

**Exploitation and Optimization of Reservoir Performance in
Hunton Formation, Oklahoma**

QUARTERLY TECHNICAL PROGRESS REPORT

Submitted by

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Abstract

West Carney field – one of the newest fields discovered in Oklahoma – exhibits many unique production characteristics. These characteristics include:

- 1) decreasing water-oil ratio;
- 2) decreasing gas-oil ratio followed by an increase;
- 3) poor prediction capability of the reserves based on the log data; and
- 4) low geological connectivity but high hydrodynamic connectivity.

The purpose of this investigation is to understand the principal mechanisms affecting the production, and propose methods by which we can extend the phenomenon to other fields with similar characteristics.

In our experimental investigation section, we continue to describe the use of surfactant to alter the wettability of the rock. By altering the wettability, we should be able to change the water-gas ratio in the reservoir and, hence, improve the productivity from the well.

In our Engineering and Geological Analysis section, we present our rock typing analysis work which combines the geological data with engineering data to develop a unique rock characteristics description. The work demonstrates that it is possible to incorporate geological description in engineering analysis so that we can come up with rock types which have unique geological characteristics, as well as unique petrophysical characteristics. Using this rock typing scheme, we intend to develop a detailed reservoir description in our next quarterly report.

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Executive Summary

The analysis of available data continued during this quarter. Based on our analysis, we realize that it is possible to improve hydrocarbon recovery by altering the wettability of rock. We also carefully examined the geological analysis of more than 27 cores. We observed that by combining the geological pore type description, we can come up with a rock typing scheme which has unique geological and petrophysical characterizations. By using this rock typing scheme, we intend to develop a detailed reservoir description.

Experimental

Kishore Mohanty, University of Houston

Objective

The objectives of the third phase of this project are to test the feasibility of using Hunton reservoir as a gas storage reservoir and improve near-wellbore wettability. The feasibility of the gas storage was tested in the laboratory scale by conducting huff-puff test with gas. Treatment of the near-well bore region by a surfactant solution can decrease near-wellbore water blocking and increase gas productivity. Laboratory wettability tests are described in this report.

Methodology

In this study, we are investigating a surfactant treatment that can make the near-well formation non-wetting with respect to water. The laboratory studies were conducted in two scales. The first set of experiments was done on a surface scale, where carbonate surfaces (calcite) were treated with a surfactant solution to study its effect on wettability. The second set of experiments is being conducted with Hunton carbonate cores to study the effect of surfactants on effective gas permeability.

Results

Surfactant D was used for this study. Synthetic brine (0.1 N NaCl prepared in distilled water) and field brine were used as the liquid phase. The temperature was at ambient conditions in the lab, which varied from 22°C to 24°C. Air was used as the gas phase. A calcite plate was made smooth by grinding on a diamond plate. The plate was equilibrated with the synthetic brine for a day and then dried. Then it was equilibrated with the surfactant solution for a day. The plate was then dried, a drop of brine was placed on the plate and the contact angle was measured by a contact angle goniometer. The contact angle after the surfactant treatment is 114°. On a clean calcite plate, the water contact angle is 33°. Thus, the treatment with this surfactant makes the calcite surface hydrophobic.

A carbonate core from the Hunton field has been cleaned, vacuum dried and then fully saturated with the field brine. The brine permeability is measured. The cores would be flushed with humidified N₂ gas to a residual brine saturation at a pressure gradient of about 10 psi/ft. The gas permeability at this residual saturation would be measured. The cores would then be flooded from the opposite end with 6 PV of ethanol to remove any residual brine. The core would then be flooded for 3 PV with surfactant solutions and aged in room temperature for a period of 24 hours. The aged core would again be flooded with 6 PV of ethanol followed by 6 PV of synthetic brine to remove non-adsorbed surfactants and ethanol, respectively. The core would be then flooded with humidified N₂ gas to a residual brine saturation at a pressure gradient of about 10 psi/ft and 100 psi/ft. This experiment is under progress and the results will be reported in the next report.

Results and Discussion

Engineering and Geological Analysis

Mohan Kelkar, The University of Tulsa

Detailed geological analysis was completed on more than twenty wells. Over 12 different pore types were described. These pore types include fine pore matrix, coarse scale matrix, interconnected vugs and fractures. Three different rocks were identified – limestone, dolomite, and partial dolomite. This makes the total number of pore types equal to twelve.

Our goal is to integrate the data from pore types into petrophysical properties so that the data based on geological knowledge can be combined and have consistent petrophysical properties. For the purposes of discussion, here is a list of pore types and the associated number to each pore type:

Pore Codes	
Limestones	
1	Interconnected Vuggy Porosity
2	Coarse Matrix Porosity
3	Fine Matrix Porosity
4	Fracture
Dolomite	
5	Vuggy
6	Coarse Crystalline
7	Medium to Fine Crystalline
8	Fracture
Partly Dolomitized Limestone	
9	Interconnected Vuggy Porosity
10	Coarse Matrix Porosity
11	Fine Matrix Porosity
12	Fracture

We first wanted to find out if any of the pore types have similar porosity characteristics so that, for the purposes of petrophysical characterization, they can be combined. To achieve this goal, we generated Q-Q plots. Q-Q plots represent porosity values at a particular percentile against porosity value at the same percentile for another pore type. Figure 1 shows a plot of Pore Code 1 vs. Pore Code 11. The advantage of the Q-Q plot is that it would show the similarities in

porosity distributions for two sets of data irrespective of the type of porosity distribution. If the distribution is similar, the data would fall on the 45 degree line. If the data is not similar, it would indicate deviation from the 45 degree line. In Figure 1, we can assume that pore code 1 and pore code 11 have similar porosity distributions.

