STATE LANDS ENERGY RESOURCE OPTIMIZATION PROJECT

1991 Annual Progress Report

Project coordinated by

Bureau of Economic Geology
The University of Texas at Austin

Cooperative research conducted with

Center for Petroleum and Geosystems Engineering
The University of Texas at Austin

College of Engineering
Texas A&M University

College of Geosciences
Texas A&M University

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Preface

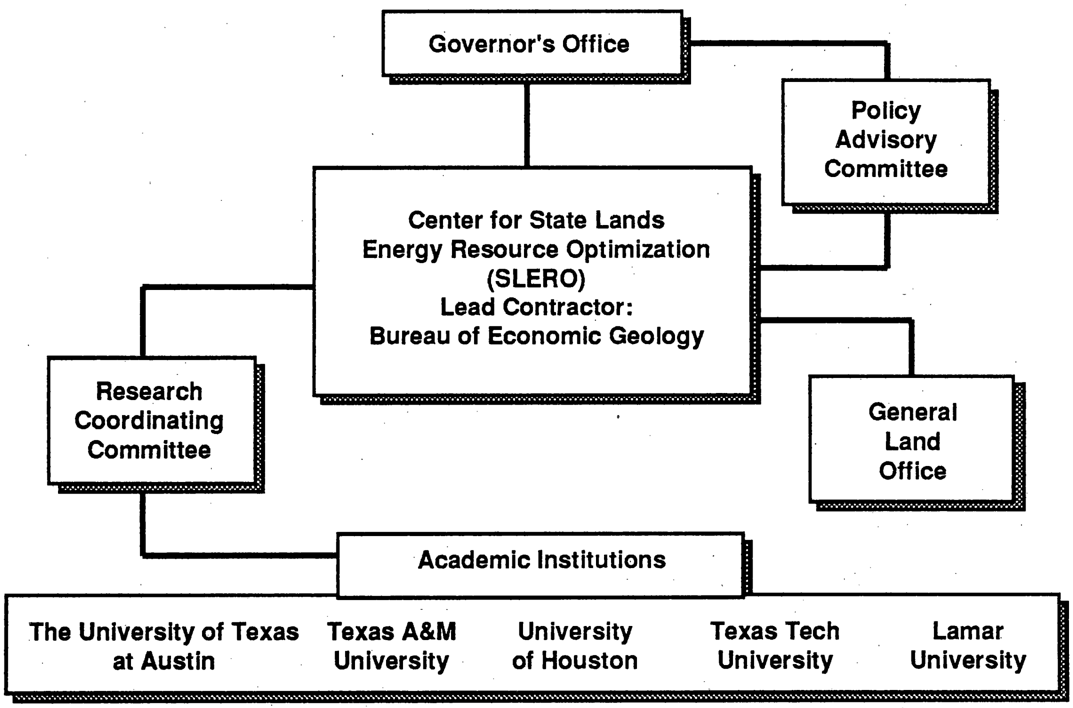
The State Lands Energy Resource Optimization (SLERO) Project, for which the Bureau of Economic Geology is the lead contractor and coordinating institution, is a five-university consortium study of hydrocarbon resources on Texas State Lands. The five universities are The University of Texas at Austin, Texas A&M University, the University of Houston, Texas Tech University, and Lamar University, and the entire program is aided by the cooperation of the General Land Office of Texas. Project personnel include geologists, petroleum engineers, geophysicists, and chemists. The interdisciplinary nature of this project is directed toward a more thorough understanding of the geologic controls on production and the development of appropriate recovery technologies to address the specific needs of State Lands reservoirs. Transfer of these technologies to industry, in particular to independent operators, is expected to result in increased efficiency of hydrocarbon recovery from State Lands and increased revenue to the Texas Public School Fund. The project is divided into three parts: (1) play analysis and resource assessment, (2) reservoir characterization, and (3) development of advanced extraction technology.

The play analysis and resource assessment part of this research program involves dividing the oil and gas fields on Texas State Lands into geologically based families, such that fields with similar depositional histories, trapping styles, production efficiencies, and extraction difficulties are grouped into "plays." Play analysis provides the framework for making a quantitative assessment of the remaining resources on State Lands. Importantly, even maturely developed oil reservoirs may still contain substantial volumes of both "mobile" oil (oil that is movable at reservoir conditions and that can be conventionally recovered) and "residual" oil (oil that requires expensive and technically complex reservoir stimulation). The relative amounts of these resource types vary among the geologically based plays. Quantifying the amounts of these two types of oil on State Lands, as well as quantifying the remaining natural gas resource, is critical both for designing field development programs and for optimizing the recovery economics of Texas hydrocarbon resources and is the focus of the resource assessment task.

The reservoir characterization part of this project includes selection of multiple State Lands fields and reservoirs for site-specific research. Inasmuch as the goal of reservoir characterization is to design advanced field development programs, the specific fields chosen for detailed study are selected within the play analysis framework, and chosen fields typify plays that capture major portions of the total remaining State Lands resource. The process of reservoir characterization itself is multidisciplinary, involving geologists, petroleum engineers, and geophysicists. The details of each reservoir span the range of reservoir types in Texas, from relatively young gas fields in the deep Tertiary sandstones of the Gulf Coast to mature oil reservoirs in the limestones and dolomites of the West Texas Permian Basin.

To date, six State Lands fields and two subregional study areas are undergoing characterization research, and selection of several more fields over the course of this four-year project is anticipated. Reservoir characterization studies comprise geological, petrophysical, and geophysical investigation of the reservoir along with an assessment of original and remaining resources using cores, well logs, and seismic data. This work incorporates the results of petrophysical and diagenetic studies to produce two- and three-dimensional models of reservoir flow units. Seismic studies are designed to improve the existing vertical and lateral resolution offered by conventional seismic techniques by employing such techniques as cross-borehole tomography and surface reflection seismic surveys.

The final part of the project, development of advanced extraction technology, uses the geologic and engineering models developed within the play framework to design efficient and advanced field development projects. During this stage of the project we have worked especially closely with operators of State Lands reservoirs to implement the results of our research as infill drilling, waterflood optimization, and enhanced oil recovery programs. This includes drilling of infill wells geologically targeted to tap unswept reservoir compartments, design of waterflood programs to sweep parts of the reservoir incompletely exploited, and design of state-of-the-art carbon dioxide and surfactant floods to sweep residual oil.



Organizational structure of Project SLERO

Bureau of Economic Geology
The University of Texas at Austin

Activity 1: State Lands Play Analysis and Resource Assessment

Task 1: Data collection and verification

The principal effort for this task was computer data entry and quality assurance of both geologic and engineering data from State Lands reservoirs. The sources for these data were Railroad Commission of Texas files and technical literature. Geologic data were cataloged as alpha-numeric data and placed in coded tables. Reservoir engineering data were cataloged as numeric data. All information was cross-checked against the original source, and as an additional check of accuracy, all data were separately verified to be within reasonable geologic and engineering constraints.

Temperature and pressure are two of the critical data elements required in calculating volumes of reservoir gas in place. These data are being entered into the database as both discrete elements and as Geographic Information System (GIS) maps. The geographic and geologic characteristics of reservoir temperature and pressure are being further checked by placement in a geographic and geologic context. As part of the preliminary analysis we have produced temperature gradient maps and have constructed linear regression equations for each geologic play.

State Lands reservoirs are also being classified by the currently employed recovery method and by current well spacing. This information will be entered into the database.

Task 2: Play analysis

All State Lands reservoirs having cumulative production greater than 1 million barrels (MMbbl) of oil or 6 million cubic feet (MMcf) of gas (equivalent to 1 MMbbl of oil) were located on commercial base maps, and their boundaries were digitized into the GIS. The boundaries of geologically based plays for oil production on State Lands were also digitized in the GIS. The reservoir locations and play boundaries were compared, and modifications to play boundaries or to the play designation of individual reservoirs were made where appropriate. Significant modifications were made to the play boundaries for Siluro-Devonian, Upper Guadalupian, and Strawn Fluvial-Deltaic Sandstone reservoirs.

Much of the effort this year was directed toward dividing Ellenburger reservoirs into plays. The Ellenburger Karst-Modified Dolostone group produces oil from reservoirs that were initially formed in a peritidal depositional environment and were subsequently affected by extensive dolomitization and sub-Middle Ordovician karsting. Karst-related fractures and interbreccia pores are the dominant pore types, and fault-related fracturing is subsidiary. The reservoir traits show that this group has moderately thick net pay, low porosity, and low initial water saturation, as well as moderate permeability and residual oil saturation. The Ellenburger Ramp Carbonate group produces oil from reservoirs that were also formed in a peritidal to middle- to outer-ramp depositional environment but were subsequently exposed to dolomitization. The dominant pore types are intercrystalline and interparticle, fault-related fractures and karst fractures being subsidiary. Reservoir traits indicate that this group has the thinnest net pay, highest porosity, highest residual oil and initial water saturation, and moderate permeability. The Ellenburger Tectonically Fractured Dolostone group produces gas from reservoirs that were also initially formed in a pertidal environment and were subsequently extensively dolomitized, affected by variable intra-Ellenburger sub-Middle Ordovician karsting and, finally, extensively fractured. The dominant pore type is fault-related fractures with karst fractures and intercrystalline porosity mainly occluded with cement. Reservoir traits show this group to have the thickest net pay and low porosity, permeability, and initial water saturation.

Analysis of State Lands reservoirs identified two new oil plays from mapping by formation and lithology. The first of these is a Pennsylvanian play in the Panhandle that is equivalent to the Cleveland gas play in the Bureau's Atlas of Major Texas Gas Reservoirs. The second new play is a West Texas Wolfcamp oil play, which is a group of reservoirs that circle the Midland Basin and are related to possible shelf-margin to basin slump features.

Task 3: Resource assessment

Computer software has been used to assess hydrocarbon volumes in 5 oil plays, which represent 458 reservoirs. The oil plays for which hydrocarbon volumes have been evaluated are Leonardian Restricted-Platform Carbonate, Ellenburger Karst-Modified Dolostone, Ellenburger Ramp Carbonate, Queen Tidal-Flat Sandstone, and Upper Guadalupian Sandstone. These five plays contain 5,316 million stock-tank barrels (MMSTB) of remaining mobile oil. If produced, this volume of oil would be worth $4.89 billion in State severance tax at a $20/bbl selling price. Additional oil could be produced if enhanced oil recovery (EOR) techniques were applied.

Resource assessment was completed on two gas plays, Ellenburger Tectonically Fractured Dolostone and Wilcox Fluvial/Deltaic Sandstone. These two plays together contain a remaining resource of 31.7 trillion cubic feet (Tcf). If produced, this volume of gas would be worth $2.18 billion in State severance tax at a selling price of $1.50/Mcf.

Resource assessment activities included a literature search on Texas basic energy economic information, with an emphasis on enhanced oil recovery costs. All data obtained from this literature search, and additional information on EOR projects obtained from the Bartlesville Project Office of the U.S. Department of Energy, will be entered into the computer database.

A key control on the State's oil resource is oil price. Therefore, another aspect of resource assessment activities was an econometric study of the effects of oil price on development well completions, development reserve additions, and oil production in West Texas. Ninety-seven percent of the oil reserve additions in West Texas during the decade of the 1980's are attributable to development and redevelopment of existing reservoirs. The effects of the 1981 oil price deregulation provide insight into price as a control on drilling and reserve additions. The relationships among economic factors controlling development well completions, development reserve additions, and oil production can be used to predict the future oil supply from West Texas reservoirs.

The 1981 price deregulation within the United States resulted in an oil market in which domestic drilling and reserve additions were sensitive to world oil price. The economic factors controlling West Texas oil supply varied widely during the subsequent decade. Average annual oil price ranged from $10.40 to $33.80 (1982 $). Average well-drilling costs ranged from $29.12 to $74.40 per foot (1982 $). At the same time, inflation ranged from 5 to 12 percent, while the annual average real prime interest rate fluctuated from 4.6 to 10.6 percent. These economic factors were the basis for investment decisions that resulted in 4,452 MMSTB of development reserve additions, 35,600 development well completions, and 4,689 MMSTB of oil production during the 1980's in West Texas.

During the 1980's, a significant oil price increase was followed by an equally significant price decrease, producing a price-time series amenable to modeling future reserve-growth scenarios. In West Texas, the oil price increases of the early 1980's resulted in increased reserve additions after an initial time lag; that is, annual reserve additions declined for the first two years of the decade, then increased in 1983. The number of development wells completed and oil production also display a time lag. In contrast, drilling costs and drilling rig utilization rose immediately after this price increase. In the second half of the 1980's with the sharp decreasing price in 1986, an immediate and concomitant decline occurred in rig utilization, in development well completions, and in reserve additions. Between 1985 and 1986, annual reserve additions declined from 744 to 174 MMSTB (nearly 75 percent) before recovering to approximately 540 MMSTB in the latter part of the decade. Thus, there was a time lag in the response of oil supply parameters to price increases but no time lag in the response of supply to sharp price decreases. This time lag is related to free market mechanisms controlling a deregulated oil price. It also provides insight into the assessment of how future oil price variations will affect the West Texas oil supply.

Activity 2: Reservoir Characterization

Keystone field: Keystone field, in Winkler County, Texas, is located in the northwest part of the Central Basin Platform of the Permian Basin, approximately 10 mi from the platform margin. The principal trapping mechanism is a north-northwest-trending anticline. Keystone field produces from numerous reservoirs ranging in age from Ordovician to Permian. Our studies focus on the Colby reservoir, equivalent to the Queen Formation, and the San Andres reservoir. Both reservoirs are of Permian (Guadalupian) age.

