Optimization of CO_2 Injection Operating Conditions for Enhanced Gas Recovery and Carbon Sequestration in a Carboniferous Sandstone Reservoir

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Abstract. CO_2 emissions are a global issue that many countries face. In handling this issue, one of them is by utilizing energy resources to cover CO_2 emissions. However, among the many methods used to absorb CO_2, one of the most effective is a process by injecting CO_2 into the earth layer that also known as carbon sequestration, which is one of the most effective ways to reduce CO2 emissions. CO_2 injection into gas reservoirs not only benefits CO_2 gas storage but can also increase gas production in carboniferous sandstone reservoirs, a process known as Enhanced Gas Recovery (EGR). Operating the CO_2 EGR variable, namely the mass flow rate of CO_2 injection, CO_2 injection temperature, and CO_2 injection pressure, can condition the optimal recovery value. The Beggs-Brill method is used for modeling the CO_2 EGR injection pressure drop in production and injection wells, while the Darcy equation is used in the reservoir. Heat transfer equations are used to model temperature gradients in production wells, injection wells, and reservoirs. When the injection well and production well model is compared to the PIPESIM software simulation, the pressure and temperature gradient for injection wll model have average errors of 0.364% and 0.754%, respectively. The validation results in production wells have a mean error of 0.871% for the pressure gradient model and 0.334% for the temperature gradient model. Meanwhile, when the reservoir compared to the COMSOL Multiphysics software simulation, the mean error for pressure and temperature gradient models is 0.0897% and 0.0106%, respectively. According to the modeling, the amount of CO_2 stored in the reservoir is 21.134 tons per day and can be absorbed by 80.36%. GA produced the best optimization results on the three variables, increasing profits from 5998.534 USD/day to 17123.327 USD.

Keywords: Carbon Sequestration · CO_2 Injection · Enhanced gas recovery · Optimization

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1 Introduction

Utilization of energy resources has received more attention in recent times to cover the ever-increasing demand for energy around the world due to the increase in population and energy consumption. And the focus has shifted towards cheap, clean and environmentally friendly resources such as renewable sources or cleaner fossil fuels such as natural gas to reduce carbon dioxide (CO_2) emissions and the challenge of global warming due to burning fossil fuels with 33.14 Giga ton CO_2/ year [1] and greenhouse gas effect [2].

Despite the many methods applied to sequester CO_2, one such as in oil and gas reservoirs has formed a trap for hydrocarbons under caprock sealing for millions of years at high pressures which ensures rock integrity providing long term absorption for CO_2 with less environmental impact [3]. Likewise, CO_2 is implemented into gas reservoirs to improve the Enhanced Gas Recovery (EGR) process which is an effort to increase gas production from a gas reservoir that has decreased production. The concept is not much different from Enhanced Oil Recovery (EOR) by injecting energy or mass through an injection well into the oil reservoir. However, the process is quite complex due to the adsorption of gases on the surface of the reservoir rock, the immiscibility of CO_2 and natural gas, and thus the possibility of breakthrough production wells of CO_2 [4, 5].

Meanwhile, Geologists and Petroleum Engineers are interested in predicting the thickness and area of the sandstone reservoir. Every reservoir must have a finite limit and with this one can explain this limitation by reconstructing the depositional environment in which sandstone accumulates [6]. The environment is a geomorphic unit in which physical, biological and chemical processes operate to form a deposit (genetic unit). If a particular geomorphic unit containing a sandstone reservoir is placed in the overall depositional model, predictive methods can be made that are useful in petroleum exploration and production. Then, in general, sandstones containing primary porosity and permeability (good reservoir characteristics) are deposited where high energy currents operate in the depositional environment [6]. During the movement of water, or air, as a current, the clay and silt grains remain suspended while the sand grains are transported as a base load. Winnowing sand accumulates as "clean" sand with interconnected pore spaces.

