**SIMULATION STUDIES TO EVALUATE
THE EFFECT OF FRACTURE CLOSURE
ON THE PERFORMANCE
OF NATURALLY FRACTURED RESERVOIRS
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ABSTRACT

The second year of this three-year research program to evaluate the effect of fracture closure on the recovery of oil and gas from naturally fractured reservoirs has been completed. The overall objectives of the study are to: (1) evaluate the reservoir conditions where fracture closure is significant, and (2) evaluate innovative fluid injection techniques capable of maintaining pressure within the reservoir.

Simulation studies have been conducted with a dual porosity simulator capable of simulating the performance of vertical and horizontal wells. Each simulation model has been initialized with properties typical of the Austin Chalk reservoir in Pearsall Field, Texas.

During year one, simulations of both vertical and horizontal well performance were made assuming that fracture permeability was insensitive to pressure change. Sensitivity runs indicated that the simulator was predicting the effects of critical reservoir parameters in a logical and consistent manner. The results confirmed that horizontal wells could increase both rate of oil recovery and total oil recovery from naturally fractured reservoirs.

During the second year the performances of the same vertical and horizontal wells were evaluated with the assumption that fracture permeability was a function of reservoir pressure. This required repetition of most of the natural depletion cases simulated in year one while invoking the pressure-sensitive fracture permeability option. To investigate sensitivity to in situ stress, two stress conditions were simulated for each primary variable. The water injection cases, begun in year one, were extended to include most of the reservoir parameters investigated for natural depletion, including fracture permeability as a function of net stress and the use of horizontal wells.

The results thus far confirm that pressure-sensitive fractures degrade well performance and that the degradation is reduced by water injection pressure maintenance. Furthermore, oil recovery can be significantly increased by water injection pressure maintenance.

EXECUTIVE SUMMARY

1.0 SUMMARY

Fractured reservoirs contain a significant part of the remaining hydrocarbon reserves of the United States. Moreover, oil production from fractured reservoirs is increasing due to the recently accelerated development drilling activity in such reservoirs.

The remarkable advances in horizontal drilling technology are of particular interest to operators with large holdings in known fractured reservoir trends, such as the Austin Chalk in Texas and the Bakken Shale in the Williston Basin. Horizontal well bores offer a practical means to exploit these difficult reservoirs and others like them. In many instances, horizontal well completions offer the only economically feasible exploitation method.

This study is to investigate the pressure sensitivity of fractured reservoir systems and its impact on hydrocarbon recovery. The principal objective is to develop innovative techniques for counteracting the natural tendency of fractures to deform and reduce reservoir flow capacity as pressure is reduced by fluid withdrawals. The work is planned in three tasks, each of one-year duration. A brief description of each task follows:

Task 1: Select a candidate field, establish its reservoir properties, and initialize a mathematical simulator of a typical segment of the reservoir. Make performance forecasts assuming natural depletion and using both vertical and horizontal well bores. Forecast secondary recovery performance with gas or water injection assuming vertical well exploitation. Make sufficient runs for each forecast mode to establish the sensitivity of the forecasts to key reservoir properties. For these simulations, the fractures are assumed to have no pressure sensitivity.

Task 2: The natural depletion and secondary recovery forecasts of Task 1 will be repeated, but assuming the fracture permeability to be stress dependent. The characterization of the permeability-stress relationship will be based on the most current published research findings.

Task 3: The production problems arising from fracture permeability reduction will be addressed. Those reservoir and operating conditions which manifest the most severe problems will be identified. Innovative approaches to resolving these problems with fluid injection and horizontal wells or combinations of vertical and horizontal wells will be evaluated.

The Task 1 work was completed and reported in the first Annual Report. The TRIAD reservoir simulator was revised to treat horizontal wells and fracture permeability as a function of reservoir pressure. The Austin Chalk reservoir in Pearsall Field, Texas, was selected as the prototype for

the study. Prototype simulators were initialized and 68 simulations of natural depletion and secondary recovery were performed.

This report discusses the work carried out in the second contract year in fulfillment of Task 2. The modified simulator was applied to determine how pressure-sensitive fracture permeability impacts oil recovery. This required running a series of reservoir parameter sensitivity simulations for each type of well completion, vertical and horizontal, and for each type of operation, natural depletion or water injection pressure maintenance. Further consideration of gas injection was excluded on the basis of its inferior performance in the Task 1 studies.

2.0 CONCLUSIONS

The conclusions arising from the second year or Task 2 studies were as follows:

1. Interpretations of production test data from a horizontal Austin Chalk Well in Pearsall Field revealed:
 - Support for the multiple fracture swarm conceptual model.
 - Fracture permeability is in the range of 1 to 10 md.
 - Positive skin factor.
2. Published experimental data confirmed the suitability of the fracture deformation logic programmed in the TETRAD simulator.
3. Simulations of natural depletion with and without fracture deformation indicated that:
 - Well productivity decline is exacerbated resulting in a prolongation of the recovery period by as little as 27 days to as much as 1.95 years.
 - Recovery factors are generally slightly reduced. The reductions are greatest if either the fracture porosity to matrix porosity ratio is quadrupled or if the ratio of matrix to fracture permeability is divided by 10. Both resulted in a maximum decrement of 2% of STOIP[†]. This is equivalent to 10 to 11% of the recovery factor realized when fracture deformation is ignored.
4. Simulations of a 640-acre horizontal line drive water flood, first ignoring, then including fracture deformation effects, demonstrated that:

[†]Stock tank oil initially in place.

- Reservoir pressure is maintained, and well productivity is stabilized prior to water breakthrough.
- Productivity deterioration due to fracture deformation was greatly attenuated. The most severe case prolonged the recovery period only 0.9 years.
- Recovery factors were essentially independent of fracture deformation.
- The fractional recovery at water breakthrough was reduced as effective stress was increased. Most commonly, the recovery difference was $\leq 1\%$ of STOIP. Quadrupling the fracture porosity/matrix porosity ratio resulted in breakthrough recovery lowered as much as 6% of STOIP.
- For the most part, the oil rate versus oil recovery profiles were little affected by deformation. Differences were principally exacerbations of producing rate decline, confined to the first 1 or 2% of recovery. The quadrupling of the fracture/matrix porosity ratio produced the widest producing rate divergences.

5. The horizontal water flood simulations also demonstrated recovery factor sensitivity to reservoir parameters, as follows:

- Recovery was sensitive to matrix permeability, k_m , and relatively insensitive to fracture permeability, k_f .

k_m , md	k_f , md	Recovery
.001	10	.554
.0001	10	.500
.00001	10	.393
.0001	1	.514
.0001	10	.500
.0001	100	.506

- Water flood recovery was more sensitive to increasing fracture/matrix porosity ratios, ϕ_f / ϕ_m , than to reducing ratios:

	ϕ_f , %	ϕ_m , %	Recovery
base case	.0984	3.36	.500
ϕ_f / ϕ_m	.3936	3.36	.552
increase	.0984	.834	.554
ϕ_f / ϕ_m	.0492	3.36	.487
decrease	.0984	6.72	.489

- Lowering matrix capillary pressure reduced recovery (from .500 to .446 for the cases simulated).
 - Increasing fracture capillary pressure from 0 to $\frac{1}{2}$ of matrix values reduced recovery by 1.3% of STOIP.
 - Increasing fracture residual oil saturation, S_{orw} from 0 to $\frac{1}{2}$ of matrix S_{orw} reduced recovery < 1% of STOIP.
 - Changing fracture relative permeability shape from linear to curved reduced recovery < $\frac{1}{2}$ % of STOIP.
6. Comparing horizontal water flood and natural depletion simulations shows that water flooding substantially improves recovery factors. Expressed as a multiple of depletion recovery, the range is from 2.3 to 5.5 times. Contrasting the two recovery methods for identical reservoir parameters reveals:
- Sensitivity to a 10 times k_m / k_f increase is reversed, that is, depletion recovery is reduced but water flood recovery is increased, yielding a recovery improvement multiple (water flood/depletion) of 4.9 times without deformation. If fracture deformation is included the multiple increases to as much as 5.5 times.
 - Sensitivity to a 0.1 times k_m decrease is also reversed, that is, depletion recovery increases while water flood recovery reduces, reducing the recovery improvement multiple to 2.3 times. The multiple does not change with fracture deformation.
 - Sensitivity to a 10 times k_f increase is noticeable for depletion but insignificant for water flood, yielding water flood recovery improvement multiples of 2.8 to 2.9 times.

- Reduced ϕ_f / ϕ_m ratios provided negligible sensitivity effects, depletion or water flood. Recovery multiples for water flooding over depletion varied from 3.0 to 3.1.
- Depletion recovery was considerably more sensitive to ϕ_f / ϕ_m increases than was water flood. Recovery improvement multiples, neglecting deformation effects, were 3.2. Fracture deformation increased the multiple to as much as 3.6 times.
- Fracture capillary pressures > 0 had opposing recovery impact for depletion (progression), compared to a water flood (regression). Recovery improvement multiples varied insignificantly with deformation from 2.7 to 2.8 times.
- Matrix capillary pressure reduction also had opposing recovery implications but water flood degradation was about 5 times greater than depletion improvement. Deformation produced insignificant recovery improvement variations from 2.5 to 2.6 times.
- Inclusion of fracture $S_{orw} > 0$ reduced depletion and water flood recovery factors almost equally and deformation effects were negligible. Water flood recovery were 2.8 times depletion recovery.
- Changing fracture relative permeability shape from linear to curved slightly improved the water flood recovery multiple to 2.9 times.

INTRODUCTION

3.0 BACKGROUND

A significant fraction of the remaining domestic oil and gas reserves is contained in reservoirs wherein naturally occurring fractures provide the means of fluid flow. Increased attention is being given to such reservoirs because of the potential for improved productive capacity and ultimate recovery offered by the long horizontal well bores made possible by recent advances in horizontal drilling technology. Examples of naturally fractured reservoirs in the United States include: Elk Basin in Montana and Wyoming, Bakken formation in the Williston Basin, Lisburne in Alaska, and Spraberry and the Austin Chalk trend in Texas.

The global fluid flow in a fractured reservoir takes place within a system of intersecting fissures in the reservoir rock. The volume of the fracture-related voids is, however, very small in comparison to the bulk volume of the reservoir, usually less than 1% and often much less. The greatest part of the reservoir storage volume is contained in the intervening porous rock, commonly referred to as the "matrix." The matrix is usually of very low permeability, often in the microdarcy range, but has more typical porous media porosity. Matrix porosity varies from a few percent up to a few tens of percent.

Reduction of void volume in conventional porous media due to the increased stresses induced by fluid withdrawals is a known phenomenon. It is usually accounted for in reservoir engineering calculations by the pore volume compressibility. It is generally acknowledged that similar reductions must also take place in the fissure void network. Since shrinkage of fissure voids would be expected to reduce their permeability, perhaps more drastically than for conventional porous media, this could have serious well productivity and reservoir flow mechanics implications.

There is a rather large body of writings in the technical literature, particularly in the field of rock mechanics, dealing with the assessment of fissure permeability and the tendency of this type of permeability to be stress sensitive. Researchers in this field have performed rather extensive studies of fracture systems, mainly in the shallow subsurface and commonly related to large construction projects. These studies have included in situ measurements of principal rock stresses and fracture properties, such as fracture aperture, length, height and orientation, and the description of complex rock joint systems.

Although fissures are often referred to in terms implying that they are planar features, they really are not. The fracture surface is commonly rough and undulating. The surface roughness can be characterized by the distribution of individual asperity heights. The stresses which cause the rock to fracture will commonly have a shear component which induces some displacement along the fracture surface. Even a slight displacement can be sufficient to juxtapose higher than average asperities, thus preventing the rock from mating and the fracture from closing. Larger displacements can lead to a situation where the waviness of the fracture will play a role in

keeping the fracture surfaces from mating perfectly. Thus, it is common that fractures do not completely heal as stress is increased and measurable permeability can be observed to extremely high stress levels.

A fracture flow system, therefore, is seen to be a complex system of flattened flow channels that, due to their tortuosity, intersect other channels to form a complex network. In many respects, this network is not unlike a normal porous media, in that fracture permeability will be highly variable and flow will tend to be tortuous. It differs in the respect that the fractures do have a planar element that imparts a highly directional permeability to the reservoir.

