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Quarterly Technical Report

INTEGRATION OF ADVANCED GEOSCIENCE AND ENGINEERING TECHNIQUES TO QUANTIFY INTERWELL HETEROGENEITY

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DISCLAIMER

OBJECTIVE

The objective of this project is to integrate advanced geoscience and reservoir engineering concepts with the goal of quantifying the dynamics of fluid-rock and fluid-fluid interactions as they relate to reservoir architecture and lithologic characterization. This interdisciplinary effort will integrate geological and geophysical data with engineering and petrophysical results through reservoir simulation. Subcontractors from Stanford University and the University of Texas at Austin (UT) are collaborating on the project. Dr. Jerry Harris, Associate Professor in the Department of Geophysics at Stanford, is supervising the geophysical research. Dr. Gary Pope, Director of the Center for Petroleum and Geosystems Engineering at UT, is supervising the hydrologic and tracer research. Several members of the PRRC staff are participating in the development of improved reservoir description by integration of the field and laboratory data, as well as in the development of quantitative reservoir models to aid performance predictions.

SUMMARY OF TECHNICAL PROGRESS

GEOLOGIC STUDIES

Use of Field Data for Permeability and Porosity Estimates

To describe the flow properties as input to a simulator, reservoir simulation requires an estimate of spatial permeability and porosity Typically cores, logs, or transient tests are used to estimate the areal permeability variation throughout the reservoir. Unfortunately, modern logs and core information are available at only one point in the reservoir (Well 1-16). As with many fields approaching the end of their productive life, much of the pumping equipment has been sold, limiting the use of pressure buildup testing as a tool for gathering the data required for permeability estimates. Additionally, the reservoir pressure (~900 psi) is quite low, resulting in low producing rates which require long shut-in periods to reach the radial flow period. throughout the field.

In this project, pressure buildup tests, inverse-DSTs, and an interference test were investigated as tools for estimating permeability. Buildup and inverse-DST tests give permeability estimates at the well and a measurement of skin, which proved very useful this quarter. The interference test well pair included storage and positive skin at both the signal and observation well, making interpretation difficult. Earlier work suggested that the inverse-DST technique would suffice for both injection and pumping wells, however mechanical problems at the temporarily abandoned wells precluded field wide application.

The injection well rate-pressure history provide a steady state solution to the continued need for fieldwide permeability estimates. Monthly injection volumes and the average wellhead pressure were used to construct Hall plots.[1]

The injection history provided an additional source of permeability information. The data from 18 of the 20 injection wells was sufficient to make estimates, based on steady-state flow, of permeability. This technique used the slope from Hall plots to estimate steady-state permeability without skin. Only late in the waterflood operation did damage occur in the injection wells as evidenced by the rapid increase in the Hall plot slope.

The skin estimates from one pressure buildup test on Well 1-16 and two inverse-DSTs (Well 1-2 and Well 1-16) suggest that skin damage varied from 2.6 to 3.8. Analysis of permeability from an interference test between Wells 1-16 and 1-3 agreed with both the early time inverse-DST and pressure buildup test permeability calculations. A procedure was developed to adjust the Hall plot permeability for skin in the event that simulation required estimates of permeability greater than the Hall plot estimates without skin.

Procedure to Adjust Permeability from Hall Plot Analysis Technique

From the radial flow equation:

$$q = \frac{kh}{141.2\mu B} \left| \frac{p - p_{wf}}{\ln\frac{r_e}{r_w} - 0.75 + s} \right|$$

it is evident that

$$\frac{k_1}{A + s_1} = \frac{k_2}{A + s_2}$$

where k_1 is from the Hall plot and k_2 is the adjusted permeability, and

$$A = \ln\frac{r_e}{r_w} - 0.75$$

or A = 6.43 for 40 acre spacing.

Then for $s_1 = 0$ and $s_2 = 3$

$$k_2 = k_1\left(1 + \frac{s_2}{6.43}\right) = 1.47k_1$$

Steady-state permeability was estimated from the slope, m, of a plot of cumulative psi-days versus cumulative injection as seen in Fig. 1.

The flat portion of the derivative curve (slope) was used to calculate an average slope, m, which was used to estimate steady-state permeability from the following equation as described by Hall.

$$k_1 = \frac{\mu_w B_w \ln\frac{r_e}{r_w}}{0.00707h}$$

The permeability-thickness product resulting from the Hall plot analyses is compared with the value resulting from the primary production history match is illustrated in Fig. 2.