By examining these issues, this research will optimize the operating conditions for CO2 EGR injection and carbon sequestration in the carboniferous sandstone reservoir by considering the existing costs. That will highlight one of the optimized variables to the value of the objective function (profit). It is used in this optimization process to increase profit through changes in production parameters that can be seen from changes in the production system's performance in generating profits.

2 Methodology

2.1 Determination of EGR CO_2 Input and Reservoir Properties

The case study of the operating conditions used for CO2 EGR injection in this final project is based on data from the gas project in Krechba, Salah, Algeria. Meanwhile, the state of the natural gas reservoir is based on data from the Crude Assay Manual in

Table 1. Natural gas composition.

Compounds	*Compounds Formula*	*Mol*	*%Mol*	*Mr*
Ethane	C_2H_6	0.2161	21.61	44.010
Propane	C_3H_8	0.0009	0.09	30.070
Iso-butane	C_4H_{10}	0.0099	0.99	44.097
N-Butane	C_4H_{10}	0.0376	3.76	58.124
Iso-Pentane	C_5H_{12}	0.2044	20.44	58.124
N-Pentane	C_5H_{12}	0.2169	21.69	72.151
Carbon Dioxide	CO_2	0.3142	31.42	72.151

the Algerian Condensate Field [7]. The injection pressure data obtained from the gas project is 1071 psi and the CO_2 mass injection rate is 0.3044 kg/s. Then, from these data it is known that the reservoir has a porosity of 17% carboniferous sandstone which is porous at a depth of 1850 m below the surface. The reservoir permeability is 13 mD. Meanwhile, the reservoir pressure data is at 25961.76 psi and the reservoir temperature is 50 °C [8] (Table 1).

2.2 Pressure Drop and Heat Transfer Modeling for Injection Well, Production Well and Reservoir

When carbon dioxide (CO_2) is injected, it causes a rise in temperature and a decrease in pressure. Therefore, empirical equations must be derived to comprehend the alterations and effects brought on by the fluid. In this analysis, the pressure drop in injection and production wells is modeled with the help of the Beggs-Rill equation, while the pressure drop in the reservoir is modeled with the help of the Darcy equation. Mass and energy balance equations are utilized to simulate the temperature gradient across all components. Fluid properties were predicted with the help of the Peng-Robinson vapor-liquid equilibrium and the commercial software HYSYS [9]. With a goal of less than 4% average model error, the model is validated by comparing it to simulation results generated by PIPESIM software for the injection and production wells and COMSOL Multiphysics for the reservoir.

2.3 Pressure Drop and Heat Transfer Modeling for Injection Well, Production Well and Reservoir

Value of additional recovery, cumulative production, mass flow rate, and time of EGR injection are used to determine the rate of natural gas production. When figuring out how much natural gas is being produced, it's also important to account for the reservoir's Original Gas in Place (OGIP) volume. Earnings, calculated by multiplying the rate of natural gas production by the selling price of natural gas, provide the data needed to determine the production rate.

$$Pt = V_{pd} \times P_{NG} \tag{1}$$

$$V_{pd} = \frac{G_p}{t} \tag{2}$$

$$G_p = \mathrm{G} \times \left(1 - \frac{\frac{p}{z}}{\frac{pi}{zi}}\right) \tag{3}$$

$$G = Ah\emptyset S_{gi} \tag{4}$$

$$B_{gi} = 0.028793 \times \frac{\frac{p}{z}}{\frac{pi}{zi}} \tag{5}$$

$$S_{gi} = 0.0000005 \times \mathrm{f\,g}^5 \times 0.00004 \times \mathrm{f\,g}^4 \times 0.001 \times \mathrm{f\,g}^3 \times 0.0071 \times \mathrm{f\,g}^2 \times 0.0521 \times \mathrm{f\,g} \times 0.02623 \tag{6}$$

$$f_g = \frac{1}{1+M} \tag{7}$$

$$M = \frac{\mu_{ng}}{\mu_{mix}} \tag{8}$$

The primary motivation behind any manufacturing procedure is the generation of a profit. If revenue is higher than EGR production costs, a profit is made in the EGR process. Therefore, it is essential to generate as much income as possible throughout production in order to avoid losing money.

