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Moslehi, S.; Voskov, D.

DOI
10.3997/2214-4609.202521225

Publication date
2025

Document Version
Final published version

Citation (APA)
Moslehi, S., & Voskov, D. (2025). *DARTS-well: An Open-Source Coupled Wellbore-Reservoir Numerical Model for Energy Transition Applications*. Paper presented at 6th EAGE Global Energy Transition Conference and Exhibition , Rotterdam, Netherlands. https://doi.org/10.3997/2214-4609.202521225

DARTS-well: An Open-Source Coupled Wellbore-Reservoir Numerical Model for Energy Transition Applications

S. Moslehi[1], D. Voskov[1,2]

[1] Delft University of Technology; [2] Stanford University

Summary

Subsurface CO_2 sequestration plays a crucial role in advancing carbon neutrality and supporting the transition to sustainable energy. However, the unique behavior of CO_2, particularly during cold CO_2 injection into depleted hydrocarbon reservoirs, poses challenges to wellbore injectivity. Addressing these challenges requires a numerical model that captures the complex interplay between wellbore dynamics and reservoir processes. In this work, we present DARTS-well, an open-source, fully coupled wellbore-reservoir model developed using the Operator-Based Linearization (OBL) technique. To this end, a transient, multi-segment, two-phase, non-isothermal wellbore model based on the Drift-Flux Model (DFM) is first developed and then coupled with the Delft Advanced Research Terra Simulator (DARTS) as the reservoir simulator. The model is demonstrated through test cases involving CO_2 injection into a depleted reservoir, illustrating its potential to enhance the design and optimization of subsurface CO_2 disposal systems.

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Introduction

The global shift toward a low-carbon future demands technologies to support the energy transition. Among these, subsurface solutions such as geothermal energy production, underground hydrogen storage, and carbon capture and sequestration (CCS) are among potential options. In particular, CO_2 sequestration in depleted or low-pressure hydrocarbon reservoirs has emerged as a viable pathway to mitigate greenhouse gas emissions. However, the complex behavior of CO_2 during injection in depleted reservoirs presents significant modeling challenges, especially in capturing the coupled dynamics between the wellbore and reservoir.

To address these challenges, we present DARTS-well: an open-source, fully-coupled wellbore-reservoir numerical simulator for energy transition applications. The model couples a non-isothermal transient multi-segment wellbore model based on a two-phase drift-flux model (DFM) with the DARTS reservoir simulator (Delft Advanced Research Terra Simulator) using Operator-Based Linearization (OBL). The framework enables accurate simulation of key phenomena, such as multiphase flow and thermal effects under dynamic injection scenarios. We demonstrate the capabilities of DARTS-well through some test cases involving CO_2 injection into a depleted reservoir, showcasing its potential to improve design and decision-making in subsurface systems.

Method

In this study, open-DARTS is used as the reservoir simulator and as the platform to solve the system of wellbore governing equations for the fully coupled well-reservoir model. Open-DARTS is a computationally efficient simulator that can be used to model various energy transition problems. In the framework of open-DARTS, the evaluation of the residuals and construction of the Jacobian matrix are done using the operator-based linearization (OBL) approach, which provides an opportunity to control the non-linearity in physics by changing the resolution of the parameter space, increasing performance, flexibility, and robustness of simulation (Khait and Voskov 2017).

To develop a multiphase wellbore model, the DFM is used and validated against OLGA (Bendlksen 1991) for single-phase and multiphase flows and vertical and inclined wells (Moslehi and Voskov 2025). To include and solve the wellbore governing equations in open-DARTS in a fully coupled manner, we reformulated the discretized mass conservation equation in our previous study (Moslehi and Voskov 2025) to allow seamless integration of well mass conservation equations into the system. In this study, we also reformulate the energy conservation equation in operator form, as follows

$$V_i\phi_{0i}[\alpha(\omega)-\alpha(\omega^n)]_i + V_i E_{\mathrm{p}}^i[\hat{\alpha}(\omega)-\hat{\alpha}(\omega^n)]_i$$
$$-\Delta t \sum_{l\in L(i)}\sum_{j=1}^{n_{\mathrm{p}}}[q_j\beta_j(\omega^{l,\mathrm{up}}) + q_i E_{\mathrm{p}}^l\hat{\rho}_j(\omega^{l,\mathrm{up}})] - \Delta t q_{E,i} = 0,$$

where

$$\alpha(\omega) = \sum_{j=1}^{n_{\mathrm{p}}} s_j\rho_j U_j\,, \qquad \hat{\alpha}(\omega) = \sum_{j=1}^{n_{\mathrm{p}}} s_j\hat{\rho}_j,$$

$$\beta_j(\omega) = \rho_j h_j, \qquad j = 1,\dots,n_{\mathrm{p}},$$

$$E_{\mathrm{p}}^i = g\times 10^{-3}(L_{\mathrm{w}} - z_i - z_{\mathrm{ref}})\cos\theta.$$

