NANO-PETROPHYSICS OF THE HYBRID SHALE-OIL BONE SPRING FORMATION, LEA COUNTY, NEW MEXICO

by

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Abstract

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Despite the increased hydrocarbon production in hydraulically stimulated unconventional reservoirs, how fluid flows through the rock matrix in these reservoirs is still not well understood. It has been shown that much of the porosity in unconventional mudrocks is nanometer in size, making research challenging as analyzing these pores requires specialized methodologies. These pore networks affect fluid flow by their pore sizes, pore throats, and topology (pore connectivity). The Bone Spring Formation is one of the fastest growing unconventional plays in the world. It is a hybrid shale-oil system with high total organic carbon (TOC) source rocks juxtaposed against organic-lean reservoir layers such as sandstone and carbonate. However, there are very limited studies of nano-petrophysics (the interaction of fluids with porous media with a strong presence of nano-sized pore spaces) of organic-rich and organic-lean facies of Bone Spring Formation, which is the focus of this research. To achieve this objective, several core samples of both organic-rich and organic-lean facies in the Bone Spring Formation were taken from two nearby wells (both vertical and conventional wells with one being productive during 1984-2016 and the other dry).

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. The nanopetrohysics were investigated by mercury intrusion capillary pressure (MICP), contact angle (wettability) tests, spontaneous imbibition and vapor absorption. Pyrolysis was conducted to analyze maturity and TOC while X-ray diffraction (XRD) was carried out for determining mineral composition Porosity in the study samples varied from 0.3-3.2% with the majority of pore throats being 5-50 nm, which are likely organic or intraparticle types. Connectivity of the pore systems is very low for water (hydrophilic fluid) but high for n-decane (hydrophobic fluid). An integrated analysis of MICP, imbibition, wettability, and well logging results suggests that there is isolated porosity that is water-wet. No difference between the nano-petrophysics, in regards to porosity, pore-throat size, wettability, and permeability, of the different organic-rich and organic-lean facies in the two wells was observed. Our results from this area go against previous SEM studies which suggest TOC would be the main driver of porosity in the Bone Spring Formation but still supports that the reservoir intervals contain a higher percentage of non-organic hosted porosity.

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Chapter 1 – Introduction

1-1 Study Location

The Permian Basin has long been one of the most prolific basins for hydrocarbon exploration in the United States. The basin is subdivided into several basins including the Delaware, Midland, and Val Verde basins, with the Delaware and Midland Basins being the most productive (Figure 1-1). The Delaware Basin is one of the most well researched and explored basins in the world. The first major oil discovery in the Permian was in 1921, and new discoveries rapidly increased along the carbonate reefs around the shelves of the basins and on top of the uplifted platforms (Sloss, 1988). New oil field discovery peaked in the 1950s and steadily declined until the advent of new unconventional reservoir completion practices such as horizontal drilling and hydraulic stimulation (Dutton et al, 2003).



Figure 1-1 - Location of basins and structures in the Permian Basin and the interpreted outline of the precursor Tobosa Basin (outlined in red) (Sloss, 1988)

Before the 1970s, the Bone Spring was considered a secondary target if deeper gas targets such as the Ellenburger Formation were missed or dry (Jackson et al, 2014). Eventually, the Bone Spring has become a primary conventional target with wells targeting diagenetic fairways with zones of increased porosity caused by dolomitization (Jackson et al, 2014). The Bone Spring has not been a prolific conventional reservoir, but by the year 2000, over 70,000 MMbbl of oil were produced (Dutton et al, 2003). With the introduction of hydraulic fracturing and horizontal drilling, production has increased dramatically and is now one of the fastest emerging unconventional plays in the United States. Between 2008 and 2015, over 1000 horizontal wells have been drilled in the Bone Spring Formation (Jackson et al, 2014). Following the price drop of crude oil in June 2014 and associated drilling rig decrease, nearly 2/3 of the stable increase of rig counts have happened in the Permian Basin since August of 2016.

The Bone Spring Formation is broken down into different larger sandstone and carbonate intervals with the sandstone intervals (known as the 1st, 2^{nd,} and 3rd Bone

Spring Sandstones) being the main target for production. Despite being named sandstones, these intervals are also interbedded with smaller organic-rich carbonate and shale intervals, which provide the source of hydrocarbons. These different facies are all included together when discussing the larger sandstone intervals.

The Bone Spring is a very attractive unconventional target due to multiple pay zones, high TOC, and large formation thickness (average of 3,000 ft) (Jackson et al, 2014). Much of the exploration has been in the "WolfBone" play where the well is landed at the base of the 3rd Bone Spring Sandstone so both the Bone Spring and underlying Wolfcamp Formations can be stimulated. However, multiple horizontal wells are often stacked targeting other intervals in the 1st, 2nd, and 3rd Bone Spring Sandstones. Porosity for productive wells can vary from 8-20% in the sand layers, but all have very low permeability at an average of less few millidarcies (Jackson et al, 2014). New completion practices have increased to a recovery of oil in place (OOIP) to as high as 30% (Jackson et al, 2014).

In such a lithologically complex formation, different facies will be in contact with the stimulated fracture network of unconventional wells. Therefore, an understanding of both pore structure of, and fluid flow through, the matrix in the sand, shale, and carbonate facies throughout the Bone Spring Formation from this research could be very useful for future exploration and possibly lead to increased producibility. It is theorized that a combination of the mixed wettability, low connectivity, and small pore throats are the cause of the steep production decline in unconventional reservoirs (Hu et al, 2012; Hu et al, 2015b).

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1-2 Previous work

Tying increased producibility to the nano-petrophysics in unconventional reservoirs has been difficult. First, the location of the pore system in most unconventional reservoirs was not well understood until investigations using scanning electron microscopy (SEM) were applied to observe that much of the nano-sized porosity in many mudrocks reside in organic matter (Curtis et al, 2011; Loucks et al, 2009; Milliken et al, 2013). These pores are the result of the conversion of kerogen to hydrocarbons. Research has been slow as standard laboratory methods are unable to describe 3-D pore networks at such a small scale (Curtis et al, 2011).

With much of the porosity residing as organic matter-hosted pores and at such a small size, other complexities are introduced when trying to understand fluid flow through the matrix of mudrocks. These complexities include hydrocarbon molecules adsorbing to the walls of the organic pores, creating a higher density layer that could either increase or decrease storage depending on if the adsorbed molecules can be produced (Ambrose et al, 2012; Wang and Reed, 2009). Conventional reservoir models use classical Darcy flow, however, if applied to unconventional reservoirs, the calculations will be too low (Kuila and Prasad, 2013). Diffusion is likely the driving force for much of the mass transfer in nanometer-sized pore networks, while larger pores or fractures will be governed by Darcy flow (Hu et al, 2015b). The wettability will also affect the fluid flow through the matrix. If much of the porosity resides in nano-sized organic matter-hosted pores, organic hydrocarbon molecules (even as a wetting fluid for these pores) will likely flow at a slower rate because of size interference (Hu et al, 2015b). The extent of the connected pores is also much less than that of conventional rocks, generally only less than 500 μ m from the sample edge (Hu et al, 2012). The combination of these factors is

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the likely cause of the production decline seen in unconventional wells as hydrocarbons are not able to replenish the depleted pores near the edge of a stimulated fracture fast enough to keep up the high production rate.

There are numerous petrophysical studies of the Bone Spring Formation but only a few are focused at the nanometer scale. These nanometer-scale studies used scanning electron microscopy (SEM) and typically saw that the majority of porosity was hosted within organic grains with some isolated intraparticle pores (Alcantar-Lopez and Chipera, 2013). During heating experiments done in the lab, Bone Spring Formation samples increased in porosity significantly from the conversion of kerogen into hydrocarbons, to a point in the wet-gas window after which porosity decreased (Dahl et al, 2012). Some standard core analysis shows that an increasing carbonate content decreases porosity and permeability and that increasing TOC often increases porosity and permeability (Stolz et al, 2015). Other work has shown that the Wolfcamp Formation, which the Bone Spring overlies and is similar in lithology, the porosity is similar for both siliceous and carbonate facies but that permeability is less in carbonate intervals (Kvale and Rahman, 2016). The upper Bone Spring averages 4% TOC and 8% porosity in productive unconventional intervals (Malik et al, 2013). However, there is no published work that describes the different reservoir and source rock facies in the Bone Spring Formation with respect to pore connectivity, wettability, and fluid flow.

1-3 Nano-petrophysics in the Bone Spring Formation

The Bone Spring Formation has been described as a hybrid shale oil system with organic-rich source rocks juxtaposed against organic-lean reservoir intervals (Jarvie, 2012). The different source and reservoir rocks are thinly bedded and any stimulated fracture network would almost certainly come in contact with both. Understanding the pore system and fluid flow through these different units could be critical to understanding overall producibility for unconventional production in the Bone Spring.

The Bone Spring Formation is also unique in that it had produced oil from conventional wells before it became an unconventional target. These conventional oil wells typically targeted diagenetic pinchouts on the slope of the basin or avenues of increased porosity through dolomitization.

The study area was chosen specifically not only to test the hybrid producing system but also to see if these nanometer scale changes could affect the producibility of different areas. Two wells were chosen, one a producing conventional well and the other a dry conventional well three miles away. Samples were taken with different mineralogy and TOC contents.