The Keystone (Colby) reservoir produces solution-gas-driven oil from a zone approximately 300 ft thick at a depth of 3,500 ft. The reservoir is composed of porous, very fine grained arkosic sandstones interbedded with generally low porosity sandy dolomite and anhydritic dolomite. Sandstones are interpreted to have been delivered to the shelf margin via eolian transport and reworked in the shallow-marine environment. Interbedded carbonates were deposited as tidal-flat facies sediments, suggesting the shelf was an intermittently exposed hypersaline environment. The Colby reservoir has been vertically divided into five sandstone-dominated units. Isopach maps of each of these five units, and completion interval data, indicate that large areas of thick sandstones are not open to wellbores. This is especially true for sandstone unit III, which contains an area of approximately 590 acres in which intervals 40 ft thick or greater that are proven productive in other parts of the field are not accessed by wellbores. Conservative estimates based on porosities measured in cores and estimates of net pay thickness and saturations indicate 4 MMSTB of mobile oil are not accessed by existing wellbores on State Lands.

The Keystone (San Andres) reservoir produces solution-gas-driven oil from two zones, one approximately 250 ft thick and the other approximately 300 ft thick, at a depth of 4,000 ft. The San Andres Formation at Keystone field is composed of dolomite and anhydritic dolomite and small amounts of gypsum. The two oil-productive zones occur within a 700-ft section of open-marine facies rocks, which are overlain by 300 ft of low-porosity tidal-flat facies rocks. The upper producing interval is the principal reservoir zone in the downdip eastern part of the study area. The lower producing interval is the principal reservoir zone in the updip western part of the study area. The San Andres reservoir has never been waterflooded, and a pilot waterflood is planned for a one-section area in the eastern part of the study area. We are currently calibrating wireline logs with core data from an analogous field to provide the operator with a prediction of the continuity of flow units within the area targeted for a pilot waterflood.

Las Tiendas (Olmos) field: Las Tiendas (Olmos) field is classified as part of the Upper Cretaceous Olmos Deltaic and Delta-Flank Sandstone play of the Bureau's Atlas of Major Texas Gas Reservoirs. This play, covering portions of Webb, Dimmit, LaSalle, Frio, Zavala, Maverick, and Atascosa Counties, includes deltaic and barrier/strandplain reservoirs in its more updip portion and distal deltaic, lower shoreface, and inner shelf reservoirs in its relatively downdip portion. Las Tiendas is representative of the downdip fields in Webb and LaSalle Counties, which have been designated as tight gas formations by the Federal Energy Regulatory Commission and the Railroad Commission of Texas.

The Olmos Formation dips gently to the southeast. Low-relief folding and minor faulting is related to differential compaction above the underlying Lower Cretaceous shelf margin. The reservoir is composed of stacked lenses of mostly thin, very fine-grained shaly sandstones. Sandstone lenses can be correlated over long distances between wells, but individual thin sandstones have limited lateral continuity. Individual sandstone beds are sharp based, and tops of sandstones and interbedded sandy siltstones and shales are moderately to heavily bioturbated. Where sandstones are more than 1 ft thick, or where sand deposition was relatively rapid, unbioturbated sandstones have been preserved. These sandstones are commonly massive or subparallel, horizontally stratified. Low-angle cross-stratification is interpreted as hummocky cross-stratification. Current ripples are less common. Moderate- to high-angle cross-stratification is conspicuously absent. These beds are interpreted to be distal delta-front, transitional, and inner-shelf deposits on a storm-dominated, low-energy shelf. The unbioturbated sandstones have average permeabilities that range from 0.4 md in the northeast to 0.05 md in the southwest; maximum permeabilities rarely exceed 1 md. Porosity and permeability are reduced by the presence of detrital and authigenic clays and calcite cement.

Sandstone beds occur as 10- to 50-ft-thick lenses of sand-rich strata separated by 0 to 50 ft of siltstone and shale. Sandstone lenses can be correlated between wells for tens of miles. Individual thin sandstones are at the limits of log resolution but appear to have a more limited lateral extent. Pinch-outs of individual sandstones and updip permeability reduction are primarily responsible for trapping gas. Small (30 to 130 ft) normal faults interrupt regional homoclinal dip and trap gas locally. The shelf sandstones form lenticular, strike-elongate deposits. Lower sandstone lenses are lenticular in plan view, connected to an Olmos delta to the west, and are in transitional contact with shale in all other directions. Upper sandstone lenses are strike-elongate but thicken updip into coeval shoreface deposits.

Gas production in Las Tiendas field averages approximately 50 Mcf/d per well for 75 wells; cumulative production for the field is more than 20 Bcf of gas through 1990. Las Tiendas is one of six large (10 to 50 Bcf) Olmos fields that together form a continuous producing trend in northwest Webb and southwest LaSalle Counties. Cumulative production from the downdip trend is more than 150 Bcf. These fields were discovered and initially developed simultaneously between 1970 and 1974. Many wells were assigned to fields without geological or geographical consideration; thus, field boundaries overlap within the continuous producing area. Well spacing ranges from 40 to 320 acres for these fields. Because of the wide spacing of wells and low permeabilities of the reservoir sandstones, significant gas reserves remain on State lands in the Las Tiendas area. These reserves can be exploited profitably with a geologically targeted drilling program after gas prices return to about $2/Mcf.

Lavaca Bay field: Lavaca Bay field, located in Calhoun County, is a gas field in the Downdip Frio Barrier/Strandplain Sandstone of the San Marcos Arch play. Lavaca Bay covers approximately 10 mi^2 and contains 35 producing wells and 17 nonproductive wells, which are irregularly spaced. Nineteen reservoirs, discovered from 1964 to 1986, have produced 70 Mcf of gas The reservoirs, located at depths between 9,000 and 13,000 ft, are composed of sandstone interbedded with shales that were deposited as progradational-aggradational depositional units. Sandstone bodies are interpreted as proximal- to distal-shoreface deposits composed of beach-ridge sandstone. Shales are interpreted as shelf mudstone facies and swale deposits. In addition to the lateral heterogeneity of the sandstone bodies, individual sandstone units have thickness and structural variations related to major growth faults and associated minor faults. The result is an overlapped mosaic of complex reservoir compartments.

The gas-productive section is divided into 26 sandstone/shale depositional units on the basis of well-log lithofacies interpretation and correlation, and the depositional units are grouped into 5 sequences. Each depositional unit is characterized by well-log and producing parameters that include (1) structural top, (2) total thickness, (3) net-sandstone thickness (H), (4) relative deflections of spontaneous potential (SP) and/or gamma rays (GR), (5) deep resistivity (R), and (6) SP or GR profile character. These data are additionally combined to form the numerical relationships (SP)(H), (R)(H), and (SP)(H)(R). The value of (SP)(H)(R) is interpreted as a quantitative measure of hydrocarbon flow capacity, (SP)(H) is interpreted as a quantitative measure of flow capacity, and SP is interpreted as a quantitative measure of permeability. Cross plots between permeability measured in sidewall cores and relative SP deflection demonstrate a correlative relationship, which supports interpretations made from well-log parameters alone. Production and well-log parameters were sorted and plotted against production for each depositional unit. Production data and the numerical relationship (SP)(H)(R) have linear relationships. The correlation coefficients progressively decreased for the relationship of production data versus (SP)(H), production data versus (R)(H), production data versus H, production data versus SP, and production data versus R. Initial potential, first-year cumulative production, and total cumulative production data have been obtained for each well.

The distribution of these data within individual reservoirs was determined by contour mapping. Correlative trends of structure, (SP)(H), and R maps, and production maps delineated stratigraphic-structural and fluid reservoir boundaries. The reservoir architecture and flow character were described by the H, SP, (SP)(H), and (H)(R) maps. Maps of (SP)(H)(R) were used to identify and rank recompletions and infill well targets and to estimate potential additional gas production.

Evaluation of all 26 depositional units of Lavaca Bay field indicated more than 30 potential zones of recompletion in existing wells and 10 infill well locations that individually target between 2 and 8 reservoirs. Results have been discussed with the field operator, and approximately 20 recompletion opportunities and 2 infill well opportunities will be targeted when economics become more favorable.

Delaware Mountain Group: The study of the Permian (Guadalupian) Delaware Mountain Group focuses on reservoir characterization of shallow sandstone reservoirs in the Bell Canyon Formation in the Screw Bean field area of Culberson and Reeves Counties (Blocks 58 and 59, TWP 2). Additionally, a regional sequence stratigraphic study of the Delaware Mountain Group is being conducted to evaluate and develop exploration concepts that can be integrated with new seismic data in the basin.

The Delaware Mountain Group is approximately 3,300 ft thick and includes in ascending stratigraphic order the Brushy Canyon, Cherry Canyon, and Bell Canyon Formations. Each approximately 1,000-ft-thick formation is characterized by a cyclically interbedded succession of sandstone, siltstone, and limestone. Oil and gas accumulations occur at multiple stratigraphic horizons in thin, laterally discontinuous sandstone reservoirs. Reservoir-quality sandstones are characterized by high primary porosity (15 to 25 percent) and low permeability (0.1 to 200 md). Low primary recovery efficiency (approximately 17 to 21 percent) and high watercut reduce cumulative production with hydrocarbon accumulations generally related to stratigraphic and hydrodynamic trapping mechanisms. Although hydrocarbons are produced from sandstones in all three formations, most of the production on State Lands occurs in the Bell Canyon and to a lesser degree the Cherry Canyon Formations.

Previous geologic work has related reservoir sandstone distributions to either turbidity currents or bottom-hugging hypersaline density currents from long-lived linear submarine channels that presumably extended more than 40 mi into the basin. Depositional models derived from these studies were used to explain pronounced northeast-southwest production trends in the uppermost Bell Canyon Formation (Ramsey sandstone). Application of these models has contributed to linear drilling trends that are separated by undrilled fairways poorly defined by dry holes. Because more than 80 percent of Delaware wells contain only acoustic and gamma-ray log suites, fresh-water, hydrodynamic charge relationships that control hydrocarbon emplacement have not been integrated into early exploitation and exploration strategies. Furthermore, shallow-well completion techniques have contributed to a poor understanding of reservoir geometries and have not exploited the multiple/pay-horizons that exist in the Delaware Mountain Group. Consequently, production maps showing drilling density in the Delaware Basin give the incorrect impression of a mature and completely exploited basin.

The regional study area includes 32 blocks in Culberson, Reeves, and Loving Counties in West Texas representing an approximately 1,500 mi^2 region, whereas the detailed study area includes 2 blocks in Culberson and Reeves Counties. Approximately 700 logs in the study area compose the subsurface computer database.

Detailed facies analysis of 8,000 ft of Delaware Mountain Group core has identified five facies with distinct petrophysical attributes: (1) structureless sandstone (reservoir facies), (2) organic-rich siltstone (lutite), (3) very thinly laminated sandstone and siltstone, (4) thinly bedded ripple-laminated sandstone and siltstone, and (5) nodular limestone with wispy siltstone laminae. Acoustic and gamma-ray log traces were calibrated to core and plotted against core facies to quantitatively define log facies. Core-calibrated log facies were extrapolated to uncored wells and mapped to establish facies diversity trends, lithology ratios, and the spatial distribution of reservoir and nonreservoir facies in the Screw Bean field area.

Preliminary results from this study indicate that the arrangement, distribution, and architecture of reservoir sandstones are best explained by an eolian-derived turbidite depositional model. Detailed subsurface correlations reveal that cyclic patterns of deep-water sedimentation are a primary control on the distribution and occurrence of hydrocarbons in shallow sandstone reservoirs in the Delaware Basin. Symmetric depositional cycles are characterized by 100- to 130-ft-thick eolian-derived turbidite successions that produce multiple discrete hydrocarbon reservoirs.

Application of the eolian-derived turbidite model to the Screw Bean field area illustrates three low-cost development strategies that will provide significant reserve additions to State Lands. Cumulative production from the Screw Bean study area as of October 1991 was 1.2 MMbbl of oil. With the average recovery efficiency from Delaware reservoirs at 17 percent, an estimated 7.5 MMbbl of oil lies in place in the study area. The following development strategies should provide an estimated 2 MMbbl of oil in additional recoverable reserves. These techniques include (1) recompletion of 16 percent of wells that perforated only one reservoir horizon but contain multiple-pay horizons, (2) deepening of 18 percent of wells that penetrate only the top 50 ft of the Bell Canyon Formation, and (3) infill drilling in a five-section undrilled fairway that contains multiple reservoir horizons productive in adjacent producing trends.

Powderhorn field: The Powderhorn (Miocene) field is located in Calhoun County, approximately 5 mi northwest of Port O'Connor. The field is part of the Miocene Barrier/Strandplain Sandstone play of the Bureau's Atlas of Major Texas Gas Reservoirs. Powderhorn field is located on an anticline in the hanging wall of an up-to-the-coast antithetic fault above a major reactivated Frio growth fault. Some reservoirs are structural traps, but most are combination structural/stratigraphic traps in which closure is partly due to pinch-out of sandstone units. Powderhorn field contains 11 producing reservoirs. The lowermost reservoir is the 5,200 ft, or No. 5 Sand, which has produced more than 4 MMbbl of oil and 1 Bcf of gas from sandstones deposited in washover-fan and flood-tidal delta environments. The major gas-producing reservoirs are the No. 3 and No. 1 Sands, which have produced approximately 11 and 30 Bcf, respectively. These reservoirs are developed in fluvial- and distributary-channel fills and crevasse splays. Other Powderhorn reservoirs produce from tidal-inlet fills, barrier cores, and bayhead deltas. Since discovery of the field in 1939, total oil and gas production from all Powderhorn reservoirs has been approximately 6 MMbbl of oil and 50 Bcf of gas, from an area less than 2 mi^2.

