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AN INTEGRATED STUDY OF THE GRAYBURG/SAN ANDRES
RESERVOIR, FOSTER AND SOUTH COWDEN FIELDS
IN ECTOR COUNTY, TEXAS, CLASS II

Final Report
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Midland, Texas

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National Petroleum Technology Office
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EXECUTIVE SUMMARY

Laguna Petroleum, with partial funding from the DOE, embarked on this project to show that a small independent producer could use the techniques of modern geoscience to economically increase oil production and add reserves through optimization of a very mature waterflood. For the project area, one section of the Foster-South Cowden oil field, incremental production of 190,000 BO in six years has been achieved and at least 600,000 barrels of proven reserves have been added. The project work has included cleanup and redirection of the injection water, a careful evaluation of all wells as potential workover candidates, re-entry of abandoned wells, the use of modern fracturing technology to re-frac wells and new infill wells. Workover candidates are selected through the analysis of pressure transient tests, the analysis of produced water chemistry, the results of reservoir simulation, and an understanding of the well's history and mechanical condition. The waterflood optimization has been guided by reservoir simulation based on a geologic description developed from 3D-inversion modeling, well log analysis, core analysis and history matching. This final report presents the methodology used to achieve the increase in production and reserves in a form such that it can be applied by other operators in similar situations. The total cost to date of the project including 3D seismic, new drills, deepenings, workovers and technical support has been approximately 3 million dollars. The incremental barrels produced and future additional reserves were developed at a cost of \$3.80 per barrel.

ABSTRACT

The Grayburg reservoir of the Foster-South Cowden field has been produced since 1938 and waterflooded since 1962. Production had declined to near abandonment level at the start of this project in 1994. The initial approach to waterflood optimization was conventional. A flow model was constructed from a geological model that was based on logs and cores. Production data was assembled and validated as were the few measured pressures taken early in the field's history. Production testing of all wells was initiated with new equipment to provide accurate current production data. Pressure transient testing of all wells was initiated to identify workover candidates and to provide accurate current pressures for history matching. History matching pressures and water cuts validated the flow model and the flow model has since guided field operation, subject to the limits imposed by the spacing of the well data which was one reliable well log per 32 acres of reservoir. At this scale compartmentalization of the reservoir was obvious, requiring the use of 3D seismic to define porosity and flow barriers in the area between wells.

The 3D seismic survey has been used to calculate a 3D inversion model. Seismic inversion model traces exhibit a high degree of correlation to the well log data and a correlation was developed between seismic velocities and porosity. The correlation was used to develop porosity maps for each zone. In addition, the seismic data was interpreted to provide gross thickness maps for each zone. These maps, plus the log and core data, form the basis for the reservoir description used in the flow model. The resulting flow model was revalidated through the history matching process and has continued to guide the redevelopment of the waterflood.

Past development of the field had commingled production from the upper Grayburg, lower Grayburg, and San Andres in a number of wells. The results of the flow model and the pressure transient testing showed that cross flow was occurring and injection profiles showed that the A zone of the upper Grayburg had taken about 80% of the injected water. The conclusion was confirmed by selectively testing the individual zones in the new drills and workovers and led to the decision to concentrate on the upper Grayburg waterflood. This in turn, led to the near term abandonment of the lower Grayburg and San Andres reservoirs by setting bridge plugs. The lower Grayburg has only produced on primary from a few wells and is both a primary and waterflood candidate. The San Andres does not appear to have sufficient continuity to flood.

Pressure transient testing of all wells has continued on a routine basis. Analysis of the buildup tests has determined that the majority of upper Grayburg producers require re-fracturing to increase productivity and optimize the flood. A series of re-fracs have resulted in a seven-fold increase in production from the re-fraced wells. The increase in production has allowed an increase in injection that has accelerated the progress of the waterflood on a pore volume throughput basis.

Significant differences exist in the chemical analysis of produced water from the upper Grayburg, lower Grayburg, San Andres and injection water from the Canyon, Ellenburger and Santa Rosa formations. Santa Rosa water was used for injection early in the life of the flood and the Canyon and Ellenburger more recently. A few produced water analyses were found in the well histories and provide a sparse data set from the 1940's to 1995. Produced water analyses have been routinely acquired since 1995 and are now being utilized to determine the zone actually producing and to complement the engineering data set. The produced water analyses are also used to monitor the effectiveness of the scale and corrosion inhibition programs.

Early in the project (1995) the existing waterflood facilities were evaluated for continued use in the project. The injection water was of such poor quality that it plugged 75 micron filters on a regular basis. Sulfate reducing bacteria, scale, corrosion, oil carryover and high total solids all contributed to the plugging problem. These problems were solved by 1) adding a 750 barrel gun barrel to increase residence time, 2) physically cleaning the heater treaters to remove sludge which was composed of iron sulfate, fine-grained silt, and organic material, 3) controlling sulfate reducing bacteria with a biocide and 4) eliminating an incompatible injection make up water from the system.

PROJECT OBJECTIVES

Laguna Petroleum Corporation of Midland, Texas, with partial funding from the U. S. Department of Energy, has conducted this project to demonstrate that a small independent producer can use modern geoscience methods to optimize oil recovery from a very mature oil field. The integration of data and techniques from all geoscience disciplines has yielded results greater than would have been achieved without integration. The cost of successfully accomplishing these goals has been low enough for even small independent operators to afford.

The objectives of the project were to:

- Thoroughly understand the 60-year history of the field.
- Develop a reservoir description using geology and 3D seismic.
- Isolate the upper Grayburg in wells producing from multiple intervals to stop cross flow.
- Re-align and optimize the upper Grayburg waterflood.
- Determine well condition, identify re-frac candidates, evaluate the effectiveness of well work and obtain bottom hole pressure data for simulation utilizing pressure transient testing field wide.
- Quantitatively integrate all the data to guide the field operations, including identification of new well locations utilizing reservoir simulation.

FIELD HISTORY

Grayburg–San Andres reservoirs are upper Guadalupian, shown in Figure 1, deposited in a restricted, shallow water, carbonate platform environment on the Central Basin Platform. These reservoirs have been prolific producers for over 75 years. Beginning in the 1950's, fracturing was introduced and waterfloods were implemented in most of the major fields. Reservoir heterogeneities have generally caused low recovery efficiencies. In the Upper Grayburg, where this project is focused, primary has recovered about 8% OOIP, the conventional waterflood has increased the recovery efficiency to about 18% OOIP, and with the ongoing enhanced waterflood the ultimate recovery will exceed 21% OOIP. Recovery efficiencies for the Lower Grayburg and San Andres are much lower. This is within the range of primary and secondary recoveries for Grayburg/San Andres reservoirs on the Central Basin Platform, but below the optimum (Ruppel, et al, 1995). Recovery of the large remaining oil resources from these reservoirs depends on a solid understanding of the heterogeneities and an integrated geological, geophysical, and engineering effort. Although many of the Grayburg–San Andres reservoirs can be coaxed to give up accelerated reserves through standard field management, significant incremental reserves can only be recovered by an integrated approach to field management which includes a geologically and geophysically based reservoir characterization. It is estimated that 17 billion barrels remain in Permian dolomitized, shallow water platform carbonate systems in the Permian Basin (Tyler and Banta, 1989).

The Foster/South Cowden Fields, shown in Figure 1, are located on the eastern margin of the Central Basin Platform in central Ector County, immediately west of Odessa Texas. Like most Grayburg and San Andres reservoirs, they are situated on the shallow

shelf at Grayburg time which trends north to south and oblique to the paleo-wind direction. Unlike the Grayburg reservoirs to the north and northwest, there are few siliciclastics and none are reservoir quality. Grayburg reservoir quality diminished rapidly to the west into the high intertidal and sabkha environments. The shelf varies in width, partially controlled by deep-seated uplifts along the spine of the platform. The fields are part of the trend of Grayburg and San Andres production that extends from Yates Field at the southwest to the Seminole Field at the north end of the platform.

The study area includes more than 70 wells, and approximately 1,000 acres. An index map showing the location of the study area in the southern portion of the Foster Field is shown in Figure 2. The Foster Field was discovered in 1934, however, the study area was not developed on 40 acre spacing until 1941. The wells were completed open hole. After being shot with nitro, the wells produced from the upper and lower Grayburg and San Andres. There is over 600' of gross productive interval, and from 50' to 150' of net productive interval in the Grayburg and San Andres in Section 36, Figure 3. Not all wells were completed in all zones as some wells were drilled and produced only from the upper Grayburg. In the mid 1950's, the wells were hydro-fraced with a three fold increase in production realized.

In 1962, one well in each $\frac{1}{4}$ section was converted to injection, resulting in approximately 80 acre 5 spots. Initial injection into the depleted zones was taken on vacuum. 13 injection profiles in the 1962 to 1980 time frame show most (60-85%) of the water was injected into the upper Grayburg A zone, some (10-15%) of the water being injected into the upper Grayburg B zone, and almost no water being injected into the lower Grayburg and San Andres. Post 1980 profiles indicate fill was covering all perforations except in the A zone. Cross flow in the well bore between zones has been a problem in many water floods and this project is no exception. The lack of injection into the lower Grayburg and San Andres has lead to significant differences in reservoir pressures between zones. The upper Grayburg has been the only reservoir supported since the inception of the waterflood. This lead to cross flow from the A in the upper Grayburg, to the lower Grayburg and San Andres. The reservoir has defied recent attempts to vertically redistribute the injection water.

During the late 1970's and early 1980's 20 acre infill wells were drilled, resulting in approximately 40 acre 5 spots, and the existing upper Grayburg only producers were deepened to the San Andres. The San Andres and lower Grayburg intervals were perforated, stimulated, and tested together. Once production was established from the deeper interval, a bridge plug was set and the upper Grayburg zones perforated, stimulated and tested separately. The bridge plug was then pulled and all zones were produced together. The initial production tests of the lower Grayburg and San Andres, coupled with the high porosity in the San Andres lead to the conclusion that considerable production could be allocated to these zones. This also reduced the allocated contribution of the upper Grayburg. As will be discussed in the section on **Production Allocation in Commingled Wells**, these conclusions were erroneous.

As of the end of the year 2000, 6.6 MM STB of oil have been produced and 35 MM STB of water injected into the Grayburg and San Andres Section 36. Production had declined to near abandonment level at the start of this project. Over time, a number of well bores have been abandoned or temporarily abandoned for mechanical or economic reasons, creating large gaps in the waterflood pattern.

It is crucial to understand the history of the field, so past mistakes are not repeated. The engineers and geologists that developed the field from the 1940's to 1990's were both intelligent and capable. The success of this project today is due in large part to the reservoir and well work that has gone before. Today, however, we have the luxury of hindsight and can build on the successes and failures of the past. A thorough review of the production history of the field, including drilling reports, completions, remedial well work, injection history and well production changes over time, on a well by well basis, is essential for this or any study to succeed. For example, a well "watering out" and plugged in the 1970's may be successfully reentered when the reasons for plugging are understood and reinterpreted in today's technical and economic environment.

As many West Texas fields were the training grounds for young engineers and geologists in large corporations, the reservoirs often suffered from a lack of employee continuity. Projects are often initiated by one team, undertaken by a second team, and the results available to yet a different team who may or may not have an understanding of the rationale behind a project. The lack of continuity or "ownership", and the cyclic nature of oil prices, may result in significant advances not being recognized or implemented. The current study has benefited from a stable and committed work force as the operator and the present team members have all been working on the project for 4 to 6 years. We humbly suggest that ours is still only an imperfect understanding of work in progress.

