Evaluation of Residual Oil in the Wara, Mauddud, and Burgan Formations, Burgan Field, Kuwait.

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Abstract. As part of the 2040 mission to "optimize the value of Kuwait's hydrocarbon resources through exploration, development and production to ensure sustainability", KOC's FD S&EK group and Core Laboratories teamed up to re-evaluate existing reservoirs, re-classify and characterize the resources of the Burgan Field, Kuwait. Residual oil saturation (Sor) is an essential parameter in the calculation of reserves, identification of bypass pay, and designing drilling and completion as well as enhanced oil recovery strategies. However, Sor is difficult to predict, as it often correlates poorly with rock quality. This study aims to 1) develop a residual oil saturation model that integrates capillary pressure and waterflood imbibition datasets for the range of rock properties associated with the Wara, Mauddud, and Burgan formations in the Burgan Field, 2) validate measured core plug saturation data by comparing it to the residual oil saturation model and well-log saturation models, and 3) identify new or bypassed pay zones. Sor at the conclusion of the Pc and waterflood experiments correlated reasonably well with published trends as a function of porosity. Sor distribution from the Wara formation agreed well with published data from sandstone reservoirs as a function of porosity, generally ranging from 5 to 60 percent with an average around 25-30 percent. A reasonable agreement was found between the Sor distribution from the Burgan formation when compared to published data from sandstone reservoirs, however, the data was more poorly sorted (broad distribution), likely due to heterogeneity and coring fluid filtrate invasion variability. The Sor for the Mauddud and Burgan formations tended to be less or significantly less than the published trend for that rock quality (porosity). A comparison of core-measured saturations versus the Sor model indicates that the Capillary Number (Nc) was likely exceeded in the reservoir for intervals with higher reservoir quality during coring due to high filtrate invasion rates, thus reducing the measured saturations to unrealistic (low) values. Despite evidence of previous production in the Middle Burgan some wells show a significant fraction of oil that may have been bypassed and could be produced by normal means. Residual oil that would need EOR treatment to produce is between about 25-30% of theoretical original oil in place based on irreducible water saturation.

1 Introduction

The research presented herein is part of a larger scope collaboration between Kuwait's Oil Company's (KOC) South and East Kuwait Field Development (FD S&EK) team and Core Laboratories, which aims to re-evaluate existing reservoirs within the Burgan Field, South Kuwait, re-classifying and characterizing its resources. This paper draws on the findings from other aspects of the project but focuses on the characterization of residual oil. Datasets involved in this evaluation include core waterflood and trapped capillary pressure (Imbibition) values from legacy data across the Burgan Field and newly acquired residual oil measurements from recent wells (Figure 1).

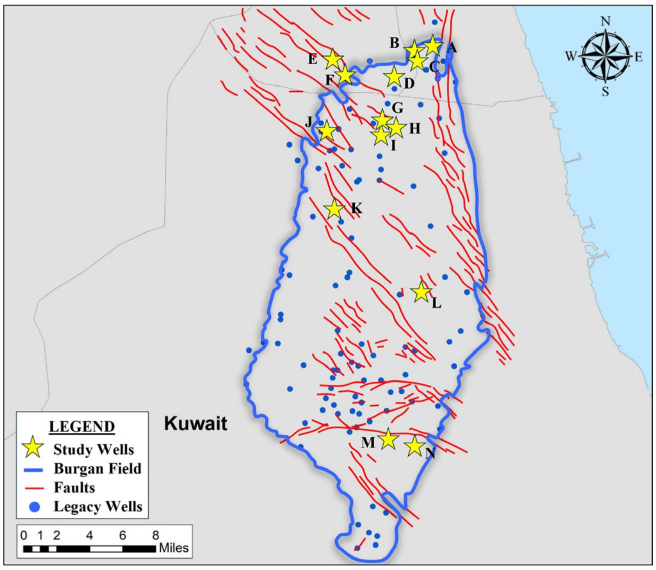

Fig. 1. Location of study wells within the Burgan Field (outlined) in Southern Kuwait.

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1.1 Geologic overview

The geologic units of interest are the Cretaceous (Albian-Cenomanian) Wara, Mauddud, and Burgan formations (Figure 2). The Wara Formation consists primarily of incised valley fill sandstones in the Middle and Upper members encased in Lower Wara shales [1]. The Mauddud displays similar character across the study area, recording deposition in a low gradient carbonate ramp with a general increase in the grain dominated facies stratigraphically upward in the wells studied. And the Burgan Formation includes braided fluvial sandstone to estuarine deposits in the Lower Member, lowstand alluvial and tidal bays in the Middle Burgan, and transgressive coastline deposits in the Upper [1].