The following maps and sections have been constructed: (1) isopach maps of all reservoir sandstones, (2) facies maps of all reservoir sandstones, and (3) a grid of 14 stratigraphic cross sections. We have assembled an extensive well database that includes well identifiers, producing reservoir, location, elevations, dates, initial production test data, wireline logs available and obtained to date, conventional and sidewall core intervals, completion, stimulation, and workover summaries, and structural tops and thicknesses.

Conventional two-dimensional common-depth-point seismic data, obtained from the field operator, have been interpreted in the field area. Time-to-depth conversions have been accomplished using synthetic seismograms created from sonic and density logs from several recently drilled wells. Impedance variation between wells has been modeled using log-derived parameters for density, velocity, porosity, and fluid saturations. Gas saturation has a significant effect on seismic response, and the presence of gas can be detected in some Powderhorn reservoirs on the existing seismic data. A higher resolution three-dimensional seismic survey is being planned.

Development drilling since the inception of Project SLERO has resulted in four infill producers and one dry hole on an attempted field extension. Most significant was the recently completed Apache No. 17 State Tract 49. This well made a deeper pay discovery and added at least 750,000 bbl of oil and an unknown amount of gas to field reserves. This represents a reserves increase of more than 12 percent. A twin well has been planned, which will accelerate production of the newly discovered oil. The operator has an aggressive drilling campaign planned for 1992, including both development and step-out wells.

Seventy-Six West and Colmena-Cedro Hill fields: Geologic characterization of Seventy-Six West field concluded early in 1991, and the research effort since then has shifted to Colmena-Cedro Hill field. Colmena-Cedro Hill field is representative of the Eocene Jackson-Yegua Barrier/Strandplain Sandstone play and is similar to the Seventy-Six West field. Resources of this South Texas Jackson-Yegua play are substantial, having a cumulative production of 624 MMbbl of oil as of 1988, and a remaining mobile oil resource estimated at more than 1 Bbbl.

The Jackson-Yegua Barrier/Strandplain Sandstone play produces oil from depths of 150 ft to a maximum of about 4,000 ft in a northeast-southwest trend through Zapata, Jim Hogg, Webb, Duval, and Bee Counties. Oil production is from the sandstone facies of strandplain-barrier bar systems in the Jackson Group and the Yegua Formation. The Mirando, Loma Novia, and Government Wells Sandstones of the lower Jackson Group and the Cole Sandstones of the middle and upper Jackson Group are the principal reservoir sandstones. Sandstone bodies are strongly strike-oriented, reflecting the location of the barrier sandstone belts. Local, dip-oriented sandstone units are also present, and these formed from minor input from wave-dominated cuspate deltas and tidal-channel facies, which crosscut the barrier sandstones. The trapping mechanism is primarily an updip permeability pinch-out as barrier sandstones thin against muddy back-barrier/lagoonal facies. However, subtle faulting and flexuring of the Jackson Group and Yegua Formation along large listric growth faults of the Wilcox fault zone played an important role in creating secondary structural traps.

At Colmena-Cedro Hill field in northwest Duval County, 10.4 MMbbl have been produced from three Cole reservoir sandstones (informally termed 1st, 2nd, and 3rd Cole sandstones) of the uppermost Jackson Group. Production is from a depth of 1,425 to 1,475 ft. The 3rd, or lowermost, Cole sandstone was deposited during a progradational episode and overlies a thick succession of marine shelf mudstone. The overlying 2nd Cole sandstone represents a further episode of progradation and appears to be best developed seaward of the 3rd Cole sandstone depocenter. Rapid local marine inundation following the 2nd Cole sandstone is implied by the landward shift in deposition of the 1st Cole sandstone, which occurred before further progradation of successive subparallel barrier islands. The final episode of outbuilding was deposition of coastal barriers seaward of the Colmena-Cedro Hill field limits. The barriers were subsequently dissected by a moderately sinuous mixed-load fluvial system. The three strike-oriented Cole sandstone barriers were each modified by contemporaneous crosscutting channel facies of probable tidal origin, resulting in a highly complex reservoir geometry. The trapping mechanism is primarily an updip stratigraphic pinch-out where the 1st, 2nd, and 3rd Cole barrier island sandstones grade into corresponding muddy back-barrier/lagoonal facies. However, structural control on oil entrapment is also very important at Colmena-Cedro Hill. Because the field has an extensive gas cap and strong aquifer drive, subtle structural movement can determine whether the 1st, 2nd, or 3rd Cole sandstone lies within the gas-, oil-, or water-saturated parts of the field.

The reservoir heterogeneity at Colmena-Cedro Hill field indicates considerable potential for untapped reservoir compartments, which provide targets for infill drilling and, ultimately, increased oil recovery. This reservoir heterogeneity, with its potential for bypassed mobile oil, is the principal focus of the SLERO research. Infill drilling locations were proposed to test these concepts at both Seventy-Six West and Colmena-Cedro Hill fields. Two wells have already been successfully completed as oil producers at Seventy-Six West, and the operator at Colmena-Cedro Hill has indicated intention to drill additional wells during 1992.

The efficiency of secondary recovery techniques in oil fields with low-gravity oil (approximate API gravity of 20) and high permeability (1,000 md), such as at Seventy-Six West and Colmena-Cedro Hill fields, has been identified as a subject of research interest. Analysis of production trends and waterflood design has identified areas of inefficient drainage at Colmena-Cedro Hill, and these areas have also been targeted for infill wells to be drilled in 1992.

Available data for Colmena-Cedro Hill field are limited. Data include 1940's, 1950's, and 1980's vintage spontaneous potential and resistivity logs, and several gamma-ray and neutron logs from the late 1930's. No conventional cores are available, although there are several sidewall core analyses. Records of oil, water, and gas production are incomplete, and reconstruction of field development history was difficult. Engineering data are limited, and there are no records of pressure-volume-temperature (PVT) tests, pressure buildup/drawdown tests, fluid-level surveys, or current reservoir pressure.

Geologic characterization of the Colmena-Cedro Hill and Seventy-Six West fields is complete. Volumetric analysis and associated engineering studies, such as the geologically optimized waterflood design, are under way. Development in both fields continues, and several infill drilling targets have been proposed for 1992. A waterflood is planned for the future.

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Activity 2: Reservoir Characterization

Task 1: Laboratory analysis and theoretical modeling

The goal of this project was to develop a method to estimate permeability from thin-section images and to apply this method to SLERO reservoirs. Our technique differed from others in that the pore occupation by wetting and nonwetting phases was to be determined directly by solidifying these phases in place in the rock and observing them by microscopy.

We accomplished this by a technique described by R. W. Wunderlich in "Imaging of Wetting and Nonwetting Phase Distributions: Application to Centrifuge Capillary Pressure Measurements" (SPE 14422, 1985). In this method, dyed epoxy is drained from a core sample in a centrifuge in the same manner that brine would be drained during a conventional centrifuge capillary-pressure measurement. During centrifugation, after a sufficient time for drainage has elapsed, this epoxy is hardened in place. The sample is then placed in a vacuum and the second dyed epoxy allowed to invade the remaining pore space and also harden in place. The second epoxy thus occupies the pore space occupied by the nonwetting phase during centrifugation.

We encountered two problems with the epoxy technique. First, imbibition of epoxy into the core samples was surprisingly slow, especially imbibition of the second epoxy, which represents the nonwetting phase. As a result, some thin-section photomicrographs did not accurately portray the distribution of phases present during centrifugation. Second, at centrifuge speeds as low as 2,000 rpm, the Hassler-Bruner boundary condition was violated. The Hassler-Bruner boundary condition specifies that wetting-phase saturation is unity and capillary pressure zero at the lower surface of the sample. Wunderlich observed a similar phenomenon in his experiments. As a consequence of absence of this boundary condition, the capillary pressure at each location could not be determined.

A by-product of this work was measurement of centrifuge brine-air capillary-pressure curves for core samples from Keystone (Colby) Well No. 4. These data will be reported in a report now in preparation.

Task 2: Interpretation of well-log data

Mineralogical Modeling and Well-Log Analysis of Seventy-Six West Field

The sandstone reservoirs at Seventy-Six West field are rich in volcanic grains, including ash shards, feldspars, volcanic rock fragments, and heavy minerals. Montmorillonite is the dominant clay and coats many of the sand grains.

Most well logs are very old. However, the Manfred Production No. 15 Seventy-Six West DCRC State Oil Unit, drilled in 1987, was logged with a suite of modern Schlumberger logs, and 24 sidewall core analyses are available. Thus the study concentrated on computer analysis of logs from this well. Cross plots, quick-look analysis methods, and Schlumberger's statistical ELAN program analyses were employed.

Well-log data were digitized, depth-matched, and environmentally corrected. Cross plots indicate that the Catahoula sandstones apparently have higher calcite and heavier mineral contents than the deeper Jackson (Cole) sandstones. Four quick-look techniques were attempted, including apparent water resistivity (R_{wa}), resistivity overlay (R_o), SP overlay (R_{xo}/R_t), and EPT-porosity overlay. These quick-look methods readily identified the hydrocarbons known to be present in the Cole sandstones. These quick-look methods also indicated the probable presence of gas in an untested Catahoula sandstone.

The ELAN program was used to construct a detailed mineralogical model of the Jackson-Catahoula interval. Separate sandstone and shale models were combined to yield a representation of these rocks. The results are in good agreement with quick-look findings. The ELAN analysis also documented the differences in formation water salinities between sandstones and adjacent shales.

Permeability Stratification Using Log Analysis Techniques Enhanced by Principles of Mineralization in the Keystone (Colby) Reservoir

The complexity of the Keystone (Colby) reservoir presents a challenge to the geologist, petrophysicist, and engineer. Thinly laminated beds of sandstone and dolomite that are discontinuous over the extent of the reservoir, which is already complicated by folding and differential compaction, make mapping of productive zones a difficult task. Mud salinity, altered by dissolution of halite in the shallow interval of the borehole, exceeds tool specifications and reacts with cements in deeper intervals, presenting additional challenge to the interpretation of wireline measurements. The presence of heavy minerals and ferromagnetic materials exceed the limitations of traditional wireline interpretation models.

This study focuses on four wells: Keystone Cattle Company Nos. 401, 403, 405, and 406. Available logs are natural gamma-ray, neutron-density, dual lateral logs, microspherically focused resistivity log, and caliper log. A long-spaced sonic was run in this well, but not over the Colby reservoir. Pattern recognition is used to correlate potassium, thorium, and uranium measurements to the gross stratification observations of the mudlog. Principles of mineralization are used to qualify the most likely trace and heavy minerals present within these stratifications. The neutron and density data were corrected for the presence of these minerals, and total porosity was estimated. Resistivity data are used to quantify fluid saturations. Mineralization from ground-water weathering has a direct effect on alteration of original permeabilities, resulting in permeability stratification. Porosity, saturation, and permeability estimates from corrected logs of Well No. 403 were compared with core measurements where possible.

Values of electrical properties were measured in cores from the J. B. Walton No. 4. Four of these cores are sandstone, and two are dolomite. Capillary pressure and porosity measurements have been made on these samples to confirm and augment the commercial core analysis. Permittivity and dissipation increase with water-filled porosity, and the dolomites have larger values of these properties than do the sandstones at comparable porosities.

Dielectric logs offer a means of determining both water saturation and porosity, whereas lower frequency resistivity logs are used to determine water saturation. The electrical properties measured in cores will be helpful in improving log interpretation.

Lavaca Bay Log Analysis

The goal of log analysis study at Lavaca Bay field is to determine petrophysical parameters needed for reserves calculations, especially porosity and saturations, by utilizing modern statistical log analysis models. Paper copies of dual induction, LDT, and borehole compensated sonic logs were digitized. Because most of the logs were digitized from paper copies and the original magnetic tapes are not available, most of the data are inadequate for sophisticated processing and analysis, especially for identification of lithology and mineralogy. Log data tapes are available for some wells, and the tapes contain many useful curves, including those from DIL, BHC, LDT, EPT, and/or NGT, and/or LSS. Six wells, ST26-6, ST26-7, ST27-3, ST37-2, Fee No. 9, and Fee No. 1, were selected for detailed analysis. These wells were drilled through many of the reservoirs at Lavaca Bay field, including the most prolific reservoir.

Two wells, ST26-6 and ST27-3, have been partially processed using the Schlumberger Atlantis workstation. Environmental corrections have been made, and first-pass interpretation techniques have been applied to narrow the focus to key problems. It is obvious from basic cross-plotting techniques that considerable clay and some heavy minerals are present in these reservoirs. Core porosities are lower than neutron porosities, even in gas-producing intervals. This is consistent with the presence of shale and/or heavy minerals in the reservoir. The effect of this lithology on the neutron log masks the common indicator of gas, which is based on crossover of density and neutron-derived porosities. Log interpretation in this environment requires knowledge of type, composition, and distribution of shale in the reservoir.

Log analysis alone is insufficient for accurate evaluation of the remaining resources in Lavaca Bay field, and log analysis should be combined with other analytical methods, such as pressure, production, and core analysis. The combination of these methods will aid identification of reservoir compartments. It is anticipated that subtle variations in lithology can be identified by log analysis and that these variations will be useful in mapping the field.

Task 3: Measurement of reservoir heterogeneity using tracer data

Using analysis of production and injection data, and the geological interpretation provided by Doug Hamilton (UT/BEG), we discussed some possible locations for infill wells. The area of the field selected for infill drilling includes parts of Sections 62 and 61. This area comprises one injection well and six producing wells. Initially we simulated the reservoir as having just one layer, using Hamilton's maps to obtain porosities, thicknesses, structural features, and facies boundaries. To simulate heterogeneity, we used a two-dimensional areal stochastic permeability distribution generated by the Turning Bands Method. The permeability fields have variability specified by the Dykstra-Parsons heterogeneity coefficient, and spatial ordering measured by the correlation-length parameters.

