FORN HUFF-N-PUFF

①
I-12560

DR-2002-8

DOE/BC/10640-21

**COMPUTER SIMULATION OF RECOVERY OF HEAVY CRUDE OIL
USING CARBON DIOXIDE DRIVE OR HUFF-N-PUFF**

Final Report

Work Performed for the Department of Energy
Under Contract No. DE-AS19-81BC10640

Date Published—November 1983

Colorado State University
Fort Collins, Colorado

DO NOT MICROFILM
COVER

U. S. DEPARTMENT OF ENERGY

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DOE/BC/10640-21
Distribution Category UC-92a

COMPUTER SIMULATION OF RECOVERY OF HEAVY CRUDE OIL USING CARBON DIOXIDE DRIVE OR HUFF-N-PUFF

Final Report

DOE/BC/10640--21

DE84 002484

By

Roland Begin

and

David A. Krueger, *Principal Investigator*
Department of Physics
Colorado State University
Fort Collins, Colorado 80523

Kenneth L. Spence, *Technical Project Officer*
Bartlesville Energy Technology Center
P.O. Box 1398
Bartlesville, Oklahoma 74005

Work Performed for the Department of Energy
Under Contract No. DE-AS19-81BC10640

Date Published—November 1983

UNITED STATES DEPARTMENT OF ENERGY

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

Table of Contents

I.	Introduction	1
II.	Overview of Model	5
III.	Mathematical Development of the Model	11
	A. Governing Equations	11
	B. Pressure Equation Derivation	15
	C. Finite Differencing of Equations	19
IV.	Solution Method	25
V.	Phase Properties	29
	A. Thermodynamic Equilibria	29
	B. Density	32
	C. Viscosity	35
	D. Saturation	36
	E. Compressibility	37
	F. Relative Permeability	39
VI.	Sample Runs	42
VII.	Discussion and Conclusions	48
VIII.	Nomenclature	51
IX.	References	53
X.	Appendix	55
	A. Sample Input Format	55
	B. Sample Output Format	58
	C. Source Code for CO2CYCL	62

List of Figures and Tables

Figure II-1.	Model geometry	8
Figure III-1.	Flow geometry	12
Figure III-2.	Grid detail	20
Figure IV-1.	Solution flow chart	28
Figure V-1.	Fluid phase behavior	30
Figure V-2.	Relative permeability	40
Table VI-1.	Results of Sample Runs	43
Table VI-2.	Gas front location during sample runs	44

Acknowledgment

The authors thank F. C. Orr, Jr. for providing a copy of his computer program for simulating one-dimensional convection of four phase, four component mixtures.

I. Introduction

It has been estimated by the U.S. Bureau of Mines that the total amount of heavy oil deposits in this country exceeds 150 billion barrels (bbl).¹ This resource includes 55.5 billion bbl of oil with an API gravity less than 20° and 21.3 billion bbl that lie in shallow reservoirs which are less than 1500 feet deep. Forty percent of the proven heavy crude deposits are in Kansas, Missouri, and Oklahoma in reservoirs that are shallower than 500 feet deep.² Most of the remaining deposits are located in deeper reservoirs located in California and Louisiana. Given the great variety of conditions that can exist in different reservoirs and the importance of the economic and environmental considerations involved in tertiary recovery operations, the development of a number of alternative technologies to recover this oil is crucial.

Many enhanced recovery techniques exist.^{3,4} Waterflooding, for example, has been a standard secondary recovery practice for decades. However, by itself it is seldom useful in the recovery of highly viscous crude oils. This is due to the adverse mobility ratio of water to such crudes. In general, a mobility ratio, $(K_w/\mu_w)/(K_o/\mu_o)$, greater than one is considered unfavorable since water will usually finger through the oil at such ratios resulting in poor oil recovery.

Immiscible gas displacement processes (e.g., using air as the displacing fluid), like waterfloods, have been utilized in recovery operations for many years. Although such processes have even less favorable mobility ratios than do waterfloods, they have the advantage that the injected gas, being lighter than oil or water, will generally form a gas cap, thereby forcing the oil to migrate downdip to a well.

In contrast to immiscible displacements where one fluid phase displaces another fluid phase without mixing between the phases, in miscible displacements no distinct interface exists between the displaced and displacing fluids. That is, miscibility implies that the two fluids can mix in all proportions. Generally, the recovery of heavy oil requires the application of such miscible displacement processes. Chemical solvents, dry gas, enriched gas, and carbon dioxide are typical displacing agents in miscible floods. Often, to improve the recovery economics, a small quantity of miscible fluid is driven by a large slug of immiscible fluid. Dry gas displacements are generally applicable only in reservoirs where pressures are in excess of 2500 psi, whereas enriched gas and chemical solvent displacements are useful down to roughly 1200 psi.⁴

Displacement processes that use CO₂ as the displacing agent can be classed as either miscible or partially miscible. Complete miscibility of CO₂ with oil is not generally achieved unless the reservoir pressure is greater than about 1500 psi. This minimum miscibility pressure (MMP) will vary considerably depending upon both the oil composition and the reservoir temperature. The displacement mechanisms most important in CO₂ processes are the reduction of the oil viscosity and swelling of the oil. These will be active to some degree even at pressures below the MMP. Various techniques have been tried using CO₂. These include carbonated water-flooding, water-alternated-with-gas (WAG) injection, CO₂ mixed with flue exhaust gases, and continuous CO₂ injection. Because the solubility of CO₂ in oil increases with pressure, the application of CO₂ processes have so far been generally limited to relatively deep reservoirs (>2000 feet).

The recovery of heavy crude from shallow deposits such as those described above presents some unique problems to be investigated. At these depths the maximum pressure that the reservoir can withstand without fracturing is usually less than 500 psi (assuming a pressure gradient of 1 psi/foot of depth). Since the solubility of CO_2 in oil increases with pressure this restriction is an important one. This situation could be improved somewhat if the injectivity of the reservoir were increased by hydraulically fracturing the formation. It is plausible to assume that injection of CO_2 into such fractures would serve to stimulate the oil in the near vicinity of the fracture. The resultant increase in swelling and decreased viscosity of the oil phase near the fracture should help displace the oil toward the fracture. As injection of CO_2 continues and the oil and water become saturated, a mobile gas phase will develop. The appearance of gas in the pores blocks the flow of oil and water reducing their relative permeabilities drastically. However, assuming a favorable ratio of vertical to horizontal absolute permeability, then since the gas is less dense than the oil it will tend to percolate up through the reservoir eventually forming a secondary gas cap at the top of the formation. This gas cap will then aid in the displacement of oil toward the fracture and the well bore.

Because of the enormously complex nature of the system described above, the present study is limited to an investigation of the behavior of the flows in and near a fracture. The numerical model simulates multicomponent, multiphase, compressible flow through a horizontal two-dimensional porous medium which is bounded on one side by a one-dimensional fracture. The absolute permeability of the fracture is assumed to be much greater (five orders of magnitude or more) than that

of the reservoir matrix, resulting in the simplification that flow in the matrix is predominately perpendicular to the fracture face. Flow in the matrix parallel to the fracture is ignored in this model.

The fluid system consists of three components in three phases. Component 1 is the injected fluid, e.g., CO_2 , and can exist in any of the three phases - gas, oil, and water. Component 2 is the hydrocarbon component and is assumed to be heavy enough so that it exists only in the oil phase. Component 3 is the aqueous component and is restricted to the water phase. All fluid properties, except viscosity and relative permeability, are assumed to be linear functions of pressure and composition. The temperature of the system is taken as constant and effects due to capillary pressure and gravity are not included.

The mathematical formulation is based on a set of molar continuity equations (one per component), the phase equilibrium condition, and a volume conservation equation. Reduction of this system of equations to a single equation in pressure leads to a sequential (implicit pressure-explicit moles) method of solution. In-step iterations are performed to increase the implicitness of the method. The algorithm includes time step control and a volume balance check.

A flow chart of the computer code as well as the source code and input and output formats are included in the Appendix. Three sample problems are examined.

II. Overview of Model

The fundamental relation describing flow in a porous medium is Darcy's Law which simply states that the volumetric flow rate, $\vec{Q}$, through a porous medium is directly proportional to the pressure gradient. For single phase, single component flow this relation has the form:

$$\vec{v} = -(K/\mu) (\nabla P - \rho g \nabla D) \quad (\text{II-1})$$

where:

$\vec{v} = \vec{Q}/A$ = the apparent macroscopic velocity (also known as the superficial or Darcy velocity),

K = absolute permeability of the medium,

μ = viscosity of fluid,

P = pressure,

ρ = fluid density,

g = acceleration due to gravity,

D = depth,

A = contact area.

In multiphase, multi-component flow each fluid phase, e.g., gas, oil, and water, is assumed to be individually governed by Darcy's Law and each component is subject to the constraint of mass conservation. Darcy's Law for some phase j may be written:

$$\vec{v}_j = -(k_{rj} K / \mu_j) (\nabla P_j - \rho_j g \nabla D) \quad (\text{II-2})$$

where

k_{rj} = relative permeability of phase j (dimensionless and $0 < k_{rj} < 1$),

μ_j, ρ_j = viscosity and density of phase j.

In general, the pressures in the phases will not be equal due to the presence of capillary pressure, i.e., the pressure difference across the interface separating two fluid phases. If, however, the capillary pressure is small compared to the externally imposed pressure gradient then the pressure in the different phases are approximately the same and $P_j \rightarrow P$.

Conservation of mass of component i can be expressed:

$$D_t(\phi \sum_j x_{ij} \rho_j S_j) = -\nabla \cdot \sum_j x_{ij} \rho_j \vec{v}_j \quad (\text{II-3})$$

where

x_{ij} = the mole fraction of component i in phase j,

ϕ = porosity,

S_j = saturation of phase j,

D_t = the partial derivative operator with respect to t.

In this model, we assume that the system is a horizontal plane and we can therefore neglect gravity in our formulation. We further assume that the capillary pressure is zero.

There will be an equation like Eq. (II-3) for each component of the system. These equations must be discretized and solved for each grid block in the system (see Sec. III). The geometry of the system and its corresponding discrete representations are illustrated in Fig. II-1.

Finally, we observe that if the permeability of the fracture is much larger than that of the rock matrix, and the well is located as indicated in the figure, then although the flow in the fracture will be both parallel and perpendicular to the fracture axis the flow in the matrix will be primarily perpendicular to the fracture. That is, even though we are considering a two-dimensional geometry the flow in each matrix "branch" will be essentially one-dimensional. This results in a substantial simplification of the solution algorithm.

The conditions leading to this simplified flow geometry can be made more quantitative. The basic constraint is that the flow in the reservoir matrix perpendicular to the fracture (y-direction) be much greater than that parallel to the fracture (z-direction):

$$q_{Ry} \gg q_{Rz} \quad \text{or} \quad \Delta z D_y(P_R) \gg \Delta y D_z(P_R) \quad (\text{II-4})$$

This implies that the pressure gradients in the z-direction in both the matrix and the fracture are approximately the same:

$$D_z(P_R) \approx D_z(P_F) \quad (\text{II-5})$$

where

P_R = pressure in the rock matrix,

P_F = pressure in the fracture.

Figure II-1. Model geometry.

If we also assume that the flow into each matrix branch is roughly equal then we get:

$$\Delta z (K_R / \mu) D_y (P_R) \approx h (K_F / \mu) D_z (P_F) / n_z \quad (\text{II-6})$$

where

h = fracture width,

n_z = number of grid blocks in fracture.

Combining relations (II-4), (II-5), and (II-6), yield the condition:

$$h / (n_y \Delta y) \gg K_R / K_F$$

where

n_y = number of grid blocks in matrix branch .

If the fracture is approximated by two closely spaced parallel plates then its permeability is given by:⁵

$$K_F \approx h^2 / 12 \quad .$$

Thus, the flow condition reduces to:

$$h^3 / 12 K_R \gg \ell_R \quad .$$

If $h \sim 1 \text{ mm} = 10^{-3} \text{ m}$ and $K_R \sim 10^2 \text{ md} = 10^{-9} \text{ cm}^2$, then

$$h^3/12K_R = 10^5 \text{ cm} \gg \ell_R$$

which is easily satisfied for simulations of flows in laboratory cases. Therefore, for fractures having high permeabilities the simplified flow geometry described above is clearly reasonable.

With the preliminary exposition of the concepts of flow behavior and component mass continuity complete, we are ready to begin the mathematical construction of our model.

III. Mathematical Development of the Model

A. Governing Equations

The development of the numerical model begins with the molar balance of each component in each of the system's grid blocks. The molar continuity of component i in the k^{th} fracture grid block is given by:

$$\begin{aligned} [\Delta(\sum_j N_{ij})/\Delta t]_k &= [\sum_j x_{ij} \rho_j q_{zj}]_k - \Delta z/2 \\ &\quad - [\sum_j x_{ij} \rho_j q_{zj}]_k + \Delta z/2 - [\sum_j x_{ij} \rho_j q_{yj}]_k + h/2 \end{aligned} \quad (\text{III-1})$$

where:

- N_{ij} = number of moles of component i in phase j ,
- x_{ij} = molar fraction of i in j ,
- ρ_j = molar density of phase j ,
- q_{zj}, q_{yj} = volumetric flow rates of phase j along the fracture axis (z -direction) and perpendicular to the fracture (y -direction).

The flow geometry is indicated in Fig. III-1.

For convenience later in reducing the initial system of equations to a single equation in pressure, we transform the discrete form of the continuity equation (Eq. (1)) into the corresponding differential form:

$$[D_t(\sum_j N_{ij})]_k = -\Delta z [D_z(\sum_j x_{ij} \rho_j q_{zj})]_k - [\sum_j x_{ij} \rho_j q_{yj}]_k + h/2 \quad (\text{III-2a})$$

Figure III-1. Flow geometry.

Here D_t and D_z are differential operators representing the partial derivative of the argument with respect to the operator subscript.

Similar reasoning leads to an equation of continuity for component i valid for blocks in the reservoir matrix:

$$[D_t(\sum_j N_{ij})]_k = -\Delta y [D_y(\sum_j x_{ij} \rho_j q_{yj})]_k \quad . \quad (\text{III-2b})$$

There are three continuity equations for each grid block in the system. For example, in the fracture:

$$\begin{aligned} \text{CO}_2(i=1): \quad [D_t(N_{11}+N_{12}+N_{13})]_k = \\ -\Delta z [D_z(W_{1z})]_k - [W_{1y}]_k + h/2 \end{aligned} \quad (\text{III-3})$$

$$\text{HC}(i=2): \quad [D_t(N_{22})]_k = -\Delta z [D_z(W_{2z})]_k - [W_{2y}]_k + h/2 \quad (\text{III-4})$$

$$\text{H}_2\text{O}(i=3): \quad [D_t(N_{33})]_k = -\Delta z [D_z(W_{3z})]_k - [W_{3y}]_k + h/2 \quad (\text{III-5})$$

where:

$$W_{1z} = \rho_1 q_{1z} + x_{12} \rho_2 q_{2z} + x_{13} \rho_3 q_{3z}$$

$$W_{2z} = x_{22} \rho_2 q_{2z}$$

$$W_{3z} = x_{33} \rho_3 q_{3z}$$

with similar expressions for W_{1y} , W_{2y} , and W_{3y} .

For a compressible fluid system we require that the total volume of the fluids be conserved. If the rock matrix is incompressible then the pore volume is constant and the above condition constrains the total fluid volume to be equal to the pore volume at all times:

$$[V_{\text{pore}}]_k = [V_{\text{fluid}}]_k = [N_{11}V_{11} + N_{12}V_{12} + N_{13}V_{13} + N_{22}V_{22} + N_{33}V_{33}]_k \quad (\text{III-6})$$

where:

V_{ij} = volume of a mole of component i in phase j .

Finally, the components are distributed among the three phases so as to insure thermodynamic equilibrium. We consider two possible cases: (a) the oil and water phases are not completely saturated with CO_2 , therefore there is no mobile gas phase present; (b) the oil and water are saturated and a mobile gas phase is present. This implies (see Sec. V-A on phase equilibria) for case (a):

$$\frac{x_{12}}{x_{13}} = \frac{\theta_{12}}{\theta_{13}} = \eta = \text{constant} \quad (\text{III-7a})$$

where θ_{12}^P and θ_{13}^P are the molar solubilities of CO_2 in the oil and water, respectively, and for case (b):

$$x_{12} = \theta_{12}^P \quad (\text{III-7b})$$

$$x_{13} = \theta_{13}^P$$

Observe that Eqs. (III-3) to (III-6) and either (III-7a) or (III-7b) can be combined and reduced to a single equation in pressure (see next section). For N grid blocks there will be N such equations in pressure which must be solved simultaneously.

A set of semi-empirical equations relating fluid properties, such as density, viscosity, relative permeability, etc., to the pressure and composition of the system completes the mathematical description of the model.

B. Pressure Equation Derivation

As mentioned above, Eqs. (III-3) to (III-7) can be reduced to a single equation in pressure. This equation has the following form in the fracture:

$$\begin{aligned} AD_t(P) = & -\Delta z [D_z(W_{1z}) + \delta_2 D_z(W_{2z}) \\ & + \delta_3 D_z(W_{3z})] - [W_{1y} + \delta_2 W_{2y} + \delta_3 W_{3y}] \end{aligned} \quad (III-8)$$

where A, δ_2 , and δ_3 are time-lagged coefficients which are dependent upon the particular phase equilibrium condition considered.

For case (a), where no mobile gas is present in the grid block, we find that:

$$A = C_{\text{eff}}(A'/A'')$$

$$C_{\text{eff}} = -[N_{11}D_P(V_{11}) + N_{12}D_P(V_{12}) + N_{13}D_P(V_{13}) \\ + N_{22}D_P(V_{22}) + N_{33}D_P(V_{33})]$$

$$A' = (N_{13} + N_{33})x_{22} + \eta(N_{12} + N_{22})x_{33} \quad (\text{III-8a})$$

$$A'' = V_{13}(N_{13} + N_{33})x_{22} + \eta V_{12}(N_{12} + N_{22})x_{33}$$

$$\delta_2 = [V_{22}A' + \eta N_{13}(V_{12} - V_{13})]/A''$$

$$\delta_3 = [V_{33}A' - N_{12}(V_{12} - V_{13})]/A''$$

When a mobile gas phase is present we have case (b) and:

$$A = (C_{\text{eff}} + C')/V_{11}$$

$$C' = (V_{11} - V_{12})(N_{12} + N_{22})^{\theta_{12}}/(1 - \theta_{12}^P) \\ + (V_{11} - V_{13})(N_{13} + N_{33})^{\theta_{13}}/(1 - \theta_{13}^P) \quad (\text{III-8b})$$

$$\delta_2 = [V_{22}(1 - \theta_{12}^P) + (V_{12} - V_{11})\theta_{12}^P]/[V_{11}(1 - \theta_{12}^P)]$$

$$\delta_3 = [V_{33}(1 - \theta_{13}^P) + (V_{13} - V_{11})\theta_{13}^P]/[V_{11}(1 - \theta_{13}^P)]$$

Note that in Eqs. (III-8a) and (III-8b) above, C_{eff} is the effective compressibility of the fluid system.

Now, using Darcy's Law (neglecting gravity), we can substitute into Eq. (III-8):

$$q_j = \tau v_j = -\tau \lambda_j \nabla P$$

where:

τ = cross-sectional area perpendicular to flow (τ_F = fracture cross-sectional area, τ_R = reservoir branch cross-sectional area),

λ_j = mobility of phase j,

$\lambda_{jz} = (k_{rj}/\mu_j)K_{frac}$,

$\lambda_{jy} = (k_{rj}/\mu_j)K_{res}$.

For the fracture block adjacent to the well block the total volumetric flow rate across the well-fracture interface is a constant value set by the user of the model. Thus, for $k = 2$:

$$\begin{aligned} [AD_t(P)]_k &= [W_{1z} + \delta W_{2z} + \delta W_{3z}]_{k-\Delta z/2} \\ &+ \tau_F [w_{1z} + \delta w_{2z} + \delta w_{3z}]_{k+\Delta z/2} D_z(P) \\ &+ \tau_R [w_{1y} + \delta w_{2y} + \delta w_{3y}]_{k+h/2} D_y(P) \end{aligned} \quad (III-9)$$

where:

$$w_{1z} = \rho_1 \lambda_{1z} + x_{12} \rho_2 \lambda_{2z} + x_{13} \rho_3 \lambda_{3z} ,$$

$$w_{2z} = x_{22} \rho_2 \lambda_{2z} ,$$

$$w_{3z} = x_{33} \rho_3 \lambda_{3z} .$$

Note that the injection term $[]_{k-\Delta z/2}$ can be written:

$$[] = \rho_1 q_{1z} + (x_{12} + \delta_2 x_{22}) \rho_2 q_{2z} + (x_{13} + \delta_3 x_{33}) \rho_3 q_{3z}$$

$$= [\rho_1 f_1 + (x_{12} + \delta_2 x_{22}) \rho_2 f_2 + (x_{13} + \delta_3 x_{33}) \rho_3 f_3] Q$$

where:

f_j = fractional flow of phase j ($f_j = \lambda_j / \sum_j \lambda_j$),

Q = total volumetric flow rate.

