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The relevance of the Joule–Thomson effect to CO2–geothermal operations, with reference to production and injection wells

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Research Article

Keywords:

Posted Date: November 17th, 2026

DOI: https://doi.org/10.21203/rs.3.rs-11620467/v1

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Additional Declarations: No competing interests reported.

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Introduction

The idea of using carbon dioxide (CO_2) as a geothermal fluid was first suggested by Brown (2000) for the simultaneous execution of fracking and heat mining in low-permeable hot dry rock (HDR) systems. In 2011, Randolph and Saar proposed a new idea: combining CO_2 storage with geothermal energy extraction from hot underground rocks. They termed this process "CO_2 Plume Geothermal". We prefer to call this process as "CO_2-geothermal". This process creates a thermosiphon cycle between the injection and producer wells by exploiting the fact that the density of CO2 is sensitive to changes in temperature and pressure, being high at low temperatures and high pressures, and vice versa. The heat capacity of the rock is then used to heat the injected CO_2 to the reservoir temperature. The heated supercritical ($scCO_2$) is produced to the surface to extract energy through the expansion in a turbine. The cooled CO_2 is then compressed into a liquid phase and injected back into the reservoir. Figure 1 shows the entire process. This concept can be used in geological systems such as saline aquifers (SA) and depleted hydrocarbon (oil and gas) reservoirs. A significant number of studies have been published in the literature discussing various aspects of CO_2-geothermal operations based on physical and mathematical models (e.g. Pruess, K., 2006; Adams et al. 2015; Turunc et al., 2024; Yerima et al. 2024; Madani et al. 2025).

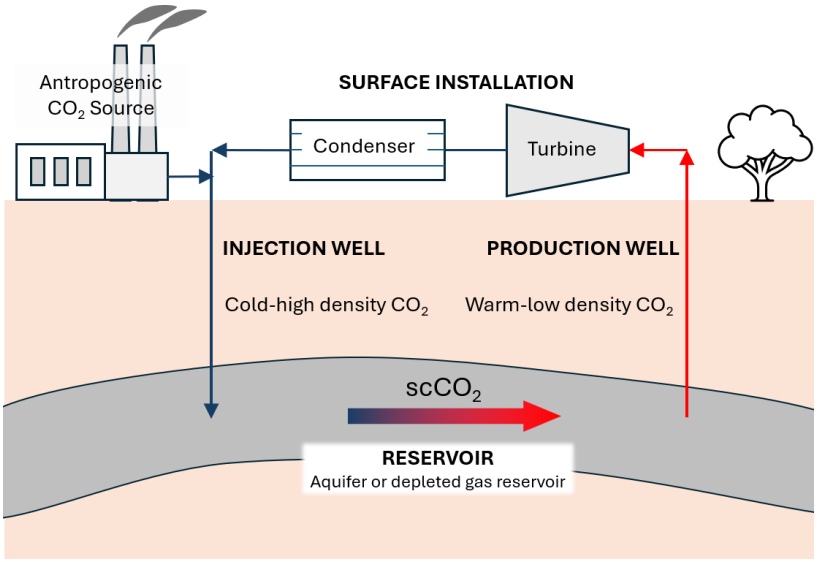


Figure 1 Schematic of the of the CO_2-geothermal cycle and its components.

As can be seen in the schematic diagram, the CO_2 geothermal system consists of three main components: the reservoir, the wells, and the surface installation. Given the thermodynamics of CO_2 at the production wellhead, designing the surface installations, i.e., the energy-power production unit, is relatively straightforward and based on well-established thermodynamic principles. At this point, development of new generation CO_2 turbines plays a significant role in improving energy efficiency (Fleming et al. 2020; Schifflechner et al. 2024).

CO_2-geothermal reservoir engineering relies especially on well-developed R&D and engineering due to the emerging geological carbon storage (GCS) applications. When using depleted gas reservoirs (DGRs) for GCS, the abundance of field history data can facilitate initial phase of CO_2-geotermal projects while greenfield hydrothermal geothermal projects suffer from lack of subsurface data, geological model, and great degree of uncertainties in the project outlook. Therefore, DGRs are technically better candidates for CO_2-geothermal than SAs. The reservoir utilization of DGRs in this context is widely discussed in the literature by employing a GCS period to build up reservoir pressure and establish CO_2 concentration through the planned production well (Ezekiel et al., 2021; Turunc et al., 2024).However, scCO_2 production through the wellbore remains insufficiently characterized: as the fluid ascends, Joule-Thomson (JT) cooling driven by the pressure drawdown may create severe temperature drops consequently erode the planned enthalpy gain out of the project. Only a limited number of studies have investigated this issue, although the outcome relates to the calculation of energy extraction. To our knowledge, very few studies explicitly refer to high-temperature losses in CO_2-geothermal well production due to the JT effect. Atrens et al (2010) mention larger temperature drops for CO_2 than water in the production well caused by additional temperature decrease by JT expansion in addition to the radial temperature loss. They also suggest that the reduction in both pressure and temperature decreases the amount of exergy available at the wellhead for generating electricity. Randolph et al. (2012) used an in-house wellbore simulator to create a model of a CO_2-geothermal well at a depth of 2,500 metres. They claim that, after sufficient production time (10 days), the temperature profile of the production well reaches the adiabatic limiting case, in which there is no heat transfer from the surrounding formations. They calculated that, in this case, the temperature difference between the bottomhole and wellhead is approximately 40°C. This low temperature difference is basically caused by JT cooling along the well. In his study Lei H. (2022), uses a generic reservoir at a depth of 3800 m and a thickness of 136 m to simulate the heat extraction process using the ECO2N and T2WELL modules of the TOUGH2 reservoir simulator family. This study identifies the JT effect as causing a significant temperature loss of approximately 85°C, which the author highlights as a disadvantage in CO_2-geothermal projects. No further details about the effect were provided. Liu et al. (2026) developed a mathematical model that coupled heat transfer and CO_2 compressibility to investigate strategies for enhancing the efficiency of heat transfer from the reservoir to the surface in CO_2-geothermal systems. They drew attention to the potential for high temperature losses in the production wellbore but did not explicitly discuss the underlying causes.

