Application of Integrated Reservoir Management and Reservoir Characterization to Optimize Infill Drilling

Quarterly Report September 13 - December 12, 1997

Work Performed Under Contract No.: DE-FC22-94BC14989

For
U.S. Department of Energy
Office of Fossil Energy
Federal Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
Fina Oil & Chemical Company
6 Desta Drive
Suite 4400
Midland, Texas 79701

Disclaimer

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

FINA OIL & CHEMICAL COMPANY

QUARTERLY TECHNICAL PROGRESS REPORT

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

INSTRUMENT NO. DE-FC22-94BC14989--15

**NORTH ROBERTSON UNIT DEPARTMENT OF ENERGY
CLASS II OIL PROGRAM PROJECT**

REPORTING PERIOD: 9/13/97 TO 12/12/97

This Quarterly Progress Report summarizes the technical progress of the project from 9/13/97 TO 12/12/97.

ACTIVITY II.1 - MANAGEMENT AND ADMINISTRATION

PROJECT MANAGEMENT AND ADMINISTRATION - TASK II.1.1

Project Status

The eighteen 10-acre infill wells which were drilled as part of the field demonstration portion of the project are all currently in service with no operational problems. These wells consist of fourteen producing wells and four injection wells. The producing wells are currently producing a total of approximately 450 bopd, down from a peak rate of 900 bopd. Unit production is currently averaging approximately 2,700 bopd, 12,000 bwpd and 18,000 bwipd.

ACTIVITY II.2 - FIELD DEMONSTRATION

IMPLEMENTATION OF FIELD DEMONSTRATION - TASK II.2.1

Hydraulic Fracture Design

Analysis of the open-hole well log data and the rate-pressure data from the hydraulic fracture jobs performed on the 10-acre infill wells at NRU indicates that only minor adjustments may need to be made before future wells are fracture-stimulated. Overall, the HF designs performed by the service companies resulted in stimulations with excellent conductivity. By utilizing the available core, well log, and rock-log data, we were able to improve the targeting of the productive intervals within the three major Clear Fork intervals. By using three separate fracs in the majority of the wells we obtained better fracture penetration and improved conductivity.

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/Clear Fork 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 appear to act as source beds for the higher quality reservoir rock. These intervals include:

Lower Clear Fork:	MF4 and MF5 zones	(±7,000 to 7,200 ft)
Middle Clear Fork:	MF1A, MF2, and MF3 zones	(±6,350 to 6,500 ft, and ±6,750 to 6,900 FT)
Upper Clear Fork:	CF4 Zone	(±6,150 to 6,250 ft)

We have utilized three-stage completion designs to keep the treated intervals between 100 and 250 ft. We have performed both CO foam fracs and conventional cross-linked borate fracs using a new premium frac fluid on an equal number of new wells, with outstanding results for both designs. The advantages of each type of frac design are listed below:

CO Foam Fracs: exceptionally clean frac fluid
 increased relative oil permeability
 created solution gas drive reduces cleanup requirements
 formation of carbonic acid for near-well stimulation
 reduction in interfacial tension helps remove water blocks

Cross-linked Borate: exceptionally clean frac fluid
 low fluid loss without formation-damaging additives
 excellent proppant-carrying capacity
 polymer-specific enzyme breaker aids in post-frac cleanup
 90% of original fracture conductivity retained

Pre-frac cleanup acid jobs have been performed to remove near-well damage using between 1000 and 3000 gallons of 15% acid. Most intervals have been perforated for limited-entry fracturing (>2bbl per perforation), with average injection rates between 30 and 40 barrels per minute, depending on the size of the interval. The size of the frac jobs has ranged from 25,000 gallons of fluid and 42,000 lbs of sand to 76,000 gallons of fluid and 157,000 lbs sand. Both 16/30 and 20/40 Ottawa sand were utilized as proppants. Resin-coated sand was 'tailed-in' for most frac jobs to reduce sand flowback during production. The conventional fracs have been flowed back immediately at 1 barrel per minute to induce fracture closure, while the foam fracs have been shut-in 2-5 days after stimulation to allow the CO₂ to migrate into the formation.

All jobs have been radioactively traced to estimate vertical fracture propagation. Using this information, we have been successful in avoiding fracturing down into an underlying water zone in the Lower Clear Fork, and we have been able to avoid any fracture communication between stages. All hydraulic fracture jobs were designed to yield fracture half-lengths of approximately 200 ft.

