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An Overview of Relating Pore Size Distribution Diagrams to Permeability

NOORAH AL MULHIM
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Reviewed and approved* by the following:

Anne Menefee
Assistant Professor of Energy and Mineral Engineering
Thesis Supervisor

Eugene Morgan
Associate Head for Undergraduate Education and Assistant Teaching Professor, Department of Energy and Mineral Engineering
Honors Adviser

* Electronic approvals are on file.

ABSTRACT

Pore size, pore structure, and pore size distribution (PSD) are primary controls on permeability in porous media. Measuring PSD is a straightforward exercise and typically shows a bimodal distribution of pore sizes in rocks. The set of larger pores is the primary control on permeability, whereas the set of smaller pores contributes only a fraction to the bulk permeability. Permeability is a measure of a rock's ability to conduct fluid, however, its relationship to pore size distribution is complex. This thesis provides a comprehensive literature review comparing the advantages and disadvantages of pore size distribution measurements and permeability models for various reservoir engineering applications. In addition, an analytic evaluation of models that attempt to predict permeability based on PSD data either empirically or semi-empirically is presented, along with a discussion of limitations of such models and recommendations for best practices. To enclose the relationship between pore size distribution and permeability requires more research from specialists in the field work. Regarding this matter, there are no accurate testings to conclude this relationship.

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Chapter 1

Introduction

Pore size is defined as the distance between grains within the matrix of a rock. This distance represents a void space that does not contain any solid materials that would prohibit fluids to flow through. While an idealization, pore size is typically modeled as the diameter of a cylindrical tube, and the pore size distribution (PSD) is used to characterize the variations in pore spaces within a certain rock. The most common types of PSDs are uni-modal and bi-modal. A uni-modal distribution has only one peak, indicating that the pores are all roughly the same size. A bi-modal distribution has two peaks, indicating that there are two different pore sizes present in the material.

Different methods can be employed to determine pore size distribution, including mercury intrusion porosimetry, nuclear magnetic resonance imaging, and scanning electron microscopy. These methods enable researchers to measure the shapes and sizes of pores in a rock sample and produce a distribution curve that illustrates the prevalence of various pore sizes in the sample. Pore size distribution is a critical parameter in the realm of petroleum engineering, as it directly impacts the behavior of fluids within reservoir rocks. Reservoir rocks are permeable structures that store hydrocarbons and other fluids, and their pore size distribution can affect their ability to transport, store, and produce these fluids. The permeability of the reservoir rock, which is a measure of how easily fluids can flow through it, is impacted by the pore size distribution. If the pores are too small, fluid flow may be obstructed, leading to low permeability and subpar fluid production. Conversely, if the pores are too large, fluids may flow too easily, leading to rapid depletion of the reservoir and lower overall recovery.

The analysis of pore size distribution is essential to reservoir engineering, as it plays a role in many of the rock properties that govern our ability to extract or inject fluids underground, such as permeability, swelling, etc. It is possible to have two sets of identical particles that have the same void ratio and porosity to have different PSD and thus different permeability (Juang et al. 1986). Hence, the understanding the pore size distribution of reservoir rocks is critical for accurately characterizing their properties and predicting their behavior, which is essential for optimizing production and maximizing ultimate recovery in the oil and gas industry

This thesis first presents a literature review exploring pore size distribution measurement techniques such as mercury intrusion porosimetry, adsorption methods, and nuclear magnetic resonance, as well as current permeability models and a brief description of their applicability. Advantages and disadvantages for each technique, depending on the reservoir type or engineering applications, are also discussed. The leading theories that relate pore size distribution to permeability are then reviewed. The objective of the thesis is to conduct a comprehensive review study to evaluate the correlation between pore size distribution (PSD) and permeability in different types of porous media. This objective is pursued by analyzing the results of previous research studies that have examined this relationship, and identifying common trends and patterns in the data. By achieving this objective, the thesis hopes to contribute to the current understanding of the relationship between PSD and permeability, and to provide insights that could inform future research and engineering applications.

