Numerical Study of Temperature Profiles of Transient Flow in the Geothermal Oilfield

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Abstract. Some petroleum wells that are no longer productive still have heat in their formation rocks. Those heat can be extracted and utilized by injecting working fluid into the wellbore. The current study’s objective was to create a 2D numerical calculation program for transient flow temperatures inside the well then it was used to calculate the temperature distribution in oil and gas fields in the Arun field and BK Area. The injected fluids were modeled as a double-pipe heat exchanger. Heat transfer processes inside the wellbore were convection in the inner pipe and the annulus and conduction in the pipe walls and rock formations. The computational calculation used a finite difference method. The computation results were then compared with calculations from the literature. After being validated, the program was used to calculate the Arun field and BK Area temperature distributions. This study found that compared with the reference literature, the current results had a similar optimum temperature range of 130°C-160°C but had different profiles shape with an average deviation of 12%. In the Arun fields, simulation results indicated that the field could reach temperatures between 90°C-120°C and was classified as a medium-temperature geothermal source. BK Area could reach optimum temperatures between 50°C-80°C and be classified as the low-temperature geothermal.

1. Introduction
Geothermal energy has become a feasible resource of clean energy either in direct or indirect utilization. Direct utilization of geothermal energy does not require energy conversion. Its application includes hot springs for tourism, district heating, and food drying. Indirect utilization of geothermal energy needs an energy conversion process, from thermal energy to electricity, known as Geothermal Power Plant.

Geothermal extraction from abandoned wells becomes an alternative solution to maintain the sustainability of unused oilfields. After hydrocarbon depleted, the wells will be left and abandoned. There are existing wellbores that can be utilized by injecting working fluid from the surface into these wells [1] since petroleum wells have similar characteristics to geothermal wells. Besides containing oils and/or gases, petroleum wells often contain wastewater [2] that can be divided into three classes: high-temperature sources (above 150°C), moderate temperature sources (90°C - 150°C), and low-temperature sources (below 90°C) [1].

In Indonesia, the utilization of geothermal at abandoned oilfield is not yet well investigated. No article was found in the literature studying significantly about the geothermal at abandoned oilfield.
utilization in Indonesia. The analysis of potential geothermal energy from abandoned petroleum well then needs to be developed. Based on the 2017 Annual Report of SKK MIGAS [3] exploration and exploitation region of petroleum oil and gas in Indonesia has decreased since 2013 from 321 regions to 255 regions in 2017. That means that 66 regions have been terminated and no longer produce any petroleum products. One technique to study its potential for geothermal use is to investigate injected and extracted water temperature distribution. The fluid is injected from the surface then heated up by the rock formation as it flows down. When the fluid reaches the bottom of well that acts as a heat exchanger, it gains the maximum temperature. The fluid then changes direction and flows upward. The returned fluid will be extracted at the wellhead then can be used for other purposes depending on the temperature obtained.

In this study, a numerical solution was developed using a finite difference method to calculate the water profile temperature for oilfield geothermal development. It was assumed that no additional water flows from the formation to the wellbore, and there is no phase change inside the wellbore. Heat transfer analysis included the unsteady state transient process inside a double pipe heat exchanger. The program was used to analyze the feasibility of geothermal utilization in Arun and BN oilfields in Indonesia.

2. Model Description
The heat exchanger takes shape as a coaxial double-pipe, where there is casing as the outer pipe and tubing as the inner pipe, as shown in (Figure 1). Water as working fluid is injected into the drill pipe or the tubing and flows downwards until reaching the targeted depth while gaining heat from the surrounding rock formation. After the fluid reaches the bottom hole, it turns direction, flows upwards through to the annulus between the casing and tubing of the wellhead to be extracted. The tubing usually is thermally insulated to reduce heat transfer between fluid in the tubing and the annulus [1]. There are five regions of the heat exchanger system: (1) drill pipe (geostring), (2) drill pipe wall (geostring wall), (3) annular region, (4) interface between the annulus and the formation, (5) formation.

![Figure 1. Schematic of the double-pipe heat exchanger model in an abandoned well.](image-url)
3. Program Workflow Diagram

The program starts by defining the variables that will be used and taken into account. The program will receive input in the form of dimensions, initial conditions, boundary conditions, and fluid properties that have been determined based on existing data. Calculations in the program occur continuously until the specified time. Calculations made include calculation of fluid rate, convection coefficient, and heat transfer at discrete volumes. The result of this program is the temperature gradient in the selected oil well. The detail of the program flow diagram is shown in Figure A1.