This study aims to demonstrate the significance of the JT effect in a wellbore and, if applicable, determine its potential impact on the engineering components of such systems, particularly in cases involving CO_2-geothermal energy extraction. The study begins with a theoretical discussion, followed by a numerical analysis. The numerical study comprises various modelling cases concerning CO_2 production and injection using a commercial wellbore simulator and propose design considerations for future CO_2-geothermal projects. Our aims can be summarised as follows:

1. Elaborating on the physics of the thermal effects that influence the production and injection of CO_2 in vertical wells;
2. Modelling the behaviour of CO_2 in production and injection wellbores using models and a commercial wellbore simulator coupled with a generic reservoir model;
3. Analysing the thermal effects, including JT, during CO_2-geothermal production and injection;
4. Analysing the impact of thermal effects, including JT, on CO_2-geothermal energy extraction performance.

JT effect in geologic storage and energy extraction

The JT effect is defined as the temperature shift of a real gas or liquid during compression or expansion, which typically results from a pressure change through a valve or porous plug. This process is adiabatic if it is insulated to prevent heat exchange with the environment. This effect is observed due to deviations from the ideal gas model, since an ideal gas is known to exhibit no JT effect. The temperature change (T) for a given pressure drop (P) in an isenthalpic process is defined by the JT coefficient (μ_{JT}), see Eq. 1).

$$\mu_{JT} = \left(\frac{\partial T}{\partial P}\right)_H \text{ with } \left(\frac{\partial H}{\partial P}\right)_T dP + \left(\frac{\partial H}{\partial T}\right)_P dT = 0 \quad (1)$$

Figure 2 shows the inversion curve of the CO_2 JT effect. Above the curve, μ_{JT} is negative, indicating warming through expansion or cooling through compression. Below the inversion curve, μ_{JT} is positive, indicating cooling through expansion and warming through compression. At the point where the curve is crossed, μ_{JT} is equal to zero and no temperature change occurs. In the thermodynamic conditions that could occur during the geological storage of CO_2 and CO_2-geothermal operations, μ_{JT} is predominantly positive, meaning cooling could be expected during expansion and warming during compression. This thermodynamic window is shown as a dashed area in the figure. As illustrated in figures 3a and 3b, μ_{JT} is lowest in the liquid state and highest in the gaseous state for CO_2. Consequently, greater cooling is anticipated in CO_2 storage and CO_2-geothermal systems when CO_2 is in its gaseous or supercritical state as opposed to its liquid state.

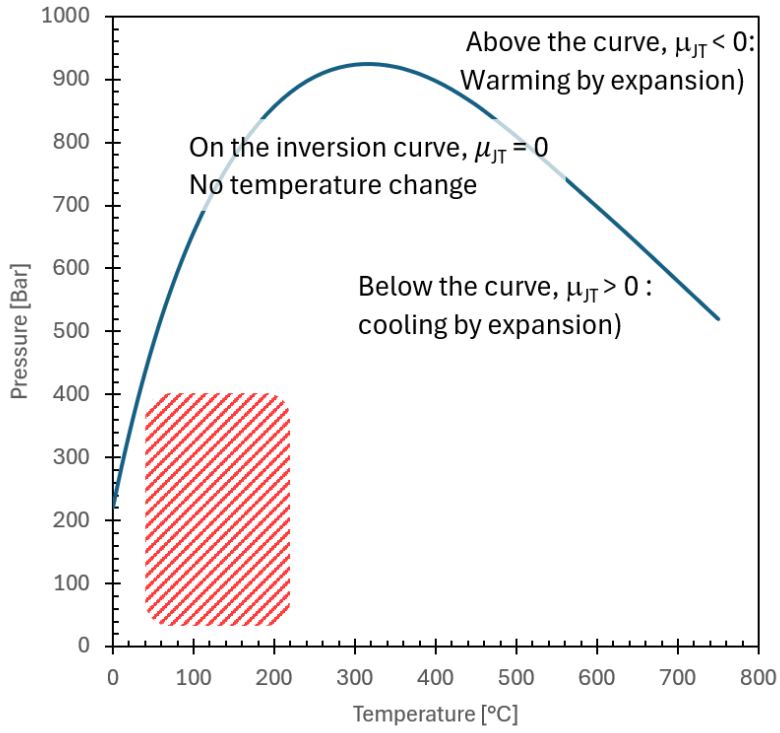


Figure 2 The JT inversion curve for CO_2 (NIST, 2025) and the P-T area (dashed) highlighting the thermodynamic zone that could be applicable to CO_2-geological storage and geothermal operations.

