Science Application International Corporation
McLean, Virginia

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, 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.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615) 576-8401.

Available to the public from the National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Rd., Springfield VA 22161

DISCLAIMER

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

DOE/PC/91008-7
Distribution Category UC-122

Naturally Fractured Reservoirs: Optimized E&P Strategies Using A Reaction-Transport-Mechanical Simulator In An Integrated Approach

By
Thomas Hoak (SAIC)
Roger Jenkins (SAIC)
Peter Ortoleva (LCG)
Gonca Ozkan (LCG)
Mamdouh Shebl (LCG)
Walid Sibbo (LCG)
Kenneth Sundberg (Phillips)
Kagan Tuncay (LCG)

July 1998

Work Performed Under Contract No. DE-AC22-94PC91008
Subcontract G4S51730

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

Robert Lemmon, Technology Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by:
Science Applications International Corp
1710 Goodridge Drive, MS E-8-2
McLean, VA 22102
with
Laboratory for Computational Geodynamics
and
Phillips Petroleum Company

Table of Contents

1 EXECUTIVE SUMMARY	vi
I. Project Concept.....	vi
II. Key Issues.....	vii
A. Phase I (first six quarters).....	vii
B. Phase II (second five quarters)	ix
III. Accomplishments of Year One.....	ix
IV Phase I Tasks to be Completed in Year Two.....	xi
V In the Annual Report.....	xiii
References	xiii
2 SEDIMENTATION HISTORY RECONSTRUCTION.....	1
I. Overview.....	1
II. Generalized Stratigraphy and Sedimentology of the Permian Basin.....	1
A. Precambrian Rocks (Crystalline Basement).....	3
B. Ellenburger Group (Lower Ordovician)	5
C. Simpson Group (Middle Ordovician).....	5
D. Montoya Formation (Upper Ordovician)	5
E. Fusselman Formation (Silurian).....	8
F. Wristen Formation (Late Silurian).....	8
G. Thirtyone Formation (lower Devonian).....	9
H. Woodford Formation (Late Devonian-Early Mississippian).....	9
I. Morrow Formation (Pennsylvanian).....	10
J. Atoka Formation (Pennsylvanian)	10
K. Strawn Formation (Pennsylvanian).....	12
L. Canyon Formation(Pennsylvanian-Missourian)	12
M. Cisco Formation(Pennsylvanian-Virgilian).....	12
N. Wolfcamp Series (Permian-Wolfcampian)	13
O. Clear Fork Formation (Permian-Leonardian).....	14
P. Sprayberry-Dean Formations (Permian-Leonardian).....	15
Q. San Andres-Grayburg Formations (Permian-Guadalupian).....	15
R. Queen Formation (Permian-Guadalupian-Ocean)	16
S. Capitan Reef, Seven Rivers, Tansill and Yates Formations (Permian-Guadalupian).....	16
T. Castile (Permian-Guadalupian).....	17
U. Salado (Permian-Guadalupian).....	17
V. Rustler (Permian-Ochoan).....	17
W. Dewey Lake (Permian-Ochoan)	17
X. Permian-Holocene Sediments.....	17
III. Data Gathering, Formatting, and Analysis	18
IV. Core Studies.....	27
A. Lithologic Data Files.....	40
1. Cambro-Ordovician.....	40
2. Middle Ordovician	40
3. Late Ordovician.....	41

4. Siluro-Devonian.....	41
5. Mississippian.....	42
6. Pennsylvanian	42
7. Permian.....	44
9. Leonardian Time:	45
10. Guadalupian Time:	45
11. Ochoan time.....	46
12. CIRFLITH reference data base :.....	49
References.....	49
3 STRUCTURAL GEOLOGY AND TECTONICS	53
I. Introduction	53
II. Overview of Permian Basin.....	53
III. Methodology of Present Study.....	56
IV. Satellite Imagery Linear Features Analysis	56
V. Comparison to Maps Based on Earlier Aerial Photo Interpretation.....	68
VI. Aeromagnetics and Gravity.....	71
VII. Ellenburger Structural Geology.....	77
VIII. Previous studies and existing models	80
IX. Regional Shortening Calculation Methodology.....	91
X. Tectonic Development and Stress Regimes Throughout Basin Evolution.....	94
References.....	97
4 THERMAL AND PRESSURE REGIME.....	101
I. Rationale.....	101
II. Thermal Regime.....	101
III Fluid Pressure.....	106
References.....	109
5 STABILITY AND FAILURE OF CAVITIES IN POROELASTIC MEDIA	111
I Introduction	111
II Cavity in a Poroelastic Medium.....	112
A. Formulation.....	112
B. Porosity-Free Medium Solutions.....	113
1. Calculation of $\frac{S}{\Xi}$	115

2. Stress Field at the Surface of the Ellipsoidal Cavity.....	118
3. Spherical Cavity Case.....	119
III Effective Medium Parameters for Porous Composites.....	120
A. Formulation.....	120
B. Elastic Moduli of Calcite and Dolomite.....	122
C. Porous Calcite - Dolomite Composites	122
1. Numerical example.....	123
IV Failure/Collapse Criterion.....	125
A. Failure Function	125
B. Failure Optimization.....	126
V Illustrative Examples.....	126
A. Failure Function F	128
B. Matrix Texture.....	129
C. Cavity Shape and Orientation	131
D. Fluid Pressure.....	133
E. Far Field Stress Tensor Effects.....	133
VI Conclusions.....	134
References.....	139
 6 SEDIMENTARY BASIN DEFORMATION: AN INCREMENTAL STRESS	
APPROACH.....	141
I. Introduction	141
II. Rheology.....	142
III. Tectonic History Data Input.....	142
IV. Finite Element Solution of Basin Deformation Dynamics.....	143
A. Basic Equations.....	143
B. Constitutive and Governing Equations.....	145
C. Displacement Reformulation	145
D. Integral Formulation.....	146
1. Incremental Form.....	146
E. Finite Element Formulation.....	147
F. Iteration Procedure.....	148
V. Preliminary Results.....	149
References.....	157

1

Executive Summary

(P. Ortoleva)

I. Project Concept

Fractured reservoirs are important exploration and development targets. Our ability to effectively exploit this tremendous resource, however, has been limited by the internal complexity of these reservoirs, the history of geologic influences during basin evolution, and the myriad of interacting mechanical, hydrologic and diagenetic processes that underlie their evolution on the geologic and engineering time scales.

Complex reservoir lithologic geometries and fracture networks have made the prediction of subsurface production-induced fluid flow difficult. Production from these reservoirs has also been hindered by the lack of an adequate reservoir model for optimizing new technologies (e.g. horizontal drilling, coiled tubing, multiple lateral entries) that have facilitated efficient exploitation of anisotropic reservoirs such as fractured zones. In addition, it has been difficult to integrate all of the geologic characterization data into a realistic reservoir model. Today we have a diverse suite of sophisticated technologies and interpretive methodologies for characterizing, predicting, modeling and producing hydrocarbons from naturally fractured carbonate reservoirs.

The purpose of this project is to optimize these modern exploration and production technologies using a new basin and reservoir simulator that automatically integrates recent advances in basin analysis with geochemistry, hydrology, and geomechanics. Our project is being conducted by a partnership between Science Applications International Corporation (SAIC), the Indiana University Laboratory for Computational Geodynamics (LCG) and Phillips Petroleum Company (PPC). It represents an integrated approach to optimize exploration and production strategies for naturally fractured carbonate oil reservoirs. The project has been designed to utilize geologic and geophysical data derived from common sources available to an exploration and field development team. The location, properties and spatial extent of the reservoir are being predicted by integrating seismic, subsurface geologic and engineering data, potential field geophysics and spaceborne imagery, with our basin diagenesis, hydrology, mechanics simulator, *CIRF.B*.

CIRF.B is a unique quantitative reaction-transport-mechanical (RTM) model developed at LCG. It simultaneously solves equations for mineral and pore fluid reaction, fluid and thermal transport, fracture evolution, and incremental stress rheology (elastic, plastic, fracture and pressure solution). To account for the complex interdependent nature of these processes, the *CIRF.B* model computations of the various processes are done self-consistently. A change in one parameter initiates simultaneous changes in other reservoir parameter calculations. Thus, *CIRF.B* solves the fully coupled basin RTM problem.

The output of the model is the evolution of the areal and volumetric distribution of porosity, permeability, and the properties of petroleum and aqueous phases (e.g. pressure and composition). Our method has a greater predictive power than geostatistical models because it takes into account changes that occur to the reservoir rocks due to fluid-rock reactions and other dynamic processes including basin deformation and sedimentary, sea level and thermal histories.

The methodology and results of this project are being tested using the Andector-Goldsmith Field in the Permian Basin, West Texas. Our study area includes the Central Basin Platform and the Midland Basin. The Andector-Goldsmith Field lies at the juncture of these two zones in the greater West Texas Permian Basin. Although the modeling is being conducted in this area, the results have widespread applicability to other fractured carbonate and other reservoirs throughout the world.

II. Key Issues

This project is divided into basin analysis and production phases as follows:

- Phase I: Predict and evaluate the pre-production state of the naturally fractured reservoir.
- Phase II: Predict the effect of production on the reservoir characteristics.

A. Phase I (first six quarters)

In this phase, we are identifying the mechanisms key to reservoir development over geological time and augmenting our basin simulator *CIRF.B* to capture them. Several concepts are discussed in the literature for the origin of fractures in the Clear Fork and Ellenburger Formations (that bear the producing intervals in our Andector-Goldsmith/Permian Basin study area). These and other concepts are being tested in this project.

In general there are many factors which lead to fracturing. Those being considered in this project include:

- fluid overpressuring (OP)
- karst and vug collapse/fracturing
- tectonic activity

We are reviewing OP data provided by Powley (1996, unpublished report). It is possible that OP could have been sufficient to lead to hydrofracturing or enhanced tectonic fracturing in an earlier period of basin development. This is likely the case in the closely related Anadarko Basin, which still has high OP in its deeper zones and underpressuring (UP) in its marginal zones.

Another model to consider is that involving vug collapse and karst-related fracturing. For example, vug and karst collapse and associated fracturing can take place in the absence of tectonism (Kerans, 1989,1990). Thus, we have developed a vug collapse criterion that can capture the effect of overburden on vug stability. Our vug collapse criterion also allows for a large range of stress conditions including the effects of platform uplift. In the Permian Basin, the majority of Ellenburger fractured production comes from structural traps. As a result, it is essential to evaluate the role of tectonic stress on fracture development. The tectonic stress regime is a potential mechanism for fracture formation regardless of rock texture, fluid pressure or other factors (notably vugs and karsts).

In our approach, fracturing is being addressed in several complementary ways:

- the vug/karst collapse/fracture criterion,
- the kinetics of microfracture nucleation and growth within the matrix, and
- the macroscopic approach operating on a length scale much greater than the typical vug or karst feature size.

In all cases it is effective stress ($\underline{\sigma} + \alpha p \underline{I}$) that dictates rock failure (Chapter 6). In the three cases α represents the effective stress coefficient, but its interpretation is different. In the macroscopic approach, α reflects the presence of macroporosity. Furthermore, the macroporosity affects rock strength as manifested in a macroscopic failure criterion.

It is essential to evaluate trap integrity and seal horizons. These are particularly important for complex fractured reservoirs such as Andector-Goldsmith.

Seals in the context of fractured reservoirs can be of various types. Ductile rocks form ideal seals; their deformation, that would otherwise be the driving force for fracture creation, is manifested as a ductile reshaping. Thus ductile strata overlying brittle ones can, in an anticlinal configuration, create a good reservoir.

In this project we are placing more quantitative limits on these concepts. We shall follow the effects of pressure solution, grain growth/dissolution, and other diagenetic transformations on ductility/brittleness. This is being captured in terms of the rate and geometry of deformation.

These ideas will be developed further in Year 2. These concepts are being tested in the Midland/Central Basin Platform study area. Fracture mapping will be a major part of the testing and calibration effort.

B. Phase II (second five quarters)

In this production phase of our study, we shall use the preproduction state of the reservoir and new reservoir modeling features added to *CIRFB* to address the problems associated with assessing the reserves in fractured/vuggy carbonate reservoirs, and the consequences of production on reservoir characteristics. The latter include vug collapse and fracture closure due to fluid pressure drawdown. Vug failure and fracture closure can decrease production by destroying permeability but, when done carefully, can enhance producibility by creating fracturing that connects vugs. The purpose of Phase II is to optimize producibility over the lifetime of the reservoir. Phase II will be discussed later reports.

III. Accomplishments of Year One

Two primary tasks and technology transfer activities were the focus of the last year. Geologic data necessary to model the evolution of the Permian Basin were collected. Existing *CIRFB* computer code was modified in order to model specific problems inherent in simulation of the Permian Basin and other fractured carbonate systems. We have also carried out technology transfer activities to generate operator interest in the project and encourage utilization of the technology advanced by our research program. Progress on specific tasks addressed are as follows.

Task 1: Collect geologic data necessary to model Permian Basin evolution

This task involved several subtasks. These subtasks included collection of data to synthesize the evolution of regional tectonics, sedimentation, thermal properties, sea level variations, fluid and organic composition, and the maturation history in the Permian Basin.

The sedimentation and depositional history was determined. This effort involved compilation of extensive literature, and its synthesis into a coherent quantitative description suitable for input into our *CIRFB* simulator (Chapter 2). Because of the primary focus of this project on the Ellenburger and Clear Fork Formations, particular effort addressed the geology of these two formations, although information on most regionally-persistent formations was

developed to more accurately model the area. Information about lithofacies distribution, texture, chemical composition and diagenetic processes were integrated into this synthesis because most rheologic and diagenetic processes are strongly influenced by rock composition and texture. This information has been compiled into well files for input into *CIRF.B*. These files contain the information necessary to accurately model the basin sedimentary and subsidence/upheaval history. The well files were also used with our sedimentary history re-creation module to analyze the three dimensional structure of the internal state of the sediments. A variety of three dimensional graphical analysis tools developed at LCG are being used to generate images of these patterns as presented in Chapter 2.

The structural geology and tectonics of the Permian Basin were determined using an integrated approach incorporating satellite imagery, aeromagnetics, gravity, seismic data, regional subsurface mapping and published literature (Chapter 3). The two primary emphases were on 1) delineating the temporal and spatial evolution of the regional subsidence; and 2) calculating the amount of regional shortening or extension. Secondary objectives included delineation of basement and shallower fault zones, identification of structural style, preliminary characterization of fractured zones, and analysis of surficial linear features on satellite imagery and their correlation to deeper structures.

Tectonic data were collected in order to define the deformation history of the basin. This information is essential in order to define the boundary conditions used in the *CIRF.B* stress module, and predict the internal deformation experienced within the region of interest. Because basin stress and deformation depends strongly on imposed tectonic and sedimentary loading, this information is essential to the development of an accurate and realistic fracture prediction. Significant effort involved characterization of the surficial geology and other data (including spaceborne imagery, subsurface characterization of structural data from published geologic maps that integrate published literature and related models) yielding a coherent synthesis of regional tectonic evolution. This is used as *CIRF.B* input to specify geologic boundary conditions for the modeling region (i.e., the change in time of the lateral and lower boundary of the simulation domain). In addition, potential field geophysical data (aeromagnetics and gravity) were integrated into the interpretation to provide independent confirmation of regional structural trends, especially at deeper structural levels. This tectonic synthesis is presented in Chapter 3.

Thermal history and data for the basin have been assessed using available literature and proprietary data from PPC. This information is used to constrain the timing of hydrocarbon generation from source beds. Integrated with basin hydrodynamics, this will allow us to predict the geometry and dynamics of hydrocarbon accumulations in the second year of this project. Information on basin thermal history and evolution of basin thermal properties is discussed in Chapter 4.

Sea level data and fluid composition information will be synthesized in the next quarterly report. This data will be supplemented by assessment of sediment organic content and maturation history that will appear in the next quarterly report.

Task 2: Modification of *CIRF.B* to Predict Pre-Production State of Andector-Goldsmith Unit

CIRF.B is being modified to predict the pre-production state of the Andector-Goldsmith Field. This effort involves testing and calibrating a new multi-phase flow reaction-transport module. We also modified the incremental stress solver (Chapter 5) and the Eshelby matrix inclusion calculations to account for vug collapse using a Druker-Prager model (Chapter 6).

Task 8: Technology Transfer

We have initiated a major technology transfer effort. We created a brochure describing the nature, objectives, and importance of the project. We will be sending this brochure to operators active in this area and those with production in similar carbonate reservoirs and distributing it at the AAPG Annual Meeting in Dallas. From these contacts, we plan to generate additional interest in the modeling effort in general and the project in particular. This will also allow us to develop operator interest for the modeling short course to be held next year.

Papers describing our vug collapse criterion (Chapter 5) and basin mechanics simulation (Chapter 6) were prepared for journal submission. Materials were prepared for the 1997 AAPG Annual Meeting (including posters, a *CIRF.B* brochure, a brochure on naturally fractured reservoir optimization, and an invited half-hour lecture on basin modeling by P.J. Ortoleva). In addition, LCG has arranged for an exhibitor's booth at this meeting to publicize this project and related LCG research. Outreach activities with Chevron, Mobil and Amoco have been scheduled around this conference. We have also prepared materials for the SW Regional Meeting of the AAPG to be held in San Angelo in June to showcase the project and generate industry interest.

IV Phase I Tasks to be Completed in Year Two

Although the majority of this task is now complete, some additional geologic data will be gathered. A more rigorous fracture mapping study will be carried out as well as delineation of the organic sedimentology. The majority of this data will come from published literature and PPC and other industry reports.

Logs and core analysis data for wells in the Permian Basin will be collected to assist in more precise characterization of carbonate reservoirs in the basin. These data will also be included in our database for the Permian Basin.

New three dimensional PPC seismic cross sections covering the area of interest will be obtained as available to provide constraints on stratigraphic interpretations. These seismic cross sections will also be incorporated into the tectonic history interpretations and the simulation of the Permian Basin.

Additional thermal history data such as vitrinite reflectance (R_o), T_{max} , and production index (PI) available from PPC will be integrated into the LCG thermal history database. Samples for vitrinite reflectance measurements will be selected and analyzed by PPC. Data from these measurements will be used to more accurately quantify the history of heat flux into the basin. This thermal data will be used to fix the boundary conditions (basement heat flux) needed for the *CIRFB* temperature module.

As the modeling of the pressure regime is very important for the assessment of the tectonic and diagenetic history, and hence, the development of natural hydrofractures in carbonate reservoirs, pressure data available at PPC will be collected, integrated with the data provided by other industry partners, and input into our Permian Basin database. We will use the pressure data to check the accuracy of *CIRFB* predictions of the original reservoir pressure and its evolution in the geological past.

Additional efforts will be invested in compiling a list of major petroleum companies and independent operators working in the Permian Basin to obtain additional information throughout the basin. This data will be used to enlarge our basin database and give the *CIRFB* code the ability to yield a more comprehensive model of the Permian Basin and the distribution of naturally fractured reservoirs within it. Contacts with major and independent operators in the Permian Basin will also be used to establish the bases.

Task 4: Calibrate *CIRFB*

Reservoir engineering data from throughout the Andector-Goldsmith Field will be collected, synthesized and used to perform production trend mapping to confirm subsurface fracture trends. This information will be confirmed with PPC three-dimensional seismic data to verify subsurface permeability trends. Given the low intrinsic permeability observed in both the Clear Fork and Ellenburger reservoirs, natural fractures must be present to account for the production rates observed. The production trend mapping, augmented by seismic analysis, will confirm the three-dimensional aspect of these fracture-controlled trends. Completion of this work is essential to insure an understanding of the pre-production state of the Andector-

Goldsmith Unit. This state will be that predicted by the *CIRFB* model at the end of simulated basin evolution.

Task 8: Technology Transfer

Papers describing our vug collapse criterion (Chapter 5) and basin mechanics simulation (Chapter 6) will be submitted for publication in the next quarter. Materials will be presented at the 1997 AAPG Annual Meeting (including posters, a *CIRFB* brochure, a brochure on naturally fractured reservoir optimization, and an invited half-hour lecture on basin modeling by P.J. Ortoleva). In addition, LCG will have an exhibitor's booth at this meeting to publicize this project and related LCG research. Outreach activities with Chevron, Mobil and Amoco will take place at this conference. We will also have materials available at the SW Regional Meeting of the AAPG to be held in San Angelo in June to showcase the project and generate industry interest.

V In the Annual Report

The remaining chapters of this report delineate the specific accomplishments of Year I activities. Most of these chapters are also being prepared for publication. Specific topics covered are as presented in the Table of Contents.

References

- Kerans, C. (1989) Karst-Controlled Reservoir Heterogeneity and an Example from the Ellenburger Group (Lower Ordovician) of West Texas, Bureau of Economic Geology, Report of Investigations No. 186.
- Kerans, C. (1990) Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas, Bureau of Economic Geology, Report of Investigations No. 193.

2

Sedimentation History Reconstruction

(M. Shebl, T. Hoak, K. Sundberg and P. Ortoleva)

I. Overview

During the first year of this project, data for reconstructing the depositional history was gathered and formatted for input into our automatic basin sedimentary history reconstruction module. The output of this module was then used to develop an understanding of the three dimensional configuration of the lithologic units comprising the basin.

II. Generalized Stratigraphy and Sedimentology of the Permian Basin

The Permian Basin occupies an extensive area encompassing nearly 300,000 km² in southeast New Mexico and west Texas. Major structural elements within this region include the Delaware Basin, the Central Basin Platform, and the Midland Basin (Fig. 2-1). During the Paleozoic, the basin was the site of the Tobosa Basin (Galley, 1958), a shallow marine basin with boundaries corresponding to the later Permian Basin. The region has experienced nearly equal amounts of clastic and carbonate sedimentation whose areal extent reflects the complex interplay between sea level, sediment supply, basin accommodation space (subsidence) and regional tectonics.

The region has experienced one primary period of tectonism during the late Mississippian-late Middle Pennsylvanian. Final deformation occurred during the early Permian. This deformation coincided with continental collision and the formation of the Marathon-Ouachita thrust belt. Following this deformation, the region has experienced little tectonism except related to Laramide (Cretaceous-Tertiary-age) and Basin-and-Range (Paleocene-Recent) extensional deformation along the western margin of the Delaware Basin. This later deformation has not affected the majority of the Permian Basin. Details of the tectonic evolution are provided in the Chapter 3.

Fig. 2-1 Location map of major structural elements and modeling area in the Permian Basin, West Texas (after Hanson et al., 1991).

The stratigraphy will be discussed in order from oldest to youngest. The Ellenburger and Clear Fork formations will be discussed in greater detail because understanding their evolution currently represents one of the primary objectives of the CIRF.B modeling effort.

SYSTEM	SERIES	NORTHWEST SHELF	CENTRAL BASIN PLATFORM	MIDLAND BASIN & EASTERN SHELF	DELAWARE BASIN	VAL VERDE BASIN	
PERMIAN	ECHOA	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO	DEWEY LAKE RUSTLER SALADO CASTLE	RUSTLER SALADO	100
	GUADALUPE	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES GLORIETA	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES SAN ANGELO	DELAWARE MT GROUP BELL CANYON CHERRY CANYON BRUSHY CANYON	TANSILL YATES SEVEN RIVERS QUEEN GRAYBURG SAN ANDRES	100-10
	LEONARD	YESO WICHITA	CLEAN FORK WICHITA	LEONARD SPRAYBERRY, JEAN	BONE SPRING	LEONARD	100-20
	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP	WOLFCAMP	100-30
	VIRGIL	CISCO	CISCO	(ABSENT OR THIN) CISCO	(ABSENT OR THIN)	(ABSENT OR THIN)	100-40
PENNSYLVANIAN	MISSOURI	CANYON	CANYON	CANYON	CANYON	CANYON	100-50
	DES MOINES	STRAWN	STRAWN	STRAWN	STRAWN	STRAWN	100-60
	ATOKA	ATOKA	ATOKA	ATOKA	ATOKA	ATOKA	100-70
MISSISSIPPIAN	MORROW	MORROW	(ABSENT) MORROW	(ABSENT)	(ABSENT)	(ABSENT)	100-80
	CHESTER MEREMEC OSAGE KINDERHOOK	CHESTER MEREMEC OSAGE KINDERHOOK	CHESTER MEREMEC OSAGE KINDERHOOK	CHESTER MEREMEC OSAGE KINDERHOOK	CHESTER MEREMEC OSAGE KINDERHOOK	CHESTER MEREMEC OSAGE KINDERHOOK	100-90
	DEVONIAN	DEVONIAN	DEVONIAN	DEVONIAN	DEVONIAN	DEVONIAN	100-100
SILURIAN	(UNDIFFERENTIATED)	SILURIAN	SILURIAN	SILURIAN	SILURIAN	SILURIAN	100-110
	(UNDIFFERENTIATED)	(UNDIFFERENTIATED)	(UNDIFFERENTIATED)	(UNDIFFERENTIATED)	(UNDIFFERENTIATED)	(UNDIFFERENTIATED)	100-120
ORDOVICIAN	UPPER	MONTTOYA	MONTTOYA	MONTTOYA	MONTTOYA	MONTTOYA	100-130
	MIDDLE	SIMPSON	SIMPSON	SIMPSON	SIMPSON	SIMPSON	100-140
	LOWER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER	ELLENBURGER	100-150
CAMBRIAN	UPPER	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN	CAMBRIAN	100-160
PRECAMBRIAN							100-170

Fig. 2-2 Stratigraphic nomenclature of the Permian Basin (modified after Hanson et al., 1991).

A stratigraphic column for the region is shown in Fig. 2-2. The majority of the following discussion is modified and synthesized from the regional summary provided by Frenzel et al. (1988) and Hanson et al. (1991). Where additional sources are used, they will be explicitly referenced.

A. Precambrian Rocks (Crystalline Basement)

Little is known about the internal variation found in the Precambrian-age basement of the Permian Basin. Precambrian-age outcrops are found in the Trans-Pecos area and in central New Mexico. In the basin proper, the majority of information comes from subsurface regions of uplift such as the Central Basin Platform where complex structure and relatively shallow drilling depths to basement have allowed (sometimes accidental!) several wells to penetrate into crystalline basement (Hills, 1984; Shumaker, 1992). Unfortunately, cuttings and core samples of these wells are rarely preserved and there are few reliable records of basement samples. Even fewer wells have had isotopic age measurements for the basement samples. As a result, a great deal of our information is indirect, coming from interpretations of gravity, aeromagnetism and seismic data. From these data, we know that the Precambrian is cut by numerous NW- and NNW-trending fault systems, thought to be wrench faults (Hills, 1984; Shumaker, 1992) (Fig. 2-3). The

Fig. 2-3 Basement configuration beneath West Texas (modified after Hills, 1982).

age of initial deformation of much of this crust was thought to be Proterozoic in age. The interpreted composition of the basement is apparently quite variable ranging from granophyres through mafic intrusives. In Andector Field, core studied as part of the current project found basement rocks that we characterized as a muscovite schist. This rock showed a penetrative cleavage fabric and a strong lineation on this surface. Small porphyroblasts of unknown mafic mineral (chlorite?) were also present in these cored samples. This occurrence will be discussed in detail in future reports.

In several localities, a Cambrian-age deposit designated the "Granite Wash" is found lying unconformably on top of the crystalline basement. The nature of this lithofacies apparently reflects the composition of the underlying eroded source. Due to limited well penetrations, the regional extent and occurrence of this facies is poorly

understood. It has been penetrated in a very limited number of wells on the Central Basin Platform.

B. Ellenburger Group (Lower Ordovician)

The Ellenburger Group represents the deepest, large hydrocarbon reservoir in the Permian Basin. The Ellenburger was deposited on a broad, open cratonic basin (Fig. 2-4). This Paleozoic basin has been called the Tobosa Basin. Its depocenter now corresponds to the approximate center of the Delaware Basin. It is important to realize that the present geometry of the Permian Basin, composed of the Central Basin Platform and the adjacent Delaware and Midland basins, only achieved its present configuration in the early Permian. As a result, the majority of pre-Permian lithologies show similar lithologic characteristics and correlate across the Permian Basin. Ellenburger reservoirs are structural traps composed of thick dolomites deposited on a restricted circulation carbonate ramp environment. The Ellenburger attains a thickness of more than 550 m south of the Llano Uplift, and a maximum thickness of 490-520 meters in the southern Delaware Basin.

The Ellenburger is considered a classic fractured reservoir. In nearly all fields it is described as pervasively fractured. The significance and genesis of this brecciation will be discussed in greater detail in a section that follows this general overview of all regional stratigraphy. In addition, this later section will discuss models of Ellenburger deposition and diagenesis in greater detail.

C. Simpson Group (Middle Ordovician)

The carbonates of the Ellenburger Group are unconformably overlain by the Simpson Group. The Simpson Group is composed of up to 700 meters of green to gray shales interbedded with limestone and occasional sandstone. The Simpson Group is readily divided into formations (e.g. Bromide and Tulip Creek formations) whose distinct log characteristics permit their identification of that formation throughout the area. The basal sands are apparently the best reservoirs in the group. The Delaware Basin represents the western extent of deposition and the sands thin to the west and south (Fig. 2-5).

D. Montoya Formation (Upper Ordovician)

The Montoya (Upper Ordovician) lies unconformably on top of the Simpson Group. It represents a transgressive system that ranges in thickness up to 180 meters. To the east,

Fig. 2-4 Isopach map of the Ellenburger Formation and an E/W stratigraphic section across the region. Datum is top of lower Ellenburger. Modified after Hanson et al. (1991).

Fig. 2-5 Regional isopach map of Simpson Formation. Modified after Hanson et al. (1991).

in the Midland Basin, the Montoya is redesignated the Sylvan Shale. There its thickness ranges from 0-30 meters with an average of 7-10 meters. The shale is greenish-gray in color. The greatest thickness of the Montoya Formation is between 150 and 180 m at the southeastern part of the Delaware Basin. Thickening of the Montoya Formation is abrupt along the east edge of the depositional basin, suggesting that the rate of subsidence was faster in the Delaware Basin than in the area of the Central Basin Uplift (Frenzel et al., 1988). In most areas, the Montoya is not considered a drilling target primarily because it generally lacks an adequate reservoir seal. Although the Montoya does contain abundant zones of fracture-enhanced porosity that allows communication with overlying and underlying reservoirs, the absence of a top seal precludes the preservation of large hydrocarbon reserves. If the top seal is not present, economic production requires continuity with overlying Siluro-Devonian reservoirs.

E. Fusselman Formation (Silurian)

The Fusselman Formation represents the oldest Silurian age formation in the Permian Basin subsurface. It is a shallow-water carbonate unit that lies conformably on the Montoya Formation and facies-equivalent Sylvan Shale (to the east in the Midland Basin). There are two dominant lithologies. In the basin, the Fusselman is a biogenic limestone ranging between 15-60 meters thick. To the north and west, the Fusselman thickens to over 250 meters. Fusselman traps are: 1) structural closures; 2) truncation by Pennsylvanian-Permian erosion on uplifted blocks of the Central Basin Platform; and 3) truncation by Woodford Shale along the eastern eroded margin of the formation. The overlying Wristen Formation is thought to represent the source beds of most of the Fusselman hydrocarbons and also represents the reservoir seal. Although the Fusselman dolomite facies are areally extensive, hydrocarbons are only found near the limestone facies where it is overlain and sealed by the Wristen Formation or the Woodford Shale.