Evaluation

Post-frac pressure transient tests performed over specific completion intervals indicate that we are obtaining fracture half-lengths between 80 and 150 ft with average radial flow skin factors of approximately -5.0. However, as these tests were short-term post-frac pressure drawdown tests performed on pumping wells as they were cleaning up, the accuracy of the results could be uncertain.

Material balance decline type curve analyses performed on each new producing well after six to twelve months of production indicated that the average fracture half-length was slightly over 200 ft, and that the average near-wellbore skin factor was about -5.7. These values compare extremely well with the design criteria for the frac jobs.

Rock Properties

We were able to record full-wave sonic logs on most of the 10-acre infill wells. Using the compressional and shear travel times and the bulk density obtained from well logs, we calculated rock mechanical properties such as shear modulus, bulk modulus, Young's modulus, and Poisson's ratio.

In many cases, we were unable to get good fracture closure pressures from the rate-pressure data obtained from the frac jobs performed to date. Even for wells that were treated with conventional borate crosslinked fluids and force-closed, it was often difficult to pick a unique value for closure pressure as an insufficient amount of data was recorded during flowback. For the most part, we know that the fracture closure pressure for each individual zone is between 4000 and 5000 psi. Fortunately, we could use the available open-hole log data to obtain good estimates for both closure and initiation pressures.

The reliability of this data depends primarily on the difference between the static and dynamic values for bulk modulus, Young's modulus, and Poisson's ratio that are used to calculate both closure and initiation pressures. The well-log derived data is considered dynamic data due to the method in which it is measured. The input required for fracture design is static mechanical property data. We plan to obtain the lab data required for this comparison by performing tests on approximately 30 core samples in the near future. However, it would appear that the dynamic full-wave sonic data used to calculate closure pressure yields results that compare very well with what we have noted from the frac jobs. This is not unexpected as the dynamic and static mechanical properties for harder (carbonate) rocks such as the Clear Fork tend to be similar, while for more friable rock (sandstone), the static and dynamic properties can differ greatly.

Once we are certain of the relationship between the static and dynamic properties, we can then build transforms between typically-recorded open-hole log data (such as gamma ray and bulk density) and the rock mechanical properties--and no extravagant log suites will be required to obtain data for frac designs. Due to the fact that there are no extreme variations of rock mechanical properties throughout the Clear Fork section, we have already recorded sufficient full-wave sonic data to design fracture treatments throughout the Unit.

The major problem in an active waterflood environment is to get an accurate handle on reservoir/pore pressure, since it is also required to estimate both the fracture closure and initiation pressures. In many areas of the Unit, pore pressure can vary greatly due to uneven waterflood support. The Formation Test data obtained during the initial 10-acre infill drilling program was a great data source for

estimating pore pressure across the Unit. On a related topic, it is interesting to note that for the Tract 35 wells in which we obtained relatively poor full-wave sonic data (NRU 3533, 3537, and 3538), we also had trouble fracture-treating the wells. The sonic data may have been adversely affected by gas coming out of solution from high pressure water flows known to exist in the Lower Clear Fork interval. These same flows could have adversely affected cementing and fracturing operations.

We were able to estimate values for fracture closure pressure and fracture initiation pressure for each zone of every well utilizing the available open-hole log data. Areal maps were also constructed based on the mean values for closure and initiation pressure for each completed interval in every well. The following relationships were used:

$$\text{Fracture Initiation Pressure, FIP} = 2 * \left[\left(\frac{I}{1-I} \right) * (P_{ovbn} - P_{pore}) \right] + P_{pore} + S_{tensile}$$

$$\alpha = \text{Biot's constant} = 1 - \frac{K}{K_{ma}}$$

$$\text{Fracture Closure Pressure, } S_x = \left[\left(\frac{I}{1-I} \right) * (P_{ovbn} - P_{pore}) \right] + P_{pore}$$

for which:

I = Poisson's Ratio

P_{ovbn} = Overburden Pressure ≈ 1.0 psi/ft

P_{pore} = Pore Pressure ≈ 0.45 psi/ft (Clear Fork - current conditions)

$S_{tensile}$ = Tensile Strength, psi/ft (negligible)

K = Bulk Modulus, $\text{psi} * 10^6$

K_{ma} = Bulk Modulus of Pure Matrix, $\text{psi} * 10^6$

Note, that after fracture initiation, that Biot's constant in the direction of least principal stress (horizontal, in this case) is no longer a function of rock compressibility, and may be assumed to be equal to 1, and therefore, is not included in the expression for closure pressure.