Here, V_i is the void volume of grid cell i, and ϕ_{0i} is its porosity, ω and ω^n denote the primary variables at the current and previous time steps, respectively, and Δt is the time step size. q_j is the phase volumetric rate (see our previous study for details on its calculation for wells, reservoirs, and perforation

connections), and $\hat{\rho}_j$ is the phase mass density. $q_{E,i}$ represents the energy source/sink term for grid cell i, while s_j, ρ_j, h_j and U_j denote phase saturation, molar density, molar enthalpy, and molar internal energy, respectively. n_p is the number of phases and g is the gravitational acceleration equal to 9.80665 m/s^2. E_p^i is phase specific potential energy at cell centroids, while E_p^l is phase specific potential energy at connections. L_w is the total well length, z the along-wellbore depth, and z_ref the along-wellbore depth of the well's lowermost segment centroid. Potential energy terms are included only for wells since depth variation along the wellbore is significant.

In the coupled model, the energy equation can be solved using either temperature or enthalpy as the primary variable. As the simulation involves single-phase flow without phase transitions, both options are numerically stable. The resulting nonlinear reservoir–wellbore system is solved iteratively using the Newton–Raphson method. During Jacobian assembly, phase volumetric rates in the reservoir and perforations are differentiated analytically, while those in the wellbore are differentiated numerically.

Test case

In this section, the developed coupled wellbore-reservoir model is used to simulate the injection of pure dry CO_2 into a depleted hydrocarbon reservoir, considering two permeability cases: 20 mD and 200 mD. The data for this test case are inspired by a depleted hydrocarbon reservoir in the North Sea, planned for CO_2 injection with the properties listed in Table 1. Here we used a mixture of CH_4-CO_2 with thermal fluid properties described in Wapperom and Voskov (2024). Under the conditions of this simulation, no phase transitions occur in the system, and as H_2O is not included, formation dry-out and hydrate formation effects are not considered in this study.

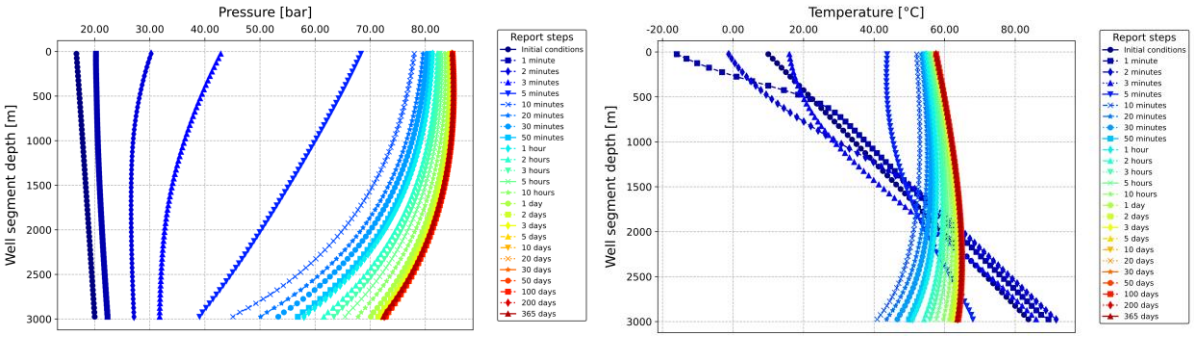
Table 1 *Reservoir and well properties used in the simulation.*

Wellbore Geometry	Inclination angle: 0 (Vertical wellbore) Total length: 3 km (60 segments, each segment 50 m) Diameter: 0.1 m Wall absolute roughness: 2.5×10^{-5} m
Reservoir Geometry	Grid type: A 2D cylindrical grid Thickness: 250 m (5 cell, each cell 50 m) Radius: 1000 m (50 cells with logarithmic spacing)
Reservoir Rock Properties	Porosity: 0.2 Horizontal/vertical permeability: 20/2 mD and 200/20 mD in the two cases Volumetric heat capacity: 2200 kJ/m^3-°C Thermal conductivity: 181.44 kJ/m-°C-day Compressibility: 0 bar^{-1}
Fluid Properties	Fluid density: Peng-Robinson equation of state (PR-EoS) Fluid enthalpy: PR-EoS Fluid viscosity: Fenghour et al. correlation (1998) Fluid thermal conductivity: 10 kJ/m-°C-day (Constant)
Initial Conditions	Wellhead pressure: 16.7 bar Reservoir pressure: 20 bar Wellhead temperature: 10°C Geothermal gradient: 0.025°C/km Reservoir temperature: 83.75°C Reservoir and well initial fluid composition: Pure CH_4 (s_w = 0) Fluid at rest (i.e., υ_{fluid} = 0 m/s)
Boundary Conditions	**At wellhead:** Injection rate: 20 kg/s (ramp-up time of 4 minutes) Injection fluid enthalpy: -2852 kJ/kmol (@ P = 55 bar and T = 30°C) Injected fluid composition: Pure CO_2 **Heat exchange between well and formations:** Method: Semi-analytical model using the Chiu and Thakur time function Pipe wall thickness: 5 mm Overall heat transfer coefficient (Ui): 0.2 BTU/ ft^2-hour-°F Rock specific heat capacity: 2500 J/kg-°C Rock thermal conductivity: 3 W/m-°C Rock density: 2100 kg/m^3 **At reservoir boundaries:** Constant pressure at radial boundaries using infinitely large grid cells

