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The Economics of Low Enthalpy Geothermal Resources: A Case Study for Small Heat Harnessing Concept in Oklahoma

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ABSTRACT

Geothermal as a renewable source of energy has a wide range of applications. Particularly heating and cooling with eventually electricity generation could be an alternative to large scale pure electricity generation of geothermal power plants. This paper shows the economics of various concept considered to provide heating and cooling of the Well Construction Technology Center (WCTC) at the University of Oklahoma, costs which are approximately $25,000 to $30,000 per year. The goal of this paper is to perform a through economic study of various type of geothermal concept for heating and cooling system which may also include small power generation. Our focus on geothermal is an effort to offset CO2 and other greenhouse gas emissions that result from burning fossil fuels while consistently providing baseload power to the facility. The WCTC is uniquely suited to geothermal heating and cooling because of its proximity to a shut-in well. This paper is a discussion of the design and economics of four geothermal options that will enhance or otherwise utilize the existing well for its geothermal capacity. The following concepts are analyzed and discussed in this paper:

1. Shallow-depth geothermal wells
2. Resume OU 24-1 production
3. Single well injector/producer system
4. Dual well enhanced geothermal system (EGS)

Our results show the sensitivity of geothermal development for long- and short-term return. Although short term economics are not favorable, we believe that if look into the future, such concepts may help reducing the University's carbon footprint making the pursuit of a geothermal system worthy of further consideration.

1. INTRODUCTION

Geothermal energy becomes the major driven force for the energy industry as an alternative to mitigate the fossil fuel usages. The steady growth makes geothermal a common renewable energy across much of the world, but especially in geothermal hot spots such as the Pacific Rim, Iceland, and American West. There are multiple uses for geothermal energy, including direct use for heating buildings and the generation of electricity. Depending upon the temperature of the heat source, the manner of power generation will change. The highest temperature geothermal projects use dry steam, those of middling temperature use flash steam, and the lowest temperature projects use a binary cycle (Barbier 1997, 2002). Electricity-generating geothermal developments considered in this study would utilize a binary cycle power generator due to the low geothermal gradient and lack of hot spots in the area of interest.

Power generated from geothermal resources does not add to greenhouse gas emissions and is endless with the increase in production capacity up to 10715 MWe during the last four decades (Gallup, 2009). Given the depth and large numbers of abandon wells due to oil and gas activities, the shut-in oil wells Oklahoma would become the potential candidate. The underground heat exchangers installed in these wells allows the heat transfer that could possibly extract geothermal energy from these well (Ghoreishi-Madiseha et al. 2014). By analyzing new design concepts to utilize geothermal energy in areas that are not hot spots, such as Oklahoma, we hope to bring geothermal energy to a wider audience.

Drilling shallow to intermediate geothermal well generates geothermal power from shallow ground. The shallow ground from well contribute as the energy reservoir with temperature ranging 50-600F. The system utilized low-modeterate temperature to provide heating and cooling, which is determined by terrestial heat flow and local thermal conductivity structure. The ground-source heat pump helps providing the energy from the shallow system, inlcuding open-system (using ground water as heat carrier) and closed system (using underground heat exchanger) (Sanner 2001). The geothermal option brings benefits of low operating costs, slow maintenance, no supplemental heat required, low cost integrated water heating, low environmental impact and longer life expectancy (Sanner 2011). The refrigerant component in closed system absorbs the heat in winter, resulting in high efficiency of level seasonal electric demand (U.S. DOE, NREL 2019). However, the expensive installation costs would hinder the potential of this alternative.