RESERVOIR DESCRIPTION

Reservoir description is a critical first step both in waterflood optimization and in building a flow model. Construction of a geological model requires input from geology, geophysics, log and core analysis. Construction of a flow model requires maps of structure, thickness, porosity and permeability as starting points. These maps are the quantitative output of the geological model. If the maps are inaccurate then the flow model will be inaccurate and waterflood optimization will be impossible. Complete understanding of the depositional and diagenetic history is a starting point for accurate maps. Of particular concern is the continuity of the flow units from well to well. The drilling records, cores, logs, and 3D seismic from the project area plus experience with the regional geology are the inputs to this understanding.

Available data was collected from a variety of sources. Phillips Petroleum, Amoco, Great Western, and various other operators in the area allowed Laguna access to data. No operator had a complete set of data for all wells, which necessitated an extensive search of other local sources. Scout tickets were obtained from local geologic libraries, as were available electric logs, mud logs, and sample logs. The core data available at the inception of the project was almost entirely from the upper Grayburg. Although cores

were taken in six wells, the only cores still available were 177 ft from the upper Grayburg and 60 ft from the San Andres in the Sun Witcher #6 (WH6) Figure 4. The core was located at the Texas Bureau of Economic Geology Core Repository. Core reports were available for the other five cored wells in the study area.

Logs were digitized and cross sections built in the Reservoir Description portion of WorkBench. WorkBench is a suite of software that was used for log analysis, reservoir simulation, pressure transient test analysis and decline curve analysis of the production data. Easily identifiable rock units were correlated using a cross section network. In addition to subdividing the Grayburg into nine (9) units, the Dewey Lake, Santa Rosa, Rustler, Yates, Seven Rivers, Queen, lower Queen, San Andres, Holt, Glorieta, Cisco, and Canyon were identified where present. These additional tops permitted a more complete evaluation of the tectonic history of the area. Lowstand or regressive upper Grayburg wedges in the down dip portion of the study area (east-southeast) were also identified. Structure and isopach maps were constructed to evaluate structure and tectonic history, and identify correlation problems. This was done early in the program to prepare for the evaluation of the integrated geology and seismic and the sequence stratigraphy developed from the core study.

The reservoir description is an integration of the 3-D seismic interpretation with a geologic model derived from the core description, thin section study, log analysis, mapping, and cross section work. Geological evaluation of the Grayburg/San Andres reservoirs has included completion of the reservoir description and preparation of property maps for each layer. The maps included: Structure Figure 5, PHIH Figure 6, Gross Thickness Figure 7, and Gross Average Porosity Figure 8. The maps were based on logs and core analyses. There are twenty (20) wells in, and adjacent to, the project for which modern full logging suites exist and forty-nine (49) wells for which some logs exist. No logs are available for six (6) wells in the project area. Average well spacing in the project area is 14 acres/well.

Once the net feet of pay for each zone was determined, historic production allocation was undertaken. The completion records were evaluated to determine which zones had been in production in which years, when zones were added or deleted, and when a producer's status changed. The merging of the geologic zonation with production histories was completed - as was an effort to determine which zones were receiving flood support. Any and all injection profiles were collected and used to allocate injection to each zone.

An effort was made to match seismic attributes to the initial potential and cumulative production of the older 40 acre spaced wells, and to the porosity maps generated in the geological reservoir description. Although there is a fair to good gross correlation to the initial potentials, when an attempt was made to match seismic attributes to the porosity for individual zones less than 100' thick, the correlation coefficient was not high. Inversion Modeling of the seismic was attempted, and a usable seismic velocity/log porosity transform completed.

Although 15 "potential flow units" have been identified with cores and logs, it became necessary to reduce the number of layers, because many of the wells were completed open hole in multiple layers and shot with nitro or deepened below casing and re-completed open hole. This necessitated reducing the number of layers by ignoring tight zones that are less than 20' thick.

The upper and lower Grayburg in the study area has historically been divided into 10 zones. The upper Grayburg was divided into the A1, A2, B1, and B2 in descending order. The lower Grayburg was divided into the C, D, E, F, G and H. The A and B zones are each 7' to 120' thick. The C through H zones are each typically less than 40' thick. Based on the core evaluation, the lower Grayburg is better divided into three: the C zone, D-E-F zone and G-H zone.

Break in Slope

It had been postulated from the inception of the study that the break in slope on the shelf which cuts across the Southeast corner of Section 36, Figure 5, is significant. Geologically, there is a panel of dip, across which it is difficult, if not impossible, to correlate log units. In addition, the uppermost Grayburg interval down dip of the shelf break thickens rapidly towards the shelf edge to the east. This thickening is also seen on the seismic profiles as a wedge of sediments at or near the top of Grayburg. As there are no cores available from the down dip section, it is still difficult to draw sequence stratigraphic conclusions. The down dip sequence may be correlative with the sequence discussed by Ruppell and Bebout (1996) in their study of the South Cowden Field to the southeast. The up dip sequence in Section 36 may represent a high stand interval not identified in South Cowden. Geologically, the evidence suggests that for the flow model the up dip and down dip sections should be treated as separate reservoirs with a flow barrier separating them.

Core and Log Developed Depositional and Diagenetic History of the Grayburg and San Andres

As a result of the preliminary simulation completed at the end of Phase One of the study, it was realized that the upper Grayburg is the only waterflooded reservoir, the lower Grayburg is a virtually undeveloped reservoir and the San Andres could have untapped oil in place. The lower Grayburg and the San Andres were also the least understood. The drilling program implemented in Phase Two included the recovery of core from both the lower Grayburg and the San Andres to better understand these reservoirs.

Once a model for the depositional environments and diagenetic history was integrated into the cross section network, a number of additional flow units were broken out. Maps of net porosity by zone were constructed after the additional correlations were completed, locating different facies relative to the topography at a particular time became possible. For instance, the upper B zone in the WH6 is in the deeper shelf wackestone facies. It is predicted that a grainstone/ packstone shoal might be present up paleostructure to the west-southwest. On the net porosity map for the B zone, a porosity thick is seen approximately 1300' to the southwest, trending southeast to

northwest. This is perpendicular to the prevailing paleowind direction and confirms the supposition that paleostructure and paleowind directions impacted reservoir distribution. Because of the dearth of porosity logs in most of the older wells, it was difficult to construct meaningful net pay maps for many of the units. It was at this point that it became critical to integrate the 3-D seismic interpretation with the geologic model.

Upper Grayburg Depositional History

The core in the WH6 was of immense value in understanding the depositional environments and diagenetic history of the upper Grayburg and San Andres in the study area. Fourth order sequences and fifth order parasequences were delineated and a depositional model developed which was extended across the study area. The upper Grayburg (A & B zones in Figure 3) is an overall shallowing upward sequence composed of a series of shallowing upward parasequences. There are occasional subaerial exposure surfaces with each succeeding flood resulting in the deposition of a package of shallower units. The deeper water fusulinid/peloid mudstones to wackestones shallow into fusulinid/peloid packstones and eventually into packstone/grainstone shoals with skeletal grains, coated grains, and ooids with vertical burrowing, all indicative of high energy and representing the best quality reservoir. The grainstones had good to excellent primary interparticle porosity. The packstones have good leached interparticle porosity. All carbonates have been dolomitized.

The major lowstand event represented by the exposure surface at the top of the C zone also serves as the point where sand becomes a major component of the system, unlike the Northwest Shelf and Northern Central Basin Platform where the Premier Sands are present in the basal Grayburg. Thin sands and wispy laminated shales correlate across the area and represent flow unit boundaries. Discrete sand grains found in carbonates in the upper Grayburg do not appear to act as nuclei for ooids or coated grains and must therefore have been transported in following the development of the rounded grains. Peloids and ooids are often coated with a veneer of sand grains like "cookie dough rolled in sprinkles". This indicates that the sand was introduced late in the depositional history, possible as the transgression reached a source of terrigenous siliciclastics updip.

There are Maximum Flooding Surfaces above the boundaries between the A and B, and, B and C zones. Above the exposure surfaces at the A/B boundary and, A1 and A2 boundaries are transgressive ooid grainstones. Both of the transgressive ooid grainstones are anhydrite cemented, indicating the presence of a sabkha updip.

Both depositional facies and diagenetic textures were described and evaluated in the Grayburg and San Andres in the WH6 well. The best reservoir quality rocks are the grainstones and packstones developed in the shoal facies. The grainstones interparticle porosity network was partially occluded by post depositional anhydrite cement that significantly reduced the primary porosity. The packstone facies have well connected intergranular porosity developed during post depositional dissolution of the muddy matrix. The permeability is predicted to be good to excellent, based on visual estimations of the pore geometries. The effective porosity, estimated from visual

analysis of the thin sections (10-12%), is considerably higher than that derived from whole core analysis (6-8%). These higher porosities are more in line with what was expected from the initial engineering evaluation.

There is a significant amount of both primary and secondary anhydrite in the thin sections. The primary anhydrite is probably associated with the shallow, low energy lagoon and sabkha found updip, and overlying the grainstone facies. The primary anhydrite is present as snowflake - shaped, well defined displacive crystals that grew in the lagoonal lime mud during or immediately following deposition. In the reservoir facies, large optically continuous anhydrite crystals often occludes pore space in the matrix, but appears to have preceded the development of the secondary interparticle porosity. The intertidal and supratidal facies were not found in this core.

The evaluation of the facies and sequences in the cores has led to a better understanding of the depositional history of the study area. This area appears to have been, impacted by periodic rejuvenation of southwest to northeast trending deep structures, as facies belts are narrow. The facies belts would have moved rapidly, in response to minor sea level or tectonic fluctuations, up or down dip enough to create a very heterogeneous reservoir. Grainstone/packstone facies belts wrap around the northeast (down dip plunge end) end of the deep-seated structure. For the deep structure to have continued influence on the distribution of the facies belts, there had to be periodic small scale "adjustments". The paleowind direction also impacted reservoir distribution. Prevailing paleowinds were from the east - northeast, placing the structural nose in the optimum position for shoal development

Lower Grayburg Depositional History

The lower Grayburg was cored in three wells to gain information on the 170' thick interval, which the reservoir simulation had identified as having significant untapped reserves. 120' of lower Grayburg core was recovered in the Foster Pegues #11 (FP11), 37' of core in the H. C. Foster #11 (FS11), and 48' in the Witcher #12 (WH12).

The interval is composed primarily of dolomitized shallow subtidal to supratidal shallowing upward carbonate sequences with minor anhydrite. The only porous intervals are thin, fenestral rich high intertidal facies and subtidal packstones. There is a significant interval with tidal flat "Teepee Structures" in the D zone, and evidence of at least 34 ft of subaerial exposure in the C zone. Capping the C zone is a red to gray terrigenous sand which transgressed the top of the lower Grayburg subaerial exposure surface. This surface and the associated karstification have also been identified, over 60 miles to the northwest, in the Eunice Monument South (Grayburg) Field on the west side of the Central Basin platform in Lea County, New Mexico, where it also represents the boundary between the upper and lower Grayburg (R. Lindsay, pers. comm.).

There are some fine-grained siliciclastics that have percolated down into the karst associated with terminal San Andres event and at the base of the Grayburg. A number of exposure surfaces with associated minor karstification are seen in this section and associated with the correlatable tops of flow units (Zones D through H).

There are some small, 2-4 ft long vertical fractures with oil staining near the top of the lower Grayburg. The deepest water fusulinid wackestones are found within 30 ft of the transgressive base of the Grayburg. The best reservoir facies, the subtidal packstones, lie above the fusulinid facies in a linear trend, just up dip of the break in slope on the shelf.

San Andres Depositional History

The San Andres was deposited in an overall deeper water and higher energy, environment than the lower Grayburg. There is a total lack of siliciclastics in the San Andres in the study area and distinctive sands at the base of sequences are absent. Much of the San Andres in core was composed of higher energy packstones and grainstones. The presence of fenestral structures in the WH6 indicates shallowing upward to sea level of the grainstone shoals. The presence of solid hydrocarbon residue (SHR) in the WH6 core, coupled with low oil saturations in the basal portion of the WH12 and FS11, indicates the cores penetrated the transition zone or were near the oil/water contact.