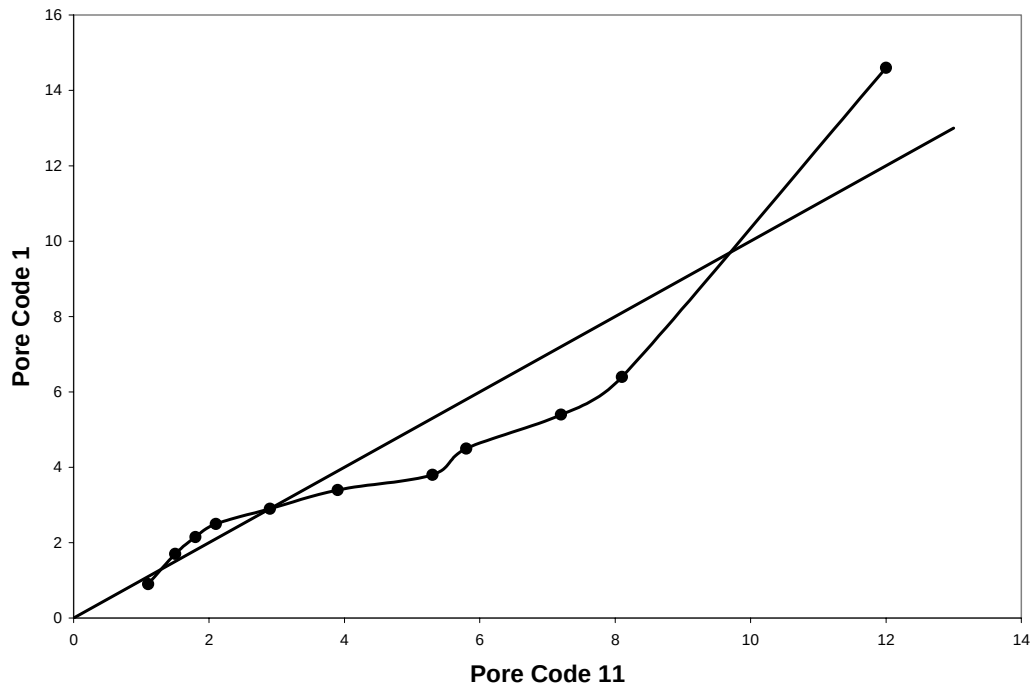


Figure 1: Q-Q plot for pore code 1 vs. pore code 11

Figures 2 through 6 show several Q-Q plots indicating similarities in porosity distributions. This plots show similarities among the porosity values among various pore codes. Although not shown, similar plots are created for each of the pore types against the other pore type to examine the similarities and the differences. The goal is to group together the pore types which have similar porosity characteristics and keep the pore types separate which have distinct pore type characteristics.