Chapter 2 – Geologic Background

2-1 Tectonic Setting

The Delaware basin is a subbasin in the larger Permian Basin. It lies in the southwestern portion of the basin with the Central Basin Platform to the east, the Diablo Platform to the west, and the Northwestern Shelf to the north (Figure 1-1). The Permian Basin evolved from the ancient Tobosa Basin which was formed in late Pre-Cambrian time, possibly related to the Grenville Orogeny, which created a wide but shallow area of subsidence (Walper, 1977; Hills, 1984). Based on gravity data and Precambrian cores containing volcanic rocks, an aulacogen that possibly formed a triple point with the advancing Grenville orogeny around the area that the Delaware Basin now lies, produced high angle faults through the basement rock (Walper, 1977; Hills, 1984). The area was in a shallow marine setting and was tectonically stable throughout much of the Early to Middle Paleozoic (Sloss, 1988). Deposits into the Tobosa Basin consisted of carbonate

reefs, turbidity currents, and debris flows that would come to characterize the future Permian Basin.

During Late Pennsylvanian time the advancing Ouachita-Marathon Orogeny created flexural subsidence in the Permian Basin (Hills, 1984). The compression of the thrust belt reactivated basement faults from the formation of the Tobosa Basin and caused structures such as the Central Basin and Diablo Platform to be uplifted creating distinct subbasins such as the Delaware Basin (Hills, 1984). The newly created Delaware Basin was tilted to the east with the deepest section being next to the Central Basin Platform (Soreghan and Soreghan, 2013). Subsidence occurred from Late Pennsylvanian through Early Permian (Wolfcampian) time during which tectonic activity ceased (Sloss, 1988).

In the Middle Permian, the thrusting of the Ouachita-Marathon Orogeny stopped (Hills, 1984). After this time the Delaware Basin was remarkably stable with only minor Cenozoic volcanism in some areas modifying the existing structure of the basin. The basin being so tectonically stable since the Paleozoic meant the many hydrocarbons produced had no chance to escape (Soreghan and Soreghan, 2013).

2-2 Depositional History

The Tobosa and eventual Permian Basins were covered in a shallow sea up until Middle Permian (Guadalupian) time. Marine water flowed into the area by a series of channels (Figure 2-1). For the Delaware Basin, marine water was flowing into the channel until carbonate reefs restricted the channels around the end of Guadalupian time after which marine deposition ceased and evaporites were formed (Ross, 1986).

Despite the sea and the adjacent uplifted areas, the basin deep was starved of sediment through much of Permian time (Hills, 1984). All of the Permian Basins share a similar pattern of sedimentation pattern that started with the Tobosa Basin and continued even after the separate basins evolved. Large carbonate reefs were built up on the shelf of the basins and on the uplifted Central Basin Platform, Diablo Platforms and Northwest Shelf bounding the Delaware Basin (Hills, 1984). The clastics being eroded from the uplifted platforms and the Ouachita-Marathon orogeny were trapped behind the carbonate banks during times of highstand sea level (Soreghan and Soreghan, 2013). During highstand sea level, carbonate platforms were built up to sea level on the shelf and became unstable resulting in carbonate debris flow into the basin (Figure 2-1). During lowstand sea level, siliciclastic sedimentation was able to pass through the carbonate platforms and deposit debris flows and turbidity currents onto the shelf and basin. Organic activities thrived in the water of the basin at both high and lowstand times (Nance and Rowe, 2015). However, during lowstand sea level, there was likely less marine water influx creating a reducing condition that preserved more organic matter (Nance and Rowe, 2015).



Figure 2-1 Interpretations of paleogeography for sea-level (a) lowstand and (b) highstand. Shows siliceous sediment deposition during lowstand and unconsolidated carbonate debris during highstand (Nance and Rowe, 2015)

The Permian Basin was on the southwestern edge of Equatorial Pangea around 5-10° north of the equator (Soreghan and Soreghan, 2013). The surrounding area was likely very arid due to the presence of evaporite deposits found outside the basin. The method of transport for the siliciclastic sediments during low stand sea level was likely a

combination of both alluvial and eolian (Figure 2-1). The source of the sediments is still under debate. Some have suggested the Ancestral Rocky Mountains while others have the main contribution being from the advancing Marathon Orogeny (Soreghan and Soreghan, 2013).

The Wolfcamp Formation underlies the Bone Spring Formation (Figure 2-2). The Wolfcamp Formation is unique to the succeeding formations of the basin as its lithology in the basin, especially on the eastern edge next to the Central Basin Platform, is very thick siliciclastic shale and terrigenous sediments due to the active uplift of the area (Sloss, 1988). Tectonic activity ceased during Wolfcamp time and the Wolfcamp Formation filled in the deepest section of the Delaware Basin. The Wolfcamp has a gradational contact with the Bone Spring Formation and there is a debate on how exactly to pick the top of the Wolfcamp Formation (Sloss, 1988).





The Bone Spring Formation consists of interbedded siliciclastic, carbonate, and shale rocks of up to 3,500 ft (Mazzullo and Reid, 1987). The Bone Spring Formation is slope to basin deposits correlated to the Abo-Yeso Formation that lies at the top of the shelf (Figure 2-3) (Mazzullo and Reid, 1987). The Formation is further broken down into different members representing sea level changes (Gawloski, 1987). These members are three sequences of predominantly siliciclastic sediment (1st, 2nd, and 3rd Bone Spring Sand) alternating with three sequences of predominantly carbonate allochthonous

sediment (1st, 2nd, and 3rd Bone Spring Carbonates) (Figure 2-2) (Gawloski, 1987). There are also different members that have been suggested such as another sandstone/shale member within the 1st Bone Spring Carbonate known as the Avalon Sand (Montgomery, 1997a).

In both the major Bone Spring Sand and Carbonate sequences the layers are interbedded with siliciclastic, carbonate, and shales facies (at a smaller thickness than shown in Figure 2-2). Organic-rich layers of shale or carbonate are interlaminated with organic-lean sandstone or carbonate layers (Dutton et al, 2003). Wackestone and mudstone make up much of the carbonate members, that became carbonate breccias from debris flows while the sands consist of fine to very fine, angular to sub angular quartz sand (Dutton et al, 2003).



Figure 2-3 Schematic N-S cross section of the northern Delaware Basin to illustrate general shelf-to-basin relationships between the Bone Spring, Wolfcamp, and the Abo-Yeso shelf equivalent (Gawloski, 1987)

Chapter 3 - Methods

3-1 – Sample and Data Procurement

Core samples were acquired from the New Mexico Bureau of Geology. Two wells, the State MX 1 (API: 30-025-28164) and State No. 1 (API: 30-025-28468), approximately 3 miles apart, were chosen from available samples spanning the Bone Spring Formation (Figure 3-1). These wells were chosen as they were both vertical, conventional wells in the Bone Spring Formation. The State MX 1 has successfully produced oil since 1984 but recently became inactive in December 2016, while the State No. 1 was dry. Other analysis data about the wells and samples were donated to the New Mexico Bureau of Geology by Weatherford Laboratories and was obtained along with the core samples. Available data includes X-Ray Diffraction (XRD), pyrolysis, TOC, vitrinite reflectance, and kerogen type. Weatherford Laboratories' procedures for these techniques are provided in Chapter 7.

A)





Figure 3-1 Location of study wells A) and location of study wells in relation to Scharb Field productive area in Lea County New Mexico, modified from (Montgomery, 1997a)

As different lithologies are not easily apparent by visual inspection (Figure 3-2) the chosen sample depths were restricted to those with XRD data (which provides mineralogy). Sample depths were chosen to provide a wide range of siliceous and

carbonate rock. Pyrolysis and TOC are also needed for any petrophysical study and was taken into account when choosing sample depths. Most available cores at the New Mexico Bureau of Geology only extended into the 1st or 2nd Bone Spring Sandstone. The State No 1 extended all the way into the 3rd Bone Spring Sandstone but had XRD and pyrolysis data primarily in the 1st Bone Spring Sandstone. To give an accurate depiction of the 1st Bone Spring Sandstone, 7 sample depths (5 in the State No 1 and 2 in the State MX 1), along with one depth from the State No. 1 well in the 3rd Bone Spring Sandstone as a comparison, were chosen as the sample depths of the study.



Figure 3-2 - Core slab of State MX 1 showing the 1st Bone Spring Sandstone

The list of samples obtained, as well tests performed is presented in Table 1. XRD and TOC were available for all samples, and pyrolysis data was available for most samples. Mercury intrusion capillary pressure (MICP) (Chapter 4-3) was performed on all samples and contact angle (wettability) tests (Chapter 4-2) were performed on all but two samples. In addition, imbibition was carried out on both State MX 1 samples, the 3rd Bone Spring Sand sample in the State No 1, and a siliceous and carbonate-rich sample from the 1st Bone Spring Sandstone in the State No 1. (Chapter 4-4).

	Tests Performed								
Sample ID [#]	Well	Formation	Lithology	Sample	Contact	MICP	Imbibition	XRD	Pyrolysis
				Depth (ft)	Angle				
NO9208	STATE	1 st Bone	Siliceous	9208	х	х		х	
	NO 1	Spring SS							
NO9209	STATE	1 st Bone	Siliceous	9209	x	×		x	
	NO 1	Spring SS	Siliceous	9209	^			~	
NO9214	STATE	1 st Bone	Siliceous	9214	Х	х	х	Х	Х
1100214	NO 1	Spring SS							
NO9218	STATE	1 st Bone	Carbonate	9218	x	×		х	х
	NO 1	Spring SS	Calibonato	0210					
NO9222	STATE	1 st Bone	Carbonate	9222	Х	х	х	х	х
	NO 1	Spring SS							
NO10338	STATE	3 rd Bone	Siliceous	10338	Х	х	х	х	х
1010000	NO 1	Spring SS							
MX9564	STATE	1 st Bone	Carbonate	9564		×	Х	х	Х
	MX 1	Spring SS							
MX9580	STATE	1 st Bone	Siliceous	9580		х	X	X	X
	MX 1	Spring SS							

Table 1 List of study samples and tests performed

Using a circular saw, the core samples were dry cut into 1 cm cubes for MICP and imbibition tests. The cubes were labeled with a numerical number for tracking in the lab tests, and the direction of bedding plane (if any) was marked. The cubes were weighed to observe any changes in weight during experiments and measured for imbibition tests. For imbibition tests, 4 of the 6 sides (all but the bottom and top) of the cubes were epoxied. This is to help fluid flow in only one direction. Before any tests, the cubes were placed in a 60° C dry oven for at least two days. For contact angle tests, thin slabs (2-3mm x 1 cm x 1 cm) were cut from 1-cm cubes and the surfaces polished with sandpaper.