The profiles of pressure and temperature along the wellbore for the two reservoirs are plotted over time in Figures 1 and 2, respectively. As shown in Subfigures 1-a and 2-a, reservoir permeability has a significant impact on the pseudo-steady-state (PSS) bottom-hole pressure (BHP). Higher permeability results in a BHP closer to the far-field reservoir pressure to achieve the same injection rate. Consequently, as reservoir permeability is higher, the pressure drop from the wellhead to the bottom of the well increases, leading to a larger temperature drop along the wellbore. For example, in the 20-mD case, the PSS bottom-hole temperature (BHT) is 63°C, while in the 200-mD case, BHT is as low as

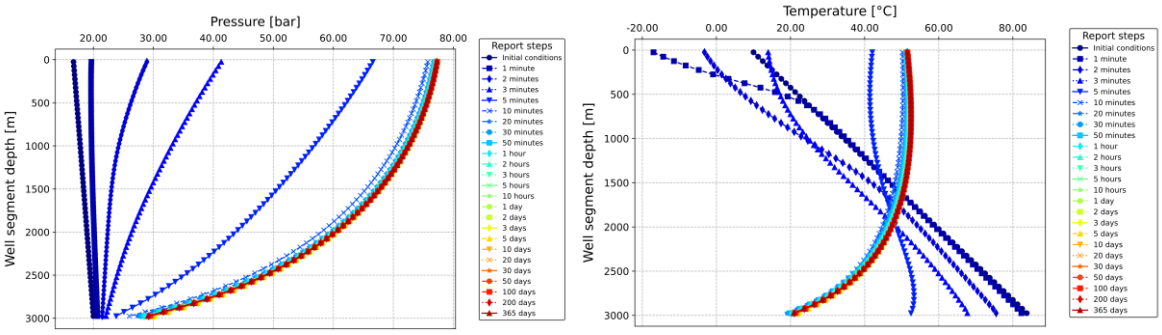
21°C. This has important implications for hydrate formation, which may occur at higher reservoir permeabilities and could negatively impact well injectivity.

Subfigures 1-b and 2-b illustrate the early-time thermal response during well start-up. At the onset of injection, rapid expansion of injected CO_2 causes cooling near the wellhead. However, the reservoir permeability has little influence on the minimum temperature observed at the wellhead during this initial phase.



(a) Pressure profiles. (b) Temperature profiles.

Figure 1 *Profiles of pressure and temperature along the wellbore over time for reservoir K = 20 mD.*



(a) Pressure profiles. (b) Temperature profiles.

Figure 2 *Profiles of pressure and temperature along the wellbore over time for reservoir K = 200 mD.*

Figures 3 and 4 show the distribution of reservoir fluid properties after one year of CO_2 injection for the two permeability cases. In both cases, the maximum reservoir pressure closely follows the BHP of their injection well. As previously discussed, a lower reservoir permeability necessitates a higher BHP to sustain the same injection rate. This leads to a denser injected fluid near the wellbore, which is clearly reflected in the density distribution subfigures. In contrast, for the higher-permeability reservoir, the BHP is closer to the far-field pressure, resulting in a larger pressure gradient and thus greater cooling of the injected CO_2. This effect is visible in the temperature distribution subfigures, where lower injected fluid temperatures are observed.

