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Evaluation of Closed-Loop Geothermal Heat Extraction Concepts Using Reservoir Simulation

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Keywords

Closed Loop Geothermal, supercritical CO2, pipe-in-pipe configuration, U-shape configuration, Direct-use, Electricity Generation, Reservoir Simulation, Numerical Simulation.

ABSTRACT

This work evaluates the feasibility of closed-loop geothermal (CLG) heat extraction concepts using reservoir simulation and proposes required conditions to guide the development of future field-ready technologies for electricity generation. Additionally, this paper explores alternative direct-use applications of this technology based on depleted/abandoned petroleum wells with high reservoir temperatures. Using a thermal reservoir simulator, base-case simulation models were verified against published results for a pipe-in-pipe and U-shaped configurations. Then, a sensitivity study is presented, which considers reservoir depth, reservoir temperature, fluid type, and total flow rate to determine required conditions for electricity generation using CLG concepts. Results show that residence time, flow rates, reservoir temperatures, and fluid thermal properties are the main parameters impacting the amount of thermal energy produced. Higher flow rates lead to lower production temperatures, however higher mass flow rates yield more thermal energy production. Water, CO_2, and water enhanced with nanoparticles of copper are evaluated as working fluids. Direct-use applications may be technically and economically feasible when using depleted/abandoned petroleum wells that are already completed, as capital investment is reduced. However, electricity generation will require technology advances and/or novel approaches to be cost competitive. This paper demonstrates that CLG is a concept that may be used for direct use applications with abandoned oil and gas wells, and with technology developments, it could also be applied for electricity generation from geothermal reservoirs. Additionally, this paper illustrates how to apply available petroleum reservoir simulation software to simulate geothermal heat extraction.

1. Introduction

As the world explores alternative energy sources to fossil fuels, geothermal energy is considered one of the cleanest and reliable energy sources that could pivot this change. Nevertheless, this alternative energy source has not been completely developed, and needs more efficient concepts and designs that will surpass investment challenges, along with producing geothermal energy from deeper and hotter resources. Geothermal concepts require a system that is capable of transferring heat from a hot source rock to a working fluid. The main problem with these rock formations is their low permeability, which makes the flow of the working fluid through the rock a challenge.

At varying depths, hot reservoirs can be found anywhere in the world; however, another challenge for this alternative energy source is to overcome the experimental phase of technology development. Promising concepts may present issues during experimental studies and/or the initial investment for commercialization could be prohibitively high to justify an economic deployment. Closed-loop geothermal (CLG) systems have emerged as an alternative to traditional geothermal concepts for deep reservoirs. CLG systems do not rely on the permeability of the rock, where the working fluid flows in a pipeline loop, without direct contact with the porous media. The fluid gains temperature as it flows in the well, while the rock surrounding the well cools down by conduction. CLG has shown low-temperature output potential in previous modeling evaluations (Nalla et al., 2005). Nevertheless, new drilling tools and techniques, supported by advances in the oil and gas industry, could enable the development of CLG concepts for implementation at greater depths and higher temperatures that have not been feasible in the past.

The main objective of this paper is to evaluate the feasibility of CLG heat extraction technologies and to propose required conditions that will aid in the further development of these technologies for electricity generation. In addition, this work will illustrate the possible uses of this technology, especially for direct use applications in remote communities near abandoned petroleum wells with high temperatures at depth.

2. Modeling Closed-Loop Geothermal Systems

This work consists of three stages for the evaluation of CLG concepts using petroleum engineering software. In the first stage, models of two CLG configurations (pipe-in-pipe and U-shape), built using a thermal reservoir simulator (CMG-STARS), are verified against published results, demonstrating the modeling capabilities of this software to capture coupled well and reservoir transport processes. In the second stage, different parameters are modified to determine their impact on the performance of different CLG concepts. Also, supercritical carbon dioxide (sCO_2) and a fluid with nanoparticles of copper are evaluated as alternative working fluids. In the third stage of this work, the application of an abandoned oil and gas well in the Haynesville Shale Play is studied to determine its performance as a retrofitted CLG system.

2.1 Modeling Verification and Base Case

At first, two base case scenarios are created to compare our models with previously published results. A CLG pipe-in-pipe model is verified against results presented by Nalla et al. (2005). Based on this model an experimental matrix is developed for the concept evaluation. Then, a U-shaped model is also verified against the Slender Body Theory (SBT) model described by

Beckers (2016). The verified U-shape model is used to evaluate the effect of different parameters in an experimental matrix. Note that these models are based on hypothetical cases, so the reservoir parameters are to be treated as shown in natural circumstances, calculating pressure and temperatures along the wellbore with appropriate gradients. Furthermore, the model is created assuming a homogeneous reservoir rock surrounding the well. The following sections present the input parameters for the model and results for the verification/base case scenarios.

2.1.1 CLG Pipe-in-Pipe Modeling Verification

Nalla et al. (2005) proposed a pipe-in-pipe model, evaluating the effect of different parameters on the performance of this configuration. One of the cases suggested Nalla et al. (2005) is selected for the CMG-STARS model verification. The input parameters are presented in Table 1.

Table 1: Input parameters of pipe-in-pipe base case model taken from Nalla et al. (2005).

Parameter	Value
Tubing inner diameter	3 in.
Tubing outer diameter	3.5 in.
Insulation outer diameter	4 in.
Casing inner diameter	9 in.
Casing outer diameter	9.625 in.
Well depth	5,593 m
Basal heat flux	0.1 W/m2
Rock thermal conductivity	1.89 W/(m °C)
Rock heat capacity	1875.7 kJ/(m3 °C)
Working fluid heat capacity	4186.8 kJ/(m3 °C)
Insulation thermal conductivity	0.07 W/(m °C)
Circulation rate	100 gpm (6.3 L/s)
Surface temperature	26.7 °C
Bottom hole temperature	350 °C

The model was simulated using CMG-STARS with FlexWell and consisted of a water circulation process in a vertical well with a duration of 20 years. Water is injected from the surface into the annular space between the casing and the insulated tubing and produced from the bottom of the well to surface in the tubing as shown in Figure 1. Figure 2**Error! Reference source not found.** shows the results for the base case compared with the results reported by Nalla et al. (2005). The difference between Nalla et al. (2005) results and the ones obtained using CMG-STARS is of 4.8% after 5 years of simulation, with the results from CMG-STARS displaying a lower output temperature. Early times on the simulation differ from the ones obtained in Nalla et al. (2005). Additionally, the final output temperature from Nalla et al. (2005) neglects transport properties of the fluid, such as, viscosity and flow regime, so there are no friction losses in the system. The CMG-STARS simulation considers frictional losses of 2,000 kPa at the outlet of the system, leading to the difference in the results for both models. This case will be used as the base case for the sensitivity analysis of the pipe-in-pipe CLG configuration.

