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APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING

Cooperative Agreement Number: DE-FC22-94BC14989

FINA OIL AND CHEMICAL COMPANY

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Reporting Period: September 13, 1996 to December 12, 1996

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QUARTERLY TECHNICAL PROGRESS REPORT

"APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING"

INSTRUMENT NO. DE-FC22-94BC14989

NORTH ROBERTSON UNIT DEPARTMENT OF ENERGY CLASS II OIL PROGRAM PROJECT

REPORTING PERIOD: 9/13/96 TO 12/12/96

This Quarterly Progress Report summarizes the technical progress of the project from 9/13/96 TO 12/12/96.

ACTIVITY II.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - *TASK II.1.1*

Project Status

At this time, eighteen 10-acre infill wells have been drilled and completed as part of the Field Demonstration phase of the project at the North Robertson (Clearfork) Unit (NRU). The fourteen (14) producing wells are pumped-off and producing at stable rates. The four injection wells are completed and have been on injection for three to four weeks. Current Unit production is approximately 3,400 STBO/D, of which approximately 900 STBO/D is being produced from the 10-acre infill wells (**Fig. 1**). A change in the Statement of Work has been approved so that we can drill additional 10-acre infill wells and/or convert 20-acre producing wells to injection during the next quarter as budget constraints and rig availability allow.

ACTIVITY II.2 - FIELD DEMONSTRATION

IMPLEMENTATION OF FIELD DEMONSTRATION - *TASK II.2.1*

Core Analysis

We took 2,730 feet of core in four wells as part of an intensive effort to collect needed rock data. The data will be used to help quantify the extent of small scale vertical and lateral heterogeneity, refine the depositional model, improve our understanding of the relationship between porosity and

permeability, and help us choose additional 10-acre infill drilling locations within the NRU Clearfork Formation.

We attempted to cut cores continuously through the entire Clearfork section. Parts of the section were not cored due to significant mechanical difficulties caused by very long core times--often greater than 200 minutes per foot. This continuous core gives us the ability to make foot by foot comparisons of reservoir quality, rock type, and depositional environment, which ultimately will help us correctly model fluid movement within the reservoir.

The core was initially described by Fina geologists in Midland, Texas and then sent to David K. Davies & Associates, Inc. in Kingwood, Texas for more detailed description. Pore-scale analyses will be performed to verify the Budget Period I studies and to refine the "rock-log" model developed at that time. In addition, thin-sections are being made and described from the clipped ends of special core plugs which were taken in all potential reservoir intervals and in all rock types. Capillary pressures will also be run on these clipped ends to give us a representative set of data for each individual reservoir rock type.

The special core plugs (1.5 inch by 3 inch) were stored in sealed containers filled with degassed lease crude to preserve the native state of the rock characteristics and fluid content. We are in the process of obtaining much needed relative permeability, capillary pressure, wettability, and electrical properties data. The special core work is being performed by Core Petrophysics in Tulsa, Oklahoma.

FIELD OPERATIONS AND SURVEILLANCE - *TASK II.2.2*

Operations

All new wells are being operated in accordance with Fina Oil & Chemical's normal operating procedures.

Reservoir Surveillance

Currently, plans are being made to update the reservoir surveillance data acquired during Budget Period I. Pressure transient tests (pressure buildups and pressure falloffs) will be recorded to monitor pressure trends in the infill areas, and cased-hole pulsed-neutron logs will be run to monitor changes in water saturation in the near-wellbore area. All data (core, fluid, and well logs) acquired as part of the Field Demonstration phase of the project are currently being analyzed so that we may validate the Budget Period I Reservoir Characterization, Reservoir Management studies and update our Reservoir Simulation studies.

Well Testing

One injection well in Section 329 (#3536) was 'pre-produced' for a three or four week period, prior to being placed on injection in order to conduct near-wellbore wettability tests and try to optimize both injection and production in all wells. After the well was placed on production,

wettability was altered from the natural oil-wetting tendency to water-wet in the near-wellbore region to determine the effect on production efficiency. Making the rock water-wet in the near-wellbore region meant that formation water was coating the rock surfaces and that the oil was in the center of the pore space.

We noted that altering the near-wellbore wettability did not significantly alter the producing characteristics of the well, although this may have been due to the fact that the well had significant paraffin- and asphaltine-formation tendencies which are normal operating problems at the NRU. The well has been placed on injection, and the wettability in the near-wellbore region was returned to its natural oil-wet condition. Hopefully, these experiments will allow us to determine the optimum wetting conditions for both production and injection scenarios.

