Journal of Natural Gas Science and Engineering 57 (2018) 322–330

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

journal homepage: www.elsevier.com/locate/jngse

Beyond fracking: Enhancement of shale gas desorption via surface tension reduction and wettability alteration

Osman SalahEldin Hussein[a,*], Khaled Abdalla Elraies[a], Abdullah Almansour[b], Hazlina Husin[a], Juhairi Aris B. Mohd Shuhili[a]

[a] *Department of Petroleum Engineering, Universiti Teknologi PETRONAS, Seri Iskandar, 32610, Perak, Malaysia*
[b] *National Center for Oil & Gas Technology, King Abdulaziz City for Science and Technology (KACST), P.O.Box 6086, Riyadh, Saudi Arabia*

ARTICLE INFO

Keywords:
Shale gas
Surface tension
Pendant drop
Surfactant
Shale wettability
Hydraulic fracturing

ABSTRACT

A significant amount of water used during hydraulic fracturing operation in shale reservoirs remains trapped in the formation mainly due to capillary forces. In this paper, the effect of Alpha Foamer® surfactant in enhancing the efficiency of the fracturing fluid was investigated in the presence and absence of Betain C60 as a co-surfactant at various fracturing water salinities. The performance of Alpha Foamer® surfactant was examined by measuring the surface tension and contact angle between the surfactant solutions and methane gas at different pressures and temperatures. The result indicates that Alpha Foamer® has significantly reduced the surface tension between water and methane gas from 69 mN/m to 33.2 mN/m at critical micelle concentration of 0.25 wt%. The addition of Betain C60 as a co-surfactant has slightly reduced the surface tension to 26.6 mN/m. It has also been observed that the increase in the pressure and temperature would be an advantage with additional reduction in the surface tension. In addition, the selected surfactant and co-surfactant concentrations have shown a significant reduction in the contact angle that makes the shale formation strongly water wet. The shifting of the wetting phase due to receding contact angle would aid in desorption of methane gas from shale matrix. The desorption is further enhanced with the reduction of surface tension between fracking fluid and methane gas by surfactant. The findings from this research can be used to optimize fracturing fluid, and to improve the overall sweep efficiency and shale gas productivity as well as water flowback.

1. Introduction

Conventional reservoirs are usually high quality reservoirs with high vertical and horizontal permeability but they have small amount of reserves. Whereas unconventional reservoirs have large amount of reserves but the permeability is extremely low in comparison with conventional resources, which makes it a challenge to produce the original hydrocarbon in place (Canadian Society for Unconventional gas (CSUG), 2010). The recent growth of unconventional gas is due to the fact that most conventional reservoirs have depleted and further recovery would mean higher cost and effort (Miller and Sorrell, 2013). Unconventional reservoirs have large amount of gas or oil but it is hard to produce (permeability < 0.1 md) and needs artificial stimulation such as fracturing to increase the well permeability. Thus, today's oil companies have to make a decision to further enhance the production of the conventional reservoirs or to research and figure out a way to produce a substantial amount of oil/gas from the unconventional reservoirs.

Shale is one of the promising unconventional formations that contain both oil and gas. The gas within the shale formation could be classified into adsorbed gas, free gas and solution gas. The adsorbed gas is attached to the organic matter or clay and it can reach up to 80% of the total gas in place and can be desorbed by the decline of pressure over time (Das, 2012). The free gas is held in pores or spaces created by fracking while the solution gas is held within other liquids such as oil and bitumen (Cowan and RNCan, 2011).

Hydraulic fracturing has been used since the 1940s in order to improve well permeability and promote extraction of oil and natural gas (Montgomery and Smith, 2010). Hydraulic fracturing is an important technique that allows for an economical production from shale deposits. It creates fracture networks in the shale to allow the trapped gas to escape from pores and natural fractures. The fracking fluid (99% water and proppant, 1% chemicals) is pumped into the well at high pressure creates a pathway for the gas to flow while the proppant holds

* Corresponding author.
E-mail addresses: osman.salah_g03484@utp.edu.my (O.S. Hussein), Khaled.elraies@utp.edu.my (K.A. Elraies), aalmansour@kacst.edu.sa (A. Almansour), hazlina.husin@utp.edu.my (H. Husin), juhairi.shuhili@utp.edu.my (J.A.B. Mohd Shuhili).

https://doi.org/10.1016/j.jngse.2018.07.011
Received 31 March 2018; Received in revised form 24 June 2018; Accepted 12 July 2018
1875-5100/

the fractures open (McBride and Sergie, 2015). However, the drawback of hydraulic fracturing is the huge amount of water that remains trapped in the formation, which could lead to a significant reduction in the relative permeability of the gas.

