DOE/BC/15212-2
(OSTI ID: 784394)

DEVELOPMENT OF RESERVOIR CHARACTERIZATION
TECHNIQUES AND PRODUCTION MODELS FOR EXPLOITING
NATURALLY FRACTURED RESERVOIRS

Semi-Annual Report
January 1, 2001-June 30, 2001

By:
Michael L. Wiggins
Raymon L. Brown
Faruk Civan
Richard G. Hughes

Date Published: August 2001

Work Performed Under Contract No. DE-AC26-99BC15212

The University of Oklahoma
Norman, Oklahoma

**National Energy Technology Laboratory
National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma**

DISCLAIMER

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

This report has been reproduced directly from the best available copy.

Development of Reservoir Characterization Techniques and Production Models
for Exploiting Naturally Fractured Reservoirs

By
Michael L. Wiggins
Raymon L. Brown
Faruk Civan
Richard G. Hughes

August 2001

Work Performed Under DE-AC26-99BC15212

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Tom Reid, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
The University of Oklahoma
Office of Research Administration
1000 Asp Avenue, Suite 314
Norman, OK 73019

Table of Contents

Abstract	v
Introduction	1
Results and Discussion	3
Task I. Characterize Fractured Reservoir Systems	3
Task II. Develop Interwell Descriptors of Fractured Reservoir Systems	7
Task III. Develop Wellbore Models for Fractured Reservoir Systems	27
Task IV. Reservoir Simulations Development/Refinement and Studies	27
Task V. Technology Transfer	41
Conclusion	42
References	44

Abstract

Development Of Reservoir Characterization Techniques And Production Models For Exploiting Naturally Fractured Reservoirs

For many years, geoscientists and engineers have undertaken research to characterize naturally fractured reservoirs. Geoscientists have focused on understanding the process of fracturing and the subsequent measurement and description of fracture characteristics. Engineers have concentrated on the fluid flow behavior in the fracture-porous media system and the development of models to predict the hydrocarbon production from these complex systems. This research attempts to integrate these two complementary views to develop a quantitative reservoir characterization methodology and flow performance model for naturally fractured reservoirs.

During the current reporting period, research has continued on characterizing and modeling the behavior of naturally fractured reservoir systems. Work has progressed on developing techniques for estimating fracture properties from seismic and well log data, developing naturally fractured wellbore models, and developing a model to characterize the transfer of fluid from the matrix to the fracture system for use in the naturally fractured reservoir simulator. The research is currently on schedule as proposed.

During this reporting period efforts have moved forward in formalizing the relationship between the seismic signals and important flow properties of fractured reservoirs using production data. A genetic algorithm and software program has been implemented to obtain fracture density and aspect ratio through the inversion of fractured reservoir rock models using conventional well logs. In addition, a fuzzy logic inference model has been developed to obtain the fracture index from well logs. The software is ready for further testing.

Wellbore performance models for naturally fractured reservoirs have been incorporated into the naturally fractured reservoir simulator but have not been tested. Work during this period has focused on developing a model to characterize fluid transfer between the matrix and fracture system for incorporation in the simulator. The development of the reservoir simulator continues in a timely manner.

Finally, there has been a change in project personnel during the current reporting period. Dr. Ronald Evans has retired and Dr. Anuj Gupta has left the University of Oklahoma. Drs. Faruk Civan and Richard Hughes have replaced them. This has led to a transition period during the first half of 2001. However, the project is on schedule and the research is progressing in an orderly manner.

Introduction

Many existing oil and gas reservoirs in the United States are naturally fractured. It is estimated that from 70-90% of the original oil and gas in place in such complex reservoir systems are still available for recovery, provided new technology can be implemented to exploit these reservoirs in an efficient and cost effective manner. Enhanced oil recovery processes and horizontal drilling are two fundamental technologies which could be used to increase the recoverable reserves in these reservoirs by as much as 50%. This research is directed toward developing a systematic reservoir characterization methodology which can be used by the petroleum industry to implement infill drilling programs and/or enhanced oil recovery projects in naturally fractured reservoir systems in an environmentally safe and cost effective manner. It is anticipated that the results of this research program will provide geoscientists and engineers with a systematic procedure for properly characterizing a fractured reservoir system and a reservoir/horizontal wellbore simulator model which can be used to select well locations and an effective EOR process to optimize the recovery of the oil and gas reserves from such complex reservoir systems.

The focus of the research is to integrate geoscience and engineering data to develop a consistent characterization of the naturally fractured reservoir. During the current reporting period effort has focused on relating seismic data to reservoir properties of naturally fractured reservoirs, scaling well log data to generate interwell descriptors of these reservoirs, enhancing and debugging a naturally fractured reservoir simulator, and developing wellbore models for use in the simulator.

Many of the factors controlling flow through fractured reservoirs also dominate the seismic response of the reservoir. It is this relationship that offers the key to using seismic signals to predict important flow properties of fractured reservoirs. When the fractured reservoir rock is treated as a strictly elastic material, the seismic response is only an indication of the crack porosity. In this case production tests have to be used to better estimate the flow properties of the fractured reservoir. If the attenuation of the seismic signals is taken into account, the seismic can be used to predict important flow properties throughout the reservoir. During this reporting period efforts have moved forward in formalizing the relationship between the seismic signals and important flow properties of fractured reservoirs.

Conventional well logs may be used for fracture detection since they often exhibit abnormal values in response to fractured zones within a borehole. Efforts have focused on obtaining quantitative description and characterization of naturally fractured reservoirs using conventional well logs. A genetic algorithm has been used to obtain fracture density and aspect ratio through the inversion of fractured reservoir rock models using the model proposed by O'Connell and Budiansky (1977, 1984).

The response of conventional well logging tools is affected only indirectly by the presence of fractures. It is through these indirect effects that the fractures may be detected (Serra, 1986). Then in order to "see" fractures from conventional well logs, the available log-suite must be examined quantitatively to distinguish fractures from other features that may produce similar well log responses. Fuzzy logic is a convenient way to map an input space into an output space when the input variables are related among themselves and with the output variable in a complex but implicit manner. The problem of fracture detection from well logs clearly fits within the fuzzy logic range of applicability. During the current period, a Fuzzy Inference System has been

developed to analyze a suite of well logs to estimate the fracture index. It is anticipated that combining the information gathered from the analysis of the well logs, the crack density, aspect ratio and fracture index, will provide greater insight into characterizing a naturally fractured reservoir.

Wellbore models for use in the naturally fractured reservoir simulator have been developed and implemented in the simulator. Flow from both the fractures and matrix is allowed to occur and is considered through productivity indexes that are proportional to the equivalent fracture and matrix permeabilities, respectively. Work has also progressed on developing a naturally fractured reservoir simulator for use in a PC environment. During the current reporting period, work has focused on developing models to describe the transfer of fluids between the matrix and fracture system. This is seen as a major concern in adequately modeling the performance of naturally fractured reservoirs. Additionally, steps continue to move the program from a mainframe to a desktop computing environment. The modeling effort is proceeding in a timely fashion.

Changes in project personnel have also occurred during the current reporting period. Dr. Ronald Evans retired from the U. of Oklahoma at the end of December 2000 and asked that he be replaced on the project team. In addition, Dr. Anuj Gupta left the University for another position. As a result, there has been an element of transition during the last six months as two new faculty members have been added to the research team. Dr. Faruk Civan will focus his efforts on the refinement on the naturally fractured reservoir simulator. Dr. Richard Hughes will assist with the development of interwell descriptors.

Results and Discussion

For many years, geoscientists and engineers have undertaken research to characterize naturally fractured reservoirs. Geoscientists have focused on understanding the process of fracturing and the subsequent measurement and description of fracture characteristics. Engineers have concentrated on the fluid flow behavior in the fracture-porous media system and the development of models to predict the hydrocarbon production from these complex systems. This research attempts to integrate these two complementary views to develop a quantitative reservoir characterization methodology and flow performance model for naturally fractured reservoirs.

During the current reporting period, research efforts have focused on relating seismic data to reservoir properties, determining fracture index from well log data using fuzzy logic, implementing naturally fractured wellbore models, and developing a model to characterize the transfer of fluids from the matrix to the fracture system for implementation in the naturally fractured reservoir simulator. Details of the work conducted for the various research tasks are discussed in the following sections.

Task I. Characterize Fractured Reservoir Systems

One of the early developments of this project was an approach to describing the specific compliance of cracks in terms of the apertures of the cracks. This work has been used to establish the strength of crack-induced elastic anisotropy in terms of the crack porosity (Brown et al., 2001c). Since crack permeability can also be expressed in terms of the crack porosity, this approach places a common parameter, the crack porosity, between the engineer and the geophysicist.

One of the problems facing the application of these ideas is the estimation of the specific compliance for the cracks. This requires that the elastic component of the seismic response be calibrated using well control. Once calibration is accomplished, seismic studies can be effectively used to map the crack porosity throughout a fractured reservoir as well as the orientation of the fracture system when there is a dominant fracture system. Some of the difficulties facing this approach will be discussed.

After the crack porosity has been determined by geophysical studies, the engineers can use well tests and/or production data to estimate the permeability of the formation around the well. This measure of the permeability combined with the seismic estimate of the crack porosity can be used to estimate the crack aperture. Both crack aperture and spacing are important as they relate to important engineering parameters controlling the flow through fractured reservoirs and the coupling between the matrix and the fractures. Production tests can be combined with the crack porosity (determined from the elastic portion of the seismic response) to estimate the crack apertures and ultimately the crack spacing. These parameters are extremely important from an engineering point of view because they control the mass transfer between the matrix and the fractures. Saturation (and more importantly, the time-dependence of saturation) is one of the important elements of understanding this mass transfer and some of our earlier studies have addressed the effects of saturation upon the seismic response (Brown et al., 2001a). Unfortunately, the ideas described are restricted to the availability of well control and do not easily extend away from the well control without making a number of assumptions.

The ultimate goal for production seismic work is to be able to use the seismic response to estimate the permeability and other flow properties away from the well control. In this way both

the aperture and fracture spacing can be mapped throughout the field and calibrated using the production tests at the well control. Seismic attenuation is likely to be indicative of the permeability of fractured reservoirs since the movement of the saturating fluids is one of the controlling factors for the seismic attenuation. An approach describing how seismic attenuation measurements of permeability can be used to map important fracture parameters throughout the reservoir is presented. The goal of course is to map the matrix-to-fracture mass transfer throughout the reservoir as well as the fracture permeability.

Calibration of the Elastic Component of Seismic Response. In this section we refer to the elastic component of the seismic response in order to differentiate it from the seismic attenuation. The elastic response can be computed from a strictly elastic model of the reservoir rocks. It is the elastic component of the seismic response that can be used to obtain the crack porosity. For example, a popular model for the excess elastic compliance of a fractured reservoir has been given by Schoenberg and Sayers (1995)

$$S_{ijkl}^c = \frac{Z}{4} (n_j n_k \delta_{il} + n_j n_k \delta_{il} + n_j n_k \delta_{il} + n_j n_k \delta_{il}) \dots\dots\dots 1$$

where Z is the specific compliance or a measure of the strength of the excess compliance introduced by the fractures. Some authors use a Z factor that is proportional to the crack density (e.g., Hudson, 1980, 1981). There are a number of such analytical estimates for Z that depend upon a specific crack model. Unfortunately, the crack models typically used make a large number of assumptions that leave a lot of questions regarding their practical application.