The terminal event of the San Andres is a major sea level drop and subaerial exposure surface with an associated drop in the water table, interpreted in core, of at least 95 ft. During subaerial exposure the grainstones and packstones, underwent intense dissolution. The tight mudstones and wackestones were prone to dissolution by fresh water in the vadose environment along vertical planes of weakness, roots, burrows and other vertical features, and acted as cave roofs and floors.

The reservoirs, identified in core, are; an interval of leached fusulinid wackestone to packstone, a fine grained skeletal packstone to grainstone, a mottled, cross-bedded, skeletal packstone with fractures bleeding oil, and an interval of very porous and permeable cross-bedded ooid and skeletal packstones and grainstones. The reservoir intervals are separated by mud-rich packstones and wackestones.

There are intervals of massive anhydrite with collapsed mudstone and wackestone rubble at the base. The 1 to 6' thick anhydrite intervals are interpreted to be cavern fill cement. At the base of the anhydrite fill are angular breccia clasts ranging in size from 1" to 1' and fine-grained cave sediment. The mud-rich packstone roof of one cavern displays crackle breccia, indicating that the cavern was open at one time. The grainstone intervals in the FS11 have considerable patchy anhydrite cement. This cement can significantly reduce the porosity and permeability in an interval and increase the tortuosity of fluid flow.

It is believed that subaerial exposure and fresh water diagenesis has significantly altered the San Andres reservoir. Evaluation of the slabbed core indicated the presence of fresh water diagenesis as deep as 95 ft below the top of San Andres. There are intervals with mudstone and wackestone roof collapse breccias encased in massive anhydrite cavern fill, interbedded with porous grainstone and packstone intervals (the tested intervals), with only minor dissolution but variable anhydrite infill. Other

cavernous intervals are filled with very fine sand and silt which percolated down, and partially filled, solution enlarged vertical fractures in the vadose zone. The karst model proposed for the upper San Andres assumes significant areal variability and, therefore, the core permeabilities may not be representative of the intrawell intervals away from the well bore. Log analysis would typically lead to the conclusion that both of the tested intervals should be productive.

The tested San Andres zones are not commercially productive even with fracture stimulation. The large amount of secondary porosity cannot be contacted despite the development of a better understanding of the reservoir. Although the porous grainstone and packstone intervals locally have excellent porosity and permeability, they have become compartmentalized, during fresh water diagenesis, shale infiltration during exposure, and later anhydrite pore infilling during burial, which reduced overall permeability

The San Andres/Grayburg boundary is both a barrier to oil migration and a seismic reflector despite its lack of a paleosol or clastic rubble. Total dissolved solids in the San Andres waters are 50% higher than in Grayburg waters, and reservoir pressures are significantly different. Core analysis of the San Andres indicates a high percentage of secondary porosity, which is confirmed by sonic/neutron-density crossplot log analysis. The down dip extent of this exposure surface is unknown. Log correlation of the vadose interval as a depositional sequence would result in misinterpreting the truncated San Andres in tectonically active areas. An understanding of the importance of diagenesis in the San Andres reservoir is critical in successful well completions.

CONVENTIONAL AND SPECIAL CORE ANALYSIS

Conventional core analysis consists of measurements of porosity, permeability and saturation while special core analysis includes measurement of relative permeability. These rock properties are essential to both building a flow model and waterflood optimization. If these rock properties are inaccurate then the flow model will be inaccurate and waterflood optimization will be impossible.

Core Permeability vs. Porosity

Maps of porosity and permeability are required for each layer in the flow model. The porosity map is based on the inversion model from the 3D seismic survey, calibrated to the well log and core porosity. Plots of core permeability vs. porosity are made from the data in the core reports. These plots generally show a correlation between the log of the permeability and the porosity. This correlation is used to transform the porosity map to a permeability map.

Core analyses were available for six existing wells in and adjacent to the study area Table 1, Figure 4. A total of 950 feet of Grayburg and 40 feet of San Andres had been recovered prior to the inception of this study. A series of plots Figure 9 of core permeability vs. porosity were generated from the existing core reports. In addition, 267' of lower Grayburg and 209' of San Andres core was recovered in three new drills, the FP11, FS11 and the WH12 during this study.

The calculated arithmetic average core porosity for the Grayburg and San Andres formations are 5.41% and 8.05%, respectively. The corresponding geometric average core permeabilities are 2.13 and 1.15 md, respectively. It is noteworthy that the San Andres Formation shows a higher average porosity than the Grayburg Formation while the opposite is true of the permeability. These values are similar to those reported by adjacent operators.

The plots of the core permeability vs. porosity, Figure 9A, contain analyses from all the cored wells. The wide scatter of data appears to show no distinct trend. However, with further evaluation, there appears to be three distinct populations: a high permeability/low porosity "fracture field", a low permeability/high porosity or "vuggy field", and a permeability/porosity field which exhibits a "normal" distribution for shallow Guadalupian shelf carbonates.

Interparticle Porosity Field

In Figure 9B, a plot of only the Grayburg reservoir, most of the analyses fall above the reference line (.01 md, 0% porosity, to 1000 md, 18% porosity). Thin sections from the WH6 show leached grainstone shoals with better connectivity and larger pore throats in the intervals with better permeability. Although a sample with 8% porosity may have a range of from .1 to 10 md of permeability, it is apparent that the Grayburg reservoir quality intervals consist of grain-rich units with higher permeability. Although there is less high porosity (>10%) reservoir in the upper Grayburg than in the San Andres, the higher permeability makes it a better waterflood candidate.

"Vuggy" Porosity Field

In Figure 9C, a plot of only San Andres analyses, most of the analyses fall below the reference line. Although there is a significant fraction of the samples with higher porosity, they have significantly lower permeability than the Grayburg. Whereas a Grayburg grainstone with 8% porosity may have 10 md permeability, a similar San Andres grainstone with 10% porosity may have only 1md of permeability.

The San Andres reservoir has undergone an extensive period of subaerial exposure and karstification and the diagenetic overprint has created a reservoir with isolated "patches" of leached grain-rich sequences with good permeability, and larger areas with leached grains and patchy interparticle anhydrite cement.

Although the logs and cores from the BR10, FS11, WH12, and WH6 indicate zones with 18 - 20% porosity, the low permeability (averaging 1 md at 10%) would preclude a successful waterflood on 20 acre spacing, and raise the risk of a successful waterflood on 10 acres. This conclusion is supported by the marginal results a San Andres waterflood west of the study area, and confirmed by production tests in the WH12, FS11, and WH2.

Fracture Field

Figure 9D, is a plot of only those samples believed to represent fracture porosity. Fractures are present in the upper Grayburg in the WH6, Johnson #19 (JN19), M7, and

Foster Pegues #3X (FP3X) lower Grayburg in the FP11, FS11 and WH12, and in the San Andres in the FS11 and WH12. In each well, there are a limited number of low porosity and high permeability values, indicating that fractures make only a minor contribution to the overall reservoir. Although many of these fractures are oil stained, log analysis of these zones have less than 3% porosity and would not have been considered pay without the core. "Chatter" on the sonic log is evident in those intervals with fracture porosity in core, and can be used to predict fractured intervals on logs.

Lower Grayburg Low Porosity

The lower Grayburg was not cored in the area prior to the study. The interval is composed primarily of intertidal to supratidal facies with minor subtidal intervals. The best quality reservoir is found in the down-dip portion of the interval where the basal 50' of the lower Grayburg (Zones G and H), are composed of transgressive, high energy grain-rich subtidal facies.

The majority of the lower Grayburg interval is composed of tight (<4% porosity) mud-rich facies with low permeability (< .2 md). There is a small component of "vuggy" porosity (<3%) with low permeability (~.3 md) associated with exposure surfaces within the interval. As in the upper Grayburg and San Andres, there is a component of fracture porosity with up to 20 md of permeability. The lower Grayburg is a poor quality reservoir over much of the study area, only prospective in the southeast, down-dip area. The FP11 and WH2 are both in the down-dip area and are productive from high energy grain-rich subtidal facies not present in the cored wells.

Permeability/Porosity Transform

The seismically derived porosity maps are used to generate maps of permeability, using a porosity to logarithmic permeability transform. The slope of the transform equation was initially based on the available core analysis. The intercept was modified during the history matching process, to account for the presence of low porosity high permeability natural fractures in the reservoir, Figure 10. There is significant anecdotal information indicating a preferential direction of permeability bearing 270 to 290 degrees in both Section 36 and Section 31 to the east.

These fractures are observed in the cores and affect the measured core permeability. In wells where core porosity and permeability are measured in plug as opposed to whole core, the amount of fracture porosity can be significantly under reported. In whole core analyses, the amount of fracture porosity can also be under reported. Fractures, which are contained within bed boundaries, are another source of measurement error. Exposure surfaces and associated "Caliche Profiles" which are often not preserved during coring, and thin fenestral tidal flat caps can also serve to increase permeability and still be thin enough not to be measured.

This effectively increases the minimum permeability from approximately 0.2 md to the range of 2-3 md. This change was necessary in order to produce and inject the measured actual volumes in the simulator. History matching has partially validated this method of developing a permeability map and the history matching work is continuing.

Water-Oil Relative Permeability

Amoco Producing Company, operator of the South Foster Unit that borders the project area on the north, provided three laboratory derived steady-state water-oil relative permeability measurements. The average porosity, air permeability and water saturation for these three samples are reported to be 12.7%, 1.48 md and 21.1%, respectively. The three sets of data for both water and oil relative permeabilities were averaged and normalized to an initial water saturation of 21.1%. The lab composite water-oil relative permeability data provided a starting point for the history matching process.

Water Saturations

Water saturations for the San Andres, in the FS11 Figure 11, calculated using neutron/density cross-plot porosity appear to be too optimistic (9 - 20% Sw) when compared with visual inspection of the core and the production history of other wells in the area. When water saturations for the same interval are calculated using sonic porosity, some zones calculate to have higher, and more realistic, saturations (34 - 46% Sw), while other zones calculate "wet" (50 - 100% Sw). When two zones with cross-plot porosities of 14 - 18% and low Sw's (calculated by both methods) were perforated and acidized, pumping production rates of only 4 - 5 BOPD and 6 - 8 BWPD were obtained.

The WH2 was deepened from the upper Grayburg through the lower Grayburg and the San Andres to contact reservoir not previously productive at this area. Again, as in the FS11, Sw calculations using neutron-density cross-plot porosities are overly optimistic Figure 12. Water saturations calculated using sonic porosities were more variable and more realistic. A lower zone, 4388 - 4398 ft, was perfed and acidized based on fair mud log shows and fair to good crossplot water saturations (16 -45%). This zone flowed 100% water, confirming the sonic derived water saturations (55 - 100%) were correct. The zone from 4290 - 4315 ft had crossplot porosities of 9-13% and sonic derived water saturations of from 12 - 45%. Upon completion, the San Andres produced 3,500 BO and 13,500 BW in less than 6 months. There appears to be the dual porosity system present in this interval as the water production initially dropped at a faster rate than the oil production. The oil production decline at a rapid rate to 4-5 BOPD and 30 BWPD and the San Andres was abandoned after producing for only 6 months. The well was recompleted in the lower Grayburg and has continued to produce.

INTEGRATION OF GEOPHYSICS INTO RESERVOIR DESCRIPTION

The initial approach to construction of the flow model was conventional. Logs and cores provided the basis for a geological model. History matching pressures and water cuts partially validated the flow model, subject to the limits imposed by the spacing of the well data, which was one reliable well log per 32 acres of reservoir. At this scale compartmentalization of the reservoir was obvious, requiring the use of 3-D seismic to define the reservoir in the area between wells.

