Science of the Total Environment 574 (2017) 314–321

Contents lists available at ScienceDirect

Science of the Total Environment

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

# Quantity of flowback and produced waters from unconventional oil and gas exploration

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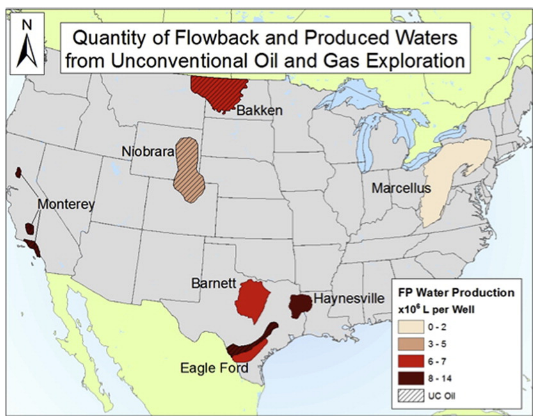
## HIGHLIGHTS

- Estimated flowback and produced water volume from unconventional oil and gas wells is 1.7 to 14.3 × $10^6$ L per well.
- A small fraction (4-8%) of the flowback and produced waters is composed of returned injected hydraulic fracturing fluids.
- The majority (92-96%) of flowback and produced waters is composed of naturally occurring formation brines.
- A significant volume (20-50%) of unconventional oil and gas wastewater is generated during first 6 months of production.

## GRAPHICAL ABSTRACT




## ARTICLE INFO

*Article history:*
Received 3 August 2016
Received in revised form 8 September 2016
Accepted 9 September 2016
Available online xxxx

Editor: D. Barcelo

*Keywords:*
Hydraulic fracturing
Wastewater
Brines
Unconventional energy
Shale gas
Tight oil
Flowback fluids
Produced water

## ABSTRACT

The management and disposal of flowback and produced waters (FP water) is one of the greatest challenges associated with unconventional oil and gas development. The development and production of unconventional natural gas and oil is projected to increase in the coming years, and a better understanding of the volume and quality of FP water is crucial for the safe management of the associated wastewater. We analyzed production data using multiple statistical methods to estimate the total FP water generated per well from six of the major unconventional oil and gas formations in the United States. The estimated median volume ranges from 1.7 to 14.3 million L (0.5 to 3.8 million gal) of FP per well over the first 5–10 years of production. Using temporal volume production and water quality data, we show a rapid increase of the salinity associated with a decrease of FP production rates during the first months of unconventional oil and gas production. Based on mass-balance calculations, we estimate that only 4–8% of FP water is composed of returned injected hydraulic fracturing fluids, while the remaining 92–96% of FP water is derived from naturally occurring formation brines that is extracted together with oil and gas. The salinity and chemical composition of the formation brines are therefore the main limiting factors for beneficial reuse of unconventional oil and gas wastewater.



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http://dx.doi.org/10.1016/j.scitotenv.2016.09.069

## 1. Introduction

Following the rapid development of unconventional oil and gas in the United States, problems arising from the management, disposal, and spills of associated wastewater have become major environmental issues associated with hydraulic fracturing (Kahrilas et al., 2015; Lauer et al., 2016; McLaughlin et al., 2016; Mohan et al., 2013; Warner et al., 2013). Over the last decade, the most common disposal practice in the U.S. has involved injection of FP water into Class 2 brine disposal wells, which has recently been reported to induce micro-scale earthquakes (Clark and Veil, 2009; Ellsworth, 2013; Veil, 2015; Vengosh et al., 2014; Weingarten et al., 2015), and in one case, also contamination of surface water (Akob et al., 2016; Kassotis et al., 2016). Geological limitations for injection wells, technological and economic barriers to treatment prior to disposal, water scarcity issues, and other management practices have led to an increased interest in evaluating the potential for reuse of FP water (Clark and Veil, 2009; Lutz et al., 2013; Stepan et al., 2010; Veil, 2010; Veil, 2015). Currently, well lifetimes are projected to be around 30 years, meaning that during downturn periods when only few new wells are being drilled, as is currently (summer and fall 2016) the case, thousands of wells already in production nation-wide will continue producing wastewater (Bai et al., 2013). Long term projections estimate that the growth of the hydraulic fracturing waste water treatment and recycling technologies will be significant, accounting for an estimated \$3.8 billion in revenue by 2025 (Wrobetz and Gartner, 2016). This projected growth calls for the necessity for a better understanding of the volumes and quality of wastewater produced from unconventional oil and gas exploration.