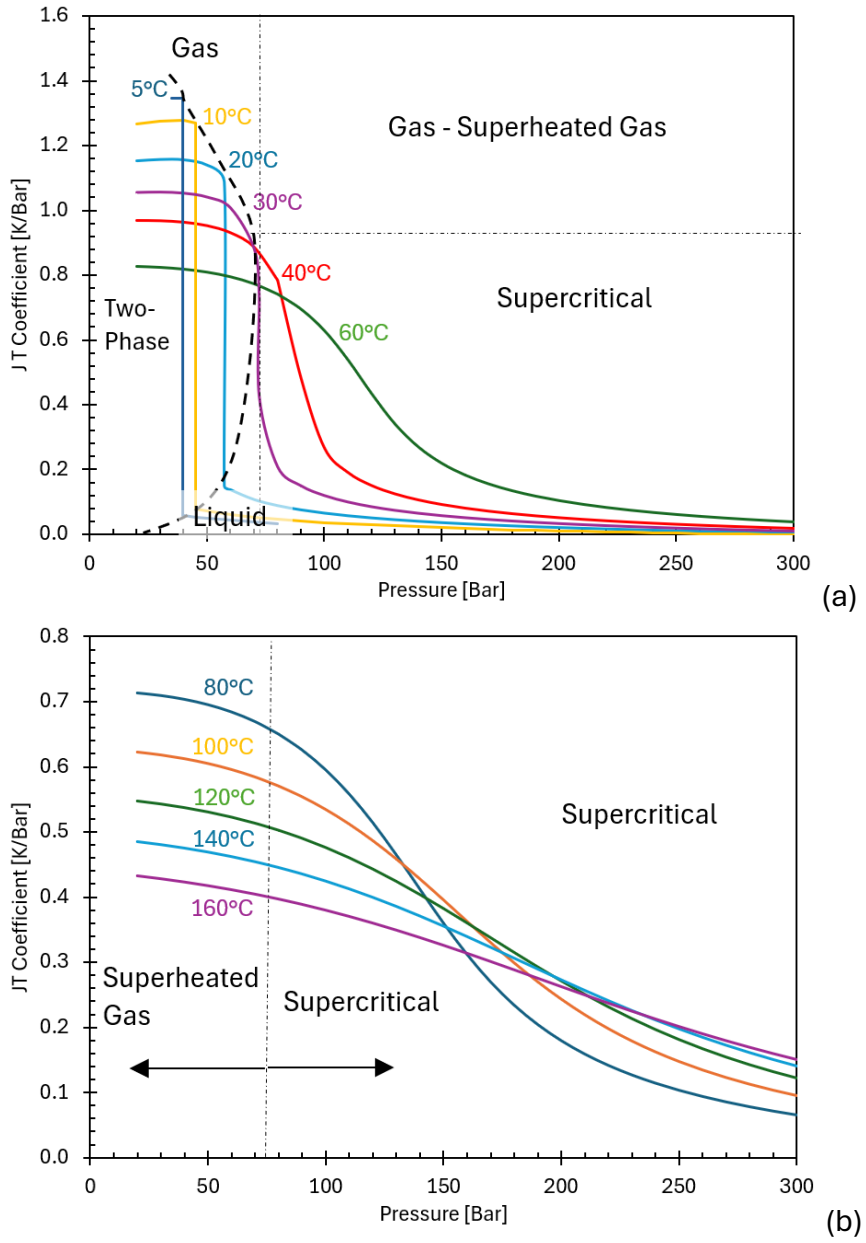


Figure 3 The JT coefficient as a function of pressure for various temperatures that could be applicable to CO_2-geothermal systems (a and b) (Data retrieved from NIST, 2025).

JT cooling may have a significant impact on the near wellbore region, whether for storage or geothermal applications. This issue is particularly significant when a depleted hydrocarbon reservoir is used for CO_2 storage. Upon arrival at the bottom of the well, the high-pressure CO_2 is suddenly exposed to the low pressure of the depleted reservoir, resulting in expansion during its flow through near wellbore region. This quasi-adiabatic expansion, and therefore the cooling effect, is calculated to be greater in low-permeability, low-temperature depleted reservoirs, especially when the flow velocities are high. The consequences of JT cooling near the wellbore have been investigated using both experimental and numerical studies. The temperature near the wellbore is estimated to be so low that the thermodynamic conditions enter the hydrate formation window and hydrate formation could block the pores and reduce injectivity (Oldenburg, C.M., 2007; Amir et al., 2025; Chesnokov et al. 2025). It has been posited that the process of JT cooling has the capacity to modify the risk of salt precipitation and fines migration, thereby influencing injectivity (Yang et al., 2016; Ahmad et al., 2019; Burgass et al.

2023; Tamáskovics et al., 2023; Guo et al., 2024). Another potential risk that is often discussed is the geomechanical outcomes that may endanger the integrity of the wellbore by damaging its connection to the formation. It is also emphasised that cooling may trigger the formation and/or opening of fractures in the caprock, leading to higher CO_2 leak rates from the reservoirs (Gor, G.Y.; Prévost, J.H. 2013; Vilarrasa, V.; Laloui, L., 2016; Thompson et al, 2021; Alkan et al., 2026). The potential for risk incident is contingent upon the interaction of marginal conditions; in this regard, JT cooling represents a salient consideration that merits meticulous assessment prior to the implementation of CO_2 injection in depleted reservoirs, whether for the purpose of permanent storage or energy extraction. A substantial body of literature on the subject is available, thereby facilitating straightforward decision-making (e.g. Indina et al., 2024; Alkan et al., 2026). In most cases, numerical models can be employed to characterise the thermodynamics of hydrate formation envelope or geomechanical changes for given specific conditions. However, in instances where extreme conditions (such as exotic combinations of CO_2 with other gases as impurities and/or atypical porous media) are anticipated, experimental support may also be necessary.

While JT cooling holds considerable promise for the reservoir engineering of depleted hydrocarbon reservoirs intended for CO_2 storage, its impact on the CO_2 flow within a well has received comparatively less attention for research. The primary rationale for this is that the CO_2 flow in a well, whether for injection or production, does not satisfy the adiabatic assumption of the JT effect. Nonetheless, under the prevailing flow conditions, the upward or downward JT effect may occur and cause significant changes to the thermodynamic conditions at the point of arrival at the target, i.e. the reservoir (injection) or surface (production). The upward case is of particular significance, as it relates to the heat extraction and energy production performance of CO_2-geothermal systems, as illustrated in Figure 1.

JT effect in CO_2-geothermal wells

The potential for the JT effect to occur within the wellbore is a subject that merits further discussion. The primary argument against JT is the non-constant enthalpy during flow in the wellbore. This is a valid point considering that the enthalpy changes due to the changes in gravitational and kinetic energy terms. Furthermore, the heat transfer from the formation alters the heat content of the fluid, for example CO_2 in this instance. Nevertheless, the JT can still be effective in the wellbore. The following simplified theoretical approach is intended to elucidate this aspect.

