1. Introduction

Production of hydrocarbons in Pakistan is dominated by extraction from poor-quality reservoir rock1,2). Economical production from such reservoirs requires good understanding of the relationships between porosity, permeability, pore structure and other rock properties3). Reservoir permeability, porosity, and pore size are directly related to the fluid flow capacity, storage capacity, and reservoir performance, respectively4,5). In addition to porosity and permeability of the tight sand, pore structure is one of the main challenging areas in reservoir characterization, which depends on pore size, shape, volume, specific surface area and spatial distribution6).

Permeability in tight rocks including shale/mudstone is of typically several orders of magnitude lower than in coarse-grained lithology, such as siltstones and sandstones7-9). Permeability varies in the range from nanopores to megapores. Absolute permeability measured in various shales by different analytical methods generally falls into the nano Darcy range10,11). A common potential problem is that core samples for pulse decay measurement may include induced fractures that affect the measurements12).

A large number of methods including empirical equations and other low-cost and easily measurable parameters, such as permeability and porosity for quantifying pore sizes, have been introduced in the last decades. Winland’s empirical equation suggests that the highest statistical correlation that permits the calculation of pore-throat radius corresponds to the 35th percentile of the cumulative mercury saturation curve and is called \( r_{35} \). This parameter is interpreted as the point where the modal pore aperture occurs and the pore network becomes interconnected, and continuous fluid path through the sample is established13).

Winland’s empirical equation is used as a helpful evaluative technique and can be utilized as a somewhat arbitrary “net pay cut-off” point in evaluating a rese-
Reservoir rock is classified into five petrophysical categories based on the $r_{35}$ pore throat radius\textsuperscript{17}, which is the dominant control on the permeability and flow characteristics of the reservoirs.

1. **Pore throat radius $>10 \, \mu m$ is defined as 'Megaporous'**
2. **Pore throat radius $>2 \, \mu m$ and $<10 \, \mu m$ is defined as 'Macroporous'**
3. **Pore throat radius $>0.5 \, \mu m$ and $<2 \, \mu m$ is defined as 'Mesoporous'**
4. **Pore throat radius $>0.1 \, \mu m$ and $<0.5 \, \mu m$ is defined as 'Microporous'**
5. **Pore throat radius $<0.1 \, \mu m$ is defined as 'Nanoporous'**

The concept of hydraulic flow unit has been used extensively as a technique to predict reservoir rock properties with reliable accuracy. Amaefule et al.\textsuperscript{18} introduced the terms Flow Zone Indicator (FZI) and Reservoir Quality Index to characterize the hydraulic flow unit using the Kozeny-Carmen (K-C) model and predicted permeability in a reservoir interval with no exposure of the core data.

Hydraulic flow unit is a rather simple approach which is defined as a distinct interval of reservoir rock containing unique characteristics of rock properties such as porosity, permeability and pore geometry\textsuperscript{19}. Therefore, reservoir performance can be estimated by dividing the reservoir into various hydraulic flow unit, of which the key rock properties can be estimated with sufficient accuracy\textsuperscript{20}. According to Gunter et al.\textsuperscript{21}, that similarity in pore geometry is an indication of identical diagenetic processes occurring during deposition of rock.

The Cretaceous Lower Goru sandstones are extremely heterogeneous reservoir rocks located in the Middle Indus basin\textsuperscript{22} and are a main strategic reservoir in Pakistan with an ultimate recovery of more than 1 TCF (Trillion Cubic Feet). The Goru formation is divided into two parts based on the lithological features. The upper part of the Goru formation is sandstone whereas the lower part mainly consists of sandstone. The depositional environment of the upper part of the formation is generally considered to be of marine origin whereas the lower part was formed in deltaic environments. Sembar shale is the underlying layer to the Lower Goru sand\textsuperscript{23,24}. The Lower Goru sandstones have been frequently described and discussed\textsuperscript{1,23,25,26}. However, all previous studies were limited to determine the pore size distribution either for high porosity and permeability range or low porosity and permeability range in the reservoir rock.

The present study used a simple and cost-effective approach to predict pore size distribution in a complex heterogeneous reservoir (porosity 10 to 30 \% and permeability 0.01 to 1000 mD) based on routine core analysis data of 237 samples and geophysical well logs obtained from the Sawan-07, Sawan-02, and Sawan-3B wells in the Sawan field of the Middle Indus Basin of Pakistan (Fig. 1). All well logs required for this study were present in the studied wells. Sand-shale layers in the lower reservoir section of the Sawan-3B well caused successive increase and decrease of porosity in the well. The grain size of the studied sandstone is medium to coarse grain and relatively well sorted\textsuperscript{20}.