$$Prpfit = R - B_{CO_2} - B_R - B_{op} \tag{9}$$

where

$$R = \left(VNG_{pd} \times PR_{NG}\right) + \left(VCG_{pd} \times PR_{CG}\right) \tag{10}$$

$$B_{CO_2} = V_{CO_2} \times Pr_{CO_2} \tag{11}$$

$$B_R = V_{prod} \times Pr_R \tag{12}$$

$$B_{op} = W_p \times Y \times Pr_E \tag{13}$$

Revenues proceed from the sale of natural gas per day and expressed in the Eq. 10. The condition of natural gas market price for March 7, 2022 based on NYMEX and NGX data has price of 5.036 USD/MMBtu, whereas condensate gas from EDMONTON Condensate has price of 119.53 USD/bbl. Parameter for the Eqs. 10–13 which is natural gas price, price, separation cost and pumping cost are shown in Table 2.

By dividing the amount transported to the production line by the amount injected into the reservoir, one can determine the total amount of stored in the reservoir over a given time interval. Equation 14 displays the formula.

$$F_{CO_2} = \frac{Q_{prod}CO_2}{Q_{inj}CO_2} \tag{14}$$

Alternatively, if all of the injected substance is kept in the reservoir, its value is zero, while if all of it is transported to the production line, its value is one.

Table 2. NP value parameter.

Parameters	Value	Units
PR_{NG}	5.036	USD/MMBtu
PR_{CG}	119.53	USD/bbl
Pr_{CO_2}	58.30	USD/ton
Pr_R	15	USD/ton
Pr_E	0.031	USD/kWh

2.4 Optimization of CO_2 Operation Injection Enhanced Gas Recovery

Profit maximization is achieved through optimization by controlling EGR operating parameters. Pressure, mass flow rate, and injection temperature are the operational conditions that can change. Both the duelist algorithm (DA) [10] and the genetic algorithm (GA) [11] have been used, both of which are relatively new examples of stochastic algorithms. We will now talk about the optimal outcomes produced by optimization algorithms.

3 Result and Discussion

3.1 Modeling of Pressure and Temperature Gradients in Injection and Production Wells

For modeling pressure drop in injection and production wells, the Beggs-Brill method is used, while for modeling temperature gradient, the mass and heat transfer equation are used. The actual conditions of the Krechba gas field in Algeria serve as the basis for the modeling of the injection inlet. The Darcy equation takes as input the characteristics of the injection and production wells as shown in Table 3.

For every 50 m of depth in injection and production wells, PIPESIM is used to validate models of pressure and temperature gradients. Adjusting the injection mass flow rate at the inlet, changing the injection pressure, and changing the steam quality under different operating conditions are all part of the model validation process, which is then compared to the results from PIPESIM. The pressure gradient model has a mean deviation of 0.364% and the temperature gradient model has a mean deviation of 0.754% in the injection well, while the mean deviation of these two variables is 0.871% and 0.334%, respectively, in the production well. Both Fig. 1 and Fig. 2 display models of pressure and temperature gradients, as well as the results of PIPESIM simulations conducted in injection and production wells.

3.2 Modeling of Pressure and Temperature Gradients in Reservoir

Reservoir pressure and temperature gradients are modeled with the help of the Darcy equation, along with the mass and heat transfer equations. The reservoir characteristics used to solve the Darcy equation are listed in Table 4.