Chapter 2

Pore size distribution measurement techniques

2.1 Mercury Intrusion Porosimetry

Pore structure analysis is an important step in permeability calculations, but can require sophisticated techniques. One technique that is used to obtain the pore size distribution is mercury intrusion porosimetry (MIP). It is a common method due to its simplicity and ease of use compared to the other methods. This method exploits the property of mercury as being a nonwetting liquid, which implies that external pressure needs to be applied to allow the intrusion of mercury into the porous media. Hence, MIP devices characterize the pore size distribution based on the mercury pressure and the occupied volumes. It also requires some input parameters that are either determined experimentally or given as a known value, including surface tension, contact angle, pressurization rate, etc. The highest pressure that MIP devices can reach is up to 400 MPa and thus pores with a radius smaller than 2nm cannot be measured (Berodier et al. 2016). This also raises concerns about the accuracy of this method, as it only measures the pore entry size instead of the actual pore size. To illustrate, the volume of a large pore that is only reachable through a significantly narrow pore is recorded at the pressure of the smaller pore. Additionally, Van Brakel et al. (1981) confirmed the flaw of MIP method by proving that when pressure is reduced, some amount of intruded mercury will remain trapped in the porous media.

2.2. Adsorption Methods

Adsorption methods are commonly used to provide a complete pore size distribution analysis. In pore structure analysis, it is preferred to use water vapor adsorption instead of nitrogen adsorption for several reasons. One of these reasons is that nitrogen cannot easily go through the small pores and the small pores volume thus are not accounted for. In addition, as is the case in the MIP method, nitrogen adsorption underestimates the large pores volume that are reachable through narrow pores channel. The use of water vapor adsorption method focuses on first determining the t-curve, which shows the adsorbed film thickness over range of relative pressures for a specific heat of adsorption. Different absorbents could have different heat of adsorption and the greater the heat of adsorption, the greater the amount adsorbed. Hagymassy Jr et al. (1969) divided the t-curve into two parts for the sake of determining the complete pore structure. For the small pores, the t value is used to determine the total small pore volume at low relative pressures up to 0.5. On the other hand, for large pores, the t value is used as a correction term over higher relative pressures between 0.4 to 1. These investigations, however, disregard hydrophobic substances as their surfaces repel water molecules and thus this method cannot be applied. Also, this technique provides satisfactory results solely for small pores. However, it is possible for water molecules to have adequate space to freeze in large pores. Hence, this causes expansion in the pore volume size which leads to less accurate results.

2.3. Nuclear Magnetic Resonance

Recent research has investigated the applicability of nuclear magnetic resonance (NMR) relaxometry measurements in estimating the pore size distribution. This method uses the relationship between the proton NMR signals to the T1 and T2 relaxation times which are influenced by the environment, and hence provide a characterization of the overall pore size distribution. Stingaciu et al. (2010) suggested that NMR relaxometry method represents a viable alternative to determine the pore size distribution by showing that the yielded results agree to the other common techniques. In addition, the method is considered advantageous as it is non-destructive and provides detailed analysis for many samples in a brief period. Furthermore, Lyu et al. (2018) developed a new method for determining the convention factor in the T2 NMR used for very tight nanopores in unconventional reservoirs. Nevertheless, one of the drawbacks of this method is that it is simplified, as many assumptions have been made such as homogeneous distribution of the paramagnetic centers. Such assumptions can lead to an overestimation of the large pores diameter, and thus the overall PSD results may be skewed.

2.4. X-ray computed tomography (XCT)

X-ray computed tomography (XCT) is a valuable technique for examining the micro-scale pore structure of natural and synthetic porous materials. Ping et al. (2012) have shown that high-resolution XCT images provide more accurate information on porosity and pore size, but have a limited field of view, whereas low-resolution images capture larger pores and a larger field of view, but tend to overestimate pore size and connectivity. Consequently, both high- and low-resolution XCT imaging can produce misleading results on the pore structure and fluid flow.