One of the major problems associated with fracking is the large volume and quality of water needed to sufficiently fracture the formation. Additionally, around 60–80% of the fracturing fluid water may be retained by the shale formation and only 20–40% of the fracturing fluid water is recovered back at the surface (Environmental Resources Management (ERM), 2014). In such a low permeability formation, capillary pressure can reach very high values that cause an imbibition effect. Water imbibed into the micropores of shale will become immobile and held in by capillary forces thus be retained permanently in the matrix (He, 2011; International Human Resources Development Corporation (IHRDC), 2010). Unpropped fractures that lose their width and become disconnected from propped fractures during flowback as well as clay swelling can also cause water to be retained. This huge amount of water trapped in the formation can block the flow path of the gas, which results in low recovery. The gas and oil production from shale formation occurs mainly due to formation fracking that create paths and improve the permeability of the formation thus improving the overall recovery. Slick water, gelled water, or CO2-foam can be used to fracture the formation. Foam is considered a beneficial fluid for fracking unconventional shales that are known for retaining huge amounts of water (Gupta, 2009). However, foam breaks after a short while which releases the retained water into the formation. In this case, surfactant type and concentration would play an important role to improve the foam stability thus improving the formation fracking as well as reducing the surface tension between the gas (free or adsorbed) and water. It was also reported that shale cores treated with surfactants show higher oil recovery and fluid flowback (Kim et al., 2016) leading to easier flow of gas. A detailed study was conducted on the effect of surfactant adsorption on Marcellus and Collingwood shale wettability using the contact angle and surface tension measurements (Zhou et al., 2016).

Adding surfactants into hydraulic fracturing fluid may contribute to improve gas productivity through reducing interfacial tension, altering rock wettability, or decreasing water imbibition. The added surfactant decrease the interfacial tension and increase relative permeability rates of both the gas and liquid phase (Kumar et al., 2006; Li and Firoozabadi, 2000).

In this paper, the effect of introducing surfactants to the fracking fluid was experimentally investigated for the purpose of enhancing the shale gas production and water flowback. This was accomplished by measuring the surface tension between surfactant solution and methane gas using difference brine salinities at various pressures and temperatures. Core shale sample from the Middle East was also used to investigate the impact of surfactant on the shale wettability. Reducing the surface tension between the fracturing fluid and original methane gas in place could enhance the relative permeability to both water and gas, which reflects directly on the overall sweep efficiency.

2. Research methodology

2.1. Materials and procedures

Properties of surfactant and co-surfactants used in this research are presented in Table 1. Alpha Foamer® was used as the main surfactant in all solutions, while TX-100 and Betain C60 were used as co-surfactants. The methane gas used as the surrounding phase has a purity of 99.995% to represent the shale gas. Sodium chloride (NaCl) was used to prepare the brine and vary the salinity of the samples. The main tests conducted in this research are presented in Fig. 1.

The surface tension and contact angle were measured using high pressure/high temperature pendant drop instrument, manufactured by Temco Core lab. Fig. 2 shows the setup for the experiment which consists of a visual cell, light source, fluid accumulator, hand pump, backpressure regulator, heating metal straps connected to temperature controller, and a camera. The surface tension is then estimated by analyzing the digitized drop shape as a function of fluid/gas density. The built-in software fits the shape of the drop to Young-Laplace equation to calculate the surface tension. For pendant drop method (Bashforth and Adams, 1883), derived equation (1):

$$\gamma = \frac{\Delta\rho\, g\, R_0^2}{\beta} \tag{1}$$

Where γ is the surface tension, $\Delta\rho$ is the density difference, g is the gravitational constant, R_0 is the radius of drop curvature at apex, and β is the shape factor. According to equation (1), the densities of the two phases in contact needs to be known to measure the surface tension based upon the Young-Laplace equation.

The density of all solutions has been calculated using DMA 4500 Anton Paar density meter. The device operates according to the oscillating U-tube method. The oscillating U-tube is a technique to determine the density of liquid and gases based on an electronic measurement of the frequency of oscillation.

2.2. Device calibration

The accuracy of all measuring devices deteriorate over time by normal wear and tear. Depending on the type of the instrument and the environment in which it is being used, it may deteriorate very quickly or over a long period of time (Brei, 2013). Measuring the surface tension between air and water at ambient conditions helps in ensuring the device will give accurate results throughout this experiment. As can be seen in Table 2, more than one reading was recorded and the average is taken to improve the accuracy of the result. The surface tension between water and air was found as 72.5 mN/m which is similar to the standard of pure water and air at 25 °C and 14.7 psia known to be around 72.4–72.7 mN/m (Bartell and Niederhauser, 1950; Sachs and Meyn, 1995; Schmidt, 1981). Hence, it is confirmed that the experimental setup is calibrated for further investigation.

2.3. Shale characterization

The shale core sample obtained from Middle East was analyzed using the Supra 55 VP FE-SEM Electron microscope manufactured by the German company Carl Zeiss. It has an Energy Dispersive X-ray Spectrometer (EDS) for elemental analysis and mapping that can be used to identify the mineralogy of the shale sample.

Analytik-Jena Multi N/C® TOC analyzer and MultiWIN evaluation software were used to measure the Total Organic Content (TOC). The shale sample was grinded, treated with 10% hydrochloric acid (HCl), and dried in the oven at 105C to demineralize it from carbonates.

The Porosity of the shale sample was conducted using a Scanning Electron Microscope (SEM) and ImageJ software for post processing, image segmentation, and analysis. These images obtained from (SEM) were analyzed using ImageJ software in order to generate results that include concerning pore count, pore size, interpore distance, and porosity percentage.

The permeability was estimated using CoreLab SMP-200. Approximately 30 g of crushed sample was placed into the test chamber and filled with helium gas. The pressure decline curve was then recorded for up to 2000 s. Following the measurement procedure of (Konoshonkin and Parnachev, 2015), a simulator history match of the pressure decline curve then yields the matrix permeability of the shale sample.

Capillary pressure and pore size distribution were measured using AutoPore IV 9500 produced by Micromeritics Company. Similar to (Liu et al., 2017), the process uses mercury intrusion porosimetry (MIP) to quantify the pore-size distribution.