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THM Modelling to Evaluate Cooling Effect during CO_2 Injection in a Highly Depleted Gas Reservoir

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Summary

The safe and efficient storage of CO_2 in depleted gas reservoirs requires a detailed understanding of thermo-hydro-mechanical (THM) interactions and cooling near injection wells. This study investigates these phenomena in the Elkton Formation at Edson Field, a highly depleted gas reservoir in Alberta.

CO_2 injection produces localized near-wellbore cooling, with temperatures dropping to 32 °C and a maximum JT-induced cooling of ~4.2 °C within a 30 m zone. Over time, the cold front propagates radially through combined advection–conduction transport.

Coupled THM simulations reveal moderate horizontal stress relaxation (~4–5 MPa), a dominant vertical stress that maintains a stable faulting regime, minor lateral thermal contraction, and vertical poro-elastic expansion, resulting in ~0.13 mm uplift. These findings demonstrate that near-wellbore THM effects are manageable, supporting the reservoir's mechanical stability during CO_2 injection.

This study is important because it provides critical insights into the thermal and mechanical response of depleted reservoirs, guiding operational strategies, monitoring programs, and risk assessment for safe, long-term CO_2 storage.

Theory / Method / Workflow

Joule-Thomson Effect Near the Wellbore

The Joule-Thomson (JT) effect describes the temperature change of a real gas during expansion at constant enthalpy, with no external heat exchange (Oldenburg, 2007). When CO_2 flows from high to low pressure through a restriction, such as a porous medium, its temperature decreases because of the positive Joule-Thomson coefficient (μJT) under reservoir conditions (Span & Wagner, 1996; Oldenburg, 2007).

Localized cooling in the near-wellbore region can induce thermal stresses, modify permeability, and influence fracture behavior, potentially affecting well integrity and storage safety (Pruess & García, 2002; Mazzotti et al., 2009). Understanding these effects is critical for highly depleted reservoirs, where low initial pore pressure amplifies the mechanical response to cooling.

CO_2 Injection Simulation

CO_2 injection into the Elkton Formation was simulated using PIPESIM, a steady-state multiphase flow simulator, to estimate bottom-hole injection temperatures and pressures for the planned injection rates (e.g., 10 kg/s). A local grid refinement around the injector (600 m radius, with block sizes from 200 m to 2 m) was applied to resolve near-wellbore thermal gradients during the injection period.

Thermo-Hydro-Mechanical (THM) Coupling Workflow

A sub-model (1,000 m × 1,000 m) centred on the injector well was extracted from the full-field dynamic model to capture localized thermal and mechanical effects. The reservoir was upscaled

from 26 layers to 5 layers, preserving porosity and permeability through pore-volume-weighted averaging. A volumetric correction factor (VMOD = 300) was applied to ensure consistency with the full-field depletion trend.

- The THM model integrates overburden, caprock, reservoir, and underburden units in FLAC3D, with fluid flow and heat transfer simulated in CMG GEM. A one-way coupling workflow transfers pressure and temperature from GEM to FLAC3D, where stress, strain, and deformation are computed under drained, fixed-stress conditions, as shown in Figure 1. Data exchange occurs at regular intervals throughout the injection period.
- Constitutive Models and Rock Properties
- Overburden (Fernie Siltstone) and underburden (Shunda Mudstone) were modeled as linear elastic.
- The reservoir (Elkton Dolostone) and caprock (Nordegg Shale) were modeled using an elasto-plastic Mohr–Coulomb formulation to capture localized yielding and thermo-poroelastic effects.
- Thermal properties (conductivity, heat capacity, thermal expansion) were assigned based on laboratory measurements and literature values.
- Mechanical parameters (Young's modulus, Poisson's ratio, cohesion, friction angle, bulk and shear moduli) were included to ensure realistic coupling of thermal, hydraulic, and mechanical processes.

