# Optimization of $CO_2$ Enhanced Oil Recovery Operating Condition: A Case Study, Prudhoe Bay, North Slope Alaska, USA

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**Abstract.** Fossil fuel consumption continues to increase every year and the possibility to find new reserves will be increasingly difficult. It can be estimated that if the current rate of consumption and production continues, oil reserves will be depleted in 50 years. The increasing difficulty in finding new oil fields causes oil companies to try to increase the Recovery Factor value to maintain the economic level of oil. To increase the RF value, an EOR operation is carried out which can produce about more than 50% to 80% OOIP. To get the optimal recovery value, it is necessary to optimize the $CO_2$ EOR operating condition variables, including mass flow rate of $CO_2$ injection, $CO_2$ injection temperature, and $CO_2$ injection pressure. The modeling of the $CO_2$ EOR operating pressure gradient in production and injection wells uses the Begg's-Brill method, while the Darcy equation for reservoirs uses the Darcy equation. For modeling the temperature gradient on the production well, injection well, and reservoir using the heat transfer equation. Based on the optimization results using Genetic Algorithm, the net profit increased from 1,458.02 USD/day to 9,510.33 USD/day. While the optimization results using the Killer Whale Algorithm get an increase in net profit from 1,458.02 USD/day to 9,509.71 USD/day.

**Keywords:** $CO_2$ EOR · Optimization · Genetic Algorithm · Killer Whale Algorithm

## 1 Introduction

Fossil energy is a fundamental driver of technological, socioeconomic, and other development advances. The great use of fossil fuels has begun since the mid-19th century when industries such as power plants appeared [1]. According to statistical review of World Energy 2021 data [2], it is shown that mankind from 1965 to 2021 has consumed oil amounting to 3,873,642 Kbpd. Fossil fuel consumption will continue to increase every year and the possibility of finding new reserves will be increasingly difficult. It is


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foreseeable that if the current rate of consumption and production continues, oil reserves will be exhausted in 50 years, natural gas in 50.9 years, and coal in 132 years [3].

The increasing difficulty in finding new oil fields has caused most oil companies in the world today to focus more on maximizing the Recovery Factor (RF) or the recovery rate of existing oil fields as well as to maintain the level of the oil economy. The average RF from oil fields around the world is about 20% to 40%. Meanwhile, the average RF for gas fields around the world is around 80% to 90% [4]. This is good news because with such RF values, oil and gas inventories can still leave oil storage from 202 0 production of 1732 Bbpd and is expected to last for more than 50 years [2].

In general, oil production begins with relying on natural flow or artificial lifting only produces an average of 30 percent Original oil in Place (OOIP). Using secondary recovery methods such as waterflooding and gas pressure maintenance produces oil production up to an average of 50% OOIP. While the tertiary recovery method or commonly called Enhanced oil Recovery (EOR) produces around more than 50% to 80% OOIP [5]. The EOR recovery technique is an important study in oil and gas-related research because it can increase the RF of an oil field and increase oil reserves globally. The EOR technique that is currently popularly used is to inject $CO_2$ into the reservoir. $CO_2$ EOR alone accounts for as much as one-third Mbpd of oil in the world which mostly comes from the Permian Basin in the Americas and weyburn fields in Canada [6].

$CO_2$ injection is an EOR technique that has great application potential in oil production. According to data from the International Energy Agency, the corresponding oil resources for the development of $CO_2$ injection in the world are about 300–600 billion barrels of earth. Compared to other types of gases, $CO_2$ is the most widely used injection gas in addition to low minimum mixed pressure (MMP) and low compression costs. Oil wells that widely use $CO_2$ gas injection applications have reservoir characteristics with a permeability of 0–50 mD, a depth of 1500–3500 m, a thickness of 0–100 m, a maximum temperature of 80–120 °C, and an oil content with a low viscosity of 0–100 mPa s [7].

This research will be conducted to determine the operating conditions model of oil production with the EOR recovery method at prudhoe Bay Reservoir using $CO_2$ injection fluid. The algorithms applied to this study are the Genetic Algorithm (GA) and the Killer Whale Algorithm (KWA), which are search techniques used in computing to find the right solution or approximate solution for optimization and search problems. The study will also consider the increase in total profits from the optimized $CO_2$ EOR operating conditions.

## 2 Methodology

In this research, the author raised a topic of problems, namely, how to get maximum profit from the oil production process by increasing the recovery factor of oil production. However, in maximizing the profits from oil production, there are several things that can affect the benefits that will be obtained, such as the cost of procuring $CO_2$, the cost of separating $CO_2$ and the operational costs of the $CO_2$ injection process.

After some problems can be identified, then the steps are compiled that are expected to solve the problems that have been identified. The first step is to make a modeling of the pressure gradient and temperature gradient of each part in terms of the data that has been

**Table 1.** Input parameter for pressure gradient and temperature gradient modeling

| Parameters | Value |
| --- | --- |
| Diameter Well | 9.625 in / 0.244475 m |
| Gravitation | 9.8 $m/s^2$ |
| Gravity factor | 1 |
| Well depth | 8600 ft / 2621.28 m |
| tubing thickness | 0.296 in / 7.5814 m |
| roughness of tubing | 0.001 in / 0.0254 m |
| Temperature Reservoir | 132.8°$F$ / 56 °C |
| ambient temperature | 31 °C |

**Table 2.** Variable input EOR operating conditions [8][9]

| Parameters | Value |
| --- | --- |
| Injection Temperature | 31 degC |
| Injection Pressure | 1071 psia |
| Mass rate of injection vapor | 0.3044 kg/s |

obtained. The next step is to calculate the profit from the $CO_2$ EOR operation before optimization is carried out. After that, optimization can be carried out using genetic algorithms and killer whale algorithms to obtain the most optimal values for variables that can affect profits from oil production. The optimization result is said to be optimal if it has reached a total profit value that is greater than the total profit before optimization.