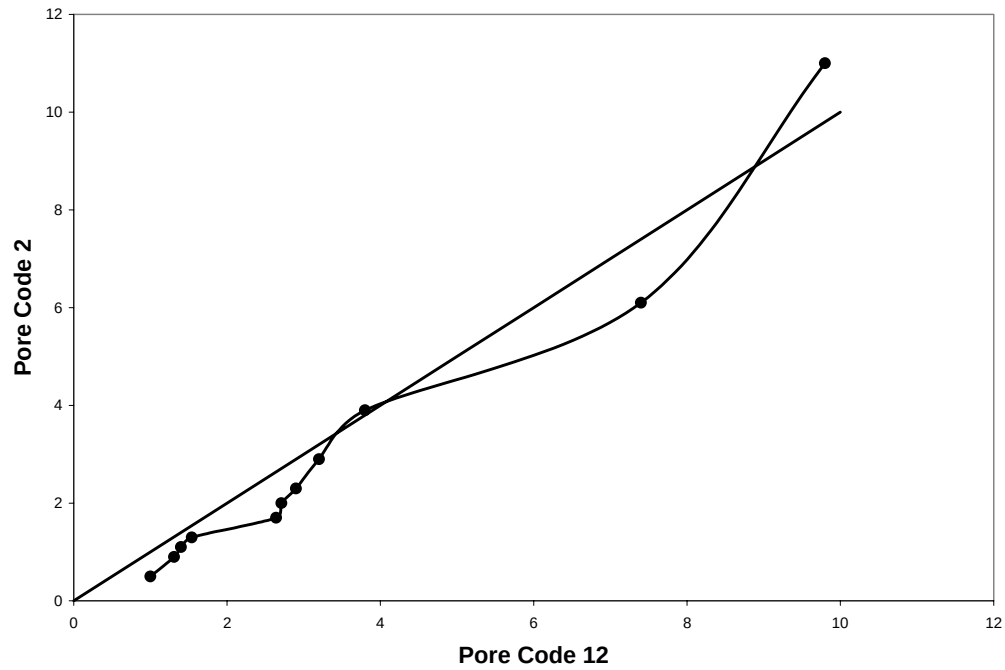


Figure 2: Q-Q Plot of Pore Code 2 vs. Pore Code 12

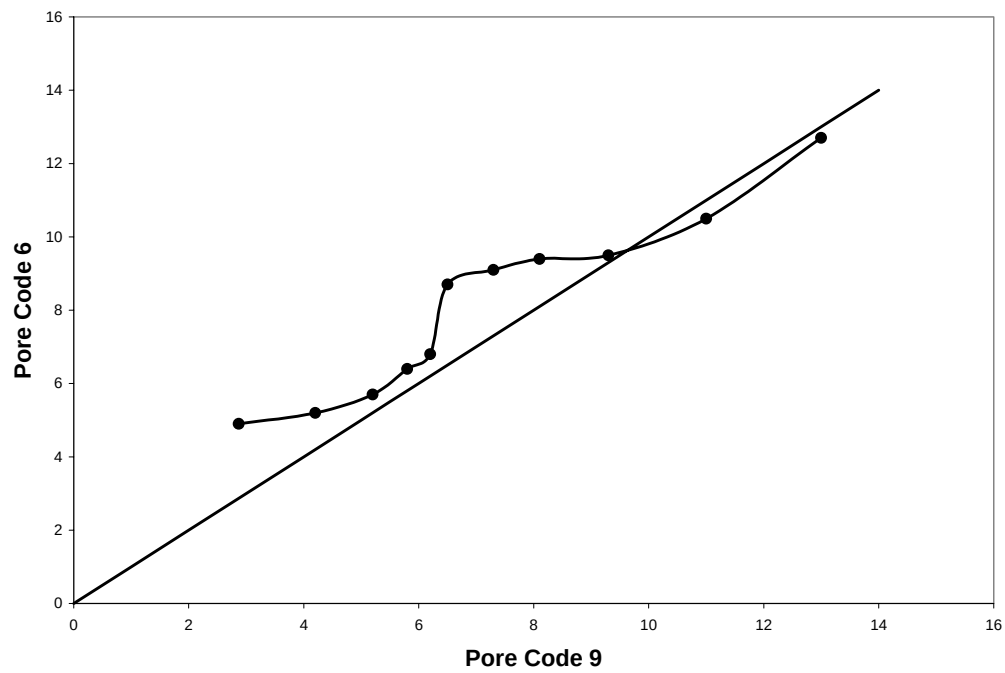


Figure 3: Q-Q Plot of Pore Code 6 vs. Pore Code 9

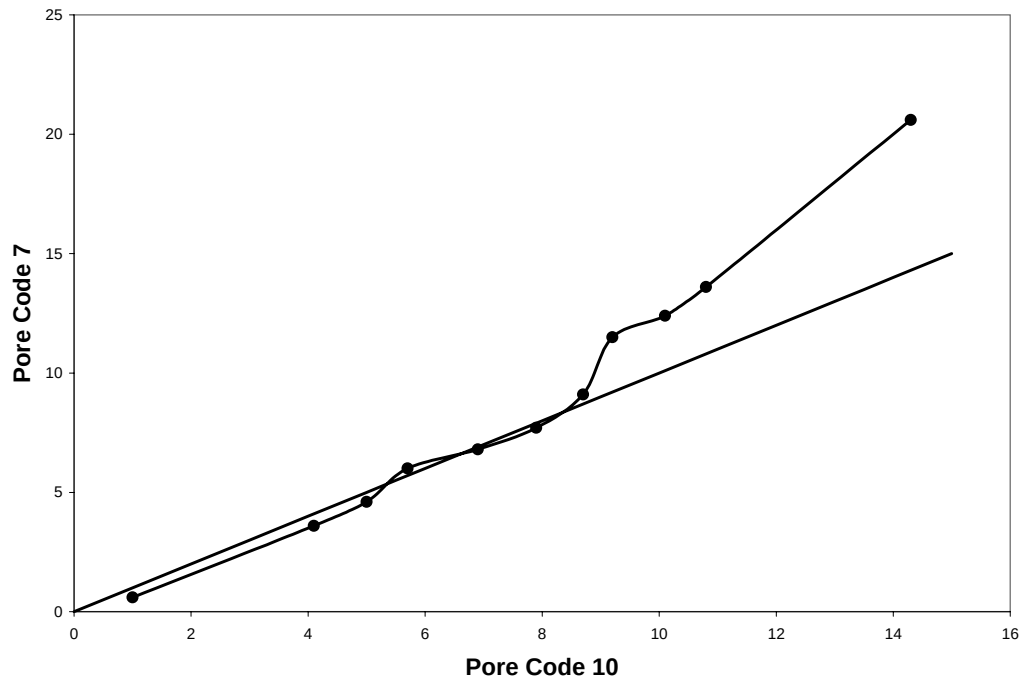


Figure 4: Q-Q Plot of Pore Code 7 vs. Pore Code 10

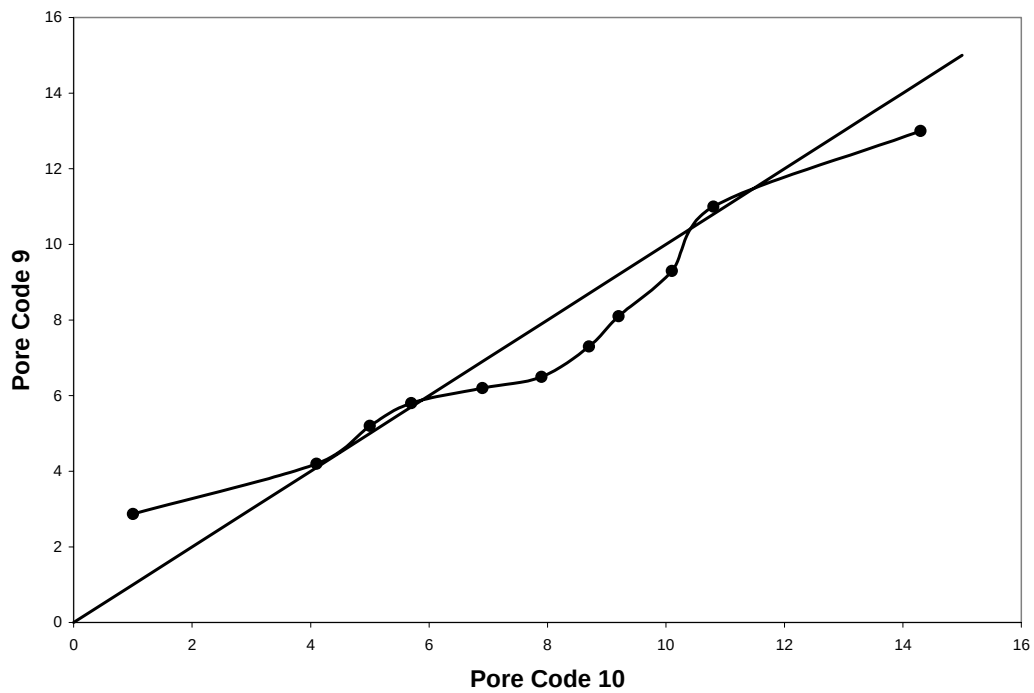


Figure 5: Q-Q Plot of Pore Code 9 vs. Pore Code 10

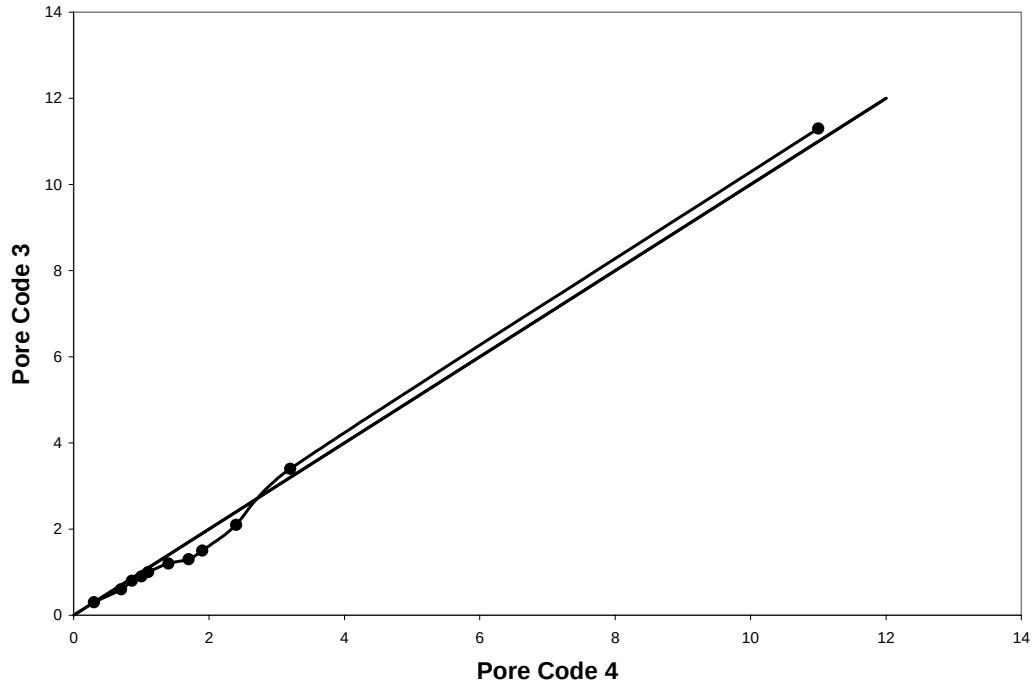


Figure 6: Q-Q Plot of Pore Code 3 vs. Pore Code 4

Using the Q-Q plot as a guideline, we divided the data into five rock types as shown below:

Rock Type	Pore Type
1	3
2	1,2,8,11,12
3	6,7,9,10
4	5
5	4

In effect, the twelve pore types are divided into 5 different rock types. Although, pore code 3 and pore code 4 show similar porosity distributions (see Figure 6), they have to be separated because the permeability characteristics of the two rock types is different as discussed below.

To validate our analysis, after combining the pore types, we generated porosity distribution for each rock type, which is presented in Figures 7 through 11.