Table 3. Pressure drops and temperature gradient injection and production well modeling input parameters

Parameters	Value	Units
Gravity Coefficient	9.8	m/s^2
Pipe Diameter	0.1503934	m
Well Depth	1850	m
Injection Pressure	1071	Psia
Injection Mass Flow Rate	0.3044	kg/s
Injection Temperature	31	°C
Tubing Thickness	0.0089408	m
Absolute Roughness	0.0000254	W/m^2K

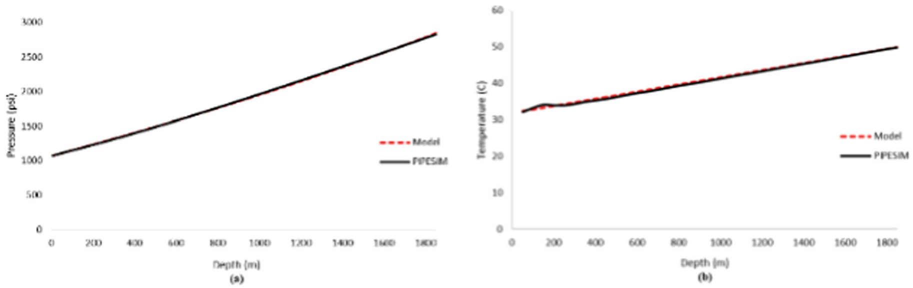

Fig. 1. Model and PIPESIM simulation results for injection well pressure (a) and temperature gradient (b).

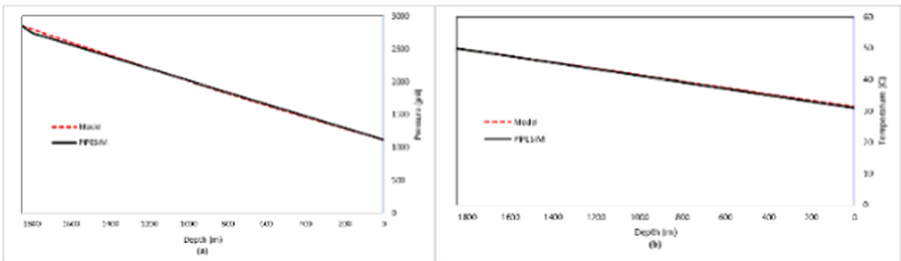

Fig. 2. Model and PIPESIM simulation results for production well pressure (a) and temperature gradient (b).

The Pengg-Robinson vapor-liquid equilibrium and the commercial software HYSYS are used to make approximations of the fluid properties. The injection well model's outlet is the reservoir model's inlet, and the production well model's inlet is the injection well model's outlet. The produced gas associated with the well's output at the surface facilities. They will also be reclaimed for reuse in the injection well. Comparing the model and

Table 4. Pressure drops and temperature gradient reservoir modeling input parameters

Parameters	Value	Units
Reservoir Length	100	m
Reservoir Pressure	25961.76	psi
Reservoir Temperature	50	°C
Reservoir Thickness	314	$_{s}2$
Permeability	13	mD
Porosity	17	%

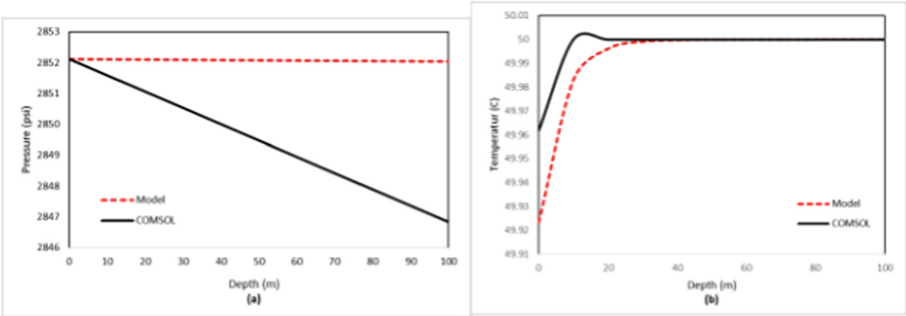

Fig. 3. Model and PIPESIM simulation results for reservoir pressure (a) and temperature gradient (b).

the results of a COMSOL Multiphysics simulation, the average pressure discrepancy is 0.0897% and the average temperature discrepancy is 0.0106%. In Fig. 3, we can see the simulated pressure and temperature gradient generated by the model in COMSOL.

