A Petrophysics and Reservoir Performance-Based Reservoir Characterization of the Womack Hill (Smackover) Field (Alabama)

Introduction
Womack Hill Field is located on the border of Choctaw and Clarke counties, Alabama (Fig. 1). Hydrocarbon production is found in the Jurassic sequence consisting of the Smackover and Norphlet formations. Bottomhole pressure analysis has confirmed the pressure separation of the Lower Smackover-Norphlet reservoir from the Upper Smackover reservoir (Daigre, et al¹ (1986)). Womack Hill Field produces from the Upper Smackover carbonate reservoir at depths ranging from 11,090 feet (subsea) at the crest of the structure to 11,360 feet (subsea) at the water-oil contact. The oil trap on top of the reservoir is provided by the anhydrite in the overlying Buckner member of the Haynesville formation. A very large normal fault to the south of the field provides a lateral seal (Qi, et al² (1998)). Pruet and Hughes Company discovered Womack Hill Field, in November 1970 (Carlisle Unit 16-4 Well No.1). This well was completed in the Upper Smackover carbonates and initially flowed 600 STB/D through perforations at 11,422 to 11,432 feet (measured depth).

The original oil in place (OOIP or N) at Womack Hill Field is estimated to be 87.1 MMSTB (Core Labs³ (1974)) and the cumulative production has reached over 30 MMSTB, so we estimate the oil recovery to be on the order of 35 percent. We believe that because the recovery is apparently high, additional development opportunities are probably limited to isolated compartments or areas of severe pressure depletion.

The objective of this work is to develop an integrated reservoir description for this field in order to establish reservoir management strategies and to provide a basis for reservoir simulation. To develop such a study we must analyze all of the available data. The core and well log data are used to generate distributions of reservoir properties across the field and the production history is analyzed using both simplified analysis of rate (i.e., EUR plots), as well as the decline type curve technique to obtain estimates of oil-in-place and reservoir properties. The results of the analysis of the petrophysical and production data will be combined and interpreted simultaneously in order to draw conclusions and recommendations with regard to the continued operations and developments at Womack Hill Field.

Abstract
The primary objective of this work is to perform a complete characterization of the Womack Hill (oil) Field in Southern Alabama using petrophysical and reservoir performance data — and to provide reservoir management strategies that lead to improved oil recovery activities at Womack Hill Field. The process for achieving this goal requires the following specific objectives:

- To develop correlations between the core and well log data in order to generate spatial distributions of reservoir properties such as: porosity, permeability, net pay, etc.
- To analyze the production history on a per well basis using the decline type curve technique to provide estimates of:
  - Oil-in-place (N),
  - Effective permeability (k),
  - Flow capacity (kh),
  - Reservoir drainage area (A), and
  - Near-well skin factor (s).
- To determine the Estimated Ultimate Recovery (or EUR) for each well using the production data. The EUR is used to establish the volume of recoverable oil-in-place.
- To draw conclusions and provide recommendations regarding infill drilling, well completions, and production practices based on the results of integrating the geological data and the production history analysis.
Current Status

Womack Hill is a mature oil field that has been producing for more than 30 years. Production reached its peak in 1977 as result of an infill drilling campaign. Since then, oil and gas rates have steadily declined, as shown on Fig. 2. Currently, only 12 production and 3 injection wells are active (Mancini, et al. (2001)) producing 640 STB/D of oil, 330 MSCF/D of gas, and 6,700 STB/D of water (Fig. 3). The water cut is over 90 percent and the amount of injection water required in the Western part of the field increases continuously, which ultimately reduces the profitability of the field. As the estimated oil recovery is 35 percent, an additional recovery of 5 to 10 percent appears quite possible through a detailed reservoir description and a better understanding of the reservoir performance.

The main issues that exist with regard to Womack Hill Field are:

1. The high degree of heterogeneity that typically exists in carbonate reservoirs. This requires a substantial amount of data to develop a representative reservoir model. The volume of core data is limited, so it is somewhat more difficult to establish relationships between well log measurements and the results of production data analysis.

2. There is an incomplete record of the water production due to reporting practices in Alabama. Fig. 2 shows that the water production record began in 1981. As we do not have a complete record of the water production record, we must limit our analysis and interpretation of the WOR (water-oil ratio) and \( f_w \) (fractional flow of water) behavior to essentially a qualitative analysis.

3. The lack of wellbore pressure data in general, as well as the limited amount of pressure data taken as "shut-in" pressures (surrogates for "local" average reservoir pressures). The lack of wellbore pressure data is further amplified because production was prorated at early times (the first few years).