The wellbore was modeled mathematically for further calculation using numerical analysis. The mathematical model is formulated from the heat transfer processes inside the wellbore. The model consists of general formulation, numerical solution scheme, and evaluation of coefficient vectors for every region.

3.1. General Formula

To estimate the temperature at any given time and depth of the well, the model used a 2D mass and energy balance equation in a radial (r) and axial (z) direction. It is assumed no temperature variation along the angular (θ) direction. The main equations and boundary conditions are tabulated in Table 1.

| Name of equation                  | Differential Form equations                                                                 | Equation |
|----------------------------------|---------------------------------------------------------------------------------------------|----------|
| Cylindrical Heat Diffusion       | $\rho C_p \left( \frac{\partial T}{\partial t} + v_r \frac{\partial T}{\partial r} + v_z \frac{\partial T}{\partial z} \right) = -\left( \frac{1}{r} \frac{\partial (r \phi)}{\partial r} + \frac{\partial q_1}{\partial z} \right)$ | (1)      |
| Continuity                       | $\frac{1}{r} \frac{\partial (r \phi)}{\partial r} + \frac{\partial \phi}{\partial z} = 0$                                         | (2)      |
| Initial Condition                | $T(r,z,t=0) = \psi(r,z)$                                                                     | (3)      |
| General Boundary Condition (BC)  | $q = -k_1 \left( \frac{\partial T_1}{\partial r} \right)_{r=r_1} = h_1(T_{\text{solid}} - T_{\text{fluid}}) \quad \text{on } A_1 \quad \forall \ t$ | (4)      |
|                                  | $\left( \frac{\partial T_1}{\partial r} \right)_{r=0} = 0 \quad \text{at } r = 0 \quad \forall \ t$                                | (5)      |
|                                  | $v_z = \frac{W}{\rho A_f} \quad \text{at } z = 0 \quad \forall \ t$                       | (6)      |
|                                  | $v_r = \psi (\phi, W, \rho, A_f) \quad \text{on } A_1 \quad \forall \ t$                  | (7)      |
| BC Region 1                      | $q = -k_1 \left( \frac{\partial T_1}{\partial r} \right)_{r=r_1} = h_1(T_{2} - T_{j_1}) \quad \text{at } r = r_1 \quad \forall \ t$ | (8)      |
| BC Region 2                      | $-k_1 \left( \frac{\partial T_{1_1}}{\partial r} \right)_{r=r_1} = h_{1_1}(T_{2} - T_{j_1}) \quad \text{at } r = r_1 \quad \forall \ t$ | (9)      |
|                                  | $-k_1 \left( \frac{\partial T_{2_1}}{\partial r} \right)_{r=r_1} = h_{2_1}(T_{2} - T_{j_1}) \quad \text{at } r = r_2 \quad \forall \ t$ | (10)     |
| BC Region 3                      | $-k_1 \left( \frac{\partial T_{3_1}}{\partial r} \right)_{r=r_2} = h_{2_2}(T_{2} - T_{j_3}) \quad \text{at } r = r_2 \quad \forall \ t$ | (11)     |
|                                  | $-k_1 \left( \frac{\partial T_{3_1}}{\partial r} \right)_{r=r_3} = h_{3_3}(T_{4} - T_{j_3}) \quad \text{at } r = r_3 \quad \forall \ t$ | (12)     |
| BC Region 4                      | $k_3 \left( \frac{\partial T_3}{\partial r} \right)_{r=r_3} = h_{\text{eff}}(T_{4} - T_{j_3}) = k_{\text{eff}} \left( \frac{\partial T_3}{\partial r} \right)_{r=r_3} \quad \text{at } r = r_3 \quad \forall \ t \quad \text{where}$ | (13)     |
\[ k_{\text{eff}} = k_j \phi (1 - \phi) \]

BC Region 5

\[ \frac{\partial (\rho \nu r)}{\partial r} = 0 \]

where \( \rho C_p \) is defined by region (14)

3.2. Finite Difference Scheme

These differential equations in Table 1 are converted into algebraic equations approximation using a finite difference scheme as described in Table 2. Coefficient vectors of the finite difference equation system for Region 1, 2, 3, and 5 in Equation (16) are corresponding to each region of the well are defined in this section as described the Region 4 is only defined by a single formula. The detail of the coefficient vector is attached in Table A2. These mass and energy balance equations were solved simultaneously for all regions as a transient solution using appropriate initial and boundary conditions.