Therefore, it is important to choose an appropriate resolution based on the rock sample's pore size distribution and the research objectives to ensure both accuracy and representativeness. While XCT alone may not provide a complete pore size distribution, it can reveal pore structure details that are missed by MIP, a commonly used technique for pore structure characterization. MIP covers a wider range of pore sizes than XCT and can handle larger samples, making it a useful reference for evaluating XCT results.

2.5. Comparing and Contrasting PSD Measurement Techniques

The choice of PSD technique for nanopores vs macropores largely depends on the size of the pores and the frequency range of interest. For small nanopores, with sizes in the nanometer range, the signal-to-noise ratio (SNR) is often low, and the signal may be heavily influenced by noise and other factors (Knop et al., 2021). In such cases, absorption methods can provide a more accurate estimate of the PSD than the MIP and NMR.

The increased spectral resolution can help in accurately characterizing the pore size distribution of small nanopores. For larger or macropores, with sizes in the micrometer or larger range, the MIP or Welch method can be sufficient for PSD estimation. MIP provides a higher resolution for measuring PSD, especially in the smaller pore size range, while NMR has a lower resolution due to the limited number of data points that can be obtained. MIP provides information on both total porosity and pore size distribution, while NMR provides information on the effective porosity and the relaxation time of the fluids within the pores.

MIP can measure PSD over a wider range of pore sizes (typically from 0.003 to 100 microns) compared to NMR, which is limited to larger pores (> 10 microns). MIP requires the sample to be dried and vacuum-impregnated with mercury before measurement, which may alter the PSD. On the other hand, NMR requires the sample to be saturated with fluids to measure the PSD under in-situ conditions. MIP provides a high level of accuracy for measuring PSD, especially for smaller pore sizes. NMR is less accurate for smaller pore sizes but provides better accuracy for larger pores.

The choice of PSD technique may also be influenced by the characteristics of the rock type being analyzed. For example, rocks with vuggy porosity may require specialized techniques such as MIP, while rocks with intergranular porosity may be analyzed using standard PSD techniques such as the Welch method. Rocks with high levels of clay minerals, for example, may require specialized techniques such as nitrogen adsorption to accurately estimate the PSD. Organic matter can clog or occlude pores, which can make it difficult to accurately estimate the PSD. In such cases, it may be necessary to use specialized techniques such as nuclear magnetic resonance (NMR) spectroscopy to accurately estimate the PSD.

The choice of PSD technique depends on the specific properties of the pore size distribution being analyzed. Unimodal distributions can be analyzed with most PSD techniques, while bimodal and multimodal distributions may require more specialized techniques (Yao & Lui, 2017). However, the choice of technique should always be validated through experimental data and/or simulations. The accuracy of PSD techniques can depend on a variety of factors, including the type of technique used, the characteristics of the signal being analyzed, and the properties of the pore size distribution (Yao & Lui, 2017). However, in general, no single PSD technique is always more accurate than others. The choice of PSD technique depends on the specific properties of the sample being analyzed and the requirements of the application.

According to Knop et al. (2021), it is important to carefully consider the characteristics of the sample being analyzed and the requirements of the application when choosing a PSD technique. It may be useful to compare the results of multiple techniques on the same data to determine which technique provides the most accurate estimate of the PSD. Additionally, it may be necessary to perform experimental validation to confirm the accuracy of the chosen technique. Some techniques may be more accurate for narrow distributions, while others may be better suited for broad distributions (Yao & Lui, 2017). The accuracy of a technique may depend on the size scale of the pores being analyzed, as some techniques may perform better for small nanopores, while others may be more suitable for larger macropores (Knop et al., 2021).

