TWO-PHASE FLOW IN GEOTHERMAL WELLS:
DEVELOPMENT AND USES OF A COMPUTER CODE

A Report
Submitted to the Department of Petroleum Engineering
of Stanford University
in partial fulfillment of the requirements
for the degree of

MASTER OF SCIENCE

by
Jaime Ortiz-Ramirez
June 1983
ACKNOWLEDGEMENT

I would like to thank Comision Federal de Electricidad de Mexico for financial support for my studies at Stanford University. I greatly appreciate the additional support received from the Stanford Geothermal Program.

I appreciate the help given by the Instituto de Investigaciones Electricas de Mexico in obtaining the Cerro Prieto Data.

I am in a great debt with Prof. Jon S. Gudmundsson for his suggestions and effort as my research advisor.

I want to thank Prof. Roland N. Horne for his advice during my studies at Stanford.

Finally, I want to express my thanks to my wife for her patience and encouragement during my graduate studies.
ABSTRACT

A computer code is developed for vertical two-phase flow in geothermal wellbores. The two-phase correlations used were developed by Orkiszewski (1967) and others and are widely applicable in the oil and gas industry.

The computer code is compared to the flowing survey measurements from wells in the East Mesa, Cerro Prieto, and Roosevelt Hot Spring geothermal fields with success. Well data from the Svartsengi field in Iceland are also used.

Several applications of the computer code are considered. They range from reservoir analysis to wellbore deposition studies. It is considered that accurate and workable wellbore simulators have an important role to play in geothermal reservoir engineering.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ABSTRACT</td>
<td></td>
</tr>
<tr>
<td>1. INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>2. LITERATURE SURVEY</td>
<td>3</td>
</tr>
<tr>
<td>3. VERTICAL TWO-PHASE FLOW</td>
<td></td>
</tr>
<tr>
<td>3.1 Description</td>
<td>6</td>
</tr>
<tr>
<td>3.2 Two-Phase Flow Equations</td>
<td>9</td>
</tr>
<tr>
<td>3.3 Two-Phase Flow Correlations</td>
<td>11</td>
</tr>
<tr>
<td>3.4 Single-Phase Liquid Flow</td>
<td>17</td>
</tr>
<tr>
<td>3.5 Heat Transfer Equations</td>
<td>18</td>
</tr>
<tr>
<td>4. COMPUTER CODE</td>
<td></td>
</tr>
<tr>
<td>4.1 Description</td>
<td>20</td>
</tr>
<tr>
<td>4.2 Validation</td>
<td>24</td>
</tr>
<tr>
<td>5. USES OF WELLBORE MODELS</td>
<td></td>
</tr>
<tr>
<td>5.1 Pressure and Temperature Profiles</td>
<td>28</td>
</tr>
<tr>
<td>5.2 Discharge Analysis</td>
<td>29</td>
</tr>
<tr>
<td>5.3 Casing Design</td>
<td>31</td>
</tr>
<tr>
<td>5.4 Fluid Enthalpy</td>
<td>33</td>
</tr>
</tbody>
</table>
5.5 Scale Deposition ......................... 34
5.6 Wellbore Heat Transfer .................. 36
5.7 Well Test Analysis ....................... 37
5.8 Decline Curves ......................... 38

6. CONCLUSIONS ............................. 39

NOMENCLATURE ............................. 41

REFERENCES

APPENDIX A Flow Diagram and Program Listing
APPENDIX B Data Used
APPENDIX C Derivation of equations
1. INTRODUCTION

In geothermal field development the engineer is concerned with fluid flow in the reservoir and wellbore. Two-phase flow occurs in the wellbore of the wells in liquid dominated reservoirs. The engineer is therefore interested in simulating two-phase wellbore flow to obtain information about the reservoir and production characteristics of wells.

Two-phase vertical flow in geothermal wells has been studied by many investigators. The equations that describe such flow are the continuity, momentum, and energy equations. These are then used to express the total pressure drop up the wellbore in terms of its potential, acceleration, and frictional components. In studies of this nature we are able to draw upon the extensive two-phase literature of the nuclear and oil and gas industries.

While many papers have been published with geothermal wellbore flow models, there are not many studies that show how these models can be used. The step from theoretical models to engineering applications seems not to have received a lot of attention. There may exist many applications which still need to be discovered. The problem
is that we do not have extensive measurements of geothermal well behavior. However, as more data becomes available it is important to have an accurate and workable wellbore simulator. Continuous interaction between field measurements and flow modeling studies should advance our understanding of geothermal well characteristics.

The main purpose of the present work was to develop a workable geothermal wellbore simulator, the work is based on earlier efforts at Stanford University. A new computer code was written with minor modifications of the commonly used two-phase flow correlations. The applications considered (8 main categories) are based on known problems in geothermal reservoir engineering.
2. LITERATURE SURVEY

Most of the available correlations for vertical two-phase flow in wells have been developed for the oil and gas industry. These correlations have been modified to suit the condition that exist in geothermal wells. A complete analytical description of one dimensional two-phase flow is given by Wallis.

Gould used a combination of correlations from Hagedorn-Brown, Ros, Turner-Ros, Aziz, and Orkiszewski and coupled them with heat transfer equations to model two-phase flow in geothermal wellbores. The data he used to validate the model came from the Wairakei and Broadlands geothermal fields in New Zealand and East Mesa in the Imperial Valley. Gould found that the Hagedorn-Brown and Turner-Ros correlations were the most consistent.

Upadhyay et al. concluded that the correlations used by Orkiszewski and Hagedorn-Brown predict accurately the overall pressure drop in geothermal wellbores. Fandriana et al. compared four different correlations and found that Orkiszewski gave the best result.
Chierici et al\textsuperscript{18} developed a geothermal wellbore model based on a previous work done by Chierici for oil and gas wells. They use the same criteria as Orkiszewski to determine the flow regimes. Barelli et al\textsuperscript{22} included the effect of non-condensable gases on wellbore flow. They varied CO\textsubscript{2} content to match the flowing temperature and pressure profiles. It was found that an increased CO\textsubscript{2} concentration brings about an increase in pressure but has little effect on temperature.

Nathenson\textsuperscript{44} made calculations for a typical geothermal well showing the effects on production of varying reservoir parameters. Elliot\textsuperscript{72} compared the available power at wellhead for self flowing and pumping wells. Butz and Plooster\textsuperscript{13} used a two-phase wellbore simulator to investigate the effects of well casing diameter and productivity index on the flow rate to show that casing design can be optimized.

Bilicki et al\textsuperscript{14} examined the effects of fluid temperature, pressure, equivalent salinity, reservoir drawdown coefficient, heat loss, and well. They found that the most important parameter governing flow in geothermal wells is the reservoir temperature.

Miller\textsuperscript{15} has developed a wellbore model and coupled it with a simple reservoir model. The transient behavior of single and two-phase flow well during a well test was investigated. Hoang\textsuperscript{16} has also coupled reservoir and
wellbore models and reported good agreement with the reservoir properties calculated using conventional well testing techniques.

Goyal et al.\textsuperscript{21} used flowing surveys (temperature and pressure) from Cerro Prieto wells to compare with calculated pressure and temperature profiles. They found that the calculated profiles were quite sensitive to measured wellhead parameters and well inside diameter.
3. VERTICAL TWO-PHASE FLOW

3.1 Description

Vertical two-phase flow has mainly been studied by semi-empirical methods. Correlations that were developed for two-phase flow in oil and gas wells have successfully been applied to geothermal wells.

Orkiszewski\(^4\) classified existing correlations for vertical two-phase flow in wells into three categories:

First, liquid holdup is not considered in the determination of the mixture density which is just corrected by pressure and temperature. Liquid holdup and the pressure losses are expressed using empirically correlated friction factor. There is not distinction between flow regimes.

Second, liquid holdup is considered in the calculation of mixture density. Holdup is correlated separately or in combination with friction losses. The friction losses are based on the properties of the mixture. There is not distinction between flow regimes.

Third, liquid holdup is used to calculate the mixture density. Holdup determination is based on the slip velocity
(difference between gas and liquid velocities). The friction losses are determined using the continuous phase. Four flow regimes are considered.

Hagedorn-Brown\textsuperscript{4} belongs to the second category, while the Duns-Ros\textsuperscript{3}, and the Orkiszewski\textsuperscript{4} correlations belong to the third category.

Flow regimes commonly used in the two-phase literature are as follow:

Bubble. In this regime the liquid phase is the continuous phase and occupies most of the pipe volume, and the gaseous phase appears as small bubbles distributed through the liquid. The liquid phase is decisive in the pressure gradient calculation.

Slug. The liquid phase remains as the continuous phase, but the bubbles have increased in number and size and now join to form a single bubble which form and size approaches the pipe diameter. The velocity this bubble is by far larger than the velocity of the liquid. Both liquid and gas contribute in the total pressure gradient.

Transition. In this regime the gaseous phase becomes the continuous phase and some liquid is entrained as small droplets into the gaseous phase. The gas has a greater influence on the total pressure gradient than the liquid.

Mist. The gaseous phase is the continuous phase and the
liquid is entrained in the gas. The gaseous phase controls the pressure gradient and liquid causes secondary effects.

When dealing with two-phase flow we have to refer to the saturation states of water. These are defined as states at which a phase change begins or ends. The saturated-liquid line is the state at which the first bubble of steam forms, and the saturated-gas line is the state at which the first liquid droplet forms. The subscript "f" is commonly used to indicate states in the saturated-liquid line, and the states in the saturated-gas line will be referred by the subscript "g".

If the quality \( x \) is defined as the fraction of the total mass which is saturated gas, enthalpy of the liquid-gas mixture \( h_m \) can be calculated from

\[
h_m = (1 - x) h_f + x h_g
\]  

(1)

and specific volume of the gas-liquid mixture \( \nu_m \) will then be expressed by

\[
\nu_m = (1 - x) \nu_f + x \nu_g
\]  

(2)

If the void fraction \( \alpha \) also called gas holdup is the volume of gas or steam actually present in a given pipe section, expressed as the fraction of the total volume of
that pipe section, then the density of the liquid-gas mixture as a function of the void fraction is given by

$$\rho_m = (1 - \alpha) \rho_f + \alpha \rho_g \quad (3)$$

The superficial velocities $V_{sl}$ and $V_{sg}$ of liquid and gas respectively will be defined as

$$V_{sl} = \frac{q_l}{A} \quad (3a)$$

and

$$V_{sg} = \frac{q_g}{A} \quad (3b)$$

where $q_l$ and $q_g$ are the volumetric flowrates of the two phases and $A$ is the cross-sectional flow area. Eqs. (1), (2), and (3) are derived in Appendix C.

3.2 Two-Phase Flow Equations

The basic equations for steady one-dimensional two-phase flow are, the continuity equation:

$$W_t = \rho_m V_m A \quad (4)$$

and the momentum equation

$$\frac{dV_m}{dz} = -\frac{dp}{dz} A - \pi \gamma_w D - \rho_m g A \quad (5)$$

Substituting Eq. (4) in Eq. (5) we get
\[ \rho_m A \frac{\hat{v}_m}{dz} = -\frac{dp}{dz} A - \pi \mathcal{C}_w D - \rho_m g A \quad (6) \]

Multiplying the whole equation by \( dz / A \) and solving for \(-dp\)

\[-dp = \rho_m g \, dz + \pi \mathcal{C}_w D \frac{dz}{A} + \rho_m v_m \, d\hat{v}_m \quad (7)\]

 Rewriting the kinetic term of Eq.(7) as done by Poettmann and Carpenter

\[ \rho_m v_m \, d\hat{v}_m = -\frac{q_3 \, Wt}{A^2 \, \bar{p}} \, dp \quad (8) \]

and denoting \( \pi \mathcal{C}_w D / A \) by \( t_f \), which is the pressure drop per unit length due to friction, Eq.(7) can be rewritten as

\[-dp = \rho_m g \, dz + t_f \, dz - \frac{q_3 \, Wt}{A^2 \, \bar{p}} \, dp \, dz \]

Solving for \(-dp\)

\[-dp = \left[ \frac{\rho_m g + t_f}{1 - \frac{q_3 \, Wt}{A^2 \, \bar{p}}} \right] \, dz \quad (9)\]

The minus sign is needed because we are considering \( z \) as positive in the upward direction.
3.3 Two-Phase Flow Correlations

The procedure described by Orkiszewski\(^1\) will be followed in this work. It has been used successfully in the oil and gas industry. Orkiszewski method has also been applied to geothermal wells giving reasonable results in determination of pressure drops. The method will now be described.