3.3 Natural Gas Production Rate

Equation 4 is used to determine the amount of natural gas in the reservoir, denoted as Original Gas in Place (OGIP), with OGIP obtained using parameters based on the reservoir's initial condition, which are 326521.47 m^3 (11.531 MMCF) natural gas. Gas recovery is calculated to be 90.91% of OGIP using Eq. 3, yielding a total of 296837.70 m^3 (10.4827 MMCF) natural gas.

Injection can increase natural gas production to about 40.798 m^3/day under normal conditions of operation, with the natural gas fraction consisting of 24.20% C 4 H 10, 53.11% C 5 H 12, and 22.69% gas condensate. Consequently, the daily outputs of C 4 H 10, C 5 H 12, and condensate gas are 30.008 m^3/day, 1.0596 MMBtu/day, and 10.790 m^3/day, 67.867 bbl/day. At this level of output, the EGR amounts to about $7611.897 per day.

The EGR price was determined by plugging NP values into Eqs. 10–13. The daily cost of is $1533.299. Recycling costs $76.493 per day, and the cost of pumping water is

Table 5. Shows the profit calculation

Parameters	Value	Units
Revenue	7611.897	USD/day
CO2 Purchase cost	1533.299	USD/day
Recycling cost	77.493	USD/day
Pumping cost	2.570	USD/day
Profit	5998.534	USD/day

$2.570.16 per day. After income and expenditures have been tallied, the net profit can be determined (Table 5).

The study involved the transformation of the into the supercritical state as it entered the reservoir. Supercritical can be combined with the natural gas already present in the reservoir. The HYSYS-generated mixing result for natural gas indicates that following mixing, the gas's composition is 78.39% and is 21.61%. Using Eq. 14, we find that 0.961, or 80.357% of the injected, is absorbed and stored in the reservoir. Because of this, 26.3 tons per day are being kept in storage.

3.4 Sensitivity Analysis

Analysis of the sensitivity of the profit to changes in operating conditions such as temperature, pressure, and injection mass flow rate is performed. This profit sensitivity analysis curve for varying mass flow rate injection is shown in Fig. 4a. Increased revenue from EGR and Carbon Sequestration can be expected from a linear increase in injection mass flow rate under conditions of constant temperature and pressure. This is because natural gas production increases in proportion to the amount injected into the reservoir, despite the fact that associated costs (including those for buying, recycling, and pumping) also increase.

A sensitivity analysis for variations in injection pressure at a constant mass flow rate and injection temperature is depicted in Fig. 4b. The graph demonstrates that as injection pressure is raised, profits decline. Since increasing injection pressure decreases natural gas production and raises pump operating costs, it is not a viable option.

Figure 4c demonstrates how a sensitivity analysis of varying injection temperatures under constant mass flow rate and pressure leads to a rise in revenue. Increasing the injection temperature boosts natural gas production and reduces pumping expenses.

The findings suggest that maximizing mass flow rate and temperature is the key to maximizing profits. In order to increase the mas flow rate, it was necessary to increase the injection pressure. High injection pressure increases the cost of operating the pumps and reduces profits as natural gas production rates drop. Finding the optimal mass flow rate, temperature, and injection pressure for your operation is crucial for achieving maximum profitability.