Resuming shut-in well production employs the use of produced water as the geothermal heating source. Many oil field cases have retrofitted heat recovery from the mature wells (Bu and Ma 2012). One study conducted in Pleasant Bayou field shows that both gas and hot water from existing well can be utilized to generate electriciy (Riney 1992). Another case locates in the Naval Petroleum Reserve No.3, Teapot Dome Field in Wyoming, USA, where a 250kW binary power plant was installed to utilize low-enthalpy energy from co-produced hot water. This plant generated 1064 MWh of electricity as of 2010 (Johnson and Walker 2010). In Huabei oil field from China, a power plant utilizes the low-temperature water stream. The 400kW binary power generator has produced cumulative electricity of approximately 31 x104 kWh (Xin et al. 2012). The water and gas from an abandoned well in a Texas field allow the installation of binary unit with a net power of 340 kW (Sanyal et al. 2010). The output power of geothermal power generated in oil fields located in Los Angeles basin is around 7430 kW (Bennet et al. 2012). Overall, resuming hot water from shut-in well alleviate heating costs in the installment. Liu et al (2018) have shown a systematic study of low temperature geothermal options from oil and gas applications, proposing a roadmap to identify good candidates for geothermal oil recovery.

Another proposed geothermal option is to convert the oil and gas into a single geothermal injector and producer system to power a Organic Rankine Cycle (ORC) generator unit. The single injector and producer system advances the heat recovery that the ORC converts the thermal energy of hot water into electricity. The concept requires high flow rates and long-term energy output which extracts heat from reservoir rock (Bodvarsson et al. 1985). The underground injection helps avoiding envronmal impacts from disposal, providing pressure support to the reservoir, extracting heat from rock matrix and preventing ground subsidence (Santya et al. 1995). The ORC unit proposed in this paper brings the new technology of focusing at lower tempertures which can harness the geothermal heat power. This binary systen also utilizes hot water from the ground to generate power then return water to the ground at lower temperature (Climeon, 2019).

An improvement of the initially proposed single injection/production system with ORC unit is to create dual well enhancement geothermal system (EGS). The dual well system includes injector well which inserts cold water into fractures in rock matrix and eventually provides hot water through producer well. The EGS utilizes the benefits of permeability and conductivity in the rock matrix when reservoir has been stimualated to extract the economical amounts of heat from low permeability geothermal reserouces (Capuano et al. 2008). This requires one of two conductivity mechanism: hydraulic fracturing and hydro-shearing (Rinaldi et al. 2015, Gischig and Preisig 2015). The EGS system is forcasted to generate the power exceeding 517800 MWe, surpassing the resource base hosted by conventional hydrothermal system of 9057 MWe (Williams et al. 2008). The heat production from source rock involves the effective hydraulic pathway for heat exchange (Nadimi et al. 2018). Numerous case studies of EGS have been investigated, the most recent being supported by Department of Energy's Frontier Observatory for Research in Geothermal Energy (FORGE). One of the FORGE's sites in Utah has developed the numerical model of the hydraulic fracturing stimulation to obtain the optimal completion design (Nadimi et al 2018). In Idaho, the Raft geothermal field is investigated to determine the viability of combined geothermal and hydraulic stimulation techniques to improve energy production (Bradford et al. 2014). The proper understandings of rock mechanics, completion design and stimulation strategy ensure the success of EGS implication. We believe that the scientific outcomes of these projects could open new ways to look at our concept.

In this paper, our focus is to convert a shut-in oil well located in Cleveland County. OU 24-1 produced from the Pennsylvanian Unconformity and Viola as recently as 1998; however, since 2004 the well has been inactive. The well most recently produced 18 barrels of water per day, which we plan to be used in tandem with a heat pump to heat and cool the WCTC. If the well were turned back onto production, it is unlikely that this amount of liquid production could be used in a binary cycle power module to provide electricity; however, in this paper we will still discuss an option to rework the well so that it can provide enough energy to operate a binary cycle system. Additionally, the geology of the area of interest in Oklahoma has not been considered to have a high geothermal potential. The geothermal gradient in Cleveland County is 1.3 °F/100 ft. Using this gradient, the bottom hole temperature at the total vertical depth of OU 24-1 (8,861 ft) is 183 °F. The binary cycle module that we have looked in to require an extremely high flow rate at a greater temperature differential than the existing well can provide, which constrains our potential solutions. However, future developments, may lead to smaller units requiring lower rates.