An alternative approach is suggested from the results of Schoenberg and Sayers (1995). They have a series of equations that can be used to estimate Z if the excess compliance is known. For example, if the P-wave anisotropy or the shear wave splitting has been measured over a fractured reservoir, then the magnitude of Z can be estimated using their results. In our case we want to express the specific compliance Z as a linear function of the crack porosity. Using K as the constant of proportionality, this can be written in the form

$$Z = K \phi_c \dots\dots\dots 2$$

where K is to be determined by calibration. Now suppose that we have determined that the reservoir has a shear-wave splitting of 10% with a known crack porosity value of 5%. Assuming that the cracks are scalar without any difference between the tangential and normal components, we can use Schoenberg and Sayers' (1995) Eq. 16 to write the shear-wave-splitting fraction in a modified form as shown in Eq. 3.

$$\text{Shear Wave Splitting Fraction} = 1 - \sqrt{1 - \delta} \dots\dots\dots 3$$

Using the value of 10% for the shear wave splitting in the above equation, the δ factor can be determined and used in the following expression modified from Schoenberg and Sayers (1995) to find the specific compliance (Z) for the fractures.

$$Z = K\phi_c = \frac{\delta}{\mu(1-\delta)} \dots\dots\dots 4$$

Using the example crack porosity (ϕ_c) of 5%, leads to an estimate of the calibration constant K when given a value of the shear modulus (μ) for the background or matrix that is fractured.

The basic idea described here can be used in practice to calibrate the elastic part of the seismic and can be used in mapping away from known systems of fractures. The controlling factor, the specific compliance, for the elastic response is the crack porosity. The approach can also be based upon P-wave measurements. There are some complications when applying these ideas. For example, if more than one fracture set exists, one has to identify their respective orientations and account for their presence in the calibration. Some of these fractures may be closed which will require additional considerations. The weakest aspect of this approach is the accuracy to which the crack porosity can be determined by independent means. However, when integrating the production and the seismic data, a consistent picture is likely to develop.

In summary, the elastic portion of the seismic response is controlled by the crack porosity. Elementary crack models may be used to estimate this effect, but a powerful advantage can be gained by calibrating the elastic response over a fractured reservoir with a crack porosity that is known. The advantage gained is that the calibration overcomes some of the simplifying assumptions used for published crack models (Brown et al., 2001b).

Determining Fracture Aperture and Spacing. The motivation for using a specific compliance that is proportional to the crack porosity is the basic equation often used to describe flow through a set of parallel plates (e.g., Oda, 1985) with aperture A, crack porosity (ϕ_c) and normal $\mathbf{n}$.

$$k_{ij} = \frac{A^2\phi_c}{12}(\delta_{ij} - n_i n_j) \dots\dots\dots 5$$

Following the lead of Oda (1985) and Brown and Bruhn (1998), a similar functional form for the permeability is proposed in Eq. 6.

$$k_{ij} = \lambda(\phi_c)A^2\phi_c(\delta_{ij} - n_i n_j) \dots\dots\dots 6$$

The appeal of Eq. 6 is that the permeability is tied to two factors, the aperture (A) and crack porosity (ϕ_c). Given some experience with a particular formation, it is likely that the functional form for $\lambda(\phi_c)$ varies with lithology and burial history. Brown and Bruhn (1998) describe one form for this function that we refer to as the connectivity in this paper. Thus a seismic measurement of the elastic response at a well can determine the crack porosity while a well test provides the permeability. Actually only the multiplicative factor in front of the directional part of Eq. 6 with subscripts is determined in a production test. However, that is exactly what is needed. The combination of the two measurements can then be used in the above equation with a known connectivity to obtain the aperture of the fractures. We will discuss below why this is important for engineering purposes.

Seismic measurements of the elastic properties of a fractured reservoir yield an estimate of the crack porosity (ϕ_c) as described earlier and well test measurements provide a measure of the scalar component of the permeability at the well. The directional component of the permeability can often be associated with the seismic anisotropy. However, engineers cannot live with just a picture of the permeability of a fractured reservoir. There are many issues related to the coupling between the matrix and the fracture system that have to be answered in order to completely describe the flow behavior of the reservoir. For example, the engineers want some measure of the spacing between fractures and the aperture of the fractures. The fracture spacing and aperture are used to estimate how a fractured reservoir will behave during a waterflood.

As described, the seismic determination of the crack porosity at a well along with the determination of the permeability using well tests can be used to determine the crack apertures at the well. Armed with the crack aperture (A) and the crack porosity (ϕ_c), Eq. 7 can be solved to obtain an estimate of the fracture spacing at the well.

$$\phi_c = \frac{\text{Volume of Cracks}}{\text{Total Volume}} = \frac{A}{A + \text{Spacing}} \approx \frac{A}{\text{Spacing}} \dots\dots\dots 7$$

The next problem is how to use the seismic to map these flow properties away from the well control. Away from the well control, the elastic part of the seismic yields only the fracture porosity so that the permeability, aperture and spacing cannot be determined. This is where the determination of seismic attenuation plays a role. More specifically, the measurement of the intrinsic attenuation via seismic can be used to get still another measurement of the permeability of the reservoir (Parra et al., 2000). Using this measurement, combined with the determination of the fracture porosity, leads to estimates of the fracture aperture and spacing (using the above equations) away from the well control.

In summary, production tests at wells offer an important constraint upon fractured reservoir performance when integrated with seismic studies. The problem of how to map reservoir properties away from the well control still exists. Seismic attenuation offers the key to solving this problem. A brief description of the importance of the intrinsic attenuation and the role it can play is given below.

Relating Attenuation To Permeability. One cause of seismic attenuation is related to the movement of the saturating fluid. This type of attenuation is referred to here as intrinsic attenuation. Still another cause of apparent attenuation is the elastic scattering. It is the intrinsic attenuation that holds information on the permeability of a formation.

Parra et al. (2000) illustrate a method of modeling the intrinsic seismic attenuation. In that paper, the authors develop a model that depends upon the length scales of fluid movement. The model depends upon the stiffness of the rock, the permeability tensor of the rock and the local flow length scales. The resulting model is used to tie the seismic attenuation to the tensor permeability. The model has a general applicability in being able to consider fluid movement at different scales. The problem to be solved is exactly how these length scales can be determined. Brown et al. (2001b) give an example of how the length scales of fluid movement effect the attenuation of the fractured reservoir. One of the important issues here is verification of the type of fluid movement that contributes to the measured attenuation. For pore-scale fluid movement, direct measurements upon core can be made to study the problem (e.g., Parra et al., 2000). For

fracture-scale fluid movement, the length scales are unknown and not easily verified in a laboratory environment. The problem then is verification at the field scale. This will require a careful separation of the effects of elastic scattering and the intrinsic attenuation.

If the intrinsic attenuation of the seismic response can be utilized to estimate the permeability as function of position throughout a fractured reservoir, then Eqs. 6 and 7 can be used in principle to estimate the aperture and spacing throughout the reservoir. This means that engineers using models of the matrix-fracture coupling can better predict the performance of reservoirs. Four major problems face this approach to predicting fractured reservoir properties:

1. Understanding the attenuation mechanisms at seismic frequencies.
2. Determining the total seismic attenuation from surface and crosswell measurements.
3. Separation of the intrinsic attenuation from the elastic scattering attenuation.
4. Estimating the connectivity function in Eq. 6

If these problems can be overcome, there is at least a format for mapping important fractured reservoir properties using the seismic response.

Summary. At this point in the project, software and theoretical concepts have been developed for correlating the seismic response to important parameters controlling the flow in fractured reservoirs. The elastic component of the seismic response is used to map the crack porosity. The crack porosity determined in this way can be combined with well tests to predict the aperture and the fracture spacing at the position of a well. This is important for engineering purposes since engineering models of the flow can be used to model the mass transfer between the matrix and fracture system. Unfortunately, this measurement only applies at available well positions. The intrinsic attenuation of the seismic response is the key to mapping the aperture and spacing throughout the reservoir. However, there are some major hurdles to using the attenuation even with the models being used at present. As we move into applying these ideas, the goal will be to evaluate some of the problems facing the application of seismic attenuation and issues associated with the frequency dependence of the signals. Initial efforts with real data will necessarily be rather naïve. A 3D (poststack and migrated) seismic survey over the Teapot Dome field will be studied in order to evaluate the potential role of fracturing in this field to test and validate the concepts developed in this project.

Task II. Develop Interwell Descriptors of Fractured Reservoir Systems.

In previous progress reports, a self-consistent physical model based on the theory of O'Connell and Budiansky (1984) was reported. This model uses conventional well logs to obtain two parameters that can be used to constrain seismically derived values for fracture spacing and fracture aperture (permeability). The first of these parameters was the *crack density*, defined as:

$$\varepsilon = N * \frac{2}{\pi} \langle \frac{A^2}{P} \rangle \dots\dots\dots 8$$

where N is the number of cracks per unit volume, A is the area in plain-form of the crack, and P is the length of the perimeter of the crack.

The second parameter was an *aspect ratio* (the ratio of the crack thickness or aperture to the crack diameter) of the crack. This ratio can be obtained from a characteristic frequency for fluid flow between cracks which can be estimated from

$$\omega_s \approx 4 \left(\frac{K}{\eta} \right) \left(\frac{c}{a} \right)^3 \dots\dots\dots 9$$

where η is the viscosity of the fluid, and c/a is the aspect ratio of the crack.

From parameters obtained from conventional well logs and equations related to the complex form of the bulk modulus and the shear modulus, a genetic algorithm was developed to obtain ε and c/a . A complete description of the algorithm can be found in the January 2001 Semiannual Technical Progress Report and in paper SPE 67280 (Martinez *et al.*, 2001). To test the model, a synthetic example was developed. Logs used include the caliper, Gamma Ray, Spontaneous Potential, Sonic, Neutron Porosity and Bulk Density logs. A Photoelectric log was also used as a lithology tool. Figure 1 shows the generated crack-density and aspect ratio logs.

After testing the algorithm on the synthetic example, the method was applied to a field case. Through another project at the University of Oklahoma, we had a reasonably complete suite of conventional logs for approximately 40 wells in the Bermejo Field in Ecuador. This field is made up of four distinct reservoirs from essentially two formations. The Bermejo North and Bermejo South Basal Tena reservoirs are distributary channel sandstones. The Bermejo North and Bermejo South Hollin reservoirs are fairly thick fluvial sandstone reservoirs. The Bermejo North and South reservoirs are isolated from each other by high angle reverse faults which form both stratigraphic relief for the trap and the seal for the reservoirs on one side. Between the Basal Tena and Hollin formations there are interbedded shale, sandstone and limestone formations which have thus far proved unproductive. Figure 2 shows the crack density results from the model for the wells BS-05, BS-14, BS-17 and BS-18. We are presently analyzing these results as well as those for the aspect ratio. Due to the level of faulting and the structural relief shown in the reservoir, fracturing should be expected. The operator does not feel that any of the reservoirs show naturally fractured behavior. These results are being compared to the production response in each well to see whether the log-derived crack density and/or aspect ratio are indicating enhanced productivity due to fractures.