The flow regimes are determined as by Duns and Ros\(^3\). The upper limit for bubble flow in their pattern map was approximated by a third degree polynomial. In order to make use of this flow pattern map we need to get the liquid number \(N\) and the gas number \(N_g\). For the units given in the nomenclature:

\[
N_L = 1.938 \frac{V_{sl}}{\gamma} \left( \frac{p_L}{\gamma} \right)^{\frac{1}{4}} \tag{10}
\]

\[
N_g = 1.938 \frac{V_{sg}}{\gamma} \left( \frac{p_L}{\gamma} \right)^{\frac{1}{4}} \tag{11}
\]

where \(\gamma\) is the surface tension (dynes/cm), then the flow regimes are determined as follows:

- **Bubble** \(0.1 < N_g < 1.024 + 1.475 N_L - 1.75 \times 10^{-2} N_L^2 + 1.088 \times 10^{-3} N_L^3\) \(\tag{12}\)

- **Slug** \(N_g < 50 + 36 N_L\) \(\tag{13}\)

- **Transition** \(N_g < 75 + 84 N_L\) \(\tag{14}\)

- **Mist** \(N_g > 75 + 84 N_L\) \(\tag{15}\)

Once the flow regime is determined the value for \(\Phi_m\) and \(t_f\) are obtained according to the following criteria.
Bubble flow

The density of the mixture $\rho_m$ can be determined using Eq. (3)

$$\rho_m = (1 - \alpha) \rho_L + \alpha \rho_g$$

(3)

where $\alpha$ is determined according to Griffith and Wallis

$$\alpha = \frac{1}{2} \left[ 1 + \frac{q_t}{Vs \ A} - \sqrt{\left( 1 + \frac{q_t}{Vs \ A} \right)^2 - \frac{4 \ q_g}{Vs \ A}} \right]$$

(16)

where $Vs$ is the slip velocity and for which they suggested a value of 0.8 ft/sec.

The friction loss gradient $t_f$ is given by

$$t_f = f \ \frac{V_L^2 \ \rho_L}{2 \ g \ D}$$

(17)

where $V_L$ is the real velocity of liquid and is calculated as

$$V_L = \frac{q_L}{A \ (1 - \alpha)}$$

(18)

The friction factor $f$ is obtained using a standard Moody diagram as a function of Reynolds number

$$N_{Re} = 1488 \ V_L \ \rho_L \ / \ \mu_L$$

(19)

Slug flow

The density of the mixture $\rho_m$ is calculated by
\[ \rho_m = \frac{Wt + \rho_l Vb A}{q_t + Vb A} + \Gamma \rho_l \]  

(20)

where \( \Gamma \) is a correlated liquid distribution coefficient, introduced by Orkiszewski, which implicitly accounts for the following:

- Liquid is distributed in places the slug, the film around the gas bubble and in the gas bubble as entrained droplets.
- The friction loss has two contributions, one from the liquid slug and the other from the liquid film.
- The bubble rise velocity \( V_b \) approaches zero as mist flow is approached.

The bubble rise velocity \( V_b \) was correlated by Griffith and Wallis \(^q\) as a function of the bubble Reynolds number

\[ Nb = \frac{1488 D V_b \rho_l}{\mu_l} \]  

(21)

and the liquid Reynolds number

\[ N_{Re} = \frac{1488 D V_t \rho_l}{\mu_l} \]  

(22)

where \( V_t \) is the total superficial velocity given by

\[ V_t = V_{sl} + V_{sg} \]  

(23)

the bubble rise velocity is then calculated from the following set of equations when \( Nb \leq 3000 \)
\[ V_b = (0.546 + 8.74 \times 10^{-6} \, N_{Re}) \sqrt{g \, D} \] (24)

when \( N_b \geq 8000 \)

\[ V_b = (0.35 + 8.74 \times 10^{-6} \, N_{Re}) \sqrt{g \, D} \] (25)

when \( 3000 < N_b < 8000 \)

\[ V_b = \frac{1}{2} V_{bi} + V_{bi}^2 + \frac{13.59 \, \mu_L}{\rho_L \sqrt{D}} \] (26)

where \( V_{bi} = (0.251 + 8.74 \times 10^{-6} \, N_{Re}) \sqrt{g \, D} \) (27)

In the Orkiszewski method the friction loss gradient \( t_f \) in the slug regime is calculated from

\[ t_f = f \frac{V_t^2 \rho_l}{2 \, g \, D} \left[ \frac{q_L + V_b \, A}{q_t + V_b \, A} + \Gamma \right] \] (28)

where the friction factor \( f \) is obtained from a Moody diagram as a function of the liquid Reynolds number given by Eq.(22)

The liquid distribution factor \( \Gamma \) is determined using the following equations

when \( V_t \leq 10 \)

\[ \Gamma = \left[ (0.013 \log \mu_L) / D^{1.38} \right] - 0.681 + 0.232 \log V_t \\
-0.428 \log D \] (29)

when \( V_t > 10 \)
\[
\Gamma = \left[ \left( 0.045 \log \mu_L \right) / D^{0.799} \right] - 0.709 - 0.162 \log \nu_t - 0.888 \log D \tag{30}
\]

and restricted by the limits

\[
\Gamma \geq -0.065 \nu_t \quad \text{when } \nu_t \leq 10 \tag{31}
\]

\[
\Gamma \geq -\frac{V_b A}{q_t + V_b A} \left( 1 - \frac{\rho_m}{\rho_L} \right) \quad \text{when } \nu_t > 10 \tag{32}
\]

These restrictions are to avoid pressure discontinuities between flow regimes.

Transition flow

In the transition regime the mixture density \( \rho_m \) and the friction loss gradient \( t_f \) are calculated for the slug and mist regimes and then weighted with respect to \( Ng, \) and \( Lm \) and \( Ls \) the lower and upper limits of the transition regime, as proposed by Duns and Ros:

\[
\rho_m = A \left( \rho_m \right)_{\text{SLUG}} + B \left( \rho_m \right)_{\text{MIST}} \tag{33}
\]

\[
t_f = A \left( t_f \right)_{\text{SLUG}} + B \left( t_f \right)_{\text{MIST}} \tag{34}
\]

where

\[
A = \frac{Lm - Ng}{Lm - Ls} \tag{35}
\]

and

\[
B = \frac{Ng - Ls}{Lm - Ls} \tag{36}
\]
Mist flow

In this regime Orkiszewski calculated \( \rho_m \) and \( t_f \) as Duns and Ross\(^3\):

The density of the mixture is given by

\[
\rho_m = (1 - \alpha) \rho_l + \alpha \rho_g \tag{3}
\]

where \( \alpha \) is obtained assuming negligible slip between phases, then

\[
\alpha = \frac{1}{1 + \frac{q_l}{q_g}} \tag{37}
\]

The friction-loss gradient is calculated from

\[
t_f = f \rho_g V_{sg}^2 / 2 \rho g D \tag{38}
\]

where \( V_{sg} \) is the superficial gas velocity.

In the mist flow regime the friction factor \( f \) is obtained from a Moody diagram as a function of the gas Reynolds number

\[
N_{RG} = 1488 D V_{sg} \rho_g / \mu g \tag{39}
\]

and a correlated form of the Moody relative roughness factor \( e/D \) that was developed by Duns and Ross\(^3\). \( e/D \) is limited to be bigger than 10**-3 and less than 0.5.

\[
N_w = 4.52 \times 10^{-7} (V_{sg} \mu g / \gamma)^2 \rho_g / \rho_l \tag{40}
\]
if $N_w < 0.005$

$$e/D = 34 \sqrt[3]{( \rho g \nu s^2 D )}$$ \hspace{1cm} (41)

if $N_w > 0.005$

$$e/D = 174.8 \sqrt[3]{( N_w )^{0.302}} / ( \rho g \nu s^2 D )$$ \hspace{1cm} (42)

3.4 Single Phase Liquid Flow

In single phase liquid flow the kinetic term will be negligible and for units given in nomenclature, Eq. (9) becomes:

$$-dp = \frac{1}{144} \left[ \rho_L + t_f \right] dz$$ \hspace{1cm} (43)

The calculation of $\rho_L$ has to be done carefully because it represents the most important part of the total pressure gradient. The following procedure has been proposed by Gould:

$$\rho_L = 62.4 \gamma_w / B_w$$ \hspace{1cm} (44)

where $B_w$ is the formation volume factor of water and is given by:

$$B_w = 1.0 + 1.2 \times 10^{-4} T_x + 1.0 \times 10^{-6} T_x^2 - 3.33 \times 10^{-6} \overline{P}$$ \hspace{1cm} (45)

and $T_x = \overline{T} - 60$.

$\gamma_w$ = specific gravity of water
\[ T = \text{Average temperature (°F)} \]
\[ P = \text{Average pressure (psia)} \]

The friction loss gradient \( t_c \) is obtained from the equation:

\[
t_c = \frac{1}{144} f \frac{\rho_L V_L^2}{2 g_c D} \tag{46}
\]

where the friction factor \( f \) can be calculated by Colebrook\textsuperscript{19} equation

\[
f = \left\{ 1.14 - 2 \log \left( \frac{e}{D} + \frac{9.28}{N_{RE} \sqrt{f}} \right) \right\}^{-2} \tag{47}
\]

where

\[ N_{RE} = 1488 D V \rho_L / \mu_L \tag{48} \]

the friction factor \( f \) has to be calculated by iteration when using Eq.(47).

3.5 Heat Transfer Equations

When geothermal fluids flow toward the surface there may exist a temperature difference between the formation and the wellbore. This will result in unsteady radial heat transfer.

Ramey\textsuperscript{20} gives an approximate solution to this problem which permits estimation of fluid and casing temperature as
a function of time. Assuming steady flow in pipe, flow-work is zero, and the total-energy equation can be written as

\[ h_i = h_{i-1} - Q + \frac{g}{g_c} \frac{\Delta z}{J} + \frac{\Delta V t^2}{2 g_c J} \]  \hspace{1cm} (49)

The amount of heat lost by the fluid and transferred to the ground in an increment of pipe is given by

\[ Q = U D U \left( T - T_r \right) \frac{A z}{W t} / f(t) \]  \hspace{1cm} (50)

where \( U \) (Btu/hr/sqft/F) is the overall heat transfer coefficient and \( f(t) \) is a time dependency function expressed by

\[ f(t) = -\ln \left( \frac{r_c}{2 \sqrt{\alpha' t}} \right) - 0.29 \]  \hspace{1cm} (50a)

and \( r_c \) = is the outer casing radius (ft)

\( \alpha' \) = Thermal diffusivity of earth (sqft/day)

\( t \) = flowing time (days)

For wells with high flow rates where the convection heat transfer is predominant, the time function cancels out in Eq. (50).
4. COMPUTER CODE

4.1 Description

A computer code has been developed to solve Eq.(9) which determines the pressure drop in a vertical two-phase flow. The code is based on earlier work done by Fandriana et al\textsuperscript{2}. When the current effort was initiated it was found that the Fandriana et al\textsuperscript{2} code did not work except for limited input conditions. Also, the calculations were time consuming and therefore costly. The modified computer code takes about ten times less time for execution and accepts a wide range of input conditions. Although the new code is more workable than the previous code, it is limited to use Orkiszewski's method. In the Fandriana et al\textsuperscript{2} code there were options to use the methods of Orkiszewski,\textsuperscript{1} Duns and Ros,\textsuperscript{3} Beggs and Brills, and Hagedorn-Brown.\textsuperscript{4}

Pressure drop in two-phase wellbore flow is determined by Eq.(9) which includes the effects of potential energy, friction and acceleration:
\[ \Delta P = \frac{1}{144} \left[ \frac{\phi m + t_f}{Wt q_s} \right] \frac{\Delta z}{1 - \frac{4637 A^2}{4637 A^2 p}} \] (9)

In the computer code this equation is solved by dividing the total length of the well into intervals where the fluid properties can be considered constant.

The computer code solves a one-dimensional steady-state wellbore model. It includes calculations of the pressure and temperature along with other flowing parameters at different depths. The flowing conditions at the top or bottom of a geothermal well are needed as input. The input data required for the wellbore calculations are shown in Appendix A.2. The computer code solves the pressure drop and the heat transfer Eqs. (9), (49), and (50) simultaneously using simple iteration. The total pressure drop is split into its friction, potential and kinetic terms to show their individual effects. In the code is possible to handle up to eight different diameters with their respective absolute roughness.

A flow diagram of the computer code is given in Appendix A.1. A brief description of the main steps of the code will now be given:

1. Divide the total well length in several intervals.
2. Calculate the rock temperature at the middle of the interval using Lagrange interpolation on the shut-in temperature.

3. Assume a temperature drop, and using Eqs. (49) and (50) calculate enthalpy of mixture.

4. Assume a pressure drop for the interval.

5. Calculate fluid properties for the average pressure and temperature.

6. Calculate the pressure drop using single phase liquid or two-phase flow correlations as needed.

7. Compare with assumed pressure drop, if a good agreement is not achieved repeat from step 4.

8. Using the calculated pressure drop and assumed temperature drop determine enthalpy of mixture for single phase, and for two-phase use the calculated pressure drop to get the temperature drop.

9. Compare results in step 8 with ones in step 3 if there is not a good agreement repeat from step 3.

10. Once the pressure and temperature match has
been obtained proceed with the next interval.
The calculations end when the total well
length has been reached.

The enthalpy of steam and water are obtained from steam
tables values using Lagrange interpolation. Steam Density
is also calculated from steam tables. The density of the
brine is calculated according to Eq.(44). The way in which
the remaining variables are obtained can easily be deduced
from the program listing in Appendix A. It has to be
mentioned that in determining the fluid properties the
presence of non-condensable gases is not taken into account.
When the geothermal fluid has a high content of non-
condensable gases the model should be used with discretion.