Interval testing was performed in the Lower Clearfork zone on two wells (#1509, #3534), in the Middle Clearfork zone on two wells (#3532, #2705), and in the Upper Clearfork interval on one well (#3018) in order to determine the relative contribution of each completed interval to production. In addition to interval producing rates, pressure drawdown data was recorded as each well's producing fluid level was pumped down, and analyses were performed to provide information concerning the production efficiency of each zonal completion. The results of these tests are summarized in the Reservoir Management section of the report.

Reserves - Incremental vs. Accelerated

Early results indicate that approximately 65% of the production from the new infill wells is incremental, and approximately 35% may be acceleration of existing reserves. The new wells account for approximately 900 STBO/D of the total Unit production, and the amount of incremental production since the Field Demonstration was implemented is between 600 and 700 STBO/D. On an individual well basis, most of the additional production in Section 329 of the Unit (**Fig. 2**) appears to be due to acceleration of existing reserves, while most of the additional production in Sections 326 and 327 appears to be incremental. These trends were predicted prior to drilling on the basis of differing reservoir rock types that occur in the two areas. The Section 329 infill area is dominated by grainstone shoal facies with fairly good permeability and porosity characteristics. The reservoir within Sections 326 and 327 is dominated by lagoonal facies with good storage capacity (porosity), but relatively lower permeability and connectivity. We will continue to monitor and report individual well producing characteristics in an effort to quantify incremental reserves added via infill drilling.

Well Stimulation

As a result of the data acquisition process (core and logs) during the Field Demonstration phase of the project we have found that we could identify discrete intervals within the Glorieta/Clearfork section that contribute most to production. These are intervals of relatively high permeability and porosity reservoir, which are separated by larger intervals of lower permeability and porosity rock that act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clearfork:	MF4 and MF5 zones	(±7,000 to 7,200 ft)
Middle Clearfork:	MF1A, MF2, and MF3 zones	(±6,350 to 6,500 ft, and ±6,750 to 6,900 ft)
Upper Clearfork:	CF4 Zone (varies in Unit)	(±6,150 to 6,200 ft)

We have utilized three-stage completion designs to keep the treated intervals between 100 and 250 ft. We have performed both CO_2 foam fracs and conventional cross-linked borate fracs. All well's rates have held up extremely well over time for both hydraulic fracture designs. The major factor controlling initial potential appears to be confinement of the vertical completion interval and localized reservoir quality.

ACTIVITY II.3- INTEGRATION/VALIDATION

VALIDATION OF RESERVOIR CHARACTERIZATION - *TASK II.3.1*

Thin Section Analyses

Numerous thin sections of the cored intervals have been prepared. Plans are to use information from these thin sections to enhance our understanding of pore size, pore distribution, rock type, and depositional environment.

Depositional Environments

Additional refinements were made to the depositional environment model based on data from recently acquired core taken from the latest 10-acre infill wells. The planned coring program and a cursory description of these cores have been completed. This represents 2,730 ft of core in four wells. The preliminary depositional environments described from this new data are as follows:

Open Shelf

- Open Shelf - general
- Fusilinid Shoal
- Shoal - general
- Inter-Shoal

Reef

- Reef Center
- Reef Talus Apron
- Reef Debris Apron

Open Lagoon

Restricted Lagoon

Island

- Island Center
- Near Island Beach

Algal Mat
Outer Island Beach

Tidal Flat
Algal Mat
Tidal Channel
Shallow Sub-Tidal Silty Dolostone

Supratidal

There are several significantly new features not noted from previous core descriptions. The first is the presence of large patch reefs and associated porous debris aprons in the Lower Clearfork within Section 327. Previous work suggested that a 'shelf' edge existed to the east of Section 327, and that the large reefs would only exist along this shelf edge. This new core information implies that there is no shelf edge as such, just patch reefs and debris aprons scattered across the Unit. This information could help explain the erratic distribution of good producing wells in the south-central portion of the Unit. It is important to note that the debris aprons and shoals around these reefs typically have good reservoir quality. In addition, smaller and less well developed reefs and bioherms have been noted in the upper portions of the Middle Clearfork and Upper Clearfork.

