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Reservoir Characterisation by Using Flow Units Technique: A Case Study.

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Abstract
For a successful reservoir engineering management, it is essential to have an effective description and characterization of the hydrocarbon reservoirs as well as a sufficient petrophysical data. There are different reservoir characterizations techniques and that depends on complexity and type of reservoirs. The integration of sufficient core analysis data is the primary the primary target of reservoir description to permit identification of zones with similar fluid-flow characteristics. This paper presents a practical application of the flow units' technique to a classic North Sea reservoir using a statistical analysis for the flow zone indicator to differentiate flow units. In this paper the application of this technique is discussed to examine how a better reservoir description can be achieved for a specific reservoir. This article describes a new attempt to apply this technique to a North Sea reservoir. The technique takes account of the wide variety of petrophysical characteristics present comparing with others. The general porosity-permeability cross plot shows a large scatter, indicating poor overall correlation between porosity and permeability. However, by using flow unit technique a reasonable relationship between porosity and permeability can be shown to exist for each individual flow unit. The flow unit technique provides a comprehensive reservoir description. Six flow units are defined; three of these exhibits good-to-excellent reservoir quality, one is good reservoir quality and two are poor reservoir quality.

Keywords: porosity, permeability, reservoir, characterization.

1. Introduction

Accurate reservoir characterization is a key step in developing, monitoring, and managing a reservoir and optimizing production. To achieve accuracy and to ensure that all the information available at any given time is incorporated in the reservoir model, reservoir characterization must be dynamic [1]. One of the most important challenge of geoscientists and engineers is to improve reservoir description techniques. It is well recognised that improvement in reservoir description will reduce the quantity of hydrocarbons left behind in the reservoir [2]. Core analysis provides a varied menu of laboratory data for reservoir description and produces to aid understanding reservoir anatomy[2]. Reservoir description can be defined as result of efforts aimed at discretizing the reservoir into subunits, such as layers and grid blocks and assigning appropriate values of all pertinent physical properties to these subunits. Keelan [3] presented a treatise on core data usage as an aid for reservoir description. Flow units are related to geological facies distribution, but do not necessarily coincide with facies boundaries [4].

Flow Unit Technique

Geological information is essential for the model development by simulators, which is difficult and expensive to obtain in practice. In addition, the simulation for complex reservoirs is pretty time-consuming, usually taking several hours or even days [5,6,7].

A flow unit or Hydraulic unit (HU) is a zone that is continuous over a defined volume of the reservoir, and assembly uniform flow properties and bedding characteristics. Delineation and mapping of flow units is based on consideration of reservoir stratigraphy and vertical/lateral variation of permeability [3,8]. A flow unit can be viewed as a representative elementary volume of the total reservoir rocks [9] within which geological and petrological properties that affect fluid flow are internally consistent and significantly different from the properties of other rocks volumes [2]. A flow unit provides a basis for determination of net pay, and the thickness of reservoir which makes the greatest contribution to the flow of injected and produced fluids. Flow units are often identified by (a) geological attributes of texture, mineralogy, sedimentary structure, bedding contacts and nature of permeability barriers and by b) petrophysical properties of porosity, permeability, and capillary pressure. Identification of flow units therefore requires an integrated core analysis program. The route to flow units used in this study is presented by the following steps [2]:

- Collection of all data; permeability, porosity, depth, grain density, etc.
- Calculation of reservoir quality Index (RQI), porosity index ($Ø_z$) and flow zone indicator (FZI) from all porosity and permeability data and differentiation of flow units by statistical analysis of flow zone indicator values.
- Selection of some samples from each flow unit for further analysis, to include pore throat size characterisation.
- Determination of mercury injection capillary pressure curves on samples from each flow unit.
- The pore throat size distribution calculation.

Presentation of complete description of each flow unit, characterized by porosity, permeability, capillary pressure, and pore throat size distribution. A method of characterisation of flow units has been developed by Amaefule et al. In this method, porosity and permeability values are used to determine a reservoir quality index (RQI) and a porosity index ($Ø_z$). These variables are used to determine a value of the flow zone indicator (FZI).

