameter saved:	Drawdown vs. time at node given by CONSTANT 2001
2 parameters saved:	Well head temperature vs time for well given in CONSTANT 1
3 parameters saved:	Flow rate vs time for well given by CONSTANT 1
4 parameters saved:	Drawdown vs time at node given by CONSTANT 2002
5 parameters saved:	Drawdown vs time at node given by CONSTANT 2003
6 parameters saved:	Drawdown vs time at node given by CONSTANT 2004
7 parameters saved:	Drawdown vs time at node given by CONSTANT 2005

8 parameters saved: Drawdown vs time at node given by CONSTANT 2006

9 parameters saved: Drawdown vs time at node given by CONSTANT 2007

10 parameters saved: Drawdown vs time at node given by CONSTANT 2008

11 parameters saved: Drawdown vs time at node given by CONSTANT 2009

12 parameters saved: Drawdown vs time at node given by CONSTANT 2010

If, for example, a 6 were placed in CONSTANT 10, then all the parameters defined from 6 back to 1 (inclusive) would be saved on Tape 9. (Integers)

CONSTANT 12 - Place here the first n steps in the time step transient that information is to be placed on Tape 9 for the parameters given in CONSTANT 10. (Integer)

CONSTANTS 311-315 - List here those reservoir nodes that contain some source or sink flow (production or injection). (Integers)

CONSTANTS 2000-2010 - Place in CONSTANTS 2001-2010 those reservoir nodes whose pressure response transient (drawdown) will be saved on Tape 9. CONSTANT 2000 gives total number on nodes desired. (Integers)

ARRAY 7 - List here, in order from 2001-2280, the flow rates from the respective reservoir nodes (currently RRGE #1 is node 2067, RRGE #2 is node 2109, RRGE #3 is node 2123). Production nodes are input with a negative value, injection with a positive value, no flow or artesian flow with a zero. (All REAL)

In addition to the above, the inclusion of the time step immediately after "TIME STEP AND/OR SOLUTION SCHEME" in the EXECUTION Subroutine must be made. A constant time step for the entire transient or changing time step may be employed. A steady-state solution may be obtained by using CINDSL in place of the existing CNBACK backward differencing scheme.

Optional input includes array titles for the transient pressure response data written on Tape 9 for nodes flagged by constants 2001-2010. These titles will also be written on Tape 9.

The preceding represents the only values that need to be changed for different runs involving production wells, injection wells, or a combination of the two. Note that well temperature response may be obtained for only one well at a time while reservoir pressure response may be obtained at all reservoir nodes. All other constants and array values represent particular well and reservoir characteristics that need not be changed. As new wells are added, though, more constants and arrays describing them will have to be included. Likewise, if the reservoir dimensions are changed or more nodes added, or both, then additional node, conductor, constant, and array data would need to be included. At the present time all properties are input in feet, hours, pounds (mass and force), and BTU unless otherwise stated explicitly in the program deck.

A sample of the input values required to run the transient as given in Figures 6 through 8 is shown below. This sample calculates the dotted line portion of these figures only. The input listing in Appendix B gives the entire deck needed to run this transient.

```
BCD 3CONSTANTS DATA
         .
         .
         .
        1,2       $ RRGE WELL NUMBER FOR THIS RUN
         .
         .
         .
        5,415.    $ WELL FLOW RATE (GPM), + FOR OUTFLOW
         .
         .
         .
       10,4       $ # GRAPHS TO BE PLOTTED
         .
         .
         .
       12,69      $ NUMBER OF POINTS TO BE PLOTTED
         .
         .
         .
      311,2109    $ FIRST FLOW NODE
      312,0       $ SECOND FLOW NODE
      313,0       S THIRD FLOW NODE
      314,0       $ FOURTH FLOW NODE
      315,0       $ FIFTH FLOW NODE
         .
         .
         .
     2000,2       $ NUMBER OF NODES TO FOLLOW
     2001,2109    $ RRGE #K1
     2002,2067    $
     2003,0       $
     2004,0       $
     2005,0       $
     2006,0       $
     2007,0       $
     2008,0       $
     2009,0       $
     2010,0       $
         .
         .
         .
BCD 3ARRAY DATA
         .
         .
         .
```

```
    7    $ INITIAL FLOW RATES IN FIELD (GPM)
    .
    .
   0., 0., 0., ........-415.0, ........0.
    .
    .

BCD 3EXECUTION
    .
    .
    .
REM **** TIME STEP AND/OR SOLUTION SCHEME ****
    SCALE(1.0,DTIMEI,1.0,OUTPUT,1.0
          TIMEND,1.0)
    CNBACK
    SCALE(1.0,DTIMEI,24.,OUTPUT,24.
          TIMEND,624.)
    CNBACK
```