For the remaining fracture blocks the pressure equation is given by:

$$\begin{aligned} [AD_t(P)]_k &= \Delta z \tau_F [D_z(w_{1z} D_z(P)) + \delta_2 D_z(w_{2z} D_z(P)) + \delta_3 D_z(w_{3z} D_z(P))]_k \\ &+ \tau_R [(w_{1y} + \delta_2 w_{2y} + \delta_3 w_{3y}) D_y(P)]_{k+h/2} \end{aligned} \quad (III-10)$$

Finally, the pressure equation for blocks in the reservoir matrix branches is:

$$\begin{aligned} [AD_t(P)]_k &= \Delta y \tau_R [D_y(w_{1y} D_y(P)) + \delta_2 D_y(w_{2y} D_y(P)) \\ &+ \delta_3 D_y(w_{3y} D_y(P))]_k \end{aligned} \quad (III-11)$$

The above pressure equations, Eqs. (III-9), (III-10), and (III-11), along with the continuity equations, Eqs. (III-3), (III-4), and (III-5) are now transformed into finite difference equations for a numerical solution for the pressures and compositions in each grid block.

C. Finite Differencing of Equations

The differential equations presented above are differenced according to the following approximations:

$$[D_t(P)]_k \approx (P_k^{\ell+1} - P_k^{\ell}) / \Delta t$$

$$[D_z(P)]_{k+\Delta z/2} \approx (P_{k+n_r}^{\ell+1} - P_k^{\ell+1}) / \Delta z$$

$$[D_y(P)]_{k+\Delta y/2} \approx (P_{k+1}^{\ell+1} - P_k^{\ell+1}) / \Delta y$$

$$[D_z(P)]_{k-\Delta z/2} \approx (P_k^{\ell+1} - P_{k-n_r}^{\ell+1}) / \Delta z$$

$$[D_y(P)]_{k-\Delta y/2} \approx (P_k^{\ell+1} - P_{k-1}^{\ell+1}) / \Delta y$$

$$D_z(GD_z(P))_k \approx [G_+^{\ell} P_{k+n_r}^{\ell+1} - (G_+^{\ell} + G_-^{\ell}) P_k^{\ell+1} + G_-^{\ell} P_{k-n_r}^{\ell+1}] / (\Delta z)^2$$

$$D_y(GD_y(P))_k \approx [G_+^{\ell} P_{k+1}^{\ell+1} - (G_+^{\ell} + G_-^{\ell}) P_k^{\ell+1} + G_-^{\ell} P_{k-1}^{\ell+1}] / (\Delta y)^2$$

The superscripts ℓ and $\ell+1$ denote, respectively, the current and advanced time levels. The subscripts refer to either grid block or grid interface location (Fig. III-1 and III-2). The G coefficients are evaluated "upstream" so if the flow in the figure is left to right then $G_+ \rightarrow G_k$ and $G_- \rightarrow G_{k-1}$, whereas if the flow is to the left, $G_+ \rightarrow G_{k+1}$ and $G_- \rightarrow G_k$.

We assume that flow into or out of the fracture is governed primarily by the pressure drop in the rock matrix. Therefore the pressure gradient across the fracture-matrix interface is approximated by:

Figure III-2. Grid detail.

$$[D_y(P)]_{k+h/2} = (P_{k+1}^{\ell+1} - P_k^{\ell+1}) / (\Delta y/2) \quad .$$

Substitution of the above difference approximations into Eq. (III-10) yields a difference equation in pressure valid for fracture blocks not adjacent to the well block:

$$\alpha_{k, k-n_r}^{\ell, \ell+1} + \beta_{k, k}^{\ell, \ell+1} + \gamma_{k, k+n_r}^{\ell, \ell} + \varepsilon_{k, k+1}^{\ell, \ell+1} = \theta_k^{\ell} \quad . \quad (\text{III-12})$$

where:

$$\alpha_k^{\ell} = r_z \tau_F a_{k-}^{\ell}$$

$$\gamma_k^{\ell} = r_z \tau_F a_{k+}^{\ell}$$

$$\varepsilon_k^{\ell} = r_y \tau_R e_{k+}^{\ell}$$

$$\beta_k^{\ell} = -\{r_z \tau_F (a_{k+}^{\ell} + a_{k-}^{\ell}) + r_y \tau_R e_{k+}^{\ell} + A_k^{\ell}\}$$

$$\theta_k^{\ell} = -A_{k, k}^{\ell, \ell}$$

with:

$$a_{k+}^{\ell} = w_{1z+}^{\ell} + \delta_2^{\ell} w_{2z+}^{\ell} + \delta_3^{\ell} w_{3z+}^{\ell}$$

$$a_{k-}^{\ell} = w_{1z-}^{\ell} + \delta_2^{\ell} w_{2z-}^{\ell} + \delta_3^{\ell} w_{3z-}^{\ell}$$

$$e_{k+}^{\ell} = w_{1y+}^{\ell} + \delta_2^{\ell} w_{2y+}^{\ell} + \delta_3^{\ell} w_{3y+}^{\ell}$$

$$r_z = \Delta t / \Delta z, \quad r_y = 2\Delta t / \Delta y$$

and A , δ_2 , δ_3 and the W 's were defined earlier.

The difference equation for the fracture block adjacent to the well is obtained by substituting the difference approximations into Eq. (III-9) yielding:

$$\beta_2^{\ell} p_2^{\ell+1} + \gamma_2^{\ell} p_{2+n_r}^{\ell+1} + \varepsilon_2^{\ell} p_3^{\ell+1} = \theta_2^{\ell} \quad (\text{III-13})$$

where γ and ε have the same definitions as in the previous case and:

$$\beta_2^{\ell} = -\{r_z \tau_F a_{k+}^{\ell} + r_y \tau_R e_{k+}^{\ell} + A_k^{\ell}\}$$

$$\theta_2^{\ell} = -A_2^{\ell} p_2^{\ell} - \underline{Q}^{\ell}$$

$\underline{Q}^{\ell}$ = number of moles flowing into or out of well block during a time step.

Note that during injection of a single fluid we have:

$$\underline{Q}^{\ell} = \Delta t [\rho_j]_{k=1}^{\ell} Q_{in}$$

where Q_{in} is the user-defined, total volumetric injection rate.

During the production phase of the huff-n-puff cycle this becomes:

$$\underline{Q}^{\ell} = \Delta t \{ \rho_1 f_1 + (x_{12} + \sigma_2 x_{22}) \rho_2 f_2 + (x_{13} + \delta_3 x_{33}) \rho_3 f_3 \}_{k=2}^{\ell} Q_{out}$$

where Q_{out} is the volumetric production rate.

Substitution of the appropriate difference approximations into Eq. (III-11) gives the pressure difference equation for matrix grid blocks:

$$\alpha_k^{\ell} p_{k-1}^{\ell+1} + \beta_k^{\ell} p_k^{\ell+1} + \epsilon_k^{\ell} p_{k+1}^{\ell+1} = \theta_k^{\ell}$$

where:

$$\alpha_k^{\ell} = r_y^{\tau} R e_{k-}^{\ell}$$

$$\epsilon_k^{\ell} = r_y^{\tau} R e_{k+}^{\ell}$$

$$\beta_k^{\ell} = -[r_y^{\tau} R (e_{k+}^{\ell} + e_{k-}^{\ell}) + A_k^{\ell}]$$

$$\theta_k^{\ell} = -A_k^{\ell} p_k^{\ell}$$

with:

$$e_{k+}^{\ell} = w_{1y+}^{\ell} + \delta_2^{\ell} w_{2y+}^{\ell} + \delta_3^{\ell} w_{3y+}^{\ell}$$

$$e_{k-}^{\ell} = w_{1y-}^{\ell} + \delta_2^{\ell} w_{2y-}^{\ell} + \delta_3^{\ell} w_{3y-}^{\ell}$$

Note that $r_y = \Delta t / \Delta y$ except for the matrix branch grids blocks adjacent to the fracture where $r_y = 2\Delta t / \Delta y$. Consistency with the assumption described above on the pressure gradient governing flow between the fracture and the matrix requires that the w 's in the relevant equations contain the absolute permeability of the matrix. This requirement includes the case where fluid is moving from the fracture to the matrix and the relative mobility, λ_j , of the fluid is evaluated "upstream" in the fracture block.

Finally, the continuity or composition equations ((III-3), (III-4), (III-5)) are differenced explicitly. That is, the flow rates q_j in those equations are rewritten as $f_j Q$ where the Q 's are calculated from the solutions just obtained to the matrix of pressure equations

discussed above. Following the numbering order discussed in Sec. II, this pressure matrix equation has the form:

$$\begin{bmatrix}
 \beta_2 & \epsilon_2 & - & - & \gamma_2 & - & \dots \\
 \alpha_3 & \beta_3 & \epsilon_3 & - & - & - & \dots \\
 - & \alpha_4 & \beta_4 & \epsilon_4 & - & - & \dots \\
 . & . & . & . & . & . & \dots \\
 . & . & . & . & . & . & \dots \\
 . & . & . & . & . & . & \dots \\
 \alpha_{2+n_r} & - & - & - & \beta_{2+n_r} & \epsilon_{2+n_r} & - & - & \gamma_{2+n_r} \\
 - & - & - & - & \alpha_{3+n_r} & \beta_{3+n_r} & \epsilon_{3+n_r} & - & - \\
 . & . & . & . & . & . & . & . & . \\
 . & . & . & . & . & . & . & . & . \\
 . & . & . & . & . & . & . & . & .
 \end{bmatrix}
 \begin{bmatrix}
 P_2 \\
 P_3 \\
 P_4 \\
 . \\
 . \\
 . \\
 P_{2+n_r} \\
 P_{3+n_r} \\
 . \\
 . \\
 .
 \end{bmatrix}
 =
 \begin{bmatrix}
 \theta_2 \\
 \theta_3 \\
 \theta_4 \\
 . \\
 . \\
 . \\
 \theta_{2+n_r} \\
 \theta_{3+n_r} \\
 . \\
 . \\
 .
 \end{bmatrix}$$

Utilizing the tridiagonal nature of segments of this matrix a modified Gaussian elimination algorithm was used to solve this set of equations.

IV. Solution Method

The solution approach employed in this numerical model is sequential. We implicitly solve the matrix of differenced pressure equations and use the solutions to calculate enter-block flow rates. These flow rates are then substituted into the explicitly differenced set of continuity equations to give the overall component composition of each block at the new time level.

To improve the accuracy of the pressure and composition solutions we use an in-step substitution iteration procedure. This consists of using the most recently computed compositions to predict the relative permeabilities and other fluid properties at the advanced time step and then substituting these values back into the coefficients of the pressure matrix and continuity equations and recalculating pressures and compositions. The procedure is repeated until the predicted relative permeabilities satisfy a pre-set convergence criterion.

There are a number of possible sources of error related to the length of the time step that are inherent in sequential solution algorithms. These include time truncation errors, numerical stability of the solutions, overshooting, and continuity of the solution at the bubble point. We have included several time step controls in the model to reduce the effect of these errors.

The time truncation error is most easily controlled by limiting the magnitude of change of some important variable during any time step.⁶ We choose to limit the pressure rise allowed during a step. This is readily accomplished by reducing the step size by a factor $DPLIM/DPMAX$ where $DPMAX$ is the maximum pressure change calculated for a step and $DPLIM$ is the maximum change allowed and is defined by the model user.

Overshooting occurs when the flow into a block is less than the flow out of a block and the time step is so long that the block is completely emptied and a negative composition results. This occurs most frequently in the presence of a mobile gas phase. When such a condition is present, the step is halved and the entire calculation for that step is repeated.

The numerical stability limitation is due to the explicit calculation of relative permeabilities. Although we use in-step substitution iterations to improve the relative permeability values, convergence of those values will not occur in such an iterative process for any time step that violates the following condition:⁷

$$2\Delta t D_{sg}(f_g) [|q_y| + |q_z|] / V_p \leq 1$$

where

V_p = pore volume of a block,

q = volumetric flow rate,

$D_{sg}(f_g)$ = the change in the fractional flow of gas with respect to a change in gas saturation during a time step,

Δt = length of time step.

At present we set the well flow rates based upon the above stability constraint. However, this is not sufficient to control the size of $D_{sg}(f_g)$ at the bubble point where this derivative can be relatively large. A subroutine which would incorporate the above stability criterion into the model is included in the listing of the source code (see Appendix), however, it is currently not completely operational and therefore not being implemented.

Finally, if during a time step a mobile gas phase appears in some block k, then to insure a continuous transition from the immobile gas case to the mobile gas case, the step length must be sufficiently short so that only a very small amount of mobile gas is present at the end of the step. This is necessary because the thermodynamic equilibrium conditions that govern the two cases are quite different. Too long a step could result in a solution which was inconsistent with the equilibrium assumption based on conditions at the beginning of the step. We have included in the model a time step control at the bubble point governing the appearance of a mobile gas phase in a block. This control needs to be generalized to include the possibility of the gas phase disappearing during a step as well.

Finally, a volume balance check is performed during each step by comparing the total fluid volume with the pore volume in each grid block. This provides a rough measure of the accuracy of the solutions obtained.

A flow chart of the solution scheme is included in Fig. IV-1.

Figure IV-1. Solution flow chart.

V. Phase Properties

A. Thermodynamic Equilibria

The phase behavior of the system modelled by this simulator involves mass transfer between three phases (gas, oil, water) and may be represented on a ternary phase diagram (see Fig. V-1). Phase equilibrium is subject to the following restrictions:

- (1) Of the three components present in the system (CO_2 , hydrocarbons (HC), and H_2O), only the transfer of CO_2 molecules is assumed to occur between the gas and the two liquid phases.
- (2) The carbonated oil and carbonated water solutions are assumed to be "weak".

Assumption (1) implies both immiscibility between the oil and water phases and the absence of any extraction of HC and H_2O molecules into a vapor phase. The latter conclusion is reasonable since we are considering for the purposes of this model only "heavy" oils, that is oils of 20° API gravity and below, which generally contain little or no "light" components. Furthermore, this implies that the gas phase is composed of only CO_2 .

Assumption (2) is justified since the primary focus of the model is to investigate the flow behavior of oil and water in shallow reservoirs, where the relatively low formation fracturing pressure limits the useful pressure range to about 500 psia and below. At such low pressures the carbonated oil solutions (and, of course, the carbonated water) can be considered to be weak due to the relatively low solubility of CO_2 (<20 mole % in oil).

Assumption (2) then leads to two important conclusions: first, Henry's Law states that the solubility of a weak solution of gas in a

Figure V-1. Fluid phase behavior.

liquid at low pressures is proportional to the gas pressure.⁸ Thus, the solubility of CO₂ in the oil and water is approximately linear with pressure. Second, the ratio of the concentrations of a solute in two different solvents (again, assuming "weak" solutions) is constant for a given pressure and temperature (distribution law).⁸ This latter conclusion, coupled with the assumptions of solubility linear with pressure and isothermal conditions, leads to the result that the ratio of the concentrations (and the solubilities) is a constant over the pressure range considered above.

Phase equilibrium calculation:

We determine how injected gas is partitioned among the three phases at equilibrium conditions for a given overall composition characterized by a point on the ternary phase diagram (see Fig. V-1). If the composition point, depicted by Z on the diagram, is above the solubility line (which is a function of pressure alone) then three mobile phases - gas, oil, and water - exist. If the composition point is below the line then only the oil and water are mobile and any gas that is present is either in solution or is immobile residual gas. We will henceforth refer to the latter case, where no mobile gas phase is present, as case A and to the case where mobile gas is present as case B.

For case A, the equilibrium condition is given by:

$$x_{12}/x_{13} = \theta_{12}/\theta_{13} = \eta$$

where θ_{12}^P and θ_{13}^P are the solubilities of CO₂ in oil and water, respectively, as functions of the average pressure, P and η is the constant solubility ratio, θ_{12}/θ_{13} .

For case B, the condition is simply:

$$x_{12} = \theta_{12}P$$

$$x_{13} = \theta_{13}P$$

i.e., the mole fractions of CO_2 in oil and water are equal to their saturated values.

If z_i is the overall mole fraction of component i in the system and the index $i = 2, 3$ refers to oil and water, respectively, then it can be shown¹⁶ that the concentration of CO_2 in water with no attendant solubility restriction is:

$$x_{13} = \{ [1 + \eta z_1 + z_2(\eta - 1)] - \sqrt{[1 + \eta z_1 + z_2(\eta - 1)]^2 - 4z_1\eta} \} / 2\eta$$

If $x_{13} < \theta_{13}P$ then the CO_2 is all in solution, no mobile gas exists, and the equilibrium condition of case A can be applied to determine x_{12} . Then, using the constraint that $x_{12} + x_{22} = x_{13} + x_{33} = 1$, x_{22} and x_{33} can be calculated.

If, however, $x_{13} \geq \theta_{13}P$ then the liquid phases are saturated and CO_2 must begin to bubble out of solution. Therefore, the equilibrium condition of case B must be invoked, where then $x_{12} = \theta_{12}P$ and $x_{13} = \theta_{13}P$. Any remaining CO_2 must enter a mobile gas phase.

B. Density

Gas phase density is calculated using the compressibility equation of state:

$$PV = nzRT$$

where:

P = pressure,

V = volume,

n = number of moles,

z = compressibility factor,

R = universal gas constant = 8.3 J/mol°K,

T = temperature (°K).

Assuming that T = 35°C then the molar density of the gas is given by:

$$\rho_1 = P/zRT = 2.7 \times 10^{-6} P/z$$

where P is in psia and z is assumed to be a linear function of pressure for P < 500 psi.⁹

The calculation of liquid (oil or water) phase densities requires experimental data on the density vs. pressure behavior of the pure liquid and of the CO₂ saturated liquid.¹⁰⁻¹⁵ This information, coupled with the assumption that a molecule of CO₂ dissolved in the liquid occupies the same volume in the unsaturated liquid as it does in the saturated liquid allows us to calculate the molar density of the liquid phases via the following relation:

$$\rho_j = [x_{ij}V_{ij} + x_{jj}V_{jj}]^{-1}$$

where:

j denotes the phase = 2 for oil, = 3 for water,

x_{ij} is the mole fraction of CO_2 in phase j ,

x_{jj} is the mole fraction of oil in the oil phase or of water in the water phase,

V_{ij} is the specific molar volume of the component i located in phase j .

The specific volumes of oil and water, V_{22} and V_{33} , are obtained by inverting the mass density of the respective pure component and multiplying by the appropriate molecular weight. Mole fractions are calculated based on the most recent pressure and composition solutions.

The specific volume of CO_2 in oil, V_{12} , is calculated utilizing experimental data on the swelling factor, f , of CO_2 -saturated oil. By definition, the volume of a quantity of saturated oil is equal to the product of the swelling factor, the number of moles of dead oil, and the specific volume of the oil at standard conditions. The swelling factor is assumed to be linear with pressure. V_{12} is then found to be given by:

$$V_{12} = (1 - \theta_{12}P) [fV_{22}(P=1 \text{ atm}) - V_{22}(P)] / (\theta_{12}P) .$$

The specific volume of CO_2 in water requires data on the mass densities of pure and CO_2 -saturated water at various pressures. We find that:

$$V_{13} = (1 - \theta_{13}P) [m_3 / \rho_3', \text{sat} - V_{33}] / (\theta_{13}P) + m_1 / \rho_3', \text{sat}$$

where:

m_1, m_3 = molecular weights of CO_2 and H_2O ,

ρ_3', sat = mass density of CO_2 -saturated water.

C. Viscosity

In this model the viscosities of the CO_2 gas phase and the water phase are assumed to be constant. Since the gas is pure and the solubility of CO_2 in water is relatively small this assumption is a reasonable approximation to the actual behavior of the system under consideration. On the other hand, the oil phase viscosity is assumed to be a function of both pressure and composition. Over a limited range of pressure and dissolved gas composition it has been observed that the log of the oil viscosity varies linearly with the pressure and the amount of gas dissolved in the oil.^{11,12} Thus, we approximate the oil viscosity by the following relation:

$$\log \mu_2 = AP + Bx_{12} + C$$

where:

μ_2 = oil phase viscosity (cp).