Reservoir Quality Index:

Hydrocarbons reservoir quality primarily controlled by two properties: porosity (storage capacity) and permeability (flow capacity). In porous media, the mean flow radius determined from porosity and permeability provides a comparative estimate of the mean pore throat size available for fluid flow. A reservoir quality index can be derived from the Darcy and Poiseuille equations with the Kozney-Carman equation. The reservoir quality index is a close approximation to the mean flow (pore throat) radius in a reservoir rock and is defined as follow:

From Kozeny-Carman equation:

$$(k/(Ø) = r_m^2 / 8\ \tau^2] \qquad (1)$$

$$r_m^2 = 8\tau^2 (k/Ø) \qquad (2)$$

The generalized form of Kozeny-Carman relation is given by the following equation [1]:

$k = [Ø^3/(1-Ø)^2]\ (1/F_s\ \tau^2\ S_{gv})$ (3)

Dividing both sides of the equation (3) by Ø, and taking the square root of both sides will yield:

$\sqrt{(k/Ø)} = Ø_z\ (1/\sqrt{F_s}\ \tau^2\ S_{gv})$ (4)

Where; k= permeability, μm^2.
$Ø_z = 1/(1-Ø)$, ratio of the pore volume-to-grain volume.
F_s= shape factor (=2 for circular cylinder)
S_{gv}= surface area per unit gran volume and τ = tortuosity
Mean hydraulic Unit, r_m can be related to S_{gv}; $S_{gv} = (1/r_m)\ Ø_z$, therefore equation (3) becomes;

$\sqrt{(k/Ø)} = r_m / \sqrt{F_s}\ \tau$. (5)

If the Unit of k in generalized Kozney-Carman equation is mD (mD = $9.869 \times 10^{-12} cm^2$) with the assumption the factor $\sqrt{F_s}$ equals 1, then reservoir Quality Index can be defined as;

$RQI\ (\mu m) = 0.0314 \sqrt{(k/Ø)}$ (6)

There have been more advanced theoretical and experimental studies recently; Nomura et al. [10] presented a modification of the Kozeny–Carman (KC) equation based on a semilog–sigmoid (SS) function of a soil particle size distribution (PSD) and Safari et al. [11] developed a porosity–permeability relationship for ellipsoidal grains [12].

Flow Zone Indicator

Statistical techniques based only on one variation in permeability have been used by many investigators [13] to zone the reservoir into layers. The problem is that these approaches ignored geological attributes that control reservoir zonation [14]. The flow zone Indicator (FZI) is a unique that incorporates the geological attributes of texture and mineralogy to discriminate the distinct pore geometrical facies (flow Units)[1]. It is given by:

$FZI = RQI / Ø_z$. (7)

$Ø_z = Ø/(1-Ø)$ (8)

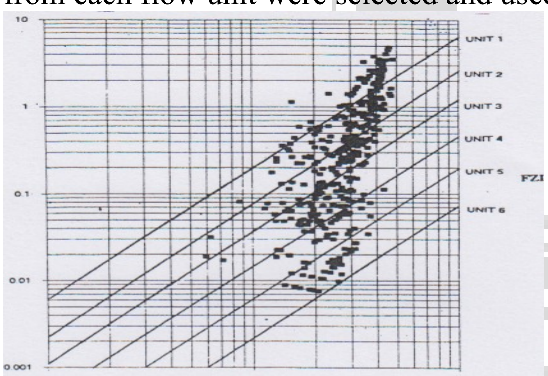
Where;
Ø = porosity, fraction
$Ø_z$ = porosity Index.

The FZI values for all samples are grouped by cluster analysis to produce zones of similar FZI value rocks which are defined as flow units. The Kozeny-Carman equation indicates that for any flow unit, a log-log plot of RQI, versus $\O_z$ should give a straight line with a slope line with $\O_z$ equal to 1, designated as the FZI, is a unique parameter for each flow unit. The reservoir quality index (RQI) and flow zone indicator (FZI) are related as follow:

$$\text{Log (RQI)} = \text{Log } (\O_z) + \log \text{(FZI)} \tag{9}$$

Characterization of flow Units

RQI and FZI were calculated by using equations 6 & 7 and a plot of RQI versus $\O_z$ was made to group flow units (Fig. 1) which shows possibility of existence of six flow units. Since it was found difficult to classify the data into groups, a statistical analysis for FZI was made by frequency against FZI (Fig 2&3). Six flow units have been grouped and their properties are shown in table (1). Samples from each flow unit were selected and used for further analysis.