Chapter 3

Permeability models in porous reservoirs

Permeability measures the ability of a rock to conduct fluids through it. Hence, it is essential in determining the overall flow capability and the amount of fluid that can flow in or out of a reservoir. The higher the permeability of a rock, the easier it is for fluids to flow through it. The SI unit of permeability is $m^2$and in the field unit it is expressed as Darcy. In most natural reservoirs, permeability varies widely with spatial position. Since it is a heterogenous and anisotropic property, determining the reservoir permeability is quite complex. Several factors significantly influence the permeability such as the grain size, grain shape, and pore size distribution. In recent years, there has been a growing interest in developing computational models to predict gas permeability in nanoporous shales. These models aim to better understand the behavior of shale formations and help in the exploration and production of shale gas. Due to the complex nature of nanoporous shales, traditional experimental methods are often limited in providing accurate and efficient permeability measurements. Therefore, researchers are turning to computational models to provide a more comprehensive understanding of the permeability behavior of shale formations. These models involve a combination of theoretical, empirical, and simulation-based approaches, and they often incorporate factors such as the rock's mineralogy, pore structure, and fluid properties.

3.1. Javadpour permeability model

Javadpour (2009) contended that Darcy's law, which has been widely adapted for determining permeability and flow in petroleum reservoirs, is not applicable to nanoscale pores in shales. The existence of the extremely small pores in some samples was detected using the atomic force microscopy. The contribution of Knudsen diffusion and slip flow makes the gas flow behavior deviate from Darcy flow. It has been demonstrated that Knudsen diffusion is significantly effective in the nanopores, however, the effect is negligible in larger pores. A new term was introduced as apparent permeability that includes the permeability dependence to the gas type, temperature, and pressure. The results show that the ratio of the apparent permeability to Darcy significantly increases for pores in the range of less than 100nm radii. Thus, this explains the underestimation of Darcy permeability to the gas production in these nanopores shales.

3.2. Civan permeability model

Further improvement to the Javadpour model was made by Civan (2010). Most permeability models imagine the pores as channels, where fluid flows directly in a straight line. However, this is not the case in a rock, where flow is more tortuous. With gases, the fluid is not flowing efficiently because it must turn around and cause a larger pressure difference. Tortuosity is the difference between straight capillary tube and a bendy one. Civan (2010) model suggests that the nanopore medium consists of a bundle of tortuous capillary tubes and provides a definition of the pore's tortuosity. In addition, it thoroughly analyzes the effect each of the apparent gas permeability, rarefaction coefficient, and Klinkenberg gas slippage factor on gas permeation through the media by presenting improved correlations for each individually. On grain surfaces, gases exhibit a certain velocity, and this causes an additional flux leading to greater permeability for gases than liquids. The Klingenberg equation states that the gas permeability is equal to the liquid permeability times the correction coefficient. As the mean flow path increases and the radius decreases, this means we have slippage factor and thus a large correction for the liquid permeability measurement.

3.3 Darabi permeability model

Darabi (2012) proposed an improved permeability model to describe gas flow in tight pores. The apparent permeability function APF is based on Knudsen diffusion and the slippage effect as well as including all the other essential parameters that were ignored by Javadpour (2009) and Civan (2010) such as surface roughness. The determination of the flow regime based on the Knudsen number is explained. For a Knudsen number between 0 - 0.001, it is a Darcy flow in which pressure gradient is needed across the interface for the fluid to flow from higher pressure to lower pressure. Whereas a Knudsen number of 10 and higher, it is a free molecular flow. In free molecular flow, the flow path is so small that it is almost hard to say there is a pressure effect. Hence, Knudsen flow is based on the difference in concentration purely and molecules move to the direction of lower concentration. The findings show that there is underestimation in the gas flow rate using the previous permeability model compared to APF. Also, it is confirmed that the actual gas flow in these nanopores is faster than the flow predicted by Darcy's equation due to molecular diffusion and pressure gradient. Regarding Knudsen diffusion, it is reported that it contributes to about 20% of the gas flow rate, which emphasizes the importance of this mechanism.