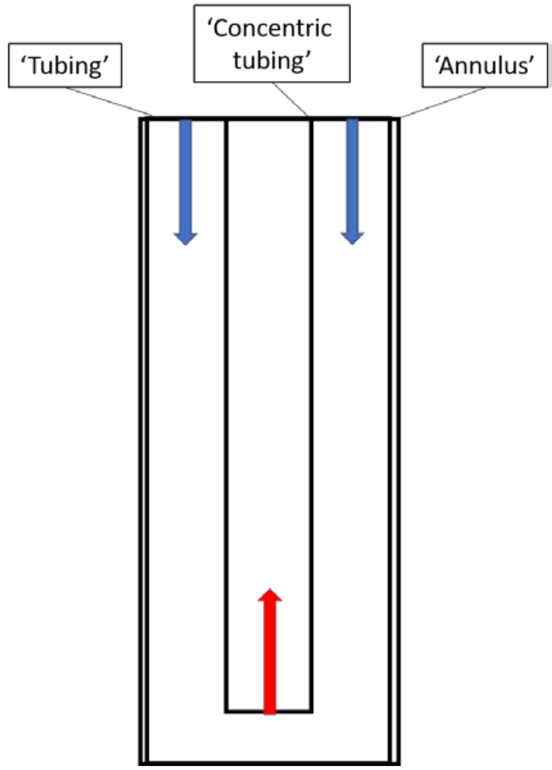

Figure 1: Pipe-in-pipe configuration scheme.

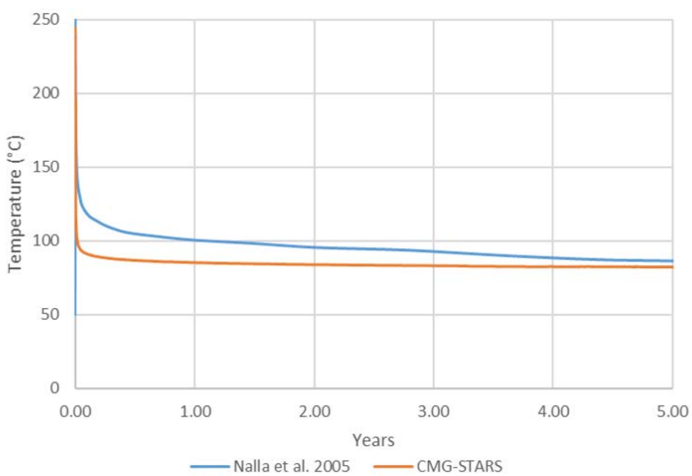

Figure 2: Surface fluid temperature output for 5 years of simulation for Nalla et al. (2005) and CMG-STARS.

2.1.2 U-Shape Modeling Verification

A CLG U-shape model built using CMG-STARS is verified using results previously presented by Beckers (2020) based on the Slender Body Theory (SBT), an analytical model. The U-shape configuration consists of two horizontal wells, an injector, and a producer, that connect at the toe of their horizontal sections. From one well, cold fluid is injected, which circulates through the wells gathering heat from the rock formations and produced at surface in the producer well. The input parameters are presented in Table 2. All the process is performed in a closed-loop configuration where the working fluid has no direct contact with the rock. Figure 3 displays a schematic of the CLG U-shape configuration from an industrial concept.

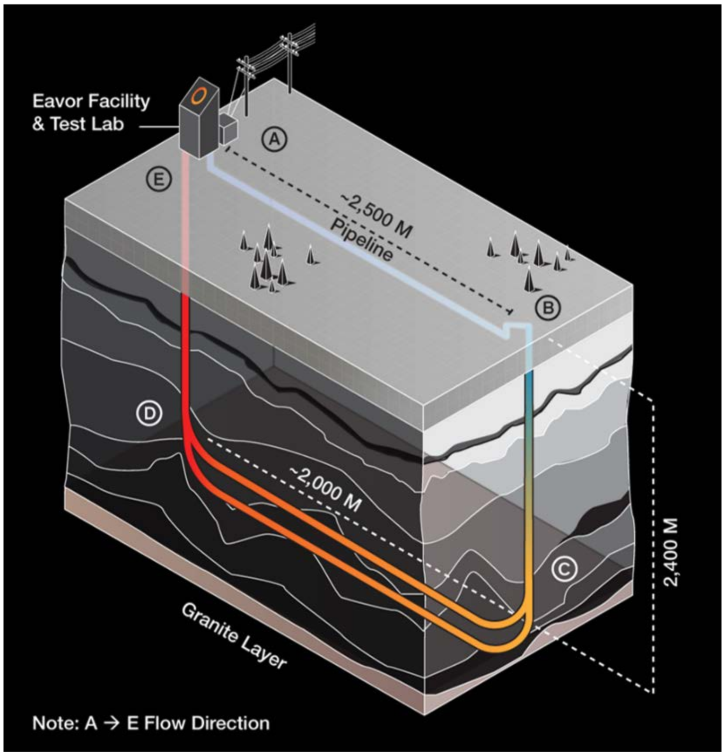

Figure 3. U-Shape closed-loop configuration. Taken from Eavor Inc. (2020).

Table 2: Input parameters to verify with the SBT analytical model. Modified from Beckers (2020).

Parameter	Value
Vertical depth	3,000 m
Surface temperature	15 °C
Reservoir temperature	250 °C
Geothermal gradient	80 °C/km
Number of laterals	1
Surface spacing between injector and producer well	2,000 m
Downhole spacing between injector and producer well	2,000 m
Rock thermal conductivity	3 W/(m °C)
Rock heat capacity	950 J/(kg °C)
Rock density	2,800 kg/m3
Well diameter	6 in.
Total production flow rate	30 L/s
Injection temperature	50 °C
Lifetime	20 years

Water circulation was simulated for 20 years. Figure 4 shows the results for the base case compared with the results from the SBT analytical approach from Beckers (2020). After 20 years of simulation, it is observed that both models have similar results. After 3 years of simulation, both models reach a stable temperature, confirming what has been described in theory where CLG applications reach a constant temperature output after years of use. The SBT outlet temperature in the proposed simulated time is around 69 °C, while the model created in CMG-STARS, shows an outlet temperature of 65 °C after 20 years of simulation.