The lack of wellbore pressure data and prorated early production data significantly inhibit our application of the decline type curve analysis technique. We can infer an indication of "better" reservoir properties in certain areas of the field, but this is an essentially qualitative assessment (comparison of one profile to another).

Lastly, the lack of pressure data may also limit the application of reservoir simulation, as these data are required to calibrate the reservoir model.

Analysis/Interpretation/Integration Procedure

The following tasks are employed as the mechanisms to analyze, interpret, and integrate the petrophysical and engineering data from Womack Hill Field:

1. Collect/catalog the well log, core, and production data.

2. Convert data into an appropriate electronic format.

3. Develop correlations between core and well log data to predict reservoir permeability using well log responses.

4. Analyze and interpret the reservoir performance data using decline type curve analysis and EUR analysis.

5. Integrate the geological data and the results of reservoir performance analysis by generating maps of distributions of reservoir properties throughout the field.

6. Establish recommendations to optimize the reservoir management strategies, such as: infill drilling, producer/injector conversions, reservoir testing procedures, etc.

Our work to date has focused on points 1-5 — although point 6 has received attention, it has proven extremely difficult to propose/perform testing or other operational activities due to the present economic and technical conditions at Womack Hill Field.

Correlation of Petrophysical Data

At Womack Hill Field the following well log responses are typically available:

- (SP) Spontaneous potential
- (ILM) Shallow resistivity
- (LLS) Deep resistivity
- (GR) Gamma ray
- (ROHB) Bulk density
- (DPhi) Density derived porosity
- (NPhi) Neutron derived porosity

In addition, substantial volumes of whole and sidewall core data are available — admittedly, all of these data are quite old (1970's vintage) and we have encountered significant difficulties in trying to correlate the core and well log data.

As an example, in Fig. 4 we provide a presentation of the core and well log data — showing the well log data and core permeability profiles along of the stratigraphic column for Well 1639 (all wells are referenced according to their corresponding state permit number). The reservoir has been divided into three "flow units" (Mancini, et al. (2001)) (A, B, and C), and we note that our work (using the core and well log data) confirms these assignments.

As shown, the core permeability data are quite scattered, giving us an indication of the level of heterogeneity in the reservoir. The wells at Womack Hill Field produce from the Upper Smackover carbonate reservoir, which is typically characterized by a high level of heterogeneity. This makes it difficult to establish correlations between the petrophysical variables on a regional scale (Kopaska-Merckel, et al. (1994)). As such, our approach is to establish correlations for each of the three flow units on a local scale (i.e., for individual wells).

As part of our characterization of the petrophysical data, we distributed the core data (porosity and permeability) into the appropriate flow units and aligned the corresponding well log measurements to construct data tables for correlation purposes. We have core data for 14 wells in Womack Hill Field — however; we selected the core and well log data for only 9 wells (as shown in Table 1). We find that there is no...
consistent suite of well logs for all wells — however, we do note that the GR, LLS and some sort of porosity log are generally available. As such, we selected GR, LLS, and (core) porosity as independent variables to keep the same set of input data for all correlations. We recognize that basing the correlations on core porosity is less than optimal (since these data obviously will not generally be available), but our goal became the qualitative correlation of these data — as a mechanism to verify reservoir quality.

To develop our correlations of the petrophysical data we selected a nonparametric technique that is based on estimating the optimal transformation of each variable (the dependent as well as the independent variables). This method has an advantage over conventional multiple regression algorithms that it does not require an assumed correlating function (i.e., model) between the variables — where a preconceived model could yield an inaccurate representation.

The nonparametric method generates a transform value for each data point of the dependent and independent variables. Once the transform for each of the variables has been established, a nonparametric correlation is generated between the dependent variable and the sum of the transform values, this is called the optimal transformation. Parametric correlations can be generated by fitting these transform curves using appropriate functions (generally polynomial functions (GRACE7 1996)). The dependent variable (in this case permeability) is estimated by determining the inverse of the optimal transform. The details for this process are given by Breiman and Friedman7 1985).

Our first approach in developing the "core-log" correlations was to analyze simple relationships between the variables, which could allow us to obtain less cumbersome correlations if a strong (yet simple) relationship is found between these variables. We studied the relationship between core permeability and each available well log signal. Fig. 5 presents crossplots of core permeability against GR, RHOB, LLS, and ILM for Flow Unit A in Well 1639. No single plot indicates a clear tendency between the core permeability and any of the well log variables. GR and RHOB do not provide significant character to the correlation since the behavior of these variables is essentially constant through the section (see also Fig. 4). Although the resistivity data do exhibit some variation, the overall relationship of resistivity with the core permeability is essentially random (i.e., no obvious pattern is evident).