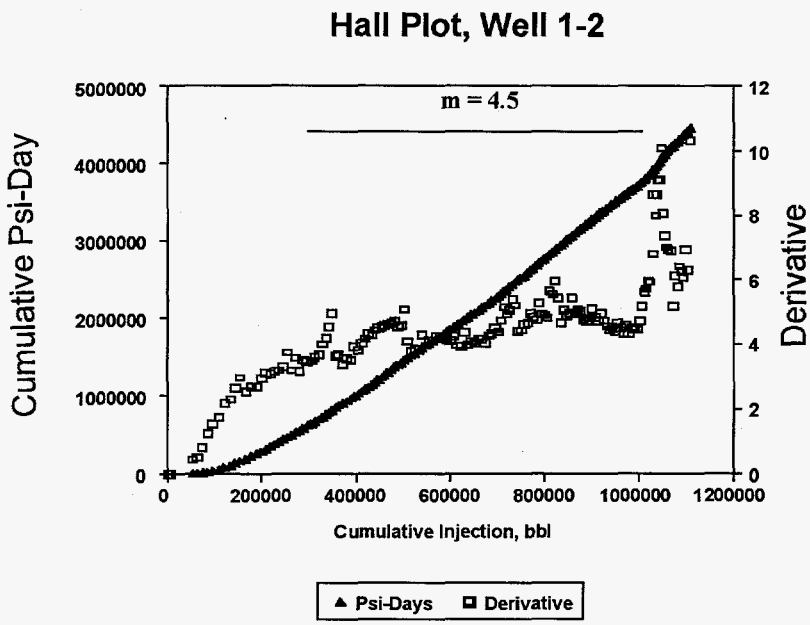


Fig. 1. Typical Hall Plot

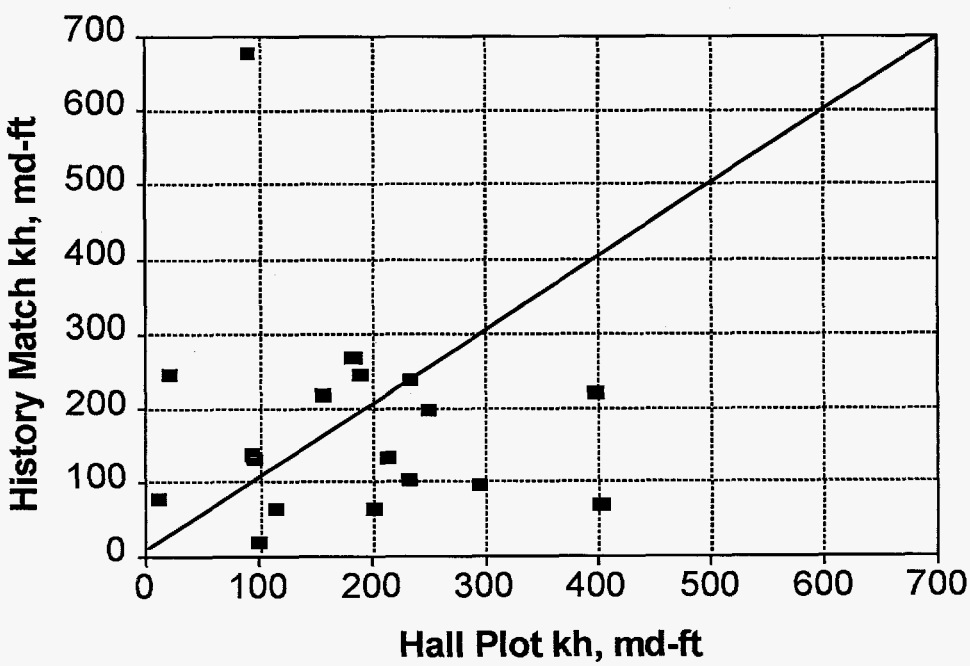


Fig. 2. History Match kh vs Hall Plot kh

Porosity Prediction from Rescaled Old Gamma Ray Logs

As seen in Fig. 3 a positive correlation was also observed between core porosity and gamma ray. This relationship was used to calculate the porosities in the uncored wells using the rescaled gamma ray logs.

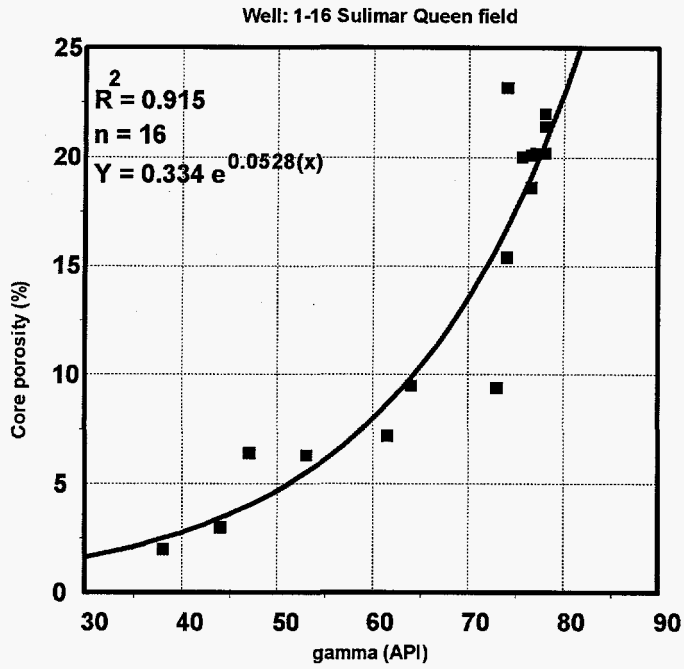


Fig. 3. Showing the relationship between gamma ray values and core porosity in well 1-16, in the Sulimar Queen Field.