The void spaces along the fracture surface between the points of contact will have a tendency to deform and reduce the aperture with increasing stress. The degree of deformation is dependent upon the mechanical properties of the rock and the equilibrium state stress conditions. In oil field operations, this equilibrium is disturbed by the withdrawal of reservoir fluids. As a consequence, the fluid pressure is reduced and the rock is subjected to increased stress.

4.0 OBJECTIVES

This study was proposed on the basis of two observations arising from prior research:

1. Horizontal wells improve oil recovery from reservoirs containing tectonic fractures. This improvement is due to the larger number of vertical fractures intersected by the well bore.
2. Oil recovery in these reservoirs suffers because the fractures are inclined to close as reservoir pressure depletes, thus exacerbating the well productivity decline. The tendency of natural water encroachment or fluid injection is to retard or arrest reservoir pressure decline and fracture closure, thus reducing well productivity decline and offering the possibility of improved recovery.

Neither observation has been systematically quantified or evaluated. The primary purpose of this study is to rectify these shortcomings; thus, the work has the following general objectives:

1. To evaluate the impact of fracture closure on hydrocarbon recovery from reservoirs having pressure-sensitive, naturally occurring fractures.
2. To investigate innovative developmental and fluid injection methods for improving hydrocarbon recovery from such reservoirs.

The study will rely on state-of-the-art reservoir modelling techniques to provide reliable simulations of reservoir behavior. Analysis of these results is proposed as the basis for all observations and conclusions arising from this work.

DISCUSSION

5.0 LITERATURE REVIEW

A extensive search of the technical literature was performed as part of Task 1. That effort established the core reference material for the study as presented in the bibliography of the first Annual Report. The search for literature has continued as updated editions of the primary reference sources have become available.

A cumulative list of all documents located and copied to date is provided in the bibliography. It is anticipated that new documents will be identified and added to the reference database as the study continues into its final year.

6.0 RESERVOIR DESCRIPTION

The simulators employed thus far have properties drawn from the published data for the Pearsall Field, Austin Chalk reservoir. They are not, however, specific to any well or portion of the prototype reservoir.

The characteristics of the prototype Austin Chalk reservoir were discussed in a comprehensive manner in the first Annual Report. The following discussion summarizes the basic reservoir characteristics from that report, presents the current year deformable fracture property data, and updates analyses of the well performance data began in year one.

6.1 Summary of Basic Reservoir Data

The following discussion summarizes the basic reservoir features of the reservoir simulators used thus far.

Porosity and permeability development is confined to compartments of rather intense fracturing ("fracture swarms") separated by intervals of impermeable, non-reservoir quality chalk development^{7,10}. The compartments tend toward vertical dip and uniform and parallel strike over very long distances. Vertical fractures, parallel to the strike of the compartment, are predominant. Steeply dipping secondary fractures intersect the principal set at nearly right angles, and microfracturing is extensive within the fracture swarms but almost completely absent in the inter-swarm rock⁷. Principal fracture spacing as close as three per foot and fracture porosity up to 0.001 (fraction of core bulk volume) are reported by the same source. Secondary and micro fractures would further increase the total fracture porosity.

The gross thickness of the reservoir varies from about 400 feet to more than 700 feet. On the basis of vertical well core data and a net pay porosity cut-off of 3%, one operator¹¹ has computed

a net thickness to gross thickness ratio of 0.321 and a corresponding average porosity of 3.90% for the net rock.

The gravity of the produced oil is known to vary between 29° and 37°API suggesting variable fluid composition and saturation pressure. One bottom-hole oil sample reported⁷ a saturation pressure, p_b of 2350 psig, solution gas-oil ratio, R_s of 825 scf/STB, oil formation volume factor, B_o of 1.5v/v and oil viscosity, μ_o , of 0.6 cp. The source acknowledged oil composition variability but cited observed initial producing gas-oil ratios in the 500-600 Scf/STB range as support for p_b of 1650 psig as compared to a virgin reservoir pressure of approximately 2600 psig.

The ranges cited⁷ for effective reservoir properties and the values assumed for the base case simulators are as follows:

<u>Property</u>	<u>Value Range</u>			<u>Simulator</u>
porosity, fraction:				
matrix, ϕ_m	0.02	-	0.05	0.0336
fracture, ϕ_f	0.0005	-	0.001	0.000984
permeability:				
matrix, k_m , μ d	0.01	-	0.1	0.1
fracture, k_f , md	3.0	-	10.0	10.0
water saturation	0.30	-	0.65	0.30
thickness:				
gross	400.	-	700.	544.
net	128.4	-	224.7	174.
fluid properties:				
oil gravity, °API	21.	-	43.	37.
R_s , scf/STB	280.	-	825.	730.
gas gravity (air = 1)	0.93	-	0.95	0.95
P_b , psig	1625.	-	2350.	2350.
temperature, °F		-	190.	190.
B_o , v/v	1.183	-	1.382	1.393
μ_o , cp		-	0.6	0.452

6.2 Deformable Fracture Properties

The central thesis of this study is that naturally fractured petroleum reservoirs will experience permeability reduction during primary depletion operation. The permeability reduction arises from fracture deformation caused by the increasing net confining stress, that is, less of the external geostatic stress is offset by internal fluid pressure as fluids are withdrawn and fluid pressure is reduced. The definition of these properties in the current simulation studies is the subject of this section.

6.2.1 Background

Laminar, isothermal, steady-state single phase fluid flow in planar, constant aperture fractures is commonly expressed by the so called "cubic law." Several workers including Lomize³⁴, Snow³⁵, Louis³⁶ and Witherspoon *et al*³⁷ have developed the relationship. It is reproduced here as presented by Jones¹:

$$Q = 5.11 \times 10^6 \frac{H \Delta P w^3}{L \mu} \quad (6.1)$$

where:

- Q = flow rate (reservoir barrels/day)
- H = height of fracture face (feet)
- ΔP = pressure differential (psi)
- w = fracture aperture (inches)
- L = length of fracture face (feet)
- μ = fluid viscosity

Equation 6.1 applies to flow in smooth walled fractures. By analogy to pipe flow, the friction created by flow between rough-walled fractures would be expected to cause a deviation, expressible by a friction factor, f , of the form:

$$f = \frac{4 \Delta P w H^2 C}{L Q^2 \rho} \quad (6.2)$$

where:

- ρ = fluid density (pounds per cubic foot)
- C = unit conversion constant = 6.35×10^8 for the units of this discussion

Lomize studied flow in rough fractures fabricated by cementing quartz grains to smooth plates and found that the cubic law did not always apply. He correlated the deviation through friction factors, one for the laminar flow regime and another for the turbulent flow regime:

$$\text{laminar} \quad f = \frac{96}{N_{re}} \left[1 + 6.0 \left(\frac{e}{w} \right)^{1.5} \right] \quad (6.3)$$

$$\text{turbulent} \quad \sqrt{f} = \frac{1}{2.55 \log \left(\frac{2.48w}{e} \right)} \quad (6.4)$$

where:

e = fracture surface roughness (inches)

and Reynolds Number, N_{re} is a dimensionless group defined as:

$$N_{re} = \frac{496 R_h \rho V}{\mu} \quad (6.4)$$

where:

R_h = hydraulic radius, $w/2$ for fractures (inches)

V = fluid flow velocity (feet/second)

Louis, working with rough-walled fractures created from concrete slabs, developed similar friction factor relationships:

$$\text{laminar} \quad f = \frac{96}{N_{re}} \left[1 + 3.1 \left(\frac{e}{w} \right)^{1.5} \right] \quad (6.5)$$

$$\text{turbulent} \quad \sqrt{f} = \frac{1}{2 \log \left(\frac{3.8w}{e} \right)} \quad (6.6)$$

Jones attributed the coefficient differences to the authors' dissimilar treatments of roughness geometry. Figure 6.2.1, reproduced from the Jones paper, shows that the Lomize fractures are idealized while those of Louis are more realistic. It also illustrates the fundamental problem of how to determine fracture aperture and roughness for real fracture systems.

Jones used the pipe flow analogy to develop an equation for fracture flow using the friction factor to correct the pressure drop for the increase caused by fracture roughness.

$$Q = 5.06 \times 10^4 H \left[\frac{\Delta P w^3}{f L \rho} \right]^{\frac{1}{2}} \quad (6.7)$$

Noting that flow velocity, V is Q / wH and adjusting for units, Jones showed that Equation 6.7 reduces to the cubic law equation (Equation 6.1) in the case of flow in smooth walled, planar fractures for which the friction factor is $96 / N_{re}$.

Reiss³⁸ used Darcy's law to define fracture permeability:

$$k_f = \frac{10.65 Q L \mu}{H w \Delta P} \quad (6.8)$$

where k_f is fracture permeability in Darcies.

Thus, the permeability of a rough-walled fracture becomes:

$$k_f = 5.39 \times 10^5 \mu \left[\frac{w L}{f \Delta P \rho} \right]^{\frac{1}{2}} \quad (6.9)$$

Jones' experimental studies of naturally fractured sandstone concluded that the Cubic Law governs flow in large aperture fractures ($b > 0.0253$ inches) and that deviation increases as the aperture is diminished.

While the equations discussed thus far provide the basics of fracture fluid flow, their application requires a knowledge of fracture aperture and surface roughness. In practical cases these parameters are difficult, if not impossible to define. Furthermore, the effect of increasing confining stress has not yet been addressed.

Walsh³⁹ developed a useful model relating fracture conductivity (e.g. Darcy-feet) and confining stress. Warpinski *et al*⁴⁰ have expressed the Walsh model as:

$$K_f^n = A + B \ln \sigma_c \quad (6.10)$$

where A and B are constants, n is 1/3 and σ_e is the effective stress as defined by the effective stress law:

$$\sigma_e = \sigma - \alpha p \quad (6.11)$$

where:

- σ = confining stress (psi)
- α = poroelastic parameter
- p = pore pressure, psi

The main parameters controlling fracture conductivity at any pore pressure are B which controls the conductivity reduction and α which defines the stress law influence including the effect of hysteresis observed when the fracture is alternately loaded (increasing effective stress) and unloaded (reducing effective stress).

6.2.3 Fracture Permeability versus Pore Pressure

The experimental results published by Warpinski *et al* for North Sea fractured chalks provided the basis for the fracture permeability versus pore pressure function used in these simulation studies. The authors measured the conductivity of a core plug containing an axial fracture during repeated loading (increasing confining stress) and unloading (diminishing confining stress) cycles until a reproducible cycle was achieved. This process "seasoned" the sample and rendered the data suitable for interpretation. The authors point out that the in situ condition of the rock and fracture may differ from the "seasoned" sample condition. The procedure was performed at four levels of pore pressure.

The chalk fracture apertures were very small and permeabilities were in the microdarcy range. As a result, inertial/turbulence effects were quite noticeable, requiring all conductivity measurements to be corrected for turbulence. To make the correction, conductivities were measured at several flow rates and for selected levels of net stress. Flow rates were varied by adjusting upstream and downstream pressures such that average pore pressure remained constant. The intrinsic conductivity at each net stress point was computed by fitting the data to a modified form of the Forcheimer equation:

$$\frac{1}{K_f} = \frac{1}{K_{fi}} + bQ_{atm} \quad (6.12)$$

where K_{fi} , the intrinsic conductivity is defined by the intercept of $1 / K_f$ as a function of gas flow rate at atmospheric conditions, Q_{atm} . The slope, b, is related to the turbulence factor, β as follows:

$$\beta = b \frac{\mu h w^2}{\rho_{atm}} \quad (6.13)$$

The computed b values were surface-fitted as functions of confining stress, σ and pore pressure p , thus enabling conversion of measured conductivity, K_f to intrinsic conductivity, K_{fi} at any stress condition.

The corrected conductivity was transformed and fitted to a three dimensional surface of the form:

$$K_f' = X_1 + X_2\sigma + X_3P + X_4\sigma^2 + X_5\sigma P + X_6P^2 \quad (6.14)$$

where X_n are the fit coefficients and K_f' is the transformed conductivity:

$$K_f' = \left[\frac{K_f}{K_{fo}} \right]^\lambda \quad (6.15)$$

and

K_{fo} = maximum K_f for fitted data set (Darcy-feet)
 λ = transform parameter ($-3 < \lambda < +3$)

The poroelastic parameter, α , was evaluated from the fitted coefficients of the K_f' - σ - P surface as follows:

$$\alpha = - \frac{\left[\frac{\partial K_f'}{\partial P} \right]}{\left[\frac{\partial K_f'}{\partial \sigma} \right]} \quad (6.16)$$

$$\alpha = \frac{X_3 + X_5\sigma + 2X_6P}{X_2 + 2X_4\sigma + X_5P}$$

The TETRAD simulator expresses deformable fracture properties as exponential functions. Porosity is treated as a function of pore pressure and permeability is expressed as a function of porosity. The porosity relationship is:

$$\phi_f = \phi_{fo} \exp [c_f (P - P_o)] \quad (6.17)$$

where, c_f is fracture compressibility.