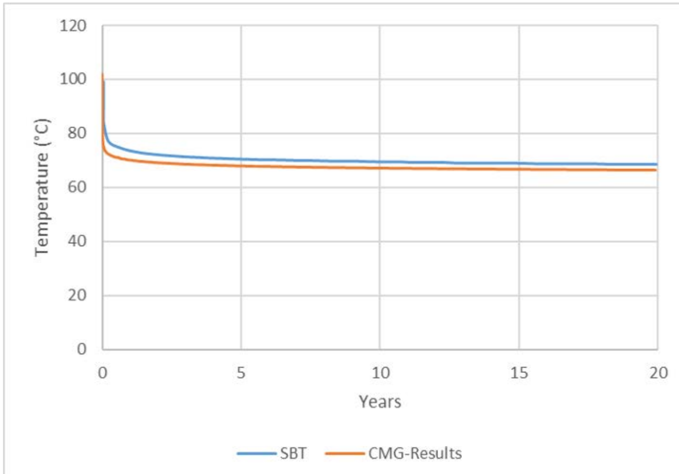

Figure 4: Surface fluid output temperature after 20 years of water circulation for the SBT analytical model and CMG-STARS.

There is a 3.17% relative difference between the models, with the CMG-STARS model showing lower temperature outputs. This is due to limitations with the SBT approach, which does not consider the pipe and cement heat transfer barrier that takes place between the reservoir and the working fluid. In other words, the SBT considers direct heat conduction between the rock and the fluid, while CMG-STARS with FlexWell captures this heat transfer resistance between rock and fluid. Details about the implementation of the FlexWell option to couple transport phenomena in the well and reservoir are described in Rocha (2021).

2.2 Sensitivity Analysis

A sensitivity analysis is proposed to get a better perspective on the potential of closed-loop systems by evaluating the main parameters that could enhance the working fluid outlet temperature. The parameters evaluated are lateral length, injection flow rate, and reservoir temperature. One experimental matrix is evaluated for each of the configurations proposed: pipe-in-pipe and U-shape.

2.2.2 Pipe-in-pipe

A L-shape model is proposed where the well has a vertical section and then it turns 90 degrees to have a long horizontal section. The well proposed is similar to the one showed in Figure 1, with the difference of having a horizontal section located at 3658 m (12,000 ft). The base case parameters are presented in Table 3.

Table 3: Parameter values for the cases evaluated in the pipe-in-pipe configuration.

Parameter	Value
Reservoir depth	3,658 m (12,000 ft)
Surface temperature	15 °C (59°F)
Rock thermal conductivity	3 W/(m °C)
Rock heat capacity	950 J/(kg °C)
Rock density	2800 °kg/m^3
Production tubing inner diameter	0.1 m (4 in.)
Production casing inner diameter	0.2 m (8.7 in.)
Reservoir permeability	0.01 mD
Reservoir porosity	10%
Injection temperature	50 °C (122 °F)
Heat transfer fluid	Water
Total production flow rate	10 L/s
Lateral length	1,829 m (6,000 ft)
Reservoir temperature	187 °C (369 °F)

The parameter variations are described in the following experimental matrix:

- Five injection flow rates: 1.5 L/s (855 bbl/day), 8.7 L/s (4,717 bbl/day), 10 L/s (5,434 bbl/day), 15 L/s (8,579 bbl/day), and 20 L/s (10,869 bbl/day).
- Four different lateral lengths: 500 m (1,640 ft), 1,000 m (3,281 ft), 2,000 m (6,562 ft), and 3,000 m (9,843 ft).
- Three different reservoir temperatures: 150 °C, 250 °C, and 350 °C.

When one of the parameters is changed, the two remained stayed constant as in the base case (Table 3). All the proposed cases are run for 20 years of simulation.

For **injection flow rates**, results are as expected and in agreement with previous work, with higher flow rates resulting in lower output temperature. The case with an injection flow rate of 20 L/s achieves an output fluid temperature of 76 °C, while an injection rate of 1.5 L/s results in an output temperature of 100 °C. Figure 5 shows the output temperature for all five flow rates, where it can be seen that after two years of water injection, all cases reach a stable temperature showing that the rock is not able to transfer adequate thermal energy to the working fluid; nonetheless, the process does not deplete the surrounding temperature of the well during the simulation period. Considering the potential thermal energy output calculations from Beckers (2016), fluid injection rates between 10 L/s and 20 L/s generate 1MW$_{th}$, approximately.

For **well lateral length**, results show that longer lateral lengths lead to higher output temperature. Even with the longer horizontal section of 3,000 m (9,843 ft), the highest temperature output barely reaches 84 °C, as is shown in Figure 6. After 6,660 m of flow through the loop, which corresponds to the heal of the production well, the temperature gain is only 34 °C, meaning limited heat transfer from the reservoir to the working fluid. Nevertheless, this specific model has a reservoir temperature of 187 °C, which is considered a high-temperature reservoir. When the well lateral length is increased six times, the temperature gain only increases by 26%. The lateral length needs to be combined with higher reservoir temperatures to achieve a performance appropriate for electricity generation. These results motivated the evaluation of geothermal direct use applications using abandoned petroleum wells, which is presented in Section 2.4.

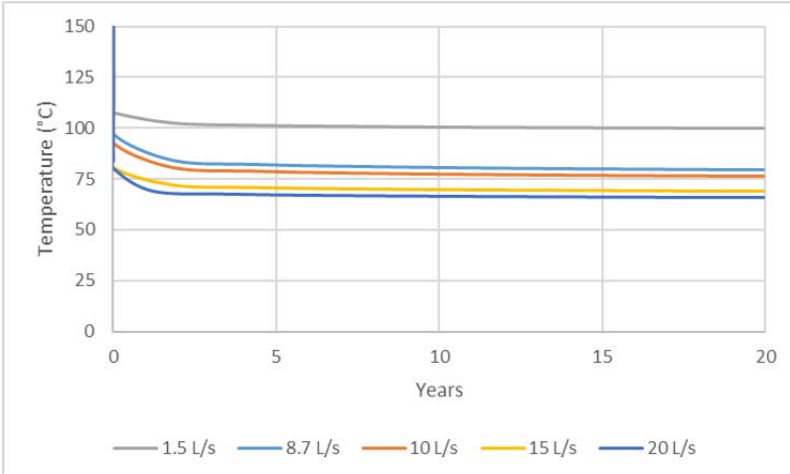

Figure 5: Surface fluid temperature output for 20 years of simulation for different flow rates in a pipe-in-pipe configuration.