The correlation is expressed as:

$$\square = 0.334\, e^{0.0526(\square)}$$

where "□" is the porosity in percent and "□" the gamma ray value in API units.

Similar relationships between gamma and porosity in the Sulimar Queen and the adjacent fields suggest a regional trend. *This relationship is only good for the sand portion of the Shattuck zone as determined from the core description.* In the Shattuck sand zone, the gamma ray values may not be controlled by the amount of clay but by the amount of uranium present, which is confirmed by the spectral gamma ray log from one well in the Queen Field. This uranium is assumed to be present in the formation water since gamma ray values are proportional to total volume of water (W_{TV}). The total volume of water represents the percentage of the total rock volume occupied by the water. The following relationship developed in well 1-16 could be used with caution to predict the total volume of water (W_{TV}):

$$W_{TV} = 0.0000458\, (\square)^{2.90237}$$

Where, "W_{TV}" is the total volume of water in percentage, and "□ "the gamma ray value in API units. The water saturation for a particular porosity can be obtained as follows:

$$S_w = [W_{TV}/\square] \times 100$$

Rescaling of old logs

The old gamma ray logs have different scale ranges, therefore, comparison of gamma ray (API) values from different wells has little meaning. Also, porosities obtained using the relationship developed in Well 1-16 (eq. 1) may not be reliable. In order to make old gamma logs useful and reliable, they were rescaled using the methodology described by Barrett.[2]

The rescaling procedure for old gamma ray logs consists of the following steps:

(1) Use the modern logs to find the average high and low gamma ray value in the zone of interest. In the Sulimar Queen Field, the presence of 6-ft thick anhydrite bed above the producing Shattuck member provided the lowest gamma ray value of approximately 12 API units. Within the Shattuck zone, the average high value is 80.5 API was found.

$$New\ low = 12\ API\ Units;\ New\ high = 80.5\ API\ Units$$

(2) Once the new high and low gamma ray values for the entire field are obtained, "m" for each well containing old gamma ray log can be calculated using the following relationship:

$$m = (new\ high - new\ low)/(old\ high - old\ low)$$

Old highs and lows are different for individual wells.

(3) In this step "B" for each well containing old gamma ray logs can be calculated using the following relationship:

$$B = new\ high - [\ m\ .\ (old\ high)]$$

(4) After "m" and "B" for each well are obtained, the old logs can be rescaled using the following equation.

$$\textbf{(Rescaled value)}\ Y = mx + B$$

Where "x" is the old log value in API units at a particular depth.

Example: For Well: 1-14:

New high = 80.50 API New low = 12.00 API

Old high = 80.74 API Old low = 34.46 API

$$m = (80.5 - 12.0)/(80.74 - 34.46) = 1.48$$
$$B = 80.5 - [1.48\ (80.74)] = -39$$

Using the "m" and "B", the complete gamma ray log in well 1-14 was rescaled. Fig. 4 shows the rescaling in Well 1-14 of Sulimar Queen Field. The rescaled logs have the minimum of 12 API and maximum of 80 API values. Note the presence of anhydritic portion in the rescaled gamma ray logs which were not identifiable in unscaled logs.

Porosity Estimation from Rescaled Gamma Ray Logs

The relationship developed between core porosity and gamma ray values (eq. 1) in well 1-16 was used to calculate the porosity from the rescaled gamma ray logs. The gamma ray derived porosities were also compared with the core porosities in Wells 1-14 and 5-1 to determine the reliability of the method as seen in