For permeability the function becomes:

$$k_f = k_{fo} \exp \left[\eta \frac{\phi_f - \phi_{fo}}{1 - \phi_{fo}} \right] \quad (6.18)$$

where, η is a fitting parameter.

The problem is reduced, therefore, to choosing values of c_f and η which best fit the computed fracture porosity versus pore pressure and permeability versus fracture porosity functions, respectively.

The fracture porosity and permeability functions required for TETRAD input were developed using the Warpinski *et al* coefficients, X_n . The procedure was as follows:

- a. Compute α from Equation 6.16 for stress conditions representative of the prototype reservoir.
- b. Compute K_f from the Walsh equation (Equation 6.10) for the same stress conditions. The cubic form of the equation was assumed, that is, $n = 1/3$ requiring the further modification of the coefficients to $A = 1.526$ and $B = 0.1368$
- c. Compute fracture permeability assuming that the conductivity ratio, K_f / K_{fo} for the derived function is equivalent to the permeability ratio, k_f / k_{fo} for the scaled function. Thus,

$$k_f = k_{fo} \frac{K_f}{K_{fo}}$$

where k_{fo} is the model fracture permeability at initial pore pressure conditions

- d. Compute fracture porosity, ϕ_f assuming that the cubic relationship pertains. Thus,

$$\phi_f = \phi_{fo} \left[\frac{K_f}{K_{fo}} \right]^{1/3}$$

where ϕ_{fo} is the model fracture porosity at initial pore pressure conditions.

- e. Compute the average fracture compressibility, c_f by fitting Equation 6.17 to porosity versus pore pressure.
- f. Determine the simulator input parameter, η , by fitting Equation 6.18 to the calculated permeability versus porosity function.

The fitting parameters were determined for two assumed stress conditions. The base case assumption was that the rock was lithostatically loaded, making all three components of the confining stress equal, that is, $\sigma_{xx} = \sigma_{yy} = \sigma_{zz}$ and

$$\sigma = \frac{(\sigma_{xx} + \sigma_{yy} + \sigma_{zz})}{3} \quad (6.19)$$

and

$$\sigma_{zz} = \gamma_o Z$$

where,

$$\gamma_o = \text{assumed overburden gradient} = 1.0 \text{ psi/foot}$$

and

$$Z = \text{average reservoir depth} = 6592 \text{ feet}$$

This resulted in a base case confining stress of 6592 psig.

The alternative confining stress case assumptions were:

$$\sigma_{zz} = 0.9Z$$

$$\sigma_{yy} = 0.75\sigma_{zz}$$

$$\sigma_{xx} = 1.1P_o$$

Substitution of these values in Equation 6.19 gave an alternate confining stress of 4560.8 psig.

The base case computed fracture porosity and permeability values are shown as functions of pore pressure on Figure 6.2.2. The basic assumed parameters were: confining stress of 6592 psi, initial pore pressure of 3000 psi, porosity at initial pore pressure of .000984 and permeability at initial pore pressure of 10 md. The points are the values derived from the Warpinski *et al* experimental data and the solid lines show the fitted form of Equations 6.17 and 6.18.

Figure 6.2.3 displays the same information for the alternate assumed confining stress of 4560.8 psi.

6.3 Well Performance Data

Horizontal well performance data, fluid production rates, bottom-hole measured pressures and wellhead pressures were provided by a field operator near the end of fiscal year one. The data were presented in the first Annual Report, but there was insufficient time to attempt to analyze the data. This has been done as part of the current year work.

This data provided daily rates of oil, gas, and water production for five horizontal well bores. Two of the wells, B-1 and B-2, were in the same multi-well lease while wells A-1, A-2 and P-1 are on single well leases. During selected periods measured bottom-hole pressures from wells equipped with surface readout devices were provided.

The daily production data were often highly variable making recognition of trends difficult. For this reason the data, excluding pressures, were smoothed by filtering in the frequency domain using a fast Fourier transform. The smoothed production data for wells A-1, A-2, B-1, B-2 and P-1 are shown on Figure 6.3.1 through Figure 6.3.5. The format and scale of these figures are the same as was used to display the raw data in the first Annual Report, Figures 7.3.1 through Figure 7.3.5.

6.3.1 Pressure Transient Analysis

Well B-1 was placed on continuous production on October 24, 1987. From that time through March 1, 1988 the production and pressure data show three cycles of drawdown followed by build-up. The chronology of the test during the stated time interval is summarized in Table 6.3.1.

Table 6.3.1
Well B-1 Well Test Chronology

Beginning Date	Ending Date	Well Activity
10/24/87	12/17/87	drawdown
12/18/87	12/29/87	shut-in
12/30/87	1/17/88	drawdown
1/18/88	1/29/88	shut-in
1/30/88	2/19/88	drawdown
2/20/88	3/01/88	shut-in

Figure 6.3.6 displays the production and pressure data for this time period on an expanded time scale. It clearly shows the three drawdown-build-up cycles. If the pressures are assumed to be rigorously periodic, that is, recorded at fixed 24-hour time increments, they should be amenable to conventional well test analysis.

The Automate II[†] computer-aided well test analysis software was used to match the observed pressure response by non-linear multiple regression. Four models of increasing complexity were tried to see which would best reproduce the observed pressure behavior:

- a) single porosity, storage and skin, vertical well
- b) single porosity with storage and skin, horizontal well with infinite conductivity well bore
- c) dual porosity, transient, storage and skin, vertical well
- d) dual porosity, transient, storage and skin, horizontal well with infinite conductivity well bore

Unfortunately, the pressure response was not sufficiently diagnostic to clearly indicate dual porosity behavior. The results of the Automate II regression computed pressures are compared to the measured data in Miller-Dyes-Hutchinson (MDH) format on Figures 6.3.7 (model a), Figure 6.3.8 (model b), Figure 6.3.9 (model c) and Figure 6.3.10 (model d). A visual inspection of these four plots reveals that there is little difference in the quality of the computed pressure matches. There are, however, significant differences in the matching parameters of interest: skin factor (S) and permeability (k) as are common to all models; transmissivity (λ) and storativity (ω) ratios rendered by the dual porosity models; and the vertical to horizontal

[†]© by Garrett Computing Systems, Inc.

permeability ratio (k_v / k_h) defined by the horizontal well models. Table 6.3.2 summarizes the parameters used for the illustrated pressure matches.

Table 6.3.2
Well B-1 Well Test Analysis Results

Parameter	Model a	Model b	Model c	Model d
C, stb/psi	0.128 $\pm$.075	0.538 $\pm$.056	0.287 $\pm$.087	0.647 $\pm$.058
S	-4.33 $\pm$.099	0.960 $\pm$.040	-7.17 $\pm$.039	.0023 $\pm$.171
kh, md-ft	101.8	164.1	57.6	147.0
k, md	0.585 $\pm$.020	0.547 $\pm$.002	0.192 $\pm$.008	0.490 $\pm$.002
k_v / k_h	n.a.	0.033 $\pm$.003	n.a.	0.258 $\pm$.072
λ	n.a.	n.a.	8.5E-8 $\pm$ 3E-10	7.6E-6 $\pm$ 3E-7
ω	n.a.	n.a.	7.1E-6 $\pm$ 3E-7	2.6E-4 $\pm$ 4E-5

The table includes the regression determined confidence interval for each parameter. Since a smaller confidence interval relative to the magnitude of the parameter implies a better determined result, one could conclude that permeability is best determined by either of the horizontal well models, b or d. Note, however, that model b assumes a single porosity medium, whereas, model d assumes the medium to be dual porosity. Skin factor is clearly best defined by model c which assumes a vertical well in a dual porosity medium, while permeability ratio, k_v / k_h , is better defined by the single porosity model b than the dual porosity model d. As to the dual porosity parameters, model c is superior for both transmissivity ratio (λ) and storativity ratio (ω).

Knowing that the well bore to be horizontal and the medium to be fractured, one would anticipate that model d should best fit the data. The comparison shows this to be insupportable.

On the basis of the number of parameters best defined, model c scores points for S, λ and ω , model b for k and k_v / k_h and model d for k only. Taken at face value, this scoring would favor model c as being most applicable with model b as a close second.

Upon inspection, the model c dual porosity parameters (λ and ω) seemed unreasonably small. Reasonable first estimates of fracture and matrix permeability, porosity and compressibility might be as follows:

$$\begin{aligned} k_f &= 0.5 \text{ md} \\ k_m &= 0.00001 \text{ md} \end{aligned}$$

$$\begin{aligned}
\phi_f &= .001 \\
\phi_m &= .03 \\
c_f &= 10^{-5} \text{ psi}^{-1} \\
c_m &= .5 \times 10^{-5} \text{ psi}^{-1}
\end{aligned}$$

By definition, transmissivity ratio is defined as:

$$\lambda = \sigma \frac{k_m}{k_f} r_w^2 \quad (6.20)$$

Referring to Section 9.3.4 of the first Annual Report, the shape factor, σ , could have a value as low as $2 / L^2$. Assuming fracture spacing of one foot ($L=1$) and a well bore radius (r_w) of .375 feet, λ could be as low as 2.8×10^{-4} . By contrast, the model λ is four orders of magnitude smaller.

The storativity ratio definition is:

$$\omega = \frac{\phi_f c_f}{(\phi_f c_f + \phi_m c_m)} \quad (6.21)$$

Therefore, a reasonable first estimate of ω would be 0.063. Again the model ω value is four orders of magnitude smaller.

The above observations bring into question the model c dual porosity parameters λ and ω . It would seem, therefore, that the observed pressure behavior is best represented by the b model, the homogeneous reservoir medium, horizontal well model. Thus, if it is assumed that the reservoir is actually of the dual porosity type and that the matrix permeability is very much less than the fracture permeability, it is reasonable to conclude that this test indicates a fracture permeability-thickness of about 160 md-ft and a skin factor of 1. No conclusion regarding k_f / k_m is drawn since this parameter is known to be very sensitive to placement of the horizontal well bore within the productive interval.

Attempts to make similar analyses of well B-2 test data were unsuccessful due to data irregularities. Pressure data for wells A-1, A-2 and P-1 were too sparse to be analyzed.

6.3.2 Well Test Simulation

Well B-1 pressure matches were attempted using both prototype simulators, vertical well and horizontal well, and both deformation options for fracture properties, standard and deform[†]. It was hoped the potentially more rigorous treatment allowed by the simulators might reveal the data to be more diagnostic of fracture deformation and multi-fracture swarm horizontal well behavior.

The matches obtained with the vertical models are shown on Figure 6.3.11 for the standard option and on Figure 6.3.12 for the deform option. In terms of quality, they are about equal and neither is particularly good. To obtain these matches it was necessary to allocate 100% of the production to the simulated swarm. The matching parameters, k_f and S , are displayed on each figure.

Figure 6.3.13 and Figure 6.3.14 show the horizontal model matches for the standard and deform option treatments, respectively. All production was withdrawn from two of the prototype fracture swarms via a 900-foot horizontal offset with an assumed flowing pressure gradient of 0.01 psi/ft. The build-up shapes are shown to be a slightly better matched but again, there is nothing to choose in the quality of the standard and deform option matches. A test match, assuming a single fracture swarm produced a pressure build-up almost identical to the vertical well model match. It is concluded that the slightly improved matches of build-up shape provide qualitative validation of the multiple fracture swarm, horizontal well model. The indistinguishable standard and deform option matches frustrated any conclusion regarding fracture deformation.

It is quite possible that the matches could be further improved if other reservoir data were changed, *e.g.* number of penetrated fracture swarms, swarm dimensions, well bore length, transmissivity ratio (λ), storativity ratio (ω) or k_v / k_h . This was not attempted because to have done so would not render the interpretation any more conclusive with regard to fracture deformation.