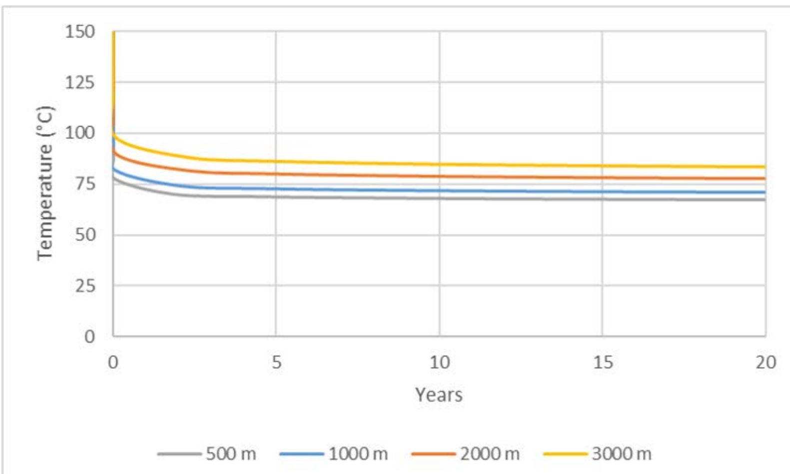

Figure 6: Surface fluid temperature output for 20 years of simulation for different lateral lengths in a pipe-in-pipe configuration.

When evaluating **reservoir temperatures**, the higher reservoir temperature evaluated (i.e., 350 °C) showed the highest temperature output, which allows producing fluid at 108 °C at the surface after 20 years of water injection (Figure 7). According to Verkis (2014), that specific case shows feasible conditions for electricity generation. On the other hand, at reservoir temperature below 250 °C, the results show fluid temperatures of less than 90 °C, which is the minimum temperature outlet required by Organic Rankine Cycle (ORC) power plants (Verkis, 2014).

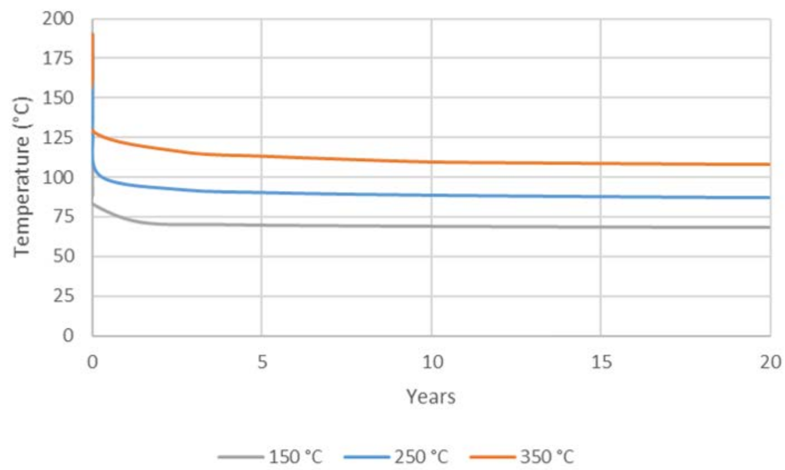

Figure 7: Surface fluid temperature output for 20 years of simulation for different reservoir temperatures in a pipe-in-pipe configuration.

An additional simulation case is presented, which combines the input parameters leading to the best performances during the sensitivity analysis. This case consists of a vertical depth of 5,000 m (16,404 ft), with 2,000 m (6,561 ft) of lateral length, reservoir temperature of 250 °C (482 °F). Two injection rates are analyzed: 15 L/s (8,579 bbl/day) and 10 L/s (5,434 bbl/day). The remaining parameters are maintained constant as in the base case. Figure 8 shows the geometry of the model as well as the initial reservoir temperature distribution.

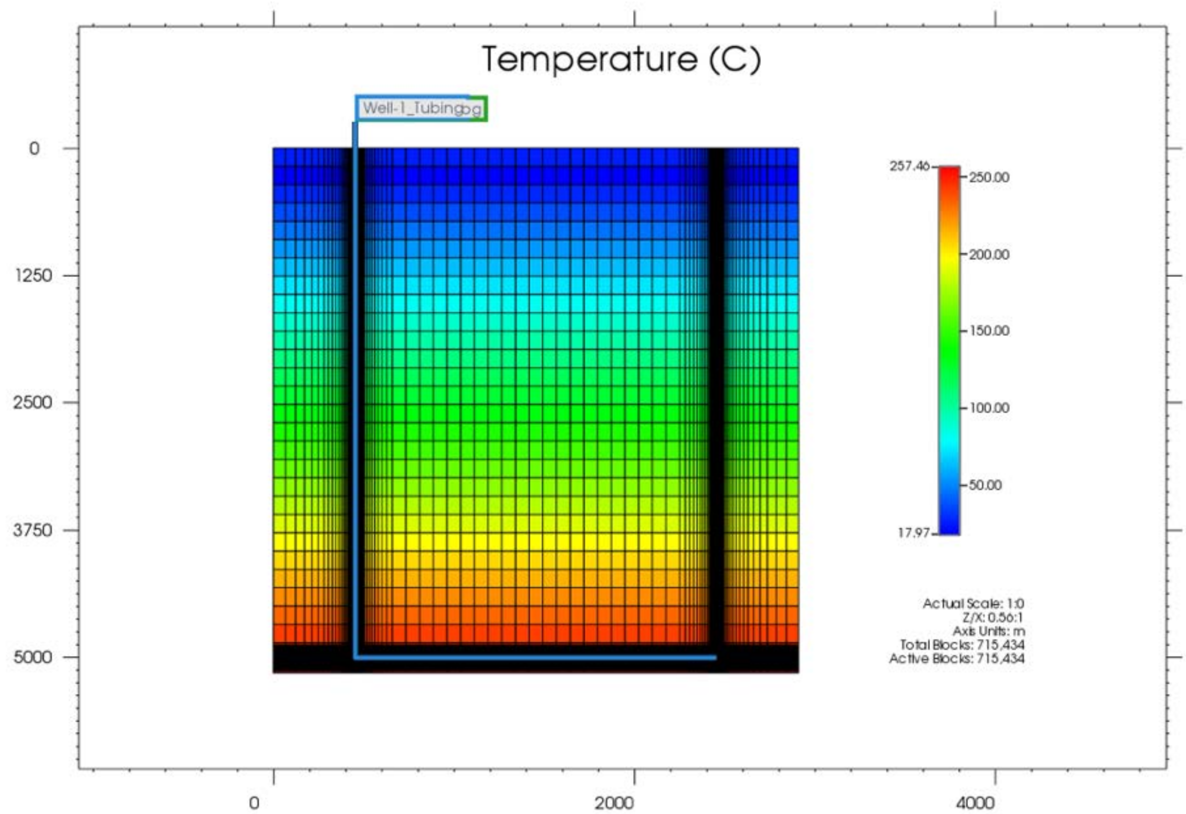

Figure 8: Well geometry and initial reservoir temperature distribution for best performance case.