When a well is hydraulically fractured, it is done so in stages, with each stage being plugged, while the next is being drilled and fractured (Mohammad et al., 2014; Wang and Zhang, 2014). This creates an increase in pressure and a backup of both fluids and gas, while further stages are drilled. When the final stage is drilled, the fluids and gas are allowed to flow up out of the well for a period of time of up to about 2 months (Mantell, 2011). Many operators call this stage the “Flowback” period, where the water returning from the well is made up partially of drilling and injected hydraulic fracturing fluids, and formation brines that are entrapped in the target formations and are extracted together with the oil and gas (Barbot et al., 2013; Gregory et al., 2011; Veil, 2010). Water generated after the flowback period, during the lifetime of oil and gas production, is commonly called “produced water” (Gregory et al., 2011; Mantell, 2011). The distinction between “flowback” and “produced water” definitions can be subjective when reporting data, and combined flowback and produced water (FP Water) data are reported in many instances without a specific distinction. In this study, we examine the volume and salinity of FP water generated through time, and use the water salinity data to distinguish the contribution of naturally occurring formation brines relative to the returned hydraulic fracturing fluids, which together generate the FP water (Bai et al., 2013; Blondes et al., 2015; Clark and Veil, 2009; Gregory et al., 2011; Mantell, 2011; Rowan et al., 2015; Veil, 2010; Veil, 2015; Veil et al., 2004; Warner et al., 2013). In many cases hydraulic fracturing is conducted with freshwater, although reuse of FP water is becoming more common in some areas like in the Marcellus Formation. When using freshwater for hydraulic fracturing, the FP water initially has low salinity, yet mixing with formation brines quickly raises the salinity of the water generated during the first several weeks of production and eventually leveling out to values that represent the maximum level of salinity of the formation brines, typically between 2 and 3 months since hydraulic fracturing (Balashov et al., 2015; Barbot et al., 2013).

When quantifying the variations of water production volumes across formations with time, several methods have been used to generalize production rates within unconventional oil and gas basins in the U.S. (Bai et al., 2013; Balashov et al., 2015; Kondash and Vengosh, 2015; Lutz et al., 2013; Nicot and Scanlon, 2012; Nicot et al., 2014; Scanlon et al., 2014a; Scanlon et al., 2014b; Valko, 2009). Depending on the method used to interpret the data, vastly different quantities of wastewater have been reported for the same basin over similar time periods (Kondash and Vengosh, 2015; Scanlon et al., 2014a). In order to evaluate the reason for these discrepancies, we examine three different methods for quantifying FP water volume that include mean values, median values, and mean values obtain from DrillingInfo Desktop's Type Curve tool, a software that provides data on oil and gas wastewater volume (DrillingInfo, 2015). We show in this paper that the different methodologies could result in different volumetric estimates for FP water from unconventional oil and gas exploration.

Based on the integration of the wastewater volume and flowback water salinity data, this study aims to evaluate the overall and dynamic volume variations and differential salinity of wastewater generated from unconventional oil and gas wells. The ultimate objective of this study is to evaluate the relative proportions of returned hydraulic fracturing fluids relative to naturally occurring formation water in FP water during the lifetime of unconventional oil and gas wells. Through understanding the temporal variability in water quantity and water quality, researchers and industry professionals could evaluate, design, and implement best management practices for FP water (Murray, 2013; Stepan et al., 2010; Veil, 2015).

## 2. Materials and methods

### 2.1. Data sources

The DrillingInfo Desktop application was used to download data for wells in the major unconventional gas and oil formations in the United States, focusing on the oil, gas, and FP water production values of each well on a monthly basis (DrillingInfo, 2015). We used two methods to extract production values from DrillingInfo (DI) Desktop. The application's “Type Curve” function produces a decline curve for the reservoir of interest, compiling monthly production data and adjusting the curves as if each well began at the same time. This average monthly data was then downloaded and graphed to produce the first decline curve reported in this paper (light blue line in Figs. S1, S2). DrillingInfo Desktop also allows the raw data to be downloaded for each well. We compiled monthly raw water, oil, and gas production data from the DI Desktop program, similarly adjusting first production to begin all wells at the same time, then created individual decline curves based on both the mean and median values obtained from the downloaded raw data. We calculated bootstrap confidence intervals of monthly production data for both the mean and median data sets (Figs. S1, S2). The process of calculating bootstrap confidence intervals involves randomly sampling with replacement, from the original dataset to form a new distribution of sampled mean or median values (Efron and Tibshirani, 1994; Lutz et al., 2013). This process is often called resampling. Bootstrap confidence intervals were calculated by resampling from the original dataset to form distributions of the resampled means and medians. Each resample was the same size as the original sampled data and the resampling process was repeated 10,000 times to form the resampled distributions. The 95% confidence intervals were gleaned from the resampled distributions (values at the 0.025 and 0.975 percentiles). The bootstrap confidence interval provides a reliable estimate of the variations of production at any point in time (shaded regions of Figs. S1, S2, Table S1).

### 2.2. Data analysis

Decline curves were first used by Arps (1945) to estimate ultimate recovery of currently producing conventional wells using limited data from initial production. Since then, varying empirical and theoretical methods have emerged attempting to estimate ultimate recovery of oil, natural gas, and FP water (Arps, 1945; Bai et al., 2013; Ilk et al., 2008; Jackson et al., 2014; Mutalik and Joshi, 1992; Valko and Lee, 2010; Wang and Zhang, 2014). We used data provided by DrillingInfo