F. Wristen Formation (Late Silurian)

The Fusselman is overlain by the Wristen Formation. Its stratigraphic thickness ranges from a minimal 30 cm to more than 90 meters thick. The formation is present across the southern Central Basin Platform and the southern Midland Basin. To the north and west, the Upper Silurian thickens markedly to over 460 meters and changes facies to a shallow-water carbonate lithology that includes limestone and dolomite with coral and stromatoporoid reefs.

G. Thirtyone Formation (lower Devonian)

The lower Devonian Thirtyone Formation is dominated by chert in the western area of the basin and changes to a chert and limestone to the east. Thickness ranges from 0-300 meters and the formation is found in the same areas as the underlying Wristen Formation. The Thirtyone Formation produces from tectonically brecciated structures (Delaware Basin chert reservoirs), chert and limestone reservoirs (central and northern Central Basin Platform), and an unusual reservoir called tripolite. Tripolite contains calcite and dolomite within a siliceous framework. These rocks range from siliceous dolomites to slightly calcareous, dolomitic chert. The key attribute to these reservoirs are their very high porosity (average 16%), low permeability and very small pore throats due to microfracturing.

H. Woodford Formation (Late Devonian-Early Mississippian)

The Devonian formations were deposited into a subsiding, deepening basin following an erosional event that is observed at Middle Devonian time. Woodford thickness reaches a maximum of 185 meters. Commencing in the late Devonian, the Woodford Formation shales transgressed the underlying formations. The transgression persisted through the Mississippian. These shales form important reservoir seals capping the Paleozoic-age reservoirs. Because of their organic richness, they are also considered the primary source beds for most of the hydrocarbons in the underlying reservoirs. In addition, the Woodford shales represent one of the best regional markers for stratigraphic correlations due to their marked contrast with underlying and overlying formations on geophysical logs.

In northern parts of the Permian Basin the entire Mississippian System is less than 30 m thick. The Mississippian Period was transitional between two very different tectonic styles in the evolution of the Permian Basin. From the Cambrian time until the Mississippian the Permian Basin region was a relatively stable part of the midcontinent craton, as indicated by the abundance of shallow-water carbonate deposition. In Late Mississippian time, local structures, formed by earlier epeirogenic few and relatively mild tectonism, began to develop and assert themselves. Increasingly more violent tectonism became the style and the geologic environment of the Permian Basin until Middle Permian time. Deposition characteristics in the Permian Basin changed from predominantly carbonates to dominantly shales, and later to coarse-grained and thicker clastics (Frenzel et al., 1988). The greatest of all the tectonic episodes that affected the evolution of the

Permian Basin was the Marathon-Ouachita Orogeny, whose initial phase occurred during Late Mississippian times.

I. Morrow Formation (Pennsylvanian)

The Pennsylvanian rocks of the Midland Basin, Central Basin Platform, and Delaware Basin are extremely variable in distribution, thickness, and lithology. The Pennsylvanian strata which consist of shales, carbonates and sandstones, were deposited in various environments such as shallow-marine carbonate shelves, fluvial coastal plans, and deltas. In the Delaware Basin, the Pennsylvanian-Mississippian contact in the deep part of the Delaware Basin is typically below 4,250 m.

In the Midland Basin, Pennsylvanian rocks are generally less than 300 m thick near the eastern and western margins, and less than 150 m in its center. The typical depth to the Pennsylvanian-Mississippian contact is approximately 3,000 to 3,500 m near the basin axis. The beginning of Pennsylvanian time also saw the deposition of the Morrow Formation whose deposition was restricted to what is now the Delaware Basin (Fig. 2-6a). The Midland Basin and Central Basin Platform areas were topographically elevated and shed sediments into the deeper Delaware Basin depositional environments. All of these uplifted areas around the Delaware Basin represent the source for the Morrow terrigenous clastics.

J. Atoka Formation (Pennsylvanian)

The dramatic onset of regional tectonic deformation in the late Pennsylvanian (Atoka-time) produced marked changes in the paleogeography of the Permian Basin (Fig. 2-6b). As flysch and related clastic sedimentation occurred in the foredeep in front of the advancing Ouachita-Marathon fold-and-thrust belt, significant deformation to the north significantly modified the geometry of the Paleozoic-age Tobosa Basin. The presence of these foredeep-related sediments in the Permian Basin proper, however, did not occur until Virgilian time. Most notably, this deformation resulted in the basin configuration we see today composed of the Delaware and Midland basins with the Central Basin Platform separating the two basins. From its inception, the Delaware Basin has been deeper and more asymmetric than the Midland Basin.

The maximum thickness observed in the Delaware Basin is 110 meters. On the Northwest Shelf, the Atokan section consists of a series of time-transgressive carbonate shelves that prograded southward into the Delaware Basin. In the northern part of the

Fig. 2-6 a) Morrowan paleogeographic map; b) Atokan paleogeographic map; c) Upper and Lower Strawn paleogeographic map. Modified after Hanson et al. (1991).

Eastern Shelf, a variable thickness of the Bend Conglomerate is present. This facies was deposited in terrestrial to near-shore marine depositional systems.

K. Strawn Formation (Pennsylvanian)

The Desmoinesian-age Strawn Formation in the Permian Basin has been subdivided into two stratigraphic units based on fusulinid fossil zonations. The lower or early section is dominated by shallow marine and terrestrial sediments deposited over much of the Midland Basin and Northwest Shelf of the Delaware Basin (Fig. 2-6c). Thicknesses of the Strawn sediments range from 0-70 meters. Because of uplift and related erosion along the southern part of the Central Basin Platform, many of the uplifted blocks remained topographically high well into the Permian.

During upper or late Desmoinesian time, fluctuations in eustatic sea level profoundly affected the nature and distribution of sediments (Fig. 2-6c). This time marked the beginning of the rapid subsidence of the Midland and Delaware basins. Due to this subsidence, many nonmarine facies were flooded and the two basins became deep water, sediment-starved systems. Pennsylvanian oil is trapped stratigraphically in clastic rocks near shelf margins or hinge lines and also in reef-like carbonate buildups within the Midland Basin. The most significant Pennsylvanian oil accumulations are in the carbonates of the Horseshoe Atoll, which is as much as 915 m thick. The atoll is composed of biohermal and biostromal carbonate buildups and their respective talus deposits.

L. Canyon Formation(Pennsylvanian-Missourian)

Due to continuing deepening of the basins and concurrent sea level highstands, the Canyon section is composed almost entirely of shelf limestones (Fig. 2-7a). The deep basin areas received only thin sections of shale. Maximum thickness of the Magdalena Shale facies of the Canyon-Cisco system is 280 meters. The shelf limestones show thicknesses of up to 50 meters.

M. Cisco Formation(Pennsylvanian-Virgilian)

The Cisco facies represent a continuation of those Canyon deposits over most of the Permian Basin. Only along the eastern margin of the Midland Basin did a change in depositional system occur. In this area, the basin was relatively shallow and rapidly filled (Fig. 2-7b). As a result, the shelf edge prograded out into the basin. Although these sediments appear laterally continuous with the Canyon-age parts of the reef, these Cisco sands were mistakenly attributed to the older depositional system.

Fig. 2-7 a) Missourian (Canyon facies) paleogeographic map. b) Virgilian (Cisco facies) paleogeographic map. note establishment of dual basin and platform configuration (modified after Hanson et al., 1991). In the Permian Basin, the Leonardian strata are represented by the Glorieta, Clear Fork, Tubb, Abo, Ouachita, Ouchita-Albany, Sprayberry/Dean, and Bone Spring formations.

During Virgilian time and extending into middle Wolfcampian time, the Marathon-Ouachita system developed along the south side of the Permian Basin and shed muds and sands into the adjacent basins.

N. Wolfcamp Series (Permian-Wolfcampian)

Continued growth of the carbonate shelves and margins continued into the Permian. As the carbonate systems grew along the basin margins, the Delaware and Midland basins became starved because no sediments were able to bypass the shelf margin carbonate systems and reach the deep basin. The Wolfcampian Series consists of a thick (over 670 meters) sequence of carbonates and siliciclastics. There are two primary depositional styles. Although the geometry of many Wolfcamp deposits suggest reef environment, most of them are composed of grainstones and small mud-prone buildups. In the Delaware and Midland basins, debris flow carbonates dominate Wolfcampian time. These debris flows were sourced from adjacent platform areas. The thickest

Fig. 2-8 Map of generalized Permian facies showing locations of principal reef systems along basin margins (modified after Hanson et al., 1991).

Wolfcampian deposits are located adjacent to the Central Basin Platform. it reaches 4,300 m thickness and thins northward to approximately 1,585 m in Ward County and to less than 610 m in the western Delaware Basin (Wilde, 1976). In the Midland Basin the Wolfcampian is represented by mostly gray shales with interbedded limestones and some sandstones near the basin margin. These rocks attain a thickness of about 600 m in the deep parts of the basin (Wilde, 1976).

O. Clear Fork Formation (Permian-Leonardian)

In the Permian Basin, the Leonardian strata are represented by the Glorieta, Clear Fork, Tubb, Abo, Ouachita, Ouachita-Albany, Sprayberry/Dean, and Bone Spring formations. Clear Fork carbonates were deposited as upward-shoaling sequences of shallow-marine to supratidal platform carbonate sediments. Thicknesses of the Clear

Fork range up to 825 meters thick. The Clear Fork is areally restricted to the northeast Central Basin Platform and the adjacent Northwest Shelf. Clear Fork sediments were partly to completely dolomitized and contain abundant sulfate minerals as nodules and cements. Rapid lateral migration of shoreline facies has resulted in extreme lateral discontinuity (Tyler et al., 1991) that impedes reservoir continuity between wells.

P. Sprayberry-Dean Formations (Permian-Leonardian)

These deposits are restricted to the Midland Basin depocenter. These are typically deep water submarine fan, very fine-grained sandstones and siltstones that were deposited basinward of the southward-prograding Northwest Shelf. In the Midland Basin, the lower Leonardian strata attain up to 350 m in thickness that were deposited in deep (more than 200 m) waters. The Sprayberry Formation is about 300 meters thick and the Dean is about 65 meters thick. In the Delaware Basin, the lower Leonardian strata reaches a maximum of 915 m thickness (Hardy, 1976). Because of complex internal architecture of the submarine fans, recovery efficiency of these reservoirs is quite poor (~10% of oil-in-place). These reservoirs contain fractures and have low matrix permeability. To date, there has been little attempt to characterize the fractures in these formations.

Q. San Andres-Grayburg Formations (Permian-Guadalupian)

The San Andres and overlying Grayburg are frequently lumped together because of their close association on the Central Basin Platform, their similar depositional environments and because together they represent the largest hydrocarbon reservoir in West Texas. Both the San Andres and Grayburg formations were deposited in the open marine shelf environment that surrounded the Midland Basin. Depositional environments range from bar and bank complexes along the shelf edge to restricted subtidal lagoons and tidal flats shoreward of the shelf margin. Over time, the San Andres shelf edge prograded eastward into the basin so that the Grayburg shelf edge lies basinward of the San Andres shelf. It reaches 250 to 425 m thickness and consists of cyclic limestone, dolomite, and evaporites of a shallow shelf depositional environments ranging from open marine to sabkha and tidal flat.

San Andres-Grayburg reservoirs consist of upward-shallowing cycles approximately 100 meters thick. The lower two-thirds of each cycle is composed of subtidal facies such as dolomitized skeletal wackestone to pellet grainstone. Local bioherms and skeletal grainstones are also present. Overlying this assemblage is a thin

zone of subtidal to intertidal pellet, skeletal and grainstones. These grainstones are well-sorted, often laminated and crossbedded and interpreted to indicate high-energy deposition. The top of each cycle is capped by a supratidal sequence consisting of interbedded mudstone, siliciclastic siltstone and pisolite facies. These mud-rich flooding surfaces are easily recognizable on most log suites. The dominant production associated with these formations are found on the eastern margin of the Central Basin Platform. On the Ozona Arch, there are also reservoirs found in the high-energy facies of the Grayburg Formation. These units range in thickness from 170 to 365 m.

R. Queen Formation (Permian-Guadalupian-Ocean)

The Queen Formation represents a tidal flat sandstone that is found along the northern edge of the Delaware Basin, the margins of the Central Basin Platform and the southeast edge of the Midland Basin. The Queen Formation thickens to the southeast in the Midland Basin and thins onto the Central Basin Platform and Northern Shelf. Thicknesses of the Queen range from 5 meters to more than 100 meters in the Midland Basin. Queen reservoir sands consist of a diverse suite of eolian, tidal flat and shoreface-tidal flat depositional environments. The sands are overlain by sabkha dolomitic mudstones and massive anhydrite. The massive anhydrite is commonly overlain by eolian sheet sands. The anhydrite generally represents the seal for individual reservoir sands.

S. Capitan Reef, Seven Rivers, Tansill and Yates Formations (Permian-Guadalupian)

The Capitan Reef and related facies form a continuous trend along the western margin of the Central Basin Platform. The Capitan Formation represents the true reef facies. The Seven Rivers, Yates and Tansill formations represent the restricted platform equivalents of the middle and lower Capitan Reef. On the west side of the Central Basin Platform, the Yates Formation is a sequence of siliciclastics associated with sabkha carbonates and evaporites. These sediments were deposited in a prograding tidal flat, lagoonal setting upslope of the shelf-margin reef. Sediments were sourced from the Northwest Shelf, Eastern Shelf, and Southern Shelf. Yates reservoirs consist of siltstone to fine-grained sandstone with varying amounts of cement and clay content. Lithologically, the Yates and Seven Rivers are very similar. The average thickness of the Seven Rivers, Yates, and Tansill sequence ranges from 300 to 490 m. The Delaware Mountain Group

ranges in thickness from 285 to about 1,070 m. The overall thickness of the Guadalupian sequence in the Midland Basin is up to 820 m.

T. Castile (Permian-Guadalupian)

In late Permian time, continued restriction of the Permian Basin resulted in deposition of the Castile Formation evaporites. These evaporites form a thick (600 meter) blanket that effectively precludes vertical migration of fluids. This formation is characterized by centimeter-scale laminations of brown calcite and white anhydrite (varves). Any hydrocarbons generated from the darker varves were apparently expelled laterally into the carbonate reefs. There are no remaining hydrocarbons thought to be present in the Castile.

U. Salado (Permian-Guadalupian)

The Guadalupian-Ocean sediments in the Permian Basin consist of the Salado, Rustler, and Dewey Lake formations. In the Delaware Basin, the Guadalupian-Ocean sediments reach up to 1,375 m in thickness. They also suggest a maximum water depth of deposition that is more than 200 m (Frenzel et al., 1988). The Salado evaporites added to the thickness deposited earlier but were deposited in shallow water lacking significant organic material. The Salado Formation reaches a maximum thickness of 670 meters.

V. Rustler (Permian-Ochoan)

Deposition of the Rustler involved continued deposition of evaporite and dolomite. Prior to deposition of the Rustler, subaerial exposure is thought to have removed approximately 100 meters of overburden. The Rustler Formation achieves a maximum thickness of 160 meters.

W. Dewey Lake (Permian-Ochoan)

These sediments are continental red beds that reach a maximum thickness of 60-70 meters.

X. Permian-Holocene Sediments

The Permian section is capped by an unconformity. This unconformity separates the Permian from the overlying Triassic-age Santa Rosa Sandstone that reaches a

maximum thickness of 80 meters. Another unconformity is present that separates the Lower Cretaceous-age Trinity Sandstone from the underlying Triassic section. The Trinity ranges in thickness from 0-10 meters. Separated from the underlying Trinity by another unconformity, the Lower Cretaceous-age Edwards Limestone reaches a thickness of 30 meters. Finally, overlying these rocks are the sediments of the Tertiary-age Ogallala Group (up to 30 meters thick) and additional Pleistocene and Holocene alluvial deposits.

III. Data Gathering, Formatting, and Analysis

Due to proprietary restrictions on raw data, Phillips had to provide us with the interpolated stratigraphic data in the area of interest (Permian Basin). From this data, stratigraphic information for 230 control points in the basin were used in our construction of the sedimentation history of the Permian Basin. Forty five additional well data were obtained from publicly available cross sections from the Texas Bureau of Economic Geology. This data was integrated with the 230 control well data, and formatted and input into the LCG basin database.

The modeling area was extended to include the eastern one third of the Delaware Basin, the entire Central Basin Platform, and most of the Midland Basin. The modeled area terminates southward halfway between the Delaware Basin and the Val Verde Basin. The computational grid to be used delineates the modeling domain for the sedimentary history reconstruction module. Fig. 2-9a shows the location of the modeling domain and the basement structures in the Permian Basin. Fig. 2-9b shows the grid and the aforementioned 275 wells used in the simulation domain to date. It also shows geographic information such as the location of major cities, longitude and latitude, and orientation of the modeling domain.

As we will show, the inclusion of the stratigraphic data from the 275 wells allows our sedimentary history reconstruction module to simulate the three dimensional sedimentary history of the Permian Basin. This has been verified by comparing our simulation cross sections with published ones. Fig. 2-10 represents a three dimensional stratigraphic simulation of the major units in the Permian Basin. Fig. 2-10a is a southwestern view of the basin. It shows considerable relief on the bottom of the Ellenburger, which coincides with the top of the basement in most parts of the basin. The deepest part of the basin is to the west-southwest (toward the center of the Delaware Basin). Another deep portion of the Permian Basin is located in the center of the Midland Basin. This portion of the Permian Basin is shown clearly in the southeastern view (Fig. 2-10b). The north-northwest view of the Permian Basin indicates that the

Fig. 2-9a Map view showing the basement structural features of West Texas and southeastern New Mexico, and the boundaries of the sedimentation modeling domain (modified from Hills, 1970).

Fig. 2-10a A southwest view of the Permian Basin, as reconstructed by our sedimentary history module using data wells. Formations depicted are from top to bottom: Tertiary, Quaternary, Cretaceous, Triassic, Permian (Ochean), Permian (U. Guadalupian), Permian (M. Guadalupian), Permian (L. Guadalupian), Permian (Leonardian), Permian (Wolfcampian), Pennsylvanian, Mississippian, Devonian, Silurian, Ordovician (Mohawkian), and Ordovician (Canadian), and Cambrian.

Fig. 2-10b A southeast view of the Permian Basin.

Fig. 2-10c A northwest view of the Permian Basin.

Fig. 2-10d A northeast view of the Permian Basin.

Fig. 2-9b Surface contour map on top of the Ellenburger Group showing the grid, location of wells used in the sedimentary reconstruction simulation, longitude and latitude, city locations, and orientation of the modeling domain in the Permian Basin.

Delaware Basin is much deeper than the Midland Basin (Fig. 2-10C). The basement and the overlaying formations dip generally from the northern part of west Texas toward the center of the Delaware and Midland basins (Fig. 2-10D). The dip of these formations is greater in the Delaware Basin than in the Midland Basin.

The overall structure of the Permian Basin is fairly simple and controlled primarily by the uplift of the basement to form the Central Basin Platform. The compressional tectonics resulting in the folding and relief development in the lower one third of the stratigraphic column started in the early Pennsylvanian. The relief on the

basement is best depicted by the overlying Ellenburger Group. Note that the discrepancy between the bottom of the Ellenburger and the bottom of the simulation domain is due to the presence of the Granite Wash (the Bliss Formation) that is locally present. In most areas, however, the Ellenburger carbonate is fairly constant in thickness throughout the Permian Basin (Fig. 2-11a). Our simulated relief of the Ellenburger Group shows the location of the Midland Basin, and the much deeper, Delaware Basin. It also shows that these two basins are separated by the Central Basin Platform, which trends northwest-southeast. The relief persisted throughout the lower one third of the stratigraphic column. This is depicted by the similarity of the relief on top of the Simpson and the Ellenburger carbonates in the light of the fairly constant thickness of the Simpson Carbonates (Fig. 2-11b). This relief stayed fairly constant up to the Wolfcamp Formation and related unconformities. The change in the Wolfcamp thickness, particularly along the Central Basin Platform, was most probably due to erosion (Fig. 2-11c). After the uplift, erosion and an unconformity developed below the Wolfcamp Formation and sedimentation continued with minor interruptions until the Quaternary. This is depicted by the constant thickness and the fairly flat morphology of the formations in the upper part of the stratigraphic section, such as the Yates Formation (Fig. 2-11d) and the Quaternary deposits (Fig. 2-11e).

The three dimensional isopach cross sections of these formations show a number of interesting features (Fig. 2-11a-e). Fig. 2-11a is an east-west view of the Ellenburger Group. It shows spatial continuous sedimentation of the Ellenburger Group, with a 3.1 Km of relief difference between the northeast and southwest corners of the basin. Sedimentation was fairly continuous throughout up to the Pennsylvanian (Wolfcampian), when the Permian Basin achieved its current shape. The uplift and erosion lowered the maximum relief difference on top of the Wolfcamp Formation to about 2 km between the shallow part of the formation (along the eastern portion of the basin) and the deep part of the formation (along the western portion of the basin) (Fig. 2-11c).

Using the slicer in our stratigraphic reconstruction module, oriented cross sections in the modeling domain can be obtained. Fig. 2-12a shows a vertical, north-south cross section along the right edge of the modeling domain. It shows the continuous and fairly constant thickness for most formations along the eastern side of the modeling domain, toward central Texas. Fig. 2-12b is a vertical section cutting across the Central Basin Platform (nearly perpendicular to its axis). It shows the relief on the lower one third of the stratigraphic section (up to the Wolfcamp) along the Central Basin Platform. This relief is reduced or eliminated by the erosion of the top of the Wolfcamp. The vertical, north-south view along the western side of the modeling domain (Fig. 2-12c) shows the

Fig. 2-11a A three dimensional depiction of the Ellenburger Group showing the location of the Midland Basin, and the much deeper, Delaware Basin separated by the Central Basin Platform which trends northwest-southeast.

Fig. 2-11b A three dimensional depiction of the Simpson Group.

Fig. 2-11c A three dimensional depiction of the Wolfcamp Formation.

Fig. 2-11d A three dimensional depiction of the Yates Formation.

Fig. 2-11e A three dimensional depiction of the Quaternary deposits.

Fig. 2-12a A vertical north-south cross section along the eastern edge of the modeling domain.

Fig. 2-12b A vertical north-south cross section along the center of the modeling domain.

Fig. 2-12c A vertical north-south cross section along the curved western edge of the modeling domain.

topography of the basement forming the Delaware Basin and the areas north and south of it. It also shows the noticeable increase in the Wolfcamp Formation thickness westward in the modeled part of the Delaware Basin. This depiction is in accord with published cross sections across the Permian Basin (Matchus and Jones, 1984).

Our east-west cross sections across the Permian Basin are also in general agreement with published data. The front of the domain view (Fig. 2-13a) shows the high land separating the Val Verde Basin (not shown in Fig. 2-13a) from the rest of the Permian Basin. It shows the regional dip of all formations from central Texas to the Delaware Basin. It also shows the down folding of the basement to form the Midland Basin and the deeper Delaware Basin. The east-west cross section across the center of the modeling domain (Fig. 2-13b) shows the location of the Midland Basin, the Central Basin Platform, and the Delaware Basin. It shows the increase in thickness of formations in the lower one third of the stratigraphic section as they enter the Delaware Basin area. It also shows the regional dip of the formations from central Texas to the Delaware Basin. The east-west cross section along the northern edge of the modeling domain (Fig. 2-13c) shows that there is a slight down folding with a slight dip of the formations from central Texas to the Texas-New Mexico border. It also shows a corresponding gentle south ward dip in the basement until reaching the northern edge of the Delaware Basin, where the basement dip increases dramatically.

The additional stratigraphic information gathered during this period and used in augmenting the Permian Basin database resulted in a better control and more realistic stratigraphic three dimensional reconstruction of the basin. Therefore, our efforts to collect stratigraphic and sedimentologic information from the literature and major operators in the area will continue to maximize the information that will be available for *CIRFB* input and building a more comprehensive database for the Permian Basin.

IV. Core Studies

To correctly and comprehensively model the carbonate reservoir attributes stratigraphic, lithologic, thermal, and tectonic data must be used. During our October 1996 visit to Phillips Petroleum, the lithologic examination of six full-length cores from the Ellenburger Group and the Upper Clear Fork Formation was performed. This examinations indicated that both the Ellenburger Group and the Clear Fork Formation consist primarily of carbonates. Fig. 2-14a,b shows typical core intervals from the Ellenburger Group and the Clear Fork Formation.

Fig. 2-13a A vertical east-west cross section along the southern edge of the modeling domain.

Fig. 2-13b A vertical east-west cross section along the center of the modeling domain.

Fig. 2-13c A vertical east-west cross section along the northern edge of the modeling domain.

Fig. 2-14 Typical core intervals from (a) the Ellenburger Group and (b) the Clear Fork Formation.

The Ellenburger Group is composed mostly of fine to coarsely crystalline light-colored carbonates. The studied cores composed principally of dolomite with less than one percent anhydrite and traces of shale. Anhydrite is present as very thin (1 to 15 cm) intervals scattered throughout the cores section or as partial or complete pore-fillings. Shale is present as very thin (1 to 9 cm) layers or as stylolitic seams. The Ellenburger Group contains about 5 percent limestone. The limestone is confined to the lower Ellenburger in the southern part of West Texas area (Wright, 1979).

The Clear Fork Formation consists of alternating zones of massive dolomite, sandy dolomite, argillaceous dolomite, shale, and anhydrite. Locally, the Clear Fork Formation contains considerable amounts of rip-up clasts, rock fragments, and anhydrite nodules. The rock fragments and rip-up clasts range from a few millimeters to tens of centimeters in diameter. The shale and anhydrite make only about ten percent of the Clear Fork Formation. However, their distribution in the Clear Fork Formation indicates deposition in a very shallow marine environment, such as tidal flat and shallow marine (subtidal) environments.

The amount and distribution of porosity and permeability are of great importance to hydrocarbon production. The Ellenburger dolomite can be divided into two main lithologic types: upper mud-dominated facies which typically have less than 2 percent matrix porosity, and lower medium to coarse-grained ooid-peloid grainstone facies. The Ellenburger grainstone facies typically have porosity on the order of 10 percent (Tyler et al., 1991). The mud-dominated facies, where unfractured, provide the seal for the Ellenburger oil reservoirs (Wright, 1979). In the studied cores, porosity of the Ellenburger is represented mainly by matrix dissolution pores. They range in size from one millimeter or less to several centimeter in diameter (Fig. 2-15a-d). Commonly, these dissolution pores are arranged along certain planes, with their long axes parallel to these planes (Fig. 2-15b-d). These planes might represent paleo-groundwater table during different stages of the Ellenburger history. Considerable amount of the dissolution pores and caves formed during the Ellenburger karstification show later stage of diagenetic pore filling (Fig. 2-16a-d). The pore filling is primarily of secondary dolomite or anhydrite composition. These pore fillings nucleate along the walls of the pores and propagate into their centers (Fig. 2-16a,b). Along the pore walls well developed dolomite crystals precipitate and fill most of the pore space (Fig. 2-16c). Contorted and concentric textures similar to those found in geodes and cave walls are common in the Ellenburger (Fig. 2-16d). These textures likely indicate precipitation from carbonate saturated groundwater after percolation and evaporation along the cave walls. Similar features are commonly observed in many open caves around the world. Considerable amounts of remnant porosity is

Fig. 2-15 Porosity distribution in the Ellenburger Group. (a) Primarily of irregular, matrix dissolution pores. (b) Core interval showing the distribution of vuggy porosity. (c) A close-up of an interval depicted in (b). Note the arrangement of vugs along certain planes (most probably paleo-groundwater table). (d) A close-up of an interval depicted in (b). Note the extensive dissolution along fractured zones. Second generation of fractures and microfractures commonly intersect or in close proximity to these vugs.

Fig. 2-16 Pore fillings in Ellenburger Group. (a) Core interval showing distribution of dolomite cavity-fillings. They are present as partial or complete vug and fracture-fillings. (b) Close-up of carbonate cavity-fillings showing their association with fractures. (c) Core photograph showing well crystallized diagenetic dolomite cavity-fillings. (d) Contorted, layered, concentric secondary dolomite deposits present along the inner surface of vugs. Textures are similar to those commonly observed in geodes and modern caves.

present in these pores, vugs, or cavities after the precipitation of secondary wall lining and pore fillings. In the Ellenburger, most of the pores or cavities are connected with or in close proximity to microfractures (Fig. 2-17a-d). Fractures seem to noticeably increase the Ellenburger permeability. Although, different degrees of secondary carbonate precipitation took place along some of these fracture (Fig. 2-17b-d), the remaining porosity and permeability along these fractures seem to effectively connect vugs, and hence, increase the overall permeability of the Ellenburger hydrocarbon reservoirs.

Fractures in the Ellenburger Group have three main morphologies as revealed from the studied cores. These morphologies are: 1) Parallel to subparallel, dendritic, open fractures (Fig. 2-18a,b); 2) Two sets of straight to slightly curved fractures which intersect each other in high angles (i.e. perpendicular or near perpendicular to each other) (Fig. 2-18c); and 3) Straight or slightly curved fractures propagating radially from vugs which are completely or partially collapsed (Fig. 2-18d). The dendritic fractures are most probably the result of fracturing exerted on the Ellenburger during the uplift of one part of the formation relative to another due to movements in the basement. As these fractures tend to concentrate in areas of structural deformation and show considerable dissolution porosity (Fig. 2-18a,b), they make an attractive exploration target. The perpendicular to nearly perpendicular sets of fracture are most probably due to compression and shear stress. Although, some of these fractures show variable degrees of secondary cementation, the remnant porosity and permeability along them and their relationship to vugs distribution might be of great importance in characterizing and managing Ellenburger reservoirs (Fig. 2-18c). The fractures associated with vug collapse are commonly open or partially cemented fractures (Fig. 2-18d). Core examination also indicated that many vugs are filled with anhedral to subhedral carbonate micro-crystals or rock fragments. These vug fillings could be the result of either vug-collapse or diagenetic crystallization. Detailed petrographic examination will be needed to accurately distinguish between the two origins, and correctly interpret the sedimentologic and tectonic history of carbonate reservoirs. Although, vug collapse tends to lower the local reservoir porosity by filling the pore space with rock fragments, it increases the reservoir permeability by connecting isolated vugs with open to partially cemented fractures. Therefore, areas with high concentration of vugs or cavities, where vugs collapse can be detected or predicted, make another attractive exploration target. Therefore, as mentioned above in the executive summary, the relationship between fracturing, tectonism, and vug collapse will be investigated and characterized.

