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Naturally Fractured Reservoirs: Optimized E&P Strategies Using a Reaction-Transport-Mechanical Simulator in an Integrated Approach

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Summary of Project Accomplishments

Major accomplishments of this project occurred in three primary categories: 1) Fractured Reservoir Location and Characteristics Prediction for Exploration and Production Planning, 2) Implications of Geologic Data Analysis and Synthesis for Exploration and Development Programs, and 3) Fractured Reservoir Production Modeling. The results in each category will be discussed in turn.

A. Fractured Reservoir Location and Characteristics Prediction for Exploration and Production Planning

This project has demonstrated the viability of the most advanced fractured reservoir predictive model. No other model has integrated such a complete set of RTM (reaction, transport, mechanical) processes in a three spatial dimensional finite element simulator. No other model allows for the integration of commonly available remote, downhole and core data directly to constrain the prediction of fractured reservoir characteristics and petroleum reserve and quality prediction.

To test our approach, Andector Field fractured reservoirs were modeled using our RTM basin/reservoir simulator. The latter is based on a coupled dynamics of continuous elastic and ductile rock deformation, fracturing, faulting, diagenesis, and petroleum generation, expulsion and migration. It was shown that our RTM model can be used to predict the location and characteristics of naturally fractured, carbonate reservoirs. It was shown that less complete or statistical correlation models can be much less reliable in making such predictions.

The tremendous challenges of fractured reservoir prediction defy simple analysis. Fig. 1 indicates the cross-coupled nature of the many operating processes that affect fractured reservoir location and characteristics. Rates of change of any one variable (fracture length and orientation, fluid pressure, grain size, etc.) are affected by the values of all the other variables. The approach taken in this project is unique it its inclusion of a comprehensive list of processes and its accounting for all the cross-coupling relations among them. Clearly, models limited to a few variables, not coupled to the entire network of other variables, are likely to have serious limitations.

An example of a popular, simplified approach is curvature analysis. It attempts to relate fracture location to the curvature of sedimentary layers. However, it is the rate of curvature development that determines fracture. Whether a given total flexure developed rapidly or slowly determines whether fracturing occurs. Thus, very slow bending of a bed will allow ductile deformation to take up the induced local extensional strain so that fractures do not occur.