A vertical well with a constant diameter is used to produce CO_2 as a single component from a depleted reservoir that has been filled with CO_2 after the initial content was depleted for geothermal energy extraction purposes. Subsequent steady-state conditions are attained following a period of production, thus leading to the assumption that heat transfer from the formation is negligible at this stage. With these assumptions and considering that no work is done during the flow, the change in the CO_2 enthalpy is directly depending on the change in the gravitational and kinetic energy. The enthalpy is not strictly constant because of gravity and kinetic energy and the change of the enthalpy with P and T of Eq. 1 that can be modified to:

$$\left(\frac{\partial H}{\partial P}\right)_T dP + \left(\frac{\partial H}{\partial T}\right)_P dT = dE_k + dE_g \qquad (2)$$

Where E_k and E_g define the kinetic and gravitational energy components successively. The temperature change in the wellbore can therefore be estimated with the following formulation:

$$\left(\frac{\partial H}{\partial T}\right)_P dT = -\left(\frac{\partial H}{\partial P}\right)_T dP + dE_k + dE_g \text{ and} \quad (3)$$

$$dT = \frac{-\left(\frac{\partial H}{\partial P}\right)_T dP + dE_k + dE_g}{\left(\frac{\partial H}{\partial T}\right)_P} \text{ which can be reformulated as}$$

$$dT = \mu_{JT} dP + \frac{dE_k + dE_g}{\left(\frac{\partial H}{\partial T}\right)_P} \quad (4)$$

By definition:

$$\left(\frac{\partial H}{\partial T}\right)_P \approx C_P \quad (5)$$

Where C_p is the specific isobaric heat capacity, of CO_2 in this case. The final formulation can be expressed as follows:

$$dT = \mu_{JT} dP + \frac{dE_k + dE_g}{c_P} \quad (6)$$

The equation suggests that a temperature change occurs in a vertical pipe due to the JT effect, in addition to changes in temperature resulting from changes in kinetic and gravitational energies, even when there is no restriction in diameter. Clearly, the magnitude of the JT effect depends on the prevailing thermodynamic conditions, as well as the contributions of kinetic and gravitational energies. In the liquid phase, the magnitude of the effect is comparatively significantly lower due to the lower JT coefficient of CO_2 in this phase. Assuming that the flow diameter remains constant, the contribution of the change in kinetic energy can be considered negligible. The effect of gravitational energy is attributed to the specific heat capacity of CO_2 under the given thermodynamic conditions.

A numerical study has been conducted to investigate the thermal effects including JT in the wells and its relevance to energy extraction from CO_2-geothermal systems. To this end, a generic reservoir model coupled to the surface with production and injection wells was created using a commercial reservoir-wellbore simulator.

Modelling & methodology

The numerical study was performed using the GEM and CoFlow modules of the CMG suite. Both simulators have been developed, tested and validated against a variety of theoretical and measured background knowledge, and the results have been reported (CMG GEM and CMG CoFlow, 2025). CMG GEM, the compositional reservoir simulator within the CMG suite, has been widely applied in geological carbon storage (GCS) studies to model CO_2 behaviour in candidate reservoir types containing native fluids such as hydrocarbons and saline water. In this study, a depleted gas reservoir scenario was considered, with methane and irreducible saline water defined as the native reservoir fluids. A robust fluid model based on the Peng-Robinson equation of state (EoS) was implemented in GEM, together with a CO_2 solubility model for the aqueous phase; methane was assumed to be insoluble in water.

The wellbore simulator CoFlow, also part of the CMG suite, enables coupling of the GEM reservoir model with injection and production wells. For the production well, the hydraulics and fluid thermodynamics computed at the uppermost perforation block are transferred to CoFlow, where the thermal and hydraulic physics are solved to obtain the wellbore pressure and temperature profiles, along with the associated fluid properties. For the injection well, the specified wellhead boundary conditions are solved to determine the corresponding bottomhole conditions and, consequently, the injectivity as well as thermal changes during flow through bottomhole, while GEM simultaneously solves the flow equations for the reservoir and the well-perforation matrix.

A cyclic CO_2 injection and production system has been designed within a generic gas reservoir model. It is assumed that the re-utilization periods, such as pressurisation and CO_2 establishment, have been completed and the reservoir is ready for energy extraction by CO_2-geothermal methods to begin. The petrophysical parameters are based on typical North Sea gas reservoirs. Further details on the model can be found in previous studies (Turunc et al., 2024). In this study, geothermal gradients of 21°C/km and 38°C/km are assumed for a 3500 m deep reservoir, in order to model reservoirs with two different initial temperatures, namely 90°C and 150°C, and to examine the difference in behaviour between low-enthalpy and medium-enthalpy reservoir conditions. The injection temperature is set to 32°C to avoid a phase change in the wellbore. The geometrical and thermal parameters of the production wellbore model are given in Table 1.

Table 1 Geometrical and thermal parameters of the wellbore models

Parameter	Value, unit	Parameter	Value, unit
Injection rate	80 kg/s	Tubing roughness	0.0046
Production rate	75 kg/s	Thermal cond. of tubing	44.9 W/m.K
Injection pressure	80 bars	Casing ID	33.34 cm
Injection temperature	32°C	Casing OD	34.29 cm ($13^{1/2}$ in)
Injection enthalpy	289 kJ/kg	Thermal cond. of casing	44.9 W/m.K
Tubing depth	3500 m	Thermal cond. of rock	2.1 W/m.K
Tubing ID	23.02 cm	Thermal cond. of cement	0.8 W/m.K
Tubing OD	24.45 cm ($9^{5/8}$ in)	Cement thickness	5.1 cm

To isolate the contribution of each individual mechanism, two wellbore simulations are performed, considering only conductive heat loss to the formation and all thermal effects. These are referred to as “only heat transfer” (OHT) and “all thermal” (AT). Comparing the temperature profiles obtained in each simulation reveals the relative contribution of each temperature loss mechanism to the predicted wellhead temperature.