### 2. Characterization of Hydraulic Unit

Winland Dale from Amoco first proposed the empirical equation between porosity, permeability, and pore throat radius to obtain net pay cut-off from mercury invasion tests in clastic rocks which was unpublished, but was later released by Kolodzie\textsuperscript{27}:

$$
\log r_{35} = 0.732 + 0.588 \log K_{\text{air}} - 0.864 \log \phi
$$

The development of the Winland empirical equation\textsuperscript{16,28} identified a range of experimentally derived equations for the calculation of pore-throat radius corresponding to range from 10 to 75 \% of the cumulative mercury saturation curve in increments of 5 \%. The best correlation coefficient ($r$) was obtained by a multiple regression analysis for the equation of $r_{25}$, taking log $K$ as the dependent variable.

$$
\log r_{25} = 0.204 + 0.531 \log K_{\text{air}} - 0.350 \log \phi
$$

Where $r_{25}$ is the pore aperture radius corresponding to the 25th percentile of mercury saturation, $r_{35}$ is the pore aperture radius corresponding to the 35th percentile of mercury saturation.
mercury saturation, ‘$K_{air}$’ is the uncorrected air permeability (mD), and ‘$\phi$’ is porosity in percentage.

The concept of the mean hydraulic-unit radius is a significant approach to determine the hydraulic unit, based on appropriate relationships between capillary pressure, porosity, permeability, and geological variation in the reservoir rock\(^4\).

\[
0.0314 \frac{k}{\phi} = \frac{1}{\sqrt{f_z \tau S_{vgr}}} \frac{\phi}{(1 - \phi)}
\]  

(3)

Where $S_{vgr}$ is specific surface area per unit grain volume, $\phi$ is porosity, $f_z$ is shape factor and $\tau$ is tortuosity factor.

Equation (3) can be written as follows\(^{18,21}\):

\[
RQI = FZI \times f_z
\]  

(4)

Where ‘FZI (µm)’ represents the flow zone indicator, FZI is the only petrophysical property related to geological conditions based on mineral grain that is used to divide the reservoir interval into homogeneous subgroups. ‘$\phi_z$’ represents the normalized porosity and can be defined as:

\[
RQI = 0.0314 \frac{k}{\phi_z}
\]  

(5)

Where ‘RQI’ represent reservoir quality index, ‘$\phi_z$’ for core porosity, and ‘$k$’ for core permeability.

\[
\phi_z = \frac{\phi_z}{(1 - \phi_z)}
\]  

(6)

The value of FZI is given at the intercept of a unit-slope line with the coordinate $\phi_z = 1$, on a log-log plot of RQI versus $\phi_z$. Each value of FZI can be attributed to a single hydraulic flow unit (HFU).

The hydraulic flow unit is a part of hydrocarbon reservoir that is uniform in the horizontal and vertical directions and has similar static and dynamic characteristics. Each hydraulic flow unit has consistent pore geometry, i.e. pore size and distribution within the reservoir rock. Application of the hydraulic flow unit approach requires estimation of the porosity and permeability from well logs. The hybrid model developed by Ismail et al.\(^{29}\) was used as a source of permeability in the studied reservoir interval and the density log was used to calculate porosity. The permeability and porosity were used to estimate the reservoir quality index and normalized porosity. The calculated parameters were drawn on the log-log plot to identify the hydraulic flow unit in the studied interval on the basis of the well log analysis.

3. Material and Methods

More than 237 core samples were collected from the Lower Goru formation in the Sawan gas field, Pakistan. These samples were obtained from the Sawan-07, Sawan-02, and Sawan-3B wells. Thin section and scanning electron microscope (SEM) analyses were also available from the literature. The sandstone model composition was determined from all thin sections at 300 points per thin section\(^{26}\).

The facies analysis of these samples was achieved based on sedimentological core descriptions and wireline log data. Permeability measurements were performed in a Hassler type core holder with 400 psi confining stress. Porosity was estimated by injection of helium at 120 kPa pressure using a helium pycnometer, and the grain volume ($V_g$) and pore volumes of the samples were measured using the helium pycnometer.

On the basis of lithological variations, the Lower Goru formation is divided into the A, B, and C intervals\(^{25}\). The Lower Goru acts as a heterogeneous sandstone reservoir, so the porosity and permeability data can be divided into low permeable and high permeable zones to distinguish the pore size distribution by various approaches.