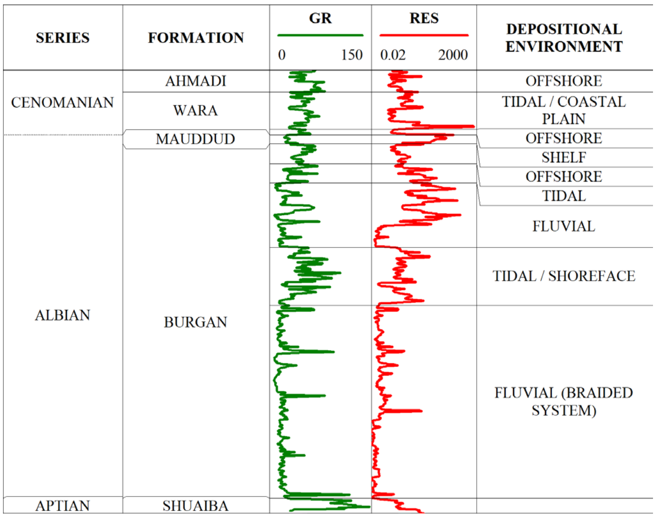


Fig. 2. Aptian to Cenomanian stratigraphy and representative gamma ray (GR) and resistivity (RES) logs in the Burgan Field, South Kuwait. Modified from [1].

The petrographic facies observed in the different formations are consistent across the entire Burgan Field, including clean sandstone, dolomitized sandstone, argillaceous sandstone, sandy mudrock, and shale in the Wara and Burgan formations and packstone, dolostone, and wackestone in the Mauddud. The clean sandstones are typically unconsolidated to lightly consolidated and display the best reservoir quality. Reservoir quality in the sandstones decreases due to dolomite cementation, argillaceous content, and siderite replacement of clay matrix. Grain size also appears proportional to reservoir quality, with upper fine to medium grained sandstones displaying the best permeability and porosity. Porosity in the sandstones consists predominantly of intergranular primary pores and subordinate amounts of secondary porosity. Porosity in Mauddud carbonates is typically dominated by matrix micro to nanopores, and it is significantly impacted by diagenetic cementation. Isolated moldic pores are locally present, as well as intraclastic pores within agglutinated foraminifera. The mudrocks are typically very tight, with porosity consisting mainly of nanopores among clay particles in the matrix.

1.2 Methodology and Definitions

Factors controlling residual oil saturation include rock type and properties, wettability, initial oil saturation, type of test and test conditions. In less than strongly water-wet systems, residual oil is also dependent on gravity, water throughput, and capillary number (velocity, interfacial tension). McPhee, Reed, and Zubizarreta [2] define residual oil saturation as follows:

1. "*True residual oil saturation (Sort) is a function only of the rock/fluid system. It is the final oil saturation at the microscopic level that can be achieved under the influence of viscous, capillary, and gravitational forces. It is the saturation at which the imbibition capillary curve becomes asymptotic and will provide the microscopic sweep efficiency. This saturation is typically lower and closer to true residual oil than from waterflood tests.*
2. *Remaining oil saturation (ROS) is the oil saturation that is achieved at the end of a field life within the pores contacted and swept by water. The value is dependent on true residual oil and microscopic sweep but also dependent on areal sweep efficiency and the number of pore volumes flooded through the pores.*
3. *Residual oil saturation (Sorw) is the final value of oil saturation from laboratory waterflood displacement experiments and depends primarily on the flow rate (or differential pressure) applied, permeability and capillary end effects, and test methodology.*"

Legacy data used in this study include porous plate capillary pressure measurements on extracted samples, centrifuge capillary pressure measurements on preserved samples, and waterflood tests on extracted samples and in wettability-restored samples, whereas newly acquired data from recent wells consist entirely of wettability-restored waterflood measurements. The capillary pressure data in this study fit the definition of true residual oil (Sort), while the waterflood test data fit the definition of Sorw above. All experiments represent brine displacing oil. Wettability restoration for newly acquired data was done with produced oil corresponding to the geologic formation being tested in different parts of the Burgan Field. Centrifuge saturations correspond to inlet face saturations converted from capillary pressure curves using Forbes method [3]. The waterflood residual oil saturations used in this study have not been corrected for capillary end effects, thus Sorw values in this case represent conservative estimates.

Using large datasets, Felsenthal [4] showed that residual oil saturations after waterflood tests in sandstones and carbonates vary widely, with averages in the range of 25% (Figure 3).