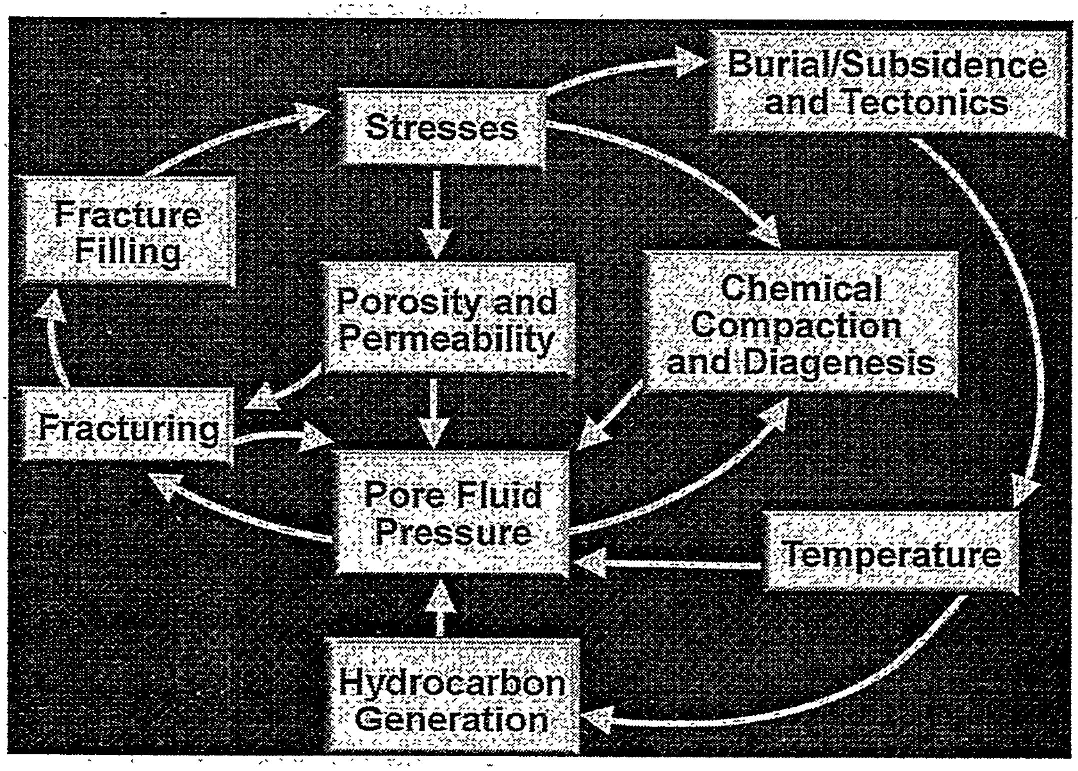

Fig. 1 Complex network of coupled processes underlying the dynamics of a sedimentary basin or evolving reservoir.

Furthermore, in an evolving geomechanical medium, rheology is continuously changing. Thus, it is not only curvature and flexure rate but also the interval in time in the geological past that determine whether fracturing can occur. Finally, even if the inclusions form, they may have healed or infilled with cements. It is the inclusion of all these factors that gives our modeling its unique power.

New physical models and related numerical techniques were developed to arrive at our advanced RTM model. These include:

- a new fracture network dynamics model for predicting the statistics of fracture density, length and orientation, and their influence on a basin/field history;
- formulae relating the predictions of this (the aforementioned) fracture network model to fracture intensity, rose diagrams and other traditional characterization data for checking and calibrating our model;
- a new organic kinetic modeling approach for predicting the rate of oil generation;
- the full coupling of fracture kinetics with rock stress, hydrology and geochemistry so that all associated reactions and feedback loops are accounted for;
- a calibration of the rock rheologic properties accounting for their dependence on grain size, porosity, mineralogy and fracture network characteristics;
- a new multi-phase flow law that accounts for dynamic wetting phenomena; and
- methods for predicting the onset of fracturing of vuggy and karst reservoirs in response to fluid pressure drawdown during primary production or natural processes.

These advanced modeling techniques developed under this project and with our industry partners give our basin/reservoir RTM simulator its unique predictive power.

Our fracture genesis RTM modeling of the pre-production state of Andector Field illustrated a number of points including:

- fracture can occur in zones lacking flexure or tectonic extension if the zones possess a low ratio of the least to maximum compressive stress; this situation is strongly (and predictably) lithologically controlled;
- the rate of flexural deformation is as important as the geometry of the flexure itself; as a result, analysis of present-day static flexure does not always serve as a reliable indicator of fracturing;
- the timing and location of fractures in the geological past is as important as present-day fractures in determining present-day reservoir location and characteristics, especially in light of synfracturing maturation, expulsion and migration; and
- the pre-production state of fracture intensity and orientation as well as petroleum emplacement could be predicted by our RTM model; some improvements in our model and its interface to geological data can make our model a powerful new tool for integrated basin and field E&P analysis.

Additional insight was gained in the following areas:

- The complex dynamics of fracture-mediated expulsion of petroleum from source rock can be oscillatory. Each pulse of expelled petroleum can have its own migration history depending on the relative timing of fracturing and that of the development of transport parameters along petroleum migration pathways.
- Better methods for estimating the compression/extension and basement heat flux histories would facilitate more accurate basin/reservoir RTM modeling and that our comprehensive model is optimally configured to make optimal use of this data due to its integrated multi-process approach. A method combining the approach outlined in the detailed Report D combined with our RTM modeling is an excellent basis for estimating the extension/compression history.
- A dynamic fracture network model, when embedded in a fully coupled basin model, can be used to analyze the shifting directionality of petroleum migration imposed by the changing orientation of dominant fractures.
- The ratio of the rock shear to bulk viscosity was shown to be key to understanding the complex history of fracturing and fracture healing as rock rheologic parameters change due to diagenesis and mechanical alteration (compaction, fracturing, gouge).

These general principles were illustrated using our RTM simulator and, conversely, can be transformed into quantitative predictions via our simulator.