The second new piece of information concerns the MF3 layer (± 6,850 ft) of the Middle Clearfork that has been reinterpreted as a solution collapse breccia with associated open natural fractures. These features were caused by dissolution of carbonate beneath extensive exposure surfaces. The presence of these surfaces is supported by presence of coal beds, abundant 'fresh' water plant debris zones, erosion lag soils, and some root casts. Parts of the Unit were only partially exposed, most probably as a series of small islands and associated carbonate sand beaches. This information is of important economic significance, because there is more natural fracturing in the MF3 zone than previously thought. Further analyses will determine the interconnection and influence of this fracturing from solution collapse breccias.

Rock Fabrics

We have described four basic rock fabrics:

1) *Homogeneous*--which is made up of relatively uniformly distributed lateral and vertical porosity and permeability. The best example of this type of rock fabric is found within selected portions of the MF1A layer. We are not implying that this zone is perfectly homogeneous like some silica clastic sands, however, this layer is much closer to this type of homogeneity than all other zones in the Clearfork.
2) *Fractured*--which is made up of solution collapse breccias as described above. Fractures are 2-4 inches in length and very roughly estimated to be 4-6 inches apart. Not all of these fractures are open, as many have been plugged with anhydrite. Portions of the MF3 layer are a good example of this fabric.
3) *Bimodal*--which is made up of two distinct pore sizes. The larger size pores are typically formed from the dissolution of fossil debris, and the smaller pores are typically intercrystalline in origin.

4) *Heterogeneous*--which is made up of anhydrite nodules, and porous dolostone. This fabric is common throughout much of the Clearfork/Glorieta section. The size and distribution of these anhydrite nodules vary dramatically.

Porosity versus Permeability Relationships

Improving our understanding of the relationship between porosity and permeability has been one of the key efforts of our geologic work. Our approach has been to integrate all geologic and engineering data in an attempt to refine our existing porosity-permeability algorithms, and to redefine flow unit boundaries. Now that we have finished the infill drilling program and loaded all new core and open-hole log data into our database, we can begin to update our porosity-permeability relationships and flow unit definitions as described in the following paragraphs.

Early indications are that by using multiple geologic 'filters' it is possible to dramatically reduce the scatter on our porosity versus permeability crossplots, thereby providing us with more robust algorithms. 'Filters' include devices such as depositional environment data, shallowing upward sequence tops, rock type data, mud log data, and numerous open-hole log responses (PE, Spectral Gamma-Ray, Invasion Profile, etc.).

Additionally, we have found that neural network technology allows us to combine curve data in multiple ways to help find unique permeability signatures. Our research has only just begun in this area, however, early results are very promising and we will continue to report our findings during Budget Period II.

Updating the Core-Log Model

We have completed extensive work on improving the porosity versus permeability algorithms used in the early phases of this project. Results to date indicate that several new lines of research hold promise:

1) Generation of $\emptyset$ versus k plots for each shallowing upward carbonate cycle (previously called flow unit tops).
2) Generation of $\emptyset$ versus k plots for each depositional environment.
3) Use of Neural-Network programs to identify characteristic sequences based on core and log responses.
4) Improvement of the old core-log algorithms using new open-hole log data.
5) Formulation of unique $\emptyset$ versus k relationships for small areas of the field related to the $\emptyset$ versus k relationships for the core in that area.

Fina geologists will work closely with David K. Davies & Associates, Inc. in order to combine these various techniques and formulate the best method or combinations of methods to obtain optimal permeability-porosity relationships.

Special Core Analysis (SCAL)

Approximately 120 preserved (3 inch by 1.5 inch) core plugs were cut from the new whole core in 10-acre infill wells 1509, 3533, 1510, and 3319 in order to obtain a representative sampling of all 'pay' rock types that were defined during Budget Period I. Thin-section descriptions and capillary pressure measurements are being obtained from the clipped ends of all 120 core plugs.

The SCAL plugs were further screened both visually (thin-sections and slabbed core), and using a computerized axial tomography (CT) scan machine at Texas A&M University to eliminate the plugs that possessed major barriers to flow (which is almost always in the form of anhydrite nodules) as shown in **Fig. 3**. A CT number of 2550 and above indicates the presence of extensive anhydrite. Pure dolomite has a CT number of about 2350 and the number for pure limestone is around 2250. CT numbers less than 2200 are indicative of good porosity or fracturing.