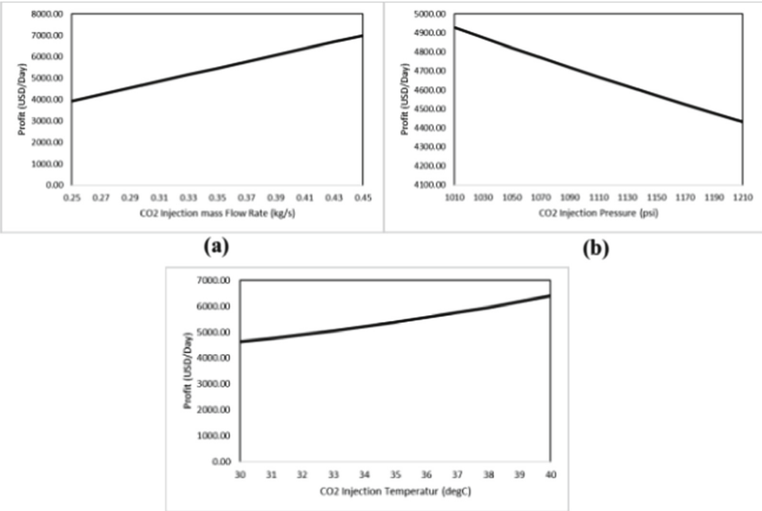

Fig. 4. Changes in pressure (a), mass flow rate (b), and temperature (c) sensitivity analysis curve

Table 6. Optimized variables determined by optimization results

Optimization Variable	Optimization Technique	
	DA	GA
Pressure	1071.0015	1070.9998
Temperature	39.891	39.999
Mass flow rate	0.62028	0.6249

3.5 Optimization of CO_2 Injection Operations EGR and CS

Optimizing the pressure, temperature, and CO_2 injection mass flow rate of the EGR and CS processes, as was previously stated, aims to maximize profits. Profit is the sum of revenue or income minus the total cost of running the pumps and other operational expenses associated with EGR CO_2 injection and CS. This optimization relied on constraints including a minimum production well head pressure of 1071 psi, a temperature range of 30–40 °C for CO_2 injection, and a mass flow rate of 0.3044–0.625 kg/s for CO_2 injection. Stochastic algorithms optimization techniques are used in this study because of their ability to locate the global optimum. In this study, we employ the stochastic algorithms optimization strategies of the Duelist Algorithm (DA) and the Genetic Algorithm (GA). Optimization outcomes, including best-case scenarios for each method, are shown in Table 6. All regions will experience the same constant mass flow rate, but as shown in Figs. 6, 7, and 8, pressure and temperature will drop everywhere as a result of thermal and hydraulic losses.

Table 7. CO_2 EGR and cs profit calculation

Parameters	DA	GA
Income from natural gas (USD/day)	14.232	14.394
Income from condensate (USD/day)	20189.441	20419.848
CO2 Purchase cost (USD/day)	3124.412	3148.198
Recycling cost (USD/day)	157.908	159.110
Pumping cost (USD/day)	3.609	3.606
Profit (USD/day)	16917.744	17123.327

By increasing the rate of natural gas and gas condensate production while decreasing the cost of CO_2 purchase, the cost of recycling CO_2, and the operating cost of the pump, maximum profit is obtained using the optimum variables generated using the DA and GA optimization techniques. Table 7 shows the outcomes of the optimized variables used to calculate revenue, CO_2 procurement costs, CO_2 recycling costs, pump operating costs, and net profit for each optimization method.

In Table 7, we see the two-valued profit of each optimization method. Because it consistently generated the same objective function value and optimal optimization variables, GA was the most effective optimization method. The daily profit generated by using GA methods is 17123.327 USD, an increase of 185.46% over the daily profit generated using the previous optimization strategy of 5998.534 USD. The profit value drops, however, when DA optimization is applied, leading to an 182.03% increase. Tables 6 and 7 show that there is little difference between DA and GA when it comes to determining the optimal variables and calculating profits. This is due to the fact that the DA and GA approaches share the same optimization strategies, which means that the resulting optimum variables are very similar.

At each iteration, the stochastic optimization method finds a locally optimal solution, which maximizes the objective function. When the fitness value reaches the global optimum, it will remain there, as this is the best possible optimization outcome. To guarantee that the objective function's value was maximized, the fitness plot was run five times for each optimization method employed in this study. As can be seen in Fig. 7, DA and GA optimization algorithms typically undergo a number of iterations of the objective function before reaching an optimal solution (Fig. 5).