While testing the original code developed by Fandriana et
al. 2 a jump in the pressure gradient was detected when
going from $V_t < 10$ to $V_t > 10$ within the slug regime using
the orkiszewski correlation. The jump was partially due
to the low viscosities in geothermal wells < 1 cp compared
to the high viscosities encountered in oil and gas wells (>
10 cp) for which the correlation was developed. It was
found that the cause of this jump was the factor introduced
by Orkiszewski to correlate experimental data for the
density of two-phase mixtures. In order to give a smooth
pressure gradient the next modification in calculating the
factor was done:
\[ \Gamma = -0.065 \, Vt - 0.1 \] (51)

and

\[ \Gamma = \left[ \frac{0.045 \, \log M}{D^{0.799}} \right] - 0.709 - 0.162 \log Vt - 0.888 \log D \] (30)

This second equation restricted by

\[ \Gamma \geq - \frac{Vb \, A}{q + Vb \, A} \left( 1 - \frac{\rho_m}{\rho_l} \right) \] (32)

Eqs. (51) and (30) are evaluated and the bigger value of the factor is to be taken.

This simple procedure became to give a smooth change in pressure gradient and still the agreement with field data was satisfactory.

4.2 Validation

The present computer code was tested against measured pressure and temperature profiles from wells in the Imperial Valley, Cerro Prieto, and Roosevelt Hot Springs.

(a) East Mesa 6-1

The data for this well were obtained from Fandriana et al.\(^2\). The production zone was set at 7000 ft and the inside pipe diameter 0.7267 ft. The total mass flow rate was
102,500 lb/hr. A pipe roughness of 0.0003 ft was considered in the calculations. The heat transfer coefficient was arbitrarily determined to be 10 Btu/hr/sqft/F and water gravity was taken 1.0208. Appendix B.1 shows the shut-in temperature and measured pressure and temperature profiles of the east Mesa well.

Using the above data, calculations were made starting at bottomhole. The calculated flashing point was at 4079 ft depth showing good agreement with measurements. The calculations showed single phase at the bottom up to flashing point and then going through bubble, slug and transition flow regimes. The superficial velocities at wellhead were 0.987 ft/sec and 107 ft/sec for water and steam respectively. The good agreement with field data can be observed in Fig.1.

(b) Cerro Prieto M-90

Flowing data for well M-90 in Cerro Prieto was obtained from Castaneda (1983). The measurements are from a test carried out on February 21st 1978. The production zone was estimated to be at 4261 ft depth. The well has a uniform inside pipe diameter and equal to .5808 ft. The total mass flow rate was 356,840 lb/hr. The pipe roughness was taken as 0.0003 ft. The enthalpy at wellhead was determined to be 578 Btu/lb. The heat transfer to the ground was considered negligible and
the water gravity was assumed 1.019. Table B.2 shows the shut-in temperature as well as the pressure and temperature profiles measured during the test.

The measured and calculated pressure profile for this well are compared in Fig. 2. The calculations were started at the wellhead using the measured enthalpy, and saturation temperature corresponding to 590 psia. The results show that well is flowing in two-phase flow. Flashing point was detected at wellbottom. The bubble and slug regimes were observed for these data. It has to be mentioned that using the measured temperature at the wellbottom single phase liquid flow is detected at the bottom but flashing point is calculated at a higher point and the agreement with measured profile is not satisfactory. This may be possible to the high content of CO₂ observed in this well.

(c) Roosevelt Hot Springs 14-2

The data for well 14-2 in Roosevelt Hot Springs were taken from Butz and Plooster³, and is a flowing pressure survey identified as log 78-6. For the purpose of our calculations the production interval was considered at 2996 ft. The well has a 0.7433 ft inside diameter casing from surface to bottom. The total mass flow rate at the time of the test was 325,000 lb/hr. The pipe roughness was considered to be 0.0003 ft. An enthalpy of 502 Btu/lb was taken as the average reported in Fig.12 of Butz and
Plooster\textsuperscript{13}. The heat transfer to the ground was considered zero. Table B.3 gives the pressure profile for this well; the temperature profile was not available.

The comparison of measured and calculated profiles is shown in Fig.3. The calculations were started at wellbottom. A downhole temperature of 512 F was assumed to match the 502 Btu/lb enthalpy. It can be observed that the agreement is quite good. The flashing point was calculated at 2604 ft, and the bubble and slug flow regimes were observed above the flashing point.
5. USES OF WELLBORE MODELS

5.1 Flowing Pressure and Temperature Profiles

Knowing the discharge conditions and casing schedule of a geothermal well it is possible to calculate the temperature and pressure profiles. Based on these profiles the depth at which the flashing point is occurring can be determined. This point is characterized by a significant change in the pressure gradient.

A good example of the use of temperature profiles is in correlating the kind of minerals that will deposit on the pipe wall at different depths according with the temperatures present at those depths.

In the analysis of mechanical stress on casing and on casing cementing due to thermal effects the temperature profile is required.

The pressure and temperature profile can be useful in determining the depth for setting a pump into the wellbore when needed. Elliot gives a complete analysis of self flowing and pumping geothermal wells, concluding that pumping is not recommendable on an energy basis but it may
be useful in preventing scaling in the wellbore.

The precision of these calculated profiles greatly depends on the quality of input data. Goyal et al.\textsuperscript{21} have done some sensitivity studies using Cerro Prieto flowing well data and found that the parameters to be measured, in order of decreasing accuracy, are well inside diameter, wellhead pressure, dryness fraction and mass flow rate. They observed a 70\% increase in bottomhole pressure for a 20\% decrease in enthalpy.

5.2 Discharge Analysis

The productivity index (PI) is the ratio of the rate of production (Wt) to the pressure drawdown in the reservoir, and is expressed as\textsuperscript{23}

\[
PI = \frac{W_t}{(p_s - p_{wf})} \quad \text{lb/hr/psi} \quad (52)
\]

It is a measured of the ability of the well to flow. \( p_s \) is the static reservoir pressure and can be obtained using well test analysis techniques or by a sufficiently long shut-in time. \( p_{wf} \) is the wellbottom flowing pressure and can be measured using subsurface pressure instruments, or using a wellbore flow model and wellhead measurements.

In calculating the discharge curve of a geothermal well and the effect of the productivity index on it We consider
that flow in the reservoir is steady state or semi-steady state, we can then consider the PI constant for a wide range of pressure drawdown as long as the fluid in the reservoir is flowing as single phase liquid.

As an example of how the wellbore model can be applied in calculating discharge curves data from Svartsengi well # 12 in Iceland \(^{24}\) will be used. Table I shows the data for this well.

**TABLE I. Data for Svartsengi well # 12 in 1983**

- \(P_{wh} = 220.6\) psia
- \(T_{wh} = 390.3\) °F
- \(W_t = 333,432\) lb/hr
- \(h_m = 429.12\) Btu/lb
- Wellbottom = 3936 ft
- \(\phi_i\) of pipe = 1.0521 ft from 0 to 1991 ft
- \(\phi_i\) of bare-hole = 1.0208 ft from 1991 to bottom
- Reservoir pressure = 1279 psia

With these data and considering heat transfer negligible the wellbore model predicted a flowing wellbore pressure of 1050 psia. Using Eq.(52) a PI of 1456 lb/hr/psi was calculated. Knowing the PI and considering it constant, several wellbottom flowing pressures were calculated for different total mass flow rates. Using the wellbore model these
wellbore flowing pressure were corrected for wellhead conditions.

Fig. 4 shows the characteristic production curve for the original 1456 lb/hr/psi PI. It also shows the curves for 500 and 1000 lb/hr/psi assumed PI's. As can be observed the decline of the discharge curve with respect of wellhead pressure is bigger for low than for high productivity indexes. Analyzing additional data from the computer output it was observed that for low productivity indexes the pressure drop in the wellbore represents a small fraction of the total available pressure. The same observation has been made by Butz et al.³

5.3 Casing Design

Wellbore flow models can be very useful in the design of casing schedules. To observe the effect of inside diameter in the wellbore performance several runs were made for Svartsengi well #12 using the data given in Table 1 assuming that the well is totally cased with a same casing to bottom and using an arbitrarily PI of 1280 lb/hr/psi. Three different diameters were assumed 13 3/8", 9 5/8", and 7 5/8" which are commonly used in geothermal wells.

From Figs. 5, 6, and 7 it can be seen that for a given flowrate the wellhead pressure is lower for a smaller
diameter due to an increase in friction losses. In these figures, A is pressure drop in reservoir, B is pressure drop due to potential in single phase liquid, C is the pressure drop due to friction in single phase liquid, D is pressure drop due to potential in two-phase flow, and D is the pressure drop due to friction in two-phase flow.

Svartsengi well # 12 presents an interesting case in which for low flow rates the pressure at wellhead increases with increasing flow rate, this occurs up to a maximum discharge pressure at which for higher flow rates pressure wellhead decreases as expected. This behavior has been noticed in measured output curve for other similar wells in the Svartsengi field.

From Figs. 5, 6, and 7 we observe that increasing wellhead pressure with increasing flow rate tends to disappear for small diameter. It can also be noticed that the pressure drop due to potential effects in two phase-flow is diminishing for small diameters for which we have higher velocities. This may be due to the fact, that in contrast to single phase liquid flow an increase in diameter or decrease in flow rate in two-phase flow does not necessarily represents a reduction in pressure gradients. This is because of the presence of gas (steam) which slips through the liquid without contributing to the lift.

Finally, we note that below the flashing point the pressure drop is mainly controlled by the potential term so
the casing size is not as critical as in two-phase flow.

5.4 Reservoir Fluid Enthalpy

To analyze the effect of the reservoir fluid enthalpy in the performance of a geothermal well, several runs were made using data for Svartsengi well # 4 given in Table II.

<table>
<thead>
<tr>
<th>TABLE II</th>
<th>Data for Svartsengi Well # 4 in 1975</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pwh</td>
<td>263.04 psia</td>
</tr>
<tr>
<td>Twh</td>
<td>405.54 F</td>
</tr>
<tr>
<td>Wt</td>
<td>467,280 lb/hr</td>
</tr>
<tr>
<td>h</td>
<td>454.2 Btu/lb</td>
</tr>
<tr>
<td>Wellbottom</td>
<td>3,359 ft</td>
</tr>
<tr>
<td>0i of pipe</td>
<td>0.7218 ft from 0 to 1148 ft</td>
</tr>
<tr>
<td>0i of pipe</td>
<td>0.5676 ft from 1148 to bottom</td>
</tr>
</tbody>
</table>

The overall heat transfer coefficient was considered negligible. Using the wellbore model a bottom hole pressure of 1067 psia and a temperature of 472 F were calculated. Considering everything constant the wellbottom temperature was increased to simulate an increase in reservoir fluid enthalpy. The increase in temperature was taken to a point in which the flashing occurs a few feet above the wellbottom. It was not increased more because if flashing
occurs at the reservoir then the productivity index can not be considered constant anymore.

From Fig. 8 it can be seen that wellhead pressure depends greatly on the reservoir fluid enthalpy. Bilicki et al. have concluded that reservoir temperature is a decisive parameter in the flow performance of geothermal wells.

Wells producing from two-feed zones in a steady-flow can be analyzed using wellbore models. The well performance will depend on the enthalpy of the fluids entering the well. Grant et al. refer to the case of two-feed zones, showing in a schematical way how a well with an upper steam-feed and a water lower-feed will cycle when operated at low flow rates. A well with a cold water entrance may stop flowing or diminish its flow performance due to lowering of mixture enthalpy.

5.5 Scale Deposition

Scale deposition such as calcium carbonate will normally occur immediately above the flashing point. This deposition can occur in a length of several feet and form rapidly causing a decrease in flow rate or in wellhead pressure even when the reservoir characteristics remain practically constant.
The wellbore model was used to simulate scale deposition in Svartsengi well # 4 with the data given in Table II. The scale deposition was assumed to occur in the 300 ft immediately above the flashing point which was calculated at 1890 ft. The incrusted interval was assumed to have a constant diameter and the roughness was considered 0.003 ft which is an average for concrete. The mass flow rate, wellbottom flowing pressure and the productivity index were kept constant so the flashing point remained at the same depth.

Fig. 9 shows the reduction in wellhead pressure as a function of the fraction of cross-sectional area that has been incrusted. It can be noticed that this curve is concave downwards in contrast with a productiln decline curve which would probably be concave upwards. This behavior of incrustation has been observed in Svartsengi. The present wellbore model and approach have been applied to wells in the Miravalles geothermal field in Costa Rica. A good match with field data has been achieved. Grant et al, mention that an increasing decline in flow as flow approaches zero is characteristic of deposition.

It remains to determine the rate of deposition. Usually is assumed that the volume of scale deposited per unit length will increase linearly with cumulative production. Then using this criteria the pressure drop at the wellhead would decrease slightly at the beginning of incrustation and
declining faster as more and more area has been incrusted.

5.6 Wellbore Heat Transfer

When obtaining the characteristic production curves of a geothermal well in a short time the enthalpy of the mixture increases with flow rate and shows a reduction at low rates. This has been observed in the Los Azufres geothermal field in Mexico. If we look at Eq.(50) we notice that for high flow rates and low wellbore temperature the amount of heat transferred to the ground decreases. If the shut-in temperature and the remaining reservoir/fluid parameter are known the overall heat transfer coefficient can perhaps be estimated by matching the measured and calculated profiles.

For geothermal wells with commercial flow rates the formation around the well reaches thermal equilibrium after few days or weeks in most instances, the heat conduction can then be neglected in our calculations.