Table 2. Algebraic equations approximation using a finite difference scheme.

| Name of equation                          | Algebraic Form          | Equation |
|-------------------------------------------|-------------------------|----------|
| The first-order spatial discretization    | \( \frac{\partial T}{\partial t} = \frac{T_{m+1}^{t+\Delta t} - T_m^t}{\Delta t} \) | (15)     |
| The second-order spatial discretization   | \( A T_m^{t+\Delta t} + B T_m^t + C T_{m+1}^{t+\Delta t} = D \) | (16)     |

\( A, B, C, \) and \( D \) are the vectors of the coefficients

3.3. Other Heat Transfer Properties

Other general heat transfer properties and correlations used to find the convection coefficient inside the heat exchanger are shown in Table 3.

Table 3. Fluid properties and convection heat transfer coefficient correlations.

| Properties/Correlation          | Formula                              | Equation |
|---------------------------------|--------------------------------------|----------|
| Water Density. [4]              | \( \rho = (-3.254 \times 10^{-8}) T^4 + (5.316 \times 10^{-5}) T^3 + 0.03455 T^2 + 9.615 T + 49.47 \) | (17)     |
| Water Thermal Conductivity. [5] | \( k = (-6.22 \times 10^{-6}) T^2 + 0.005105 T - 0.3583 \) | (18)     |
| Water Heat Capacity Coefficient | \( C_p = 0.014567 T^2 - 9.4147 T + 5698 \) | (19)     |
| Water Viscosity [5]             | \( \mu = \begin{bmatrix} (-1.66 \times 10^{-18}) T^2 + (4.689 \times 10^{-15}) T^6 \\ (-5.655 \times 10^{-12}) T^4 + (3.776 \times 10^{-9}) T^6 \\ (-1.509 \times 10^{-6}) T^3 + 0.00036087 T^2 \\ -0.047867 T + 2.72 \end{bmatrix} \) | (20)     |
| Water Prandtl Number. [5]       | \( \text{Pr} = \begin{bmatrix} (-2.274 \times 10^{-10}) T^5 + (4.671 \times 10^{-7}) T^4 \\ -0.00038227 T^3 + 0.15597 T^2 - 31.72 T + 2582 \end{bmatrix} \) | (21)     |
Properties/Correlation | Formula | Equation
---|---|---
Nusselt number for water flow inside pipes. Gnielinsky correlation [5] | \[ \frac{Nu_D}{0.027Re_D^{4/5}Pr^{1/3} \left( \frac{\mu}{\mu_s} \right)^{0.14}} \] | \[0.7 \leq Pr \leq 16,700, \quad Re_D \geq 10,000, \quad \frac{L}{D} \geq 10\] (23)
Nusselt number for water flow inside drilled pipes. [5] | \[ Nu_D = \frac{0.05}{0.027Re_D^{4/5}Pr^{1/3} \left( \frac{\mu}{\mu_s} \right)^{0.14}} \] | \[0.7 \leq Pr \leq 16,700, \quad Re_D \geq 10,000, \quad \frac{L}{D} \geq 10\] (23)
Nusselt number for water flow inside annulus pipes. Seider and Tate correlation from [5] | \[ Nu_D = 1.86(Re_DPr)^{1/3} \left( \frac{D_h}{L} \right)^{1/3} \left( \frac{\mu}{\mu_s} \right)^{0.14} \] | \[Re < 2300\] (24)

Table 3. (continued)

| Properties/Correlation | Formula | Equation |
---|---|---|
Nusselt number for fully developed laminar flow in a circular tube annulus. [5] | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{4.792} \] | \[0.05\] | \[4.792\] |
| | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{4.834} \] | \[0.10\] | \[4.834\] |
| | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{4.833} \] | \[0.20\] | \[4.833\] |
| | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{4.979} \] | \[0.40\] | \[4.979\] |
| | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{5.099} \] | \[0.60\] | \[5.099\] |
| | \[ \frac{D_i}{D_o} \] | \[ \frac{Nu_o}{5.24} \] | \[0.80\] | \[5.24\] |

3.4. Boundary Conditions
There are two main processes in the computational program, the circulating process, and the recovery process. They both have the same heat transfer solution scheme but with different boundary conditions.