The difficulty with the O'Connell and Budiansky model is that this model was originally developed for use on core-scale samples. It is not readily clear exactly what the model is calculating when used at a scale consistent with what the log suite is measuring. Additional experimentation is necessary to quantify how to use the model. The plan for this experimentation will be provided following a discussion of another technique that may prove equally promising, that of using fuzzy logic to obtain a "fracturing index" from conventional logs.

The response of conventional well logging tools is affected only indirectly by the presence of fractures. It is through these indirect effects that the fractures may be detected (Serra, 1986). Then in order to "see" fractures from conventional well logs, the available log-suite must be examined quantitatively to distinguish fractures from other features that may produce similar well log responses.

Fuzzy logic is a convenient way to map an input space into an output space when the input variables are related among themselves and with the output variable in a complex but implicit manner. The problem of fracture detection from well logs clearly fits within the fuzzy logic range of applicability.

Figure 1. Synthetic Example Crack Density and Aspect Ratio Logs

Figure 2A: Bermejo Field Crack Density Logs

Figure 2A: Bermejo Field Crack Density Logs

Many of the problems faced in engineering, science and business can effectively be modeled mathematically. However when constructing these models many assumptions have to be made which are often not true in the real world. Real world problems are characterized by the need to be able to process incomplete, imprecise, vague or uncertain information. There are many other domains which can best be characterized by linguistic terms rather than, directly, by numbers.

Fuzzy sets were introduced by Zadeh (1974) as an approach to handling vagueness or uncertainty and, in particular, linguistic variables. Classical set theory allows for an object to be either a member of the set or excluded from the set. This, in many applications, is unsatisfactory since, for example, if one has the set that describes all males who are tall as those whose height is greater than 5'8" then a 6'0" male is a member of the set. A male whose height is 5'7 3/4", however, is not a member of the set. This implies that a man who is 1/4" shorter than another tall man is not tall.

Fuzzy sets differ from classical sets in that they allow for an object to be a partial member of a set. So, for example, John may be a member of the set 'tall' to degree 0.8. He is tall to degree 0.8. Fuzzy sets are defined by a membership function. For any fuzzy set A the function μ_A represents the membership function for which $\mu_A(x)$ indicates the degree of membership that x, of the universal set X, belongs to set A and is, usually, expressed as a number between 0 and 1:

$$\mu_A(x): X \rightarrow [0,1] \dots\dots\dots 9$$

Fuzzy sets can either be discrete or continuous. Discrete sets are written as:

$$A = \mu_1/x_1 + \mu_2/x_2 + \mu_3/x_3 + \dots\dots\dots + \mu_n/x_n \dots\dots\dots 10$$

where $x_1, x_2, \dots x_n$ are members of the set A and $\mu_1, \mu_2, \mu_3, \dots \mu_n$ are their degrees of membership. A continuous fuzzy set A is written as

$$A = \int_x \mu(x)/x \dots\dots\dots 11$$

Note that $\int_x$ is not used with their usual meaning in the previous definition. In this case $\int_x$ is the continuous summation of $\mu(x)/x$ over the entire domain.

To be able to deploy fuzzy logic in a rule-based computer system, one needs to be able to handle the operators 'AND' and 'OR' and to be able to carry out inference on the rules. Therefore we need to be able to perform the intersection and union of two fuzzy sets. The intersection of two fuzzy sets A and B is specified in general by a binary operation on the unit interval; that is, a function of the form

$$i: [0,1] \times [0,1] \rightarrow [0,1] \dots\dots\dots 12$$

For each element x of the universal set, this function takes as its argument the pair consisting of the element's membership grades in set A and in set B , and yields the membership grade of the element in the set constituting the intersection of A and B . Thus,

$$(A \cap B)(x) = i[A(x), B(x)] \dots\dots\dots 13$$

for all $x \in X$

The functions i that qualify as fuzzy intersections must satisfy the following axioms for all $a, b, d \in [0,1]$:

Axiom 1: $i(a,1) = a$ (boundary condition).

Axiom 2: $d \geq b$ implies $i(a,d) \geq i(a,b)$ (monotonicity).

Axiom 3: $i(a,b) = i(b,a)$ (commutativity).

Axiom 4: $i(a, i(b,d)) = i(i(a,b), d)$ (associativity).

Functions that satisfy these axioms are called t-norms. Examples of some t-norms that are frequently used as fuzzy intersections (each defined for all $a,b \in [0,1]$) are:

Standard intersection: $i(a,b) = \min(a,b)$

Algebraic product : $i(a,b) = ab$.

Bounded difference : $i(a,b) = \max(0, a + b - 1)$

Like fuzzy intersections, the union of two fuzzy sets A and B is specified in general by a binary operation on the unit interval; that is, a function of the form

$$u : [0,1] \times [0,1] \rightarrow [0,1]. \dots\dots\dots 14$$

For each element x of the universal set, this function takes as its argument the pair consisting of the element's membership grades in set A and in set B , and yields the membership grade of the element in the set constituting the union of A and B . Thus,

$$(A \cup B)(x) = u[A(x), B(x)] \dots\dots\dots 15$$

for all $x \in X$.

The functions u that qualify as fuzzy intersections must satisfy the following axioms for all $a, b, d \in [0,1]$:

Axiom 1: $u(a,0) = a$ (boundary condition).

Axiom 2: $d \geq b$ implies $u(a,d) \geq u(a,b)$ (monotonicity).

Axiom 3: $u(a,b) = u(b,a)$ (commutativity).

Axiom 4: $u(a, u(b,d)) = u(u(a,b), d)$ (associativity).

Functions known as t-conorms satisfy all the previous axioms. The following are examples of some t-conorms that are frequently used as fuzzy unions (each defined for all $a, b \in [0,1]$).

Standard union: $u(a,b) = \max(a,b)$

Algebraic sum: $u(a,b) = a + b - ab$.

Bounded sum: $u(a,b) = \min(1, a + b)$

The most widely adopted t-norm for the union of two fuzzy sets A and B is the standard fuzzy union, and for the intersection of two fuzzy sets A and B is the standard fuzzy intersection. The truth value of a fuzzy proposition is obtained through fuzzy implication. In general a fuzzy implication is a function of the form:

$$\mathfrak{I}: [0,1] \times [0,1] \Rightarrow [0,1] \dots\dots\dots 16$$

which for any possible truth values a, b of given fuzzy propositions p, q , respectively, defines the truth value, $\mathfrak{I}(a,b)$, of the conditional proposition "IF p , THEN q ". There are several accepted ways to define $\mathfrak{I}$. One way is defining $\mathfrak{I}$ as:

$$\mathfrak{I}(a,b) = u(c(a),b) \dots\dots\dots 17$$

for all $a, b \in [0,1]$, where u and c denote a fuzzy union and a fuzzy complement, respectively. According to the previous definition for fuzzy implication, it is possible to obtain infinite expressions for fuzzy implication depending upon the selection of the fuzzy union and the fuzzy complement, particularly, for the standard fuzzy union and the standard fuzzy intersection we have:

$$\mathfrak{I}(a,b) = \max(1-a, b) \dots\dots\dots 18$$

The family of fuzzy implication relations obtained from the implication definition given by Eq. 17 are called the S implications. Another implication definition widely accepted is given by:

$$\mathfrak{I}(a,b) = \sup\{x \in [0,1] \mid i(a,x) \leq b\} \dots\dots\dots 19$$

Again, depending on the selection for the fuzzy implication is possible to obtain different fuzzy implication equations, they are usually called R-implications.

Essentially the advantage of a fuzzy set approach is that it can usefully describe imprecise, incomplete or vague information. However, being able to describe such information is of little practical use unless we can infer with it. Assuming that there is a particular problem that cannot (at all or with difficulty) be tackled by conventional methods such as by developing a mathematical model, after some process (e.g. knowledge acquisition from an expert in the domain) the 'base' fuzzy sets that describe the problem are determined. The rules (usually of an IF...THEN... nature (if-then)) are thus determined. These rules then have to be combined in some way referred to as rule composition.

Finally conclusions have to be drawn - defuzzification. There are variations on this approach but essentially we can define a Fuzzy Inference System (FIS) as:

The base fuzzy sets that are to be used, as defined by their membership functions;

The rules that combine the fuzzy sets;

The fuzzy composition of the rules;

The defuzzification of the solution fuzzy set.

All these components of a FIS present complex, interacting choices that have to be made. The rest of this section describes each component in turn and discusses the various approaches that have been used to aid the FIS developer.

As described earlier, a fuzzy set is fully defined by its membership function. How best to determine the membership function is the first question that has to be addressed. For some applications the sets that will have to be defined are easily identifiable. For other applications they will have to be determined by knowledge acquisition from an expert or group of experts. Once the names of the fuzzy sets have been established, one must consider their associated membership functions.

The approach adopted for acquiring the shape of any particular membership function is often dependent on the application. In some applications membership functions will have to be selected directly by the expert, by a 'statistical' approach or by automatic generation of the shapes. The determination of membership functions can be categorized as either being manual or automatic. The manual approaches just rely on the experience of an expert and his/her subjective judgment. All the 'manual' approaches suffer from the deficiency that they rely on very subjective interpretation of words.

The automatic generation of membership functions covers a wide variety of different approaches. Essentially what makes automatic generation different from the manual methods is that either the expert is completely removed from the process or the membership functions are 'fine tuned' based on an initial guess by the expert. The emphasis is on the use of modern soft computing techniques (in particular genetic algorithms and neural networks).

As has already been seen, the fuzzy set approach offers the possibility of handling vague or uncertain information. In a fuzzy rule-based system the rules can be represented in the following way:

If (x is A) AND (y is B)... AND... THEN (z is Z)

where x, y and z represent variables (e.g. distance, size) and A, B and Z are linguistic variables such as ‘far’, ‘near’, or ‘small.’ The process of rule generation and modification can be done manually by an “expert” or automatically using neural networks or genetic algorithms.

Aggregation is the process by which the fuzzy sets that represent the outputs of each rule are combined into a single fuzzy set. The input of the aggregation process is the list of truncated output functions returned by the implication process for each rule. The output of the aggregation process is one fuzzy set for each output variable. Given a set of fuzzy rules the process is as follows:

For each of the antecedents find the minimum of the membership function for the input data. Apply this to the consequent.

For all rules construct a fuzzy set that is a truncated set using the maximum of the membership values obtained.

Once the rules have been composed the solution, as has been seen, is a fuzzy set. However, for most applications there is a need for a single action or ‘crisp’ solution to emanate from the inference process. This will involve the ‘defuzzification’ of the solution set. There are various techniques available. Lee (1990) describes the three main approaches as the max criterion, mean of maximum and the center of area. The max criterion method finds the point at which the membership function is a maximum. The mean of maximum takes the mean of those points where the membership function is at a maximum.

The most common method is the center of area method, which finds the center of gravity of the solution fuzzy sets. For a discrete fuzzy set this is

$$\frac{\sum_{i=1}^n u_i d_i}{\sum_{i=1}^n u_i} \dots\dots\dots 20$$

where d_i is the value from the set that has a membership value u_i . There is no systematic procedure for choosing a defuzzification strategy.

Several of the most commonly recorded conventional well logs, (i.e., Caliper, Gamma Ray, Spontaneous potential, Sonic, Density correction, MSFL, Shallow and deep resistivity), will be used in this study to obtain a continuous log of fracture index through a FIS.