A 3D seismic survey was acquired over three and one half square miles of this mature oil field. After initial attempts to correlate seismic to reservoir properties were

unsuccessful, the 3-D seismic data set was reprocessed to retain high frequencies, thereby improving vertical resolution to the range of 50 feet. The seismic traces sample an area of 110 by 110 feet (bin size). The seismic inversion model traces exhibit a high degree of correlation to the well log data and a correlation was developed between seismic velocities and porosity for each geologic zone. The correlation was used to develop porosity maps for each zone, which were then used in the flow model. The resulting flow model was validated through the history matching process and used to guide the redevelopment of the waterflood.

Seismic Inversion Modeling and Mapping Porosity

To satisfy the objective of mapping quantitative values related to the reservoir, seismic inversion modeling is used. Seismic inversion modeling is a method of converting seismic amplitude trace data (wiggle traces) into traces which resemble sonic log curves. In practice, it is a process of converting seismic amplitude data from sinusoidal traces containing a seismic wavelet to blocky, log-like traces with wavelet complexity removed. The ambiguities of the seismic wavelet (inadequate resolution and reflection interference) are removed from observations.

Geophysically derived rock property parameters reported in the topical report have accuracy and sensitivity significant to engineering model development. The objective of further geophysical work has been to refine the parameter of porosity distribution for the most prominent oil-producing Grayburg reservoir, primarily the upper Grayburg.

Refining the geophysical model includes improving the vertical resolution of seismic inversion model traces and expanding adequate quality data across the entire seismic survey. Reprocessing the data volume was the basis of optimum success in reaching these objectives. A number of technical aspects of data processing were specifically targeted.

Reflection time errors, in the form of inaccurate time structure, are present in the original data volume. One example is of an anticlinal feature (reflection time) in the southwest part of the survey that is not indicated by close well control. A new re-refraction statics model was built, and the false structure was removed.

Improvement of signal-to-noise ratio of stacked traces was a primary objective. Noise rejection methods were tested to reduce the effects of coherent noise, with an offset dependent technique ultimately being used. Coherent noise is not a severe problem so overall improvement from the noise rejection step is minor. Strong, more random noise and low fold most affect the data quality of the Grayburg reflection, and careful muting of early arrivals was effective.

Optimizing Common Depth Point (CDP) stack accuracy, resulting in optimum frequency bandwidth, is the key to maximum vertical resolution. Automatic statics were applied following the re-refraction model. Integrated sonic logs tied to the seismic reflection times provided velocity control. Average velocity values applied to correct for normal moveout were guided by these well data.

A processing technique not applied to earlier data processing included Dip Move Out (DMO) correction. Little visible difference was noticed in data as a result of DMO application.

Seismic data processing must incorporate proper pre-stack trace amplitude equalization (scaling). Each stacked output trace contains amplitude information that is vital to calculating accurate inversion model velocity values. Traces to be summed must have consistent characteristics of amplitude and bandwidth. Noise in the pre-stack traces must be reduced so that reflection data will determine amplitude-scaling factors. Data traces in field record order (common source and increasing offset distance) are shown in Figure 13. Data with no spectral balancing (left) are compared to the fully processed traces with muting, spectral balancing, and noise attenuation (right). The unprocessed traces show characteristics of random noise, first arrival strength, trace-to-trace amplitude variation, and bandwidth limitations. Processed traces show trace-to-trace amplitude consistency and bandwidth optimization. Also shown is the fold-limiting effect of the shallow reflection time of the Grayburg.

Seismic profile data from two data volumes are shown in Figure 14. The 1996 data volume underwent a "fix" early in the project to optimize the amplitude spectrum bandwidth, but static and dynamic corrections were not modified. The data used for previous studies is on the left, and data used for the re-evaluation are on the right. The inversion model data are exemplified in Figure 15.

Inversion Model Recalculation

A new Seismic Inversion Model volume was calculated using the reprocessed data. Model input velocity parameters were modified from previous model values to produce velocity values calibrated to be in line with values from well data, and with research data. Previous results produced good relative velocity values, but better absolute velocity values were achieved with the revision. Inversion model-derived velocity data are compared to log-derived velocity data in Figure 17. The graph for the lower Queen comparison shows the inversion velocity values to be too low, perhaps an effect of constraining two closely spaced reflections. The Grayburg inversion-derived velocity values are very close to the well-derived values.

Data Analysis and Utilization

The analysis methodology used in earlier work was used with the new inversion model. The top of the Grayburg zone "A" was picked on the inversion model traces using the lower Queen isochron as a guide to the Grayburg position. On the structural shelf (Section 36) the top of the Grayburg zone is also a very clear change in the interval velocity (as with well logs). On the slope (Section 31) the top of the "A" zone is not the first carbonate encountered below the Queen clastics. The lower limit of the seismic "A" zone was determined from the zone thickness, converted to time, measured in wells. The values of velocity from the inversion model were averaged across the "A" interval between the two horizons. Then a cross-plot relationship was used to convert those

velocity values to porosity values for each seismic bin position. The resulting porosity distribution was used as a parameter in the engineering flow simulation model.

The engineering model requirements demand the thinnest intervals possible to be measured and mapped. The intervals of production used in the production model are the Grayburg A (~120 ft), the Grayburg B, (~100 ft), and the Grayburg C-D (~70 ft). The upper Grayburg "A" zone, is the primary zone of interest of the re-analysis. Thickness of the A zone is shown in Figure 7.

Quantitative comparison of inversion-derived velocity versus log-derived porosity is accomplished for each zone by cross plotting. The geologic parameter most useful to explaining historical production and advancing future development is rock porosity. The form of porosity most likely to be imaged by the seismic data in this project is Gross Average Porosity of a defined gross interval. The relationship of velocity and porosity is handled as a linear function, although, according to Schlumberger Log Interpretation Charts, the relationship is slightly non-linear. Porosity values used for calibration of the transform are chosen strictly from neutron density logs.

The cross-plot of the well derived average porosity versus average interval velocity from the inversion model for the Grayburg "A" zone is shown in Figure 16. Wells exhibit some amount of scatter from the two-slope linear function used to convert velocity to porosity. The amount of scatter is comparable to the laboratory-type studies (in several articles published in a Society of Exploration Geophysicists publication). Previous reports of this project have discussed potential errors inherent to both well data and seismic data. Well log-derived porosity values come from a variety of log types from wells drilled over a large span of years. Wide variation in log quality and age is a potential cause for significant scatter. Seismic data-related problems, either unresolved, or beyond resolving, contribute to inaccurate seismic velocity calculation in the inversion model. Noise and acquisition limitations are chief among these problems. Above all, other studies suggest that porosity and velocity have a diffuse relationship, partly caused by factors related to geologic facies type and mineralogy. For a relationship of porosity versus a given value of velocity, an error bar of about 5% wide exists. The cross-plot graphs of data for this project show a similar scatter of points.

The range of porosity shown on the graph in Figure 16 covers just the range of values in wells, but porosity across the survey extends below and above those values. The distribution of points suggests a nonlinear relationship. A higher slope line was used to convert higher velocities to values of less than four percent porosity and a lower slope line was used to convert lower velocities to values of more than four percent porosity. The final step in mapping is to convert the inversion model-derived average interval velocity values to porosity values using the cross-plot line relationship, Figure 16. The conversion is handled automatically by the Vest 3DSEIS program, which uses either a linear recursion method to determine the fit of the line or, in the case here, a line determined by the user. Points shown on the graph represent the values of gross average porosity calculated from well log data. Orange-colored dots indicate data from modern well logs, likely to have more accurate measurements than older logs.

The interval velocity was compared to the Gross Average Porosity values at included well points using the seismic-guided log analysis software in the Vest interpretation system. The comparison for all wells available with gross average porosity estimate has a poor relationship, Figure 16. It was recognized that the neutron-type logs, ranging in age from the 1950's to 1970's, lack the calibration consistency needed to measure porosity accurately and should not be used to calibrate seismic data as porosity data. When only wells with recent, calibrated neutron density logs were considered, the correlation of inversion-derived average interval velocity with Gross Average Porosity is reasonably good. Spreadsheet values of Gross Average Porosity in qualified wells range from less than 3% to more than 8%, but the porosity in other, non-calibration wells likely exceeds these limits. The scatter of the points from the line that they determine, is within 1.5% typically with only a few points falling intolerably (> 2%) away from the line. The area around these wells may not be imaged perfectly by the seismic data or the calculated porosity values may have unrealized problems. Difference maps, commonly used to reduce mistie values inherent in the conversion process, are not used (so far) for this project.

A display was made, Figure 17, to relate conventional seismic data character and inversion model seismic data character with rocks and reservoir. The vertical scale of the well log data can be compared with the more limited, but useful resolution of the seismic data.

Figure 18 shows maps of the porosity distribution calculated for each conversion line. The final porosity distribution map uses the porosity values less than 4% from the upper map and values of more than 4% from the lower map. The higher slope curve contributes lower porosity values. The lower slope curve contributes higher porosity values and eliminates negative porosity values.

Figure 19 shows the porosity distribution used in the flow simulation model. Areas of high porosity are displayed in red shades and areas of low porosity in blue shades. The shelf-edge low porosity area, significant as a barrier to fluid flow, is a dominant feature of the map. High porosity areas in Section 36 are major contributors to production and are areas with additional potential. Figure 20 shows the porosity distribution in Figure 19 with a contour overlay of the depth of the Grayburg. The porosity barrier is coincident with the structural shelf edge.

Inclusion of Porosity, Thickness and Structures from Seismic Interpretation in the Flow Model

Maps of the gross average porosity, gross zone thickness and structure were imported as an array of x, y, z points into the WorkBench simulator. Files of x and y map location plus the property value for that location was used to transfer the seismic information to the flow model. Each of the 110' by 110' grid blocks from the seismic survey had an associated property value which results in map defined by about 7,000 points. Each layer of this simulator was built using this technique.

GEOLOGICAL SUPPORT OF THE ENGINEERING AND GEOPHYSICAL EFFORTS

Historically, field studies and simulations in mature fields have been conducted by the engineer and geologist, while the geophysicist and the geologist look at the same property hoping to develop new pool, stratigraphic, or down dip reserves utilizing 2D and 3D. This project attempts to integrate all three disciplines in the evaluation of a mature field, and on a scale appropriate to an independent operator. One of the main drawbacks in integrating geophysical understanding in studies of mature fields is the dearth of successful interdisciplinary reservoir studies. Although these disciplines work at similar scales, e.g. 110 by 110 ft bins in a 3D, and 100 by 100 ft cells in a simulation, 5 - 10 millisecond seismic intervals and 40 - 120 ft thick flow units, their understanding of what the other disciplines abilities, limits, and data requirements are not always clear. Both disciplines are used to working closely with the geologist, but a gap exists between the geophysical and engineering sciences, which appears to be best bridged by the geologist. During Phase Two of this project, the geologist became the project manager. It is in the dual role of project manager and geologist that, communication and understanding among the three disciplines has expanded. Although it is not recommended that the geologist manage every tri-discipline project, it has become evident that until such time as the engineering and geophysical disciplines become more familiar with each other's areas, the geologist can best bridge this gap.

CROSS FLOW

Cross flow in the well bore between zones has been a problem in many water floods and this project is no exception. Section 36, where this project is centered has historically produced from the upper Grayburg, lower Grayburg, and San Andres. In many cases all of these zones have been open in the same well bore. The upper Grayburg has been waterflooded since 1962 using a variety of patterns. Historically, injection profiles show that 80% of the injection water was entering the A zone of the upper Grayburg and has defied even recent attempts to better vertically redistribute the injection.