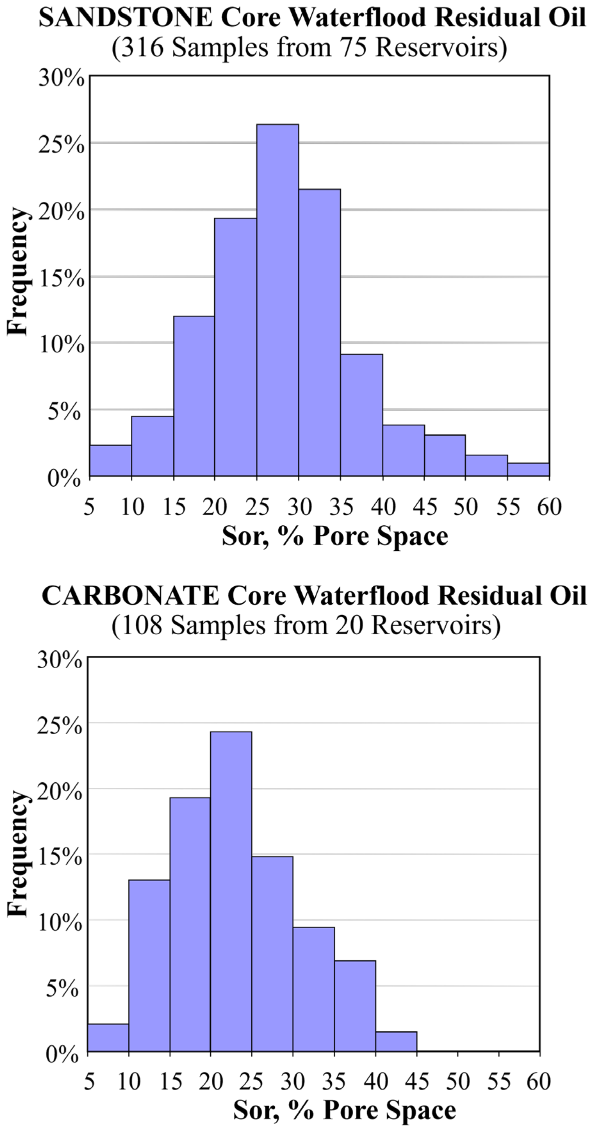


Fig. 3. Measured residual oil saturations for multiple sandstone and carbonate reservoirs. Modified from Felsenthal [4].

Research shows that maximum trapped gas saturation, which is analogous to residual oil saturation in water-wet scenarios, generally decreases with increasing porosity in intergranular pore systems [3] [5-10] (Figure 4). This relationship is generally interpreted to represent the pore-body to pore-throat aspect ratio of the rock, which decreases with increasing consolidation, but also the proportion of clays and microporosity present in the rock. The interpretation for clay-associated pores and other types of microporosity is that gas or oil generally do not enter these spaces, except for larger maximum gas saturations [8].

Many of the legacy data in this study represent testing done on solvent-extracted samples (i.e., water-wet conditions), but the recent data was measured on wettability-restored samples which show varying degrees of oil-wetness.

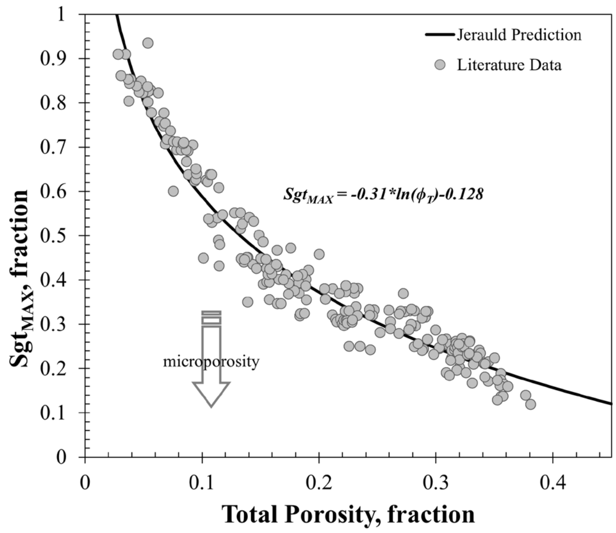


Fig 4. Maximum trapped gas in intergranular systems according to data published by [3] [5-10].