In order to accomplish this goal, the original well log data needs to be preprocessed prior to the use of the FIS. Once the data is preprocessed, we proceed to define the membership functions and the implications required by the Fuzzy Inference System in order to obtain a fracture indication index.

The presence of a single fracture or a system of fractures can cause minor to significant departures from the “normal” well log response. Such abnormalities may be recorded by the different logging devices. When analyzing conventional well logs to determine the presence of fractures several aspects have to be taken into account:

1. No single tool gives absolute indication of the presence of fractures.
2. Conventional logging tools are affected only indirectly by the presence of fractures, and it is only by these indirect effects that the fractures can be detected.

3. Abnormal responses of the different logging tools may also be the result of phenomenon not related to fractures.

Caliper Log: Fractured zones may exhibit one of two basic patterns on a caliper log:

A slightly reduced borehole size due to the presence of a thick mud cake, particularly when using loss circulation material or heavily weighted mud. (Suau, 1989).

Borehole elongation observed preferentially in the main direction of fracture orientation over fracture zones due to crumbling of the fracture zone during drilling.

SP Log: Frequently the SP-curve appears to be affected by fracturing. The response of the SP curve in front of fractured zones has the form of either erratic behavior or some more systematic negative deflection probably due to a streaming potential (the flow of mud filtrate ions into the formation). However streaming potentials can also occur from silt beds. (Crary et al., 1987).

Gamma Ray Log: Radioactive anomalies are recorded by the Gamma Ray log in fractured zones. The observed increase in gamma radioactivity (without concurrently higher formation shaliness) can result from water-soluble uranium salts deposited by connate water along fracture surfaces. (Rider, 1986)

Density Log: Since density logs measure total reservoir porosity, fractures often create sharp negative peaks on the density curve. Assuming that more mudcake accumulates at fractures than elsewhere, the $\Delta\rho$ correction curve reacts to this build up as wheel as to the fluid behind the mudcake reporting an anomalous high correction to the density log.

Neutron log: Similar to the density log, any neutron-type log also measures total reservoir porosity in carbonate rocks. A neutron log by itself is not a reliable fracture indicator. However comparison of neutron log response with other porosity logs may be helpful in determining the zones that may be fractured in the reservoir.

Sonic Log: Large fractures, particularly the subhorizontal ones, tend to create “cycle skipping” on the normal transit time curve. This causes the measured travel time to be either too long or too short. (Bassiouni, 1994).

Laterlogs: The dual laterlog generally provides three resistivity measures, the deep laterlog, the shallow laterlog and the microspherically focused log (MicroSFL). The MicroSFL, which measures resistivity at the invaded zone, responds with high fluctuations in front of fractures. In fresh muds the deep and shallow laterlogs will qualitatively indicate fractures. The shallow curve, due to its proximity to the current return, is more affected than the deep laterlog, and therefore registers a lower resistivity value.

Data Filtering and Scaling. The preprocessing stage is comprised of two major steps: data filtration and data scaling. The main objectives of the preprocessing are: (1) Reduce random noise in the measurements, (2) Scale and normalize the logs within the same range, so they can easily be compared in the Fuzzy inference system, and (3) Obtain the statistical characteristics of the data in order to design appropriate membership functions.

A filter is a mathematical operator that converts a data series into another data series having prespecified form. A digital filter's output $y(n)$ is related to its input $x(n)$ by a convolution with its impulse response $h(n)$ (Mathworks, 1999):

$$y(n) = h(n)X(n) = \sum_{m=-\infty}^{m=\infty} h(n-m)x(m) \dots\dots\dots 21$$

In general, the z-transform, $y(z)$ of a digital filter's output $y(n)$ is related to the z-transform $x(z)$ of the input by:

$$y(z) = H(z)X(z) = \frac{b(0) + b(1)z^{-1} + \dots + b(n_b)z^{-n_b}}{a(0) + a(1)z^{-1} + \dots + a(n_a)z^{-n_a}} x(z) \dots\dots\dots 22$$

where $H(z)$ is the filter transfer function. Here, the constants $b(j)$ and $a(j)$ are the filter coefficients and the order of the filter is the maximum of n_a and n_b . Many standard names for filters reflect the number of a and b coefficients present:

When $n_b = 0$ (that is, b is a scalar), the filter is an Infinite Impulsive response (IIR)

When $n_a = 0$ (that is a is a scalar), the filter is a finite Impulsive Response (FIR), all zero, non-recursive, or moving average (MA) filter.

If both n_a and n_b are greater than zero, the filter is an IIR, pole zero recursive, or autoregressive moving average (ARMA) filter.

It is simple to work back to a difference equation from the z-transform relation shown earlier. Assume $a(1)=1$. Move the denominator to the left hand side and take the inverse z transform:

$$y(n) + a_2y(n-1) + \dots + a_{n_a+1}y(n-na) = b_1x(n) + b_2x(n-1) + \dots + b_{n_b+1}x(n-n_b) \dots\dots\dots 23$$

This is the standard time-domain representation of a digital filter, computed starting with $y(1)$ and assuming zero initial conditions. The progression of this representation is:

- $y(1) = b_1x(1)$
- $y(2) = b_1x(2) + b_2x(1) - a_2y(1)$
- $y(3) = b_1x(3) + b_2x(2) + b_3x(1) - a_2y(2) - a_3y(1)$

For sake of simplicity, in this study, a moving average (MA) filter is implemented with different well logs. This moving average is obtained using six data points (3 data points forward and 3 data points backward from the input value) with the same weight. Since the well log data files to be used in this study are digitized every 0.5 ft, the length of the filter is 3 ft, which is reasonable to detect deviation from the moving average with wavelengths of the order of inches (as might be expected for discrete fractures).

Since fractures are correlated with anomalies in well logs, this six point moving average is used as a "background" value to which each data point is compared. The entire population of

deviations from the background is then used to design membership functions. Depending on which well log is being considered, either positive, negative, or absolute deviations from background are significant:

Sonic log: Only differences which represent an increase in sonic transit time, relative to the background transit time, are significant when considering the influence of fractures on the sonic log.

Caliper: Only positive deviations from background value may indicate the presence of fractures.

MicroSFL: Since the response of this tool fluctuates dramatically in front of fractures, both, positive and negative deviations from background value are significant.

Natural gamma ray: Only positive deviations from background are significant when considering the influence of fractures on this log.

Spontaneous potential: The erratic response that this log may exhibit in the presence of fractures makes both positive and negative deviations from background value important.

Density correction: Only positive deviations from background value are important.

Resistivity logs: In this case, since shallow and deep resistivity logs need to be analyzed together, a different procedure must be implemented. Fracture detection with these logs is based on the principle that a logging tool, which looks deep into the rock mass, is less influenced by fractures than a shallow reading device (Schlumberger, 1989). In vertical fractures, the shallow resistivity log will register a lower resistivity. The procedure followed to incorporate resistivity logs in the fracture detection algorithm are summarized in the following steps:

- Take the ratio between the shallow and deep reading tools.
- Subtract this ratio from a background value.
- The presence of fractures may be indicated by a high positive deviation from background.

Data scaling is necessary for two reasons. First, it is desired to account for essential variability in the filtered log data, and, without some type of scaling process, those logs with the largest original variance would dominate the subsequent analysis. Second, it is desired to have all logs measured in similar units.

In this study a linear scaling method that maps the maximum log value to one and the minimum log value to zero will be used. The linear scaling has the following form:

$$z_i = \frac{x_i - a}{b} \dots\dots\dots 24$$

where z_i is the scaled value, x_i is the original value, a and b are scaling constants.

Once each well log is filtered and scaled, the next step is to define the membership functions. Two membership functions have been designed for each well log. Each membership function maps the universe of discourse (in this case, the entire preprocessed curve) to a fuzzy subset, which expressed whether the probability of fractures is high or low. Membership functions are designed for each log according to the significance of the deviation from background value to the presence of fractures. Two cases are identified:

- (a) When positive deviation from background may be related to fractures (sonic, caliper, and gamma ray and resistivity logs). In this case a sigmoidal membership function will be used. This membership function is defined as (Roger et al, 1997):

$$sig(x; a, c) = \frac{1}{1 + \exp(-a(x - c))} \dots\dots\dots 25$$

where a is the slope at the crossover point, $x = c$.

Depending on the sign of the parameter a , a sigmoidal MF is inherently open right or left. An open right sigmoidal MF indicates high likelihood of fractures, while an open left sigmoidal MF indicates low likelihood of fractures. The crossover point is assumed to be the mean plus one standard deviation of the data. The form that the final MF takes is shown in Figure 3.

- (b) When absolute deviations from background may be related to a high probability of fractures as in the spontaneous potential and MSFL logs, the generalized bell MF seems to be appropriated. A generalized bell MF is specified by three parameters (Roger et al, 1997)

$$bell(x; a, b, c) = \frac{1}{1 + \left| \frac{x - c}{a} \right|^{2b}} \dots\dots\dots 26$$

where c represents the MFs center, a determines the MF width, and, b is an additional parameter related to the slope at the point $c+a$.

The center and width of the MF is taken as the mean and standard deviation of the data, respectively. The form that the final MF takes is shown in Figure 4.

- (c) The membership function for the output variable-fracture index will indicate the probability of fractures according to the logs analyzed. In this case, sigmoidal membership functions are used to indicate high and low fracture index.

To apply FIS to fracture identification the rules need to be set. Among the rules that are being used to obtain a fracture intensity index from conventional well logs are:

- If (caliper is high) and (sonic is high) then (fracture index is high).
- If (resistivity is high) and (MSFL is high) then (fracture index is high).

The number of rules necessary to fully specify output variables for all input variables is given by $S \cdot n$, where S is the number of fuzzy subsets assigned to the input variables and n is the number of input variables.

Figure 5 shows three of the Fuzzy Inference Process rules used have been put together to show how the output of each rule is combined into a single fuzzy set, and finally the output fuzzy set was defuzzified using the centroid calculation method which returns the center of area under the curve.

Figure 5. Fuzzy Inference Process

The data studied in this example include a full set of conventional well logs run in the Bermejo field in Ecuador. The Fracture index logs obtained for the wells analyzed are presented in Figure 6. At this point we only have the fracture index given by the Fuzzy Inference System for several wells in the field, but the global analysis is still to be done.

Again, a more detailed analysis of exactly what the fracture index is indicating needs to be quantified. To that end, we have obtained the geologic characterization of cores from the Frontier formation in Wyoming, the Mesa Verde formation in Colorado and the Austin Chalk formation in Texas. We are in the process of contacting the current operator for the wells to obtain the well logs. From a comparison between the geologic characterization of the core, the fracture density and aspect ratio of the O'Connell and Budiansky model and the fracture index from the fuzzy logic model we will attempt to evaluate the ability of the models to obtain something quantitative about the level of fracturing.

Figure 6A: Fracture Index Logs BN-03, BN-05 and BN-06

Figure 6B: Fracture Index Logs BS-14, BS-17, BS-18 and BS-27

Task III. Develop Wellbore Models for Fractured Reservoir Systems.

During the last project period, work focused on refining and implementing vertical and horizontal wellbore models in the naturally fractured reservoir simulator. Details of the models were presented in the Semi-Annual Report for the period ending December 31, 2000. This work is complete pending testing when the reservoir simulator is fully developed. It is anticipated that this element of the simulator will be fully tested during the next reporting period.