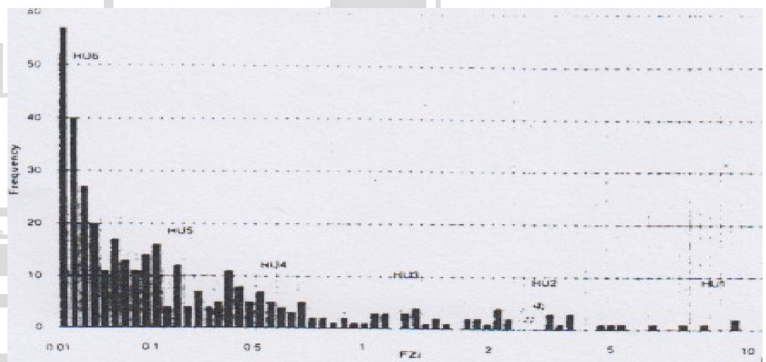


Fig 1. RQI vs. FZI **Fig. 2. Frequency versus FZI (interval=0.15)**

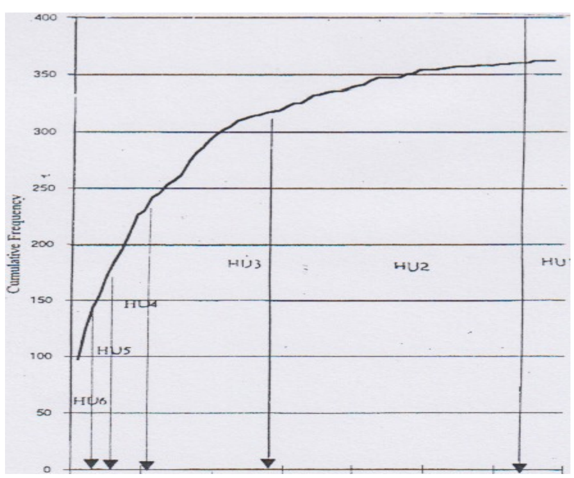


Fig. 3. FZI versus cumulative frequency

Table 1. Flow Unit Plug Data

Unit	Sample	Depth	Porosity	kh	GD	$Ø_z$	RQI	FZI
1	357	11726	30.3	2380	2.63	0.435	2.783	6.402
	261	11631	27.9	1810	2.63	0.387	2.529	6.536
	364	11733	25.2	1190	2.62	0.337	2.158	6.405
2	281	11651	32	582	2.65	0.471	1.339	2.846
	321	11690	23.1	196	2.66	0.300	0.915	3.045
	289	11659	27.4	483	2.65	0.377	1.318	3.493
3	547	11935	28.1	67	2.59	0.391	0.485	1.241
	279	11649	26.1	43	2.65	0.353	0.403	1.141
	424	11793	18.8	16	2.69	0.232	0.290	1.251
4	561	11949	23.5	5.6	2.68	0.307	0.153	0.499
	230	11435	18.2	2.6	2.71	0.222	0.119	0.533
	475	11863	16.8	1.6	2.71	0.202	0.097	0.480
5	306	11676	27.1	1.7	2.67	0.372	0.079	0.212
	270	11640	19.3	0.42	2.69	0.239	0.046	0.194
	388	11757	17.8	0.34	2.67	0.217	0.043	0.200
6	582	9987	22	0.09	2.7	0.282	0.020	0.071
	602	10007	19.6	0.06	2.7	0.244	0.017	0.071
	654	10059	18.9	0.05	2.69	0.233	0.016	0.069

Porosity-Permeability Relationship

It is generally recognised that there is no fundamental interdependence between porosity and permeability. A core specimen may possess strong capacity, but if sealed through the centre it may have no permeability [15]. The reverse situation of high permeability combined with a low porosity is also possible (e.g. where almost all porosity is confined to a single wide pore). Environmental and

