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Morphological and petrophysical evaluation of tight gas resources and energy production in Pakistan

Aftab Ahmed Mahesar [a,*], Ghazanfer Raza Abbasi [c], Abdul Majeed Shar [b], Muhammad Ali Shaikh [a]

[a] *Institute of Petroleum and Natural Gas, Mehran University of Engineering and Technology, Jamshoro, Sindh, Pakistan*

[b] *Department of Petroleum Engineering, NED University of Engineering and Technology, Karachi, Sindh, Pakistan*

[c] *Department of Petroleum Engineering, Edith Cowan University, Western Australia, Australia*

[*] Corresponding author: Aftab Ahmed Mahesar, Email: engr.aftabmahesar@gmail.com

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ABSTRACT

Tight gas is a highly potential source of energy that can meet the energy deficit in Pakistan. The production of gas from conventional gas reserves are continuously declining in a massive manner and increasing demand of hydrocarbons as an energy source is soaring at huge levels. Therefore, the energy deficit can only be met through tight gas unconventional sources of energy. Tight gas is a natural gas having very low permeability and marginable matrix porosity which extends diversely into the geological formations of Pakistan. That is the major reason of huge level of uncertainty for development of tight gas reservoirs. However, the production mechanism of tight gas reservoirs is too much difficult and complex as compared to conventional resources of hydrocarbons. Hence, the tight gas resources are equivocal and debatable regarding the sustainability and utilization. This paper provides a systematic study on the tight gas reservoirs through petro-physical evaluation of outcrop samples of tight rocks. In this regard, an experimental study is carried out on outcrops of tight gas near Chilton formation Indus basin trough and different techniques namely SEM (Scanning Electron Microscopy), AFM (Atomic Force Microscopy) have been employed to evaluate the permeability, porosity and fluid saturation. Furthermore, simulation studies on the core flooding in the close packed outcrop samples have been performed in order to estimate the permeability reduction caused by different phases.

1. Introduction

Pakistan's crude oil production is declining at great level; however, the demand of energy supply is increasing in a huge manner because of urbanization of population. Pakistan's current annual consumption of oil is 160 million barrels. During the year 2017-2018, oil consumption increased by 10% [1-2]. Oil imports increased by 9%. Natural gas production in Pakistan and utilization has remained at balanced position till 2018. However, the current soaring demand of gas has increased to 15% from 2017 to 2018 and that is the major source of energy. Presently the demand of gas in Pakistan is 9 billion cubic feet per day. Increasing demand of energy needs more exploration and novel discoveries are needed. However, the future of Pakistan is dependent upon the more undiscovered (unconventional resources) including tight and shale gas [3-6]. Hence gas is an important source in Pakistan. The natural gas is used in Pakistan for the last 100 years ago [7]. The first tight gas well was discovered in province of Sindh Pakistan in Kirthar fold belt near the premises of Jamshoro. The well produced 16 million cubic feet per day of natural gas near Sajawal gas field in Kirthar fold [8-9] belt Sindh. This was the major breakthrough in the history and sustainable development of unconventional resources of tight gas resources of Sindh. Sajawal gas field is located 60 km north of Jamshoro to Karachi which also has a remarkable feature bin the exclusive club of unconventional resources of natural gas in Sindh Pakistan. Sindh has witnessed a huge deposit of unconventional resources more than 110 TCF of shale and tight gas particularly 60 TCF of tight gas in the Indus basin. Several formations of unconventional resources such as lime stone, Habib Rahi, Goru, Pirkoh, Nari, Pab Sandstone, carbonate, siltstone, Sembar and Gazij possess enormous amount of tight and shale gas are also witnessed in the Indus basin [10-14].