The objective function starts off with a low value early in the iteration process but gradually increases until it reaches a global optimum around the 20th iteration. The effectiveness of the optimization method in searching the best pressure and temperature variables of CO_2 EGR and carbon sequestration is demonstrated graphically in Figs. 6, 7 and 8 by comparing the results of the initial (pre) and final (post) optimizations using the same model and optimized variables according to Table 6 (mass balances). Optimized mass flow rate, pressure, and temperature variables are used to inject carbon dioxide (CO_2) into an injection well, with the same level of detail and accuracy as the pre-optimization simulation (refer to Table 6).

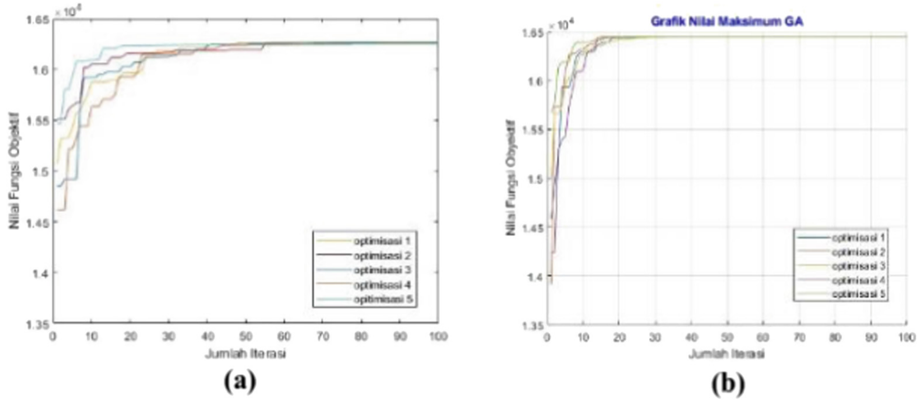

Fig. 5. Increase in objective function during iterations using DA (a) and GA (b)

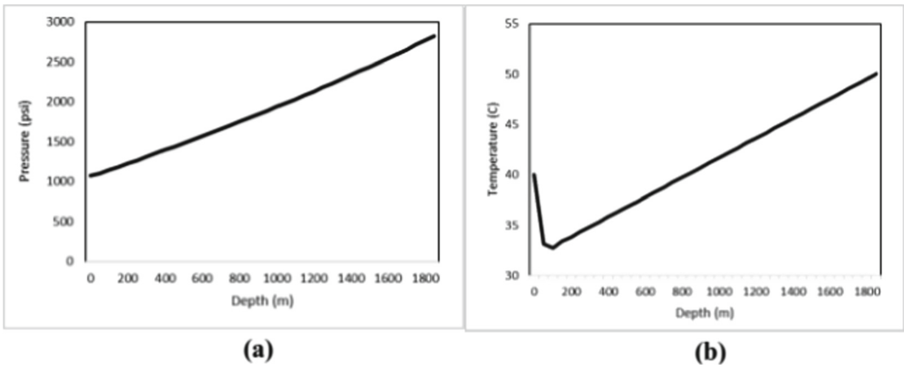

Fig. 6. Optimization results for injection well pressure drop (a) and temperature gradient (b).

Degradation of temperature and pressure with only a slight variation is depicted in Figs. 1 and 8. The temperature of CO_2 is greater than that of the rock outside the tubing in injection wells, so the CO_2 cools along the first 100 m of the well before warming up again at thermal equilibrium. Meanwhile, as a result of gravity, the force exerted on CO_2 is constantly on the rise. It has also been found that the influence of temperature on the pressure of supercritical CO_2 is negligible. The density of CO_2 impacts the gravitational pull and pressure drop. As a result, the nonlinearity of the injection well tube and rock can be captured by the model using the Beggs-Brill method.

In spite of the similarities between the pressure differences before and after optimization (Figures 7a and 3a), the pressure degradation is slightly different. Meanwhile, the outlet temperature of the injection well is depicted by the reservoir inlet temperature in Figs. 7b and 3b, and these two values are not the same. Accordingly, the nonlinearity effect brought on by the temperature gradient is a major contributor. Overall, the results show that the reservoir model based on Darcy and mass energy balances method successfully represents the nonlinearity of reservoir rock.