The constants A, B, and C must be determined from experimental data describing the variation of the viscosity of pure and CO_2 -saturated oil with pressure. A is the slope of the $\log \mu_2$ vs. P data for pure oil. C is the intercept of that graph with the $\log \mu_2$ axis. B relates the viscosity to the oil composition and is given by $B = (A' - A)/\theta_{12}$, where

A' is the slope of the CO_2 -saturated oil viscosity curve and θ_{12} is the molar solubility of CO_2 in the oil.

The user must determine A , A' , and C from available experimental data and input these values into the model (see INPUT formats). Note that in general $A' < A$ and $B < 0$.

D. Saturation

Knowledge of the equilibrium composition of the system and of the specific volumes of the components leads directly to phase saturations.

The total fluid volume is given by:

$$V_f = \sum_{i,j} N_{ij} V_{ij}$$

Phase saturations are then given by:

$$S_j = \sum_i N_{ij} V_{ij} / V_f$$

Thus:

$$\text{gas} - S_1 = N_{11} V_{11} / V_f$$

$$\text{oil} - S_2 = (N_{12} V_{12} + N_{22} V_{22}) / V_f$$

$$\text{water} - S_3 = (N_{13} V_{13} + N_{33} V_{33}) / V_f$$

where:

$$V_f = N_{11} V_{11} + N_{12} V_{12} + N_{13} V_{13} + N_{22} V_{22} + N_{33} V_{33} .$$

E. Compressibility

The effective compressibility of the fluid system is defined by:

$$C = C_{\text{eff}}/V_f$$

where:

$$C_{\text{eff}} = -[N_{11}D_P(V_{11}) + N_{12}D_P(V_{12}) + N_{13}D_P(V_{13}) + N_{22}D_P(V_{22}) + N_{33}D_P(V_{33})]$$

$$V_f = \text{the total fluid volume .}$$

Assume that CO_2 behaves like a compressible ideal gas, i.e., $PV = nzRT$ (see Sec. V.B). We expand the volume in a Taylor series:

$$V = V_o + [D_P(V)]_{P_o} \Delta P + \frac{1}{2} [D_P^2(V)]_{P_o} (\Delta P)^2 + \dots$$

Rearranging:

$$C = -\Delta V/(V_o \Delta P) \approx -\{[D_P(V)]_{P_o} + [D_P^2(V)]_{P_o} \Delta P/2\}/V_o .$$

Applying the first and second derivatives to the above equation of state gives:

$$C = [1-\Delta P/P_o]/(zP_o) .$$

Thus, the first term in the expression for C_{eff} can be written:

$$N_{11}V_{11}[1-\Delta P/P_o]/(zP_o)$$

where

P_o = the most recently computed value for the pressure,

ΔP = the change in the pressure from the last step to the present step.

The second and third terms in C_{eff} involve the compressibility of dissolved gas in oil and water. Referring back to the section on densities it is easily seen that:

$$-N_{12}D_P(V_{12}) = [a_s V_{22}(1) + (V_{22}(1) - V_{22}(P)) / (\theta_{12} P^2)] N_{12}$$

where a_s is the slope of the swelling factor f ,

$$-N_{13}D_P(V_{13}) = [m_3 a_3 + (m_1 - m_3) a_3^{sat}] / (b_3)^2$$

where a_3^{sat} and a_3 are the slopes of mass density of saturated and pure water, respectively, and b_3 is the density of water at atmospheric pressure.

Finally, the last two terms of C_{eff} represent the compressibilities of pure oil and pure water. Noting that:

$$V_{22} = m_2 / (a_2 P + b_2)$$

$$V_{33} = m_3 / (a_3 P + b_3)$$

where a_2, a_3 and b_2, b_3 are, respectively, the slopes and intercepts of the oil and water mass density curves, we get:

$$-N_{22}D_P(V_{22}) = a_2 N_{22} V_{22}^2 / m_2$$

$$-N_{33}D_P(V_{33}) = a_3 N_{33} V_{33}^2 / m_3 \quad .$$

F. Relative Permeability

The three-phase relative permeabilities of gas, oil and water are calculated from either functional representations of two-phase relative permeabilities or from experimental data obtained on two-phase systems. The general form of the two-phase relative permeability curves is shown in Fig. V-2.

In the figure, k_{rw} and k_{row} are, respectively, the relative permeabilities of water and of oil to water in the oil-water system. In the oil-gas system, k_{rg} and k_{rog} are the relative permeabilities of gas and of oil to gas. When the water saturation S_w is reduced to its connate value S_{wc} its relative permeability k_{rw} is zero. When $S_w = 1 - S_{or}$, where S_{or} is the residual oil saturation, k_{rw} reaches its endpoint value E_w . Similarly, the oil relative permeability k_{row} reaches its endpoint value E_{ow} when $S_w = S_{wc}$ and is zero when $S_w = 1 - S_{or}$.

In the oil-gas system, S_L is the liquid saturation and equals the sum of the oil and water saturations. When $S_L = S_{Lc} = S_{wc} + S_{og}$, where S_{og} is the residual oil to gas, the relative permeability of the gas k_{rg} is equal to its endpoint value E_g and is zero when the gas saturation S_g equals the critical gas saturation S_{gc} . The oil endpoint of the oil-gas curve is E_{og} and for consistency should equal E_{ow} .

The relative permeability of a phase can be considered to be a function of the effective saturation of that phase with the following general form:^{16,17}

Figure V-2. Relative permeability.

$$k_{rj} = E_j (S_{eff})^{e_j}$$

There are four such functions needed in this model. The endpoint values E_j and the exponents e_j are set by the user. In the oil-water system, for $j = w$ the effective saturation S_{eff} is given by $(S_w - S_{wc}) / (1 - S_{or} - S_{wc})$ and for $j = ow$ it is $(1 - S_w - S_{or}) / (1 - S_{or} - S_{wc})$. In the oil-gas system, for $j = og$, $S_{eff} = (S_L - S_{Lc}) / (1 - S_{Lc})$ and for $j = g$, $S_{eff} = (S_g - S_{gc}) / (1 - S_{Lc} - S_{gc})$, where $S_L = 1 - S_g$ and $S_{Lc} = S_{wc} + S_{og}$.

Three-phase relative permeabilities are then calculated from the two-phase permeabilities using Stone's second model¹⁸ with a slight modification when $EK_{row} < 1$. The water and gas permeabilities are equal to their respective two-phase values and the oil permeability is given by:

$$k_{ro} = (k_{row} + k_{rw})(k_{rog} + k_{rg}) / E_{og} - (k_{rw} + k_{rg})$$

Note that for $S_o < S_{or}$, $k_{row} = 0$ and k_{rw} is obtained by linearly interpolating between E_w and 1. Similarly, for $S_w < S_{wc}$, $k_{rw} = 0$ and k_{row} is obtained by interpolation and for $S_L < S_{Lc}$, $k_{rog} = 0$ and k_{rg} is evaluated by interpolation.

Finally, the relative mobilities λ_j of the three phases are given by:

$$\lambda_j = k_{rj} / \mu_j$$

and the fractional flow rates f_j by

$$f_j = \lambda_j / \sum_j \lambda_j$$

VI. Sample Runs

Three sample problems were run using this numerical model. In each of these problems the following input parameters were held constant.

Number of grid blocks in fracture (NBZ) = 4
Number of grid blocks in matrix branch (NBY) = 3
Length of fracture (FRLTH) = 90.0 cm
Length of matrix branch (RSLTH) = 2.0 cm
Fracture width (HFRAC) = 0.1 cm
Vertical thickness of system (DEPTH) = 10.0 cm
Fracture porosity (PORF) = 1.0
Matrix porosity (PORR) = 0.3
Absolute permeability of fracture (PRMF) = 10^7 md
Absolute permeability of matrix (PRMR) = 10^2 md
Initial reservoir pressure (PRSI) = 150
Initial time step length (DT) = 3.0 min
Maximum pressure change allowed per step (DPLIM) = 50
Injection flow rate (QINJ1) = $2.0 \text{ cm}^3/\text{min}$
Production flow rate (QPROD) = $0.1 \text{ cm}^3/\text{min}$
Initial matrix composition (:vol%), 5% CO₂, 45% HC, 50% H₂O
Solubility of CO₂ in oil = (OILSOL*P) = 4.54×10^{-4} P
Oil density: 3.53×10^{-6} P + 0.9943
Saturated H₂O density: 1.68×10^{-4} P + .9943
CO₂ viscosity = .015 c.p.
H₂O viscosity = 1.0 c.p.
Oil viscosity = $10^{(1.09 \times 10^{-4} \text{ P} - 3.985 \times 12 + 2.699)}$ c.p.

Note: oil densities, solubilities, viscosity data taken from Miller.¹²

For the following runs, well cycling control is pressure limited. That is, the well is switched to injection mode when the pressure drops to some minimum value (in this case 150 psi) and to production mode when the pressure rises to some maximum value (250 psi for these runs). A brief soak period occurs between the injection and production periods. Table VI-1 contains the accumulated values of moles of CO₂ input and moles of CO₂, oil, and water output at the end of each injection/production cycle, for each of the three cases examined. Table VI-2 shows the location of the gas front at the end of each cycle for the three runs made.

Table VI-1. Results of Sample Runs *

	Run 1	Run 2	Run 3
<u>Cycle 1</u>			
CO ₂ injected	.0586	.0547	.0546
CO ₂ produced	.0248	.0214	.0194
Oil produced	1.03×10^{-4}	2.11×10^{-4}	6.38×10^{-4}
Water produced	.163	.587	.424
<u>Cycle 2</u>			
CO ₂ injected	.143	.106	.140
CO ₂ produced	.0774	.0578	.072
Oil produced	2.88×10^{-4}	3.36×10^{-4}	9.47×10^{-4}
Water produced	.455	.898	.632
<u>Cycle 3</u>			
CO ₂ injected	.215	.166	
CO ₂ produced	.133	.104	
Oil produced	4.65×10^{-4}	4.5×10^{-4}	
Water produced	.735	1.167	
<u>Cycle 4</u>			
CO ₂ injected		.229	
CO ₂ produced		.161	
Oil produced		6.5×10^{-4}	
Water produced		1.686	

* See text for details of run parameters. Quantities are in units of accumulated moles.

Table VI-2. Gas Front Location During Sample Runs

	Run 1				Run 2				Run 3			
<u>Cycle 1</u>	<u>2</u>	<u>6</u>	<u>10</u>	14	<u>2</u>	<u>6</u>	<u>10</u>	14	<u>2</u>	<u>6</u>	10	14
	<u>3</u>	<u>7</u>	<u>11</u>	15	<u>3</u>	<u>7</u>	<u>11</u>	15	<u>3</u>	<u>7</u>	11	15
	<u>4</u>	8	12	16	<u>4</u>	8	12	16	<u>4</u>	8	12	16
	5	9	13	17	5	9	13	17	5	9	13	17
<u>Cycle 2</u>	<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>	<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>	<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>
	<u>3</u>	<u>7</u>	<u>11</u>	15	<u>3</u>	<u>7</u>	<u>11</u>	15	<u>3</u>	<u>7</u>	<u>11</u>	15
	<u>4</u>	8	12	16	<u>4</u>	8	12	16	<u>4</u>	8	12	16
	5	9	13	17	5	9	13	17	5	9	13	17
<u>Cycle 3</u>	<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>	<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>				
	<u>3</u>	<u>7</u>	<u>11</u>	15	<u>3</u>	<u>7</u>	<u>11</u>	15				
	<u>4</u>	8	12	16	<u>4</u>	8	12	16				
	5	9	13	17	5	9	13	17				
<u>Cycle 4</u>					<u>2</u>	<u>6</u>	<u>10</u>	<u>14</u>				
					<u>3</u>	<u>7</u>	<u>11</u>	<u>15</u>				
					<u>4</u>	8	12	16				
					5	9	13	17				

Results are given describing the efficiency of the recovery process and the fraction of CO_2 trapped in the reservoir for each of the three sample cases. Recovery efficiency is calculated in thousands of standard cubic feet (MSCF) of CO_2 injected and not recovered per barrel (bbl) of oil recovered. The fraction of CO_2 trapped is a dimensionless quantity calculated from the moles of CO_2 injected less the moles of CO_2 recovered divided by the moles of CO_2 injected.

Run 1

For this case, it was assumed that CO_2 was soluble in water, i.e., the molar solubility of CO_2 in H_2O at pressure P was given by $\text{WATSOL} \cdot P \rightarrow 2.1 \times 10^{-5} P$. Furthermore, the fracture was assumed to initially contain 50% oil and 50% water.

Three cycles were run for this case. The recovery factor, R , at the completion of the first cycle, which lasted 76.8 minutes, was calculated from the data in Table VI-1 to be 217 MSCF/bbl. The fraction of CO_2 trapped, F , was found to be 58%. The second cycle lasted 124.7 minutes, with $R = 150$ MSCF/bbl and $T = 46\%$ at the end of the cycle. The third cycle continued for 116.3 minutes, at the end of which $R = 116$ MSCF/bbl and $T = 38\%$.

Run 2

Here, CO_2 was not allowed to dissolve into the water. This was done by lowering the solubility factor four orders of magnitude from the value used in Run 1. The initial composition of the fracture was the same as in Run 1. Four cycles were completed.

The first cycle lasted 77.2 minutes, at the end of which $R = 104$ MSCF/bbl and $T = 61\%$. The second cycle lasted 79.8 minutes, with

R = 90.9 MSCF/bbl and T = 37% at its conclusion. The fourth and final cycle lasted 109.3 minutes. The final recovery factor and fraction of trapped gas were, respectively, R = 69.0 MSCF/bbl and T = 30%.

Run 3

In this last run, the solubility of CO₂ in water was increased to the level used in Run 1 and the initial composition of the fracture was changed to 70% volume saturation of oil and 30% volume saturation of water. Only two cycles were run for this case.

The first cycle lasted 66.6 minutes. R was then found to equal 36.4 MSCF/bbl and T to be 65%. At the end of the second cycle, which lasted 128.8 minutes, R = 47.4 MSCF/bbl and T = 49%.

Analysis and Conclusions

Reduction of the solubility of CO₂ in pure water had the expected effect of allowing the CO₂ gas to migrate further into the fracture/matrix system than for the case of CO₂ being allowed to dissolve normally into pure water. Since reservoir brines generally have varying levels of dissolved salts which act to reduce the CO₂ solubility of water the actual CO₂ gas migration will be intermediate to that indicated by Runs 1 and 2.

If the reservoir is assumed to be water-wet then the initial composition of a fracture could well lie between the oil-water volume ratio of 50/50 used in Run 2 and 70/30 used in Run 3. The latter case has clearly the most optimistic projection of MCF/bbl of the three runs made.

In the first two runs each succeeding injection/production cycle resulted in an improved recovery factor and a lower amount of

trapped gas. However, in the final run the opposite effect was observed. It would be interesting to investigate the effect of a larger number of cycles per run on the recovery factor and trapped gas fraction.

Optimally, the injection cycle should continue until the reservoir pressure rises close to the fracturing pressure of the rock in order to obtain the maximum stimulation of the oil possible.²⁰ Furthermore, the investigation of the effects of cycles of different duration upon the production is clearly an area where more work is needed.

VII. Discussion and Conclusions

Previous work has demonstrated the utility of carbon dioxide as an agent in the recovery of heavy crude oil.²⁰ Similarly, hydraulic fracturing has been used to increase the injectivity of a reservoir and thereby improve recovery. It is not well understood, however, what effect introducing a fracture into a reservoir would have on a CO₂ stimulation process.

We have developed a numerical model for use in the investigation of the compressible flow behavior of injected and reservoir fluids in the vicinity of a high-conductivity fracture. The two-dimensional model includes a rock matrix that is bounded on one side by a linear fracture. Flow into and out of the system is only through a well at one end of the fracture. We have neglected gravity and have assumed that there are no variations in the vertical direction. The combination of a high conductivity fracture with a horizontal areal model significantly reduces the computation necessary to describe the evolution of the system because a direct matrix solution of the problem is possible.

We are interested in modeling the behavior of fluids in fractured shallow reservoirs where pressures must be kept small enough (<500 psi) to preserve the competency of the rock. This pressure restriction thus allows us to assume a linear behavior for most fluid properties, thereby making complex equation-of-state calculations unnecessary and further reducing the computational effort.

The model allows up to three fluid phases to exist - gas, oil, and water - and furthermore allows dissolved gas to exist in both the oil and water phases. Well behavior can be either injection, production, or soak, and at the user's option, can be either pressure or time limited.

This arrangement facilitates the modeling of a huff-n-puff process. The model could, if desired, be readily converted to investigate drive processes as well by placing well block(s) on the other boundaries of the rock matrix.

In our runs we have observed, as expected, that the existence of a fracture increases the portion of the reservoir contacted by the injected CO_2 . In general we find that the water, being much more mobile than the oil, is displaced away from the fracture while the oil remains near the fracture and is stimulated by the CO_2 . The degree of stimulation and consequent increase in oil mobility is very clearly dependent on the amount of mobile gas phase present in the system.

A large free gas saturation reduces the efficiency of the recovery process by blocking the pores and inhibiting oil and water flow. Several runs indicate that limiting the presence of free gas in the system is an important factor in improving recovery efficiencies.

One possible way to accomplish this is by alternately injecting water into the system (WAG process) thereby increasing the pressure and forcing free gas into solution with the oil. A few runs were made to investigate the efficacy of such a process. Preliminary indications are that such a process would indeed result in higher oil recoveries than a pure CO_2 -stimulation treatment. Furthermore, this prediction is supported by various field studies such as the Lick Creek project.²⁰

We have also looked at how stimulation is affected by the degree of solubility of CO_2 in the water. If the reservoir brine has a high dissolved salt content (>200,000 ppm) then the solubility of CO_2 in water falls to 20% that of the pure water case. The model user should

estimate roughly the salt content of the reservoir brine and adjust the input solubility of CO_2 in water accordingly.

We now turn to the numerical features of this model. Although the basic formulation of the model is of the form of an implicit pressure-explicit composition calculation, the inclusion of a scheme for in-step iterations on the coefficients of the pressure-composition terms makes the model more implicit and therefore less subject to stability problems. Recently, however, we have found that limiting the iterations to one or two passes seems to be sufficient to keep the accuracy of the model within reasonable bounds. The automatic volume balance check that is included in the model predicts less than a 5% volume mismatch for the case of limited iterations.

Time truncation error is controlled by restricting the pressure change allowed during a step. This method of time step control works quite well and could be easily modified to investigate the use of other possible control parameters, such as saturation or fractional flow rates.

We have found that time step control at the bubble-point of the system is an important factor in maintaining the desired level of accuracy in the model's predictions. This is due to the existence of different fluid phase equilibrium conditions on the saturated and unsaturated sides of the bubble-point. Different equilibrium conditions imply that slightly different systems of equations govern the flow behavior in the two cases. Therefore, in order to make the transition from unsaturated case to the saturated case as smooth as possible, the time step at the bubble-point must be sufficiently small so that only a very small amount of gas phase is present at the end of the time step in which the gas first appears. We implemented an algorithm which

appears to adequately satisfy this criterion. The algorithm has been generalized to include the effect of gas disappearing in the system.

The formats of the input data required and the results output from the model are detailed in the Appendices. Note that the source code, with the exception of the PROGRAM statement, is ANSI standard FORTRAN 77.

VIII. Nomenclature

C_{eff}	- effective compressibility
f_j	- fractional flow of phase j
g	- gravitational acceleration
h	- fracture width (cm)
i	- subscript index denoting component
j	- subscript index denoting phase
k	- grid block index
k_{rj}	- relative permeability of phase j
$K_F; K_R$	- absolute permeability of (fracture; rock matrix) (millidarcies)
$\ell_F; \ell_R$	- length of (fracture; matrix branch) (cm)
$n_z; n_y$	- number of grid blocks along (fracture:z; matrix branch:y)
N_{ij}	- number of moles of component i in phase j
P_k	- average pressure in grid block k (psi)
q_z, q_y	- volumetric flow rate along (fracture:z; matrix branch:y) (cm ³ /sec)
r_z, r_y	- mesh ratio ($\Delta t/\Delta z$; $\Delta t/\Delta y$)
S_j	- saturation of phase j
Δt	- length of time step (sec)
V_{ij}	- specific molar volume of component i in phase j
W_{iz}, W_{iz}	- pressure equation coefficients containing mobility terms

x_{ij} - mole fraction of component i in phase j
 $\Delta y, \Delta z$ - grid block dimension in direction (y:along matrix branch;
 z:along fracture)

$\alpha, \beta, \gamma, \theta, \delta_2, \delta_3$ - coefficients in pressure equation

θ_{12} - molar solubility coefficient for CO_2 in oil

θ_{13} - molar solubility coefficient for CO_2 in water

η - θ_{12}/θ_{13}

λ_j - mobility of phase j ($= k_{rj}/\mu_j$)

μ_j - viscosity of phase j (c.p.)

