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The fate of fracturing water: A field and simulation study

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ABSTRACT

Hydraulic fracturing of multi-lateral horizontal wells for shale gas production usually requires a great amount of water. Field data indicate that only a small fraction of the injected water can be recovered during the clean-up phase. Especially, when shale oil and gas wells undergo month-long shut-in periods after multi-stage fracturing processes. Field data also indicate that in some wells, such shut-in episodes surprisingly increase the oil and gas flow rate. However, the fate of non-recovered water in the reservoir and the reasons behind increased early-time oil and gas production after a long shut-in period are poorly understood.

In this paper, we first interpret the flowback data of a 18-well pad completed in the Horn River Basin. Then, we use a numerical simulator to investigate the parameters controlling water and gas production during the flowback process. In the simulation model, the shale reservoir is represented by a fracture–matrix model, where the fractures form a continuum of interconnected network. The simulation results show that the counter-current imbibition of fracturing water during the shut-in period can result in a significant gas build-up in the fractures and therefore increases early-time gas production rate. It was also concluded that early-time water and gas production depends on reservoir properties such as capillary pressure and complexity of created fracture network and operational parameters such as shut-in time. The gas production rates from reservoirs with higher capillary pressure is higher at the beginning of flowback process but the production rate falls later. The complexity of fracture network created during hydraulic fracturing process has a great effect on load recovery and gas production. As the complexity increases, the gas production rate increases and load recovery decreases due to higher contact surface created between fractures and shale matrices. Further, field data and simulation results show that extended shut-in period increases early-time gas production but it decreases load recovery and late-time gas production.

1. Introduction

Shale reservoirs, considered unconventional resources, have emerged as a significant source of energy supply in the United State and Canada, meet the increased global demands for oil and gas [38]. Unconventional resources with ultralow matrix permeability are capable of producing oil and gas at economic rates when completed by hydraulically fractured horizontal wells [45]. Without drilling horizontal wells and hydraulic fracturing stimulation, oil and gas production from tight reservoirs will not be high enough to have an economic justification. Well productivity might be improved further if the hydraulic fractures are connected to a secondary fracture network. This fracture network may be pre-existing in a naturally fractured reservoir and/or may be generated locally by the hydraulic fracturing operation [27,57].

Completion of a horizontal well with a multistage fracturing treatment requires a great amount of water-based hydraulic fracturing fluid to be injected into the target formation to create multiple fractures and increase the contact surface between the wellbore and reservoir [34]. The fracturing fluid injected into the formation should be recovered before placing the stimulated well on production. The hydraulic fracturing treatment is followed by flowback operation (post-stimulation flow period) to (1) clean and (2) prepare the fractured horizontal well for a long-term production [17]. However, in practice, only a small fraction of injected fluid, as low as 5% of the total injection volume in Haynesville shale to as high as 50% in Barnett and Marcellus shales, can be recovered during the clean-up phase [14,40]. Some authors suggest that fracturing fluid leak-off into the shale matrix is restricted and a large fraction of the injected water remains in fractures as an

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immobile phase, due to gravity segregation, capillarity and fracture closure [23,26,29,48]. This explanation is backed by the argument that effective water imbibition into shale matrix is limited because the mobility of water in ultra low-permeability media is too low. Furthermore, shale formation can be party oil wet due to high content of organic materials [49]. However, most of the literature considers shales to be water wet, and subsequently the spontaneous imbibition of water into shale rock may be a major mechanism responsible for water retention and low fracturing fluid recovery (e.g. [31,41,51,58]). Additionally, field data analysis [40] suggests that shale reservoirs might be initially at sub-irreducible water saturation condition. This results in an even greater capability of shale matrix to imbibe and trap the injected water [31].

Capillary pressure, which is a function of rock wettability, pore radius and interfacial tension, controls spontaneous imbibition in both conventional [10,12,60] and low-permeability reservoirs [55,61]. The role of the capillary forces on water retention after fracturing treatments in tight reservoirs has been investigated by many authors [14,43,47]. In low-permeability reservoirs, capillary pressure can be several hundred psi [33] and therefore, fracturing fluid imbibition results in fluid retention, known as water blockage [9,22]. Increased water saturation at the vicinity of fracture face in tight gas reservoirs, causes the relative permeability of gas to be reduced and profoundly impedes gas flow [54]. For instance, the studies of Shanley et al. [53] indicate that gas production reduces dramatically when water saturation exceeds 40–50% near the fracture faces. Subsequently, Kamath and Laroche [36] showed that water blockage is a transient phenomenon and the duration depends on rock properties and type of fluid, and pressure gradient in the reservoir. They also found that many earlier laboratory studies had overestimated the gas deliverability loss caused by water blockage. This finding was later confirmed by Mahadevan and Sharma [44]. Recently, Wang et al. [56] investigated the impact of each damage mechanism and concluded that a higher fracturing water loss does not always result in a lower gas production. Furthermore, at the end of a hydraulic fracturing treatment, the well may experience intentional or unintentional shut-in because of (1) safety issues, (2) logistical issues or (3) simply the belief that soaking is beneficial [18]. Some recent field tests and observations show that extended shut-in time after hydraulic fracturing treatment may decrease water recovery and increase early-time gas production [4]. This observation is also in agreement with simulation studies conducted by Settari et al. [52], Cheng [14], Agrawal and Sharma [5] and Fakcharoenphol et al. [25].