Figure 9 shows the surface temperature output after 20 years of water circulation for the two flow rates considered. The temperature stabilizes after the first year. As was expected, the lower flow rate, 10 L/s, shows a higher temperature output due to increased residence time, which can provide a potential power of 2 MW_{th}. Longer wells, combined with larger lateral lengths, higher reservoir temperatures, and optimum flow rates, will represent a feasible pipe-in-pipe CLG project for electricity generation.

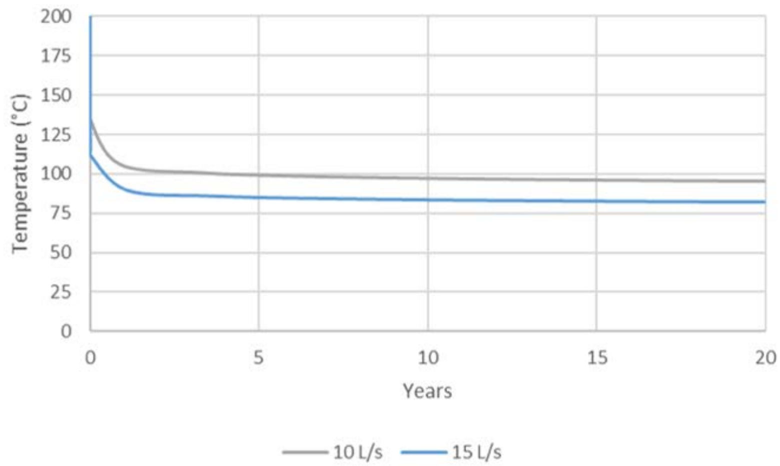

Figure 9: Surface fluid temperature output for 20 years of simulation for the proposed pipe-in-pipe ideal cases.

2.2.3 U-Shape

For the U-shape configuration, different parameters are proposed to evaluate its performance that could be used for electricity generation. The base case parameters are the same ones described in Table 2. The parameter variations are described in the following experimental matrix:

- Four different flow rates: 8.7 L/s (4,717 bbl/day), 12.6 L/s (6,857 bbl/day), 15 L/s (8,579 bbl/day) and 19 L/s (10,285 bbl/day).
- Four different lateral lengths: 500 m (1,640 ft), 1,000 m (3,281 ft), 2,000 m (6,562 ft), and 3,000 m (9,843 ft). 10 L/s of flow rate is used for all lateral length cases.
- Five reservoir temperatures: 150 °C, 250 °C, 350 °C, 450 °C, and 500 °C. Well depth is adjusted to achieve the desired temperatures using a gradient of 50 °C/km. A flow rate of 15 L/s (8,579 ft) is used for all the reservoir temperature cases.

All cases are simulated for 20 years of water injection.

Figure 10 shows the surface fluid temperature output after 20 years of water injection for different flow rates. As expected, the lowest flow rate (8.7 L/s or 4,717 bbl/day) displays the highest temperature output, while 19 L/s (10,285 bbl/day) achieves the lowest temperature. Having flow rates around 10 to 20 L/s are considered the best scenario based on the given parameters.

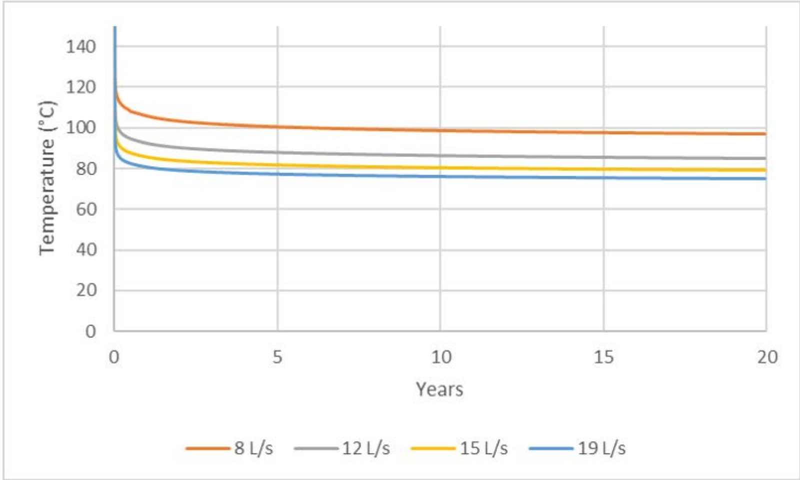

Figure 10: Surface fluid temperature output for 20 years of simulation for different flow rates in a U-shape configuration.

A longer horizontal distance between wells leads to higher temperature output; however, this difference is not as high as it could have been expected. There is a difference of 15 °C between all four cases, while the difference in distance is about 2,500 m. Temperature profiles along the well show how the flowing fluid is unable to gather enough energy from the reservoir. For the longest distance between wells evaluated (3,000 m) the fluid is not able to reach more than 90 °C, while the reservoir temperature is about 250 °C. This parameter variation shows that even if the fluid residence time is increased, there is still low heat conduction between the source rock and the flowing fluid.

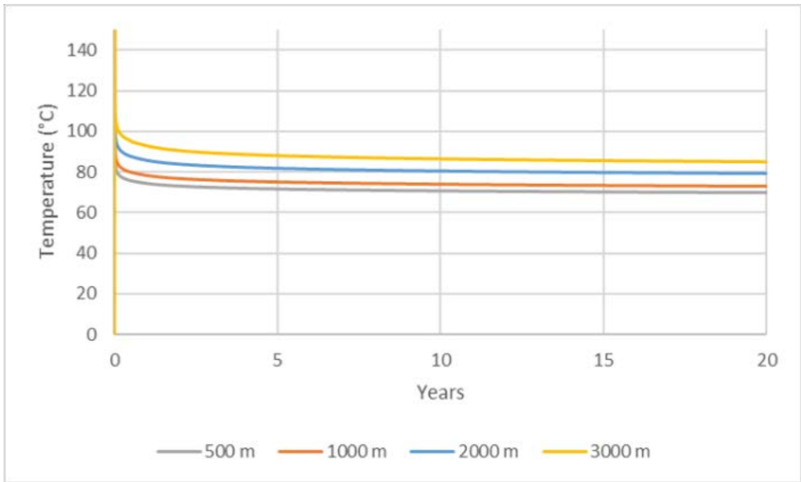

Figure 11: Surface fluid temperature output for 20 years of simulation for different lateral lengths.