The aim of this research is to propose engineering designs to mitigate energy utilization costs at the WCTC building at the University of Oklahoma using environmentally sustainable solutions (hence reducing the carbon footprint). Potential solutions to this issue exist in the form of geothermal developments that generate heat, electricity, or both. Geothermal energy is especially suited to address the needs of the WCTC building because it is an environmentally attractive energy supply capable of meeting baseload power demands. Other renewable energy sources such as wind and solar cannot provide power as consistently as geothermal sources without storage capabilities. To determine the financial performance of proposed solutions, it is vital to consider the current utilization at the WCTC building. Fig. 1 displays the quantity and cost of the natural gas consumed by the WCTC building over the course of 2018. All geothermal solutions presented in this report attempt to generate savings by mitigating these annual costs. Some solutions presented also create value by reducing summer cooling expenses or generating electricity. Our final recommended solution presents the most financially and environmentally viable option for geothermal development at the WCTC location.

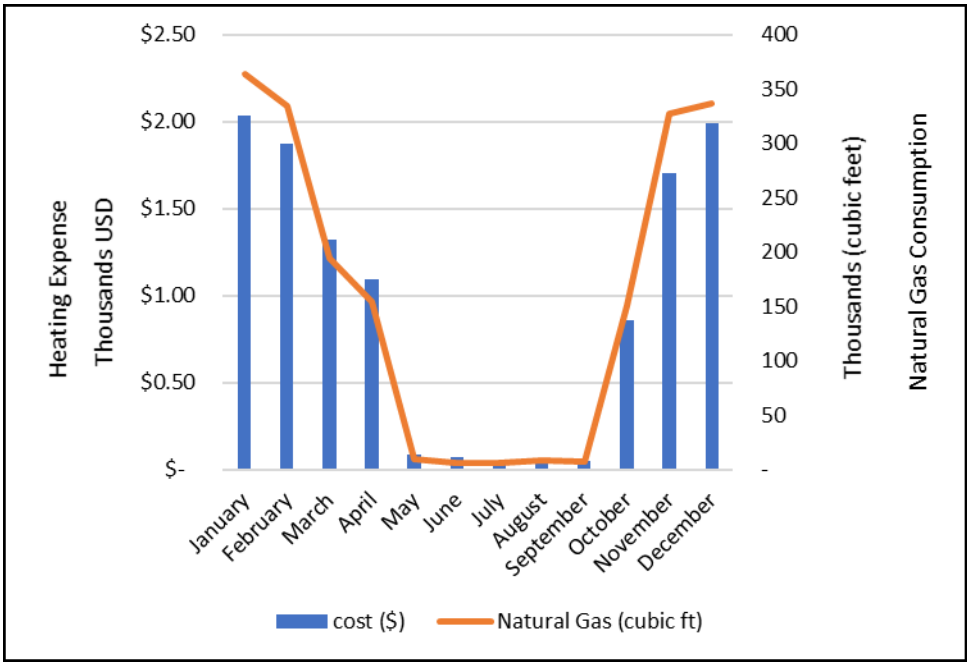


Figure 1. The WCTC building experiences a cyclical demand for natural gas with peak consumption during the winter months.

2. SITE CHARACTERIZATION

It is necessary to establish a consistent assumption regarding the geothermal gradient in the vicinity of WCTC building in order to analyze the options that will be presented in this paper. The gradient is presented in literature as 1.3 degrees Fahrenheit per 100 feet of depth for the general area of the WCTC building (Fig. 2). Temperature gradients in general do not always exhibit linear behavior at extreme depths, but aberrant trends in Oklahoma's gradients have not been identified for the area of interest (Cheung 1975). Furthermore, most local wells in the area have true vertical depths that are too shallow to provide the data which could accurately characterize a transitioning gradient. The economics of geothermal electricity generation are highly sensitive to geothermal gradient, and further analysis by proficient geologists is recommended if a full-scale geothermal electricity-generating operation is planned for the WCTC building.