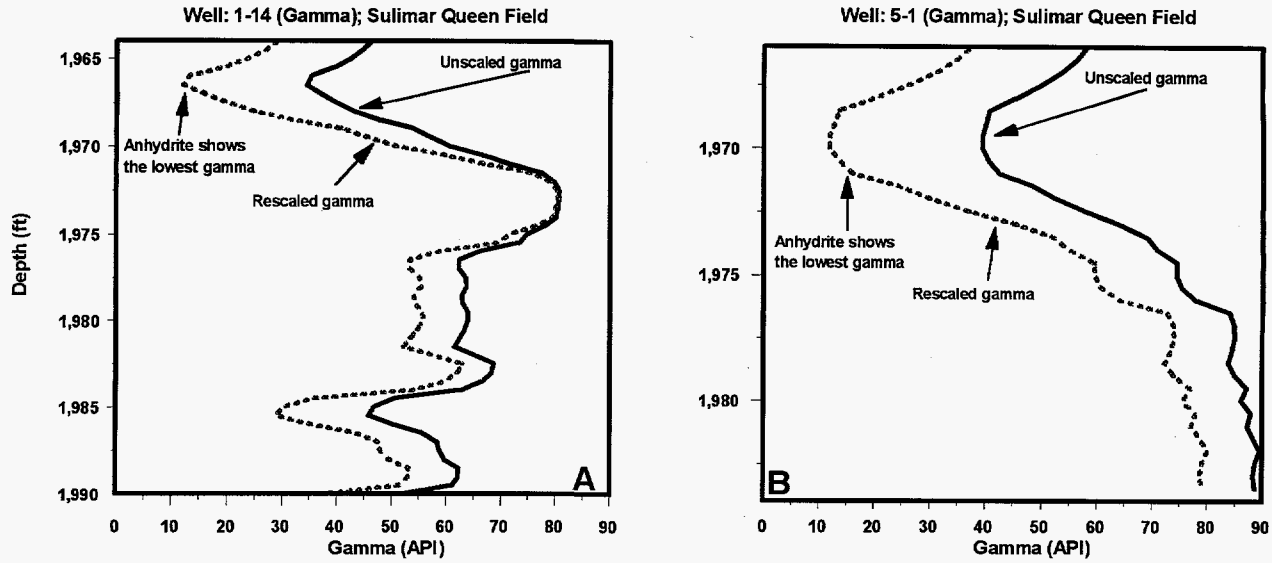


Fig. 4. Comparison of Unscaled and Rescaled Gamma Ray Logs

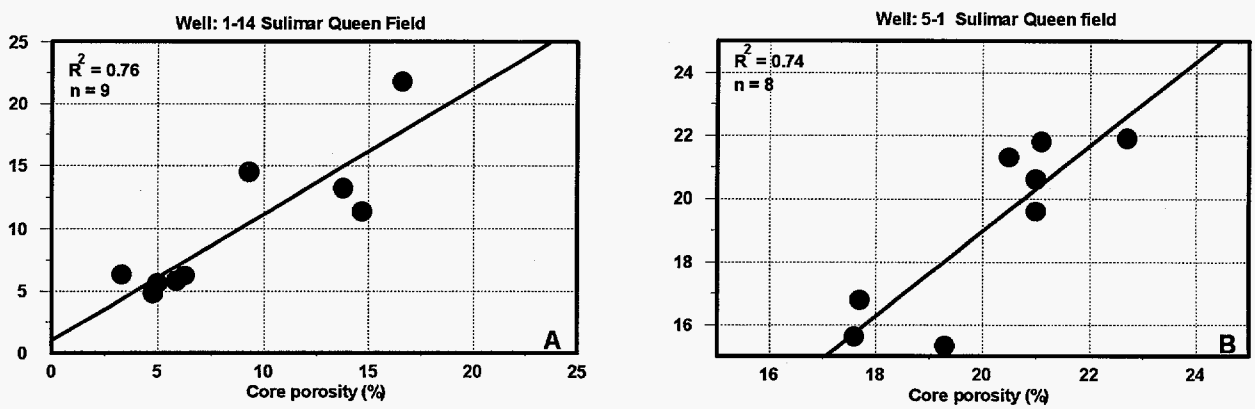


Fig. 5. Comparison of core porosity and porosity predicted using rescaled gamma ray logs in the Sulimar Queen Field.

Fig. 5. The rescaling of gamma ray logs improved the porosity prediction from the logs. Porosity calculated from the rescaled gamma ray logs also captured the presence of individual high and low porosity zones which were not distinguishable from the unscaled gamma ray logs.

FIELD OPERATIONS

The non-reactive thiocyanate tracer analyses were completed. The produced tracer concentration profile is seen in Fig.6 along with the average producing rate, bbl/hr, as a function of cumulative production.

Notice that at about 35 bbl produced the tracer concentration falls rapidly. Tracer injection was down the well annulus which has a volume of approximately 35 bbl. The continued addition of tracer from the annulus during the initial producing period voids the early portion of the test. Tracer injected during the oil wettability test

will be down the tubing with a packer set above the producing zone to minimize the afterflow problem encountered

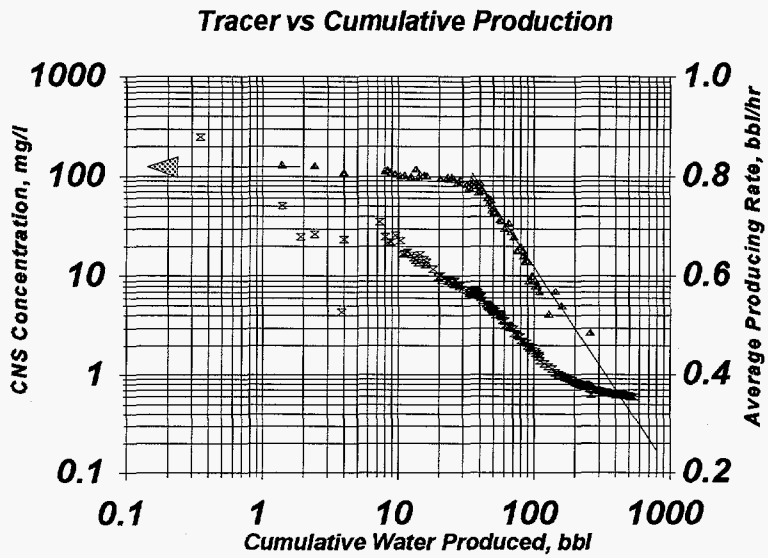


Fig. 6. Tracer Profile and Accompanying Rate

during the non-reactive tracer test.