The reservoir rock volume was divided into hydraulic flow unit using the estimated reservoir quality parameters including reservoir quality index, normalized porosity and flow zone indicator Eqs. (2) and (3). These distinct hydraulic flow unit were then used to analyze the pore size distribution. The available thin section study was compared with the proposed hydraulic flow unit, and lateral and vertical distribution of the pore size geometry. The complete methodology and work flow of this study are described in Fig. 2.

4. Results and Discussion

The main detrital mineralogical components in the Goru formation are detrital quartz, mafic volcanic rock fragments (VRF), mica and feldspar (Fig. 3). The reservoir quality parts of the A and B intervals are clas-
sified as quartz arenites, whereas the C interval contains a significant amount of VRF.

The other important minerals are carbonate fragments, muscovite, strongly altered biotite, and chert. Tourmaline and zircon and some rutile occur as accessory minerals. Diagenetic components are quartz cement, chlorite cement, carbonates (mainly calcite and Fe-dolomite cement), and glauconite. The sandstones are characterized as medium to coarse-grained and moderately to well-sorted with differing degrees of compaction.

The core measured porosity values of the Lower Goru formation reveal low to excellent porosities, ranging from 6 to 30%. The permeability values range from 0.01 to 1252 mD (Table 1).

### 4.1. Routine Core Analysis

The measured porosity and permeability were used in the Winland and Pittman empirical equations to examine the pore size distribution and their reliability to the heterogeneous sandstones reservoir. In particular, both equations are based on uncorrected air permeabilities, whereas the use of corrected permeability values in the Winland equation would result in smaller values for smaller pore size than in the Pittman equation.

The mean values of pore sizes previously reported were greater than by the Winland method except in micro and nano pores. The result showed that mean pore throat sizes from the previous approach are 29.754, 5.567, 0.965, 0.2651, and 0.068 μm for mega, macro, meso, micro, and nano pores, respectively (Fig. 4).

To differentiate the reservoir interval into various pore sizes (megapores, mesopores, macro pores, micropores, and nanopores), the $r_{25}$ was plotted against porosity and permeability values (Fig. 5). The result
indicates that the data is well sorted and porosity and permeability have a strong relationship to distinguish the pore size distribution.

4.2. Hydraulic Flow Unit Classification

To identify the optimal number of hydraulic flow unit, the reservoir rock properties including RQI and normalized porosity are plotted against FZI (Fig. 5). Sampling data lying along the straight line correlation with unit slope have the same FZI and could be classified into six discrete rock types indicating six hydraulic flow unit as shown in Fig. 5. It is important to note that each of these hydraulic flow unit (HFU1, HFU2, HFU3, HFU4, HFU5, and HFU6) have unique pore geometry and bedding characteristics which result in consistent flow of fluid through the porous media. Gunter et al.\textsuperscript{21} stated that similarity in pore geometry is an indication of similar diagenetic processes during deposition of rock. Note that hydraulic flow unit with greater RQI and FZI values will behave like a better quality reservoir in terms of fluid flow through its pore spaces.

Based on the hydraulic flow unit and flow characteristics (porosity and permeability), the reservoir pore size can be classified into megapores (HFU5 and HFU6), macropores (HFU3 and HFU4), mesopores (HFU2 and HFU3), micropores (HFU1 and HFU2) and nanopores (HFU1) (Fig. 5 and Table 1).

In particular, HFU3 (mesopores), HFU2 (micropores) and HFU1 (nanopores) reflect heterogeneity in the reservoir interval with porosity range from 10 to 20 % and permeability of less than 10 mD. These hydraulic flow unit also have various types of pore distribution with lowest reservoir quality index and flow zone indicator. Therefore, permeability is directly related to pore sizes and pore throat radii. The selection of perforation interval should be designed on the basis of the identified hydraulic flow unit.

Comparing the obtained results from the predicted HFUs with the empirical equation Pittman\textsuperscript{15} indicate the reliability and accuracy of the proposed technique in the heterogeneous reservoir rock. Figure 6 confirms that the mega and macro pores in HFU4, HFU5, and HFU6 have pore sizes from 0 to 60 μm with a high percentage of pore distribution, indicating that such a flow unit will reflect better quality reservoir rock with high fluid flow through the pore spaces.
Mercury injection saturation increases with decreased pore size, but also depends on the pore size distribution. High mercury injection pressure is needed to inject the fluid into a more complex network.