(i) Circulating Process
The circulating process means that there is a water circulation process inside the wellbore. Water circulation is provided by injecting water in the drill pipe region. The water flows down to the bottom of the wellbore, then turns around and flows upward in the annulus region to the surface to be extracted. The boundary conditions only applied in the circulating process are shown in Equations (26) and (27). There was no other difference in the heat transfer completion for the circulating process and the recovery process.

\[ T_{1,1}^{1} = T_{2,1}^{1} \]  \hspace{1cm} (26)
\[ T_{3,n}^{1} = T_{1,1}^{1+\Delta t} \]  \hspace{1cm} (27)
(ii) Recovery Processes

The recovery process is a process where there is no circulating fluid inside the wellbore. The well is closed by shutting down the main valve at the surface, known as a shut-in process. The recovery process is needed to be done to prevent kick and even worse is blow out. Kick is an entry of formation fluids (oil, gas, or water) into the wellbore caused by the formation pressure exceeding the pressure exerted by the water injected. While blowout is an uncontrolled flow of formation fluids into the atmosphere at the surface.

The recovery process requirement indicates that the formation pressure is higher than the water circulating pressure. There are many methods to estimate when it is time to shut the well. In this study, estimation was carried out using the energy balance approach. The energy balance equation is shown by Equation (28). The total ideally has the same amount as the total heat transfer in the system. The system’s total heat transfer can be calculated using the heat exchanger formula shown in Equation (29). The system equation shows in Equation (30).

\[ E_{total} = E_{in} - E_{out} \]  
\[ Q_{HE} = UA \Delta T_{lm} \]  
\[ UA \Delta T_{lm} = m_{in}(c_{in} + c_{borehole}) - m_{out}c_{ext}c_{p_{loss}} \Delta T_{lm} \]

Each of the variables in Equation (30) is then determined one by one rearranged until getting the \( v_{loss} \) allowed equation. The \( v_{loss} \) allowed equation is shown by Equation (31). While the actual \( v_{loss} \) must be smaller than the \( v_{loss} \) allowed.

\[ v_{loss} = UP_2 \times \left[ \frac{UP_1}{s_f R_{COND} + R_{CONV}} \right] \]

\( UP_1 \) and \( UP_2 \) are just variables to simplify the actual formula. \( UP_1 \) shown by Equation (32), \( UP_2 \) shown by Equation (33), \( R_{COND} \) shown by Equation (34), and \( R_{CONV} \) shown by Equation (35). While \( s_f \) is a safety factor, and in this study, the value is assumed to be 2.

\[ UP_1 = \frac{m_{in}(c_{in} + c_{borehole}) - m_{out}c_{ext}}{2 \pi Z \Delta T_{lm}} \]
\[ UP_2 = \frac{dz}{\rho_j \gamma_{j}} \]
\[ R_{COND} = \frac{\ln(t_4/t_3)}{k_{pipe}} + \frac{\ln(t_5/t_4)}{k_{eff}} \]
\[ R_{CONV} = \frac{1}{h_{j r_1}} + \frac{1}{h_{j (r_3 - r_4)}} \]

4. Program Code Developments

The computational program written in Matlab was made to calculate the transient temperature and velocity profiles in the wellbore regions. The computational program was consist of the main program and 18 subroutines to solve the current calculation. Initially, the temperature was assumed to be linear at every region, while the velocity gradient is assumed to be linear at Regions 1 and 3 based on the initial temperature. The Tridiagonal Matrix Algorithm (TDMA) was then used to solve temperature profiles in drill pipe, drill pipe wall, and annulus regions. Density, heat constant, thermal conductivity, Prandtl number, enthalpy, and viscosity properties of working fluid were programmed to vary with fluid temperature. Next, the convective heat transfer coefficient \( (h) \) at the fluids were calculated using Reynolds and Nusselts number correlations and based on the drill pipe region temperature and velocity profiles. The formation, interface of the annulus, and outer wall temperature calculation were then calculated using the TDMA subroutine.
5. Validation of the Current Computational Program Results