CO_2 enters the production well from the reservoir at two different simulated reservoir temperatures: 90°C and 150°C. The pressure profiles in the well are calculated using flow equations for a vertical pipeline, considering both gravity and kinetic terms. In the injection case, the flow direction is downwards and the same principles apply. In the OHT option, the only thermal component is heat transferred from the surrounding formations via the well's integrity components. The overall heat transfer coefficients are calculated as a function of the casing, cement and tubing thicknesses, as well as the heat transfer parameters, to calculate heat loss along the well. In the AT option, however, temperature changes are estimated by including the following components in addition to heat transfer via the surrounding formations.

$$dT \approx \mu_{JT}\, dP - \frac{g\, dz}{C_p} - \frac{d\left(\frac{v^2}{2}\right)}{C_p} \quad (7)$$

In this expression, the last term on the right-hand side represents the temperature change due to kinetic effects during flow. Assuming no change in velocity, this term can be neglected. The second term accounts for the temperature change due to the gravitational effect and the change in depth and specific isobaric heat capacity (C_p). The first term is the JT effect on temperature, as discussed in previous sections.

Following assumptions are made in the study:

- The geothermal gradient is assumed to be constant throughout the depth of the well.
- In the AT case, all thermal components that lead to a temperature change are included.
- There is no additional work in the wellbore.
- The flow and heat transfer are in a steady state, leading to quasi-adiabatic conditions. Profiles are taken after approximately one month of production/injection, once steady-state conditions for flow and heat transfer from the surroundings have been reached.
- There is no phase change in the wellbore; the CO_2 enters the wellbore in a supercritical gas phase and remains so until the wellhead. The same principle applies to injection: the injection temperature is kept at 32 °C to avoid a possible phase change.

In the geothermal industry, the total thermal energy (Q_{th}) produced is mostly given by Eq. 8, where m is the production rate, and h_p and h_i are the enthalpies of production and injection of the geothermal fluid at wellhead conditions.

$$Q_{th} = m * \left(h_p - h_i\right) \quad (8)$$

Unfortunately, there is limited measured data available in the literature with which to test and validate the accuracy and capacity of wellbore simulators. The existing data mainly originates from enhanced oil recovery (EOR) and geological carbon storage (GCS) projects involving the injection of CO_2 into specific reservoirs. Efforts to validate the wellbore simulators are ongoing within the framework of related international projects such as RETURN (e.g. Amro et al., 2024). The major challenges are yet the modelling phase transitions and transient state flow accurately. This is why we excluded these aspects from our study.

Results and discussion

Figures 4a and 4b show a comparison of the pressure profiles in the well for the OHT and AT modes at reservoir temperatures of 90°C and 150°C respectively. The profiles are significantly different in both cases, with the pressure drop being lower at 150°C than at 90°C. This difference is worth discussing, as it may also have a significant effect on the JT effect. Temperature plays a dominant role in CO_2 density and viscosity, both of which decrease with increasing temperature at comparable pressures. For example, at a pressure of 250 bar, the density of CO_2 is approximately 638 kg/m^3 at 90°C, whereas it is 415 kg/m^3 at 150°C. The dynamic viscosities are 51.3 10^{-3} mPa.s at 90°C and 34.8 10^{-3} mPa.s at 150°C respectively. Although the volumetric rate increases with decreasing density for the same mass rate, increasing the density and viscosity at 90°C increases both the gravity and the kinetic components of pressure losses. Therefore, overall pressure loss is greater at 90°C, resulting in lower pressure at the wellhead. The pressure drops with AT mode at 90°C is slightly higher than

at 150°C compared to OHT mode. This is due to the higher CO_2 densities and viscosities resulting from JT cooling to lower temperatures, as will be discussed below.

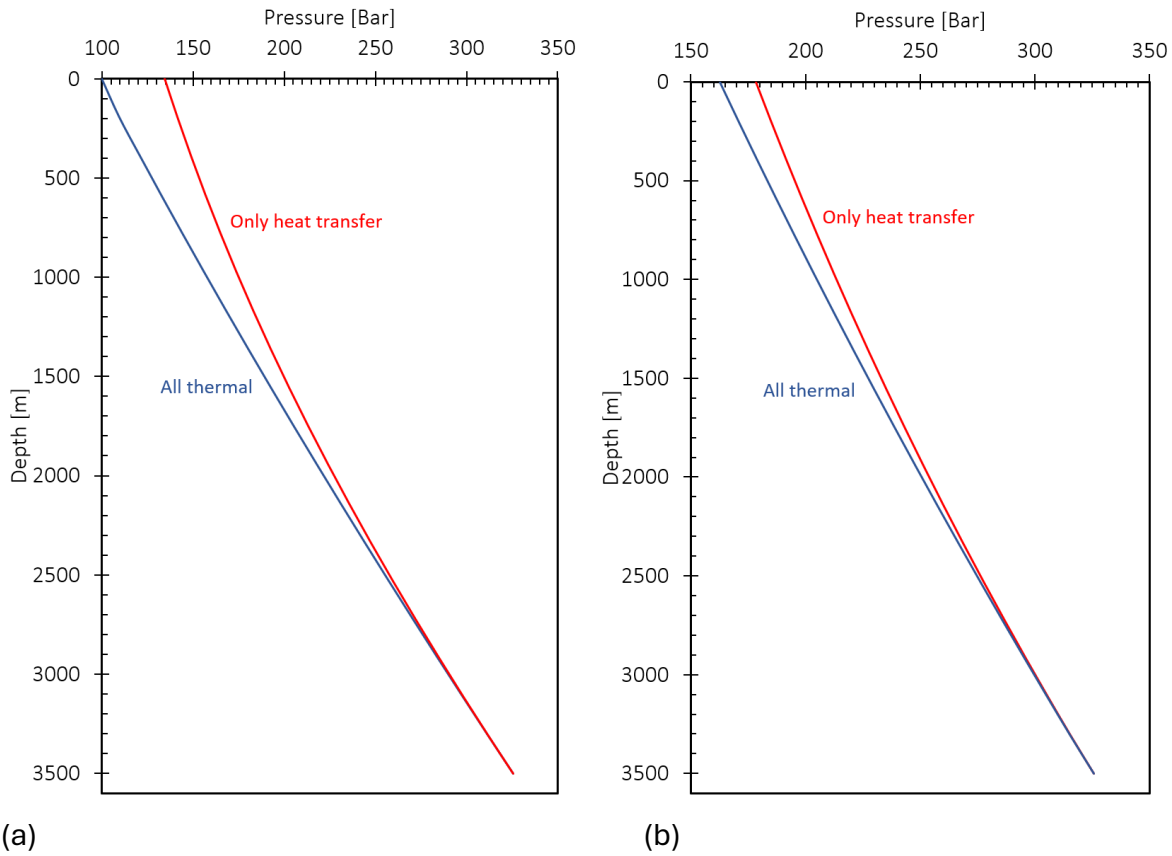


Figure 4 Flowing CO_2 pressure profiles in the production well after one month of for OHT and AT modes (a) for the 90°C and (b) for 150°C reservoir cases.