Several computational issues were addressed in evaluating the success of our modeling approach. The computational requirements of our 3-D simulator put our simulations at the forefront of modern computational challenges. The comprehensiveness of our model implies that we simulate over 100 variables (stress tensor, fracture network characteristics, fluid phase saturations and composition, etc.). For minimally acceptable spatial resolution, we require 100,000 finite elements or more (being a more acceptable minimum). This level of computation requires enormous quantities of CPU time.

Typical CPU requirements are as follows:

- 1-D simulations — 6 to 48 hours
- 3-D minimal resolution — 1-3 months

These numbers are for an 8-processor Silicon Graphic Origin 2000. The range of times depends on both the completeness of the sedimentary history (i.e., the number of formations resolved) and the time period of the basin history (i.e., 500 My for the West Texas Permian Basin, West Texas and 78 My for the Piceance Basin, Colorado). Computational demands of our approach must be balanced by their potential benefits. Thus, a simpler approach that fails to account for several processes, would be fraught with greater uncertainty. However, computational demands will certainly be addressed. Computer speed has steadily doubled every eighteen months for the last two decades. Also, we believe that a speed enhancement of a factor of two to five in our code will be obtained in the next six months and much greater efficiency will come with planned optimization, physical approximations, and massive parallelism. Parallel hardware is expected to become much more affordable in the next few years. Thus, the million finite element, comprehensive simulations required for accurate, high spatial resolution modeling should be obtainable in a few CPU days in the next few years on readily available parallel platforms.

It must be recognized that many of the E&P software tools now routinely used would not have been practical on platforms available ten years ago. Only through the development of advanced software will the new generation of E&P tools be available for 2000 and beyond. Our software is already practical for the midsize producer for 1-D and low resolution 3-D simulations and will be practical for high resolution modeling in the near future. Our simulator is presently practical for E&P studies for major petroleum companies.

Improvements of our approach will come with the following advances:

- methods to facilitate and more efficiently collect and format the geological input data;
- development of more complete organic kinetics (for kerogen and fluid petroleum);
- upgrading the flow model to allow for three phases (oil, water and gas) and the exchange of components between them;
- improvements that allow dual porosity/permeability flow;
- improved calibration of the flow, rock mechanics, organic kinetic and other laws;
- development of an improved user interface for non-expert users;
- better output features for easier comparison of model predictions and known geologic data; and
- optimization shell for determining the best values of less well-constrained geological data (such as compression/extension heat flux histories).

These improvements are planned for future projects.

Technical details on many of these accomplishments and conclusions are found in the Reports A, B and C found below.

B. Implications of Geologic Data Analysis and Synthesis for Exploration and Development Programs

In this facet of our project we developed a direct approach to the geological data to derive its interpretations and to formulate it as input data to calibrate and test our RTM simulator-based approach.

We have pursued two primary objectives in the geological analysis and synthesis. The first objective was to understand the regional controls on deformation via an integrated structural analysis incorporating satellite imagery, aeromagnetics, gravity, seismic, regional subsurface mapping and published literature. We primarily addressed the temporal and spatial evolution of the regional stress state and calculated the amount of regional shortening or contraction in order to define model boundary conditions. The second primary objective was to characterize fracture attributes and fracture genesis in the Ellenburger Group. Each of these two objectives is discussed in an attached report.

The key to understanding the timing of natural fractures in the Ellenburger is to link the diagenetic history with the depositional, karst and tectonic histories. From this perspective, a distinction can be made between tectonic and karst-related fractures. A relatively quick, simple method that appears to work in many cored wells studied to date throughout West Texas is whether the fracture crosscuts late, coarsely crystalline dolomite, and whether Fe-rich cements and or pyrite encrust or infill the fractures. In addition, we have calculated that approximately 50-70% of all fractures analyzed in the Phillips-SFBU #4-62 well formed as a result of karst processes. However, in areas adjacent to faults, we believe that the importance of karst fracturing relative to tectonic fracturing is significantly reduced and tectonic fractures are dominant.

A critical aspect of the model is the timing of hydrocarbon migration relative to the precipitation of the different diagenetic and fracture cement phases. A careful study of fracture cements should be undertaken to delineate the presence and characteristics of hydrocarbon inclusions related to the different fracture cement phases. This information would further refine the maturation, migration, entrapment history and will permit additional insight into the major migration pathways. This key point underscores the need to fully utilize an RTM dynamic model for understanding fracture genesis. Thus, data from cores provide point information that can be extrapolated into the target zone via the RTM model.