ρ_j - molar density of phase j (moles/cm³)

τ - area open to flow (cm²)

ϕ - porosity

$D_t(F(y, z, t, P, N_{ij}))$ - operator denoting partial derivative of F with respect to t

IX. References

1. U.S. Bureau of Mines: Heavy Crude Oil Resource, Reserve, and Potential Production in the United States, IC 8352, 1967.
2. Ball Associates, Ltd.: Surface and Shallow Oil-Impregnated Rocks and Shallow Oil Fields in the United States, Bu-Mines Monograph 12 (1965).
3. Petroleum Training and Technical Services: Technical Review of Enhanced Oil Recovery Literature - Final Report, DOE/ER/10086-T1 (April 1980).
4. Smith, C. R.: Mechanics of Secondary Oil Recovery, Kreiger Publishing Co., Huntington, New York (1975).
5. Lamb, H.: Hydrodynamics, Cambridge University Press (1932).
6. Goodrich, J. H. and Watts, R.: Target Reservoirs for CO₂ Miscible Flooding - Final Report, DOE/MC/08341-17 (October 1980).
7. Todd, N. R., O'Dell, P. M., and Hirasaki, G. J.: "Methods for Increased Accuracy in Numerical Reservoir Simulators," Soc. Pet. Eng. J. (December 1972) 515-530.
8. Peaceman, D. W.: Fundamentals of Numerical Reservoir Simulation, Elsevier Scientific Publishing Co., Amsterdam (1977).
9. Landau, L. D. and Lifshitz, E. M.: Statistical Physics, Pergamon Press, Ltd., Oxford, England (1980).
10. Crawford, H. R., Neill, G. H., Bucy, B. J., and Crawford, P. B.: "Carbon Dioxide - A Multipurpose Additive for Effective Well Stimulation," J. Pet. Tech. (March 1963) 237-242.
11. Walker, J. R. and Dunlop, D. D.: "Physical Properties of Carbonated Oil," J. Pet. Tech. (August 1963) 873-876.
12. Miller, J. S. and Jones, R. A.: "A Laboratory Study to Determine Physical Characteristics of Heavy Oil After CO₂ Saturation," SPE/DOE 9789 (1981).
13. Simon, R. and Graue, D. J.: "Generalized Correlations for Predicting Solubility, Swelling, and Viscosity Behavior of CO₂-Crude Oil Systems," J. Pet. Tech. (January 1965) 102-106.
14. Dodds, W. S., Stutzman, L. F., and Sollami, B. J.: "Carbon Dioxide Solubility in Water," Ind. and Eng. Chem. (1956) 1 92-95.
15. Parkinson, W. J. and DeNevers, N.: "Partial Molar Volume of Carbon Dioxide in Water Solutions," I and EC Fundamentals (November 1969) 709-713.

16. Orr, F. M.: "Simulation of the One-Dimensional Convection of Four Phase, Four Component Mixtures," DOE/ET/12082-8 (June 1980).
17. Crichlow, H. B.: Modern Reservoir Engineering - A Simulation Approach, "Prentice-Hall, Inc., Englewood Cliffs, New Jersey (1977).
18. Stone, H. L.: "Estimation of Three-Phase Relative Permeability and Residual Oil Data," J. Can. Pet. Tech. (1973) 12 53-61 .
19. Patton, J. T., Coats, K. H., and Spence, K.: "Carbon Dioxide Well Stimulation: Part 1 - A Parametric Study," J. Pet. Tech. (August 1982) 1798-1804.
20. Reid, T. B. and Robinson, H. J.: "Lick Creek Meakin Sand Unit Immiscible CO₂/Waterflood Project," J. Pet. Tech. (September 1981) 1723-1729.

X. Appendix

A. Sample Input Format

- - - C O 2 C Y C L - - -

(HUF N' PUF) CO2 DISPLACING 17 DEG.WILMINGTON OIL IN FRAC'D. RES. .

NUMBER OF GRID BLOCKS

IN FRACTURE = 4
IN RESERVOIR BRANCH = 3

TIME STEP LENGTH = 3.000 SECONDS
NUMBER OF TIME STEPS = 200

PRESSURE CHANGE LIMIT PER TIME STEP = 50.0000PSI

BUBBLE-EDGE TOLERANCE ON MOLE FRACTION OF CO2 IN OIL = .0010

MAXIMUM NUMBER OF CONVERGENCE ITERATIONS ALLOWED 5

RESERVOIR GRID SCHEME

-----> Z

.

.

. Y

V

1	2	6	10	14
	3	7	11	15
	4	8	12	16
	5	9	13	17

LENGTH OF FRACTURE (CM)= 90.0000
LENGTH OF RESERVOIR BRANCH (CM)= 2.0000
WIDTH OF FRACTURE (CM)= .1000
DEPTH OF SYSTEM (CM) = 10.0000

FRACTURE X-SECTIONAL AREA (SQ.CM.)= 1.0000
RES. BRANCH X-SECTIONAL AREA (SQ.CM.)= 225.0000

ASSUMED POROSITY IN RESERVOIR= .3000
IN FRACTURE= 1.0000

PERMEABILITY IN FRACTURE (MD) = .1000E+08
PERMEABILITY IN RESERVOIR (MD) = 100.0000

INITIAL RESERVOIR PRESSURE (PSI)= 150.0000

CO2 INJECTION FLOW RATE (CC/SEC)= 2.0000
PRODUCTION FLOW RATE = .1000

FUNCTIONAL FORM OF FLUID DENSITIES

BLACK OIL : .3530E-05 X P + .9450E+00
SAT-D. OIL SWELLING FACTOR: .1000E-03 X P + 1.
PURE H2O : .3000E-05 X P + .9943E+00
SAT-D. H2O: .1680E-04 X P + .9943E+00

SLOPE OF GAS COMPRESSIBILITY FACTOR = -.3500E-03

SOLUBILITY COEFFICIENTS

OIL - .4540E-03
WATER - .2100E-04

VISCOSITY OF OIL =

10 ** (.1090E-03*P -.3985E+01*X12 + .2699E+01) C.P.
(WHERE X12 IS THE MOLE FRACTION OF CO2 IN OIL)

VIS. CO2 = .0150 VIS. H2O = 1.0000 (CP)

MOLEC. WGTS. (GMS/MOL) - CO2: 44.0000 OIL: 200.0000 H2O: 18.0000

RELATIVE PERMEABILITY DATA

SWC= .100	EKRO =1.000	EO = 2.00
SOR= .200	EKRW =1.000	EW = 2.00
SOG= .200	EKROG=1.000	EOG= 2.00
SGC= .050	EKRG =1.000	EG = 2.00

MESH RATIO FOR PRESSURE EQUATION

IN FRACTURE = .1333E+00
IN RESERVOIR = .4500E+01

INITIAL COMPOSITION IN MATRIX (VOLUME FRACTIONS)

.0500 .4500 .5000

IN FRACTURE

.0000 .5000 .5000

INJECTION COMPOSITION (VOLUME FRACTIONS)

1.0000 .0000 .0000

HUF-N-PUF WELL MODE SEQUENCE

MODE: 1 = CO2 INJECTION

2 = WATER INJECTION

-1 = PRODUCTION

+10 = POST-INJECTION SOAK

-10 = POST-PRODUCTION SOAK

1	10	-1	-10	1	10	-1	-10	1	10	-1	-10	1	10	-1	-10
1	10	-1	-10	1	10	-1	-10	1	10	-1	-10	1	10	-1	-10
1	10	-1	-10	1	10	-1	-10								

MAX. PRESSURE BUILD-UP ALLOWED DURING INJECTION CYCLE: 250.0000

MIN. PRESSURE ALLOWED: 150.0000

PRESSURE DIFFERENCE REQUIRED TO END SOAK CYCLE: .0500

PRINT KEYS

IPRNT= 5 IP(1)=1 IP(2)=1 IP(3)=0 IP(4)=

B. Sample Output Format

IT= 5 TIME= 7.48274 STEP = .60642. SEC
=====

CUMI (PV)	.023755	.000000	.000000
CMOLIN (MOLES)	.006473	.000000	.000000
CMOLPR (MOLES)	.000000	.000000	.000000

WELL MODE: CO2 INJECTION
CYCLE: 1

TSTRT - INITIAL STEP (SEC) = .3000E+01
TDPCHG(I) - TIME STEP AFTER TRUNCATION ADJUST.
TOVERF - TIME STEP AFTER OVERSHOOT ADJUST.(FRAC.)
TOVERR - TIME STEP AFTER OVERSHOOT ADJUST.(RES.)
TBUBBL - TIME STEP AFTER BUBBLE EDGE ADJUST.
.6064E+00
IMOB - PASSES THROUGH SUBR. MOBTR = 9

TIME SPENT IN SUBR. IMPEM = .2358E-01 SECONDS.
TIME SPENT IN SUBR. PHASE = .1343E-02 SECONDS.

PRESSURES

(FRACTURE ----->)

K =	2	6	10	14
	169.809	169.747	169.712	169.694
	169.674	169.631	169.596	169.578
	169.443	169.399	169.363	169.346
	169.327	169.283	169.247	169.229

K	QZ	QY	N11	N12	N22
1	.2000E+01				
2	.1111E+01	.3678E+00	.0000E+00	.4242E-02	.5312E-01
3	.0000E+00	.1778E+00	.9617E-03	.1176E-03	.9575E-01
4	.0000E+00	.8916E-01	.9617E-03	.1771E-06	.9574E-01
5	.0000E+00	.0000E+00	.9617E-03	.1016E-09	.9574E-01
6	.5347E+00	.2664E+00	.0000E+00	.3649E-03	.5321E-01
7	.0000E+00	.1785E+00	.9617E-03	.1482E-05	.9574E-01
8	.0000E+00	.8950E-01	.9617E-03	.1648E-08	.9574E-01
9	.0000E+00	.0000E+00	.9617E-03	.1294E-11	.9574E-01
10	.2675E+00	.2668E+00	.0000E+00	.3086E-05	.5319E-01
11	.0000E+00	.1787E+00	.9617E-03	.9423E-08	.9574E-01
12	.0000E+00	.8961E-01	.9617E-03	.1412E-10	.9574E-01
13	.0000E+00	.0000E+00	.9617E-03	.1360E-14	.9574E-01
14	.0000E+00	.2670E+00	.0000E+00	.9821E-08	.5319E-01
15	.0000E+00	.1788E+00	.9617E-03	.3994E-10	.9574E-01
16	.0000E+00	.8966E-01	.9617E-03	.3673E-13	.9574E-01
17	.0000E+00	.0000E+00	.9617E-03	.1360E-14	.9574E-01

K	N13	N33	CMPEFF	VTOT	VOLERR
1					
2	.1473E-02	.4292E+00	.1017E-04	.1924E+02	-.1450E+00
3	.7147E-04	.1259E+01	.2714E-03	.4502E+02	.4324E-03
4	.1078E-06	.1260E+01	.2720E-03	.4502E+02	.4126E-03
5	.6181E-10	.1260E+01	.2723E-03	.4502E+02	.4025E-03
6	.1955E-03	.6203E+00	.3871E-05	.2250E+02	-.2697E-05
7	.9019E-06	.1260E+01	.2714E-03	.4502E+02	.4286E-03
8	.1003E-08	.1260E+01	.2721E-03	.4502E+02	.4084E-03
9	.7874E-12	.1260E+01	.2724E-03	.4502E+02	.3984E-03
10	.1669E-05	.6218E+00	.3379E-05	.2250E+02	-.9086E-08
11	.5735E-08	.1260E+01	.2715E-03	.4502E+02	.4256E-03
12	.8592E-11	.1260E+01	.2722E-03	.4502E+02	.4055E-03
13	.8279E-15	.1259E+01	.2725E-03	.4502E+02	.3955E-03
14	.5311E-08	.6218E+00	.3374E-05	.2250E+02	.2050E-09
15	.2431E-10	.1260E+01	.2716E-03	.4502E+02	.4241E-03
16	.2235E-13	.1260E+01	.2722E-03	.4502E+02	.4040E-03
17	.8279E-15	.1259E+01	.2726E-03	.4502E+02	.3941E-03

K	V11	V12	V22	V13	V33
2	.2051E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
3	.2053E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
4	.2056E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
5	.2058E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
6	.2052E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
7	.2054E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
8	.2057E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
9	.2058E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
10	.2053E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
11	.2054E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
12	.2057E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
13	.2059E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
14	.2053E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
15	.2054E+04	.4449E+02	.2115E+03	.3224E+02	.1809E+02
16	.2057E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02
17	.2059E+04	.4450E+02	.2115E+03	.3224E+02	.1809E+02

K	RHOMOL(1)	RHOMOL(2)	RHOMOL(3)	F1	F2	F3	TMOB
2	.4875E-03	.5021E-02	.5512E-01	.00000	.00549	.99451	.40840
3	.4870E-03	.4733E-02	.5526E-01	.00000	.00066	.99934	.33692
4	.4863E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33709
5	.4860E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33703
6	.4873E-03	.4754E-02	.5525E-01	.00000	.00204	.99796	.50011
7	.4869E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33715
8	.4862E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33707
9	.4858E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33701
10	.4872E-03	.4728E-02	.5527E-01	.00000	.00191	.99809	.50099
11	.4868E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33713
12	.4861E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33705
13	.4857E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33699
14	.4871E-03	.4728E-02	.5527E-01	.00000	.00191	.99809	.50099
15	.4868E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33712
16	.4860E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33704
17	.4857E-03	.4728E-02	.5527E-01	.00000	.00065	.99935	.33698

	Z1	Z2	Z3	S1	S2	S3	X(1,2)	X(1,3)
2	.01171	.10884	.87945	.00000	.59384	.40616	.073956	.003421
3	.00014	.07065	.92921	.04386	.44996	.50618	.001227	.000057
4	.00000	.07063	.92937	.04393	.44979	.50629	.000002	.000000
5	.00000	.07064	.92936	.04396	.44979	.50625	.000000	.000000
6	.00083	.07894	.92023	.00000	.50091	.49909	.006811	.000315
7	.00000	.07063	.92937	.04387	.44981	.50632	.000015	.000001
8	.00000	.07063	.92937	.04394	.44979	.50627	.000000	.000000
9	.00000	.07064	.92936	.04397	.44979	.50624	.000000	.000000
10	.00001	.07880	.92120	.00000	.49997	.50003	.000058	.000003
11	.00000	.07063	.92937	.04388	.44980	.50631	.000000	.000000
12	.00000	.07064	.92936	.04395	.44979	.50626	.000000	.000000
13	.00000	.07064	.92936	.04398	.44979	.50622	.000000	.000000
14	.00000	.07880	.92120	.00000	.49996	.50004	.000000	.000000
15	.00000	.07063	.92937	.04389	.44981	.50631	.000000	.000000
16	.00000	.07064	.92936	.04395	.44979	.50626	.000000	.000000
17	.00000	.07064	.92936	.04399	.44979	.50622	.000000	.000000

	S2	X1	X2	X3	RHO	VIS	KR
2	.5938	.0740	.9260	.0000	.9463	264.7446	.5938
3	.4500	.0012	.9988	.0000	.9456	515.9482	.1139
4	.4498	.0000	1.0000	.0000	.9456	521.7494	.1137
5	.4498	.0000	1.0000	.0000	.9456	521.7430	.1137
6	.5009	.0068	.9932	.0000	.9457	490.1874	.5009
7	.4498	.0000	1.0000	.0000	.9456	521.7088	.1137
8	.4498	.0000	1.0000	.0000	.9456	521.7524	.1137
9	.4498	.0000	1.0000	.0000	.9456	521.7372	.1137
10	.5000	.0001	.9999	.0000	.9456	521.5157	.5000
11	.4498	.0000	1.0000	.0000	.9456	521.7777	.1137
12	.4498	.0000	1.0000	.0000	.9456	521.7478	.1137
13	.4498	.0000	1.0000	.0000	.9456	521.7325	.1137
14	.5000	.0000	1.0000	.0000	.9456	521.7902	.5000
15	.4498	.0000	1.0000	.0000	.9456	521.7759	.1137
16	.4498	.0000	1.0000	.0000	.9456	521.7454	.1137
17	.4498	.0000	1.0000	.0000	.9456	521.7302	.1137

C. Source Code for CO2CYCL

PROGRAM CO2 (TAPE1=INPUT,TAPE4=OUTPUT)

TWO DIMENSIONAL SIMULATION
OF
THREE PHASE, THREE COMPONENT
FLOW
IN A
FRACTURED POROUS MEDIUM

WRITTEN BY: ROLAND BEGIN
DEPARTMENT OF PHYSICS
COLORADO STATE UNIVERSITY
FORT COLLINS, COLORADO 80521
LAST REVISION: MAY 15, 1983

PARAMETER (ISZ=52)
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / TIMES / TPHASE,TIMPEM,TDPCHG(100),TSTRT,TOVERF(100),
TOVERR(100),TBUBBL(100),XJUMP
DATA NOUNIT / 4 /

VARIABLE DEFINITIONS.

VBLK(K) - VOLUME OF GRID BLOCK
C(I,K) - VOLUME FRACTION OF COMPONENT I IN BLOCK K.
CN(I,K) - MOLES OF COMPONENT I IN BLOCK K
CNGC(K) - MOLES OF RESIDUAL GAS IN IN BLOCK K
(IMMOBILE AND INSOLUBLE IN OIL AND WATER PHASES)
X(I,J,K) - MOLE FRACTION OF COMPONENT I IN PHASE J IN
BLOCK K.
S(J,K) - SATURATION OF PHASE J IN BLOCK K.
F(J,K) - FRACTIONAL FLOW OF PHASE J IN BLOCK K.
WT(I) - MOLECULAR WGT. OF COMPONENT I (GM / MOLE)
RHO(J,K) - DENSITY OF PHASE J IN BLOCK K (GM / CC)
RHOMOL(J,K) - MOLAR DENSITY OF PHASE J IN BLOCK K (MOL/CC)
VISO(K) - VISCOSITY OF OIL PHASE IN BLOCK K (CP)
VISG - VISCOSITY OF GAS PHASE
VISW - VISCOSITY OF WATER PHASE
AKR(J,K) - RELATIVE PERMEABILITY OF PHASE J IN BLOCK K.
PRSAV(K) - AVERAGE PRESSURE IN BLOCK K (PSI)
QZ(K) - VOLUMETRIC FLOW RATE IN FRACTURE (CC/SEC)
QY(K) - VOLUMETRIC FLOW RATE IN ROCK MATRIX
(PERPENDICULAR TO FRACTURE)

```
C
C      I - COMPONENT INDEX.
C
C          1 - CO2
C          2 - HYDROCARBON.
C          3 - WATER.
C
C      J - PHASE INDEX
C
C          1 - GAS PHASE.
C          2 - OIL PHASE.
C          3 - WATER PHASE.
C
C      INITIALIZE COMPOSITIONS, RELATIVE PERMEABILITY AND
C      PHASE BEHAVIOR DATA.
C
C      T1 = SECOND()
C      CALL INITL
C      T2 = SECOND()
C      TINIT = T2 - T1
C      WRITE (NOUNIT,50) TINIT
50    FORMAT ('1',' TIME SPENT IN SUBR. INITL = ',E10.4,' SECONDS.'//)
C
C      BEGIN MAIN LOOP. SET PHASE COMPOSITIONS AND SATURATIONS.
C
C      100 T1 = SECOND()
C          CALL PHASE
C          T2 = SECOND()
C          TPHASE = T2 - T1
C
C      PRINT RESULTS AND WRITE OUT PLOT DATA.
C
C      CALL PRNTS
C
C      CALCULATE OVERALL COMPOSITIONS AT THE NEW TIME LEVEL.
C      PERFORM ACCURACY CHECKS AND IN-STEP ITERATIONS ON
C          PHASE PROPERTIES.
C
C      T1 = SECOND()
C      CALL IMPEM
C      T2 = SECOND()
C      TIMPEM = T2 -T1
C
C      REPEAT LOOP UNTIL MAX TIME REACHED.
C
C      IF (IT .LE. ITMAX) GO TO 100
C      STOP
C      END
```

SUBROUTINE INITL

INITIALIZES RESERVOIR GEOMETRY, FLUID PROPERTIES AND FINITE
DIFFERENCE GRID SCHEME

PARAMETER (ISZ=52)

```
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
. DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RLTH,HFRAC,
. DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / TIMES / TPHASE,TIMPEM,TDPCHG(100),TSTRT,TOVERF(100),
. TOVERR(100),TBUBBL(100),XJUMP
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
. IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
. OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PR SOLD(ISZ),PD SOAK,DPLIM,PRSI,
. PRSMAX,PRSMIN
COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
. THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
. WLZ(ISZ),W2Z(ISZ),W3Z(ISZ),WLY(ISZ),W2Y(ISZ),
. W3Y(ISZ)
COMMON / FLOW / QZ(ISZ),QY(ISZ),QFLOW,QINJ1,QINJ2,QPROD,
. IWELL(50),JWELL,TWELL,TLIMIN,TLIMPR,TLIMSK
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
. CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
. A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
. TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
. EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / PRM / IPERM,NSW,NSL,TSW(3,20),TSL(3,20),ITPT
COMMON / TMPVAL / PRM1(3,ISZ),PRMT(3,ISZ),XCN(3,ISZ),XPRSAV(ISZ),
. RHOT(3,ISZ),XT(3,3,ISZ),FT(3,ISZ),TMOBT(ISZ)
COMMON / UPDATE / CUMI(3),CUMP(3),CMOLIN(3),CMOLPR(3),PROD(3)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
. C13DUM,C33DUM
```

INTEGER KK(20)
DATA NOUNIT/ 4 /

***** READ INPUT DATA *****

READ (1,26) TITLE
FORMAT (2I5)

WRITE(NOUNIT,32) TITLE

READ (1,26) RECORD

READ NO. OF TIME STEPS, BLOCKS, TIME STEP LENGTH .