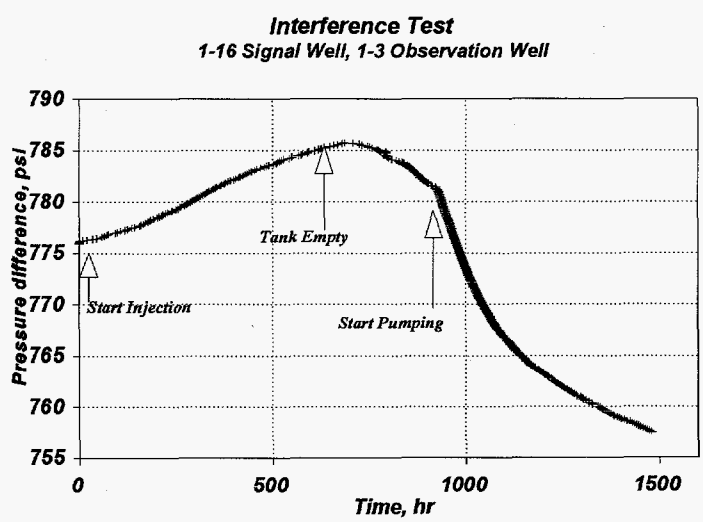


Fig. 7. Observation Well Pressure History

During tracer addition and production, the bottomhole pressure at Well 1-3, located 270 ft to the west of Well 1-16, was monitored with an electronic gauge. The pressure history is seen in Fig.7.

Injection of the tracer was by gravity from a 100 bbl tank down the annulus. The annular fluid level continued to fall after the tank was emptied and the pressure at the observation well increased from 784 psi to 785 psi before decreasing. Pumping the signal well to recover the CNS tracer resulted in a rapid decrease in the

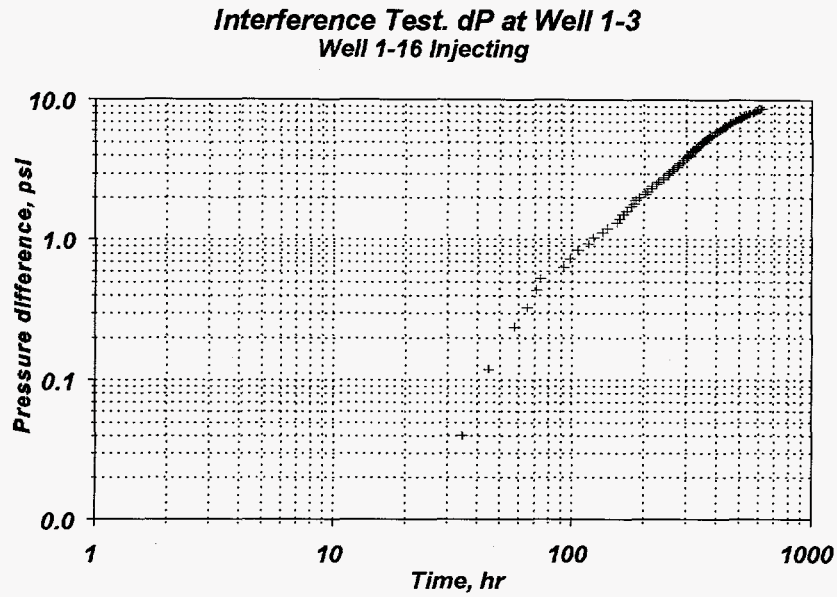


Fig. 8. Pressure Difference vs Injection Time

bottomhole pressure at well 1-3. Both the gravity injection rate and the producing rates varied during the test, but generally, the producing rate was twice the injection rate.

The pressure difference versus time at Well 1-3 during the injection period seen in Fig. 8 was matched to the dimensionless exponential-integral curve.[3] Based on calculations with the match points and the 4 bbl/day injection rate, the permeability is 4.8 md. The presence of storage and skin at both the signal and observation wells was not accounted for with this analytical technique.

Similarly, the pressure difference curve during the production period, Fig.9, was matched to the exponential-integral curve and the interwell permeability was found to be 6.2 md with a 9 bbl/day producing rate.

TECHNOLOGY TRANSFER

Contact was made with an independent oil company with production from the Queen formation. The company expressed an interest in applying the advanced geoscience and engineering techniques to a Queen reservoir offsetting the Sulimar Queen. The waterflood forecasting technique is of special interest to them because their properties have not been waterflooded. Similar interest has been informally expressed by other operators in the area. The offset operator has formally submitted engineering data to the PRRC for inclusion in the Sulimar dataset.