Tight gas is a natural gas (methane) having less than or equal to 0.1mD and below 10% matrix porosity [12]. Due to low permeability and porosity it is considered as less effective [13, 14] and economical because these rocks have no capacity to flow with in porous medium through interconnected pore spaces. This is the major reason why unconventional resources are important. Tight gas is almost trapped in impermeable hard rock's such as sandstone and limestone formations. These formations are considered as low permeable and having tight thin effective thickness of single or multi-layered distribution [15]. For commercial production of unconventional resources of gas, tight gas must be hydraulically fractured (fracked). Drilling, well design, completion method and hydraulic fracturing are the fracking techniques [16-17] which are same to some extent but there is a difference in formation evaluation, reservoir analysis and production mechanism. The fundamental parts of tight gas construction sand well include rotary drilling of a well bore ultimately completed with a hydraulic fracturing stimulation job. The most current technique is hydraulic fracturing [18] or fracking which was initially introduced by USA and it has resulted in increase of tight gas formation at reduced gas price. Tight gas potential was confirmed through successful drilling by multi fracking at Indus basin of Sindh. For successful ratio of tight gas resources effective horizontal and multistage fracking technology are important. Several studies have been made on the morphological and petro-physical evaluation of rock samples. Bera et al. [19] measured the nanoscale porosity in reservoir carbonate rock using focussed ion beam-Scanning Electron microscopy (FIB- SEM). This technique established the existence of nanoscale pores (50-300m) inside the solid dolomite matrix. Their results also established the degree of connectivity of these pores with microscale pores of size 2-5 μm. Al-Bazzaz et al. [20] have studied the pre grain morphology of rock fragments from Maud dud Burgsin carbonate reservoirs by SEM and analysed its porosity and permeability by using a petrographic image. Lin et al. [21] has proposed a novel experimental methodology which employed differential imaging and high salinity contrast brine attained by X-ray tomography to acquire three dimensionally spatially resolved information on connectivity and porosity of two rock samples. The authors found that the total porosity values achieved from the three-phase segmentation for two carbonate rock samples were found to have good agreement with helium porosity measurements. Majeed et al. [9] have conducted permeability tests and SEM characterisation on tight gas samples procured from Kirthar fold belt. They found that core damage in samples was related to higher stress permeability. Ostensen [22] observed that the permeability of tight gas sandstone cores was due to micro cracks and have also devised a model based on flow through micro cracks. The model was used to correlate the permeability/stress curve in tight gas sandstone. On the other hand, the porosity of tight sand cores decreased linearly with the logarithm of net confining stress, in agreement with the Walsh-Grosenbaugh model of crack compressibility.

There isn't much literature information available on the morphological characterisation, and petrophysical properties of tight gas samples. Hence, in the present study a detailed investigation has been carried out to probe the morphology of these samples procured from Indus basin by materials characterisation techniques such as SEM, AFM respectively. Furthermore, porosity and permeability measurements have been conducted to establish pore connectivity. Additionally, simulation studies were also performed to simulate the data of core samples.

2. Experimental

2.1. Collection of Samples

The outcrop samples were received from the lower Indus basin field and were marked as X, Y and Z (Fig. 1). These outcrop samples were analysed for porosity, permeability and fluid saturation tests. For gas sampling, nitrogen was used for fluid intrusion within the rock samples.

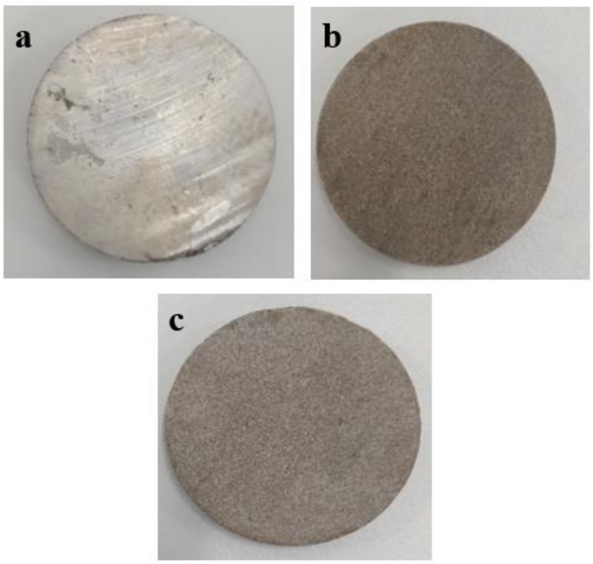

Fig. 1. Cross sectional images of tight gas samples, (a) X (b) Y (c) Z

2.2. Preparation of Material

3-inch outcrop rock samples were dried in an oven at 1000 ^{o}C for 24 h. It is ensured that the outcrop samples were completely dried prior to measurement of core properties. The composition of brine used (3.5% NaCl) had similar composition to the water used in displacement experiment. For core flooding experiment, the bulk volume of brine was prepared which was then filtered to avoid the undesired solids during core flooding.

2.3. Petrophysical Properties Evaluation

The permeability and porosity of outcrop sample was measured with poroperm equipment at a temperature of 23oC and pressure of 14.7 psi. Initially, the dry sample was weighed followed by saturation of the outcrop with brine by using vacuum saturator. Then the weight of the rock sample was computed to determine the initial brine saturation. The dried rock sample was placed in the core holder under pressure of 2000 psi and temperature around 90 °C similar to the reservoir conditions. The nitrogen gas flow rate was maintained at 0.1 cc/min or 0.2 cc/min in accordance with the RPS (Relative permeability system / core flooding system) software. This software automatically measured the values of permeability with respect to differential pressure. A pictorial representation of the system is shown in Fig. 2. The permeability of outcrop sample was measured from 25-100 psi confining stress.

