International Journal of Greenhouse Gas Control 74 (2018) 142–154

Contents lists available at ScienceDirect

International Journal of Greenhouse Gas Control

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

Development of an analytical simulation tool for storage capacity estimation of saline aquifers

Reza Ganjdanesh*, Seyyed A. Hosseini

Bureau of Economic Geology, Jackson School of Geosciences, The University of Texas at Austin, Austin, TX, United States

ARTICLE INFO

Keywords:
Enhanced analytical simulation tool
EASiTool
Dynamic capacity estimation
CO_2 storage in saline aquifers
Pressure buildup
Brine extraction

ABSTRACT

An enhanced analytical simulation tool (EASiTool) was developed to estimate CO_2 storage capacity in saline aquifers. The tool provides a quantitative estimate of storage capacity for multi-well injection/extraction systems by applying novel analytical models for both closed- and open-boundary saline aquifers and analyzes the potential of enhancing storage efficiency by integrating active brine management (brine extraction technology). EASiTool includes a user-friendly interface and can be used to provide reservoir and basin-scale storage capacity estimates. The software and user manual are available for download at: http://www.beg.utexas.edu/gccc/EASiTool/.

1. Introduction

Geologic storage of CO_2, captured from industrial sources is intended to help reduce CO_2 atmospheric emissions. CO_2 injection results in a pressure increase in the storage formation (Cihan et al., 2013; Nicot, 2008). The magnitude of the pressure increase, which varies with time and location, is of major concern and can limit storage capacity and well injectivity. Pressure increases near the wellbore impact injectivity (how rapidly CO_2 can be injected through the injection well), and, at the reservoir scale, pressure increases affect the cumulative storage capacity of the reservoir. The pressure effect is important because the "pressure plume" is much larger than the CO_2 plume during injection as a result of the diffusive nature of pressure transport (Birkholzer et al., 2011). Although most of the pressure buildup occurs near the wellbore, the regional pressure increase caused by injecting CO_2 inversely impacts the injectivity of the neighboring injectors. The pressure interference in a multi-well system does not allow the total injectivity to increase linearly with the number of injectors (Pooladi-Darvish et al., 2011). The type of boundary condition is another top criterion that characterizes the pressure distribution and injectivity. For closed-boundary formations, the injected CO_2 into a porous formation is accommodated by compression of formation fluid and rock material. For open-boundary formations, additional CO_2 can be accommodated by the displacement of native brine out of the host formation (Mathias et al., 2011b). Another critical concern is the impact of pressure buildup on the integrity of the storage formation and caprock (Mathias et al., 2009; Rutqvist et al., 2008). The estimated pressure buildup should not exceed the maximum allowable injection pressure (Kim and Hosseini, 2014). A satisfactory estimate of the fracturing pressure is needed to assess the storage capacity of a given formation. A viable approach for management of formation pressure is to extract the native brine residing in the storage reservoir to create additional pore volume for injected CO_2 (Birkholzer et al., 2012; Buscheck et al., 2011; Ganjdanesh et al., 2015, 2014; Heath et al., 2014). Though the brine extraction should not be considered as a required element of CO_2 storage, it can benefit many projects by improving injectivity, increasing storage capacity, reducing failure risk, managing CO_2 plume movement, and lowering monitoring costs. This strategy decouples the pressure interference of neighboring CO_2 operations from each other, which potentially can reduce the site characterization and monitoring costs (Buscheck et al., 2011; Goudarzi et al., in press). The extracted brine can be used in a desalination process or be disposed in another saline formation.

Current analytical models developed to estimate pressure buildup are based on single-well models and are difficult to implement by nontechnical users (Azizi and Cinar, 2013a; Ehlig-Economides and Economides, 2010; Mathias et al., 2011a; Nordbotten et al., 2005; Zeidouni et al., 2009). To our knowledge, no analytical simulation tool for reservoir-scale storage capacity estimation has addressed all the concepts listed above. Although commercial numerical simulators can address all these issues, they are time consuming and expensive, and require highly technical individuals to run them. Also, their large, sophisticated data requirements typically exceed the level that can be supported by available field data. This fundamental difference has direct implications for uncertainty quantification, when a range of possible predictions is needed based on uncertainty in model inputs.