Figures 5a and 5b show the calculated temperature profiles in the well for the OHT and AT modes, for two different reservoir temperatures. In the OHT mode, the temperature differences between the bottom of the well and the wellhead are minor: approximately 3.3°C for the 90°C case, and 8.2°C for the 150°C case. The greater cooling in the 150°C case is due to the higher temperature profile compared to the geothermal gradient (or lower formation temperature), resulting in a higher heat transfer rate. The temperature profile along the wellbore differs significantly in the AT mode. This has two main reasons. The first is the conversion of gravitational energy as a function of the inverse of the isobaric specific heat capacity. The heat capacity of CO_2 at an average temperature of 70–200 bar is 2500 J/kg K, varying minimally with changes in pressure and temperature. Based on this, the effect of gravitational energy conversion on temperature change can be estimated to be around 14°C in the 90°C case along the flow to the wellhead. On the other hand, JT cooling is calculated as a function of the pressure difference and the JT coefficient, which is a function of T and P, as depicted in Figure 3 and Figure 4. At pressures of up to 200 bar and the corresponding temperatures, the JT coefficient can be estimated to be around 0.1. At lower pressures, however, the JT coefficient increases to 0.2 and beyond. This also helps to explain why the cooling rate steepens at depths shallower than approximately 2000 meters. Assuming an overall JT coefficient of 0.15 for a total pressure loss of 225 bar, the estimated JT cooling is approximately 34°C. Combined with gravitational energy conversion, this results in a total temperature decrease of 48°C, which closely matches the simulated values shown in the figure.

For the 150°C case, the temperature decrease along the well is slightly greater than for the 90°C case (56°C versus 50°C). However, when the effect of heat transfer is excluded, the same temperature drop can be attributed to the other thermal components. It should be noted here that the specific heat capacity of CO_2 is significantly lower at high pressure, meaning that a greater temperature drop can be attributed to gravitational energy conversion in this case. For instance, Cp is 1640 and 2070 J/kg K at 200 bar and 150°C and 120°C, respectively. Assuming an average temperature and pressure of the latter, the gravitational thermal conversion can be approximated at 16.5°C. The JT coefficient for this interval is higher than for the 90°C case, being approximately equal to 0.20. Using these values, a total temperature drop of 57°C can be predicted, which again matches the numerical prediction perfectly.

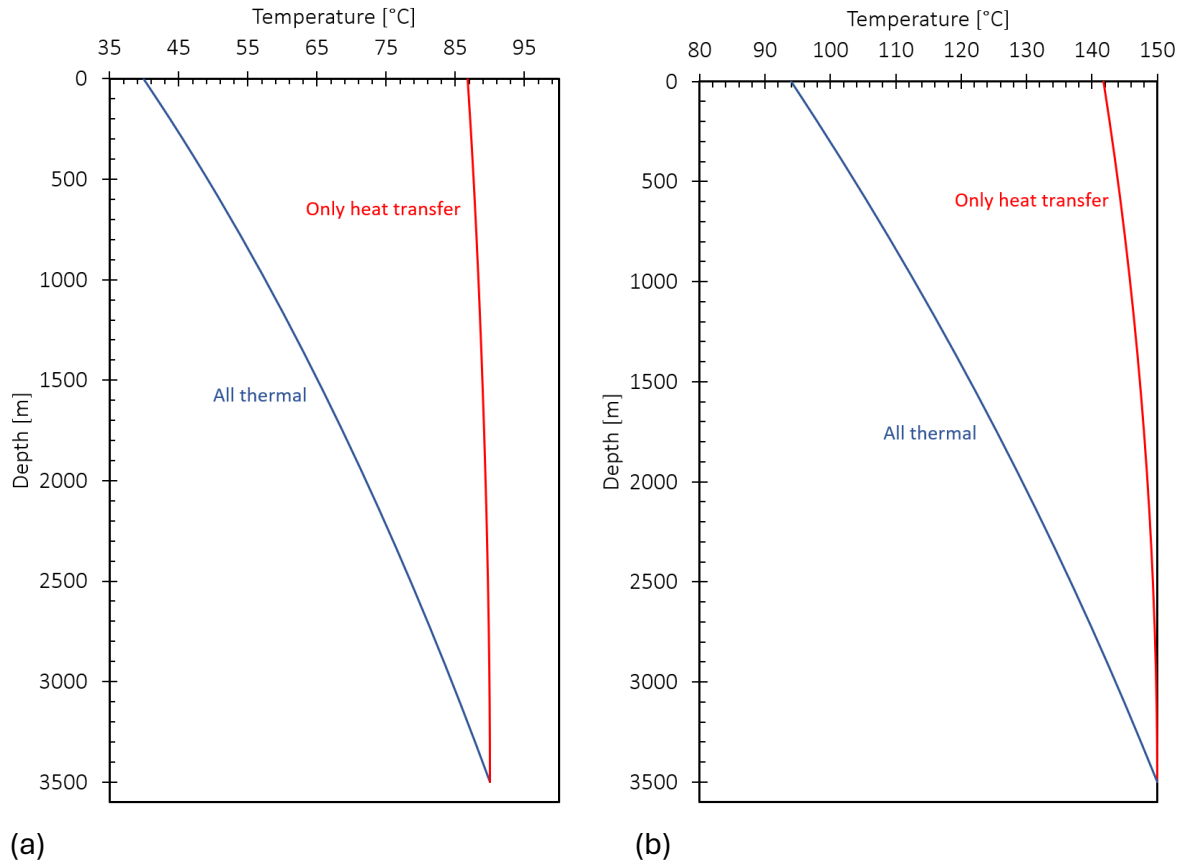


Figure 5 Flowing CO_2 temperature profiles in the production well after one month of production for OHT and AT modes (a) for the 90°C and (b) for 150°C reservoir cases.