READ (1,1) ITMAX,NBZ,NBY,DT

WRITE(NOUNIT,2) NBZ,NBY,DT,ITMAX

```

C
C
      READ LIMITING PRESSURE CHANGE
      READ (1,26) RECORD
      READ (1,809) DPLIM
      READ (1,26) RECORD
      READ (1,809) XJUMP
      WRITE (NOUNIT,802) DPLIM
802  FORMAT (2X,'PRESSURE CHANGE LIMIT PER TIME STEP = ',F10.4,
1     'PSI')
      WRITE (NOUNIT,801) XJUMP
801  FORMAT (/2X,'BUBBLE-EDGE TOLERANCE ON MOLE FRACTION OF CO2 ',
      'IN OIL = ',F10.4/)
      READ (1,26) RECORD
      READ (1,9) MXCNVRG
      WRITE (NOUNIT,803) MXCNVRG
803  FORMAT (2X,'MAXIMUM NUMBER OF CONVERGENCE ITERATIONS ALLOWED',
      5X,I5/)
C
      DZ=1./FLOAT(NBZ)
      DTDZ=DT/DZ
      IF (NBY.EQ.0) GO TO 888
      DY = 1./FLOAT(NBY)
      GO TO 889
888  DY = 1.
889  CONTINUE
      DTDY = DT/DY
      TIME=0.
      TWELL=0
      DTNEW = 1.
      NR = NBY + 1
      NBFIN = NR * NBZ + 1
C
      WRITE (NOUNIT,50)
50  FORMAT (/2X,'RESERVOIR GRID SCHEME',/,10X,'-----> Z',/,10X,
1     ' ',/,10X,' ',/,10X,'. Y',/,10X,'V')
      NBZP1 = NBZ + 1
      DO 51 KF=1,NBZP1
51  KK(KF) = 2 + (KF-1) * NR
      WRITE (NOUNIT,52) (KK(I),I=1,NBZ)
52  FORMAT (4X,'1',20I5)
      IF (NBY.EQ.0) GO TO 56
      DO 53 J=1,NBY
      DO 54 I=1,NBZ
54  KK(I) = KK(I) + 1
53  WRITE (NOUNIT,55) (KK(I),I=1,NBZ)
55  FORMAT (5X,20I5)
C
C
56  IT = 0
      ITCNT = 0
      ISTABL = 0
      IMOB = 0
      ICNVRG = 0
      IBUBBL = 0

```


C
C
C
C

***** READ DATA FOR PRESSURE EQUATION *****

809 READ (1,26) RECORD
READ (1,26) RECORD
READ (1,809) FRLTH,RSLTH,HFRAC,DEPTH,PORR,PORF
FORMAT (6F10.4)
AFRAC = HFRAC * DEPTH
ARES = DZ * FRLTH * DEPTH
READ (1,26) RECORD
READ (1,811) A22DEN,B22DEN,ASWELL,A33DEN,B33DEN,A3SDEN,
1 B3SDEN

811 FORMAT (8E10.4)
READ (1,26) RECORD
READ (1,26) RECORD
READ (1,810) PRSI,PRMF,PRMR
810 FORMAT (4E10.4)

C

VFRBLK = FRLTH * DZ * AFRAC * PORF
VRSBLK = RSLTH * DY * ARES * PORR
WRITE (NOUNIT,820) FRLTH,RSLTH,HFRAC,DEPTH,AFRAC,ARES,PORR,PORF,
1 PRMF,PRMR,PRSI
820 FORMAT (/// 2X,'LENGTH OF FRACTURE (CM)= ',F10.4,
1 /2X,'LENGTH OF RESERVOIR BRANCH (CM)= ',F10.4,
1 /2X,'WIDTH OF FRACTURE (CM)= ',F10.4,
1 /2X,'DEPTH OF SYSTEM (CM)= ',F10.4,
2 // 2X,'FRACTURE X-SECTIONAL AREA (SQ.CM.)= ',F10.4,
3 /2X,'RES. BRANCH X-SECTIONAL AREA (SQ.CM.)= ',F10.4,
4 // 2X,'ASSUMED POROSITY IN RESERVOIR= ',F10.4,
4 /2X,' IN FRACTURE= ',F10.4,
5 // 2X,'PERMEABILITY IN FRACTURE (MD)= ',E10.4,
6 /2X,'PERMEABILITY IN RESERVOIR (MD)= ',F10.4,
7 /// 2X,'INITIAL RESERVOIR PRESSURE (PSI)= ',F10.4)

C

READ (1,26) RECORD
READ (1,810) QINJ1,QINJ2,QPROD
WRITE (NOUNIT,823) QINJ1,QINJ2,QPROD
823 FORMAT (//2X,'CO2 INJECTION FLOW RATE (CC/SEC)= ',F10.4,
1 /2X,'WATER INJECTION FLOW RATE = ',F10.4,
2 /2X,'PRODUCTION FLOW RATE = ',F10.4)

C

WRITE (NOUNIT,825) A22DEN,B22DEN,ASWELL,A33DEN,B33DEN,
1 A3SDEN,B3SDEN
825 FORMAT (///2X,'FUNCTIONAL FORM OF FLUID DENSITIES',//,
1 T10,'BLACK OIL : ',T30,E10.4,' X P + ',E10.4,/,
2 T10,'SAT-D. OIL SWELLING FACTOR: ',T40,E10.4,' X P + 1.'
3 ,/,T10,'PURE H2O : ',T30,E10.4,' X P + ',E10.4,/,
4 T10,'SAT-D. H2O: ',T30,E10.4,' X P + ',E10.4/))

C

```

      READ (1,26) RECORD
      READ (1,811) ZSLOPE
      WRITE (NOUNIT,826) ZSLOPE
826    FORMAT (2X,'SLOPE OF GAS COMPRESSIBILITY FACTOR = ',E10.4/)

```

```

      ***** END PRESSURE DATA *****

```

```

      READ SOLUBILITY COEFFICIENTS

```

```

      READ (1,26) RECORD
      READ (1,811) OILSOL,WATSOL
      WRITE (NOUNIT,830) OILSOL,WATSOL
830    FORMAT (///T5,'SOLUBILITY COEFFICIENTS:',//,T5,'OIL -',
1        T20,E10.4,/,T5,'WATER -',T20,E10.4)

```

```

      RATSOL = OILSOL / WATSOL
      SUMSOL = OILSOL + WATSOL
      OILRAT = OILSOL / SUMSOL
      WATRAT = WATSOL / SUMSOL

```

```

      READ COMPONENT NAMES AND PROPERTIES

```

```

      READ (1,26) RECORD
      READ (1,6) VISG,VISW,(WT(I),I=1,3)
      READ OIL VISCOSITY PARAMETERS
      READ (1,26) RECORD
      READ (1,811) AVIS1,AVIS2,CVIS
6    FORMAT (5F10.0)

```

```

      CALCULATE VOLUME OF OIL MOLE AT P = 1 ATM.
      V22ATM = WT(2) / (A22DEN * 14.7 + B22DEN)

```

```

      CALCULATE OTHER COEFFICIENTS NEEDED LATER IN CODE

```

```

      FOR SUBR. PHASE
      C22DUM = A22DEN / WT(2)
      C33DUM = A33DEN / WT(3)
      C13DUM = (WT(3) * A33DEN + (WT(1)-WT(3)) * A3SDEN) / B33DEN**2
      FOR SUBROUTINE VISOIL
      BVIS = (AVIS2-AVIS1) / OILSOL

```

```

      WRITE (NOUNIT,815) AVIS1,BVIS,CVIS
      WRITE (NOUNIT,27) VISG,VISW,(WT(I),I=1,3)
815    FORMAT (/1X,'VISCOSITY OF OIL = 10 ** (' ,E10.4,' * P + ',
1        E10.4,' * X12 + ',E10.4,' ) C.P.',/,20X,
2        '(WHERE X12 IS THE MOLE FRACTION OF CO2 IN OIL)')

```

```

C
C   READ RELATIVE PERMEABILITY DATA.
C
  READ (1,9) IPERM,NSW,NSL
  IF (IPERM.EQ. 0) GO TO 45
  DO 30 I=1,NSW
    READ (1,3) (TSW(L,I),L=1,3)
30  CONTINUE
  DO 35 I=1,NSL
    READ (1,3) (TSL(L,I),L=1,3)
35  CONTINUE
  EKRW=TSW(2,NSW)
  WRITE(NOUNIT,17)
  WRITE(NOUNIT,18) (L,TSW(1,L),TSW(2,L),TSW(3,L),L=1,NSW)
  WRITE(NOUNIT,19)
  WRITE(NOUNIT,18) (L,TSL(1,L),TSL(2,L),TSL(3,L),L=1,NSL)
  GO TO 48
45  READ (1,26) RECORD
  READ (1,26) RECORD
  READ (1,3) SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,EKRG,EO,EW,
1EOG,EG
  WRITE(NOUNIT,5) SWC,EKRO,EO,SOR,EKRW,EW,SOG,EKROG,EOG,SGC,EKRG,EG
  IF (EKRO.NE. EKROG) WRITE(NOUNIT,36)
48  CONTINUE

C
C
C
C   *****
C   INITIALIZE PRESSURES, DENSITIES, RELATIVE FLOW RATES,
C   AND MESH RATIO
C
  DO 110 K=2,NBFIN
    QZ(K)=0
110  QY(K)=0

C
C   INITIALIZE MESH RATIO
    DTDZ = DTDZ / FRLTH
    DTDY = DTDY / RSLTH
    DTT = DT
    DTDZT = DTDZ
    DTDYT = DTDY

C
    WRITE (NOUNIT,816) DTDZ,DTDY
816  FORMAT (//1X,'MESH RATIO FOR PRESSURE EQUATION:',/,
1    10X,'IN FRACTURE = ',E10.4,/,
2    10X,'IN RESERVOIR = ',E10.4)

C
C   INITIALIZE PRESSURES AND PERMEABILITIES
    DO 130 K=2,NBFIN
      PRSAV(K) = PRSI
      PRSOLD(K) = PRSI
      DO 130 J=1,3
130  AKR(J,K) = 0

```

C
C
C
C

```

RHMOL(1,2) = 2.7E-6 * PRSI / (1.+ ZSLOPE * PRSI)
RHMOL(2,2) = (A22DEN * PRSI + B22DEN) / WT(2)
RHMOL(2,1) = RHMOL(2,2)
RHMOL(3,2) = (A33DEN * PRSI + B33DEN) / WT(3)

```

C
C
C

READ INITIAL COMPOSITIONS (VOLUME FRACTIONS).

C

READ (1,26) RECORD

READ RESERVOIR MATRIX COPOSITIONS

```

READ (1,14) (C(I),I=1,3)
CN1RS = C(1) * RHMOL(1,2) * VRSBLK
CN2RS = C(2) * RHMOL(2,2) * VRSBLK
CN3RS = C(3) * RHMOL(3,2) * VRSBLK
WRITE (NOUNIT,13) (C(I),I=1,3)

```

C
C

READ FRACTURE COMPOSITIONS

```

READ (1,26) RECORD
READ (1,14) (C(I),I=1,3)
CN1FR = C(1) * RHMOL(1,2) * VFRBLK
CN2FR = C(2) * RHMOL(2,2) * VFRBLK
CN3FR = C(3) * RHMOL(3,2) * VFRBLK
WRITE (NOUNIT,15) (C(I),I=1,3)

```

C

CALCULATE MOLES OF RESIDUAL GAS PRESENT

```

CNGCFR = 0
CNGCRS = SGC * RHMOL(1,2) * VRSBLK
KB = 2

```

```

DO 128 KF=1,NBZ
  KBDUM = KB + NBY
  DO 125 K=KB,KBDUM
    DO 122 I=1,3
      DO 122 J=1,3
        X(I,J,K) = 0
        X(1,1,K) = 1.

```

122

```

      CNG(2,K) = 0
      CNG(3,K) = 0
      IF (K.GT.KB) GO TO 124
      CN(1,K) = CN1FR
      CN(2,K) = CN2FR
      CN(3,K) = CN3FR
      CNGC(K) = CNGCFR
      VBLK(K) = VFRBLK
      GO TO 125

```

124

```

      CN(1,K) = CN1RS
      CN(2,K) = CN2RS
      CN(3,K) = CN3RS
      CNGC(K) = CNGCRS
      VBLK(K) = VRSBLK

```

125

CONTINUE

```

128     KB = 2 + KF * NR
        VPORE = 0
        DO 135 K=2,NBFIN
135     VPORE = VPORE + VBLK(K)
        DO 150 I=1,3
            CMOLIN(I)=0
            CMOLPR(I)=0
            OIPMOL(1) = (CN1FR + NBY * CN1RS) * NBZ
            OIPMOL(2) = (CN2FR + NBY * CN2RS) * NBZ
            OIPMOL(3) = (CN3FR + NBY * CN3RS) * NBZ
            CUMI(I)=0
            CUMP(I)=0
            PROD(I)=0
150 CONTINUE
C
C     READ INITIAL INJECTION COMPOSITIONS.
C
        READ (1,26) RECORD
        READ (1,14) (C(I),I=1,3)
        F(1,1)=1.
        F(2,1) = 0
        F(3,1) = 0
        DO 200 J=1,3
            DO 200 I =1,3
200         X(I,J,1) = 0
        X(1,1,1) = 1
        WRITE(NOUNIT,11) (C(I),I=1,3)
C
C             READ INSTRUCTIONS FOR HUF-N-PUF CYCLE CONTROL
C
        READ (1,26) RECORD
C
        READ (1,40) (IWELL(J),J=1,40)
40     FORMAT (16I4)
C
C             NOTE: IWELL=1 => HUF (INJECT CO2)
C                   IWELL=2 => HUF (INJECT WATER)
C                   IWELL=-1 => PUF (PRODUCTION)
C                   IWELL=+10 => SOAK (POST INJECT)
C                   IWELL=-10 => SOAK (POST PROD.)
C
        WRITE (NOUNIT,43) (IWELL(J),J=1,40)
43     FORMAT (//1X,'HUF-N-PUF WELL MODE SEQUENCE',/10X,
1       'MODE: 1 = CO2 INJECTION',/16X,'2 = WATER INJECTION',/15X,
2       '-1 = PRODUCTION',/14X,'+10 = POST-INJECTION SOAK',/14X,
3       '-10 = POST-PRODUCTION SOAK',//2X,16I4,/,2X,16I4,/,2X,8I4//)
C
C             INITIALIZE WELL MODE COUNTER
C
        JWELL = 1

```

```

C
C      READ PARAMETERS DEFINING WELL MODE CHANGES
      READ (1,26) RECORD
      READ (1,9) ILIMIT
      READ (1,26) RECORD
      IF (ILIMIT.EQ.1) THEN
        READ (1,41) PRSMAX,PRSMIN,PDSOAK
        WRITE (NUNIT,46) PRSMAX,PRSMIN,PDSOAK
      ELSE IF (ILIMIT.EQ.2) THEN
        READ (1,41) TLMIN,TLIMPR,TLIMSK
        WRITE (NUNIT,47) TLMIN,TLIMPR,TLIMSK
      END IF
41      FORMAT (3F10.4)
46      FORMAT (1X,'MAX. PRESSURE BUILD-UP ALLOWED DURING ',
1         'INJECTION CYCLE: ',F10.4, '//,2X,'MIN. PRESSURE',
2         ' ALLOWED: ',F10.4, '//,2X,'PRESSURE DIFFERENCE ',
3         'REQUIRED TO END SOAK CYCLE: ',F10.4//)
47      FORMAT (2X,'INJECTION CYCLE LIMITED TO ',F10.4,'SEC.',/,
1         2X,'PRODUCTION CYCLE LIMITED TO ',F10.4,'SEC.',
2         ',/2X,'SOAK CYCLE LIMITED TO ',F10.4,'SEC.'//)

C
      IF (IWELL(1).EQ.1) QZ(1) = QINJ1
      IF (IWELL(1).EQ.2) QZ(1) = QINJ2

C
C
C
C
      READ PRINT KEYS.

      READ (1,26) RECORD
      READ (1,9) IPRNT,(IP(J),J=1,3)
      WRITE(NUNIT,12) IPRNT,(IP(J),J=1,3)
      RETURN
1  FORMAT(3I5,2F10.0)
2  FORMAT(' NUMBER OF GRID BLOCKS:',/,10X,'IN FRACTURE = ',I5,/,
1     10X,'IN RESERVOIR BRANCH = ',I5,/,
2     ' TIME STEP LENGTH      =',F6.3,' SECONDS '/
3     ' NUMBER OF TIME STEPS =',I5/)
3  FORMAT(4F10.0/4F 10.0/4F10.0)
5  FORMAT('// RELATIVE PERMEABILITY DATA: '//5X,
1  'SWC=',F5.3,10X,'EKRO =',F5.3,10X,'EO =',F6.2/5X,
2  'SOR=',F5.3,10X,'EKRW =',F5.3,10X,'EW =',F6.2/5X,
3  'SOG=',F5.3,10X,'EKROG=',F5.3,10X,'EOG=',F6.2/5X,
4  'SGC=',F5.3,10X,'EKRG =',F5.3,10X,'EG =',F6.2/)
9  FORMAT (15I5)
11 FORMAT('/ INJECTION COMPOSITION (VOLUME FRACTIONS): '//5X,3F10.4/)
12 FORMAT (/ PRINT KEYS: '//5X,'IPRNT=',I2,3X,'IP(1)=' ,I1,3X,
1     'IP(2)=' ,I1,3X,'IP(3)=' ,I1,3X,'IP(4)=' ,I1/'1')
13 FORMAT (/ INITIAL COMPOSITION IN MATRIX (VOLUME FRACTIONS):',
1     '/,5X,3F10.4/)
14 FORMAT (7F10.0)
15  FORMAT (' IN FRACTURE :',/,5X,3F10.4)

```

```

17 FORMAT (//1X,'OIL-WATER RELATIVE PERMEABILITIES:'//15X,
1      'SW',8X,'KRW',7X,'KROW')
18 FORMAT (20(/5X,I3,3F10.3))
19 FORMAT (//1X,'GAS-OIL RELATIVE PERMEABILITIES:'//15X,
1      'SL',7X,'KROG',7X,'KRG')
21 FORMAT (//1X,'PLOT KEYS:'//6X,'IPLT=',I2,3X,'ISAT=',I2,3X,
1      'IBLK=',I2,3X,'IFLO=',I2,3X,'IPRO=',I2,3X,'IPRESS = ',I2)
22 FORMAT (2A4)
23 FORMAT (//1X,'SATURATION AND COMPOSITION PROFILES STORED IN FILE
1      ',2A4,' AT TIME STEPS:'//5X,10I5)
24 FORMAT (//1X,'BLOCK OVERALL COMPOSITIONS STORED IN FILE ',2A4,
1      ' FOR BLOCKS:'//5X,10I5)
25 FORMAT (//1X,'FLOWING COMPOSITIONS STORED IN FILE ',2A4,
+      ' FOR BLOCKS:'//5X,10I5)
26 FORMAT (20A4)
27 FORMAT (///1X,'VIS. CO2 = ',F10.4,5X,'VIS. H2O = ',F10.4,4X,
1      '(CP)',//,1X,'MOLEC. WGTS. (GMS/MOL) - CO2: ',F10.4,3X,
2      'OIL: ',F10.4,3X,'H2O: ',F10.4)
31 FORMAT (1X,I3,3F10.4)
32 FORMAT ('1'/26X,'- - - C O 2 C Y C L - - -'//1X,20A4/)
36 FORMAT (/1X,'----- WARNING: EKROG NOT EQUAL TO EKRO -----')
37 FORMAT (//1X,' COMPONENT PRODUCTION DATA STORED IN FILE ',2A4)
      END

```

SUBROUTINE PHASE

THIS SUBROUTINE WILL CALCULATE MOLE FRACTIONS OF
COMPONENTS PRESENT IN THE VARIOUS PHASES AND THE VOLUME
SATURATIONS OF THOSE PHASES.