* Corresponding author.
E-mail address: reza.ganjdanesh@beg.utexas.edu (R. Ganjdanesh).

https://doi.org/10.1016/j.ijggc.2018.04.017
Received 1 November 2017; Received in revised form 14 March 2018; Accepted 24 April 2018

Nomenclature

B_g	Gas formation volume factor, rm^3/sm^3
c_g	Gas compressibility, Pa^{-1}
c_r	Rock compressibility, Pa^{-1}
c_w	Brine compressibility, Pa^{-1}
c_t	Total compressibility, $S_g c_g + (1 - S_g)c_w + c_r$, Pa^{-1}
Ei	Exponential integral function
E_S	Storage efficiency, $(-)$
f_g	Fractional flow of gas
$F_{\lambda g}$	$(\lambda_g + \lambda_w)/\overline{\lambda_g}\|_{S_{g,ave}}$, $(-)$
h	Formation thickness, m
k	Permeability, m^2
k_{rg}	Gas relative permeability, $(-)$
$\overline{k_{rg}}$	Gas relative permeability in gas zone, $(-)$
k_{rw}	Brine relative permeability, $(-)$
$\overline{k_{rw}}$	Brine relative permeability in brine zone, $(-)$
P	Pressure, Pa
P_D	$2\pi hk\overline{k_{rg}}(P - P_i)/q_{Inj}B_g\mu_g$, $(-)$
P_{DExt}	$2\pi hk(P_i - P)/q_{Ext}B_w\mu_w$, $(-)$
P_i	Formation initial pressure, Pa
q_{inj}	Gas injection rate, sm^3/s
q_{ext}	Brine extraction rate, sm^3/s
r	Radius, m
r_{BL}	Radius of Buckley-Leverett front, m
r_D	Dimensionless radius, r/r_w
r_{dry}	Radius of dry front, m
r_e	Formation external boundary radius, m
r_{eD}	r_e/r_w, $(-)$
r_w	Wellbore radius, m
S_g	Gas saturation, $(-)$
S_{gBL}	Gas saturation of Buckley-Leverett front, $(-)$
S_{gdry}	Gas saturation of dry front, $(-)$
t	Time, s
t_D	$k\overline{k_{rg}}t/\mu_g\phi r_w^2(c_g + c_r)$, $(-)$
t_{DExt}	$kt/\mu_w\phi r_w^2(c_w + c_r)$, $(-)$
γ	Euler's constant, 0.577215
ε	$qB_g(c_g + c_r)\mu_g/4\pi hk\overline{k_{rg}}$, $(-)$
η_{D2}	$(c_g + c_r)/c_t\|_{S_{g,ave}}$, $(-)$
η_{D3}	$(\overline{\lambda_w}/\overline{\lambda_g})(c_g + c_r)/(c_w + c_r)$, $(-)$
λ_g	Gas mobility, k_{rg}/μ_g, 1/Pa.s
$\overline{\lambda_g}$	Gas mobility in gas zone, $\overline{k_{rg}}/\mu_g$, 1/Pa.s
λ_w	Gas mobility, k_{rw}/μ_w, 1/Pa.s
$\overline{\lambda_w}$	Gas mobility in gas zone, $\overline{k_{rw}}/\mu_w$, 1/Pa.s
μ_g	Gas viscosity, Pa.s
μ_w	Brine viscosity, Pa.s
ξ_{BL}	$1/4\varepsilon(df_g/dS_g)\|_{S_{gBL}}$, $(-)$
ξ_{dry}	$1/4\varepsilon(df_g/dS_g)\|_{S_{gdry}}$, $(-)$
φ	Porosity, $(-)$
ρ_{sat}	Saturated rock density, kg/m^3
α	Biot's coefficient, $(-)$
ν	Poisson's ratio, $(-)$
K	Initial total horizontal-to-vertical ratio, $(-)$
α_T	Coefficient of thermal expansion, 1/K
ΔT	Temperature drop, K
E	Young's modulus, Pa
σ_{v0}	Initial vertical stress, Pa
σ_{H0}	Initial maximum horizontal stress, Pa
σ_{h0}	Initial minimum horizontal stress, Pa
β_h	Horizontal pore-pressure/stress coupling ratio, $\frac{\Delta\sigma_h}{\Delta P} = \frac{\Delta\sigma_H}{\Delta P}$, $(-)$
β_v	Vertical pore-pressure/stress coupling ratio, $\frac{\Delta\sigma_v}{\Delta P}$, $(-)$
μ	Coefficient of the fault friction, $\tan\phi$, $(-)$
ϕ	Fault friction angle, (radian)
θ	Fault plane angle with respect to minor principal stress, (radian)