For reservoir temperature variation, a geothermal gradient of 50 °C/km is assumed to give a more realistic approach. To achieve the desired temperature at depth, the models also have variations in the depth of the reservoir correlated to the mentioned geothermal gradient. A higher reservoir temperature leads to a higher fluid temperature output at surface. As expected, the 500 °C and 450 °C reservoir temperatures give surface temperatures above 150 °C. On the other hand, at temperatures below 450 °C, the results show fluid temperatures of less than 150 °C.

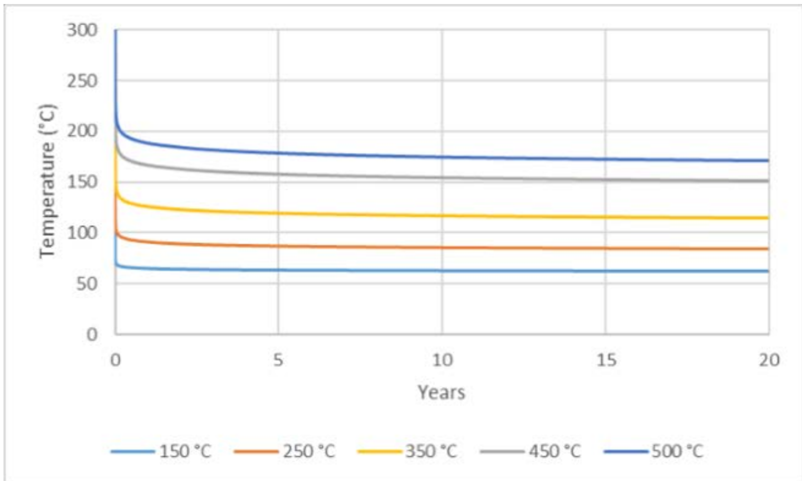

Figure 12: Surface fluid temperature output for 20 years of simulation for different reservoir temperatures.

An additional simulation case is presented, which combines the input parameters leading to the best performances during the sensitivity analysis. This case consists of a vertical depth of 9,000 m (29,528 ft) with 3,000 m (9,843 ft) of lateral length, reservoir temperature of 450 °C (842 °F), and an injection flow rate of 15 L/s (8,579 bbl/day). The vertical section of the producer is thermally insulated from the surface to 3,500 m, as the rock temperature at that location is around 175 °C so the fluid does not have to interact with the colder rock at the producer well. Two different flow rates are evaluated; 15 L/s and 20 L/s, the remaining parameters are kept the same as the base case.

After 20 years of water circulation, results show high temperature output at both, 15 L/s and 20 L/s. As shown in Table 4, this case can provide a potential power of nearly 8 MW_{th}. Additionally, the insulated section gives a higher temperature output as the heated fluid does not cool down when flowing through shallow sections of the well path. Deeper wells, combined with larger lateral lengths, higher reservoir temperatures, and optimized flow rates, could lead to feasible U-shape projects for electricity generation.

2.3 Working Fluids

In this section, we evaluate two alternative working fluids, Supercritical Carbon Dioxide (sCO_2), and water with nanoparticles of copper.

2.3.1 Supercritical Carbon Dioxide

As an alternative to water, carbon dioxide shows closer energy outputs than water in early investigations. Considering the critical point for CO_2 of 27 ºC and 10 MPa, sCO_2 can develop a thermosiphon effect that supports fluid circulation in the loop, so no pump would be needed in the process, reducing investment and energy input during the operation of the CLG system. sCO_2 could be used as working fluid and increase the power output when the injected fluid can travel to sufficient depths, to build up pressure and maintain the thermosiphon. On the other hand, the flow rate needed for sCO_2 is about 5 times higher than that of the water to achieve the same thermal efficiency.

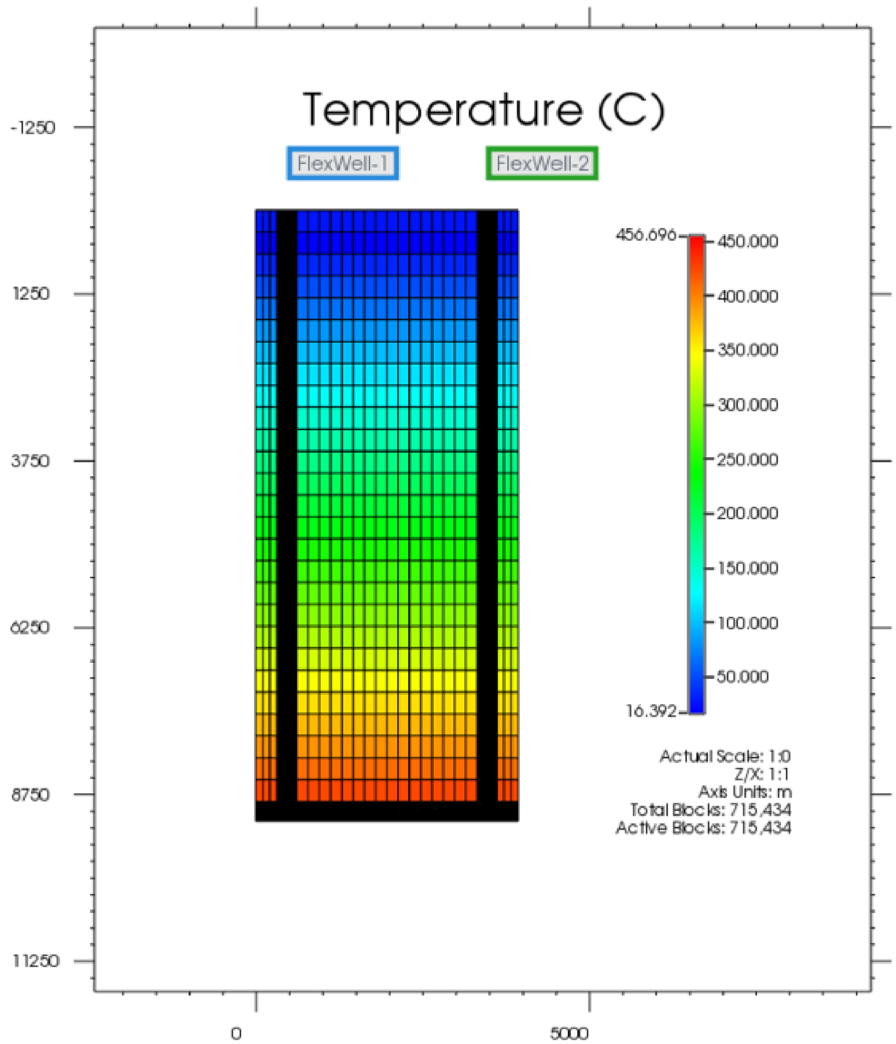

Figure 13: IK 2D view with initial reservoir temperature distribution for a U-shape best performance case.

