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A Novel Technique for the Quantitative Determination of Wettability of a Severely Heterogeneous Tight Carbonate Reservoir

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Abstract

The objective of this study is to accurately measure the wettability contact angle of a cretaceous carbonate reservoir in a vertical well set-up known for as an unconventional tight carbonate oil reservoir. Also, to investigate the relative heterogeneity of these samples using digitally captured images; these images accurately capture natural pore-system in this carbonate rock samples and their wettability performance attributed towards building a vertical depth wettability/ heterogeneity model. To capture, measure and model natural tight matrix static contact angle wettability in order to understand their new physics that will advance unconventional tight oil reservoir characterization.

Entire vertical well depth reservoir core rock samples, in the form of rock fragments, are selected, then imaged, and then characterized for porosity, permeability, tortuosity/ heterogeneity, and pore/ grain-wettability contact angle in 2D format utilizing SEM-BSE imaging techniques. The generated big data images will be quantified using pre-defined logic for tortuosity/ heterogeneity and wettability contact angle measurement. Each rock sample will process several images captured at X40 (mm), X400 (μm), and X4000 (nm) magnifications and will investigate wettability/ heterogeneity relationships for unconventional tight pore system from the entire vertical depth.

From measured data and computed logics, the major portions of captured rock investigated show water wet tendency. The wettability distribution in the vertical 250 feet shows strong to medium and even weak water-wet system variation ($\theta = 10°$ - $\theta = 90°$). The dominant wettability is medium-water-wet ($\theta = 30°$ - $\theta = 60°$), and it is found in the middle section of the vertical column. Medium-water-wet indicates a good candidate for secondary recovery water injection development programs. This study includes tortuosity/ heterogeneity quantifications from imaging 2D technology which is valuable in understanding vertical/ horizontal fluid movements.

The authors feel that this study will narrow the gap in understanding contact angle wettability, heterogeneity characterizations from static conditions viewpoint and hence, the reservoir crude oil recovery vertical profile history from vertical rock samples.

Introduction

Generally, tortuosity and static wettability contact angle properties are both heterogeneous in porous media. They are two complex phenomena that are difficult to evaluate together or even separately; nevertheless, their formation in the vertical thickness of the reservoir.

Classic Kuwait carbonate reservoir is recognized to exist as a thick and fractured limestone formation located in North Kuwait that indicates good production, but production is getting difficult in this formation (1). In the North field, referred to in this study as "LIMESTONE" formation averages about 430 feet of net-oil-pay. It exhibits a low matrix permeability from 0.0001 to 10's millidarcies and high porosity – about 18%. Thus, these petrophysical reservoir general descriptions justified the agenda of maximizing the production from LIMESTONE via characterizing the wettability as well as the tortuosity for future improved oil recovery production programs.

A total of 27 core samples were proposed for this study. This study proposes the investigation of static wettability contact angle and its subsequent tortuous-heterogeneity measurements through big data pore-scale modeling using 2D digital imaging technologies. 27-core chips from carbonate native samples covering the entire thickness of the selected reservoir are the candidates for EOR/ IOR unconventional reservoir characterization and a case study for using this novel technique.

This study proposes a detailed characterization of this formation to accelerate future reservoir planning and development. Since the world's demand for oil is increasing, and the price of oil is also growing, reservoir engineers, who are responsible of field development, are looking forward to developing this formation in the short term. This study is to offer information trial of reservoir characterization application that suggests a novel proposed method for tortuous-heterogeneity and wettability contact angle determination for tight carbonate oil reservoirs.

Background

Wettability is a complex phenomenon for it is difficult to yield accurate measurements, control quantitative repeatability, shorten the time of experimental data generation, and high cost of analysis (2-10). A new and novel technique using digital imaging technologies has addressed all these issues. Captured rock physics is deterministically reported and big-morphological-quantified- data is measured. This technique can be applied to any Kuwaiti EOR/ IOR reservoir candidate (11-14). Thus, this knowledge will assist in understanding the nature of the reservoir and how better to drain it.

In this study, 2-dimensional images are used to characterize the morphology of the grains and pores, using a two-step process (8, 14). In the first step, the image is captured. In the second step, the area and average pore contact angle of such features are scanned using image analysis software that has the ability to accurately measure several morphological parameters of pore and grain spaces as indicated in Figure 1. This study utilizes area measurement and contact angle as the criterion parameter for all analyses. Morphological features are calculated based on area and contact angle, which brings the level of information accuracy into two dimensions. This information, which is considered "Big Data," is taken and analyzed to find answers that enable cost and time reductions.

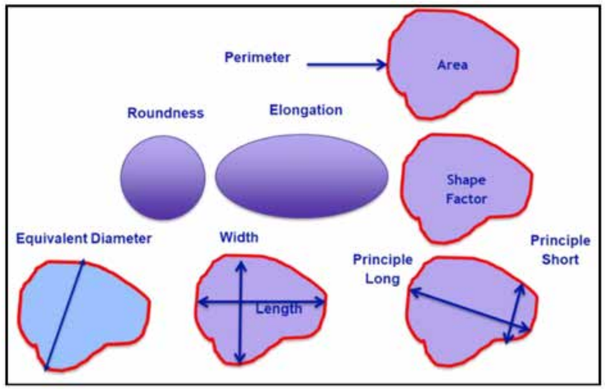

Figure 1—Pore/ grain boundary morphological reservoir wettability contact angle and tortuous-heterogeneity model.

In order to measure the complexity of a porous medium, tortuosity is used to describes the geometry of flow path. In other words, tortuosity is a measure of the degree to which the flow paths in a porous medium deviate from straight lines. In the field of reservoir engineering, it is a measure of the complexity of the pore structure of a rock and is an important parameter in determining the fluid flow characteristics of a reservoir.