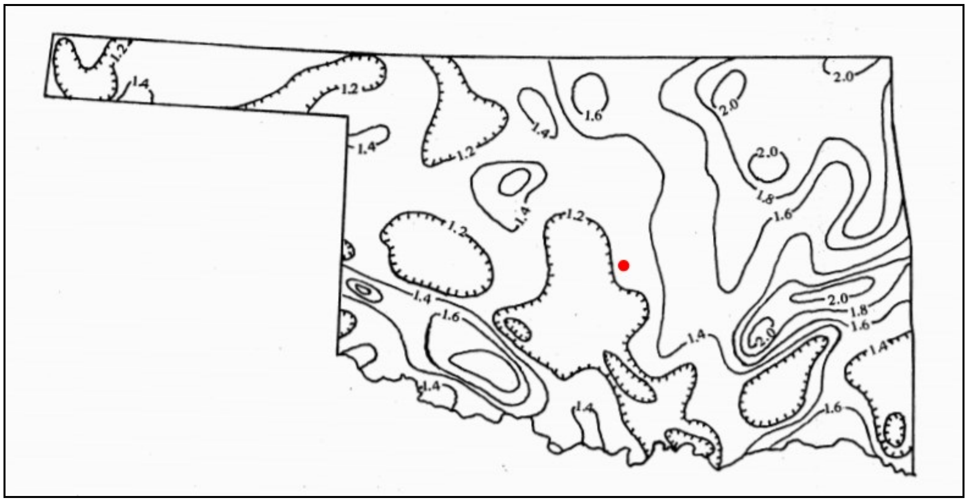
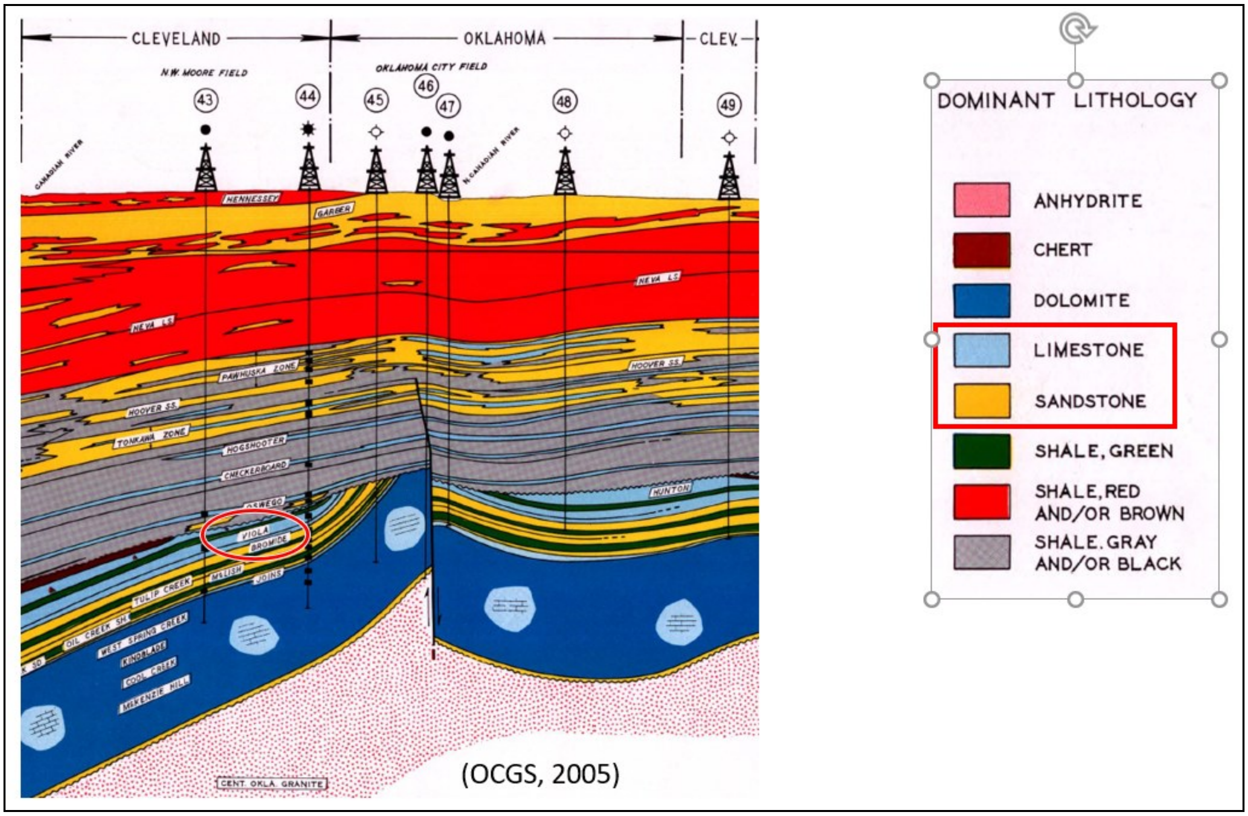