As might be expected, thermal components, including JT cooling and gravitational energy conversion, have a significant impact on temperature and a slight impact on pressure at the wellhead. This clearly has unfavourable implications for energy extraction at the surface. The issue can be quantified using the above examples. In the case of 150°C, the estimated wellhead conditions when considering only heat transfer along the well (a realistic assumption in a hydrothermal reservoir) are P_{wh} = 178 bar and T_{wh} = 142°C. This yields a CO_2 enthalpy of approximately 520 kJ/kg. However, when the conditions at the outlet of a power plant are considered (P_{in} = 80 bar and T_{in} = 32 °C), which are equal to the wellhead conditions at the injection wellhead, the enthalpy is approximately 290 kJ/kg. This thermodynamic difference results in an energy production of approximately 17.5 MW_{th} at a production rate of 75 kg/s using equation (8). However, considering all thermal effects in the wellbore, such as JT cooling, the

CO_2 enthalpy would reduce drastically (h_p = 435 kJ/kg) and the energy production would be approximately 11.1 MW_{th}. A similar prediction can be made for the low-temperature case: 2 MW_{th} in the realistic (AT) case versus 12 MW_{th} in the oversimplified (OHT) case. The cases are compared in Figure 6 in terms of energy outputs.

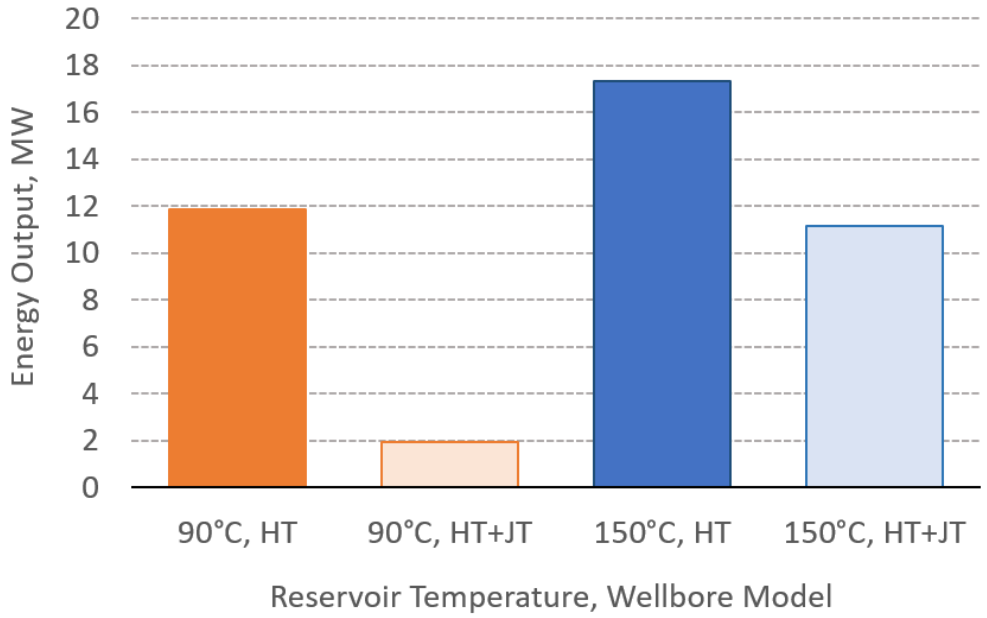


Figure 6 Comparison of the low (90°C) and high (150°C) temperature reservoir cases with all thermal (realistic, AT) and only heat transfer (oversimplified, OHT) modes in terms of energy outputs.

In a CO_2-geothermal process, CO_2 is used in a power plant to extract energy, after which it is injected back into the reservoir to enable continued energy extraction and finally carbon storage. During injection, the expected temperature change occurs in the opposite direction, raising the temperature of the CO_2 as it travels down the well. The same thermal components influence the temperature profile from the wellhead to the bottom of the well. However, the implications are opposite this time, resulting in warming (compression) instead of cooling. Additional runs were performed with P_{in} = 72 bar and T_{in} = 32°C as wellhead conditions, to investigate this aspect. Geological heat transfer and the JT effect warm the CO_2. *Figure 7*(a) and 6(b) show the results of the wellbore calculations used to simulate injection into the reservoirs at temperatures of 90°C and 150°C using the two modes. As expected, the two profiles are almost identical, with the only significant difference being between the OHT and AT options in two cases. CO_2 warming along the wellbore is significant, with slightly higher warming in the 150°C case. This is certainly due to the higher geothermal gradient in this case. The arrival and flow of the higher-temperature injection fluid into the reservoir reduces its cooling rate. For example, CO_2 enters the reservoir at approximately 69°C and 72°C in the 90°C and 150°C scenarios, respectively. This aspect supports certainly the use of the CO_2-geothermal concept for energy extraction over a longer period.