Land [11] and Jerauld [8] proposed equations (1) and (2) to account for changes of residual gas depending on initial gas saturation. Both models show that residual gas values vary progressively less as the initial gas increases (Figure 5). Land's model could result in a steeper curve and higher maximum trapped gas saturations than Jerauld.

$$Sgt = \frac{Sgi}{1 + \left(\frac{1}{SgtLab} - \frac{1}{SgiLab}\right) * Sgi} \tag{1}$$

$$Sgt = \frac{Sgi}{1 + \left[\left(\frac{1}{SgtMax}\right) - 1\right] * Sgi^{\left(\frac{1}{1-SgtMax}\right)}} \tag{2}$$

Where:

- Sgt = calculated trapped gas saturation
- Sgi = initial gas saturation
- SgtLab = trapped gas saturation measured in the laboratory
- SgiLab = initial gas saturation measured in the laboratory
- SgtMax = maximum trapped gas saturation

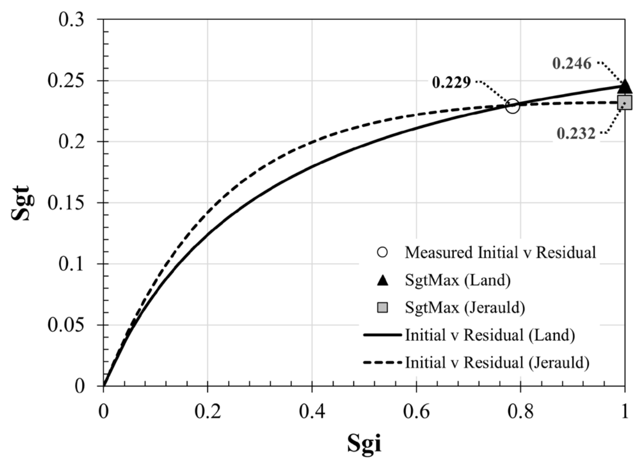
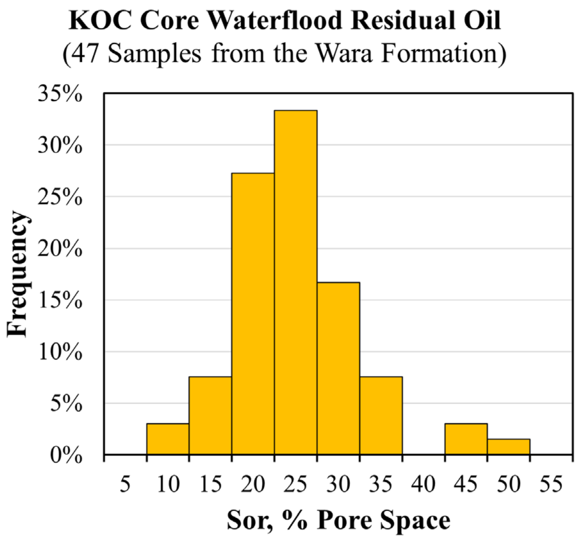
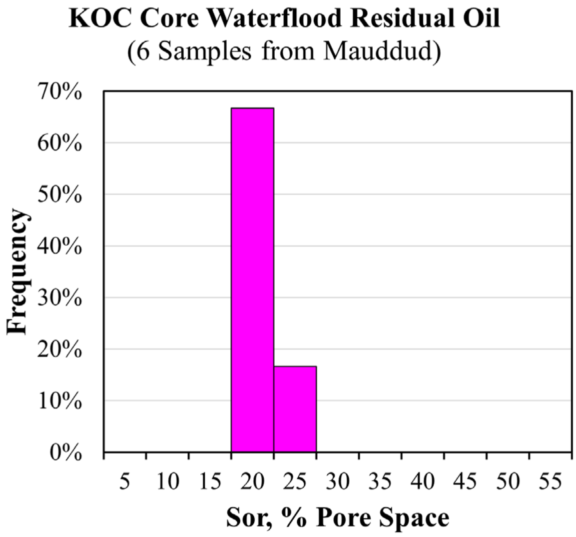


Fig. 5. Comparison of residual versus initial gas saturations calculated by Land's [11] and Jerauld's [8] equations.

2 Results and discussion

The distributions of residual oil saturations measured in the Wara, Mauddud, and Burgan formations in this study are consistent with those presented by Felsenthal [4] with average Sor around 25% but ranging up to 55% (Figure 6).