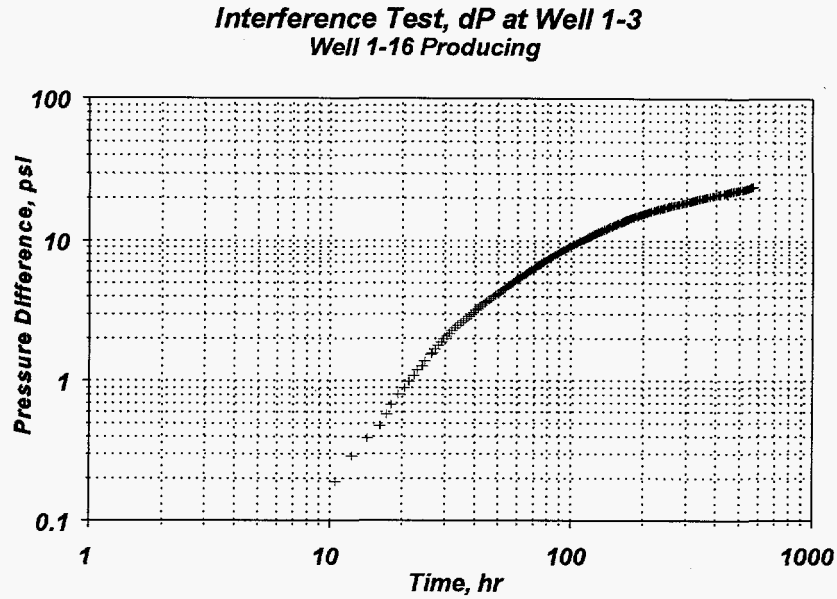


Fig. 9. Pressure Difference vs Producing Time

Prototype development of a graphical database progressed significantly during the second quarter. The prototype can be viewed via the World Wide Web at

http://baervan.nmt.edu/~nathan/map/htmldocs/inject.html

with any viewer. The prototype is not complete, however the database includes enough information to construct Fig.10 demonstrating the differences in recovery efficiency of 18 of the units seen in the point and click map. Each number corresponds to a unit seen in the graphical database with 18 being the Sulimar Queen. Notice that the greater the water production (water injection history in the state dataset is not complete), the greater the oil production. Also the watercut escalates rapidly once cumulative water-to-oil ratio exceeds four.

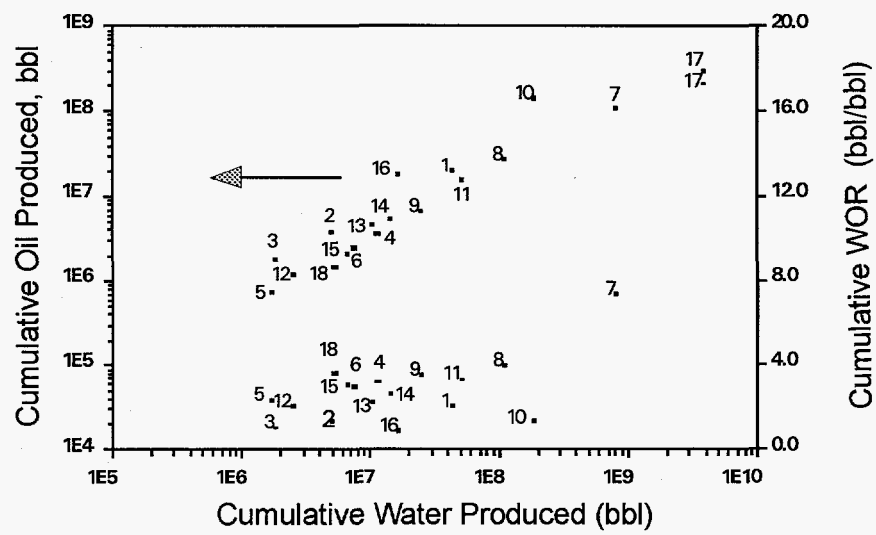
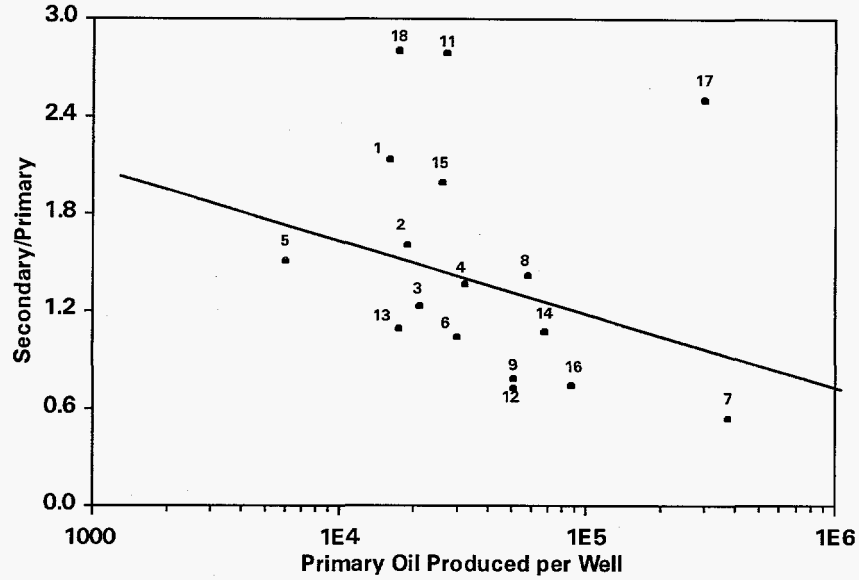