The Cole C sandstone was also simulated assuming two layers, each layer having a stochastically generated permeability field. This simulation was based on well logs and permeability obtained from sidewall cores. Permeability fields were produced for each layer and facies using the same method as used in the previous simulation. Water saturation distribution was estimated for each layer by matching the producing watercut for each well. The UTCHEM code was modified to handle variations in fluid transmissibility caused by barriers to flow due to faults or facies boundaries. The results of a newly drilled well (No. 62-29) were recently included. Another tracer simulation was constructed in which well No. 62-18 was assumed to be an injection well

Task 4: Construction of data model

The principal tasks this year were expansion of the quantity of data available in the archive, documentation of the access mechanisms to the data archive, and expansion of the access mechanisms that can be used to retrieve data from the archive. Special attention has been paid to network-access mechanisms, so that the data may be easily distributed to remote sites. The goal of this work has been to document the data available and allow as many user-access mechanisms as possible.

Expansion of the quantity of data available has involved two basic tasks. These are the development of programs that will facilitate the task of entering data as they are gathered and gathering data from some of the fields being studied. The programs that have been developed allow the easy entry of data from standard forms, such as those used by the Railroad Commission of Texas, into a known-file format. This shortens the length of time required to enter the data and increases their reliability.

Mechanisms for access to the data were improved during this year by simplifying some of the existing methods of network access as well as adding additional mechanisms. The use of the existing network-access mechanisms was simplified by consolidating available data into directory structures that more closely resemble the organization of the project. This should allow researchers to access data on the basis of the geographical field of interest instead of the type of data available. Access to data stored in the archive was also improved with the addition of Data Access Language. Data Access Language allows users of personal computer systems, such as the Apple Macintosh, to access data stored in relational databases on larger machines. This allows capabilities such as access and downloading into applications on a personal computer.

Future work will focus on documenting existing data and expanding the quantity of data available. These are the two most important aspects of this phase of the project. Some work will also be done to the expansion of network-access mechanisms, particularly the use of DECnet or IP tunnels, to provide personal computer base protocols to remote sites.

Activity 3: Advanced Extraction Technology

Task 1: Waterflood surveillance and optimization

Production Strategy to Improve Oil Recovery from the Keystone (Colby) Reservoir

Waterflooding is currently being used to improve oil recovery from Keystone (Colby) field. The efficiency of waterflooding projects in recovering oil, however, depends on how they are implemented. A simulation study of the Keystone (Colby) reservoir was conducted to determine the impact of different waterflood strategies on oil production.

The Keystone (Colby) reservoir is composed of interbedded layers of fine- to medium-grained sandstone, dolomite, anhydrite, and anhydritic dolomite. These layers have different petrophysical properties, making predictions of oil recovery from waterflooding difficult. Because of this layering, the injection profile is highly nonuniform, which degrades oil recovery.

A quarter five-spot simulation model for the Keystone (Colby) field was developed for the BOAST II simulator to study different waterflood recovery strategies. Because crossflow between layers is important in layered reservoirs, the simulator was modified to provide crossflow information. Log and core data were used to develop a representative model of the field. The model consists of one high-, one medium-, and two low-permeability layers. As expected, the model predicted that the injection profile was nonuniform and that the injected water rapidly channeled through the high-permeability layer and broke through at the production well.

The first production strategy studied was to reduce the flow rate through the high-permeability layer to delay water breakthrough. The flow rate was reduced by lowering the injectivity and/or productivity index for wells in the high-permeability layer. Lowering the flow rate reduced the oil production rate, even when the flow rate was reduced after water breakthrough at the production well. Lowering the flow rate also reduced water production. Crossflow of oil between the low- and high-permeability layers was important in maintaining oil production after water breakthrough.

The second production strategy studied was to increase the injectivity and/or productivity of the formation. Stimulating all four layers resulted in an increase in both the oil and water production rates. Stimulating only the medium-permeability layer created a more uniform injection profile and increased the oil production rate, although not so much as when the high-permeability zone was also stimulated. Future studies will determine the effects of these production strategies on the water/oil ratio.

A Numeric Simulation of Seventy-Six West Field

If Seventy-Six West field is operated in its present mode, an additional 350 MSTB of oil can be recovered, for a projected cumulative production of 4.9 MMSTB of oil. This represents approximately 10 percent of the original oil in place, indicating that there is considerable potential for improved recovery. The purpose of numeric stimulation is to determine the current status of the reservoir and to evaluate potential future operation strategies. A three-dimensional black-oil simulator, BOAST II, is being applied. The simulator model of the reservoir consists of two layers, representing the Cole "B" and "C" sandstones. It is assumed that there is no communication between the two layers. The orientation of the grid will be such that one of the principal axes is parallel to the direction of the deposition of the beach-ridge facies. The study is being carried out in two phases:

1. An improved characterization of the reservoir will be provided by an approximate history-match study focusing on material balances and pressures using production and injection data. Where petrophysical properties and PVT properties of the reservoir fluids are not available, reasonable estimates have been made.
2. A study will be conducted to determine the most suitable locations for drilling infill wells. Inefficient drainage of the compartments and poor waterflood response are the inefficiencies that can be corrected by strategically located infill wells.

The major problem with this reservoir is extremely low reservoir pressure: approximately 10 psi. Thus, the principal emphasis of this study is to devise appropriate means to supply external energy to the reservoir. The EOR processes under consideration are waterflooding, polymer flooding, or a combination of the two. The motivation for studying polymer flooding lies in the fact that the polymer may provide a more favorable mobility ratio than that of a waterflood. Therefore, this possibility will be explored in further detail. The northeast corner of the field will be studied first because the geological interpretation suggests that a fault isolates it from the rest of the field. As the study proceeds, the other compartments will be added to the simulation.

Thus far, three infill wells have been drilled on the basis of the reservoir characterization study (Doug Hamilton, UT/BEG). Waterflood optimization, coupled with EOR techniques, may provide additional infill drilling opportunities for increased ultimate recovery.

Task 2: Development of inhibitive muds for wellbore stability

Drilling records and electric logs were reviewed for seven SLERO reservoirs: Seventy-Six West, Las Tiendas, Lavaca Bay, Keystone (Colby), Delaware Mountain Group, Keystone (San Andres), and Colmena. The field that displayed the largest degree of wellbore instability was Seventy-Six West. Unfortunately, shale samples are available as cuttings only. Shale cores are available from Las Tiendas field, and laboratory testing has begun on this field.

Four laboratory tests were performed on three shale core sections. These tests indicated that the shales are moderately reactive to normal fresh-water drilling fluids and only slightly reactive to a mud that contains 5 percent KCl plus PhPa polymer. The core from the Tri-Bar Well contains three shale sections near the bottom of the well that were highly eroded. Six-inch-long samples of core were collected from each section. Testing indicated that all three zones had similar compositions and reactivity to the various fluids tested. The shales have a cationic exchange capacity (CEC) of about 5.0, which places them in the clay content range of "moderate" relative to other shale formations. The water adsorption test indicated that the shales retain about 3 percent moisture when in equilibrium with a 50-percent relative humidity environment, which also placed them in the "moderate" relative adsorptive range. These compositional tests suggest that this shale would be of the moderately reactive type and that the use of highly inhibitive muds may not be necessary for achieving satisfactory wellbore stability. This is consistent with reported drilling results.

Two different tests were run to evaluate the interaction of the shale with various drilling fluids: a swelling test and a dispersion test. The swelling test consisted of cutting $0.5 \times 0.5 \times 1$ inch samples from the shale cores using diesel oil rather than water as the cooling fluid. Avoiding contact of the cores with water during preparation ensured that the samples would stay intact before testing. Eight of these samples were placed in contact with eight different drilling fluids, which ranged in inhibition quality from "no inhibition" to "very high inhibition." One of the fluids tested was a lignosulfonate mud that had a composition similar to the mud used during actual drilling of the well. Results from the swelling tests showed that after 24 hours the sample in the lignosulfonate mud had swelled 3.8 percent. The most inhibitive fluid tested was a 5-percent KCl mud that contained 5 lb/bbl of the inhibitive polymer PhPa. This fluid reduced the swelling of the shale by 70 percent; that is, it swelled by only 1.2 percent during 24 hours. The shale was also exposed to pure deionized water, and it was found that this fluid was more reactive than the lignosulfonate mud because a final swelling of 5.5 percent resulted after 24 hours. The swelling tests indicated that the lignosulfonate mud chosen for this well may have been a good choice. It was also shown that, should wellbore stability drilling problems arise on subsequent wells in the Las Tiendas field, 5-percent KCl mud containing 5 lb/bbl of the inhibitive polymer PhPa would be an excellent drilling fluid.

The final testing method consisted of measuring the degree of dispersion of shale into various drilling muds. This test is used to help select the most inhibitive mud, but it is also used for studying the degree of dispersion of shale drilled cuttings into a drilling mud. Shale dispersion is a serious problem in some wells because an excess amount of solids in the mud can cause excessive pump pressures. To perform the dispersion tests, 20 g of 4- to 8-mesh shale pellets that were ground from the core were placed in a 400-ml aging cell containing 350 ml of the test mud. The mixture was hot-rolled for 16 hr at 150°F, then poured through a 200-mesh screen. The amount of shale that passed through this screen is a measure of the dispersion tendencies of the shale in that mud. The shale placed in the lignosulfonate mud had a 50-percent dispersion level, which is high. Only the deionized water test fluid, which had a 58-percent level of dispersion, was higher. Once again, the 5-percent KCl mud containing 5 lb/bbl PhPa polymer, displayed the highest level of inhibition. Only 3 percent of the shale passed through the 200-mesh screen (a 3-percent dispersion level) when this fluid was used. Should dispersion of solids into the mud be a problem in the Las Tiendas field, the 5-percent KCl/PhPa fluid is recommended.

Task 3: Gas production performance and optimization

The key issue to be addressed at Lavaca Bay field is delineation of poorly produced reservoirs. This means that before performing any production optimization, a study of compartmentalization of the reservoirs must be completed.

One approach to this problem is to analyze the *p/z* plot of wells completed in a single compartment. Initial gas-in-place can be calculated from a plot of *p/z*-vs-Gp, the initial gas in place (G) is obtained by linear extrapolation, taking the value of Gp at *p/z* = 0. In practice, however, *p/z* plots may not exhibit a perfectly linear relationship because: (1) reservoir pressure is not recorded under the pressure equilibrium or (2) reservoir volume is not fixed.

To determine an average *p/z* for an entire reservoir, we used a rate-weighted *p/z* as

$$p/z \quad = \quad \frac{\mathrm{S}\left(\frac{p}{z}\right)_{\mathrm{j}} \cdot q_j}{\mathrm{S}\, q_j},$$

where $\left(\frac{p}{z}\right)_{\mathrm{j}}$ is the shut-in *p/z* of well j at a particular time and q_j is the production rate from well j.

We took q_j to be an annual rate and $\left(\frac{p}{z}\right)_{\mathrm{j}}$ to be at the shut-in pressure of well j at the end of every year. For this purpose, $\left(\frac{p}{z}\right)_{\mathrm{j}}$ is plotted against time to obtain a pressure history of the well.

The 19 reservoirs constituting Lavaca Bay field are designated, from shallowest to deepest, as F-25, F-31, F-33, F-34, F-36, F-37, F-39, F-40A, F-40B, F-43, F-44, F-45, F-46, F-11,000, F-48, F-49, F-50, F-12,500, and F-12,800. Preliminary results of individual reservoir analyses indicate that the F-25, F-33, F-37, F-40A, F-44, F-46, F-49, and F-12,500 reservoirs are compartmentalized, as is suggested by commercially available production data. However, State Tract 26 Well No. 4 of the F-46 reservoir appears to have been receiving additional production from other zones. Other reservoirs indicating similar behavior are F-34 (Alcoa No. 3), F-36 (State Tract 37 No. 2), F-39 (State Tract 39 No. 2 and Alcoa No. 5), F-45 (State Tract 41 No. 30, State Tract 39 No. 1, and State Tract 45 No. 6), and F-46 (State Tract 26 No. 4). These reservoirs, along with F-31, F-40B, and F-43, do not seem to have been properly designated as individual reservoirs. The remaining reservoirs (F-50, F-11,100, and F-12,800) have insufficient data to be analyzed. Future work will include volumetric reserve estimation based on the results of geologic reservoir characterization (J. Ulises Ricoy, UT/BEG). Both results should complement one another in delineating actual reservoir compartmentalization. The engineering study will then proceed to investigate methods to optimize the production performance of the field.

College of Engineering
Texas A&M University

Activity 2: Reservoir Characterization

Task 1: Multiphase properties of porous media

An immiscible displacement experiment was conducted on a sandstone core sample to monitor pressure drop and saturation profiles, which will be used in determining those fluid flow functions. We also took two-dimensional images during an immiscible displacement experiment on a sandstone core sample to examine core heterogeneities on saturation distributions. For the purposes of future study, two SLERO cores (Continental No. 4 Walton "D" 3,189.4 and 3,359.2 ft, both from Keystone field) were chosen for cleaning with an extraction/distillation and pressure flow-through method.