The k_f and S parameters used in each model to produce the matches are indicated on the appropriate illustration. The results for all four models are summarized in Table 6.3.3.

[†]With reference to fractures, "standard" infers $\partial k_f / \partial p = 0$, whereas "deform" infers $\partial k_f / \partial p \neq 0$.

Table 6.3.3
Well B-1 Test Data Simulation Match Parameters

Parameter	Vertical Standard	Vertical Deform	Horizontal Standard	Horizontal Deform
S	15.2	10.4	3.55	2.53
kh, md-ft	870.	940.	371.	411.
k, md	25.0	27.0	5.80	6.42
k_v / k_h	0.1	0.1	0.1	0.1
λ	6.75E-6	6.25E-6	2.91E-5	2.63E-4
ω	0.314	0.335	0.314	0.335

Since the test well bore is known to be horizontal, the simulation matches suggest fracture permeability-thickness of about 400 md-ft and a skin factor around 3.

7.0 RESERVOIR SIMULATION

The basic reservoir simulators used in the current year work are identical to those initialized in year one. Their characteristics are fully described in Sections 9.1 and 9.2 of the first Annual Report and will not be repeated here. A brief summary of their essential features is provided by way of introduction.

All Task 2 case studies were performed on one of four models patterned after the Schnerk⁷ and Lichtenberger¹⁰ Austin Chalk conceptual model described in Section 7.2 of the first Annual Report:

- (1) horizontal well natural depletion (horizontal depletion).
- (2) horizontal well secondary recovery (horizontal injection).
- (3) vertical well natural depletion (vertical depletion).
- (4) vertical well secondary recovery (vertical injection).

All four models simulated a 640-acre rectangular reservoir segment. The major fractures were assumed to be vertical, parallel and of unlimited length. The fractures were further assumed to develop in "swarms" of constant width. The simulators excluded the impermeable rock intervening the fracture swarms; however, the horizontal well flowing pressure gradients were adjusted to compensate.

The simulation grid was oriented so fracture strike paralleled the Y-axis (long axis) of the reservoir segment. Thus, a horizontal well paralleling the X-axis could drain all fracture swarms included in the segment. Conversely, a vertical well could only drain a single-fracture swarm.

The horizontal depletion model employs a single horizontal well bore along the segment central X-axis (horizontal length; 3,733.5 feet). Communication between fracture swarms exists only in the well bore. The model is schematically depicted by Figure 9.1.1 of the first Annual Report. The horizontal injection model adds horizontal injection wells along both Y-direction boundaries of the reservoir segment. This arrangement is illustrated by Figure 9.1.3 of the same report.

The vertical depletion model simulates a single fracture swarm produced through a central vertical well. Thus, it has a reduced X-direction length equal to the width of one fracture swarm but the same Y-direction length as the horizontal model. This model is depicted in Figure 9.1.2 of the first Annual Report. The vertical injection model, depicted by Figure 9.1.4 in the same report, is basically the vertical depletion model with vertical injection wells added at either Y-direction boundary.

7.1 Fracture Permeability and Porosity

The essential difference between the Task 1 (year one) and Task 2 (current year) simulations lies in the treatment of fracture permeability and porosity, the basis of which has been described in Section 6.2.3. The terms "deform" or "deform option" are used to refer to this treatment. The following table contrasts the standard and deform option treatments of fracture properties as used in this study. For convenience, the f subscripts have been omitted.

	Standard	Deform Option
Permeability	constant	$k = k_o \exp \left[\eta \frac{\phi - \phi_o}{1 - \phi_o} \right]$
Exponent, η	not used	$\eta = f(\sigma)$
Porosity	$\phi = \phi_o [1 + c(p - p_o)]$	$\phi = \phi_o \exp [c(P - P_o)]$
Compressibility	7.821×10^{-5}	$c = f(\sigma)$

The discussion following Equation 6.16 and Equation 6.17 in Section 6.2 explains that η and c_f were determined for two conditions of confining stress, 6592 and 4560.8 psig. The values best fitting the data were:

σ , psig	η	c_f
6592.0	3260.5	8.614×10^{-5}
4560.8	3545.8	12.99×10^{-5}

The remainder of the report describes the rather large number of cases simulated in the course of the past year. For each reservoir variant there were three variations of fracture permeability and porosity:

1. *Standard permeability and porosity option.* This was the basic Task 1 assumption; therefore, many of these cases were completed in year one, including all vertical and horizontal model natural depletion cases. Fewer injection cases were completed, mainly because the Task 1 scope excluded horizontal well usage, but also because time constraints permitted only four cases for each combination of injected fluid (water only, gas only, gas and water). This left a sizeable number of injection cases to be completed as part of the current year work effort. All cases in this category have the name prefix **DPCK** signifying dual porosity and constant k.
2. *Deform option permeability & porosity, $\sigma=6592$ psig.* This and the next category are entirely Task 2 work. The name prefix **DPVK** for dual porosity and variable k

distinguishes these cases. The name suffixes are the same as DPCK cases having the same basic reservoir properties. Thus, Case DPCK_H1A and Case DPVK_H1A differ only in respect to fracture permeability and porosity treatment.

3. *Deform option permeability & porosity, $\sigma=4560.8$ psig.* The name prefix of these cases follows the above convention, but new suffixes were required for uniqueness.

The case name suffix is comprised of three characters: two letters and one digit. One of the letter positions is reserved to signify the model type: an H for the horizontal well model or a V for the vertical well model. The second letter uniquely identifies the reservoir parameter variant. The digit is used to indicate the producing well completion layer: 1 for middle layer ($K=3$), 2 for bottom layer ($K=5$), and 3 for top layer ($K=1$).

7.2 Primary Recovery Forecasts for a Horizontal Well

The base case horizontal depletion model incorporating the deform option for $\sigma=6592$ psig is Case DPVK_H1A and for $\sigma=4560.8$ psig is Case DPVK_H1B. In all other respects the reservoir data defining these cases were identical to Case DPCK_H1A described in the first Annual Report. By way of review, these models regarded the reservoir segment as seven identical vertical fracture swarms, isolated from each other by transmissibility discontinuities and penetrated by a single horizontal well bore whose axis is perpendicular to the fracture swarm strike.

Most of the reservoir parameters investigated in year one were repeated with the deform option enabled. The parameters not included were shape factor, fracture block size, and dual permeability. Parameters which were investigated were:

- relative conductivity, k_m / k_f , k_f constant
- relative conductivity, k_m / k_f , k_m constant
- relative storativity, ϕ_m / ϕ_f , ϕ_f constant
- relative storativity, ϕ_m / ϕ_f , ϕ_m constant
- matrix capillary pressure
- fracture capillary pressure
- fracture relative permeability, k_{rg} & k_{rog}

The presentation in this discussion emphasizes the effect of confining stress on oil recovery for each of the above listed reservoir parameters and makes no comparisons on the basis of reservoir parameter variation per se. The sensitivity of recovery to reservoir parameter variability was the focus of the year one studies and none of the current work was found to be contradictory to those findings.

A total of 34 cases were required to demonstrate the sensitivity of the various reservoir parameters to the effect of confining stress. As in year one, cases were terminated when the oil-producing rate fell below 25 STB/day.

7.2.1 Base Case

The base cases incorporating the deform option are named DPVK_H1A and DPVK_H1B. The Case DPVK_H1A deform input variables corresponded to a confining stress of 6592 psig. In every other respect it was identical to its namesake, DPCK_H1A. Case DPVK_H1B used the deform input variables for 4560.8 psig.

Figure 7.2.1 compares the two DPVK cases to the standard permeability and porosity Case DPCK_H1A. The effect of the deform option is shown to be a reduction of producing rate during most of the case duration. The main consequence, however, is a prolongation of the recovery time period, as the impact on overall recovery appears quite small. The recovery comparisons are better quantified in Table 7.2.1.

Table 7.2.1
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, Base Case Reservoir Definition

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1A
DPCK_H1A	n.a.	234.9	16.37	-
DPVK_H1A	6592.0	231.7	16.14	-1.41
DPVK_H1B	4560.8	232.4	16.19	-1.10

7.2.2 Relative Conductivity (matrix/fracture)

The ratio of matrix permeability to fracture permeability in the base case model was .0001/10 or 10^{-5} . The next series of runs looked at the recovery-confining stress implications of order of magnitude changes: either to 10^{-4} or to 10^{-6} . The changes were effected first by changing the matrix permeability at constant fracture permeability and then by revising fracture permeability at constant matrix permeability.

The performance plots comparing the results for the 10^{-4} cases are Figure 7.2.2 (k_f constant, Case H12 and Case H1G) and Figure 7.2.3 (k_m constant, Case H1F and Case H1D). Both show rate reductions for the deform option cases that more or less parallel the standard permeability option results. Thus, there is a more noticeable recovery reduction due to the deform option than

was observed for the base case. Table 7.2.2 and Table 7.2.3 quantify the reductions in terms of recovery factor and percent change.

Table 7.2.2
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $k_m / k_f = .001/10 = 10^{-4}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H12
DPCK_H12	n.a.	163.4	11.38	-
DPVK_H12	6592.0	155.4	10.83	-4.83
DPVK_H1G	4560.8	152.9	10.65	-6.41

Table 7.2.3
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $k_m / k_f = .0001/1 = 10^{-4}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1F
DPCK_H1F	n.a.	150.8	10.50	-
DPVK_H1F	6592.0	140.1	9.76	-7.05
DPVK_H1D	4560.8	136.3	9.50	-9.52

Figure 7.2.4 and Figure 7.2.5 and the like numbered tables offer the same type of comparisons for the cases with k_m / k_f of 10^{-6} . The performance plots show more pronounced differences between the standard and deform options, particularly the constant k_m cases for which k_f was increased to 100 md, Case H1K and Case H1F. While these differences persist for much of the recovery life, the ultimate recovery is essentially independent of how fracture deformation is treated. There is, nonetheless, a small recovery increment for the higher fracture permeability alternatives, Case H1K and Case H1E, and obviously these cases recover the oil at much accelerated rates over Case H13 and Case H1H.

Table 7.2.4
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $k_m / k_f = .00001/10 = 10^{-6}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H13
DPCK_H13	n.a.	249.8	17.40	-
DPVK_H13	6592.0	249.4	17.37	-0.17
DPVK_H1H	4560.8	251.8	17.54	+0.80

Table 7.2.5
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $k_m / k_f = .0001/100 = 10^{-6}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1K
DPCK_H1K	n.a.	253.6	17.66	-
DPVK_H1K	6592.0	253.6	17.67	-0.06
DPVK_H1E	4560.8	255.3	17.79	+0.74

The results for this series of cases show that an order of magnitude increase in relative conductivity, as done for Case H12 and Case H1G and Case H1F and Case H1D, has a much greater negative effect on cumulative oil recovery than the positive effect of an order of magnitude reduction, as in Case H13 and Case H1H and Case H1K and Case H1E. In other words, reducing the contrast between fracture and matrix permeability tends to reduce oil recovery more rapidly than increasing the contrast increases oil recovery.

7.2.3 Relative Storativity (fracture/matrix)

The base case storativity ratio, ϕ_f / ϕ_m fracture porosity was $0.000984/0.033594 = 0.0293$. In the next series of cases, this ratio was altered to be either one-half or four times as great. Again, there were two possibilities: either change the fracture value and keep the matrix value constant, or change the matrix and leave the fracture values unchanged.

Modification of porosity, particularly matrix porosity, would directly impact model oil-in-place and well performance. To avoid this problem and keep total oil-in-place approximately the same from case to case, net thickness was adjusted to offset the matrix porosity change. The

modification of net thickness required a further, reciprocal modification of permeability to retain the same transmissibility from case to case. As oil-in-place in the fracture was a small part of the total in-place volume, no compensatory changes were made for cases with modified fracture porosity,

The halved storativity ratio cases are Case H14 and Case H1I for which $\phi_f / \phi_m = .000492/.033594$ and Case H1P and Case H1L for which $\phi_f / \phi_m = .000984/.067188$. Oil recovery performance for the Case H14 and Case H1H combination is shown on Figure 7.2.6 and for the H1P/H1L combination on Figure 7.2.7. Table 7.2.6 and Table 7.2.7 provide the numerical comparison of recovery. The two sets of cases are shown to be very nearly the same, suggesting that the effect storativity ratio has on recovery is independent of which porosity is varied. Furthermore, neither alternative is particularly sensitive to deformation effects, although the rate at which oil is recovered is seen to be adversely impacted as confining stress is reduced.