For the validation of the current program, a wellbore model from Santoyo-Gutiérrez [7] was used as a reference. The wellbore geometries are the diameter of 0.2191 m, depth of 6100 m, depth step size of 100 m, and drill pipe diameter of 0.1143 m. For well drilling operation, the fluid flow rate of 15.14 kg/s, the geothermal gradient of 0.0292°C/m, the surface temperature of 26.7°C, and inlet fluid temperature of 57.2°C. The thermophysical and transport properties are shown in Table 4.

| Component     | k (W/m·°C) | Cp (J/kg·°C) | ρ (kg/m³) | μ (Pa·s) |
|---------------|------------|--------------|-----------|---------|
| Formation     | 2.25       | 880          | 2640      | -       |
| Cement        | 0          | 0            | 0         | -       |
| Casing        | 43.33      | 418.7        | 8048      | -       |
| Drilling fluid| 2.25       | 3930         | 1200      | 0.045   |

The validation process was necessary to validate the computational heat transfer processes’ results by comparing the current study results and literature [7] with fluid properties changing with temperature. The fluid used in this study was water with properties used were density, heat capacity, conductivity, viscosity, and Prandtl number.

Figure 2 shows the pipe temperature profile comparison between the current result with changing fluid properties at the drill pipe and annulus. There are three parameters used to evaluate the computational program by comparing the results with the reference results. They are the distribution temperature range, the trendline shape, and profile pattern by circulating time. Figure 2a shows that the current and reference results have a similar temperature range with 57°C as the lowest point (same as the injection temperature) and the highest point is around 130°C, but neither of them has the same trendline. The reference trendlines are curvy, showing that the heat transfer process inside the drill pipe is not linear. The rate of heat transfer tends to get smaller to a depth of 1,100 meters and then rises slowly until the deepest point. While the current results trendlines are linear, Figure 2a shows no significant change in heat transfer rate inside the drill pipe because some of the formulas used are assumed to be constant heat rate.

By the time the maximum temperature reaches inside the drill pipe, the temperature decreases in previous simulator results (from around 130°C in 2 hours of circulating time to around 110°C with 24 hours circulating time). There is no significant temperature profile change in current results in any circulating time except 5 hours of circulating time. The five hours of circulating time have the lowest maximum temperature than the others, just about 120°C, while the others are around 130°C. Comparing the current study and reference at the drill pipe region has an average deviation of 8%, with the smallest deviation equal to 0% and the largest deviation equal to 21%.

Figure 2b shows that the temperature range at annulus between the current results and reference results are not similar except at first 2 hours circulating time starting from 57°C to around 140°C at 5500 meters depth. While the other circulating times have a very different temperature range, temperature ranges are from around 40°C to 160°C. The temperature is close to the formation temperature at the lowest point due to the formation surface temperature of 15°C, which is lower than the water injected temperature of 38°C. Within the first 2 hours of circulating time, the water at the surface of the annulus region can still be maintained around 38°C, but after several hours the heat is transferred to the surface ground. The trend lines of the reference results are curvy, with a lower heat rate before 1100 meters depth. There is another significant change at around 5500 m depth. At above 5500 m depth, the temperatures tend to increase, while below 5500 m, the temperatures tend to decrease (changes of heat rate direction).
It causes the arching of the temperature curve that results from analytic results. It might occur due to the boundary conditions used in equations (26) and (27). The boundary conditions impose the calculation on the deepest part of the well to similar values. Based on the temperature gradient data of the rock formations used, the actual temperature at the deepest point of the well should be higher than at the boundary conditions used. The greater the difference between the actual value and the boundary conditions used, the greater the curvature formed due to the lack of information about changes in values to depth. The data in question is the rate of fluid mass used and the convection coefficient of heat transfer.

By the time the maximum temperature reaches inside the drill pipe, the temperature decreases in previous simulator results (from around 140°C in the first 2 hours of circulating time to around 110°C with 24 hours circulating time). There is no significant temperature profile change in current results in any circulating time except for the first 2 hours of circulating time. There is a change in the 5 hours of circulating time temperature profile but not too significant. The maximum temperature is around 3 degrees below the others. Comparing the current study and reference, the temperature in the annulus pipe region has the smallest deviation equal to 0% and the largest deviation equal to 31%.