3-2 – Mineralogy

XRD analysis was performed by Weatherford Laboratories and these results were obtained through the New Mexico Bureau of Geology. The methods for XRD used by Weatherford Laboratories are outlined in Appendix A - Methods and Procedures for Geochemical Analysis at Weatherford Laboratories. X-Ray Diffraction (XRD) was performed on all sample depths in the study, which provides bulk percentages of both minerals and clays. These bulk percentages were used to calculate lithology using the sCore Lithofacies for organic mudrocks (Gamero-Diaz et al, 2013).

3-3 – Geochemistry

Geochemical analysis was performed by Weatherford Laboratories and these results were obtained through the New Mexico Bureau of Geology. Pyrolysis and total organic carbon (TOC) percentages were performed on all sample depths in the study (except for two sample depths in State No 1 that did not have pyrolysis data). Vitrinite reflectance was also performed on the two State MX 1 samples. The methods for all geochemical analysis are outlined in Appendix B.

. Pyrolysis data given is S1, S2, S3, and T_{max}. S1 represents the residual hydrocarbons left in the rock. These hydrocarbons could be derived from the maturation of organic molecules in the rock or have migrated from elsewhere. S2 measures the remaining hydrocarbon generating potential in the rock. S3 measures any trapped carbon dioxide left in the rock. Finally, Tmax is the highest temperature reached during maximum S2 generation. T_{max} is converted to an equivalent vitrinite reflectance, which measures the thermal maturity (Jarvie, 2012). Thermal maturity is also compared against actual vitrinite reflectance, measurement of light reflected off vitrinite molecules that correspond to thermal maturity, which is available for several samples.

3-4 - Wettability

Procedure for Wettability

The wettability of the rock sample surface was tested using DI water, API (American Petroleum Institute) brine, and 10% (V/V) isopropyl alcohol (IPA)) in DI water, and n-decane. Both DI water and API brine are water wetting. API brine, composed of 8% NaCI and 2% CaCl₂ by weight, is used as it has a high salinity like that of formation water (Wendell, 1969). The organic fluid n-decane is used to as a proxy for oil to determine the wettability of the sample surface towards oil. IPA is a zwittering fluid which is both hydrophilic and hydrophobic. These tests show the extent to which the rock surface is water wet or oil wet in millimeter scale. One slab of sample is used for DI water and API brine, using opposite sides of the sample. The fluids n-decane and IPA are done on separate thin slabs. An SL200KB Optical Contact Angle Meter (Kino USA) is used to determine the contact angle (Figure 3-4). A droplet of liquid is placed on a thin slab of

sample that is 10 mm x 10mm x 2-3mm in size. An instrument records and measures the contact angle of the droplet on the surface of the sample with time. If the liquid is spreading on the sample the surface is wetting to this fluid and will have a small contact angle (Figure 3-3).



Figure 3-3 Range of contact angles for wetting and non-wetting fluids placed on the surface of a sample (Webb, 2001).



Figure 3-4 SL200KB Optical Contact Angle Meter

3-5 - Mercury Intrusion Capillary Pressure (MICP)

To investigate the pore system of the Bone Spring, MICP analysis is performed due to its ability to investigate a wide range of pore-throat sizes down to 2.8 nm in size (Gao and Hu, 2013). MICP involves surrounding a sample with liquid mercury and applying pressure so that mercury intrudes into the pores. Mercury has a high surface energy and is nonwetting to geological materials therefore only external pressure will force it into pores once the capillary pressure is exceeded (Hu et al, 2015a). The Washburn equation (Equation 3-1) shows that the pore throat radius that is intruded is inversely proportional to the applied external pressure (Washburn, 1921; Gao and Hu, 2013).

$$\Delta P = - \frac{2\gamma \cos \theta}{R}$$
 Equation 3-1

Where:

 ΔP = External pressure applied (Pa)

 γ = Surface tension of mercury (485 dynes)

 θ = Contact angle between mercury and pore wall

R = Pore throat radius

The use of the Washburn Equation in MICP data interpretation has been assuming a constant surface tension and contact angle. However, it has been shown that at small pore diameters, such as those seen in unconventional hydrocarbon reservoirs, the contact angle will increase exponentially with decreasing pore diameter so that error in such small pore size distributions can be as high as 44% (Wang et al, 2016). A modified Washburn Equation is used that has a variable contact angle and surface tension (Equation 3-2). In the modified equation surface tension and contact angle are now functions of the pore throat radius. The function of R, f(R), is given by Equation 3-3. The solution of f(R) = 0 is the pore radius that corresponds to the pressure needed to overcome the capillary pressure of that pore. An algorithm is used to iteratively solve the pore radius for a given capillary pressure using the Newton-Raphson method (Wang et al, 2016).

$$\Delta P = -\frac{2\gamma_{Hg}(R)\cos\theta_{Hg}(R)}{R}$$
 Equation 3-2
$$f(R) = p_c R + 2\gamma_{Hg}(R) \cos \theta_{Hg}(R)$$
 Equation 3-3

Where:

 p_c = Capillary pressure of intruded pore

Large pore throats are invaded at low pressures with smaller pores being invaded at higher pressures. Porosity can be obtained from this pore throat size distribution as the cumulative intrusion of mercury into the sample at each pressure step is measured. The Washburn Equation (Equation 3-2) assumes that pores are all cylindrical which is not always the case but gives a close approximation of pore throats (Hu et al, 2015a). The range of pore diameters that can be examined is 2.8 nm to 50 µm.

Permeability can be indirectly estimated from MICP results by determining the pore throats at which hydraulic conductance is at a maximum (Gao and Hu, 2013; Katz and Thompson, 1987) (Equation 3-4). This point is determined by locating an inflection point in the cumulative intrusion of mercury into the sample by pressure. Each pore diameter will have a specific capillary pressure that must be exceeded before mercury is intruded into the pores. An inflection point in the graph represents a pore diameter that is being intruded.

$$k = \left(\frac{1}{89}\right) (L_{max})^2 \left(\frac{L_{max}}{L_c}\right) \phi S(L_{max})$$
 Equation 3-4

Where:

$k = Permeability (m^2)$

 L_{max} = Pore throat diameter when hydraulic conductance is at a maximum (when mercury percolates through sample after overcoming capillary pressure of specific pore diameter)

 L_c = Pore throat diameter of intruded pore. Determined by inflection point on MICP intrusion curve

$\phi = Porosity$

 $S(L_{max})$ = Mercury saturation at percolation (ratio of cumulative intrusion at L_{max} to the total pore volume)

Procedure for MICP

A 1 cm cube of sample is dried in 60° C dry oven for at least 2 days before the MICP test. The MICP analysis was performed on a Micromeritics Autopore IV 9510 machine (Figure 3-5). The sample is placed in an apparatus known as a penetrometer and inserted into the machine which is evacuated and then filled with mercury. Different penetrometers are used for different assumed porosity ranges and use different filling pressures for the start of the analysis, which determines how large pores can be analyzed. For each MICP test, two different analyses are performed. The first is a low-pressure test to detect larger pores around 50 µm in size. Sample and penetrometer are weighed before the beginning of the test. The pressures tested are from 5 psi to 30 psi and at each step the pressure is allow to equilibrate for 10 seconds. The sample and penetrometer are weighed after the test as not all mercury will be able to be extruded after the test. After low-pressure analysis, the high-pressure analysis is done from 30 psi up to 60,000 psi. Equilibration time is set at 45 seconds for the high-pressure intrusion. The extrusion curve of mercury as the pressure drops is also recorded.



Figure 3-5 Micromeritics Autopore IV 9510

3-6 - Spontaneous Imbibition and Vapor Absorption

Spontaneous imbibition is a process driven by capillary pressure during which a nonwetting fluid is displaced by a wetting fluid (Gao and Hu, 2012). For this work, the nonwetting fluid is air, and the wetting fluid is tested as DI water and n-decane. The rate of imbibition is controlled by capillary pressure and permeability (Hu et al, 2001). Capillary pressure is affected by the wettability of the fluid whereas permeability is

affected by the porosity and connectivity of the pores. As fluid is imbibed into the sample with time, the cumulative imbibition vs. time) can be expressed by Equation 3-5.

Where:

I(t) = Cumulative Imbibition

S = Sorptivity

t = Time

Models have shown that pore connectivity can affect the wetting front of the fluid being imbibed through the sample. If not all pores are connected, the absolute porosity may be constant with distance from the edge but the porosity that is connected to the edge will decrease. This edge accessible porosity will affect the wetting front causing a slower imbibition rate. If accessible porosity is equal to effective porosity, like an open fracture, the slope of a plot (log cumulative imbibition vs. log time) will be 1. This socalled imbibition slope in well-connected pore systems has been shown to exhibit a value of 0.5 (i.e., square-root-of-time relationship as described in Equation 3-5) while low connectivity will often have a value of about 0.25 (Hu et al, 2012).