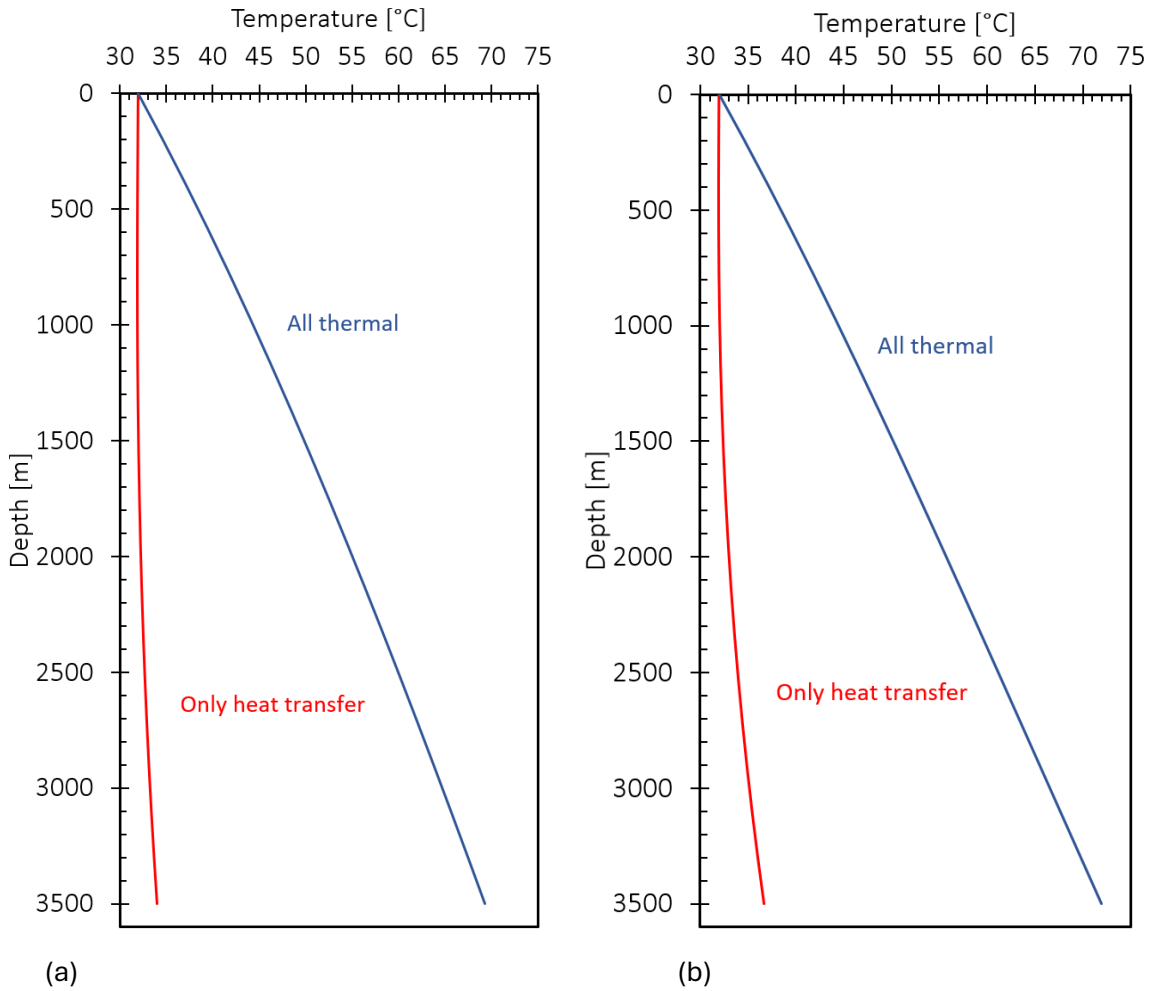


Figure 7 Temperature profiles along the injection well considering only heat transfer (OHT) and all thermal effects (AT) (a) into 90°C reservoir (b) into 150°C reservoir models.

Conclusions

The present study aims to demonstrate and discuss the significance of thermal effects, including the Joule–Thomson effect, in the flow of CO_2 through geothermal wellbores. A theoretical discussion is first presented on the importance of the JT effect and gravitational energy conversion when using CO_2 as a geothermal fluid. The behaviour of CO_2 in production and injection wellbores is then examined using a commercial wellbore simulator coupled with a generic reservoir model featuring realistic flow rates. In order to circumvent the uncertainties inherent in the modelling phase changes, the wellbore conditions are selected to ensure single-phase CO_2 flow in the borehole during both production and injection. This fundamental assumption is both reasonable and preferable, since a phase transition in the borehole would result in the cooling of the production well and an additional decrease in energy extraction. The evaluation of the results was conducted at the point at which the simulations demonstrated steady-state flow conditions. The following conclusions can be drawn:

1. When CO_2 is used as a geothermal fluid, the JT effect makes it a significant component of wellbore flow equations. The lower specific heat capacity of CO_2 also highlights the importance of gravitational energy conversion during the upwards and downwards circulation of fluids in the borehole. It should be noted that these effects are negligible when water is used as the geothermal fluid.

2. The numerical results demonstrate that the thermal components under discussion in the study exert a considerable influence on CO_2 flow in the borehole at a realistic flow rate for CO_2-geothermal operations. Although the role of heat transfer from the surrounding formations through the well integrity component is relatively minor, the other thermal components — including the JT effect and gravitational energy conversion — have been shown to have a significant impact on production conditions at the wellhead. While the extent of CO_2 cooling is certainly due to the thermodynamic conditions in the borehole, the temperature is still low enough to significantly reduce energy extraction performance at the surface. Numerical assessments indicate that energy extraction could be reduced by 80–90% due to enthalpy losses in the wellbore.
3. Furthermore, the thermal effects must be considered during the injection process. In this instance, the effect is positive, with the CO_2 being warmed in accordance with the geothermal gradient and the thermodynamics of the wellhead and wellbore. Whilst the warming effect has been demonstrated to reduce the rate of cooling of the reservoir, it has been shown not to offset the adverse impact of the Joule-Thomson (JT) effect on energy extraction during the production process.
4. The design and engineering of CO_2-geothermal systems should therefore consider reservoir-well coupled modelling to enable a realistic assessment of energy extraction.

The above results suggest that energy extraction in the CO_2-geothermal concept is significantly affected by wellbore flow conditions. While there are currently no field measurements to corroborate the numerical evaluations on the production side, basic physical principles and related simulation runs clearly demonstrate that CO_2 cools significantly during its ascent from the reservoir to the surface. This additional cooling raises questions about the feasibility of CO_2-geothermal projects, as the efficiency of energy extraction depends on the pressure and temperature of the CO_2 at the production wellhead.

Acknowledgments

We thank to our colleagues, Dr. Oleksandr Burachok and Patrick Kowollik, for initiating and developing the concept of the study. We also thank Computer Modelling Group (CMG), Calgary, Canada for their support in making simulation tools available.

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