### 2.1 Collecting $CO_2$ EOR Parameter Input Data and Reservoir Characteristic Data

To conduct the modeling, data are needed in the form of input parameters, operating conditions of $CO_2$ EOR injection, reservoir characteristics and oil composition. The parameters of pressure gradient and temperature gradient modeling are determined according to API standards to determine the thickness and roughness of tubing based on the diameter of the injection well and production well. The following are the input parameters used to model the Pressure Gradient and Temperature gradients that can be seen in.

For the operating parameters of $CO_2$ EOR injection, data based on field data of EOR operations in North Slope Alaska, Prudhoe Bay, USA were used. The following are the variable data of $CO_2$ injection operations inputs used for modeling and optimization shown by Table 2.

**Table 3.** Characteristics of the reservoir [9]

| Parameters | Value |
|---|---|
| Reservoir Thickness | 156 ft / 47.5488 m |
| Reservoir Length | 100 m |
| Permeability | 0.25 mD |
| Porosity | 20% |

**Table 4.** Properties of north slope oil [10]

| Parameters | Value |
|---|---|
| API Gravity | 32.1 |
| Gor | 750 scf/stb |
| Gas Specific Gravity | 0.865 |
| Viscosity 20 degC | 11.1 cP |
| 40 degC | 6.4 cP |
| 50 degC | 5.1 cP |

As for the data on the characteristics of the reservoir, it refers to the data on the field conditions of the North Slope Alaska Reservoir, Prudhoe Bay, USA. Rock and reservoir data are shown in Table 3.

The property and composition of oil in this study refers to field conditions at Alaska's North Slope oil well, Prudhoe Bay, Alaska. The following are data on the properties of oil in reservoirs which can be seen in Table 4.

### 2.2 Optimization Objective Function

The objective function is a mathematical function obtained from the purpose of the study so that optimization can be carried out. The purpose of this study is to increase the advantages of the $CO_2$ Enhanced oil recovery process by optimizing the variables that affect the advantages of this process. The things that affect the advantages of this process are the cost of procuring the $CO_2$ used for injection, the cost of separating the $CO_2$ returning from the reservoir after injection, and the operational costs required for this process such as the electricity cost of using a pump. The variables optimized in this study were injection temperature, injection pressure, and injection period flow rate.

Therefore, it can be determined that the formulation of the objective function of the $CO_2$ EOR process, which is a function of oil sales profits, $CO_2$ procurement costs, $CO_2$ separation costs, and operational costs, can be mathematically written in the following (Eq. 1).

$$p_{max} = f_1\begin{pmatrix} R_{oil}\,,\ C_{CO_2\,procurement} \\ C_{CO_2\,Recycle}\,,\ C_{operation} \end{pmatrix} \tag{1}$$

where $R_{oil}$ is the profit of oil sales which is a function of the volume of oil production per day, this function can be mathematically seen in (Eq. 2).

$$R_{oil} = f_2(V_{pd}) \tag{2}$$

The volume of oil production itself is a function of the amount of oil recovered and the length of the injection time, mathematically it can be seen in (Eq. 3).

$$V_{pd} = f_3(oil\ recover,\ t_{inj}) \tag{3}$$

The amount of recovered oil is a function of the recoverable fraction of oil, mathematically written in (Eq. 4).

$$oil\ recover = f_4(N_p) \tag{4}$$

The recoverable oil fraction is a function of the HCPV of the injected $CO_2$ which can be written mathematically in (Eq. 5).

$$N_p = f_5((F_i)_{BT}) \tag{5}$$

While the HCPV value of $CO_2$ injected is a function of the mobility factor that can be written mathematically in (Eq. 6).

$$(F_i)_{BT} = f_6(M) \tag{6}$$

The mobility factor value itself is a function of the value of the viscosity of the mixture and the viscosity of $CO_2$ injected, mathematically it can be written in (Eq. 7).

$$\dot{M} = f_7(\mu_o, \mu_s) \tag{7}$$

The viscosity value of the mixture and the viscosity of the injected $CO_2$ are influenced by 2 decision variables in the form of injection pressure and injection temperature because $CO_2$ and a mixture of oil and $CO_2$ are compressible fluids whose fluid properties can change along with changes in pressure and temperature. Mathematically it can be written in (Eq. 8).

$$\mu_o, \mu_s = f_8(P_{inj}, T_{inj}) \tag{8}$$

To calculate the amount of oil production per day, it takes the value of the length of time for the injection of $CO_2$ which is a function of the volume of $CO_2$ injected, mathematically it can be written in (Eq. 9).

$$t_{inj} = f_9(V_{CO_2inj}) \tag{9}$$

The volume value of $CO_2$ injected is a function of the type of time of $CO_2$ injection and the mass of $CO_2$ injected, which can be written in (Eq. 10).

$$V_{CO_2inj} = f_{10}(\rho_{inj}, m_{CO_2inj}) \tag{10}$$

The mass value of $CO_2$ injected is a function of the decision variable in the form of a mass flow rate which can be written in (Eq. 11).

$$m_{CO_2 inj} = f_{11}\left(\dot{m}_{inj}\right) \tag{11}$$

The density value is also a function of the decision variable of injection pressure and injection temperature that affects the nature of compressible fluids, which can be written in (Eq. 12).

$$\rho_{inj} = f_{12}\left(P_{inj}, T_{inj}\right) \tag{12}$$

So that the objective function equation of this research can be written in (Eq. 13) below.

$$\begin{aligned} P_{max} = R_{oil} - \big(C_{CO_2\,procurement} \\ + C_{CO_2\,Recycle} \\ + C_{operation}\big) \end{aligned} \tag{13}$$

For the constraints used can be written in the following mathematical equation.

$$\dot{m} \leq 0.4\,\text{kg/s} \tag{14}$$

$$P_{inj} \leq 1071\,\text{psi} \tag{15}$$

$$T_{inj} \leq 65\,^{\circ}\text{C} \tag{16}$$

A large mass flow rate can increase the flow rate of production, thereby increasing profits. However, if the flow rate of the injection period is too large, the amount of $CO_2$ carried to the production line will increase, increasing the cost of $CO_2$ recovery. Therefore, an upper limit is given for the injection flow rate of 0.4 kg/s. To get a large mass flow rate, it needs a large injection pressure as well. However, too much injection pressure can also increase the operational costs of the pump because to get a large injection pressure, a large pump power is required as well so that the required electricity costs will be more expensive. Therefore, an upper limit of injection pressure is given of 1071 Psi. While a large injection temperature can produce energy from a large injection process so that the volume of oil production also increases and can increase profits. However, if the injection temperature is too large, it will affect the efficiency of the pump so that it requires greater operational costs. so that an upper limit is given for the injection temperature of 65 °C.