Therefore, for a typical Clear Fork interval, under current stress conditions, we have:

$$FIP = 2 * \left[\left(\frac{0.28}{1-0.28} \right) * (1.0 - [0.3 * 0.45 \text{ psi / ft}]) \right] + 0.3 * 0.45 \text{ psi / ft} = 0.808 \text{ psi / ft}$$

$$S_x = \left[\left(\frac{0.28}{1-0.28} \right) * (1.0 - 0.45) \right] + 0.45 = 0.664 \text{ psi / ft}$$

Net Pressure Analyses (Nolte Plots)

The calculated bottom hole treating pressures taken from the frac jobs performed during the initial 10-acre infill drilling program were utilized together with the calculated values of log-derived closure

stress for each individual completion interval to construct Nolte plots. The characteristic shape of the plot gives a qualitative indication of the way in which the fracture propagated, and what its geometry might be.

Several diagnostic net pressure plots taken from SPE 14263 by Conway, *et al.* of Halliburton Services show the different fracture geometries that correspond to specific responses on the Nolte plot. We note that for the most part, the hydraulic fracture jobs at NRU appear to be Type II (Perkins and Kern) and Type III (Penny) for which vertical fracture propagation is extensive or uncontrolled. This is what we would expect in a formation with no major barriers to vertical fracture growth. Fortunately, the vertical growth is not so rapid as to cause a premature screenout in most cases. The few jobs that did screenout prematurely were wellbore screenouts due to insufficient injection rate or pressure. In addition, some of these frac designs called for 16/30 proppant which requires a greater fracture width than 20/40 sand (see Design Example below).

Fracture Simulation

The accurate determination of rock properties and formation stresses are extremely important parts of the overall hydraulic fracture design. However, they are far more important in areas in which there is a great variation in rock mechanical properties. If a 3-D fracture simulator is utilized to design a frac job, these properties should be input on a layer-basis, and layers with distinctly different properties (reservoir and rock) should be separated. For the Clear Fork at North Robertson, most of the interval contains layers with very similar properties. The layers possessing distinctly different characteristics usually are not extensive enough to alter (i.e., confine) vertical fracture propagation.

Example 2-D fracture simulations were performed using both the PKN and GDK models for all three completion intervals in well NRU 3534. Because we have a fairly good idea of how the fractures are propagating vertically from the work we have performed previously, we can input a good estimate of gross frac height that is a required input to the 2-D model. In addition, instead of using individual layer reservoir and rock properties, lumped or average values are input to the 2-D model. By comparing the results for NRU 3534 with the 3-D frac designs for the Lower and Middle Clear Fork intervals, we see that for the smaller LCF interval that the 2-D model agrees fairly well with the 3-D results. However, when the interval becomes larger, such as for the MCF interval, and the variations in layer properties are slightly more pronounced, then the results generated by the two models vary appreciably. This indicates the importance of having a layer-by-layer reservoir description input capability, and a 3-D fracture simulator.

At the same time, changing most of the rock mechanical properties by as much as 50% will have little impact on the fracture dimensions—as long as the changes are consistent. The value input by the service company for Young's modulus is approximately half of what we calculated from the open-hole log data (another reason to do those static-dynamic core tests). They obviously felt more comfortable with a value of 5.6×10^6 than the actual value of 11.5×10^6 . But this change makes little difference since they have normalized every layer so that there is no great variation in Young's modulus between layers.

Future Data Requirements

After we have performed the necessary static-dynamic core data comparison, and built a transform to utilize basic open-hole log data as described above, no further acquisition of rock mechanical properties data should be needed for the Unit wells.

If money is to be spent in acquiring useful data for frac design, we should focus on the following:

1. obtain accurate values for the leakoff coefficient and closure stress from a limited number of minifrac tests,
2. optimize the frac fluid rheology (i.e., increasing viscosity) to improve the proppant-carrying characteristics of the frac fluid, and,
3. find the proppant that meets our conductivity requirements (see below).