Fig. 10. Water vs Oil Production

The ratio of secondary recovery to primary performance is seen in Fig.11. The average S/P ratio is 1.4

Fig. 11. Secondary to Primary Ratio

Data Integration



Integrating the descriptive reservoir data from the outcrop study, petrographic analyses, and the field tests with the dynamic production history was achieved by automatically history matching the field primary performance on a well-by-well basis. An innovative approach to automatic history matching involved developing correlations for scale up of the small scale log and core properties to grid block size. A depth to free gas saturation correlation was developed which indicated the presence of a gas cap. The variables in the correlating equations were estimated using a global optimization technique to match the primary gas and water producing rates. The flow equations were constrained with the oil rate which is the most precisely measured of the dynamic data.

Estimating upscaled reservoir properties. Geological examination of the Queen outcrop and reservoir engineering observations lead to the distinction between two major flow units: the upper clean sand and the bottom sands composed of shaley or anhydritic sands. Hence, as an initial geological model, a two-layer system representing the two flow units was established. A grid of 3000 horizontal blocks was constructed. The block size was 200 ft × 200 ft .

The rescaled gamma ray logs API units-correlation shown in Fig. 5 provided a quantitative porosity distribution for the two-layered reservoir. Porosity logs were derived for each well and the porosity cut-off to distinguish layer one from layer two was picked. The average porosity for each layer was obtained using a simple arithmetic average. Thus, two porosity values were available at each well location. A deterministic smooth mapping method was used to estimate the horizontal spatial distribution of the porosity for each layer.

Simulation of the Sulimar Queen reservoir also requires the spatial distribution of the permeability, gas saturation, and the water saturation. Permeability was correlated with porosity using a power function:

$$k = 10^{[A(\phi - B)]}$$

The correlation was different for each layer which results in estimating two correlation parameters A and B for each layer. The initial guess for A and B was derived using the average porosity and the Hall plot transient test permeabilities presented earlier. The initial values along with unknown reservoir properties were adjusted by the automatic history matching process. Three advantages to this approach are:

1. The k-phi correlations include the lithology of each layer, thus the geology is honored.
2. The number of permeability estimates is from one for each of the 6000 grid blocks to four correlating parameters.
3. Since the permeability resulting from the correlations is at the grid block scale, upscaling is not a problem.

Permeability is not the only parameter required to numerically simulate the Sulimar Queen reservoir. The spatial distribution of the GOR during early primary producing period varied from a solution gas GOR of 300 cf/bbl downdip to 13,000 cf/bbl on the structural high. The initial simulation runs could not produce enough solution gas to match the production history. Thus, it was apparent that a gas cap was present. The location of the gas cap was estimated by correlating the gas saturation with depth.

$$S_g = A \times depth - B$$

Again automatic history matching was used to estimate correlating parameters A & B. Water saturation was set at 80% of the pore volume downdip in the aquifer and 30% in the oil column.

Petrophysical and PVT data are also required for simulation. Corey type relative permeability curves were assigned to each layer. The end point water saturation for each layer was fixed based on laboratory derived relative permeability data. The initial values for the curvature and the k_{rw} end point were based on the laboratory data. The end points and the curvature exponent were determined automatically during the history matching process.

Complete Sulimar Queen PVT data were not available so data from the nearby Caprock Queen were substituted. The Queen reservoirs in the area are noted for their low initial reservoir pressure resulting in low values for the original gas in solution. As a result, simulating the primary gas performance history based on solution gas alone could not be done. The actual produced volumes were five to ten times greater than the simulated volumes. Thus, the need to include a gas cap in the reservoir description. The final reservoir model was obtained by adjusting the parameters used in the correlating equations to match the dynamic production history. This time-consuming process was achieved, using an automatic history matching algorithm.

Automatic history matching. Ultimately, the various field and laboratory data are integrated with a reservoir simulator. The scale is dictated by the size of the grid blocks. Selecting proper grid block size results in a dilemma in balancing the need for detailed reservoir description with the need for practical computation time. A very fine geological description that takes into account the thin section core description will lead to prohibitive run time. In the case of the Sulimar Queen, the horizontal grids were sized at 200 ft × 200 ft. This size resulted in 6000 grid blocks for the two layer system which established the final reservoir scale for modeling.

An accurate reservoir model must honor all available field data and most importantly the production

history at established scale. Most reservoir properties are not measured at the established grid block size. For that matter, they are seldom available at any scale, hence it is necessary to develop innovative ways to estimate the unknowns at 200 ft^2 scale.

