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Estimation of fracture height growth in layered tight/shale gas reservoirs using flowback gas rates and compositions—Part II: Field application in a liquid-rich tight reservoir

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While hydraulic fracturing is the key to unlocking the potential of unconventional low-permeability hydrocarbon resources, challenges remain in the monitoring of subsurface propagation of fractures and the determination of which geologic intervals have been contacted. This is particularly challenging for wells that are completed in multiple hydraulic fracture stages (multi-fractured horizontal wells or MFHWs) where fracture spacing may be very close and fracture geometry complex. Understanding the fracture extent is important not only for assisting with hydraulic fracture design, but also for mitigating unwanted fracture growth into non-target geologic intervals that do not contain hydrocarbons (e.g. zones with high water saturation). Popular current technologies used for hydraulic fracture surveillance include microseismic (surface and subsurface monitoring) and tiltmeter surveys. While these methods have proven useful for characterizing the extent of created hydraulic fractures, they do not necessarily lead to an understanding of what portions of the geologic section (bounding and target intervals for MFHWs, for example) are in direct hydraulic communication with the well.

A solution for establishing the extent of hydraulic fracture growth from target to bounding zones is to first obtain a fluid composition fingerprint of those intervals while drilling through them, and then compare these data with fluid compositions obtained from flowback after hydraulic fracturing. In the current work, a MFHW completed in a liquid-rich tight reservoir is used to test this novel concept. Gas samples extracted from the headspace of isojars® containing cuttings samples, obtained during drilling of the MFHW well, were used to geochemically fingerprint geologic intervals through which the well was drilled. The cuttings samples were collected at high frequency in the vertical, bend and lateral sections of the well over a measured depth range of 4725 ft (1440 m). A compositional marker was identified in the bend of the horizontal well above which the average methane to ethane (C_1/C_2) ratio was 15.7, versus 2.6 below it. The flowback gas compositions were observed to be intermediate (average $C_1/C_2 = 7.4$) between the reservoir above and below the marker, suggesting fracture height grew above the compositional marker.

In order to estimate fracture height growth from the geologic interval and flowback compositions, a compositional numerical simulation study was performed. An innovative approach was used to estimate recombined in-situ fluid compositions, on a layer-by-layer basis, by combining the cuttings gas compositional data with separator oil compositions. The resulting numerical simulation model, initialized through use of the layered fluid model and a detailed geological model developed for the subject well and offset drilling locations, was used to history match flowback rates, pressures and gas compositions. The gas compositions of the fingerprinted geologic intervals were therefore employed as a constraint on fracture height growth, estimated in the model to be 175 ft (53 m, propped height). However, because of the uncertainty in model input parameters, a stochastic approach was required to derive a range in hydraulic fracture properties.

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The current study demonstrates for the first time that it is possible to constrain fracture height growth estimates from flowback data, combined with gas compositional data obtained from cuttings data, provided that the geochemical fingerprints are distinct.

1. Introduction

Multi-fractured horizontal wells (MFHWs) have become commonplace in the development of low-permeability (tight) reservoirs, and the resulting hydraulic fracture network created during stage-by-stage stimulation treatments is critical for achieving maximum well performance (Gandossi, 2013). Therefore characterization methods that can be used to evaluate the effectiveness of hydraulic fracture networks are important for improved design of stimulation treatments. An equal, if not more important, goal of characterization, is the determination of the extent of the hydraulic fracture network spatially, including potential contact with non-target geologic intervals. One way to address these concerns, as well as improve fracture characterization for design considerations, is to provide methods that allow the portion of the geologic column that is in direct hydraulic communication with the well through the fracture network to be determined. Until now, such methods have proven elusive.