Task IV. Reservoir Simulator Development/Refinement and Studies.

One of the major characteristics in modeling naturally fractured reservoirs is the computation of the fluid exchange between the matrix and the fracture network. This calculation is very difficult at the field scale due to the required detail of fracture description is generally not available. During the current reporting period, the reservoir simulator has been refined for use in modeling naturally fractured reservoirs including the incorporation of wellbore performance models for vertical and horizontal wells. This work has progressed in a timely manner; however, simulation results indicated problems in describing the transfer of reservoir fluids from the matrix to the fracture. This observation has led to an extensive critical review of the currently available models for describing matrix to fracture fluid transfer and on developing a method to describe this physical process that can be incorporated into the naturally fractured reservoir simulator.

Fluid Transfer Modeling. An element of the research on naturally fractured reservoir modeling has focused on representing fluid matrix-fracture transfers. Some of the mechanisms investigated include gravity and capillary effects, capillary continuity or discontinuity of the matrix blocks, and reimbibition phenomenon. In general, fluid transfer models can be grouped into two broad categories depending on the fluid system in the reservoir. Single-phase models have had great application in well test analysis while multiphase models have been predominant in modeling secondary recovery in naturally fractured formations.

Single Phase Models. Barenblatt et al. (1960) proposed a model for naturally fractured reservoirs that is analogous to the model used for heat transfer in a heterogeneous medium. They assumed that the outflow of fluids from the matrix blocks into the fractures was steady state since the process of transfer occurs under a sufficiently smooth pressure change. Without giving details on mathematical derivation, they assumed that fluid transfer rate is a function of the viscosity of the fluid, pressure drop between the matrix and fracture media, and some matrix-rock properties related to geometry and porous interconnectivity in the matrix system. The fluid transfer rate per unit volume of rock was calculated from the following expression.

$$\tau = \frac{\sigma k_m}{\mu} (p_m - p_f) \dots\dots\dots 27$$

where σ is a shape factor related to the specific surface of the fractures.

Warren and Root (1963) presented an application of Eq. 27 in a dual-porosity model for well test data analysis. They proposed an analytical approximation to estimate the geometric factor based on the assumption that sets of parallel fractures are uniformly distributed in a specific reservoir region. A representation of three normal sets of fractures is shown in Fig. 7.

Fig. 7. Gridblock in the dual-porosity model as idealized by Warren and Root.

In general, the shape factor is given by

$$\sigma = \frac{4n(n+2)}{L^2} \dots\dots\dots 28$$

Warren and Root did not present the derivation of this expression. For the particular case of three normal sets of fractures with isotropic rectangular matrix blocks, Eq. 28 becomes

$$\sigma = 6.67 \left(\frac{1}{L_x} + \frac{1}{L_y} + \frac{1}{L_z} \right)^2 \dots\dots\dots 29$$

where L_x , L_y , and L_z are the block lengths along x , y , and z -direction, respectively.

Several researchers have adopted Eq. 27 for modeling fluid transfer in both dual-porosity and dual-permeability models in single and multiphase flow. However there is no agreement on the shape factor. Bourbiaux et al. (1999) presented a comparison of shape factors found in the literature. Table 1 shows the numerical value of the product σL^2 as calculated from different researchers. Methods presented by Kazemi et al. (1976), Thomas et al. (1983), and Coats (1989) are computed and verified through numerical solutions of multiphase flow equations similar to those proposed by Warren and Root. They will be discussed in the next section.

Lim and Aziz (1995) calculated shape factors for dual porosity simulation by combining analytical solutions of pressure diffusion for various flow geometries. For a system composed of one set of fractures, a matrix slab of infinite lateral extent was used to derive a partial differential equation. For systems with two and three normal sets of fractures two approaches are used. The first approach assumes that a matrix block surrounded by two sets of fractures can be represented by a cylinder, and a matrix cube can be approximated by a sphere. The second approach that was

Table 1. Values of the geometric factor, σL^2			
Number of sets of fractures	1	2	3
Warren and Root (1963)	12	32	60
Kazemi et al. (1976)	4	8	12
Thomas et al. (1983)	--	--	25
Coats (1989)	8	16	24
Lim and Aziz (1995)	9.9	19.7	29.6
Quintard and Whitaker (1996)	12	28.4	49.6
Noetinger et al. (1998, 2000)	--	28.4	--
Bourbiaux et al. (1999)	--	20	--

used is the application of the Newman product of dimensionless solutions for diffusion in planes. From these two approaches, similar values were obtained. For the general case of an anisotropic, rectangular matrix blocks, they reported the following expression for the shape factor

$$\sigma = \frac{\pi^2}{k_m} \left(\frac{k_x}{L_x^2} + \frac{k_y}{L_y^2} + \frac{k_z}{L_z^2} \right) \dots\dots\dots 30$$

where the average matrix permeability is computed from the following expression

$$k_m = (k_x k_y k_z)^{1/3} \dots\dots\dots 31$$

Quintard and Whitaker (1996) applied the volume average technique to up-scaling problems from pore scale to Darcy scale and to even larger scales. This method is based on a solution of a system of equations that have been obtained from the averages taken over a representative volume of the local-scale flow equations.

The random walk method (Noetinger et al. 1998, 2000) uses a stochastic process to compute the matrix-fracture exchange function as the probability density function of the time required for a particle to leave a matrix gridblock chosen at random. Bourbiaux et al. (1999) pointed out that this method avoids the explicit resolution of any large linear system and therefore is well adapted to parallel computation. To obtain a shape factor for the Warren-Root model, Bourbiaux et al. numerically studied a two dimensional flow problem by using a square matrix block discretized into several triangular elements. Using a dual-porosity formulation, they defined two dimensionless variables and observed the asymptotic value the dimensionless fluid transfer rate corresponding to the shape factor under steady-state flow conditions.

In the solution to the problem of flow of water in fractured media, Duguid and Lee (1977) considered a porous solid medium with several fractures, which were approximated as cylindrical tubules of elliptical cross sectional area. These cracks have average dimensions, are randomly distributed throughout the matrix, and have porous walls that allow fluid transfer. A representation of their model is shown in Fig. 8.

Fig. 8. Gridblock in the dual-permeability model as idealized by Duguid and Lee.

The formulation of the flow transfer term assumes one-dimensional flow from the matrix to the fracture with an interaction at the block boundary where pressure is assumed to remain constant and equal to the pressure in the fracture. The following approximation was given for the fluid transfer rate per unit volume of rock.

$$\tau = \frac{\sigma k_m}{\mu} \left[(p_m - p_f) + 2 \sum_{n=1}^{\infty} (-1)^n (p_m - p_i) e^{-\xi t} + 2 \sum_{n=1}^{\infty} (p_f - p_i) e^{-\xi t} \right] \quad 32$$

where

$$\xi = \frac{k_m n^2 \pi^2}{2l^2 \mu \phi_m c_i} \quad 33$$

and the shape factor is defined as follows

$$\sigma = \frac{4\phi_f}{\pi c l} \quad 34$$

This formulation differs from those previously discussed in using average fracture properties and geometry, fracture permeability, ϕ_f , fracture aperture, $2c$, and fracture length, $2l$, to define the shape factor rather than matrix block geometry. A direct comparison cannot be done between this approach and those previously discussed for the following reasons. Eqs. 28-30 are in terms of block size while Eq. 33 is in terms of fracture size. Moreover, shape factors calculated from Eqs. 28-30 are independent of fracture width, independent of fracture length, and dependent on fracture porosity since the larger the fracture porosity, the smaller the matrix blocks. On the

other hand, according to Eq. 34, the shape factor is independent of fracture spacing, which is an important characteristic in determining block size in most dual-porosity models. Finally, fluid transfer rate defined by Eq. 31 approaches the steady state solution given by Eq. 27.

Multiphase Models. The complexity of having more than one fluid has been represented by a series of models that consider gravity and capillary effects. Methods to obtain the fluid exchange functions are based on geometric factors, subdomains and empirical parameters, also called empirical transfer functions.

Geometric Factor Methods. These methods extend single-phase models for fluid transfer to multiphase flow in fracture media by modifying both the shape factor and including terms that account for gravity and capillary effects. Kasemi et al. (1976), Thomas et al. (1983), and Coats (1989) extended single-phase flow equations proposed by Warren and Root² to two-phase flow.

The first modification consisted in the use of effective permeability evaluated at the average saturation in the matrix to account for additional resistance to flow due to the presence of other phases. Second, single-phase models are modified by including gravity effects. Kazemi's (1976) original multiphase flow model did not account for gravity effects, which were later added by Gilman and Kazemi (1983) as follows

$$\tau = \sigma k_m \left[\omega \left(\frac{k_r}{\mu B} \right)_{om} + (1 - \omega) \left(\frac{k_r}{\mu B} \right)_{of} \right] \left[(p_{om} - \rho_{om} g D_m) - (p_{of} - \rho_{of} g D_f) \right] \dots\dots\dots 35$$

where ω is a weighting factor that takes values of one if flow is from matrix to fracture and is zero when flow goes in the opposite direction. D_m and D_f are elevations of the matrix and fractures required to account for the gravity head in both media. A more complex version of Eq. 35 was introduced by Gilman and Kazemi (1988), who incorporated additional terms to account for the gravity effects due to fracture elevation differences between adjacent gridblocks.

Sonier et al. (1988) presented a similar form of incorporating the gravity effects. In that case, the weighting function was applied directly to the relative permeability instead of the mobility term. Moreover, elevations were calculated for each phase by assuming that saturation in the matrix and the fracture is the same throughout the gridblock. The following expression was proposed to compute the elevation

$$D_{ap} = \left(\frac{S_{ap} - S_{api}}{1 - S_{orap} - S_{api}} \right) L_z \dots\dots\dots 36$$

Thomas et al. (1983) included pseudorelative permeability and pseudocapillary pressure curves to account for gravity effects in the flow terms but did not give details on how they were obtained. However, discussion and application of pseudo-curves are given elsewhere (Coats et al., 1983; Dean and Lo, 1986; Rossen and Shen, 1987).

Finally, the last major modification to the single-phase model consisted on defining new shape factors for fluid exchange. Using a standard seven-point finite difference formulation of the single-phase flow problem (Kazemi and Gilman, 1993), the following shape factor for a three-dimensional homogenous matrix block was obtained by Kazemi (1976).

$$\sigma = 4 \left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2} \right) \dots\dots\dots 37$$

where L_x , L_y and L_z represent the matrix block dimensions. For the general case of an anisotropic, rectangular matrix blocks, Gilman and Kazemi (1988) presented the following expression for the shape factor

$$\sigma = \frac{4}{k_m} \left(\frac{k_x}{L_x^2} + \frac{k_y}{L_y^2} + \frac{k_z}{L_z^2} \right) \dots\dots\dots 38$$

Even though these shape factors are used in several commercial simulators, it has been indicated they do not properly model pressure gradients within the matrix blocks, since their application is equivalent to assuming a linear pressure gradient between the center of the matrix block and each fracture/matrix boundary (1995).

Thomas et al. (1983) performed a numerical simulation study to compute the shape factor for fluid exchange by matching single-block experiments with three dimensional dual porosity results. For water/oil imbibition, they found an excellent agreement by using σL^2 equal to 25 (Table 1), and for gas/oil gravity drainage, σL^2 equal to 2.