Fig.10 gives effect of heat transfer on the pressure profile at well 6-1 in East Mesa field. The curve to the left was calculated assuming an overall heat transfer coefficient of 10 Btu/hr/sqft/F but the other curve assuming zero heat transfer. It can be noticed that the curve with overall heat transfer coefficient equal zero will flash at a deeper point and also will have a higher pressure at the
wellhead because of its higher enthalpy.

5.7 Well Test Analysis

Transient pressure tests have been used with good results in oil and gas industry and have become an important technique to obtain reservoir data. Unfortunately these analytical and graphical techniques are based on bottomhole pressure measurements which are very difficult to obtain in geothermal wells.

Hoang\(^4\) approaches the problem using a wellbore flow model to calculate wellbottom pressures and couples them with a simple reservoir simulator. He assumes steady-state flow in the wellbore and single fluid phase flowing in a radial form in the reservoir. The permeability and porosity are considered uniform anywhere in the reservoir. A good agreement was obtained in comparing simulated reservoir parameter in this form and the ones obtained by means of the conventional well test techniques.

Miller\(^5\) has coupled a transient wellbore model with a simple reservoir model. A single phase liquid flow was assumed at the reservoir and single or two phase flow in the wellbore. Calculation using this approach have been made obtaining interesting results but no matching with field data were reported.
5.8 Decline Curves

Production decline curves provides a simple method for predicting the future behavior and life of a reservoir. They are based on the assumption that reservoir behavior can be determined from any mathematical relationship that can be matched to the production history. The usual method is to plot the production rate of unrestricted wells against the production time and then extrapolate the resultant curve for estimating future behavior.

When a well has been producing in a restricted way the obtainment of decline curves is not possible. Cutler and Johnson\textsuperscript{30} proposed for oil wells the use of bottomhole pressures and productivity index data for calculating the production decline curve that the well would have followed if it were allowed to produce without restriction.

Because of the lack of a physical model supporting decline curve methods their uses appear limited\textsuperscript{25}. They cannot predict the effects of changes in management practice or the character of the reservoir such as cold water entry. However, many successful predictions have been made using this simple method.
CONCLUSIONS

1. A workable computer code has been developed to simulate vertical two-phase flow in geothermal wells. Reasonable results can be obtained when the input data are of good quality.

2. Using the computer code the output characteristic curve can be obtained considering constant productivity indexes.

3. In casing design is very useful to split the total pressure gradient in its potential, friction and kinetic terms to observe its individual effects. In single liquid phase flow the casing diameter is not critical because the pressure drop is mainly controlled by the potential term.

4. The reservoir temperature is a very important parameter in well flow performance in the liquid dominated reservoir.

5. The wellbore flow models can be applied to analyze the effect of cold water entrance in wellbores.

6. A good example of use has been in simulating
scale deposition.
7. The use of wellbore flow models in the obtaining reservoir characteristics seems to be limited due to the high resolution needed in well test analysis techniques.
8. Wellbore flow models can be used in obtaining of overall heat transfer coefficient when the pressure and temperature profiles are matched.
9. The model can be used in evaluating production histories to analyze them using production decline curves.
NOMENCLATURE

A  cross-sectional area of pipe, sqft
D  inner pipe diameter, ft
e  absolute roughness of pipe, ft
f  Moody friction factor, dimensionless
g  gravity acceleration, ft/sec
gc  gravitational constant, ft-lbm / lbf-sec
h  enthalpy, Btu/lbm
J  Mechanical equivalent of heat (778 ft-lbf / Btu)
Lm lower limit mist flow, dimensionless
Ls higher limit slug flow, dimensionless
Nb bubble Reynolds number, dimensionless
Ng gas number, dimensionless
Nl liquid number, dimensionless
Re Reynolds number, dimensionless
p  pressure, psia
Q  heat transferred to surroundings, Btu /lmb
g  volumetric flow rate, ft / sec
t  time, sec
tf friction-loss gradient, lb/ft /ft
U  overall heat transfer coeff., Btu/hr/sqft/F
V  velocity, ft/sec
Vb bubble rise velocity, ft/sec
Vs slip velocity, ft/sec
Vsg superficial gas velocity
Vsl superficial liquid velocity, ft/sec
Wt total mass flow rate, lbm/hr
$x$  steam quality, dimensionless
$z$  depth, ft
$\alpha$  void fraction, dimensionless
$\delta_w$  specific gravity of water, dimensionless
$\Gamma$  liquid distribution coeff., dimensionless
$\rho$  density, lbm/ft
$\gamma$  surface tension, dynes/cm
$\tau_w$  shear stress, lbf/sqin
$\mu$  viscosity, cp.
$\gamma$  specific volume, ft /lbm

Subscripts:

$f$ and $L$  liquid
$fg$  vaporation
$g$  gas
$m$  mixture
$t$  total
REFERENCES


28. Coordinadora Los Azufres, Mexico: "Internal Reports".


Fig. 1. Measured and Calculated Flowing Pressure Profile for Well East Mesa 6-1.
Fig. 2. Measured and Calculated Flowing Pressure Profile for Well M-90.
Fig. 3. Measured and Calculated Flowing Pressure Profile for Well Roosevelt Hot Springs 14-2.
Fig. 4. Characteristic Production Curves for Svartsengi Well 12.
Fig. 5. Available Pressure Curves for Svartsengi Well 12.
Assuming a Single 13 3/8" Casing to Bottom.
Fig. 6. Available Pressure Curves for Svartsengi Well 12.
Assuming a Single 9 5/8 " Casing to Bottom.
Fig. 7. Available Pressure Curves for Svartsengi Well 12. Assuming a Single 7 5/8 " Casing to Bottom.
Fig. 8. Calculated Pressure Profiles Showing the Effect of Fluid Enthalpy in Svartsengi Well 4.
Fig. 9. Scale Deposition Simulation for Svartsengi Well 4.
Fig. 10. Calculated Pressure Profiles to observe Heat Transfer Effect in Well East Mesa 6-1.
A.1 Computer Code Flow Diagram

Start

Input variables at initial point: pressure, temperature, enthalpy, initial point depth, total mass flow rate, water gravity, heat transfer coefficient, casing design, and shut-in temperature.

Print out input variables

Calculate Psat using T(1)

\[
\frac{P(1) - Psat}{P(1)} \geq 1 \times 10^{-3}
\]

-1 E-3 ≥

Superheated steam

Two-phase flow

Liquid flow

End
Single-Phase Liquid Flow

K=initial
Increment=1
K=final

Assume: T_avg

Calculate: heat transfer, h_avg

Assume: P_avg

Calculate: Fluid properties at P_avg and T_avg

Calculate: Pressure drop (DPC)

DPC - DPE  \[
\frac{\text{abs}}{\text{DPE}} < 1 \times 10^{-3}
\]

Yes

Calculate: h_u

h_u - h_avg  \[
\frac{\text{abs}}{\text{h_avg}} < 1 \times 10^{-4}
\]

NO

YES
2

Print out conditions at the end of interval

1

Check for flashing point

Yes

Print out: conditions at flash flash point

Two-phase Flow
Two-Phase Flow

K=initial
Increment=1
K=final

Assume:
Pressure drop (DPE)

Calculate:
Tavg, Pavg, heat Transfer, fluid properties, steam quality

Check for flashing point

Single Liquid flow

Determine:
liquid and gas numbers

Bubble Griffith-Wallis
 Slug Orkiszewski
 Transition Duns-Ros
 Mist Duns-Ros

Print out: condition at interval end

\[
\text{abs} \left( \frac{\text{DPE} - \text{DPC}}{\text{DPE}} \right) \leq 1E-3
\]
A.2 Input Data For Two-Phase Flow Code

Card:
1. RUN FOR ..........................................................

2. P(1) Pressure at the initial point ........... (psia) = 
   T(1) Temperature at the initial point .......... (F) = 
   Z(1) Depth of initial point .................. (ft) = 

3. WGR Water Gravity ........................................ =
   WT Total Mass Flow Rate ....................... (Lb/Hr) =
   ENM1 Enthalpy of mixture at initial point (Btu/Lb) =
   HCO Overall Heat Transfer Coeff... (Btu/Hr/sqft/F) =

4. INC Number of intervals ................. =

5. ANG Angle of flow from the horizontal ...... (Deg) =
   DWELLB Depth of the wellbottom ................ (ft) =
   DWELLH Depth of the wellhead ................ (ft) =

6. ISIGN +1 (if going down), -1 (if going up) .... =

7. ND Number of different diameters .......... =

8. DIA(1) Diameter of pipe at initial point .... (ft) =
   DIA(2) Diameter of pipe at first interval ...... (ft) =
   DIA(3) Diameter of pipe at second interval ... (ft) =
   DIA(4) Diameter of pipe at third interval .... (ft) =

9. AROG(1) Absolute roughness at initial point .... (ft) =
   AROG(2) Absolute roughness first interval ...... (ft) =
   AROG(3) Absolute roughness second interval ... (ft) =
   AROG(4) Absolute roughness third interval .... (ft) =

10. ZDIA(1) Depth of initial point ............... (ft) =
     ZDIA(2) Depth at which first interval ends .. (ft) =
     ZDIA(3) Depth at which second interval ends (ft) =
     ZDIA(4) Depth at which third interval ends .. (ft) =

11. NPT Number of rock temperature points ........ =

12. and 13. Depth(ft) Rock Tem(F) Depth(ft) Rock Tem(F)

    1 ............ ............ 5 ............ ............
    2 ............ ............ 6 ............ ............
    3 ............ ............ 7 ............ ............
    4 ............ ............ 8 ............ ............
A.3 Computer Code Listing