Current methods for hydraulic fracture characterization range from remote sensing to pressure-transient analysis-based techniques. These methods can be further classified by their temporal relationship to the stimulation treatment: syn- and post-stimulation (Clarkson et al., 2014). Syn-stimulation methods, which refer to characterization methods that use data collected during the stimulation treatment, include microseismic and tilmeter surveys, distributed temperature and acoustic surveys (DTS/DAS), and net pressure analysis (frac modeling). Microseismic surveys (Warpinski, 2009; van der Baan et al., 2013; Yousefzadeh et al., 2015) can be used to infer fracture location, orientation and geometry from the location of microseisms generated during hydraulic fracturing; failure mechanisms may also be inferred. Tiltmeter surveys (Wright et al., 1998; Fisher and Warpinski, 2012) may be also used to infer fracture orientation and geometry based on measured rock mass displacements, and can combined with microseismic data for improving hydraulic fracture diagnostics (Warpinski et al., 2006). DTS/DAS have proven useful for detecting sections of the horizontal lateral that have been stimulated (Cannon and Aminzadeh, 2013; Sookprasong et al., 2014; Wheaton et al., 2016), while stimulation treatment data combined with hydraulic fracture modeling can be used to interpret fracture properties such as fracture conductivity and height growth (Liu and Valko, 2015; Bai et al., 2016). None of these methods provide a direct indication of what portions of the reservoir are in direct communication with the well. Post-stimulation methods include chemical tracer surveys, pressure-transient analysis (e.g. flow/buildup welltest analysis) and rate-transient analysis of short-term (flowback) and long-term (online) production data. Chemical tracers involve doping of frac fluids with a variety of chemicals (by stage), enabling the source of inflow (successful stages) to the well to be determined (Salman et al., 2014). However, native fluid properties are usually not sufficiently evaluated and considered when using this technique. Pressure-transient analysis/rate-transient analysis (PTA/RTA) techniques may be used to infer certain properties of the fracture (e.g. Barree et al., 2005) through interpretation of flow-regimes related to hydraulic fractures (e.g. bilinear, linear flow). Flowback analysis, an evolving form of RTA, has proven useful for estimation of the pore volume associated with propped and unpropped hydraulic fractures (e.g. Abbasi et al., 2014; Clarkson et al., 2014; Williams-Kovacs and Clarkson, 2016); recent studies have even included analysis of salinity and fluid chemistry data (e.g. Zolfaghari et al., 2016) to provide additional constraints on this analysis. However, these methods cannot be used to evaluate fracture height growth without additional constraints. An important additional constraint not previously considered is hydrocarbon composition sampled from bounding and target intervals as well as the composition of flowback fluids.

In the Part I paper, Ghaderi and Clarkson (2016) suggested that if bounding and target interval fluids (e.g. natural gas) can be fingerprinted and are found to be geochemically distinct, then this information, combined with flowback gas compositions and rate-transient analysis of flowback rates/flowing pressures, may be used to assess the degree of fracture penetration into the bounding interval of a 2-layer system. An analytical method was developed for this purpose, and tested using numerical simulation. The initial technique however is limited to a 2-layer system, a dry gas reservoir, and assumes that the flowback signature is primarily linear flow. With the current focus of unconventional reservoir development on liquid-rich plays, and with the possibility of more complex (e.g. multi-layer) reservoir and fluid behavior, more sophisticated methods such as compositional numerical simulation may be required to interpret fracture height growth using flowback data. The intent of the current (Part II) paper is to apply the concept introduced by the Part I paper to a multi-layer liquid-rich tight reservoir with the aid of compositional numerical simulation.

Kanfar and Clarkson (2016) recently demonstrated a workflow that combined compositional numerical simulation (using a triple porosity framework for modeling the hydraulic fracture network) with stochastic methods to enable flowback and online production data to be interpreted for fracture and reservoir properties associated with a liquid-rich tight gas reservoir. However, fracture height was assumed to be constrained to the height of the target interval. The current work expands the use of the Kanfar and Clarkson (2016) approach for flowback analysis to include estimation of fracture height growth by adding reservoir/flowback fluid compositions as a constraint.

The objective of this study was to develop a combined geochemical and modeling approach that enables estimation of fracture height growth in reservoirs where fluid chemistries vary vertically. The herein presented case study illustrates the use of gas compositions collected while drilling, as well as flowback fluid compositions, to constrain fracture height estimation obtained from compositional numerical simulation. Gas cuttings samples, collected while drilling and placed in isojars®, were used to derive gas sample fingerprinting at a high resolution in the vertical, bend and lateral sections of a well completed in a liquid-rich tight reservoir. These data in turn allowed gas compositions at various intervals within the zone containing the well to be distinguished. After hydraulic fracture stimulation of the subject well heel stages, the flowback fluids were sampled and gas compositions determined to allow for comparison with those obtained while drilling. A detailed geologic model, constructed for the development area containing the subject well, as well as the new gas compositional