The lower Grayburg was identified early in this project as an underdeveloped reservoir. Most of these lower Grayburg completions were commingled with the upper Grayburg resulting in cross flow from the waterflooded upper Grayburg to the lower Grayburg after the pressure depleted in primary production.

The San Andres has been completed in about 15 wells. In general these completions included the upper Grayburg and lower Grayburg as well. As in the lower Grayburg, this practice also resulted in cross flow from the upper Grayburg to the lower Grayburg and San Andres after the pressure depleted in primary production.

Identification of the cross flow in the producers was confirmed by the pressure transient testing program where wells with multiple zones show the humping behavior characteristic of multiple layers Figure 21. Water chemistry was also a good tool to identify cross flow since the zones have different water chemistries.

Since the majority of the producers were producing from multiple intervals an attempt was made to change the distribution of the injection water in order to waterflood all intervals. However, after a series of mechanical changes were made on both the surface facilities and the injectors, the upper Grayburg continued to take the majority of the injection water.

At this point, the relative economic values of each of the reservoirs were evaluated. It was determined that the San Andres had produced only a small fraction of oil from a few wells. Laguna tested the San Andres in several new wells with only limited success. The porosity of the San Andres is significantly higher than that of the Grayburg and in some wells, pressure transient tests have shown natural fractures in the San Andres. However, long term subaerial exposure and karstification caused compartmentalization of the San Andres, therefore the reservoir does not appear to have sufficient continuity to flood, has lower porosity and is below the oil/water contact in much of the study area.

The lower Grayburg had only been completed as a single zone in a few wells. Laguna completed it as a single zone in several new wells and recompletions of deeper wells and it has produced reasonably well on primary, but with a steep decline. It is a reasonable waterflood candidate but will require many more completions to reach a well spacing dense enough for waterflood. The porosity and permeability of the lower Grayburg is less than half that of the upper Grayburg. Development of the lower Grayburg has been postponed until the upper Grayburg waterflood reaches its economic limit.

The conclusion from this evaluation was to abandon lower producing intervals and install bridge plugs to stop the cross flow and focus on the upper Grayburg waterflood since it had the most chance of technical and economic success. Bridge plugs were installed below the upper Grayburg, followed by a pressure build up test to confirm success. Water chemistry and production tests were also used to confirm that the bridge plug had stopped cross flow. The San Andres does not appear to have sufficient potential to justify future development. The lower Grayburg has both primary and waterflood potential but will require a significant increase in the number of completions to be waterflooded. It also may be areally restricted.

PRESSURE BUILD-UP PROGRAM

The pressure build up program has been in operation for 6 years and is a major source of reservoir information. Sonic determination of fluid level and the casing pressure are used to calculate bottom hole pressure. Initially, the tests lasted for three to four days, interpretation required a significant amount of extrapolation of the data and the results were uncertain. Over time the process has been fine-tuned and integrated into Laguna's normal operations at minimal additional cost. The pumper shoots fluid levels using a time schedule based on past experience. Tapes are read and the data entered into a spreadsheet that calculates bottom hole pressure. The pressure and time columns of the spreadsheet are imported into the Welltest module of WorkBench where the data is analyzed. Data from the field is analyzed periodically until the results are

conclusive. Due to the characteristics of the reservoir, the average shut in time required to achieve a good data set is approximately 30 days. To date over 60 build up and drawdown tests have been analyzed.

Initially, the program was used to provide pressures for history matching the reservoir simulation. Since few measured pressures had been taken prior to the study, data was acquired to establish a baseline for future simulations. As the project progressed, the pressure transient testing became instrumental in the identification of wells for stimulation. It has also been used post fracture to evaluate the effectiveness of the fracture treatment in terms of wing length of the fracture generated and the productivity of the well after the fracture. The post frac data is obtained using a drawdown test so that the well does not have to be shut in following a restimulation.

Three tests on Brock #5 (BR5) will be used to illustrate the pressure transient testing process. Figure 21 is a log-log type curve buildup from February 1998 when the well was producing from the upper Grayburg and the San Andres. For about 200 hours this data could be matched with a single low pressure (about 250 psi) zone. This period represents the San Andres. From 200 hours on the data breaks up from the single zone line due to the higher pressure upper Grayburg. Adjacent single zone upper Grayburg producing wells show pressures of 1500 to 1800 psi. The adjacent injectors show pressures of over 2000 psi. The difference in pressure causes cross flow in the wellbore from the upper Grayburg to the San Andres.

Figure 22 is a log-log type curve buildup from May 1998 after a bridge plug was set between the upper Grayburg and the San Andres. The data represents a 28-day shut in time and is fit by a single zone, homogeneous, infinite model. Reservoir pressure is 1660 psia and the well does not show a frac. This behavior shows the well is a re-frac candidate.

After clearing a screening for mechanical integrity the well was re-fraced and Figure 23 shows the wells performance in a post frac drawdown test. The log-log data show the characteristic half slope straight line associated with an infinite conductivity fracture. The frac length is calculated to be 233 feet.

WELL WORK

The porosity development identified by the seismic influences the direction of migration, with several high porosity "dead zones" being identified in the model. The model shows that these "dead zones" have high oil saturation with little withdrawal. The north portion of the Brock lease shows high oil saturation in the model. A lease line injector, Altura Witcher #3 (AW3) and the Brock #9 (BR9) injector to the south have interfered with each other to create an area of high oil saturation.

One of the first recommendations of the project was to plug back and recomplete the Brock #13 (BR13) in the upper Grayburg. The well is located in an area of high oil saturation as simulated by the model. The well was perforated and fracture stimulated in the upper Grayburg in 1995. Initial producing rates were 85 BO, 213 BW and 3 MCF

per day. The well is currently producing 25 BO, 125 BW and 3 MCF per day. The success of the workover validated the flow model.

Another unswept zone to the southwest on the Foster lease was identified. This area has not been supported by injection to the west and it was predicted that older waterflood injectors on Section 36 displaced oil towards the west side of the Foster lease, where it was not captured due to the lack of producing wells. One new drill, the FS11, penetrated the upper Grayburg in this area and was completed as a lower Grayburg producer. In February of 2000, the well was plugged back and completed in the upper Grayburg. After fracture treating the upper Grayburg the well produced 40 BOPD, 355 BWPD and 2 MCFPD and is currently producing 12 BOPD, 161 BWPD and 1 MCFPD. The success of the recompletion also validated the flow model.

Isolation of the upper Grayburg from cross flow with other zones allowed Laguna to concentrate effort on optimization of the upper Grayburg waterflood. Once a good, single zone pressure transient test was obtained the wells were ranked as re-frac candidates. A very important conclusion from the pressure transient testing was that none of the old wells showed significant fracture wing length although all were fracture stimulated. Some wells were fraced several times with the latest job in the late 70's and early 80's. The only wells that showed fractures were those that were re-fraced by Laguna as part of this project. This observation led to the hypothesis that improving the connection between the wellbore and the reservoir was necessary. Re-fracs or acid jobs were the techniques chosen. If a well is a single zone producer based on the pressure transient test, the water salinity, and production tests; and is mechanically competent, then a re-frac is scheduled. In a few cases, continued cross flow was possibly due to a bad cement job. Those wells were eliminated from the list of re-frac candidates. Thirteen wells were identified and ranked as re-frac candidates. Table 2 summarizes the results of this work.

The fracture treatments previously performed on the wells typically consisted of 40,000 gallons of fluid and 20,000 lbs. of sand. Although the treatments achieved initial producing rates considered successful, the relatively small treatments created short frac wing lengths that closed with time, resulting in rapid production declines. It was decided much larger treatments had to be utilized in order to achieve greater frac lengths. Both conventional and non-conventional frac designs have been utilized in the field with good results. The conventional fracs are three times as large as had been utilized in the field prior to the project and have resulted in contacting larger volumes of reservoir. A "pipeline" fracturing technique, designed to increase the induced fracture length yet control frac height has also been used. Fracture lengths over 200' have been achieved utilizing this method.

The BR5 is an example of a well identified as a re-frac candidate. After isolating the upper Grayburg with a CIBP, pressure transient analysis showed the well to have a bottom hole pressure of 1660 psia, single zone influence and no frac. The well was conventionally fraced in 1998 with 30,000 gallons 35# cross-linked gel and 97,500# 16/30 sand. Producing rates prior to the workover were 6 BO, 6 BW and 1 MCF. Initial

rates after recovering load were 72 BOPD, 200 BWPD and 10 MCFPD. The well currently produces 20 BOPD, 75 BWPD and 3 MCFPD. Post frac draw down analysis indicates a fracture wing length of over 200' was achieved.

The Foster Pegues #8 (FP8) is an example of a well offset by injection wells yet not connected to the waterflood. Pressure transient analysis indicated a bottom hole pressure of over 2000 psia with no frac. The well was fraced in 1998 with 30,000 gallons 35# cross-linked gel and 118,600# 16/30 sand. After recovering load the well produced 25 BOPD, 455 BWPD and 2 MCFPD and is currently producing 20 BOPD, 385 BWPD and 2 MCFPD. Prior to the workover the well was producing 2 BOPD, 14 BWPD and -0- MCFPD.

A "pipeline" fracture technique was utilized in stimulating the Brock #8 (BR8). Pressure transient analysis was inconclusive yet the wells production of 1/2 BO and 1/2 BW per day indicated the well needed to be stimulated. After an acid job was unsuccessful in achieving acceptable production rates, the well was fraced in January of 2000 with 34,000 gallons of 35# cross-linked gel, 13,000 gallons of 35# linear gel and 37,000# 16/30 sand. Initial production from the well is 20 BOPD, 404 BWPD and 2 MCFPD with little sign of decline. A fracture length of 200' was indicated by post frac drawn analysis.

To date thirteen wells have been re-stimulated, plugged back or drilled and completed in the upper Grayburg. Prior to the well work, total production from the thirteen wells was 37 BOPD, 181 BWPD and 9 MCFPD. Production from the wells after the re-fracs peaked at 467 BOPD, 3167 BWPD and 145 MCFPD and has since stabilized at 222 BOPD, 2018 BWPD and 43 MCFPD. This represents a 6-fold increase in total sustained production from the thirteen wells, see Table 2.

One of the most important effects of this well work is simply the increase in withdrawal rates achieved see Figure 24. The model has shown that the reservoir has been over injected compared to withdrawals for the entire life of the waterflood. There is sufficient energy in the reservoir now to support many years of increased withdrawals on the current level of injection. In addition the increased withdrawals accelerate the progress of the waterflood on a pore volume through put basis.

USE OF WATER CHEMISTRY ANALYSES

Water Analyses

There are 356 analyses ranging from two partial analyses done in 1940 to a series of "base line" analyses completed in May of this year. A major question is: what did the virgin Grayburg and San Andres waters look like? By the 1970's when the first large scale water analysis program was undertaken, the water flood had been ongoing for fifteen years. Although this had been primarily a water disposal program, breakthrough to producing wells had occurred as early as 1963. A "Typical Grayburg water analysis" recorded in 1963 represents the best guess as a base line Grayburg analysis. A "San Andres water", supplied by Martin Water Labs, from an unknown location in the area had

been used as the standard San Andres. Until this year, however, there was no documented San Andres *only* water collected in the study area. Water collected from the WH2 and FS11 in July and August have provided a "Typical San Andres" for the Foster Field. It is now known that the San Andres water has significantly more Total Dissolved Solids than the Grayburg and that the ratios of cations and anions are different. This is a strong indication that the Grayburg and San Andres are not in communication and that they should be viewed as separate reservoirs.

Injection water has varied greatly through time. Every available water, from Canyon (very high TDS) to "Fresh Water" (shallow Santa Rosa and Hendricks Reef water), as well as Grayburg and San Andres, have been injected in Section 36. The compatibility problems resulting from this mixture have undoubtedly had an adverse effect on the reservoir.