Nine (9) hydraulic flow units were identified in the studied reservoir interval on the basis of well log analysis as shown in Fig. 7. HFU1, HFU2, and HFU3 consist of mainly macropores whereas HFU4, HFU5, HFU6, and HFU7 contain both macro and megapores. High disruption can be observed in HFU8 and HFU9 inferring the presence of a mixed type of pores with random flow potential due to the heterogeneity of the reservoir. Any regular trend of FZI is absent in HFU8 and HFU9. Flow potential of the hydraulic flow unit increases from HFU1 to HFU9. The hydraulic flow unit identified from well log analysis, i.e. HFU1, HFU2, HFU3, HFU4, HFU5, HFU6, HFU7 and HFU8, all overlap with the core analysis prediction. The results reveal that log prediction identified higher flow zone indicator values than core analysis data.

The estimated data points identifying the hydraulic flow unit on a log-log plot of normalized porosity and reservoir quality index revealed that lower region as well as upper region data points of core and well log data are not consistent with the hydraulic flow unit. The A and C areas in the plot illustrate those regions where the identified hydraulic flow unit are not consistent, i.e. identified as mega and nanopores. In contrast, the B area of the plot shows a region where the identified hydraulic flow unit agreed with the well log and core data prediction (Fig. 8).

4.3. Petrographic Image Analysis

Petrographic image analysis is a very useful technique that provides a method to separate connected from unconnected pores and to distinguish bulk mineralogy from reactive mineralogy as a function of pore size.

Obtained thin sections were analyzed to generate high-resolution binary images showing pore-space versus non-pore space using a laser scanning microscope (LSM 700) with imager Z2m (Zeiss). The pore and pore throat sizes were determined from these binary images at a scale of 250 μm on the same reservoir interval, and the results are compared with the proposed technique.

In general, the Lower Goru sandstones mainly consist of quartz arenite that shows advanced diagenetic alteration throughout the entire type section. The sandstones are medium to coarse-grained and moderately to well-sorted with differing degrees of compaction. The grain-size distribution with chlorite rims ranges from less than 0.06 to greater than 2 mm26).

The sample 3304.5 m (Fig. 9) is characterized by high amounts of Fe-chlorite and Fe-dolomite cementation and calcite cementation. The prevalent cement is quartz (Q), carbonate, and chlorite (Chlr), commonly with a patchy distribution. Secondary porosity formed because of dissolution of feldspar grains (Fsp) (Fig. 9) and VRF. Good porosity and permeability can be observed in the thin sections. In some locations, these components had been fully dissolved and only the chlorite rims covering the grains remain.

In a typical two-dimensional cross-section of the rock, four megapores (P1 = pore size/pore throat size = 77/14.5, P3 = 53/8.3, P4 = 37.5/10.41, P5 = 35.41/12) and one macropore (P2 = 19/12.5) are identified from the binary image at a scale of 250 μm (Fig. 9).
pores are marked in white color with a black background and the pore throat size and pore size are shown with red dots.

The sample 3407.2 m (Sawan-3B) contains quartz (Q) cements as both pore filling and as idiomorphic quartz outgrowths. Quartz overgrowths and outgrowths occur preferentially where chlorite rims covering detrital quartz grains are thin or discontinuous. The sample shows good porosity and pores are mostly interconnected which enhance the reservoir characteristics. Secondary porosity is also present due to dissolution and fracturing, which are also important in establishing the Goru formation as a good potential reservoir (Fig. 10).

The sample 3307.2 m demonstrates two macropores (P1 = pore size/pore throat size = 68.75/20.83 and P2 = 52.08/12.5) on the binary image at a scale of 250 μm (Fig. 10). The pores are marked in white color with a black background and the pore throat size and pore size are shown with red dots.

The pore size of a core sample of Sawan-3B indicated high pore throat size at recommended mercury saturation of 25 %, whereas a core sample from Sawan-2 showed relatively low pore throat size (Fig. 11). Similar characteristics of studied rock samples can be observed in Fig. 12, where the gamma ray response is relatively low for Sawan-3B core samples as compared to Sawan-2. In general, the low range of gamma ray response in the Sawan-3B well at the studied depth indicate better quality of reservoir rock in terms of porosity, permeability, and pore size.