Design Example

From a performance and cost-effectiveness standpoint, it would appear that BJ's 35 lbm/gal Spectra-Frac G fluid will work well for hydraulic fracture jobs in the Clear Fork at the North Robertson Unit. It would also seem that a max sand concentration of 8 ppg with an 8 ppg RC sand tail-in will be sufficient for our purposes, although higher sand concentrations can be considered. The example calculations below are for the Lower Clear Fork with the following characteristics:

Depth to mid-perfs = 7050 ft
 net height (pay) = 100 ft
 gross height = 200ft
 design fracture half-length = 250 ft
 injection rate = 30 bpm
 proppant = 20/40 Ottawa sand
 frac fluid = 35 ppg gel
 max sand concentration = 8 ppg
 frac job pumped down 5.5" OD casing

1. Dimensionless Fracture Conductivity:

We want to achieve a dimensionless fracture conductivity, $C_f D$, of at least 10.0, and a fracture half-length of around 250 ft. Designing for dimensionless conductivities greater than 10 will increase the cost of the frac job, however, the stimulated production rate will not increase greatly. Due to conductivity reduction caused by proppant crushing and various chemical processes, we actually need to design for a dimensionless fracture conductivity of 30.0, as long-term fracture conductivity for a sand proppant will be reduced to about 30% of the initial value. Therefore:

$$w k_f C_f D \Pi \chi_f k_{oil}$$

$$w k_f = (30)(\Pi)(250 \text{ ft})(0.05 \text{ md}) = 1178.1 \text{ md-ft}$$

20/40 Ottawa sand meets our conductivity requirements for the closure stress (4500 psi) and temperature (115°F) in this interval. Neither Jordan sand, nor Brady sand meet the conductivity

requirement. A proppant should be chosen so that the conductivity requirements are met, the created fracture width is large enough to safely receive the proppant, and the diameter of the perforations is large enough to prevent premature screenout. The diameters for each individual proppant size may be calculated as:

$$\text{Proppant Diameter, in.} = 0.4114 * ((1./(\text{small mesh}^{**1.06})) + (1./(\text{large mesh}^{**1.06})))$$

For 20/40 proppant, diameter = 0.02543 in.

For 16/30 proppant, diameter = 0.03295 in.

For 12/20 proppant, diameter = 0.04672 in.

As a rule of thumb the fracture width should be at least three times the proppant diameter. Therefore:

For 20/40 proppant, required frac width = 0.0763 in.

For 16/30 proppant, required frac width = 0.0989 in.

For 12/20 proppant, required frac width = 0.1402 in.

Note, if we wish to use a proppant size of 16/30 or above, we must design for a fracture with a width greater than 0.0989 in. or we may screenout.

In addition, the perforation diameter should be at least six times the proppant diameter:

For 20/40 proppant, required perf diameter = 0.1526 in.

For 16/30 proppant, required perf diameter = 0.1978 in.

For 12/20 proppant, required perf diameter = 0.2804 in.

This should not be a problem since we used 0.41 in. diameter holes on all wells, and the perforation diameter will only increase during injection due to friction-related wear.

The permeability of 20/40 Ottawa sand is 180,000 md. For this particular proppant, we will need to design for a fracture width of at least:

$$w = \frac{1178.1 \text{ md} - \text{ft}}{180,000 \text{ md}} = 0.006545 \text{ ft} = 0.07854 \text{ in}$$

Note: this is greater than our minimum width required of 0.763 in. (from above).

2. Proppant Volume Required:

Previous Clear Fork field experience indicates that for a 100 ft frac interval, the fracture will grow both up and down approximately 50 ft, therefore the gross height is approximately 200 ft for a 100 ft net height.

$$\text{Proppant Volume} = (2 \text{ wings})(250 \text{ ft})(0.006545 \text{ ft})(200 \text{ ft})(7.48 \text{ gal/ft}^3)$$

$$\begin{aligned}
 &= 4,895.7 \text{ gals} \\
 \text{For } \mathbf{i}_{\text{propp}} &= 0.38: \\
 \text{Lbm Proppant} &= (\text{Volume})(\text{SG Proppant})(\text{Density H}_2\text{O})(1 - \mathbf{i}) \\
 &= (4,895.7 \text{ gal})(2.65)(8.34 \text{ lbm/gal})(1 - 0.38) \\
 &= 67.084 \text{ lbm}
 \end{aligned}$$

3. Fracture Fluid Viscosity:

We would like to have a frac fluid viscosity between 50 cp and 100 cp for perfect proppant support and to achieve a well distributed proppant pack. For previous 10-acre infill well stimulation's, viscosity was usually between 25 cp and 30 cp. We may want to try to increase viscosity to provide better proppant transport, increase fracture width and improve conductivity. Optimum results were obtained when the jobs were pumped at injection rates between 30 BPM (small jobs - LCF) and 40 BPM (large jobs - MCF/UCF).

