



Development of a halite dissolution numerical model for hydraulically fractured shale formations (Part I)



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SUMMARY

Gas-shales are gas bearing organic-rich mudstone with extensive natural fractures. Matrix permeability is typically in the region of 10^{-4} mD or less, and pore throat sizes are in the vicinity of 100–1000 nm. Consequently, stimulation is required to achieve economic gas recovery rates. Horizontal wells combined with successful multi-stage hydraulic fracture treatments are currently the most established method for effectively stimulating such formations.

The injected fracture fluid typically contains 1–7% KCl for the purpose of clay stabilization. However chemical analysis of the flowback water shows that it contains 10–20 times more dissolved solids than the injected fluid; total dissolved solids (TDS) can be as high as 197,000 mg/L with chloride levels alone being as much as 1,510,000 mg/L (Haluszczak et al., 2013).

This paper outlines the development and validation of a fully implicit fluid transport and halite dissolution numerical model that is used to predict and analyze the ionic compositions of flowback water from hydraulically fractured shale formations. The simulator is designed to predict the concentration of Na^+ and Cl^- , which are the two most predominant ionic species in flowback water. The paper presents a method for numerically simulating halite dissolution using the dual porosity dual permeability paradigm (DPDP) as the foundation for fluid transport in fractured reservoir.

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1. Introduction

Gas shales are sedimentary rocks that comprise very fine grained, organic rich silt and clay particles. These formations are defined by their ability to serve as both source and reservoir rock, and the extremely small pore throat diameter within the rock matrix. Unlike conventional reservoirs, which typically have permeabilities in the range of millidarcies or darcies, shale gas reservoirs have permeabilities in the range of nanodarcies. Consequently these reservoirs are incapable of producing economically feasible rates of gas or oil without effective stimulation.

Horizontal wells combined with successful multi-stage hydraulic fracture treatments are currently the most established method for effectively stimulating, and enabling economic development of gas bearing organic-rich shale formations. Hydraulic fracturing process reinitiates natural fractures and creates new hydraulic fractures. The process essentially creates a fracture network in the stimulated reservoir that resembles the leafless limbs of a tree,

with branches propagating from the perforations and limbs intersecting and overlapping.

All hydraulic fracturing jobs require a post-stimulation flow period (cleanup) to prepare the well for long-term production. However the reservoir typically captures a percentage of the injected fluid that may later hinder oil and gas flow. The volume of fracture fluid captured is a function of the formation geology and engineering operations; the percentage of fracture fluid recovered is one of the key indicators of fracture treatment effectiveness.

1.1. Flowback water volume and composition

A survey conducted in 1995 by the American Petroleum Institute (API) showed that the US exploration and production segment of the oil and gas industry generated almost 18 billion bbl of produced water that was transported to offsite commercial disposal facilities (Puder and Veil, 2006). The EPA estimates that national flowback water volume ranges from 10% to 70% of the injected fluid (EPA, 2012); recovery in Marcellus shale is in the range of 9–15%. In a multistage fracture treatment for example, each stage typically stimulates 300–500 ft and requires 300,000–600,000 gallons of water. A multistage fracture treatment on a 4000 ft lateral

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Nomenclature

A	Area, ft ²	z	Gas compressibility factor
B_w	Water formation volume factor, RB/STB	Z	Elevation referenced from datum, ft
C_g	Gas concentration, lbm-mol/cu ft	α_c	Volume conversion factor, 5.614583
D_c	Diffusivity coefficient, ft ² /D	β_c	Transmissibility conversion factor, 1.127
k	Absolute permeability, mD	β^*	non-Darcy coefficient, ft ⁻¹
k_r	Relative permeability, mD	Φ	Potential, psi
m_c	Component 'c' weight fraction, lbm/lbm	ρ	Density, lbm/ft ³
$m_{c,hd}$	Mass of component 'c' from halite dissolution	ϕ	Porosity, fraction
M	Molar mass, g/mol	μ	Viscosity, cp
P_{cgw}	Capillary pressure (gas and water phase), psi	γ_p	Gravity of phase p , psi/ft
p	Pressure, psi	v	Superficial velocity, RB/(D-ft ²)
P_L	Langmuir pressure, psi	v^*	non-Darcy flow velocity, ft/D
q_w	Water flow rate, STB/D	Δ	Gradient operator
S	Skin factor		
s	Saturation, fraction		
V_b	Bulk volume, ft ³	Subscripts	
V_E	Volume of adsorbed gas per unit volume of reservoir rock, scf/cu ft	F	Fracture domain
V_L	Langmuir volume, scf/cu ft	g	Gas phase
Δx	Distance along the x -direction, ft	Ma	Matrix domain
Δy	Distance along the y -direction, ft	Ma_F	Matrix – fracture domain boundary
Δz	Distance along the z -direction, ft	sc	Std. conditions
		w	Water phase