The Clear Fork Formation consists primarily of a very shallow marine tidal flat to subtidal, bioturated mudstone or pellet packstone/grainstone. The porosity of the Clear

Fig. 2-17 Pores-fractures relationship in the Ellenburger Formation. (a) Most vugs are associated with fractures. (b) Core interval showing abundance of fractures. (c) Close-up of (b) showing abundance of carbonate cementation along fractures. Note remnant space along these fractures. (d) Core photograph showing that carbonate cement may only partially fill fractures, leaving the Ellenburger with valuable remnant permeability. This partial filling of fractures seems to be typical of the Ellenburger cores from the Andector area.

Fig. 2-18 Fractures in the Ellenburger Group. (a) Core interval showing tension fractures and stylolitic seams in the Ellenburger. (b) Close-up of (a) showing the parallel, dendritic, open tension fractures. (c) Two sets of nearly perpendicular fractures with abundant carbonate partial fracture-fillings, most probably of compressional origin. Considerable amounts of permeability seem to exist along these fractures. (d) Fractures associated with vug collapse are commonly open or partially cemented with secondary dolomite.

Fork reservoirs typically range from 5 to 12 percent (Tyler et al., 1991). The studied cores indicated that porosity distribution is homogenous throughout the porous interval (Fig. 2-19a). The pores are characterized by fairly circular, oval, or tubular burrows (Fig. 2-19b-d). Some of these pores are partially or completely filled with secondary carbonate and/or anhydrite pore fillings (Fig. 2-19c,d). Although, fractures abundance in the Clear Fork Formation is not as much as that in the Ellenburger Group, the close association of fractures and vugs is quite clear (Fig. 2-20a-d). Fractures in the Clear Fork seem to connect pores that are partially or completely filled with secondary carbonate or anhydrite pore fillings. Most of the fractures in the Clear Fork are high angle (near vertical), irregular or dendritic in shape, and propagating normal to the walls of vugs or caves (Fig. 2-21a-d). These fractures are similar in morphology to the tensional fractures in the Ellenburger (described above), and hence, probably similar in origin too.

Except for the karstification in the Ellenburger, both the Ellenburger and the Clear Fork carbonates are expected to be similar in characteristics since both are of supratidal to subtidal origin. Therefore, except of vug collapse due to purely karstification processes, the origin and effects of fracturing on the reservoir quality is expected to be the same. Hence, studying a non-conventional fractured reservoir, such as the Ellenburger Group, and a more conventional fractured carbonated reservoir, such as the Clear Fork, might enhance our understanding and ability to model and predict the characteristics of carbonate reservoirs in the Permian Basin and other similar geologic settings.

For more understanding of the mineralogical composition, distribution of porosity and permeability, the morphology of pore space, and the relationship between vugs and fractures distribution in the Ellenburger Group and the Clear Fork Formation, petrographic examination of the thin sections provided by Phillips Petroleum from Ellenburger Group and the Clear Fork Formation in the Andector-Goldsmith field will be conducted during the next quarter. The mineralogical and textural information resulting from this examination will be used in augmenting the well files used by *CIRFB* to model the reaction-transport-mechanical characteristics of these reservoirs. The textural attributes of these reservoirs will be used in connection with the tectonic history of the area of interest to verify the origin and the characteristics of vug collapse, and predict the distribution and the effect of vug collapse features on the reservoir quality of these carbonate units.

Fig. 2-19 Porosity in the Clear Fork Formation. Typical intermatrix dissolution pores (white spots) and fine intracrystalline pores are scattered throughout the core interval (a). Most pores are 1 to 5 mm in diameter and most probably formed by bioturbation and animal burrowing (b). Some of the pores are completely or partially filled with carbonate (c), or anhydrite (d). Note the association of some microfracture with these pores.

Fig. 2-20 Fractures in the Clear Fork Formation. Although not as abundant as in the Ellenburger Group, fractures are commonly observed in the Clear Fork Formation. They are commonly associated with or in close proximity to vugs (a). Most fractures seem to be of extensional origin (b). Most of them are connecting vugs that were later filled with anhydrite or carbonate pore-fillings. Most vugs in the Clear Fork Formation are associated with fractures. (c) These fractures increase connectivity between vugs (d).

Fig. 2-21 Extensional fractures in the Clear Fork Formation. They consist primarily of long, parallel to subparallel sets of irregular to dendritic morphology. They commonly run parallel to the long axis of elongated vugs (a), perpendicular to the walls of irregularly shaped vugs (b), perpendicular to the walls of rock fragments, (c) or perpendicular to a major fracture zone (d) in areas with considerable karstification and vuggy porosity.

A. Lithologic Data Files

Lithologic data of various formations in the Permian Basin was collected primarily from literature. This data included the predominant lithology, porosity, permeability, mineralogical composition, and thickness of the major sedimentary units in the Permian Basin, including the Central Basin Platform, and the Delaware and Midland basins. This data is used to trace the distribution of lithologic attributes, and the facies changes of different stratigraphic units throughout the study area. This information is utilized by *CIRFB* to model the changes in the physico-chemical conditions and the diagenetic pathways in the Permian Basin.

The heart of the Permian Basin is a structural sag with the deep Delaware Basin and the shallower Midland Basin being separated by the Central Basin Uplift. The area coincides with that of the older Tobosa Basin, which ceased to exist as an active tectonic element after the deposition of the Woodford back shales in Late Devonian time (Frenzel et al., 1988).

1. Cambro-Ordovician

Late Cambrian sediments in the Permian Basin are represented by thin sandstone (Bliss Sandstone) that is mainly the product of granite wash erosion. It increases in thickness from less than a meter in the southern part of the Permian Basin to about 300 m in the Llano Uplift. The transgressive character of the first Paleozoic deposits in the Permian Basin is depicted in the lateral change in facies northward, from the lower Ordovician limestone of the Llano area to sandstone in the El Paso area (Frenzel et al., 1988).

The lower Ordovician Ellenburger Group contains both calcitic and dolomitic limestone members. South and east of the Permian Basin the Ellenburger is mainly of calcitic limestone composition and contains fossils of Early Ordovician age (Cloud and Barnes, 1948). Northward it becomes uniformly dolomitized and contains very few fossils. The dolomite areas are uniformly mesocrystalline with scattered cherty places and are commonly fractured. Thick deposits of the Ellenburger dolomite indicate deposition in the epeiric shallow Tobosa Basin during Early Ordovician time.

2. Middle Ordovician

The restricted distribution of the Simpson Group in the Permian Basin represents the fully developed area of the Tobosa Basin in the Middle Ordovician time. The

Simpson Group consists of alternating areas of limestone, sandstone, and dark green shale. The Simpson Group locally overlies a thin basal conglomerate, which is most probably due to the erosion of the upper part of the Ellenburger Group.

3. Late Ordovician

The Late Ordovician Montoya Formation, which overlies the Simpson Group in most of the Permian Basin, consists of cherty, finely crystalline calcitic and dolomitic carbonates. The basal Montoya contains quartz grains derived from the underlying Simpson Group. The remainder of the Montoya is dominated by limestone, dolomite and chert. Moving westward, the facies becomes more dolomitic and cherty west of the Central Basin Platform. The distribution of the Montoya Formation in the Permian Basin is restricted to the Tobosa Basin.

Montoya carbonates in the area overlying the Central Basin Uplift are predominantly limestone. In contrast, it consists predominantly of dolomite in the Delaware Basin which is considered the depocenter (Galley, 1958). The inference from this observation is that the carbonate sedimentation rate was the same as the rate of crustal subsidence, thus maintaining shallow-water shelf conditions in the depocenter suitable for dolomite formation (Frenzel et al., 1988).

4. Siluro-Devonian

The Sylvan Formation, which overlies the Montoya in the Tobosa Basin, consists predominantly of gray-green shale. The remainder of the section between the Montoya and the Woodford formations is divided into the Fusselman, Wristen, and Thirtyone formations. The Fusselman Formation consists of a sequence of cherty, medium to coarsely crystalline dolomite and limestone with various amounts of interbedded green shale and inclusions of anhydrite. In the Midland Basin, the Fusselman is dominated by a coarsely crystalline dolomite facies. The Wristen Formation consists of calcareous mudstone and green, dark brown, or gray shale. The Thirtyone Formation consists predominantly of chert in the western part of the Permian Basin. The chert in the Thirtyone Formation grads eastward to cherty limestone and then to mostly limestone in the eastern side of the Permian Basin.

The abundance of fossil plants in the shale and the abundance of algal mat growths in shallow water carbonates of the Siluro-Devonian section indicate stagnant, anoxic shallow water depositional environment where only anaerobic bacteria could survive. This anoxic environment persisted during the deposition of the Woodford Formation in

the Tobosa Basin, and explains the high organic content of the Woodford shale that makes it an important source rock for hydrocarbons generation in the Permian Basin (Frenzel et al., 1988).

5. Mississippian

Early Mississippian sedimentation was mostly in transgressive depositional environments, like those of the Early Ordovician. The Mississippian deposits range from clastics in the southern part of the Permian Basin to thin carbonates farther north, and their thicker carbonates cover most of the basin (Frenzel et al., 1988).

The Early Mississippian Kinderhook Formation consists of green-gray shale and commonly overlies the Woodford Formation. The Middle Mississippian Osage and Meramec carbonates change in facies from calcitic limestone to argillaceous and silty, or siliceous and cherty, limestone. The limestone is not dolomitic as are most of the pre-Mississippian carbonates. These strata are locally interbedded with dark gray and brown shale beds. The Upper Mississippian Chester Formation consists predominantly of shale that grades northward to thin-bedded limestone (Frenzel et al., 1988).

6. Pennsylvanian

The greatest volumes of paleozoic rocks in the Permian Basin are of Pennsylvanian or Permian age. During the early Pennsylvanian time, most of the Midland Basin was a site for shallow marine and terrestrial sedimentation. In the Midland Basin, the Pennsylvanian strata consist predominantly of gray to black marine shale with some sands, silts, and carbonates near the basin margins.

At the western part of the Delaware Basin, along the shelf-edge, Pennsylvanian cyclic carbonates are dominant and consist predominantly of algal bioherms and associated grainstone shoals. The thickest accumulations of Pennsylvanian rocks consist of predominantly fine-grained terrigenous clastics, particularly gray-black shales, with some thin interbedded siltstones and sandstones. To the west and northwest, the clastics change facies to shelf carbonates. The maximum water depths and rates of subsidence at the depocenter occurred in the eastern part of the Delaware Basin, in a north-south trend parallel and adjacent to the Central Basin Platform. The Morrow Formation is a thick section composed of thin individual units of repetitive nearshore siliciclastics and less abundant carbonates that were deposited on the gently southward-sloping shelf. Morrow hydrocarbon reservoirs are oolitic grainstones, and micritic limestones in areas where siliciclastic deposition was minimal. In the siliciclastic section, principal reservoirs

include fluvio-deltaic and tidal channels, near-shore bars and strandlines. In the Delaware Basin, the dominantly shelf facies change downdip into deeper water facies such as shales and fine-grained sandstones.

Atoka Formation lithologies vary considerably based on its position in the Permian Basin. Overall, they are dominated by cyclic marine and terrestrial deposits. Hydrocarbon reservoirs in the Atoka Formation are dominated by porous algal reefs and associated oolitic facies and grainstones. On the Central Basin Platform, Ozona Uplift and parts of the northern Midland Basin, thin cyclic shallow-marine carbonate reefs, high energy oolite shoals and nearshore-marine to terrestrial siliciclastics were deposited. At this time, there were no pronounced shelf margins so that gradual facies changes occur along ramps. Downdip facies include organic-rich shales, and shaly limestones in the deep water portion of the Midland Basin.

In the Central Basin Platform area, the Atoka Formation and later Pennsylvanian rocks are confined to the flanks of the platform as a sequence of interbedded limestones, red, green, and gray shales, and scattered conglomerates (Jones, 1953) with variable thickness. The carbonate units of this sequence consist of porous phylloid algal mounds and form stratigraphic hydrocarbon traps.

In the Central Basin Uplift, Ozona Arch and North Basin Platform, the Strawn Formation consists of cyclic fluvial and marine siliciclastics and subordinate marine limestone deposits. Along the southern Central Basin Platform, thick alluvial fan chert conglomerates lie along the boundaries of major uplifted blocks. Basin margin facies grade via gentle ramps into thin shallow-basin shales and shaly micritic limestones in the deep portions of the Midland Basin. Locally, along the Eastern and Northwestern shelves, algal banks formed that created slightly steepened ramps into the Midland Basin. Shelf facies along the basin margins include back-reef micritic limestones and shales, algal reefs and grainstones. In the northern Midland Basin, the Horseshoe Atoll was formed on the Garza Platform. The rocks that compose this structure represent the largest Pennsylvanian hydrocarbon trap in the United States (Hanson et al., 1991). Other areas were the site of deposition of grainstone shoals, islands, and algal wackestone facies. These thickened sections represent the locus of deposition of younger carbonate reefs and related facies.

Along the eastern side of the Midland Basin, reef, bank and shelf-edge sediments of the Canyon Formation were deposited over upper Strawn carbonate build-ups. This deposition resulted in thick stacked sequences of limestone along the basin margins.

During sea level highstands the Cicso Formation consists of carbonates. During lowstands, deltas prograde beyond the shelf edge. Beyond the shelf, thick accumulations

of slope muds and sands comprise most of the Cisco Formation. because of earlier carbonate buildups, bottom topography was irregular and the slope sediments of the Cisco Formation developed complex depositional patterns around the topographic highs. In those areas where sand-rich areas of the submarine fans are present, significant oil and gas reserves are found.

7. Permian

Permian rocks contain the vast majority of the hydrocarbon (more than two-thirds of the oil and one-third of the natural gas) produced from west Texas (Hanson et al., 1991). The San Andreas Formation is the most important oil-producing unit of the Permian Basin area. The Permian Capitan Reef complex, which form the Permian flanks of the Delaware Basin, is one of the world's best-exposed ancient reefs. The general mode of sediment deposition during the Permian was infilling of the topographically low areas of the Permian Basin area.

8. Wolfcampian Time:

Although the geometry of many Wolfcamp deposits suggest reef environment, most of them are composed of grainstones and small mud-prone buildups. In the Delaware and Midland basins, debris flow carbonates dominate Wolfcampian time. These debris flows were sourced from adjacent platform areas. Along the northwestern shelf, west edge of the Delaware Basin, the Wolfcampian consists of a cyclic sequence of limestone and interbedded shales that reaches up to 380 m in thickness. In Lea County, New Mexico, it is represented by shoaling-upward cycles. It consists of a basal transgressive unit of shale and argillaceous limestone overlain by bioclastic wackestone, phylloid algal wackestones, and bioclastic grainstones (Cys, 1985). The phylloid algal wackestones occur as low-relief bioherms and biostones forming important hydrocarbon reservoirs in the area.

In the Delaware Basin, Wolfcampian rocks are represented by dark gray shales with occasional thin limestones and sandstone interbeds. They were deposited in the deep marine waters of a rapidly subsiding basin. The thickest Wolfcampian deposits are located adjacent to the Central Basin Platform. In the Midland Basin the Wolfcampian is represented by mostly gray shales with interbedded limestones and some sandstones near the basin margin.

9. Leonardian Time:

Along the northwestern shelf, the lower Leonardian consists of a red-bed sequence of fluvial sandstones interbedded with evaporite and dolomite. The evaporite and dolomite content increases southward toward the Delaware Basin shelf margin. At the shelf margin, the Wichita-Albany Formation is entirely dolomite. The dolomitized organic buildups of the Wichita-Albany Formation are important hydrocarbon reservoirs.

In the Midland Basin, the lowermost Leonardian is represented by the Dean Sandstone which consists of quartzose sandstones and siltstones. It is overlain by the Spraberry Formation which consists of a sequence of fine-grained quartzose sandstones and siltstones interbedded with gray shales and some limestones. The Dean and Spraberry Formations were deposited during episodes of deep water resedimentation of shelf-driven carbonate debris associated with clastic sedimentation by submarine canyons associated with suspension settling of fine-grained sediments (Handford, 1981). The Spraberry Formation is overlain by limestones and shales of the Wichita-Albany Formation. In the northeastern portion of the Central Basin Platform, the Wichita-Albany Formation consists primarily of phylloid-algal bafflestones (organic buildups). Along the shelf margin of the northern Midland Basin, the Wichita-Albany Formation organic buildups are replaced by oolite shoals (Mazzullo, 1982).

The Clear Fork Formation, and its equivalent Yesso Formation, consist of complex evaporite and dolomite units with interbedded sandstones in some places. Their facies range from sabkha and tidal flat to shelf-edge grainstone barrier bars (Mazzullo, 1982).

In the Delaware Basin, the lower Leonardian strata are composed predominantly of dark gray, deep marine shales which grade upward into interbedded shales, quartzose sandstone, and limestones.

10. Guadalupian Time:

On the Northwestern Shelf, the San Andres Formation is the major hydrocarbon reservoir. It consists of cyclic limestone, dolomite, and evaporites of a shallow shelf depositional environments ranging from open marine to sabkha and tidal flat. In the San Andres Formation porous, dolomitized open marine and tidal flat limestones and dolomites commonly change facies laterally into nonporous anhydritic dolomite and anhydrite of sabkha deposits.

The middle Guadalupian Grayburg and Queen Formations, and their equivalent units, change in facies from massive to thick-bedded, occasionally lenticular, gray dolomitic limestone shelfward, to the north, to thin- to thick-bedded dolomite with some

sandstones basinward. These units are conformably overlaid by the Capitan Reef complex.

The Capitan deposition began in relatively deep (approximately 100 m) water (Yurewicz, 1977), which became shallower with time until it reached 30 m or less near the end of Capitan deposition (Babcock, 1977). The Capitan Formation consists of calcareous sponges with algae and talus deposits that interfinger with sandstones of the Delaware Mountain Group. It grades laterally into the Seven Rivers, Yates, and Tansill Formations, which represent backreef shelf dolomites interbedded with some sandstones that change to an evaporite-dominated system several kilometers from the shelf margin.

In the Delaware Basin, the Delaware Mountain Group consists predominantly of light gray, very fine-grained sandstones and siltstones interbedded with shales and reaches about 900 m in thickness. The sediments that formed these strata are interpreted to be deep-marine basinal turbidite and density current deposits (Williamson, 1979).

In the Midland Basin, the San Andres and Grayburg Formations were deposited in environments ranging from normal to restricted shallow-marine hypersaline. The basinal carbonate strata of the San Andres Formation range in thickness from a few tens of meters to about 300 m. The carbonate strata are thin near the center of the basin and thicken toward the shelves. The shelf dolomite facies of the San Andres grades into basinal limestone near the shelf edges and then into shales, siltstones, and some sandy limestone near the axis of the Midland Basin.

11. Ochoan time

The Ochoan sediments of the Northwest Shelf consist of the Salado, Rustler, and Dewey Lake Formations. They compose a sequence of evaporitic strata marking the final stage of Permian Basin filling. In the Delaware Basin, Ochoan rocks consist primarily of laminated anhydrite and some salt beds. These rocks indicate a general lowering of the sea level in an arid climate. The Ochoan rocks in the Delaware Basin are represented by the Castile (up to 640 m of anhydrite), Salado (up to 725 m of mainly halite), Rustler (up to 120 m of red anhydritic shale, anhydrite, and some dolomite), and Dewey Lake (up to 107 m of red sandstones and shales with minor amounts of gypsum) formations. In the southwestern part of the Delaware Basin the Rustler Formation is mostly limestones and dolomites.

The Ochoan Series of the Midland Basin is quite similar to that of the Delaware Basin except for the following: The basal Rustler Formation is often a red sandstone, especially in the Midland Basin area. The Castile Formation is absent in the Midland

Basin. The Salado, Rustler, and Dewey Lake formations are thinner in the Midland Basin than in Delaware Basin, reaching a maximum thickness of about 365 m. In the Delaware Basin, the Guadalupian-Oceanic sediments reach up to 1,375 m in thickness. They also suggest a maximum water depth of deposition that is more than 200 m (Frenzel et al., 1988).

The above discussion is meant to show the extensive variation in the sedimentary lithofacies characteristics in any given stratigraphic unit or in any given location throughout the stratigraphic column of the Permian Basin. To depict the lateral and vertical change in facies in the Permian Basin, lithologic well files (Table 2-1) are constructed. These well files include detailed descriptions of the strata of the Permian Basin. These data include the stratigraphy of the area (with more emphases on the reservoir, source, and seal units), age of the lithologic units, depth to the formation top, and the lithology of these units. These files also include petrographic attributes such as permeability, initial and final porosity, average grain size, and the modal percentage of the mineral constituents of these units.

The sedimentological attributes of the stratigraphic units in the Permian Basin are used to model not only the sedimentation history and the facies distribution in the basin, but also, through *CIRF.B*, the physico-chemical evolution of the basin. Modeling the physico-chemical evolution of the basin facilitates modeling the diagenetic pathway, and predicting the diagenetic processes that defined which authigenic minerals precipitated or dissolved. This data enhances our prediction of the distribution of matrix porosity and permeability.

Coupled with the tectonic history of the Permian Basin, the modeling of the diagenetic pathway will enable us to predict the distribution of compaction, pressure solution, and fracturing features. Therefore, constructing these lithology well files is of great importance to modeling the sedimentology and the chemical and physical environments controlling the diagenetic processes acting in the Permian Basin. As a result, it will be possible to predict the chemical and physical conditions under which fracturing and vug collapse assumed place in the Permian Basin.

The lithology well files also include a code which enable us to fill the gap that might result from missing data of any given lithologic unit. This code allow the user to chose between using a specific data set or using a standard data set. The specific data set is created for units where the user has enough data to input the stratigraphic attributes for a given stratigraphic unit. When such data is not available, the user might chose to use the standard lithology. The user can do that by choosing the closest standard lithology to the stratigraphic unit of interest, based on available information or extrapolation from adjacent

Table 2-1

Well File Name: Lithology
 Operator: Amerad Pet. Corp.
 Well Name: #2 Record
 Well Location: Latitude: 32.67
 Longitude: 103.30

Drilling Surface Elevation: 1060

Total Depth (m) Below sea level: 2980

Total Drilled Depth: 4040

Bottom Age (MY): 426

Geologic Age	Formation	Age	Depth (m)	Code	Lithology	Perm (darcy)	IP	FP	AGS (mm)	Qtz	Feld	Cly	Cal	Dol	Anhy	Hal	Ch	Py	Prx	Amph	Gyp	Gl
Quaternary	-	0	0.00	L	SS-Sh	0.015	0.6	0.3	0.600	0.60	0.10	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tertiary	Ogallala	1.8	180.19	L	Sandstone1	0.07	0.5	0.2	1.100	0.92	0.03	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cretaceous	-	95	360.38	L	SS-LS	0.02	0.6	0.1	0.900	0.48	0.05	0.05	0.40	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Triassic	Dockum	230	540.57	L	Shale1	0.001	0.6	0.4	0.035	0.30	0.05	0.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Permian-U. Ochoan	Dewey-Lake	250	720.76	L	Shale2	0.003	0.6	0.4	0.030	0.25	0.05	0.70	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Permian-M. Ochoan	Salado	256	784.39	L	Anhydrite	0	0	0	0.150	0.00	0.00	0.01	0.00	0.02	0.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Permian-L. Ochoan	Tansill	259	848.09	L	SS-Anhy	0.01	0.3	0.1	1.000	0.35	0.03	0.02	0.00	0.00	0.45	0.15	0.00	0.00	0.00	0.00	0.00	0.00
Permian-U. Guadalupian	Yates	260	900.96	L	Dolomite1	0.05	0.7	0.1	0.250	0.30	0.04	0.03	0.05	0.50	0.06	0.00	0.01	0.01	0.00	0.00	0.00	0.00
Permian-M. Guadalupian	Grayburg	265	1444.81	L	Dolomite2	0.018	0.7	0.2	0.200	0.00	0.00	0.04	0.05	0.80	0.08	0.01	0.02	0.00	0.00	0.00	0.00	0.00
Permian-L. Guadalupian	San Andres	267	1444.81	L	Dolomite3	0.017	0.7	0.1	0.150	0.00	0.00	0.08	0.00	0.80	0.09	0.01	0.02	0.00	0.00	0.00	0.00	0.00
Permian-Leonardian	Clearfork	270	2097.32	L	Limestone1	0.01	0.7	0.1	0.150	0.00	0.00	0.15	0.60	0.15	0.08	0.00	0.02	0.00	0.00	0.00	0.00	0.00
Permian-Wolfcamp	Wolfcamp	274	2523.47	L	Limestone2	0.06	0.7	0.1	0.200	0.00	0.00	0.35	0.55	0.04	0.05	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Pennsylvanian	Atoka	309	2540.96	L	Conglomerat	0.05	0.4	0.1	5.000	0.55	0.10	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mississippian	Barnett	325	2549.87	L	Sh-LS	0.003	0.7	0.2	0.150	0.04	0.01	0.35	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Devonian	Woodford	355	2558.76	L	Shale3	0.0002	0.6	0.3	0.030	0.25	0.05	0.40	0.00	0.00	0.00	0.00	0.30	0.00	0.00	0.00	0.00	0.00
Late Silurian	Wristen	410	2622.61	L	Shale4	0.0001	0.7	0.4	0.020	0.10	0.05	0.70	0.10	0.03	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00
Silurian	Fusselman	426	2674.36	L	Dolomite4	0.083	0.7	0.1	0.250	0.00	0.00	0.01	0.18	0.78	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00
Ordovician-Mohawkian	Simpson	454	2789.97	L	LS-Sh	0.01	0.7	0.1	0.200	0.23	0.02	0.25	0.48	0.01	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00
Ordovician-Canadian	Ellenburger	480	2839.84	L	Dolomite5	0.07	0.7	0.1	0.250	0.00	0.00	0.02	0.10	0.85	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Cambrian	Bliss	500	3878.69	L	Sandstone2	0.2	0.5	0.2	2.000	0.80	0.15	0.02	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Precambrian	Basement	590	3910.54	N	Igneous	0	0	0	0.350	0.60	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.20	0.00	0.00	0.00

areas. These choices can later be changed or modified when more detailed lithologic data becomes available.

The construction of lithologic well files to cover most of the stratigraphic units in the Permian Basin will continue throughout the next year as additional information about these stratigraphic units becomes available. These data will be used to test and calibrate the *CIRF.B* prediction of the stratigraphic units attributes, reservoir characteristics and fracture distribution in the Permian Basin.

12. CIRFLITH reference data base :

CIRFLITH is the platform for inputting the lithology well files to the specification of the *CIRF.B* basin simulator. It allows the generation of specific lithology well files to the stratigraphic units where their lithologic attributes are available. It also allows the user to select a standard lithology for stratigraphic units where their specific lithologic attributes are unavailable.

CIRFLITH is a menu driven interface in which the lithology name, permeability, initial porosity, final porosity, average grain size, and the modal percentage of minerals constituting this lithology are available for input into a well file and then to *CIRF.B*.

The standard lithology is constructed based on the average composition of most commonly observed lithologies as reported in the literature. This increases the universal applicability of *CIRF.B* modeling, particularly in areas where only limited data are available. This is the case in most hydrocarbon frontier exploration areas.

References

- Babcock, J.A. (1977) Calcareous algae, organic stones, and the genesis of the upper Capitan Limestone (Permian, Guadalupian), Guadalupe Mountains, West Texas and New Mexico, in M.E. Hileman and S.J. Mazzullo, eds., *Upper Guadalupian Facies, Permian Reef Complex, Guadalupe Mountains, New Mexico and West Texas*, 1977 Field Conference Guidebook, Permian Basin Section, Society of Economic Paleontologists and Mineralogists Publication 77(16), 3-44.
- Cloud, P.E. and V.E. Barnes (1948) *The Ellenburger Group of Central Texas*, Austin, University of Texas Publication 4421.

- Cys, J.M. (1985) Lower Permian phylloid algal mounds Tatum Basin, southeastern New Mexico, U.S.A., in D.F. Toomey and M.H. Nitecki, eds., *Paleoalgeology, Contemporary Research, and Application*, New York, Springer-Verlag.
- Frenzel, H.N., R.R. Bloomer, J.M. Cys, J.E. Galley, W.R. Gibson, J.M. Hills, W.E. King, W.R. seager, F.E. Kottlowsski, S. Thompson III, G.C. Luff, B.T. Pearson and D.C. Slicon (1988) The Permian Basin region, in *The Geology of North America D(2)*, Geological Society of America Publication, 261-307.
- Galley, J.E. 91958) Oil and geology in the Permian Basin of Texas and New Mexico, in L.G. Weeks, ed., *Habitat of Oil: A Symposium*, AAPG Special Publication, 395-446.
- Handford, C.R. 91981) Sedimentology and genetic of Dean and Spraberry Formations (Permian), Midland Basin, Texas, *AAPG Bulletin* **65**, 1602-1616.
- Hanson, B. M., B.K.Powers, C.M. Garrett, D.E. McGookey, E.D. McGlasson, R.L. Horak, S.J. Mazzullo, A.M. Reid, G.G. Calhoun, J. Clendening and B. Claxton (1991) The Permian Basin, in H.J. Gluskoter, D.D. Rice, and R. B. Taylor, eds., *Economic Geology*, Geological Society of America Publication, *The Geology of North America*, Vol P-2, 339-355.
- Hardy, D.G. (1976) Bone Spring(s) Formation, in *Lexicon of Permian Stratigraphic Names of West Texas and Southeastern New Mexico*, West Texas Geological Society Publication **76-66**, 51-53.
- Hill, C.A. (1996) *Geology of the Delaware Basin Guadalupe, Apache and Glass Mountains New Mexico and West Texas*, SEPM Permian Basin Section Publication **96-39**.
- Hills, J.M. (1970). Late Paleozoic structural directions in southern Permian Basin, West Texas and southeastern New Mexico, *AAPG Bulletin* **54**, 1809-1827.
- Hills, J.M. (1984) Sedimentation, tectonism, and hydrocarbon generation in Delaware Basin, West Texas and southeastern New Mexico, *AAPG Bulletin* **68**, 250-267.
- Jones, T.S. (1953) *Stratigraphy of the Permian Basin of West Texas*, West Texas Geological Society.

- Kerans, C. (1990). Depositional Systems and Karst Geology of the Ellenburger Group (Lower Ordovician), Subsurface West Texas, Bureau of Economic Geology, Report of Investigation No. 193.
- Matchus, E.J., and T.S. Jones (1984) East-west cross section through Permian Basin of West Texas: West Texas Geological Society, Publication No. 84-79.
- Mazzullo, S.J. (1981) Facies and burial diagenesis of a carbonate reservoir, Chapman Deep (Atoka) Field, Delaware Basin, Texas, *AAPG Bulletin* **65**, 850-865.
- Shumaker, R.C. (1992). Paleozoic structure of the Central Basin Uplift and adjacent Delaware Basin, West Texas, *AAPG Bulletin* **76**, 1804-1824.
- Tyler, N., D.G. Bebout, C.M. Garrett, Jr., E.H. Guevara, C.R. Hocott, M.H. Holtz, S.D. Hovorka, C. Kerans, F.J. Lucia, R.P. Major, S.C. Rupple, and G.W. Vander Stoep (1991) Integrated characterization of Permian Basin reservoirs, University Lands, West Texas: Targeting the remaining resource for advanced oil recovery: Bureau of Economic Geology, Report of investigation No. 203, The University of Texas at Austin.
- Wilde, G.L. (1976) Wolfcamp series, in *Lexicon of Permian Stratigraphic Names of West Texas and southeastern New Mexico*, West Texas Geological Society Publication **76-66**, 327-331.
- Wright, W.F. (1979) *Petroleum Geology of the Permian Basin*, West Texas Geological Society, Publication **79-71**, 98.