These studies allowed us to choose 46 plugs, representing the reservoir rock types (Rock Types 1, 2, 3, and 5), for special core studies. The plugs were sent to Core Petrophysics in Tulsa, Oklahoma for special core analysis. An additional plug screening was performed by obtaining oil permeabilities for all 46 SCAL plugs to determine which samples should be used for relative permeability tests. We are currently performing wettability, relative permeability, capillary pressure, and electrical properties measurements on the screened plugs to update our database for reservoir flow simulation. Results will be reported as they become available.

VALIDATION OF RESERVOIR MANAGEMENT ACTIVITIES AND PERFORMANCE ANALYSIS - *TASK II.3.2*

Material Balance Decline Curve Analysis

Once sufficient data are acquired, we will analyze early production data from new wells utilizing material balance decline type curve methodologies formulated during Budget Period I. Early rate and fluid level measurements will allow us to verify the results of previous analyses and obtain early estimates of individual well potentials, bottomhole pressures, and formation flow characteristics. The results of this work will be reported in the next Quarterly Progress Report.

Pressure Transient Tests

Short-term pressure drawdown tests were used to measure formation flow characteristics in the new producing wells. We recorded drawdown rather than buildup tests to avoid shutting in recently completed wells. These tests were being recorded over individual completion intervals (i.e., Lower, Middle, or Upper Clearfork), and were used to estimate the completion efficiency and the relative contribution of each zone to total production. This information will aid in injection well profile modification work to be performed during Budget Period II.

To date, we have recorded both Lower (NRU 3534) and Middle (NRU 3532) Clearfork drawdown tests in the Section 329 area, and Lower (NRU 1509), Middle (NRU 2705) and Upper (NRU 3018) Clearfork drawdown tests in the Section 327 infill area. We have found that the

hydraulic fracture jobs have been successful and are producing fractures with half-lengths on the order of 100 ft (skin factor = -5.0). A log-log plot summarizing the results for the analysis of the NRU 3532 Middle Clearfork pressure drawdown test is shown in **Fig. 4**.

Results also indicate that the Middle and Upper Clearfork intervals are much more significant contributors to total production than was previously thought. At this point it appears that each interval's approximate contribution to total oil production is as follows:

	Section 327	Section 329
Upper Clearfork	20%	10%
Middle Clearfork	50%	65%
Lower Clearfork	30%	25%

This information, together with newly acquired core and log data, will allow us to target our completion intervals much more effectively at the NRU.

During the next quarter, we will perform extended pressure buildup tests on new 10-acre wells, as well as follow-up tests on the same 20-acre wells that were tested during Budget Period I. On several of the wells we will record pressure data with a bottomhole gauge as well as from surface with an acoustic well sounder (AWS) for comparison purposes. If the AWS data is of sufficient quality, we will record future pressure buildup tests using this system to avoid costs associated with setting the bottomhole gauges (rig time and slickline unit).

Pressure falloff tests will be recorded on all new injection wells after completion. Results will be reported as they become available.

Injection Profiles

The results of approximately 25 injection profiles recorded during the second quarter of 1996 indicate the need for a revised injection well workover plan. Many of the injectors contain large amounts of fill, and other wells inject into only a very small percentage of the total productive interval (usually the Lower Clearfork).

We have attempted to improve injection efficiency by identifying the intervals in the producing wells that are the largest contributors to total production. Rather than attempting to inject water across a large 1200 ft interval as was done previously, we will attempt to target fairly small, specific intervals. Profile modification may be attempted in existing injectors, and an effort will be made during the completion of new injection wells to avoid high permeability streaks that take most of the injection water. Results of some of this work will be reported as they become available.

VALIDATION OF RESERVOIR SIMULATION - *TASK II.3.3*

Updated reservoir models are being generated at present. Results will be reported as they become available.

Geostatistical Modeling

During Budget Period II, more work is planned to improve the definition of the uncertainty in the reservoir model forecasts. New log and core data are being obtained from more closely spaced infill wells that will allow the spatial continuity of the porosity and permeability fields to be examined on a finer scale. Additional realizations of the reservoir model will be generated with less horizontal continuity, and then will be used to forecast reservoir performance as above. The effect of the horizontal continuity on the forecast spreads will then be observed. Results will be reported as they become available.

Deterministic Modeling

All simulation models will be updated to incorporate changes in reservoir description (rock types), PVT, and special core properties as they become available during Budget Period II. We will also investigate the use of a dual-porosity simulation model to better capture the behavior of a reservoir consisting of high permeability productive streaks surrounded by large intervals of low permeability rocks that may act as a hydrocarbon source for those high-permeability intervals. If the number of reservoir layers in the simulation models can be significantly reduced, then several of the model areas may be combined into a larger simulation model to eliminate the current assumptions regarding boundary flux in each model area.