Current simple methodologies in calculation of storage capacities, according to a DOE/NETL carbon sequestration report, are based on static properties of the formations – e.g., porosity, area, and thickness – combined with an empirical storage efficiency factor (NETL, 2010), which does not consider the dynamic behavior of the process. Several volumetric methods have been developed to estimate the storage resource potential, such as the Carbon Sequestration Leadership Forum method (CSLF, 2008), the University of North Dakota Energy & Environmental Research Center method (Gorecki et al., 2009), and the DOE/NETL (NETL, 2010) and USGS (Brennan et al., 2010) approaches. In dynamic capacity estimation, characteristics of the storage operation – e.g., number of injectors, duration of injection, injection rates, areal extent of operation, and brine extraction – considerably affect the storage capacity assessment.

In this study, an Enhanced Analytical Simulation Tool (EASiTool) for simplified reservoir models is developed to predict pressure impact on CO_2 injectivity and reservoir storage capacity of geologic formations (Ganjdanesh and Hosseini, 2017; GCCC, 2017). The EASiTool includes three major features: (1) an advanced closed-form, analytical solution (Azizi and Cinar, 2013a,b; Hosseini et al., 2014; Mathias et al., 2011a) for pressure buildup calculations that is used to estimate both injectivity and reservoir-scale pressure elevation, in both closed- and open-boundary formations; (2) a simple geomechanical model coupled with the base model to evaluate and avoid the possibility of fracturing reservoir rocks by injecting cold, supercritical CO_2 into hot formations (Kim and Hosseini, 2015, 2014); and (3) an analytical solution to assess the possibility of enhancing storage efficiency by integrating brine management (Dake, 1998; Earlougher et al., 1968; Ganjdanesh and Hosseini, 2017). In addition, the EASiTool is complemented by a sensitivity analysis tool that allows users to assess the effect of input parameter uncertainties on model prediction, and to support risk assessment and decision making. This is done by assuming a user-defined change in input parameter (one parameter at a time) and running the simulation to recalculate the storage capacity. Results of a sensitivity analysis are plotted in tornado charts for both open- and closed-boundary conditions.

In this study, we formulated the analytical models implemented in the toolbox using MATLAB software. The results from the analytical approach (EASiTool) were compared with the output from the application of a detailed numerical simulator. The effect of brine extraction

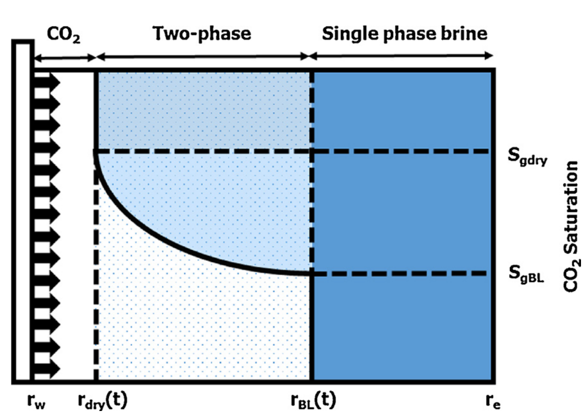

Fig. 1. Schematic diagram of the physical model showing the regions that develop from one-dimensional flow of CO_2 and brine through fully penetrating vertical wells (McMillan et al., 2008).