One of the key factors that affects tortuosity is the rock type. Other factors that can affect tortuosity include the porosity, permeability, and grain size of the rock.

There are several methods that can be used to measure tortuosity in a reservoir. One common method is to measure the ratio of the apparent fluid flow path length to the straight-line distance between the inlet and outlet points of the flow path as shown in Figure 2 (Tortuosity = L/L0). In oil production, it is an important topological characteristic of oil reservoir rocks as well as its accurate determination is needed in enhanced oil recovery studies.

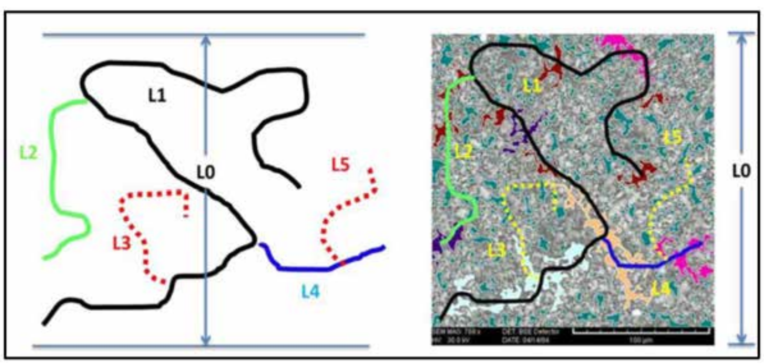

Figure 2—Schematic description of tortuosity.

Tortuosity is an important parameter in reservoir simulation and modeling. It is used to model the flow of fluids through porous media and to predict the behavior of reservoirs under different conditions. In particular, it is used to estimate the effectiveness of recovery processes such as waterflooding, gas injection and enhanced oil recovery methods. Tortuosity can be described as distance 1-D which is less complex, as area 2-D, or as reservoir unit volume 3-D which is more complex. Therefore, it will depend on the model logic and data that is needed to be obtained to interpret tortuous path.

According to Dai et al., 2012, tortuosity cannot be measured neither in a conventional lab tests nor to be estimated precisely via an empirical formula. Several studies showed different methods to calculate tortuosity based on their models. While the concept of tortuosity is poorly understood, because the work does not go beyond much simplified models or using nondeterministic approaches, one of recent studies mentioned that tortuosity is a tensorial property and it is function of pore geometry.

In this incepted research study, wettability characterization (quantitatively) and tortuosity characterization (qualitatively and quantitatively) are considered a deterministic microscopic approach based on measuring the contact angle and area of actual pore size and distribution.

The study objectives are:

1. to accurately measure the wettability contact angle of a cretaceous carbonate reservoir in a vertical well set-up known for as an unconventional tight carbonate oil reservoir.
2. to investigate the relative heterogeneity of these samples using digitally captured images; these images accurately capture natural pore-system in this carbonate rock samples and their wettability performance attributed towards building a vertical depth wettability/ heterogeneity model.
3. To capture, measure and model natural tight matrix static contact angle wettability in order to understand their new physics that will advance unconventional tight oil reservoir characterization.
4. To predict the applicable recovery methods for such reservoir.

Table 1—Formulation of models.

Parameter	Method	Units	Approach	Description	Comments
Pore Area	Σ Pore Area	μ-m^2	Visual Counting	Measured	Accurate
Grain Area	Σ Grain Area	μ-m^2	Visual Counting	Measured	Accurate
Wettability Contact Angle θ°	Rough edges between pore and grain	(θ°) Degrees	Visual Counting	Measured	Accurate
Porosity	$\phi = \frac{\sum PoreArea}{\sum PoreArea + \sum GrainArea}$	Fraction	Summation/ Statistical	Calculated	Low Error
Grain Diameter	$GrainDiameter = \frac{I}{1.32}$	μ-m	Kumar& Cui Sieve Method	Calculated	Originally Applied for mm-scale Grain Particles
Absolute Permeability	$k = 5.6281 \cdot \frac{d^2 \cdot \phi^3}{(1-\phi)^2}$	Milli-Darcy	Carmen & Kozeny	Calculated	Diameter & Porosity are Accurately Measured
Class Pore Area	Total Pore Areas Fitted in a Range of Pore Areas where MHR is Located	μ-m^2	Visual Counting	Measured	Accurate
Wettability	Θ = Pore Shapes and Morphology	Degrees	Pore/grain Orientations (New Proposal)	Measured	2-D 0° - 360°

Methodology

In order to achieve the objective of this study:

- Entire vertical well depth reservoir core rock samples, in the form of rock fragments, are selected, then imaged digitally.
- Then these samples will be characterized for porosity, permeability, tortuosity/ heterogeneity, and pore/ grain-wettability contact angle in 2D format utilizing SEM-BSE (scattered electron microscope- backscattered electron detector) imaging techniques as indicated in Figure 3.

- The generated big data images will be quantified using pre-defined logic for tortuosity/ heterogeneity and wettability contact angle measurement.
- Each rock sample will process several images captured at X40 (mm) which represents millimeter scale, X400 (µm) which represents the micrometer scale of pore-spaces, and X4000 (nm) magnifications which represents the nanometer scale and will investigate wettability/ heterogeneity relationships for unconventional tight pore system from the entire vertical depth.
- Figure 4 represents the logical experimental design for this research.
- The study is spanned over 27 core samples based on actual fresh cores, and a routine core analysis (RCA) was conducted to statistically measure some properties such as air permeability, porosity, and grain density.
- Pre-logics of tortuosity used in this study shown in Table 2. In this study, on two of them are considered which are (2D τ, Pore Area model) and (3D t, Frequency Volume model).
- The equations used for this study are available in Table 1

In the raw big data task, the data generated from 2D Image Technology and will be analyzed by the following pore geometry that represents the morphology of each pore captured in the BSE-SEM image:

1. Pore counts.
2. Pore Area, A (μm^2).
3. Pore Perimeter, P (µm).
4. Pore Elongations, unit less.
5. Pore Roundness, unit less.
6. Pore Width, W (µm).
7. Pore Length, L (µm).
8. Pore Aspect Ratio, τ (L/W) unit less.
9. Principle Long Axis, (µm).
10. Principle Short Axis, (µm).
11. Equivalent Diameter, (µm).