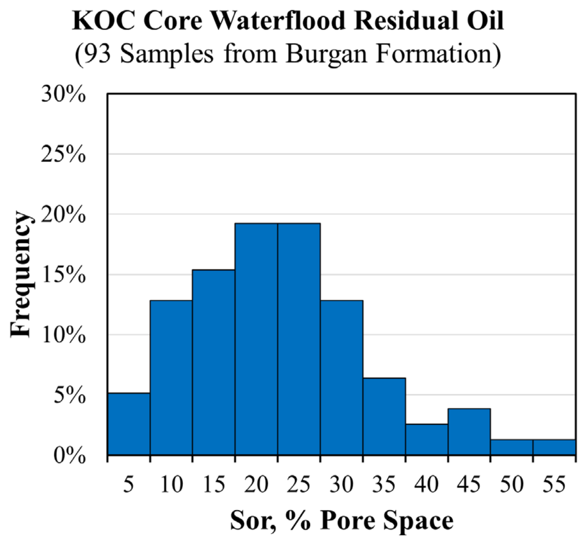


Fig. 6. Histograms of residual oil saturations in the a) Wara, b) Mauddud, and c) Burgan formations in this study.

Comparison of initial and residual oil saturations (Figure 7) shows distributions consistent with Land's equation (1), with a median trapping constant (C = (1/SgtLab)-(1/SgiLab)) of 3.01 and average 4.19. The Sor values measured in this study closely approach the maximum trapped values calculated with Land's equation (Figure 8), with a few exceptions where the C constant is less than 1. Jerauld's equation (2) results in even closer estimates for SorMax compared to measured Sor values (Figure 9).

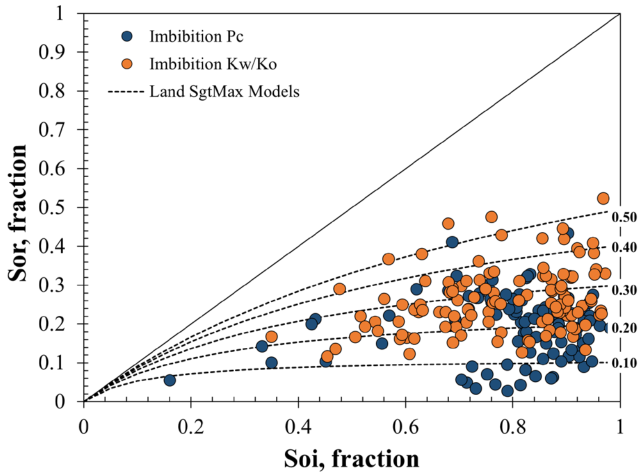


Fig. 7. Residual oil saturation (Sor) versus initial oil saturations (Soi) measured in this study with SgtMax models from Land [11] for comparison.

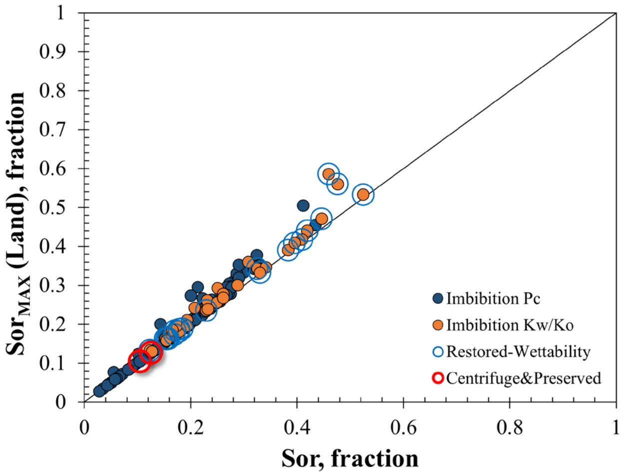


Fig. 8. Comparison of maximum residual oil calculated using Land's [11] equation to residual oil measured in this study.

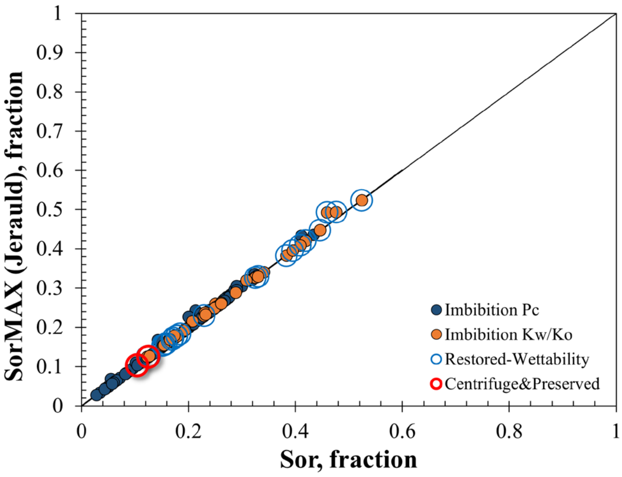


Fig. 9. Comparison of maximum residual oil calculated using Jerauld's [8] equation to residual oil measured in this study.