The literature temperature profiles [7] are not linear, whereas the temperature profiles of the current program tend to be linear due to the assumptions: (i) the porosity of rock formations unchanged based on depth, (ii) the shape of the well is the same from top to bottom with no insulation, (iii) other structure mounted to it while the real wellbore has a cement structure mounted around it to a certain depth, and (iv) the gradient of the formation was considered linear. This current computational programing is suitable for short circulating time only, at least up to 24 hours of circulating time, because the results still have similar temperature gradient behavior with a similar temperature range.
inside the wellbore. The program might not be suitable for long circulating time because the results will be unsteady.

6. Application the Study to Indonesia Oilfield Data

6.1. Rock Formation Properties

An oilfield characteristic is unique depending on the rock formations, the field locations, and fluid content. Well’s characteristics may have many different forms because of different well-test methods used to take the Pressure-Volume-Temperature (PVT) Data [8]. While the well’s characteristics data consist of different kinds of data due to different formations, the calculation only uses the wells’ depth and the temperature in certain depth, as shown in Table 5. The same variables available by the PVT data were only depth and wellbore temperature at a certain depth. The oilfield data were from references [9] and [10].

| Oilfield         | Depth (m) | Temperature (°C) |
|------------------|-----------|------------------|
| Arun Field       | 3048      | 178              |
| BK area - BN Field | 689.61   | 99.17            |

The rock material for this research was assumed as sandstones with 12.23% volumetric moisture content and shown in Table 6. The properties are consist of porosity ($\psi$), thermal conductivity ($k_f$), density ($\rho_f$), and heat capacity ($C_{pf}$).

| Properties       | Value    | Unit       |
|------------------|----------|------------|
| Porosity ($\psi$)| 22.28    | %          |
| Thermal Conductivity ($k_f$)| 3.354 | W/mK       |
| Density ($\rho_f$)| 2047.29  | kg/m³      |
| Heat Capacity ($C_{pf}$)| 909.61 | J/kgK      |

6.2. Variables of Design

Design variables of the heat exchanger consisted of inner pipe sizing and outer pipe sizing. The variables were referring to API Casing Table Specification as selected variables are shown in Table 7. The parameters were already discussed in the previous section, but several parameters have not been discussed yet. They were the fluid losses coefficient ($\xi$) and some of the boundary and initial conditions. The fluid losses coefficient was assumed to be 7.5% or 0.075. The boundary condition that was already discussed was only the wellbore temperature in a certain depth. Other boundary conditions need to be examined: water injection temperature, injection mass flow rate, surface ground temperature, and formation temperature gradient. While the significant initial conditions were (i) fluid extraction temperature, (ii) initial temperature gradient of the fluid in the drill pipe region, drill pipe wall, annulus region and in the interface between annulus and the pipe wall region, and (iii) the lowest and highest point temperature of Region 1 to 4. The boundary and initial conditions were given differently in every case. The common conditions are shown in Table 8, while the initial conditions for every field are shown in Table 9.
### Table 7. Design variables of the heat exchanger.

| Pipe          | ID (in) | OD (in) | ID (mm) | OD (mm) |
|---------------|---------|---------|---------|---------|
| Inner-pipe    | 4.090   | 4 ½     | 103.89  | 114.30  |
| Outer-pipe    | 7.636   | 8 ¼     | 193.95  | 222.25  |

### Table 8. Common boundary and initial conditions.

| Conditions                          | Value | Unit | Notes   |
|-------------------------------------|-------|------|---------|
| Water Injection Temperature         | 300   | K    | -       |
| Water Injection Mass Flow Rate      | 5     | kg/s | -       |
| Surface Ground Temperature          | 300   | K    | -       |
| Formation Temperature Gradient      | -     | -    | Linear  |
| Temperature at Region 2 Highest Point | 300 | K    | -       |
| Water Extraction Temperature        | 315   | K    | -       |
| Temperature at Region 4 Highest Point | 300 | K    | -       |

### Table 9. Initial conditions for every field.

| Field      | Temperature at Region 1 Deepest Point (K) | Temperature at Region 2 Deepest Point (K) | Temperature at Region 3 Deepest Point (K) | Temperature at Region 4 Deepest Point (K) |
|------------|-------------------------------------------|-------------------------------------------|-------------------------------------------|-------------------------------------------|
| Arun       | 375                                       | 385                                       | 375                                       | 400                                       |
| BK Area: BN| 330                                       | 335                                       | 330                                       | 340                                       |