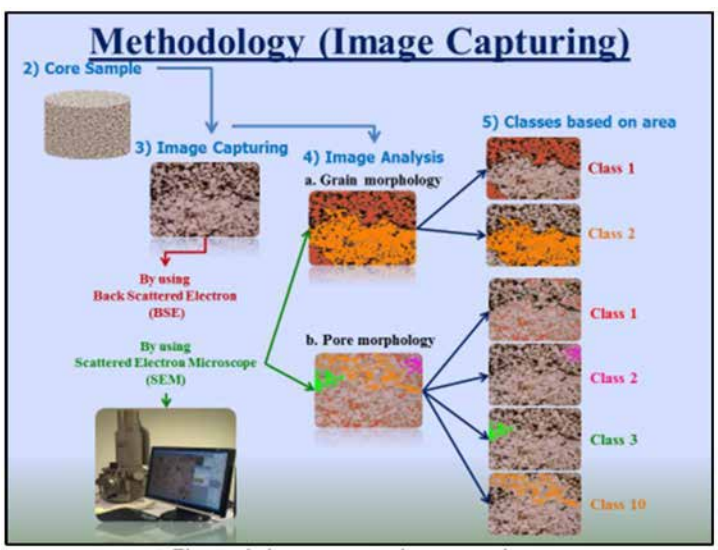

Figure 3—Image capturing procedure.

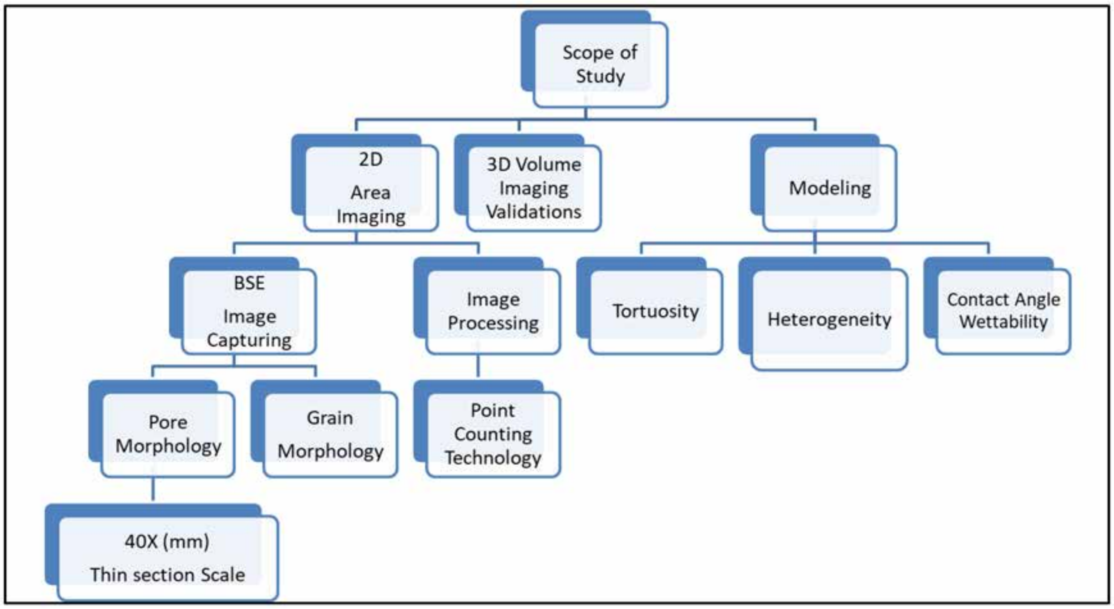

Figure 4—Logical experimental design.

These deterministic measured parameters are critical to understand relationships between pore geometry, porosity distributions, path propagations, and tortuosity of the shale rock. The data will be used to develop models, interpretation, and comparative studies to quality and quantify Tortuosity. Using the discovered knowledge, a logic framework diagram will be created to quantify heterogeneity.

Table 2—Pre-logics of tortuosity used in this study

Model	Name	Factors	Units	Source
1D τ	Aspect Ratio	Width/ length	%	Al-Bazzaz 2009
1D τ	Sieving Method	((Principle L + Principle S)/2)/ 1.32	%	Kumar& Cui 2007
1D τ	Equivalent Diameter	Equivalent Diameter/ Total Diameter	%	Al-Bazzaz 2007
2D τ	Pore Area	Class Area/ Total Area	%	Al-Bazzaz 2007
2D τ	Shape Area	Elongation/ Roundness	%	Al-Bazzaz 2016
3D τ	Frequency Volume	Frequency * 2D τ	%	Al-Bazzaz 2016
3D τ	MPSD	Measured Mean Pressure	%	Al-Bazzaz 2016
3D τ	Pore Volume Imaging	Under development	%	Al-Bazzaz 2016

Result and Discussion

Routine core analysis with porosity and permeability cross plotting is shown in Figure 5 and Figure 6 where R^2= 14.8% for this formation as like any carbonate reservoir so that BSE-SEM technique will be utilized for better interpretation. Table 3 presents routine core analysis for air permeability, porosity, and grain density. 7 rock types are presented in this reservoir.