Table 7.2.6
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $\phi_f / \phi_m = .000492/.0336$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H14
DPCK_H14	n.a.	225.7	16.05	-
DPVK_H14	6592.0	224.5	15.96	-0.56
DPVK_H1I	4560.8	224.5	15.96	-0.56

Table 7.2.7
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $\phi_f / \phi_m = .000984/.0672$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1p
DPCK_H1P	n.a.	230.4	16.05	-
DPVK_H1P	6592.0	228.7	15.93	-0.75
DPVK_H1L	4560.8	228.9	15.95	-0.62

The cases with quadrupled storativity ratio are Case H15 and Case H1J ($\phi_f / \phi_m = .003936/.033594$) and Case H1M and Case H1N ($\phi_f / \phi_m = .000984/.0083985$). Table 7.2.8,

Table 7.2.9, Figure 7.2.8, and Figure 7.2.9 summarize, respectively, these sets of cases. The recovery performance graphs show that quadrupling ϕ_f or quartering ϕ_m also yields very similar results, suggesting again that storativity ratio is the correlating parameter. In contrast to the halved storativity set of cases, these cases are shown to be highly sensitive to confining stress. The differences are quantified in the tables and shown to be quite significant.

Table 7.2.8
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $\phi_f / \phi_m = .00394/.0336$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H15
DPCK_H15	n.a.	280.9	17.47	-
DPVK_H15	6592.0	260.2	16.17	-7.44
DPVK_H1J	4560.8	249.3	15.50	-11.28

Table 7.2.9
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $\phi_f / \phi_m = .000984/.008340$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1M
DPCK_H1M	n.a.	250.8	17.47	-
DPVK_H1M	6592.0	234.2	16.31	-6.64
DPVK_H1N	4560.8	228.5	15.92	-8.87

7.2.4 Fracture Capillary Pressure

The base case formulation assumed capillary pressure to be nonexistent in the fractures. Sensitivity to this assumption and the magnitude of fracture capillary pressure was investigated in the year one Case H16 and Case H17. These cases assumed fracture oil-water and gas-oil capillary pressure to be simple fractions of matrix values: one half for Case H16 and two tenths for Case H17. The same assumptions were made for the deform option Case H23 and Case H24, respectively.

The effect of the deform option when fracture capillary pressure is non-zero is illustrated by Figure 7.2.10 ($p_{cf} = .5p_{cm}$) and Figure 7.2.11 ($p_{cf} = .2p_{cm}$). In form, both illustrations are quite similar to the base case deform option, as displayed on Figure 7.2.1. A lowering of the production rate is evident over most of the recovery period, resulting in prolongation of the time-recovery function; however, the eventual recovery fraction is shown to be essentially independent of stress. The latter observation is borne out by the recovery numbers given in Table 7.2.10 and Table 7.2.11.

Table 7.2.10
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $p_{cf} = .5p_{cm}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H16
DPCK_H16	n.a.	252.8	17.72	-
DPVK_H16	6592.0	252.3	17.68	-0.23
DPVK_H23	4560.8	254.3	17.82	+0.56

Table 7.2.11
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $p_{cf} = .2p_{cm}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H17
DPCK_H17	n.a.	242.2	16.91	-
DPVK_H17	6592.0	240.2	16.77	-0.83
DPVK_H24	4560.8	241.5	16.87	-0.24

Comparing the above results to the base case numbers (Table 7.2.1) clearly shows that oil recovery is increased as fracture capillary pressure is increased.

7.2.5 Matrix Capillary Pressure

Sensitivity of oil recovery to matrix capillary pressure was tested by the year one Case DPCK_H1Q and Case DPCK_H1R. Case H1Q used capillary pressure functions of the same shape as the base case but shifted to remove the threshold capillary pressures, that is, the

oil-water capillary pressure at 100% wetting saturation was reduced from 1.99 to 0. psig. The function had the same form as the base case:

$$\frac{1}{P_{cm}} = a(S_w) + b$$

where S_w is water saturation and a and b are coefficients. The removal of the threshold was a simple matter of adjusting the b coefficient.

The Case H1R capillary pressure function shapes were altered to the more "L-shaped" curves shown on first Annual Report Figure 9.3.22 and Figure 9.3.23. The threshold capillary pressure was removed, as it was for Case H1Q and the oil-water function form was changed to:

$$\frac{1}{P_{cm}^2} = a(S_w) + b$$

For both cases, the gas-oil capillary pressure function was computed from the oil-water function in proportion to the ratio of interfacial tensions, as is explained in Section 9.2.2 of the first Annual Report.

Figure 7.2.12 shows the results obtained for the H1Q data set (Case H1Q and Case H1S). Deformation is shown to reduce rate of recovery, much as it did in the base case. As time progresses, however, the curves cross so that ultimate recovery increases slightly in an inverse relationship to net confining stress. Table 7.2.12 gives the magnitude of the recovery improvement.

Table 7.2.12
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $1 / p_{cm} = f(S_w)$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1Q
DPCK_H1Q	n.a.	243.2	16.94	-
DPVK_H1Q	6592.0	247.9	17.27	+1.95
DPVK_H1S	4560.8	250.0	17.41	+2.77

Figure and Table 7.2.13 show that the H1R data set gave a similar result (Case H1R and Case H1T); however, the recovery factor differences are diminished.

Table 7.2.13
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, $1 / p_{cm}^2 = f(S_w)$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H1R
DPCK_H1R	n.a.	250.2	17.43	-
DPVK_H1R	6592.0	249.7	17.39	-0.23
DPVK_H1T	4560.8	252.1	17.56	+0.75

7.2.6 Fracture Relative Permeability

The base case and all cases discussed thus far employed linear relative permeabilities with zero or unity endpoint values for the fracture system. The base case further assumed zero capillary pressure. Other relative permeability and capillary pressure combinations were investigated during year one by Cases H30 through H33. The functions used are fully described by Section 9.3.9 and Figures 9.3.14 through 9.3.17 in the prior Annual Report. During the current year, the same series of cases was repeated with the deform option invoked. This required four additional cases to accommodate the lower confining stress alternative. The following Table 7.2.14a summarizes key property differences for this series of cases in comparison to the base cases, H1A and H1B.

Table 7.2.14a
Comparison of Relative Permeability Function Shapes and Endpoints

Case	S_{wi}	Shape	S_{orw}	S_{org}	$(p_{ct})_{ow}$	$(p_{ct})_{goer}$
H1A,H1B	0.30	linear	0.	0.	0.	0.
H30,H34	0.06	linear	0.056	0.032	0.5930	0.0502
H31,H35	0.15	linear	0.140	0.080	1.4825	0.1256
H32,H36	0.06	curved	0.056	0.032	0.5930	0.05024
H33,H37	0.15	curved	0.140	0.080	1.4825	0.1256

The endpoint values (S_{wi} , S_{or} , p_{ct}) for Case H30 (also Case H34) and Case H32 (also Case H36) were 0.2 of the rock matrix values. The two functions differ with respect to shape: linear for Case H30 and Case H34 versus curvilinear for Case H32 and Case H36. The results for the cases using these data are presented by Figure 7.2.14 and Table 7.2.14b for the linear k_r functions and by Figure and Table 7.2.15 for the curvilinear functions. Both figures show the now familiar pattern of production rate degradation as a consequence of fracture deformation first seen in the base cases. The linear function rate decline (Figure 7.2.14) closely follows that of base case (Figure 7.2.1) for most of its duration, but eventually crosses over to yield a small recovery increment. The curvilinear function decline (Figure 7.2.15) is more severe than, but similar in character to, the base case but eventually reaches about the same ultimate recovery level.

Table 7.2.14b
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, fracture k_r & p_c
(linear k_r : p_c , S_{wi} & S_{or} = 0.2 of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H30
DPCK_H30	n.a.	238.7	16.67	-
DPVK_H30	6592.0	236.4	16.51	-.096
DPVK_H34	4560.8	237.8	16.61	-0.36

Table 7.2.15
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, fracture k_f & p_c
(curvilinear k_f : p_c , S_{wi} & $S_{or} = 0.2$ of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H32
DPCK_H32	n.a.	233.0	16.27	-
DPVK_H32	6592.0	229.5	16.02	-1.54
DPVK_H36	4560.8	229.2	16.00	-1.66

The endpoints for Case H31 and Case H35, and Case H33 and Case H37 were increased to one half of matrix values. Again, the functions differed with respect to shape: linear for H31/H35, curvilinear for Case H33 and Case H37. These cases are summarized by Figure and Table 7.2.16 (linear) and 7.2.17 (curvilinear). The rate degradations shown by these figures are very similar to the series just discussed (*c.f.* Figures 7.2.14 and 7.2.16 or Figures 7.2.15 and 7.2.17) but they ultimately recover a little more oil. The recovery increment is seen by comparing Table 7.2.16 to Table 7.2.14 (linear k_f) or Table 7.2.17 to Table 7.2.15 (curvilinear k_f).

Table 7.2.16
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, fracture k_f & p_c
(linear k_f : p_c , S_{wi} & $S_{or} = 0.5$ of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H31
DPCK_H31	n.a.	243.4	17.06	-
DPVK_H31	6592.0	243.2	17.05	-0.06
DPVK_H35	4560.8	245.3	17.19	+0.76

Table 7.2.17
Oil Recovery Sensitivity to Confining Stress
Horizontal Depletion Model, fracture k_f & p_c
(curvilinear k_f : p_c , S_{wi} & $S_{or} = 0.5$ of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_H33
DPCK_H33	n.a.	237.3	16.66	-
DPVK_H33	6592.0	236.3	16.56	-0.60
DPVK_H37	4560.8	237.4	16.64	-0.12

7.3 Primary Recovery Forecasts for a Vertical Well

All natural depletion sensitivity cases described in Section 7.2 were also run on the vertical natural depletion model with the minimum rate constraint reduced to 1 STB/day. The vertical model case names are identical to those of the horizontal model, but the letter "V" was substituted for "H" in the name suffix.

The results obtained from the vertical model simulations are not individually discussed in this report because their characteristics were so similar to the horizontal model results. Detailed discussion of each case, or even groups of cases would have been quite redundant.

The vertical model simulation results are displayed in Figure 7.3.1 through Figure 7.3.17 in the same format and sequence as used in Section 7.2, the horizontal model discussion. By appropriate pairing of figures, the vertical model oil production rates and gas-oil ratios can be seen to have the same general characteristics as those of the corresponding horizontal model results. Two exceptions to this general agreement, are the altered fracture permeability series: Case V1F and Case V1D versus Case H1F and Case H1D, and Case V1K and Case V1E versus Case H1K and Case H1E.

The first exception can be seen if Figure 7.2.3 and Figure 7.3.3 are compared. It is evident that the vertical model 1 STB/d rate cut-off is far less restrictive than the 25 STB/d used for the horizontal model. In fact, this observation is generally true and explains the usually higher vertical model recovery factors.

The second exception arises if Figure 7.2.5 and Figure 7.3.5 are compared. The difference here is in the shape of the rate-recovery curves, the vertical model decline being more pronounced in the first part of the recovery period and much less precipitous in the later stages, and attributable to the characteristics of the two well types. The exaggeration of k_m / k_f in these cases serves to amplify these characteristic differences.

Vertical model case tabulations comparable to those presented in Section 7.2 are not presented. Instead Table 7.3.1 directly compares vertical model oil recovery factors versus the comparable horizontal model values for all deform option cases (name prefix: DPVK). If Case V1F and Case V1D are excepted, the comparison shows that the vertical model - horizontal model recovery differentials are all less than 0.33% of STOIP. A similar tabulation for the standard option fracture permeability cases (name prefix: DPCK) may be found in the first Annual Report, Table 9.4.2.