Figure 2: A map of Oklahoma's geothermal gradients as presented in Cheung's 1975 thesis. The red dot marks the location of the WCTC, corresponding with a 1.3 deg F / 100 ft gradient.

There are two formations of general interest to this project; the Viola limestone and the granite bedrock. To better understand the production outcomes of OU 24-1, we analyzed three separate formations for resuming production and recompletion. The initial water production of OU 24-1 and two other analogous wells were used to determine the feasibility of using these formations to produce geothermal energy. OU 24-1 had initial water production of 87 barrels of water per day from the Viola formation and an initial water-oil-ratio (WOR) of 3. Another scenario would be to recomplete the well into the Penn Unconformity or lower Viola. An analogous well in the area, was completed in the Upper Viola formation and produced an initial 15 barrels of water per day. In the Lower Viola formation, another well only produced an initial 40 barrels of water per day. A stratigraphic column of Cleveland County is presented in **Fig. 3**.



(OCGS, 2005)

Figure 3: A stratigraphic column of Cleveland County, where the WCTC is located. The formation targeted by the OU 24-1 well is circled in red.

The granite bedrock is pertinent to deeper geothermal solutions for two reasons. Firstly, the greater depth of the bedrock corresponds with higher downhole temperatures, which will increase the prospects of economic geothermal developments. Secondly, the granite has a relatively high thermal conductivity when compared to the overlying sedimentary formations. This higher thermal conductivity will allow for higher heat flows as energy is absorbed. The value of granite thermal conductivity utilized in this work is 3.6 W/m*K (Cho et al. 2009).

3. ELECTRICITY GENERATION POTENTIAL

Design parameters for low-temperature geothermal electricity generation were supplied by the a commercial ORC manufacturer (Climeon, 2019). A company contact provided the essential operating requirements of one of their 150 kW modules, which use a binary cycle process to transfer heat energy from produced hot water into a working fluid, which will transform into steam to turn turbines and generate electricity. The vital requirements of the modules are a minimum temperature differential of 70 degrees Celsius between the inlet and outlet fluids and a minimum nominal flow rate of 30 L/s. This flow rate is extraordinarily high (it is equivalent to 16,303 bbl/d) and was confirmed after direct inquiry. Typical geothermal systems rely on flows of very hot fluids; lower temperature systems require greater flow rates to compensate for the relatively modest energy potential per unit volume of produced geothermal fluids. For the sake of exploring more reasonable technical and financial possibilities, the economic calculations for options 3 and 4 were performed with an assumption of 5 L/s flow.

The conversion efficiency of the modules was stated as 10-12% for the 70 degrees Celsius temperature differential. This limits the minimum depth required to generate electricity, which is deeper than the current TVD of OU 24-1. The shallowest depth that satisfies the 70-degree differential occurs at 9,690 ft, though the operation of the ORC system is expected to draw down local temperatures significantly in steady-state conditions. Consequently, options 3 and 4 model a TVD of 13,000 ft, which has an expected bottom hole temperature of 237 degrees Fahrenheit (114 deg C). Conversion efficiency describes the amount of heat energy that can be successfully transformed into electrical energy. The cost of this module was approximately $400,000. Generated electricity would be sold directly to the local power grid or used internally by the University of Oklahoma. The value utilized in this paper's financial models is 9.51 cents per kWh (Electricity Local 2019).