Data obtained from imbibition Pc and waterflood analyses represent similar ranges of porosity, but waterflood data typically display slightly higher residual oil saturations than imbibition Pc (Figure 10). This difference is normal and expected due to differences in the test type. No significant differences are observed between wettability-restored and extracted waterflood samples. Preserved samples analysed by centrifuge capillary pressure show lower average Sor than porous plate samples, but both datasets are within similar ranges of Sor. Many samples show Sor values below the expected trend for intergranular systems. The measured values were used to define a minimum Sor trend (SorMIN) and alternative Sor trend (SorALT) that best fits the entire cloud of data.

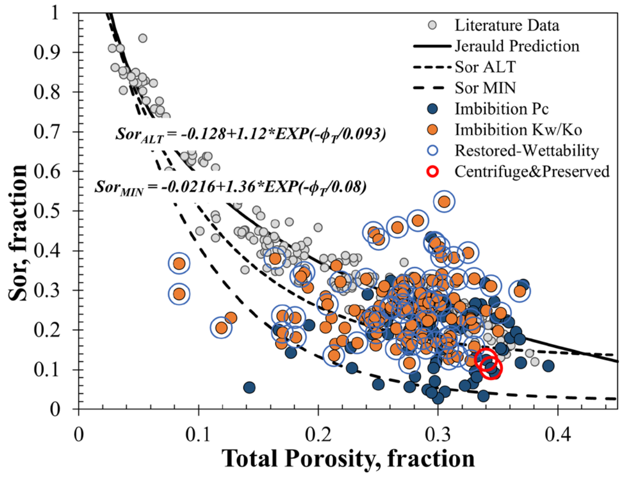


Fig. 10. Measured residual oil versus total porosity in this study compared to published trends from intergranular systems [3] [5-10] along with an alternative model and minimum Sor model to account for the variation in Sor observed in this study. Samples not circled represent steady state KwKo (extracted) and porous plate capillary pressure (extracted).

Separating the data by geologic formation shows that the Wara conforms more closely to the Sor trend expected for intergranular pore systems (Figure 11), whereas the Mauddud and the Burgan show a large proportion of data points with lower Sor values than expected for their reservoir quality (Figures 12 and 13).

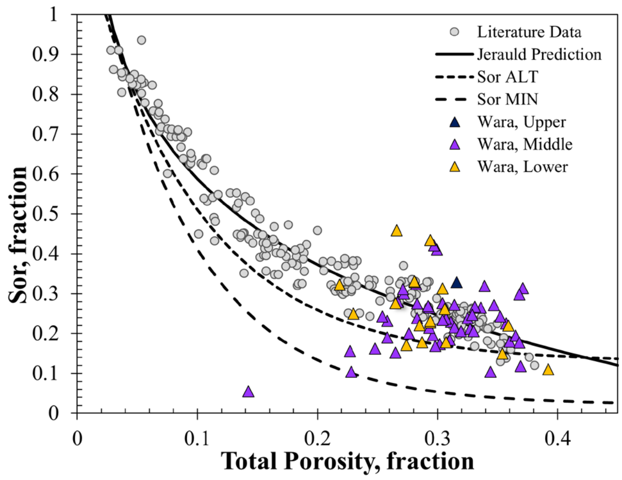


Fig. 11. Residual oil saturations versus porosity in the Wara Formation in this study.

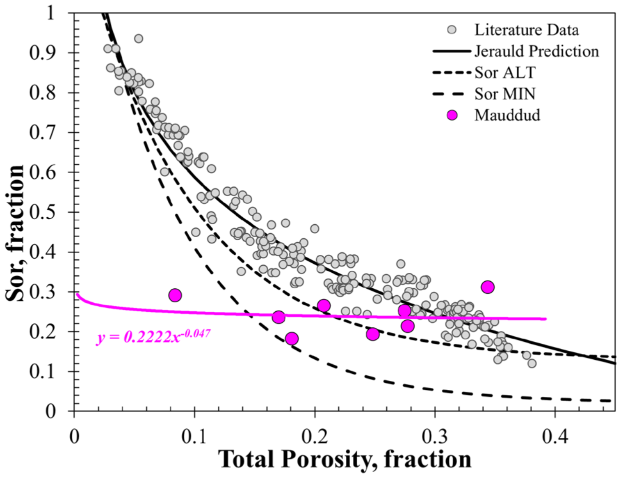


Fig. 12. Residual oil saturation versus porosity in the Mauddud Formation in this study.