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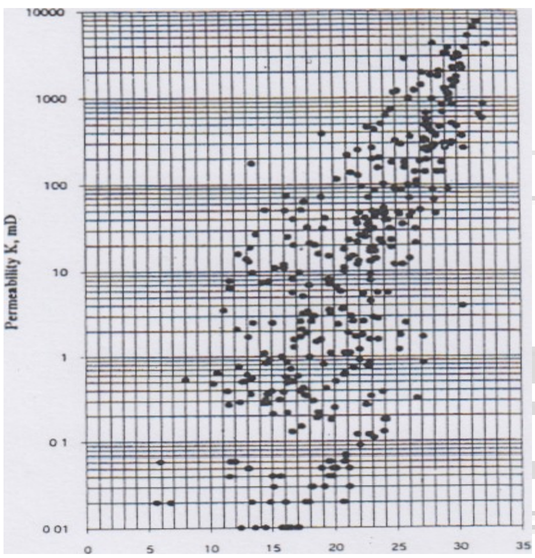
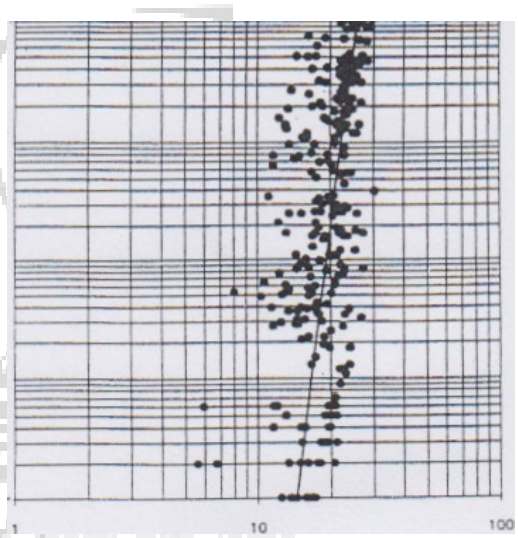
depositional factors influencing porosity and influencing permeability, and often there is relationship between the two. The relation varies with formation and rock type and reflects the variety of pore geometry present. Typically, increased permeability is accompanied by increased porosity. Constant permeability accompanied by increased porosity indicates the presence of more numerous but smaller pores [8]. Post depositional processes in sands including compaction and cementation result in a shift to the left of the permeability-porosity trend line. Dolomitization of limestone tends to the right. The typical permeability and porosity trends for various rock type have been presented by Keelan and Marchall [8]. A simple plot of k versus Ø has a little mathematical meaning. For the selected reservoir, the porosity and permeability data are plotted on both semi-log and log-log scales, as shown in figures 4 & 5. By using the flow unit technique, a well-defined relationship between porosity and permeability can be shown to exist for each individual flow unit (Fig 6). This figure shows the existence of distinct flow units as determined from a lot of RQI versus $Ø_z$ on log-log scale.



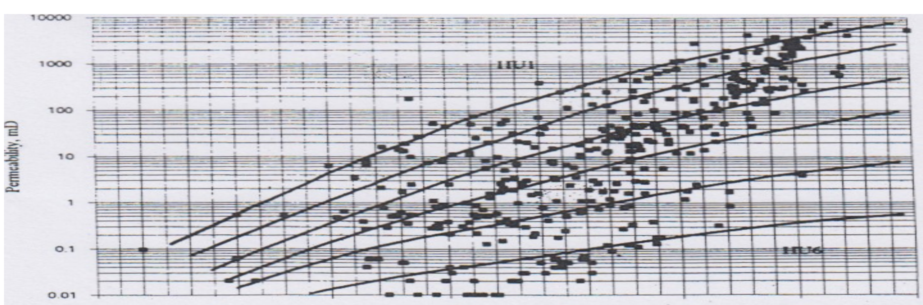


Porosity. %

Porosity, %

Figure 4. Porosity versus log permeability.

Figure 5. Log porosity versus log permeability.



Porosity, 7.

Figure 6. Cross plot of permeability versus porosity for different hydraulic units

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Experimental Procedure

All laboratory work was conducted using 1-inch cores. Core analysis porosity-permeability data from 410 core lugs was used to work out the porosity-permeability relationship using the flow unit's technique. After flow unit characterizations, six flow unit groups have been selected, and sample of each individual flow unit were selected for mercury injection analysis using injection pressure up to 50000 psi. Finally, the pore size distribution and mean flow radius were calculated.