Vapor absorption is the same as imbibition but instead of the sample being in contact with the fluid it is suspended above it. Fluid enters the sample in typical imbibition by both the sample/water interface and by vapor condensation due to water being evaporated from the fluid sample dish (Hu et al, 2001). During imbibition, when the sample is suspended in a fluid, it is supported by buoyancy. As fluid is taken up by the sample the water level drops and thus the buoyancy force drops. This will result in readings of cumulative imbibition being too heavy. Procedures for negating these effects

during imbibition are detailed in the next section. Vapor absorption is done to compare the results of imbibition without the effects of buoyancy force and vapor condensation (which has been shown account for up to 30% of the total imbibed fluid in samples of tuff) acting on samples suspended in fluid (Hu et al, 2001).

Procedure for Spontaneous imbibition and Vapor Absorption Tests

A 1 cm cube of sample is dried in 60° C oven for at least 2 days. Before the test, it is allowed to cool in a desiccator for 30 minutes as the changing of temperature during the test could affect weighing. The effects of two different fluids were measured, DI water and n-decane (oil wetting fluid). One sample cube was used for DI water and vapor absorption tests, with n-decane vapor absorption being done last, and a separate cube was used for n-decane tests. The DI water imbibition and vapor absorption tests are run before the n-decane vapor absorption test. After each DI water test, the sample is returned to the oven for at least 2 days to remove imbibed water.

The apparatus for measuring imbibition of fluids into the sample is shown in Figure 3-6. The 1 cm cubes are connected to the balance via a wire and a custom made holder inside of a closed chamber with a small hole in the top. The chamber is used so that there is a constant relative humidity during imbibition and vapor absorption. A petri dish containing the testing fluid is inside the chamber. An adjustable jack raises the closed chamber so that the sample bottom is in contact with the fluid in the petri dish. The balance is connected to a computer which sends weight measurements based on a predetermined time interval.

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B)

Figure 3-6 A) Schematic and B) Picture of Imbibition/Vapor Absorption Test Setup.

The core sample and the sample holder are weighed before the test. The petri dish with the fluid is also weighed. Once the sample comes in contact with the fluid a timer is started and the computer begins sending weight measurements to the computer. For imbibition a measurement is taken every second for 2 minutes, then every 30 seconds until 1 hour has passed, every 60 seconds until 6 hours in total have passed, and finally every 5 minutes for up to 24 hours in total. For vapor absorption, the weight is measured every second for 30 seconds, every 2 minutes until 30 minutes have passed, every 5 minutes until 6 hours have passed, and finally every 10 minutes until 24 hours (for n-decane) or 72 hours (for DI water) have passed. The DI water tests were performed in triplicate to reduce errors in water surface tension effects by getting an average imbibition slope. The DI water imbibition tests were run on each sample for 6, 12, and 24 hours. Vapor absorption for DI water was run for 3 days. The n-decane imbibition tests were performed once for 8 hours and for 2 days during vapor absorption. Spot checks were periodically done to confirm the accuracy of the time and weight recorded by the computer.

After completion of the imbibition test, the sample is raised from the fluid by lowering the adjustable jack. Quickly, any excess fluid is wiped off by an already weighed Kimwipe that has been slightly moistened in the testing fluid (DI water or ndecane). The Kimwipe is then weighed again to get a measure of this excess fluid. The sample and sample holder are then weighed. This provides a check against the buoyancy effects discussed and any condensed fluid on the sample holder. Finally, the petri dish and the testing solution are also weighed to check against the cumulative imbibition measured by the computer and to see the effect of evaporation.

To determine pore connectivity, the measurements were plotted by log cumulative imbibition vs. log time. Corrections were made for buoyancy and for

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evaporation based on the measurements before and after the tests. Lines were fit at different times during the imbibition process. At the beginning of the test, there is often a time period of up to a few seconds for the balance readings to become stable and increase steadily. Also, if the wetting front reaches the top of the sample the imbibition rate will decrease as the semi-inifinite boundary for Equation 3-5 breaks down. The different slope regions were determined by the graphical plotting of the acquired data.

3-7 - Production Data

Production data for the two wells being analyzed, along with nearby wells, was acquired from a generous complimentary subscription from DrillingInfo. DrillingInfo gathers production, completion, well logs and a variety of other data for wells all around the United States from a variety of different sources. Different filters were used to look at production in the research area. These include only showing wells targeting the Bone Spring Formation and restricting the perforation interval of the wells, when available, to around the depths of the State No 1 and State MX 1 wells. Such filtering is necessary as there are many hydrocarbon targets within the Delaware Basin and within the thick Bone Spring Formation. Production decline analysis will also be performed on the State MX 1 well. Decline curve analysis is performed using the Arps Equation as the State MX 1 was completed as a conventional vertical well (Kupchenko et al, 2008)

Chapter 4 – Results

4-1 Mineralogy

The mineral composition of the samples fall into two categories: the rocks either contain primarily quartz or dolomite (Table 2; Figure 4-1). There are minor amounts of clay in the quartz-rich samples and a few percent of pyrite in most samples. Based on

the lithology diagram in Figure 4-1, the dolomite samples were either silica-rich carbonate mudstone or carbonate-dominated lithotype. The predominantly quartz-rich samples range from silica-dominated lithotype to clay or carbonate-rich siliceous mudstone.











Figure 4-1 X-ray diffraction (XRD) results for study samples from State MX 1 (A-B) and

State #1 (C-H); data from Weatherford Laboratories

Figure 4-2 Diagram for sCore Lithofacies Classification Scheme for Organic Mudstones for State MX 1 and State No 1 samples. Modified from (Gamero-Diaz et al, 2013)

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		XRD (%)							
Well	Depth	Quartz	Dolomite	Illite/Mica	Illite/Smectite	K- Feldspar	Plagioclase Feldspar	Pyrite	Lithofacies
State No. 1	9208	59	18	8	4	3	5	3	Carbonate-rich siliceous mudstone
State No. 1	9209	52	5	20	9	4	5	3	Clay-rich siliceous mudstone
State No. 1	9214	50	7	22	9	4	5	2	Clay-rich siliceous mudstone
State No. 1	9218	14	84	1	1	-	-	-	Carbonate-dominated lithotype
State No. 1	9222	38	59	1	1	1	-	-	Silica-rich carbonate mudstone
State No. 1	10338	70	2	15	6	1	3	2	Clay-rich siliceous mudstone
State MX 1	9564	96	1	2	1	-	-	-	Silica-dominated lithotype
State MX 1	9580	23	68	3	2	1	1	2	Silica-rich carbonate mudstone

Table 2 Summary of XRD results and associated sCore Lithofacies (Weatherford Laboratories) (Gamero-Diaz et al, 2013)

4-2 Geochemistry Results

Geochemical data for all sample depths in the study is displayed in Table 3. TOC from all samples ranges from 0.99 – 4.17%. S1, the residual hydrocarbons left in the rock, values range from 0.26 – 1.38 mg/g. Vitrinite equivalency (T_{max} converted to an equivalent vitrinite reflectance value) averages 0.72 for both wells (Jarvie et al, 2001). Measured vitrinite reflectance from the State MX 1 well is 0.62. Both of these values fall at the beginning of the oil generation window (also confirmed by production of oil from State MX 1 well and surrounding area). From pyrolysis results, the hydrogen index (HI) and oxygen index (OI) are calculated to determine the kerogen type for all samples. All but one sample are Type II-III kerogen, which is oil-prone and marine organic matter. Results of kerogen type and maturity are displayed in Figure 4-12. Table 3 - Geochemical analyses for all samples (data from Weatherford Laboratories; shaded rows are sample depths not

included in this study).

Well Name	Depth	тос (%)	S1 (mg/g)	S2 (mg/g)	S3 (mg/g)	T _{max} (⁰C)	Vitrinite Equivalency (from T _{max})	Vitrinite Reflectance (measured; %)	HI (mg HC/g TOC)	OI (mg CO₂/g TOC)
STATE MX 1	9543	3.58	1.32	8.08	0.48	442	0.72	N/A	226	13
STATE MX 1	9563	1.63	0.59	3.26	0.46	447	0.73	N/A	200	28
STATE MX 1	9564	2.85	1.24	7.00	0.80	436	0.72	0.63	246	28.1
STATE MX 1	9580	0.99	0.56	1.39	0.61	448	0.73	0.63	140	61.4
STATE MX 1	9587	3.55	1.38	12.70	0.80	444	0.73	0.63	358	23
STATE NO. 1	9208	0.46	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
STATE NO. 1	9209	4.17	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
STATE NO. 1	9214	1.65	0.26	2.40	0.42	440	0.72	N/A	146	25.53
STATE NO. 1	9218	2.40	0.82	4.80	0.60	439	0.72	N/A	201	25.02
STATE NO. 1	9222	1.82	0.55	3.47	0.52	443	0.73	N/A	191	28.60
STATE NO. 1	10338	1.03	0.54	1.72	0.57	443	0.72	N/A	168	55.56



Figure 4-3 Kerogen type and maturity for State MX 1 and State No 1 samples

4-3 Wettability

As discussed, the wettability of the surface of a sample is assessed by measuring the contact angle of a droplet of wetting liquid onto it with time. The raw data pictures showing this process are presented in Figure 4-4, and an example of the final results is shown in Figure 4-5. Measurements are taken for variable amounts of time for each liquid until the contact angle does not change much. For each sample n-decane, DI water, API brine, and 10% (V/V) IPA in DI water is used.