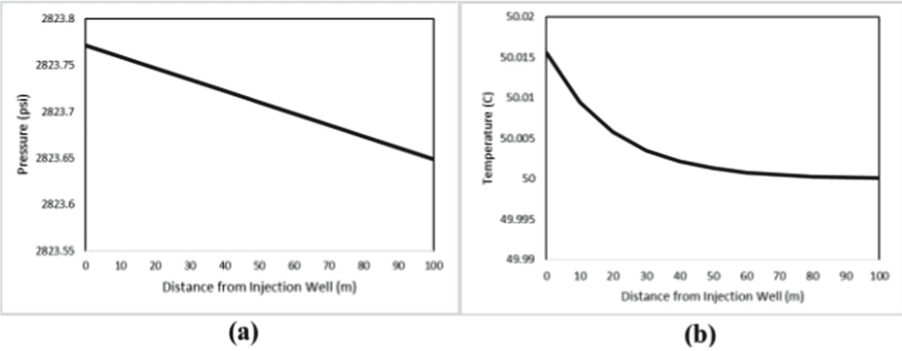

Fig. 7. Optimization results for reservoir pressure drop (a) and temperature gradient (b).

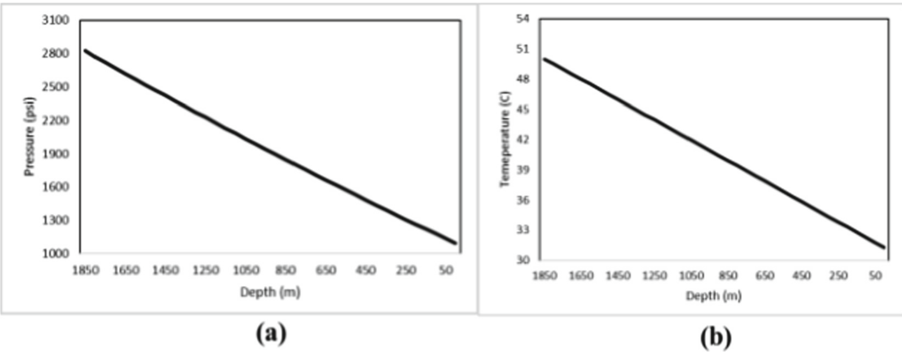

Fig. 8. Optimization results for production well pressure drop (a) and temperature gradient (b).

It is not possible to distinguish between pre- and post- optimization natural gas production well conditions (Figs. 2, 8). When you move away from the reservoir, the pressure and temperature drop. In turn, this means that the reservoir pressure will be lower, resulting in a lower pressure at the outlet of the production wells after optimization.

4 Conclusion

To model CO_2 EGR and CS, we can break the process down into its component parts—the injection well, the reservoir, and the production well. The Beggs-Brill method is used to model injection pressure drop in injection and production wells, while the Darcy equation is used to model injection pressure drop in the reservoir. Simulations of temperature gradients rely on mass and heat transfer equations. On average, the PIPESIM software simulation was off by 0.364% for pressure drops and by 0.754% for temperature gradients in the injection well model. Mean deviations of 0.0897 and 0.0106 were found between the validated reservoir pressure drop model and the COMSOL Multiphysics software simulation of the temperature gradient, respectively. Model-predicted pressure drops and actual temperature gradients in a production well typically deviate by 0.871% and 0.334%, respectively. Importantly, the nonlinearity of the wellbore can be captured by both the Darcy and mass energy balances method reservoir model and the

Beggs-Brill method injection and production wells model. According to the sensitivity study, the profit will rise with an increase in mass flow rate and temperature but fall with an increase in CO_2 injection pressure. Genetic Algorithm (GA) provided the best optimization results, with profits rising from 5998.534 USD/day to 17123.327 USD/day, an increase of 185.46% over the non-optimized starting point of the injection. CO_2 storage capacity is 6495.033 tons when injection parameters are optimized.

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