$$\text{Shear Rate, } \mathbf{g}, = \left(\frac{2n'+1}{3n'} \right) * \left(\frac{6 * q_{\text{inj, onewing}}}{h_{\text{net}} * \text{width}^2} \right)$$

where:

$$n' = \text{Power Law Index} \approx 0.45 \text{ for } 35 \text{ ppg HPG gel}$$

$$q_{\text{inj, onewing}} = 30 \text{ bpm}/2 = 15 \text{ bpm}$$

$$\text{width, } W = 0.006545 \text{ ft} = 0.07854 \text{ in (see above)}$$

$$h_{\text{net}} = 100 \text{ ft (see above)}$$

therefore:

$$\mathbf{g}, = \left(\frac{2 * (0.45) + 1}{3 * (0.45)} \right) * \left(\frac{6 * 15 \text{ bpm}}{100 \text{ ft} * (0.006545 \text{ ft})^2} \right) = 29,569 \text{ bbl} / \text{min} - \text{ft}^3$$

$$\mathbf{g}, = 29,569 \text{ bbl} / \text{min} - \text{ft}^3 * 5.6148 \text{ ft}^3 / \text{bbl} * 1 \text{ min} / 60 \text{ sec} = 2767.1 \text{ sec}^{-1}$$

$$\text{Apparent Viscosity, } \mathbf{m}_{\text{app}} = 47,880 * K' * \mathbf{g}^{(n'-1)}$$

where:

$$K' = \text{Consistency Index} \approx 0.04 \text{ for } 35 \text{ ppg Hpg gel}$$

therefore:

$$\mu_{\text{app}} = 47,880 * 0.04 * (2767.1 \text{ sec}^{-1})^{(-0.55)} = 24.5 \text{ cp}$$

We should then be looking for a frac fluid with properties that yield a slightly higher viscosity for future work as discussed above.

4. Tubular Design (Limited Entry Perforating):

$$P_{\text{surf}} = \text{BHTP} - P_{\text{hyd}} + \Delta P_{\text{fric}} + \Delta P_{\text{pf}} + \Delta P_{\text{fe}}$$

where:

BHTP = bottom hole treating pressure, psi

P_{surf} = surface injection pressure, psi

P_{hyd} = hydrostatic pressure, psi

ΔP_{fric} = friction pressure drop through tubulars, psi

ΔP_{pf} = friction pressure drop through perforations, psi

ΔP_{fe} = fracture entry friction, psi (assume negligible)

Average frac gradient for Lower Clear Fork at NRU = 0.664 psi/ft

At a mid-perf depth of 7050 ft:

$$\text{BHTP} = \text{Frac Gradient} * \text{Depth} = 0.664 \text{ psi/ft} * 7050 \text{ ft} = 4681.2 \text{ psi}$$

$$P_{\text{hyd, pad}} = \text{Hyd. Grad.} * \text{Depth} = 0.44 \text{ psi/ft} * 7050 \text{ ft} = 3102 \text{ psi}$$

For 5.5" casing at an injection rate of 30 bpm and 8 ppg frac sand:

$$\Delta P_{\text{fric}} = \text{Fric. Grad.} * \text{Depth} * \text{Corr. Factor}$$

From SPE Monograph 12, Fig. 9-17:

$$\text{Corr. Factor} \approx 0.075556 * \text{sand conc.} + 1.0 = 1.6045$$

$$\Delta P_{\text{fric}} = 0.05 \text{ psi/ft} * 1.6045 * 7050 \text{ ft} = 565.6 \text{ psi}$$

$$\Delta P_{\text{pf}} = \frac{0.2369 * r_{\text{ff}} * i_{\text{pf}}^2}{d_{\text{perf}}^4 * a^2}$$

where:

r_{ff} = frac fluid density, ppg

i_{pf} = injection rate/perforation, bbl/min-perf

d_{perf} = perforation diameter, in

a = discharge coefficient ≈ 0.9

To increase the fluid pressure within the wellbore during fracturing, and increase the chance of propagating a fracture with sufficient half-length, we will use limited entry perforating (i.e., ≥ 2 bbl/min-perf). For an injection rate of 30 bpm we would use 15 holes. A ballout acid job must be