Sample Preparation

From the cluster analysis, six flow units were distinguished for the reservoir. Eighteen samples were selected from these six flow units and were scheduled for mercury injection analysis. The fragments were trimmed down to 1.0'' diameter and 1.0'' in length to fit the autopore penetrometers. They were then fried in an oven overnight at 105^0C. The porosity and permeability for all samples were measured at reservoir stress condition in core laboratory by using core measurements system (CMS-300).

Mercury Injection Tests

The clean dry core samples were placed in the bulb of a penetrometer, then the sample and penetrometer were weighted together. The penetrometer containing the sample was loaded into the low-pressure chamber of the autopore II 9220 porosimeter and the penetrometer was evacuated to a pressure of 0.5 psia. The bulk volume of the sample was measured at this point. Then mercury was injected into the core plug at increasing incremental pressures from 0.5 to 25.0 psia. At each pressure point, mercury intrusion was monitored while the pressure held constant. Equilibrium was identified when the rate of intrusion dropped below 0.001 ml/g-sec. The pressure and the total volume for that point is determined by the use of a maximum intrusion volume of approximately 0.0142 of the sample pore volume. Whenever this volume of mercury has entered a pore, pressure is maintained constant, and the data is recorded. The injection pressure was reduced to atmospheric, and the penetrometer was removed and weighted with the sample and mercury in place. It was then loaded into the high-pressure chamber of the Autopore system. The cumulative volume of mercury injected was increased to a maximum of 5000 psia with data being recorded as already described.

Calculation of Mercury Injection Data

Grain density, bulk density and volumes of mercury injected for injection pressure were calculated from the sample weight data obtained. The cumulative mercury intrusion was then plotted against injection pressure. Initial intrusion at low pressure is the result of mercury conforming to the surface irregularities of the plug; these irregularities have been created during core lugging and are not representative of the core structure. The threshold pressure at which injection into the pore structure begins is identified by an increase in the gradient of this plot. Cumulative injection up to this injection pressure is subtracted as surface porosity from measured data before subsequent calculations are made. For higher permeability samples this threshold pressure cannot be easily identified since these samples have a high proportion of large pore throats, and therefore intrusion into the pore volume occurs at low pressure. Cumulative volumes of mercury injected are expressed as a fraction of the total volume of mercury injected at 50,000 psia and the pore throat radius (micron) is given by

$$r_i = 2\,\sigma_1 \cos\theta_1 / P_{ci} * C \qquad (10)$$

Where;

σ_1 = interfacial tension between air-mercury (=485 Dynes/cm)

Θ_1 = Contact angle between air and mercury measured in laboratory ($\cos\theta_1 = 0.766$)

Pc = Capillary Pressure, psia

C = constant (=0.145)

The mean radius is given by:

$$\bar{r}_i = (r_{i-1} + r_i) / 2 \qquad (11)$$

Using this relation, a graph of the fraction of pore volume injected versus pore throat radius can be constructed. The differential of this gives a pore size distribution (PSD).

$$PSD = dv / d\log(r) \qquad (12)$$

Where;

dv = change in mercury filled pore volume and, r = pore throat radius (μm)

Oil-brine capillary pressure data is obtained from air-mercury data by the following conversion:

$$Pc\,(o\text{-}b) = Pc\,(a\text{-}Hg) * (\sigma_2 \cos\theta_2 / \sigma_1 \cos\theta_1) \qquad (13)$$

Where;

Pc (o-b) = Oil-brine capillary pressure, psi, Pc (a-Hg) = air-mercury capillary pressure, psi.

σ_2 = Interfacial tension between oil and brine (=48 Dynes/cm)

Θ_2= Contact angle between oil and brine measured in laboratory ($\cos\theta_2$=0.866)

The mean flow radius, (Rmh) is a measure of the average of pore size of the sample and is given by;

$$Rmh = \left[\sum_{i=1}^{n} r_i * \triangle S_i\right]^{1/2} \qquad (14)$$

$$\triangle S_i = |\,S_{i+1} - S_{i-1}| \qquad (15)$$

S = mercury saturation, fraction.