3.4. Sakhaee-Pour permeability model

Sakhaee-Pour (2012) investigated the interaction of gas with the shale through the observation of the effect of both adsorbed layers and gas slippage on gas permeability. When a highly absorbed gas such as CH_4 and CO_2 gets adsorbed on the outer ring of an ultra-tight pore, it reduces the area available for flow. The reason such gases get adsorbed is because they have differences in the charge between the positive and negative side which create polarity. Subsequently, a polar molecule interacts with the charged surface and gets attached to it reducing the pore throat radius and thus impacts the permeability. The results suggests that as pressure decreases, the effect of adsorbed layer decreases and the slip effect increases resulting to greater gas permeability as production continues.

3.5. Applicability of permeability models

There are some points that need to be addressed in terms of the applicability of the discussed permeability model. In Javadpour (2009)'s model, the area at which the magnitude of the permeability significantly changes are when pore size is smaller than 10 nm. Most measurement techniques can only go down to about 2µm, so we cannot confidently measure a pore size this small and verify the results. More importantly, it is exceedingly rare to have a shale that only has pores in the order of 1nm. Usually, rocks exhibit a bimodal distribution of pore sizes, where the larger pores are the dominant contributor to the flow and to the permeability measurement. Hence, the nanopores will be measured only if these larger pores did not exist. Also, the presented apparent permeability equation is not expressed in the unit of m^2meaning it is not measuring permeability but something else. A drawback of Civan (2012) model is that it doesn't provide a single equation that combines all the major observations to calculate the permeability. In addition, some parameters that appear in the equations need to be first found experimentally, which adds complexity. The major defect of Darabi (2012) model is that APF is based on pressure gradient while in Knudsen diffusion the pressure impact begins to break down as we have a handful of molecules in small space and thus the flow is purely driven by the difference in concentration. The main strength of Civan (2010) and Sakhaee-Pour (2012) models is that they consider adsorption in shales, which affects the flow through that particular pore and thus impacts permeability measurement.

Chapter 4

Relating PSD to permeability

Rocks with similar properties such as void ratio and porosity may exhibit variation in the pore spaces and, consequently, the conductivity of fluids differs. It is worth noting that porosity-permeability relationships are a well-established concept in the literature, and they have been extensively studied in the context of various geological formations. The porosity of a rock refers to the percentage of the rock's volume that is comprised of void space, while permeability refers to the ability of fluids to flow through the rock's pore spaces. The relationship between porosity and permeability is often used to estimate the flow capacity of subsurface formations, and it is commonly assumed that a higher porosity corresponds to a higher permeability. However, it is important to distinguish between porosity-permeability relationships and PSD-permeability relationships, which is the focus of this thesis. PSD provides a more detailed characterization of the size and distribution of pore spaces within a rock, and its relationship with permeability is not as well-known or established in the literature.

A relationship between PSD and permeability exists, and it is crucial to account for it; however, it is an extremely complicated one. There is no obvious or general relationship can be used universally to accurately predict the permeability of a rock or reservoir based on its PSD. Generally, the actual permeability of any rock is the summation of permeability through each individual pore. In a rock, we have thousands of pores that each is contributing to the flow by some amount and the total measured permeability is as a result of each of those addition to flow. Researchers made only a few attempts to build a model that predicts the total permeability at certain circumstances. This chapter provides a comprehensive review of this important research relating PSD to permeability, and the relevance of different techniques to different applications or reservoirs.