Virgin Formation Waters

Soon after the project began, it was discovered that more than 320 samples of produced and injected water from the study area had been collected and analyzed. The oldest complete analyses date from 1962, at the inception of the waterflood (there were two partial water analyses dating from 1940). Upper Grayburg produced water originally contained +/-27,000 ppm TDS, lower Grayburg +/-37,000 ppm TDS and San Andres +/-63,000 ppm TDS. Samples began to be collected periodically, at least yearly, from both producing and water injection wells during the 1970's and continued to the present. It became obvious that any and all available water was injected. During the 1960's local water sources, producing from the Ogalalla (10,743 PPM TDS), Santa Rosa (3,873 PPM TDS), and a "water well" (1,050 PPM TDS) were utilized. In 1966, a sample of injected water contained 6,299 PPM TDS, significantly fresher than either the Grayburg or San Andres. Two produced water analyses from that same time contained between 13,500 PPM to 14,800 PPM, indicating that the fresh injection water had already changed the water chemistry in the formation. During the late 1970's and 1980's, Canyon (Pennsylvanian), Ellenburger (Lower Ordovician), and "Hendricks Reef Water" (upper Permian) waters were being used as "make up water". The "Virgin Formation Waters" chart Figure 25 indicates the range of TDS in these waters. Hendricks Reef Water contains half the TDS of original upper Grayburg water. Canyon water contains almost five times the TDS of the upper Grayburg and twice the TDS in the San Andres. Ellenburger produced water contains four times the TDS of virgin upper Grayburg water.

The upper Grayburg virgin formation water chemistry is from samples taken at the inception of the water flood. The lower Grayburg water is an average of samples taken from isolated tests of the interval during this study (1996-1998). The lower Grayburg was tested separately in the WH2 deepening, and the WH12, FS11, and FP11 new drills. Water samples from those tests are remarkably consistent Figure 26.

The San Andres was tested separately in the WH2, WH12, and FS11 during this study (1996-1998). As in the lower Grayburg tests, the water chemistry was remarkably consistent Figure 27. One other point of interest is that the lower Grayburg and San Andres in these wells do not appear to have been contaminated by flood water. This is as expected, as the wells are not near locations where lower Grayburg and/or San

Andres injection has taken place. Hendricks Reef Water analyses date from 1971 and 1975, Canyon samples were collected from various wells in the study area from 1981 to 1996. The Ellenburger sample was collected from a well in the study area in 1998.

Based on the original history match, over 80% of the injected water was pumped into the upper Grayburg, less than 10% into the lower Grayburg/San Andres. It is estimated that 5%+/- of the water was injected into the lower Queen (not part of the reservoir) via open holes with casing set above the top of the upper Grayburg. Historically, the overwhelming preponderance of the injection water has been cycled through the upper Grayburg, which was originally the primary waterflood target and has become so again.

The samples of injection water from 1977 through 1996 showed Figure 28 a steady increase in Sodium and/or Potassium (reported together), Calcium (as Ca), Magnesium (as Mg), Chloride (as Cl), Sulfate (as SO₄), bicarbonate (as HCO₃) and TDS. A similar increase in the major cations, anions, and TDS were also seen in the produced waters Figure 29. Although all the major cations and anions have changed over time, the TDS, sodium, and chloride are most consistent. Ratios such as calcium to magnesium and calcium to chloride are also used to differentiate between formation and flood water. The TDS will be reported on here as that value which has become the "shorthand" analyses most often discussed amongst the study participants.

In addition to the 320 water samples analyzed prior to the inception of the project, over 350 new water samples have been collected and analyzed starting in November 1995. The potential uses of this data set were beginning to be realized at this time and, as a result, periodic sampling of each well was initiated. In addition, water samples were taken prior to and following any change in a wells status (setting CIBP's, re-fracturing, etc.). The produced water analyses are now being used as a real time indicator of the success or failure of day-to-day field operations. Some of the questions that are being addressed are:

- What is the source of produced water? Virgin formation, flood water or a mix?
- Was the setting of a CIBP successful in isolating a zone or zones?
- Was fracture stimulation successful in producing from a single zone (Pipeline Frac) or multiple zones (conventional frac)?
- What is the cause of a sudden change in production?
- Is water being coned up from a deeper reservoir?
- Is there a casing leak?

Two independent methods provide data on the success of a plug back, re-frac, or acid stimulation. Water analyses can identify the source of produced water and bottom hole pressure tests identify how many zones are open. Samples of produced water were collected prior to and after any well work, and were analyzed within days of collection. Although a bottom hole pressure test provides a large volume of engineering data, it can take up to a month to complete, necessitate shutting in the well, and shutting in of production. The water chemistry analyses, although subject to interpretation, can be used to provide an answer within a few days of the well work. The bottom hole pressure

tests have, in the majority of cases, supported the conclusions drawn from the produced water analyses. In those cases where a Bottom Hole Pressure Test with a high confidence level conflicts with the water analyses, the bottom hole pressure test is considered to be more reliable.

Source of Produced Water

The BR5 serves as an example of how water analyses can be used to determine the source of produced water. The upper Grayburg in the BR5 was re-fractured in August (see Well Work). The water analyses from before (51,700 PPM TDS) and after (42,700 PPM TDS) the procedure are significantly different and indicate the frac contacted previously under-produced, though somewhat flooded, reservoir. Three water samples taken 8/24, 8/31, and 9/21 Figure 30 indicate a slow increase in the TDS from 42,700 to 44,300 to 46,000 PPM. This may indicate an increasing percent of flood water is being produced. The San Andres is not considered to be a source of the water in the well.

INJECTION WATER QUALITY

Early in the project (1995), the injection water was of such poor quality that 75 micron filters became plugged on a regular basis. High total dissolved solids (TDS), scale, corrosion, and oil carryover were all present, to varying degrees. However, before recommending any mechanical or chemical changes, the existing waterflood facilities were evaluated for continued use, and a water quality study was conducted. Also, historic water analyses were collected and tabulated which became useful in evaluating the history of the water used as floodwater.

During the project numerous suspended solids surveys were conducted of the produced water at the heater treaters, within the surface facilities and exiting the facilities. One of the first observations was that black "Slugs" of water were periodically seen in the injection system. The slugs were analyzed and determined to be a mixture of iron sulfate, fine-grained silt, and organic material. If this material were to continue to enter the injection system, the well bore interface in injectors would "sludge over" as it is believed that the average particle size of the sludge was larger than the average pore throat size of the reservoir.

The source of this sludge was found to be the four individual heater treaters of the leases, flow lines and suction tank. Thus, it was necessary to clean-up the entire injection system. Each heater treater was manually cleaned, followed by chemical cleaning and flushing of the flow lines and suction tank at the main battery.

The addition of the off lease Henderson Canyon water was determined to be another source contributing to the loss of water quality all through the injection system. The Henderson wells produced from the Canyon formation. The Henderson lease water is sweet, containing 20-30 parts per million soluble iron and three times the TDS of virgin Grayburg water. When this water is mixed with the sour, H₂S laden San Andres/Grayburg waters, iron sulfide precipitation occurs. This results in a tremendous increase of the suspended solids in the injection water and the suspended solids cause the oil carryover problems. The mixing of the Henderson lease water with the San

Andres/Grayburg waters also caused corrosion and scaling tendencies. Because of the incapability of the Henderson water with flood waters in the study area, the Henderson water was removed from the system.

Additionally, it was determined that the suspended solids and chemistry of the water entering and exiting the existing 1000 BBL suction tank upstream of the injection pump exhibited little change. In 1996 a gun barrel was set in the system for additional retention time, settling capacity, and oil skim capability to help alleviate the oil carryover problem and suspended solids. However, a suspended solids survey performed after setting the gun barrel indicated the vessel was having little effect. Furthermore, a study of the amount of oil entrained in the water indicated a significant amount of hydrocarbons were being passed through the vessel. In 1997 the gun barrel was drained and an internal design flaw was detected in the vessel. A study performed after the vessel was redesigned showed a significant improvement in the quality of the water leaving the gun barrel. The suspended solids were lowered and the oil in water carryover was reduced from 286 ppm to 42 ppm.

The oil entrapment study showed that most of the hydrocarbon carry over entering the system was proportional to the rate at which the produced water from the Witcher lease was transferred to the main battery. The Witcher transfer pump moved water at such a high rate that it provided little time for hydrocarbons to be removed by skim or overflow and also trapped oxygen into the transferred water. When oxygen from the Witcher system mixed with the soluble iron from the Henderson lease, iron oxide suspended solids formed. The iron oxide will combine with the naturally occurring hydrogen sulfide yielding high levels of iron sulfide suspended solids. These solids attract hydrocarbons which adhere to the solids causing significant oil carry-over. Removing the Henderson water from the system and installing a smaller transfer pump on the Witcher lease, alleviated the oil carry over problem entering the system.

As a result of this work there has been a great improvement in water quality. The TDS of the injection water has dropped from 74,000 PPM to 53,000 PPM over the past four years and the oil in water carry over problems have been minimized allowing 10 micron filters to be used on a continuous basis. Additional benefits have been the decrease in corrosion, oil emulsion related problems, and overall reduction in operating costs.

INITIAL RESERVOIR SIMULATION

The first flow models were built in Baker-Hughes' (previously SSI's) WorkBench using log and core data from the geological model. The models were centered on Section 36 with an additional ring of cells to account for the influence of offset production. Pseudo wells were used to simulate the effects of production and injection in the adjacent leases. The productive interval was simulated with five layers including three layers, A, B, and C, in the upper Grayburg, one layer for the lower Grayburg and one layer for the San Andres. Based on a preliminary KH allocation, this model showed that 81% if the cumulative production came from the upper Grayburg, 5% from the lower Grayburg and 14% from the San Andres. The vertical distribution of the production would change as a

result of later work and will be discussed in the section on **Production Allocation in Commingled Wells**.

Identification of the lower Grayburg as essentially unproduced was the first result from the modeling work. This has led to the drilling of 3 new wells. As Table 3 shows these wells have made a significant contribution. The wells initially flowed and the reservoir pressures indicate near original conditions. Decline rates have been 30-40% per year as would be expected in a reservoir initially undersaturated by about 1000 psia. The lower Grayburg will be evaluated as a waterflood candidate and awaits the availability of enough well bores to design a flood.

The San Andres appeared to have primary production potential, but results have been disappointing. Several of the wells in Table 3 were initially completed in the deeper San Andres zone. Pressures were high and on a different gradient than the Grayburg and water salinity is different, confirming that they were separate reservoirs. Water zones, in some cases both below and above the oil zone, made completion difficult. Due to these high pressure water zones, water production has been high and oil production low. Due to karstification the reservoir is limited and lacks continuity, resulting in high decline rates. Based on the results, the San Andres does not have additional development potential and its' past contributions to total production have been overestimated.

As discussed previously, the water salinity's differ between the Grayburg and the San Andres, thus providing an indicator of which zone is producing water. Although the wells in Table 3 were intended as lower Grayburg producers, the water salinity indicated that much of the water is being produced from the San Andres. The water production is due to vertical extension of the hydraulic fracture downward to connect to water zones in the San Andres.

The initial simulation showed the upper Grayburg to be an inefficient waterflood suffering from both areal and vertical sweep problems. Review of old injection profiles indicated that the A zone of the upper Grayburg took about 80% of the injected water leaving the B and C zones relatively unswept. The flood was initiated on 80-acre patterns by converting old open hole producers to injectors. There was no attempt to account for the areal heterogeneity shown by the seismic porosity map in Figure 20. Infill drilling during the flood has increased recovery but was not directed by any deterministic information about areal heterogeneity. In fact the porosity maps built for the initial simulation (Figure 8) from log and core values do not show the same heterogeneity as the seismic porosity map in Figure 19 .