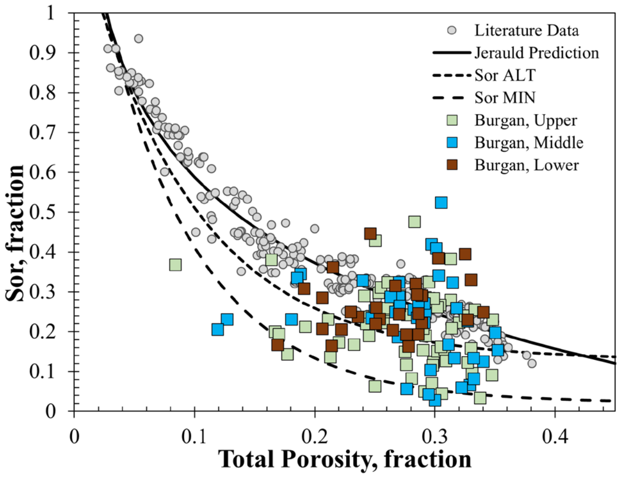


Fig. 13. Residual oil saturation versus porosity in the Burgan Formation in this study.

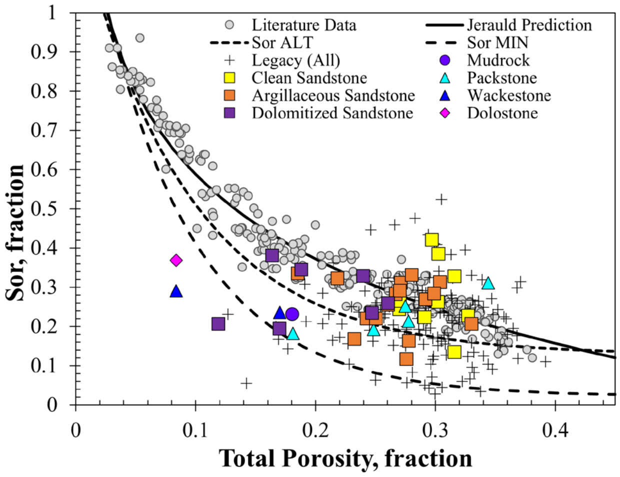


Fig. 14. Residual oil saturation versus porosity by rock types in this study.

Sor values below the expected [3] [5-10] trend line generally correspond with argillaceous siliciclastic rock types, mud-dominated carbonates, and dolostones (Figure 14). These rock types have lower total porosity values and elevated proportions of microporosity occurring among detrital clay particles, micrite, and microcrystals, respectively.

The observed variations in Sor are not tied to different regions within the Burgan Field (Figure 15) largely because similar rock types and ranges of reservoir quality occur in all the wells analysed.

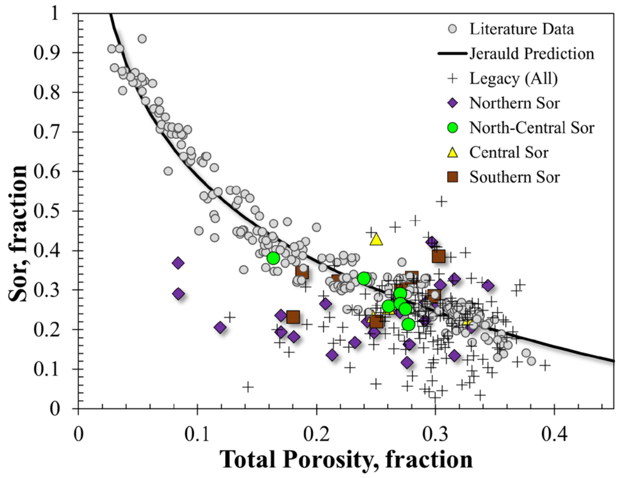


Fig. 15. Residual oil saturation versus porosity by regions in this study. Wells included in each region are as follows: Northern = A-F, North-Central = G-J, Central = K-L, and Southern = M-N.

Comparison between fluid saturation models and the porosity based Sor models for each formation shows intervals of unrealistically low oil saturations (Figure 16), where the capillary number (Figure 17) may have been exceeded in higher reservoir quality intervals. This may reflect high filtrate invasion rates during coring and drilling.

Despite historical production, some streaks of producible oil (i.e., bypass pay) remain in parts of the Middle Burgan, ranging between 10% and 25% in most wells. Residual oil saturations that would require enhanced oil recovery techniques range between 25% and 30% in the study wells (Figure 18).