3

Structural Geology and Tectonics (T. Hoak)

I. Introduction

The structural geology and tectonics of the Permian Basin were investigated using an integrated approach incorporating satellite imagery, aeromagnetism, gravity, seismic, regional subsurface mapping and published literature. The two primary emphases were on: 1) delineating the temporal and spatial evolution of the regional stress state; and 2) calculating the amount of regional shortening or contraction. Secondary objectives included delineation of basement and shallower fault zones, identification of structural style, characterization of fractured zones, analysis of surficial linear features on satellite imagery and their correlation to deeper structures.

Gandu Unit, also known as Andector Field at the Ellenburger level and Goldsmith Field at Permian and younger reservoir horizons, is the primary area of interest and lies in the northern part of Ector County. The field trends northwest across the county line into Andrews County. The field(s) are located along an Ellenburger thrust anticline trap on the eastern margin of the Central Basin Platform (see Fig. 3-1 for location).

II. Overview of Permian Basin

Before conducting detailed discussions about the geology of the Permian Basin, it is helpful to provide some geographic boundaries and review the primary geologic elements that compose the region. Fig. 3-1 represents a location map that outlines the primary areas of interest in the Permian Basin. This map also outlines the location of the proposed modeling area.

The study area lies on the eastern margin of the Central Basin Platform and extends eastward into the adjacent Midland Basin (see outline of area on Fig. 3-1). The Central Basin Platform is a NW-trending uplifted basement block that separates the Midland Basin (to the east) from the Delaware Basin (to the west). The Central Basin Platform (or CBP) was uplifted in mid-late Pennsylvanian time. Until that time, the two basins and the CBP were relatively low relief features within a shallow Paleozoic-age

Fig. 3-1 Location map of major structural elements and modeling area in the Permian Basin, West Texas (after Hanson et al., 1991).

basin that has been called the Tobosa Basin. Following the development of the two individual basins by uplift of the CBP, the Tobosa Basin ceased to exist. The Central Basin Platform represents an uplifted zone of basement rock. As a result, drilling depths to deeper reservoir horizons (e.g. Ellenburger Formation) is much shallower. This shallow drilling greatly improves the economics of wells and fields along this structure.

In Wolfcampian time, the uplift of the CBP ceased, and a regional erosional unconformity developed that beveled off the top of the underlying structures. Above this unconformity, the carbonate reef and related proximal facies were deposited on the relatively flat erosional surface. A consequence of this erosional event and subsequent deposition is that deeper fold and thrust structures are capped by flat-lying carbonate reservoirs at shallower depths. These stratigraphic trap reservoirs, together with the deeper structural traps, represent a complex system of multiple pay zones that greatly increase the economic potential of drilling activity in this area.

The northern termination of the CBP is the Northwest Shelf. The Northwest Shelf represents a broad shelf extending northward to the Palo Duro Basin. This shelf, though only slightly faulted, extends from the Midland Basin to the broad depositional shelf that extends northward to the Matador Arch. The San Simon Syncline represents a narrow sag that separates the CBP from the shelf region. The southern termination of the CBP is the Val Verde Basin. The Val Verde Basin represents a foredeep basin of the Pennsylvanian and early Permian-age Marathon Fold-and-Thrust Belt. The Val Verde Basin is filled with over 15,000 feet (>5000 m) of flysch and related clastic rocks derived from the advancing thrust sheets.

The Midland Basin represents the primary focus of this study. In cross-section perpendicular to the basin axis, its shape is slightly asymmetric and deepens to the west. The western boundary is delineated by the complex folds and faults that have formed along the eastern margin of the Central Basin Platform (including the Gandu Unit). The eastern basin boundary is somewhat indistinct and is designated the Eastern Shelf. The Eastern Shelf represents a gradual rise from the western, deepest part of the basin. As a result, the eastern boundary of the Midland Basin is somewhat arbitrary.

The Delaware Basin contrasts strongly with the Midland Basin. The Delaware Basin is significantly deeper, is more asymmetric and deepens to the east. Because of its greater burial depth and sediment influx, organic sediments in the Delaware Basin have experienced greater thermal maturity and much of the deeper hydrocarbon reserves have been converted to natural gas. The western margin of the Delaware Basin is bounded by the Salt Flat Graben, a Tertiary-age system related to the Basin-and-Range extensional

tectonics. Finally, further to the west, lies the Diablo Platform, a paleogeographic high that has persisted since the Paleozoic.

III. Methodology of Present Study

The structural geology and tectonics of the Permian Basin were investigated using an integrated approach incorporating satellite imagery, aeromagnetism, gravity, seismic, regional subsurface mapping and published studies from the literature. There are two primary fractured reservoirs of interest in the primary modeling area of the Gandu Unit. The deepest reservoir is the Ellenburger Formation and the second is the shallower Clear Fork Formation. The Ellenburger, considered a classic fractured reservoir, was deformed by contractional (thrust) tectonics during the Pennsylvanian-age Ouachita Orogeny that caused the majority of regional deformation. The younger, Permian-age Clear Fork Formation was not affected by this deformation and is not generally regarded as a fractured reservoir. However, detailed analysis of core from this formation demonstrates that significant vuggy porosity is present that is interconnected with microcracks. Given the low permeability of the Clear Fork in the Gandu Unit, we believe that the microcracks and related vuggy porosity represent the critical pathways for fluid flow. Understanding the genesis of these fractures is a major objective for our modeling effort.

To assess the potential for basement and deeper structural control on the permeability and fracture trends in the Clear Fork reservoir, we investigated the relationship between basement and Ellenburger structural trends, and surficial trends observed on satellite imagery. If a correlation exists between the different structural levels, this would indicate the likelihood that the intermediate Clear Fork structural level possesses similar structural anisotropy trends. An illustration of these relationships is shown in Fig. 3-2. To accomplish this comparison, a linear features analysis was conducted of three LANDSAT thematic mapper images that span an area from the western edge of the Delaware Basin (Delaware Mountains) northeastward across the Central Basin Platform to the approximate center of the Midland Basin. The along-strike variations were assessed along the length of the Central Basin Platform by examining the area to the northwest of the Gandu Unit.

IV. Satellite Imagery Linear Features Analysis

Linear features represent segments of streams, arroyos, escarpments, ridges and

Fig. 3-2 Schematic diagram illustrating relationship between topographic surface, subsurface reservoirs and deeper basement level structures. Basement related structural deformation will propagate up through the stratigraphic section and be expressed on the surface as a subtle linear feature.

cliffs. Additional linear features arise from spectral differences between rock/soil types, vegetation-types/density and soil moisture content. No obvious cultural features were interpreted, however, every interpreted feature was not compared to topographic maps in order to eliminate all known cultural sources such as ranch roads, seismic survey lines, oil field infrastructure, etc. The majority of linear features were compared with published geologic maps. Interpreted features were not field inspected to determine the nature of the linear feature anomaly due to practical time constraints. Linears were also compared to published, field-verified aerial photolinear studies for the area of Ector County.

LANDSAT and other satellite-based imagery provide an excellent opportunity to rapidly perform an analysis over a wide area. The large area covered by the image provides a regional perspective difficult to achieve using conventional aerial photography. Whereas the larger scale image of the aerial photos do reveal greater ground detail, their use over large areas requires large numbers of photos that often prevent regional features from being readily apparent. It should be emphasized, however, that more recent satellite imagery systems (e.g. 10 meter resolution monochromatic SPOT from France, and 3 meter resolution Soyuz-Karta KVR1000 satellite imagery from the former Soviet Union) have resolution very close to that of high-altitude aerial photography (approximately 1 meter resolution) with the flexibility to perform interactive processing of the image to maximize the information that can be obtained from the data. It is for this reason that satellite imagery is preferable to aerial photo interpretation although the cost of the latter is significantly less.

The three images were designated as Pecos, Midland and Mesca in reference to the dominant geographic element in each scene (see Fig. 3-3 for boundaries of individual LANDSAT imagery scenes). The Pecos image is centered on the Pecos River and extends from the Delaware Mountains on the west across the Delaware Basin and Central Basin Platform into the Midland Basin. The Midland image is centered on the Midland-Odessa area and overlaps with the Pecos sheet. It covers the eastern margin of the Central Basin Platform and the western Midland Basin. The Mesca image is named for the Mescalero Ridge. It represents the northwestward continuation of the Central Basin Platform as observed in the other sheets and covers the eastern and western margins of the Central Basin Platform. Additional regional coverage was examined to confirm that these major linear feature trends are also present on these sheets. These additional images were not included in the present study because they extended significantly beyond the primary boundaries of the area of interest, and processing and interpretation for these areas was not included in the budget.

Fig. 3-3 Boundaries of LANDSAT images used for linear features analysis.

Linear features were interpreted on transparent overlays from the three images provided by Phillips Petroleum. These linears were digitized and put on a computer-based regional base map to compare the interpreted linear features with underlying structural trends at the Ellenburger level (discussed in more detail later). The composite image of all linear features (see Fig. 3-4) shows a wide range of linear feature trends. Several regional lineaments have been previously interpreted for this area of Texas. Work by Bolden (1984) interpreted several major WNW-trending lineaments referred to as the Pecos Lineament and the Concho Lineament. These were interpreted as representing left-lateral wrench systems. Less prominent NE-trending linear zones were interpreted as the right lateral antithetic shear set. These two zones have been added to Fig. 3-4. Note that the Pecos Lineament is composed of a series of parallel, shorter linear features. There are several areas along the Pecos River where small NE-trending linear features disrupt the continuity of the larger NW and WNW-trending linears. Although the significance of these linears is unknown, both the Pecos and Concho lineaments seem to have clear expression in the LANDSAT images interpreted during this study. Whether these lineaments represent regional wrench or strike-slip systems cannot be verified with the existing data.

Linear features from the three images were interpreted using strike-frequency diagrams (rose diagrams). These diagrams show the dominant linear feature orientations (azimuths) that are present in the data. Fig. 3-5 shows the rose diagrams for the three domains. The Pecos region is the most instructive because of the diversity of fault trends that have been mapped on the surface (Geologic Atlas of Texas, Van Horn-El Paso Sheet, Barnes, 1983; Tectonic Map of Texas, Ewing et al., 1995). Faults in the Apache Mountains (to west of Delaware Basin) trend E/W to WNW and are crosscut by NNW and NW-trending faults that trend parallel to those exposed in the Delaware Mountains that form the Salt Flat Basin graben system. In the Delaware Mountains (also to west of Delaware Basin), NE-trending faults are also present although they appear subordinate to the larger displacements observed on the NNW and NW-trending sets. Many of these mapped faults occur along topographic depressions and drainages. Based on these observed relationships and the orientations observed in the Van Horn-El Paso Sheet, we have interpreted the linear feature trends mapped in the Pecos image to represent subsurface faults that do not appear at the surface. Instead, these subsurface faults create a preferred orientation for regional drainages and other linear anomalies. Given the dominant trends observed in the Pecos image, and the similarity of these linear feature trends to those mapped faults further west, it is reasonable to conclude that the linear features overlie subsurface fracture systems.

Fig. 3-4 Composite image of all interpreted linear features. Concho and Pecos regional lineaments from Bolden (1984).

Interpreted Linear Features: Rose Diagrams

Pecos Region

Midland Region

Mesca Region (all orientations, unfiltered)

Mesca Region (filtered data to remove aeolian (?) features: possessing trends between 280-310°)

Fig. 3-5 Orientations of linear features for the LANDSAT images. See Fig. 3-3 for scene boundaries.

On the Midland image, we see less of the NE-trend and a larger number of WNW linears. In this area, a greater percentage of regional drainages lie parallel to this trend. In the Pecos image, we found significant numbers of N/S, NE, WNW and E/W-trending drainages. After we cross the Pecos River, however, we find that the NE and WNW trends become dominant. This difference in linear feature orientation across the Pecos River probably reflects the influence of the major wrench system that has been interpreted to lie along the Pecos River trend (Bolden, 1984).

In the Mesca image, there is a dominance of WNW linear features. This trend is expressed by topographic drainages and differences in sediment composition infilling these topographic lows spots. According to the map legend (Geologic Atlas of Texas, Big Spring Sheet, Barnes, 1983), these sediments are aeolian deposits that have infilled topographic depressions. The rose diagram for the Mesca region has included these aeolian deposits because they infill these depressions. Given the aeolian nature of the sediments, it is likely that the WNW trend we observe is actually a reflection of the prevailing wind direction. We have also filtered the total linear features data set for this image area to remove the dominant WNW trend. The effect of these various filters is shown in Fig. 3-6. When these linear feature azimuths ($280-300^{\circ}$) are removed, the data set looks very similar to that for the Midland region with a greater percentage of E/W-trending feature similar to those in the Pecos image.

Based on the similarities and differences between the three data sets, it appears that the Pecos River is a major zone that separates the linear feature fabric of the Pecos region from that of the Mesca and Midland regions to the north. North of the river, there is a remarkable similarity in orientations. By analogy with the Van Horn area to the west and south of the primary area, it is likely that the various linear features represent incipient fault systems given the similarity observed between fault trends between that area and the interpreted linear features of the study area.

To assess basement and deep subsurface control on the linear feature trends, the location of the observed surficial linear features were compared against detailed subsurface structure maps at the Ordovician-age Ellenburger Formation level. A comparison of these faults and related fold axes against the surficial linear features is made in Fig. 3-7. From these rose diagrams, we find that the subsurface faults possess a dominance of NNW and WNW trends with subordinate NNE trends. Although this is similar to the surficial linears, the NE-trend observed in the surface does not appear as prominent at depth. Given the variation in displacement along most of the deeper NW-trending regional faults, and the locally prominent subsurface presence (especially in the Andector-Gandu Unit) of NE-trending crossfaults, it is likely that the NE fault trend is present to permit

Interpreted Linear Features: Rose Diagrams (filtered)

Mesca Region

(all orientations, unfiltered)

Population 305
Vector Mean 293.87 Degrees

Mesca Region

(filtered data to remove aeolian (?) features possessing trends between 280-310°)

Population 227
Vector Mean 288.52 Degrees

Mesca Region

(filtered data to remove aeolian (?) features possessing trends between 290-300°)

Population 272
Vector Mean 292.91 Degrees

Mesca Region

(filtered data to remove aeolian (?) features possessing trends between 300-310°)

Population 272
Vector Mean 290.7 Degrees

Fig. 3-6 Effect on frequency diagrams created by filtering the Mesca image data set to remove the influence of pronounced aeolian features possessing a NW trend. Upon removal of NW trend, rose diagram appears similar to those calculated from the Pecos and Midland images.

Comparison Between Interpreted Linear Features and Subsurface Structural Trends:

Ellenburger Structural Datum Fold Axes
(for area 31-33° N , 102-103° W)

Midland Region

Ellenburger Structural Datum Faults
(for area 31-33° N , 102-103° W)

Pecos Region

Mesca Region
(all orientations, unfiltered)

Mesca Region
(filtered data to remove aeolian (?) features possessing trends between 280-310°)

Fig. 3-7 Comparison between subsurface structural trends and surficial linear features. Note similar dominant NW and WNW trends. Also, note paucity of NE-trending data in subsurface.

differential regional displacement and subsidence along the NW fault trends. It is possible that the NE-trend results from preferential dissolution of shallow evaporites along faults that formed at shallower levels orthogonal to the deeper regional trends (Hills, 1984; 1985). Displacement along these orthogonal faults would be essential to insure strain compatibility and permit the observed differential displacements along the length of the NW-trending regional faults.

Visual inspection of an overlay map (Fig. 3-8) between individual surficial linear features and subsurface structural trends, it is clear that there are significant areas where an excellent correspondence exists. Given the depth (>8000' for most areas) of the subsurface structure, it should be expected that there will be some lateral offset of surficial linear features compared to the subsurface structural location. There are, however, several areas where there is less or little correlation between the individual subsurface structures and surficial linears. This apparent lack of correlation, however, is largely because subsurface maps do not show structures beneath all linears. In contrast, nearly all subsurface structures have linear features associated with them. This may be a function of subsurface data density in that areas off the Central Basin Platform that do not possess large numbers of deep penetrations. Additional regional mapping on deep subsurface horizons and comparison to surficial linears would be necessary to evaluate this hypothesis.

It was expected, based on results from other regions, that there would be a correlation between individual, large displacement subsurface faults and corresponding surficial linear trends. In Gaines and Andrews counties, there is an excellent correspondence between larger subsurface faults and surficial linear features. Only where the Concho Lineament crosses through the area are there a large number of oblique surficial linear feature trends that do not correlate to the subsurface. Further south, in Ector and Midland counties, there is also good correlation between larger subsurface faults and linear features. In this area, the dominant NW-trending basement faults show lengthy zones of parallel to subparallel linear features on the surface. There are several areas in Ector County where there are anomalous NE-trending surficial linears that do not correspond to obvious subsurface features. This NE-trending zone, however, has been designated as the Andrews Shear Zones and is thought to represent a primary basement structural boundary. It is marked by a strong negative gravity and magnetic anomaly (see later discussion in potential field geophysics section). In contrast, to the south in Crane, Upton and Pecos counties, there is less correlation with the magnitude of displacement on subsurface faults and the presence of parallel surficial linear trends. The Concho and Pecos regional lineaments mapped by Bolden (1984) do manifest themselves as zones of

Fig. 3-8 Overlay of subsurface Ellenburger faults and folds with surficial linear features interpreted from LANDSAT imagery.

shorter linear features. These lineaments do appear to separate areas of distinct linear feature trends as discussed earlier. In addition, along their trace they are responsible for the local lack of correlation between the subsurface structural trends and the surficial linear features.

Given the overall corresponding similarities between surficial linears, subsurface structures and basement structural trends, we are confident that subsurface stratigraphic horizons such as the Clear Fork Formation, are fractured along similar trends. As a result, we intend to use those linear features that correlate with deep subsurface structures to constrain fracture trends in shallower Post-Wolfcampian-age subsurface reservoir horizons.

V. Comparison to Maps Based on Earlier Aerial Photo Interpretation

In 1969, Phillips Petroleum Company initiated a study of surface linear features using high altitude, stereoscopic aerial photography. The study was limited to Ector County. In comparing the results of this study with the newer LANDSAT imagery interpretation, it is important to remember the much higher resolution of the aerial photos. Aerial photos have a ground resolution of approximately 1 meter compared to LANDSAT Thematic Mapper which has a 30 meter ground resolution. As a result, aerial photo interpretation will observe smaller features and provide more detail. Unless integrated with other photos from across a region, however, the photo study will often not pick up large features of regional extent. Logistically, it is difficult to work on several dozen (or more) stereopair aerial photos at a single time.

Fig. 3-9 is a composite image of the aerial photographic interpretation with those linears interpreted from LANDSAT imagery analysis. Most of the larger features common to both data sets are apparent. The photo interpretation shows a greater number of additional linear elements, especially along NW, E/W, and NE azimuths. Fig. 3-10 compares the linear features interpreted from the aerial photos against those interpreted from the entire Midland LANDSAT image. Although several of the photolinears correspond to subsurface structures, similar to the LANDSAT interpretation, there are numerous surficial linears that do not appear to directly correspond to subsurface structures. Most importantly, the LANDSAT interpretation identified all of the major trends present and was performed much more rapidly. Ground verification of several of the linears may yield additional insight into the characteristics of each linear. However, given the low topographic relief in this area and poor outcrop, it is unlikely that significant information would be gained to make such an exercise fruitful.

Fig. 3-9 Composite image of linear features interpretation from aerial photos and LANDSAT imagery.

Ector Photolinears

Midland Region-LANDSAT linears

Population 708
Vector Mean 288.56 Degrees

Data from individual four quadrangles on Figure 9.

Quad 2

Quad 1

Quad 3

Quad 4

Fig. 3-10 Comparison between aerial photo linear interpretation and LANDSAT linear feature interpretation.

VI. Aeromagnetics and Gravity

Phillips Petroleum Company provided regional aeromagnetic and Bouguer gravity maps. These maps were supplemented by public domain total field aeromagnetic (NURE) and Bouguer gravity maps (Keller and Peeples, 1985). Phillips' map set contained maps of: total magnetic intensity, total field Bouguer gravity, first and second vertical derivative Bouguer gravity, first horizontal derivative Bouguer gravity, and Bouguer gravity residuals. All of these maps were compared with overlays of published basement block interpretations (Gardiner, 1990; Shumaker, 1992; Yang and Dorobek, 1993; 1995). In general, most of these authors have attempted to subdivide the basement of the Permian Basin into large county-scale (40 mile width), fault-bounded basement blocks. When these various block orientations were subjected to crustal stresses related to the Ouachita/Marathon collision to the south, they experienced regional shortening (contractional or thrust faulting) along with wrench deformation (strike-slip motion). The orientation of block boundaries relative to the imposed stress dictates the sense of slip and the partitioning of regional strain between thrust and strike-slip fault displacement. As a result, it is important to compare the various basement geometric models against the potential field geophysical data to give us our best regional perspective (in the absence of seismic mapping of the basement) into the geometry of the basement. Although direct evidence (e.g. wellbores) are considered favorable, additional calibration comes from limited regional seismic interpretation of the basement horizon. By integrating any available basement well penetrations with seismic, we provide the best approach to calibrating our basement structural interpretation. The quality of our basement interpretation is critical because of the widespread interpretation and documentation of basement involvement in thrust tectonics, particularly along and within the Central Basin Platform uplift.

The aeromagnetic map was compiled from NURE (National Uranium Resource Evaluation) program data collected by contractors working for the Department of Energy. This data was that used by Keller and Peeples (1985) and also reprocessed by Phillips Petroleum Company. In West Texas, two different subcontractors collected NURE data using different instrumentation. As a result, re-leveling of the data was necessary that has been performed by several academic groups (e.g. Keller and Peeples, 1985). The aerial surveys were conducted along E/W flight lines at an average spacing of 3 miles. N/S tie lines were flown with a 15 miles spacing. A magnetic measurement or datum was collected approximately every 90-160 feet. Interestingly, Keller and Peeples (1985) have interpreted the magnetic signature of the Central Basement Platform to be of higher

amplitude than would be expected for such a depth. They believe that the Central Basement Platform is likely cored by mafic rocks that may be related to a failed or aborted rift system. Limited penetrations of basement in this area to date, however, have not penetrated such mafic materials.

On the Bouguer gravity maps, the Central Basin Platform is a pronounced gravity high extending to the southeast from West-Central Gaines County to Pecos County. An example of the gravity maps along with the interpretation of Gardiner (1990) is shown in Fig. 3-11. Along its axis, it is broken into two positive anomalies by a NE-trending saddle that extends from the corner of the New Mexico-Texas border into Martin County to the northeast. This zone has been interpreted as the Andrews Shear Zones by Gardiner (1990). He describes this area as a 15-20 km wide zone of right-lateral strike-slip deformation. En Echelon folds observed at Emma, South Andrews, and Midland Farms fields confirm the nature and shear sense. According to Gardiner (1990), the NE-trending swing in the Atokan facies documented in Emma field suggests that the shear zone was active during Pennsylvanian time. Several prominent positive anomalies also correlate with interpreted crustal blocks. Fig. 3-11 is a overlay of interpreted crustal blocks from Gardiner on the total field Bouguer gravity map. Fig. 3-12 is the same interpretation on a aeromagnetic total field map. From these maps, it is possible to delineate most of the crustal block boundaries.

Direct comparison of Gardiner's maps with the data indicate several areas where the interpretation of the potential field data sets could be improved. In general, there are significant differences between the aeromagnetic and Bouguer gravity data sets that favor different interpretations. However, those areas in which the interpretation and potential field geophysical disagree are often directly substantiated by subsurface well control and seismic data. As a result, we have not yet attempted to make a reinterpretation of many of these zones, especially in structurally complex areas, where forthcoming detailed seismic information is required to assess and modify the existing interpretation.

Several authors (Hills, 1984; Shumaker, 1992) have interpreted that the basement decollement or regional detachment surface is found at a depth of approximately 30,000 feet. As a result, significant basement involvement is interpreted in most structural sections and tectonic reconstructions. Figs. 3-13,14 illustrates the interpreted geometry of several basement-involved reservoir structures. Note the overall consistency in interpretation in which the regional thrusts are interpreted to flatten into a regional detachment surface at the ~30,000 feet depth. This depth to the regional detachment is supported by the geometry of the fold structures in which the hanging wall ramp would indicate a similar depth to the regional detachment. Ideally, we could directly compare

Fig. 3-11 Interpreted crustal blocks from Gardiner (1990) on regional Bouguer gravity basemap.

Fig. 3-12 Interpreted crustal blocks from Gardiner (1990) on regional aeromagnetic basemap.

Fig. 3-13 Complex fold and thrust relationships along the Central Basin Platform margin. Note that regional detachment surface has been interpreted at ~30,000 feet.

Fig. 3-14 Structural sections illustrating complex, basement-involved fold and thrust relationships along the Central Basin Platform margin. Note relatively low angle dips of fault planes. majority of regional detachments lie at ~30,000 feet.

basement magnetic susceptibility data, collected from actual basement rock samples, with magnetic maps and gravity interpretations to more closely constrain the interpretations. Unfortunately, there are few penetrations of basement in the modeling area. Because the Ordovician-age Ellenburger Formation, a dolomitized limestone, lies unconformably on a relatively flat basement surface, we can use the geometry of the Ellenburger structural datum to approximate that of the underlying basement.

VII. Ellenburger Structural Geology

The Ellenburger Formation represents a laterally continuous dolomitized limestone of Ordovician age. In the study area, its thickness extends up to 1500 feet thick. In most of the area of interest, it lies unconformably on a relatively flat basement surface. As a result, we are able to approximate the basement structural configuration by using an Ellenburger structure map. Existing published maps (Gardiner, 1990) were supplemented by maps from Phillips Petroleum Company for Andector Field, and by structural contour maps purchased from Geomap, Inc. of Midland, Texas. Faults, interpreted fold axes and fault displacements were calculated and digitized for this area. These digital files were overlaid with linear features data, basement block interpretations and other structural interpretations. Because of limited regional coverage purchased from Geomap, we supplemented this interpretation with published regional Ellenburger maps of Gardiner (1990). In the area of overlap, we verified the consistency of the two interpretations. Some minor differences in location are thought to be due to the relatively large scale map published by Gardiner and the subsequent inaccuracies involved in increasing the size of the map to correspond to the Geomap data set. Fig. 3-15 is the composite image of the Ellenburger structure map compiled from the Geomap data and that of Gardiner (1990). In this image, the majority of structures trend NW and most folds show associated faults. The general model of these structures is best approximated by that of fault-propagation folds (see Fig. 3-16). In these folds, initial regional shortening is accommodated by folding above a slowly-propagating thrust fault. One of the desirable aspects of this fold mechanism is the overall steady-state growth. In other words, the fold grows as the associated fault follows a gradual (i.e. non-instantaneous) displacement path. This behavior makes it ideally suited for computer modeling using the CIRF.B code.

Fig. 3-15 Composite image of Ellenburger structure from Gardiner (1990) and geomap structure maps.

Fig. 3-16 Schematic model of typical fault-bend folds. note that fold growth occurs simultaneously with incremental slip along fault. Characteristic long limb-short limb relationship is widely observed throughout the Permian Basin.

VIII. Previous studies and existing models

Integrated tectonic synthesis of the Permian Basin region has been attempted by only a few individuals. Instead, a much greater emphasis has historically been placed on the complex depositional and diagenetic changes experienced by petroleum reservoir rocks. Because so many major advances in regional interpretation appear to have been driven by technology advances (e.g. additional well control, aeromagnetics, gravity, seismic, etc.), it is particularly informative to study the available literature chronologically.

It has long been recognized that the structural geology of the Permian Basin cannot be fully explained by models involving only pure end-member extensional or contractional (thrust) tectonics. Because of the en echelon fold and fault geometries, combined with complex fault displacement patterns, various amounts of wrench (or strike-slip) deformation have been integrated into regional models. The now-popular model of wrench-dominated regional tectonics is actually quite old. Harrington (1963) was the first geologist to suggest the model of wrench displacement to explain the complex thin-skinned fold-and-thrust fault geometries. Harrington recognized two phases of deformation. The first was interpreted to have occurred pre-Atoka time and deformed the 4000-6000' feet of sediments found between the basement and the overlying Barnett Shale. The second phase involved differential subsidence along normal faults that formed after the Wolfcampian-age uplift, synchronous with sedimentation and related loading.

According to Harrington (1963), the first deformation phase, the dominant one in the region, can be geometrically modeled by using wet tissue paper overlying parallel glass plates. By imposing a right lateral shear couple between the glass plates, Harrington was able to demonstrate that the observed pre-Wolfcamp (largely Pennsylvanian in age) fold geometries could be formed by strike-slip motion. In Harrington's model, the dominantly N/S compression imposed by the Ouachita-Marathon thrust system was transferred into E/W compression by thin-skinned deformation along wrench systems. The N/S trending basement fault zones interpreted to flank the Central Basin Platform would have caused local shortening accommodated by folding and thrusting along NW-trends. Perhaps most importantly, especially from an exploration perspective, is Harrington's rebuttal of the long-standing hypothesis that all pre-Permian anticlines must be overlain by a Permian-age or younger structure. The recognition that this relationship need not exist was a major stimulus for renewed exploration at deeper structural levels such as the Ellenburger Formation.

Hills (1970) used subsurface data to suggest the possibility of extensive lateral displacement along pre-Permian faults in the Permian Basin. Hills' primary objective was to determine the direction of tectonic forces responsible for regional deformation. Hills interpreted two tectonic systems. The first consists of folds and faults possessing orientations of N35W (folds) and N55-80E (right lateral faults), and N50-65W (left lateral faults). The age of this deformation is thought to be early Late Mississippian to late Middle Pennsylvanian. There also are a series of NNW-trending faults that appear to be right lateral systems with larger displacement that formed synchronous with the other faults. It is this system of conjugate faults that has been interpreted to control the jagged geometry of the Central Basin Platform, especially along its eastern margin.

A second, later deformation phase as interpreted by Hills (1970), is marked by the relaxation of stress and normal fault motion reactivation of older fault systems. The timing of this deformation is interpreted to be middle-to-late Permian in age and fault displacements relatively minor. It is this deformation that apparently localized evaporite deposition in the Permian stratigraphy by controlling the geometry of salt pans. Finally, during the Tertiary, the western margin of the Permian Basin was uplifted and Basin-and-Range tectonism commenced in this area. This deformation has apparently been restricted to the western Delaware Basin and the basin margin.