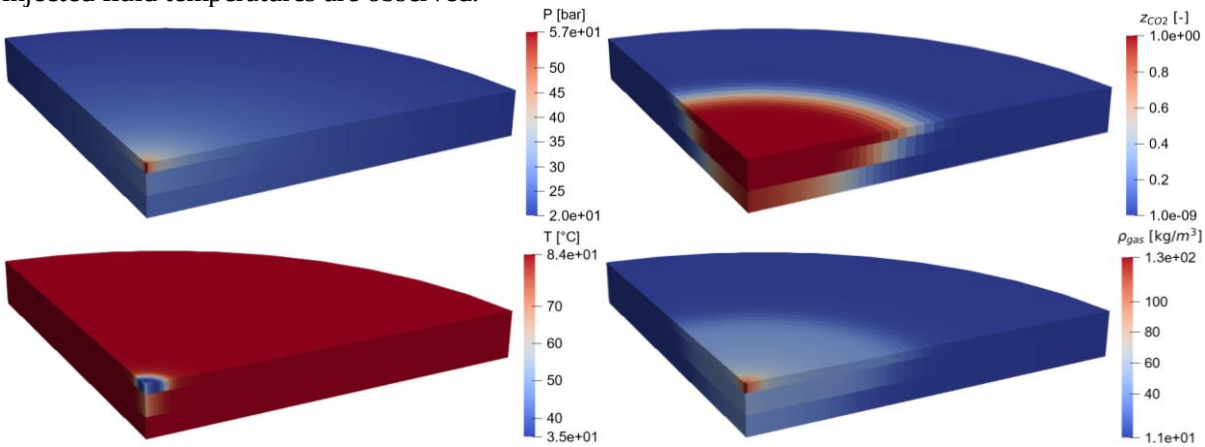


Figure 3 *Fluid properties for the reservoir K = 20 mD, including p_{fluid} (fluid pressure), z_{CO2} (overall mole fraction of CO_2),T (temperature), and ρ_{gas} (density) after 1 year of CO_2 injection. The cylindrical*

reservoir is visualized by clipping it to one-quarter of its horizontal extent and half of its vertical extent to enhance the clarity of the results.

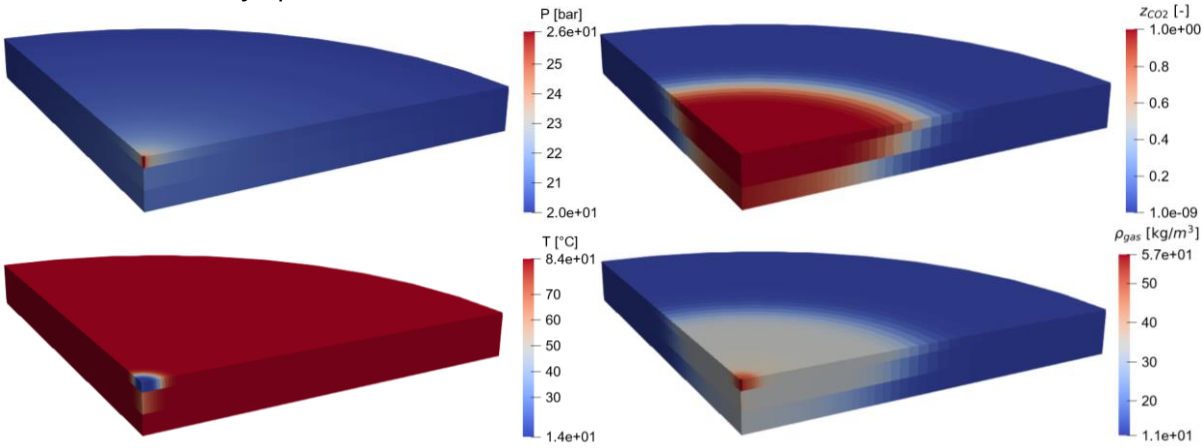


Figure 4 *Fluid properties for the reservoir K = 200 mD, including p_{fluid} (fluid pressure), z_{CO2} (overall mole fraction of CO_2),T (temperature), and ρ_{gas} (density) after 1 year of CO_2 injection. The cylindrical reservoir is visualized by clipping it to one-quarter of its horizontal extent and half of its vertical extent to enhance the clarity of the results.*

Regarding computational performance, ramp-up time step sizes are employed, starting from 2 seconds during the transient phase and increasing to 10 days during the PSS period. The simulation uses a maximum of five Newton-Raphson iterations per time step during the transient time.

Ongoing work

To simulate CO_2 injection into depleted reservoirs with greater fidelity, it is important to include liquid CO_2 in the system to accurately represent scenarios involving liquid-CO_2 injection. Additionally, the presence of water near the wellbore must be considered, as it can influence near-wellbore permeability through mechanisms such as formation dry-out, salting-out, and hydrate formation. Moreover, presence of impurities in the injected CO_2 may sensibly affect phase behavior. The integration of these effects into the model will be addressed in future work.

Acknowledgments

We want to acknowledge the financial support of the ASSET program. We thank the DARTS research group for valuable discussions regarding the implementation of the code. We also thank Curtis Oldenburg and Jean-Claude Hild for their assistance in clarifying several concepts of the DFM model and fluid flow in CO_2 wells.

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