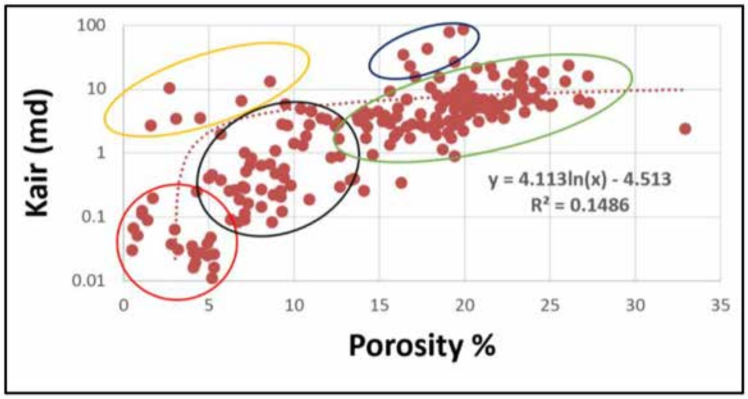

Figure 5—Semi-logarithmic crossplot of air-permeability and porosity.

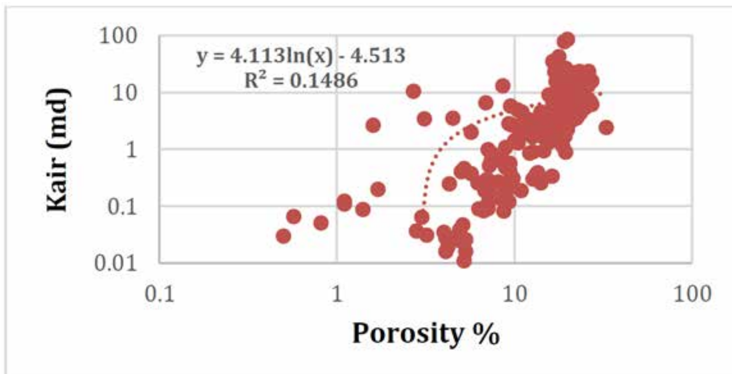

Figure 6—Log-log crossplot of air-permeability and porosity.

Table 3—Routine core analysis for this study. It shows that there are 7 rock typ

Sample No.	Depth	GD	Kair (Amb)	K∞ (Amb)	Ø (Amb)	
#	(ft)	gm/cc	mD	mD	%	Reasons for Selection
1	7684.2	2.84	0.0001	0.0001	4.9	Dolomite, tight matrix
2	7688.4	2.69	15.1	13.1	18.5	maximum perm
3	7700.4	2.69	0.0001	0.0001	1.5	minimum perm
4	7708.6	2.69	11.1	8.73	23.1	maximum por
5	7713.25	2.7	0.0001	0.0001	5.2	Tight Matrix
6	7718.45	2.67	23.6	20.5	26.1	maximum perm
7	7720.2	2.64	2.42	1.64	32.9	maximum por
26**	7721.9	2.69	6.15	4.56	27.3	KOC Selection
8	7735.3	2.71	0.0001	0.0001	2.6	minimum perm
9	7741.45	2.7	0.0001	0.0001	3.6	minimum perm
10	7755.2	2.62	35	26.1	16.4	maximum perm
11	7759.85	2.71	5.85	3.83	25.1	maximum por
27**	7767.1	2.69	5.16	4.37	20.9	Company Selection
12	7773.8	2.72	4.51	4	14.1	Dolomite
13	7777.7	2.74	7.82	6.03	20.2	maximum GD
14	7806	2.69	16	12.6	27.2	maximum por
15	7820.75	2.7	86	71	19.9	maximum perm
16	7828.9	2.7	0.0001	0.0001	4.4	minimum perm
17	7838.95	2.71	78.6	70.3	19.1	maximum perm
18	7848	2.88	1.7	1.19	14.2	Dolomite
19	7854.4	2.7	5.46	3.9	25	maximum por
20	7878.2	2.71	0.0001	0.0001	6.2	minimum perm
21	7887.8	2.71	6.57	5.05	21.6	maximum por
22	7889.7	2.7	13.1	12.2	8.6	maximum perm
23	7918.3	2.67	0.0001	0.0001	1.8	minimum perm, Tight matrix
24	7926.5	2.69	0.0001	0.0001	2.2	minimum perm, Tight matrix
25	7933.8	2.71	0.481	0.366	8.9	maximum perm, maximum por

Figure 7 indicates grain density from routine core analysis. There are three main grain minerals in this limestone reservoir that make the heterogeneities more complex such as limestone, sandstone, and dolomite (it creates fracture). Thus, it could have an impact on oil production process.

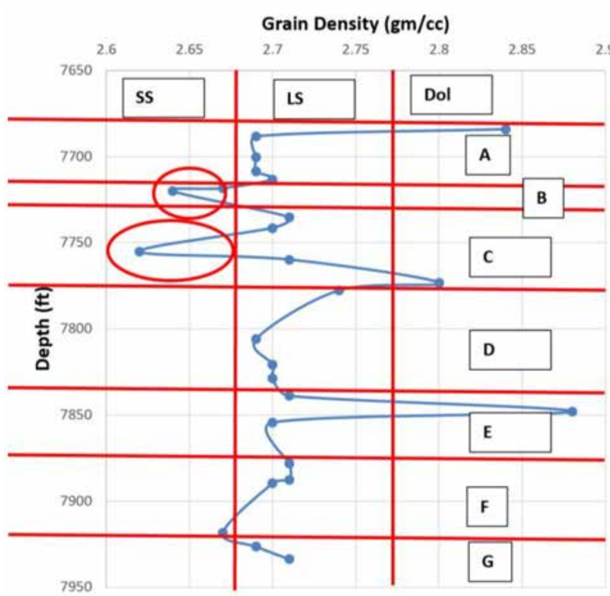

Figure 7—Grain Density Vs. Depth Profile

Figure 8 shows digital absolute permeability Carmen and Kozeny with depth Profile from SEM. Figure 9 shows digital porosity with depth Profile from SEM.