Hills (1970) outlined four pieces of evidence which he felt indicated the dominance of wrench motion: 1) lack of thickening of pre-Permian rocks; 2) analogous distribution of hydrocarbon reservoirs on both sides of several major faults; 3) the steepness of the fault planes; and, 4) the ability to explain observed geometries with lateral displacement with only limited reverse sense displacement. Given the apparent conjugate relationships between the NW- and NE-trending fault systems, Hills suggests that the primary regional compression direction was oriented approximately E/W. Over time, the gradual relaxation of the E/W compressive regime was replaced by a more N/S orientation. The timing of folding related to this latter stress regime is dated sometime between late Pennsylvanian to early Permian time.

In a later paper, Hills (1984) discussed the tectonic evolution of the Delaware Basin, especially the thermal and maturation history of the region. Additional information, including a basement interpretation based on potential field geophysical data, is presented which suggests that the basement in the region is part of a N/S trending aulacogen. Little new information was presented to modify the earlier (1970) interpretation of the structural evolution of the basin. This aulacogen interpretation was modified in a later publication (Hills, 1985).

Hills (1985) summarized the current understanding of the tectonic evolution of the Permian Basin. Although the overall stress regime evolution was not modified, additional significant detail was presented on the tectonic evolution and timing constraints on basin evolution. Most importantly, Hills provides an excellent, though condensed, summary of the geologic evolution of the subdomains or regions that together constitute the Permian Basin. There are several important points that should be discussed in detail. Hills (1985) describes the eastern boundary of the Midland Basin as possessing little evidence of tectonism. Instead, the Eastern Shelf is largely a stratigraphically-controlled boundary with rocks of the Pennsylvanian-Permian-age carbonate shelf dipping gently westward into the basin. Underlying this shelf, the basement gradually becomes shallower to the east. Hills attributes the observed deformation to a late Precambrian-age event that formed the Paleozoic-age Tobosa Basin and a early late Paleozoic deformation that formed the deep complex fold and thrust structures that dominate the regional structural geology. Tertiary and later tectonic deformation was restricted to the far western margin of the Delaware Basin. Limited Tertiary intrusive activity is found within the Delaware Basin but its influence is considered minor. In addition, Hills demonstrates the dissimilarity in structural intensity found across the Central Basin Platform. The magnitude of faulting is considerably greater along the CBP-Delaware Basin Boundary. This assessment has helped us to refine our modeling area of interest to extend eastward from the top of the CBP. Given the limited tectonic deformation in the Midland Basin, particularly as we move eastward, we can arbitrarily choose the eastward limit of our modeling boundary.

Hills (1985) also describes jointing and minor faulting to be more intense over the edges of deep thrust zones of early Wolfcamp age. This suggests the importance of accurately mapping these zones to delineate zones of enhanced fracture permeability critical to production.

One of the earliest modern integrated models was that of Gardiner (1990). Gardiner performed a study that integrated potential field geophysics, seismic and subsurface interpretation (including erosional limits) to develop a model of regional deformation. The primary objective of the work was to map the regional Paleozoic fault fabric and determine the spacing and evolution of the major fault/fold systems. Gardiner greatly extended the work of Hills and refined the basement block boundaries. From this work, Gardiner outlined the boundaries of six "crustal" blocks that are roughly 40 miles on their longest dimension (see Fig. 3-17). The boundaries of these blocks represent major discontinuities that separate zones of distinct or different structural orientations and /or structural styles. In addition, Gardiner established a time sequence of tectonic

Fig. 3-17 Interpreted crustal blocks from Gardiner (1990). Interpretation based on integrated analysis.

events for the CBP and developed a predictive model to recognize undiscovered fault systems.

A map of Ellenburger structure (see Fig. 3-18) demonstrates that the majority of deformation occurs along faults that form the boundaries of Gardiner's crustal blocks. The centers of the blocks are relatively undeformed. Erosional limits are markedly affected by the block boundaries and are used to delineate the chronology of block development and interaction.

The modeling area of interest (especially the Gandu Unit) lies primarily within the Midland Basin, the Mid-CBP transition zone, and the Andrews Shear Zone. As a result of our limited focus, we will only discuss Gardiner's detailed results for these three areas. The Mid-CBP Transition Block is an area of ~1600 square miles dominated by NW-trending reverse faults in the northern area (including Gandu Unit) and NW-trending reverse faults in the southern area. Both areas contain less dominant NE-trending normal faults. There is a NE-trending sag corresponding to the center of the area. The majority of traps are faulted anticlines thought to be associated with left lateral strike-slip deformation along the southern block boundary. According to Gardiner, the central blocks were uplifted from Barnett through Atokan time. The eastern edge was uplifted slightly later from Atokan to Strawn time.

The Andrews Shear Zone underlies an area of ~850 square miles dominated by NE-trending faults and folds within an overall right lateral shear zone. The area is dominated by *en echelon* folds and possible eroded flower structures. There is some stratigraphic trapping potential associated with the Woodford erosional limit. The area experienced slight movement from the late Mississippian but the majority of motion occurred from the Atokan through late Wolfcampian.

The Midland Basin area is a large area (>~6000 square miles) that is dominated by small NE and NW-trending faults and related folds. All structures are similar in style but smaller in size to those seen in the Mid-CBP Transition Zone. Principal traps in the Midland Basin include restraining bends along strike-slip faults and small faulted anticlines. Additional production is found in stratigraphic traps, especially pinch-outs and erosional truncations. The majority of uplift occurred prior to the Mississippian with isolated fault block movement during Barnett-Strawn time. Since that time, the region has experienced regional subsidence.

As Gardiner concludes, the future production potential of the Permian Basin is slight compared to its history. However, there appears to be additional areas for exploration along the margins of the structural blocks where oblique-slip motion between blocks enhances the development of fractured structural traps. Stratigraphic traps are

Fig. 3-18 Interpreted crustal blocks from Gardiner (1990) on Ellenburger regional structure basemap.

best pursued within the interior of the blocks where depositional influences can be understood without the complexity of the pervasive tectonic overprint.

Shumaker (1992) expanded on the work of Hills (1985) and provided more detailed documentation of deformation processes, especially in folded-and-thrusted oil fields along the Central Basin Platform. Shumaker identifies and describes structural styles present in the Central Basin Uplift and adjacent Delaware Basin. These structures are put into a regional framework that integrates the results from numerous published field studies to arrive at an interpretation that minimizes the significance of strike-slip deformation except along several well-documented zones. One of the most interesting results from Shumaker's study is his synthesis of the along-strike variation in fold and thrust geometry along the western margin (eastern edge of Delaware Basin) of the Central Basin Platform. Historically, this boundary had been interpreted as a significant wrench system (e.g. Hills, 1970). Shumaker, however, showed that the thrusts are relatively shallowly-dipping and that there is significant duplication of stratigraphy related to the complex folding and thrusting (see Fig. 3-19). Shumaker does not find the large (tens of miles, Hills, 1970) strike-slip displacement on the West Platform Fault. Instead, it appears that this zone is dominated by reverse faulting and tight folding. In addition, Shumaker finds little evidence for the regional system of N/S-trending right lateral strike-slip faults previously interpreted (Hills, 1970). Instead, according to Shumaker, the region has experienced differential uplift and variable vergence because of an overall left lateral shear imposed along E/W and WNW-trending faults throughout the Central Basin Uplift. Lesser amounts of right lateral slip have occurred along the less important (to accommodate regional strain) NE-antithetic faults. This fault geometry results in an overall counter-clockwise rotation of blocks within the Central Basin Uplift. Variations in fold trends and reverse faults may reflect differential rotation of fault blocks rather than complex changes in regional stress. As a result, it is believed that most of the structures formed within the context of an overall E/W-oriented regional principal compressive stress.

Shumaker's model is confusing because of the relative scarcity (especially on detailed field structure maps) of E/W and WNW faults. These faults are somewhat more prominent, however, on the simplified regional map that Shumaker created. This simplified map (Fig. 3-20) does not show the dominance of NW-trending faults, especially on a field-scale, throughout the region. This simplification incorrectly gives much greater importance to the WNW- and E/W-trending fault systems. As a result, Shumaker's geometric model is somewhat confusing. By reference to his diagram in the corner of Fig. 3-20, the relationships between structures becomes clearer. The E/W and

Fig. 3-19(a) Structural sections illustrating complex fold and thrust relationships along the Central Basin Platform Margin. note that regional detachment surface has been interpreted at ~30,000 feet.

Fig. 3-19(b) Additional sections illustrating complex fold and thrust relationships along the Central Basin Platform margin. Note relatively low angle dips of fault plans and tight, basement-involved folding. Majority of regional detachments lie at ~30,000 feet.

Fig. 3-20 Interpretation of regional kinematics from Shumaker, 1992. note large numbers of E/W-trending wrench zones. Overall block rotation is clockwise due to left lateral displacement along NW-trending wrench systems. Contrast with Gardiner (1990) in Figs. 3-17,18 and Yang and Dorobek (1995) in Figs. 3-21,22.

WNW faults are interpreted as the dominant regional strike-slip faults and show a left-lateral sense of shear. The NW-trending faults are dominated by thrusting as is observed in most areas. The NE-trending faults show antithetic shear or right lateral. The overall kinematics of the CBP interior blocks involve counterclockwise rotation. This implies that the displacement along the NE-trending crossfaults is less significant compared to that on the E/W and WNW-trending left lateral set. If the latter NE-trending set (left lateral) did show major displacement, the overall sense of rotation for the enclosed blocks would be clockwise. Because most blocks that compose the CBP, however, do show clockwise rotation (e.g. Gardiner, 1990; Yang, 1993; Yang and Dorobek, 1987; 1993; 1995), however, it is necessary that either the NE-trending crossfaults show greater displacement or an alternative kinematic model is required. The former explanation involving greater displacement along NE-trending faults is contrary to that which is observed.

Interestingly, Gardiner (1990) describes and documents a transition from clockwise block rotation and right lateral shear in the northern part of the CBP that sharply contrasts with the counterclockwise block rotation and left lateral shear in the southern part of the CBP where most of Shumaker's data was based. As a result, the differences between the various models possibly reflect the local geology that typify the different areas in which each geologist performed their syntheses.

A remedy for this significant kinematic problem was defined by Yang (1993) and Yang and Dorobek (1987; 1993; 1995). Yang (1993) and Yang and Dorobek (1987; 1993; 1995) used the earlier work of Gardiner and Shumaker to simplify the geometry of the regional block boundaries in order to facilitate flexure modeling of the CBP and adjacent Delaware and Midland basins. Instead of the six blocks of Gardiner, Yang and Dorobek delineated only two major crustal blocks; the Andector and Fort Stockton blocks. This simplification appears to more closely correspond to the primary differences in structural style between the different areas. Unlike most previous models, Yang and Dorobek had extensive regional seismic data that they used to constrain the geometry of the boundary regions between crustal blocks. They were also able to use these same profiles to better characterize the internal deformation within these fault-bounded blocks. As a result, the accuracy of their regional shortening calculation is much better. Most importantly, their model is better able to reflect the deformation observed throughout the region, not just in a limited area where subsurface data are abundant such as in individual oil and gas fields (e.g. Shumaker, 1992).

Yang and Dorobek (1995) generate clockwise rotation of smaller blocks within the CBP by right lateral displacement along NNW-trending fault zones that dominate the

CBP: Evidence in support of the model includes: 1) extensive N/S-trending *en echelon* folds and faults (including flower structures) for the area north of the Andector Block; and 2) close correspondence in structural style between individual E/W-trending faults on either side of the CBP that appear to correlate across zones that have experienced right lateral offset. This model explains the differences in regional shortening observed across the study area (Fig. 3-21). From this figure, it is clear that there are significant differences in regional shortening along-strike of the Central Basin Platform that suggest a simplified model of regional kinematics (Fig. 3-22). In the model, the non-parallelism of the faults that bound the CBP cause the development of local extension and contraction along the block boundaries. As a result, local transpression and transtension occurs, similar to that documented by Gardiner (1990). Calculated basement shortening decreases northward along the western boundary of the Fort Stockton Block and southward along the eastern block boundary. Similar variations in basement shortening are also observed along the eastern and western boundaries of the Andector Block.

In this study, we will primarily use the results of Yang and Dorobek along with those of Gardiner. This is a logical choice because our primary area of interest lies in the area where these authors had the most data to support their interpretation. In contrast, Shumaker's work concentrated on the CBP southwestern margin where the data indicate a somewhat contrary interpretation. Nonetheless, it seems possible to integrate some of the more general aspects of Shumaker's model.

IX. Regional Shortening Calculation Methodology

The calculation of regional shortening represents one of the primary objectives of the project and is a critical input into the CIRF.B simulator. To calculate regional shortening, the Ellenburger Formation was used as a structural datum to understand the distribution and displacement history of faults and related folds throughout the modeling domain. From the available Ellenburger structure maps, the vertical displacement was calculated on all faults. In addition, fold axes were interpreted. The majority of regional shortening occurred along NE/SW trending section lines. Lesser shortening occurred along an orthogonal direction.

To calculate regional shortening for input into the CIRF.B model, we have used the Ellenburger structural map as a basement-equivalent surface. The methodology for calculating the shortening is two fold. The first step is to remove the displacements on a given fault. The second step is to remove the regional shortening component that was accommodated by folding above this thrust. These two steps are repeated for every fault

Fig. 3-21 Regional shortening calculations taken from Yang and Dorobek (1995). Note variations in shortening along the different fault zones.

Fig. 3-22 Block rotations proposed by Yang and Dorobek (1995) during the kinematic evolution of the Central Basin Platform. Due to non-parallelism and differential displacement rates along bounding stick-slip faults, significant volume problems are created that require thrusting and normal faulting to maintain constant volume deformation.

in the modeling domain. At this point, we have developed the following methodology to generate computer-based grids for *CIRFB* input. We have chosen to grid the area of interest with half-mile grid spacing. The orthogonal grid will be laid out parallel and perpendicular to the NE-trending direction of maximum regional shortening. This direction is chosen perpendicular to the maximum fault displacement and perpendicular to the dominant regional fold axes. The second direction is used to calculate the lateral displacement of the grid parallel to the direction of greatest shortening. A schematic of the calculation methodology is shown in Fig. 3-23. Due to previously unrecognized structural complexity in the Andector-Gandu area, it is necessary to have several regional seismic lines to constrain subsurface fault and fold geometries. In the absence of this seismic data, the errors associated with the shortening calculation are potentially serious enough to cause complex three-dimensional strain compatibility and related analytical problems during the modeling. We anticipate having the seismic data available in late January and will discuss and present the regional shortening calculation results in the next quarterly report.

X. Tectonic Development and Stress Regimes Throughout Basin Evolution

The evolution of the stress regime over the time frame of basin evolution represents one of the most critical pieces of data for input into the *CIRFB* model. By knowing the orientation, duration and magnitude of the far-field regional stresses acting on the boundaries of the modeling regime, we can better predict the geometry and kinematics of crustal movement and fracturing in the model. Local stresses, for example those related to local folding and faulting, will be solved during the *CIRFB* model run by the stress solver module.

The majority of authors (Hills; 1970, 1982, 1985; Horak, 1985; Gardiner; 1990; Shumaker, 1992) propose an overall NE/SW-directed regional shortening for the Central Basin Platform and the Midland and Delaware basins. There are several different time frames that have been outlined for the initiation and cessation of tectonism in the region.

According to Gardiner (1990), the driving force for deformation in the CBP and adjacent Delaware and Midland basins was the onset of Ouachita deformation in early Mississippian time. This NW-directed Ouachita crustal shortening caused the breakup of basement crust in the CBP into the six major structural blocks outlined earlier. In the CBP area, there are three main episodes of tectonic movement: 1) Barnett time (late Mississippian); 2) Atokan (early Pennsylvanian); and 3) Strawn (mid-Pennsylvanian).

**Step 1:
initial structural configuration**

**Step 2: Remove fault displacement
by restoring hangingwall/footwall cutoffs.
Calculate shortening due to fault displacement.**

**Step 3: Remove shortening component
due to folding in hangingwall**

Fig. 3-23 Methodology for calculation of regional shortening on Ellenburger structural datum.

In Barnett time, existing NW-trending fault systems were reactivated, marking the initial uplift of the Ft. Stockton, Sand Hills and Lea-Andrews blocks. Regional thickness changes in the Barnett Shale suggest uplift of the CBP began at its center and progressed to the margins. Initial tectonic movement was thought to be vertical prior to increasing oblique-slip during the subsequent phases. During the Atokan, contraction reached its climax, forming throughgoing basement wrench faults. Major systems include the Big Lake-Barnhart fault that separates the Midland Basin from the Reagan Uplift to the south. This orientation shift is also supported by the Montoya erosion pattern and a magnetic anomaly. In Strawn time, NE-trending faults appear to become active and crosscut the older NW-trending set. Increased wrench motion along the Andrews Shear Zone probably enhanced the formation of the Inez field anticlinal structure as well as NE-trending faults such as those that form Hutex and Pritchard fields in Andrews County. Continued motion along the NE-trending scissors fault lying between the Ft. Stockton and Sand Hills blocks probably caused a NE-trending regional principal stress orientation. Gardiner has also delineated the dominant structural fabric, trap types and age of structural movement for each of the six structural megablocks. These have been summarized in Table 1 (modified from Gardiner, 1990).

Although Gardiner's synthesis for the regional stress evolution is in general agreement with earlier work (e.g. Hills, 1970; 1982; Font, 1985; Horak, 1985; Price and Henry, 1985) his interpretation is not without controversy. The controversy results from the fact that the NW-trending stress regime from the Marathon-Ouachita collision is oriented at right angles to that interpreted from the NE-trending stress regime interpreted from local fault and fold structures that compose the CBP, Midland and Delaware basins. Horak (1985) discusses the fact that the two stress regimes appear contradictory. He suggests that the Delaware and Midland basins may represent impactogens similar to those observed today in China in front of the Himalaya Thrust Front. Because the Delaware Basin overlies the ancestral Tobosa Basin center, it likely represents an area of thickened crust that may have been weaker than adjacent basement areas that underlie the Midland Basin and Central Basin Platform.

An alternative interpretation for thickened crust in the Delaware Basin is based on the potential field geophysics which indicate that the CBP is an area probably underlain by a large mafic mass. The CBP correlated with a gravity and magnetic high or positive anomaly. However, the gravity high is much larger than would be expected based on structural relief alone. This suggests either a mafic core or a thickened crust beneath this area. Given its greater thickness, it may have been older, cooler and more susceptible to uplift during regional shortening.

As Yang and Dorobek (Yang, 1993 and Yang and Dorobek, 1987; 1993; 1995) have shown, the geometry of the Delaware and Midland basins can be satisfactorily modeled as resulting from the flexural response to the imposed load created by the CBP uplift. Following the initial uplift of the CBP, the N/S- to NW-oriented regional stress of the Marathon-Ouachita collision regional shortening was imposed on the dominant NW-trending basement structural anisotropy of the Central Basin Platform. Depending on the kinematics of the local blocks, the regional strain was accommodated by differential shortening (expressed via folding and thrusting involving basement) and strike-slip motion along favorably oriented fault systems. Given the basement involvement, it seems likely that significant shortening was accommodated by the sedimentary cover by shortening and thrusting before throughgoing wrench systems developed in the sedimentary cover. It is this complex juxtaposition and overprinting of contractional and wrench tectonics that has challenged regional interpretations and tectonic syntheses in West Texas and the Permian Basin.

References

- Barnes, V.E., 1983, Geologic Atlas of Texas, Van Horn-El Paso Sheet, Bureau of Economic Geology, The University of Texas at Austin.
- Barnes, V.E., 1983, Geologic Atlas of Texas, Big Spring Sheet, Bureau of Economic Geology, The University of Texas at Austin.
- Bolden, G.P., 1984, Wrench Faulting in Selected Areas of the Permian Basin, *in*: Moore, G. and Wilde, G., eds., Transactions of the Southwest Section of the AAPG, Southwest Section Publication 84-78, 131-140.
- Borger, R.L., 1990, An Example of the Use of Satellite Image Analysis and Digital Data Integration in Exploration for Hydrocarbons in West Texas, *in*: Flis, J.E. and Price, R.C., eds., *Permian Basin Oil and Gas Fields: Innovative Ideas in Exploration and Development*, Midland, Texas, West Texas Geological Society Publication 90-87, 1-11.
- Ewing, T.E., 1990, The Tectonic Map of Texas, Bureau of Economic Geology, Austin, Texas The University of Texas at Austin.
- Ewing, T.E., 1990, The Tectonic Framework of Texas: Text to accompany "The Tectonic Map of Texas", Bureau of Economic Geology, Austin, Texas The University of Texas at Austin. 36 p.

- Frenzel, H.N., Bloomer, R.R., Cline, R.B., Cys, J.M., Galley, J.E., Gisbon, W.R., Hills, J.M., Seager, W.R., Kottowski, R.E., Thompson III, S.J., Luff, G.C., Pearson, B.T., and Van Siclen, D.C., 1988, The Permian Basin Region, in: L.L. Sloss, ed., *Sedimentary Cover of North America*, Geological Society of America, The Geology of North America, V D-2, 261-306.
- Gardiner, W.B., 1990, Fault Fabric and Structural Subprovinces of the Central Basin Platform: A Model for Strike-slip Movement, in: Flis, J.E. and Price, R.C., eds., *Permian Basin Oil and Gas Fields: Innovative Ideas in Exploration and Development*, Midland, Texas, West Texas Geological Society Publication 90-87, 15-27.
- Harrington, J.W., 1963, Opinion of Structural Mechanics of Central Basin Platform Area, West Texas, AAPG Bulletin, 47, 2023-2038.
- Henry, C.A. and Price, J.G., 1985, Summary of the Tectonic Development of Trans-Pecos Texas, Bureau of Economic Geology, Misc. Map #36, University of Texas at Austin.
- Hill, C.A., 1996, Geology of the Delaware Basin Guadalupe, Apache and Glass Mountains New Mexico and West Texas, SEPM Permian Basin Section Publication 96-39, 480 p.
- Hills, J.M., 1970, Late Paleozoic Structural Directions in Southern Permian Basin, West Texas and Southeastern New Mexico, AAPG Bulletin, 54, 1809-1827.
- Hills, J.M., 1984, Sedimentation, Tectonism, and Hydrocarbon Generation in Delaware Basin, West Texas and Southeastern New Mexico, AAPG Bulletin, 68, 250-267.
- Hills, J.M., 1985, Structural Evolution of the Permian Basin of West Texas and New Mexico, in: Dickerson, P.W., and Muehlberger, W.M., eds., *Structure and Tectonics of Trans-Pecos Texas*, Midland, Texas, West Texas Geological Society Publication 85-81, 89-99.
- Horak, R.L., 1985, Trans-Pecos Tectonism and its Effect on the Permian Basin, , in: Dickerson, P.W., and Muehlberger, W.M., eds., *Structure and Tectonics of Trans-Pecos Texas*, Midland, Texas, West Texas Geological Society Publication 85-81, 81-87.
- Keller, G.R., and Peeples, W.J., 1985, Regional Gravity and Aeromagnetic Anomalies, in: Dickerson, P.W., and Muehlberger, W.M., eds., *Structure and Tectonics of Trans-Pecos Texas*, Midland, Texas, West Texas Geological Society Publication 85-81, 101-105.
- Shumaker, R. C., 1992, Paleozoic Structure of the Central Basin Uplift and Adjacent Delaware Basin, West Texas, AAPG Bulletin, 76, 1804-1824.

- Yang, K-M., 1993, Late Paleozoic Synorogenic Stratigraphy, Tectonic Evolution, and Flexural Modeling of the Permian Basin, West Texas and New Mexico, Unpublished Ph.D. dissertation, Texas A&M University, College Station, Texas 142 p.
- Yang, K-M., and Dorobek, S.L., 1992, Mechanisms for Late Paleozoic Synorogenic Subsidence of the Midland and Delaware Basins, Permian Basin, Texas and New Mexico, in Mruk, D., and Curran, B., eds., Permian Basin Exploration and Production Strategies—Applications of Sequence Stratigraphic and Reservoir Characterization Concepts, Midland, Texas, West Texas Geological Society Fall Symposium, 45-60.
- Yang, K-M., and Dorobek, S.L., 1993, Late Paleozoic Synorogenic Stratigraphy and Tectonic Evolution of the Permian Basin, West Texas and New Mexico, in: Cromwell, D., and Gibbs, J., eds., New Dimensions in the Permian Basin: 3D and Environmental Geosciences, Midland, Texas, West Texas Geological Society Publication 93-93, 8-18.
- Yang, K-M., and Dorobek, S.L., 1995, The Permian Basin of West Texas and New Mexico: Tectonic History of a "Composite" Foreland Basin and its Effects on Stratigraphic Development, in: *Stratigraphic Evolution of Foreland Basins*, SEPM Special Publication #52, 149-174.
- Yang, K-M., and Dorobek, S.L., 1995, The Permian Basin of West Texas and New Mexico: Flexural Modeling and Evidence for Lithospheric Heterogeneity Across the Marathon Foreland, in: *Stratigraphic Evolution of Foreland Basins*, SEPM Special Publication #52, 38-49.

4

Thermal and Pressure Regime (K. Sundberg, M. Shebl and P. Ortoleva)

I. Rationale

Diagenetic, hydrologic and mechanical processes are strongly dependent on temperature and fluid pressure. In this chapter, data on these two parameters are discussed. The results will be used for simulation input for *CIRFB* simulation (in the form of basin heat flux) and for model calibration and testing in the case of fluid pressure measurements.

II. Thermal Regime

The Permian Basin area of Texas is a Paleozoic basin that has been in a stable configuration for a long time. Figure 4-1 (Katz et al., 1994) shows a burial history of a Central Basin Platform well. In this history

- (1) a slowly subsiding basin is filled by sediment for about 250 my;
- (2) a rapid subsidence and basin filling takes place from about 280 to 250 mybp;
- (3) the area becomes quasi stable for the last 250 my; and
- (4) during this last interval, petroleum generation and migration takes place.

Heat flow in the area has been relatively constant over the Permian basin. Katz et al. (1994) argue that the depth to the oil window across the Central Basin Platform is at a relatively constant depth (Figure 4-2). This uniformity indicates that the temperature profiles have been more or less constant for a long time. In particular, the temperature profiles have been stable during the extended period of stability following the rapid subsidence and deposition at the close of the Paleozoic.

Mineralogically, the entire basin is dominated by carbonates. As a result, the gross physical properties like matrix density and thermal conductivity will be relatively constant with depth. Consequently, the relatively uniform temperature will imply a relatively isotropic heat flow. These observations are consistent with other geochemistry and with observations of current temperature.

Figure 4-1. Idealized burial history of a Central Basin Platform well (Katz et al., 1994). Not rapid deposition at the close of the Paleozoic and relative stability thereafter.

Figure 4-2. Generalized cross section across the Central Basin Platform (Katz et al., 1994). The top of the oil window is indicated to lie at a relatively uniform depth. It shows no or only limited response the faulting that defines the edge of the platform.

Vitrinite reflectance, which behaves to a first approximation, as a maximum reading paleothermometer, is linearly related to depth over large parts of the Basin. Because vitrinite reflectance is an effective maximum temperature paleothermometer, we can conclude the paleotemperature history has been linear with depth, at least during the time of oil and gas generation.

Stahl and Carey (1975) published vitrinite reflectance data for a collection of wells in the Delaware Basin segment of the Permian basin. Their data for the Ellenburger Formation are summarized in Table 4-1 and presented graphically in Figures 4-3 and 4-4. We see that the reflectance is a linear function of depth over the basin. The Ellenburger depths considered range from 5,000 to 20,000 ft, so this linearity is not just an artifact of considering a small portion of one formation in one area. The relation holds over a large party of the Permian Basin. Figure 4-5 shows an index map locating these wells.

Bostick (1971) published a modification of a graph by Karwell (1956) and Teichmuller and Teichmuller (1968) relating vitrinite reflectance, maturation time, and temperature. Reference to this graph, using a maturation time of time since the close of the Permian (elapsed time since the rapid subsidence), provide estimates of the source rock temperature relationship seen in Figure 4-4. That relation would indicate a paleogeothermal gradient of $1.1^{\circ}\text{F}/100\text{ ft}$.

Subsurface temperature measurements are generally consistent with this value. Figure 4-6 shows an edited collection of bottom hole temperature observations for the eastern Delaware Basin, Central Basin Platform, and western Midland Basin. Plotting these temperatures as functions of depth, one obtains the geothermal gradient of $0.96^{\circ}\text{F}/100\text{ ft}$. Given the well-known tendency for bottom hole temperatures to underestimate true formation temperatures, these geothermal gradients can be taken as functionally equal. The edited data are seen in Table 4-2. The editing performed simply eliminated a few wells with bottom hole temperatures that were clearly below those one would expect. The source of the errors could have been errors in measurement, cold drilling mud, etc.

The geothermal gradient estimated here can be used to estimate heat flow in the area. This is a Fick's law problem, and it will allow us to make an estimate of the effective thermal conductivity of the Permian Basin section.

The gradient we estimate is somewhat larger than that of Nichols (1947). See the contours on Figure 4-5. We expect related thermal effects in this area to be more important than one might expect based on classic values from the literature. However, one should realize, these values will undergo further refinement in the course of the study.

Table 4-1. Vitrinite reflectance values for wells from selected Delaware Basin fields.

Field	Form	Depth	Ro	Ro fit	Age	D-Age
Grey Ranch, Blackstone	Elbg	14350	1.9	1.75	480	230
Mi Vida	Elbg	18250	2.25	2.26	480	230
Worsham Bayer	Elbg	16850	1.98	2.07	480	230
Wyatt	Elbg	7000	0.95	0.79	480	230
Pecos Valley - South	Elbg	7450	0.65	0.85	480	230

Ro and Depth, Delaware Basin

Figure 4-3. Vitrinite reflectance as a function of depth for selected Delaware Basin Wells.

105

Figure 4-6. Permian Basin bottom hole temperatures and least squares fit to produce an effective geothermal gradient.

III Fluid Pressure

Fluid pressure data are being gathered from a number of sources (Phillips Petroleum Co., Dr. David Powley, and the literature). These data will be processed to yield a three dimensional view of the fluid pressure and of seals in the Permian Basin area.

In Fig. 4-7 pressure data provided by Dr. D. Powley is shown. Frame (a) is a cross-section that shows the distribution of underpressured and normally pressured stratigraphic units throughout the central Midland Basin. Frame (b) is a pressure/depth plot showing the presence of overpressure (in King County, Texas) along the eastern margin of the Midland Basin. The overpressuring is within a compartment that lies on the same depth range as the Clear Fork Formation. Such overpressure is a key factor in preventing vug collapse.

The pressure data being gathered is a key element of our *CIRFB* testing and calibration efforts. This data will be compared with *CIRFB* predicted present-day pressure distributions across the Midland Basin and the Central Platform Uplift.

Finally, it may be quite important in understanding the Midland Basin to explain why its pressure configuration is opposite to the typical case. The latter is overpressure in the deeper parts of a basin and normal to underpressure in the basin margins.