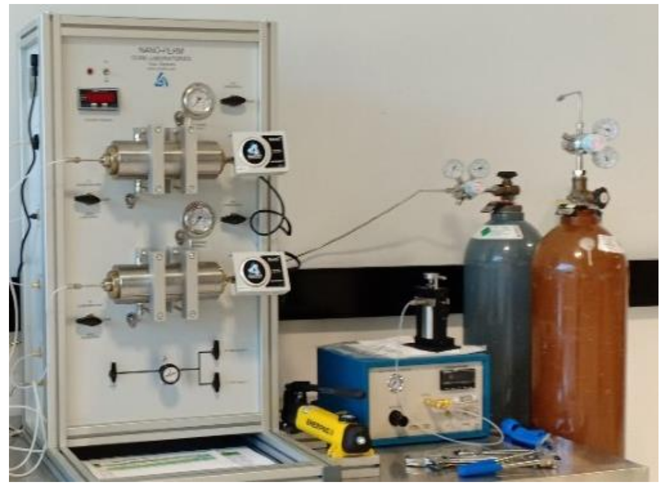

Fig. 2. Pictorial representation of the instrument for permeability and porosity measurements

2.4. AFM and SEM Measurements

Tight gas samples before and after liquid nitrogen treatment were observed by using Hitachi SU3500 Scanning Electron Microscope [23-24]. The SEM image obtained covered an area of 40000 µm2 with a magnification of 550 X. The Image J software was used for quantitative determination of the image and for measuring the pore size of the fractures. The equipment employed for AFM was Nano surf C 3000 controller ECS 204. We have utilised AFM contact mode in the present study. In the present method tip is pulled over the surface at a constant cantilever deflection.

2.5. Simulation Methodology

Sendra Software was used for simulation studies to assess the performance and durability of formation in terms of enhancing gas production. This software allows precise knowledge of the graphic orientation and proper division of grids. The software was also employed to simulate multi dimension of the core sample.

3. Results and Discussion

3.1. AFM and SEM Measurements

The effect of change in confining stress from 25 to 100 psi is reflected in the SEM micrographs in Fig. 3. It can be observed that increase in confining stress from 25 to 100 psi resulted in enhanced fractures in the tight gas samples represented by Fig. 3(d). Similar observation have been reported by several authors [25-26].

AFM images of box size (10 x 10 μm) depicting both the top view and surface roughness are shown in Fig. 4. The images reveal the depth, radius fractures of pores, cracks, roughness and mineral deposition of tight gas samples investigated in the present study. The images demonstrate the existence of clear fractures and pore connectivity when subjected to confining stress of 100 psi (Figs. 4(c) and 4(d)) as compared to AFM images without stress (Figs. 4(a) and 4(b)). Similar topographic images have been obtained by other researchers [27-28].

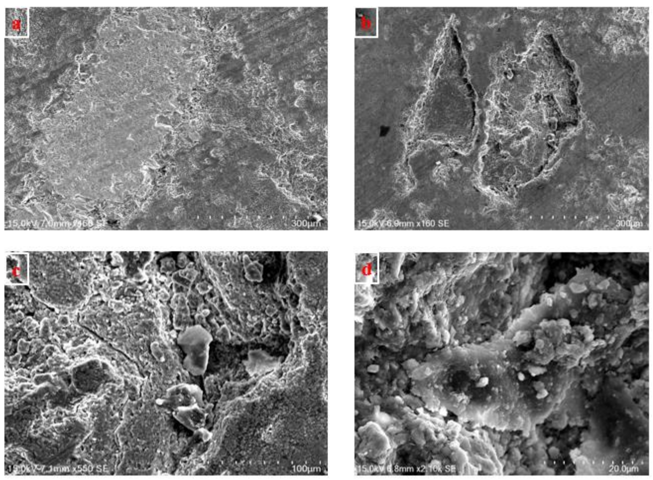

Fig. 3. SEM micrographs depicting increase in fractures with various values of confining stress (a) 25 psi (b) 50 psi (c) 75 psi (d) 100 psi