4. SYSTEM DESIGN

Over the following pages, this report will present analysis for 4 distinct geothermal development options at the WCTC building. Basic technical and financial characteristics of these options are displayed in Table 1.

Table 1: Presents the geothermal development options considered for WCTC

Option	Description	Heat Savings	Electricity Generation
1	Shallow geothermal wells	Yes	No
2	Resume production	Yes	No
3	Single well producer/injector	Yes	Yes
4	Dual well EGS	Yes	Yes

Option 1 – Shallow Geothermal Wells. In order to provide basic geothermal heating and cooling at the WCTC, we investigated the costs and benefits of drilling shallow to intermediate geothermal wells. Our assumptions are based on interviews with various heat pump companies, with extensive experience on geothermal systems for residential and commercial buildings. The result of the interview suggested drilling 15-20 500 ft deep wells and installing eight 5,000-ton heat pump units to handle the refrigerant and heat exchange needs. The estimated cost was $120,000 for drilling and surface equipment and $380,000 to retrofit the current HVAC system at the WCTC building location. Ongoing costs include $160/unit per year, as well as an assumed $5,000 maintenance for unforeseen circumstances every 5 years. Other assumptions include maintenance cost growth of 1% per year—in line with inflation—and savings growth of 0.5% per year, which is based on the assumption that utilities will be forced to keep price growth lower than inflation. The heating costs of the WCTC building are $10,000 per year, and we assume that the cooling cost is projected at $15,000 per year. Assumptions and financial performance metrics of the project can be found in Table 2.

Table 2: Financial performance and assumptions for shallow geothermal development

Financial Metrics	
20-year NPV	($250,000)
Payback period	21 years

Assumptions
10% discount rate
1% maintenance cost growth rate
0.5% savings growth rate
$5,000 maintenance every 5 years

Option 2 – Resume Production of OU 24-1. The OU 24-1 well's last production values were 6 bopd and 18 bowd. The water produced from the well has associated heat energy as a result of the local geothermal gradient. OU 24-1 has a bottom hole temperature of 84 degrees Celsius (183 deg F). In this option, the WCTC HVAC system would be retrofitted, the OU 24-1 well would be returned to production, and the hot water would mitigate the facility's heating costs. The produced water has the potential to supply approximately 7% of the facility's daily energy needs during peak months of use. This translates to roughly $725 of annual savings in the WCTC heating bill. These savings are insignificant compared to the cost of renovating the WCTC HVAC system, resulting in poor financial projections for this option. In comparison to option 1, this option provides only a fraction of the heating cost savings and doesn't provide any mitigation for summer cooling costs. Though it does require less up-front investment, option 2 has a lower NPV than option 1.

Option 3 – Single Well Producer/Injector. In this proposed solution, the OU 24-1 well is converted into a geothermal system that simultaneously injects and produces water to power an ORC unit. To achieve the minimum temperature differential required by the ORC unit, the well would have to be extended into the granite bedrock. Falcone et al, 2018, have shown the importance of deep single well solution and the need of further research. Unfortunately, as will become apparent, the extensive depletion of reservoir temperature due to the high flow rate required by the ORC unit would require extensively deeper, cost-prohibitive drilling; however, the system is still uneconomic when the depletion of reservoir temperature is ignored. The proposed modification to the OU 24-1 well would include deepening the wellbore, installing insulated tubing, acquiring an ORC unit, and purchasing a pump. A sketch of the system is provided by Fig. 4. The flow capacity of the OU 24-1 well and the geothermal deliverability of the underlying granite formation present two technical challenges that prevent the adoption of option 3. The economics associated with the option are also not particularly favorable. The OU 24-1 well has 8 3/4-in casing which extends to 1250 ft and a 5 1/2-in production tubing up to 8,861 ft. With the target velocity of 1 m/s, the configuration allows the flow capacity of 4.7 L/s for tubing and 14.0 L/s for annulus. With the maximum allowable velocity of 3 m/s, flow capacity of 7.2 L/s for tubing and 21.5 L/s for annulus. The flow capacity values, based on the target and maximum allowable rates, reveal that they are less than the required rate of 30 L/s, making the system unfeasible to attain heat exchange and electricity generation while maintaining affordable costs for lower than the required rate (**Fig. 5**).