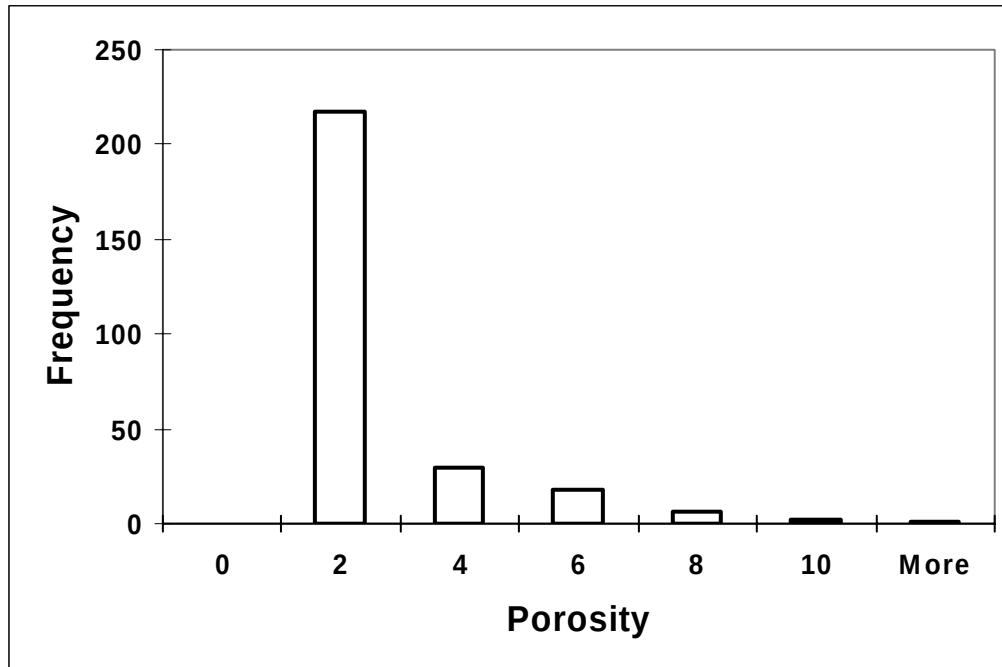


Figure 7: Porosity Distribution of Rock Type 1

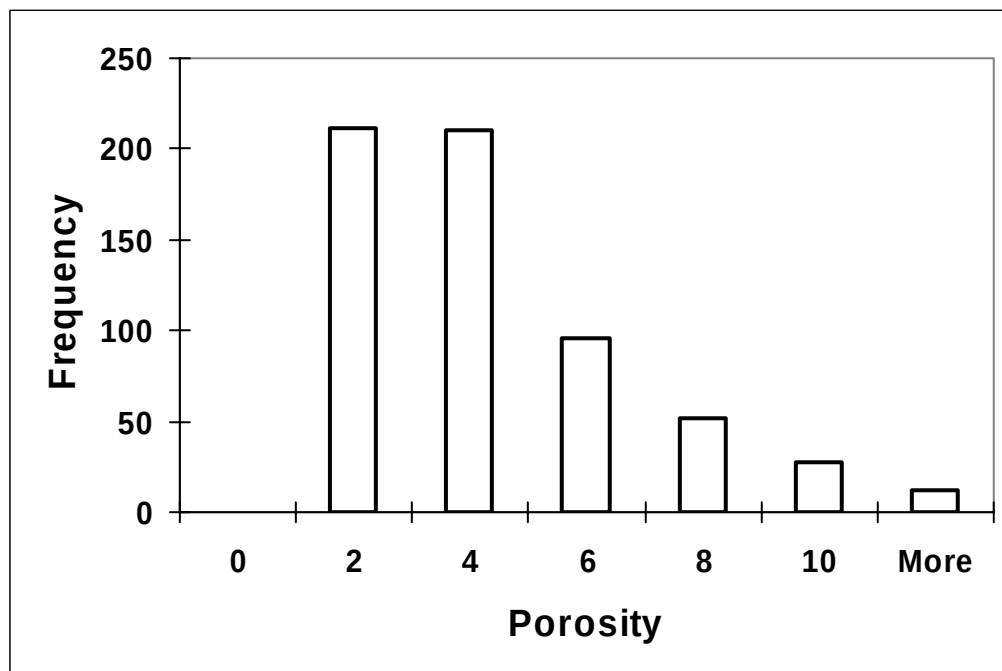


Figure 8: Porosity Distribution of Rock Type 2

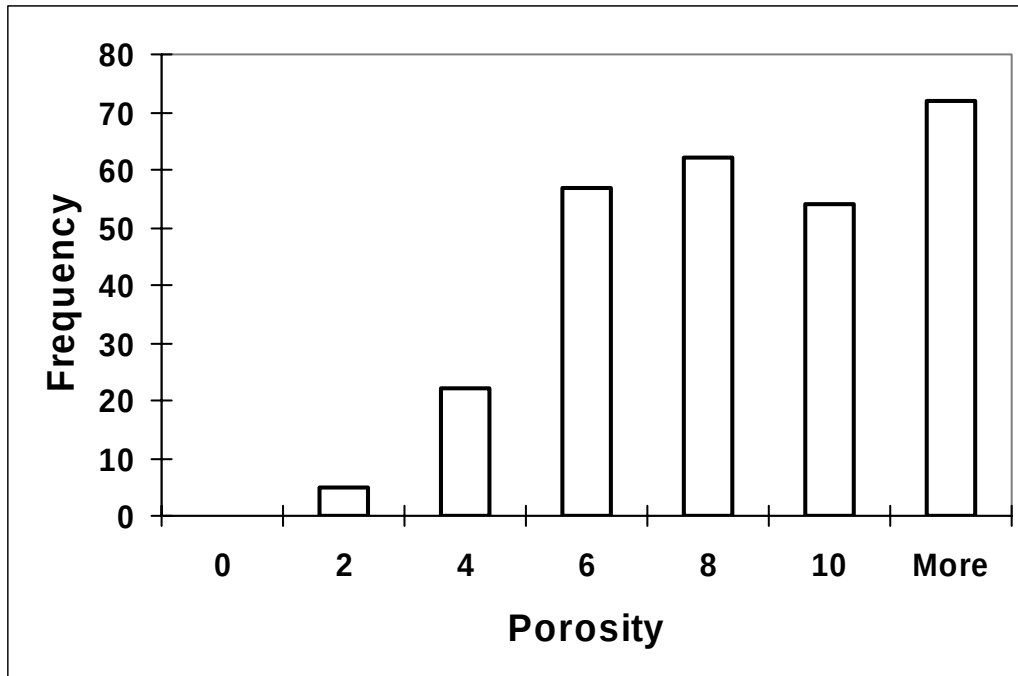


Figure 9: Porosity Distribution of Rock Type 3

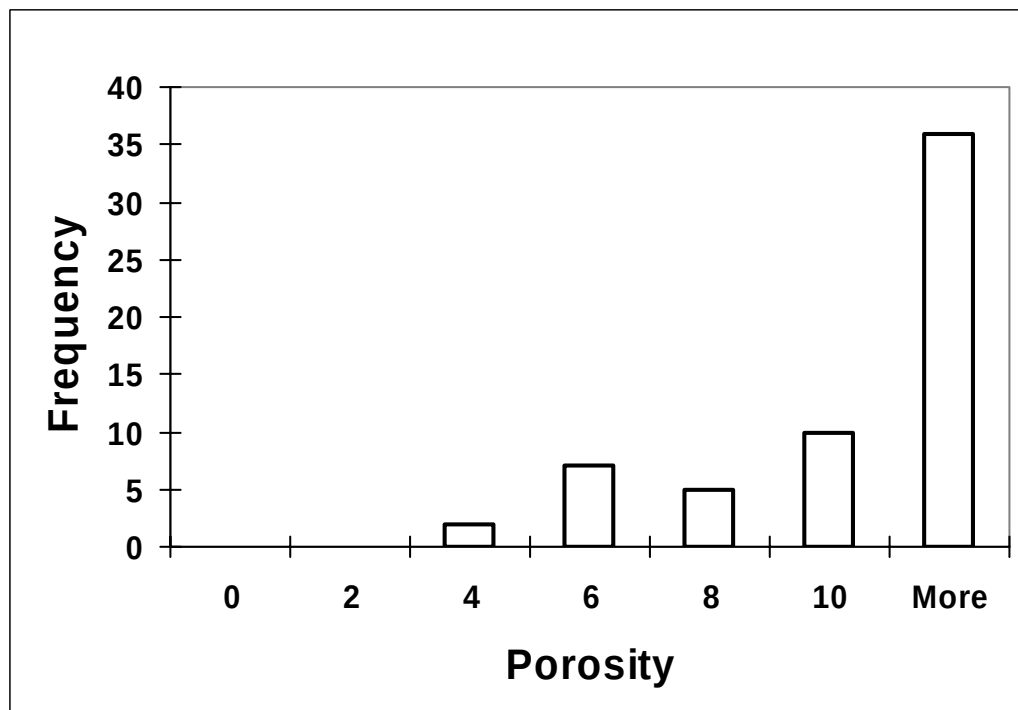


Figure 10: Porosity Distribution of Rock Type 4

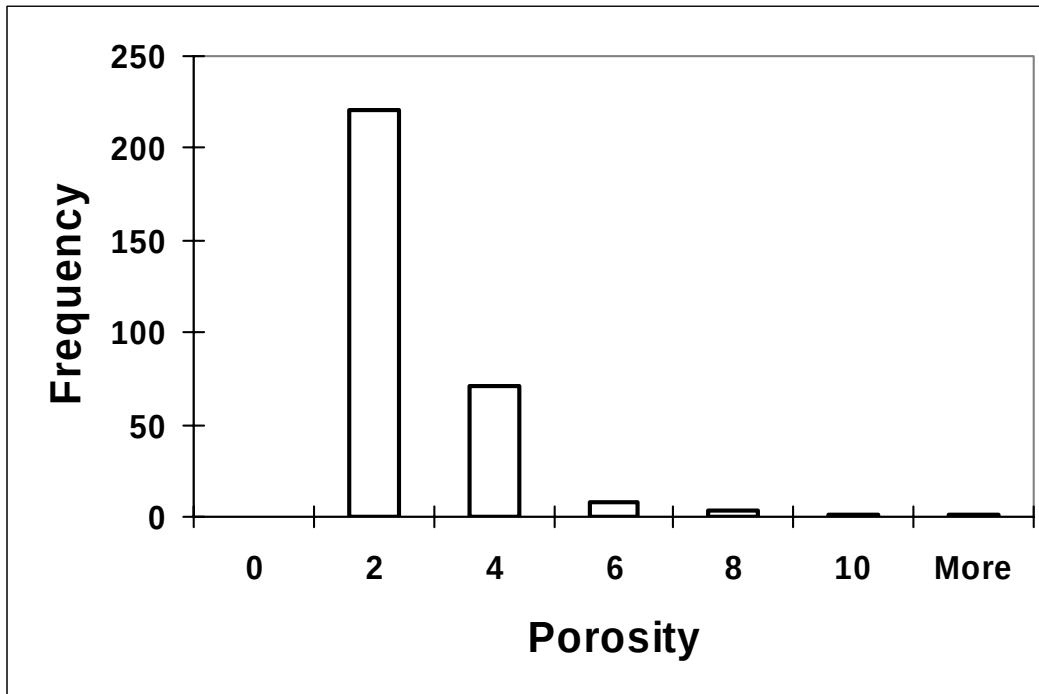


Figure 11: Porosity Distribution of Rock Type 5

As shown in these figures, the porosity distribution for each rock type is unique. As one observes the porosity distribution from Rock Type 1 to Rock Type 4, the distribution indicates higher porosity values. This is consistent with the pore types. In Rock Type 1, it is mostly limestone or partially dolomatized limestone; whereas, Rock Type 4 represents vuggy dolomite indicating high porosity values. Rock Type 5 and Rock Type 1 have similar porosity characteristics; however, their permeability distributions are different as discussed below.

Once the rock types are classified, we generated permeability – porosity relationships for each of the rock types. We would expect a different relationship for each rock type. The figures for each of the rock types are shown below. For Rock Type 1, most of the data are below 4% porosity, and the permeability values are typically less than 1 md.