During the depth shifting process we observed that a significant variation exists between the core and well log-derived porosity, over the entire scale of porosity values. As an effort to try to resolve these differences, we considered the relationship between these two variables (core and well log porosity) on the flow unit scale. Fig. 6 shows the relation between the porosity derived from the bulk density log and the core porosity for Well 1639 (Flow Unit A). We note that the relationship is extremely poor, and that the only positive comment we can make is that the data appear to be evenly distributed (although randomly) about the 45° line (i.e., the perfect correlation line).

Generally speaking, well log derived porosity values are of the most consistent variables that can be estimated — unfortunately, this is not the case in Womack Hill. To use the well log derived porosity as input data for the correlation would produce significant errors, as it has little or no relation to the formation permeability. However, a comparison of the logarithm of the core permeability with core porosity yields a reasonably linear trend (Fig. 6). As such, we elected to use the core porosity in lieu of the well log-derived porosity to obtain more consistent (yet qualitative) results.

We selected the GR, LLS, and core porosity as input data for the "Flow Unit" correlations. Although the GR log is thought to have relatively little character, it does provide certain petrophysical characteristics, as the accuracy of the correlation tends to improve when the GR data are included. Typically, the ILM and LLS responses follow essentially the same tracks — however; we prefer use of the deep resistivity (LLS) over the shallow resistivity (ILM) because the LLS resistivity utilizes information at distances further into the reservoir, and because the LLS resistivity log is the more common well log acquired in Womack Hill Field.

Once the data sets are prepared for correlation, we use the GRACE program (1996) to establish the nonparametric correlations for each variable — generating the corresponding optimal transformations. The results of this effort are nonparametric — i.e., there is no functional form to the correlation. As we require some type of functional form in order to apply the correlation, we utilize parametric correlations for each "transform function," where these parametric correlations are generated by fitting the "optimal transform" data (an output of this procedure) using quadratic polynomials (a feature of the GRACE program). As an example, in Fig. 7 we present the transformations for each variable (Well 1639 — Flow Unit A). Finally, the correlation that is used to predict the dependent variable is obtained by calculating the inverse of the optimal transformation. We note that the correlation function matches the tendency exhibited by the measured data — which confirms the robustness of the non-parametric method.

**Statistical Analysis of Core-Data**

In order to generate a petrophysical model of the reservoir we must establish a distribution of the formation properties throughout the reservoir drainage area. Our ultimate goal in this effort is to provide a reservoir description that can be used for numerical simulation. To accomplish this goal we segment the data according to "flow units" (as described earlier) and we develop histograms (i.e., probability distributions) of porosity and the logarithm of permeability. These histograms confirm that porosity and the logarithm of permeability both (generally) follow a normal distribution for the reservoirs investigated at Womack Hill Field.

Fig. 8 provides an example of this behavior for Well 1639 — Flow Unit A. We note that most of the wells in Womack Hill
Field yield similar histogram trends. It is our intention to use the mean value of porosity and the logarithm of permeability established from a particular histogram to represent the average for a particular flow unit. Using these results we developed maps of porosity and permeability based on the average values for each flow unit.

Analysis of Reservoir Performance — General
Fig. 2 presents the historical behavior of the oil, gas, and water production rates at Womack Hill Field since production began in December 1970. Oil and gas production peaked in 1977 at 6,200 STB/D and 3,200 MSCF/D of oil and gas, respectively. Since then, oil and gas flowrates have steadily declined while the water rate has consistently increased. This production decline has reduced the profitability of the field — which leads to the current program of production optimization and field management strategies to improve the performance and overall recovery. Currently there are 3 injection wells (in the Smackover) which are active, although there are also some injection wells that are also used periodically. The producing gas-to-oil ratio (GOR) has remained relatively constant (approximately 500 scf/STB) indicating that the reservoir pressure remains above the bubblepoint pressure (approximately 1925 psia).

Fig. 3 presents the field-wide cumulative production for oil, gas, and water. The oil and gas curves are nearing their respective "plateaus" and should not be expected to change their behavior without substantial intervention (i.e., infill drilling, well stimulation, improved artificial lift, etc.). We also note from Fig. 3 that the cumulative water production curve is still increasing at a substantial rate, although it does appear to be trending towards a plateau (probably in the range of 55-60 MMSTB of water). To date, the total oil production is 30.5 MMSTB, along with 43.3 MMSTB of water and 15.1 BSCF of gas.