4.1. Empirical PSD-permeability relationships

Juang (1986) explains how pore size distribution relates to permeability. The collected pore size distribution data of the studied samples determined by mercury intrusion porosimetry method were presented in the density function vs the pore diameter graph. The density function is the bell curve for the pore diameter of a given sample. Most rocks are log-normal and bimodal distribution meaning that there are two pore diameter values that tie for having the highest frequency. To predict the permeability, a PSD-based model with double integral summing the area of under the density function curve. In other words, how much a given pore diameter over two dimensions is contributing to the actual permeability of the sample. The equation used to predict permeability is the following:

$$k = \frac{\gamma n^2}{32\,\mu} \int_0^\infty \int_0^\infty \tilde{x}\; G\left(x_j\right) f(x_i)\, f(x_j)\, dx_i dx_j \tag{1}$$

Although the proposed permeability model seems to be a highly effective means of predicting permeability, this study was only tested on soils and not rocks means that its applicability to rocks cannot be assumed or guaranteed. Further testing would be required to determine its effectiveness for predicting permeability in rocks.

Similarly, Marshall (1958) developed an equation to establish the correlation between permeability and pore size distribution in materials that exhibit isotropic behavior. The permeability is calculated using the following equation:

$$K = \epsilon^2 n^{-2} [\, r_1^2 + 3r_2^2 + 5r_3^2 + \cdots + (2n-1) r_n^2]/8 \tag{2}$$

The represented equation is based on capillary flow as if the fluid is flowing in straight lines. It also considers continuous summation instead of a district one. The predication of permeability uses the radius of each pore squared. This implies that the small pores don't contribute that much to permeability even though there is this molecular diffusion. Whereases, pores with three orders of magnitude larger are the dominant contributors. Hence, the total permeability will be equal to the larger pores' component only because the small pores are too small to be considered. In addition, the squared terms render the difference of the two different PSDs even further apart from each other. In terms of limitation, the validity of the equation was assessed by comparing the permeabilities derived from it with the actual measurements obtained from sands and porous stones. It should be noted that the equation's suitability has not been tested for rocks, and it is primarily applicable to isotropic materials that do not contain extended conducting pathways. Also, to use the equation, it is crucial to obtain a precise measurement of the pore size distribution, which comes with its own challenges as described in Chapter 2.

4.2. Evaluating PSD-permeability relationships from experimental datasets

The pore structure of deeply buried sandstone reservoirs plays a crucial role in controlling their permeability. Qiao et al (2020) identifies the importance of pore structure in controlling the permeability of deeply buried sandstone reservoirs. The study specifically focuses on how pore structure controls the permeability of these reservoirs. Qiao et al (2020) used a combination of laboratory experiments and computer simulations to study the pore structure and permeability of sandstone samples from the Junggar Basin. They found that the pore structure of the sandstone samples was complex, with a range of pore sizes and shapes (Qiao et al. 2020). The authors observed that the larger pores in the sandstone samples tended to be connected, forming interconnected pore networks that allowed fluids to flow through the sample more easily.

According to Qiao et al., (2020), porosity is not the only factor controlling permeability: Although porosity is an important factor in determining permeability, it is not the only factor. The article states that "the heterogeneity and connectivity of the pore space also have significant impacts on permeability" (Qiao et al., 2020). The article also notes that pore throat size distribution is important and that size distribution of the pore throats is a critical factor that controls permeability. Qiao et al. (2020) also found that the size and connectivity of the pore networks were key factors in determining the permeability of the sandstone samples. Samples with larger and more interconnected pore networks had higher permeability than samples with smaller and less connected pore networks. Qiao et al., (2020) identify the significance of pore structure in controlling the permeability of deeply buried sandstone reservoirs and provide insights into the intricate correlation between pore structure and fluid flow in these reservoirs. Qiao et al., (2020) suggest that a range of pore structure factors can impact the permeability of deeply buried sandstone reservoirs and that a comprehensive understanding of these factors is necessary for the effective exploration and exploitation of such reservoirs

In another study, Xi et al. observed that pore throat size plays an important role in controlling the reservoir quality and oiliness of tight sandstones. Pore throat size has a dramatic effect on porosity. In tight sandstones, Xi et al., (2016) identified that the porosity is typically low due to the small size of the pores. However, the size of the pore throats can influence the connectivity between the pores, which affects the overall porosity (Xi et al. 2016). When the pore throats are too small, the pores may not be connected, resulting in low porosity and poor reservoir quality.