The Dean-Stark extraction method was used, applying a sequence of solvents, including toluene, methanol, and a mixture of chloroform and methanol. Two-dimensional images of the core sample were taken using magnetic resonance imaging (MRI) to validate the cleaning efficiency after each extraction process. These images indicate that oil in the outer regions of the core was removed, whereas a significant amount of oil remained in the center of the core. Images taken after successive cleaning steps indicate that progress is being made. The most effective solvent seems to be an azeotropic mixture of chloroform-methanol. Pressure flow-through cleaning is more effective than distillation/extraction methods because the solvent is able to contact more rock surfaces when injected under pressure. A SLERO core (Continental No. 4 Walton "D" 3,189.4 ft) was intensively cleaned using this method after a distillation/extraction process was completed. A Hassler core holder was used for cleaning the SLERO core, the circumference of which was covered with a heat-shrinkable teflon tube to protect the rubber sleeve from solvents. A sequence of solvents (e.g., chloroform and toluene) and solvent mixtures (e.g., a mixture of chloroform and methanol and a mixture of chloroform, acetone, and methanol) was injected with increasing flow rate, the total fluid volume being 6,700 ml over a period of 80.5 hr. Because the amount of oil cleaned from the core was 0.06 g after approximately 1,200 pore volumes injected, it is thought that no more oil will be cleaned out. Nuclear Magnetic Resonance images of the core indicated only marginal improvements. Because this core is quite old and was not preserved, it is likely that the original oil has been oxidized. The combined method of extraction and flow-through will be used for cleaning additional SLERO core. We are considering the use of surfactants for further extract and the use of core samples from the Delaware Mountain Group.

Many operations in the petroleum industry involve three fluid phases and necessitate the use of three-phase relative permeabilities. One model from the literature is sensitive to the value of the residual oil saturation. If it is too low, the predicted isoperms have an unrealistic shape. Moreover, the model may produce singularities. We have found that since these singularities occur in the limit where the model predicts elimination of the mobile oil phase, the occurrence of these singularities can be used to estimate the residual oil saturation. A residual minimally above this estimate ensures that singularities that produce isoperm with realistic shapes never occur in a physically realistic situation.

Ten three-phase experimental studies were analyzed for model evaluation, and most were found to be flawed. Three methods of residual oil estimation were used: (1) the minimum of the two-phase residuals, (2) a linear interpolation between the two-phase residuals, and (3) zero. There is no reason to believe that any one of these methods will be applicable in all situations.

Task 2: Induced chemical gas drive

The objective of this project is to investigate the effects of surfactant in carbonated water imbibition/production processes for EOR in fractured, low-permeability reservoirs. Laboratory tests have shown that cycled carbonated water imbibition/production, along with the associated gas-drive process, can improve oil recovery rates and recovery efficiencies. In the present work, the focus is on the use of surfactant with carbonated water to greatly increase the imbibition rates and the effectiveness of the induced solution-gas-drive mechanism. The experiments of such chemical processes will be conducted under simulated reservoir conditions to obtain suitable data for future field applications.

We have completed construction of the imbibition apparatus. The specially designed Hassler sleeve type core holder can withstand high temperatures and high pressures. Heated water is circulated outside the Hassler sleeve to maintain the core sample at a given temperature and supply an adjustable overburden pressure between several hundred psi and 3,000 psi. A syringe pump is used to drive carbonated water/surfactant solution over the imbibition surface of the core sample at a slow and steady flow rate. During the experiments the core sample is first saturated with water before being placed into the core holder, and the initial oil saturation is obtained by flowing oil through the core to displace the water. Carbonated water/surfactant solution is then delivered to the core surface under high pressure to carry out imbibition. As oil is being replaced by water, the temporal and spatial variation of oil saturation within the core is monitored by Nuclear Magnetic Resonance Imaging (NMRI). By analyzing the recorded NMRI data, the imbibition rate and the total amount of recovered oil can be obtained. At the end of the imbibition process, the system pressure is decreased and the production by induced gas drive begins. The surfactant is expected to form an *in situ* foam as CO_2 is released from the water and oil phase. The latter will greatly reduce the mobility of the gas phase. The existence of such dispersed system may improve the recovery efficiency of the gas-drive process.

The apparatus has been thoroughly tested under high-temperature and high-pressure conditions. We are now ready to carry out imbibition and production testing. Limestone core samples were initially used in the tests. After further consideration of the acidic nature of the experiment and because of the fact that most of the SLERO fields contain dolomitic rock instead of limestone, we decided that dolomite should be used. Outcrop dolomite from Vanderpool, Texas, will be used first to test the methods. Samples from Keystone (Colby) will be studied thereafter. We have also obtained crude oil, which will be used in the later stages of the experiments once the technique is proven to be effective. Procedures have been developed and tested to filter and prepare the crude oil for testing.

As a preliminary test of the effects of surfactant on the imbibition rate of water in carbonate rock, we conducted a room-temperature spontaneous imbibition experiment at one atmosphere. The limestone samples were first saturated with water. Initial oil saturation was obtained by flushing octane through the core inside a Hassler sleeve core holder. The oil-saturated sample was then immersed into either pure water or water/surfactant solution. The weight changes due to replacement of oil by water were measured by a precision balance. Preliminary tests showed that when the oil-saturated rock was immersed in surfactant solution, the initial imbibition rate was much larger than if the rock were immersed in pure water. This increased imbibition rate is most likely caused by the surface tension gradient effects arising from the surfactant concentration gradients.

Task 3: Integrated characterization technology

The objectives of this investigation are to generate multiple realizations of reservoir properties, primarily porosity and permeability, in the Keystone (San Andres) reservoir. This will enable design of optimal recovery schemes and location of new infill drilling targets. The method used for construction of these different realizations is conditional simulation, which is a stochastic modeling technique. It entails probabilistic modeling of reservoir properties that address the two major problems of reservoir characterization: (1) scaling of flow properties and (2) uncertainty due to missing information. Fractal geostatistics provides the framework for dealing with these problems.

After consultations with R. P. Major (UT/BEG), a study area was chosen for detailed investigation. Block B-2, Section 13 (Winkler County) was picked as the study area. This area was chosen because of the availability of recent acoustic logs. All available recent well logs were digitized and analyzed. No cores are available from this reservoir, so log-core relationships from an analogous field were provided by R. P. Major and M. H. Holtz (UT/BEG). Fractal analysis for three wells were conducted to determine intermittency exponents. Two pairs of fractal cross sections were constructed. The data show fractional Gaussian noise (fGn) behavior. Each cross section was generated on a rectangular grid whose outer columns were filled with well-log data and whose intermediate grid blocks were filled with interpolated values. The interpolation was carried out in two stages. First, a simple linear interpolation was carried out. Then, a noise array was generated and added to the linearly interpolated array. The noise was scaled in such a way as to retain the statistical structure of the well-log data, which is determined by the semivariogram. The advantage of this technique is that multiple realizations can be generated for the same set of data, and each realization adheres to the well log data on the edges of the grid.

The simulations of heterogeneity conducted thus far are two-dimensional simulations. Currently, the results of the two-dimensional simulations are being analyzed. Once this is done, we plan to extend the method to three-dimensional simulations.

Task 4: Use of P/Z vs GP plot to characterize gas reservoir heterogeneities

We developed a three-dimensional, one-phase simulator to simulate flow of gas through hydraulic fracture in a layered reservoir. The purpose was to match the production history of a well with sufficient data in the Olmos Formation to give us a better understanding of the permeability and hydrocarbon distribution at Las Tiendas field. From published geological data in the Olmos Formation, and the skewness of P/Z versus Gp plot in Las Tiendas field, we realized the gas production in Las Tiendas field is best described by a commingled gas well with little or no crossflow. We developed a two-cell general material balance model that can describe the production history of a two-layer or a two-compartment reservoir. The model incorporates the following three parameters: (1) differential depletion coefficient, a measure of flow from the layers into the wellbore, (2) cross-flow coefficient, a measure of flow between layers, and (3) volume ratio, the ratio of gas volume between layers.

The proposed model provides a simple, rapid method of simulating the pressure and rate response of a commingled gas reservoir. It can be used to match the production history of the wells and to characterize and estimate the gas in place of the reservoir in Las Tiendas field.

Activity 3: Advanced Extraction Technology

Task 1: Improved recovery research

Previous laboratory experiments have shown that oil production by spontaneous water imbibition is enhanced by dissolving carbon dioxide in the carrier water. Studies conducted during the past year show that additional oil recovery is proportional not only to the amount of CO_2 dissolved into the water, but also to temperature, water salinity, and pressure of the system. These basic laboratory studies were used as a benchmark for studies to compare recoveries by pressure depletion, waterflooding, CO_2 miscible and immiscible displacement, and water and carbonated water imbibition displacement in the Keystone (San Andres) reservoir.

Crude oil having 38° API gravity from the Keystone (San Andres) reservoir was used to commence this series of experiments. Formation brine from the Keystone (Colby) reservoir was also used. The salinity of the brine was determined to be 88,000 ppm. In addition, the experiments were conducted at reservoir temperature (90°F) and pressure (1,850 psi).

Initial experiments indicated the inclusion of CO_2 in the formation water caused the brine to become somewhat acidic, which in turn reacted with the formation to produce approximately 10-percent increase in the formation permeability. This effect would be particularly helpful in assisting recovery in very low permeability carbonate rocks. The studies demonstrated that reservoir temperature is a limiting factor in any CO_2 displacement process. Gas comes out of solution at elevated temperatures and, therefore, would course through the higher permeability zones. As the temperature increases, oil viscosity decreases and oil more quickly (easily) moves through the reservoir to the wellbore. However, as temperature increases, water is able to hold less CO_2 in solution. A comprehensive analysis of results obtained during the last year of work shows that there is an optimal set of pressure-temperature values for a given crude oil.

Additional experiments are being conducted with the support of NMRI methods to develop greater insight into these processes. Natural depletion is the first production mechanism to be studied using this technique. Nitrogen is dissolved in Keystone (San Andres) reservoir dead oil at a pressure of 450 psi to obtain an initial gas/oil ratio.

Task 2: Well stimulation research

Las Tiendas field: Research approaches for this task are divided into 4 parts: (1) use of a three-phase, three-dimensional reservoir simulator to model gas-water-frac fluid flow in hydraulically fractured gas reservoirs, (2) investigation of the effects of various parameters on frac fluid cleanup behavior and well performance in both single layered and multilayered gas reservoirs, (3) development of new pressure transient analysis methods for fractured well test data with cleanup effect involved, and (4) development of analysis procedures for well production performance and well test data for hydraulically fractured wells in the Olmos Formation of Las Tiendas field.

Extensive simulation runs have been made for six fractured wells. The simulation of these six actual gas wells has revealed several important aspects associated with the frac fluid cleanup behavior and well production performance. For single-layered formations, a systematic simulation plan has been carried out to study the effects of various factors on frac fluid cleanup behavior and well production performance. For multilayered, anisotropic formations, simulation runs have been done to study cleanup and well production performance. Buildup data are simulated and have been analyzed for such cases. A numerical model is being developed to obtain pressure and pressure-derivative type curves for hydraulically fractured wells having an invaded zone near the fracture. Analytical approximations were derived to help identify characteristics of flow regimes and zone properties. A simulator for simulating two-phase flow in hydraulically fractured reservoirs has been modified. This simulator is designed to generate pressure and pressure-derivative type curves for analyzing well test data in hydraulically fractured reservoirs with multiphase flow.

Several factors, including injected frac fluid volume, injection time, formation permeability, formation porosity, formation anisotropy, initial water saturation, initial reservoir pressure, flowing bottom-hole pressure, fracture conductivity, frac fluid viscosity, relative permeability curve, propped-created fracture length ratio, and dimensionless fracture length, were considered for simulating single-layered formations. For multilayered anisotropic formations, simulation runs have been done to study cleanup and well production performance. Important factors such as fracture length, fracture conductivity, and formation anisotropy were investigated. Pressure buildup data were simulated and analyzed for such cases. A numerical model is being developed to obtain pressure and pressure-derivative type curves for hydraulically fractured wells with an invaded zone near the fracture, and analytical approximations were derived to help identify characteristics of flow regimes and zone properties. These new type curves and analysis procedure are essential for satisfactory well test data analysis. A simulator for simulating two-phase flow in hydraulically fractured reservoirs has been modified. This simulator is designed to generate pressure and pressure-derivative type curves for analyzing well test data in hydraulically fractured reservoirs with multiphase flow.

Keystone field: The goal of this task is to develop an understanding of paraffin deposition in reservoirs and to determine if paraffin is depositing in the Colby or San Andres reservoirs. We will develop useful rules for paraffin deposition and removal in wellbores and use these rules in Keystone field to increase production rates or reduce operating costs.

The initial objective of this research is to develop an accurate finite difference paraffin simulator for the reservoir and the adjacent formations. Once this simulator has been developed, it will be validated with field data. With this simulator, we wish to gain a better understanding on how paraffin affects reservoir performance.

The second objective of this research is to develop an accurate finite difference paraffin simulator for the wellbore. This simulator will be coupled to the paraffin reservoir simulator. Once this paraffin simulator has been developed, it will be validated with field data. With this simulator, we will study paraffin deposition in the wellbore. We also plan to study various thermal methods used to remove paraffin from the wellbore. The final results of this project will be useful rules for paraffin deposition and thermal removal methods in wellbores.

The paraffin reservoir simulator is nearly completed. This simulator is a fully implicit, two-dimensional radial simulator that conserves mass and thermal energy. It has three pseudocomponents: gas, oil, and vapor. These pseudocomponents can exist in three phases, vapor, liquid, and solid. The gas pseudocomponent can exist in the vapor or the liquid phase, the oil pseudocomponent can exist in the liquid phase only, and the paraffin pseudocomponent can exist in either the liquid or the solid phase. To describe which phase the paraffin is in, the solubility of paraffin must be known. To obtain the solubility of the paraffin, the ideal-solution theory was used.