Beyond the experimental and numerical studies, analytical modeling has been attempted to understand the flowback data. Some models assume that there is a single phase flow of water through the primary fracture network to the perforation, during the first hours of flowback. The studies of Ilk et al. [35], Clarkson [15] and Abbasi et al. [3] are cases in point. Xu et al. [59], Ghanbari et al. [30] and Abbasi [1] analyzed the flowback data obtained from wells completed in the Horn River shale members. They concluded that shale gas reservoirs do not show any single-phase flow regime, instead showing an immediate gas breakthrough after an extended shut-in period. More recently, several authors (e.g. Ezulike and Dehghanpour [24] and Clarkson and Williams-Kovacs [16]) have attempted to estimate fracture parameters such as effective fracture half-length and fracture permeability from analyzing flowback rate and pressure data. Li et al. [42] carried out simulation studies by varying several fracture parameters to identify possible correlations between early gas production and key fracture parameters in shale reservoirs. Later, Alkouh et al. [6] combined two-phase flowback data with long-term gas production data and presented a new method to estimate effective fracture volume. Li et al. [42] and Alkouh et al. [6] assumed that most of the injected water is in both hydraulically induced and natural fractures and imbibition is not a major effect. However, the effects of soaking period and fracturing fluid imbibition on early-time production data are poorly understood. This paper aims at understanding the interaction between fracturing fluid and reservoir matrix and its effect on early-time production data. The reset of this paper is divided into three sections. Section 2 describes the geological overview of the Horn River Basin and the well pad completed in this formation. Section 3 presents the volumetric analysis of the production data obtained from wells completed in the Horn River Basin. Section 4 presents the numerical study of flowback process to investigate how fracturing fluid imbibition affects the early-time gas production.

2. Shale members related to this study

Horn River Basin. Muskwa, Otter Park and Evie formations belong to the Devonian age of the Horn River Basin. The total thickness of these shale members is in the range of 160–180 m and the total organic content is approximately 4% [50]. Original gas-in-place of the Horn River Basin is estimated at 500 trillion cubic feet (Tcf) by the Canadian society for unconventional gas reservoirs [19]. The Horn River shales are on average comprised of 60% quartz, 20% clay, 10% carbonate and 10% other minerals [46]. The clay concentration of these shale members generally decreases with depth [21,41].

Well pad description. Flowback water and gas production data, are collected from a pad of 18 hydraulically fractured horizontal wells completed in Muskwa (MU), Otter Park (OP) and Evie (EV) formations. In each formation, three wells are completed on the right side and another three wells are completed on the left side of the well pad. This results in the total of six wells in each formation, and the total of 18 wells for the pad. The fracturing fluid used for the treatment is the same for all wells and mainly consists of fresh water. However, the total injected volume is different for each well. All the 18 wells of the pad were placed on shut-in prior to first production for an average period of 60 days. During the flowback operation, the cumulative water and gas production was measured frequently. More details about this well pad and operational parameters are presented elsewhere [1].

3. Volumetric analysis of early-time flowback data

The volumetric analysis of early-time production data is presented in two sections. In the first section, we compare the early-time flowback efficiency and cumulative gas recovery after 72 h and classify the wells into different groups. In the second section, we compare the cumulative water and gas production versus time to identify different flow regimes.

3.1. Water recovery during the flowback period

Fig. 1 shows a comparative graphical presentation of cumulative gas production and flowback efficiency of different wells completed in Muskwa, Otter Park and Evie formations. Cumulative water recovery after 72 h is considered here because the majority of fluid flowback occurs during the first 72 h of production [7] and the duration of flowback for all wells were not the same. Based on cumulative gas production and flowback efficiency (Fig. 1), the wells can be classified into two groups:

- Low water and high gas production. Wells OP-R2, OP-R3, OP-L3, EV-L1, EV-L3 and EV-R3 belong to this group.
- High water and low gas production. Wells MU-R2, MU-R3, MU-L2, MU-L3 and OP-L1 belong to this group.