The optional titles were not used in this particular example in the SINDA-3G run but were added in a plotting program that used the values on Tape 9 to generate Figures 6 through 8.

In rare instances the user may wish to run transients (or steady-state solutions) that have not been previously discussed, such as injection followed immediately by production from the same well, or a shut-in (no-flow) well temperature distribution. These types of problems require program modification and will not be reported here.

APPENDIX D

The Effect of Reinjection on Reservoir Temperature

The reservoir model developed for Raft River did not take into account temperature effects. The apparent homogeneity of the reservoir, as evidenced by the almost identical temperatures at well bottom in the three wells ($3^{o}F$ total temperature difference), was the main reason for choosing a simpler model accounting for pressure effects only. Cold water reinjection, though, may upset this reservoir balance and render the constant temperature assumption invalid. However, this appendix will show that reinjection is only a minor concern of localized nature.

Lauwerier[27] addressed the problem of describing the reservoir temperature response to injection of hot water into an oil bearing layer. His method was general enough to apply the results to cold water injection into a geothermal reservoir. The basic assumptions in Lauwerier's model were that the thickness, permeability, and porosity of the reservoir were uniform, and that a constant injection rate was maintained. In addition, the thermal conductivity of the porous media reservoir was constant and equal to that of the caprock (rock formation above and below the porous reservoir). The thermal conductivity in the direction of flow was assumed to be zero indicating that heat transfer in the flow direction occurred only by the physical fluid movement in that direction. Finally, the temperature across the fluid face was assumed everywhere constant, and the fluid and porous media were always in thermal equilibrium.

Figure 15 shows a vertical cross section in the x-y plane of Lauwerier's model. Water of temperature T_0 is pumped at a constant rate into an injection well located in a reservoir initially at temperature $T_1 = 0$. The water may flow only in a layer of thickness 2b at a temperature T_1, which is constant at any cross section and only dependent on the distance x from the injection well.