Using a dual-porosity idealization, Coats (1989) proposed a model in which the effects on the exchange function due to viscous gradients in the fracture are ignored. Without presenting the derivation, the following shape factor was recommended

$$\sigma = 8 \left(\frac{1}{L_x^2} + \frac{1}{L_y^2} + \frac{1}{L_z^2} \right) \dots\dots\dots 39$$

Even though, Coats proposed an equivalent expression for anisotropic matrix, he stated that for anisotropic matrix permeability, the shape factor definition loses meaning completely.

The model for fluid exchange proposed by Duguid and Lee (1977) was extended to multiphase conditions by Evans (1982). The basic modification consisted on using effective permeability instead of absolute reservoir permeability. Capillary effects are considered and gravity effects were not taken into account. Evans did not present any numerical solution of his model.

Subdomain Methods. These methods consist of using a matrix block subdivision scheme that allows the computation of pressure and saturation distributions within the matrix blocks. To calculate intramatrix flow, these methods apply single-porosity flow equations that consider gravity, viscous, and capillary effects within the matrix subdomains. Finally, the equations are combined with single-porosity fracture equations to calculate matrix/fracture transfer flow. Even though these methods theoretically should yield more accurate exchange function estimation, they are not currently applied in full field simulation studies since the large number of computational nodes that are required prohibits its use. To calculate intramatrix flow, these methods apply single-porosity flow equations that consider

The first attempt to apply this technique was the multiple interacting continua (MINC) model introduced by Pruess and Narasimhan (1985). In the MINC model, a matrix block is

divided into several computational volume elements whose block interfaces are parallel to the nearest fracture. The division of the porous matrix block gave rise to a model of nested elements as shown in Fig. 9. However, the model is formulated in a way that regular fracture geometry is not required, provided that matrix subdomain surfaces are parallel to fracture planes.

Pruess and Narasimhan validated the MINC algorithm by comparing simulations with analytical solutions available from the work of Warren and Root. To obtain a good agreement, fine spatial resolution and small time steps were required. The model was applied to multiphase systems of water and its vapor flowing in a highly fractured formation.

Wu and Pruess (1986) compared numerical results from the MINC and dual porosity models based on shape factors for fluid exchange. They found that the MINC model yields accurate predictions for water imbibition. Large differences were found when matrix blocks in the dual porosity model were enlarged.

Fig. 9. Gridblock and matrix subdivision in a nested-block model.

Additional to the nested block geometry, Gilman (1986) proposed a stacked block model. The nested blocks represent randomly distributed fracture media and the stacked blocks represent a system where the primary flow path is offered by horizontal fractures. Fig. 10 shows a representation of the stacked block model.

As opposed to the MINC model, the nested model proposed by Gilman requires shape factors to account for flow between the matrix subdomain in contact with the fracture. Shape factors were computed from Eq. 37. Gilman verified the proposed models by comparing the numerical solution with the analytical solution given by Warren and Root. Gilman explained the differences between numerical and analytical solutions as a result of the inability of modeling pressure-transient response within the matrix by the dual-porosity analytical solution. It was concluded that nested matrix blocks should be used for single-phase dual-porosity simulation. Phase segregation during a waterflood was simulated with the vertically stacked block model.

where only the bottom subdomain was connected to the fracture. Shape factors were also used and calculated from Eq. 37 as it was in the case with nested blocks.

Fig. 10. Gridblock and matrix subdivision in a stacked-block model.

Beckner et al. (1991) combined Gilman's nested and stacked models. In the lateral direction, subdomains are the same as the MINC method, which reduces a two-dimensional problem to one-dimension. In the vertical direction, the stacked model is adapted to account for fluid segregation due to gravity. Fig. 11 shows a representation of a typical gridblock and a half-matrix block used in this model.

Fig. 11. Gridblock and matrix subdivision in Beckner et al. model.

For this special geometric distribution of matrix blocks, two geometric constants were derived and applied to flow in the vertical and the horizontal direction. These geometric constants include cross sectional flow areas, absolute permeability and distances between the subdomain centers. These geometric constants play a similar role as the shape factors in Gilman's model.

All models based on the subdomain method are applicable to a naturally fractured reservoir that can be modeled with large matrix blocks with low matrix permeability or contain high viscosity fluids. In these cases, pressure-transient phenomenon within matrix blocks is important and cannot be properly modeled with regular dual-porosity models. They are also useful when the saturation distribution within the matrix blocks control imbibition and gravity segregation processes. For instance, conventional dual-porosity reservoir simulators would give optimistic recovery predictions when compared to multi-subdomain simulators (Beckner et al., 1991).

Empirical Parameter Methods. Aronofsky et al. (1958) presented a model that reproduces the recovery profile observed in laboratory experiments of fractured cores. This model is based on the idealization of a fractured media as composed of identical porous-matrix blocks separated by fractures. Water is allowed to flow through the fractures and to imbibe into the matrix blocks. The observed recovery exhibits a continuous monotonic variation as a function of time that converges to a finite limit. The basic assumption in this model is that "none of the properties that determine the rate of convergence change sufficiently to affect the rate or the limit."

The cumulative oil volume transferred to fracture from a piece of porous-rock matrix surrounded by water when water imbibition is the prevailing force in displacing oil can be approximated by a single-parameter exponential function according to Aronofsky et al. as follows

$$R = R_{\infty} (1 - e^{-\lambda t}) \dots\dots\dots 40$$

where λ is a constant that gives the rate of convergence to the maximum recoverable oil volume, R_{∞} . This maximum oil volume can be calculated from the following expression

$$R_{\infty} = \phi_m (1 - S_{orm} - S_{wcm}) \dots\dots\dots 41$$

where ϕ_m is the matrix porosity, S_{orm} is the residual oil saturation obtained by imbibition alone, and S_{wcm} is the connate water saturation in the porous matrix block.

Kazemi et al. (1992) showed that all Mattax and Kyte's (1962) data collapse into a single correlation if appropriate dimensionless terms are defined. If the dimensionless time is given by

$$t_D = \left[\frac{\sigma_{ow}}{\mu_w} \sigma \sqrt{\frac{k}{\phi}} \right] t \dots\dots\dots 42$$

and the dimensionless rate is computed from the following expression

$$\lambda_D = \left[\frac{\sigma_{ow}}{\mu_w} \sigma \sqrt{\frac{k}{\phi}} \right]^{-1} \lambda \quad \dots\dots\dots 43$$

oil recovery given by the single-parameter exponential function in Eq. 40 is written as follows

$$R = R_\infty (1 - e^{-\lambda_o t_o}) \quad \dots\dots\dots 44$$

In Fig. 12, correlation of Mattax and Kyte's data with Eq. 44 is presented. It can be seen that this one-parameter exponential function works very well in history match of rock samples totally or partially submerged in water.

In Eqs. 42 and 43, the shape factor, σ , was calculated from a generalized expression given by

$$\sigma = \frac{1}{V_m} \sum_s \frac{A_m}{d_m} \quad \dots\dots\dots 45$$

where V_m is the volume of the matrix block, A_m is the matrix surface area in contact with the fracture, and d_m is the distance from the fracture plane to the center of the matrix block. For the particular case of rectangular matrix blocks with all six sides imbibing, Eq. 45 reduces to Eq. 37.

Kazemi et al. (1992) proposed a multi-parameter exponential function for fitting cumulative oil recovery given by

$$R = R_\infty \left(1 - \sum_{i=1}^{\infty} a_i e^{-\lambda_i t} \right) \quad \dots\dots\dots 46$$

The physical interpretation of Eq. 46 was provided by Civan (1993) and Gupta and Civan (1994) who worked with two- and three-parameter exponential functions and showed that a higher number of parameters was not necessary. The basic principle behind the physics of water imbibition is a dynamic process through several stages, each one occurring at a rate proportional to the amount of oil remaining in that stage. For instance, the two-parameter exponential function is used to represent a fracture-matrix interaction where the rate of oil depletion is the matrix is directly proportional to the oil left behind in the matrix block according to Eq. 47 (Civan, 1998).

$$\frac{dR_m}{dt} = -\lambda_3 R_m^\alpha \quad \dots\dots\dots 47$$

Oil droplets that escaped from the net of interconnected and dead-end pores in the porous-rock matrix accumulates over the fracture surface at a rate equal to the difference between the rate of oil release from the matrix and the rate of entrainment by the fluid system flowing through the fracture as expressed in the following relationship

$$\frac{dR_m}{dt} = -\lambda_1 R_m^\alpha - \lambda_2 R_s^\beta \quad \dots\dots\dots 48$$

Fig. 12. Imbibition oil recovery correlation with one-parameter exponential function (After Kazemi³⁰).

Finally, the rate at which oil droplets are produced from the fracture surface by the fluid flowing through the fracture is proportional to the amount of oil available over the fracture plane in contact with the matrix. The mathematical expression that computes this rate is given by

$$\frac{dR}{dt} = -\lambda_2 R_s^\beta \dots\dots\dots 49$$

In Eqs. 47-50, λ_1 and λ_2 are the rate constants of the consecutive transfer process, α and β are stoichiometric coefficients that establish the fraction of oil available to flow in each stage, and R_m and R_s denote the volume of oil remaining in the matrix and at the fracture surface, respectively. The simultaneous solution of the rate equations (Eqs. 47-50), subject to

$$R_m = R_\infty, \quad R = 0, \quad t = 0 \dots\dots\dots 50$$

gives the following equation that computes the oil recovery from the matrix due to water imbibition

$$R = R_{\infty} (1 + a_1 e^{-\lambda_1 t} - a_2 e^{-\lambda_2 t}) \dots\dots\dots 51$$

where the coefficients a are functions of the rate constants according to

$$a_1 = \frac{\lambda_2}{\lambda_1 - \lambda_2} \dots\dots\dots 52$$

and

$$a_2 = \frac{\lambda_1}{\lambda_1 - \lambda_2} \dots\dots\dots 53$$

In the derivation of Eq. 51, $\alpha=1$ and $\beta=1$ were assumed in order to obtain a simple analytic expression. For the general case of $\alpha \neq 1$ and $\beta \neq 1$, a numerical solution of Eqs. 47-50 is required³⁴. Relationships expressed in Eqs. 47-49 establish that the only driving force is the amount of oil remaining in each stage of this dynamic process and do not take into account the interaction of viscous, capillary, and gravity forces.

When fitting oil recovery profiles from cores, the computation of the rate constants λ_1 and λ_2 averages all viscous, capillary, and gravity force effects that prevail during the experiment. That is why empirical parameter exponential functions are good for history match and not for prediction unless, as stated by Aronofsky et al. (1958), “none of the properties that determine the rate of convergence change sufficiently to affect the rate” can be assumed.

Two main applications of empirical parameter exponential functions in simulation of flow through a fractured media are available. The first attempt is related to analytically solving the Buckley-Leverett flow problem in one dimension where fractures are surrounded by an oil-bearing rock matrix undergoing water imbibition. To account for the variation of water saturation at the fracture surface, de Swaan (1978) introduced the one-parameter exponential function with a correction by a convolution. Davis and Hill (1982) corrected a minor error in de Swaan formulation and later the analytical solution was numerically verified by Kazemi et al. (1992). Rasmussen and Civan (1998) obtained alternative analytical solutions to the governing equation by an asymptotic approximation. The use of two-parameter exponential exchange function was presented by Civan (1993, 1998) to obtain quadrature solutions for a one dimensional waterflooding problem.