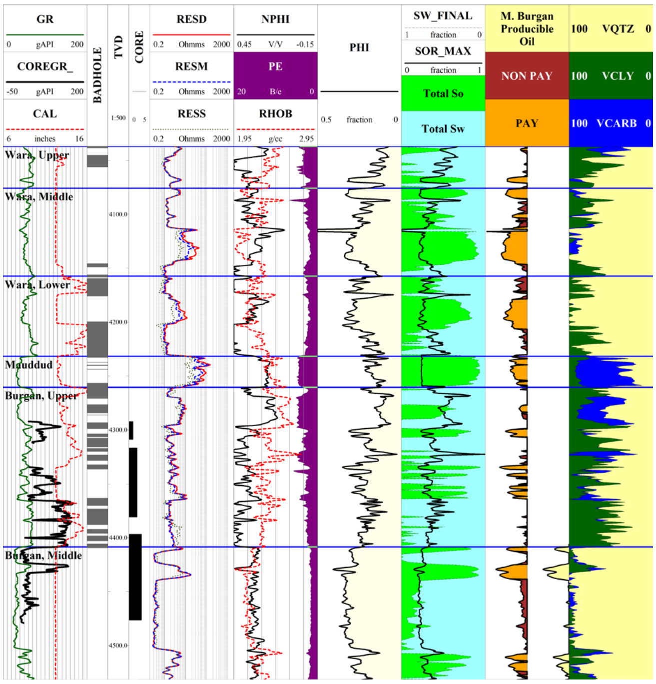


Fig. 16. Petrophysical models showing water and residual oil in the Wara, Mauddud, and Burgan formations well K.

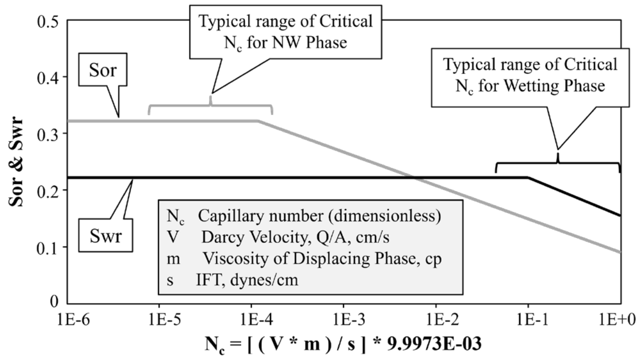


Fig. 17. Generalized capillary desaturation curves after [12].

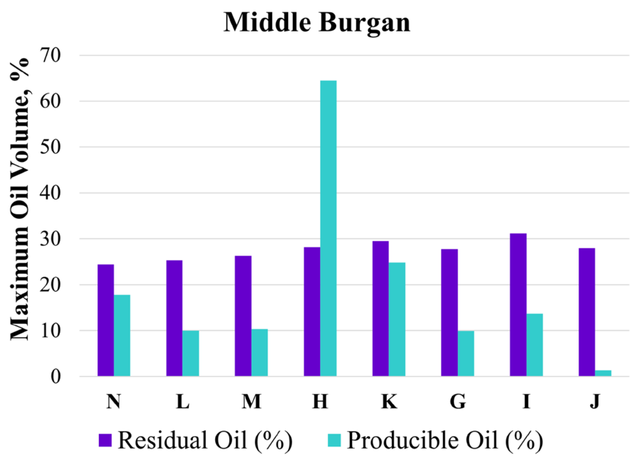


Fig. 18. Assessment of oil present in the Middle Burgan Formation from petrophysical models of water saturation and residual oil applied to each study well. No net pay cutoffs used. Producible oil calculated as the difference between Sw and Sor.

3 Conclusions

Residual oil saturation (Sor) distribution from the Wara formation agreed well with published data from sandstone reservoirs as a function of porosity, generally ranging from 5 to 60 percent with an average around 25-30 percent.

A reasonable agreement was found between the Sor distribution from the Burgan formation when compared to published data from sandstone reservoirs, however, the data was more poorly sorted (broad distribution), likely due to heterogeneity and coring fluid filtrate invasion variability.

In general, the Sor data from the Wara formation agreed with published data trends, while the Sor for the Mauddud and Burgan formations tended to be less or significantly less than the published trend for that rock quality (porosity)

A review of the core Sor indicates that the Capillary Number (Nc) was likely exceeded in the reservoir for intervals with higher reservoir quality during coring due to high filtrate invasion rates, thus reducing the Sor to unrealistic (low) values.

Despite evidence of previous production in the Middle Burgan some wells show a significant fraction of oil that may have been bypassed and could be produced by normal means.

Residual oil that would need EOR treatment to produce is between about 25-30% of theoretical original oil in place based on irreducible water saturation.

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