Table 4: Temperature gain and potential thermal output for an ideal U-shape case.

Flow Rate (L/s)	Temperature Output (°C)	ΔT (°C)	MW_{th}
15	167	117	7.4
20	148	98	7.9

Using the previous pipe-in-pipe base case parameters, sCO_2 is evaluated. Three different flow rates are evaluated taking into account similar mass rates that were used with water in the previous models; 147,416 m^3/day (2.5 kg/s), 737,080 m^3/day (12.3 kg/s), and 3,685,400 m^3/day (61.5 kg/s). Results for sCO_2 as working fluid show a similar trend as the results for water. The higher the flow rate, the lower the temperature output and after one year of injection of the fluid, the temperature output seems to stabilize for the next 19 years. Compared to water, sCO_2 shows lower thermal performance. While water cases showed a potential power of 7 MW_{th}, sCO_2 shows a potential of 500 kW_{th}.

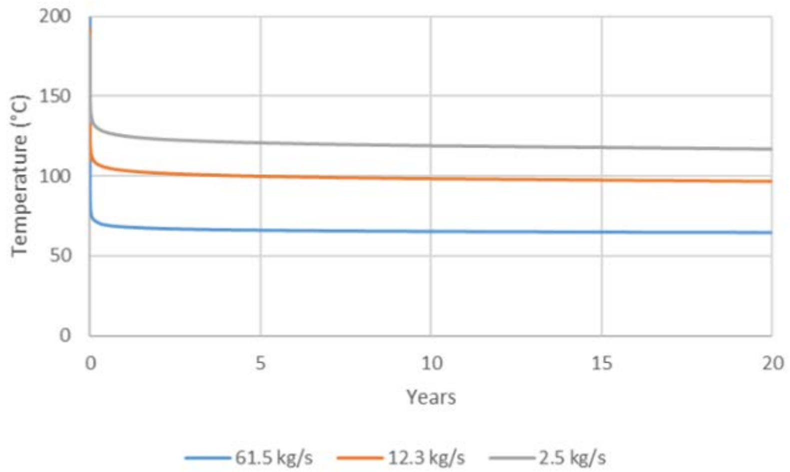

Figure 14: Surface fluid temperature output for 20 years of simulation for different mass rates using sCO2 as working fluid.

<u>2.3.2 Water with nanoparticles of copper</u>

Here we consider adding nanoparticles of copper to water to enhance the thermal properties of the working fluid. Because of the size of a nanoparticle, it is expected to flow in the loop as a molecule of fluid. Furthermore, since the fluid has no physical contact with the rock in a CLG system, the actual composition of the fluid will not deteriorate the rock properties, which could be an issue when using nanoparticles in an injected fluid. Previous studies have shown a large improvement in effective conductivity with fluids that contain copper nanoparticles, an advantage that can be used to enhance the heat extraction on a CLG concept (Choi and Eastman, 2001).

Bhanushali et al. (2017) performed a study to enhance the thermal conductivity of water using different particle shapes, where thermal conductivity was enhanced by 40% when using long nanowires, suggesting future developments in low filler fraction and high aspect ratio to increase even more the thermal conductivity of the working fluid. In our simulations, only water conductivity is modified to simulate the addition of nanoparticles, from 53,500 J/(m day °C) to 80,250 J/(m days °C) (50% increase). After 20 years of simulation, results display an average increase in the outlet temperature of 2 °C, when comparing to the original results with water as working fluid (Figure 15). When comparing the results into a potential power generation, the fluid with nanoparticles of copper may show an increased potential power as thermal conductivity is increased to 6300 J/(kg °C). Results for water with nanoparticles of copper show better results, as not only the heat capacity is increased, also its density is increased which also enhances the thermal potential.

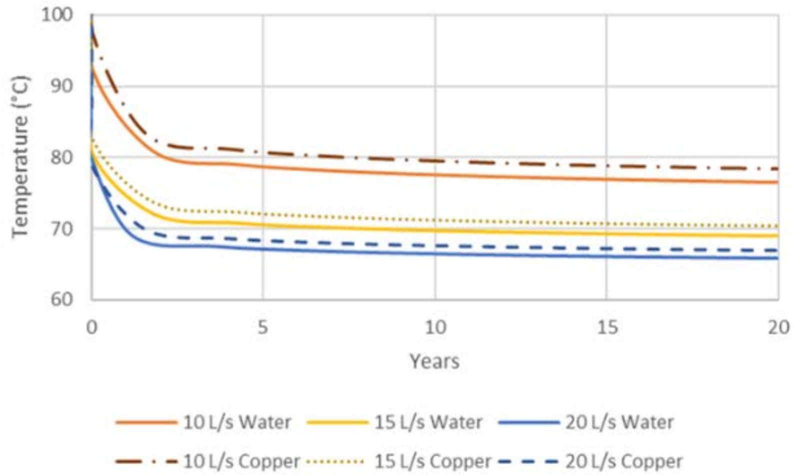

Figure 15: Surface fluid temperature output for 20 years of simulation for different mass rates using water with nanoparticles of copper as working fluid compared to normal water at the same flow rates.

2.4 Geothermal Direct-Use from Petroleum Wells

From the sensitivity analysis results, outlet temperatures and flow rates suggested thermal outputs that can be utilized for direct-use applications. There are also new technology developments using temperature outputs as low as 75 °C where a binary power plant cycle can be used for electricity generation (Verkis, 2014). Additionally, there are oil and gas reservoirs with temperatures that can reach up to 180 °C. Abandoned and low productive wells in those locations can be retrofitted into either geothermal direct-use applications or electricity generation using binary power plants.