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PRSOLD(ISZ),PDSOAK,DPLIM,PRSI,
PRSMAX,PRSMIN
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
DIMENSION X10(ISZ)

CALCULATE MOLE FRACTIONS OF CO2 IN OIL AND WATER
CALL EQUILIB (CNGC,CN,PRSAV,CNG,X,X10)

CALCULATE PHASE DENSITIES
CALL DENSE (PRSAV,X,RHO,RHOMOL,VN)

CALCULATE OIL PHASE VISCOSITY
DO 50 K=2,NBFIN
VISO(K) = VISOIL (PRSAV(K),X(1,2,K))

CALCULATE EFFECTIVE COMPRESSIBILITY
(NOTE: EFF. COMP.= CMPEFF/P.V.)
CALL CMPRES (CNG,CN,PRSAV,CMPEFF,VN)

CALCULATE PHASE SATURATIONS
CALL SCALC (CNG,CN,VN,SGCX,S,CNGC)

CALCULATE RELATIVE PERMEABILITIES AND
FRACTIONAL FLOW FUNCTIONS
CALL PERM (S,VISO,SGCX,AKR,F,TMOB)

SET DENSITY OF GAS AND WATER IN WELL
RHOMOL(1,1) = RHOMOL(1,2)
RHOMOL(3,1) = (A33DEN * PRSAV(2) + B33DEN) / WT(3)
RETURN
END

SUBROUTINE EQUILIB (CNGCX,CNX,P,CNGX,XX,X10)

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
DIMENSION CNGCX(ISZ),CNX(3,ISZ),P(ISZ),CNGX(3,ISZ),XX(3,3,ISZ),
X10(ISZ)

PHASE EQUILIBRIUM CALCULATION

PARTITION COMPONENTS INTO PHASES

DO 100 K=2,NBFIN
DENOM = CNX(1,K) - CNGCX(K) + CNX(2,K) + CNX(3,K)
Z2 = CNX(2,K) / DENOM
Z3 = CNX(3,K) / DENOM
Z1 = 1. - Z2 - Z3
IF (Z1.LT.1.E-20) Z1 = 0
DUM = 1. + RATSOL * Z1 + Z2 * (RATSOL-1.)
DUM1 = SQRT(DUM**2 - 4. * Z1 * RATSOL)
X1W = (DUM - DUM1)/(2. * RATSOL)
X10(K) = RATSOL * X1W
DUMSOL = OILSOL * P(K)
IF (X10(K) .LT. DUMSOL) THEN
UNSATURATED LIQUID / IMMOBILE GAS
XX(1,3,K) = X1W
XX(1,2,K) = X10(K)
XX(2,2,K) = 1. - X10(K)
XX(3,3,K) = 1. - X1W
ELSE
SATURATED LIQUID / MOBILE GAS
XX(1,2,K) = OILSOL * P(K)
XX(1,3,K) = WATSOL * P(K)
XX(2,2,K) = 1. - XX(1,2,K)
XX(3,3,K) = 1. - XX(1,3,K)
END IF
CNGX(2,K) = XX(1,2,K) * CNX(2,K) / XX(2,2,K)
CNGX(3,K) = XX(1,3,K) * CNX(3,K) / XX(3,3,K)
CNGX(1,K) = CNX(1,K) - CNGX(2,K) - CNGX(3,K)
IF (CNGX(1,K).LT.1.E-10) CNGX(1,K) = 0
100 CONTINUE
RETURN
END

SUBROUTINE DENSE (P,XX,DENGM,DENMOL,VNX)

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
DIMENSION P(ISZ),XX(3,3,ISZ),DENG(3,ISZ),DENMOL(3,ISZ),
VNX(3,3,ISZ)

CALCULATES PHASE DENSITIES

DO 100 K=2,NBFIN

GAS PHASE DENSITY

ZCMP = 1.+ ZSLOPE * P(K)
DENMOL(1,K) = 2.7E-6 * P(K) / ZCMP
VNX(1,1,K) = 1. / DENMOL(1,K)
DENG(1,K) = WT(1) * DENMOL(1,K)

OIL PHASE DENSITY

DENSITY DATA FROM MILLER'S WILMINGTON 17 DEG. API DATA
(T=95 DEG. F.)

RODEAD = A22DEN * P(K) + B22DEN
VNX(2,2,K) = WT(2) / RODEAD
WT2 = XX(1,2,K) * WT(1) + XX(2,2,K) * WT(2)
SOLOIL = P(K) * OILSOL
FWELL = ASWELL * P(K) + 1.
VNX(1,2,K) = (1. - SOLOIL) * (FWELL * V22ATM - VNX(2,2,K)) / SOLOIL
DENG(2,K) = WT2 / (WT(2) * XX(2,2,K) / RODEAD + VNX(1,2,K) * XX(1,2,K))
DENMOL(2,K) = DENG(2,K) / WT2

WATER PHASE DENSITY

DENSITY DATA FROM PARKINSON & DE NEVERS SAT'D. WATER
DATA @ T=95 DEG.F. (SEE FIG. 7)

RHOSAT = B3SDEN + A3SDEN * P(K)
RHOH2O = B33DEN + A33DEN * P(K)
VNX(3,3,K) = WT(3) / RHOH2O
WT3 = XX(1,3,K) * WT(1) + XX(3,3,K) * WT(3)
SOLWAT = P(K) * WATSOL
VNX(1,3,K) = WT(3) * (1. - SOLWAT) * (1/RHOSAT - 1/RHOH2O) /
SOLWAT + WT(1) / RHOSAT
IF (VNX(1,3,K).LT.0) VNX(1,3,K)=1.E-20
DENG(3,K) = WT3 / (WT(3) * XX(3,3,K) / RHOH2O + VNX(1,3,K) * XX(1,3,K))
DENMOL(3,K) = DENG(3,K) / WT3

100 CONTINUE
RETURN
END

```

SUBROUTINE CMPRES (CNGX,CNX,P,CMP,VNX)

C
PARAMETER (ISZ=52)
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
. DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
. DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
. OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PRSOLD(ISZ),PDSOAK,DPLIM,PRSI,
. PRSMAX,PRSMIN
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
. CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
. A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
. C13DUM,C33DUM
DIMENSION CNGX(3,ISZ),CNX(3,ISZ),P(ISZ),CMP(ISZ),VNX(3,3,ISZ)

C
C          CALCULATES AVERAGE COMPRESSIBILITY OF FLUID SYSTEM
DO 100 K=2,NBFIN
  PSQDEN = 1./(P(K)*P(K))
  V22SQ = VNX(2,2,K)*VNX(2,2,K)
  V33SQ = VNX(3,3,K)*VNX(3,3,K)
  ZCMP = 1. + ZSLOPE * P(K)

C
  C11 = CNGX(1,K)*VNX(1,1,K)/((ZCMP*P(K))*(1-(P(K)-PRSOLD(K))/
1      PRSOLD(K))
  C22 = C22DUM * CNX(2,K) * V22SQ
  C33 = C33DUM * CNX(3,K) * V33SQ
  C12 = CNGX(2,K) * (ASWELL * V22ATM + (V22ATM-VNX(2,2,K))
1      * PSQDEN / OILSOL)
  C13 = CNGX(3,K) * C13DUM

C
  CMP(K) = C11 + C22 + C33 + C12 + C13
100 CONTINUE
RETURN
END

```

SUBROUTINE SCALC (CNGX,CNX,VNX,XSGC,SX,CNGCX)

C

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VLK(ISZ),VFRBLK,VRSBLK,VPORE
DIMENSION CNGX(3,ISZ),CNX(3,ISZ),VNX(3,3,ISZ),XSGC(ISZ),
SX(3,ISZ),CNGCX(ISZ)

C

C

C

CALCULATE PHASE SATURATONS

DO 100 K=2,NBFIN

V11BLK = CNGX(1,K) * VNX(1,1,K)

V12BLK = CNGX(2,K) * VNX(1,2,K)

V13BLK = CNGX(3,K) * VNX(1,3,K)

V22BLK = CNX(2,K) * VNX(2,2,K)

V33BLK = CNX(3,K) * VNX(3,3,K)

VTOT = V11BLK + V12BLK + V13BLK + V22BLK + V33BLK

SX(2,K) = (V12BLK + V22BLK) / VTOT

SX(3,K) = (V13BLK + V33BLK) / VTOT

SX(1,K) = 1. - SX(2,K) - SX(3,K)

IF (SX(1,K).LT.1.E-10) SX(1,K) = 0

VGC = CNGCX(K) * VNX(1,1,K)

XSGC(K) = VGC / VTOT

100 CONTINUE

RETURN

END

SUBROUTINE PERM (SX,VISX,XSGC,AKRX,FX,XTMOB)

C
PARAMETER (ISZ=52)
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RS�TH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / PRM / IPERM,NSW,NSL,TSW(3,20),TSL(3,20),ITPT
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
DIMENSION SX(3,ISZ),VISX(ISZ),XSGC(ISZ),AKRX(3,ISZ),FX(3,ISZ),
XTMOB(ISZ)

C
C
C
CALCULATE RELATIVE PERMEABILITIES OF FLUID PHASES

KB = 2
DO 1000 K=2,NBFIN
IF (K.EQ.KB) THEN
C
SET REL. PERMS. IN FRACTURE EQUAL TO SATN'S.
AKRX(1,K) = SX(1,K)
AKRX(2,K) = SX(2,K)
AKRX(3,K) = SX(3,K)
KB=KB+NR

ELSE

C
DSW=1.-SOR-SWC
SW=SX(3,K)
SG=SX(1,K)
IF (IPERM .EQ. 0) GO TO 245

C
C
TABLE LOOK-UP AND INTERPOLATION OF REL. PERMS.

EKRO=TSW(3,1)
IF (SW .GT. TSW(1,1)) GO TO 205
AKRW=0.
IF (TSW(1,1) .EQ. 0.) GO TO 202
AKROW=1.-SW*(1.-TSW(3,1))/TSW(1,1)
GO TO 225
202 AKROW=1.
GO TO 225
205 IF (SW .LT. TSW(1,NSW)) GO TO 210
AKROW=0.
AKRW=1.- (1.-SW) * (1.-TSW(2,NSW)) / (1.-TSW(1,NSW))
GO TO 225
210 DO 215 L=2,NSW
IF (SW .LE. TSW(1,L)) GO TO 220
215 CONTINUE

```

220 LM1=L-1
    DTSW=TSW(1,L)-TSW(1,LM1)
    DSW=SW-TSW(1,LM1)
    AKRW=TSW(2,LM1)+DSW*(TSW(2,L)-TSW(2,LM1))/DTSW
    AKROW=TSW(3,LM1)+DSW*(TSW(3,L)-TSW(3,LM1))/DTSW
225 SL=1.-SG
    IF (SL .GT. TSL(1,1)) GO TO 230
    AKROG=0.
    AKRG=1.-SL*(1.-TSL(3,1))/TSL(1,1)
    GO TO 600
230 IF (SL .LT. TSL(1,NSL)) GO TO 235
    AKRG=0.
    AKROG=TSL(2,NSL)+(SL-TSL(1,NSL))*(1.-TSL(2,NSL))/(1.-TSL(1,NSL))
    GO TO 600
235 DO 240 L=2,NSL
    IF (SL .LE. TSL(1,L)) GO TO 242
240 CONTINUE
242 LM1=L-1
    DTSL=TSL(1,L)-TSL(1,LM1)
    DSL=SL-TSL(1,LM1)
    AKROG=TSL(2,LM1)+DSL*(TSL(2,L)-TSL(2,LM1))/DTSL
    AKRG=TSL(3,LM1)+DSL*(TSL(3,L)-TSL(3,LM1))/DTSL
    GO TO 600

```

C
C
C
C

COREY RELATIVE PERMEABILITY CURVES

CALCULATE OIL-WATER RELATIVE PERMEABILITIES

```

245 IF (SW .GE. SWC) GO TO 250
    AKRW=0.
    AKROW=1.-SW*(1.-EKRO)/SWC
    GO TO 400
250 IF (SW .LE. 1.-SOR) GO TO 300
    AKROW=0.
    AKRW=1.-((1.-SW)*(1.-EKRW))/SOR
    GO TO 400
300 AKRW=EKRW*((SW-SWC)/DSW)**EW
    AKROW=EKRO*((1.-SW-SOR)/DSW)**EO

```

```

C                                     CALCULATE OIL-GAS RELATIVE PERMEABILITIES
400 SL=1.-SG
    IF (SL .GE. SWC+SOG) GO TO 450
    AKROG=0.
    AKRG=1.-SL*(1.-EKRG)/(SWC+SOG)
    GO TO 600
450 IF (SG-XSGC(K).GT.1.E-3) GO TO 500
    AKRG=0.
    AKROG=EKRO*((SL-SWC-SOG)/(1.-SWC-SOG))*EOG
    GO TO 600
500 AKRG=EKRG*((SG-XSGC(K))/(1.-XSGC(K)-SOG-SWC))*EG
    AKROG = EKRO * ((SL-SWC-SOG)/(1.-SWC-SOG))*EOG
C
600 AKRO=(AKROW+AKRW)*(AKROG+AKRG)/EKRO-(AKRW+AKRG)
    IF (AKRO .LT. 0.) AKRO=0.
    AKRX(1,K) = AKRG
    AKRX(2,K) = AKRO
    AKRX(3,K) = AKRW
    END IF
C
C                                     CALCULATE TOTAL FLUID MOBILITY AND FRACTIONAL FLOW FUNCTIONS
UMOB1 = AKRX(1,K) / VISG
UMOB2 = AKRX(2,K) / VISX(K)
UMOB3 = AKRX(3,K) / VISW
XTMOB(K) = UMOB1+UMOB2+UMOB3
FX(1,K) = UMOB1 / XTMOB(K)
FX(2,K) = UMOB2 / XTMOB(K)
FX(3,K) = UMOB3 / XTMOB(K)
1000 CONTINUE
    RETURN
    END

```

SUBROUTINE PRNTS

PARAMETER (ISZ=52)

```
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
. DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
. DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
. IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / TIMES / TPHASE,TIMPEM,TDPCHG(100),TSTRT,TOVERF(100),
. TOVERR(100),TBUBBL(100),XJUMP
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
. OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PR SOLD(ISZ),PDSOAK,DPLIM,PRSI,
. PRSMAX,PRSMIN
COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
. THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
. WLZ(ISZ),W2Z(ISZ),W3Z(ISZ),WLY(ISZ),W2Y(ISZ),
. W3Y(ISZ)
COMMON / FLOW / QZ(ISZ),QY(ISZ),QFLOW,QINJ1,QINJ2,QPROD,
. IWELL(50),JWELL,TWELL,TLIMIN,TLIMPR,TLIMSK
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
. CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
. A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
. TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
. EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / PRM / IPERM,NSW,NSL,TSW(3,20),TSL(3,20),ITPT
COMMON / TMPVAL / PRM1(3,ISZ),PRMT(3,ISZ),XCN(3,ISZ),XPRSAV(ISZ),
. RHOT(3,ISZ),XT(3,3,ISZ),FT(3,ISZ),TMOBT(ISZ)
COMMON / UPDATE / CUMI(3),CUMP(3),CMOLIN(3),CMOLPR(3),PROD(3)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
. C13DUM,C33DUM
```

DIMENSION KK(ISZ)

IWRIT1 = 8

NOTE: IWRIT1=7 => WRITE MATRIX COEFFS.

IWRIT1=8 => WRITE NO. MOLES OF I IN J

IFLAG=0

ITT=IT/IPRNT

DIT=FLOAT(IT)/FLOAT(IPRNT)

DDIT=DIT-FLOAT(ITT)

IF (ABS(DDIT) .LT. 1.E-7) IFLAG=1


```

WRITE(NOUNIT,2) IT,TIME,DTT,(CUMI(I),I=1,3),
1 (CMOLIN(I),I=1,3),(CMOLPR(I),I=1,3)
2 FORMAT (/' IT=',I5,10X,'TIME=',F10.5,5X,'STEP = ',F10.5,' SEC',
1 /1X,33('='))/' CUMI (PV)'
1 ,6X,3F10.6/' CMOLIN (MOLES)',6X,3F10.6/' CMOLPR (MOLES)',
2 6X,3F10.6/)

C
IF (IWELL(JWELL).EQ.1) WRITE (NOUNIT,30)
IF (IWELL(JWELL).EQ.2) WRITE (NOUNIT,31)
IF (IWELL(JWELL).EQ.-1) WRITE (NOUNIT,32)
IF (IABS(IWELL(JWELL)).EQ.10) WRITE (NOUNIT,33)
30 FORMAT (/' WELL MODE: CO2 INJECTION')
31 FORMAT (/' WELL MODE: H2O INJECTION')
32 FORMAT (/' WELL MODE: PRODUCTION')
33 FORMAT (/' WELL MODE: SOAK')

C
NCYCLE = 1 + (JWELL-1) / 4
WRITE (NOUNIT,42) NCYCLE
42 FORMAT (5X,'CYCLE:',I5,/)

C
C
C
C
WRITE TIMES SPENT IN SUBROUTINES
AND ADJUSTED TIME STEPS
WRITE (NOUNIT,39) TSTRT
39 FORMAT (//10X,'TSTRT - INITIAL STEP (SEC) = ',E10.4)
WRITE (NOUNIT,34)
34 FORMAT (10X,'TDPCHG(I) - TIME STEP AFTER TRUNCATION ADJUST.')
```

WRITE (NOUNIT,35) (TDPCHG(I),I=1,IDPCHG)

```

35 FORMAT (10X,10(2X,E10.4))
WRITE (NOUNIT,36)
36 FORMAT (10X,'TOVERF - TIME STEP AFTER OVERSHOOT ADJUST.(FRAC.)')
WRITE (NOUNIT,35) (TOVERF(I),I=1,IOVERF)
WRITE (NOUNIT,37)
37 FORMAT (10X,'TOVERR - TIME STEP AFTER OVERSHOOT ADJUST.(RES.)')
WRITE (NOUNIT,35) (TOVERR(I),I=1,IOVERR)
WRITE (NOUNIT,38)
38 FORMAT (10X,'TBUBBL - TIME STEP AFTER BUBBLE EDGE ADJUST.')
```

WRITE (NOUNIT,35) (TBUBBL(I),I=1,IBUBBL)

```

WRITE (NOUNIT,40) IMOB
40 FORMAT (10X,'IMOB - PASSES THROUGH SUBR. MOBTR = ',I3)
WRITE (NOUNIT,29) TIMPEM
29 FORMAT (//10X,'TIME SPENT IN SUBR. IMPEM = ',E10.4,' SECONDS.')
```

WRITE (NOUNIT,27) TPHASE

```

27 FORMAT (10X,'TIME SPENT IN SUBR. PHASE = ',E10.4,' SECONDS.'//)

C
C
IF (IFLAG .NE. 1) RETURN
```



```
C
C      PRINT TABLE HEADING FOR OVERALL MOLE AND SATURATION
C      FRACTION DATA
C
WRITE(NOUNIT,3)
3 FORMAT (/8X,'Z1',6X,'Z2',6X,'Z3',6X,'S1',6X,
1   'S2',6X,'S3',6X,'F1',6X,'F2',6X,'F3',5X,'TMOB',10X,'X(1,2)',
2                                     10X,'X(1,3)')
4 FORMAT (1X,I2,10F8.5,2(6X,F10.6))
C
KB=2
DO 200 KF=1,NBZ
    KBDUM=KB + NBY
    DO 190 K=KB,KBDUM
C
        DENOM = CN(1,K) - CNGC(K) + CN(2,K) + CN(3,K)
        Z2 = CN(2,K) / DENOM
        Z3 = CN(3,K) / DENOM
        Z1 = 1.- Z2 - Z3
        IF (Z1.LT.1.E-6) Z1=0
C
C          WRITE(NOUNIT,4)K,Z1,Z2,Z3,S(1,K),S(2,K),S(3,K),
+           F(1,K),F(2,K),F(3,K),TMOB(K),X(1,2,K),X(1,3,K)
190 CONTINUE
200 KB = 2 + KF * NR
C
DO 300 J=1,3
    IF (IP(J) .NE. 1) GO TO 300
    IHD=0
    DO 275 K=2,NBFIN
        IF (J.EQ.1 .AND. S(1,K)-SGCX(K) .LT.1.E-3) GO TO 275
        IF (S(J,K) .LT. 1.E-6) GO TO 275
        IF (IHD .EQ. 1) GO TO 225
        IHD=1
        WRITE(NOUNIT,5) J
225     IF (J.EQ.1)
+       WRITE(NOUNIT,15)K,S(J,K),X(1,J,K),X(2,J,K),X(3,J,K),RHO(J,K)
+       ,VISG,AKR(J,K)
        IF (J.EQ.2)
+       WRITE(NOUNIT,15)K,S(J,K),X(1,J,K),X(2,J,K),X(3,J,K),RHO(J,K)
+       ,VISO(K),AKR(J,K)
        IF (J.EQ.3)
+       WRITE(NOUNIT,15)K,S(J,K),X(1,J,K),X(2,J,K),X(3,J,K),RHO(J,K)
+       ,VISW,AKR(J,K)
275     CONTINUE
300 CONTINUE
5 FORMAT (//7X,'S',11,6X,'X1',6X,'X2',6X,'X3',5X,'RHO',6X,'VIS',
+         6X,'KR'/)
15  FORMAT (1X,I2,5F8.4,F9.4,4F8.4)
RETURN
END
```