The study also observed that pore throat size affects permeability. As previously mentioned, permeability is a measure of how easily fluids can flow through a rock (Xi et al. 2016). In tight sandstones, the permeability is typically low due to the small size of the pores. However, the size of the pore throats can also affect permeability. When the pore throats are too small, fluids may not be able to flow through the rock, resulting in low permeability and poor reservoir quality (Xi et al. 2016). Pore-throat size also affects fluid retention. According to Xi et al., (2016), the size of the pore throats can also affect the ability of the rock to retain fluids such as oil and gas. When the pore throats are too small, fluids may become trapped within the rock, resulting in higher oiliness (Xi et al. 2016). Further, the study identified that the mineralogy of the rock can affect the size of the pore throats. In tight sandstones, minerals such as clay can block the pore throats, resulting in lower permeability and poor reservoir quality.

In the context of heterogeneous mineral dissolution and precipitation, Steinwinder & Beckingham (2019) identify that pore and pore throat distributions are vital in regulating permeability. The pore and pore throat size distributions control the connectivity between the pores, which determines the permeability of the rock. According to Steinwinder & Beckingham (2019), the dissolution or precipitation of minerals can induce alterations in the pore and pore-throat size distributions in heterogeneous mineral dissolution and precipitation settings. For example, the dissolution of minerals can lead to the formation of larger pores and throats, which can increase the permeability of the rock.

The mineralogy of the rock plays a critical role in controlling the rate and extent of mineral dissolution and precipitation. Some minerals are more soluble than others, and their dissolution can lead to the formation of larger pores and throats (Steinwinder & Beckingham, 2019). Other minerals can precipitate and clog the pores, leading to a decrease in permeability. Additionally, the rate and direction of fluid flow through the rock can also influence the dissolution and precipitation of minerals (Steinwinder & Beckingham, 2019). High fluid velocities can increase the rate of mineral dissolution, leading to the formation of larger pores and throats. However, high velocities can also lead to erosion and removal of dissolved minerals, leading to a decrease in permeability. In situations where minerals dissolve and precipitate, Steinwinder & Beckingham (2019) identify that the heterogeneity of the rock can be a key factor in regulating permeability. Local variations in mineralogy, pore and pore throat size distributions, and fluid flow can lead to variations in permeability. For example, regions with higher mineral solubility may have higher permeability because the rock matrix dissolves more easily, leading to larger pores and throat sizes.

In a porous medium, permeability and porosity are two crucial factors that regulate fluid flow. While porosity measures the void space in a rock or soil, permeability measures how easily fluids can flow through the rock or soil (Hommel et al., 2018). The correlation between porosity and permeability is intricate and depends on various factors such as pore size distribution (PSD), mineralogy, and fluid properties. Empirical relationships between porosity and permeability have been widely used to estimate permeability based on porosity measurements (Hommel et al., 2018). These relationships are often developed based on a statistical analysis of large datasets of porosity and permeability measurements.

Hommel et al. (2018) discuss the relationship between porosity and permeability in porous media that have been altered by (bio-)geochemical processes. The study highlights that the relationship between porosity and permeability is not fixed and can change as a result of various processes, such as mineral dissolution, precipitation, and microbial activity. These processes can alter the pore size distribution and connectivity, which in turn affects permeability. The study notes that the impact of these processes on porosity and permeability can vary depending on the mineralogy, fluid properties, and other environmental factors.