In the Ellenburger Group, the majority of fractures are caused by karst processes (or its enhancement during later burial) on making the formation vulnerable to post-burial fracturing. Tectonic deformation appears to be most intense in areas adjacent to fault zones and flexure related fracturing is much less common. Most tectonic fractures appear to be thinner and longer than adjacent karst-related fractures. As a result, tectonic fractures likely link up isolated karst-related zones and provide critical reservoir connectivity that may be lacking in stratified karst breccia deposits. Also, in areas where the karst breccias are sediment-dominated and locally low-permeability, tectonic fractures may provide the only reservoir quality permeability. These relationships suggest the importance of delineating structural features, especially in the basement, that control and enhance the development of karst systems. Also, it underscores the need to fully assess the fracture mechanism, given the well-documented influence of both karst and tectonic processes. Failure to consider either mechanism underestimates reservoir quality and connectivity of the karst systems. Thus, it is recommended that to more fully capture these carbonate reservoir systems, karst effects be incorporated into the deformation module.

In production trend analyses of the Andector Field, it appears that the greatest flow rates per reservoir volume are observed adjacent to fault zones. These observations indicate that the karst system is restricted in areal extent and that tectonic fractures are probably more common in fault-zone adjacent areas, in contrast to the structural culmination cored in the Phillips SFBU #4-62. Additional core data should be analyzed in regions adjacent to fault zones to compare the relative abundance of tectonic (fault) vs. karst-related fracturing in these areas. Such data is key to the calibration and testing of karst-modified rheologic behavior needed to augment our RTM model.

Most Ellenburger reservoirs are tectonic fold structures producing from karst-related breccias overprinted by tectonic fractures. The relative importance of the two fracture mechanisms to production and reservoir quality has not previously been quantified. Because it appears that tectonic fractures are less important, especially away from fault zones, this suggests that significant undiscovered Ellenburger Fields may still be present in the subsurface, given the widespread extent of karst-related processes. These reservoirs will be stratigraphic traps and/or subtle structural traps without major tectonic influence.

Over 85% of all natural fractures in the cores examined (karst-related and tectonic) are tightly cemented. In general, dolomite and pyrite cemented fractures show the greatest effective aperture although there is a wide range of fracture occlusion for all data sets. This cement significantly degrades reservoir quality. Most fractures in the basement rocks do not show mineralization. This suggests that this basement rock may be highly conductive and significant oil may be present in overlying coarse clastic rocks possessing adequate reservoir quality where deeper oil has migrated upward along the basement fractures and become trapped beneath the basal Ellenburger seal.

Karst-related fractures tend to be wider, shorter and more completely mineralized with either calcite or dolomite cements. They also tend to have lower dip angles and/or subhorizontal orientations and a wide range of azimuthal orientations. Tectonic fractures are narrower, longer, less completely mineralized or unmineralized, tend to be high-angle and display several preferred orientations (NW, NE and N/S). Drilling-induced fractures are rare, especially compared to the occurrence of such fractures in clastic systems. Given the highly fractured nature of the Ellenburger by karst and tectonic processes, it is possible that many drilling induced fractures propagate along natural surfaces and/or are arrested at abundant breccia zones where core recovery is poor.

Most fractures possess a high dip angle, especially in basement rocks underlying the Ellenburger. There appear to be two primary tectonic fracture trends, NW and NE. The NW-trending fracture set is most dominant and trends parallel to the axis of the local anticline that forms the field.

There is a limited range of length and width distributions for all fractures observed in Ellenburger cored wells. Given core sampling limitations, fracture length/width ratios tend to average around 100:1 for all fracture infill mineralogies (calcite, dolomite, clay, pyrite, quartz, anhydrite). Other wells throughout the region show a similar limited range of fracture width distributions.