4.4 Curve Matching Technique
In recent years, lithological information has been obtained from the well log response including pattern recognition and pattern classification. To increase the advantages of conventional well logs, the authors have incorporated the gamma-ray log response, HFU and thin section to analyze the lateral and vertical variations of pore structure geometry in nearby wells. A large deflection of gamma-ray log curve was observed in the Sawan-02 well compared to the Sawan-03 well at studied depths. The increase in the gamma ray response at 3304.5 m in the Sawan-02 well is due to the addition of clay mineralogy in the reservoir lithology, which can be seen in the thin section analysis, whereas the gamma ray response was low in the Sawan-3B well at 3407.2 m depth. Relatively clean sandstone was observed in the Sawan-3B well, which is evident from the thin section analysis, causing lower gamma-ray log readings. The porosity estimated from the well log analysis is low at the studied depth in the Sawan-2 well compared to the Sawan-3B well but the range of pore sizes is higher in the Sawan-02 well. The large grain sizes of the quartz in the Sawan-3B well resulted in this
lower pore size. The specific pattern of the log against the pore size estimations was observed for the identified hydraulic flow unit in the Sawan-07 well. Figure 12 shows that the log correlation in the Sawan-07, Sawan-02, and Sawan-3B (pattern recognition) wells combined with the hydraulic flow unit reflected the pore size distribution laterally and vertically.

The similar log pattern and background flow units (shown in a circle) indicate the same pore size classification that contributes most to the overall porosity and permeability. The attached thin section photos of each sample show the type of pore structure reflected by the hydraulic flow unit in nearby wells of the field.

The thin section in Sawan-3B corresponds to HFU4 and indicates macropores with pore throat size from 12.5 to 20.83 μm as shown in Fig. 12. The thin section of Sawan-02 corresponds to HFU6 and indicates megapores with pore throat size ranging from 8.3 to 14.5 μm and 4.16 to 31.25 μm, respectively. Therefore, integration of the proposed technique (HFU6) and mean pore throat size of 29.9 μm and 28.9 μm by Winland and Pittman, and petrographic image analysis can achieve verifiable and satisfactory results.

Use of hydraulic flow unit can provide satisfactory estimates of pore size, but cannot estimate pore-throat radius in the reservoir. In contrast, the Winland and Pittman equations provide poor estimation of mean pore size but can measure pore-throat radius. The identified pore sizes from thin sections and the hydraulic flow unit showed a strong relationship. Poor sorting of the grain size in the thin section of the Sawan-02 well resulted in multiple pore sizes in the reservoir section. Mega and macro pores were identified from the thin section whereas the hydraulic flow unit approach indicated macropores. The thin sections showed that grain size was relatively greater in the Sawan-3B well than in the Sawan-02. The pores identified from the hydraulic flow unit and thin sections had very good agreement because both techniques indicated macro pores. The sensitivity of the curve matching technique depends on the calculation of the parameters involved in identification of the hydraulic flow unit. The curve matching technique gives acceptable results if the properties calculated from well log incorporate adequate quality checks.

5. Conclusions

In this study, petrophysical parameters combined with thin section study were used to analyze the pore size distribution of the heterogeneous Lower Goru formation, Sawan gas field, Pakistan. The following conclusions can be drawn from the pore structure assessment of the Lower Goru formation:

1. Six hydraulic flow unit were identified in the reservoir interval based on similar rock properties. These discrete hydraulic flow unit contained unique pore geometry and were classified as megapores (HFU5 and HFU6), macropores (HFU3 and HFU4), mesopores (HFU2 and HFU3), micropores (HFU1 and HFU2) and nanopores (HFU1).

2. The proposed hydraulic flow unit were only dependent on the rock properties of a given reservoir and can be applied to any reservoir to divide the rock interval into various flow unit based on similar petrophysical properties. Furthermore, this approach can be applied to extend the relationship of pore size distribution in off-set wells.

3. The equations for \( r_{25} \) of Winland and Pittman were partially helpful because using the heterogeneous porosity and permeability values as independent variables in these equations yielded lower pore-throat radius and pore size distribution. However, the plots of calculated pore size distribution were consistent with the actual trends of the Winland and Pittman equations for high and low permeability values (0.01 to 1000 mD) and provided a better estima-
tion of the pore-throat radius.

(4) Thin section analysis is important to control the estimation of pore attributes from petrophysical techniques.

(5) Intelligent matching of log pattern recognition and classification using flow unit and photos of the thin sections can help to identify lateral and vertical variations of pore network geometry in nearby wells of the same reservoir interval.

(6) Integrating the different datasets obtained from the routine core analysis and well logs can be utilized to estimate reservoir quality including pore size distribution, porosity, and permeability to enhance the reservoir simulation, process evaluation, and forecast of reservoir behavior.

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