## 2.3 Pressure Gradient and Temperature Gradient Modeling

At this stage, pressure gradient and temperature gradient modeling are carried out in order to obtain a decrease in fluid properties using empirical equations in the temperature function. This modeling is needed because of the nature of the fluid that can change as the temperature and pressure change that occurs in the injection well, production well, and reservoir. To model the pressure gradient on the injection well used the Begg's-Brill

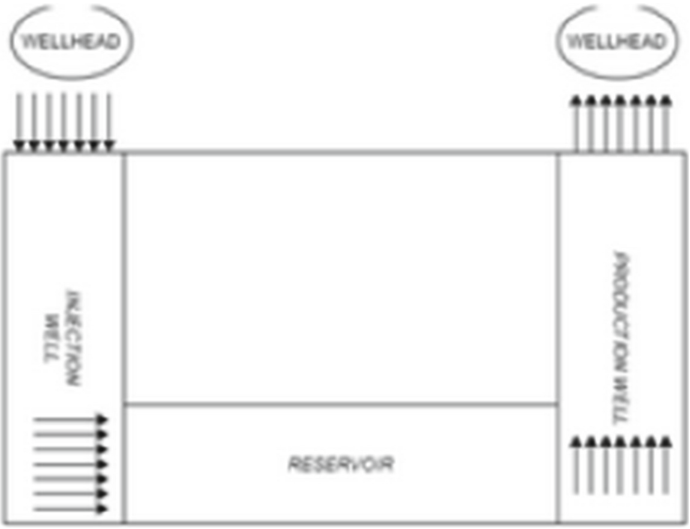


**Fig. 1.** Illustration of $CO_2$ EOR Process Model

equation and temperature gradient in injection well used equation Heat Transfer. Then the modeling results in the form of pressure and temperature output from the injection well are used as inputs to model the pressure and temperature gradients in the reservoir. To model the pressure gradient and temperature gradient in the reservoir is used darcy equation and uto model the temperature gradient in the reservoir is used the Heat Transfer equation. Then the output pressure and temperature results from the reservoir are used to model the pressure gradient and temperature gradient on the production well using the same model as the injection well. An illustration of the $CO_2$ EOR process model can be seen in Fig. 1.

After obtaining the model using the equation above, validation was carried out using PIPESIM software for injection well and production well. As for the validation of reservoir modeling, COMSOL software is used. Validation is carried out using the MAPE method and the modeling contribution can be said to be valid if the MAPE value is less than 10%.

## 2.4 Calculation of Oil Production Volume and Profit

To obtain the estimated value of oil recovery, the Koval method is used which explains that the fraction of $CO_2$ flow and the recovered oil is influenced by the $CO_2$ - oil mixture mobility ratio and the density difference between $CO_2$ and oil. The rate of oil production can then be calculated after obtaining the fraction value between $CO_2$ and oil obtained by the Koval Method equation then multiplied by the amount of oil contained in the reservoir or commonly referred to as OOIP. The OOIP contained in the prudhoe bay reservoir amounts to approximately 4,208,443.27 STB [11] based on existing field data. For the calculation of the amount of recovered oil and the profit obtained from the $CO_2$

EOR process is expressed in the (Eq. 17) and (Eq. 18).

$$R_{oil} = V_{pd} \times P_{oil} \tag{17}$$

$$V_{pd} = \frac{oil\ recover}{t_{ini}} \tag{18}$$

To calculate those costs that affect the total value of profits such as the cost of procurement of $CO_2$ (Eq. 19), to calculate the cost of separation of $CO_2$ used (Eq. 20) and to calculate operational costs used (Eq. 22). After that, it can be calculated the total value of the profit of the $CO_2$ EOR process per day using the (Eq. 24).

$$C_{CO_2} = m_{CO_2inj} \times \frac{P_{CO_2}}{1000} \tag{19}$$

$$C_{recycle} = V_{rCO_2} \times P_{sCO_2} \tag{20}$$

$$V_{rCO_2} = \frac{oil\ recover}{t_{inj}} \tag{21}$$

$$C_{op} = W_p \times K \tag{22}$$

$$W_p = \frac{q \times \left(p_{out} - p_{inj}\right)}{\eta} \tag{23}$$

$$Profit = R_{oil} - \left(C_{CO_2} + C_S + C_{op}\right) \tag{24}$$

### 2.5 Optimization of $CO_2$ EOR Operating Conditions

In this research, the genetic algorithm and killer whale algorithm are used, which are stochastic optimization techniques. The reason for the use of stochastic algorithms is because the objective function of this research is a non-linear equation. If optimization is carried out using deterministic optimization techniques, there will be uncertainty that the results obtained are optimal global values or are usually said to be trapped in the optimum local value. By using stochastic optimization techniques can be reduced the possibility of being stuck in the optimum local value. This is due to the characteristics of stochastic optimization that tests the optimization variable randomly at a specified limit to obtain the optimal optimization variable.