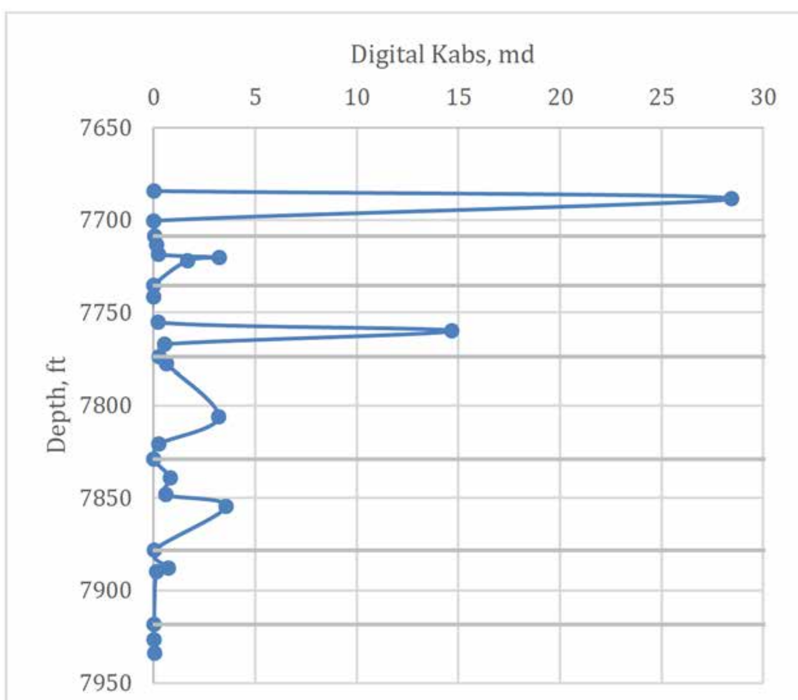

Figure 8—SEM digital absolute permeability by Carmen and Kozeny with depth Profile.

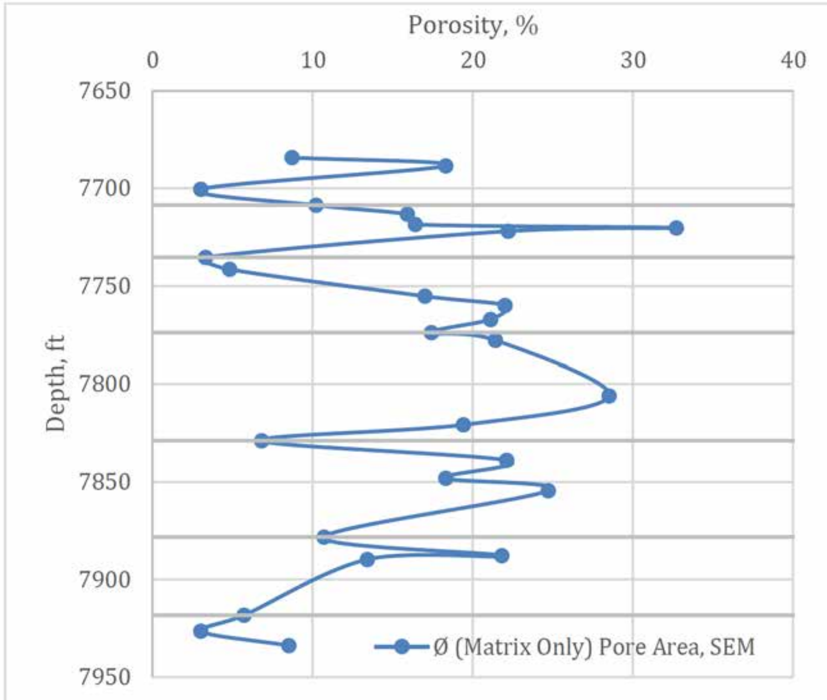

Figure 9—SEM digital Porosity with depth Profile.

Figure 10 displays static wettability contact angle distribution from top to bottom of formation vertically. At 400x, the vertical overall wettability contact angle is around θ = 60°. 400x magnification represents pore connectivity (pore throats) while 40x for thin section representation and 400x for nanopore target. Therefore, the tortuosity at this level of pore magnification (400x) will be used in this research to describe the path of fluid movements in reservoir.