Table 2

42003351620000	32.26658	102.5887	3216	KB	9230	126	137.8614
42003351820000	32.27428	102.6491	3202	KB	10158	130	146.7824
42003353380000	32.15886	102.4277	3088	KB	9109	136	136.6982
42003353690000	32.39634	102.3001	3019	KB	12650	184	170.7382
42003356260000	32.24519	102.586	3196	KB	9303	125	138.5632
42003358090000	32.34095	102.5776	3201	KB	9800	132	143.3409
42003358430000	32.49737	102.5314			9450	146	139.9763
42003359500000	32.24389	102.5583	3198	KB	9300	134	138.5343
42003364150000	32.11574	102.7735	3294	KB	8260	122	128.5367
42103324690000	31.57969	102.7031	2723	KB	6460	100	111.2331
42103324710000	31.53148	102.7142	2664	KB	6232	100	109.0413
42103325270000	31.59243	102.7291	2716	KB	6575	110	112.3386
42103325300000	31.59583	102.7302	2719	KB	6582	109	112.4059
42103326220000	31.60131	102.7225	2729	KB	4790	96	95.17918
42103326560000	31.56509	102.6371	2719	KB	9117	120	136.7751
42103327730000	31.57619	102.703	2723	KB	6420	103	110.8486
42103334140000	31.62001	102.3574	2836	KB	10100	143	146.2248
42103334500000	31.5234	102.6587	2672	KB	6025	115	107.0514
42103334540000	31.64672	102.6239	2864	KB	7700	118	123.1533
42135204010000	31.70629	102.486	3232	KB	6400	115	110.6563
42135335200000	31.89033	102.6448	3217	KB	6100	120	107.7724
42135335270000	31.89276	102.6503	3223	KB	6100	125	107.7724
42135335290000	31.75498	102.5331	3102	KB	12539	156	169.6712
42135335490000	31.84273	102.6144	3191	KB	6095	116	107.7243
42135335810000	32.01855	102.6643	3158	KB	6331	113	109.993
42135336230000	31.68936	102.4607	2946	KB	12210	153	166.5085
42135337150000	31.84343	102.6101	3184	KB	6075	110	107.532
42135337190000	31.83893	102.6132	3182	KB	6100	110	107.7724
42135338080000	31.93826	102.5293	3054	KB	14307	193	186.6672
42135339860000	31.65347	102.6292	2843	KB	9750	130	142.8602
42135340210000	32.0425	102.4633	3043	KB	10883	168	153.7519
42135342870000	31.78619	102.5651	3100	KB	12185	158	166.2681
42135342970000	32.0013	102.7681	3300	KB	5817	114	105.0518
42135345860000	32.05696	102.4774	3052	KB	10700	149	151.9927
42135356290000	31.92964	102.3669	3009	KB	13720	192	181.0243
42135356300000	31.83481	102.5183	2993	KB	8950	130	135.1697
42135357940000	31.98237	102.6876	3202	KB	6600	114	112.5789
42135359780000	31.93039	102.5868	3113	KB	6700	124	113.5402
42135361240000	31.94644	102.5831	3088	KB	6605	118	112.627
42135363900000	32.02254	102.7972	3339	KB	5850	117	105.3691
42317319270000	32.43436	102.1884	2930	KB	13218	206	176.1985
42317320480000	32.50454	102.0006	2875	KB	12224	169	166.643
42317322120000	32.48216	102.1806	2897	KB	9800	159	143.3409
42329309220000	31.95292	102.0118	2772	KB	11950	174	164.0091
42329309680000	31.95438	102.1144	2822	KB	13150	175	175.5448
42329310000000	31.80603	102.0455	2721	KB	13157	182	175.6121
42329312910000	31.81481	102.1361	2866	KB	12640	173	170.6421
42329315370000	31.79545	102.1231	2872	KB	8875	133	134.4487
42461321550000	31.57828	102.0168	2813	KB	9150	132	137.0923
42461330070000	31.59667	102.16	2881	KB	10762	153	152.5887
42475337090000	31.53891	102.9638	2642	KB	9000	143	135.6504
42475338330000	31.56589	102.8287	2649	KB	5600	97	102.9658
42495317380000	31.72501	102.9973	2763	KB	5580	100	102.7735

(a)

(b)

Figure 4-7 Pressure data from Midland Basin showing (a) underpressured and normally pressured distribution in the central part of the Midland Basin, and (b) an overpressured compartment that contains the Clear Fork Formation along the eastern margin of the basin. Overpressuring in this region helps to preserve vugs there from failure.

References

- Bostick, N.H. (1971) Time as a factor in thermal metamorphism of phytoclasts (coaly particles), Septieme Congress International de Stratigraphie et de Geologie du Carbonifere, Krefeld 23-28, Aug. 1971, Compte Rendu Band II.
- Karweil, J. (1956) Die metamorphose der kohlen vom standpunkt der chemie, *Duet Geol. Ges., Z.* **107**, 132-139.
- Katz, B.J., V.D. Robison, W.C. Dawon, and L.W. Elrod (1994) Simpson-Ellenburger Petroleum System of the Central Basin Platform, West Texas, USA, *AAPG Mem.* **60**, L.B. Magoon and W.G. Dow, eds.
- Nichols, (1947) *Trans. Amer. Inst. Min. Met. Eng.* **170**, 46.
- Stahl, W.J. and B.D. Carey, Jr. (1975) Source-rock identification by isotope analysis of natural gases from fields in the Val Verde and Delaware basins of West Texas, *Chem. Geol.* **16**, 257-267.
- Teichmuller, M. and R. Teichmuller (1968) Geological aspects of coal metamorphism, *Coal and Coal Bearing Strata*, Inter-Univ., 135th Geol. Congr., Edinburgh, Oliver and Boyd, Pub.

5

Stability and Failure of Cavities in Poroelastic Media

(G. Ozkan and P. Ortoleva)

The stress-induced failure of cavities in poroelastic media is investigated using an analytical solution of the elastic matrix inclusion problem of Eshelby and a rock failure criterion. The elastic properties of the porous matrix surrounding the cavity are modeled using a self-consistent version of the theory of Berryman while the cavity collapse criterion is based on a failure condition calibrated as a function of matrix mineralogy, grain size and porosity. The influence of the latter textural variables as well as pore fluid pressure and cavity shape and orientation relative to the far-field stress are evaluated. The region of failure on the cavity surface is identified. These results are applied to the prediction of vug stability in a sedimentary basin in the context of vuggy reservoir exploration and production.

I Introduction

Cavities in porous media form as a result of natural and engineering processes. The issue of their mechanical stability is central to applications in petroleum exploration and production, materials engineering, civil engineering, and other fields. Key examples include cavitation created due to excessive matrix acidizing treatments and the prediction of vuggy reservoir location and characteristics. The purpose of the present work is to assess the stresses surrounding a cavity and set forth a criterion for failure/collapse of the medium surrounding a cavity. A modified form of a solution of Eshelby (1957) for the elastic matrix-inclusion and a calibrated failure criterion are used to obtain an exact failure criterion for ellipsoidal cavities.

A number of factors characterizing the matrix, the pore and cavity fluid and the stress applied far from the cavity are shown here to determine its failure properties:

- cavity geometry
- cavity orientation relative to the far-field stress
- porosity, grain size and other aspects of the texture of the porous matrix
- fluid pressure and (for the multi-phase case) capillarity and wetting

- tensor far-field stress.

In the present study, only the single-phase aspects of the problem are addressed (see Ozkan and Ortoleva, 1997 for the multi-phase case).

Eshelby (1957) determined the stress inside and just outside of an ellipsoidal, pore-free elastic inclusion in an infinite elastic, porosity-free medium subjected to a far-field stress. In the present study, these solutions are modified for the poroelastic case, accounting for the influences of fluid pressure and resulting effective stress. Poroelastic coefficients of porous composites are estimated by self-consistent effective medium approximation according to Berryman (1986). The stability of ellipsoidal cavities in carbonated rocks is studied by Druker-Prager failure condition (Druker and Prager, 1952) with calibrated parameters. In Sakrani (1997), the calibration of failure parameters according to the porosity and grain sizes of the porous matrix is given.

The vug stability is affected by matrix texture, cavity shape and orientation, far field stress tensor and fluid pressure. In this study, these parameters are studied to obtain the state of far field stress that the cavity will fail.

II Cavity in a Poroelastic Medium

A. Formulation

Stresses are to be computed around a cavity in a poroelastic medium. Let $\underline{\underline{\Lambda}}$ be the tensor of poroelastic coefficients. Then strain tensor $\underline{\underline{\varepsilon}}$ and stress tensor $\underline{\underline{\sigma}}$ are related in the porous medium surrounding the cavity by

$$\underline{\underline{\sigma}} + \alpha p \underline{\underline{I}} = \underline{\underline{\Lambda}} \underline{\underline{\varepsilon}} \quad (\text{II.1})$$

for effective stress coefficient α , unit tensor $\underline{\underline{I}}$ and pore fluid pressure p . The boundary conditions adopted are that the normal stress at the cavity surface is $-p$, tangential shear is zero and that $\underline{\underline{\sigma}} \rightarrow \underline{\underline{\sigma}}^\infty$ (the far field stress) far from the cavity.

Let $\underline{\underline{\sigma}}^E(\underline{\underline{\psi}})$ be a solution of the aforementioned problem for $p=0$. Its argument $\underline{\underline{\psi}}$ is the constant value of stress far from the void. Then the solution of the problem of interest here may be shown to be

$$\underline{\underline{\sigma}} = \underline{\underline{\sigma}}^E(\underline{\underline{\sigma}}^\infty + p \underline{\underline{I}}) - p \underline{\underline{I}}. \quad (\text{II.2})$$

This result holds for voids of arbitrary shape as long as $\underline{\underline{\sigma}}^E$ is known for that shape.

In the present study, the cavity is assumed to be an ellipsoid. As coordinate system, a rectangular x_i -frame ($i=1-3$) having origin at the center of the ellipsoid is selected. According to this coordinate system, the surface of the ellipsoid (S) is written

$$S: \frac{x_1^2}{a^2} + \frac{x_2^2}{b^2} + \frac{x_3^2}{c^2} = 1 \quad (\text{II.3})$$

and the outward unit normal $\underline{n}$ of this surface at the point $P(x_1, x_2, x_3)$ is

$$\underline{n} = -\frac{1}{\sqrt{\Delta}} \left(\frac{x_1}{a^2}, \frac{x_2}{b^2}, \frac{x_3}{c^2} \right) \quad (\text{II.4})$$

where

$$\Delta = \frac{x_1^2}{a^4} + \frac{x_2^2}{b^4} + \frac{x_3^2}{c^4}$$

The poroelastic medium is assumed to be isotropic. With this

$$\sigma_{ij} + \alpha p \delta_{ij} = \lambda \varepsilon_{kk} \delta_{ij} + 2 \mu \varepsilon_{ij} \quad (\text{II.5})$$

where δ_{ij} is the Kronecker delta (components of $\underline{I}$) and λ and μ are elastic constants. The Poisson's ratio ν is given by

$$\nu = \frac{\lambda}{\lambda + \mu} \quad (\text{II.6})$$

Eshelby (1957) determined the stress inside and just outside of an ellipsoidal, pore-free elastic inclusion in an infinite elastic, porosity-free medium subjected to a far-field stress. These results can be modified to the ellipsoidal cavity problem by setting the elastic constants of the inclusion to zero. In this study, we obtain the stress field numerically, at the boundary of an ellipsoidal cavity due to a far-field stress field by following Eshelby's formulation. The numerical results for the spherical case are compared with analytical expressions given by Eshelby.

B. Porosity-Free Medium Solutions

Eshelby (1957) determined elastic fields inside and outside of an ellipsoid inclusion in a porosity-free ($\alpha = 0$) medium by superposition of several strain fields. Following his study, the "constrained" strain field just outside the inclusion can be calculated

$$\varepsilon_{ij}^c(out) = \varepsilon_{ij}^c(in) + \frac{1}{1-\nu} n_i n_j n_k n_l \varepsilon_{kl}^t - \frac{\nu}{1-\nu} n_i n_j \varepsilon_{kk}^t - n_k (n_i \varepsilon_{jk}^t + n_j \varepsilon_{ik}^t) \quad (\text{II.7})$$

where ε_{ij}^c and ε_{ij}^t are the elements of “constrained” and “transformed” strain tensors, $\underline{n}=(n_i)$ is the unit normal vector at the boundary of the inclusion and (in) and (out) describe the fields inside and just outside the inclusion boundary, respectively. (II.7) is written in indicial notation (all indicies have the range 1-3) with summation convention on repeated indicies. The transformed strain is a uniform arbitrary strain whereas the constrained strain is the strain occurred inside (or outside) the inclusion due to the applied transformed stress at the boundary of the inclusion while the boundary is constrained and cannot have any displacements. The relation between constrained and transformed strains is

$$\underline{\underline{\varepsilon}}^c(in) = \underline{\underline{S}} \underline{\underline{\varepsilon}}^t \quad (\text{II.8})$$

where $\underline{\underline{S}}$ is a fourth order tensor containing the spatial derivatives of the integral of the Kelvin solution over the ellipsoidal boundary. This tensor is described in more detail in the next section.

When a far-field strain (or stress) field $\underline{\underline{\varepsilon}}^\infty$ (or $\underline{\underline{\sigma}}^\infty$) exists, the total strain just outside the inclusion can be obtained by superposition

$$\underline{\underline{\varepsilon}} = \underline{\underline{\varepsilon}}^c(out) + \underline{\underline{\varepsilon}}^\infty \quad (\text{II.9})$$

and for a cavity, the stress continuity condition will yield to the relation

$$\underline{\underline{\varepsilon}}^c(in) + \underline{\underline{\varepsilon}}^\infty - \underline{\underline{\varepsilon}}^t = \underline{\underline{0}} \quad (\text{II.10})$$

The elements of total strain tensor can then be expressed in terms of the transformed strain

$$\varepsilon_{ij} = \varepsilon_{ij}^t + \frac{1}{1-\nu} n_i n_j n_k n_l \varepsilon_{kl}^t - \frac{\nu}{1-\nu} n_i n_j \varepsilon_{kk}^t - n_k (n_i \varepsilon_{jk}^t + n_j \varepsilon_{ik}^t) \quad (\text{II.11})$$

and the relation between the transformed and far-field strains can be obtained

$$\varepsilon_{ij}^\infty = (\delta_{ik} \delta_{jl} - S_{ijkl}) \varepsilon_{kl}^t \quad (\text{II.12})$$

(II.12) will lead to an inverse expression between transformed and far-field strain fields through a fourth order tensor $\underline{\underline{C}}$ in the form

$$\underline{\underline{\varepsilon}}^t = \underline{\underline{C}} \underline{\underline{\varepsilon}}^\infty \quad (\text{II.13})$$

We can now express the strain field at the boundary of the cavity in terms of far-field strains

$$\varepsilon_{ij} = \left(\delta_{ik} \delta_{jl} + \frac{1}{1-\nu} n_i n_j n_k n_l - \frac{\nu}{1-\nu} n_i n_j \delta_{kl} - n_k n_i \delta_{jl} - n_k n_j \delta_{il} \right) C_{klrs} \varepsilon_{rs}^{\infty} \quad (\text{II.14})$$

1. Calculation of $\underline{\underline{S}}$

Eshelby's solution depends on calculation of $\underline{\underline{S}}$ which defines the relation between constrained and transformed strains. For ellipsoidal inclusions, the elements of this tensor can be evaluated by performing the double integral

$$S_{ijkl} = \frac{1}{16\pi(1-\nu)} \int_0^\pi \int_0^{2\pi} \frac{\lambda_i g_{jkl} + \lambda_j g_{ikl}}{g} \sin \phi \, d\theta \, d\phi \quad (\text{II.15})$$

where

$$g_{ikl} = (1-2\nu) (\delta_{ik} r_l + \delta_{il} r_k - \delta_{kl} r_i) + 3r_i r_k r_l$$

$$\lambda_1 = \frac{r_1}{a^2}, \quad \lambda_2 = \frac{r_2}{b^2}, \quad \lambda_3 = \frac{r_3}{c^2}$$

$$g = \lambda_i r_i = \frac{r_1^2}{a^2} + \frac{r_2^2}{b^2} + \frac{r_3^2}{c^2}$$

$$\underline{r} = (r_i) = (\sin \phi \cos \theta, \sin \phi \sin \theta, \cos \phi)$$

As it can be seen, $\underline{\underline{S}}$ depends only on ellipsoid geometry (a, b, c) and Poisson's ratio ν .

From symmetry $S_{ijkl} = S_{jikl}$ and $S_{ijkl} = S_{ijlk}$. We can write the non zero elements of $\underline{\underline{S}}$ explicitly as

$$S_{11\underline{\underline{kk}}} = \frac{1}{8\pi(1-\nu)} \frac{1}{a^2} [(2\delta_{1k} - 1)(1-2\nu) I_1 + 3I_{1k}]$$

$$S_{22\underline{\underline{kk}}} = \frac{1}{8\pi(1-\nu)} \frac{1}{b^2} [(2\delta_{2k} - 1)(1-2\nu) I_2 + 3I_{2k}]$$

$$S_{33\underline{\underline{kk}}} = \frac{1}{8\pi(1-\nu)} \frac{1}{c^2} [(2\delta_{3k} - 1)(1-2\nu) I_3 + 3I_{3k}]$$

$$\begin{aligned}
S_{1212} &= \frac{1}{16\pi(1-\nu)} \left[(1-2\nu) \left(\frac{I_1}{a^2} + \frac{I_2}{b^2} \right) + 3 \left(\frac{1}{a^2} + \frac{1}{b^2} \right) I_{12} \right] \\
S_{1313} &= \frac{1}{16\pi(1-\nu)} \left[(1-2\nu) \left(\frac{I_1}{a^2} + \frac{I_3}{c^2} \right) + 3 \left(\frac{1}{a^2} + \frac{1}{c^2} \right) I_{13} \right] \\
S_{2323} &= \frac{1}{16\pi(1-\nu)} \left[(1-2\nu) \left(\frac{I_2}{b^2} + \frac{I_3}{c^2} \right) + 3 \left(\frac{1}{b^2} + \frac{1}{c^2} \right) I_{23} \right]
\end{aligned} \tag{II.16}$$

where

$$I_i = \int_0^\pi \int_0^{2\pi} \frac{(r_i)^2}{g} \sin\phi \, d\theta \, d\phi \tag{II.17}$$

$$I_{\underline{i}\underline{j}} = \int_0^\pi \int_0^{2\pi} \frac{(r_{\underline{i}} r_{\underline{j}})^2}{g} \sin\phi \, d\theta \, d\phi$$

and the underlined indices do not obey summation convention.

Eshelby (1957) gave closed form expressions for $\underline{\underline{S}}$ in terms of elliptic integrals.

In this study, the integrals in (II.17) are evaluated numerically by subdividing the domain and using 10-point Gaussian integration in each subdomain. The numerical results are checked with Eshelby's analytical expressions for the spherical case. For the spherical inclusion (when $a = b = c$) the elements are given explicitly and I_i and I_{ij} are

$$I_1 = I_2 = I_3 = \frac{4\pi}{3} a^2$$

$$I_{11} = I_{22} = I_{33} = \frac{4\pi}{5} a^2, \quad I_{12} = I_{13} = I_{23} = \frac{4\pi}{15} a^2$$

We can define strain vector $\underline{\underline{\varepsilon}} = [\varepsilon_{11} \ \varepsilon_{22} \ \varepsilon_{33} \ \varepsilon_{12} \ \varepsilon_{13} \ \varepsilon_{23}]^T$ including the elements of strain tensor, superscript T denotes matrix transpose. The relation between constrained and transformed strains can then be written in matrix form as

$$\underline{\underline{\varepsilon}}^c = \underline{\underline{S}} \underline{\underline{\varepsilon}}^t \tag{II.18}$$

where $\underline{\underline{S}}$ is a (6x6) matrix with elements of tensor $\underline{\underline{S}}$

$$\underline{\underline{S}} = \begin{bmatrix} S_{1111} & S_{1122} & S_{1133} & 0 & 0 & 0 \\ S_{2211} & S_{2222} & S_{2233} & 0 & 0 & 0 \\ S_{3311} & S_{3322} & S_{3333} & 0 & 0 & 0 \\ 0 & 0 & 0 & 2 S_{1212} & 0 & 0 \\ 0 & 0 & 0 & 0 & 2 S_{1313} & 0 \\ 0 & 0 & 0 & 0 & 0 & 2 S_{2323} \end{bmatrix} \quad (\text{II.19})$$

Similarly, $\underline{\underline{C}}$ can be obtained by simple matrix inversion

$$\underline{\underline{C}} = (\underline{\underline{I}} - \underline{\underline{S}})^{-1}$$

where $\underline{\underline{I}}$ is (6x6) identity matrix. The strain field at the boundary point P of an ellipsoidal cavity due to far-field strains (II.14) can then be written as

$$\underline{\underline{\varepsilon}} = (\underline{\underline{I}} + \underline{\underline{N}}) \underline{\underline{C}} \underline{\underline{\varepsilon}}^\infty \quad (\text{II.21})$$

where $\underline{\underline{N}}$ is (6x6) matrix containing Poisson's ratio ν of medium and components of outward unit normal vector $\underline{n}$ at the point P in the form

$$\underline{\underline{N}} = \frac{1}{1-\nu} \underline{\underline{N}}_1 - \frac{\nu}{1-\nu} \underline{\underline{N}}_2 - \underline{\underline{N}}_3$$

and

$$\underline{\underline{N}}_1 = \begin{bmatrix} n_1^4 & n_1^2 n_2^2 & n_1^2 n_3^2 & 2 n_1^3 n_2 & 2 n_1^3 n_3 & 2 n_1^2 n_2 n_3 \\ n_1^2 n_2^2 & n_2^4 & n_2^2 n_3^2 & 2 n_1 n_2^3 & 2 n_1 n_2^2 n_3 & 2 n_2^3 n_3 \\ n_1^2 n_3^2 & n_2^2 n_3^2 & n_3^4 & 2 n_1 n_2 n_3^2 & 2 n_1 n_3^3 & 2 n_2 n_3^3 \\ n_1^3 n_2 & n_1 n_2^3 & n_1 n_2 n_3^2 & 2 n_1^2 n_2^2 & 2 n_1^2 n_2 n_3 & 2 n_1 n_2^2 n_3 \\ n_1^3 n_3 & n_1 n_2^2 n_3 & n_1 n_3^3 & 2 n_1^2 n_2 n_3 & 2 n_1^2 n_3^2 & 2 n_1 n_2 n_3^2 \\ n_1^2 n_2 n_3 & n_2^3 n_3 & n_2 n_3^3 & 2 n_1 n_2^2 n_3 & 2 n_1 n_2 n_3^2 & 2 n_2^2 n_3^2 \end{bmatrix}$$

$$\underline{\underline{N}}_2 = \begin{bmatrix} n_1^2 & n_1^2 & n_1^2 & 0 & 0 & 0 \\ n_2^2 & n_2^2 & n_2^2 & 0 & 0 & 0 \\ n_3^2 & n_3^2 & n_3^2 & 0 & 0 & 0 \\ n_1 n_2 & n_1 n_2 & n_1 n_2 & 0 & 0 & 0 \\ n_1 n_3 & n_1 n_3 & n_1 n_3 & 0 & 0 & 0 \\ n_2 n_3 & n_2 n_3 & n_2 n_3 & 0 & 0 & 0 \end{bmatrix}$$

$$\underline{\underline{N}}_3 = \begin{bmatrix} 2n_1^2 & 0 & 0 & 2n_1n_2 & 2n_1n_3 & 0 \\ 0 & 2n_2^2 & 0 & 2n_1n_2 & 0 & 2n_2n_3 \\ 0 & 0 & 2n_3^2 & 0 & 2n_1n_3 & 2n_2n_3 \\ n_1n_2 & n_1n_2 & 0 & n_1^2 + n_2^2 & n_2n_3 & n_1n_3 \\ n_1n_3 & 0 & n_1n_3 & n_2n_3 & n_1^2 + n_3^2 & n_1n_2 \\ 0 & n_2n_3 & n_2n_3 & n_1n_3 & n_1n_2 & n_2^2 + n_3^2 \end{bmatrix} \quad (\text{II.22})$$

2. Stress Field at the Surface of the Ellipsoidal Cavity

In porosity-free media, the stress and strain tensors are related by the tensor $\underline{\underline{\Lambda}}$ in the form

$$\underline{\underline{\sigma}} = \underline{\underline{\Lambda}} \underline{\underline{\varepsilon}}$$

We can define the stress vector $\underline{\underline{\sigma}} = [\sigma_{11} \ \sigma_{22} \ \sigma_{33} \ \sigma_{12} \ \sigma_{13} \ \sigma_{23}]^T$ and the stress and strains are related in matrix form by (6x6) elasticity matrix $\underline{\underline{\Lambda}}$ as

$$\underline{\underline{\sigma}} = \underline{\underline{\Lambda}} \underline{\underline{\varepsilon}} \quad (\text{II.23})$$

and for isotropic porosity-free medium

$$\underline{\underline{\Lambda}} = \frac{2\mu}{1-2\nu} \begin{bmatrix} 1-\nu & \nu & \nu & 0 & 0 & 0 \\ \nu & 1-\nu & \nu & 0 & 0 & 0 \\ \nu & \nu & 1-\nu & 0 & 0 & 0 \\ 0 & 0 & 0 & 1-2\nu & 0 & 0 \\ 0 & 0 & 0 & 0 & 1-2\nu & 0 \\ 0 & 0 & 0 & 0 & 0 & 1-2\nu \end{bmatrix}$$

Combining (II.21) and (II.23), one can obtain the stress vector at the boundary point P of an ellipsoidal cavity due to the far-field stress vector $\underline{\underline{\sigma}}^\infty$ through Eshelby matrix $\underline{\underline{\sigma}}^E$ as

$$\underline{\underline{\sigma}} = \underline{\underline{\sigma}}^E (\underline{\underline{\sigma}}^\infty) \quad (\text{II.24})$$

and

$$\underline{\underline{\sigma}}^E = \underline{\underline{\Lambda}} (\underline{\underline{I}} + \underline{\underline{N}}) \underline{\underline{C}} \underline{\underline{\Lambda}}^{-1} \quad (\text{II.25})$$

The Eshelby matrix $\underline{\underline{\sigma}}^E$ can be calculated numerically at a specified boundary point P of an ellipsoidal cavity. This matrix is independent of far field stress field and depends only on the geometry of ellipsoid, position of point P and Poisson's ratio of the

medium. The numerical scheme first calculates the matrix $\underline{\underline{S}}$ by numerical integration using the definition of ellipsoid (a, b, c) . Then the matrix $\underline{\underline{C}}$ is evaluated from (II.20). Matrix $\underline{\underline{N}}$ is performed for the boundary point P and finally $\underline{\underline{\sigma}}^E$ is calculated from (II.25).

3. Spherical Cavity Case

In Eshelby (1957), the expression for stress field at the boundary of a spherical cavity in terms of far-field stresses is given as

$$\sigma_{ij} = \frac{15}{7-5\nu} \left\{ (1-\nu)(\sigma_{ij}^\infty - n_k n_j \sigma_{ik}^\infty - n_k n_i \sigma_{jk}^\infty) + n_i n_j n_k n_l \sigma_{kl}^\infty \right. \\ \left. - \nu n_k n_l \delta_{ij} \sigma_{kl}^\infty + \frac{1-5\nu}{10} \sigma_{kk}^\infty (n_i n_j - \delta_{ij}) \right\}$$

We can convert this expression into matrix form and obtain the Eshelby matrix for spherical case $\underline{\underline{\sigma}}_{\text{sphere}}^E$ as

$$\underline{\underline{\sigma}}_{\text{sphere}}^E = \frac{15}{7-5\nu} \underline{\underline{N}}_1 + \frac{3(1-5\nu)}{2(7-5\nu)} \underline{\underline{N}}_2 - \frac{15(1-\nu)}{7-5\nu} \underline{\underline{N}}_3$$

$$+ \frac{3}{2(7-5\nu)} \begin{bmatrix} 9-5\nu & -(1-5\nu) & -(1-5\nu) & 0 & 0 & 0 \\ -(1-5\nu) & 9-5\nu & -(1-5\nu) & 0 & 0 & 0 \\ -(1-5\nu) & -(1-5\nu) & 9-5\nu & 0 & 0 & 0 \\ 0 & 0 & 0 & 10(1-\nu) & 0 & 0 \\ 0 & 0 & 0 & 0 & 10(1-\nu) & 0 \\ 0 & 0 & 0 & 0 & 0 & 10(1-\nu) \end{bmatrix}$$

$$- \frac{15\nu}{7-5\nu} \begin{bmatrix} n_1^2 & n_2^2 & n_3^2 & 2n_1 n_2 & 2n_1 n_3 & 2n_2 n_3 \\ n_1^2 & n_2^2 & n_3^2 & 2n_1 n_2 & 2n_1 n_3 & 2n_2 n_3 \\ n_1^2 & n_2^2 & n_3^2 & 2n_1 n_2 & 2n_1 n_3 & 2n_2 n_3 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix}$$

and the definitions of $\underline{\underline{N}}_1$, $\underline{\underline{N}}_2$ and $\underline{\underline{N}}_3$ are given in (II.22).

To check the numerical procedure, $\underline{\sigma}^E$ obtained numerically for $a=b=c$ (spherical case) is compared with the $\underline{\sigma}_{\text{sphere}}^E$ at various boundary points P and it is seen that, both Eshelby's analytical solution and our numerical solution described in this report gave the same matrix for the spherical cavities.

III Effective Medium Parameters for Porous Composites

A. Formulation

Consider a porous medium composed of variety of constituents, either solid or porous grains with different material properties, and voids filled with fluid. This porous medium is not composed of a single-granular material and the coefficients of Biot's equations can be estimated by self-consistent effective medium approximation according to Berryman (1986). The effective medium approximation formulas for multiple constituent porous media can be summarized as follows

$$\frac{1}{K_{eff} + \frac{4}{3}\mu_{eff}} = \left\langle \frac{1}{K_i + \frac{4}{3}\mu_{eff}} \right\rangle \quad (\text{III.1})$$

$$\frac{1}{F_{eff} + \mu_{eff}} = \left\langle \frac{1}{F_{eff} + \mu_i} \right\rangle \quad (\text{III.2})$$

$$\frac{\alpha_{eff}}{K_{eff} + \frac{4}{3}\mu_{eff}} = \left\langle \frac{\alpha_i}{K_i + \frac{4}{3}\mu_{eff}} \right\rangle \quad (\text{III.3})$$

where K_{eff} , μ_{eff} and α_{eff} are effective bulk modulus, shear modulus and effective stress parameter, respectively. K_i and μ_i are dry frame bulk and shear moduli of the i^{th} constituent. When i^{th} constituent is solid (not porous) these values are equal to the material bulk and shear moduli $(K_m)_i$ and $(\mu_m)_i$, respectively. The expression of F_{eff} is given as

$$F_{eff} = \frac{\mu_{eff}}{6} \frac{9K_{eff} + 8\mu_{eff}}{K_{eff} + 2\mu_{eff}}$$

α_i is the effective stress parameter of the i^{th} constituent and can be calculated from

$$\alpha_i = 1 - \frac{K_i}{(K_s)_i}$$

$(K_s)_i$ is one of the bulk modulus characteristic of porous frame and is equal to $(K_m)_i$ when the i^{th} constituent is porous and composed of single granular material. The values of α_i changes in between 0 and 1 corresponding to the pure solid and void cases, respectively.