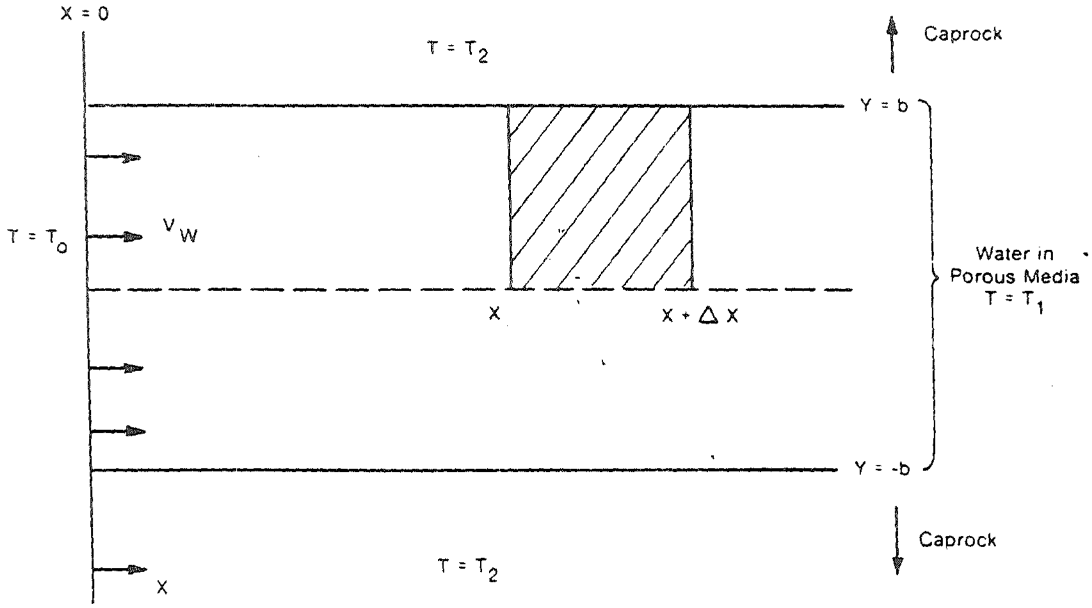


FIGURE 15 - Reservoir Thermal Front Model Used by Lauwerier

The actual problem was formulated as follows:

A horizontal water layer

$$x > 0, \quad -b < y < +b$$

is enclosed in caprock of initial temperature $T_2 = 0$. The temperature of the water layer is initially $T_1 = 0$. After time $t = 0$, the boundary

$$x = 0, \quad -b < y < +b$$

is kept at a constant temperature T_0 by injection of water of temperature T_0 at a rate of V_w at the wellbore so as to convect heat in the x-direction. Heat is transferred at the water layer-caprock interface

$$x > 0, \quad y = b \quad \text{(symmetric half layer)}$$

by conduction through the caprock. For simplification, it is assumed that there is no heat conduction in the x-direction, and that the reservoir porous media (sand, etc.) is in thermal equalibrium with the water. With these assumptions, a heat balance is applied to the hatched region of Figure 15;

$$b\rho_1 C_1 \frac{\partial T_1}{\partial t} + b\rho_w C_w V_w \frac{\partial T_1}{\partial x} - k\left(\frac{\partial T_2}{\partial y}\right)_{y=b} = 0 \qquad \text{(D1)}$$

where ρ_w = Water Density

C_w = Specific Heat of Water

V_w = Linear Water Velocity

k = Thermal Conductivity

t = Time

x,y = Spatial Cartesian Coordinates

and

$$\rho_1 C_1 = (1-f)\rho_s C_s + f\rho_w C_w \qquad \text{(D2)}$$

where f = Porosity

ρ_s = Porous Media Density

C_s = Porous Media Specific Heat

In the caprock, the normal equation for heat conduction holds;

$$k\frac{\partial^2 T_2}{\partial y^2} = \rho_s C_s \frac{\partial T_2}{\partial t} \qquad \text{(D3)}$$

assuming that the porous media and caprock have identical properties.

Introducing the dimensionless variables;

$$x = \frac{b^2 \rho_w C_w V_w}{k} \xi$$

$$y = b\eta$$

$$t = \frac{b^2 \rho_1 C_1}{k} \tau$$

$$\theta = \frac{\rho_1 C_1}{\rho_s C_s}$$

allows the problem to be expressed in the following set of equations;

For $|\eta| > 1$ $\quad \theta \dfrac{\partial^2 T_2}{\partial \eta^2} = \dfrac{\partial T_2}{\partial \tau}$

For $|\eta| = 1$ $\quad \begin{cases} \dfrac{\partial T_2}{\partial \tau} + \dfrac{\partial T_2}{\partial \xi} - \dfrac{\partial T_2}{\partial \eta} = 0 \\ T_1 = T_2 \end{cases}$

For $\tau = 0$ $\quad T_1 = T_2 = \begin{cases} T_0 \text{ if } \xi < 0 \\ 0 \text{ if } \xi > 0 \end{cases}$