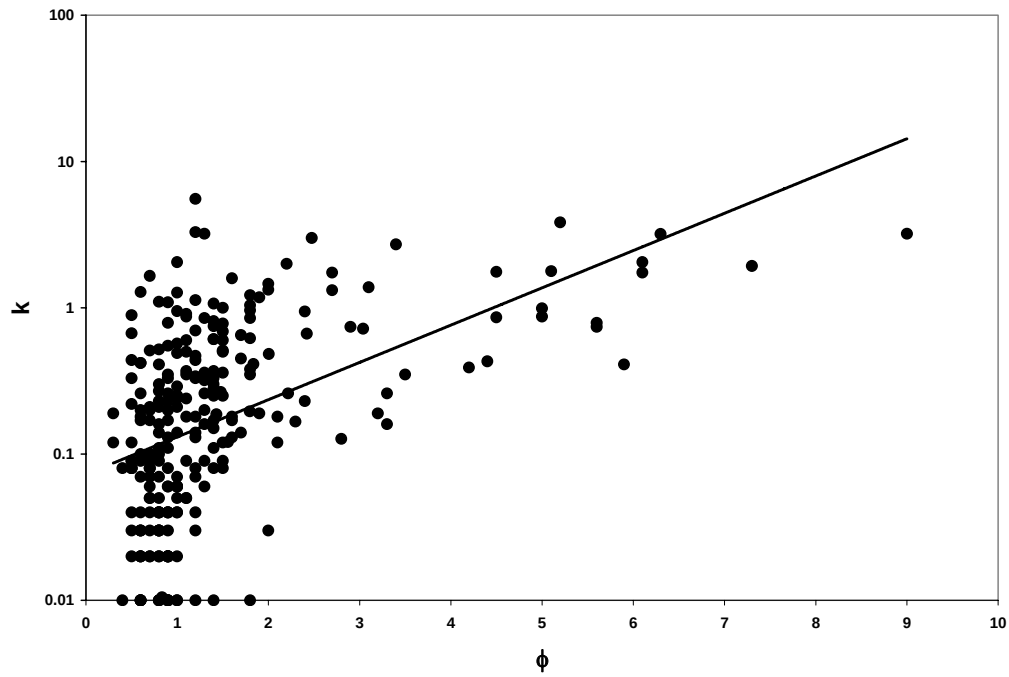


Figure 12: Log k vs. porosity relationship for Rock Type 1

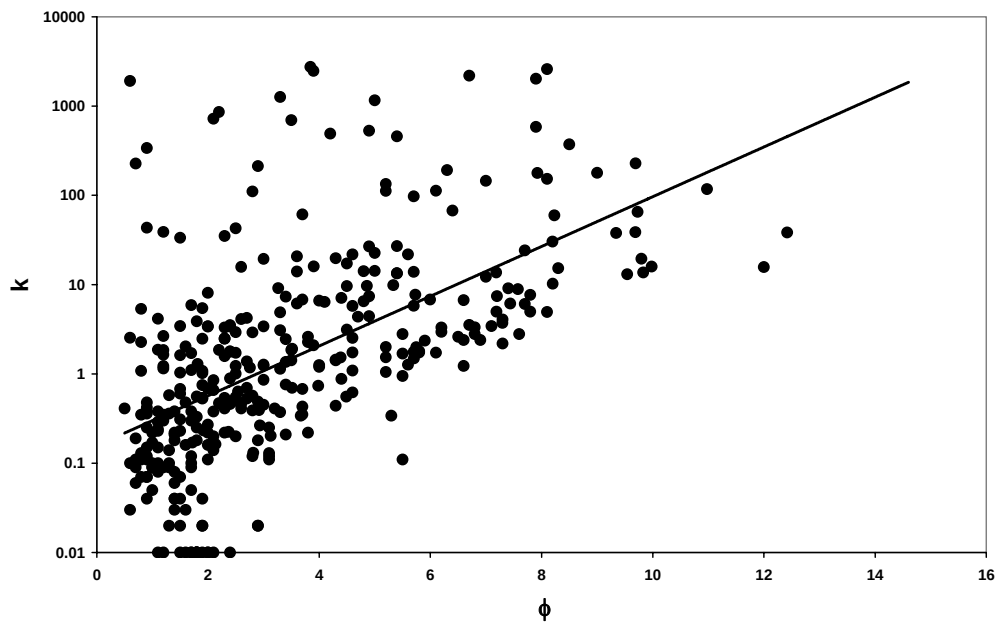


Figure 13: Log k vs. Porosity for Rock Type 2

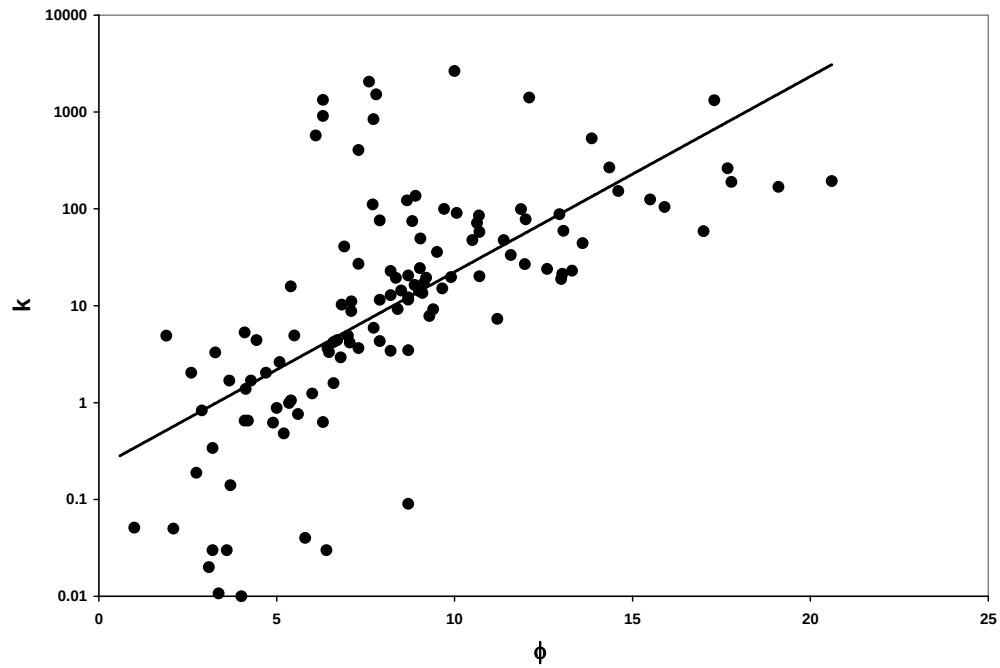


Figure 14: Log k vs. Porosity for Rock Type 3

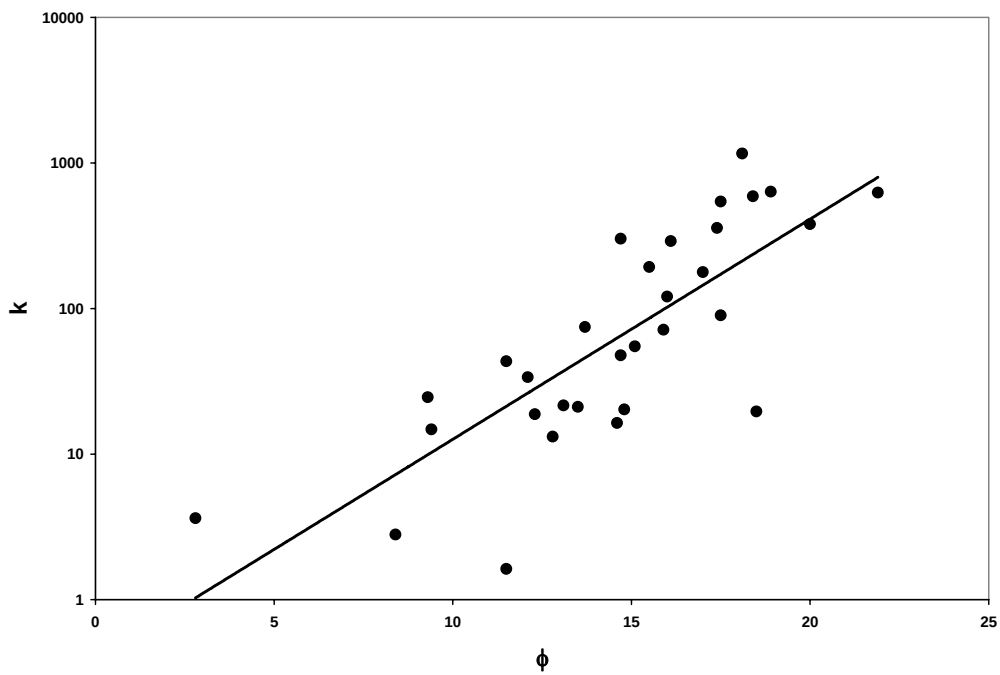


Figure 15: Log k vs. Porosity for Rock Type 4

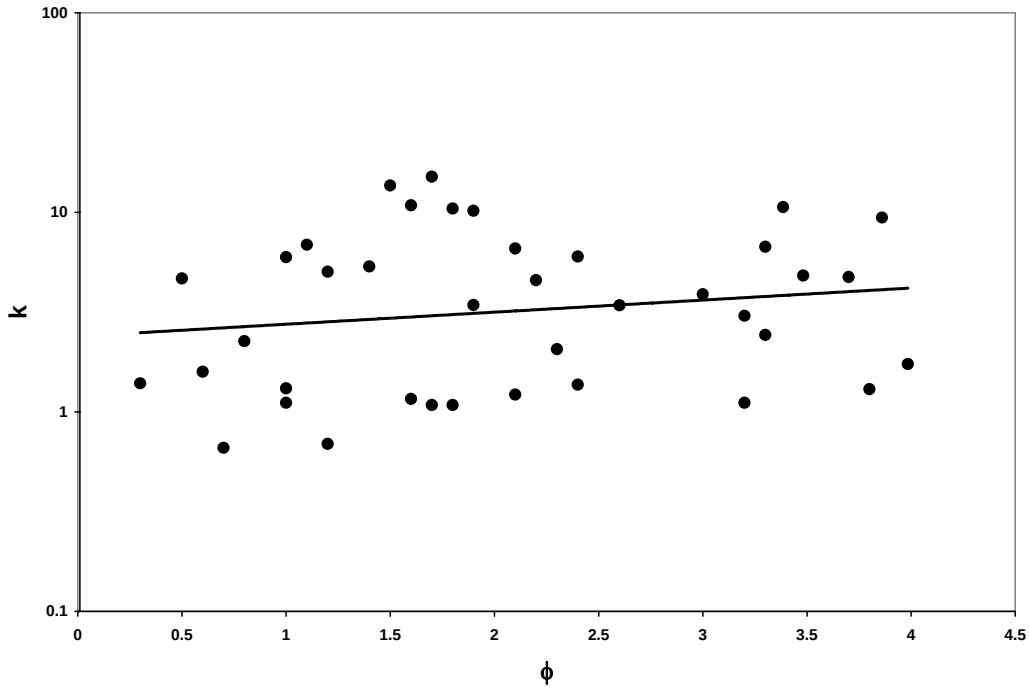


Figure 16: Log k vs. Porosity for Rock Type 5

For Rock Type 2, the permeability values can go up to 10 md. For Rock Type 3, the permeability values can go up to 100 md. And for Rock Type 4, the permeability values go up to 1,000 md. Higher porosity values for Rock Type 5 also indicate better permeability characteristics. For Rock Type 5, which represents a fractured reservoir in dolomite, the average permeability is about 5 md and is not dependent on the porosity. This is consistent with fractures in the reservoir in limestone rocks. Limestone rock is so tight (see Rock Type 1, Figure 12) that the permeability is quite low; less than 1 md. However, the enhancement can be achieved by introducing fractures. Since fractures provide the major source of conductivity, the permeability does not depend on the porosity of the rock.

We will use this rock typing scheme to populate our reservoir description in 3-D and will present the results in the next quarterly report.

Technology Transfer

No technology transfer activity was conducted during this quarter.

Conclusions

Based on the material presented in this report, the following conclusions may be drawn:

- Experimental data collection, to understand alteration of wettability by using surfactant, continues.
- A consistent rock typing scheme using geological data as an input was developed. These rock types exhibit unique petrophysical characteristics and should be able to identify conductivity regions in the reservoir.