Journal of Natural Gas Science and Engineering 35 (2016) 265–275

Contents lists available at ScienceDirect

Journal of Natural Gas Science and Engineering

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

Investigation of formation heat treatment to enhance the multiscale gas transport ability of shale

Yili Kang [a], Mingjun Chen [a, b, *], Zhangxin Chen [b], Lijun You [a], Zhiwei Hao [a]

[a] State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China
[b] Department of Chemical and Petroleum Engineering, Schulich School of Engineering, University of Calgary, Calgary T2N 1N4, Canada

ARTICLE INFO

Article history:
Received 15 June 2016
Received in revised form
21 August 2016
Accepted 22 August 2016
Available online 24 August 2016

Keywords:
Shale
Heat treatment
High temperature
Permeability
Pore structure
Multiscale

ABSTRACT

In order to achieve the most economical production of shale gas, fracture networks should be as complex as possible to connect the matrix micropores, natural fractures and induced fractures efficiently. Since shale rock is very tight, hydraulic multi-fracturing in horizontal wells has been the key technology in shale gas development. However, it is still difficult to connect small-scale pores in the matrix. Meanwhile, the recovery rate of a fracturing fluid is low, resulting in severe formation damage primarily induced by water blocking or water phase trapping. In this work, formation heat treatment is studied for the first time in gas-shale to address these issues. Samples from Longmaxi Shale are used to investigate the change in the multiscale gas transport ability after a high temperature treatment. A core sample heating system is specially designed to measure a permeability change during a high temperature treatment. Field scanning electron microscopy imaging, total organic carbon and low pressure nitrogen adsorption measurements are also implemented to analyze a change in the micro structure after the high temperature treatment. The results indicate that shale permeability increases rapidly with an increase in temperature, especially when the temperature is more than 400–500 °C, which can be described as a threshold value in a percolation model. Experimental results also indicate that the quality of the shale matrix can be dramatically improved after a high temperature treatment since there is a high quartz and organic matter content in the shale. Stimulation mechanisms of a formation heat treatment in shale gas reservoirs are described as water removing, mineral and organic matter structure changes and multiscale fracture network generation. For the field application of formation heat treatment, both its advantages and issues that still need to be addressed are deeply analyzed. It is indicated that the mid-late period of shale gas production can be extended, and problems induced by a residual fracturing fluid can be solved by formation heat treatment. Constructive field operation suggestions, which combine the advantages of electrical heating and microwave heating, are presented.

1. Introduction

Shale gas has yielded a natural gas revolution in recent years due to its huge reserves and successful development in North America. The exploitation of shale gas is recognized as the technical commanding height of the oil and gas industry. Meanwhile, this exploitation is a powerful driving force for the progress of oil and gas development technology (Wang et al., 2011).

Compared to a conventional gas reservoir, a shale gas reservoir is obviously characterized by multiscale flow channels (Kang et al., 2015a; Chen et al., 2016). In terms of pore size distribution, the proportion of nanoscale pores in shale is much higher than in conventional rocks (Javadpour et al., 2007; Passey et al., 2010). Organic matter is unevenly distributed in shale. Most of the nanopores in the matrix belong to organic matter pores. Meanwhile, the degree of natural fracture development is usually high in shale reservoirs and stratification is highly developed (Curtis et al., 2011). Therefore, shale pores, both in size and distribution, have a strong anisotropy. Various types of gas storage and flow spaces, including organic matter pores, inorganic matter pores, and natural and induced fractures, make gas storage and flow complex (Alharthy et al., 2012). Specifically, the relatively large amount of organic matter and clay minerals in the matrix results in most of the adsorbed gas existing on its nanopore walls (Bustin, 2005). In

* Corresponding author. State Key Laboratory of Oil and Gas Reservoir Geology and Exploitation, Southwest Petroleum University, Chengdu 610500, China.

http://dx.doi.org/10.1016/j.jngse.2016.08.058
1875-5100/

addition, most of the compressed free gas exists in the micro pore-fractures. Generally speaking, according to the multiscale pore-fracture structure of the shale, shale gas flow belongs to complex multi-field coupling nonlinear flow (Wang et al., 2013). Various types of gas transport behavior happen in shale reservoirs, including desorption, diffusion, seepage in the pores, seepage in the micro fractures, and fluid-solid coupling seepage in the induced fractures (Curtis, 2002; Liu et al., 2011; Killough et al., 2013; Yang et al., 2013).

Since the shale matrix is tight, it is notably difficult for the gas flow in non-stimulated shale reservoirs and micro fractures to become the main flow channels. However, due to poor connectivity, in-situ permeability of micro fractures is usually less than 100 nD (Bustin et al., 2008). In order to obtain economical production, fracture networks must become complex, and then the effective drainage area can be increased. Economides and Wang (2010) indicated that the production capacity of a shale gas depends on the largest fracture network system induced by fracturing, which is a stimulated reservoir volume. Approximately 85% of the shale gas wells in the US are developed through a horizontal well multi-fracturing technology, which can maximize the contact area between a fracture network and matrix (Wang et al., 2013). Stimulated reservoir volume fracturing in horizontal shale wells has become the core technology in shale gas development (Zou et al., 2015). After hydraulic fracturing, not only can shale reservoirs provide a much more effective drainage area for gas flow, but it can also make adsorbed gas desorb more easily. During the mid-late period of most shale gas wells production, desorption of adsorbed gas makes a significant contribution to gas production (Ibrahim and Wattenbarger, 2006; Ambrose et al., 2011). Although hydraulic fracturing can make gas desorb more easily from kerogen-clay due to complex reservoir fracture networks, it is not enough since a matrix or kerogen is not effectively connected by micro fractures. Therefore, how to accelerate gas desorption-diffusion is still a severe problem that urgently needs to be solved.