ACTIVITY II.4- TECHNOLOGY TRANSFER

NEWSLETTERS - *TASK II.4.2*

The second Project Newsletter will be distributed during the first or second quarter of 1997.

PUBLICATIONS AND PRESENTATIONS - *TASK II.4.3*

Published Papers and Professional Meeting Presentations:

1997 Annual DOE/BDM International Reservoir Characterization Technical Conference, March 2-4, 1997, Houston, TX.

- Oral presentation and poster session on project material
- "Improved Characterization of Reservoir Behavior by Integration of Reservoir Performance Data and Rock Type Distributions."

Oklahoma Geological Society Circular, *Platform Carbonates in the Southern Mid-Continent*, (in press), K.S. Johnson, March 1997.

- "Environments of Deposition for the Clear Fork and Glorieta Formations, North Robertson Unit, Gaines County, Texas."

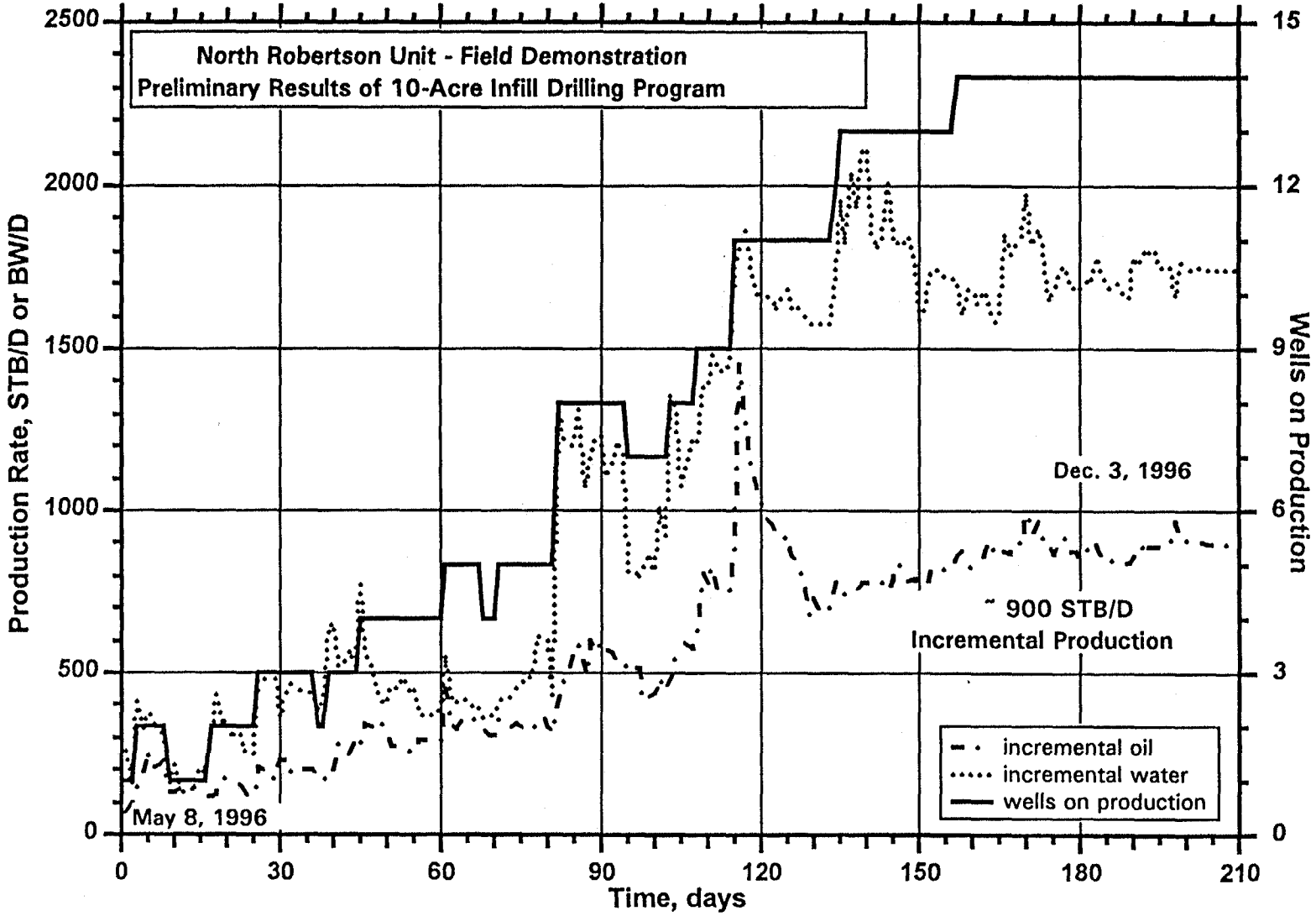


Figure 1 - Incremental Production Increase Due to New 10-Acre Infill Wells.

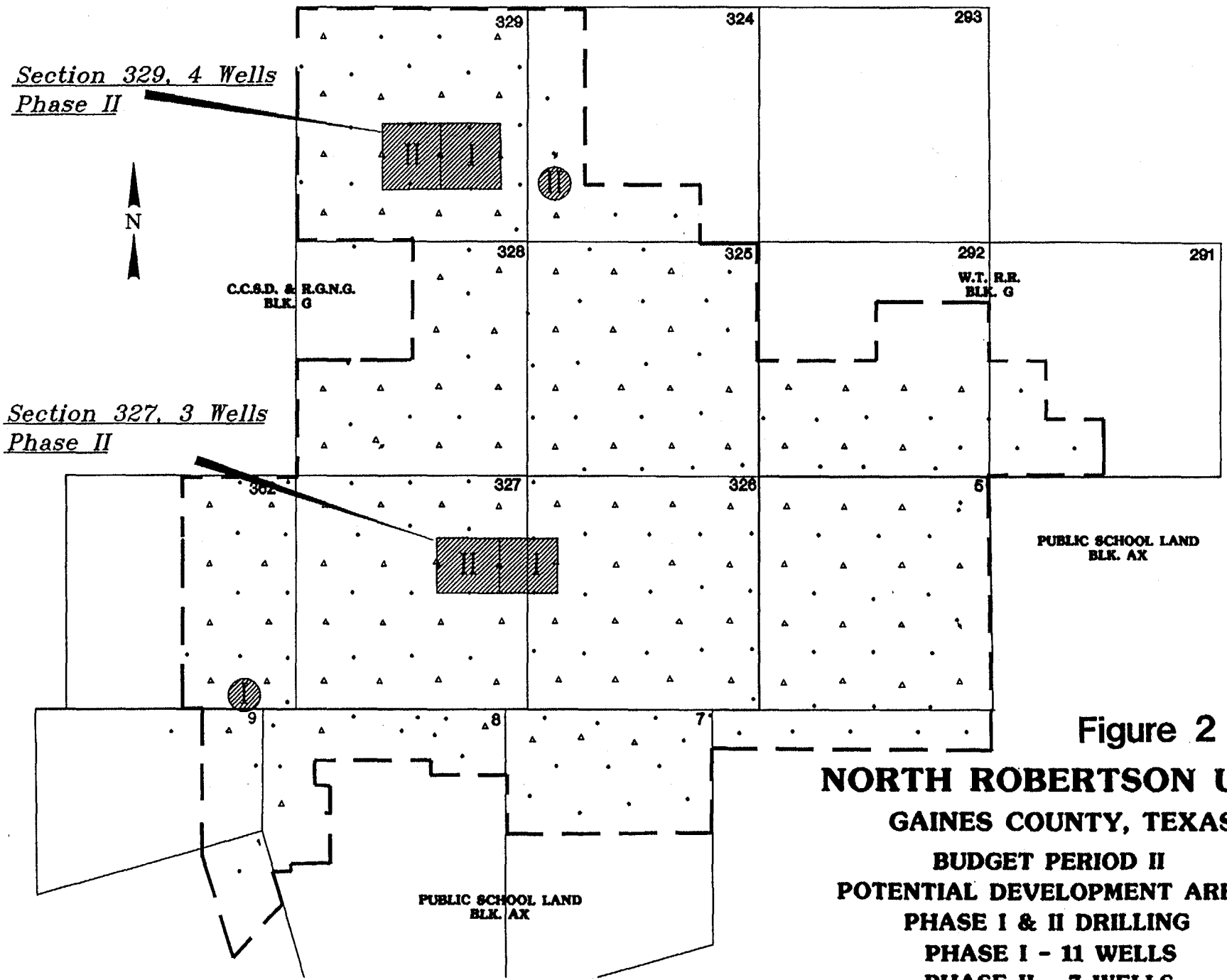
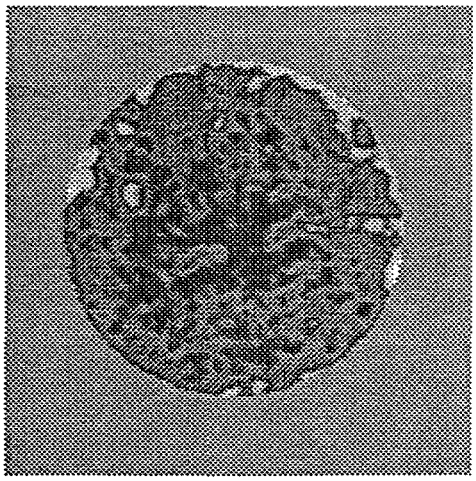