It is relevant to note that Womack Hill Field has been traditionally divided the field into two areas — the Eastern and Western areas, based on geological information, as well as production/pressure performance. In Fig. 9 we present the production profiles for the Western area — this area has produced 18.7 MMSTB of oil, 23.1 MMSTB of water, and 10.4 BSCF of gas — which represents more than 60 percent of the hydrocarbon production for Womack Hill Field. In contrast, the Eastern area (Fig. 10) accounts for the following production: 11.8 MMSTB of oil, 20.2 MMSTB of water, and 4.7 BSCF of gas.

In Fig. 11a we present a "field" curve of the logarithm of the fractional flow of water ($f_w$) versus cumulative oil production ($N_o$) — these plots are widely used for evaluation and prediction of reservoir performance — in particular, to estimate total recovery at 100 percent water production. The technique only applies at late times and assumes a log-linear relationship of WOR (or $f_w$) and oil recovery, which allows us to extrapolate the presumed straight-line trend to any desired water cut in order to determine the corresponding oil recovery. In our case, this extrapolation (to $f_w=1$) yields an oil recovery of approximately 34.5 MMSTB.

As a semi-empirical approach, we used a hyperbolic extrapolation of the cumulative oil production to estimate the ultimate recovery for the current operating conditions. The appropriate function for the cumulative oil production is given by:

$$N_o = \frac{q_i}{(1 - b)D_i} \left[1 - (1 + bD_it)^{1 - 1/b}\right]$$

where $q_i$, $b$, and $D_i$ are the parameters (i.e., constants) to be determined by regression.

As shown in Fig. 11b, the hyperbolic model (given above) satisfactorily matches the last 10 years of production data — which we believe yields a reasonable estimate of oil recovery. This approach gives an oil recovery of 34.6 MMSTB — in other words, 4.1 MMSTB of oil remains to be produced without making any substantial changes to the current field operations (total oil production to date is 30.5 MMSTB). Given the need to service equipment, maintain injection, etc., this estimate is almost certainly optimistic — and this estimate assumes that the operator will continue to produce even under conditions that may not be economically viable.

Another technique that can be used to estimate remaining reserves is to perform "estimated ultimate recovery" (or EUR) analysis on the production performance for each well. EUR analysis is a semi-empirical technique that consists of extrapolating the production rate ($q_o$) versus cumulative production ($N_o$) curve to $q_o=0$. The corresponding value of $N_o$ at $q_o=0$ represents the "recoverable" oil ($N_o,_{max}$). In Fig. 12 we illustrate this process for Well 1591. For the wells at Womack Hill Field, the recoverable oil estimate is often quite close to current cumulative production because of the lateness in the productive life for an individual well (as well as the field). We performed this analysis on all of the producing wells in the field as a mechanism to estimate the remaining field-wide recoverable oil at current conditions.

In Fig. 13 we summarize the EUR analysis results by plotting the cumulative oil production ($N_o$) for each well against its corresponding EUR. As expected, a strong correlation of $N_o$ with EUR emerges because of the mature status of the field. As a fieldwide average, we estimate that 94 percent of the total oil at current conditions has been recovered — which means that 6 percent of recoverable oil remains to be produced (presuming the current producing conditions continue). Using the 94 percent value, we compute an estimated total oil recovery of 32.5 MMSTB.

Considering a total cumulative oil production of 30.5 MMSTB (Fig. 3), the remaining oil to be produced is approximately 1.95 MMSTB (6 percent). This estimate is about half of the estimates obtained using the hyperbolic extrapolation and WOR analysis. Using the cumulative production for each "area" in Womack Hill Field (i.e., the Western and Eastern areas) we estimate the oil remaining to be produced in each area as 1.20 MMSTB in the Western area and 0.75 MMSTB in the Eastern area.
Analysis of Reservoir Performance — Field Scale

Early in the productive life of Womack Hill Field a concept emerged that the field had two compartments (or areas) — one in the west and one in the east. For field management purposes, and based on the belief that a geological division exists in the field, Womack Hill Field has been developed and managed as two independent "areas". While this issue of "separation" continues to be debated, it appears conclusive that some pressure support is benefiting wells in the Eastern area — while all of the injection wells are in the Western area.