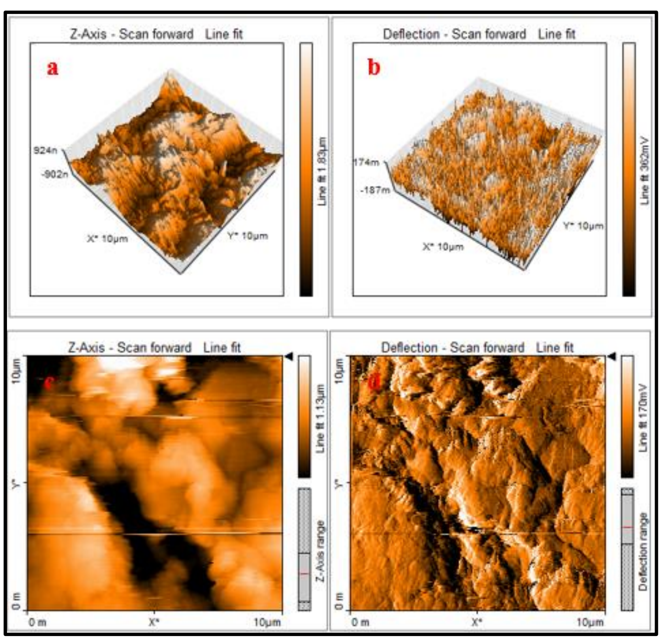

Fig. 4. Topographical AFM images of tight gas samples (a) Surface roughness, without confining stress (b) 3D image without confining stress (c) 3D image, confining stress 100 psi (b) surface roughness, confining stress 100 psi

3.2. Petrophysical Evaluation of Tight Gas Samples

The petro-physical properties such as porosity and permeability were determined by the instrument described above in Fig. 2. The experimental results revealed that initially the porosity of the samples before confining stress were 4-6% and the permeability was 17 mD. Nevertheless, increase in confining stress to 100 psi induced porosity values of 8-10% and enhanced permeability to 30 mD. These changes in permeability and porosity with increased confining stress resulted in maximum fractures. This is consistent with the results reported by authors [29-30] which stated that an increase in the confining stress has a greater effect on permeability dominated by micro fractures.

3.3. Simulation Studies on Tight Gas Samples

Simulation studies have been carried out on tight gas samples to measure the porosity, permeability, fluid saturation and capillary pressure (Special rock analysis techniques) [30-31] by using Sendra software and following results (Fig. 5) have been achieved. The Fig. 5 shows the relationship between the Kr (relative permeability), Sw (saturation of water) and capillary pressure (Pc) in tight gas samples with close packed pores permeability through Corey’s and Burdin Correlation. The Krg (relative permeability of gas) and Pc were found to decline with addition of Sw.

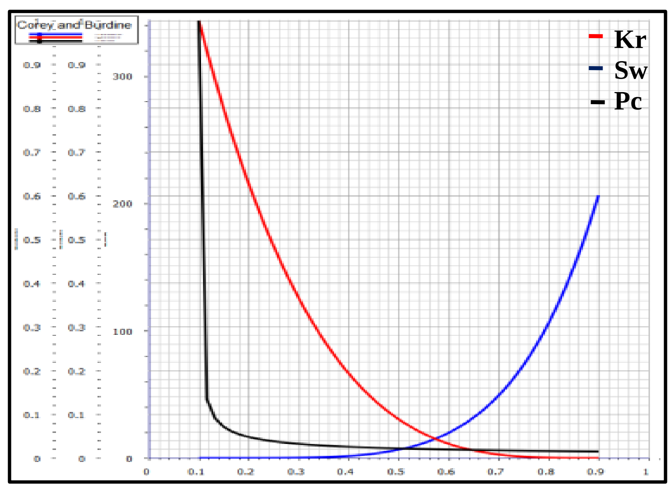

Fig. 5. Relative permeability and water saturation relationship using Corey and Burdine Correlation

The Corey and LET estimation were used in Fig. 6 simulated by Sandra software in which Kr decreased slowly with increase in Sw value and Pc also underwent decline in the middle region of curves.

Fig. 7 illustrates the effect of confining pressure on compressibility. The initial straight line in the figure reflects flow behaviour in homogeneous formation with improved skin factor for optimum production and formation. It is observed that the slope of semi log smooth line was proportional to the permeability product and thickness of natural fracture system. Hence, the discrete pressure drops in the fracture system; and flow of fluids in matrix begins with heterogeneity of the tight gas samples. Fig. 8. Reveals the periodical history of tight gas formation and initial shut-in pressure and build up pressure which is shown in the Cartesian graph.