performed prior to each frac job to ensure the perf holes are open. As an example, assume 12 of the 15 holes are open after the pre-frac acid job, therefore:

$$i_{pf}=30\text{bpm}/12 \text{ perfs}=2.5 \text{ bbl/min-perf}$$

$$r_{ff}=8.46 \text{ ppg}$$

$$d_{perf}=0.41 \text{ in}$$

$$\Delta P_{pf} = \frac{0.2369 * 8.46 \text{ ppg} * 2.5 \text{ bbl / min-perf}^2}{0.41 \text{ in}^4 * 0.9^2} = 547.3 \text{ psi}$$

therefore:

$$P_{surf}=4681.2 \text{ psi} - 3102 \text{ psi} + 565.6 \text{ psi} + 547.3 \text{ psi} = 2692.1 \text{ psi}$$

The maximum allowable surface pressure should be no less than:

$$P_{surf,max} = 2692.1 \text{ psi} + \text{safety factor} = 2692.1 + 1500 = 4192.1 \text{ psi}$$

The maximum bottom hole pressure during screenout for 8 ppg sand will be:

$$P_{BH,max} = P_{surf,max} + \text{Hyd. Grad (8 ppg slurry)} * \text{Depth}$$

$$\text{Slurry Dens. (8 ppg)} = \frac{(8.0 \text{ lbm} + 8.34 \text{ lbm})}{(8 \text{ lbm} / (2.65 * 8.34 \text{ lbm} / \text{gal}) + 1 \text{ gal})} = 12.0 \text{ lbm} / \text{gal}$$

$$\text{Hyd. Grad (8 ppg slurry)} = 0.052 * 12.0 \text{ lbm/gal} = 0.624 \text{ psi/ft}$$

$$P_{BH,max} = 4192.1 \text{ psi} + 0.624 \text{ psi/ft} * 7050 \text{ ft} = 8591.3 \text{ psi}$$

$$\Delta P_{burst,surf} = P_{BH,max} - P_{hyd} = 8591.3 \text{ psi} - 3102 \text{ psi} = 5489.3 \text{ psi}$$

For 5.5", 15.5 #/ft or 17.0 #/ft casing, this will require C-75 or better. If the safety factor were reduced to 1000 psi, 17 #/ft J-55 or K-55 would be acceptable.

The fracture initiation pressure gradient for the Lower Clear Fork is approximately 0.81 psi/ft. In order to initiate the fracture, the initial BHTP will have to be between 5150 and 5800 psi for the Clear Fork.

Core Analysis

A total of 2,730 feet of core was taken from four of the Project wells during the Field Demonstration portion of the Project. This core was taken to the Fina core facility in Midland, Texas and studied and described by a Fina geologic team, headed up by the Project Geologist, Brian Pregger.

After the initial review and description at the Fina core facility, the cores are being shipped to David K. Davies & Associates in Houston for more detailed descriptive analyses. At this time, approximately $\frac{3}{4}$ of the core has been analyzed at the Davies lab. 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. Thin section analysis will allow comparisons of reservoir quality, pore distribution and geometry, and depositional facies within the reservoir. 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.

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

The reservoir surveillance dataset is currently being updated by recording pressure transient and cased-hole well log surveys on many of the same wells from which data were acquired during Budget Period I. Pressure transient tests (pressure buildups and pressure falloffs) are currently being recorded to monitor pressure trends in the infill areas, and cased-hole pulsed-neutron logs are being run to monitor changes in water saturation in the near-wellbore area.

Summary

Between February and August 1997, pressure buildup tests were recorded on four wells at Fina Oil & Chemical's North Robertson Unit (NRU) for which simultaneous measurements of pressure-time data were made using both downhole memory gauges and acoustic well sounder (AWS) devices at surface. These tests were conducted to determine the feasibility of performing future pressure buildups using AWS technology alone. The results of the field trial on three Unit wells are presented below. The bottom hole gauge failed on one well (NRU #3527) and no data comparison could be made.