There appears to be an Ellenburger reservoir zonation found in Andector Field in which distinct fracture mineralization is restricted to certain reservoir intervals. Anhydrite mineralized fractures are restricted to the shallowest part of the reservoir. Calcite appears to show similar restrictions. Dolomite mineralized fractures are common throughout the reservoir while pyrite and quartz are found in the deepest part of the reservoir. It is possible that this implies limited downward circulation of sulfate-bearing formation waters, and restricted upward migration of deeper subsurface fluids containing dissolved silica and metals. This may also indicate that there is a hydrodynamic boundary (lateral seal) within the Ellenburger reservoir. Reservoir production data, however, suggest that such a seal has not influenced hydrocarbon production.

Approximately 30% of all natural fractures have oil-staining in them. Of these, 9% of the quartz mineralized, 7 % of the calcite mineralized, and 7% of the pyrite mineralized fractures show oil staining. In contrast, 50% of the clay mineralized, 51% of the dolomite mineralized, and 80% of the anhydrite mineralized fractures show oil staining. This information, coupled with the orientation of the majority of these different fracture sets relative to the orientation of the modern maximum horizontal stress (interpreted to be oriented at 103 degrees from analysis of anelastic strain recovery data and borehole imagery logs of drilling induced fractures), allows us to assess which fracture sets are most important to reservoir quality. From this analysis, anhydrite-mineralized fractures oriented orthogonal to this stress orientation are non-conductive and do not show oil-staining. Similarly, NNW-trending calcite-mineralized fractures are not oil-stained and are non-conductive. N/S-trending clay-mineralized fractures are non-conductive as are most dolomite-mineralized fractures oriented at high angles to the maximum horizontal stress. The key to producing these reservoirs is to evaluate the geometry of the tectonic fractures and the extent of their mineral infill relative to the dynamics of the local and regional stress state.

Other cores studied throughout the region suggest that there are significant differences in natural fracture intensity with depth. These wells demonstrate that there are additional significant karst-related breccia zones present in the deeper Ellenburger. That is, below the upper 350 feet that has long been targeted and produced during the evolution of the play.

One of the major findings of this project, in conjunction with other regional syntheses of karst terranes, is the observation that most carbonate rocks that have experienced a fall in base level and/or uplift of the carbonate terrane will show evidence of subaerial exposure and related permeability enhancement. In areas where conventional fractured reservoir analyses will be performed emphasizing structural analysis and structural traps, it is important to realize the potential for high permeability horizontal and subhorizontal zones caused by karstification. In addition, criteria developed in this project to distinguish between tectonic and karst breccias should be used to avoid potential problems in interpretation.

Given the apparent relationship between the development of karst and pre-existing structural anisotropies in the underlying stratigraphy, interpretation of low-cost gravity and aeromagnetic data may provide information to use in delineating anisotropy trends and refine zones of enhanced karst development. These trends can then be further investigated using seismic methods. This data can then be quantitatively synthesized using RTM modeling.

Further discussion on these issues is found in the detailed Reports D, E and G.

C. Fractured Reservoir Production Modeling

Analysis of Andector field production data shows several interesting volumetric and structural aspects of the reservoir.

- During the first major production phase, from 1949 to 1965, reservoir pressure decline was fairly uniform, and from 1958 to 1965 was approximately semi-log linear in time.
- Production increased dramatically from 1968 to 1972, and after this period followed decline forms consistent with a simple, direct water drive.
- The pressure transient curves indicate the reservoir pressure system has experienced one or two encounters with impermeable barriers or interference with neighboring wells.
- The pressure decline curves also show what appears to be a strong aquifer support after about 1971.
- Distribution of hydrocarbon reserves follow structure although there appears to be enhanced production rates adjacent to fault zones. Presumably this is related to enhanced fracture permeability in mesoscopic fault arrays adjacent to the larger fault systems.

The reservoir's long and complicated production history makes the decline curve analysis difficult. It is difficult to obtain permeability data for the reservoir rocks in the individual leases, and the complex re-initialization that would be required makes a reserve estimation using decline curves very difficult. However, the material balance achieved in past reservoir engineering studies was very good, and an overall recovery figure of about 40% appears reasonable.

At present, there is no recognizable evidence for the hypothesis that reservoir pressure depletion has decreased the fracture-related permeability of the reservoir. Detailed reservoir simulation beyond the scope of this project is required to fully assess this scenario, especially in light of observed data complexity.

Further comments on the production data analysis and the need for new reservoir simulation tools are discussed in the detailed Reports C, E and F.