The results of the contact angle measurements show that the sample surface of all samples is strongly oil wet (Table 4). However, most samples also show good, although less than decane, wetting to other fluids including DI Water. This suggests the sample surface is wetting to all fluids. Mineralogy does not predict wetting although the two least water wetting results were from high quartz samples (NO10338 and MX9564). Most samples were the least wetting to API brine but the contact angle for API brine, DI water, and IPA was relatively similar in most samples.



Figure 4-4 Pictures of DI water A) before and B) after the droplet contacts surface during contact angle measurement for sample NO9208.



Figure 4-5 Contact angle vs. time for different fluids on surface of NO9209

Sample ID	DI Water	API Brine	10% IPA	n-Decane
NO9208	19.71	27.74	13.57	5.47
NO9209	37.14	48.27	33.37	9.01
NO9214	38.28	43.12	31.96	0
NO9218	33.02	67.26	46.15	4.19
NO9222	44.96	28.27	39.53	0
NO10338	18.93	26.69	33.85	0
Average	32.01	40.23	33.07	3.11

Table 4 - Contact angle summary for each fluid

Note: Contact angle values are shown at 30 sec for DI water, API brine, and 10% IPA,

while n-decane drops below instrument contact angle detection limit of \sim 3 degrees in less

than a second

4-4 Mercury Intrusion Capillary Pressure (MICP)

The MICP process produces direct data on the pore throat distribution in the rock, which can be used to indirectly determine permeability and tortuosity. All acquired core samples were tested with MICP. MICP inflection points from intrusion were chosen according to Gao and Hu (2013), and an example of these chosen inflection points is displayed in Figure 4-6.



Figure 4-6 - Example showing inflection points in MICP intrusion for NO9208 sample

All study samples have at least one MICP run but several samples were rerun. For sample NO9208, the first MICP run used the penetrometer typically used for sandstone and other high porosity (>10%) samples. Porosity in NO9208 was lower than the typical porosity range analyzed by the sandstone penetrometer, so a second run was done with a penetrometer typically used for shales and other low porosity rocks. This penetrometer was consequently used for all other samples. Two samples, NO9208 (second run only with shale penetrometer) and NO9214, had anomalous spikes in intrusion around 13-22 psi. The MICP analysis of sample NO9214 was performed a second time with the same spike in intrusion. Results are presented with and without the spikes present. To remove the spike, the incremental intrusion at that pressure is subtracted from the cumulative intrusion to calculate a new porosity and pore throat distribution.

Original porosity results range from 0.3% to 5.8% (Table 5). The anomalous intrusion spikes are shown to add a large amount of perceived porosity to the sample. Removing the spike reduces the porosity of the second NO9208 MICP run by 20.3% and the two NO9214 runs by 85.2% and 94.7%. After correcting for the spike porosity, the range of all samples reduces to 0.3% to 3.2%. The duplicate runs of NO9208 have a porosity of 3.16% and 3.21 % (spike corrected). For the duplicate runs of NO9214, the corrected porosities are 0.66% and 0.31%. Two samples from the conventional producing well, MX9564 and MX9580, do not have larger porosity compared to the six samples from the dry well.

Different pore throat diameters are associated with different pore types:

- 50-1 micrometer range is related to micro-fractures within the rock
- 0.5-1 micrometers is intergranular pore space
- 50-10 nanometers are intragranular pore space such as those within pyrite

 10-5 nanometer-sized pores are organic pores created from the conversion of organic matter into hydrocarbons

5-2.8 nanometers are the spaces between clay grains being intruded
The most common pore throat diameters in all samples are likely organic pores and
intragranular pores (Figure 4-7) (Table 6). The majority of carbonate sample pores are

likely organic to intragranular pores (Figure 4-8). Siliceous samples are more varied with the majority of pore volume occupied by different pore types depending on the sample. The anomalous intrusion spikes observed are in the microfracture range in NO9214, but are predominantly in the intergranular range in NO9208.

Formation	Sample ID	Median pore-throat diameter <i>D</i> ₅₀ (volume) (nm)	Median pore- throat diameter <i>D</i> 50 (area) (nm)	Bulk density (g/cm²)	Porosity (%)	Permeability (mD)	Intrusion Spike?
1st Bone Spring	NMNO9208	58.80	1.37	2.53	3.16	1.30E-04	
1st Bone Spring	NMNO9208	N/A	N/A	2.59	3.21	4.30E-02	Yes
1st Bone Spring	NMNO9209	16.50	4.50	2.51	0.90	2.79E-03	
1st Bone Spring	NMNO9214	N/A	N/A	2.77	0.66	2.16E-02	Yes
1st Bone Spring	NMNO9214	N/A	N/A	2.12	0.67	4.89E-02	Yes
1st Bone Spring	NMNO9218	7.00	4.40	2.60	0.70	1.44E-04	
1st Bone Spring	NMNO9222	19.10	4.70	2.61	0.60	6.34E-02	
3rd Bone Spring	NMNO10338	10.30	4.10	2.57	0.65	9.93E-03	
1st Bone Spring	NMMX9564	7.90	5.70	2.63	1.85	1.09E-02	
1st Bone Spring	NMMX9580	35.30	4.50	2.60	0.43	3.94E-02	

Table 5 – Compilation of MICP results.

Note: samples with intrusion spikes are shown with spike-corrected porosity and bulk density, however, the spikes lead to

anomalously high median pore-throat diameters that could not be corrected.



Figure 4-7 Pore throat diameter as a percentage of total pore volume (pore size distribution is corrected for samples with intrusion spike anomalies)



Figure 4-8 Pore throat diameter as a percentage of total pore volume comparing siliceous vs. carbonate samples



Figure 4-9 Average Pore throat diameter as a percentage of total pore volume.

Sample ID	0.0028-0.005 μm	0.005-0.01 μm	0.01-0.05 μm	0.05-0.1 μm	0.1-1 μm	1-10 μm	10-50 μm
NO9208	0.60	7.46	40.79	34.88	10.47	1.57	3.86
NO9208*	3.22	8.43	30.80	20.53	12.10	23.29	1.63
NO9208	4.17	10.95	39.95	26.64	15.69	0.49	2.12
NO9209	16.35	23.68	19.70	7.24	14.96	16.20	1.87
NO9214*	4.18	5.02	2.23	0.69	1.15	0.99	85.76
NO9214	29.08	34.93	15.51	4.79	8.00	6.87	0.84
NO9214*	3.41	3.86	1.59	0.46	0.79	0.47	89.43
NO9214	31.50	35.68	14.68	4.22	7.27	4.38	2.29
NO9218	24.43	31.12	25.75	7.55	11.11	0.36	0
NO9222	16.68	23.97	18.61	7.77	11.14	14.22	7.61
NO10338	21.14	14.79	2.16	9.76	20.05	5.91	1.87
MX9564	10.60	40.89	37.92	2.48	3.09	2.64	2.39
MX9580	12.35	22.11	16.38	7.53	17.05	16.06	8.53

Table 6 - Cumulative pore throat diameter percentage

* Data with non-corrected intrusion spike; carbonate samples are in red.

4-5 Spontaneous Fluid Imbibition/Vapor Absorption

For all tests, DI water and n-decane (a proxy for oil) were used for fluid imbibition and vapor absorption tests. Water imbibition is done in triplicate to reduce any errors associated with surface tension. Imbibition results typically have 2-3 distinct imbibition slopes (referred to as Stages I, II, and III). These different slopes represent different phases of imbibition. Stage I (up to a few seconds) is the initial settling when the sample bottom touches the fluid. Stage II is for fluid uptake onto the sample surface (up to about 500 μ m) which has a better connectivity than the interior. Stage III corresponds to fluid imbibition through the edge-accessible and connected pore spaces of porous rock, which mostly represents pore connectivity of the rock matrix. Finally, Stage IV is a very low (~0 – 0.1) fourth slope that is sometimes seen, likely due to fluid reaching the top of the sample (Hu et al, 2001).

Fluid imbibition was first performed on the two State MX 1 samples and NO10338, which lies in the 3rd Bone Spring Sandstone (Figure 4-10; Table 8). These three samples had multiple runs with DI water with little change from the test duration of 6-hr to 24-hr. A long lasting ~0.1 slope is seen at the end of DI water imbibition for all samples that could be interpreted as Stage IV. However, the fluid reaching the top of the sample is unlikely for two reasons. First, the low slope occurs very quickly after the start of imbibition and it is doubtful that fluid could reach the top of the sample in ~30 minutes. Secondly, the MICP data show that the porosity of these samples is very low which will inhibit fluid flow. Therefore, these very low DI water imbibition slopes at the end are interpreted to be Stage III. As this third imbibition slope is very low, with no change after 24 hours, the other samples were only analyzed with one 6 hour DI water imbibition test.







Figure 4-10 DI water imbibition into MX9564 for A) 6 and B) 24 hours,

Table 7 - List of imbibition and vapor adsorption tests performed.

		Vapor Adsorption				
Sample ID	DI Water (6 hr)	DI Water (12 hr)	DI Water (24 hr)	n-Decane	DI Water	n-Decane
NO9208						
NO9209						
NO9214	Х			Х	Х	Х
NO9218						
NO9222	Х			Х	Х	Х
NO10338	Х	Х	Х	Х		
MX9564	X	Х		Х	Х	Х
MX9580	Х	Х	Х	Х	Х	Х

B)

Sample ID	Fluid	Average Stage III Slope
NO0214	DI Water	0.04
1109214	n-Decane	0.50
NOQ222	DI Water	0.05
1109222	n-Decane	0.71
NO10229	DI Water	0.21
10010000	n-Decane	0.47
MY0564	DI Water	0.12
10179304	n-Decane	-
	DI Water	0.10
10179200	n-Decane	0.45

Table 8 - Average Stage III slope for imbibition tests.