The pore size distribution plots for each flow unit are shown in figures 7 to 12.

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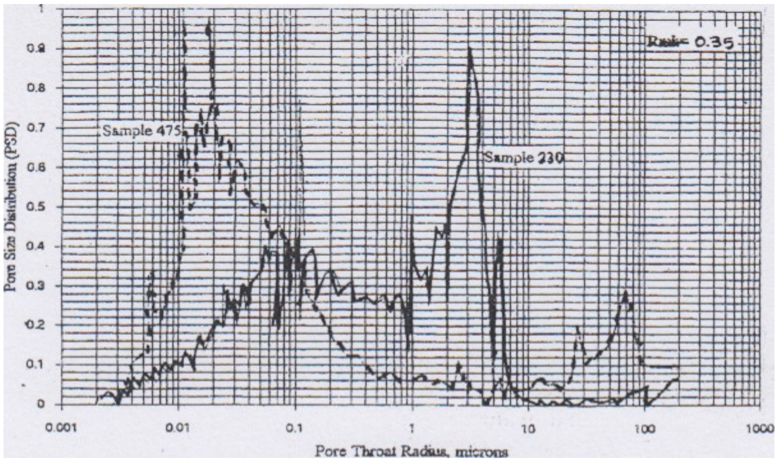

Figure 10. Pore throat size distribution plot for HU 4.

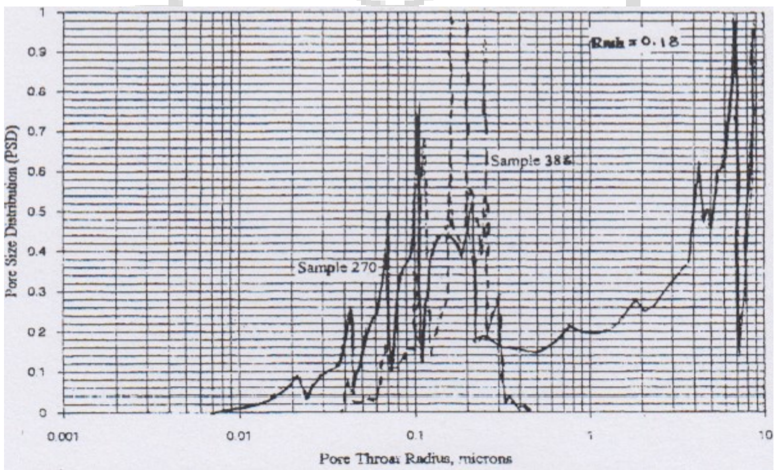

Figure II. Pore throat size distribution plot for HU 5.

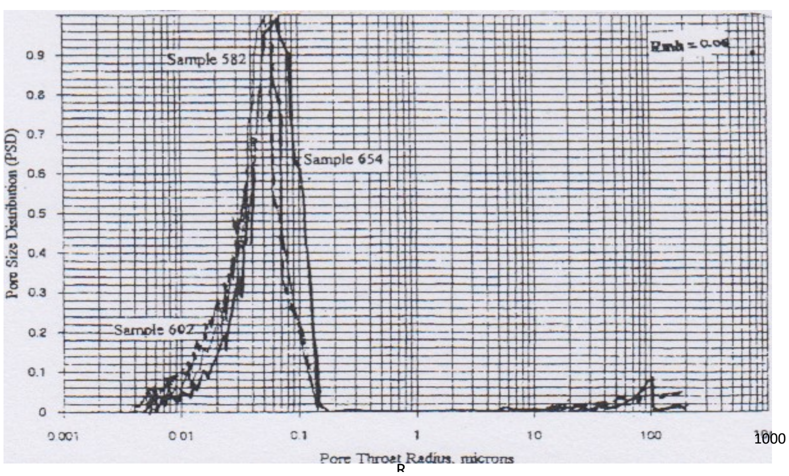

Figure 12. Pore throat size distribution plot for HU 6.