SUBROUTINE IMPEM

PARAMETER (ISZ=52)

```
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
. DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
. DEPTH,AFRAC,ARES,VLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
. IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / TIMES / TPHASE,TIMPEM,TDPCHG(100),TSTRT,TOVERF(100),
. TOVERR(100),TBUBBL(100),XJUMP
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
. OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PR SOLD(ISZ),PDSOAK,DPLIM,PRSI,
. PRSMAX,PRSMIN
COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
. THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
. W1Z(ISZ),W2Z(ISZ),W3Z(ISZ),W1Y(ISZ),W2Y(ISZ),
. W3Y(ISZ)
COMMON / FLOW / QZ(ISZ),QY(ISZ),QFLOW,QINJ1,QINJ2,QPROD,
. IWELL(50),JWELL,TWELL,TLIMIN,TLIMPR,TLIMSK
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
. CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
. A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
. TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
. EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / PRM / IPERM,NSW,NSL,TSW(3,20),TSL(3,20),ITPT
COMMON / TMPVAL / PRM1(3,ISZ),PRMT(3,ISZ),XCN(3,ISZ),XPRSAV(ISZ),
. RHOT(3,ISZ),XT(3,3,ISZ),FT(3,ISZ),TMOBT(ISZ)
COMMON / UPDATE / CUMI(3),CUMP(3),CMOLIN(3),CMOLPR(3),PROD(3)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
. C13DUM,C33DUM
```

REAL CTMOL(4)

DATA TDPCHG/100*0.0/ TOVERF/100*0.0/ TOVERR/100*0.0/

DATA TBUBBL/100*0.0/

INCREMENT TIME STEP COUNTER AND CHANGE INJECTION
RATE IF TIME MATCHES INPUT PARAMETERS

IT=IT+1

ITCNT = ITCNT + 1

DTT = DT

DTDZT = DTDZ

DTDYT = DTDY

DTSTBL = DT

```

C          STORE OLD PRESSURES
DO 50 K=2,NBFIN
50      PRSOLD(K) = PRSAV(K)
      KPY = 1
      KNY = 1
      KPZ = 1
      KPY = 1
      CALL FLOCHG
      IF (ABS(QZ(1)).LT.1.E-4) THEN
          IF (ITCNT.EQ.1) CALL STPCHG (.1,DTT,DTDZT,DTDYT)
          IF (ITCNT.GE.3) CALL STPCHG (10.,DTT,DTDZT,DTDYT)
          GO TO 90
      END IF
C
C          ELSE ENTER RAMP
      IF (ITCNT.EQ.1) CALL STPCHG (.1,DTT,DTDZT,DTDYT)
      IF (ITCNT.EQ.2) CALL STPCHG (.5,DTT,DTDZT,DTDYT)
C
C          *****
C          P R E S S U R E      E Q U A T I O N
C          SET UP PRESSURE MATRIX EQUATION ( SEE NOTES FOR DERIVATION
C          OF FINITE DIFFERENCED PREESURE SCHEME )
90      IDPCHG = 0
      IOVERF = 0
      IOVERR = 0
      TSTRT = DTT
      IBUBBL = 0
      IMOB = 0
C          RESET VARIABLES AND PRESS. EQN. COEFFS.
100     ICNVRG = 0
      IMOB1 = 0
      DO 105 K=1,NBFIN
          DO 104 J =1,3
              DO 103 I=1,3
103         XT(I,J,K) = 0
              XT(1,J,K) = X(1,J,K)
              RHOT(J,K) = RHOMOL(J,K)
              PRM1(J,K) =AKR(J,K)
104         FT(J,K) = F(J,K)
              XT(2,2,K) = X(2,2,K)
              XT(3,3,K) = X(3,3,K)
              TMOBT(K) = TMOB(K)
              W1Y(K) = 0
              W2Y(K) = 0
              W3Y(K) = 0
              ALPHA(K) =0
              BETA(K) =0
              GAMMA(K) =0
              THETA(K) =0
105         EPSLON(K)=0

```

```

C
C
C          CALCULATE RELATIVE MOBILITIES AND FLOW TERMS
C
C          CALL FLOFN1 (PRM1,VISO,RHOMOL,X)
C          CALL FLOFN2 (CNG,CN,VN,X,PRSAV,CMPEFF,S,SGCX)
C
140  QFLOW =QFLOFN(QZ(1),DTT,RHOMOL(1,1),RHOMOL(3,1),IWELL(JWELL),
1      RHOMOL(1,2),RHOMOL(2,2),RHOMOL(3,2),F(1,2),
2      F(2,2),F(3,2),X(2,2,2),X(3,3,2),DELTA2(2),
3      DELTA3(2),X(1,2,2),X(1,3,2))
C
C          ENTER PRESSURE/COMPOSITION ITERATIVE CALCULATION LOOP
C
150  CONTINUE
      KB=2
      RFRAC=2.* DTDYT
C
      DO 250 KF=1,NBZ
          KBDUM=KB+NBZ
          DO 220 K=KB,KBDUM
C
C          DEFINE UPSTREAM INDICES BASED ON
C          MOST RECENT FLOW RATES
C
      IF (K.EQ.2) THEN
C
C          FIRST FRACTURE BLOCK
C
          IF (QZ(K).GE.0) KPZ=K
          IF (QZ(K).LT.0) KPZ=K+NR
          IF (QZ(1).GE.0) KNZ=1
          IF (QZ(1).LT.0) KNZ=K
          IF (NBZ.NE.0) THEN
              IF (QY(K).GE.0) KPY=K
              IF (QY(K).LT.0) KPY=K+1
          END IF
      ELSE IF (K.EQ.KB .AND. K.GT.2) THEN
C
C          REMAINING FRACTURE BLOCKS
C
          IF (QZ(K).GE.0) KPZ=K
          IF (QZ(K).LT.0) KPZ=K+NR
          IF (QZ(K-NR).GE.0) KNZ=K-NR
          IF (QZ(K-NR).LT.0) KNZ=K
          IF (NBZ.NE.0) THEN
              IF (QY(K).GE.0) KPY=K
              IF (QY(K).LT.0) KPY=K+1
          END IF
          GO TO 180
      ELSE
C
C          RESERVOIR MATRIX BLOCKS
C
          IF (QY(K).GE.0) KPY=K
          IF (QY(K).LT.0) KPY=K+1
          IF (QY(K-1).GE.0) KNY=K-1
          IF (QY(K-1).LT.0) KNY=K
          GO TO 200
      END IF

```

C
C
C
C
C

BRANCH TO APPROPRIATE SYSTEM EQN.
AND BUILD COEFFICIENTS

INJECTION B.C. PRESSURE EQN.

```

1 ALPHA(2) = 0
1 BETA(2) = -( DTDZT * AFRAC * (W1Z(KPZ)
2           + DELTA2(K)*W2Z(KPZ) + DELTA3(K)*W3Z(KPZ))
1           + A(K) + RFRAC * ARES * (W1Y(KPY)
2           + DELTA2(K)*W2Y(KPY) + DELTA3(K)*W3Y(KPY)))
1 GAMMA(2) = DTDZT*(W1Z(KPZ) + DELTA2(K)*W2Z(KPZ) +
1           DELTA3(K)*W3Z(KPZ)) * AFRAC
1 EPSILON(2) = RFRAC*(W1Y(KPY) + DELTA2(K)*W2Y(KPY) +
1           DELTA3(K)*W3Y(KPY)) * ARES
1 IF (NBZ.EQ.1) THEN
    BETA(2) = BETA(2) + GAMMA(2)
    GAMMA(2) = 0
END IF
THETA(2) = - A(K) * PRSAV(2) - QFLOW
GO TO 220

```

C
C
C
C

SET FRACTURE COEFFICIENTS

180

```

1 ALPHA(K) = DTDZT * (W1Z(KNZ) + DELTA2(K)*W2Z(KNZ) +
1           DELTA3(K)*W3Z(KNZ)) * AFRAC
1 BETA(K) = -( DTDZT * AFRAC * (W1Z(KPZ)+W1Z(KNZ)
1           + DELTA2(K) * (W2Z(KPZ)+W2Z(KNZ)) + DELTA3(K)*
1           (W3Z(KPZ) + W3Z(KNZ))) + A(K) +
2           ARES * RFRAC * (W1Y(KPY) +
3           DELTA2(K)*W2Y(KPY) + DELTA3(K)*W3Y(KPY)))
1 GAMMA(K) = DTDZT * (W1Z(KPZ) + DELTA2(K)*W2Z(KPZ) +
1           DELTA3(K)*W3Z(KPZ)) * AFRAC
1           END OF FRACTURE B.C.
1 IF (K.EQ.2+(NBZ-1)*NR) THEN
    BETA(K) = BETA(K) + GAMMA(K)
    GAMMA(K) = 0
END IF
1 EPSILON(K) = RFRAC * (W1Y(KPY) + DELTA2(K)*W2Y(KPY) +
1           DELTA3(K)*W3Y(KPY)) * ARES
1 THETA(K) = - A(K) * PRSAV(K)
GO TO 220

```

C

```

C
C
C
200      SET RESERVOIR COEFFICIENTS
1      ALPHA(K) = DTDYT * (W1Y(KNY) + DELTA2(K)*W2Y(KNY) +
      DELTA3(K)*W3Y(KNY)) * ARES
      IF (K.EQ.KB+1) ALPHA(K) = 2 * ALPHA(K)
      BETAP = DTDYT * (W1Y(KPY) + DELTA2(K) * W2Y(KPY) +
      DELTA3(K) * W3Y(KPY))
      BETAN = DTDYT * (W1Y(KNY) + DELTA2(K) * W2Y(KNY) +
      DELTA3(K) * W3Y(KNY))
      IF (K.EQ.KB+1) BETAN = 2 * BETAN
      BETA(K) = -((BETAN + BETAP) * ARES + A(K))
      EPSLON(K) = DTDYT * (W1Y(KPY) + DELTA2(K)*W2Y(KPY) +
      DELTA3(K)*W3Y(KPY)) * ARES
      IF (K.EQ.KB+NBY) BETA(K) = -ALPHA(K)-A(K)
      IF (K.EQ.KB+NBY) EPSLON(K) = 0
      THETA(K) = - A(K) * PRSAV(K)
C
220      CONTINUE
      KB=2+KF*NR
250      CONTINUE
C
C
C
      SOLVE PRESSURE MATRIX
CALL GAUSS
C
C
C
      CHECK TRUNCATION ERROR (MAX. PRESSURE DIFFERENCE
      FROM LAST STEP)
      DPMAX = 0
      DO 260 K=2,NBFIN
      PDIF = ABS(XPRSAV(K)-PRSOLD(K))
260      DPMAX = AMAX1 (DPMAX,PDIF)
      IF (DPMAX-DPLIM.GT.1.E-1) THEN
      CALL STPCHG (DPLIM/DPMAX,DTT,DTDZT,DTDYT)
      IDPCHG = IDPCHG + 1
      TDPCHG(IDPCHG) = DTT
      GO TO 140
      END IF

```


C
C
C
C
C
C

C O M P O S I T I O N E Q U A T I O N

CALCULATE RELATIVE FLOW RATES IN GRID BLOCK K

KB=2

DO 300 KF=1,NBZ

IF (KB.GE.NBFIN-NBY) GO TO 270

PRSDIF = XPRSAV(KB) - XPRSAV(KB+NR)

IF (PRSDIF.GE.0) KBUPZ = KB

IF (PRSDIF.LT.0) KBUPZ = KB + NR

QZ(KB) = TMOBT(KBUPZ) * PRMF * 6.8E-5 * AFRAC * PRSDIF /
(FRLTH * DZ)

1
270 IF (NBY.EQ.0) GO TO 300

PRSDIF = (XPRSAV(KB) - XPRSAV(KB+1))

IF (PRSDIF.GE.0) KBUPY = KB

IF (PRSDIF.LT.0) KBUPY = KB + 1

QY(KB) = TMOBT(KBUPY) * PRMR * 6.8E-5 * ARES * 2 * PRSDIF /
(DY * RSLTH)

DO 290 K=KB+1,KB+NBY-1

PRSDIF = XPRSAV(K) - XPRSAV(K+1)

IF (PRSDIF.GE.0) KUP = K

IF (PRSDIF.LT.0) KUP = K + 1

290 QY(K) = TMOBT(KUP) * PRMR * 6.8E-5 * ARES * PRSDIF /
(RSLTH * DY)

END OF RESERVOIR B.C.

QY(KB+NBY) = 0

300 KB = 2 + KF * NR

END OF FRACTURE B.C.

QZ(NBFIN-NBY) = 0

CALCULATE COMPOSITIONS (MOLES I) AT NEW TIME LEVEL

SOLVE COMPOSITION EQUATION IN FRACTURE

DO 400 KF=1,NBZ

K=2+(KF-1)*NR

KM1=K-NR

IF (K.EQ.2) KM1=1

IF (QZ(KM1).GE.0) K1 = KM1

IF (QZ(KM1).LT.0) K1 = K

IF (QZ(K).GE.0) K2Z = K

IF (QZ(K).LT.0) K2Z = K + NR

IF (QY(K).GE.0) K2Y = K

IF (QY(K).LT.0) K2Y = K + 1

```

DO 330 I=1,3
330   CTMOL(I) = 0
      DO 350 J=1,3
        DO 350 I=1,3
          IF (J.EQ.1 .AND. I.NE.1) GO TO 350
          IF (J.EQ.2 .AND. I.EQ.3) GO TO 350
          IF (J.EQ.3 .AND. I.EQ.2) GO TO 350
          CHG = DTT * (QZ(KM1) * RHOT(J,K1) * XT(I,J,K1) *
1             FT(J,K1) - QZ(K) * RHOT(J,K2Z) * XT(I,J,K2Z) *
2             FT(J,K2Z) - QY(K) *
3             RHOT(J,K2Y) * XT(I,J,K2Y) * FT(J,K2Y))
          CTMOL(I) = CTMOL(I) + CHG
350   CONTINUE
      DO 370 I=1,3
C     OVERSHOOT CHECK
        IF (CN(I,K)+CTMOL(I).LT.-1.E-6) GO TO 410
370     XCN(I,K) = CN(I,K) + CTMOL(I)
400   CONTINUE
      GO TO 415
410   CALL STPCHG (0.5,DTT,DTDZT,DTDYT)
      IOVERF = IOVERF + 1
      TOVERF(IOVERF) = DTT
      IF (DTT.LT.1.E-5) THEN
        PRINT 430,DTT
        STOP
430     FORMAT ('STOP: OVERSHOOT. (FRAC.) DTT = ',E10.4)
      END IF
      GO TO 150
415   IF (NBY.EQ.0) GO TO 550
C     SOLVE COMPOSITION EQN. IN RESERVOIR
      KB=2
      DO 500 KF=1,NBZ
        KBI = KB+1
        KBF = KB+NBY
        DO 490 K=KBI,KBF
          KM1=K-1
          IF (QY(KM1).GE.0) K1 = KM1
          IF (QY(KM1).LT.0) K1 = K
          IF (QY(K).GE.0) K2 = K
          IF (QY(K).LT.0) K2 = K + 1
        DO 425 I=1,3
425     CTMOL(I)=0
          DO 450 J=1,3
            DO 450 I=1,3
              IF (J.EQ.1 .AND. I.NE.1) GO TO 450
              IF (J.EQ.2 .AND. I.EQ.3) GO TO 450
              IF (J.EQ.3 .AND. I.EQ.2) GO TO 450
              CHG = DTT * (QY(KM1) * RHOT(J,K1) * XT(I,J,K1) *
1                 FT(J,K1) - QY(K) * RHOT(J,K2) * XT(I,J,K2) *
2                 FT(J,K2))
              CTMOL(I) = CTMOL(I) + CHG
450     CONTINUE

```

```

C
C      OVERSHOOT CHECK
      DO 470 I=1,3
        IF (CN(I,K)+CTMOL(I).LT.-1.E-6) GO TO 520
C
C      TEMPORARY NEW COMPOSITION
470      XCN(I,K) = CN(I,K) + CTMOL(I)
490      CONTINUE
      KB = 2 + KF * NR
500      CONTINUE
      GO TO 550
520      CALL STPCHG (0.5,DTT,DTDZT,DTDYT)
      IOVERR = IOVERR + 1
      TOVERR(IOVERR) = DTT
        IF (DTT.LT.1.E-5) THEN
          PRINT 431,DTT
          STOP
431      FORMAT ('STOP: OVERSHOOT (RES) DTT = ',E10.4)
        END IF
      GO TO 150
C
C      CALCULATE DF/DS AND EVALUATE NUMERICAL STABILITY.
C      ADJUST TIME STEP IF NECESSARY.
C550  IF (ISTABL.EQ.0) CALL STABL (*150,*560)
550      CONTINUE
C
C      ITERATE ON MOBILITIES UNTIL CONVERGENCE
C      OF RELATIVE PERMEABILITIES
      CALL MOBTR (*100,*150)
C
C      NEW PRESSURES AND COMPOSITIONS
      DO 570 K=2,NBFIN
        PRSAV(K) = XPRSAV(K)
        DO 570 I=1,3
          CN(I,K) = XCN(I,K)
570
C
C      UPDATE PRODUCTION AND INJECTION DATA (MOLAR)
C
      IF (QZ(1) .GT. 0) GO TO 600
C
      DO 580 J=1,3
        DO 580 I=1,3
          CMOLPR(I) = CMOLPR(I) - DTDZT * QZ(1) * RHOMOL(J,2) *
580      X(I,J,2) * F(J,2) * FRLTH * DZ
1

```

CALCULATE APPROXIMATE PORE VOLUMES PRODUCED

RHOOIL = (3.53E-6 * PRSAV(2) + .945) / WT(2)

CUMP(1) = CMOLPR(1) / (RHOMOL(1,2) * VFRBLK)

CUMP(2) = CMOLPR(2) / (RHOOIL * VFRBLK)

CUMP(3) = CMOLPR(3) * 18. / VFRBLK

CALCULATE FRACTION OF OIP PRODUCED

DO 590 I=1,3

PROD(I) = CMOLPR(I) / OIPMOL(I)

CONTINUE

GO TO 700

MOLES INJECTED (ACCUMULATED)

IF (IWELL(JWELL).EQ.1) CMOLIN(1) = CMOLIN(1) + QZ(1) * DTT * RHOMOL(1,1)

IF (IWELL(JWELL).EQ.2) CMOLIN(3) = CMOLIN(3) + QZ(1) * DTT * RHOMOL(3,1)

PORE VOLUMES OF CO2 INJECTED

CUMDUM = QZ(1) * DTT / ((VFRBLK + VRSBLK * NBY) * NBZ)

IF (IWELL(JWELL).EQ.1) CUMI(1) = CUMI(1) + CUMDUM

IF (IWELL(JWELL).EQ.2) CUMI(3) = CUMI(3) + CUMDUM

TIME=TIME+DTT
TWELL=TWELL+DTT

RETURN
END

SUBROUTINE STPCHG (X,DT,DTDZ,DTDY)

THIS SUBR. CHANGES THE TIME STEP ISZE PER THE VALUE OF X.

REAL X,DT,DTDZ,DTDY

DT = X * DT

DTDZ = X * DTDZ

DTDY = X * DTDY

RETURN
END

SUBROUTINE FLOCHG

THIS SUBROUTINE DETERMINES THE CORRECT WELL FLOW RATE
DEPENDING ON THE VALUES INPUT FOR NUMBER OF STEPS
PER INJECTION, SOAK, AND PRODUCTION CYCLES.