Figure 2

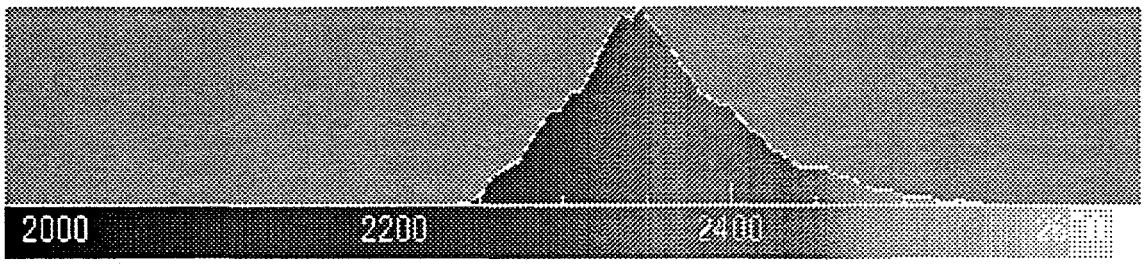
NORTH ROBERTSON UNIT

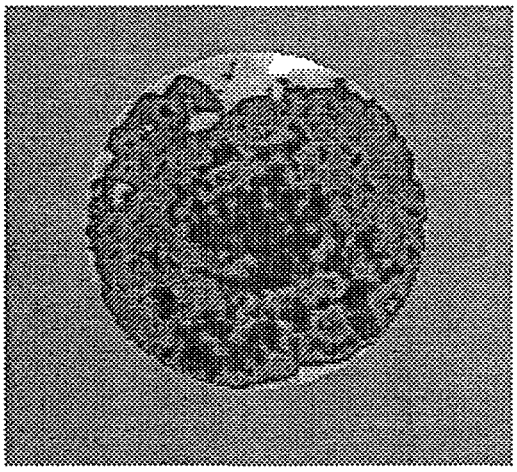
GAINES COUNTY, TEXAS

BUDGET PERIOD II
POTENTIAL DEVELOPMENT AREAS
PHASE I & II DRILLING
PHASE I - 11 WELLS
PHASE II - 7 WELLS



Fina/NRU 1509
Core No. 13, Slice No. 1
Well Depth = 7050.8 ft
Min. CT No. = 2218
Max. CT No. = 2687
Avg. CT No. = 2368





Fina/NRU 1509
Core No. 13, Slice No. 6
Well Depth = 7050.8 ft
Min. CT No. = 2199
Max. CT No. = 2744
Avg. CT No. = 2356

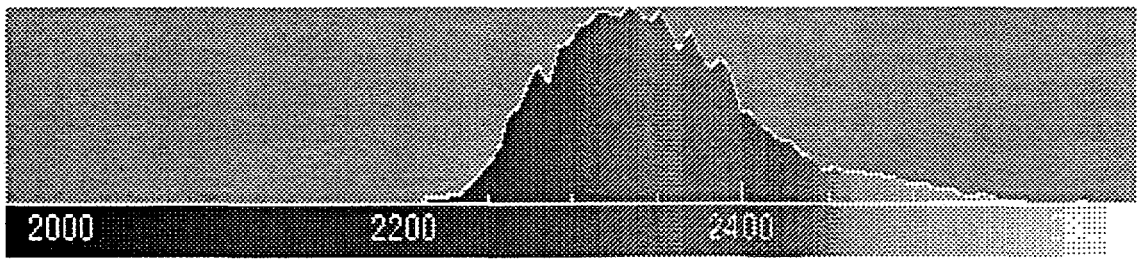


Figure 3 - Computerized Axial Tomography (CT) Images of Special Core Plug from NRU Well #1509 at 7050.8 ft.