Optimization is carried out to obtain the optimal value of the objective function by optimizing the variables that affect the objective function of the $CO_2$ EOR operation. The variables that are optimized are injection pressure, injection temperature, and injection mass flow rate. The optimization techniques used in this study are genetic algorithms or genetic algorithms and killer Whale Algorithms. The optimization algorithm in the code uses MATLAB software with input parameters modeling pressure gradient and temperature gradient in the form of pressure and temperature from reservoirs and wells, permeability, porosity, gravitational force, steam viscosity, and thermal conductivity. Optimization criteria have been successfully carried out if they get a profit value which is an objective function greater than the total value of profit before optimization.

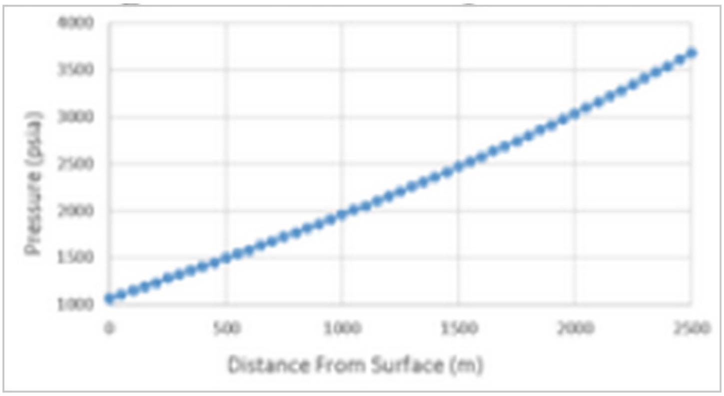


**Fig. 2.** Pressure Gradient Chart on Injection Well

# 3 Result and Discussion

## 3.1 Modeling Pressure Gradient and Temperature Gradients on Injection Well

Pressure gradient modeling on injection well is done using the Begss-Brill equation and temperature gradient modeling on injection well is done using the heat transfer equation. Modeling parameters are based on data on the field conditions of the reservoirs of North Slope Alaska, Prudhoe Bay, Alaska in Table 1 and Table 2. The results of pressure gradient modeling can be seen in Fig. 2.

From the chart above, it can be seen that the pressure of the injection fluid increases as the depth increases. The pressure change that occurred was 2605.42 psi with a $CO_2$ pressure entering the injection well of 1071 psi and a $CO_2$ pressure when exiting the injection well of 3676.42 psi. This occurs due to the influence of gravitational force which causes an increase in hydrostatic pressure as the depth increases in the injection well.

The results of temperature gradient modeling can be seen in Fig. 3. From the temperature gradient chart below, it can be seen that the temperature increases as the depth increases. The temperature change that occurred was 25.02 °C with a $CO_2$ temperature entering the injection well of 31 °C and a $CO_2$ temperature when exiting the injection well of 56.02 °C. This occurs due to temperature changes in the rock walls of the well pit as the depth increases. The increase in temperature is also caused by the increase in hydrostatic pressure with each increase in experience. Another factor that affects the temperature change that occurs is due to a decrease in potential energy from the wellhead to the reservoir so that there is an increase in enthalpy and affects the increase in the temperature of the injection fluid as the depth increases.

The results of the validation of pressure gradient modeling using the Begg's-Brill equation validated using PIPESIM software can be seen in Fig. 4.

Modeling pressure gradient in injection well is done by segmenting the depth every 50 m with validation values using the Mean Absolute Percent Error method for a pressure gradient of 2.56%. The error value that occurs is caused by the difference in computing capacity between pipesim software and the model calculations made. With a MAPE

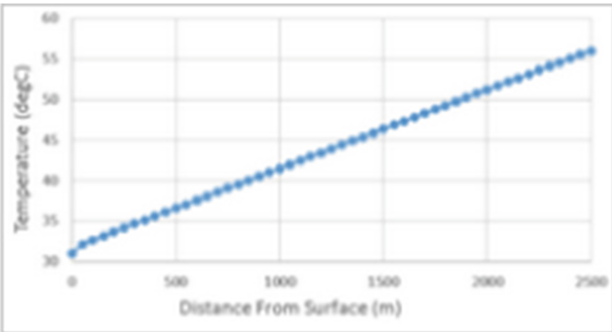


**Fig. 3.** Temperature Gradient Chart On Injection Well

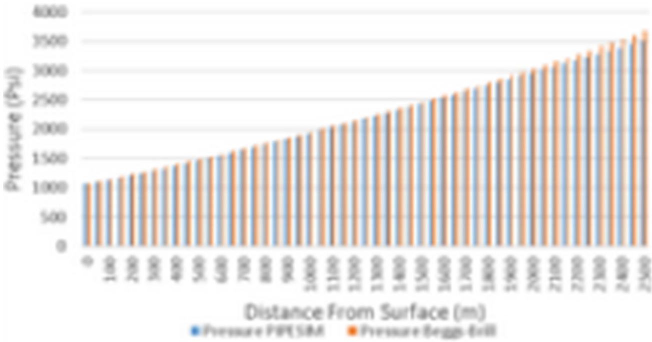


**Fig. 4.** Chart Validation of Pressure Gradient Modeling on Injection Well

value of less than 10% it can be said that the model is so accurate that it can be used to perform optimizations.

The results of the validation of temperature gradient modeling using the heat transfer equation for injection well validated using PIPESIM software can be seen in Fig. 5.

Modeling the temperature gradient in the injection well was done by segmenting the depth every 50 m with validation values using the Mean Absolute Percent Error method for a temperature gradient of 1.16%. The error value that occurs is caused by the difference in computing capacity between pipesim software and the model calculations made. With a MAPE value of less than 10% it can be said that the model is so accurate that it can be used to perform optimizations.