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PR SOLD(ISZ),PDSOAK,DPLIM,PRSI,
PRSMAX,PRSMIN
COMMON / FLOW / QZ(ISZ),QY(ISZ),QFLOW,QINJ1,QINJ2,QPROD,
IWELL(50),JWELL,TWELL,TLIMIN,TLIMPR,TLIMSK
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
C13DUM,C33DUM

HUFF N' PUFF WELL-BLOCK FLOW RATE CHANGE

IFLO = IWELL(JWELL)
IF (ILIMIT.EQ.1) THEN

PRESSURE DEPENDENT WELL CONTROL

PMAX=0

PMIN=1.E30

DO 10 K=2,NBFIN

PMAX = AMAX1(PMAX,PRSAV(K))

PMIN = AMIN1(PMIN,PRSAV(K))

IF (IFLO.EQ.1 .OR. IFLO.EQ.2) THEN

INJECTION CHECK

IF (PMAX.GE.PRSMAX) GO TO 50

RETURN

ELSE IF (IFLO.EQ.-1) THEN

PRODUCTION CHECK

IF (PMIN.LE.PRSMIN) GO TO 50

RETURN

ELSE

SOAK CHECK

IF (PMAX-PMIN.LE.PDSOAK) GO TO 50

RETURN

END IF

```

ELSE IF (ILIMIT.EQ.2) THEN
C
TIME DEPENDENT WELL CONTROL
IF (IFLO.EQ.1 .OR. IFLO.EQ.2) THEN
IF (TWELL.GE.TLIMIN) THEN
TWELL=0
GO TO 50
ELSE
RETURN
END IF
ELSE IF (IFLO.EQ.-1) THEN
IF (TWELL.GE.TLIMPR) THEN
TWELL=0
GO TO 50
ELSE
RETURN
END IF
ELSE
IF (TWELL.GE.TLIMSK) THEN
TWELL=0
GO TO 50
ELSE
RETURN
END IF
END IF
END IF
C
50 JWELL=JWELL+1
IF (IWELL(JWELL).EQ.1) GO TO 100
IF (IWELL(JWELL).EQ.2) GO TO 200
IF (IWELL(JWELL).EQ.10) GO TO 300
IF (IWELL(JWELL).EQ.-10) GO TO 350
IF (IWELL(JWELL).EQ.-1) GO TO 400
C
C CHANGE TO CO2 INJECTION MODE
100 QZ(1) = QINJ1
X(3,3,1) = 0
X(1,1,1) = 1.0
F(1,1) = 1.0
F(3,1) = 0
GO TO 500
C
C CHANGE TO WATER INJECTION MODE
200 QZ(1) = QINJ2
X(1,1,1) = 0
X(3,3,1) = 1.0
F(3,1) = 1.0
F(1,1) = 0
GO TO 500

```

```
C
C          CHANGE TO POST-INJECTION SOAK MODE
300  QZ(1) = 1.E-20
      GO TO 500
C
C          CHANGE TO POST-PRODUCTION SOAK MODE
350  QZ(1) = -1.E-20
      GO TO 500
C
C          CHANGE TO PRODUCTION MODE
400  QZ(1) = QPROD
C
500  ITCNT = 1
      RETURN
      END
```

SUBROUTINE FLOFN1 (PRM,XVISO,XRHO,XX)

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
W1Z(ISZ),W2Z(ISZ),W3Z(ISZ),W1Y(ISZ),W2Y(ISZ),
W3Y(ISZ)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
DIMENSION RMOB(3,ISZ),PRM(3,ISZ),XVISO(ISZ),XRHO(3,ISZ),
XX(3,3,ISZ)

CALCULATE FLOW TERMS FOR PRESSURE EQN.

CR = PRMR * 6.8E-5
CF = PRMF * 6.8E-5

(6.85E-5 IS FOR UNIT CONVERSION)

CFG = CF / VISG
CFW = CF / VISW
CRG = CR / VISG
CRW = CR / VISW
KB = 2
DO 1000 K=2,NBFIN
IF (K.EQ.KB) THEN
KB = KB + NR

MOBILITY TERMS ALONG FRACTURE

RMOB(1,K) = CFG * PRM(1,K)
RMOB(2,K) = PRM(2,K) * CF / XVISO(K)
RMOB(3,K) = CFW * PRM(3,K)
W1Z(K) = XRHO(1,K) * RMOB(1,K) + XX(1,2,K) * XRHO(2,K) *
RMOB(2,K) + XX(1,3,K) * XRHO(3,K) * RMOB(3,K)
W2Z(K) = XX(2,2,K) * XRHO(2,K) * RMOB(2,K)
W3Z(K) = XX(3,3,K) * XRHO(3,K) * RMOB(3,K)
END IF

FLOW TERMS PERPENDICULAR TO FRACTURE

RMOB(1,K) = CRG * PRM(1,K)
RMOB(2,K) = PRM(2,K) * CR / XVISO(K)
RMOB(3,K) = CRW * PRM(3,K)
W1Y(K) = XRHO(1,K) * RMOB(1,K) + XX(1,2,K) * XRHO(2,K) *
RMOB(2,K) + XX(1,3,K) * XRHO(3,K) * RMOB(3,K)
W2Y(K) = XX(2,2,K) * XRHO(2,K) * RMOB(2,K)
W3Y(K) = XX(3,3,K) * XRHO(3,K) * RMOB(3,K)

1000 CONTINUE
RETURN
END


```

SUBROUTINE FLOFN2 (XCNG,XCN,XV,XX,XP,XCMP,XS,XSGC)
C
  PARAMETER (ISZ=52)
  COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
    . DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
    . DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
  COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
    . OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
  COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
    . THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
    . W1Z(ISZ),W2Z(ISZ),W3Z(ISZ),W1Y(ISZ),W2Y(ISZ),
    . W3Y(ISZ)
  DIMENSION XCNG(3,ISZ),XCN(3,ISZ),XV(3,3,ISZ),XX(3,3,ISZ),
    . XP(ISZ),XCMP(ISZ),XS(3,ISZ),XSGC(ISZ)
C
  DO 1000 K=2,NBFIN
C
C      CALCULATE DELTA COEFFICIENTS AND A(K)
C
    DUM3 = XCN(3,K) + XCNG(3,K)
    DUM2 = XCN(2,K) + XCNG(2,K)
    IF (XS(1,K)-XSGC(K).LE.1.E-4) THEN
C
C      IMMOBILE GAS
      DUM3 = DUM3 * XX(2,2,K)
      DUM2 = DUM2 * XX(3,3,K) * RATSOL
      DUMV = XV(1,2,K) - XV(1,3,K)
      DNUM = DUM3 + DUM2
      DENOM = XV(1,3,K) * DUM3 + XV(1,2,K) * DUM2
      DELTA2(K) = (XV(2,2,K) * DNUM + RATSOL * XCNG(3,K) *
        . DUMV)/DENOM
      DELTA3(K) = (XV(3,3,K) * DNUM - XCNG(2,K) * DUMV)/DENOM
      A(K) = XCMP(K) * DNUM / DENOM
    ELSE
C
C      MOBILE GAS
      DUMV2 = XV(1,1,K) - XV(1,2,K)
      DUMV3 = XV(1,1,K) - XV(1,3,K)
      SOL2 = OILSOL * XP(K)
      SOL3 = WATSOL * XP(K)
      SOL2M = 1.- SOL2
      SOL3M = 1.- SOL3
      DELTA2(K) = (XV(2,2,K) * SOL2M - DUMV2 * SOL2) /
        . (XV(1,1,K) * SOL2M)
      DELTA3(K) = (XV(3,3,K) * SOL3M - DUMV3 * SOL3) /
        . (XV(1,1,K) * SOL3M)
      CMPMOB = DUMV2 * DUM2 * OILSOL / SOL2M + DUMV3 * DUM3 *
        . WATSOL / SOL3M
      A(K) = (XCMP(K) + CMPMOB) / XV(1,1,K)
    END IF
  1000 CONTINUE
  RETURN
  END

```

SUBROUTINE GAUSS

PARAMETER (ISZ=52)

COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
 . DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RSLTH,HFRAC,
 . DEPTH,AFRAC,ARES,VLK(ISZ),VFRBLK,VRSBLK,VPORE

COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLN(ISZ),
 . THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
 . W1Z(ISZ),W2Z(ISZ),W3Z(ISZ),W1Y(ISZ),W2Y(ISZ),
 . W3Y(ISZ)

COMMON / TMPVAL / PRM1(3,ISZ),PRMT(3,ISZ),XCN(3,ISZ),XPRSAV(ISZ),
 . RHOT(3,ISZ),XT(3,3,ISZ),FT(3,ISZ),TMOBT(ISZ)

THIS SUBROUTINE WILL SOLVE THE PRESSURE MATRIX
 ARISING OUT OF THE QUASI-TWO DIMENSIONAL
 CHARACTERIZATION OF A FRACTURED RESERVOIR.

REAL XALPHA(ISZ),XBETA(ISZ),XTHETA(ISZ),XGAMMA(ISZ),XEPSLN(ISZ)

XTHETA(1) = 0

XPRSAV(NBFIN+1) = 0

DO 100 K=2,NBFIN

XPRSAV(K) = 0

XALPHA(K) = ALPHA(K)

XBETA(K) = BETA(K)

XGAMMA(K) = GAMMA(K)

XTHETA(K) = THETA(K)

XEPSLN(K) = EPSLN(K)

100

```

C      KB=2
      K=KB

C
C      BEGIN FORWARD SUBSTITUTION
120    XGAMMA(K) = XGAMMA(K) / XBETA(K)
150    XEPSLN(K) = XEPSLN(K) / XBETA(K)
      XTHETA(K) = (XTHETA(K) - XALPHA(K) * XTHETA(K-1)) / XBETA(K)
      IF (K.GE.NBFIN) GO TO 400
      IF (K.GE.KB+NBY) GO TO 300
      K = K + 1
      XBETA(K) = XBETA(K) - XALPHA(K) * XEPSLN(K-1)
      XGAMMA(K) = -XALPHA(K) * XGAMMA(K-1) / XBETA(K)
      GO TO 150

C
300    KB = KB + NR
      I = NR
350    XBETA(KB) = XBETA(KB) - XALPHA(KB) * XGAMMA(KB-I)
      IF (I.LE.1) GO TO 360
      XTHETA(KB) = XTHETA(KB) - XALPHA(KB) * XTHETA(KB-I)
      XALPHA(KB) = -XALPHA(KB) * XEPSLN(KB-I)
      I = I - 1
      GO TO 350

C
360    K = KB
      GO TO 120

C
C      BEGIN BACKWARD SUBSTITUTION
400    KB = NBZ * NR + 2
      K = NBFIN

C
450    XPRSAV(K) = XTHETA(K) - XEPSLN(K) * XPRSAV(K+1) - XGAMMA(K) *
1      XPRSAV(KB)
      IF (K.LE.2) RETURN
      IF (KB-K.GE.NR) KB=KB-NR
      K = K - 1
      GO TO 450
      END

```

SUBROUTINE MOBTR (*,*)

PARAMETER (ISZ=52)
COMMON / GRID / DT,DZ,DY,DTDZ,DTDY,DTT,DTDZT,DTDYT,TIME,DTNEW,
DTSTBL,NBZ,NBY,NR,NBFIN,FRLTH,RLTH,HFRAC,
DEPTH,AFRAC,ARES,VBLK(ISZ),VFRBLK,VRSBLK,VPORE
COMMON / COUNT / IT,ITMAX,ITCNT,ICNVRG,IBUBBL,IDPCHG,IOVERF,
IOVERR,ISTABL,IMOB,IMOB1,IPRNT,NOUNIT,MXCNVRG
COMMON / TIMES / TPHASE,TIMPEM,TDPCHG(100),TSTRT,TOVERF(100),
TOVERR(100),TBUBBL(100),XJUMP
COMMON / MOLES / CN(3,ISZ),CNG(3,ISZ),CNGC(ISZ),X(3,3,ISZ),
OILSOL,WATSOL,RATSOL,OILRAT,WATRAT,OIPMOL(3)
COMMON / PRESS / PRSAV(ISZ),PRSOLD(ISZ),PDSOAK,DPLIM,PRSI,
PRSMAX,PRSMIN
COMMON / PRSMAT / ALPHA(ISZ),BETA(ISZ),GAMMA(ISZ),EPSLON(ISZ),
THETA(ISZ),DELTA2(ISZ),DELTA3(ISZ),A(ISZ),
W1Z(ISZ),W2Z(ISZ),W3Z(ISZ),W1Y(ISZ),W2Y(ISZ),
W3Y(ISZ)
COMMON / FLOW / QZ(ISZ),QY(ISZ),QFLOW,QINJ1,QINJ2,QPROD,
IWELL(50),JWELL,TWELL,TLIMIN,TLIMPR,TLIMSK
COMMON / XDENSE / RHOMOL(3,ISZ),RHO(3,ISZ),VN(3,3,ISZ),
CMPEFF(ISZ),ZSLOPE,A22DEN,B22DEN,ASWELL,
A33DEN,B33DEN,A3SDEN,B3SDEN,V22ATM,WT(3)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
COMMON / XPERM / PRMF,PRMR,PORF,PORR,AKR(3,ISZ),F(3,ISZ),
TMOB(ISZ),SWC,SOR,SOG,SGC,EKRO,EKRW,EKROG,
EKRG,EO,EW,EOG,EG,S(3,ISZ),SGCX(ISZ)
COMMON / PRM / IPERM,NSW,NSL,TSW(3,20),TSL(3,20),ITPT
COMMON / TMPVAL / PRM1(3,ISZ),PRMT(3,ISZ),XCN(3,ISZ),XPRSAV(ISZ),
RHOT(3,ISZ),XT(3,3,ISZ),FT(3,ISZ),TMOBT(ISZ)
COMMON / UPDATE / CUMI(3),CUMP(3),CMOLIN(3),CMOLPR(3),PROD(3)
COMMON / MISC / C(3),TITLE(20),ILIMIT,IP(3),ISTEP(4),C22DUM,
C13DUM,C33DUM
DIMENSION XCNG(3,ISZ),RHOGMT(3,ISZ),VNT(3,3,ISZ),XVISO(ISZ),
XSGC(ISZ),CMPEFT(ISZ),ST(3,ISZ),X10(ISZ)
LOGICAL X1,X2,X3,X4,XX1,XX2,XX3

IMOB = IMOB + 1
IMOB1 = IMOB1 + 1
IF (IMOB1.LE.1) THEN
DO 40 K=2,NBFIN
DO 40 J=1,3
PRM1(J,K) = AKR(J,K)
ELSE
DO 45 K=2,NBFIN
DO 45 J=1,3
PRM1(J,K) = PRMT(J,K)
END IF

```

C
C                                     CALCULATE NEW PHASE COMPOSITIONS
      CALL EQUILIB (CNGC,XCN,XPRSAV,XCNG,XT,X10)
C*****
C                                     CHECK FOR APPEARANCE/DISAPPEARANCE OF GAS IN A BLOCK
C                                     AND ADJUST TIME STEP FOR MINIMUM CROSS-OVER
C                                     AT BUBBLE POINT
      KMAX = 0
      TCHGMX = 1.E6
      DO 80 K=2,NBFIN
        C0 = OILSOL * PRSOLD(K)
        C1 = X(1,2,K) - C0
        C2 = X10(K) - OILSOL * XPRSAV(K)
        X1 = ABS(C1) .LE. 1.E-05
        X2 = C2 .LE. -XJUMP
        X3 = C1 .LE. -1.E-5
        X4 = C2 .GE. XJUMP
        XX1 = X1 .AND. X2
        XX2 = X3 .AND. X4
        XX3 = XX1 .OR. XX2
        IF (XX3) THEN
          IF (XX1) THEN
C                                     SATURATED TO UNSATURATED CASE
            TCHG = ( OILSOL * (XPRSAV(K)-PRSOLD(K)) ) /
                  (X10(K) - X(1,2,K))
            TCHGMX = AMIN1 (TCHGMX,ABS(TCHG))
            IF (ABS(TCHGMX-TCHG).LE.1.E-6) KMAX=K
          ELSE IF (XX2) THEN
C                                     UNSATURATED TO SATURATED CASE
            DUM = (X10(K)-X(1,2,K))/(XPRSAV(K)-PRSOLD(K))
            PX = (X10(K)-DUM*XPRSAV(K))/(OILSOL-DUM)
            TCHG = (PX-PRSOLD(K))/(XPRSAV(K)-PRSOLD(K))
C            TCHG = (OILSOL * XPRSAV(K) - X(1,2,K)) /
C                  (X10(K) - X(1,2,K))
            TCHGMX = AMIN1 (TCHGMX,ABS(TCHG))
            IF (ABS(TCHGMX-TCHG).LE.1.E-6) KMAX=K
          END IF
        END IF
      CONTINUE
80    IF (KMAX.GT.0) THEN
        CALL STPCHG (TCHGMX,DTT,DTDZT,DTDYT)
        IBUBBL = IBUBBL + 1
        TBUBBL(IBUBBL) = DTT
        RETURN 1
      END IF

```

```

C          CALCULATE PHASE DENSITIES
CALL DENSE (XPRSAV,XT,RHOGMT,RHOT,VNT)

C          CALCULATE OIL VISCOSITY
DO 60 K=2,NBFIN
60  XVISO(K) = VISOIL (XPRSAV(K),XT(1,2,K))

C          CALCULATE AVERAGE COMPRESSIBILITY
CALL CMPRES (XCNG,XCN,XPRSAV,CMPEFT,VNT)

C          CALCULATE PHASE SATURATIONS
CALL SCALC (XCNG,XCN,VNT,XSGC,ST,CNGC)

C          CALCULATE RELATIVE PERMEABILITIES
CALL PERM (ST,XVISO,XSGC,PRMT,FT,TMOBT)

C          CALCULATE FLOW COEFFICIENTS FOR PRES. EQN.
CALL FLOFN1 (PRMT,XVISO,RHOT,XT)
CALL FLOFN2 (XCNG,XCN,VNT,XT,XPRSAV,CMPEFT,ST,XSGC)

C
C  QFLOW = QFLOFN (QZ(1),DTT,RHOT(1,1),RHOT(3,1),
1      IWELL(JWELL),RHOT(1,2),RHOT(2,2),RHOT(3,2),
2      FT(1,2),FT(2,2),FT(3,2),XT(2,2,2),XT(3,3,2),
3      DELTA2(2),DELTA3(2),XT(1,2,2),XT(1,3,2))

C
C  IF (IMOB1.LE.1) RETURN 2
C          CHECK PERMEABILITY CONVERGENCE
DO 140 K=2,NBFIN
  DO 140 J=1,3
    PRMDIF = PRM1(J,K) - PRMT(J,K)
    IF (PRMDIF.EQ.0..OR. PRM1(J,K).EQ.0.) GO TO 140
    PERDIF = ABS(PRMDIF)/PRM1(J,K)
    IF (PERDIF.GT..01) GO TO 150
140  CONTINUE
  RETURN

C          NON-CONVERGENCE - REPEAT ITERATION
150  IF (ICNVRG.LE. MXCNVRG) THEN
    ICNVRG = ICNVRG + 1
    PRINT 200, K,J,AKR(J,K),PRMT(J,K),PRM1(J,K),PERDIF,ICNVRG
C  200  FORMAT (20X,'K, J, AKR, PRMT, PRM1, PERDIF, ICNVRG : ',2I3,
    4E12.4,I3)
    RETURN 2
  ELSE
    RETURN
  END IF
END

```

```

FUNCTION VISOIL (P,X12)
C
PARAMETER (ISZ=52)
COMMON / VISC / VISO(ISZ),VISG,VISW,AVIS1,AVIS2,BVIS,CVIS
C
C
VISOIL = 10 ** (AVIS1 * P + BVIS * X12 + CVIS)
RETURN
END
C*****
FUNCTION QFLOFN (Q,DT,RO11,RO31,IW,RO12,RO22,RO32,F1,F2,F3,X22,
1 X33,DEL2,DEL3,X12,X13)
C
QDUM = 1. + DEL3
IF (IW.EQ.1) QFLOFN = Q * DT * RO11
IF (IW.EQ.2) QFLOFN = Q * DT * RO31 * QDUM
IF (IABS(IW).EQ.10) QFLOFN = 0
IF (IW.EQ.-1) QFLOFN = Q * DT * (F1 * RO12 + F2 * RO22 *
1 (X12 + DEL2 * X22) + F3 * RO32 * (X13 + DEL3 * X33))
C
RETURN
END

```