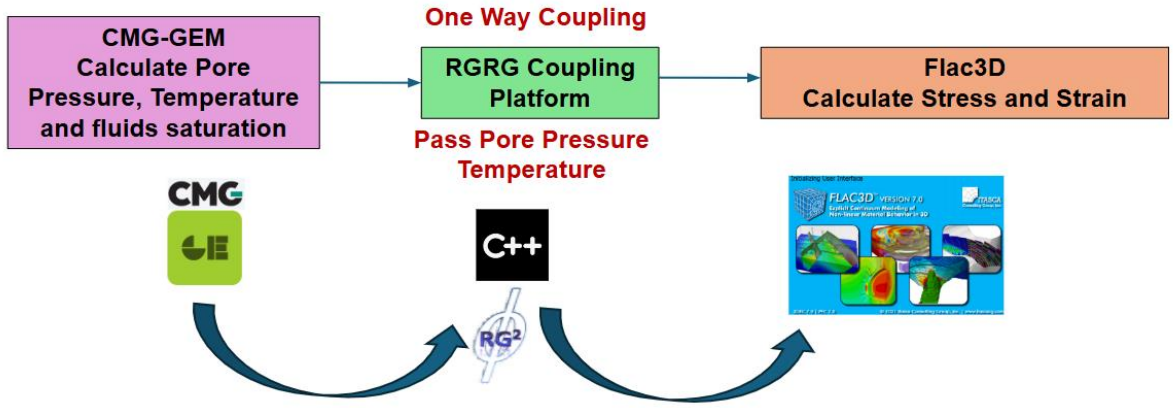


Figure 1 Workflow of the RGRG one-way THM coupling methodology

Results and Observations

The thermo-hydro-mechanical (THM) coupling simulations provided insights into the mechanical response of the Elkton Formation during CO_2 injection, building on the Joule-Thomson (JT) cooling analysis. CO_2 injection produces near-wellbore cooling that, through THM coupling, leads to stress, strain, and displacement effects in the reservoir and adjacent caprock.

Pressure and temperature propagation: Injection increases pore pressure from ~2 MPa to ~5 MPa near the well over one year, while JT cooling locally reduces temperature, forming a cold front that extends hundreds of metres. The overlying Nordegg caprock experiences limited vertical heat conduction, maintaining overall mechanical stability, as shown in Figure 2a and 2b.

Stress evolution: Horizontal effective stresses relax by ~4-5 MPa near the injector due to increased pore pressure and thermal contraction, while vertical stress remains dominant. The

reservoir retains a normal-faulting stress regime, indicating stable mechanical behaviour without tensile failure.
Strain and displacement: Horizontal strains initially show minor dilation but transition to slight contraction as thermal effects propagate. Vertical strain remains positive, causing a net vertical uplift of ~0.13 mm, while lateral displacement is negligible, reflecting a stable, elastic near-well response.
Mechanical stability: The strength-stress ratio decreases moderately (~13%) during injection but remains well above 1, confirming that the reservoir remains mechanically stable at the modeled scale.

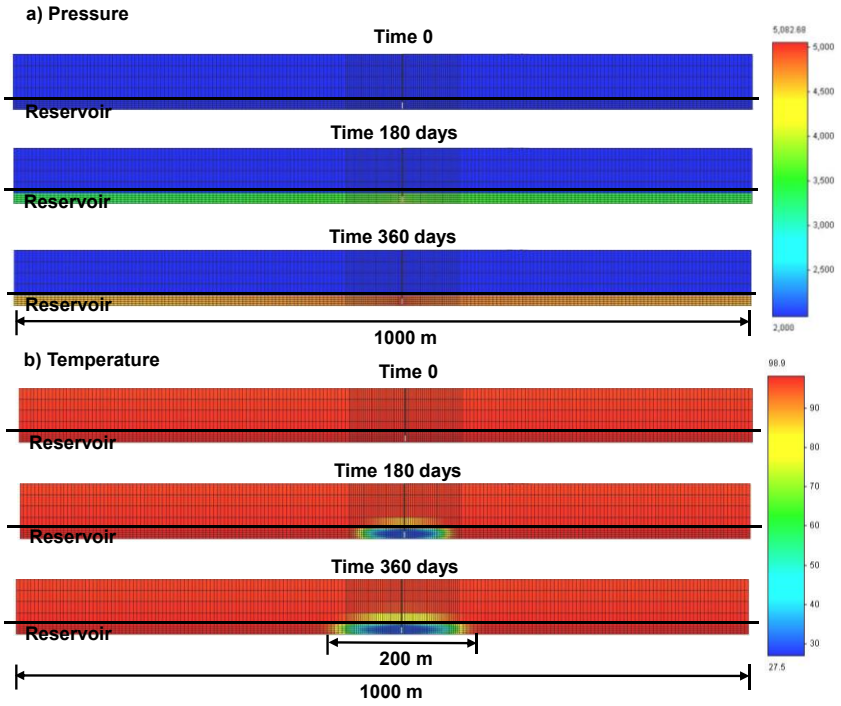


Figure 2 Temporal evolution of a) pore pressure and b) temperature Nordegg - Elkton submodel

Conclusions

- The coupled THM workflow captures the interaction among pressure, temperature, and mechanical response in a depleted carbonate reservoir.
- Near-wellbore JT cooling produces measurable but manageable stress redistribution and deformation.
- Further studies are recommended to address field-scale stability, induced seismicity, and caprock/wellbore integrity for long-term CO_2 storage security.

Novel/Additive Information

This study presents a high-resolution, coupled thermo-hydro-mechanical (THM) evaluation of Joule-Thomson cooling in a highly depleted carbonate reservoir, a scenario rarely examined in previous research. By integrating near-wellbore thermal effects with stress, strain, and

displacement analysis, the work shows how depleted pressures amplify mechanical responses, including horizontal stress relaxation, vertical uplift, and strain anisotropy. The approach demonstrates a practical workflow that combines CMG GEM and FLAC3D to quantify localized effects on injectivity, reservoir stability, and storage safety. Additionally, the analysis of strength-stress evolution offers new insights into mechanical stability under CO_2 injection, providing guidance for risk-informed operation and monitoring in depleted reservoirs.

Acknowledgements

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