Table 7.3.1
Comparison of Oil Recovery Factors
For Horizontal and Vertical Model Cases
Recovery Basis - fraction of oil-in-place

Vertical Case	Vertical Oil Recovery	Horizontal Oil Recovery	Horizontal Case
V1A	0.1630	0.1614	H1A
V1B	0.1631	0.1619	H1B
V12	0.1086	0.1083	H12
V1G	0.1064	0.1065	H1G
V1F	0.1071	0.0976	H1F
V1D	0.1047	0.0950	H1D
V13	0.1765	0.1737	H13
V1H	0.1786	0.1754	H1H
V1K	0.1774	0.1767	H1K
V1E	0.1795	0.1779	H1E
V14	0.1607	0.1596	H14
V1I	0.1613	0.1596	H1I
V1P	0.1607	0.1593	H1P
V1L	0.1609	0.1595	H1L
V15	0.1622	0.1617	H15
V1J	0.1526	0.1550	H1J
V1M	0.1650	0.1631	H1M
V1N	0.1581	0.1592	H1N
V16	0.1795	0.1768	H16
V23	0.1814	0.1782	H23
V17	0.1695	0.1677	H17
V24	0.1705	0.1687	H24
V1Q	0.1751	0.1727	H1Q
V1S	0.1769	0.1741	H1S

Table 7.3.1
Comparison of Oil Recovery Factors
For Horizontal and Vertical Model Cases
Recovery Basis - fraction of oil-in-place

Vertical Case	Vertical Oil Recovery	Horizontal Oil Recovery	Horizontal Case
V1R	0.1767	0.1739	H1R
V1T	0.1787	0.1756	H1T
V30	0.1666	0.1651	H30
V34	0.1674	0.1661	H34
V32	0.1624	0.1602	H32
V36	0.1623	0.1600	H36
V31	0.1717	0.1705	H31
V35	0.1734	0.1719	H35
V33	0.1681	0.1656	H33
V37	0.1692	0.1664	H37

7.4 Secondary Recovery Forecasts for a Horizontal Well

The secondary recovery simulations performed in year one were done on the vertical well injection model. Three types of secondary recovery were investigated: water injection, gas injection, and combined injection of gas and water. The results clearly demonstrated that water injection was the most beneficial of the three processes; therefore, the current year work has focussed on the water injection alternative alone.

Although not used in the simulations of year one, the horizontal well injection model was initialized as described in Section 9.1 of the first Annual Report. That model was used for the simulations discussed in this section.

The improved recovery potential of a line drive water flood was tested using two fully penetrating horizontal wells: a producing well completed in the uppermost model layer and an offsetting injection well completed in the lowermost model layer. Referring to Figure 9.2.2 (first

Annual Report), the producing well was positioned along the first row ($J = 1$) and within the top layer ($K = 1$), while the injection well was located along the last row ($J = 9$) and within the bottom layer ($K = 5$). Since this model represented a symmetrical element of the basic pattern, each well was regarded as a half-well for rate allocation.

The sensitivity of water injection behavior to reservoir parameter variation, including confining stress, was investigated. The list of parameters and variants, thereof, was the same as natural depletion cases described in Section 7.2.

The presentation of results which follows emphasizes the effect of confining stress on oil recovery since that is the objective of the current year tasks. Thus, comparisons of recovery on the basis of reservoir parameter variability, such as those presented in the first Annual Report, are not provided and must be visualized by the reader. Typically, two variants were simulated for each reservoir property: the one higher than the base case, the second lower than the base case. To facilitate visual comparisons of this sort, the related performance graphs are paired on the same page, one above the other.

A total of 39 cases were required to demonstrate the sensitivity of the various reservoir parameters to the effect of confining stress. Each case was terminated when the oil-producing rate fell below 25 STB/day. The same limitation applied to the natural depletion cases.

7.4.1 Base Case

The injection model base case is named DPCK_IH3. Its reservoir parameters were all identical to the base case natural depletion model, DPCK_H1A. Both models used the standard option treatment of fracture porosity and permeability. They differed only with respect to Y-direction grid block size and well completion placement.

The injection model base cases incorporating the deform option are named DPVK_IH3 and DPVK_BH3. Case DPVK_IH3 deform input variables were for a confining stress of 6592 psig. In every other respect it was identical to its namesake, DPCK_IH3. Case DPVK_BH3 used deform input variables for 4560.8 psig.

The oil-producing rate and water cut behavior of all three base cases are plotted versus oil recovery fraction on Figure 7.4.1. The impact of the deform option is much less pronounced than it was shown to be for natural depletion (Figure 7.2.1). Indeed, the only noticeable differences are the modest rate reductions during the first 2-3% of oil recovery and the somewhat earlier water breakthroughs. The ultimate recovery comparison provided in Table 7.4.1. shows an almost insignificant increase in ultimate recovery with increasing deformation.

Table 7.4.1
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, Base Case Reservoir Definition

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_IH3
DPCK_IH3	n.a.	717.2	49.96	-
DPVK_IH3	6592.0	722.3	50.31	+0.70
DPVK_BH3	4560.8	719.4	50.11	+0.30

7.4.2 Relative Conductivity (matrix/fracture)

This series of runs investigated order of magnitude changes in matrix permeability to fracture permeability ratio. The ratios were varied exactly as they were for natural depletion: first by changing the matrix permeability at constant fracture permeability and then by revising fracture permeability at constant matrix permeability.

The performance plots presenting the $k_m / k_f = 10^{-4}$ results are Figure 7.4.2 (Case UH3 and Case GH3 with k_m increased to .001 md) and Figure 7.4.3 (Case FH3 and Case DH3 with k_f reduced to 1 md). Both plots show that the deform option exacerbates the initial rate decline and accelerates water breakthrough. Both effects are quite modest, however. After the initial rate decline, both figures show that the production rate was independent of confining stress and maintained at a level in proportion to the fracture permeability. Obviously, this order of magnitude productivity difference resulted in prolongation of the low k_f cases, FH3 and DH3. This plateau period continued until water breakthrough at around 35-37% recovery. Thereafter, water cut increased and oil rate declined until the minimum rate constraint of 25 STB/d was reached. Table 7.4.2 and Table 7.4.3 quantify the ultimate differences in terms of recovery fraction and percent change from the standard option (DPCK) case.

Table 7.4.2
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $k_m / k_f = .001/10 = 10^{-4}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_UH 3
DPCK_UH3	n.a.	795.0	55.37	-
DPVK_UH3	6592.0	804.3	56.02	+1.17
DPVK_GH3	4560.8	811.1	56.50	+2.04

Table 7.4.3
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $k_m / k_f = .0001/1 = 10^{-4}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_FH3
DPCK_FH3	n.a.	738.6	51.45	-
DPVK_FH3	6592.0	746.4	51.99	+1.05
DPVK_DH3	4560.8	746.5	52.00	+1.07

While the increased k_m cases yielded a somewhat higher recovery than the reduced k_f cases, the performance plots show that both have essentially the same cut-recovery curve.

The Figure and Table number pairs, 7.4.4 and 7.4.5, offer related comparisons for the ratio: $k_m / k_f = 10^{-6}$. The performance plots show even less pronounced and probably insignificant differences between the standard and deform options, particularly for the 100 md k_f Case KH3 and Case EH3 (Figure 7.4.5).

The reduced k_m , Case VH3 and Case HH3 (Figure 7.4.4) experienced water breakthrough around 2% oil recovery. Prior to that, the rates declined, much as they did in the base cases. After breakthrough, the rate levelled briefly and then began a prolonged, largely monotonic decline, eventually reaching 40% recovery.

The increased k_f cases, KH3 and EH3 (Figure 7.4.5), experienced water breakthrough after 5% cumulative recovery. The production rates did not decline initially and remained constant until

the point of breakthrough. Thereafter, the rates began a very prolonged, gradually steepening decline versus recovery. The ultimate recoveries of these cases eventually reached or exceeded 50% of oil-in-place.

Table 7.4.4
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $k_m / k_f = .00001/10 = 10^{-6}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_VH3
DPCK_VH3	n.a.	524.4	39.31	-
DPVK_VH3	6592.0	566.8	39.48	+0.43
DPVK_HH3	4560.8	569.7	39.68	+0.94

Table 7.4.5
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $k_m / k_f = .0001/100 = 10^{-6}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_KH3
DPCK_KH3	n.a.	726.9	50.63	-
DPVK_KH3	6592.0	721.5	50.25	-0.75
DPVK_EH3	4560.8	726.2	50.58	-0.10

The following observations arise when these cases are compared to the base cases.

1. Given fixed k_f of 10 md, an order of magnitude k_m increase, as done for Case UH3 and Case GH3, gave about 5% more recovery. Conversely, an order of magnitude k_m decrease (Case VH3 and Case HH3) yielded about 10% less recovery.
2. Given fixed k_m of .0001 md, an order of magnitude k_f increase provided no recovery improvement. Conversely, an order of magnitude k_f decrease improved oil recovery about 2%.
3. Raising the ratio of k_m to k_f by one order of magnitude improved oil recovery. The recovery improvement was 5% when the change was effected by increasing k_m

(Case UH3 and Case GH3) and only 2% when done by reducing k_f (Case FH3 and Case DH3).

4. Reducing the k_m / k_f ratio one order of magnitude by reducing k_m (Case VH3 and Case HH3) recovered 10% less oil. When the ratio was changed by increasing k_f (Case KH3 and Case EH3), the recovery was comparable to the base case.

Expressed another way, the last two observations indicate that reducing the contrast between matrix and fracture permeability results in oil recovery improvement, whereas increasing the contrast results in either no change or a reduction of recovery. These results are contrary to the correlative natural depletion cases.

7.4.3 Relative Storativity (fracture/matrix)

This series of cases undertook to determine how water flood recovery would be impacted when the ϕ_f / ϕ_m was halved or quadrupled. The combinations of ϕ_f and ϕ_m and compensating net thickness and permeability changes were identical to those described in Section 7.2.3 for natural depletion.

The one half reduction of ϕ_f / ϕ_m was done for Case WH3 and Case YH3 by halving fracture porosity ($\phi_f = .000492$) and for Case PH3 and Case LH3 by doubling matrix porosity ($\phi_m = .0672$). The results, illustrated by Figure 7.4.6 and Figure 7.4.7, respectively, show almost identical recovery performance patterns and very little sensitivity to deformation stress level. The ultimate recoveries given in Table 7.4.6 and Table 7.4.7 reinforce these observations.

Table 7.4.6
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $\phi_f / \phi_m = .000492/.0336$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_WH 3
DPCK_WH3	n.a.	684.5	48.66	-
DPVK_WH3	6592.0	687.2	48.85	+0.39
DPVK_YH3	4560.8	687.1	48.84	+0.37

Table 7.4.7
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $\phi_f / \phi_m = .000984/.0672$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_PH3
DPCK_PH3	n.a.	701.6	48.87	-
DPVK_PH3	6592.0	705.3	49.13	+0.53
DPVK_LH3	4560.8	705.6	49.15	+0.57

The four times increase of ϕ_f / ϕ_m was accomplished in Case XH3 and Case JH3 by quadrupling fracture porosity ($\phi_f = .003936$) and for Case MH3 and Case NH3 by quartering matrix porosity ($\phi_m = .00834$). The results are illustrated in respective order by Figure 7.4.8, Figure 7.4.9, Table 7.4.8, and Table 7.4.9. Both alternatives perform about the same; however, the XH3/JH3 set shows plateau oil production rate and water breakthrough time to be somewhat sensitive to deformation stress. The tables show both alternatives to have very similar recovery factors.

Table 7.4.8
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $\phi_f / \phi_m = .00394/.0336$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_XH3
DPCK_XH3	n.a.	888.4	55.20	-
DPVK_XH3	6592.0	894.4	55.57	+0.67
DPVK_JH3	4560.8	890.7	55.34	+0.25

Table 7.4.9
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $\phi_f / \phi_m = .000984/.008340$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_MH3
DPCK_MH3	n.a.	796.3	55.45	-
DPVK_MH3	6592.0	801.8	55.83	+0.69
DPVK_NH3	4560.8	792.5	55.18	-0.49

The tabulated oil recovery data show that ultimate oil recovery was sensitive to the ratio of fracture to matrix porosity: reduced about 2% when ϕ_f / ϕ_m is reduced by half and increased about 5% when ϕ_f / ϕ_m is quadrupled.

7.4.4 Fracture Capillary Pressure

Natural depletion Case H36 and Case H23 explored sensitivity of recovery to stress for non-zero capillary pressure in the fractures. The specific condition was that $p_{cf} = \frac{1}{2}p_{cm}$. The same assumption was made for the water injection cases discussed in this section, Case OH3 and Case AH3.