### 3.2 Modeling Pressure Gradient and Temperature Gradients on Reservoirs

Pressure gradient modeling in reservoirs is carried out using the Darcy equation which can be seen in the Eq. (2.13) and temperature gradient modeling in reservoirs is carried out using the heat transfer equation in the Eq. (2.15). Modeling parameters are based on field condition data of the reservoirs of North Slope Alaska, Prudhoe Bay, Alaska in Tables 1, 2, and 3. For pressure and temperature inputs in the reservoir are the result

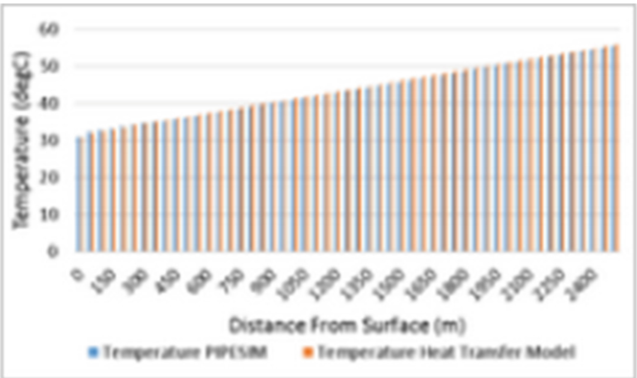


**Fig. 5.** Temperature Gradient Modeling Validation Chart on Injection Well

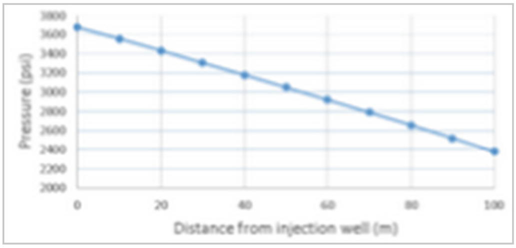


**Fig. 6.** Pressure Gradient Chart on Reservoirs

of the output pressure and temperature gradient of the injection well. The results of the pressure gradient modeling on the reservoir can be seen in Fig. 6.

In reservoirs, the injected $CO_2$ fuses with oil with total of 59% of $CO_2$ mixed based on fluid property analysis using HYSYS software. Judging from the chart above, this mixture of $CO_2$ and petroleum experienced a change in pressure from injection well to production well with a distance of 100 m. The pressure change that occurred was 1297.99 psi with a pressure of $CO_2$ entering the reservoir of 3676.42 psi and the pressure of the mixture of $CO_2$ + Petroleum when exiting the reservoir was 2378.42 psi. The occurrence of pressure changes is caused by the flow of fluid passing through porous rocks. This pressure drop is strongly influenced by the permeability of reservoir rocks. The greater the permeability, the smaller the pressure change that occurs.

The results of modeling the temperature gradient on the reservoir can be seen in Fig. 7.

The temperature of the mixture of $CO_2$ and oil also decreases as the distance from the injection well to the production well increases. However, the changes that occur are not too significant because when entering the reservoir, the temperature of the injected $CO_2$ is equal to the temperature of the surrounding rocks, which is in the range of 56 °C.

The validation results of pressure gradient modeling on the reservoir are shown in Fig. 8.

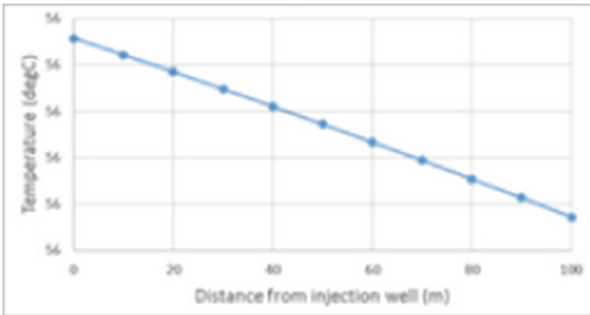


**Fig. 7.** Temperature Gradient Chart on The Reservoir

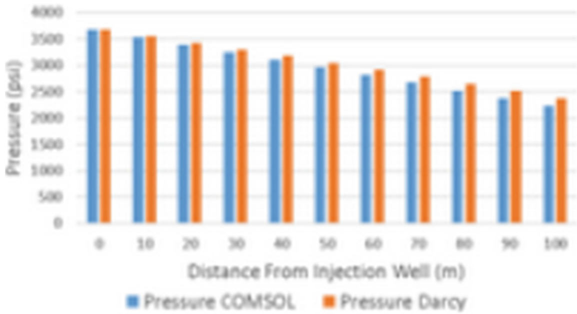


**Fig. 8.** Pressure Gradient Modeling Validation Chart on Reservoirs

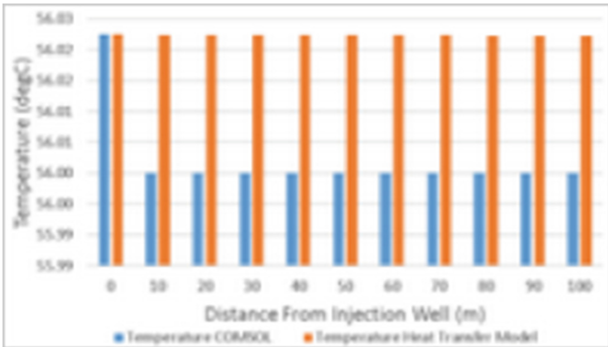


**Fig. 9.** Temperature Gradient Modeling Validation Chart on Reservoirs

The results of the validation of temperature gradient modeling on the reservoir are shown in Fig. 9.