The ideal-solution theory considers two effects on the solubility of paraffin. The two effects are the temperature effect and the solution-gas effect. The temperature affects the paraffin solubility in the following manner. When the temperature is reduced, the paraffin will solidify or precipitate from solution.

The solution gas also affects the paraffin solubility. When the solution gas is removed from the liquid, the concentration of the paraffin in the liquid increases until the liquid is saturated with paraffin. Once the liquid is saturated with paraffin, solid paraffin will precipitate from solution. As the precipitated solid paraffin particles flow through the reservoir they become deposited in the pore throats. To describe the paraffin deposition in the reservoir, the filtration theory was used.

The filtration of solid paraffin particles as they flow through the reservoir can be described by two differential equations, a continuity equation and a depositional equation. The continuity equation defines the rate of flow of solid paraffin particles at a point in the reservoir. The deposition equation defines the rate of removal of solid particles as they flow through the reservoir. By subsequent combination of the continuity equation with deposition equation, the rate of deposition of solid particles can be determined at a point in the reservoir. As the solid paraffin particles deposit, the absolute permeability of the formation is reduced. To describe the reduction in absolute permeability, a permeability porosity relationship was used.

Experiments have shown that a permeability reduction can be related to a porosity reduction. The permeability reduction model used for this project was determined by matching laboratory data. The purpose of the laboratory experiments was to determine the amount of permeability reduction that occurs as a result of paraffin deposition in linear cores. With the permeability reduction, the paraffin deposition, and the solubility for the paraffin modeled, the paraffin reservoir simulator is nearly completed. After consideration of several additional parameters, the wellbore simulator will be written and coupled to the existing paraffin reservoir simulator.

Task 3: Controlled rheology surfactants

The goal of this task is to investigate the feasibility of exploiting the unique rheological properties of SIS surfactants for improving sweep efficiency for EOR from heterogeneous reservoirs. These surfactants exhibit a network structure formation at a critical shear rate, which significantly increases the viscosity and viscoelastic rheological properties of the solutions. These properties result in the fluid exhibiting a lower mobility (higher resistance) in high-permeability regions and a higher mobility (lower resistance) in low-permeability regions, which is ideal for enhancing sweep efficiency in very heterogeneous formations, typified by the Keystone (Colby) field and similar Permian formations.

The surfactant chosen for this study was hexadecyltrimethyl ammonium salicylate (C16TMASal) at various concentrations with various electrolyte (salt) concentrations. Specific data collected include (1) rheological properties (i.e., viscosity and normal stress) as a function of shear rate, surfactant chain length and concentration, and salt concentration, (2) characterization of the basic flow behavior of these surfactants in a uniform well-characterized porous medium (e.g., glass-bead-packed beds); and (3) measurement of the flow resistance of these fluids as a function of flow rate in dolomitic core samples taken from Keystone field. We will also measure the sweep efficiency of these fluids in the cores saturated with the reservoir fluids and displaced with a waterflood. The ultimate goal is to be able to tailor the surfactant solution properties (i.e., concentration and salinity) and injection rate to maximize the enhanced sweep efficiency of the surfactant.

Rheological properties (non-Newtonian viscosity function and first normal stress difference) have been measured using a Weissenberg Rheogoniometer, as a function of surfactant chain length, and concentration of added salt (NaBr and NaCl). The increase in viscosity resulting from the formation of the shear-induced structure was evident for the C16TMASal surfactant at concentrations of 500 to 1,200 ppm, and the shear rate at which this structure forms was observed to decrease with increasing shear rate. The effect of added salt (NaBr and NaCl) in the range of 100 to 400 ppm was also studied, with the observation that the critical shear rate at which the structure forms in this range increases by as much as an order of magnitude with increasing salt content. However, the first normal stress data did not exhibit as pronounced a jump as the viscosity at the shear rate where the structure forms. The main effect of the salt on the normal stress was to decrease the magnitude somewhat with increasing salt concentration.

The resistance to flow in a uniform packed bed of 200-mm glass beads was measured as a function of flow rate and surfactant concentration, from zero to 1,000 ppm of surfactant. The flow resistance increased abruptly by almost three orders of magnitude over a finite range of the bed Reynolds number, corresponding to the formation of the SIS structure. However, neither the magnitude of the increase, nor the Reynolds number at which the increase occurred, varied greatly with concentration. The effect of increasing the concentration of NaBr on the flow resistance in this bed was also evaluated, with the observation that the onset Reynolds number decreased somewhat with increasing NaBr concentration (up to 200 ppm of NaBr), but the magnitude of the increase was not greatly affected by the NaBr.

The surfactant resistance to flow in three cores taken from the Keystone (Colby) reservoir has been measured for the same surfactant concentration range. These cores were primarily dolomitic sandstone, with permeabilities ranging from 0.18 to 170 md. In contrast to results obtained with packed glass beads, experiments with Keystone (Colby) reservoir samples demonstrated that the critical Reynolds number was an order of magnitude higher for the 500 ppm solution than for the 1,000 ppm solution. The magnitude of the jump also increased somewhat with increasing surfactant concentration.

The results of these studies verify the premise that these surfactants show excellent promise of enhancing recovery from heterogeneous formations by virtue of the structure change and corresponding increase in flow resistance over a critical range of porous-medium Reynolds number. At low velocities and low permeabilities, the Reynolds number is low, and the surfactant flow resistance is also low. However, as the permeability and velocity increase, the Reynolds number also increases, until the critical condition is reached at which the structure is formed. In this state, the surfactant flow resistance in porous medium increases from one to two orders of magnitude, resulting in a very strong "self-correcting" effect and a more uniform displacement from all regions in a medium of highly variable permeability.

College of Geosciences
Texas A&M University

Activity 2: Reservoir Characterization

Task 1: Diagenetic control on sandstone reservoir properties

Preparation of samples for organic analyses of Delaware Mountain Group sandstones has begun. Two Soxlet extraction apparatuses were assembled to extract bitumen from powered samples. A total of 58 samples were extracted in this fashion. Trace element content of the bitumen was analyzed by neutron activation analysis. Carbon isotopic composition of the bitumen was determined by stable isotope mass spectrometry. Kerogen separates were obtained from the extracted rock sample by HCl/HF digestion and heavy liquid separation. Pyrite associated with the kerogen was removed by nitric acid treatment. Sulfur and carbon isotopic compositions were determined for 15 kerogen samples. Rock-Eval Pyrolysis and total organic carbon analyses were carried out on 27 samples to characterize kerogen type, maturity, and abundance.

Comprehensive biomarker analyses of 18 rock samples and 5 oils is now complete. GERG facilities and equipment were used for these analyses. Rock extracts and oils were analyzed for alkane distributions, aliphatic and aromatic biomarker content (more than 150 compounds were analyzed utilizing HPLC and GC-MS techniques), as well as carbon and oxygen isotopic composition of separated hydrocarbon fractions. These biomarker data allowed characterization of organic matter type, environment of deposition, maturity, and source correlation of Delaware Mountain Group siltstone organic matter and oils reservoired in the sandstones.

One hundred twenty-four thin sections from siltstone and sandstone samples were point-counted. Petrographic study indicated that Delaware Mountain Group sandstones are very fine grained (mean grain size <0.10 mm) and composed of approximately 50 to 75 percent quartz, 25 to 50 percent feldspar, and <10 percent rock fragments. The sandstones are cemented by calcite and minor amounts of dolomite, halite, gypsum/anhydrite, and authigenic chlorite. Detrital clay content is very low in both the sandstones and siltstones of the Delaware Mountain Group, generally comprising less than 5 percent (volume) of the rock. Siltstone is more abundant than sandstone, comprising more than 60 percent of the interval. Siltstone median grain size is 0.010 to 0.060 mm. Like the sandstones, the siltstones are subarkosic in composition, containing approximately 60 to 80 percent quartz, 20 to 30 percent feldspar, and 10 percent rock fragments. The low permeability and high water saturation observed in these reservoirs appears to be caused by the pervasive pore-lining chlorite present in the rocks. Interpretation of Delaware Mountain Group burial history determined by mineral paragenesis is that the sandstones were extensively cemented with calcite, halite, and anhydrite early in burial history. These cements partially arrested burial compaction and preserved a high percentage of intergranular volume, which was available for generation of secondary porosity during later burial. Large-scale dissolution subsequently removed cement and some detrital material, creating abundant secondary porosity. Porosity within the reservoir sandstones is predominantly secondary in origin, created during this calcite dissolution event. Widespread chlorite authigenesis then occluded porosity, blocking pore throats and reducing permeability. Dolomite, ferroan/manganous dolomite, potassium feldspar overgrowths, quartz overgrowths, brookite, and anatase constitute the late authigenic phases. Because meteoric water influx and shale diagenesis may be eliminated as driving forces for diagenetic processes and creation of secondary porosity, the working hypothesis for this study is dissolution of carbonate cements by organic and carbonic acids generated from kerogen prior to oil generation.

Rock-Eval Pyrolysis data show that Delaware Mountain Group siltstone organic matter is oxygen-rich Type II and III kerogen, prone to generation of significant quantities of carboxylic acids and CO_2 during thermal maturation. Rock-Eval Tmax data, and various biomarker maturity indicators, show that the organic matter is at a moderate stage of maturity, well within the oil-generative phase. Correlation of carbon isotopic compositions, Ni, V, U, Th, Fe and Mn elemental content, and specific elemental ratios between organic and inorganic phases, indicate that diagenetic processes in the sandstones were driven by organic degradation. In addition, Delaware Mountain Group siltstone organic matter appears to have been the source for much of the oil stored in Delaware Mountain Group sandstones. Carbon and sulfur isotopic data and biomarker data show good correlation between Delaware Mountain Group source rock and Delaware Mountain Group oils. Biomarker content indicates that oils sourced in the Delaware Mountain Group are derived primarily from the type II kerogen and contain only traces of compounds peculiar to Delaware Mountain Group type III kerogen. Characterization of the organic geochemistry of Delaware Mountain Group siltstones and analysis of late authigenic products in the sandstones indicates that organic diagenesis controlled pore fluid chemical evolution within the sandstones and resulted in creation of secondary porosity and precipitation of authigenic minerals. Authigenic minerals in the sandstones exhibit isotopic and trace element compositions indicative of this organic influence.

Detailed study of the late authigenic clay minerals was conducted on 23 reservoir sandstone samples. These samples were studied by electron microscopy and X-ray diffraction methods. These clay minerals are dominated by chlorites of varying degrees of crystallinity. Minor amounts of illite-smectite are also present. The clay minerals line, fill, and dissect pores, causing microporosity to be a dominant porosity type.

Task 2: Subregional reservoir characterization of Lavaca Bay

Electric logs and scout tickets from 73 wells in the vicinity of the Lavaca Bay have been obtained from commercial sources. General information of study area and some structure maps were obtained from the Railroad Commission of Texas and from J. U. Ricoy (UT/BEG). The stratigraphy developed by

Ricoy was used to pick Frio Formation tops and to map nine depositional sequences. The sandstone units in the prospective sequence are evaluated on the basis of analysis of spontaneous potential (SP), gamma-ray (GR), and resistivity logs, following the methods of Ricoy. The hydrocarbon-producing potential of the reservoir is evaluated by contour mapping of various reservoir parameters, such as net-sand thickness and flow capacity. The study area is divided into two blocks on the basis of well density. Current work is concentrated in one of these blocks, which covers Lavaca Bay field and extends to the East Port Lavaca area.

The Melbourn sandstone in Sequence VII was selected for analysis because it is prominent as a thick sandstone body with relatively high resistivity. An approximate estimate of water saturation (S_w), water resistivity (R_w), and porosity were computed.

Future analyses will include mapping of hydrocarbon saturation (S_o), true resistivity (R_t), and net-sand thickness (h). The area with the highest producing potential will be identified by overlaying the contour maps of various reservoir parameters. A more detailed study involving analysis of neutron porosity logs, cores, and production data will then be carried out in that specific area.

Task 3: Application of high-resolution seismic imaging to improve bed-geometry definition

Seventh-Six West field: Digital seismic data on magnetic tapes were obtained from the University of Houston Applied Seismology Laboratory. The data were correlated vibroseis data and were in SEGY format, which allowed us to read the data into our VAX computer. Unfortunately, there were no observer's logs.

We have removed bad traces, eliminated noise spikes, removed powerline interference, and stacked the traces after determining the normal-moveout and static corrections and plotting the data. The resulting data are substantially improved. There were a number of bad traces on the original data tapes.

We have compared our output traces with sample traces that had been processed by Mobil Oil, and our traces are not as high quality. We have not been able to determine why this is the case, that is, whether additional processing was done by Mobil or whether the correlated data we received are of poor quality. We plan to continue working on this data set to see if we can improve its quality.

Powderhorn field: The project involves generating synthetic seismograms from well-log data. Well logs have been obtained, and the programs needed to generate these seismograms are available. We have begun digitizing the sonic and density logs for input to the programs that generate and plot synthetic seismograms. These synthetic seismograms will be compared with data collected during the proposed high-resolution seismic survey.

The high-resolution seismic survey of Powderhorn field is in the planning stage. We have arranged for Halliburton Geophysical Services to shoot this survey as a demonstration of the high quality of data that can be obtained with modern three-dimensional seismic techniques. Halliburton's approach to this survey is to first shoot a two-dimensional test line across the field to determine the optimal design for the three-dimensional survey, which will be shot later. Shooting of the test line was originally scheduled for fall 1991; however, because of permitting problems and poor weather, the shooting of the test line will be delayed until spring 1992.

Task 4: Quantification of microgeometry of sedimentary rocks by digital analysis of thin sections

This year's research focused on theoretical examinations of parameters to be used in the quantification of shape and size of both pores and grains in sedimentary rocks. One paper on the measurements of pore shapes has been submitted to the Journal of Geophysical Research, and another on the determination of pore sizes is in revision. These techniques are being developed for automated use in examining SLERO thin sections.