Haynesville Shale Play has reservoir temperatures that can reach up to 168 °C (Franquet et al., 2019) and the measured and vertical depths of the wells drilled in this reservoir are long enough to provide residence time for the injected fluid in a CLG concept. It is identified that a suitable location with high temperatures in the Haynesville Shale is the Grogan field, in De Soto Parish, Louisiana, where well depths can reach up to 13,000 ft (3,962 m) and horizontal sections of 3,000 ft (914 m). A simulation model was created based on previous case models and the parameters from Haynesville Shale wells to depict the potential of an abandoned well for geothermal heat extraction (Figure 16). Four different flow rates are evaluated: 5, 10, 15, and 20 L/s.

Results show that implementing a CLG concept into abandoned wells may lead to temperature outputs up to 83 °C. As it has been demonstrated in this research, this case also shows that higher the flow rates lead to lower the thermal outputs. For the flow models evaluated in this case, 5 L/s flow is the only rate where the temperature output is higher than 75 °C.

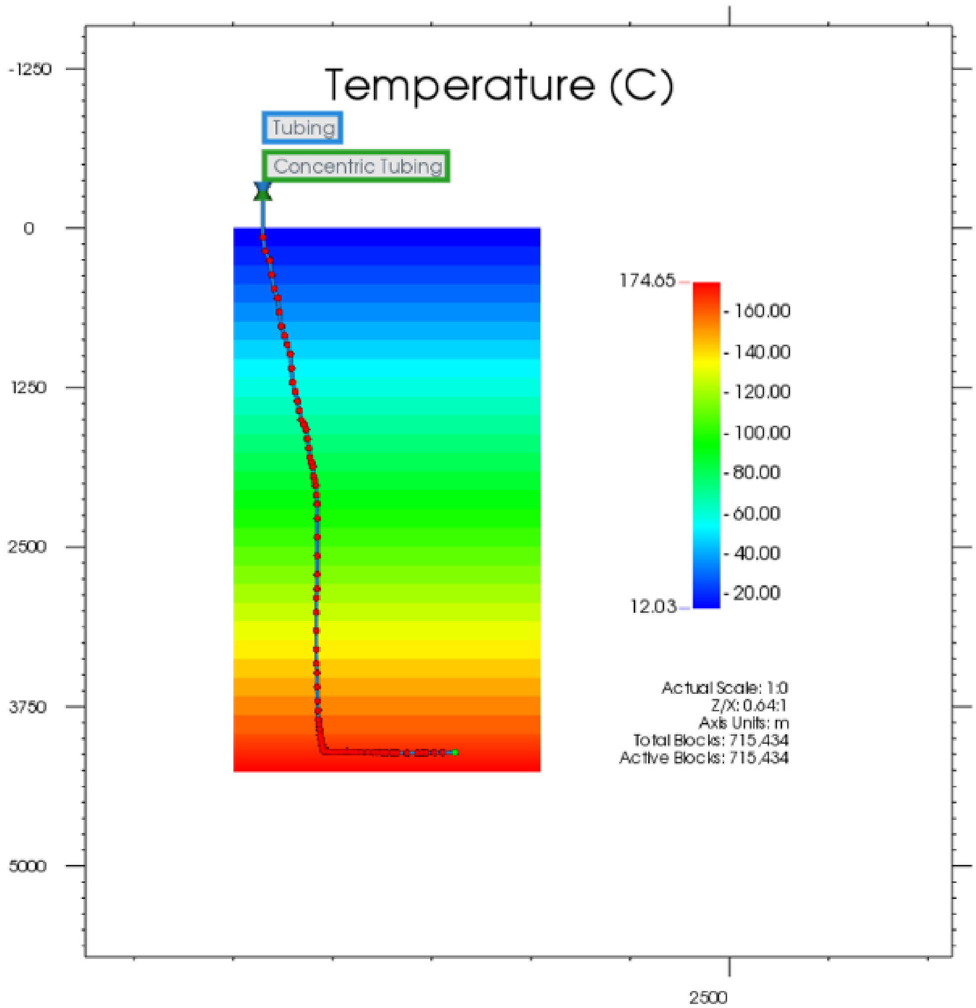

Figure 16: Vertical profile of well trajectory with temperature distribution for the Haynesville Shale case.

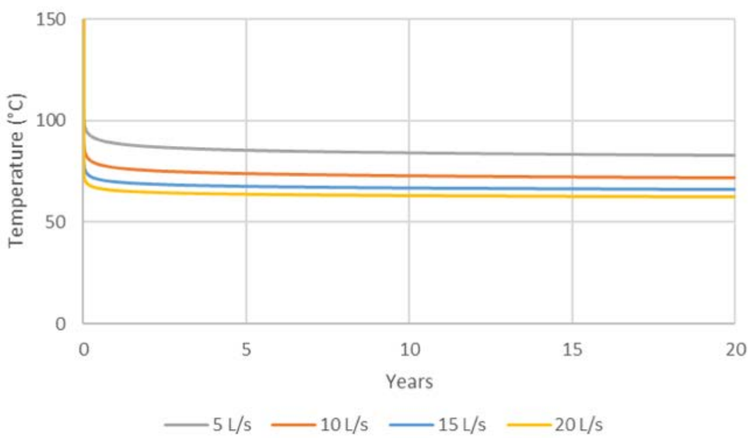

Figure 17: Surface fluid temperature output for 20 years of simulation for different flow rates for the Haynesville Shale real model.

3. Conclusions

In this work, we demonstrated how a thermal reservoir simulator, CMG-STARS with FlexWell, is capable of modeling well and reservoir transport processes associated to geothermal technologies. Models presented in this work have been verified against previously published results, achieving less than 5% relative difference between the calculated temperature outputs.

The results show that residence time, flow rate, and reservoir temperature, are important parameters that affect the thermal output from CLG systems after 20 years of fluid injection. The best performance case evaluated for a pipe-in-pipe CLG configuration, showed that abandoned petroleum wells with similar parameters can be used to achieve potential power generation of 1 MW_e. The best performance case for a U-shape configuration, displayed electrical power potential when the reservoir has an initial temperature of 450 °C. U-shape CLG systems with insulated pipes at specific locations can improve the thermal performance of CLG systems, as shown for the best performance case.

Petroleum wells, like the one studied from the Haynesville Shale, can be readapted for geothermal purposes with potential thermal power reaching up to 1 MW_e, when having multiple wells that feed a single power plant. When injecting 10 L/s to 20 L/s into the systems, a minimum of 170 °C of reservoir temperature is needed accompanied by a group of wells that feed the same power plant. To use a single closed loop well for electrical power purposes, a minimum reservoir temperature of 350°C is needed. Flow rates higher than 10 L/s could be used depending on flow frictional losses, and the wells may have a potential power of 1 MW_e.

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