Averaging around ~0.5 for all samples tested, decane imbibition showed higher Stage III slopes than DI water. (Figure 4-11; Table 8). Stage IV slope can be seen in Figure 4-11 and is much more likely to represent fluid reaching the surface of the sample than the DI water imbibition results. The results show that the pore system has a good connection to oil wetting fluids. This is supported by the sample surface being oil wet from the contact angle measurements.



Figure 4-11 Example of decane imbibition into NO10338 with all four stages of imbibition present

Vapor adsorption tests are performed to remove the potential effect of surface tension that is present in imbibition. The surface tension of the fluid has been shown to pull downward on the sample showing an apparent weight gain during imbibition. The effect is more pronounced with DI water imbibition tests for its small contact angle, but vapor adsorption is done with both DI water and n-decane. All samples showed a ~0.5 Stage III slope during vapor adsorption suggesting good pore system connection with each fluid including DI water (Figure 4-12; Table 9); the difference between imbibition and vapor absorption lies in the fact that fluid uptake during an imbibition process has to occur via a plane face while vapor absorption can happen in 3-D.



Figure 4-12 Example of vapor adsorption of DI Water into MX9580

Sample ID	Fluid	Average Stage III Slope
NO0214	DI Water	0.55
1009214	n-Decane	-
NO0222	DI Water	0.61
1009222	n-Decane	-
NO10229	DI Water	-
NO10336	n-Decane	-
MY0564	DI Water	0.49
10179304	n-Decane	0.67
MY0590	DI Water	0.66
10179200	n-Decane	0.45

Table 9 - Average Stage III slope for vapor adsorption tests.

4-6 Production Data

The State MX 1 production began in August 1984 as a conventional well (Table 10), with an initial production of 800 barrels of oil per day (BO/d) (Figure 4-13). Production continued until November 2016 when production had dropped to 2 BO/d. Cumulative production over the history of the well is 28,366 BO and 1,077 MCF of gas. An exponential decline curve (Arps Equation shown in Figure 4-13; (Arps, 1945)) was able to be fitted to the production data with a value of b=2.8. The State NO 1 is listed as a dry well with no production, and it is currently plugged, abandoned, and used as a saltwater disposal well (DrillingInfo, 2017).
	State MX 1	State No 1		
Completion Year	1984	1983		
Vertical Well?	Yes	Yes		
Total Vertical Depth (ft)	10750	11040		
Perforation Depth (ft)	9462-9472	11040?*		
Cumulative Oil (bbl)	28,435	Dry		
Status	Inactive since Nov. 2016	Inactive		

Table 10 Completion details for study wells (from New Mexico Oil Conservation Division)

* TVD for State No 1 is 11040 ft and listed perforation is 11040 ft, but the accuracy of data is questionable.



Figure 4-13 - Oil production for State MX 1. The green line is the decline curve using the

standard Arps Equation.

Chapter 5 – Discussion

5-1 Porosity and Permeability

Previous scanning electron microscopy (SEM) studies have shown a majority of porosity in the Bone Spring might reside in organic matter-hosted pore spaces and a correlation between porosity and TOC is expected (Alcantar-Lopez and Chipera, 2013). The organic-lean reservoir rocks are likely to contain significant non-organic hosted porosity. The porosity and permeability among all samples are relatively similar. The average (approximately 60%) of the pore throat sizes in all samples ranges in 5-50 nm, which are probably related to organic or intraparticle types (Table 6). As all samples have the same maturity and it would be expected to observe increased porosity with increased TOC. However, there is no correlation between TOC and porosity (Figure 5-1).



Figure 5-1 Total organic carbon (TOC) vs. porosity in study samples

The samples on average have 25% (largest percentage of pore throats) of porosity in the likely range of organic pores (5-10 nm). From Figure 5-1 and Figure 5-2 there is no correlation between TOC vs. porosity and at best a slight correlation for pore throats in the 10 nm to 50 μ m range vs. porosity. This is an unexpected result as either the majority of porosity is organic hosted, where TOC would be the main driver of porosity, or that an increase in the larger pores (>10 nm) that are likely intraparticle or interparticle would drive increased porosity. An explanation for these differing results is that due to the low porosity of the samples, and the likely presence of both mineral and organic hosted porosity, porosity is not able to be correlated to specific factors such as TOC.



Figure 5-2 Porosity (pore-throats at 10 nm - 50 um) vs. total porosity

However, there is evidence of another explanation as to why TOC or mineral hosted porosity is not correlated with increased porosity. If the likely mineral hosted porosity (>10 nm) is isolated from the organic hosted pore network (5-10 nm) then much of this porosity could be hidden from MICP analysis. The wettability tests show the

sample surface being oil-wet and the connectivity of organic fluids is assumed to be good from fluid imbibition tests. There is low connectivity seen with DI water for the samples from the imbibition tests and because of good connectivity to the organic fluid n-decane it is implied that most of the connected pore system resides in oil wetting pores. However, the wettability tests show the sample surface is also wetting to DI water and vapor absorption tests show an even higher imbibition slope for DI water than n-decane suggesting good connectivity to DI water. Good connectivity to DI water from vapor absorption could imply that there are more water wetting pores in 3D than a single plane in fluid imbibition (the sample bottom). These trends could be from water wet mineral hosted pores being isolated and not connected to the rest of organic pore network.

5-2 Mineralogy

As discussed the Bone Spring is described as a hybrid unconventional reservoir with organic-rich, typically carbonate (NO9218) or shale (possibly NO9208), juxtaposed next to organic-lean layers, typically quartz-rich siltstone or sandstone (MX9580), from fluvial or aeolian deposits that bypassed the shelf during lowstand sea level (Soreghan and Soreghan, 2013). There is a negative correlation between quartz content vs TOC in the study samples which follows the hybrid reservoir model (Figure 5-3). However, extending the dataset to more Bone Spring Formation wells in the area (Appendix C) and at different depths, there is also no correlation between quartz content and TOC (Figure 5-4). In addition, there is no correlation between mineralogy (quartz, carbonate, or clay) and porosity seen in the samples (Figure 5-5).



Figure 5-3 Quartz percentage vs. TOC in study samples



Figure 5-4 Quartz percentage vs. TOC for samples in the study and other Bone Spring Formation wells



Figure 5-5 A) Quartz and B) dolomite content (%) vs. porosity (%) in study samples

Siliceous samples studied in this work do contain a higher percentage of pore throats greater than 10 nm, likely representing intraparticle or interparticle porosity, compared to carbonate-rich samples (Figure 5-6). This would fit the hybrid source and reservoir rock unconventional reservoir if carbonates are the source rocks and siliceous intervals are reservoir rocks. Even though the porosity of siliceous and carbonate samples are similar, having additional water wetting porosity could be beneficial to producibility as the oil or gas would not adsorb to the walls of the pores.

Since the Bone Spring deposits are sediment gravity flows, it is likely that the core samples obtained are only in channels or slope deposits due to their location in the basin. This means that the samples are only in large sand units that would likely not contain the fine-grained sediment and organic particles present at basin floor fans.



Figure 5-6 Pore throat diameters by two facies

5-3 Well Logging and Producibility

The two study wells are chosen because the State MX 1 is a producing conventional well and the State NO 1 is a dry conventional well. However, there are

many complexities that could have caused the State NO 1 to be dry or why the samples of the same facies in State MX 1 well show no difference in pore structure than these in State NO 1 well. The perforation depth of the State MX 1 well is 9462-9472 ft, and the closest sample depth used in this study is at 9564 ft. Well log data shows that the perforations do show an increased porosity (Figure 5-7). This is likely due to dolomitization which has been attributed to increasing secondary porosity in the Scharb Field (Mazzullo and Reid, 1987). The well log data from the State NO 1 shows only slightly less porosity than the State MX 1 samples (Figure 5-8).



Figure 5-7 Well log data from State MX 1; four short pink lines are for perforations (9462-9472 ft) and sample depths (9564 & 9580 ft).



Figure 5-8 Well log data from State NO 1.

The porosity in the well logs is around 5-10% for the depths of the study samples, higher than that determined by MICP. This could be due to the very complex stratigraphy of the Bone Spring Formation. Mineral content variation will affect the bulk density of different layers. The bulk density of the study samples ranges from 2.51-2.89 g/cm³ (Table 5). A change of 0.2 g/cm³ in the bulk density would result in a difference of up to 6% in porosity. This change, if uncorrected, would likely still not be enough to drop the porosity down to the .5-3% from MICP, and the density log is relatively flat through the study depths. Other causes for the additional porosity seen in the logs for the study sample depths and perforations could be fractures in the rock or large vugs. Standard core analyses from other wells in the Scharb Field show the values of porosity ranging from 3-10% with permeability less than 0.1 mD in sections (Appendix D). Appendix D and other Scharb Field studies describe fractures and vugs being present in small intervals (Howard and Fraga, 1984).

No fractures are apparent from the inspection of the whole core (Figure 3-2). Microfractures are also not seen during MICP analyses in any samples, which would be likely with any large-scale fracturing of the formation. Density, acoustic, and spectral gamma ray logs can also suggest zones of fracturing. If density logs show large porosity spikes compared to neutron porosity logs, this could be due to fractures. Similarly, skips in the acoustic logs could be from fracturing (Figure 5-9). Finally, increased uranium radioactivity, as it is soluble in both oil and water, suggests high fluid flow through the rock, likely through fractures (Figure 5-9). However, the density, acoustic, and spectral logs in the study sample and perforation depths do not show any of these signs. Further information is needed to verify fractures are not present but MICP and logging results, along with visual inspection of the core, suggest fractures do not play a dominant role in contributing to the additional porosity seen in the logs.