Physical parameters being measured include porosity, pore size, pore shape, pore orientation (and anisotropy), quartz grain size, shape, and orientation. More theoretical work is being conducted to develop methods of estimating formation factor, cementation index, all grain-size and shape parameters, and permeability from digital images of the thin sections. Various methods of acquiring digital images are also being reexamined for possible applications. These include the use of electron microprobes, scanning electron miscroscopy, and fluorescence microscopy.

More computer software and hardware were acquired within the last 12 months. Image analysis is being performed on a Silicon Graphics Personal Iris system running both NASA's complex and powerful ELAS image processing software, as well as AGIS, a more user-friendly processing system developed by Delta Data Systems (Picayune, MS).

Task 5: Sulfate scaling investigation

Efforts during the past year focused on two major areas. These were prediction of calcium sulfate scale formation and calcium carbonate vein and fracture filling. Special emphasis was placed on these processes in brines, which are typical of West Texas oil fields.

Calcium sulfate scale formation: Calcium sulfate scale formation is a major problem in petroleum production in many West Texas oil fields. Current ionic models for brine solutions are largely capable of only making predictions of calcium sulfate mineral solubility at close to earth-surface temperatures and pressures. An expanded Pitzer-equation-based model was developed and experimentally tested. This model is capable of making such predictions to depths of at least 18,000 ft. This depth range covers most wells of interest. This new model has been submitted for publication.

Two practical applications of this model were made during the past year. The first was advising that if pumping rates were decreased so that more extensive cooling of the fluids occurred during production, the scaling problems could be significantly decreased or eliminated. The second was the modeling of waters from Keystone field to predict which flood waters would have the smallest scaling potential.

Calcium carbonate vein and fracture filling: Calcium carbonate minerals, dominantly calcite, commonly fill veins and fractures in rocks. This can exert a major influence on petroleum reservoir characteristics of central significance to oil production. Two studies were undertaken to better predict the distribution of calcium carbonate cements filling veins and fractures.

The first study is similar to the research done on the solubility of calcium sulfate, but is much more difficult because of the smaller existing database and the complex behavior of carbonate as part of the aqueous carbon dioxide-carbonic acid system. Work at a pressure of one atmosphere is nearing completion and high-pressure studies will begin soon.

The second type of studies on calcium carbonate behavior concerns the kinetic and mass transport parts of the problem. Computer models have been developed on the basis of existing data. An experimental evaluation of these models is under way using synthetic veins in a flow-through system.

Task 6: Estimation of clay content from electrical measurements of shaly sands

We have considered the question of whether the clay content should be modeled as a volume fraction separate from the surface bound water. Previously, it was assumed that clay content is the same as the surface layer, but this resulted in systematically underestimating clay content.

We designed another accuracy test of our four-electrode electrical impedance system, which operates over the frequency range of 0.01 to 100 Hz. We used standard resistors to determine the errors associated with the electronic instrumentation and used standard brines to determine additional errors associated with the sample cell. Average uncertainties in the impedance and phase measurements made with this system are about a factor of two smaller than the uncertainties of similar systems described in the literature.

The two- and four-electrode measurement systems were used to study the effects of the microgeometry of reservoir rocks on their complex dielectric response, measured over the frequency range of 0.01 Hz to 40 MHz. In this study, sandstone samples were cut both horizontal and perpendicular to bedding and saturated with 0.01 M KCl. As expected, the anisotropy in conductivity was relatively independent of frequency. The conductivities of the horizontally cored samples were about 6 percent greater than the conductivities of the perpendicularly cored samples. However, the anisotropy in the dielectric permittivity was frequency dependent. At high frequencies the permittivities of the horizontally cored samples were about 3 percent greater than the permittivities of the perpendicularly cored samples, but at low frequencies the permittivities of the horizontally cored samples were about 6 percent less than the permittivities of the perpendicularly cored samples. To our knowledge, this is the first time that the effects of anisotropy on the dielectric response of reservoir rocks have been studied. Preliminary results were presented March 21 at the TAMU Geophysics Department Student Colloquium. A more developed version of this work was presented in December at the American Geophysical Union annual meeting in San Francisco.

We have begun looking at measurements of clay/water mixtures as a standard by which we can judge our calculated clay properties. Our calculated clay conductivity (normalized by the water conditions) for a sandstone sample increases from 3.2 to 4.4 over the frequency range 0.001 Hz to 1.0 MHz. A measured wet kaolinite sample was nearly constant at 0.3 over the same frequency range. Electrical anisotropy experiments continued. Conductivity and permittivity were measured perpendicular and parallel to bedding.

Returning to theoretical modeling, we developed a new hypothesis regarding shaly sands. The surface water and the clay are separate components, not different manifestations of the same component. This means they should be added when estimating the volume fraction of the third phase, which is necessary when inverse-modeling electrical properties of the third phase.

An expanded abstract was written and submitted to the Society of Exploration Geophysicists for presentation at the 1991 meeting and exposition in Houston ("An effective medium approach to critical saturation," by Frank Samstag and Dale Morgan). The content of the presentation was the recent progress made regarding theoretical modeling of shaly sands as a function of partial water saturation, including the unique ability to model values of rock dielectric constant below critical saturation, which means the surface bound water behavior.

Platinum electrodes were made this summer. These are crucial to our two-electrode measurement system because of the problem of electrode polarization leading to very large errors in this system. Platinum with a coating of platinum-black electroplated on the surface is well documented as the material that best minimizes electrode polarization errors. Our four-electrode system, which has less of an error problem, can only measure up to 100 Hz. Thus, obtaining an accurate two-electrode system in place is absolutely necessary for obtaining high-frequency data. Our modeling theory predicts that high-frequency data greatly improve the estimate of clay content in shaly sandstones.

In September, the research on this project focused on a renewed effort to explain our surface-layer results in a way that would be consistent with electrochemical double-layer theory. Previously, we were normalizing the surface-layer results by each sample's respective pore water conductivity, a step that is appropriate only for a clean, two-phase mixture where one of the phases is an insulator. This meant that we should really be normalizing the surface-layer results by the surface-water conductivity, not the bulk-water conductivity. We didn't have any independent data on the surface water; therefore, we turned to double-layer theory for an estimate. We obtained equations from the literature for the conductivity, permittivity, and frequency dependence of a solid/electrolyte interfacial layer. Preliminary normalizations using these equations showed a closer match of our surface-layer results from sandstone data measured at four different bulk-water conductivities. These results were presented at the Massachusetts Institute of Technology during the last week of September.

We continued to refine the frequency-domain modeling with an emphasis on comparing the resulting surface-layer estimates to independent theoretical calculations for the surface-layer properties. Work also continued on applying the same model to saturation-domain data. The saturation-domain research was in preparation for a presentation at the Society of Exploration Geophysicists annual meeting in early November.

During November a new phase of experiments was begun. The purpose of these experiments was to test the effects of solution chemistry on the conductivity, permittivity, and streaming potential of sandstone samples that were cored from the same block. The main objective of the tests was to compare and evaluate the various theoretical models of complex electrical impedance, while varying solution concentration (KCl), and ion type (KCl, $CaCl_2$).

Task 7: Fracture containment

Fracture containment research was started in September 1990. The objectives of this task included development and validation of computer models for describing the growth of hydraulic fractures, with emphasis on simulating vertical containment of fractures. The Olmos Formation at Las Tiendas field is well suited for hydraulic fracturing studies because this formation is a "tight sand" and most wells in the field have been fractured.

A study area containing approximately 16 wells was selected on the basis of data availability. Copies were made of all relevant data available at the Bureau of Economic Geology, The University of Texas at Austin. Data were then screened for applicability to hydraulic fracture modeling. Data included numerous hydraulic fracturing proposals that were submitted to operators by service companies.

Preliminary analysis of data and modeling indicated that created fracture height, based on numerous stimulation proposals, had been underestimated in the Olmos Formation. Created propped fracture lengths were, therefore, overestimated. In the past few years it has become widely accepted that cased-hole logs tend to grossly underestimate fracture height. Some poststimulation cased-hole logging techniques were run in several Las Tiendas wells. Service companies apparently found these results to be consistent with the fracturing proposals. Microseismic methods are considered to be an effective alternative to these logging methods.

Some preliminary analysis and modeling were performed on the Maltsberger No. 1 in the study area. Vertical fracture height growth had generally been considered by the service companies not to exceed 60 ft. We found more realistic estimates to be on the order of 150 to 230 ft. Not allowing fracture height to exceed 60 ft led to propped fracture lengths of 800 to 1,000 ft. Modeling of the Maltsberger No. 1, allowing for up to 200 ft of vertical growth, led to a created propped fracture length of 450 ft. These fracture dimensions appeared to be more in line with poststimulation well performance. Similar preliminary analysis and modeling were performed on the Middleton Triphene, also in the study area. Results were in agreement with those obtained for the Maltsberger No. 1.

Four wells in the study area were selected for more detailed fracture containment studies. These wells were chosen on the basis of data availability. Two of the four wells were cored. Logs for all four wells were digitized. More complete well histories, including completion data, stimulation data, and well test data, were obtained from Ken Barrow (UT/BEG). The core available for the Maltsberger No. 1 was predominantly from the producing intervals. Core for zones above and below the producing intervals was unavailable, preventing further core analysis to determine the mechanical response of these zones. In situ stress profiles and mechanical rock properties for the four wells were calculated from only initial stimulation pressure data and available well logs. The objective was to characterize the zones above and below the producing intervals and obtain the necessary information for vertical fracture height growth calculations.

In situ stress profiles and mechanical rock properties for the four selected wells were calculated. Because of the availability of only a standard acoustic log, Poisson's ratio had to be assumed. This assumption, along with numerous others needed because of the lack of additional logs and other field-wide data, made the calculated in situ stress profiles difficult to interpret. The in situ stress profiles required smoothing to be used in vertical fracture height growth calculations.

Based on the smoothed in situ stress profiles, vertical fracture height growth was calculated to be on the order of 200 ft for all four wells. Using these height growth estimates, a two-dimensional GDK fracture model was used to calculate fracture geometry. Gas production was simulated using these fracture geometries. Simulated production matched actual production fairly well. These vertical fracture height growth estimates far exceed initial service company estimates.

Because of the degree of vertical containment, optimization of the fracture treatment can lower fracturing costs. This can offset the costs of acquiring additional logs and other field-wide data needed to improve the current success of fracturing in the Olmos Formation. On the basis of cost estimates for acquiring additional logs and other field-wide data, the economics of optimized and alternative fracture treatments will be examined. Computer modeling of multilayered systems using Finite Element techniques will continue.

Houston Petroleum Research Center
University of Houston

Activity 2: Reservoir Characterization

Task 1: Application of high-resolution seismic imaging to improve bed-geometry definition

Research efforts continue on improving the methods of crosshole tomography in a producing oil field. To date, five field experiments have been completed in Seventy-Six West field.

Results of initial experiments show that seismic signals over 1,000 Hz can be successfully transmitted between wells up to 600 ft apart using a piezoelectric "bender." In poorly consolidated lithology, such as at Seventy-Six West field, these frequencies can provide resolution on the order of 10 ft if a full tomographic data set can be acquired. The airgun provided a higher energy signal suitable for long well spacing but lower in frequency. A limited test of an arc discharge tool or "sparker" showed that transmitted signals are intermediate in both energy and frequency to those of the bender and the airgun.

Experiment 91/DC/4: Experiment 91/DC/4 at Seventy-Six West field began March 25, 1991, and was completed April 3. The target zone was the Frio Formation sandstone at approximately 530 ft in depth. This shallow target was chosen because production wells were not deep enough to provide the wide angular coverage required for imaging the deeper Cole sandstones. The experiment consisted of acquiring a full crosshole data set and a first attempt at collecting borehole to surface data. In addition, signals were recorded with a three-component accelerometer for the purpose of defining the near-field source signature.

The energy source used was the piezoelectric bender. A modification to the bender since the last experiment (90/DC/3) was the addition of a second ceramic element. In addition, the electrical power supplied to the tool was increased by a factor of two.

Crosshole data were collected between the source well, 62-9, and the receiver well, 62-19. The spacing between these wells was 600 ft. Depths for the source ranged from 40 ft below the surface to 740 ft, and the source was moved in increments of 20 ft. Receiver depths ranged from 40 to 700 ft in increments of 20 ft. The total number of resulting raypaths was 36×34, or 1,224.

A shortcoming of the bender is the lack of an attached transducer able to record the source signature. To overcome this limitation, a three-component accelerometer was placed 15 ft from the source well 62-9 to record near-field signals. We hoped that using this signal for a sweep would allow a more effective cross-correlation due to a more "realistic" signature.

Two effects were noticed in the bender data: (1) the output frequency response of the bender appeared to be bimodal (even though the input signal was linear) and (2) dispersion effects were prominent and varied from record to record. It is these deviations from the linear input that require a more representative form of the source output.

Analysis of the near-offset data from the three-component accelerometer was used to analyze the observed nonlinear response of the bender. Some of these data were used in cross-correlation with the direct input signal, but the signal-to-noise ratio still remained very low.

In addition to crosshole measurements, surface measurements were made using 24 geophones deployed at equal intervals between the two wells. Two sets of EG&G recording instruments were used to record these data. Source positions again spanned the depth range 20 to 740 ft in increments of 20 ft. The total number of borehole to surface raypaths was 38 × 24, or 912. Analysis of this RVSP data showed little or no recognizable signal. This is not completely surprising considering the energy output of the source and the characteristics of the surface geology. We have not been able to use these data for tomographic analysis.