1. //TWOPHASE JOB je.zor.TME=(1,50)
2. // EXEC WATFIV
3. //SYSIN DD *
4. $WATFIV TIME=(0,10)
5. C **************************************************************
6. C * THIS PROGRAM CALCULATES THE FLOWING PRESSURE AND TEMPERATURE *
7. C * OF A GEOTHERMAL WELL. THE FLUID CAN EITHER BE SATURATED STEAM *
8. C * OR COMPRESSED LIQUID. THE DIRECTION OF FLOW CAN EITHER BE FROM *
9. C * THE WELLHEAD OR FROM THE BOTTOMHOLE. *
10. C *
11. C **************************************************************
12. C *
13. C * INPUT VARIABLES *
14. C *
15. C * P(1) = FLOWING PRESSURE, PSIA *
16. C * T(1) = FLOWING TEMPERATURE, DEG. F. *
17. C * DIA = PIPE DIAMETER, FT. *
18. C * ND = NUMBER OF DIFFERENT DIAETERS + 1 *
19. C * ZDIAM = DEPTH OF DIFFERENT DIAMETERS ENDINGS *
20. C * DIST = PIPE LENGTH, FT. *
21. C * AROUG = ABSOLUTE PIPE ROUGHNESS, FT. *
22. C * WGR = WATER GRAVITY *
23. C * WT = TOTAL MASS FLOW RATE, LB/HR *
24. C * ENML = ENTHALPY OF FLUID AT INITIAL POINT, BTU/LB *
25. C * HC0 = HEAT TRANSFER COEFFICIENT, BTU/(HR.SQFT. BF) *
26. C * ENTH = ENTHALPY, BTU/LB *
27. C * ANG = ANGLE OF FLOW FROM HORIZONTAL, DEG. *
28. C * NPT = NUMBERS OF POINTS WITH SHUT-IN TEMPERATURES *
29. C * ROKT = SHUT-IN TEMPERATURE, DEG. F. *
30. C * DEPT = DEPTH OF SHUT-IN TEMPERATURE, FT. *
31. C * DNHLL = DEPTH OF WELLBORE (FT) *
32. C * DNHLLH = DEPTH OF WELLHEAD (FT) *
33. C * ISIGN = +1/-1, (+1=ITERATION FROM THE WELLHEAD, *
34. C * -1=ITERATION FROM BOTTOMHOLE. ) *
35. C *
36. C **************************************************************
37. C *
38. C IMPLICIT REAL*8(A-H,O-Z)
39. DIMENSION DEPT(30),ROKT(30)
40. DIMENSION P(250),T(250),Z(250),ENML(250)
41. DIMENSION DIA(10),ZDIAM(10),AROUG(10)
42. DIMENSION ITITLE(20),REG(5)
43. DATA DEP/ 4HBBLE, 4HSLUG, 4HMIST, 4HTRAN, 4MMONO/
44. DATA IIN/5/
45. DATA IOUT/6/
46. C *
47. C READ INPUT PARAMETERS
48. READ(IIN,1300)(ITITL(I),I=1,18)
49. 1300 FORMAT(18A4)
50. READ(IIN,1000) P(1),T(1),Z(1)
51. 1000 FORMAT(3F10.2)
52. READ(IIN,1003)WGR,WT,ENML,HCO
53. 1003 FORMAT(4F10.2)
54. READ(IIN,4)INC
55. READ(IIN,1010) ANG,DNHLL,DNHLLH
56. 1010 FORMAT(3F10.2)
57. READ(IIN,4)ISIGN
58. READ(IIN,4) ND
59. NC=ND+1
60. 4 FORMAT(I2)
READ(IIN,1005) (DIA(I),I=1,ND)
1005 FORMAT(8F10.0)
READ(IIN,1005) (ARGU(I),I=1,ND)
READ(IIN,1005) (ZDIA(I),I=1,ND)
READ (5,4) NPT
READ (5,16) (DEPT(I),I=1,NPT)
16 FORMAT(15F5.0)
READ (5,16) (ROK(I),I=1,NPT)
C
WRITE(IOUT,3000) ITITLE(I),I=1,18
3000 FORMAT(1H1,///,5X,18A4)
WRITE(IOUT,3010)
3010 FORMAT///,5X,'INPUT DATA AS FOLLOW:'
WRITE(IOUT,3050) KGR,WT,HCO
3050 FORMAT///,7X,'WATER GRAVITY',T35,F15.4,
76. 3 ///,7X,'TOTAL MASS FLOWRATE',LB/HR',T35,F15.4,
77. 4 ///,7X,'HEAT TRANSF COEFF',BTU/HR/SQRT/F',T35,F15.4
78. IF(ISIGN.EQ.-1) GO TO 10
79. WRITE(IOUT,3020)
3020 FORMAT///,5X,'AT THE WELLHEAD:'
80. WRITE(IOUT,3040)Z(1),P(1),T(1)
81. 3040 FORMAT///,7X,'DEPTH,FT',T24,F10.2,
82. 1 ///,7X,'PRESSURE,PSIA',T24,F10.2/7X,
83. 2 'TEMPERATURE,F',T24,F10.2
84. WRITE(IOUT,3075)
3075 FORMAT///,5X,'PIPE DIAMETER USED AS FOLLOW:',/
85. GO TO 11
86. 10 WRITE(IOUT,3030)
87. 3030 FORMAT///,5X,'AT THE WELLBOTTOM:'
88. WRITE(IOUT,3040)Z(1),P(1),T(1)
89. WRITE(IOUT,3075)
90. 11 CONTINUE
91. ND1 = ND-1
92. IF(ND1.LE.0) GO TO 8
93. DO 7 II=1,ND1
94. WRITE(IOUT,3076)ZDIA(II),ZDIA(II+1),DIAM(II+1),ARGU(II+1)
95. 3076 FORMAT(7X,'FROM',F8.1,' FT TO ',F8.1,' FT, PIPE DIAMETER (FT) =',
96. 1F9.4/,T41,' ABS ROUGHNESS (FT) =',F9.4,/
97. 7 CONTINUE
98. 8 CONTINUE
99. WRITE(IOUT,3005) INC
100. 3005 FORMAT///,5X,'TOTAL LENGTH DIVIDED IN ',T3,' INTERVALS'
101. WRITE(IOUT,3060)
102. 3060 FORMAT///,5X,'DOWNHOLE SHUT-IN TEMPERATURE AS FOLLOW:',
103. 1 ///,7X,'DEPTH,FT',T25,'TEMP,F',/)
104. DO 20 I=1,NPT
105. 20 WRITE(IOUT,3070)DEPT(I),ROK(I)
106. 3070 FORMAT(2X,F12.2,5X,F10.2)
107. WRITE(6,501)
108. 501 FORMAT(1X,/)"C"
109. C CHECK FOR DENSE STATE OF GEOTHERMAL FLUID
110. IF (T(1).GT.705.OR.P(1).GT.3200.) GO TO 100
111. C
112. C CONVERT ALL VARIABLES INTO ITS USABLE FORMS.
113. SIGN = DFMAT(ISIGN)
114. PIE = 3.1415923
115. ANG = ANG*PIE/180.
116. AROG = ARGU(1)
117. DIA = DIAM(1)
AREA = PIE*DIA*DIA/4.
DIST = DWELLB-DWELLH
DELT = DIST/DFLOAT(INC)
DELL = DELT/DSIN(ANG)
ISTATE = 0
IONE = 1
FRMON = 0.0
PMON = 0.0
FRTIP = 0.0
POTTIP = 0.0
ACCTP = 0.0
IPipe = 2
CENT = 0.0
CENT2 = 0.0
DM = 21.
IF(ISIGN.EQ.1) DM=0.00

C TEST FOR COMPRESSED LIQUID
PSAT=FPSAT(T(1))
IF(PSAT-P(1)) 201,200,600
C
C * THIS IS A COMPRESSED LIQUID (SINGLE PHASE FLOW) *
C
201 IF (DABS(PSAT-P(1))/P(1) .LT.1.0D-3) GO TO 200
CALL CONAT (T(1),P(1),MVEN,ENTH)
IF (ISTATE.EQ.0) ENTH(1) = ENTH1
WRITE(IOUT,3080)
3080 FORMAT('1',/,'X'),'LIQUID FLOW **',
     'TS','FRICITION',T64,'ACCELE.','T73','POTENTIAL',T109,'cm/a',
     'X','DEPH,FT',T10,'PRESS.PSIA',T32,'TEMP,F',T40,
     'EN,BTU/LB',T51,'Psi/100ft',T62,'Psi/100ft',T75,'Psi/100ft',
     'X','f/s','/)
WRITE(IOUT,3090)Z(1),P(1),T(1),ENTH(1)
3090 FORMAT(4X,4(1X,F10.2),3(1X,F10.4),21X,F10.4)
253 CONTINUE
DPE=DELT=0.35
C
C CHECK IF THIS IS THE FIRST POINT OR A TRANSFER FROM TWO PHASE.
IF (ISTATE.NE.0) IONE = KFLASH
IF (ISTATE.NE.0 .AND. ISIGN.EQ.1) DELZ=(DWELLB-ZFLASH)/
     DFLOAT(INC-K)
C
C START TO CALCULATE PRESSURE DROP IN THE COMPRESSED LIQUID REGION.
DO 30 K=IONE,INC
30 ZMID = Z(K) + SIGMADELZ/2.
TR = FLAIR(DEPT,ROK,T,ZMID,1,NPT)
IF (ISIGN.EQ.1) AVOGAR(ZMID,E.ZDIAM(IPipe)) GO TO 39
IF (ISIGN.EQ.1) AVOGAR(ZMID,E.ZDIAM(IPipe)) GO TO 39
IPipe = IPIPE +1
AOG=ARO(AOG(IPipe))
DIA(DIAM(IPipe))
AREA = PIE*DIA*DIA/4.
C
C ITERATION TO CALCULATE TEMPERATURE AND PRESSURE VALUES
DO 31 I=1,500
31 XI = DFLOAT(I-1)
TAV = T(K) + SIGMA*XI*.005
Q = PIE*HCO*DIA^DELL*(TAV-TR)/(WT^2.)
ENAV = ENTH(K) + SIGN*(Q-DELZ/1556.)
IF(Q .LE. 0.) ENAV = ENTH(K)
C
C CALC. PRESSURE DROP USING THE ASSUMED FLOWING TEMPERATURE.
DO 32 J=1,100
PAV=P(K)*SIGN*DPE/2.
CALL PVNT(AV,TAV,PAV,WGR,DENL,VISL)
ED=AROG/DIA
VSL=W/DTENL/AREA/3600.
REYN=1498.*DIA*VSL*DENL/VISL
CALL FRFACT(REYN,ED,FH)
DPDL=(FH*DENL*VSL/(32.2*DIA)+DENL*DSIN(ANG))/144.
DPC=DPDL*DELL
IF (J .LE. 90) GO TO 4949
IF (J .GT. 91) GO TO 4848
WRITE(6,4747)
4747 FORMAT(1X,' ',J9,' ',DPE',T21', 'DPC',T33,'PAV')
4848 WRITE(6,1515)J,DPE,DPC,PAV
1515 FORMAT(1X,I3,3(2X,F10.4))
4949 CONTINUE
IF (DABS(DPC-DPE).LT.0.001) GO TO 35
DPE=(DPC+DPE)/2.
32 CONTINUE
C SYSTEM DOES NOT CONVERGE AFTER 100 ITERATIONS
WRITE (6,34)
34 FORMAT (' NO CONVERGENCE AT PRESSURE ITERATION'+/)
GO TO 999
35 CONTINUE
CALL COWAT(TAV,PAV,HDEN,ENL)
IF (I .LE. 400) GO TO 5050
IF(I.GT.401) GO TO 5151
WRITE(6,5252)
5252 FORMAT(1X,' ',I9,' ',T12,' ','ENAV',T25,'ENL',T37,'TAV')
5151 WRITE(6,1616)I,ENAV,ENL,TAV
1616 FORMAT(1X,I3,3(2X,F10.3))
5050 CONTINUE
IF (DABS(ENAV-ENL).LT.1) GO TO 36
31 CONTINUE
C SYSTEM DOESN'T CONVERGE FOR 50000 P AND T ITERATIONS
WRITE (6,37)
37 FORMAT (' NO CONVERGENCE AT TEMPERATURE ITERATION'+/)
GO TO 999
36 T(K+1)=T(K)+XI*SIGN*0.01
P(K+1)=P(K)+DPC*SIGN
C CHECK IF FLUID IS IN SATURATED REGION
PSAT=FPSAT( T(K+1) )
IF( DABS(PSAT-P(K+1))/PSAT .LT. 1.0-3 ) GO TO 50
IF(CENT .EQ. 1.) GO TO 45
IF (P(K+1)-PSAT) 40,50,60
C
C CHANGE FROM COMPRESSIBLE FLUID TO SATURATED STEAM
C
C WITHIN THE INCREMENT. RECALCULATE AGAIN
45 CONTINUE
IF( P(K+1)-PSAT ) 42,50,46
40 CONTINUE
DELZ=DABS(P(K)-PSAT)/DPDL
DELZ=DELZ/DSIN(ANG)
CENT=1.0
DPE=DPDL*DELZ
GO TO 29
42 CONTINUE
    DELZ = DELZ - 0.2
    DELL = DELZ/DSIN(ANG)
    GO TO 29
46 CONTINUE
    DELZ = DELZ + 0.3
    DELL = DELZ/DSIN(ANG)
    GO TO 29
60 FRIT = (FMENL*VSL**2./((32.2**2.*DIA*144.)*DELL)
    ACCT = 0.0
    POTT = (DENL*DSIN(ANG)/144.)*DELZ
    FRIMON = FRIMON + FRIT
    POTMON = POTMON + POTT
    Z(K+1) = Z(K) + DELZ*SIGN
    CALL COWAT(T(K+1),P(K+1),AD,ENTH(K+1))
256. WRITE(6,3090)Z(K+1),P(K+1),T(K+1),ENTH(K+1),
257. 1FRIT*(100./DELL),ACCT*(100./DELL),POTT*(100./DELZ),VSL
50 CONTINUE
    WRITE(6,2626)FRIMON,POTMON,FRIT,POTT,ACCT
    GO TO 999
261. C
262. C THIS IS THE COMPRESSED LIQUID FLASHING POINT.
263. 50 Z(K+1) = Z(K) + DELZ*SIGN
264.  FRIT = (FMENL*VSL**2./((32.2**2.*DIA*144.)*DELL)
265.   ACCT = 0.0
266.   POTT = (DENL*DSIN(ANG)/144.)*DELZ
267.   FRIMON = FRIMON + FRIT
268.   POTMON = POTMON + POTT
269.   CALL COWAT(T(K+1),P(K+1),FL,FE)
270.   WRITE (6,51)
271. 51 FORMAT(//,10X,'FLASH POINT...
272.  WHITE (6,3090) Z(K+1),P(K+1),T(K+1),FE,
273.  1FRIT*(100./DELL),ACCT*(100./DELL),POTT*(100./DELZ)
274.   KFLASH = K+1
275.   ENTH(K+1) = FE
276.   ZFLASH = Z(K+1)
277.   ISTATE = 1
278.   XS = 0.0
279. C
280. C ** TWO-PHASE FLASHING FLOW **
281. C
282. C CHECK IF THIS IS A TRANSFER FROM COMPRESSED LIQUID REGION.
283. 200 IF (ISTATE.EQ.1) IONE = KFLASH
284.     IF(ISTATE.EQ.0) DPDL=0.009
285.     IF (ISTATE.EQ.1 AND ISTATE.EQ.1) DELZ = (ZFLASH-DWELLH)/
286.       DFLOAT(INC-K)
287.     IF (ISTATE.EQ.1) GO TO 282
288.     CALL SATEUR(T(1),DENL,EHS,EHN,VISS)
289.     ENTH(1) = EHN
290.     XS = (ENTH(1)-EHW)/(EHS-EHW)
291. 282 DELL = DELZ/DSIN(ANG)
292.   WRITE (IDUT,1010)
293. 2010 FORMAT('!',/,10X,'** TWO-PHASE FLOW **',
294.     T152,'FRICTION',T64,'ACCELE.',T73,'POTENTIAL',T109,'Qw/A',
295.     T219,'Qw/A',/7X,'DEPTH',FT,'T18,'PRES,PSIA',T32,'TEMP,F',T40,
296.     '3*EN, BTU/LB',T51,'Psi/100ft',T62,'Psi/100ft',T73,'Psi/100ft',
297.     'CT85', 'STM.FRACT',T97,'REGIME',T109,'ft/s',T119,'ft/s',/
298.     C
299. DO 210 K = IONE,INC
300.     IF(ISTATE.EQ.1 AND ISTATE.EQ.1) GO TO 254
IF(K.NE.1) GO TO 254
WRITE(6,5454)Z(1),P(1),T(1),ENTH(1),XS
5454 FORMAT(4X,4(1X,F10.2),34X,F10.4)
254 CENT1=0.0
ZMID = Z(K) + SIGN*DELT/2.
TR = FLAGR(DEPT,ROKT,ZMID.1,NPT)
IF (ISIGN.EQ.1. AND. ZMID.LE.ZDIAM(IPIFE)) GO TO 69
IF (ISIGN.EQ.-1. AND. ZMID.GE.ZDIAM(IPIFE)) GO TO 69

IPIFE = IPIFE + 1
AROG=AROG(IPIFE)
DIA= DIAM(IPIFE)
AREA = PI*DIA*DIA/4.
69 CONTINUE

C ITERATE TO FIND THE PRESSURE DROP
DPC=DPDL*DELL
DO 219 M=1,100
218 DPE=DPC
219 PAVG=P(K)+SIGN*(DPE/2.)