Figure 5-9 Spectral gamma ray and acoustic log of State MX 1; four short pink lines are perforations (9462-9472 ft) and study sample depths (9564 & 9580 ft)

Vuggy porosity would also be readily apparent in MICP analyses as interparticle pores. It is possible that the intrusion spikes during MICP for several of the State NO 1 samples, NO9208 AND NO9214, could be vugs. If the vuggy porosity, is not connected to the pore network, then this could be the cause of increased porosity seen in the well logs but not in MICP. As the cubic sample size used in MICP is only 1 cm, other samples could not have seen vuggy porosity by chance from cutting of the samples down.

Jarvie (2012) has proposed an oil crossover line for unconventional reservoirs where S1 values are plotted against TOC. The line is a one to one ratio between S1 (hydrocarbons migrated or produced in the layer) vs. TOC, and formations above the line are expected to be productive. The basis of this line is that oil or gas will adsorb to organic grains in the rock and a certain level of saturation is needed before unconventional oil wells are likely be productive. The results of S1 vs. TOC in the study samples show that most sample depths should be unproductive (Figure 5-10). Jarvie (2012) discussed that organic-lean facies juxtaposed among organic-rich ones can increase producibility as they exhibit less sorption to organic pores. No simple relationship is given for the amount of S1 hydrocarbons needed for organic-lean facies to be productive. If there is significant non-organic hosted porosity (>10 nm pore throats) as suggested, this could also theoretically lower the oil crossover line. However, even with an oil crossover line with a slope of 0.5, most sample depths still are not expected to be productive (Figure 5-10).



Figure 5-10 Jarvie's oil crossover line of S1 vs. TOC. Standard oil crossover line is slope = 1. Data above the green line should be productive wells and below the line will be unproductive (Jarvie 2012).

Chapter 6 – Conclusions and Recommendations

6-1 Conclusions

Samples were chosen to investigate whether the hybrid system of the Bone Spring, with its different lithologies and TOC contents, contains different pore systems. Conclusions from the study area are as follows:

- The majority of pore-throat size distribution is in the potentially organic (5-10 nm) or intragranular (10-50 nm) range.
- Pore connectivity is very low for water and high for organic fluids from fluid imbibition
- No significant differences in porosity or permeability is observed in organic-rich or organic-lean facies

- No differences observed to explain the increased producibility in the State MX 1 well. Other factors such as fractures could increase producibility and were not investigated in the study.
- No correlation between TOC and porosity
- Increasing quartz content is correlated to decreasing TOC
- No correlation between mineralogy vs. porosity
 - $\,\circ\,\,$ Siliceous samples have a greater percentage of pore throats in 10 nm 50 μm range
 - Possible evidence to support intraparticle or interparticle porosity is isolated from organic pore network
- If the cause of production in State MX 1 is dolomitization, the increased porosity is likely restricted to the perforated interval of 9462-9472 ft

6-2 Recommendations

Recommendations to improve on these results are to first investigate a wider area of the Bone Spring Formation. Unconventional reservoirs are highly anisotropic and with a system such as the Bone Spring with many lithologies, more data are needed to make generalizations about the wider area. Acquiring samples from the other Bone Spring Formation intervals such as the 2nd Bone Spring Sand is needed as the one sample in the 3rd Bone Spring Sand is not enough to confidently characterize the rest of the formation. As Bone Spring deposition is dominated by sediment gravity flows, the analysis needs to be from not only channels and fans, but levees and over bank deposits to determine if pore structure and TOC is different from the predominantly sandy mineralogy study samples.

Chapter 7 - Appendix

Note: Methods for XRD and Geochemical analysis were obtained directly from Weatherford Laboratories and published with their permission.

Appendix A - Methods and Procedures for Geochemical Analysis at Weatherford Laboratories

Rock Sample Preparation

Samples for Total Organic Carbon (TOC) and/or Programmed Pyrolysis may each require varying levels of sample preparation. Groups of samples are evaluated as to their respective condition as received and are handled differently depending on the various types of contaminants, lithologies, and analytical objectives. Samples are not high-graded prior to grinding unless specifically instructed by the client. When necessary and as instructed, water washing may be required to remove water-based mud. Solvent washing can be utilized to remove oil-based and/or synthetic-based mud. Additional solvent extraction of the crushed rock will be necessary to completely remove the contaminating oil-based and/or synthetic-based mud. Sample picking may also be necessary to remove lost circulation material or known cavings. Samples for TOC and Programed Pyrolysis are then ground to pass through a fine mesh sieve prior to analysis.

Total Organic Carbon

Approximately 0.10 g of crushed rock is accurately weighed and then digested with concentrated hydrochloric acid to remove all carbonates from the sample. At this point, gravimetric carbonate content can be determined if requested. Following digestion, the sample is washed through a filtering apparatus, placed in a combustion crucible and dried. After drying, the sample is analyzed with a LECO Carbon Analyzer with detection limits to 0.01 weight percent. Standards and sample duplicates are tested regularly to assure superior instrument performance.

Programmed Pyrolysis (Rock-Eval II, Rock-Eval VI, Source Rock Analyzer)

Programmed pyrolysis (Rock-Eval and SRA) is performed to assess source rock quality and thermal maturity (e.g., Peters, 1986; Peters and Casa, 1994). In programmed pyrolysis, crushed rock samples are heated in an inert environment to determine the yield of hydrocarbons and CO2. The sample is initially held isothermally at 300°C for 3 minutes, producing the S1 peak by vaporizing the free (unbound) hydrocarbons. High S1 values indicate either large amounts of kerogen-derived bitumen (as in an active source rock) or the presence of migrated hydrocarbons. The oven then increases in temperature by 25°C/minute to a final temperature of approximately 600°C, depending on the instrument type. During this time, hydrocarbons that evolve from the sample as a function of the pyrolytic degradation of the kerogen are measured, generating the S2 peak and is proportional to the amount of hydrogen-rich kerogen in the rock. The temperature at which the S2 peak reaches a maximum, "T max ", is a measure of the source rock maturity. Accuracy of T max is 1-3°C, depending on the instrument, program rate and sample size, but can also vary by organic matter type. Tmax values for samples with S2 peaks less than 0.2 mg HC/g rock are often inaccurate and should be rejected unless a definitive kerogen peak is noted from the pyrogram. Any carbon dioxide released between 300° and 390°C is also measured, generating the S3 peak, providing an assessment of the oxygen content of the rock. In addition to the standard programmed pyrolysis method, we have several additional methods available designed to provide the client with additional useful information as it relates to the geochemical nature and potential of a rock sample including but not limited to TOC quantification, Carbonate

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quantification, Reservoir Oil Quality, APIR and Kerogen Kinetic analyses. A summary of analytical results from Programmed Pyrolysis follows.

S1: free oil content (mg hydrocarbons per gram of rock)
S2: remaining hydrocarbon potential (mg hydrocarbons per gram of rock)
S3: organic carbon dioxide (mg CO 2 per gram of rock)
TOC: total organic carbon content (wt. %)
Tmax: temperature at maximum evolution of S2 hydrocarbons
Ratios: hydrogen index (HI), oxygen index (OI), production index (PI),
S2/S3, and S1/TOC

Vitrinite Reflectance and Visual Kerogen Assessment

Visual kerogen assessments complement chemical assessments by recording information from the discrete particles (macerals) that make up the sedimentary organic matter. Vitrinite macerals are particles of sedimentary organic matter derived from wood, and their reflectance of incident light under oil immersion is used to assess the thermal maturity of a sample. Vitrinite reflectance (%R o) increases with increased depth of burial (i.e., increased thermal exposure), and is an indication of the maximum temperature to which these particles have been exposed. The reflectance microscope measures the amount of reflected light relative to the incident light and expresses this ratio as a percentage. Vitrinite reflectance values range from about 0.25% (immature) to a high of about 5 or 6% (very mature). A population of vitrinite particles is found in almost all rock samples of Devonian or younger age (older samples pre-date the evolution of land plants, the source of vitrinite). Selecting the appropriate vitrinite population for subsequent reflectance measurements is a somewhat subjective process. The in situ population must be identified, and must exclude vitrinite derived from cavings and

reworked organic matter. Reworked vitrinite that was redeposited in the sediments may have higher reflectance that will skew the measurements towards higher R o values if not recognized and removed from the average. In cuttings samples, cavings from overlying less mature sediments may skew the average towards lower values. Generally, when cavings are excluded, the lowest reflecting population is found to be indicative of the indigenous population, but this evaluation is made in combination with visual kerogen assessments, Rock-Eval Tmax measurements, and data for the extent of kerogen conversion.

Vitrinite reflectance values are divided into the following stages of thermal maturity:

Stage	Reflectance Range
Immature	0.2% to 0.6%
Oil window maturity	0.6% to 1.1%
Condensate or wet-gas window	1.1% to 1.4%
Dry gas window	1.40% plus

Thermal alteration indices (TAI) are determined from the color of organic matter when viewed under transmitted light through a strewn slide mount of kerogen. Lighter colored organic matter is indicative of low maturity, whereas darker material is indicative of higher thermal maturity.

Maceral composition is an assessment of the percentages of various organic particles found in kerogen samples. These particles are related to the oil and gas potential of the organic matter and are generally described as amorphous, exinitic, vitrinitic, inertinitic, or solid bitumen percentages. The former two macerals are primarily oil-prone particulate matter, whereas vitrinitic particles are indicative of gas-prone organic matter. Inertinitic matter is very hydrogen-poor and has no potential for generation of commercial quantities of hydrocarbons. The presence of solid bitumen is indicative of in situ generated hydrocarbons, migrated hydrocarbons, or contamination. Other observations from visual kerogen assessment include the quality of the organic matter (oxidized, well preserved), and the presence of palynomorphs (which can reveal key aspects of the depositional environment).