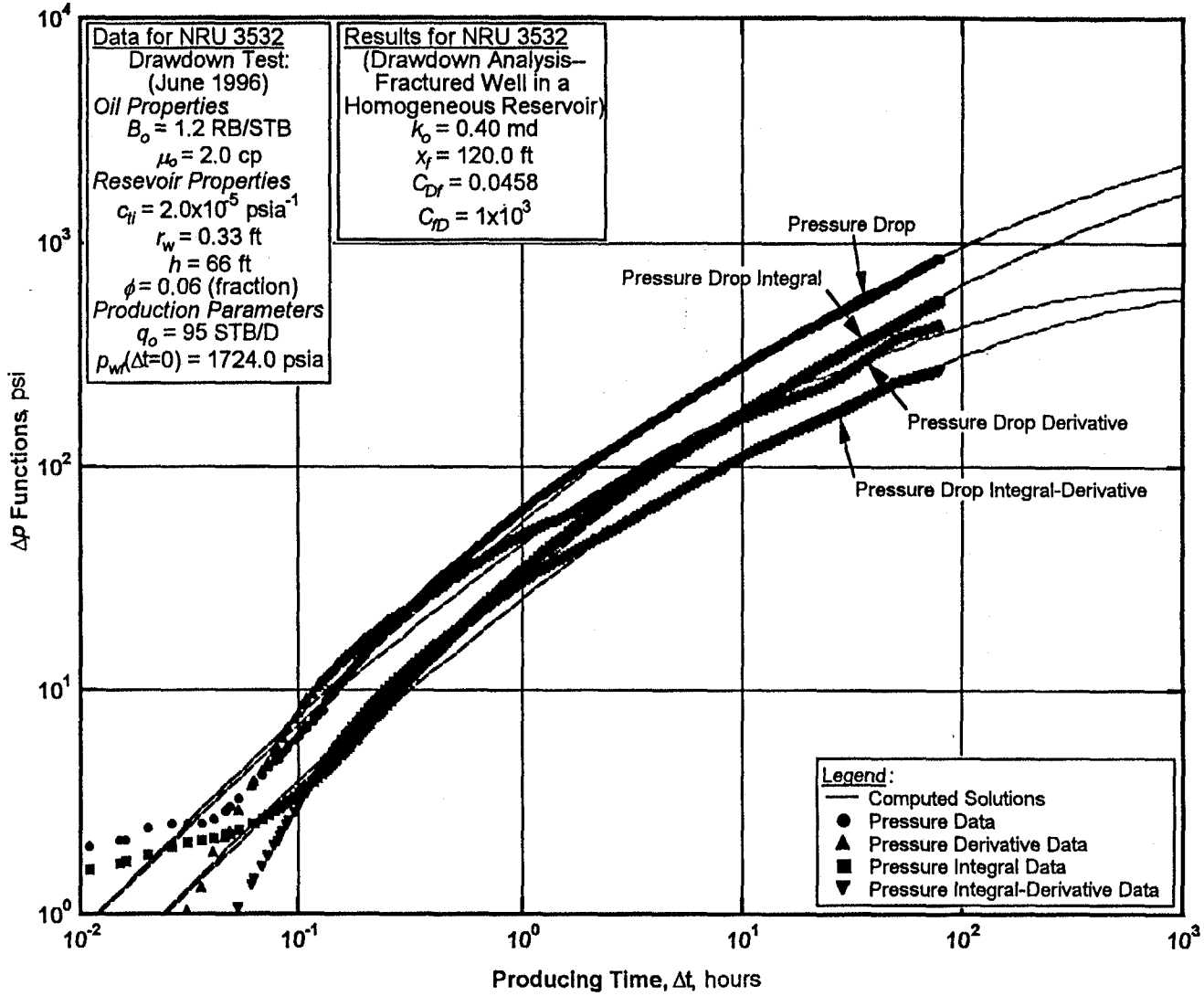


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Figure 4 - Data Match on Log-Log Plot for Well NRU 3532 Pressure Drawdown Test (June 1996). Matched Using the Model for a Well with an Infinite Conductivity Vertical Fracture in an Infinite-Acting Homogeneous Reservoir.