TAVG=FPSAT(PAVG)
550 CONTINUE

Q=3.14159*HCD*DIAM(DELL)/2.)*(TAVG-TR)/WT
IF (TR.GE.TAVG) Q =0.0
ENAV=ENTH(K)+SIGN*(Q-DELT/2./778.)
IF (Q .LE. 0. ) ENAV=ENTH(K)
CALL SATUR(TAVG,ENS,ENS,EN4,VISS)
X=(ENAV-ENM)/(ENS-ENW)
IF (X.LT.1.) GO TO 202
CENTI=CENTI+1.
IF(CENTI.EQ.100) GO TO 220
TAVG=T(K)+SIGN*CENTI*0.05
PAVG=FPSAT(TAVG)
DPE=2.*PAVG-P(K)*SIGN
GO TO 550
202 IF (ISTATE.EQ.1) GO TO 204
IF (X.GT..001) GO TO 204

C CALCULATE THE DEPTH OF THE FLASHING POINT
CENT2=1.
ENAV=ENTH(K)
TFP=TAVG
DO 5051 N=1,200
5043 IF(N.LT.190) GO TO 9090
5045 IF(N.GT.191) GO TO 3434
5047 WRITE(6,3034)
3034 FORMAT(4X,'N',T14,'TFP',T24,'ENAV',T36,'ENW',
T47,'ENS',T56,'X')
5048 WRITE(6,3434)N,TFP,ENAV,ENW,ENS,X
3434 FORMAT(1X,I5,4(1X,F10.3),1X,F10.4)
5049 9090 CONTINUE
5051 WRITE(6,5051)
5051 CONTINUE
5060 FORMAT(4X,'NO CONVERGENCE FINDING FLASH POINT')
5069 GO TO 999
5052 TAVG=(1(K)+TFP)/2.
PAVG=FPSAT(TAVG)
CALL SATUR(TAVG,DENS,ENS,ENW,VISS)
X=(ENAV-ENW)/(ENS-ENW)
GO TO 204
4204 CONTINUE
PPF=FFSAT(TFP)
Z(K+1)=Z(K)+(PPF-P(K))/DPDL
P(K+1)=PPF
T(K+1)=TFP
CALL COWAT(TFP,PPF,DENA,ENAV)
ENTH(K+1)=ENAV
KFLASH = K+1
ZFLASH = Z(K+1)
XLEN=(Z(K+1)-Z(K))
FRIT=(SDPF/144.)*XLEN
ACCT=(SEKK*(DPDL))*XLEN
PCT=(SDENTP*DSEP/144.)*XLEN
FRIT=FRIT+FRIT
PDDP=PDDP+PDD
ACCTP=ACCTP+ACCT
WRITE(IOUT,51)
WRITE(6,3090)Z(K+1),P(K+1),T(K+1),ENAV,
1FRIT*(100./XLEN),ACCT*(100./XLEN),PCT*(100./XLEN)
WRITE(6,3080)
ISTATE = 1
GO TO 253

C
204 CALL PVTHI(TAVG,PAVG,NGR,DENN,VISW)
SUR=FSURH(TAVG,PAVG)
MS=XTWH
WW=HT-WW
VSW=MM/DENN/AREA/3600
VSS=MS/DENS/AREA/3600
HLNS=VSW*(VSW+VSS)
VM=VSH+VSS
XHN=1.930*VSS*(((DENW/SUR)**0.25)
XHNL=1.930*VSW*(((DENW/SUR)**0.25)
C
CALL CKKIS(MLHS,XLN,XGN,ANG,DENN,DENS,VM,DIA,VSS,VSW, 
APV,AVG,VSU,VISS,SUR,HL,DPDL,IFP,SDPF,SEKK, 
2DAPNP,XML,XNL,XNL,SIG,DM)
IF(ISIGN.EQ.-1) DM=SDENTP
DPDL=DPDL 
DPC=DELM*DPDL
IF(L.LT.50) GO TO 1818
IF(M.GE.51) GO TO 8181
WRITE(6,7171)
7171 FORMAT(/,1X,' M',77,' DPE',T14,',',DPOL,T22,' TAVG',T29, 
1'ENAV',T30,' X',T42,' VSH',T48,' VSS',T52,' MLHS',T59, 
2'HL',T63, 'DENN',T69, 'DENS',T76, 'XLN',T82, 'XGN',T87, 
3'VSH',T93, 'SDPF',T98, 'SEKK',T103, 'SDENTP',T109, 'IFP',T112, 
4'XBL',T117, 'XSL',T122, 'XML',T129, 'SIG')
8181 WRITE(6,2121)MLHS,DPEN,DPOL,TAVG,ENAV,X,VSH,VISS, 
1MLHS,MLHS,DENS,XML,XGN,VISS,SDPF,SEKK,SDENTP,IFP,XBL, 
2XSL,XNL,SIG
F6.3,F6.2,F5.2,F7.3,I2,F4.1,F5.0,F8.4)
1818 CONTINUE
IF(CENT2.EQ.1.) GO TO 4204
IF (FABS(DPE-DCP)/DPE.LT.1.D-3) GO TO 130
CONTINUE
219 CONTINUE
220 CONTINUE
C SYSTEM DOES NOT CONVERGES AFTER 100 ITERATIONS.
WRITE(IOUT,1111)CENT1,DEE-DEP
111 FORMAT(5X,'CENT1=',F5.0,1X,'DEP=',F10.3)
WRITE (6,221) Z(K),P(K),T(K)
221 FORMAT (' TWO-PHASE FLASHING FLOW',/)
C NO CONVERGENCE AT DEPTH=',F10.3,' PRESSURE=',F10.3,' TEMPERATURE=',F10.3)
GO TO 999
300 C
310 CONTINUE
FRIT=(SDFP/144.)*DELL
ACCT=(SEGK*(PDPL))*DELL
POTT=SDENP*DZIN(ANG)/144.*DELL
FRICT=FRICT+FRIT
POTTP=POTTP+POTT
ACCTP=ACCTP*ACCT
ENTH(K+1)=ENTH(K)+DABS(ENTH(K)-ENAV)*2*SIGN
Z(K+1)=Z(K)+DELZ*SIGN
P(K+1)=P(K)+SIGN*DEP
T(K+1)=FTSAT(P(K+1))
CALL SATUR(T(K+1),DENS,ENS,ENW,VISS)
X=(ENTH(K+1)-ENW)/(ENS-ENW)
WRITE(IOUT,2000) Z(K+1),P(K+1),T(K+1),ENTH(K+1),
1FRIT*(100./DELL),ACCT*(100./DELL),POTT*(100./DELL),
2X,REG(IFP),VSH,VISS
2000 FORMAT(4X,4(1X,F10.2),4(1X,F10.4),T99,A4,2F10.4)
210 CONTINUE
WRITE(6,2626)FRIT1N,POTMON,FRICT,POTTP,ACCTP
2626 FORMAT(///,T30,'** PRESSURE ANALYSIS **',/)
C /,25X,'TOTAL FRICTION, LIQUID =',F10.4,' PSI',
25X,'TOTAL FRICTION, LIQUID =',F10.4,' PSI',
25X,'TOTAL POTENTIAL, TWO-PHASE =',F10.4,' PSI',
3 25X,'TOTAL POTENTIAL, TWO-PHASE =',F10.4,' PSI',
4 25X,'TOTAL ACCEL., TWO-PHASE =',F10.4,' PSI')
GO TO 999
C
600 IF ((FTSAT-P(1))/P(1),LT.1.0-3) GO TO 200
WRITE(IOUT,2020)
2020 FORMAT(///,15X,'SUPER HEATED STEAM, RUN TERMINATED',/)
TSAT=FTSAT(P(1))
WRITE(6,8899) P(1),TSAT
8899 FORMAT(1X,'FOR ',F10.2,' TEMP SAT = ',F10.2)
GO TO 999
C
100 WRITE (6,2040)
2040 FORMAT (' PRESSURE OR TEMPERATURE IS ABOVE CRITICAL POINT
1 PROGRAM EXECUTION IS TERMINATED ')
999 CONTINUE
C
WRITE(IOUT,2001)
2001 FORMAT(1X,///)
STOP
END
C
SUBROUTINE ORKIS(HLNS,XML,XGN,ANG,DL,OG,VM,VS,VL,VS,DL)
C
IMPLICIT REAL*8(A-H,O-Z)
600 REL=1.0D0/VL
KOUNT=1
481. CENT3=1.
482. FAC=2.*32.2*0
483. REG=1486.*DG+VSG+D/VG
484. ED=RTUB/D
485. C CHECK FOR SINGLE PHASE FLOW
486. IF(VSG.LT.0.00001)GO TO 2500
487. IF(VSL.LT.0.00001)GO TO 2600
488. XBL1=1.02355+1.47463*XSLN-0.174706D-1*XSLN**2.
489. XBL2=1.088036-2*XSLN**3-0.139331D-4*XSLN**4.
490. XBL=XBL1+XBL2
491. XSL=50.*36.*XSLN
492. XNL=75.*84.*XNLN**.75
493. IF(XGN.LT.0.1)GO TO 2500
494. IF(XGN.LT.XBL)GO TO 1
495. IF(XGN.LT.XSL)GO TO 4
496. IF(XGN.LT.XML)KOUNT=2
497. IF(XGN.LT.XML)GO TO 4
498. IF(XGN.LT.XML)GO TO 5
499. C
500. C BUBBLE FLOW CALCULATIONS
501. 1 VSL=.0
502. HL=1.5*(1.+VM/VS-DSQRT((1.+VM/VS)**2-4.*VS/G/VS))
503. IF(HL.LT.HLNS)HL=HLNS
504. RELB=1486.*DLVSL+D/HL/VL
505. CALL FRFACT(RELB,ED,FF)
506. DFF=FF*DLVSL*VSL/HL/HL/FAC
507. EKK=0.
508. DENTP=DLVHL+DG*(1.-HL)
509. LREG=1
510. GO TO 2000
511. C
512. C SLUG FLOW CALCULATIONS
513. 4 SIG=.065*DLG10(VL)/DM-.799-.709-.162*DLG10(VM)-.888*DLG10(D)
514. TLI=0.065*VM-.1
515. CC WRITE(6,1312)SIG,TLI
516. CC 1312 FORMAT(1X,2F10.4)
517. IF(SIG.LT.TLI)SIG=TLI
518. C ITERATING FOR VB
519. VB1=.5*DSQRT(32.2*0)
520. I=0
521. 10 REB=1486.*DLVB1+D/VL
522. I=I+1
523. IF(I.GT.10)GO TO 12
524. XX=DSQRT(32.2*0)
525. TX=1.251*.74-0.0*RELX*XX
526. VB=TX/2.*DSQRT(TX**2+13.5*VL)/(DL*DSQRT(D))
527. IF(REB.LE.30000.)VB=1.546*.74-0.0*RELX*XX
528. IF(REB.GE.8000.)VB=1.35*0.74-0.0*RELX*XX
529. CC WRITE(6,1212)I,II,REL,REVB1,B,V,SIG
530. CC 1212 FORMAT(1X,2I2,2F10.4,3F10.4)
531. 11 IF(DABS(VB-VB1).LT.0.001)GO TO 12
532. VB1=VB
533. GO TO 10
534. 12 CONTINUE
535. DENTP=(DLVSL+V+DG+VSG)/(VM+VB)+DL+SIG
536. IF(SIG.EQ.TLI.AND.CENT3.EQ.1.)GO TO 13
537. IF(ABS.0.0)DENTP=DM
538. TLI=VB*(1.-DENTP/DT)/(VM+VB)
539. CENT3=CENT3+1.
540. CC IF(CENT3.GT.2.)GO TO 1414
541. CC WRITE(6,1213)DENTP,SIG,TLI
542. CC 1213 FORMAT(1X,3F10.4)
543. CC 1414 CONTINUE
544. IF((SIG-TLI).GT.-1.D-5) GO TO 13
545. SIG=TLI
546. GO TO 12
547. CONTINUE
548. HL=(DENTP-DG)/(DL-DG)
549. CALL FRFACT(REAL,ED,FF)
550. XX=FF*DL*VM*VM/FAC
551. DPF=XX*(VSL+VB)*(VM+VB)*SIG
552. EKK=0.
553. IREG=2
554. IF(KOUNT.EQ.2)GO TO 51
555. GO TO 2000
556. 5 CONTINUE
557. C MIST FLOW CALCULATIONS
558. 5 KUNT=1
559. VSGP=VSS
560. 90 REYG=1485.*DG*VSGP*Q/VG
561. XWEB=454.*DG*VSGP*VSGP*ED*D/SUR
562. XWEB=0.0020466*V*L*DL/SUR/(ED*Q)
563. PR=XWEB*XXEV
564. ED=.074*Q/SUR/DG/VSGP/VSGP/D
565. IF(IGR.GT..05)FD=.0365*Q/PR**.302/DG/VSGP/VSGP/D
566. VSGP=VSGP/(1.-ED)/(1.-ED)
567. IF(KUNT.GT.1)GO TO 60
568. KUNT=3
569. GO TO 80
570. 60 IF(ED.GT..05)GO TO 70
571. FF=1./((4.*DL/LOG10(1.27*ED))**2+.067*ED**1.73
572. GO TO 90
573. 70 CALL FRFACT(REYG,ED,FF)
574. 90 DPF=FF*DG*VSGP/VSGP/FAC
575. DENTP=DL*HLNS*DG*(1.-HLNS)
576. HL=HLNS
577. EKK=VSGP*VM*DENTP/P/32.2/144.
578. IF(EKK.GT..95)EKK=.95
579. IREG=3
580. IF(KOUNT.EQ.2)GO TO 52
581. GO TO 2000
582. C CALCULATIONS FOR THE TRANSITION REGION
583. 51 DPS=-(DPF*DENTP*DSIN(ANG))/144.
584. DENMS=DENTP
585. DPF=DPP
586. GO TO 5
587. 52 DPF=-(DPF*DENTP*DSIN(ANG)*XGN/XML)/144./(1.-EKK)
588. DENMM=DENTP*(XGN/XML)
589. DPFM=DPF
590. A=(XGN-XGN)/(XGN-XGL)
591. B=(XGN-XGL)/(XGN-XSL)
592. DPF=DPF*#A+DPFM*B
593. CC WRITE(6,5252)A,B,DP,DPS,DPFS,DPFM,DENMS,DENMM
594. CC 5252 FORMAT(1X,8(1X,F10.3))
595. DPDL=A*DP+B*DPM
596. IREG=6
597. GO TO 3000
598. C
C FOR SINGLE PHASE LIQUID