It is important to note that all of the water injection wells are located in the Western region, so the water injection influence should not affect the Eastern area if a "barrier" truly exists. **Fig. 3** shows that the water injection rate has almost exceeded the oil production rate — the cumulative water injected has reached 42 MMSTB, which is 11.5 MMSTB higher than the oil withdrawal. So the amount of injected water appears to be more than sufficient to maintain the reservoir pressure. **Figs. 14 and 15** present the limited pressure data available for Western and Eastern areas, respectively. **Fig. 14** illustrates clearly the pressure increase (or maintenance) in the Western wells due to the water injection. However, the pressure maintenance has not been as effective in the Eastern area (**Fig. 15**), where the pressure in most of the wells has declined (although there certainly are exceptions). This pressure data suggests that a geological separation could exist between the two areas — but these data certainly does not serve to confirm this concept. As noted, some of the wells in the Eastern area have experienced pressure maintenance — which suggests that the "barrier" is not sealing and that some flow paths may communicate to both areas.

**Fig. 16** presents the historical field-wide oil production and water injection rates. We first note that from the beginning of the water injection program up to about year 20 (1990), the reservoir performance was approximately a 1:1 ratio (the volume of injected water per volume produced oil). Since then the injected water has increased steadily and the oil production has declined. This sharp change almost certainly cannot be attributed to a reservoir mechanism — it is far more likely to be a consequence of operational practices. In fact, in 1990 the operator first installed hydraulic "jet pumps" in the production wells in order to improve the productivity — but as revealed in **Fig. 16**, it appears that just the opposite occurred.

We also consider the phenomenon of "overproduction" of water where the ratio of the water production rates to the water injection rates versus time is presented in **Fig. 17**. This profile shows a ratio over unity — so the volume of produced water is (and always has been) higher than the volume of injected water. Water coning, water channeling, and/or strong water influx could cause this phenomenon. Empirical evidence from a site visit to Womack Hill Field suggests the possibility of water channeling and water influx. A numerical simulation model should consider the causes and effects of this phenomenon of "overproduction" of water.

Analysis of Well Performance — Decline Curves

For this work we have specifically used the Fetkovich-McCray family of decline type curves (Doublet, et al (1994)) where these type curves are formulated using pseudosteady-state (or boundary-dominated) flow behavior. We use pressure-drop normalized rate functions as well as the "material balance time" formulation to eliminate the constant $p_{wf}$ constraint associated with the original Fetkovich method. In addition, by adding the rate integral and the rate integral-derivative functions to this analysis technique, we are able to achieve much more consistent (i.e., unique) type curve matches and we generally obtain better matches of transient data for the estimation of formation flow properties.

The software WPA (Blasingame, et al (1998)) provides us a mechanism to apply this technique. In addition to production data, we also require reservoir and fluid properties, as well as an estimate of the initial reservoir pressure. Once the analysis process is completed in the WPA software, we obtain estimates of the following parameters:

**Flow terms:**
- Effective permeability, $k_r$, md
- Skin factor for near-well damage/stimulation, $s$
- Fracture-half length, $x_f$

**Volumetric results:**
- $N_C$, product, STB/psi
- Reservoir drainage radius, $r_d$, ft
- Drainage area, A, acres

**Fig. 18** illustrates the type curve match we obtained for Well 1847. As shown, the $q/\Delta p$, the "integral" of $q/\Delta p$, and the "integral-derivative" of $q/\Delta p$ are matched against the corresponding type curves. We note that most of the data lie in the "boundary-dominated flow region" — which is logical since the "transient flow region" contains few (if any) representative data (due to the proration of the field). Further, a lack of wellbore pressure data amplifies the problems encountered with the identification/analysis of data in the transient flow region — we simply have to provide a "best guess" analysis in this region, which implies that the "flow property:" results are qualitative at best.

As noted, we can only use the transient "flow property" results qualitatively, but we can utilize the "volumetric" results in a somewhat more quantitative fashion because for each well analyzed we clearly observe the late-time "harmonic" trend — which confirms the material balance correctness of this technique. Unfortunately, the parameters estimated using the "late time" data are tied to the value of total compressibility ($c_t$) specified for the analysis — this is not a value for which we have substantial confidence. Having prescribed a value for $c_t$, we can calculate the oil-in-place (N) and the reservoir drainage area ($A$). In this particular case we believe that it may be more valuable to report the $N_C$-product because our estimate of $c_t$ yields estimates of $N$ and $A$ which are clearly unrealistic.
As we have uncertainty in the estimate of $c_i$ (hence, $N$), for this work, we will use the $N_{C_r}$ product as a surrogate variable to represent the distribution of oil in the reservoir. Fig. 19 presents a crossplot EUR versus $N_{C_r}$ for all of wells that were analyzed. As shown, this plot illustrates a very strong correlation between EUR and $N_{C_r}$, even though these results are estimated independently (EUR is estimated from the rate versus cumulative production plot and $N_{C_r}$ from using decline type curve analysis). The observation of this strong relationship is logical, and it suggests that the recovery is proportional to the fluid-in-place.