in Marcellus shale will typically comprise 8–13 stages and will require 2.4–7.8 million gallons of water. Fluid cleanup from such a treatment will return 216,000–2.7 million gallons of water per well.

This wastewater stream typically contains proppants, dissolved salts and other minerals. Chemical analysis performed on flowback water shows that the TDS can reach concentrations that are 10–20 times greater than those present in the injected fluid (Hayes and Severin, 2012). Haluszczak et al. (2013) presented flowback water composition data that showed TDS as high as 197,000 mg/L, and chloride levels as high as 151,000 mg/L. These concentrations are substantially higher than the average TDS for seawater, which falls in the vicinity of 35,000 mg/L. Stepan et al. (2010), in their analysis of the feasibility of recycling flowback water in Bakken Shale, noted TDS concentrations in the region of 200,000 ppm. The source of this extra salt in Marcellus shale for example, has been attributed to seawater that has evaporated leaving crystalline salt deposits, and concentrated brine solution in the shale formation (Dresel, 1985). Current knowledge suggests that the high TDS in flowback water is the direct result of mixing between the injected fluid and this concentrated brine and dissolution of the before mentioned crystalline salt deposits.

From an environmental and public health standpoint, the volume and composition of flowback water is important, but an operator's ability to anticipate the composition and volume, and plan for the management of this waste is of critical importance. High salinity flowback water poses a serious threat to the environment because publicly owned water treatment works, and most central water treatment facilities cannot process this water to an acceptable level that will permit disposal into surface streams. Treatment of flowback water with this level of salinity requires specialized process such as crystallization (zero liquid discharge), thermal distillation, electro dialysis, reverse osmosis, forward osmosis and/or ion exchange, which are not typically found at conventional treatment facilities. Such processes are usually only found at facilities specifically designed to treat flowback water or water of similar composition. Furthermore such facilities are not found in all states practicing hydraulic fracturing, and for some states where this treatment option is available, the treatment facilities are limited

and cannot meet the demand of the hydraulic fracturing industry (Puder and Veil, 2006).

The ensuing sections of this manuscript details the method used to develop a 2-phase, 3-Dimensional, fully implicit numerical model that predicts the volume and salinity of flowback water. The model accounts for halite dissolution in the formation, and the contribution of in situ formation brine to observed changes in injected fluid salinity. The model incorporates the dual porosity dual permeability paradigm as its foundation for fluid transport in a fractured reservoir. The intent of this paper is to give the reader a detailed understanding of the steps/processes involved in developing the, from the formulation and linearization of the flow equations to the coupling of the halite dissolution process and solving the final system of equations.

2. Model development

The numerical model comprises an ion transport and halite dissolution module that is sequentially coupled to a fully implicit, dual porosity, finite difference simulator (Fig. 1). It should be noted at this point that the numerical simulator was developed not only to assess the impact of halite dissolution on flowback water salinity, but also to assess the effects of fracture cleanup, and the impact that rock compressibility, gas slippage, gas desorption, proppant diagenesis, proppant crushing and non-Darcy flow have on post fracture well performance. Consequently, the program logic outlined in Appendix 1 goes a bit beyond the scope of this paper. These model features are presented in other works by the authors and are therefore not included here.

The simulator has three (3) essential modules, all of which are coupled sequentially as illustrated in Fig. 1. The first module uses finite difference and the dual porosity dual permeability concept to determine pressures and phase saturations across time and space in the simulated reservoir in both the matrix and fracture domain. The second module uses the calculated pressures and phase saturations from module 1 to determine the change in ion concentration in each numerical gridblock in both the matrix and fracture domain. Finally, the third module determines the mass of halite that dissolves and is added to the injected fluid. The ion

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