2500 CALL FRFACT(REL,ED,FF)

DENP=DL

EKK=0.

ML=HLNS

IREG=5

DPF=FF*DL*VSL*VSL/FAC

GO TO 2000

2600 CALL FRFACT(REG,ED,FF)

EKK=0.

DENP=DG

DPF=FF*DG*VSG*VSG/FAC

IREG=3

2000 DPDL=(DPF+DENP*DSIN(ANG))/144./(1.-EKK)

3000 CONTINUE

RETN

END

C SUBROUTINE FRFACT( REY,ED,FF)

IMPLICIT REAL*8(A-H,O-Z)

FFI = 66./REY

FGI = .0056+.5/REY**.32

I=1

5 DEN=1.14-2.*DLOG10(ED*9.34/(REY*DSQRT(FGI)))

FF=(1./DEN)**2

DIFF=DABS(FGI-FF)

IF(DIFF>.0001)6,6,6

6 FGI=(FGI+FF)/2.

I = I+1

1 IF (I-10) 5,5,7

7 FF=FGI

8 IF(FF-FF1)9,10,10

9 FF=FF1

10 RETURN

END

C SUBROUTINE COWAT(TF,PP,DENL,EBP)

IMPLICIT REAL*8(A-H,O-Z)

DIMENSION A(23),SA(12)

DATA A/

16.826487794D3,-5.42206367302,-2.096666205D4,3.941286787D4,

2.5.7.3327773904,9.2035102004,-1.0391177405,6.590641667D4,

3-4.5.1116874204,1.41013892604,-2.017271113D3,7.982659717D0,

4-2.6.615671830-2.1.5224117900-3.2.862790540-2.2.42164700302,

51.269716080-10.2.074653200-7.2.1740203500-6.1.105710490-9,

61.29364193401,1.308119072-5.6.0476263380-14/

DATA SA/

18.4332754050-1.5.3621621620-6.1.72000000000-0.7.3422784982D-2,

24.975656870-2.6.537154300-1.1.1500-6.1.15000-5,

31.418800-1.7.00275316500,2.9952849260-4.2.0400-10

TC=(TI+40.)/1.8-40.

TKR=TC*273.15/647.3

PB=PP/1.5038

PNMR=PBAR/2.21202

Y=1-.SA(1)*TKR-.SA(2)/TKR**6

Z=YY(SA(3)*YY>-2.*SA(4)*TKR+2.*SA(5)*PNMR)**.5

DENL=0.0

YD=-2.*SA(1)*TKR+6.*SA(2)/TKR**7

SNMR=0.

DO 10 I=1,10
10 SNUM=SNUM+(I-2)*A(I+1)*TKR***(I-1)

661.

662. PRT1=A(12)*ZM(17, -Z/12, -Y/12, 1/5, TKR**YD/12)*SA(4)*TKR-

663. 1(SA(3)-1)*TKR*4YD/12*ZM(5,17,)

664. PRT2=PNMR*A(A13-A(15)*TKR*TKR*A(16)-A*(9, *TKR*SA(6))*SA(6)-TKR)**9

665. 2*A(17)*20.*TKR**919*SA(7)*SA(4)*SA(17)**2*SA(18)**2+PNMR*A(A19)**

666. 3PNMR*PNMR*A(20)*PNMR*PNMR*PNMR

667. PRT4=A(21)*TKR**919*(17. *SA(9)**19.*TKR*TKR))/((SA(10)**9*PNMR)**3+*

668. 4SA(11)**PNMR

669. PRT5=A(22)**SA(12)**PNMR**3+21.*A(23)/TKR**20*PNMR**4

670. ENTR=A(11)**TKR-SNUM+PRT1+PRT2+PRT3+PRT4+PRT5

671. EJS=ENTR*70.120400

672. EBP=EJS*429.9230-3

673. RETURN

674. END

675. C

676. FUNCTION FLAGR(X,Y,XARG,IDEG,NPTS)

677. IMPLICIT REAL*8(A-H,O-Z)

678. DIMENSION X(1),Y(1)

679. N=NPTS

680. NI=IDEG+1

681. L=1

682. IF(NPTS.LT.0)L=2

683. IF(NPTS.LT.0)N=-N

684. GO TO (10,20),L

685. 10 DO 11 MAX=NI,N

686. IF(XARG.LT.X(MAX))) GO TO 12

687. 11 CONTINUE

688. 12 MIN=MAX-IDEG

689. FACTOR=1.

690. DO 2 I=MIN,MAX

691. IF(XARG.NE.X(I))) GO TO 2

692. FLAGR=Y(I)

693. 2 RETURN

694. 3 YEST=0.

695. DO 5 J=MIN,MAX

696. TERM=Y(I)/FACT0/(XARG-X(I))

697. 5 RETURN

698. 4 IF(I.LE.J)TERM=TERM/(X(I)-X(J))

699. 5 YEST=YEST+TERM

700. FLAGR=YEST

701. RETURN

702. END

703. C

704. FUNCTION FPSAT(TF)

705. IMPLICIT REAL * 8 (A-H,O-Z)

706. REAL * 8 XX(9)

707. DATA XX/-.7.691734564,.2.60892369601,1.68170654602,6.42328550401,

708. 1.1.109664232550,4.16711732000,2.0975067601,1.D9,6.00/

709. TC=((TF**40.0./1.8)-40.

710. TKR=-(TC**273.15)/647.3

711. TKRM=1.-TKR

712. SUM=0.
721.      DO 10 I=1,5
722.     10 SUM=SUM+XX(I)*TKRM*I
723.      DENO=1.+XX(6)*TKRM+XX(7)*TKRM*TKRM
724.      CONS=TKRM/(XX(8)*TKRM+XX(9))
725.      PNR=DFP(1./TKR)*SUM/DENO-CONS
726.      PBAR=PNR+2.21202
727.      PPSI=PPBAR*14.5038
728.      FPSI=PPSI
729.      RETURN
730.      END
731.      C
732.      FUNCTION FTSAT(P)
733.      IMPLICIT REAL*8 (A-H,O-Z)
734.      T=116.8456P**0.22302
735.      DO 17 I=1,200
736.      PCA=FPSAT(T)
737.      XSIG=1.0
738.      IF ((PCA-P).LT.0.) XSIG=1.
739.      IF (DABS(PCA-P)/P .LT. 10-3) GO TO 43
740.      T=T+XSIG*.03
741.     17 CONTINUE
742.     43 FTSAT=T
743.      RETURN
744.      END
745.      C
746.      SUBROUTINE SATURE(T,F,DES,ENS,EHW,VIS)
747.      IMPLICIT REAL*8 (A-H,O-Z)
748.      DIMENSION TD(33),XVS(33),XES(33),XEW(33)
749.      DIMENSION XW(33)
750.      C
751.      DATA XW/1.0121DD,1.0171DD,1.0228DD,1.0290DD,1.0359DD,1.0435DD,
752.          1.0515DD,1.0603DD,
753.          1.0679DD,1.0798DD,1.0906DD,1.1021DD,1.1144DD,1.1275DD,1.1415DD,
754.          1.1565DD,1.1726DD,
755.          1.1900DD,1.2087DD,1.2291DD,1.2512DD,1.2752DD,1.3023DD,1.3321DD,
756.          1.3655DD,1.4036DD,
757.          1.4475DD,1.4992DD,1.5620DD,1.6390DD,1.7410DD,1.8490DD,2.2200DD/
758.      DATA TD/50.00,60.00,70.00,80.00,90.00,100.00,110.00,120.00,
759.          130.00,140.00,150.00,160.00,
760.          170.00,180.00,190.00,200.00,210.00,220.00,230.00,240.00,250.00,
761.          260.00,270.00,280.00,290.00,
762.          300.00,310.00,320.00,330.00,340.00,350.00,360.00,370.00/,
763.      DATA XVS/12045.00,767.600,5045.300,3408.300,2360.900,
764.          1673.000,1210.100,891.7100,
765.          466.3200,508.6600,392.5700,306.8500,242.6200,193.8500,
766.          156.3500,127.1900,104.2650,
767.          80.06200,71.47200,59.67400,50.05600,42.14900,35.59900,
768.          30.13300,25.537001,21.64900,18.16000,
769.          618.31600,15.451000,12.96700,10.77900,8.60500,6.94300,4.9300/
770.      DATA XES/2592.00,2609.00,2626.00,2643.00,2660.00,2676.00,
771.          2691.00,2706.00,2720.00,
772.          2734.00,2747.00,2758.00,2769.00,2778.00,2786.00,2793.00,
773.          2798.00,2802.00,2803.00,2803.00,
774.          82801.00,2796.00,2790.00,2780.00,2766.00,2749.00,2727.00,
775.          2700.00,2666.00,2623.00,2565.00,
776.          92461.00,2331.00/
777.      DATA XEN/209.300,251.100,293.000,334.900,376.900,419.100,
778.          461.300,503.700,546.300,
779.          3589.10,0632.200,675.500,719.100,763.100,807.500,852.400,
780.          807.700,894.700,990.300,
C
XDS=FLAGR(TD,XVS,TC,2,33)
DES=1./XDS#62.426
XHS=FLAGR(TD,XES,TC,2,33)
EHS=XHS#1000./2324.4
XHW=FLAGR(TD,XEW,TC,2,33)
EHW=XHW#1000./2324.4
VTS=.407#TC+.84-(1558.-5.9#TC)/XDS
VIS=VTS/10000.
C
C
XDW=FLAGR(TD,XSV,TC,2,33)
C
DEN=1./XDW#62.428
RETURN
C
FUNCTION FSURW(TF,PP)
IMPLICIT REAL*(A-H,O-Z)
DIMENSION STA(10),STV74(10),STV280(10)
DATA STA/
10.00,1000.00,2000.00,3000.00,4000.00,5000.00,
6000.00,7000.00,8000.00,9000.00/
DATA STV74/
275.00,63.00,59.00,57.00,54.00,52.00,51.00,50.00,49.00/
DATA STV280/
353.00,40.00,33.00,26.00,21.00,21.00,22.00,23.00,24.00/
DATA TEM1=TF
P=PP
STW74=FLAGR(STV,STV74,P,2,10)
STV280=FLAGR(STV,STV280,P,2,10)
SW=(STW74-STW280)/(280.-74.)#(TEM1-74.)*(1.-)*STW74
IF(TEM1.LT.74.)STW=STW74
IF(TEM1.GT.280.)STW=STW280
SURW=STW
FSURW=SURW
RETURN
END
C
SUBROUTINE PTH(TF,PP,SGW,DEN,VIS)
IMPLICIT REAL*(A-H,O-Z)
TA=TF-60.00
BW=1.00*11.20*6*TA+1.00*TA+3.330-6*PP
DEN=6.43DO*SGW/BW
VIS=DEXP(1.00300-1.47900-2*TF+1.9820-5*TF*TF)
RETURN
END
$DATA
RUN FOR CERRO PRIETO M-90, 21/FEB/78
0590.00 464.3 0000.0
1.0190 356840.00 577.44 00.00
43
90. 4260.7 0.0
+1
0.01
.5800 .5800
.0003 .0003
0.0000 4260.7
05
0000.2297.3281.3937.4516
0077.0102.0294.0557.567.9
$STOP
A.4 Typical Output of the Computer Code