Data Analysis Procedure

The AWS and memory gauge data for each well were analyzed as follows:

- 1) Perform graphical comparisons of raw AWS and memory gauge pressure data for each well. The AWS shut-in pressure was referenced to the bottom hole gauge depth for each case.
- 2) Perform preliminary match of raw AWS pressure data using the type curve for a well with a infinite conductivity vertical fracture in infinite-acting homogeneous reservoir, including wellbore storage (all NRU wells are hydraulically fractured). The pressure and pressure derivative data (Δp and $\Delta p'$) were matched on the pressure type curve, and the pressure integral and pressure integral derivative data (Δp_i and $\Delta p_i'$) were matched on the pressure integral type curve for completeness. Estimates of effective permeability to oil, fracture half-length (or pseudoradial skin factor), and dimensionless wellbore storage were obtained for later use, below.
- 3) The raw AWS pressure-time data were imported into PanSystem 2.4™ and matched using the appropriate model. The results of the preliminary type curve matches performed in step (2) were utilized as initial matching parameters for data matching in Pan System. Final estimates were obtained for effective permeability to oil (k_o), fracture half-length (c_f) or pseudoradial skin factor (s_{pr}), wellbore storage (C_s or C_{Dxf}), and an estimate for average reservoir pressure based on the well/reservoir model utilized (p^*).
- 4) The results were then imported into a software graphics package in order to generate semilog and log-log plots for later graphical comparisons between the AWS analysis results and the bottom hole memory gauge analysis results.
- 5) Steps (3) and (4) were then repeated after generating an Integrally-smoothed AWS data set. The analysis results for both the raw and smoothed data sets were identical for each case, therefore data smoothing is probably not necessary for data analyzed in this report.
- 6) Steps (2) through (5) were then repeated for the bottom hole memory gauge data.
- 7) Semilog and Log-Log summary plots were then generated to show analysis results for both the AWS and memory gauge data sets. The memory gauge results were taken as the “correct” evaluation for each well.
- 8) Extrapolated estimates of average reservoir pressure, $\bar{p}$, for both the AWS and memory gauge data were made using the equation for a rectangular hyperbola (RHM). This method has been shown to yield excellent estimates for $\bar{p}$ when boundary-dominated (BDF) data is available, and acceptable estimates of $\bar{p}$ when BDF data is not available. It is also much easier to apply than other pressure extrapolation techniques, such as the Modified-Muskrat Method. For the three wells that are analyzed in this report, we have no BDF data, and very little pressure data in the radial flow (middle time) region. For this reason, we place no great confidence in our estimates for $\bar{p}$, however, they are certainly

more realistic estimates for average reservoir pressure than p^* from semilog analysis, particularly when there are little, if any, radial flow data available for analysis.

- 9) All results for each well were then summarized in tabular form.

Individual Well Analyses

Well NRU 207

Well #207 was drilled and completed as an oil producing well during the 20-acre infill program in March 1987. Between 1987 and 1991, 80% of all original 40-acre wells were converted to water injectors, with the other 20% remaining as producers, primarily along the Unit periphery. Well #207 is located near the center of Section 5, which is located in the southeast corner of the NRU. Texaco's SYCO Unit is located to the east, and EXXON's Robertson (Clear Fork) Unit is located to the south. The results are shown in tabular form in **Table 1**.

Table 1 - Summary of Results for Well NRU #207

NRU 207

<u>RAW DATA</u>					
AWS Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.031	11.7	-2.88	0.1174	3390	2577
BH Memory Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.051	7.1	-2.37	0.3628	2585	2144

<u>SMOOTHED DATA</u>					
AWS Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.031	11.7	-2.88	0.1174	3390	2577
BH Memory Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.051	7.1	-2.37	0.3628	2585	2144

Well NRU 905

Well #905 was also drilled and completed as an oil producing well in 1989 during the 20-acre infill program. Well #905 is located near the northeast corner of Section 7, which lies along the southern periphery of the NRU. EXXON's Robertson (Clear Fork) Unit is located approximately ½ mile to the south.

Table 2 - Summary of Results for Well NRU #905

NRU 905

<u>RAW DATA</u>						
AWS Data						
<u>ko. md</u>	<u>xf, ft</u>	<u>spr</u>	<u>Cs1, bbl/psi</u>	<u>Cs2, bbl/psi</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.0734	1.3	+0.28	0.0061	0.0092	3924	3565
BH Memory Data						
<u>ko. md</u>	<u>xf, ft</u>	<u>spr</u>	<u>Cs1, bbl/psi</u>	<u>Cs2, bbl/psi</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.0688	1.4	+0.21	0.0052	0.0089	4131	3715