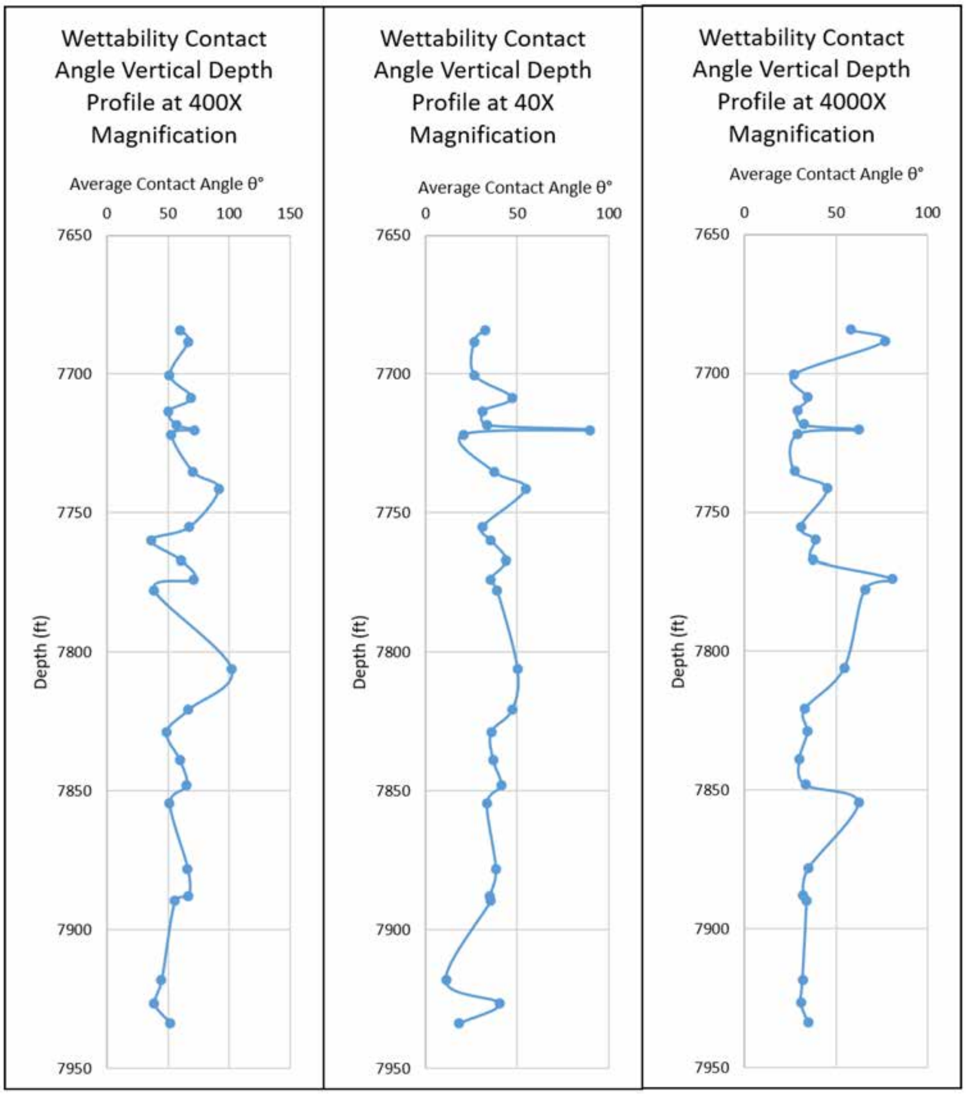

Figure 10—Average Wettability Contact Angle Depth Profile for 40x, 400x, 4000x magnification.

Figure 11 shows digital tortuosity with each class from SEM for 400x magnification based on 2D (Pore Area) pre-logic model for 27 samples (at each depth). It is clear that tortuosity is increasing with class numbers. The first sample represents the top of reservoir while the last sample represents the bottom based on the depth. It is clear that each sample has different tortuous paths and distributions. As a result, some of them represents good path, moderate path, and difficult path.