Integration of Results
We now present the integration of the results we obtained from our petrophysical and production data analyses. As a reference, we present the field-scale map of Womack Hill Field in Fig. 20.

In our approach we develop contour maps using a commercial software product (Igor Pro $^{10}$ (2002)) in order to establish spatial relationships of reservoir properties and to compare performance-derived parameters with other data such as geological and petrophysical descriptions. In Fig. 21 we present the reservoir structure based on the "top of structure" for the Upper Smackover sequence — we clearly note two ridges, one in the Eastern area and another toward the central-Western area. Most of the wells are located on these ridges (see Fig. 20), the water injection wells are down-dip on the periphery in the Western area of the reservoir. The anhydrite of the Buckner member is presumed to provide the reservoir seal, and laterally, the reservoir is bounded on the south by a major growth fault and controlled on the west, east, and north by the water-oil contact.

Fig. 22 presents a map of the gross reservoir thickness, where we can note that the reservoir thickness varies across the field — thickness ranges from 40 ft up to 180 ft. The area of maximum-thickness is on the Western ridge — on the Eastern ridge we have thicknesses that range between 100-120 ft. However, a drastic change is inferred in the "valley" between the ridges, where the lowest values of Smackover reservoir thickness are given. We should expect a low oil accumulation in the "valley" region (as well as low total oil recovery).

In Figs. 23 to 25 we present the porosity distributions generated using the statistical analysis of petrophysical data for Flow Units A, B, and C, respectively. The contours show a homogeneous trend in Flow Units A and B — however, in Flow Unit C there are insufficient data to produce a meaningful map. From Figs. 23 to 25, we can conclude that a porosity estimate of 18 percent would serve as a reasonable average value for the entire Smackover sequence (Flow Units A, B, and C). Similarly, Figs. 26 to 28 present the permeability distributions generated using the statistical analysis on the core permeability data given for Flow Units A, B, and C. Again, the shortage of data in Flow Unit C prohibits us from making any conclusions for this case. However, in Flow Units A and B the contours show an apparent permeability contrast between the Eastern and Western areas.

Permeability reaches a maximum for the field just on the Western ridge of the structure and its minimum on the southern portion of the Eastern ridge. The pressure data suggest that a flow barrier may exist between both areas, and the permeability distributions (Figs. 26 to 28) tend to confirm this hypothesis. In the absence of any geological data indicating that a fault exists in this area, this permeability contrast has to be considered as the "barrier" between the two areas.

Using pressure transient tests (in production or injection wells) we can attempt to quantify the existence/influence of this barrier, but this is unlikely due to operational difficulties with regard to well testing at Womack Hill Field (an initial testing attempt failed, other well tests have been acquired and are being evaluated). In summary, the "barrier" could simply be a reduction of permeability that was caused by a change in mesoscopic heterogeneity (depositional facies), a change in microscopic heterogeneity (diagenetic changes), or a combination of the two processes — at this point in time we simply confirm the apparent existence of this flow "contrast."

We would like to correlate our geologically-defined model with the results from the production data analyses. Fig. 29 shows the distribution of the cumulative oil production throughout the field area — this plot shows that the best production is in the Western area (where the formation is thicker and permeabilities are higher). In the Eastern area the oil production is less, presumably as consequence of the lower reservoir quality.

A map of the EUR estimated from the rate versus cumulative production plots is presented on Fig. 30, this map revels that the highest recovery is in the vicinity of the Eastern ridge of the structure, reaching a maximum value of 3 MMSTB per well. However, this higher recovery is very localized, and is surrounded by contours of much lower magnitudes. Towards the west, the distribution is more consistent and averages 1.5 MMSTB per well. As we saw earlier, EUR and the $N_{C_r}$-product correlate quite well — on Fig. 31 we can see that the areas with higher $N_{C_r}$-products generally coincides with the areas of higher EUR. These distributions reflect the fact that most of the oil-in-place lies in the area bounded by the two ridges. Outside of this area, the $N_{C_r}$-product is significantly lower. Finally, we note in Figs. 30 and 31 evidence of irregular performance behavior at Womack Hill Field, as the area with the highest EUR and $N_{C_r}$-products is in the vicinity of lower permeability and variable reservoir thickness.