The oil saturation maps from the initial simulation showed that oil had been moved in a northwest direction along a higher porosity trend off Section 36. This occurred due to the placement of the initial injectors to the south against a flow barrier and the lack of enough backup injection to the north. A well was successfully recompleted in the northwest corner of Section 36 to increase withdrawals from this area and take

advantage of the high oil saturation that had been pushed to this area. Several other workovers in this area have also been successful.

PRODUCTION ALLOCATION IN COMMINGLED WELLS

The initial simulation, pressure transient test analysis, and analysis of the produced water chemistry all identified commingled production as a problem. A spreadsheet was built to allocate the production back to the individual zones, based on the criteria of completed net thickness. This direct route to determining the true production from each zone lead to many discoveries of valuable information as the well histories were reviewed to determine when zones were completed. Another benefit was that the simulation could be run as a series of single layer models as there is essentially no vertical permeability between zones. The results of production allocation within the spreadsheet showed that the upper Grayburg produced 83% of the cumulative oil, the lower Grayburg produced 8% and the San Andres produced 9%. The A zone of the upper Grayburg has taken 80% of the injected water, produced 47% of the cumulative oil and has the best rock properties so it was logical to focus the waterflood optimization work on it first.

Based on periodic three-day production well tests, monthly lease totals, and workover reports, production was allocated to each producing well in Section 36, and Laguna's offsetting leases. Monthly injection for each injector was determined from lease reports. Production and injection data was also allocated for wells within the simulation boundaries (up to two locations outside Section 36 in most areas) in the sections bordering Section 36. Altura and Great Western have also provided updated production and injection data to Laguna for the wells to the east, north and west of Section 36.

Until 1996, production was allocated on a yearly basis. Oil production is considered to be accurate but the historic water production and injection is suspect. As part of this project, a periodic testing program has permitted the calculation of average daily production on a monthly basis beginning in 1996. These actual measurements of water production provide the data to match in the simulation. The production and injection data were then input into a "Master Spreadsheet".

In the "Master Spreadsheet", production and injection is allocated to each zone in each well. For each well, the net feet of pay was calculated from the logs for each zone, summed, and the % of total net porosity determined for each zone. It was then determined, through well history review, which zones were actually contributing to production or receiving injection and a 1/0 switch posted for contributing/not contributing. At this point, field, lease, and well and zone totals are readily available and periodically updated. To determine the production for a single zone, all the zones other than the zone of interest are turned off. The allocated portion of the production from the single zone is then ready to be input into the reservoir simulation and to be summed by field, lease, and well. The spreadsheet individual zone production is saved to a space delimited file which is then loaded into the Workbench simulator.

SIMULATION: SECOND GENERATION

The production data used for simulation is updated periodically in the spreadsheet and the simulation rerun. This process is continuing and guides the current operations. Production data from the Johnson lease and the Maurice lease, which offset Section 36 to the east, were added. Production data from the Addis lease, which offsets Section 36 to the west, were also added. The spreadsheet also accumulates production and provides a quality control check for comparison to the simulator. The production data was also loaded to the Production Data Analysis module of the Workbench for conventional decline curve analysis. The decline curve analysis provides a check on the results of the simulator.

When the seismically derived porosity map was used, the calculated OOIP in the upper Grayburg increase by 17% when compared to the OOIP calculated using maps based on well values only. Therefore the recovery efficiency decreased which indicated that the flood was not as efficient as originally thought.

The simulation model has been reoriented and extended east and west to cover a portion of these leases. The model was also reoriented to be parallel with a shelf break identified by the previous seismic and geologic work. The shelf break is a probable no flow boundary.

The original seismically derived porosity was revised and this revised map was imported into the simulation. History matching has validated the porosity map and the history matching is ongoing. The original oil in place in the upper Grayburg increased by 17% when the seismically derived porosity map was used, compared to the original oil in place calculated using maps based on well values only.

The seismically derived porosity maps are used to calculate maps of permeability, using a logarithmic porosity to permeability transform. The slope of the transform equation was initially based on the available core analysis, but the intercept was modified during the history matching process, to account for the presence of low porosity, high permeability natural fractures in the reservoir. These fractures are observed in the cores and effect the measured core permeability. This effectively increases the minimum permeability from approximately .2 md up to the range of 2-3 md, Figure 10. This change was necessary in order to produce and inject the actual measured volumes in the simulator. History matching has partially validated this method of developing a permeability map and the history matching work is continuing.

The oil saturation maps from the simulation of the A zone are shown in Figures 31 to 37. The first map, Figure 31 (365 days), shows the initial conditions in 1940. The red color indicates the initial oil saturation of 79%. Figure 32 (8,036 days) shows the oil saturation at the end of primary production and initiation of the waterflood in 1961. At this time primary recovery was 8% of the OOIP, gas saturation was in the range of 10% and the bottom hole pressure had dropped to the range of 200 psi. Figure 33 (9,132 days) shows the oil saturation in 1964, after 2 years of water injection. The dark blue color represents the residual oil saturation to water of 30% and the five grid blocks showing

this color contain the five original waterflood injection wells. Even at this early time the migration to the northwest is obvious. Figure 34 (10,958 days) shows the oil saturation in 1969, after 7 years of water injection. There are 8 wells on injection by this time and the migration to the northwest continues. Figure 35 (14,610 days) shows the oil saturation in 1979, after 17 years of water injection. There are 13 wells on injection and the migration to the northwest continues due the shelf break that is modeled with the edge of the grid that creates a no flow boundary. The area of high oil saturation is developing on the Brock lease to the northwest. Figure 36 (18,263 days) shows the oil saturation in 1989, after 27 years of water injection. There are 15 wells on injection. The migration to the northwest continues. In addition, the Witcher #10 (WH10) injector on the lease line between the Witcher and Johnson leases has failed. The result is that two areas of higher oil saturation start to develop on the Witcher lease. Figure 37 (21,550 days) shows the oil saturation in 1998, after 36 years of water injection. This is essentially the average oil saturation distribution during the project period of 1995-2000. Note that the area of high oil saturation in the outer ring of grid blocks to the north and west is an artifact of the modeling process and occurs well beyond the boundary of Section 36. Within Section 36, the oil saturation map is valid and represents a mature waterflood with areas of higher oil saturation that have been the target of the waterflood optimization well work.

The historic injection-production balance has been a concern throughout the history matching process. The historic data show that about 35 MM STB of water was injected into Section 36 in 40 years. Only about half of this metered volume could be injected for water cuts and pressures to be reasonably matched in the simulator. This is a relatively common problem with window studies such as this. Some of the injection could have been lost to other zones up the hole but the probable explanation is that injection moved outside the area modeled.

ORIGINAL OIL IN PLACE AND RECOVERY EFFICIENCY

The OOIP and production from a layer determine the recovery efficiency. The recovery efficiency is a convenient way to compare reservoirs. This project has gone through an evolution in both OOIP and production from each layer. Initially OOIP was determined using maps based on well data. The data was sparse and some of the logs had questionable calibrations. In 1996 the OOIP from the upper Grayburg was calculated to be 24.7 MMBO. As the project progressed, more wells were drilled and more modern porosity logs became available. The 3D seismic volume was inversion modeled to generate velocities, and the velocities were converted to porosity using a transform with well log porosities. The OOIP for the upper Grayburg was recalculated using the seismically derived porosity map resulting in a 17% increase to 29.0 MMBO. The OOIP for the A zone, which was calculated to be 13.8 MMBO in 1996 using well logs, increased to 16.2 MMBO in 1998 using the inversion modeled porosity values. Subsequent history matching has shown that these updated values are reasonable.

Cumulative production from Section 36 is 6.6 MM STB to the end of year 2000. This value is known quite accurately but what is not known accurately is how much came out

of each producing interval. In 1996 it was estimated that 81% of the cumulative production came from the upper Grayburg, 5% from the lower Grayburg and 14% from the San Andres. As a result of core analysis and failed completion attempts in the San Andres, the cumulative production allocation from the individual intervals was re-calculated in 1998 and showed the upper Grayburg produced 83% of the cumulative oil, the lower Grayburg 8% and the San Andres 9%. Primary recovery in the upper Grayburg was 8% OOIP. The conventional waterflood, initiated in 1962, increased the recovery efficiency to 18% OOIP and, with the ongoing enhanced waterflood, the ultimate recovery will exceed 21% OOIP. Recovery efficiencies for the lower Grayburg and San Andres are much lower.

IDENTIFICATION OF ADDITIONAL DEVELOPMENT POTENTIAL

The porosity development identified by the seismic also influences the direction of migration, with several high porosity "dead zones" being identified in the model. These "dead zones" are areas where the model shows higher oil saturation with little withdrawal. One of these is on the south east corner of the Witcher lease, where a lease line injector failed early in the life of the waterflood and was never replaced. One producer failed in this area and one was recompleted to the lower Grayburg. These wells were not replaced, and the simulation shows in Figure 37 (21,550 days) that this area has not been adequately swept by the waterflood. An additional producer was drilled in this area in December 1999. The results of the Witcher #14 (WH14), shown in Table 2 are disappointing. Pressure transient testing showed that a frac was not achieved, even though it was fraced using a standard treatment that has been successful in many other wells. It is very damaged with a skin of +29. In addition, the pressure transient testing showed that the reservoir pressure was 514 psia, which is much lower than anticipated, based on the simulation. Evaluation of the well's performance continues.

To address the low pressure in the (WH14), which was also measured in several other wells on the Witcher lease, options for additional injection were considered. A replacement of the failed lease line injector was considered as was the re-entry of the failed producer Witcher #9 (WH9). The re-entry was chosen as the least cost option to give the area some flood support and the well was re-entered and placed on injection in December of 2000.

To the southwest, on the Foster lease, another unswept zone has been identified. This area has not been supported by any injection to the west and it is probable that the older waterflood injectors on Section 36, have displaced oil toward the west side of the Foster lease, where it has not been captured, due to lack of producing wells. In 1996 the H. C. Foster #3 (FS3) was re-entered and completed in the upper Grayburg. Initial production from the well was 26 BOPD, 200 BWPD and 12 MCFPD and currently produces 7 BOPD, 3 BWPD and 1 MCFPD. One new drill, the FS11, penetrated the upper Grayburg in this area and was initially completed as a lower Grayburg producer. In February of 2000, the well was plugged back and completed in the upper Grayburg and initially produced 47 BOPD, 355 BWPD and 7 MCFPD after a small acid job and is

currently producing 7 BOPD, 40 BWPD and 1 MCFPD. The success of the recompletion validated the flow model. This well is a candidate for fracture stimulation in the future.

The north portion of the Brock lease shows high oil saturation in the model. The lease line injector, AW3 and the BR9 injector to the south have interfered with each other to create an area of high oil saturation. The success of the BR8 re-frac and BR13 recompletion validated the flow model. A new well in this area is under consideration.

RESULTS

The result of the project has been to arrest the production decline of Section 36 that was seen in the years prior to the implementation of the project. Figure 24 shows that, since 1993, when Laguna took over operations, the production from the project area has risen to 8000 BOPM from 6000 BOPM. Had the work on the field not been performed, the current production would have been less than 2000 BOPM so the result of the project work is a four-fold increase in current production rate. During 1997 the production reached over 10000 BOPM while during 1998 and 1999 production was constrained by the low oil price and extensive pressure transient testing. To year-end 2000, it is estimated an additional 190,000 barrels of oil have been recovered as a result of the work performed during the project. The ultimate recovery from the project area has increased by a minimum of 600,000 barrels of oil and the economic life of the field has been extended from near abandonment to over sixteen years.

Table 2 shows the results of the upper Grayburg work while Table 3 shows the results of the lower Grayburg work. The lower Grayburg well work has simply been to make primary well completions.