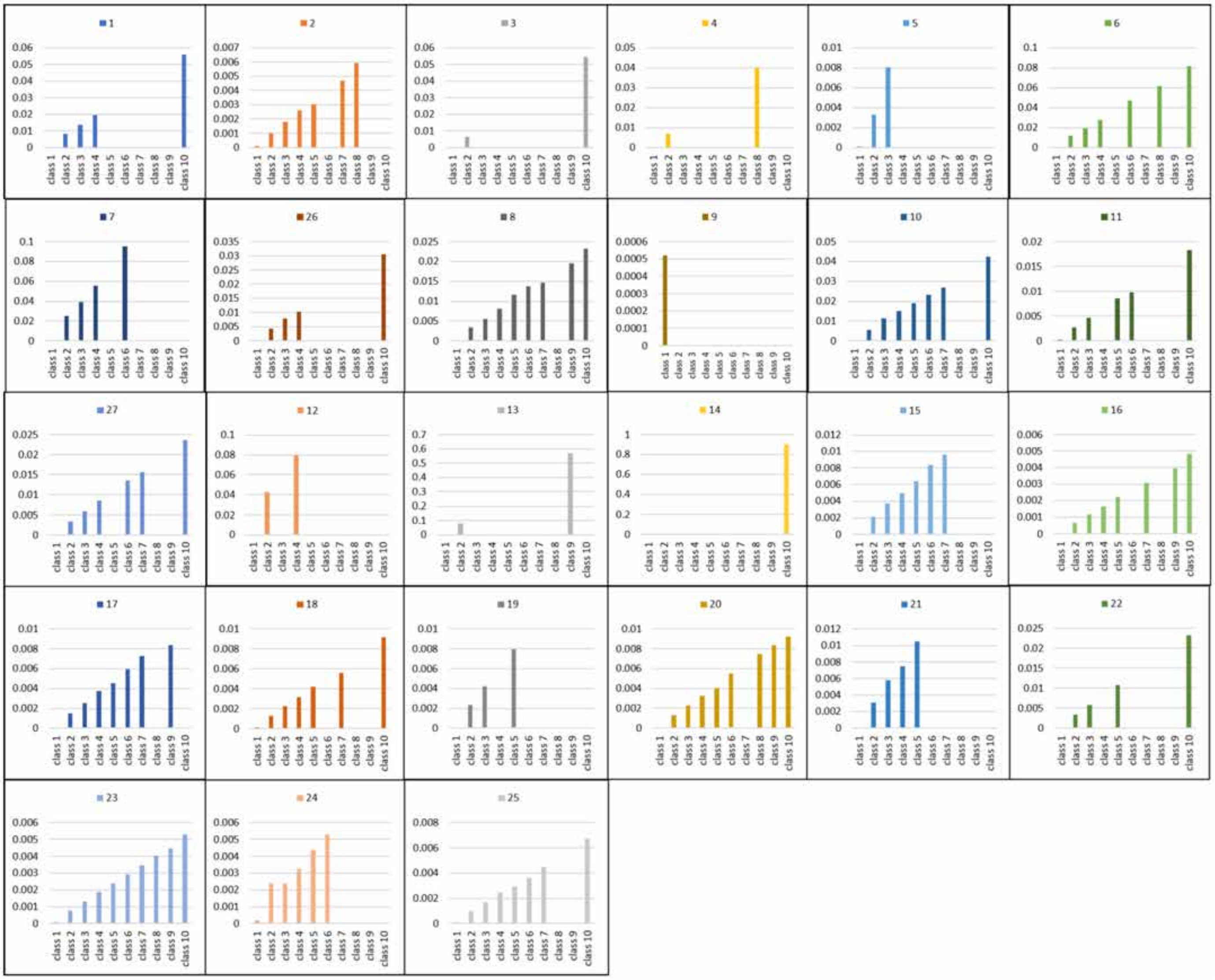

Figure 11—Digital tortuosity with each class from SEM for 400x magnification based on 2D pre-logic model.

Figure 12 shows digital tortuosity with depth Profile from SEM for 400x magnification based on 2D pre-logic model. The pore area tortuosity 2-D pre-logic model is defined as the pre-determined regional class average area over the entire total pre captured pore area. It can be seen that at high tortuosity values, the reservoir has less heterogeneity which tend to be fracture in the middle of reservoir. However, in the low tortuosity values, the reservoir is more heterogeneous. This because the relationship between tortuosity and heterogeneity which describes in this study as H = 1 – (τ fraction) or H= 100 – (τ %). This simple model is an attempt to understand heterogeneity in terms of tortuosity.

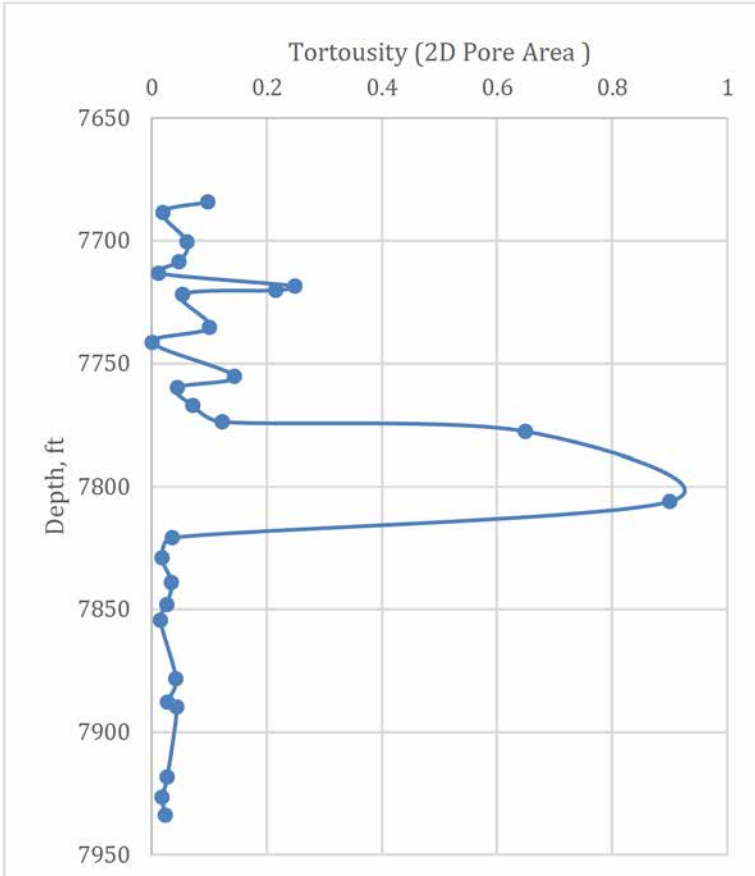

Figure 12—Tortuosity based on 2-D pre-logic model at 400x.

Figure 13 shows the relationship between mean wettability contact angle (θ°) at 400x versus tortuosity 2-D pre-logic without outlier and it could be as linear polynomial equation with order five.

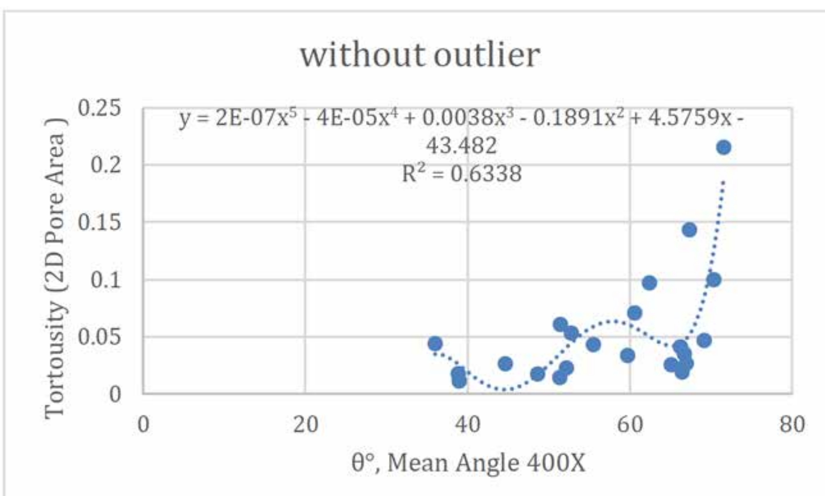

Figure 13—The relationship between mean wettability contact angle (θ°) at 400x versus tortuosity 2-D pre-logic without outlier.