Figure 7.4.10 shows the recovery performance of these cases. The deform option is seen to have little effect on oil-producing rate but somewhat greater impact on water breakthrough time. The rate and water cut stress sensitivity pattern is similar the base case plot, Figure 7.4.1. However, the inclusion of p_{cf} advanced the breakthrough by about four recovery percentage points and made the early water cut build-up more linear.

The ultimate oil recovery values given in Table 7.4.10 for these cases and in Table 7.4.1 for the base cases indicate a small reduction (approximately 1%) due to the non-zero p_{cf} . This is contradictory to the natural depletion results (Section 7.2.4).

Table 7.4.10
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $p_{cf} = .5p_{cm}$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_OH3
DPCK_OH3	n.a.	695.4	48.73	-
DPVK_OH3	6592.0	701.2	49.14	+0.84
DPVK_AH3	4560.8	697.6	48.89	+0.33

7.4.5 Matrix Capillary Pressure

Water flood oil recovery sensitivity to p_{cm} was explored in year one using the vertical injection model. The p_{cm} alternatives are discussed for the natural depletion cases in Section 7.2.5. The more extreme data, being the Case H1R data ($1 / p_{cm}^2 = f(S_w)$), were used for the cases discussed here, Case RH3 and Case TH3.

Figure and Table 7.4.11 summarize the results obtained for these cases. Referring to Figure 7.4.11, deformation is shown to have very little effect on either producing rate or total oil recovery, but water breakthrough is advanced somewhat as confining stress is reduced. Comparing the same figure to the base cases (Figure 7.4.1) reveals that reducing p_{cm} accelerated water breakthrough and reduced ultimate water flood recovery by about 5%.

Table 7.4.11
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, $1 / p_{cm}^2 = f(S_w)$

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK_RH3
DPCK_RH3	n.a.	639.8	44.57	-
DPVK_RH3	6592.0	635.8	44.29	-0.63
DPVK_TH3	4560.8	640.2	44.59	+0.04

7.4.6 Fracture Relative Permeability

Two of the four fracture relative permeability data sets used in the natural depletion cases were chosen for water injection simulations. Those were the Case H31 linear functions and the Case H33 curvilinear functions. These data sets are described in the first Annual Report, Section 9.3.9 and Figure 9.3.15 and Figure 9.3.17. Water injection Case 31H3 and Case 35H3 used the Case H31 data and Case 33H3, and Case 37H3 used the Case H33 data. The following table summarizes key features of these functions in comparison to the base water injection Case IH3 and Case BH3.

Case	S_{wi}	Shape	S_{orw}	S_{org}	$(p_{ct})_{ow}$	$(p_{ct})_{go}$
IH3,BH3	0.30	linear	0.	0.	0.	0.
31H3,35H3	0.15	linear	0.140	0.080	1.4825	0.1256
33H3,37H3	0.15	curved	0.140	0.080	1.4825	0.1256

The results for Case 31H3 and Case 35H3 are shown on Figure 7.4.12 while Case 33H3 and Case 37H3 are displayed on Figure 7.4.13. Neither shows much sensitivity to stress level; however, the curvilinear k_r produces more noticeable rate differences in the 20 to 40% recovery range (Figure 7.4.13).

Comparing the two sets of results shows that ultimate recovery was not sensitive to shape of the k_r functions, but water breakthrough, water cut buildup, and oil rate decline were noticeably so. The early production rate plateaued some 200 STB/d lower and water breakthrough was delayed about 4 recovery percentage points for the curvilinear k_r Case 33H3 and Case 37H3. Further, the linear k_r cases displayed a nearly linear water cut build-up following breakthrough.

Table 7.4.12 and Table 7.4.13 show that ultimate recovery was quite independent of both stress and relative permeability curve shape. The recoveries were, nonetheless, about 2% lower than the base cases. This difference can be largely attributed to the differing treatment of fracture capillary pressure.

Table 7.4.12
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, fracture k_f & p_c
(linear k_f : p_c , S_{wi} & $S_{or} = 0.5$ of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK31H3
DPCK31H3	n.a.	686.4	48.10	-
DPVK31H3	6592.0	689.0	48.29	+0.40
DPVK35H3	4560.8	690.4	48.38	+0.58

Table 7.4.13
Oil Recovery Sensitivity to Confining Stress
Horizontal Water Injection Model, fracture k_f & p_c
(curvilinear k_f : p_c , S_{wi} & $S_{or} = 0.5$ of matrix)

Case	σ psig	Cumulative, mSTB	Recovery Factor, %	% change versus DPCK33H3
DPCK33H3	n.a.	684.3	47.95	-
DPVK33H3	6592.0	683.7	47.91	-0.08
DPVK37H3	4560.8	689.1	48.29	+0.71

7.5 Secondary Recovery Forecasts for a Vertical Well

The vertical injection model was employed in year one to study secondary recovery by: water injection, gas injection and combined gas and water injection. The simulations clearly indicated the superiority of water injection; thus, the gas injection alternatives were dropped for the ongoing studies.

The vertical injection model employed vertical wells in place of the horizontal wells used in the horizontal injection model. Both wells were assumed to penetrate the same fracture swarm with the producer completed in the uppermost model layer and the injector completed in the lowermost layer.

The series of cases described in the foregoing section were re-simulated by the vertical injection model. The recovery performance graphs for these cases are reproduced by Figures 7.5.1

through 7.5.13. While the vertical well fluid rates were lower than the horizontal well rate levels, the two models yielded results that were very similar in terms of character and recovery fraction. Because of these similarities, the vertical injection model results are not individually discussed.

Two exceptions to this general agreement, are the altered fracture permeability series: Cases FV3 and DV3 versus Cases FH3 and DH3, and Cases KV3 and EV3 versus Cases KH3 and EH3.

The first exception is seen when Figure 7.4.3 and Figure 7.5.3 are compared. It is evident that the 5 STB/d rate cut-off used in the vertical well is more restrictive than the 25 STB/d used for the horizontal well. This observation holds for all cases and explains the usually lower vertical model recoveries.

The second exception is the different shape of the rate-recovery curves (Figures 7.4.5 and 7.5.5). The vertical well production decline is more pronounced throughout the recovery period. The difference is attributable to the characteristics of the two well types which is further amplified by the low reservoir drawdown and the relatively greater significance of flowing pressure gradient in the horizontal well bore.

Table 7.5.1 directly compares vertical injection model water flood oil recovery factors versus the comparable horizontal injection model values for all deform option cases (name prefix: DPVK). If Case KV3 and Case EV3 are excepted, the comparison shows that the vertical model - horizontal model recovery differentials are all less than 3% of STOIP and the mean difference is 1.5%.

Table 7.5.1
Comparison of Oil Recovery Factors
For Horizontal and Vertical Model Water Flood Cases
Recovery Basis - fraction of oil-in-place

Vertical Case	Vertical Oil Recovery	Horizontal Oil Recovery	Horizontal Case
IV3	0.4881	0.5031	IH3
BV3	0.4924	0.5011	BH3
UV3	0.5495	0.5602	UH3
GV3	0.5556	0.5650	GH3
FV3	0.4932	0.5199	FH3
DV3	0.4915	0.5200	DH3
VV3	0.3721	0.3948	VH3
HV3	0.3727	0.3968	HH3
KV3	0.4195	0.5025	KH3
EV3	0.4237	0.5058	EH3
WV3	0.4801	0.4885	WH3
YV3	0.4814	0.4884	YH3
PV3	0.4809	0.4913	PH3
LV3	0.4811	0.4915	LH3
XV3	0.5453	0.5557	VH3
JV3	0.5463	0.5534	JH3
MV3	0.5458	0.5583	MH3
NV3	0.5457	0.5518	NH3
OV3	0.4788	0.4914	OH3
AV3	0.4800	0.4889	AH3
RV3	0.4286	0.4429	RH3
TV3	0.4307	0.4459	TH3
31V3	0.4635	0.4829	31H3
35V3	0.4633	0.4838	35H3
33V3	0.4576	0.4791	33H3
37V3	0.4594	0.4829	37H3

NOMENCLATURE

A	- Block face area
°API	- Oil gravity
B	- Formation volume factor
c	- Compressibility
e	- Fracture surface roughness
f	- Friction factor
°F	- Temperature, degrees Fahrenheit
F	- Well block radius correction factor
Gp	- Gas produced
h	- Thickness
H	- Height of fracture face
k	- Permeability
$\bar{k}$	- Harmonic mean permeability
k_r	- Relative permeability
K	- Conductivity, kh
L	- Block dimension (fracture spacing)
L_f	- Characteristic flow path length
mSTB	- Thousand stock tank barrels
N	- Number of sets of fractures
NX, NY, NZ	- Number of grid blocks along given axis
p	- Pressure
p_b	- Saturation pressure
p_c	- Capillary pressure
p_0	- Initial well block pressure
p_{wf}	- Flowing bottom-hole pressure
psi	- Pounds per square inch
q	- Volume rate, production or injection
Q	- Reservoir flow rate
R_h	- Hydraulic radius
r_o	- Well block radius
R_s	- Solution gas-oil ratio
r_w	- Well bore radius
S	- Phase saturation
S^*	- Normalized saturation
scf	- Standard cubic feet
STB	- Stock tank barrel(s)
STOIP	- Stock tank conditions
V	- Flow velocity
V_b	- Fracture block volume
w_f	- Fracture aperture
Z	- Depth

NOMENCLATURE (cont'd)

α	- Poroelastic parameter
γ	- Stress gradient
Δ	- Difference operator
η	- Fitting parameters for Equation 6.18
μ	- Phase viscosity
π	- 3.14159...
ρ	- Phase density
σ	- Shape factor or confining stress
σ_{go}	- Gas-oil interfacial tension
σ_{ow}	- Oil-water interfacial tension
ϕ	- Porosity
Φ	- Phase potential
λ	- Transmissivity ration
ω	- Storativity ratio

SUBSCRIPTS

f	- Fracture
g	- Gas phase
i	- Irreducible or intrinsic
m	- Matrix
o	- Oil phase or at reference condition
r	- Residual
t	- Threshold
w	- Water phase
x,y,z	- Reference to given reservoir axis
xx,yy,zz	- Principal stress axis

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APPENDIX A

TETRAD

TETRAD is a state-of-the-art three-dimensional numerical reservoir simulator that can function in one of four modes:

Black Oil - Isothermal with three phases, water, gas, and oil and three component, also usually designated as water, gas, and oil. The gas component can dissolve in both the water and oil phases to represent solution gas. The oil component can be present in both the gas and water phases, to represent condensate or oil-in-water emulsion.

Multicomponent - Isothermal with three phases, water, gas, and oil. The hydrocarbon phases may each be multicomponent and hydrocarbon components may be present in any phase.

Thermal - Thermal with three phases, water, gas, and oil. All three phases may be multicomponent. Any component may be present in any phase.

Geothermal - Thermal with two phases, water and gas (no oil phase). The water and gas phases may be multicomponent. Any component may be present in any of the two phases.

The program has been extensively tested on a wide variety of problems in user environments ranging from major oil companies to independent consulting firms. It has been successfully installed on computers ranging from PC's to Cray supercomputers.

Program input is keyword driven and free format under the rules of FORTRAN 77. Default variables are extensively defined to facilitate problem set up.

The program has been efficiently interfaced to a front end gridding and data preparation package and a post processing mapping and graphics package to facilitate both data preparation and the presentation of results.

The grid algorithms will accept irregular and curvilinear grids and localized grid refinement. Any grid node may be coupled to any other grid node, to facilitate juxtaposition of non-conforming layers due to faulting and the irregular coupling of grid nodes due to grid refinement.

The initialization of saturations and pressures account for the presence of fluid contacts within a grid block. Contacts can either be sharp or with a transition zone as defined by the capillary pressure.

The simulator formulation provides a wide range of options for the degree of implicitness of the numerical solutions:

- fully implicit
- linearized implicit
- dynamically implicit
- sequentially implicit
- IMPES

Optional features of TETRAD include:

- Dual porosity/dual permeability can be treated in all four modes.
- Fully implicit treatment of flow in the well bore from the reservoir to the surface. Well bores can assume any inclination from horizontal to vertical.
- Control over the degree of numerical dispersion.
- Permeability can vary with reservoir pressure and temperature in a spatially dependent fashion.
- The input capillary pressure curves can be scaled to the porosity and permeability of each grid block according to the Leverett J function.
- Analytical aquifers can be tied to the model at any block. The aquifer options provided are:
 - steady-state
 - tank-type
 - infinite linear
 - semi-analytical aquifer options:
 - finite linear
 - infinite radial
 - finite radial
- Porosity and permeability hysteresis due to non-elastic deformation of the porous media.
- Controlled automatic switching of a well from injection to production and vice versa for cyclic "huff and puff" operation.
- Simulation of the electrical resistive heating method for enhanced recovery of heavy oils.
- Vectorised solver for use on vector computers.