Modeling pressure gradient and temperature gradient in reservoirs is carried out by segmenting the distance from the injection well by 10 m. Modeling was validated using COMSOL software with a Mean Absolute Percent Error value for a pressure gradient ofr 3. 05% and temperature gradient of 0. 06%. The error value that occurs is caused by the

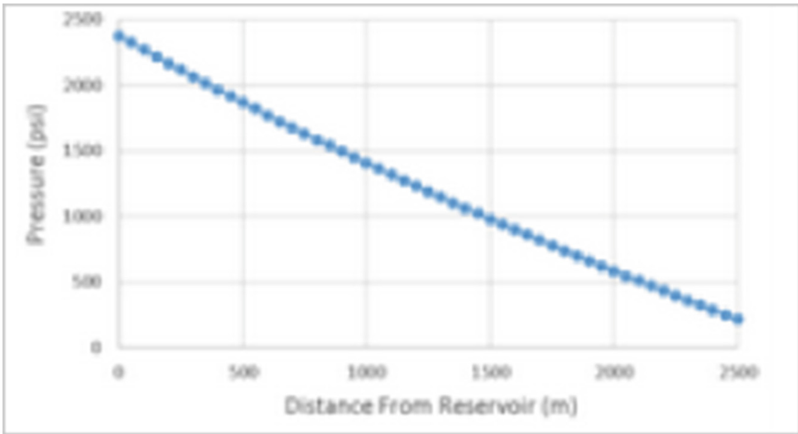


**Fig. 10.** Pressure Gradient Chart on Production Well

difference in computing capacity between the COMSOL software and the calculation of the model made. With a MAPE value of less than 10%, it can be said that the model pressure gradient and temperature gradient in the reservoir are very accurate so that they can be used to optimize.

### 3.3 Modelling Pressure Gradient and Temperature Gradient on Production Well

Pressure gradient modeling on injection well is done using the Begss-Brill equation and temperature gradient modeling on injection well is done using the heat transfer equation. Modeling parameters are based on data on the field conditions of the reservoirs of North Slope Alaska, Prudhoe Bay, Alaska in Tables 1 and 2. For pressure and temperature inputs in the production well are the result of output pressure and temperature gradient from the reservoir.

The results of pressure gradient modeling can be seen in Fig. 10.

From the graph of pressure gradient modeling results, it can be seen that the pressure from the reservoir entering the production well decreases along with the decrease in depth of the production well. The change in pressure that occurred was 2162.87 psi with the pressure of the mixture entering the production well of 2378.42 and the pressure of the mixture when it came out of the production well of 215.56 psi. This is caused by the flow of a mixture of $CO_2$ and petroleum moving against the earth's gravity so that there is a change in pressure due to the elevation that occurs. Another thing that affects the change in pressure is the friction between the $CO_2$ mixture and the oil between the tubing walls of the production well.

The results of modeling the temperature gradient on the production well can be seen in Fig. 11.

The mixture of $CO_2$ and oil decreases as the distance from the reservoir increases to the surface. The temperature change that occurred was 25.28 °C with the temperature of the mixture entering the production well of 56.02 °C and the temperature of the mixture when it came out of the production well of 30.76 °C. This is due to changes

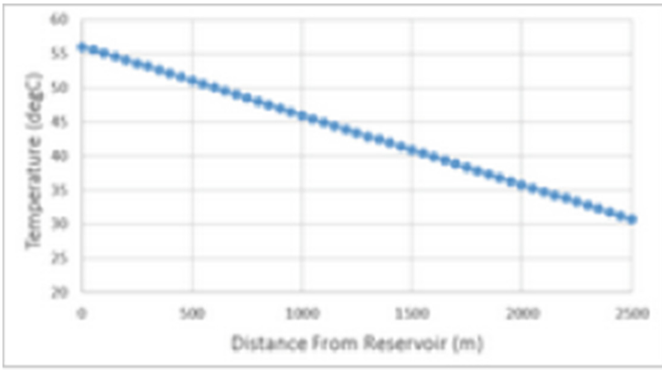


**Fig. 11.** Temperature Gradient Chart on Production Well

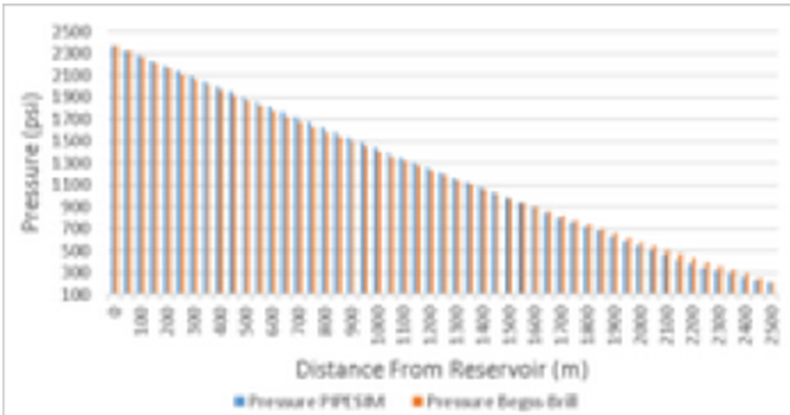


**Fig. 12.** Pressure Gradient Modeling Validation Chart on Production Well

in the temperature of rock formations around the production well which decreases as it approaches the surface which tends to be equal to the ambient temperature of 31 °C. Another thing that affects the change in the temperature of the mixture in the production well is the pressure of the mixture which also decreases as the depth of the production well decreases.

The validation results of modeling pressure gradient and temperature gradient on production well can be seen in Fig. 12 and Fig. 13.

Validation was carried out with depth segmentation every 50 m and validated using PIPESIM software with a Mean Absolute Percent Error value for a pressure gradient of 6.63% and a temperature gradient of 0.78%. The error value that occurs is caused by the difference in computing capacity between pipesim software and the model calculations made. With a MAPE value of less than 10%, it can be said that the pressure gradient and temperature gradient models in the production well are very accurate so that they can be used to optimize.