Reservoir Modelling (Simulation)
Initially we had elected to use reservoir simulation as the mechanism to integrate the reservoir character and predict reservoir performance for Womack Hill Field. Unfortunately, our efforts in reservoir simulation have been modest to date — due in large part (we believe) to the lack of water production data during the first 10-12 years of production in the field.

Efforts continue in the calibration of the reservoir simulation model using the geological and engineering data results — however, the issue of a lack of a water production history continues to be the major concern. Our efforts will most likely be
limited to the available data — and appropriate caution will be given to interpreting the results from reservoir modelling.

Summary

1. Petrophysical Data Correlation: Extensive efforts were made to integrate/correlate the core and well log data for Womack Hill Field. In summary, we believe that the porosity determined from well logs may be corrupt, or at least the vintage of the well logs used to estimate porosity may not be properly calibrated — no consistent correlations of well log porosity and core porosity were found.

As such, we elected to correlate reservoir permeability with core porosity, Gamma Ray well log response, and one of the resistivity log responses. We recognize that this is more an exercise in correlation since a prediction would require core porosity (or an accurate surrogate).

2. Production/Injection Analysis: All of the production and injection data have been thoroughly interpreted and analyzed using appropriate mechanisms (decline type curve analysis, EUR analysis, etc.). We believe that the "volumetric" results are relevant as virtually every analysis gave an appropriate signature for decline type curve analysis. However, a discrepancy in the estimate of the total compressibility for this reservoir system has arisen, and the volumetric results need to be revised (i.e., referenced to a more appropriate value of total compressibility).

It is relevant to note that independent analyses of the production data (i.e., decline type curve analysis and EUR analysis do correlate very well — despite being derived from techniques). In addition, on a fieldwide basis, the cumulative oil production is on the order to 94 percent of the estimated ultimate recovery (or EUR). This leaves approximately 1.95 MMSTB to be produced under current producing conditions.

3. Reservoir Simulation Model: The reservoir simulation efforts have largely focused on balancing the volumes of produced water. A number of different water injection/water influx schemes have been pursued, as well as a systematic study of the effect of the water-oil contact.

While revisions to this model will be proposed (based on new/revised geological/engineering data), the issue remains that the initial 10-12 years of water production were not recorded. Again, we will attempt to "balance" the unknown water production with appropriate consideration of injected water and water influx.

Nomenclature

- \( b \) = Arps' hyperbolic parameter, dimensionless
- \( c_i \) = Total compressibility, psi \(^{-1}\)
- \( D_i \) = Arps' "decline" constant, 1/D
- \( EUR \) = Estimated ultimate recovery, STB
- \( f_w \) = fractional flow of water, dimensionless
- \( GOR \) = Gas to oil (rate) ratio, dimensionless
- \( k_e \) = Effective permeability, md
- \( q \) = Production rate, STB/D
- \( q_i \) = Initial production rate, STB/D
- \( N \) = Original oil-in-place, STB
- \( N_p \) = Cumulative oil production, STB
- \( N_{p,max} \) = Maximum (or recoverable) oil production, STB
- \( p_{wf} \) = Flowing bottomhole pressure, psia
- \( \Delta p \) = (\( p_i - p_o \)), pressure drop, psi
- \( s \) = Skin factor, dimensionless
- \( x_f \) = Fracture half-length, ft
- \( \phi \) = Porosity, fraction
- \( WOR \) = Water to oil (rate) ratio, dimensionless

References


6. "GRACE" (software) Ver. 1.0, Texas A&M U., College Station, Texas (1996).


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Table 1 – Available core data for Womack Hill Field Study (Intervals and depths are given in measured depths).

<table>
<thead>
<tr>
<th>Well</th>
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<th>Core points</th>
<th>Reservoir Top (ft)</th>
<th>Comments</th>
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Table 2 – Summary results for decline type curve analysis — Womack Hill Field.

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<tr>
<th>Well</th>
<th>Area</th>
<th>$N_p_{total}$ (STB)</th>
<th>$N_c_{total}$ (STB/psi)</th>
<th>$k_o$ (md)</th>
<th>EUR (STB)</th>
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<tr>
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</table>

Figure 1 – Location of Womack Hill Field. Womack Hill Field is shown in the Gulf Coast region (after Mancini, et al. (2001)).