The objective is achieved by using automatic history matching. There are a number of challenging aspects to this task which require extensive research. Two different research directions were explored.

1. Multiple workstations for parallel history matching.
2. Improved optimization methods for faster history matching.

Multiple workstations facilitate the distribution of the optimizing process to increase the solution speed. The practical aspects implementing distributed processing were described by Ouenes.[4] This approach requires a high level of expertise in distributed computer systems, mathematical optimization, and reservoir simulation. The feasibility of the concept was demonstrated, but current technology does not permit wide and routine use of such systems. In this approach, a message-passing software such as PVM is required. However, another implementation of the multiple workstation concept was recently accomplished without the message passing software. The most recent method relies on remote copy of history matching files from one workstation to another. This is achieved with the UNIX *rcp* protocol.

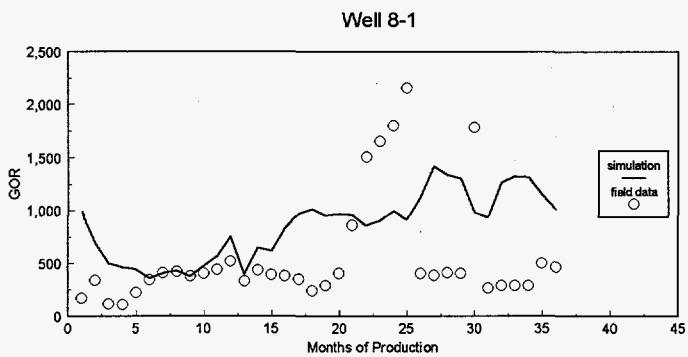
Another direction for achieving faster history matching is to chose an efficient optimization algorithm. The history matching process of multiphase flow in porous media is plagued with the local minima problem. Most conventional optimization methods fail to produce a set of reservoir parameters that provide a good match to the real field spatial production history including pressure. As a result, a stochastic optimization method was tested[5] as a means to escape from the local minima problem. The large number of unnecessary trials, increasing the number of iterations to reach a satisfactory history match, precluded application of the stochastic methods. The quality of the match is satisfactory, but the number of iterations necessary to reach the match can easily exceed two hundred. Since each iteration includes one run on the simulator that can last a few minutes to a few hours, reaching the optimal solution can be very expensive. Fortunately, our methods employ algorithms which are entirely automatic and the iterations are performed without user intervention. Recent advances in mathematical optimization[6] have led to a new algorithm that combines fast convergence with an accurate match. Unfortunately, the new algorithm was proposed too late in the life of this project to be incorporated into the black simulator. The new technique known as the Scaled Conjugate Gradients method was used to automate the DOE waterflood/polymerflood predictive model.

The Sulimar Queen primary performance was automatically history matched using the simulated annealing method.[5] Using a black oil model run on a HP 9000-735 workstation, one iteration of the 41- month primary producing period required 20 minutes. Each iteration required the estimation of 42 parameters, four for the □–□ correlations, two for the free gas calculation, sixteen to estimate the relative permeability curves, and 20 skin value estimates at the producing wells. A reasonable match of the 20 wells was achieved after 350 iterations which represents five days of time. This considerable computing time did not require any engineering time to adjust the input parameters. In other field applications of the simulated annealing method, the lack of geologic, core, field, and laboratory data required more adjustments of the optimal range of the unknown reservoir parameters. For example, in the Sulimar Queen reservoir, core and field tests have shown that the permeability is in the range of 5-50 md, where in previous reservoir studies this information was not available. As a consequence, history matching was used to find the unknown reservoir parameters which required manual adjustments of the parameter ranges.

During the primary producing period, very little water was produced and the history matching results are not illustrated. However, gas production was the key to matching the spatial producing performance of the

reservoir. The match between reported and predicted gas production for the total field is seen in Fig. 12, while typical examples of individual well matches are illustrated in Fig. 13.

Fig. 12. Field Gas Rate History Match



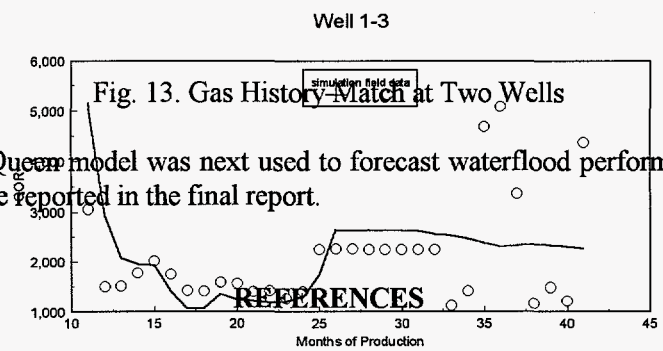


Fig. 13. Gas History Match at Two Wells

The calibrated Sulimar Queen model was next used to forecast waterflood performance. The results of the waterflood forecast will be reported in the final report.

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