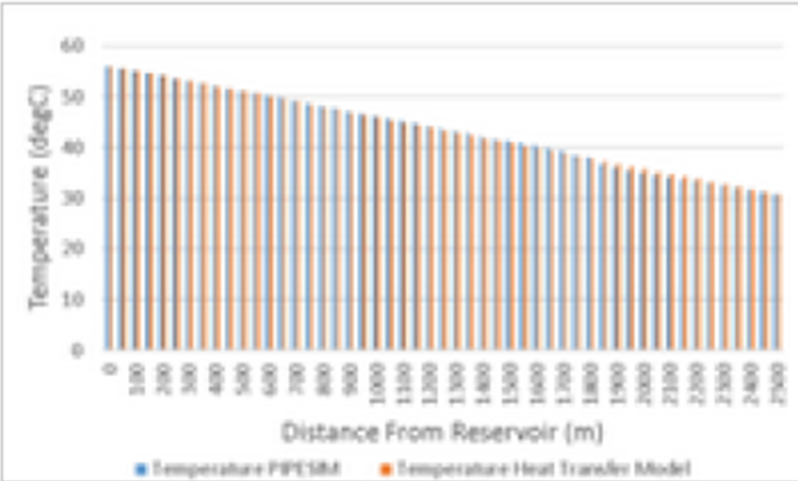


**Fig. 13.** Temperature Gradient Modeling Validation Graphs on Production Well

### 3.4 Results of Calculation of Petroleum Production and Profits Before Optimization

Based on field data from the prudhoe bay reservoir, Alaska, the amount of petroleum contained in the reservoir or known as OOIP (Original Oil in Place) is 4,208,443.27 STB. On the calculation of petroleum production using the coval method with a pressure input condition of 1071 psi, a temperature of 31 °C, and a mass flow rate of 0.3044 kg/s obtained a fractional value of petroleum displacement (Np) of 0.7193. With the operating conditions as above, the petroleum production rate was obtained at 32.28 barrels / day.

With the price of Alaska North Slope Oil type petroleum as of November 2021 is 73.03 USD / bbl. So, with the production rate above, the revenue value of 2,357.60 USD / day was obtained. For the cost of procuring $CO_2$ per day is calculated using the Eq. (2.40) with a mass of $CO_2$ injection per day of 26.3-tons and a price of $CO_2$ / ton of 15.5432 USD / ton, the cost of procuring $CO_2$ is 408.78 USD / day.

Assuming the amount of $CO_2$ carried to the production line is equal to the amount of $CO_2$ injected, the cost value of recycling $CO_2$ is obtained using the Eq. (2.41) of 484.23 USD/day. For the operational costs of the pump used are calculated using the Eq. (2.43) assuming pump efficiency of 80% then pump operational costs of 6.57 USD / day are obtained. Then the calculation of the total profit from the operation of $CO_2$ EOR with operating conditions in accordance with Table 2 can be seen in the Table 5.

### 3.5 Optimization Using Genetic Algorithm

To get an optimal total profit per day, it is necessary to optimize the operating conditions of $CO_2$ EOR with an objective function in the form of net profit, which is the sum of petroleum sales revenues, $CO_2$ procurement costs, $CO_2$ recycling costs, and pump operating costs. The optimized variables are the mass flow rate of $CO_2$ injection, $CO_2$

**Table 5.** Calculation of Total $CO_2$ EOR Profit Before Optimization

| Parameters | Value | Unit |
|---|---|---|
| Crude Oil sales profit | 2,357.60 | USD/day |
| $CO_2$ Procurement Costs | 408.78 | USD/day |
| $CO_2$Recycling Costs | 484.23 | USD/day |
| Pump Operating Costs | 6.57 | USD/day |
| Total Profit | 1,458.00 | USD/day |

**Table 6.** Variable input eor operating conditions after being optimized using genetic algorithm

| Input Parameters | Value |
|---|---|
| Injection Temperature | 65 degC |
| Injection Pressure | 999.99 psia |
| Mass rate of injection vapor | 0.4 kg/s |

injection pressure, $CO_2$ injection temperature. The following are the results of optimizing operating conditions using GA which can be seen in Table 6.

It can be seen that the optimum injection temperature of 65 °C is obtained, which according to the sensitivity analysis that has been carried out will increase the total profit obtained. An optimal injection pressure value of 999.99 psi was also obtained, which is smaller than the injection pressure before optimization. A small injection pressure will also increase the total profit as it results in cheaper pump operating costs. Meanwhile, the optimal mass flow rate value is obtained at 0.4 kg / s which if the greater the mass flow rate, it will increase the production flow rate so that more oil production will increase and increase the total profit value.

The results of individual plots with the best fitness values from the optimization of $CO_2$ EOR operating conditions using genetic algorithm can be seen in Fig. 14.

From the fitness plot graph above, it can be seen that optimization using GA reached the optimum value in the 20$^{th}$ iteration. In this optimization using GA, it is repeated 5 times. It can also be seen in the graph that the result of the objective function value obtained from the five repetitions is the same value of 9,510.33 USD / day and it can be said that the optimization has approached the optimum global value.

The net profit results after optimization using the Genetic Algorithm can be seen in Table 7.

From the Table 7, it shows that after optimization, the total profit increased by 552.28% from 1,458.02USD / day to 9,510.33 USD / day. In addition to the increase in net profit, an increase also occurred in the cost of procuring $CO_2$ from 408.78 USD / day to 537.17 USD / day, The Cost of Recycle $CO_2$ from 484.23 USD / day to 2,735.25 USD / day, and pump operating costs from 6.57 USD/day to $534.27/day. However, because

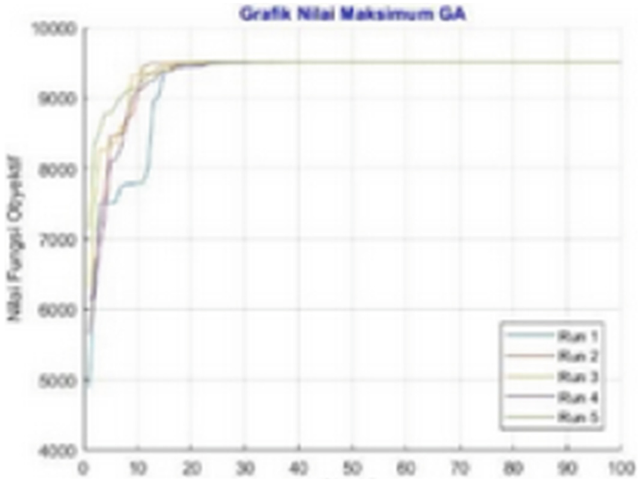


**Fig. 14.** Plot Fitness Graph Genetic Algorithm

**Table 7.** Calculation of total $co_2$ eor profit after optimization using genetic algorithm

| Parameters (USD/day) | Before Optimization | Genetic Algorithm | Increased |
|---|---|---|---|
| Crude Oil sales profit | 2,357.60 | 13,317.03 | 465% |
| $CO_2$ Procurement Costs | 408.78 | 537.17 | 31% |
| $CO_2$Recycling Costs | 484.23 | 2,735.25 | 465% |
| Pump Operating Costs | 6.57 | 534.27 | 8032% |
| Total Profit | 1,458.02 | 9,510.33 | 552% |

the production volume increased very largely from 32.28 bbl / day to 182.35 bbl / day, the net profit obtained was also very large.