$\langle \cdot \rangle$ is the volume average operator and for a porous medium with N constituent (including void phase) each having volume ratio v_i ($i=1-N$)

$$\langle Q_i \rangle = \sum_{i=1}^N v_i Q_i$$

(III.1) and (III.2) form a nonlinear system of equations for two unknowns (K_{eff} and μ_{eff}) and can be solved numerically. In most cases, the system is well conditioned and no convergence problem arises in the numerical solutions. But when there are only two constituents one having very small (or zero) shear modulus compared to the other, a singularity arises in the system. This is the case when we try to calculate the coefficients for a porous constituent “ i ” with porosity c_i . For this constituent, first phase is void with $\mu_1 = K_1 = 0$, and second phase is the solid grains with $\mu_2 = (\mu_2)_i$, $K_2 = (K_m)_i$. Berryman (1980) studied the singularity arises when one phase has a very small shear modulus and give asymptotic solutions. To obtain a solution, (III.1) and (III.2) should be written with the parameters described above (and $\mu_{eff} = \mu_i$ and $K_{eff} = K_i$, dry bulk and shear moduli of i^{th} constituent) and rearranged by introducing a new variable χ as

$$F_{eff} = \chi \mu_i \quad \frac{2}{3} \leq \chi \leq \frac{3}{2}$$

$$\mu_i = (1 - c_i - \frac{c_i}{\chi}) \mu_2 \quad (III.4a)$$

$$K_i = \frac{4}{3} \mu_i \frac{K_2(1 - c_i)}{\frac{4}{3} \mu_i + K_2 c_i} \quad (III.4b)$$

and results in a single equation in terms of this variable as

$$[3K_2(2 + c_i) + 12\mu_2(1 - c_i)]\chi^2 - [3K_2(3 - c_i) + 4\mu_2(2 + c_i)]\chi + 8c_i\mu_2 = 0 \quad (III.5)$$

After finding the root in the range of $2/3 \leq \chi \leq 3/2$, the dry bulk and shear moduli of the i^{th} constituent (K_i and μ_i) are calculated from (III.4). While obtaining (III.5), we insert

the condition of $\mu_i \neq 0$. If the calculated μ_i is zero, the asymptotic value for shear modulus given in Berryman (1980) should be used

$$\mu_i = \frac{3 - 5c_i}{3} \mu_2 \quad \text{if } c_i \leq 0.6$$

$$\mu_i = 0 \quad \text{if } c_i \geq 0.6$$

B. Elastic Moduli of Calcite and Dolomite

To calculate effective medium parameters of porous calcite-dolomite composites, we should know (or estimate) the material constants of pure calcite and dolomite grains. In Clark (1966), the values for physical properties of minerals and rocks are given. The isotropic elastic constants for calcite and dolomite are evaluated from this reference.

Calcite

In Table 7.12-Elastic constants of minerals, the compliances of calcite are listed from four different studies. The isotropic elastic constants are obtained by using the Reuss scheme for quasi-isotropic aggregates of single material. The range of calculated bulk and shear modulus and a simple arithmetic mean are given below

$$(K_m)_{\text{calcite}} = 65 - 80 \text{ GPa} \quad \text{average } (K_m)_{\text{calcite}} = 71 \text{ GPa}$$

$$(\mu_m)_{\text{calcite}} = 25 - 29 \text{ GPa} \quad \text{average } (\mu_m)_{\text{calcite}} = 28 \text{ GPa}$$

Dolomite

In Table 7.15-Rocks: elastic constants, the elastic modulus of dolomite from different regions are tabulated. The range of bulk and shear modulus and the mean values are

$$(K_m)_{\text{dolomite}} = 71 - 93 \text{ GPa} \quad \text{average } (K_m)_{\text{dolomite}} = 85 \text{ GPa}$$

$$(\mu_m)_{\text{dolomite}} = 32 - 42 \text{ GPa} \quad \text{average } (\mu_m)_{\text{dolomite}} = 37 \text{ GPa}$$

C. Porous Calcite - Dolomite Composites

The elastic constants of calcite and dolomite were used to calculate numerically the effective medium parameters for given porosity and calcite/dolomite volumetric ratio. A general numerical scheme is coded to calculate the poroelastic coefficients for $N(N \leq 10)$ solid or porous constituents. The scheme first calculates the dry frame bulk and shear moduli of porous constituents, then calculates α_i 's for each constituent. It uses Newton's iterative scheme to solve the nonlinear equations system defined in (III.1) and (III.2). After calculating effective medium bulk and shear moduli, the effective stress parameter is obtained from (III.3). For a calcite-dolomite composite, we should input: $(K_m)_{\text{calcite}}$, $(\mu_m)_{\text{calcite}}$, $(K_m)_{\text{dolomite}}$, $(\mu_m)_{\text{dolomite}}$, volumetric ratios of constituents

$v_{calcite}$, $v_{dolomite}$, v_{void} and porosity values of constituents $c_{calcite}$, $c_{dolomite}$. The total porosity (effective porosity) ϕ_{eff} is the volume average of constituent porosities

$$\phi_{eff} = v_{calcite} c_{calcite} + v_{dolomite} c_{dolomite} + v_{void}$$

We can also define material ratios for calcite and dolomite ($\phi_{calcite}$, $\phi_{dolomite}$)

$$\phi_{calcite} = v_{calcite} (1 - c_{calcite})$$

$$\phi_{dolomite} = v_{dolomite} (1 - c_{dolomite})$$

These are the volumetric ratios of solid calcite and dolomite grains (with no porosity) in the porous composite. It should be noted that, $\phi_{calcite} + \phi_{dolomite} + \phi_{eff} = 1$.

For a porous composite with given material ratios, one can conceptually lump the solid grains with voids and form many different sets of constituent volumetric ratios. Each set will result in different effective elastic constants. This freedom of lumping and forming porous constituents may be an advantage in modeling complex grains of earth materials.

In the following part, we study the effect of constituent porosity to the effective elastic constants when the material ratios and total porosity are kept constant.

1. Numerical example

Consider a porous calcite-dolomite composite with material ratios

$$\phi_{calcite} = 0.3, \quad \phi_{dolomite} = 0.5, \quad \phi_{eff} = 0.2$$

We form porous calcite as the first constituent and porous dolomite as the second. The volumetric ratios are given as

$$v_{calcite} = \phi_{calcite} + \phi_1, \quad v_{dolomite} = \phi_{dolomite} + \phi_2, \quad v_{void} = \phi_3$$

$$\text{and } \phi_1 + \phi_2 + \phi_3 = \phi_{eff}$$

We select the material elastic constants

$$\begin{aligned} (K_m)_{calcite} &= 70 \text{ GPa} & (\mu_m)_{calcite} &= 28 \text{ GPa} \\ (K_m)_{dolomite} &= 85 \text{ GPa} & (\mu_m)_{dolomite} &= 37 \text{ GPa} \end{aligned}$$

The effective medium parameters K_{eff} , μ_{eff} and α_{eff} are calculated numerically for different ϕ_1 , ϕ_2 and ϕ_3 values. The effective Poisson's ratio ν_{eff} are then obtained from effective bulk and shear modulus using the formula

$$v_{eff} = \frac{3K_{eff} - 2\mu_{eff}}{2(3K_{eff} + \mu_{eff})}$$

The results are tabulated below.

ϕ_3	ϕ_1	Cons.1 - with <u>calcite</u>			Cons.2-with <u>dolomite</u>			Effective Medium			
		K	μ	α	K	μ	α	K_{eff}	μ_{eff}	v_{eff}	α_{eff}
0.	0.2	9.27	5.94	0.868	85.	37.	0.	25.77	15.00	0.256	0.679
0.	0.1	27.53	14.48	0.607	49.78	25.13	0.414	39.01	20.20	0.279	0.507
0.	0.	70.	28.	0.	28.78	16.42	0.661	36.87	19.27	0.277	0.532
0.1	0.1	27.53	14.48	0.607	85.	37.	0.	37.22	19.55	0.276	0.529
0.1	0.05	43.85	20.36	0.374	64.96	30.57	0.236	41.66	21.05	0.284	0.472
0.1	0.	70.	28.	0.	49.78	25.13	0.414	41.72	21.04	0.284	0.472
0.2	0.	70.	28.	0.	85.	37.	0.	39.97	20.45	0.281	0.493

In the table, the effective medium parameters are grouped by the ϕ_3 values. In the first group, the porous composite has no void phase ($\phi_3 = 0$) and the effective porosity are distributed among the calcite and dolomite constituents. The first case is the porous calcite + solid dolomite combination, whereas the third is solid calcite + porous dolomite. Since calcite has lower material shear modulus than dolomite, forming calcite constituent with high porosity reduces the effective medium bulk and shear moduli and increases the effective stress parameter considerably. It can be seen from the first three cases that, the maximum elastic moduli and minimum effective stress parameter are not obtained at solid calcite or solid dolomite extreme cases, but at an intermediate constituent porosity value. The third group has only one case given on the last line of the table, solid calcite + solid dolomite + void. The constituent porosities are zero.

In the second group the void phase exists, and the remaining porosity is shared among the calcite and dolomite phases. The discussion made for the first group is also valid for this group and actually for overall results, we can say that the maximum effective bulk and shear modulus and minimum effective stress parameter can be obtained for intermediate ϕ_3 values instead of extreme cases (group 1: $\phi_3 = 0$, group 2: $\phi_3 = \phi_{eff}$).

IV Failure/Collapse Criterion

A. Failure Function

The computations of stress at the surface of the cavity, in conjunction with a rock failure criterion, allow us to estimate conditions under which the material around the cavity will fail. This calculation thereby is an estimate of the critical conditions for cavity collapse. Let $\underline{\underline{\sigma}}$ be the stress tensor at a point P on the cavity surface. Then failure occurs when a function F just exceeds zero:

$$F(\underline{\underline{\sigma}}, p, \Theta) > 0, \text{ collapse.} \quad (\text{IV.1})$$

Here p is fluid pressure and Θ is the texture (porosity, mineral volume fractions and grain size). From the poroelastic modified Eshelby solution, we see that $\underline{\underline{\sigma}}$ depends on $\underline{\underline{\sigma}}^\infty$, p , Θ and the position of the boundary point P . Hence (IV.1) can be rewritten for the failure criterion

$$\mathcal{F}(\underline{\underline{\sigma}}^\infty, p, \Theta, P, \omega) = F(\underline{\underline{\sigma}}, p, \Theta). \quad (\text{IV.2})$$

Note that failure occurs under different conditions for points P on the cavity surface. Finally, ω represents a set of angles orienting the cavity relative to the principle axes of $\underline{\underline{\sigma}}^\infty$. The failure criterion used is in the form

$$\mathcal{F} = \sqrt{J_2} + a(\Theta)J_1 - b(\Theta) \quad (\text{IV.3})$$

where J_2 and J_1 are the second and first invariants of effective stress $\underline{\underline{\sigma}}_{\text{eff}} = \underline{\underline{\sigma}} + \alpha p \underline{\underline{I}}$.

The coefficients a and b depend on texture Θ (porosity, grain sizes and volumetric ratios). The invariants can be calculated as

$$\begin{aligned} J_1 &= \text{tr} \underline{\underline{\sigma}}_{\text{eff}} \\ J_2 &= \frac{1}{2} \text{tr} \left[\underline{\underline{\sigma}}_{\text{eff}} - \frac{J_1}{3} \underline{\underline{I}} \right]^2. \end{aligned} \quad (\text{IV.4})$$

The parameters a and b were calibrated with rock mechanics data (Sakrani, 1997) such that

$$a(\Theta) = \sum_i f_i a_i \quad (\text{IV.5})$$

and similarly for $b(\Theta)$; f_i =solid matrix volume fraction of mineral i (i =calcite, dolomite). The coefficients a_i and b_i are functions of porosity (ϕ) and the grain size of mineral i (R_i)

$$a_{cal} = 0.2782 R_{cal}^{-0.0068} e^{-6.874\phi} \quad (IV.6)$$

$$a_{dol} = 0.5673 R_{dol}^{0.0669} e^{-22.727\phi} \quad (IV.7)$$

$$b_{cal} = 44.7655 R_{cal}^{-0.1956} e^{-4.0615\phi} \quad (IV.8)$$

$$b_{dol} = 49.1584 R_{dol}^{-0.2225} e^{-8.9871\phi} \quad (IV.9)$$

B. Failure Optimization

Failure occurs when it is indicated at one point P on the cavity surface. The failure envelope is written

$$\mathcal{F}(\underline{\sigma}^\infty, p, \Theta, P, \omega) = 0. \quad (IV.10)$$

Failure commences when $\mathcal{F}$ just equals zero at a point, curve or simultaneously over all the cavity surface as some parameter passes through a critical value. What the dimension (point, line or surface) of the failure will depend on a number of factors:

- anisotropy of $\underline{\sigma}^\infty$
- ω
- $a/b/c$ ratios

In short, the dimension depends on the symmetry of the problem. Nonetheless, the failure threshold for the cavity depends on this first indicated failure somewhere on the cavity surface. This occurs when the just exists point P for which $\mathcal{F}$ just vanishes and for conditions just below criticality, $\mathcal{F} < 0$ for all other points.

V Illustrative Examples

The developments of the previous sections were integrated to study cavity stability in carbonate matrices. The carbonate matrix is composed of voids and solid calcite and dolomite grains. In the calculations of cavity stability, material bulk and shear moduli of calcite and dolomite grains are taken as

$$\begin{aligned}
(K_m)_{\text{calcite}} &= 70 \text{ MPa} & (\mu_m)_{\text{calcite}} &= 28 \text{ MPa} \\
(K_m)_{\text{dolomite}} &= 85 \text{ MPa} & (\mu_m)_{\text{dolomite}} &= 37 \text{ MPa}
\end{aligned} \tag{V.1}$$

The cavity has an ellipsoidal geometry and its principal axes define $x_1x_2x_3$ frame as shown in Fig. 5-1. The ellipsoid principal dimensions are named as a , b and c respectively. In this study, to reduce one of the parameters, two minor dimensions are set equal to each other as

$$a \geq b = c$$

and we define the aspect ratio of the ellipsoid with (b/a) ratio.

In the problem, there exists a constant pressure field p throughout the porous matrix and inside the cavity. The cavity will deform under the effect of this pressure and far field loads which will add to $\underline{\underline{\sigma}}^\infty$ at the far field. The principal axes of the far field stress tensor $\underline{\underline{\sigma}}^\infty$ will define XYZ frame as shown in the figure. The principal far field stress vector is then have the form

$$\underline{\underline{\sigma}}^\infty = \begin{bmatrix} \sigma_X^\infty & -\sigma_Y^\infty & -\sigma_Z^\infty & 0 & 0 & 0 \end{bmatrix}^T$$

where σ_X^∞ , σ_Y^∞ and σ_Z^∞ are principal compressive stresses in X , Y and Z directions, respectively. In this study, we set the stresses in X and Y directions equal to each other as

$$\sigma_Z^\infty \geq \sigma_X^\infty = \sigma_Y^\infty$$

and define the far field stress anisotropy ratio with $\sigma_X^\infty / \sigma_Z^\infty$ ratio.

The vug orientation can then be defined by the orientation of principal axes of ellipsoid ($x_1x_2x_3$ frame) with respect to the principal axes of $\underline{\underline{\sigma}}^\infty$ (XYZ frame). Since two minor principal stresses and ellipsoid dimensions are set equal, the vug orientation (ω) can be defined simply by the angle between Z and x_3 axes (Fig. 5-1). $\omega=0$ represents the orientation in which the major principal axis of vug (x_1 axis) is perpendicular to the major principal stress axis (Z axis), whereas $\omega=\pi/2$ represents the parallel case. The vugs having these orientations are named as "horizontally oriented vugs" and "vertically oriented vugs", respectively.

Fig. 5-1 Schematic ellipsoidal cavity in a poroelastic continuum with properties ν, α subjected to stress $\underline{\sigma}^{\infty}$ applied far from the cavity.

A. Failure Function $\mathcal{F}$

In vug stability calculations, the failure function $\mathcal{F}$, defined by (IV.3), is obtained at every boundary point P of the cavity surface for the far field stress $\underline{\sigma}^{\infty}$. Failure stress corresponds to the smallest σ_Z^{∞} value at which $\mathcal{F}$ equals to zero for at least one boundary point. The dimension of the failure is the dimension of the set of failure points: either a single point, a curve or entire surface. This dimension depends on the symmetry of the problem. For the most symmetrical case; spherical cavity ($b/a=1$) and hydrostatic far field stresses ($\sigma_X^{\infty}/\sigma_Z^{\infty}=1$), failure will happen on the overall surface of the sphere simultaneously.

In Fig. 5-2, a series of distribution of $\mathcal{F}$ are presented for the ellipsoidal vug with $b/a=0.5$ for different orientations. The porous continuum has the following matrix texture

$$f_{calcite} = f_{dolomite} \quad , \quad \phi = 0.2$$

$$R_{calcite} = R_{dolomite} = 0.1 \text{ mm}$$

This texture will yield the poroelastic and failure coefficients of

$$\nu = 0.283, \quad \alpha = 0.495$$

$$\alpha(\Theta) = 0.038, \quad b(\Theta) = 22.385 \text{ MPa}$$

The fluid pressure and far field stress anisotropy ratio are taken as $p=5\text{MPa}$ and $\sigma_X^\infty/\sigma_Z^\infty=0.5$.

In Fig. 5-2a, the distribution of $\mathcal{F}$ is plotted for the horizontally oriented vug. The failure stress value is $\sigma_Z^\infty=27.40 \text{ MPa}$ for this orientation and the failure function at this stress state changes in the range $[-20.76 \text{ MPa}, 0.004 \text{ MPa}]$. This range is spanned with colors from blue to red in the colored figure. At the yield stress, point failure occurs at the surface points $P(0, \pm 0.5a, 0)$ in XYZ frame. Fig. 5-2b and Fig. 5-2c are plotted for vug orientations $\omega=\pi/6$ and $\omega=\pi/3$, respectively. For case b, failure stress is $\sigma_Z^\infty=29.66 \text{ MPa}$ and the failure occurs at points $P(\pm 0.898a, 0, \pm 0.410a)$. For case c, the failure stress level is increased to $\sigma_Z^\infty=36.86 \text{ MPa}$ and the coordinates of failure points are $(\pm 0.647a, 0, \pm 0.638a)$. Fig. 5-2d presents the vertically oriented vug for which the failure stress is $\sigma_Z^\infty=44.61 \text{ MPa}$ and failure function has the range $[-12.14 \text{ MPa}, 0.006 \text{ MPa}]$ on the vug surface. Due to the symmetry of vug geometry in XY plane, the failure is occurred along a curve, the vug fails through the circle having radius b .

B. Matrix Texture

The matrix texture (Θ) of the surrounding porous calcite-dolomite matrix depends on the porosity of the medium (ϕ), volumetric fractions of calcite and dolomite in the matrix ($f_{calcite}, f_{dolomite}$) and the grain sizes of the minerals ($R_{calcite}, R_{dolomite}$). When the texture of the porous matrix and the mineral elastic coefficients are specified, the material parameters (ν, α) and failure coefficients ($\alpha(\Theta), b(\Theta)$) can be obtained as described in Sections III and IV. The material and failure coefficients of the calcite - dolomite matrix with

$$f_{calcite} = f_{dolomite} \quad , \quad R_{calcite} = R_{dolomite} = 0.1 \text{ mm} \quad (\text{V.2})$$

are tabulated below for various porosity values.

Fig. 5-2 Failure function values on the surface of the ellipsoid cavity ($b/a=0.5$) at yield state of stress. (a) horizontally oriented vug ($w=0$). (b) $w=p/6$. (c) $w=p/3$. (d) vertically oriented vug ($w=p/2$).

ϕ	ν	α	$a(\Theta)$	$b(\Theta)$ (MPa)
0.05	0.309	0.136	0.178	54.84
0.10	0.301	0.263	0.096	40.10
0.15	0.292	0.383	0.058	29.75
0.20	0.283	0.495	0.038	22.39

The effective stress parameter α increases significantly, whereas Poisson's ratio is not that much affected by the change in porosity. The limits for the effective stress parameters are 0 and 1, corresponding to $\phi=0$ (no porosity) and $\phi=1$ (hypothetical case). As the porosity of the medium increases, the failure parameter a and b decrease. The failure parameter $b(\Theta)$ can be defined as the limit value for the effective stress invariants before the failure. Decreasing $b(\Theta)$ at high porosities means the failure will happen at lower stress states as the porosity increases. The failure parameter $a(\Theta)$ introduces the effect of normal stresses to the failure mechanism which mostly depends on the shear stresses. Therefore it can be concluded from the values in the table that, as porosity of the medium decreases, the contribution of normal stresses to the failure increases.

In Fig. 5-3, the variations of failure stress σ_Z^∞ of an ellipsoidal vug ($b/a=0.5$) with porosity are plotted for several fluid pressure levels. In the calculations, the matrix texture of surrounding medium is taken as in (V.2) and the far field stress anisotropy ratio is $\sigma_X^\infty/\sigma_Z^\infty=0.5$. As it can be seen from the graph, the vug in a matrix with higher porosity level will fail at smaller stresses than the vugs in the matrix with lower porosity level. Changes in the fluid pressure will not affect this behavior.

C. Cavity Shape and Orientation

In Fig. 5-4, the changes in failure stress with cavity shape and orientation are presented graphically, for a fixed stress anisotropy level ($\sigma_X^\infty/\sigma_Z^\infty=0.5$) and fluid pressure ($p=5$ MPa). The matrix texture is defined in (V.2) with porosity $\phi=0.2$. With these parameters, spherical vug will yield at $\sigma_Z^\infty=32.57$ MPa. The horizontally oriented ($\omega=0$) ellipsoidal vugs will fail at lower stress levels than spheres and the failure stress values are ordered according to their aspect (b/a) ratios, as seen in the figure. The extreme ellipsoid with $b/a=0.2$ will yield at $\sigma_Z^\infty=24.46$ MPa.

On the other hand, the vertically oriented ($\omega=\pi/2$) ellipsoidal vugs will fail at higher stress levels than the spherical vug and the failure stresses increases with the decreasing aspect ratio of vug. Vertically oriented vug with $b/a=0.2$ will stand the far field stresses up to $\sigma_Z^\infty=51.17$ MPa. The ellipsoidal vug will become more stable as its

Fig. 5-3 Variation of failure stress of an ellipsoidal vug ($b/a=0.5$) with porosity and fluid pressure, at the stress anisotropy $\sigma_X^\infty / \sigma_Z^\infty = 0.5$.

Fig. 5-4 Effect of vug shape and orientation to the failure stress, at constant porosity $\phi=0.2$, fluid pressure $p=5$ MPa and stress anisotropy $\sigma_X^\infty / \sigma_Z^\infty = 0.5$.

orientation is changed from horizontal to vertical.

D. Fluid Pressure

One of the important factors in vug stability is the fluid pressure in the porous matrix and cavity. In Fig. 5-3, the variation of failure stress of the ellipsoidal vug ($b/a=0.5$) with porosity and fluid pressure is presented. For a fixed porosity value, as the fluid pressure of the system increases, the failure stress increases and the vug becomes more stable. The increase in the vug stability due to pressure is seemed to be independent of the porosity of surrounding medium.

E. Far Field Stress Tensor Effects

In Fig. 5-5, the variations of failure stress with far field stress anisotropy are plotted for spherical and ellipsoidal ($b/a=0.5$) vugs. In calculations matrix texture is taken as in (V.2) with porosity $\phi=0.2$ and fluid pressure is kept constant at $p=5$ MPa. The spherical vug fails at lower stress levels when the far field stresses are highly anisotropic (when $\sigma_X^\infty/\sigma_Z^\infty$ ratio is small) than the hydrostatic loading ($\sigma_X^\infty/\sigma_Z^\infty=1$). At $\sigma_X^\infty/\sigma_Z^\infty=0.2$ the sphere will fail at $\sigma_Z^\infty=26.54$ MPa and at hydrostatic loading it will stand up to $\sigma_Z^\infty=35.20$ MPa. The spherical vug has the highest failure stress level at $\sigma_X^\infty/\sigma_Z^\infty=0.84$ with 36.04 MPa.

The horizontally oriented ($\omega=0$) ellipsoidal vugs ($b/a=0.5$) will behave similar to spherical vugs under far field stress anisotropy, but they will fail at lower stress levels than spheres. When $\sigma_X^\infty/\sigma_Z^\infty=0.2$, the failure stress for horizontally oriented vug is $\sigma_Z^\infty=22.47$ MPa, whereas for hydrostatic loading σ_Z^∞ increases to 28.46 MPa. The maximum failure stress is 29.60 MPa and it is obtained at the anisotropy level $\sigma_X^\infty/\sigma_Z^\infty=0.80$.

The vertically oriented ($\omega=\pi/2$) ellipsoidal vugs ($b/a=0.5$) have very high failure stress levels compared with spheres, when far field stresses have considerable anisotropy. At $\sigma_X^\infty/\sigma_Z^\infty=0.2$, the failure stress of vertical ellipsoid is $\sigma_Z^\infty=36.44$ MPa and reaches to the maximum of 44.87 MPa at $\sigma_X^\infty/\sigma_Z^\infty=0.56$. But for more symmetrical loadings (when $\sigma_X^\infty/\sigma_Z^\infty \geq 0.75$ as seen in the figure), the stability of vug suddenly decreases and it will fail at lower stress levels than a sphere. It should be noted that, for hydrostatic loading, the failure stress of the ellipsoid vug is independent of its orientation due to the symmetry of the loading.

Fig. 5-5 Effect of far field stress anisotropy on failure stress for spherical and ellipsoidal ($b/a=0.5$) vugs, at constant porosity $\phi=0.2$ and fluid pressure $p=5$ MPa.

VI Conclusions

Our analysis shows that the many system parameters can interact in complex ways to produce vug stability/instability to collapse/failure. The vug stability criteria was obtained in terms of basic parameters characterizing the internal state of a basin or reservoir system. These include rock texture, fluid pressure and stress far from a vug.

The vug collapse criterion allows for the prediction of the range of stability of vuggy reservoirs. Our analysis predicts the range of vug stability in terms of vug shape, orientation, far field stress, fluid properties and matrix texture. If these parameters are known within a basin, then vug stability can also be assessed there.

To illustrate the nature of vug stability within a basin, consider the case of no net lateral basin compression/extension and assess basin stresses via a purely poroelastic model. This one-dimensional problem can be solved exactly. For the simple case wherein the fluid pressure is hydrostatic and the fluid mass density is a constant value ρ_f then $p = \rho_f g d$ (for gravitational acceleration g and depth d). If the rock (matrix plus pore fluid) has constant mass density ρ_r then

Fig. 5-6 Depth of survival curve for ellipsoidal vugs with different shape and orientations in a calcite-dolomite basin ($\phi = 0.2$) under overburden stresses and hydrostatic fluid pressure.

$$\sigma_z^\infty = \rho_v g d$$

$$\frac{\sigma_x^\infty}{\sigma_z^\infty} = \frac{\nu}{1-\nu} + \frac{1-2\nu}{1-\nu} \alpha \frac{\rho_f}{\rho_v}$$

for Poisson ratio ν and effective stress coefficient α . These formulae allow for the analysis of the depth-dependence of vug stability for a normally (i.e. hydrostatic) fluid pressure regime.

Vug stability/depth curves are shown in Fig. 5-6. In this diagram, depth is plotted against the orientation of vugs for a family of curves of different ellipsoid aspect ratios. All other parameters (rock texture and mineralogy) are kept constant as indicated in the figure caption.

The results of Fig. 5-6 show the discrimination in the range of vug stability with respect to orientation and shape. For a given aspect ratio for the ellipsoidal vugs, the depth below which vugs are unstable depends strongly on orientation.

To analyze a particular basin or reservoir system all the above-cited parameters must be accounted for. Thus, we have developed a computational module which takes as

input matrix poroelastic constraints, far field stress, fluid pressure and vug orientation and shape and then outputs a judgment on vug stability.

In an actual system there is a statistical distribution of vug shapes and orientations: let ω be the vug orientational angle ($0 < \omega < \pi/2$) and ε be the vug aspect ratio ($0 < \varepsilon < \infty$). Let the vug distribution $\psi(\omega, \varepsilon)$ be defined as

$$\psi d\omega d\varepsilon = \text{fraction of vugs in } d\omega d\varepsilon.$$

Then the fraction of surviving vugs, x^s , is

$$x^s = \int_0^{\pi/2} d\omega \int_0^{\infty} d\varepsilon \psi(\omega, \varepsilon) [1 - \vartheta(F)]$$

for $\vartheta(F) = 1, F > 0; 0, F < 0$ where F is the vug failure criteria ($F > 0$ for failure). From Fig. 5-6 one may deduce that x^s starts as one at $d = 0$, remains one for a depth interval, and then monotonically decreases to zero for the simple case of Fig. 5-6. However, if fluid pressure is locally nonhydrostatic and as rock texture and mineralogy are not d -independent, it is seen that x^s can be a complex function of d .

Finally, a preliminary vug stability analysis was performed with lithological data taken from the Midland basin at the well location: longitude=102.8 and latitude=32.2. At this location, the variations of lithology and mineralogy with depth were as in Tables 5.1 and 5.2.

For simplicity, in each formation brittle minerals, such as quartz, feldspars and chert, were combined in the dolomite group, whereas softer minerals were combined in the calcite group. The grain sizes of calcite and dolomite groups were assumed to be equal to the average grain size of the corresponding formation. The original and current state fluid pressures were taken from the field reports surveying the region of longitude 102.6-102.8 and latitude 32.06-32.22 (that includes the well from which the lithological data was obtained). The lateral stress ratio was calculated throughout the depth assuming there was no lateral displacement.

The sequence of formations with depth, simplified rock texture and original and current state fluid pressures in each formation are given in Fig. 5-7. With these data, the vug survival analysis was performed for the Yates, San Andreas, Clear Fork, Simpson (McKee) and Ellenburger formations. The results were as follows.