Due to the low signal-to-noise ratio of the data, we were not able to pick first arrival times for use in our inversion scheme. A great deal of effort was directed at developing picking algorithms able to distinguish recorded seismic signal from background noise. However, these algorithms are effective only if the signal-to-noise ratio of the data is beyond a certain level. Unfortunately, this was not the case for most of the data recorded in experiment 91/DC/4.

Experiment 91/DC/4: Because of the poor results from experiment 91/DC/4, planning for experiment 91/DC/5 was directed at improving the signal-to-noise ratio of the recorded signal. Southwest Research Institute had recently completed design of an improved arc discharge device. This is an impulsive source with a significantly greater power output than the piezoelectric bender. However, this tool was still in the field-test stage and was not available for use in our tests.

The plan for experiment 91/DC/5 was to collect data suitable for imaging the producing Cole sandstones. Numerous constraints severely limited the number of wells that could be used for data acquisition:
(1) production wells could not be used for any attempts to deepen wells because of potential damage to the producing formation, (2) the number of existing wells that had sufficient depth for the experiment was very small, (3) the well spacing between a number of potential wells was too large, and (4) there were very few wells with sufficiently large inside diameter.

Subject to these constraints, the well combination chosen for data acquisition was the well pair 62-15 and 62-23. Well 62-15 was to be used for the source well and 62-23 for the receiver well; well spacing was 1,215 ft. We felt that the only energy source with any chance of success was the airgun. A receiver string consisting of 24 hydrophone elements with 20-ft spacing was used to record the seismic signals. Data were to be recorded from 7,215 unique raypaths. The maximum source depth was 1,290 ft, and the maximum receiver depth was 2,160 ft. Coverage of interwell space was skewed toward the receiver well but still covered the target zone of the Cole sandstones.

Numerous difficulties were experienced in the course of completing experiment 91/DC/5. Most of the problems were associated with the source well, 62-15. This was an abandoned and plugged well that had to be "unplugged" before it could be used for data collection. As such, the condition of the casing and cement bonding could not be determined beforehand.

The airgun was configured at its maximum volume of 160 $inch^3$ (maximum energy output), which had been used successfully in similar environments with well spacing approaching 1,215 ft. After looking at numerous data records, little or no signal was observed propagating in the mode in which we were interested. A closer well, 62-18, was prepared for use as a receiver well. The well spacing from 62-15 to 62-18 was 496 ft. With the airgun configured at the same maximum volume, a very strong signal should be transmitted across this much smaller distance. Again, however, the transmitted signal was not nearly as strong as expected. Usable signals were recorded but certainly not of the quality expected.

The best explanation for why such poor-quality data were recorded is that the source well, 62-15, was in such poor condition that little or no coupling to the lithology was present. Probable evidence in favor of this interpretation comes from observation of data records showing better signal propagation from certain portions of the well than from others. This variation did not appear to be geology related.

Even though the crosshole experiment did not proceed as planned, a number of data sets were collected that provide a valuable opportunity to integrate three types of seismic data.

Task 2: Data processing

Processing of data from experiment 91/DC/5 concentrated on the crosshole data collected between wells 62-15 and 62-18. We have been able to produce tomograms of the interwell lithology even though the data quality was generally poor. Frequencies of the recorded data are in the range 70 to 150 Hz. The tomograms produced from these data can be characterized as low resolution. However, features are evident that we think have geologic significance. A high velocity zone occurs at a depth of about 530 ft. This correlates with the depth of the Frio Formation sandstone.

The next stage of analysis will involve working with crosshole data acquired between wells 62-15 and 62-23. The well spacing is 1,215 ft, and well 62-23 penetrates to a depth of 2160 ft. Although it was not possible to acquire a complete crosshole data set, we think that a combination of the limited crosshole data, RVSP data, standard VSP data, and conventional surface seismic data will provide useful geologic data from the zone of the producing Cole sandstones.

Analysis has started on the acoustic log from well 62-30. The log covers the depth range 80 to 1,450 ft. The intention is to correlate the acoustic log with the standard suite of logs from this well. Next, the standard logs from wells of interest will be correlated to the standard logs of 62-30. Finally, using these relations, acoustic values can be transferred to the wells of interest. This will provide essential geological constraint for further geophysical analyses.

Progress continues on the attenuation study of bender data from Experiment 90/DC/2. Estimates of Q values are being calculated for depths from 500 to 700 ft for the zone between 62-9 and 62-19. Q estimates will be compared for frequencies ranging from 500 to 3,500 Hz. Preliminary results show Q values in the range of 25 to 30.

Task 3: Database

A Graphical User Interface that facilitates easy access to multiple engineering, geophysical, and economic databases distributed throughout the State of Texas has been developed. The software has been developed using the AIX (RS 6000) workstations.

This task involves collection of data of different types regarding certain State Lands oil and gas fields (eg., seismic data, well-log data, data on field operators, etc.). These various pieces of data are stored on computers at The University of Texas at Austin, Texas A&M University, and the University of Houston. All of these locations are connected by the NSF wide-area network. Providing a uniform user interface to these databases became a primary objective of the SLERO database committee. In the following sections the constituent parts of the project are explained.

The Master SLERO Database: A Relational database—"Master SLERO," has been designed and developed on a VAX VMS system. The Master SLERO database has data from the different fields selected for the SLERO project. The database has been designed as eight tables, namely, Coredata, Speccore, Logdata, PVT-data, Seismic data, Prodinjdata, Pressuredata, and Geologicdata. Each table has five columns: Field, Dtype, Available, Location, and Comments. Keystone (Colby), Keystone (San Andres), Delaware Mountain Group, Las Tiendas, Lavaca Bay, Colmena, Powderhorn, and Seventy-Six West are the different values for "field." Each table contains data regarding the availability, location, etc., of data pertaining to each of these fields.

The Column "dtype" specifies the type of data. For each table "dtype" has different values. For example, for each "field" name in the table Coredata, the following are the values "dtype" can have: whole cores, sidewall cores, mud/sample logs, drill cuttings, whole core PKS, sidewall core PKS, vertical and horizontal PKS, etc.

Field "availability" has values "Y" or "N" depending upon the availability of the data under consideration. "Location" specifies the site at which data pertaining to the particular "field" and "dtype" are available. The "comments" field stores any comments about the particular "field" and "dtype" that may be of interest.

Main Interface: The interface has been designed in an X-window environment. Open Software Foundation's Motif Widget set has been used in designing the Graphical User Interface, and the coding has been done in the C programming language. The Main Interface is a bulletin board containing a table of available options. The "Master SLERO," "UH Xhole" are the table entries that are fully functional. There is also a Help option describing the various constituent parts of the interface.

UH Xhole: A graphical interface was developed to convert the user's requests into SQL (Oracle) commands. The resulting commands can also be stored in a file to be copied onto some other computer system for execution. The interface has been implemented using UIL, a specification language provided by Motif. It is useful in accessing any database designed with Oracle.

The interface contains a main window with a menubar at the top and a scroll window making up the rest of the form. The following are the entries in the Menubar: File, Definition, Manipulation, Control, Servers, and Help. File has a pulldown menu attached to it containing such entries as New, Open, Save, Save As, Print, Close, and Exit. The File option is useful in storing the commands that are to be executed on a remote machine hosting the database of interest.

The Definition option also has a pulldown menu, containing entries such as Create Schema, Create Table, and Create View. These entries help the user in creating a schema, table, or view without explicitly typing an SQL statement. Selecting any of the three options brings up a dialog widget prompting the user for the name of the structure under construction. In the cases of the Create Table and View options, subsequent windows open once a structure name is obtained from the user, facilitating the full definition of the structure. For example, in case of creating a table, a text window opens for the user to define the column definitions for the table.

The Manipulation entry has Select and Insert Into options. These are useful in querying or inserting data into the database of interest. Choosing the Select option opens up more windows facilitating a comprehensive query to be made. Similarly, the Insert Into option opens windows to facilitate data entry into the database.

Control is an option in which a "Grant" can be made to a particular user or group of users. Grant is an option through which certain privileges are issued to a particular user(s) over a particular table. The "Servers" is an entry useful in opening up a terminal session with one of the computer systems listed in the pulldown menu attached to it. Currently, the pulldown menu has only one entry. An attempt has been made to use the existing knowledge of a particular editor, Emacs, in addition to the normal "cut and paste" options that the Motif Widget set provides. The Help entry gives the Emacs commands that are supported.

The Master SLERO Interface: The Master SLERO interface has been designed to facilitate an easy access to the "Master SLERO" database. The interface provides for two levels of access, namely "Executive" and "Analyst." The "Executive" level provides for a quick perusal of the data, whereas the "Analyst" level provides for a detailed "query" of the database through a detailed set of interfaces.

The interface is a form widget with a menubar at the top. The rest of the form is scroll window that is used as a canvas for viewing data. The menubar at the top of the form has the following fields: Field, Table, Query, Connect, and Help and Quit buttons.

The Field and Table constitute the "Executive" level with a provision for a quick perusal of the required data. For example, clicking at the Field entry will bring up a selection-box widget containing the field names as its entries. After one of the fields is selected, the data pertinent to that field is shown in the scroll window in the frame. Similarly, selecting the Table brings up a selection-box containing the different tables constituting the master SLERO database as its entries. The user can select any of them, and the corresponding table's data are shown in the scroll window.

"Query" is the analyst level in which a provision is made for making a detailed inquiry about the Master SLERO database. This is very similar in form and function to the UH cross-hole interface discussed previously. However, since the interface is meant to access the Master SLERO database, which has been created using VAX Rdb SQL instead of Oracle, it has been modified accordingly. The Master SLERO interface also has a "connect" option with which the user can directly connect to the Vax at the University of Houston and can query the Master SLERO database on his own without the assistance of any additional interface.

Center for Applied Petrophysical Studies
Texas Tech University

Activity 2: Reservoir Characterization

Task 1: Petrophysical determination of Vcl

Cation Exchange Capacity (CEC) data for 30 samples form the Tesoro No. 3 Webb CSL well were run. These CEC data were used to evaluate the possible use of the Waxman-Smit Shaly Sand equation for determining effective water saturation (S_{we}) in Las Tiendas field. Clay analysis indicates that the two clay minerals in the Olmos Formation sandstones are illite-smectite, mixed-layer clay, and iron-rich chlorite.

We have completed our work on Vcl determination in Las Tiendas field. The Vcl software, SHALE, was made available to the Bureau of Economic Geology, The University of Texas at Austin. Also, three companies requested and received the SHALE software package—Mesa, Sonat, and Marshall Oil. Additionally, G. L. Causey completed his M.S. thesis on this subject.

Additional Las Tiendas field cores were examined in August 1991, and samples were received in September. The clay analysis was completed, and as with the previous samples, the clay minerals were chlorite and mixed-layer illite-smectite. The Vcl values ranged from 12 to 35 percent.

We have begun a new SLERO project on the Delaware Mountain Group.

Task 2: Development of shaly sand techniques for "old" well logs results verified by engineering data

Twelve core samples were selected from the Murexco Leyendecker No. 1 from depths ranging from 7,112 to 7,231 ft. These samples have permeabilities ranging from 0.0039 to 0.34 md. A sample taken from a depth of 7,219.5 ft contained a natural fracture. It was too permeable to measure because of the fracture. Porosities for the same set of samples ranged from 2.65 to 15.93 percent.

Additional core samples were obtained in October to use in the capillary pressure work. The cores came from the Maltsberger No. 1 in Las Tiendas field. In addition, well logs, drilling reports, and other materials relevant to the well were obtained. We also selected additional core samples from the Las Tiendas area. They were picked from the Palafox C No. 1. The results from the analysis of these cores will be used in the work on capillary distribution of water saturation.

Thirty additional logs were obtained from Las Tiendas field. These logs come from an area in which the well density is low and the potential for additional gas reserves by infill drilling is possible.

Hydrocarbon pore feet thicknesses from the Olmos Formation sandstones were compared with cumulative production histories to determine how well we selected our log analysis procedures. Also, core analysis was conducted for this task.

Texas Tech University has announced the formation of a Center for Petrophysical Studies that is codirected by G. B. Asquith and M. Arnold. This is a significant step toward increasing the already existing cooperation between Geology and Petroleum Engineering at Texas Tech. It also provides a means for Texas Tech to offer core analysis and well-log analysis services to other participants in SLERO and other State projects.

A paper based on analysis of Olmos Formation sandstones from Las Tiendas field, by G. B. Asquith, G. L. Causey, and K. T. Barrow, was submitted for publication in the Gulf Coast Association of Geological Societies Transactions. The paper will be presented orally at the 1992 annual meeting in Jackson, Mississippi. An abstract on the Las Tiendas fieldwork has been accepted for presentation at the 1992 American Association of Petroleum Geologists annual meeting in Calgary.

A new digitizing board and a 386 computer were bought and paid for by the Adobe Chair at Texas Tech University, currently held by G. B. Asquith. The equipment is being used in this task. Also, new logging software has been acquired by Texas Tech University for the analysis of shaly sands. The Texas Tech University Petroleum Engineering Department paid for the software. Emphasis will be shifted to the Delaware Sands studies, and this software will be used in that work.

Task 3: Application of new techniques for analyzing bimodal porosity reservoirs on State Lands

Because of the high degree of variability in logging suites in Las Tiendas field, the following shaly sand methods were employed: (1) SP log for Vcl determination using a transform and (2) Fertl and Automatic Compensation methods to determine S_{we}.

Using a newly acquired matrix density value of 2.72 g/cm^3 to correct the density log for the presence of iron-rich chlorite, the new microporosity shaly sands technique will be tried again on the Olmos Formation sandstones. However, additional clay mineralogy work will be done before further work is performed on the microporosity shaly sand method.