Fig. 6. Relative permeability and water saturation relationship through LET Correlation Krg

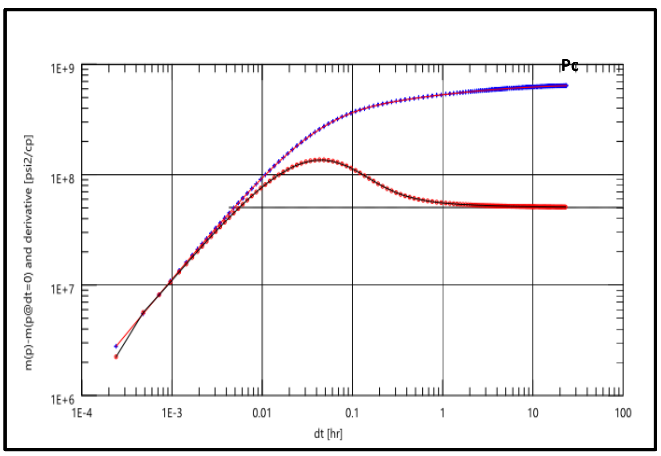

Fig. 7. Logarithmic plot of compressibility versus confining pressure

The above figure also reveals that the first interval begins from 0 to 3800 psi versus time within 4 h and production rate was 7500 Mscf/D / 7.5 MMScf/D. After production interval of 12 h, the formation was shut for about 24 h to acquire the reservoir pressure condition. However, after a period of 36 h the stabilized pressure obtained was 5350 psi as depicted in the above Fig. 8.

Fig. 9 shows the periodical history of tight gas formation for different intervals at initial and final build up conditions which are depicted as spikes on the Cartesian graph. The graph reveals that with increase in pressure from 0 to 4420 psi in 4 hrs resulted in increased production rate of 6250 Mscf/D. Furthermore, increase in pressure to 4550 psi for a period of 24 h enhanced the production rate to 13350 Mscf/D. After this production, the interval time was 22 h, and the shut-in time was 2 h.

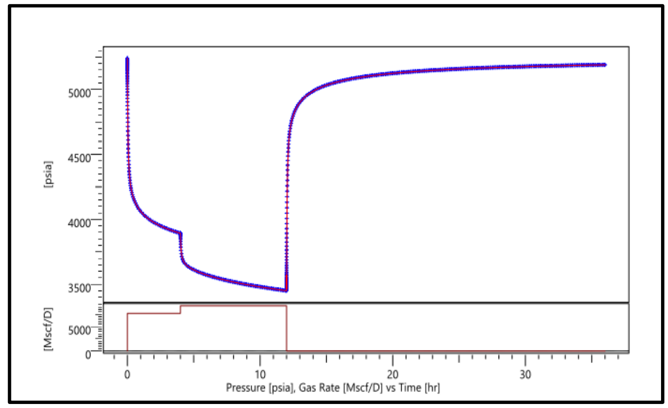

Fig.8. Plot representing Pressure, Production rate Vs Time

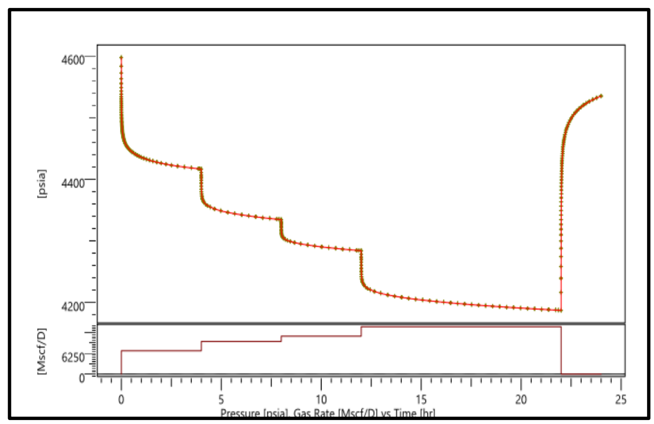

Fig. 9. Plot representing Pressure, Production rate vs Time

4. Conclusions

1. AFM images revealed the 3D and 2D pore structures of tight gas samples and also determined the pore connectivity between the rock samples.
2. Morphological characterisation by SEM established that increase in confining stress from 25 to 100 psi resulted in enhanced fractures in the tight gas samples.
3. The porosity permeability of the samples obtained before confining stress were 4-6% and 17 mD respectively. However, increase in confining stress to 100 psi resulted in porosity values of 8-10% and increase permeability to 30 mD.

4. To interpret the laboratory data, simulation technique was used in order to estimate the economical production of the lower Indus basin reservoir.
5. Special core analysis simulation was conducted using Sendra Software and correlated the relative permeability curves with particular fluid saturation.
6. In addition to technological advancement and innovation, this work is a major breakthrough to reduce cost and for sustainable development of tight gas resources present in lower Indus basin Pakistan.

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