The second application of empirical parameter exponential functions is either the direct estimation of fluid transfer rate or the calculation of pseudo-transfer functions incorporated in dual-porosity models (Kazemi et al., 1992). Fig. 13 shows a representation of a model that considers the combined use of dual-porosity idealization and empirical parameter exponential functions.

The direct computation of the oil transfer rate per unit volume of rock is obtained from the following expression

$$\tau_o = \phi_m \lambda [S_{wf} (1 - S_{orm} - S_{wcm}) - (S_{wm} - S_{wcm})] \dots\dots\dots 54$$

Fig. 13. Application of empirical parameter transfer functions in dual-porosity models.

Since it is assumed that the rate of oil recovery from the matrix block is equal to the rate of water imbibition, the water transfer rate per unit volume of rock is given by

$$\tau_w = -\frac{B_o}{B_w} \tau_o \dots\dots\dots 55$$

In the derivation of Eqs. 54 and 55, it was assumed that the oil recovery is proportional to water saturation in the fracture, the gravity force is negligible compared to the capillary force and that the oil recovery by water imbibition can be represented by the one-parameter exponential function given by Eq. 40.

Kazemi presented a comparison of coarse-grid dual-porosity numerical solutions that uses pseudofunctions with fine-grid simulations. These pseudofunctions were defined as follows

$$P_{cwf} = -\frac{\phi_m \lambda}{\sigma k_m} (\mu_o + \mu_w) (S_{wm} - S_{wcm}) \dots\dots\dots 56$$

and

$$P_{cwf} = -\frac{\phi_m \lambda}{\sigma k_m} (\mu_o + \mu_w) (1 - S_{orm} - S_{wcm}) S_{wf} \dots\dots\dots 57$$

In deriving Eqs. 56 and 57 from Eq. 54, relative permeabilities were set to unity for convenience and not for representing a physical phenomenon.

In modeling waterfloods with dual-porosity simulators and pseudofunctions, first a fine-grid simulation of a single matrix block is performed, and then λ is obtained by matching the oil recovery curve. In general, λ is the inverse time required to recover 63% of the recoverable oil from the porous-rock matrix.

Kazemi et al. found a good agreement between fine-grid simulations and coarse-grid simulation using dual-porosity models. However, in a numerical experiment with a vertical stack of 10 matrix blocks, they found good agreement only in the top and bottom blocks of the stack. As seen in Fig. 14, the average water saturation of the matrix blocks near the middle of the block column presents a different variation with time by using the one-parameter exponential assumption. The explanation given for such difference is the effect of oil re-saturation and the inability of the exponential approximation for modeling partial water coverage of matrix blocks.

Fig. 14. Water saturation differences using a dual-porosity model with pseudofunctions (After Kazemi et al.).

Conclusions. A brief review of the main mathematical models for fluid exchange between the matrix and the fracture systems has been presented with a discussion of their limitations and applications has been provided.

Single-phase models have been basically used for modeling pressure transient tests. The basic idea of modeling fluid transfer as proportional to the difference of average pressures in the matrix and fracture systems has been maintained while several expressions for computing the

geometric factor have been presented. Currently, no agreement about the appropriate shape factor has been achieved, even after forty years of intensive study of the problem.

The importance of the single-phase models is that they should provide a boundary limit for the flow problem where no effects from the multiphase interactions are present. For an ideal fluid transfer function, the single-phase flow should account for the appropriate effects of geometry and both the matrix and the fracture as a system. Currently, most models only consider the effect of either the matrix or the fracture geometry on fluid transfer. It is true that fracture distribution controls matrix geometry, but, so far, no model accounts for the combined effect of the coupled media where each system has a characteristic geometry.

The ideal fluid exchange function that considers the multiphase effects should be simplified to the expression for single-phase flow. For instance, the empirical parameter exponential approach cannot be used to simulate a reservoir that initially produced single-phase fluids. Moreover, this approach does not even need shape factors since all effects, including geometric effects, are combined into one single factor.

The idealization of the so-called sugar cube model is based on the assumption that the pressure gradient within one matrix block in a gridblock is the same in all directions. The same assumption has been carried over to the multiphase models that rely on the extension of single-phase models when using a geometric shape factor. Implicitly, the nested block model establishes the same constraint by using matrix blocks that are submerged in a gridblock where only the average fracture pressure is considered. This will result in the same pressure gradient in all directions. The stacked block model alleviates this restriction only in one direction. However, as long as only one value for pressure in the fracture within a gridblock is used, calculated pressure gradients in the sugar cube representations are not going to be representatives of those experienced by fluids in a naturally fractured rock.

A more realistic approach should consider that, once the main flow path has been established through aligned flow conducts (macro and micro fractures) in a rock, fluids in the matrix portion principally flow towards those “channels” characterized by better flow conditions. Therefore, all matrix “blocks” within a gridblock do not have uniform pressure gradients in all directions and are prone to develop pressure drops perpendicular to the main flow conducts rather than parallel to them.

The influence of pressure gradients is not expected to be a big problem in the regions away from the wellbore in highly fractured formations with fracture networks homogeneously distributed and fractures equally open to fluid flow at velocities slow enough in all directions.

Finally, formulation of an ideal fluid exchange function should be able to simulate the whole producing life of the naturally fractured reservoir, including, for instance in the black oil case, recovery of oil from natural depletion, intrusion of an active aquifer, waterflooding and water-alternating-gas, immiscible-gas injection, and gas cap expansion. It should include the interaction of viscous, capillary and gravity forces, which can equally act or individually prevail in a specific period of the reservoir life. Research is currently being conducted to attempt to develop this ideal fluid exchange function.

Task V. Technology Transfer.

Technology transfer continued during this reporting period. During this period, informal weekly and monthly meetings have been held to share information between researchers and other interested parties in engineering, geology, and geophysics. Participants have included students,

faculty, and researchers from the University of Oklahoma and industry. The project, through one of the principal investigators, has maintained a naturally fractured reservoir e-mail list server to furnish interested parties with regular updates regarding the project and on other various topics of interest related to naturally fractured reservoirs.

In March, the project team in conjunction with the Oklahoma City Section of the Society of Petroleum Engineers presented a series of papers over two days at the Production and Operations Symposium related to the progress of the research. These papers were well received by the conference participants with attendance averaging 46 people per presentation. These papers are available through the Society of Petroleum Engineers.

The research team presented the following technical papers during the current reporting period.

Brown, R.L., Wiggins, M.L. and Gupta, A.: "Seismic Determination of Saturation in Fractured Reservoirs," paper SPE 67278 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Civan, F. and Rasmussen, M.L.: "Improved Prediction of Waterflood Sweep Efficiency Using Multiexponent Matrix-to-Fracture Transfer Functions," paper SPE 67279 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Martinez, L.P. and Gupta, A.: "Interpretation of Important Fracture Characteristics From Conventional Well Logs," paper SPE 67280 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Gupta, A.: "Characterization of Mass Transfer from Matrix to Fractures," paper SPE 67282 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Quintero, E.J., Martinez, L.P. and Gupta, A.: "Characterization of Naturally Fractured Reservoirs Using Artificial Intelligence," paper SPE 67286 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Brown, R.L., Gupta, A. and Wiggins, M.L.: "Problems Calibrating Production and Seismic Data for Fractured Reservoirs," paper SPE 67317 presented at the 2001 SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Conclusion

During the current reporting period, research has continued on characterizing and modeling the behavior of naturally fractured reservoir systems. Work has progressed on developing techniques for estimating fracture properties from seismic and well log data, developing naturally fractured wellbore models, and modifying a naturally fractured reservoir simulator. The research is currently on schedule as proposed and no obstacles are anticipated for the next six-month reporting period.

Efforts have moved forward in formalizing the relationship between the seismic signals and important flow properties of fractured reservoirs using production data. A genetic algorithm and software program has been implemented to obtain fracture density and aspect ratio through the inversion of fractured reservoir rock models using conventional well logs. In addition, a fuzzy logic inference model has been developed to obtain the fracture index from well logs. The software is ready for further testing.

Wellbore performance models for naturally fractured reservoirs have been incorporated into the naturally fractured reservoir simulator but have not been tested. Work during this period has focused on developing a model to characterize fluid transfer between the matrix and fracture system for incorporation in the simulator.

Research efforts for the next reporting period will concentrate on testing the proposed methods with actual data and formalizing a naturally fractured reservoir characterization methodology. Once the naturally fractured reservoir simulator is complete, simulation studies of various exploitation strategies for naturally fractured reservoirs will be undertaken. In addition, the methodology will be tested by history matching an actual reservoir using available data. This should provide a comprehensive evaluation of the proposed reservoir characterization process.

Efforts will also begin on organizing a three-day naturally fractured reservoir symposium to be hosted by the University of Oklahoma. This symposium will invite researchers from industry and academia to submit abstracts for presenting the latest research in this area. The abstracts will be peer reviewed for inclusion in the program. This symposium will serve as the major technology transfer activity for this project.

Nomenclature

α	= Coefficient of exponential terms
A_m	= Matrix surface area in contact with the fracture
B	= Formation Volume Factor (FVF)
B_o	= Oil FVF
B_w	= Water FVF
B_g	= Gas FVF
c	= Semi-minor axis of an elliptical fracture (fracture half width)
c_t	= Total compressibility
d_m	= Distance from the fracture plane to the center of the matrix block
D	= Reservoir depth
g	= Acceleration of gravity
k	= Permeability
k_r	= Relative permeability
k_{ro}	= Relative permeability to oil phase
k_{rg}	= Relative permeability to gas phase
l	= Fracture half length
L	= Matrix block length (fracture spacing)
n	= Number of normal sets of parallel fractures
R	= Oil recovery
R_{so}	= Solution oil-gas ratio

R_{∞} = Ultimate cumulative oil recovery
 p = Pressure
 P_{cwo} = Capillary pressure
 $\tilde{q}$ = Flow rate per unit volume of rock
 r_w = Wellbore radius
 S = Phase saturation
 S_g = Gas saturation
 S_o = Oil saturation
 S_{or} = Residual oil saturation
 S_w = Water saturation
 S_{wc} = Connate water saturation
 t = Time
 V_m = Volume of matrix block
 α = Stoichiometric coefficient
 β = Stoichiometric coefficient
 ϕ = Porosity
 λ = Empirical rate constant
 μ = Viscosity
 ρ = Density
 σ = Shape factor
 σ_{ow} = Oil-water interfacial tension
 τ = Fluid transfer rate per unit volume of rock
 ω = Weighting factor

Subscripts

D = Dimensionless
 f = Fracture
 g = Gas phase
 i = Initial conditions
 m = Matrix
 o = Oil phase
 p = Porous medium
 r = Relative or residual
 w = Water phase
 x = x direction
 y = y direction
 z = z direction
 α = Phase

References

Abdassah, D. and Ershaghi, I., 1986: "Triple-Porosity Systems for Representing Naturally Fractured Reservoirs," *SPEFE* (April 1986) 113-27.

Agarwal, B., Hermansen, H., Sylte, J.E., and Thomas, L.K., 2000: "Reservoir Characterization of Ekofisk Field: A Giant, Fractured Chalk Reservoir in the Norwegian North Sea – History Match," *SPEREE* (Dec. 2000), 534-43.