6.3. Feasibility Analysis for Petroleum Wells in Indonesia based on Current Computational Results

A feasibility study is required to see whether a petroleum well feasible or not to be converted to a geothermal well. Feasibility analysis can be done with several aspects. In this study, the feasibility study was concluded only from the extraction velocity and thermal aspects. Computational heat transfer simulation of a temperature profile in a borehole could be used as data for a feasibility study from the water extraction velocity and thermal aspect. Due to the nature of the fluid flow, it was challenging to obtain PTS (Pressure-Temperature-Spinner) logging data from the well. No PTS data was available to use for comparing with the current study.

6.3.1. Velocity result analysis. Velocity analysis was conducted to ensure that the water can be extracted from the annulus region and that there were not too many losses in the water quantity. The wellbore depth influenced the extracted water velocity profiles. As the well got deeper, water loss increased along the way up, as shown in Figure 3. Figure 3a shows the velocity profile in the medium depth well of Arun field with 3000 meters depth. The water velocity is reduced by 47.6% from 0.21 m/s at the bottom to 0.11 m/s at the surface. The extracted water velocity of the BN field in Figure 3b is higher than the velocity of the Arun field. It happened because this study used the same rock formation characteristic and assumed that each field’s losses coefficient was the same. If the study used the real rock formation characteristic and losses coefficient for every field, the results might be different and closer to a real situation. While circulating time did not have a significant effect on the velocity. Figure 3b shows a less shallow well velocity profile, BN field, BK Area, with only 689 meters depth. The water velocity is reduced by 26.8% from 0.205 m/s at the bottom to 0.15 m/s at the surface.

6.3.2. Temperature result analysis. Annulus temperature profiles in Arun and BN field are shown in Figure 4. The result shows that petroleum wells in the Arun field feasible to be converted to
geothermal sources because with 27°C water injected into the well, it can be heated up to around 130°C, classified as a moderate temperature source [1]. Figure 4b shows petroleum field temperature profiles in the BN field in BK Area. This field can be classified as a low-temperature source because the highest temperature is only around 70°C to 80°C. The summary of the oilfield classification shows in Table 10. The low thermal energy can be used in the heat pump system, ground heater for greenhouses, especially in the four-season country when winter, hot spring for relaxation, housing systems, and many more. Moderate source geothermal can be used as direct energy and indirect energy. Direct use applications are similar to the application that uses the low thermal energy. Indirect use of geothermal energy after several conversion processes until it becomes electricity. For a moderate source case, the system can use a binary power plant.

**Table 10. Oilfield classification as geothermal sources.**

| Oilfield     | Maximum temperature in annulus (°C) | Geothermal classification     |
|--------------|-------------------------------------|-------------------------------|
| Arun Field   | 130                                 | Moderate temperature source   |
| BK Area      | 80                                  | Low-temperature source        |

![Wellbore depth vs. velocity](image1)

(a) Arun Field

![Wellbore depth vs. velocity](image2)

(b) BN field, BK area

**Figure 3.** Annulus velocity profiles.
7. Conclusions
There are three conclusions obtained from this study:
1. Transient computational program of oilfield geothermal gradient temperature using MATLAB was already generated.
2. The current results for temperature profiles and the WELLTHER simulator results used by Santoyo-Gutiérrez (1997) were similar in terms of temperature range but not similar in trendline and time pattern.
3. Arun is feasible to be converted as moderate temperature geothermal sources, while BN field in BK area is feasible to be converted as low-temperature geothermal sources.