Discussions

The great challenge for engineers and geoscientists in achieving a successful reservoir development strategy is to improve reservoir description techniques by integrating all relevant data including core analysis, logs, well tests, seismic surveys, and available production history. Routine core analysis providing values of porosity, permeability, and residual fluids, together with specialised core analysis will be necessary. Comprehensive reservoir description is essential for the determination of storage capacity, prediction of reservoir performance, estimation of production rates and evaluation of ultimate recovery for various depletion strategies. Engineers have great difficulty in incorporating geological heterogeneity into their numerical models for simulating reservoir behaviour. The flow unit's technique is used to integrate geological and engineering data into a system for reservoir description [16]. The technique used to describe this selected North Sea reservoir was flow units' technique, based on identifying and characterising units having similar pore throat geometrical attributes (flow Units). This technique has a wide variety of practical filed application for both clastic and carbonate rocks. The essential advantage is that it improves prediction of permeability, allocates permeability values corresponding to the porosity value for each flow unit and provides a realistic relationship between porosity and permeability. By this technique, reservoir quality and formation damage can be forecasted, and this will be helpful to achieve suitable well completion (by selecting appropriate intervals for perforating, shooting, acidizing, etc.). On the other hand, there are many theoretical models which results in obtaining different values for petrophysical properties and parameters [17] for different types of reservoirs too [18].

Analysis of Experimental Results

The classic porosity-permeability cross plot (Ø versus log k) typically shows a large scatter and is not helpful in deriving a correlation between these properties. For example, at given porosity of 25%, permeability can vary from 1.2 to 1200 mD. Although a log-log graph appears to give better correlation than the semi-log plot, this can be misleading because it does not give the physical meaning of porosity-permeability values.

The quality of the reservoir for each unit is classified by Pore Size Distribution (PSD). Flow units 2 and 3 are high quality zones and the large peaking appears on PSD versus pore throat radius. The range of pore throat radii of flow unit 2 is less than 0.2µm for small peak between 1µm to 50µm for large peak but the range for unit 3 is 0.004µm to 0.2µm for small peak and from 0.2 μm to 30 μm for large peak. It has been identified flow unit 1 is a high-quality reservoir and its range of pore size distribution is between 0.01µm and 40µm.

The flow unit 5 and 6 are very tight rocks due to the low range of pore size distribution, the range for flow unit 6 is from 0.005µm to 1µm and flow unit 5 is 0.01µm to 10µm. These two flow units are low permeable zones. Flow unit 4 is identified as tight rocks with pore size distribution from 0.003µm to 35µm. It seems that two samples of flow unit 4 are not from same flow unit and is confirmed by FZI values which are the too close to each other. This could be because of the heterogeneity of the samples due to either barriers or clay reduce the permeability or shale presence, or due to measurements errors.

4. Conclusion

The Hydraulic unit's technique has been applied for different scenarios but in this study an attempt has been made to apply the technique to a North Sea reservoir. The technique is more complex than either the depositional or layer model but is also the most realistic because it incorporates the wide variety of the geological and petrophysical characteristics. The properties used to derive flow units in this reservoir were core porosity and permeability measurements for small, medium, and large pore-throat radii. The flow unit technique provides a comprehensive reservoir description. Six flow unit are defined; three of these (flow 1, 2 and 3) exhibit good-to-excellent reservoir quality, (one flow unit 4) is good reservoir quality, two (flow Units 5,7, and 6) are poor reservoir quality. It can be said that this technique has been applied successfully to this particular North Sea reservoir. The identification of flow units for this reservoir is made possible by reservoir quality index (RQI) and porosity Index ($Ø_z$) as well as by a statistical analysis of flow zone indicator (FZI). The flow unit technique can provide a better understanding of the porosity-permeability relationship. By using this technique, a reasonable relationship has been found between porosity and permeability for each individual flow unit that does indicate the physical meaning of porosity-permeability values. By pore size distribution the reservoir quality can be classified as high and low according to the pore radius ranges. Although this technique has advantage of helping reservoir engineers in their reservoir simulation, the reservoir management still need to make more effort to integrate geological and engineering viewpoints and work together as a team. Also, enough data should be available for this technique. It is important to include the electrical properties (Archie's parameters) which subsequently lead to more advanced flow unit technique application either of clastic or non-clastic formation. The difficulties in numerical modelling would be reduced by applying this technique and engineer can incorporate engineering data with other relevant data to produce reservoir zone model.

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