Porosity alone may not be a reliable predictor of permeability as it does not account for the distribution of pore sizes in the rock. On the other hand, PSD provides more detailed information about the distribution of pore sizes in the rock, which can have a significant impact on permeability (Hommel et al., 2018). However, developing PSD-permeability relationships can be more challenging and requires more detailed measurements of the pore size distribution, such as mercury intrusion porosimetry or nuclear magnetic resonance (NMR) measurements. One reason for the lack of PSD-permeability relationships is that measuring PSD can be more complex and time-consuming than measuring porosity (Hommel et al., 2018). Additionally, PSD can vary significantly within a rock, making it difficult to develop a simple relationship between PSD and permeability (Hommel et al., 2018). Furthermore, the impact of PSD on permeability can be different depending on the mineralogy and fluid properties, making it more challenging to develop a general PSD-permeability relationship.

Chapter 5

Conclusion and Recommendations

In conclusion, pore size, pore structure, and pore size distribution (PSD) are primary controls on permeability in porous media. A range of pore structure factors can impact the permeability of deeply buried sandstone reservoirs, and a comprehensive understanding of these factors is necessary for the effective exploration and exploitation of such reservoirs. Understanding the mineralogy, fluid flow, and heterogeneity of the rock can help predict the permeability changes that may occur in these scenarios, and aid in the prediction of fluid flow behavior in subsurface reservoirs. In the context of heterogeneous mineral dissolution and precipitation, the importance of pore and pore-throat distributions in regulating permeability is critical. The pore and pore-throat size distributions control the connectivity between the pores, which determines the permeability of the rock.

Improving our understanding of PSD-*k* relationships in different reservoirs of interest can be challenging and requires a multidisciplinary approach. Some of the approaches that can be used to improve the understanding of PSD-*k* relationships include accurate measurement of PSD, using carefully designed samples, experimental work, numerical modeling, and collaboration. Accurate measurement of PSD is essential for understanding the relationship between PSD and permeability. The sampling strategy should be carefully designed to capture the spatial variability of the PSD within the reservoir.

Sampling should be done at different depths, locations, and lithologies to capture the heterogeneity of the reservoir. Additionally, numerical modeling can be used to simulate fluid flow in porous media and investigate the impact of PSD on permeability. This can involve the development of new models that can capture the complexity of the PSD-*k* relationships and incorporate the impact of mineralogical and fluid properties. Finally, a collaboration between geologists, geochemists, petrophysicists, and reservoir engineers can help to bring together different perspectives and expertise to improve our understanding of PSD-*k* relationships that prevail in different reservoirs.

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ACADEMIC VITA

NOORAH ABDULLAH AL MULHIM
Naa5461@psu.edu

Education

THE PENNSYLVANIA STATE UNIVERSITY | ANTICIPATED GRADUATION MAY 2023

- Major: Petroleum and Natural Gas Engineering, B.S.
- Honors: The President's Freshman Award, The Evan Pugh Scholar Junior Award, College of EMS Merit Award 2021-2022 & 2022-2023, Raja V. and Geetha V. Ramani Honors Scholarship.

Skills & Abilities

QUALIFICATIONS

- Known for attention to detail.
- Team building and enjoy collaborative work.
- Ability to work well under pressure and adapt easily.
- A genuine desire to achieve, outshine and evolve.

TECHNICAL SKILLS

- Proficient with: Excel, Mathematica, MATLAB, and C++.
- Fluent in: Arabic and English.

Extracurricular

JHON HOPKINS ARAMCO HEALTHCARE| MUBARRAZ, SA | MAY 2021-PRESENT
Covid-19 Testing Center

- Provided the facility with guidance for the precautionary measures to take.
- Organized patients' schedules by creating an excel database.

THE PENNSYLVANIA STATE UNIVERSITY| UNIVERSITY PARK, PA | AUGUST 2020-PRESENT
Aramco Student Association, member

- Developed schedules and list of responsibilities for other members.
- Engaged and worked collaboratively in activities.

Experience

SAUDI ARAMCO OIL COMPANY | DHAHRAN, SA | MAY 2020-JUNE 2020
Summer internship

- Intensive training course about the knowledge and skills required for petroleum engineers.
- Assigned in a workshop to learn about the oil extraction process.
- Worked closely with some senior engineers and gained knowledge and experience in reservoir engineering.