TETRAD

TYPES OF PROBLEMS

TETRAD is applicable to an unusually broad spectrum of problems:

Reservoir Fluid Types

- Volatile oil
- Dry gas
- Gas condensate
- Geothermal
- Black oil

Recovery Processes

- Primary depletion.
- Water flooding
- Gas injection
- Aquifer influx
- Gas cycling
- Miscible flooding
- Steam flooding
- Electrical heating
- Horizontal wells

Single Well Studies

- Water and gas coning or cusping
- Steam "huff and puff"
- Pressure transient tests
- Fluid flow in well bore and pipes

Complex Porous Media

- Dual porosity/dual permeability
- Fractured systems
- Vugular
- Stress dependent porosity and permeability

Simulation of Laboratory Experiments

- Fluid displacement studies
- Fractured core studies
- Flash experiments

Special Applications

- Oil-in-water emulsions
- Tracer injection tracking
- Research into simulation techniques.
- Dissolved gas-in-water systems.
- Slug flow (reduced numerical dispersion required)
- Non-elastic deformation of porous media

TETRAD

MODEL PERFORMANCE

The numbers of time steps and Newton iterations required to solve published SPE Comparative Solution Project Problems are given in the following tabulation. All simulations were performed on a 32 bit computer using double precision. The numbers required for a given installation may vary slightly from the tabulated values, depending on the accuracy of the machine.

Computational Effort Requirements SPE Comparative Solution Project Problems

Solution Project	Problem Description & Variations	Time Steps Required	Total Newton Iterations
First	3D Black Oil: fixed p_b variable p_b	17	72
		17	79
Second	2D Radial Coning	7	40
Fourth	Thermal, Steam Flooding: 2D radial huff & puff	85	282
	3D heavy oil	48	195
	3D volatile oil	35	200
Sixth	Dual Porosity, 2D Vert. water inj.	29	96

TETRAD

MODEL FORMULATION BASICS

Phases and Components

Petroleum and natural gas reservoir systems are formulated as three phase, water, gas, and oil. Geothermal reservoirs have only two phases, gas and liquid.

Reservoir fluid systems have a total of n_t components, comprised of n_w water components, and $n_t - n_w$ hydrocarbon components.

Component 1 is generally the pure water component in the water phase. Components 2 through n_w are referred to as tracer components in the water phase and can only be present in a thermal or geothermal simulation. They can be used to model a tracer such as deuterium, tritium, or dissolved gas such as CO_2 , or dissolved salt.

Components $n_w + 1$ through n_t are the hydrocarbon components, in order of increasing molecular weight. They are not present in geothermal simulations.

Conservation Equations

In a black oil or multicomponent simulation, there are n_t conservation equations, one for each component. In a thermal or geothermal simulation, there are $n_t + 1$ conservation equations, the extra equation being the energy conservation equation.

Fundamental Variables

TETRAD regards the following as fundamental variables:

- pressure (P)
- saturations of oil, gas and water phases (S_o , S_g , S_w)
- temperature (T)
- component mole fractions in water, gas, oil phases (W,Y,X)

Primary Variables

The number of primary variables is always the same as the number of conservation equations; however, the choice of primary variables depends on the type of simulation, and the presence of phases. Variable substitution is used depending on the phase status. Possible primary variables are:

- P
- S_g , or $X(2)$, or T
- S_o , or $Y(n_t)$, except for geothermal
- $W(2)$ through $W(n_w)$ for thermal or geothermal
- $X(n_w+2)$ through $X(n_t-1)$ for multicomponent
- $X(n_w+1)$ through $X(n_t-1)$ for thermal

All other variables are secondary variables.

Constraint Equations

The constraining equations are as follows:

$$S_o + S_g + S_w = 1$$

$$\Sigma W = 1$$

$$\Sigma Y = 1$$

$$\Sigma X = 1$$

Equilibrium Constants

The mole fractions are related through the equilibrium constants (K and F values). Usually, the F values will be zero.

For the water components:

$$Y_i = K_i W_i \quad i = 1, n_w$$

$$X_i = F_i W_i \quad i = 1, n_w$$

For the hydrocarbon components:

$$Y_i = K_i X_i \quad i = n_w+1, n_t$$

$$W_i = F_i X_i \quad i = n_w+1, n_t-1$$

$$W(n_t) = F(n_t) Y(n_t) \quad \text{black oil and multcomp. mode}$$

$$W(n_t) = F(n_t) X(n_t) \quad \text{thermal mode}$$

The equilibrium constants, K are functions of pressure and temperature.

As TETRAD always works with mole fractions, black oil PVT data are used internally to construct the equivalent K values for the phase equilibria.

Solution Procedure

In a *black oil* simulation, with all phases present, the primary variables are P , S_g , and S_o . If the gas phase disappears, $X(2)$ replaces S_g as a primary variable, (this is equivalent to solving for R_s , the solution gas-oil ratio). If the oil phase disappears, $Y(n_t)$, (n_t being 3 in this case) replaces S_o as a primary variable. This is equivalent to solving for the gas-condensate ratio. Once the primary variables have been found, the remaining fundamental variables can be determined from the constraint equations and equilibrium relationships. All other variables (densities, etc.) are functions of the fundamental variables.

In a *multicomponent* simulation when all phases are present, the primary variables are P , S_g , S_o , and $X(3)$ through $X(n_t-1)$. Variable substitution is performed in exactly the same manner as for black oil.

In a *thermal* simulation with all phases present, the primary variables are P , S_g , S_o , $W(2)$ through $W(n_w)$ and $X(n_w+1)$ through $X(n_t-1)$. If the gas phase or the water phase disappear (e.g. superheated steam), T replaces S_g as a primary variable. The oil phase is not allowed to disappear in a thermal simulation, although the oil saturation can go to zero. This is done by means of a pseudo K value for the heavy oil component to prevent further evaporation as the oil saturation approaches zero.

In a *geothermal* simulation, the primary variables are P , S_g , and $W(2)$ through $W(n_w)$. Variable substitution is performed in the same manner as for thermal.

In constructing the Jacobian, the primary variables are aligned on the conservation equations to make the resulting matrix as diagonally dominant as possible.

Dual Porosity

When invoked, the number of grid blocks is doubled and a dual grid is set up. The first $N/2$ grid blocks then represent the fracture system and the last $N/2$ the matrix system. The grid parameters, such as grid block sizes and formation tops are automatically dualled. Thus, the two grids occupy the same spatial positions. Each grid block in the fracture system is connected to the equivalent grid block in the matrix system by a special interaction, namely the fracture-matrix interaction.

Optionally, matrix-matrix interblock connection can be set up. These interactions then represent first degree couplings and are included as such in the inner LDU factorization and iterative inversion. However, if any of the matrix-matrix transmissibilities are specified as zero, the corresponding interblock connections are omitted to save storage. These interactions then

represent third degree couplings in the inner LDU factorization, and are not included in the default second degree factorization. In this circumstance, the number of inner iterations can increase significantly, depending on the problem. The situation can be overcome by specifying either, low matrix-matrix transmissibilities, or third degree inner LDU factorization. Both alternatives increase the storage requirement.

Implicit Well bore Simulation

For implicit well bores, the flow in the well bore is modelled as part of the overall grid. This option allows the definition of additional grid blocks to represent the well bore. The well bore blocks will be automatically coupled to each other in the direction of the well bore, and to the reservoir grid blocks. Two sets of relative permeabilities will generally be required, one for the well bore blocks, another for the reservoir blocks.

Implicit well bore modelling may not be combined with local grid refinement or dual porosity.

Numerical Dispersion Control

Weighting options are provided for relative permeabilities and viscosity.

Relative permeability weighting parameters can be specified as follows:

A zero value to indicate no dispersion control resulting in single point upstream mobility weighting.

A value of 1.0 to define a strict second order method in space. Values between 0.0 and 1.0 give a mixture of single point upstream and the second order method.

Values greater than 1.0 can be used if more dispersion control is required. On slug type problems of near unit viscosity ratio, a well defined slug can be obtained by raising the weighting parameter to about 4. On Buckley-Leverett type problems, sharp shock fronts can be obtained using a parameter of about 2.

Viscosity weighting parameters can be assigned to each phase. A parameter of 0.5 yields a central difference while 1.0 gives single point upstream. Any value between 0.5 and 1.0 can be used.

Deformation Model

The basis of the deformation model is described in SPE paper 18752, published in *SPE Reservoir Engineering*, May 1991. The approach was specifically developed for application to the Cold Lake reservoir in northeastern Alberta. In an injection cycle, porosities are assumed to follow an elastic compressibility curve until some deformation pressure is exceeded; thereafter, a dilation curve with a much greater compressibility is followed. During the subsequent production cycle,

FIGURE 6.2.1

LOMIZE³⁴

LOUIS³⁶

Lomize and Louis Models of Fracture Roughness
(reproduced from Jones¹)

Figure 6.2.2

Figure 6.2.3

Figure 6.3.1

Pearsall Field, Austin Chalk Reservoir
Well A-1 Smoothed Test Data

K&A Energy Consultants

Figure 6.3.2

Pearsall Field, Austin Chalk Reservoir
Well A-2 Smoothed Test Data

KSA Energy Consultants

Figure 6.3.3

Pearsall Field, Austin Chalk Reservoir
Well B-1 Smoothed Test Data

K&A Energy Consultants

Figure 6.3.4

Pearsall Field, Austin Chalk Reservoir
Well B-2 Smoothed Test Data

K&A Energy Consultants

Figure 6.3.5

Pearsall Field, Austin Chalk Reservoir
Well P-1 Smoothed Test Data

K&A Energy Consultants

Figure 6.3.6

Pearsall Field, Austin Chalk Reservoir
Well B-1 Multi-Rate Test

K&A Energy Consultants

Figure 6.3.7

Well B1 - multi rate
Miller-Dyes-Hutchinson plot

Figure 6.3.8

Well B1 - multi rate
Miller-Dyes-Hutchinson plot

Figure 6.3.9

Well B1 - multi rate
Miller-Dyes-Hutchinson plot

Figure 6.3.10

Well B1 - multi rate Miller-Dyes-Hutchinson plot

FIGURE 6.3.11

FIGURE 6.3.12

FIGURE 6.3.13

FIGURE 6.3.14

FIGURE 7.2.1

FIGURE 7.2.2

FIGURE 7.2.3

FIGURE 7.2.4

FIGURE 7.2.5

FIGURE 7.2.6

FIGURE 7.2.7

FIGURE 7.2.8

FIGURE 7.2.9

FIGURE 7.2.10

FIGURE 7.2.11

FIGURE 7.2.12

FIGURE 7.2.13

FIGURE 7.2.14

FIGURE 7.2.15

FIGURE 7.2.16

FIGURE 7.2.17

FIGURE 7.3.1

FIGURE 7.3.2

FIGURE 7.3.3

FIGURE 7.3.4

FIGURE 7.3.5

FIGURE 7.3.6

FIGURE 7.3.7

FIGURE 7.3.8

FIGURE 7.3.9

FIGURE 7.3.10

FIGURE 7.3.11

FIGURE 7.3.12

FIGURE 7.3.13

FIGURE 7.3.14

FIGURE 7.3.15

FIGURE 7.3.16

FIGURE 7.3.17

FIGURE 7.4.1

FIGURE 7.4.2

FIGURE 7.4.3

FIGURE 7.4.4

FIGURE 7.4.5

FIGURE 7.4.6

FIGURE 7.4.7

FIGURE 7.4.8

FIGURE 7.4.9

FIGURE 7.4.10

FIGURE 7.4.11

FIGURE 7.4.12

FIGURE 7.4.13

FIGURE 7.5.1

FIGURE 7.5.2

FIGURE 7.5.3

FIGURE 7.5.4

FIGURE 7.5.5

FIGURE 7.5.6

FIGURE 7.5.7

FIGURE 7.5.8

FIGURE 7.5.9

FIGURE 7.5.10

FIGURE 7.5.11

FIGURE 7.5.12

FIGURE 7.5.13