Figure 14 shows digital tortuosity with depth Profile from SEM for 400x magnification based on 3D pre-logic model. The pore volume tortuosity 3-D pre-logic model is defined as the pore area 2-D pre-logic model multiplied by the pore frequency. Similar to 2-D approach but with less tortuosity values that means a more complex system.

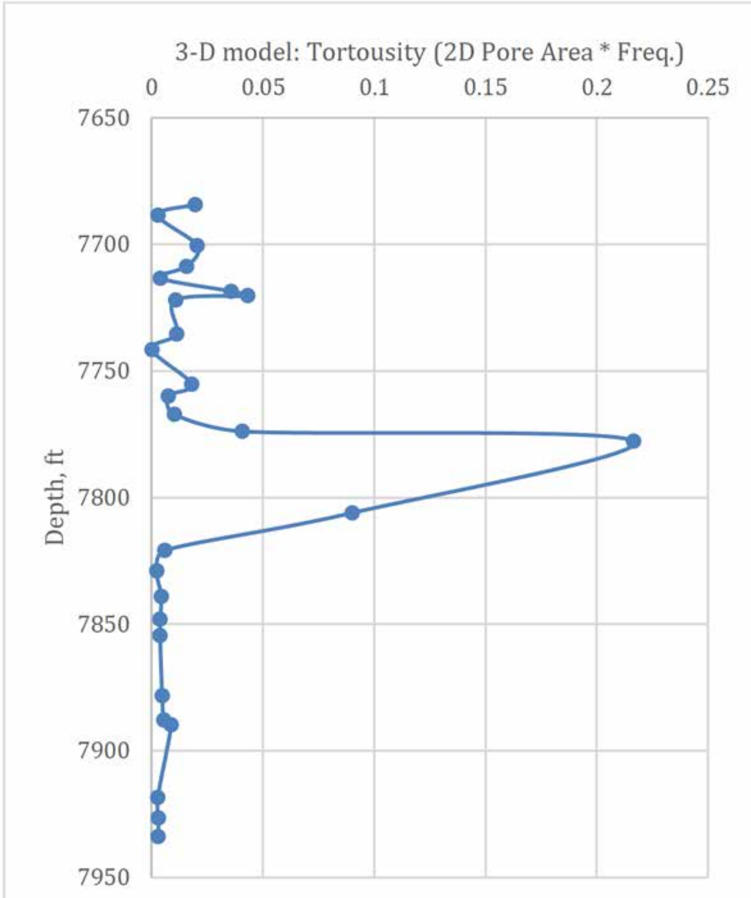

Figure 14—Tortuosity based on 3-D pre-logic model at 400x.

Table 4 presents the statistics for wettability contact angle for the three magnifications for the 27 samples. In this study, only mean value for wettability contact angle at each magnification will be considered.

Table 4—Statistics for wettability contact angle for the three magnifications for the 27 samples.

	Mean Angle 40X	Mean Angle 400X	Mean Angle 4000X
N	27	27	27
Mean	37.4	60.9	41.5
Median	35.7	60.8	34.5
Standard deviation	14.2	14.6	15.8
Minimum	11.1	36.0	26.9
Maximum	89.8	102	80.6
25th percentile	31.8	51.8	31.3
50th percentile	35.7	60.8	34.5
75th percentile	40.8	67.1	49.9

Figure 15 shows the candidate recovery type for this reservoir by using violin plot for wettability contact angle. It could be better to implement low salinity flooding based on the concept of wettability contact angle.

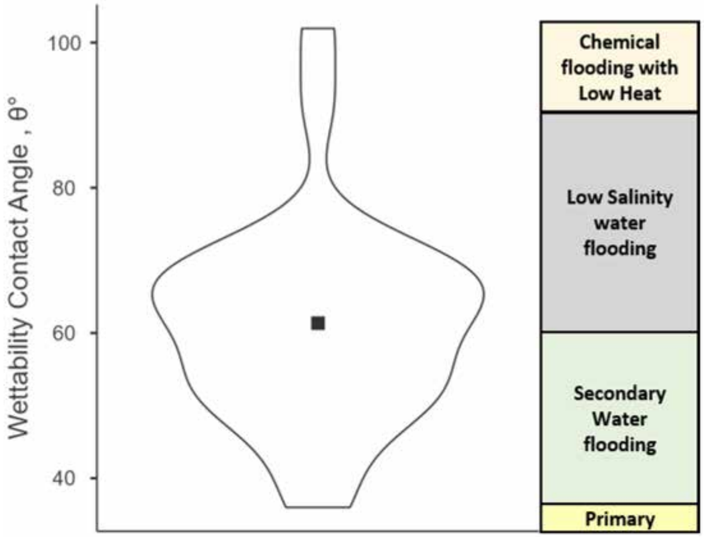

Figure 15—Candidate recovery type for this reservoir by using violin plot for wettability contact angle.

Conclusions

There are 3 main grain minerals in LIMESTONE to make the heterogeneities more complex: Limestone, Dolomite, and Sandstone, which all were confirmed in the permeability architectures of this reservoir.

From measured data and computed logics, the major portions of captured rock investigated show water wet tendency. The wettability distribution in the vertical 250 feet shows strong to medium and even weak water-wet system variation ($\theta = 10°$ - $\theta = 90°$). The dominant wettability is medium-water-wet ($\theta = 30°$ - $\theta = 60°$), and it is found in the middle section of the vertical column. Medium-water-wet indicates a good candidate for secondary recovery water injection development programs. This study includes tortuosity/heterogeneity quantifications from imaging 2D technology which is valuable in understanding vertical/horizontal fluid movements.

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