RUN FOR CECRO PRISTO H-90. 21/FEB/78

INPUT DATA AS FOLLOW:

| WATER GRAVITY | 1.0190 |
| TOTAL MASS FLOWRATE, LB/HR | 5666.0 | 0.000 |
| HEAT TRANSF. DEG/F., BTU/HR/FT/² | 8.000 |

AT THE MELHEAT:

| DEPTH, FT | 0.00 |
| PRESSURE, PSIA | 990.0 |
| TEMPERATURE, °F | 404.30 |

PIPE DIAMETER USED AS FOLLOW:

| FROM | 8.0 FT TO | 444.7 FT, PIPE DIAMETER (FT) | 0.2086 |
| ABS ROUGHNESS (FT) | 0.0001 |

TOTAL LENGTH DIVIDED IN 43 INTERVALS

DOMINOE BHT-IN TEMPERATURE AS FOLLOW:

| DEPTH, FT | TEMP, °F |
| 0.00 | 77.00 |
| 2277.00 | 848.00 |
| 3281.00 | 794.00 |
| 4357.00 | 837.00 |
| 4518.00 | 667.90 |

| # TWO-PHASE FLOW # | FRICTION | ACCELE. | POTENTIAL |
| DEPTH, FT | PRES. PSIA | TEMP, °F | EN. BTU/LB | PSI/100°F | PSI/100°F | PSI/100°F | THR. F.RAC. | RESISTE |
| 0.00 | 900.00 | 877.44 | 0.0000 | 0.0000 |
| 99.04 | 900.00 | 877.44 | 0.0000 | 0.0000 |
| 199.17 | 611.67 | 858.36 | 0.0000 | 0.0000 |
| 277.94 | 625.97 | 879.78 | 0.0000 | 0.0000 |
| 396.24 | 633.97 | 879.58 | 0.0000 | 0.0000 |
| 449.43 | 644.70 | 899.35 | 0.0000 | 0.0000 |
| 594.32 | 655.97 | 866.67 | 0.0000 | 0.0000 |
| 649.60 | 666.25 | 877.70 | 0.0000 | 0.0000 |
| 792.89 | 677.32 | 899.51 | 0.0000 | 0.0000 |
| 811.49 | 688.46 | 909.53 | 0.0000 | 0.0000 |
| 900.86 | 699.69 | 903.11 | 0.0000 | 0.0000 |
| 1084.16 | 711.91 | 908.96 | 0.0000 | 0.0000 |
| 1188.93 | 722.44 | 907.90 | 0.0000 | 0.0000 |
| 1386.13 | 732.99 | 908.24 | 0.0000 | 0.0000 |
| 1798.07 | 749.57 | 912.88 | 0.0000 | 0.0000 |
| 1844.95 | 755.34 | 912.80 | 0.0000 | 0.0000 |
| 1953.36 | 769.46 | 912.65 | 0.0000 | 0.0000 |
| 2046.46 | 781.64 | 912.64 | 0.0000 | 0.0000 |
| 2083.35 | 793.90 | 912.71 | 0.0000 | 0.0000 |
| 2181.65 | 805.97 | 912.74 | 0.0000 | 0.0000 |
| 2260.81 | 812.19 | 912.75 | 0.0000 | 0.0000 |
| 2579.81 | 845.55 | 926.72 | 0.0000 | 0.0000 |
| 2769.70 | 899.49 | 926.70 | 0.0000 | 0.0000 |
| 2778.50 | 911.67 | 926.72 | 0.0000 | 0.0000 |
| 2779.17 | 907.12 | 933.37 | 0.0000 | 0.0000 |
| 2879.24 | 901.66 | 933.37 | 0.0000 | 0.0000 |
| 2879.32 | 916.60 | 933.22 | 0.0000 | 0.0000 |
| 2979.81 | 921.96 | 933.21 | 0.0000 | 0.0000 |
| 3279.54 | 947.79 | 933.28 | 0.0000 | 0.0000 |
| 3279.55 | 949.66 | 933.28 | 0.0000 | 0.0000 |
| 3279.56 | 958.70 | 933.28 | 0.0000 | 0.0000 |
| 3379.41 | 966.83 | 933.28 | 0.0000 | 0.0000 |
| 3479.42 | 940.16 | 933.28 | 0.0000 | 0.0000 |
| 3579.43 | 934.64 | 933.28 | 0.0000 | 0.0000 |
| 3579.44 | 934.64 | 933.28 | 0.0000 | 0.0000 |
| 3679.45 | 934.64 | 933.28 | 0.0000 | 0.0000 |
| 3779.46 | 934.64 | 933.28 | 0.0000 | 0.0000 |
| 3879.47 | 934.64 | 933.28 | 0.0000 | 0.0000 |
| 3979.48 | 934.64 | 933.28 | 0.0000 | 0.0000 |

| FLASH POINT... |
| 4069.33 | 1041.59 | 871.52 | 877.44 | 0.0000 | 0.0000 | 0.0000 | 28.3195 |

| # LIQUID FLOW # | FRICTION | ACCELE. | POTENTIAL |
| DEPTH, FT | PRES. PSIA | TEMP, °F | EN. BTU/LB | PSI/100°F | PSI/100°F | PSI/100°F | THR. F.RAC. | RESISTE |
| 4266.70 | 1297.50 | 871.93 | 877.44 | 0.0000 | 0.0000 | 0.0000 | 28.3195 | 7.7561 |

| # PRESSURE ANALYSIS |
| TOTAL FRICTION, LIQUID | 1.8927 PSS |
| TOTAL POTENTIAL, LIQUID | 0.1026 PSS |
| TOTAL FRICTION, TWO-PHASE | 194.1536 PSS |
| TOTAL POTENTIAL, TWO-PHASE | 816.1507 PSS |
| TOTAL ACCELER., TWO-PHASE | 0.0000 PSS |

STATEMENTS EXECUTED 246697
COR REL SIZE OBJECT CODE | 4928 BYTES ARRAY AREA | 10784 BYTES TOTAL AREA AVAILABLE | 21248 BYTES
DIAGNOSTICS |
NUMBER OF ERRORS | 0 | NUMBER OF WARNINGS | 0 | NUMBER OF EXTENSIONS | 0 |
## APPENDIX B

Table B.1  East Mesa 6-1

<table>
<thead>
<tr>
<th>Depth ft</th>
<th>Pressure psia</th>
<th>Temperature °F</th>
<th>Temperature °F</th>
</tr>
</thead>
<tbody>
<tr>
<td>7000</td>
<td>1348.03</td>
<td>389.3</td>
<td>381.2</td>
</tr>
<tr>
<td>6000</td>
<td>961.8</td>
<td>389.2</td>
<td>369.3</td>
</tr>
<tr>
<td>5500</td>
<td>767.9</td>
<td>388.0</td>
<td>365.0</td>
</tr>
<tr>
<td>5000</td>
<td>574.0</td>
<td>387.0</td>
<td>360.2</td>
</tr>
<tr>
<td>4500</td>
<td>381.0</td>
<td>386.0</td>
<td>356.0</td>
</tr>
<tr>
<td>4050</td>
<td>208.0</td>
<td>385.0</td>
<td></td>
</tr>
<tr>
<td>4000</td>
<td>192.0</td>
<td>377.0</td>
<td>350.6</td>
</tr>
<tr>
<td>3500</td>
<td>115.0</td>
<td>338.0</td>
<td>344.4</td>
</tr>
<tr>
<td>3000</td>
<td>93.0</td>
<td>322.0</td>
<td>333.9</td>
</tr>
<tr>
<td>2500</td>
<td>75.0</td>
<td>307.0</td>
<td>320.1</td>
</tr>
<tr>
<td>2000</td>
<td>62.0</td>
<td>293.0</td>
<td>288.2</td>
</tr>
<tr>
<td>1500</td>
<td>53.0</td>
<td>283.0</td>
<td>243.3</td>
</tr>
<tr>
<td>1000</td>
<td>45.0</td>
<td>273.0</td>
<td>198.7</td>
</tr>
<tr>
<td>500</td>
<td>39.0</td>
<td>258.0</td>
<td>143.0</td>
</tr>
<tr>
<td>0.0</td>
<td>33.0</td>
<td></td>
<td>105.0</td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>Flowing Profile</td>
<td>Shut-in Profile</td>
<td></td>
</tr>
<tr>
<td>-----------</td>
<td>----------------</td>
<td>----------------</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Pressure</td>
<td>Temperature</td>
<td>Depth</td>
</tr>
<tr>
<td></td>
<td>(psia)</td>
<td>(F)</td>
<td>(ft)</td>
</tr>
<tr>
<td>82</td>
<td>593.45</td>
<td>480.4</td>
<td>0.0</td>
</tr>
<tr>
<td>328</td>
<td>616.21</td>
<td>482.9</td>
<td>2292</td>
</tr>
<tr>
<td>656</td>
<td>657.44</td>
<td>489.0</td>
<td>3937</td>
</tr>
<tr>
<td>984</td>
<td>697.26</td>
<td>495.52</td>
<td>4518</td>
</tr>
<tr>
<td>1312</td>
<td>739.92</td>
<td>502.0</td>
<td></td>
</tr>
<tr>
<td>1640</td>
<td>782.58</td>
<td>508.0</td>
<td></td>
</tr>
<tr>
<td>1968</td>
<td>832.35</td>
<td>515.8</td>
<td></td>
</tr>
<tr>
<td>2296</td>
<td>877.85</td>
<td>521.8</td>
<td></td>
</tr>
<tr>
<td>2624</td>
<td>931.89</td>
<td>527.7</td>
<td></td>
</tr>
<tr>
<td>2952</td>
<td>990.19</td>
<td>534.2</td>
<td></td>
</tr>
<tr>
<td>3280</td>
<td>1047.10</td>
<td>541.2</td>
<td></td>
</tr>
<tr>
<td>3608</td>
<td>113.90</td>
<td>548.2</td>
<td></td>
</tr>
<tr>
<td>3936</td>
<td>189.3</td>
<td>554.7</td>
<td></td>
</tr>
<tr>
<td>4018</td>
<td>212.00</td>
<td>556.7</td>
<td></td>
</tr>
<tr>
<td>4100</td>
<td>233.40</td>
<td>558.0</td>
<td></td>
</tr>
<tr>
<td>4261</td>
<td>283.10</td>
<td>558.0</td>
<td></td>
</tr>
<tr>
<td>Depth (ft)</td>
<td>Pressure (psia)</td>
<td>Temperature (°F)</td>
<td>Temperature (°F)</td>
</tr>
<tr>
<td>-----------</td>
<td>----------------</td>
<td>------------------</td>
<td>------------------</td>
</tr>
<tr>
<td>32</td>
<td>391</td>
<td></td>
<td></td>
</tr>
<tr>
<td>134</td>
<td>403</td>
<td></td>
<td></td>
</tr>
<tr>
<td>280</td>
<td>427</td>
<td></td>
<td></td>
</tr>
<tr>
<td>554</td>
<td>452</td>
<td></td>
<td></td>
</tr>
<tr>
<td>764</td>
<td>476</td>
<td></td>
<td></td>
</tr>
<tr>
<td>972</td>
<td>500</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1177</td>
<td>524</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1272</td>
<td>536</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1378</td>
<td>549</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1460</td>
<td>561</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1539</td>
<td>573</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1624</td>
<td>585</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1694</td>
<td>597</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1769</td>
<td>609</td>
<td></td>
<td></td>
</tr>
<tr>
<td>1880</td>
<td>627</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>652</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2116</td>
<td>670</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2215</td>
<td>688</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2301</td>
<td>706</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2380</td>
<td>724</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2450</td>
<td>743</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2534</td>
<td>761</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2580</td>
<td>773</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2647</td>
<td>791</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2715</td>
<td>809</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2774</td>
<td>827</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2832</td>
<td>846</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2899</td>
<td>864</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2955</td>
<td>882</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2996</td>
<td>894</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX C

a) Enthalpy of liquid-gas mixture

\[ h_m = \frac{H_L + H_g}{M_L + Mg} = \frac{H_L}{(M_L + Mg) M_L} + \frac{H_g}{(M_L + Mg) Mg} \]

\[ h_m = (1 - x) \frac{H_L}{M_L} + x \frac{H_g}{Mg} \]

\[ h_m = (1 - x) h_L + x h_g \]

b) Specific Volume of the mixture

\[ \nu_m = \frac{\nu_L + \nu_g}{M_L + Mg} = \frac{\nu_L}{(M_L + Mg) M_L} + \frac{\nu_g}{(M_L + Mg) Mg} \]

\[ \nu_m = (1 - x) \frac{\nu_L}{M_L} + x \frac{\nu_g}{Mg} \]

\[ \nu_m = (1 - x) \nu_L + x \nu_g \]

c) Density of the mixture

\[ \rho_m = \frac{M_L + Mg}{\nu_L + \nu_g} = \frac{M_L}{(\nu_L + \nu_g) \nu_L} + \frac{M_g}{(\nu_L + \nu_g) \nu_g} \]

\[ \rho_m = (1 - \alpha) \frac{M_L}{\nu_L} + \alpha \frac{M_g}{\nu_g} \]

\[ \rho_m = (1 - \alpha) \rho_L + \alpha \rho_g \]