Figure 2 – Production history of Womack Hill Field. Since 1997, oil and gas rates have steadily declined, while the water production rate has increased. GOR has remained essentially constant.
Figure 3 – Cumulative production of Womack Hill field. Oil and gas curves are on the plateau and the water continues rising.

Figure 4 – Example of log and core permeability profiles — Well 1639, Womack Hill Field, Alabama.

Figure 5 – Core permeability univariate correlations for Well 1639 (Flow unit A), Womack Hill Field.

Figure 6 – Core permeability and porosity plots — Womack Hill Field, Well 1639 (Flow unit A). Log derived porosity does not match either core porosity or have a clear trend with core permeability — core porosity and permeability show a clear relationship.

Figure 7 – Optimal transformations for independent and dependent variables (core permeability correlation) — Womack Hill Field, Well 1639 (Flow unit A).
Figure 8 – Core porosity and logarithm of core permeability histograms — Womack Hill Field, Well 1639 (Flow unit A). Both porosity and the logarithm of permeability have normal distributions.

Figure 9 – Cumulative Production in Eastern Area — Womack Hill. This area produces 38.7 percent of total oil production.

Figure 10 – Cumulative Production in Western Area — Womack Hill. This area produces 61.3 percent of total oil production.

Figure 11a – Logarithm of the fractional flow of water versus cumulative oil production. The straight-line extrapolation at $f_w=1$ yields an oil recovery of 34.5 MMSTB.

Figure 11b – Oil Recovery Estimation by Hyperbolic Extrapolation. The extrapolation yields an oil recovery of 34.6 MMSTB under current producing conditions.
Figure 12—*EUR* plot for Well 1591 — Womack Hill Field. Cumulative production is approaching total recoverable oil.

Figure 13—Summary of *EUR* Analysis — Womack Hill Field. Strong correlation — likely a consequence of the maturity of production. Approximately 6 percent of reserves remain to be produced.

Figure 14—Well pressures in Western Area — Womack Hill Field. The effect of water injection is clearly shown from year 5.

Figure 15—Well pressures in Eastern Area — Womack Hill Field. Despite water injection, well pressures for some wells are declining “normally,” while other wells appear to be receiving pressure support.

Figure 16—Water injection and oil production rate profiles — Womack Hill Field. Water injection appears to be less efficient over the last 10 years.

Figure 17—Water production rate to water injection rate ratio — Womack Hill Field. The higher volume of produced water is likely due to water coning or a strong water influx.
Figure 18—Decline type curve analysis — match plot, Womack Hill Well 1847. Most of the data lie in the boundary-dominated flow region — the transient flow regime is less well-defined.

Figure 19—EUR versus $N_c$ — Womack Hill Field. EUR and $N_c$ are estimated using independent mechanisms — however, these variables are clearly correlated.
Figure 20— Well locations in Womack Hill Field — injection wells are located only in the Western Area.

Figure 21— Top of Upper Smackover Formation. Two ridges are clearly defined by the contours, the reservoir dips to the North and is bounded by a major fault towards the South.

Figure 22— Reservoir gross thickness, Upper Smackover Formation (Flow Units A, B, and C). The contours vary across the field indicating areas of contrast (i.e., high-thickness areas are in close proximity to low-thickness ones).
Figure 23—Flow Unit A — Core porosity distribution obtained from statistical analysis (histogram for each well) — the contours tend to indicate a homogeneous reservoir model.

Figure 24—Flow Unit B — Core porosity distribution obtained from statistical analysis (histogram for each well) — the contours tend to indicate a homogeneous reservoir model.

Figure 25—Flow Unit C — Core porosity distribution obtained from statistical analysis (histogram for each well) — insufficient data.
Figure 26— Flow Unit A — Core permeability distribution obtained from statistical analysis (histogram for each well) — a permeability contrast is evident between the Eastern and Western areas.

Figure 27— Flow Unit B — Core permeability distribution obtained from statistical analysis (histogram for each well) — a permeability contrast is evident between the Eastern and Western areas.

Figure 28— Flow Unit C — Core permeability distribution obtained from statistical analysis (histogram for each well) — insufficient data.
Figure 29 – Distribution of cumulative oil production — the best productive area is the Western part of the structure, this area is presumed to have the highest reservoir quality.

Figure 30 – Distribution of estimated ultimate recovery (EUR) — note that the zone with the highest EUR is around the Eastern ridge of the structure.

Figure 31 – \( NcT \)-product estimated using decline type curve analysis — \( NcT \)-product correlates very well with EUR.