Appendix B - Methods and Procedures of X-Ray Diffraction Analysis at

Weatherford Laboratories

Bulk Sample Preparation

Spray Dry

A representative portion (6 grams minimum, preferably 10 grams) of each sample is selected for XRD analysis. Samples are disaggregated using mortar and pestle and portioned out for bulk and clay analyses. The bulk portion is ground into a slurry using a McCrone Micronizing Mill. The slurry is transferred to an air brush assembly and spray dried using a James Hutton Institute Spray Drying Oven. Randomly oriented spherical aggregates are then loaded into stainless steel sample holders. This method eliminates preferred orientation of minerals and allows for improved reproducibility of the bulk XRD patterns. [Sp. Ed. Bish, D. L. and Post, J. E. (1989); Hillier, S (2002b)].

Minimal Material

A representative portion (2 grams minimum) of each sample is selected for XRD analysis. Samples are hand ground in an agate mortar and pestle to a fine powder. A portion of each ground sample is loaded into a stainless steel sample holder, modified to accommodate a side loading method. This side loading method allows the sample to be sifted and promotes a random particle orientation, minimizing preferred orientation.

Bulk/Whole Rock Analysis

These bulk sample mounts are scanned with a Bruker AXS D4 Endeavor X-ray diffractometer using copper K-alpha radiation. To eliminate K-beta peaks and reduce background noise, nickel filter slits and air scatter screens are utilized, respectively. The

scanning parameters for a bulk scan are from 5° 2θ to 70° 2θ at a step size of 0.02° per step. Full scanning parameters are defined below (for both bulk and clay):

- Operating voltage: 50Kv
- Operating amperage: 40mA
- Axial soller slit is in place
- Goniometer diameter: 400mm
- Lynx Eye High speed detector with a 2θ scanning range of 4°
- · A nickel filter for K beta peaks
- An air scatter screen to reduce fluorescence
- Variable divergent slit at 0.3mm for bulk and 0.5mm for clay

Bulk Mineral Quantification

MDI Jade TM 9+ software and ICDD PDF 4+ 2015 database, with over 790,000 known compounds, are used to identify mineral phases present in the bulk diffractograms. Reference Intensity Ratio (RIR) method is used to quantify the whole rock. The RIRs (e.g., Mineral Intensity Factors (MIF)) are generated for each diffractometer using pure mineral standards mixed with quartz. The primary peaks of the minerals present are measured using the area under the curve to one standard deviation (subtracting the background). When an uncommon mineral that is not in our RIR library and pure mineral standards are not available, whole pattern fitting with Rietveld refinement is applied.

X-ray diffraction cannot identify non-crystalline (amorphous) material, such as organic material and volcanic glass. However, samples containing a large amount of amorphous material show an anomalous "hump" in the XRD pattern. If further evaluations are required, Bruker AXS TOPAS v4.2 software is used to provide an estimate of the amount of amorphous material. Scans undergo full-pattern-fitting and Rietveld refinement using structure phase files previously identified by Jade and ICDD software (see above). *Clay Sample Preparation*

An oriented clay fraction mount is prepared for each sample from hand ground powder. The samples are treated with a small amount of sodium hexametaphosphate as a deflocculant mixed with distilled water. The samples are then physically dispersed using a Fisher Scientific Ultra Sonifier to bring the clays into suspension. The samples are sized fractionated by centrifuging. After centrifuging, the supernatant containing the less than 2 micron clay fraction is vacuumed through a filter membrane glass tube that collects the solids on to a millipore filter.

These oriented solids are mounted on glass slides producing highly uniform diffraction mounts [Drever, 1973]. The glass slides are loaded into desiccant bowls containing 99.9% ethylene glycol for an extended period of time at a temperature of 110°C. The samples are loaded directly from the desiccant bowl to ensure maximum sample glycolation. The glycolated clays are also scanned in a Bruker AXS diffractometer using the following scan parameters: 2° 20 to 30° 20 at a step size of 0.02° per step. After the glycolated slide is scanned, the slides are heat-treated in a furnace at 375°C for one hour and rescanned at the same clay parameters stated above. This process aids in identifying the expandable, water-sensitive minerals. When samples contain high levels of carbonates combined with low clay quantities, we may need to return to the sample and remove the carbonates to obtain a better clay scan for accurate identification and quantification.

Clay Mineral Identification and Quantification

Mixed-layer clays, particularly illite/smectite (I/S) are identified following the multiple peak method of Moore and Reynolds (1997). This entails measuring the 001/002 and 002/003 peaks of the illite/smectite. NEWMOD clay mineral generation program is used to create theoretical clay patterns, clay mixtures, and illite crystallinity. Identification of the amount of smectite (percent expandability) is also verified using the heat treated diffractogram overlain on the glycolated diffractogram in MDI Jade.

Kaolinite and chlorite are identified by the relative proportions of the peaks at 3.59 Å (kaolinite 002) and 3.54 Å (chlorite 004).

Clay mineral quantification includes: (1) the actual amount of discrete clay mineral species in the sample, and (2) the "expandability" or amount of smectite in mixed-layer clays, if present. Illite/Smectite (I/S) is the most common mixed-layer clay, but there are also chlorite/smectite (corrensite) and kaolinite/smectite. There are several tables in Moore and Reynolds (1997) that list 20 positions and their correlative percent smectite in I/S (Table 8.3, p.273) or C/S (Table 8.4, p.281).

The Mineral Intensity Factor (MIF) method of Moore and Reynolds (1997) is applied to quantify the clay species. Weatherford has calculated MIFs for most clay minerals encountered. The area of the specific mineral peak being used is divided by the MIF in the quantification process. The clay species is normalized to the total clay value derived from the bulk analysis.

Appendix References

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	Appendix C	C – Additional	Geochemical	and Minera	logical Data
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(Acquired by Weatherford Labs and stored at New Mexico Bureau of Geology)

Well Name	Depth (ft)	TOC (%)	Quartz Content (%)	Dolomite Content (%)
AMOCO FED 1	6296	0.817	4	0
AMOCO FED 1	6299	1.154	18	4
AMOCO FED 1	6322	2.48	23	9
AMOCO FED 1	6327	0.137	62	5
AMOCO FED 1	6332	0.419	65	1
AMOCO FED 1	6338	1.722	35	3
AMOCO FED 1	6345	3.62	44	4
AMOCO FED 1	6356	1.85	53	3
AMOCO FED 1	6383	2.766	51	1
AMOCO FED 1	6388	1.601	57	2
AMOCO FED 1	6389	1.642	56	1
AMOCO FED 1	6393	3.333	33	2
AMOCO STATE 1	8610	4.261	44	14
AMOCO STATE 1	8769	1.444	20	66
AMOCO STATE 1	8815	4.864	44	1
AMOCO STATE 1	8819.5	3.437	41	56
AMOCO STATE 1	8825	2.238	22	77
AMOCO STATE 1	8832	3.932	86	6
AMOCO STATE 1	8840	3.277	97	1
AMOCO STATE 1	8855	5.22	55	27
ELKAN 3	9621	3.551	62	9
ELKAN 3	9624	2.349	23	76
ELKAN 3	9630	0.786	2	<u>98</u>
FEDERAL CS COM 1	7986	1.669	53	2
FEDERAL CS COM 1	8240	1.453	15	84
FEDERAL CS COM 1	8437	0.384	42	51
FEDERAL CS COM 1	8440	0.995	56	38
FEDERAL CS COM 1	8452	1.674	44	31
POTTS FEDERAL 3	6190	1.877	49	2
POTTS FEDERAL 3	6211	5.411	39	4
POTTS FEDERAL 3	6242	1.565	49	2
STATE FU 5	9189	4.168	61	2
STATE FU 5	9195	2.266	45	40
STATE FU 5	10243	1.194	99	0
STATE HQ 6	9287	2.202	53	38

STATE HQ 6	9290	1.699	39	58
STATE HQ 6	9296	1.988	46	52
STATE MX 1	9546	3.577	20	71
STATE MX 1	9567	1.632	72	23
STATE MX 1	9568	2.849	23	68
STATE MX 1	9583	0.993	96	1
STATE MX 1	9590	3.55	57	7
STATE NO. 1	9208	0.458	59	18
STATE NO. 1	9209	4.172	52	5
STATE NO. 1	9214	1.645	50	7
STATE NO. 1	9218	2.398	14	84
STATE NO. 1	9222	1.818	38	59
STATE NO. 1	10338	1.026	70	2

Appendix D - Core Analysis

Analysis by Core Lab in 1961 for State MX 2 well at 9214-9234 ft located near State MX 1, with a scanned copy of the report publicly available from the New Mexico Bureau of Geology.

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20	24.2-25.6	<u></u>	21	4.0	9.3	38.4	FV	K			*	9225	X		
21	9225.8-27.0		0.5	4.8	11.8	36.6	FV		۱ ۴		×	URILLE	\$×	} }	
22	9228.0-29.5	0.3	0.1	2.8	7.8	59.0	FV		112		1	T	X	6	
23	29.5-30.5	6.2	0.7	3.4	10.9	42.3	FV	1		19-11		0220	Sil	N	HTT:
24	30.5-31.5	0.7	<0.1	2.0	8.9	69.3	FV		1			T	TX.		
0-						10		11111	111		X	1 T	5111x		
25	9231.5-32.9	<0.1	<0.1	1.7	23.2	68.0	-		1112			1	211	Nx 0++	
20		<0.1	_ <0.1	1.7	42.9	44.7	12		111	11111	11111	1		Nº I	
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