The accomplishments and success of the work performed supports the conclusions from the project. Through the integration of modern engineering methods, geological and geophysical data, it is possible to economically recover additional oil from very mature reservoirs.

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reinterpreting the seismic data and for the geophysical study. Also since that date, Robert C. Trentham has been responsible for project management.

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Figure 2. Study area, Foster – South Cowden Project.

Figure 3. Type log, Foster - South Cowden Grayburg/San Andres Field.

Figure 6. Map of phiH of zone A1, upper Grayburg.

Figure 8. Well log-Derived Gross Average Porosity
 Grayburg A zone.

Figure 9. All core data in study area.: A. All core data, B. Grayburg data only, C. San Andres data only, D. Fracture porosity only.

Figure 11. Foster #11 water saturation calculations for San Andres Interval. Sw's calculated using Sonic porosity and Neutron/Density cross plot porosity to approximate interparticle and vuggy saturations.

Figure12. Witcher #2 water saturation calculations for San Andres. Calculated using both Sonic and Neutron/Density porosity.

Figure 13. Conventional seismic amplitude data, in unstacked field record format. Traces left have an AGC trace scaling applied, and show first break refractions, air blast, and reflections. From these input traces, data (right) have had first breaks muted, air blast rejected, an FK-type noise rejection applied to reduce ground roll (not a significant problem), and spectral balancing applied. Coherent noise types like first breaks and air blast were reduced before spectral balancing was performed so reflection signal most determines scaling values.

The Grayburg reflection occurs around 0.720 seconds. The fold of stacked traces at the Grayburg level is only about one-half of the fold for deep reflectors, but is adequate for ultimate use creating an inversion model. Random noise is more noticeable on the data at right because the effect of noise increases with higher frequency (signal-to-noise ratio decreases with higher frequency). The relative noise is reduced by the trace stacking process to produce high quality, high resolution reflection data.

Figure 14. Comparison of conventional amplitude data from the 1996 data volume (left) and the 1998 data volume (right). Incremental improvements in the reprocessed data are observed as better detail within the Grayburg zone, a result of slightly better stacking and more accurate trace scaling. The data are of comparable bandwidth in this example. Time structure accuracy of strata from 0.5 - 0.8 seconds is improved with reprocessing, using a revised refraction statics model; the comparison of time structure with horizon depth is better. The shelf margin structure is similar on both data sets, although on this profile the slope reflections of the current processing appear degraded.

Figure 15. Profile L-L' (partial) from the inversion model data volume showing ties with wells and sonic logs, and horizon (production zone boundary) placements.

Figure 17. A comparison of Seismic Inversion Model traces, Reflection Seismic data input traces, the integrated (in time) Sonic Log, and Synthetic Seismogram character for the seismic data bandwidth. The seismic wiggle traces commonly used for interpretation contain the information to create the Inverted traces. The sonic log curve shows the one-foot detail obtained from well data. The Inversion Model trace detail (in velocity units) demonstrates a vertical resolution of about 50 feet, adequate to be applied to production model building. Note that the horizons, based on the inversion data picks and geologic thickness, do not have a reflection counterpart on the wiggle trace data.

Figure 18. Seismic Inversion-Derived Gross Average Porosity values for the Grayburg A zone. These maps relate to the two-line slope cross plot graph. The upper map represents porosity data converted from the line relationship for porosities of less than 4% and the lower map represents porosity data converted from the line relationship for porosities of more than 4%.

Figure 19. Seismic Inversion-Derived Gross Average Porosity
Grayburg A zone.

Pressure Change and Derivative (psi)

Figure 21

Figure 22

Figure 24

"Virgin" Formation Waters

	HC03	S04	CL	CA	MG	NA	TDS
UPPER GRAYBURG	170	2990	13500	1530	450	7750	26390
LOWER GRAYBURG	386	2632	20295	1889	664	11245	37332
SAN ANDRES	980	3881	33846	2507	762	19855	61831
INJECTION WATER	793	3100	32000	2646	947	17757	57244
CANYON	329	1104	76532	5880	692	42193	126693
ELLENBURGER	439	1459	63917	3840	972	36064	106691

Figure 25. "Virgin" formation water chemistry from upper and lower Grayburg, San Andres, Canyon and Ellenburger producing intervals and present day upper Grayburg injection water.

Figure 26. Partial analyses of lower Grayburg produced waters.
From isolated tests in recently completed wells.

Figure 27. Partial analyses of San Andres produced waters.
From isolated tests in recently completed wells.

Figure 28. Total Dissolved Solids, Sodium, and Chloride of Injection Water from Waterflood Inception in 1962 to 1998.

Figure 29. Changes in Total Dissolved Solids, Sodium, and Chloride of Produced Water from 1976 to 1998. Note similarity to changes in Injection Water Chemistry for the same time frame.

A

		HCO3	CA	MG	NA	SO4	CL	TDS
BROCK #5	5/20/98	841	3047	583	15591	3512	28000	51576
BROCK #5	8/24/98	671	2646	777	12282	3300	23000	42677
BROCK #5	8/31/98	658	2686	753	12925	3300	24000	44324
BROCK #5	9/21/98	756	2566	826	13614	3300	25000	46063

B

		HCO3	CA	MG	NA	SO4	CL	TDS	HARDNES	pH
BROCK #6	5/21/96	915	2720	656	14165	2431	26270	47194	9500	7.3
BROCK #6	6/9/97	585	2085	680	10287	2900	19000	35538	8000	7.2
BROCK #6	12/15/97	658	1684	923	11647	2950	21000	38864	8000	7.8
BROCK #6	5/7/98	646	2245	972	13124	3512	24000	44501	9600	7.7
BROCK #6	6/1/98	585	2165	728	13496	3150	24000	44099	8400	8.2
BROCK #6	6/8/98	585	2085	874	10119	3300	19000	35965	8800	7.6
BROCK #6	6/9/98	573	2125	753	10663	2717	20000	36832	8400	7.5
BROCK #6	6/12/98	597	2165	680	11587	3087	21000	39118	8200	7.8
BROCK #6	6/18/98	500	2125	704	10902	3087	20000	37320	8200	7.6
BROCK #6	6/24/98	800	2300	365	13560	3550	23000	43600	7250	7.6
"LOST WATER"		838	2445	1532	14882	4362	31000	55059		

Figure 30. Standard water analyses for produced water from (A) Brock #5 and (B) Brock #6. Chemistry of Brock #5 (A) water samples collected before (5/20/98) and after 8/24, 8/31 and 9/21/98) a fracture stimulation – note – the change in all cations and anions from before to after frac. Chemistry of Brock #6 (B) water samples collected before (5/21/96), and after 6/9/97, 12/15/97) CIBP and after fracture stimulation. Significant changes in water chemistry from before a drop in production (5/7 and 6/1) to after the drop in production (6/8, 6/9, 6/12 and 6/18) indicate a change in the produced water. The sample taken 6/24 followed the second and larger scale treatment. The “Lost Water” water chemistry is calculated data, and represents 1/3 of the total produced water from before the production drop.

Figure 31
Oil Saturation at 01-01-40
Initial Conditions

Figure 32
Oil Saturation at 01-01-61
End of Primary

Figure 33
Oil Saturation at 01-01-64
After 2 Years of Water Injection

WorkBench

Figure 35
Oil Saturation at 01-01-79
After 17 Years of Water Injection

Figure 36
Oil Saturation at 01-01-89
After 27 Years of Water Injection

Figure 37
Oil Saturation at 01-01-98
After 36 Years of Water Injection

OPERATOR	WELL NAME	FORMATION (ZONE) CORED	DEPTH
ARCO	#10 BROCK	SAN ANDRES	4290 - 4350
LAGUNA	#11 FOSTER	LOWER GRAYBURG (D, E, F, G, H) SAN ANDRES	4085 - 4194 4194 - 4265
ARCO	#3-X FOSTER-PEGUES	UPPER GRAYBURG (A1, A2, B1, B2, C)	3850 - 4086
LAGUNA	#11 FOSTER-PEGUES	LOWER GRAYBURG (C, D, E, F)	4100 - 4216
SUN	#6 WITCHER	LOWER QUEEN, U. GRAYBURG(A1,A2,B1,B2), SAN ANDRES	3850 - 3858 3858 - 4025 4260 - 4314
LAGUNA	#12 WITCHER	LOWER GRAYBURG (G, H), SAN ANDRES	4190 - 4232 4232 - 4370
GENERAL AMERICAN	#7 MAURICE	UPPER GRAYBURG (A1, A2, B1, B2, C)	3850 - 4025
GREAT WESTERN	#19 JOHNSON	UPPER GRAYBURG (A1, A2, B1, B2, C)	3933 - 4148
RICHMOND DRILLING	#3 RESSIE MAURICE	UPPER GRAYBURG (A1)	4360 - 4473

Table 1. Cores wells in, and adjacent to, the study area included in discussion..

Table 2

**Results of DOE Project - An Integrated Study Of The Grayburg/San Andres Reservoir Foster and
And South Cowden Fields, Ector County Texas. (Upper Grayburg Only)**

Well Name	Objective of Work	Date of Work	Production Prior Work			Initial Production After Work			Current Producing Rate		
			BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD
Brock #13	Plug Back to UG Eliminate Lease Line Migration	Dec-95	0	0	0	80	20	313	25	3	125
H. C. Foster #3	Re-entry to UG Eliminate Lease Line Migration	Mar-96	0	0	0	26	12	200	7	1	35
Foster Pegues #8	Re-Frac UG Increase Withdrawal Rates	Nov-98	2	0	14	25	2	455	20	2	385
Brock #6	Re-Frac UG Increase Withdrawal Rates	May-98	3	1	9	38	10	220	22	4	110
Brock #5	Re-Frac UG Increase Withdrawal Rates	Aug-98	6	1	6	72	10	200	20	3	75
H. C. Foster #8	Re-Frac UG Increase Withdrawal Rates	Mar-99	5	1	45	17	2	150	7	1	97
Witcher #1	Re-Frac UG Increase Withdrawal Rates	Jul-99	11	2	61	43	44	29	18	4	68
Witcher #3	Re-Frac UG Increase Withdrawal Rates	Nov-99	3	2	8	7	3	116	5	1	22
Witcher #14	Drill/Complete in UG	Dec-99	0	0	0	28	24	190	6	16	56
H. C. Foster #7	Re-Frac UG Increase Withdrawal Rates	Jan-00	2	1	6	27	3	400	23	3	355
Foster Pegues #7	Re-Frac UG Increase Withdrawal Rates	Jan-00	5	1	32	37	10	135	37	8	125
Brock #8	Re-Frac UG Increase Withdrawal Rates	Feb-00	1/2	0	1/2	20	2	404	20	2	404
H. C. Foster #11	Plug Back to UG Eliminate Lease Line Migration	Feb-00	0	0	0	47	3	355	12	1	161
Total			37 1/2	9	181 1/2	467	145	3167	222	49	2018

Table 3
Results of Plugback, New Drills and Deepening in the lower Grayburg Only

Well Name	Objective of Work	Date of Work	Production Prior Work			Initial Production After Work			Current Producing Rate		
			BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD
Brock #12	Plug Back To LG	Nov-94	0	0	0	14	1	235	12	1	225
Foster Pegues #10	Re-entry to LG	Nov-95	0	0	0	25	3	12	7	2	8
Foster Pegues #11	Drill/Complete in LG	May-96	0	0	0	106	60	65	11	2	14
H. C. Foster #11	Drill/Complete in LG	Jan-97	0	0	0	35	20	250	4	1	27
Witcher #12	Drill/Complete in LG	Jan-97	0	0	0	55	16	372	16	4	104
Witcher #2	Deepen to LG	Apr-97	3	1	13	87	12	168	24	6	68
Total			3	1	13	322	112	1102	74	16	446