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| Symbol | Name                        | Unit                        |
|--------|-----------------------------|-----------------------------|
| \( A \) | Area                        | \( m^2 \)                   |
| \( C_p \) | Specific heat capacity      | \( \text{kJ} \cdot \text{kg}^{-1} \cdot \text{K}^{-1} \) |
| \( D \) | Equivalent diameter         | \( m \)                     |
| \( \varepsilon \) | Enthalpy                    | \( \text{kJ/kg} \)          |
| \( h \) | Convective heat transfer coefficient | \( \text{W} \cdot \text{m}^{-2} \cdot \text{K}^{-1} \) |
| \( k \) | Thermal conductivity        | \( \text{W} \cdot \text{m}^{-1} \cdot \text{K}^{-1} \) |
| \( \dot{m} \) | Mass flow rate              | \( \text{kg} \cdot \text{s}^{-1} \) |
| \( Nu \) | Nusselt number              |                             |
| \( Pr \) | Prandtl number              |                             |
| \( Q \) | Heat flux per unit area     | \( \text{W} \cdot \text{m}^{-2} \) |
| \( r \) | Radius                      | \( m \)                     |
| \( Re \) | Reynolds number             |                             |
| \( T \) | Temperature                 | \( \text{K} \)              |
| \( t \) | Time                        | \( \text{s} \)               |
| \( v \) | Velocity                    | \( \text{m} \cdot \text{s}^{-1} \) |
| \( W \) | Fluid mass flow rate        | \( \text{kg} \cdot \text{s}^{-1} \) |
| \( \xi \) | Losses coefficient          |                             |
| \( Z \) | Depth (axial direction)     | \( m \)                     |
| \( \phi \) | Formation porosity          |                             |
| \( \mu \) | Viscosity                   | \( \text{Pa} \cdot \text{s} \) |
| \( \rho \) | Density                     | \( \text{kg} \cdot \text{m}^{-3} \) |

**Subscript**

- \( t \): Time
- \( \Delta t \): Time steps

**Subscript**

- 1: Drill pipe region
- 2: Drill pipe wall
- 3: Annulus Region
- 4: Interface between annulus and pipe wall
5  Formation
in  Injection
ext Extraction
r   Radial direction
z   Axial direction
eff Effective
Appendix. Flow Work Diagram and equations

Figure A1. Flow diagram of the main program: transient numerical heat transfer program simulator.
Table A1. The coefficient vector for Equation (16).

| REGION                                      | A_j  | B_j  | C_j  | D_j  |
|---------------------------------------------|------|------|------|------|
| 1 Drill Pipe                                | $-\frac{v_{1,j}}{2\Delta z_j}$ | $\frac{k_1}{\rho_1 C_p}$ | $\frac{\Delta t}{\Delta z_j}$ | $\nu_{1,j}$ | $\frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2}$ | $\frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2}$ |
| 2 Drill Pipe Wall                           | $\frac{k_2}{\rho_2 C_p}$ | $\frac{(\Delta t)}{2\Delta z_j}$ | $\frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2} + \frac{2\theta_1 r_{in} T_{1,j}}{r_{in}^2}$ | $\frac{(\Delta t)}{2\Delta z_j}$ | $\frac{(\Delta t)}{2\Delta z_j}$ | $\frac{(\Delta t)}{2\Delta z_j}$ |
| 3 Annulus                                   | $-\frac{v_{3,j}}{2\Delta z_j}$ | $\frac{k_3}{\rho_3 C_p}$ | $\frac{(\Delta t)}{2\Delta z_j}$ | $\frac{k_3}{\rho_3 C_p}$ | $\frac{(\Delta t)}{2\Delta z_j}$ | $\frac{(\Delta t)}{2\Delta z_j}$ |
| 5 Formation                                 | $-\frac{k_{eff}}{2(\rho C_p)_{eff} \Delta z_j}$ | $\frac{1}{(2(\rho C_p)_{eff} \Delta z_j)}$ | $\nu_{3,j}$ | $\frac{1}{(2(\rho C_p)_{eff} \Delta z_j)}$ | $\nu_{3,j}$ | $\frac{1}{(2(\rho C_p)_{eff} \Delta z_j)}$ |
| 4 Interface between The Annular Region and The Outer Pipe Wall | $\frac{(h_{33} + k_{eff} \Delta r_3)}{(h_{33} + k_{eff} \Delta r_3)}$ | $\frac{k_{eff} \Delta r_3}{(h_{33} + k_{eff} \Delta r_3)}$ | $\frac{(h_{33} + k_{eff} \Delta r_3)}{(h_{33} + k_{eff} \Delta r_3)}$ | $\frac{k_{eff} \Delta r_3}{(h_{33} + k_{eff} \Delta r_3)}$ | $\frac{(h_{33} + k_{eff} \Delta r_3)}{(h_{33} + k_{eff} \Delta r_3)}$ | $\frac{k_{eff} \Delta r_3}{(h_{33} + k_{eff} \Delta r_3)}$ |

This equation is used for solving the temperature distribution in the interface between annular region and the outer pipe wall.