Aronofsky, J.S., Masse, L., and Natanson, S.G., 1958: "A Model for the Mechanism of Oil Recovery from the Porous Matrix Due to Water Invasion in Fractured Reservoirs," *Trans., AIME* (1958) **213**, 17-19.

Barenblatt, G.I., Zheltov, I.P., and Kochina, I.N., 1960: "Basic Concepts in the Theory of Seepage of Homogenous Liquids in Fissured Rocks (Strata)," *J. Appl. Math. Mech.* (1960) **24**, 1286-1303.

Bassiouni, Z., 1994: *Theory, Measurement, and Interpretation of Well Logs*. Society of Petroleum Engineers, SPE Textbook Series Vol. 4, 1994.

Beckner, B.L., Chan, H.M., McDonald, A.E., Wooten, S.O., and Jones, T.A., 1991: "Simulating Naturally Fractured Reservoirs Using a Subdomain Method," paper SPE 21241 presented at the SPE Symposium on Reservoir Simulation, Anaheim, California, Feb. 17-20.

Bourbiaux, B., Granet, S., Landereau, P., Noetinger, B., Sarda, S., Sabathier, J.C., 1999: "Scaling Up Matrix-Fracture Transfer in Dual-Porosity Models: Theory and Application," paper SPE 56557 presented at the SPE Annual Technical Conference and Exhibition, Houston, Oct. 3-6.

Brown, S.R., and Bruhn, R.L., 1998: Fluid permeability of deformable fracture networks: *J. of Geophys. Res.*, 103 (B2), 2489-2500.

Brown, R.L., Gupta, A., Wiggins, M.L., 2001a, "Problems Calibrating Production and Seismic Data for Fractured Reservoirs," paper SPE 67317 presented at the SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

*Brown, R.L., Parra, J.O., Xu, P.C., 2001b, Seismic attenuation and flow properties in fractured reservoirs, to be presented at the 2001 SEG International Mtg., San Antonio.

Brown, R.L., Wiggins, M.L. and Gupta, A., 2001c: "Seismic Determination of Saturation in Fractured Reservoirs," paper SPE 67278 presented at the SPE Production and Operations Symposium, Oklahoma City, OK, March 25-28.

Civan, F., 1993: "Waterflooding of Naturally Fractured Reservoirs: An Efficient Simulation Approach," paper SPE 25449 presented at the Production Operations Symposium, Oklahoma City, March 21-23.

Civan, F., 1998.: "Quadrature Solution for Waterflooding of Naturally Fractured Reservoirs," *SPEREE* (April 1998) 141-47.

Coats, K.H., 1989: "Implicit Compositional Simulation of Single-Porosity and Dual-Porosity Reservoirs," paper SPE 18427 presented at the SPE Reservoir Simulation Symposium, Houston, Feb. 6-8.

Coats, K.H., Dempsey, J.R., and Henderson, J.H., 1971: "The Use of Vertical Equilibrium in Two-Dimensional Simulation of Three-Dimensional Reservoir Performance," *SPEJ* (March 1971) 63-71.

Cox, E., 1994: *The Fuzzy Systems Handbook*, Academic Press.

Davis, G.B. and Hill, J.M., 1982: "Some Theoretical Aspects of Oil Recovery From Fractured Reservoirs," *Trans., I. Chem. E.* (1982) **60**, 245-58.

Dean, R.H. and Lo, L.L., 1986: "Development of a Naturally Fracture Reservoir Simulator and Examples of Its Use," paper SPE 14110 presented at the International Meeting on Petroleum Engineering, Beijing, China, Mar. 17-20.

de Swaan, A., 1978: "Theory of Waterflooding in Fractured Reservoirs," *SPEJ* (April 1978) 117-22. *Trans. AIME* **265**.

Duguid, J.O. and Lee, P.C.Y., 1977: "Flow in Fractured Porous Media," *Water Resour. Res.* (1977) **13** (3), 558-66.

Evans, R.D., 1982: "A Proposed Model for Multiphase Flow Through Naturally Fractured Reservoirs," *SPEJ* (Oct. 1982) 669-80.

Gilman, J.R., 1986: "An Efficient Finite-Difference Method for Simulating Phase Segregation in Matrix Blocks in Double-Porosity Reservoirs," *SPEJ* (July 1986) 63-71.

Gilman, J.R. and Kazemi, H., 1983: "Improvements in Simulation of Naturally Fractured Reservoirs," *SPEJ* (Aug. 1983) 695-707.

Gilman, J.R. and Kazemi, H., 1988: "Improved Calculations for Viscous and Gravity Displacement in Matrix Blocks in Dual-Porosity Simulators," *JPT* (Jan. 1988) 60-70.

Gupta, A. and Civan, F., 1994: "An Improved Model for Laboratory Measurement of Matrix to Fracture Transfer Function Parameters in Immiscible Displacement," paper SPE 28929 presented at the SPE Annual Technical Conference and Exhibition, New Orleans, Sep. 25-28.

Hill, A.C. and Thomas, G.W., 1985: "A New Approach for Simulating Complex Fractured Reservoirs," paper SPE 13537 presented at the SPE Reservoir Simulation Symposium, Dallas, Feb. 10-13.

Hudson, J.A., 1980: Overall properties of a cracked solid: *Math. Proc. Cambridge Philos. Soc.*, **88**, 371-384.

Hudson, J.A., 1981: Wave speeds and attenuation of elastic waves in materials containing cracks: Geophys. J. R. Astron. Soc., 64, 133-150.

Kazemi, H., 1969: "Pressure Transient Analysis of Naturally Fractured Reservoirs with Uniform Fracture Distribution," *SPEJ* (Dec. 1969) 451-62.

Kazemi, H. and Gilman, J.R., 1993: *Multiphase Flow in Fractured Petroleum Reservoirs*, in Bear, J. Tsang, C-F, and de Marsily, G. (Eds.): *Flow and Contaminant Transport in Fractured Rock*, Academic Press, Inc., San Diego, California.

Kazemi, H., Gilman, J.R., and Elsharkawy, A.M., 1992: "Analytical and Numerical Solution of Oil Recovery From Fractured Reservoirs With Empirical Transfer Functions," *SPERE* (May 1992) 219-27.

Kazemi, H., Merrill, L.S., Porterfield, K.L., and Zeman, P.R., 1976: "Numerical Simulation of Water-Oil Flow in Naturally Fractured Reservoirs," *SPEJ* (Dec. 1976) 317-26.

Klir, G.J. and Yuan, B., 1995: *Fuzzy Sets and Fuzzy Logic, Theory and Applications*. Prentice Hall.

Lee, C.C., 1990: *Fuzzy Logic in Control Systems: Fuzzy Logic Controller*, Part II. IEEE Transactions on Systems, Man and Cybernetics, 20(2):419-435.

Lim, K.T. and Aziz, K., 1995: "Matrix-Fracture Transfer Shape Factors for Dual-Porosity Simulators," *J. Pet. Sci. and Eng.* **13**, 169-78.

Martinez, L.P., Gupta, A. and Brown, R.L., 2001: "Interpretation of Important Fracture Characteristics From Conventional Well Logs," paper SPE 67280 presented at the 2001 SPE Production Operations Symposium, Oklahoma City, OK, March 24-27.

Mathworks, 1999: *Signal Processing Toolbox User's Guide*, The Mathworks Inc.

Mathworks, 1999: *Fuzzy Logic Toolbox User's Guide*. The Mathworks Inc.

Mattax, C.C. and Kyte, J.R., 1962: "Imbibition Oil Recovery from Fractured, Water-Drive Reservoirs," *SPEJ* (June 1962) 177-84.

Nauck, D., Klawonn, F., Kruse, R., 1997: *Foundations of Neuro-Fuzzy Systems*. John Wiley & Sons, UK.

Noetinger, B. and Estebenet, T., 1998: "Application of Random Walk Methods on Unstructured Grid to Up-Scale Fractured Reservoirs," paper presented the 1998 European Conference on Mathematics of Oil Recovery, Peebles, Scotland, Sep 8-11.

Noetinger, B., Estebenet, T., and Landereau, P., 2000: "Up-scaling of Double Porosity Fractured Media Using Continuous-Time Random Walks Methods," *Transport in Porous Media*, (2000) **39** (3), 315-37.

Oda, M., 1985: Permeability tensor for discontinuous rock masses: *Geotechnique*, **35**, 483-495.

O'Connell, R.J., 1984: *A Viscoelastic Model of Anelasticity of Fluid Saturated Porous Rocks*. Physics and Chemistry of Porous Media, AIP Conf. Proceedings, p.166-175.

Parra, J. O., Hackert, C. L., and P.-C., Xu, 2000, "A model to Relate P-Wave Attenuation to Fluid Flow in Tight Sands, Siliceous Shales , and Carbonate Reservoirs" , Society of Exploration Geophysicists (SEG) International Exposition and Seventy Annual Meeting, Calgary, Canada, August.

Pruess, K. and Narasimhan, T.N., 1985: "A Practical Method for Modeling Fluid and Heat Flow in Fracture Porous Media," *SPEJ* (Feb. 1985) 14-26.

Quintard, M. and Whitaker, S., 1996: "Transport in Chemically and Mechanically Heterogeneous Porous Media," *Adv. in Water Res.*, **19** (1), 29-60.

Rasmussen, M.L. and Civan, F., 1998: "Analytical Solutions for Waterfloods in Fractured Reservoirs Obtained by an Asymptotic Approximation," *SPEJ* (Sep. 1998) 249-52.

Reiss, L.H., 1980: Reservoir engineering Aspects of Fractured Formations, Gulf Publishing Co.

Rider, M.H. 1986: *The Geological interpretation of well logs*. Blackie Halsted Press.

Roger, J.S., Sun, C.T., Mizutani, E., 1997: *Neuro-Fuzzy and Soft Computing*. Prentice Hall, Upper Saddle River, NJ.

Rossen, R.H. and Shen, E.I., 1987: "Simulation of Gas/Oil Drainage and Water Oil Imbibition in Naturally Fractured Reservoirs," paper SPE 16982 presented at the Annual Technical Meeting and Exhibition, Dallas, Sep. 27-30.

Schlumberger, 1989: *Log Interpretation Principles/Applications*, Schlumberger Educational Services, Houston TX.

Schoenberg, M. and Sayers, C.M., 1995: Seismic anisotropy of fractured rock: *Geophysics* **60**, 204-211.

Serra, O., 1986: *Fundamentals of Well Log Interpretation*. Elsevier Science Publishers B.V.

Sonier, F., Souillard, P., and Blaskivoch, F.T., 1998: "Numerical Simulation of Naturally Fractured Reservoirs," *SPERE* (1988).

Thomas, L.K., Dixon, T.N., Pierson, R.G., 1983: "Fractured Reservoir Simulation," *SPEJ* (Feb.1983) 42-54.

Warren, J.E., and Root, P.J., 1963: The Behavior of Naturally Fractured Reservoirs," *SPEJ* (Sep. 1963) 245-55.

Wu, Y.S. and Pruess, K., 1986: "A Multiple-Porosity Method for Simulation of Naturally Fractured Petroleum Reservoirs," paper SPE 15129 at the California Regional Meeting, Oakland, April 2-4.

Zadeh, L.A., 1974: *Fuzzy Logic and its application to approximate reasoning*. Information Processing, 74: 591-594.