- In the Yates formation, the spherical vugs within the lower 110 meters of the formation (i.e., below 1270 meters from the surface) are predicted to collapse. The survival curves of ellipsoidal vugs are similar to that in Fig. 5-6, i.e., the vertical

Table 5.1 Lithology and thickness of formations at the well location longitude=102.8 and latitude=32.2

Geologic Age	Formation	Lithology	Thickness (m)
Quaternary		SS-Sh	170
Tertiary	Ogallala	Sandstone	175
Cretaceous		SS-LS	175
Triassic	Dockum	Shale I	170
Permian-Ochoan	Dewey-Lake	SS-Anhyd.	170
Permian-U. Guand.	Yates	Dolomite 1	520
Permian-L. Guand.	San Andreas	Dolomite 3	630
Permian-Leonardian	Clear Fork	Limestone	405
Permian-Wolfcamp	Wolfcamp	Limestone	15
Pennsylvanian	Atoka	Conglomer.	10
Mississippian	Barnett	Sh-LS	10
Devonian	Woodford	Shale 3	110
Silurian	Fusselman	Dolomite 4	110
Ordovician-Mohawkian	Simpson (McKee)	LS-Sh	50
Ordovician-Canadian	Ellenburger	Dolomite 5	990

Table 5.2 Mineralogy of formations at the well location longitude=102.8 and latitude=32.2

Formation	Av. gr. size (mm)	Quartz	Felds.	Clays	Calcite	Dolom.	Anhyd.	Halite	Chert	Pyrite
Quaternary	0.60	0.60	0.10	0.30	0	0	0	0	0	0
Ogallala	1.10	0.92	0.03	0.05	0	0	0	0	0	0
Cretac.	0.90	0.48	0.05	0.05	0.40	0.02	0	0	0	0
Dockum	0.035	0.30	0.05	0.65	0	0	0	0	0	0
Dewey-Lake	0.25	0.30	0.04	0.03	0.05	0.50	0.06	0	0.01	0.01
Yates	0.25	0.30	0.04	0.03	0.05	0.50	0.06	0	0.01	0.01
San Andreas	0.20	0	0	0.08	0	0.80	0.09	0.01	0.02	0
Clear Fork	0.15	0	0	0.15	0.60	0.15	0.08	0	0.02	0
Wolfcamp	0.20	0	0	0.35	0.55	0.04	0.05	0	0	0.01
Atoka	5.00	0.55	0.10	0.35	0	0	0	0	0	0
Barnett	0.15	0.04	0.01	0.35	0.60	0	0	0	0	0
Woodford	0.03	0.25	0.05	0.40	0	0	0	0	0.30	0
Fusselm.	0.25	0	0	0.01	0.18	0.78	0	0	0.02	0.01
Simpson	0.20	0.23	0.02	0.25	0.48	0.01	0	0	0	0.01
Ellenburg.	0.25	0	0	0.02	0.10	0.85	0.03	0	0	0

ellipsoid vugs can survive below the sphere critical line, whereas the horizontal ones collapse easily at shallower depths.

- In the San Andreas formation, current fluid pressures are much lower than the original ones. At the original state, all vugs survive at all depths within the formation. With the current state of fluid pressures, although spherical vugs do not collapse within the

Fig. 5-7 Sequence of formations, simplified rock texture and fluid pressures for each formation of the Midland Basin at the well location: longitude=102.8, latitude=32.2.

formation, horizontal or nearly horizontally oriented ones with aspect ratio $\varepsilon < 0.5$ do. Additional decrease in the fluid pressure will result in large scale vug collapse in this formation.

- In the Clear Fork Formation, all vugs survive at all depths within the formation for both the original and current state of fluid pressures.
- In the Simpson (McKee) Formation, for the original state of fluid pressures, most of the vugs survive except the horizontal ones with aspect ratio $\varepsilon < 0.3$. For the current state of fluid pressures which are much lower than the original ones, the sphere critical line is within the formation and the spherical vugs collapse in the lower 10 of the total 50 meters.
- In the Ellenburger Formation, all vugs survive at all depths within the formation for both the original and current state of fluid pressures. But the current fluid pressures are very near to the limit under which the spherical vugs fail within the formation.

References

- Berryman, J.G. (1980) Long-wavelength propagation in composite elastic media I. Spherical inclusions & II. Ellipsoidal inclusions, *J. Acoust. Soc. Am.* **68**, 1809-1831.
- Berryman, J.G. (1986) Effective medium approximation for elastic constants of porous solids with microscopic heterogeneity, *J. Appl. Phys.* **59**, 1136-1140.
- Clark, S.P.Jr. (ed.) (1966) *Handbook of Physical Constants, Revised Edition*, published by the Geological Society of America, #97.
- Druker, D.C. and Prager W. (1952) Soil mechanics and plastic analysis or limit design, *Quart. Appl. Math.* **10**, No: 2, 157-165.
- Eshelby, J.D. (1957) The determination of the elastic field of an ellipsoid inclusion, and related problems, *Proceedings of the Royal Society of London A* **241**, 376-396.
- Ozkan, G. and P. Ortoleva (1997) Multi-phase effects in material strength and cavity collapse criteria, in preparation.
- Sakrani, K. (1997) A unified texture and mineralogy-dependent model for rock deformation, doctoral thesis, Indiana University.

6

Sedimentary Basin Deformation: An Incremental Stress Approach (K. Tuncay and P. Ortoleva)

The history of basin stresses is necessary for reliable prediction of the location and characteristics of natural fracture networks that control the producibility of important petroleum reserves worldwide. Thus, the work presented here focuses on the development of a stress and deformation module for the *CIRFB* basin simulator element of our exploration and production optimization strategy.

The basis of the model being developed is the incremental stress formulation of elasto-plasticity theory. The equations of this theory are being simulated using a finite element approach.

In this report the basic model is reviewed and the finite element approach being used is presented. The advantages of our approach are in its generality—i.e. its ability to subsume a number of deformation mechanisms including poro-elasticity, nonlinear viscosity with yield exterior, pressure solution, vug collapse and hydrofracture induction and extension/ shortening/ closure. The model also uses a set of boundary conditions that allows for commonly available geological data on tectonic history.

I. Introduction

Key processes affecting reservoir location and characteristics are compaction and fracturing. The impact of these processes depends strongly on basin stress history. Thus accurate estimates of the evolution of the stress distribution are required to predict naturally fractured reservoir location and characteristics.

Fracturing occurs when fluid pressure exceeds the least compressive stress and the failure strength of the rock. As a result, estimates of the time of fracture initiation, growth, healing or closure, and fracture orientation require predictions of the stress tensor distribution and its history. Simple estimates of vertical stress from overburden and poorly constrained lateral stress conjectures are insufficient for accurate predictions. In the present approach, a three dimensional computation of basin deformation history is used to estimate stress evolution.

Stress evolution is tightly coupled to other effects. For example, fracture permeability can affect fluid pressure through the escape of fluids from overpressured zones; in turn, fluid pressure strongly affects stress in porous media. For these reasons, the ability to estimate the history of the distribution of stress must be carried out within a basin model that accounts for the coupling between all diagenetic, hydrologic and mechanical processes. The coupled model and computational simulator *CIRFB* being used and extended as described in this report is necessary to meet the objective of optimizing fractured reservoir exploration and production.

A rock rheological model has been developed for *CIRFB* based on incremental stress theory (Zienkiewicz and Corneau, 1974; Rice, 1975). The incremental stress formalism has been extended in *CIRFB* to include fracturing and pressure solution to yield a unified theory that augments elastic and viscous/plastic mechanical rock response. This rheology combined with the force balance condition allows for the calculation of rock deformation and stress, their distribution in space, and their evolution over time. The stress solver employs a moving, second order, finite element discretization. An efficient iterative approach is used to solve the resulting discretized equations. The objective of this report is to review our modeling approach and outline the finite element technique being used to simulate it.

II. Rheology

The incremental stress rheology used in *CIRFB* to integrate all the strain mechanisms has the form

$$\underline{\dot{\epsilon}} = \underline{\dot{\epsilon}}^{el} + \underline{\dot{\epsilon}}^{in} + \underline{\dot{\epsilon}}^{ps} + \underline{\dot{\epsilon}}^{fr} + \underline{\dot{\epsilon}}^{vc}. \quad (II.1)$$

Here $\underline{\dot{\epsilon}}$ is the net rate of strain given by

$$\dot{\epsilon}_{ij} = \frac{1}{2} \left(\frac{\partial v_i}{\partial x_j} + \frac{\partial v_j}{\partial x_i} \right), \quad (II.2)$$

where x_i is the i -th time independent Cartesian coordinate and v_i is the component of the rock deformation velocity along the x_i coordinate. The terms on the right hand side of the equation give the specific dependence of the contributions to $\underline{\dot{\epsilon}}$ from five processes. These are poroelasticity (el), continuous inelastic mechanical (in), pressure solution (ps), fracturing (fr) and vug collapse (vc). Specific expressions for each term have been adopted from the literature or as newly developed for *CIRFB*.

III. Tectonic History Data Input

The purpose of the *CIRFB* basin stress and deformation module is to compute the history of the spatial distribution of stress and deformation within the modeling domain given

data on overall basin tectonics. A key objective is to make the data input requirements consistent with the type of information readily available in petroleum industry basin analysis studies. The latter are typically the following:

- seismic lines and 3-D seismic data,
- aeromagnetic and gravity surveys,
- well logs,
- core analysis, and
- sedimentary history reconstructions.

From this data classical basin analysis can usually yield the following interpreted data:

- history of lateral basin compression/ extension
- history of the structure of the basement/ sediment interface, and
- sea level curve.

In *CIRF.B* these types of data are input and recast as boundary conditions for the stress/ deformation solver. The latter are summarized in Fig. 6-1.

The choice of lateral boundary conditions was adopted to enable the specification of the compression/extension history. To allow for natural compaction processes near the lateral boundaries, the vertical component of force is fixed to be zero; the horizontal deformation velocity components are specified. The latter is input as the deformation history (horizontal components of deformation displacement) at a finite set of points along the lateral boundary. This lateral boundary is assumed to remain vertical. The lateral displacement history is input as the displacement of a series of user-specified points along the horizontal border as suggested Fig. 6-2. The user supplied a set of boundary points is used by a smooth time-interpolation to yield the evolution of the map view of the four lateral boundary curves (see Fig. 6-2). Then the compressional/ extensional history is automatically recreated by a space-time interpolation using the discrete set of boundary points at a discrete set of times.

IV. Finite Element Solution of Basin Deformation Dynamics

A. Basic Equations

In this section the numerical simulation approach being developed for basin stress/ deformation history is outlined. For simplicity all rate of strain contributions in (II.1) except $\underline{\dot{\epsilon}}^{el}$ are lumped into the term $\underline{\dot{\epsilon}}^{vp}$.

Figure 6-1 Conditions at the boundary of basin simulation domain allow for imposition of ocean bottom normal pressure p_o and no shear at the top ($\underline{\tau}$ being a unit tangent vector and $\underline{n}$ being an outward-pointing unit normal vector, with respect to the basin boundary). At the sides the tectonic history fixes the evolution of the normal deformation velocity $\underline{n} \cdot \underline{u}$ and slip conditions. The normal velocity $\underline{n} \cdot \underline{u}$ is also given and the tangential shear $\underline{\tau} \cdot \underline{\underline{\sigma}} \cdot \underline{n}$ is zero there.

Figure 6-2 Schematic view of a user-specified set of boundary points on the map view of a simulation domain. Arrows indicate the displacement specified by a *CIRF* user. The intermediate points along the boundary are interpolated for a given time.

In this study we will use the updated Lagrangian approach to analyze the time dependent large deformation behavior of elasto-viscoplastic geological materials. In this approach, all static and kinematic variables are referred to an updated configuration in each time step. We first present the constitutive relations (rheology) and momentum balance equations. Then we obtain the integral form of the momentum balance equation. We transform the integral form, in which

the integral limits are functions of time, to a form which allows an incremental numerical procedure.

B. Constitutive and Governing Equations

We consider the constitutive relations in the form of

$$\dot{\sigma}_{ij} = C_{ijkl}(\dot{\epsilon}_{kl} - \dot{\epsilon}_{kl}^{vp}) \quad (6.1)$$

where σ_{ij} is the Cauchy (real) stress tensor (force per unit area in the deformed geometry), $\dot{\epsilon}_{ij}$ is the rate of deformation tensor (see II.2), C_{ijkl} is the fourth order elasticity tensor, and over dot denotes the material derivative. For the simple case where hydrofracture, pressure solution and vug collapse processes are neglected, in (6.1) $\dot{\epsilon}_{ij}^{vp}$ is the viscoplastic rate of deformation tensor taken here in the form

$$\dot{\epsilon}_{ij}^{vp} = D_{ijkl}\sigma_{kl} \quad (6.2)$$

where D_{ijkl} is the fourth order inverse viscosity tensor; $\underline{\underline{D}}$ is a function of the state of stress. In *CIRFB* the complexities of fluid pressure contributions due to effective stress in these formulae are accounted for. To simplify this presentation, these features are not put in the formulation or given here.

The momentum balance equation is

$$\sigma_{ij,j} + f_i = 0 \quad (6.3)$$

where f is the gravitational body force per unit volume. Eq. (6.3) is to be solved subject to boundary conditions shown in Figure 6-1.

C. Displacement Reformulation

It is convenient to reformulate the problem in terms of displacements defined for a small time step Δt . In that time a material point at ${}^t\mathbf{x}$ moves to ${}^{t+\Delta t}\mathbf{x}$ through a displacement $\underline{u}$:

$${}^{t+\Delta t}\mathbf{x} = {}^t\mathbf{x} + \underline{u} \quad (6.4)$$

If $\underline{\sigma}$ changes continuously in time then we expect that

$$\underline{u} \underset{\Delta t \rightarrow 0}{\sim} \Delta t \underline{v} . \quad (6.5)$$

Thus for small Δt , $\underline{u}$ and $\underline{v}$ are equivalent. In what follows the discretized time for mutation used will be for small Δt so that henceforth only deformation over a small time interval Δt will be discussed. Large scale deformation will be simulated as the accumulation of small displacements over many small Δt advancement steps.

The boundary conditions applied during the small time (Δt) period may be written as follows. Let S_ϕ and S_u be portions of the system boundary over which forces and displacements are specified, respectively. Then the boundary conditions to be imposed are

$$u_i = u_i^s \text{ on } S_u \text{ and } \sigma_{ij} n_j = t_i \text{ on } S_\phi \quad (6.6)$$

where t_i is the traction and u_i^s is the specified displacement. Equations (6.1) and (6.3) form a set of nonlinear equations in terms of the stress tensor and deformation velocities. Since the deformations are large, the system constitutes a moving boundary problem.

D. Integral Formulation

To obtain the integral form, we multiply (6.3) by an arbitrarily chosen continuous displacements such as

$$\delta u_i = 0 \quad \text{on } S_u \quad (6.7)$$

Then we integrate the equation over the total volume V

$$\int_{t+\Delta t V} (\sigma_{ij,j} + f_i) \delta u_i dv = 0 \quad (6.8)$$

By using the divergence theorem, (6.8) can be written as

$$\int_{t+\Delta t V} \sigma_{ij} \delta_{t+\Delta t} e_{ij} dv = \int_{t+\Delta t V} f_i \delta u_i dv + \int_{t+\Delta t S_\phi} t_i \delta u_i ds = {}^{t+\Delta t} R \quad (6.9)$$

where the left superscripts refer to the configuration of the body and the left subscripts refer to the coordinate axes, and e_{ij} is the small strain tensor

$${}_{t+\Delta t} e_{ij} = \frac{1}{2} ({}_{t+\Delta t} u_{i,j} + {}_{t+\Delta t} u_{j,i}) \quad (6.10)$$

Note that

$$\delta {}_{t+\Delta t} e_{ij} = \delta \frac{1}{2} ({}_{t+\Delta t} u_{i,j} + {}_{t+\Delta t} u_{j,i}); \quad {}_{t+\Delta t} u_{i,j} = \frac{\partial u_i}{\partial {}^{t+\Delta t} x_j} \quad (6.11)$$

1. Incremental Form

We define the incremental displacement as

$${}^{t+\Delta t} x_i = {}^t x_i + u_i \quad (6.12)$$

which means that the particle at ${}^t x_i$ moves to ${}^{t+\Delta t} x_i$ at time $t + \Delta t$. The solution of (6.9) requires the location of the body at time $t + \Delta t$ which is unknown. Therefore we transform (6.9) to the configuration at time t , by defining the second Piola-Kirchoff stress ${}^{t+\Delta t} S_{ij}$ which refer to the stress at time $t + \Delta t$ but measured in the configuration at time t , as

$$\int_V {}^{t+\Delta t} S_{ij} \delta {}^{t+\Delta t} l_{ij} dv = {}^{t+\Delta t} R \quad (6.13)$$

where

$$\begin{aligned} {}^{t+\Delta t} S_{ij} &= \frac{{}^t \rho}{{}^{t+\Delta t} \rho} ({}^{t+\Delta t} x_{i,s} {}^{t+\Delta t} \sigma_{sr} {}^{t+\Delta t} x_{j,r}) \\ {}^{t+\Delta t} l_{ij} &= \frac{1}{2} ({}^t u_{i,j} + {}^t u_{j,i} + {}^t u_{k,i} {}^t u_{k,j}) \end{aligned} \quad (6.14)$$

l_{ij} is the Green-Lagrange strain tensor. Since the stresses and strains are unknown, the following incremental decompositions are used

$$\begin{aligned} {}^{t+\Delta t} S_{ij} &= {}^t \sigma_{ij} + {}^t S_{ij} \\ {}^{t+\Delta t} l_{ij} &= {}^t e_{ij} + {}^t \eta_{ij}; \quad {}^t e_{ij} = \frac{1}{2} ({}^t u_{i,j} + {}^t u_{j,i}) \quad ; \quad {}^t \eta_{ij} = \frac{1}{2} {}^t u_{k,i} {}^t u_{k,j} \end{aligned} \quad (6.15)$$

Substitution of (6.15) in (6.13) yields

$$\int_V {}^t S_{ij} \delta {}^t l_{ij} dv + \int_V {}^t \sigma_{ij} \delta {}^t \eta_{ij} dv = {}^{t+\Delta t} R - \int_V {}^t \sigma_{ij} \delta {}^t e_{ij} dv \quad (6.16)$$

When the stress increment ${}^t S_{ij}$ is given in terms of incremental displacements, (6.16) becomes a nonlinear equation in terms of incremental displacements. It should be noted that (6.9) and (6.16) are, theoretically, equivalent.

When the rate of deformation is small, (6.1) can be written as

$${}^t S_{ij} = D_{ijkl} ({}^t e_{kl} - \Delta t \dot{e}_{kl}^{vp}) \quad (6.17)$$

E. Finite Element Formulation

Equation (IV.17) can be linearized as

$$\int_V {}^t S_{ij} \delta {}^t e_{ij} dv + \int_V {}^t \sigma_{ij} \delta {}^t \eta_{ij} dv = {}^{t+\Delta t} R - \int_V {}^t \sigma_{ij} \delta {}^t e_{ij} dv \quad (6.18)$$

Substitution of (IV.17) in (IV.18) yields

$$\int_V D_{ijkl} {}^t e_{ij} \delta {}^t e_{kl} dv + \int_V {}^t \sigma_{ij} \delta {}^t \eta_{ij} dv = {}^{t+\Delta t} R - \int_V {}^t \sigma_{ij} \delta {}^t e_{ij} dv + \int_V \Delta t D \dot{E}^{vp} \delta {}^{t+\Delta t} e_{ij} dv \quad (6.19)$$

When a standard formulation employing 8-node brick elements is used, approximating the displacement components in terms of its nodal values results in the following assembled matrix equation

$$(K_L + K_{NL}) \bar{u} = {}^{t+\Delta t} R - F - Z \quad (6.20)$$

where

$$\begin{aligned}
K_L^e &= \int_{V^e} B_L^T D B_L dv \\
K_{NL}^e &= \int_{V^e} B_{NL}^T {}^t\sigma B_{NL} dv \\
F^e &= \int_{V^e} B_L^T \hat{\sigma} dv \\
Z^e &= \int_{V^e} B_L^T \Delta t D \dot{\epsilon}^{vp} dv \\
K_L &= \sum K_L^e, \quad K_{NL} = \sum K_{NL}^e, \quad F = \sum F^e, \quad Z = \sum Z^e
\end{aligned} \tag{6.21}$$

where the summation operator denotes the assemblage of the element matrices. In (6.22) $B_L, B_{NL}, D, \hat{\sigma}, {}^t\sigma$ are the linear strain-displacement transformation matrix, nonlinear strain-displacement matrix, elasticity coefficients matrix, Cauchy stress matrix, and vector of Cauchy stresses in the configuration at time t , respectively. It is important to realize that (6.20) is an approximation to the actual equation to be solved (6.16). Depending on the nonlinearities in the system, the linearization of (6.16) may introduce errors. For this reason it may be necessary to iterate at each time step until (6.16) is satisfied to a required tolerance. The error is given by

$$Error = {}^{t+\Delta t} R - \int_{V^e} {}^{t+\Delta t} \sigma_{ij}^1 \delta_{t+\Delta t} e_{ij}^1 dv \tag{6.22}$$

where the superscript 1 refer to approximate values. We should note that the right hand sides of (6.22) and (6.19) are similar except the last integral arising from the viscoplastic strains.

F. Iteration Procedure

Because of the inelastic effects, the solution is obtained in two steps. In the first step the nonlinear constitutive equations are solved for the incremental stresses. This requires the solution of 6 unknowns (components of stress tensor) at each selected point. We solve for the stress increments at the Gaussian points which results in an efficient integration of the integrals containing the stresses. If we use an implicit scheme, we can write

$${}_t S_{ij}^m = D_{ijkl} (e_{kl}^{m-1} - \Delta t ({}^{t+\Delta t} \dot{\epsilon}_{kl}^{vp})^m) \tag{6.23}$$

where m is the iteration number. The incremental displacement can be solved from

$$(K_L + K_{NL}) \bar{u}^m = {}^{t+\Delta t} R - F^m - Z^m \tag{6.24}$$

We define the change in the incremental displacement between iteration m and $m-1$ as

$$\Delta \bar{u}^m = \bar{u}^m - \bar{u}^{m-1} \tag{6.25}$$

Substitution of (6.25) in (6.24) yields

$$(K_L + K_{NL}) \Delta \bar{u}^m = {}^{t+\Delta t} R - F^m - Z^m - (K_L + K_{NL}) \bar{u}^{m-1} \tag{6.26}$$

Eq. (6.26) can be rewritten by considering (IV.15), (IV.22), and (IV.23) as

$$(K_L + K_{NL}) \Delta \bar{u}^m = {}^{t+\Delta t} R - {}^{t+\Delta t} F^m \tag{6.27}$$

$${}^{t+\Delta t}F^m = \int_{{}^{t+\Delta t}V^m} {}^{t+\Delta t}B^m_L {}^{t+\Delta t}\bar{\sigma}^m dv \quad (6.28)$$

The iteration continues until Δu becomes reasonably small. When the solution at $t=t+\Delta t$ is obtained, the Cauchy stress in the deformed configuration is obtained using the relations

$${}^{t+\Delta t}{}_iS_{ij} = {}^i\sigma_{ij} + {}^iS_{ij} \quad (6.29)$$

$${}^{t+\Delta t}\sigma_{sr} = \frac{{}^{t+\Delta t}\rho}{{}^i\rho} {}^{t+\Delta t}x_{s,i} {}^{t+\Delta t}{}_iS_{ij} {}^{t+\Delta t}x_{r,j}. \quad (6.30)$$

V. Preliminary Results

Our basin deformation simulator has been tested on a number of exactly soluble problems and for cases for which simple estimates are available from the engineering literature. The code is found to be very accurate in all the test runs as long as the grid density was sufficient to resolve the features of the problem. It was also quite accurate over long times of simulated evolution.

A preliminary simulation of the West Texas Permian Basin was carried out. The domain included the eastern edge of the Delaware Basin, the Central Platform Uplift and the Midland Basin. Results are as in Figs. 6-4 to 18.

We assumed an initially flat basin. The bottom of the basin is forced to take the present-day shape of the basin (500 million years after inception). The thickness and number of layers at $t=0$ are taken as 50 meters and 5 layers, respectively. The lateral and vertical stress components at $t=100$ million years are illustrated by using two orthogonal slices in Figs. 6-4,5,6. We observe that as the west side of the basin goes down, the lateral stress components decrease as a result of the tension created by the relative movement of the bottom. The effect of the structure imposed beneath on the lateral stress components become more significant as time progress. Figs. 6-7,8,9 show the lateral and vertical stress components at $t=300$ million years. The vertical stress is almost a linear function of the depth as expected (Figs. 6-6,9). The vertical stress mainly depends on the overburden weight and slightly effected by the shape of the basin. The shear stresses increase as the basin shape evolves due to the tectonic movements. The variation of shear stress components σ_{xz} and σ_{xy} at the bottom of the basin are illustrated in Figs. 6-10,11, respectively. The blue areas in Figs. 6-10,11 corresponds to the central uplift. The shear stress components at the east and north-east side of the basin are very small because of the relatively flat shape of the basin. Fig. 6-12 demonstrates the region where σ_{xz} has highest values. The map and three dimensional view of the upper boundary of the failure zone colored with depth (failure function, $F=0$) at $t=100$ million years can be seen in Figs. 6-13,14. Figs. 6-15,16 ($t=200$ million years) and Figs. 6-17,18 ($t=300$ million years) show that the failure zone moves as the basin shape change because of sedimentation and tectonic movements. From our simulation results we conclude that the west side of the basin is more likely to be fractured than the east side.

Fig. 6-4 Variation of σ_x at 100 million years ($\times 10^4 MPa$).

Fig. 6-5 Variation of σ_y at 100 million years ($\times 10^4 MPa$).

Fig. 6-6 Variation of σ_x at 100 million years ($\times 10^4 MPa$).

Fig. 6-7 Variation of σ_x at 300 million years ($\times 10^4 MPa$).

Fig. 6-8 Variation of σ_{yy} at 300 million years ($\times 10^4 MPa$).

Fig. 6-9 Variation of σ_{zz} at 300 million years ($\times 10^4 MPa$).

Fig. 6-10 Variation of σ_x at 300 million years ($\times 10^4 \text{ MPa}$).

Fig. 6-11 Variation of σ_y at 300 million years ($\times 10^4 \text{ MPa}$).

Fig. 6-12 Upper boundary of the region with the highest σ_x values colored with depth.

Fig. 6-13 Map view of the upper boundary of failure zone colored with depth at 100 million years.

Fig. 6-14 Three dimensional view of the upper boundary of failure zone colored with depth at 100 million years.

Fig. 6-15 Map view of the upper boundary of failure zone colored with depth at 200 million years.

Fig. 6-16 Three dimensional view of the upper boundary of failure zone colored with depth at 200 million years.

Fig. 6-17 Map view of the upper boundary of failure zone colored with depth at 300 million years.

Fig. 6-18 Three dimensional view of the upper boundary of failure zone colored with depth at 300 million years.

References

- Bernabe, Y., Fryer D. T. and Hayes J. A. (1992) The effect of cement on the strength of granular rocks, *Geophys. Res. Letters* 19, 1511-1514.
- Berryman, J. G. (1980) Long wavelength propagation in composite elastic media ellipsoidal inclusions, *J. Acoust. Soc. Am.* 68, 1820-1831.
- Biot, M.A. and D.G. Willis (1957) The elastic coefficients of the theory of consolidation, *J. Appl. Mech.* 24, 594-601.
- Dewers, T. and P. Ortoleva (1990) A coupled reaction/transport/mechanical model for intergranular pressure solution, stylolites, and differential compaction and cementation in clean sandstones, *Geochim. Cosmochim. Acta* 54, 1609-1625.

- Dewers, T. and P. Ortoleva (1994a) Formation of stylolites, marl/limestone alternations, and clay seams through unstable chemical compaction of Argillaceous carbonates, in *Diagenesis Vol. IV*, K.H. Wolf and G.V. Chilingarian, eds., Amsterdam, Elsevier, 155-216.
- Dewers, T. and P. Ortoleva (1994b) Nonlinear dynamical aspects of deep basin hydrology: Fluid compartment formation and episodic fluid release, *Am. J. Sci.* **294**, 713-755.
- Drücker-Prager, D. C. and Prager, W. (1952). Soil mechanics and plastic analysis or limit design, *Quart. Appl. Math.* **10**, no. 2, 157-165.
- Eshelby, J.D. (1957) The determination of the elastic field of an ellipsoidal inclusion and related problems, *Proc. Roy. Soc. London A* **241**, 376-396.
- Evans, B., Fredrich J. T. and Wong T. -F The brittle-ductile transition in rocks, recent experimental and theoretical progress. In: The Heard Volume. *Am. Geophys. Un. Geophys. Res.* **95**, 10,907-10,920.
- Fredrich, J. T., Evans B. and Wong T. -F (1990) Effect of grain size on brittle and semibrittle strength: Implications for Micromechanical modeling of failure in compression, *J. Geophys. Res.* **95**, 10,907-10,920.
- Hirth, G. and Tullis J. (1989). The effects of pressure and porosity on the micromechanics of the brittle-ductile transition in quartzite, *J. Geophys. Res.*
- Ortoleva, P. (1994a) *Geochemical Self-Organization*, New York, Oxford University Press.
- Ortoleva, P. (1997) *Basin Compartments*, Princeton University Press, in press.
- Park, A. and P. Ortoleva (1997a) Multi-mineralic model of pressure solution mediated compaction, in preparation.
- Park, A. and P. Ortoleva (1997b) Three dimensional basin RTM modeling, in preparation.
- Payne, D., W. Sibb, J. Comer and P. Ortoleva (1997) Three dimensional structure and deposition/erosion history of the Piceance Basin, in preparation.
- Renard, F. and P. Ortoleva (1996) Water films at grain-grain contacts: Debye-Hückel, osmotic model of stress, salinity and mineralogy dependence, *Geochim. Cosmochim. Acta*, in press.
- Renard, F., P. Ortoleva and J.P. Gratier (1996) Pressure solution in sandstones: Influence of clays and dependence on temperature and stress, *Tectonophysics*, in press.

- Rice, J.R. (1975) Continuum mechanics and thermodynamics of plasticity in relation to microscale deformation mechanisms, in *Constitutive Equations in Plasticity*, A.S. Argon, ed., Cambridge: MIT Press, 23-79.
- Rice, J.R. and J.W. Rudnicki (1979) Earthquake precursor effects due to pore fluid stabilization of a weakening fault zone, *J. Geophys. Res.* **84**, 2177-2193.
- Rutter, E. H. and Hadizadeh J. (1991). On the influence of porosity on the low-temperature brittle-ductile transition in siliciclastic rocks, *J. Struct. Geol.* **13**, 609-614.
- Sakrani, K. (1997) A unified texture and mineralogy-dependent model for rock deformation, doctoral thesis, Indiana University.
- Schock, R. N., Heard H. C., and Stephens D. R. (1973) Stress-strain behavior of a granodiorite and two graywackes on compression to 20 kilobars, *J. Geophys., Res.* **78**, 5922-5941.
- Wong, T. -F (1990) Mechanical compaction and the brittle-ductile transition in porous sandstones. In: *Deformation Mechanisms, Rheology and Tectonics*, Spec. Publs. Geol. Soc. Lond. **54**, 111-122.
- Zhang, J., Wong T. -F and Davis D. M. (1990) Micromechanics of pressure-induced grain crushing in porous rocks. *J. Geophys. Res.* **95**, 341-352.
- Zimmerman, R.W., W.H. Somerton and M.S. King (1986) Compressibility of porous rocks, *J. Geophys. Res.* **91**, 12765-12777.