<u>SMOOTHED DATA</u>						
AWS Data						
<u>ko. md</u>	<u>xf, ft</u>	<u>spr</u>	<u>Cs1, bbl/psi</u>	<u>Cs2, bbl/psi</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.0734	1.3	+0.28	0.0061	0.0092	3924	3565
BH Memory Data						
<u>ko. md</u>	<u>xf, ft</u>	<u>spr</u>	<u>Cs1, bbl/psi</u>	<u>Cs2, bbl/psi</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.0689	1.4	+0.21	0.0052	0.0089	4125	3715

Well NRU 2703

Well #2703 was drilled and completed as an oil producing well in 1988 during the 20-acre infill program. Well #2703 is located near the center of Section 326, which is in the south-central region of the NRU. EXXON's Robertson (Clear Fork) Unit is approximately 1 mile to the south. The results are shown in tabular form in **Table 3**.

Table 3 - Summary of Results for Well NRU #2703

NRU 2703

<u>RAW DATA</u>					
AWS Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.043	22.5	-3.53	0.1426	3103	2373
BH Gauge Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.044	27.2	-3.72	0.0465	2850	2137

<u>SMOOTHED DATA</u>					
AWS Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.043	22.5	-3.53	0.1426	3104	2373
BH Gauge Data					
<u>ko, md</u>	<u>xf, ft</u>	<u>spr</u>	<u>CDf</u>	<u>p*, psia</u>	<u>pbar, psia</u>
0.045	2.6	-3.67	0.0479	2869	2137

Conclusions

We found that the AWS pressure buildup data analyses yielded fairly similar results to those obtained from the memory gauge analyses for the formation flow characteristics (effective permeability, fracture half-length (or pseudoradial skin factor). However, estimates for average reservoir pressure varied by 150 psi to 450 psi for the three wells analyzed. Due to the low permeability of the Clear Fork Formation, it is usually not feasible to shut in producing wells long enough to see any boundary-dominated features from which accurate estimates of well drainage area or average reservoir pressure can be made. For this reason, the difference in the shut-in pressure measurements between the AWS system and bottomhole memory gauge does not condemn the use of the AWS system alone. However, if the goal of the analyst is to obtain reservoir volume by increasing the length of the shut-in period, then bottom hole gauges should be utilized.

In addition, the difference in the character of the recorded pressure-time data (*i.e.*, anomalies) between the AWS system and the bottom hole memory gauge was significant for all three wells. The pressure-time profile was extremely different for well NRU 2703. For example, what appeared to be a changing wellbore storage (afterflow) or crossflow characteristic on the AWS data was not present in the memory gauge data.

Performing these comparisons for the Clear Fork interval at the NRU is an extreme test for AWS technology. Because we are dealing with a 1,200' test interval, with individual layers possessing different flow characteristics and pressures, it is often difficult to interpret bottom hole memory gauge data, let alone surface-acquired AWS data. Unfortunately, testing the entire interval at once is the only economic way to perform pressure transient tests at the NRU.

Deterministic Modeling/Simulation

The following work has been completed to-date for the reservoir simulation portion of the North Robertson Clear Fork study:

1) Single-Porosity, Nineteen Layer, Black Oil Simulation Studies

Section 329
Section 327
Section 005
Southern Development Model (NRDM1)

2) Single-Porosity, Nineteen Layer, Miscible Black Oil Simulation Studies (CO₂ Injection Cases)

Section 329
Section 327
Section 005
Southern Development Model (NRDM1)

3) DOE Workshops (Technology Transfer)

4) Testing and Development of Dual-Porosity, Ten Layer, Black Oil Simulation Models

5) Testing and Development of Dual-Porosity, Ten Layer, Miscible Black Oil Simulation Models

6) Dual-Porosity, Ten Layer, Black Oil Simulation Studies

Section 329
Section 327
Section 005
Section 326
Section 325 (Completion: End of January 1998)

The following work remains to be done for the reservoir simulation portion of the North Robertson Clear Fork study:

1) Dual-Porosity, Ten Layer, Black Oil Simulation Studies

Section 362 (Completion: End of February 1998)

2) Update of Reservoir Characterization for New Laboratory Data and Data from New Wells

3) Full-Field, Dual-Porosity, Ten Layer, Black Oil Simulations

4) Miscible Black Oil Simulations (CO₂ Injection Cases)

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."

1997 DOE/BDM Annual Contractor Review Meeting, June 16-20, Houston, TX .

- Oral presentation

1998 PBS/SEPM Core Workshop, February 26, Midland, Tx.

- Display of core taken during DOE field demonstration