According to the shale gas production data from the China National Petroleum Corporation (CNPC), in the South Sichuan Basin, the higher production wells always have lower water saturation and higher free gas saturation in the shale reservoirs (Liu and Wang, 2013). That is, gas-rich shale reservoirs are generally characterized by ultra-low water saturation. However, during drill-in, completion, killing and hydraulic fracturing processes, the characteristic of ultra-low original water saturation can significantly accelerate a working-fluid invasion rate into a reservoir (You et al., 2014). Hydraulic fracturing in shale gas wells typically uses considerable water and a small amount of additives as the fracturing fluid. According to the statistics of thousands of horizontal wells in the US in 2014, the mean water volume injected into a reservoir is 19,425 m^3 during hydraulic fracturing (Gallegos et al., 2015). Chekani et al. (2010) analyzed a lot of shale gas well data to indicate that the recovery rate of a hydraulic fracturing fluid was very low, usually ranging from 10% to 40%. Statistics from Horn (2009) showed that the fracturing fluid recovery rate of shale gas wells in the US usually ranged from 35% to 62%. Public information from the CNPC shows that most of its shale gas wells in the Sichuan Basin can only flow back 12%–55% of the injected fracturing fluids. Not much water flows back, which can greatly increase the water saturation in a near-fracture formation and induce serious formation damage, such as water blocking (Vidic et al., 2013; Xu et al., 2016). Therefore, if there is a way to remove the water to prevent formation damage, the production of shale gas wells can dramatically increase.

In addition, shale is mainly composed of brittle minerals and clay minerals and contains developed stratifications and fractures, which present a typical hard and brittle property. Generally speaking, the more brittle the shale formation is, the more successful the hydraulic fracturing is (Knudert and Mullen, 2009). Thus, if a method can increase the brittleness and then decrease the fracturing pressure of a shale formation, more effective drainage areas can be generated and fracture networks can become more complex.

Formation Heat Treatment (FHT) technology was first presented as a novel matrix stimulation concept by Jamaluddin et al. (1995). This technology's initial purpose was to solve the problem of production reduction caused by water blocking or water phase trapping near a wellbore. Their laboratory results demonstrated that FHT could obviously prevent formation damage caused by water near a wellbore and increase the formation permeability. On June 29, 1995, the FHT technology was tested in the field using a conventional sandstone gas well slated for abandonment (Jamaluddin et al., 1999). After being at the high temperature (from the reservoir temperature up to 382 °C) for approximately 300 min, the permeability of the near-wellbore formation was improved six-fold. This field test was successful and was a landmark. Kang et al. (2015b) indicated that a set of multiscale processes including water removing, a change in mineral structure and the generation of fracture networks could happen in a tight rock under a high temperature treatment. So far, FHT has been discussed in oil and gas development for the past two decades, especially in near-wellbore water blocking or stimulation. Additionally, some related studies of thermally altered rock properties can be found in the literature on HDR (Hot Dry Rock) geothermal extraction and nuclear waste storage (Somerton, 1992; Hayashi et al., 1999; Graves and Bailo, 2005). However, the studies in oil and gas development have still focused on conventional reservoirs, of which the lithology is quite different from that of shale rocks. Compared to other types of reservoirs, shale gas reservoirs are specially characterized by ultra-low permeability, multiscale pore structure and unevenly distributed organic matter. Additionally, for shale gas development, the problems of how to manage the low recovery rate of a fracturing fluid, how to increase a gas desorption-diffusion rate and how to increase rock brittleness urgently need to be solved. Therefore, with these problems, and thanks to the advantages of FHT, we address an application of FHT in shale gas development in this paper from the perspective of improving the multiscale gas transport ability of shale.

2. Experimental study of FHT on shale samples

2.1. Samples and methods

Shale samples from a Longmaxi formation on the east of the Sichuan Basin in China are used in this work for the experiments. Longmaxi Shale is the most commercially developed shale gas reservoir in China (Guo and Zhang, 2014). We analyzed the mineral content, total organic carbon (TOC) and vitrinite reflectance (Ro) for over one hundred samples. The main minerals are quartz and clay, of which the contents are 45.55 and 33.71%, respectively. TOC is 3.09% and Ro is 2.94%. Both the mineral content and TOC data above are percentages by weight. According to the evaluation standard from Boyer and Droser (2007), shale samples in this work are over-matured, organic-rich shale.

In order to measure a permeability change in the core samples under a high temperature condition, a high-temperature core holder, which can apply a maximum stress of 90 MPa and a maximum gas pressure of 10 MPa and work at a maximum temperature of 800 °C, was specially designed in this work to measure the permeability of a core sample at a high temperature. A tube furnace was used together with the core holder. High-purity nitrogen was used as the driving medium. On one hand, permeability