## 3.6 Optimization Using the Killer Whale Algorithm

In optimizing the operating conditions of $CO_2$ EOR using the KillerWhale Algorithm, the objective function is net profit and the variables optimized to get the optimum net profit are the mass flow rate of $CO_2$ injection, CO 2 injection pressure, CO 2 injection temperature. The results of optimization of operating conditions using KWA can be seen in Table 8. There is an increase in the injection temperature from 31 °C to 65 °C which is where the higher the injection temperature will result in a high total gain as well. The injection pressure is getting smaller from 1071 psi to 1000 psi which can reduce operational costs so that the total profit also increases. And the last parameter is the injection mass flow rate which also increases from 0.3044 kg/s to 0.4 kg/s. High mass flow rate will result in an increase in the production flow rate at the production well so that the total profit obtained will also increase.

**Table 8.** Variable input eor operating conditions after optimization using killer whale algorithm

| Input Parameters | Value |
|---|---|
| Injection Temperature | 65 degC |
| Injection Pressure | 1000 psia |
| Mass rate of injection vapor | 0.4 kg/s |

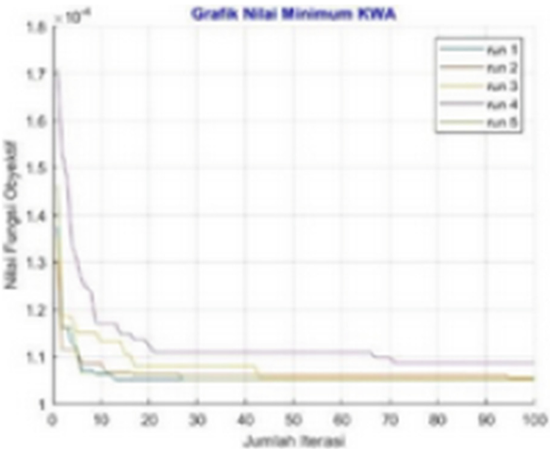


**Fig. 15.** Global Best Plot Graphs Killer Whale Algorithm

**Table 9.** Calculation of total $co_2$ eor profit after optimization using KillerWhale algorithm

| Parameters (USD/day) | Before Optimization | KillerWhale Algorithm |
|---|---|---|
| Crude Oil sales profit | 2,357.60 | 13,316.19 |
| $CO_2$ Procurement Costs | 408.78 | 537.17 |
| $CO_2$Recycling Costs | 484.23 | 2,735.08 |
| Pump Operating Costs | 6.57 | 534.23 |
| Total Profit | 1,458.02 | 9,509.71 |

The following is the best global best plot of optimized $CO_2$ EOR operating conditions using the KillerWhale Algorithm can be seen in Fig. 15. Judging from the chart below that the optimization reaches the optimum value in the 10th to 15$^{th}$ iteration range. In this optimization, it is repeated 5 times with the aim of approaching the optimum global value. Of the 5 repetitions, there are 4 repetitions with the same objective value of 9,509.71 USD / Day which can be said to be close to the optimum global value.

The net profit results after optimization using the KillerWhale Algorithm can be seen in Table 9.

From the Table 9, it shows that after optimization, the total profit increased by 552.23% from 1,458.02 USD / day to 9,509.71 USD / day. In addition to the increase in net profit, the increase also occurred in the cost of procuring $CO_2$ of 128.39 USD / day, The Cost of Recycle $CO_2$ of 2,250.85 USD / day, and the cost of pump operating of 527.66 USD / day. However, because the production volume increased very largely from 32.28 bbl / day to 182.34 bbl / day, the net profit obtained was also very large.

## 4 Conclusion

Modeling the pressure gradient and temperature gradient of $CO_2$ EOR operations can be modeled by dividing the three parts of $CO_2$ EOR operation, namely in injection well, reservoir, and production well. Pressure gradient modeling on injection well and production well uses the Begss-Bril method while temperature gradient modeling uses the heat transfer equation. For modeling pressure gradients in reservoirs, the Darcy equation is used while temperature gradient modeling in reservoirs uses the heat transfer equation. Modeling on injection wells was validated using PIPESIM software with a mean absolute percent error value for a pressure gradient of 2. 56% and a temperature gradient of 1. 16%. For modeling on reservoirs validated using COMSOL software with a value of Mean Absolute Percent Error for a pressure gradient ofr 3. 05% and temperature gradient of 0.06%. Then the modeling on the production well was validated using PIPESIM software with a Mean Absolute Percent Error value for a pressure gradient of 6.63% and a temperature gradient of 0.78%.

After optimization of operating conditions using the Genetic Algorithm and Killer-Whale Algorithm. The results of optimization using genetic algorithm showed an increase in net profit yield of 552.28% from 1,458.02USD / day to 9,510.33 USD / day. Meanwhile, the optimization results using the KillerWhale Algorithm showed an increase in net profit results of 552.23% from 1,458.02 USD / day to 9,509.71 USD / day. From the two optimization techniques used, the same operating condition values were obtained for the injection temperature and the mass flow rate of the injection. However, there is a difference in the optimal injection pressure results where the injection pressure from GA is less than the KWA. This causes the total value of the profit from optimization using GA to be slightly greater than that of KWA.

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