The solution may be obtained by applying twice a Laplace transform to T_2 (see Reference 29 for details) giving for the water layer temperature;

$$T_1 = T_0 \operatorname{erfc}\left[\frac{\xi}{2\sqrt{\theta(\tau-\xi)}} U(\tau-\xi)\right] \qquad \text{(D4)}$$

where U is the unit function defined as

$$U(z) = \begin{cases} 0 \text{ for } z < 0 \\ 1 \text{ for } z > 0 \end{cases}$$

The preceding steps have been taken directly from Lauwerier's work with slight modifications given to the symbols to represent the current geothermal application. A more appropriate form of Equation (D4) is given as follows;

$$\frac{T_1 - T_i}{T_0 - T_i} = \text{erfc}\left\{\left(\frac{x}{2bV_w}\right)\left[\frac{(\rho_w C_w)^2}{k \rho_s C_s}\left(t - \frac{\rho_1 C_1}{\rho_w C_w} \frac{x}{V_w}\right)\right]^{-1/2}\right\} \quad \text{(D5)}$$

where $T_i = T_1(0)$ ($\neq 0$ as in original development)

and T_1 is the temperature at the production well a distance x from the injection well for;

$$t > \frac{x}{V_w} \frac{\rho_1 C_1}{\rho_w C_w} \quad \text{(D6)}$$

In other words, the effect of cold water reinjection will not be felt by a production well until time t as defined in Equation (D6).

Applying Equation (D6) to the Raft River Reservoir produces an interesting result. Using the following conditions representative at Raft River;

$\rho_s C_s = 50.0$ BTU/ft^3-^{o}F [20]

$\rho_w C_w = 59.0$ BTU/ft^3-^{o}F [20]

$f = 20\%$ [24]

gives, from Equation (D2);

$\rho_1 C_1 = 51.8$ BTU/ft^3-^{o}F

The last term on the right-hand side of Equation (D6) is then;

$$\frac{\rho_1 C_1}{\rho_w C_w} = \frac{51.8}{59.0} = .88$$

Considering for a moment that RRGE #1 is a reinjection hole and RRGE #2 a production hole, then x in Equation (D6) equals 4000 ft. The average velocity, $< V_w >$, of the injected water in the reservoir is:

$$< V_w > = \frac{1}{R_o} \int_{R_w}^{R_o} \frac{Q}{2\pi r H} dr \tag{D7}$$

R_o = Radial Distance from Injection to Production Well

R_w = Effective Well Radius

Q = Injection Flow Rate

H = Aquifer Thickness (2b in Lauwerier's Model)

with;

R_o = 4000 ft.

R_w = 2 ft. (see Section 3.3)

H = 500 ft.[18]

and assuming Q = 1000 gpm

then Equation (D6) calculates that the production hole will not be influenced by the injection hole cold water for 83 years. This is far longer than the typical 30 year useful life of any power plant if, indeed, the Raft River Resource were to be used as such.

A recent investigation by Bodvarsson[29] addressed directly the cold water injection problems in geothermal reservoirs. His work will not be discussed here except to say that the results show even greater times for injection well influence than those calculated using Lauwerier's procedure.

Clearly, the model developed by Lauwerier is highly simplified, as was Bodvarsson's theoretical analysis. Nevertheless, it is possible to apply these models and formulas in order to obtain semiquantitative estimates of the cold water injection phenomena. Both of these models indicate that cold water reinjection at Raft River will not influence production well behavior for long periods of time and should not effect reservoir behavior except in localized regions near the reinjection wells.

DISTRIBUTION RECORD FOR TREE-1085

Internal Distribution

1 - Chicago Patent Group - ERDA
9800 South Cass Avenue
Argonne, Illinois 60439

3 - A. T. Morphew
Classification and Technical Information Officer
Idaho Operations Office - ERDA
Idaho Falls, ID 83401

1 - H. P. Pearson, Supervisor
Technical Information

10 - INEL Technical Library

20 - Author

10 - Special Internal

External Distribution

674 - UC-66A, GE--Resource Development, TID-4500, R65

Total Copies Printed - 719