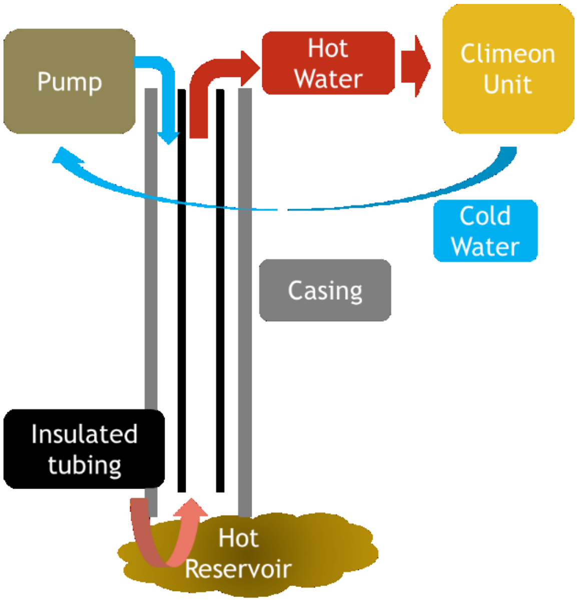


Figure 4: Option 3 features a conversion of the OU 24-1 well into an injecting/producing geothermal system to complement the Climeon generator

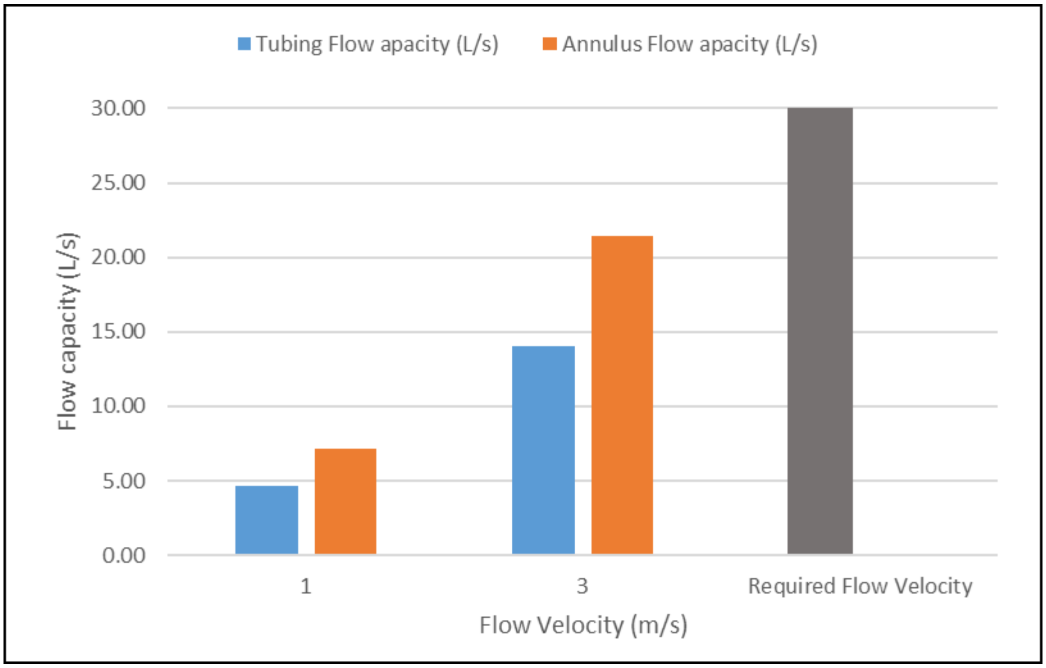


Figure 5: The Flow Capacity (L/s) based on different flow rates (m/s) compared with the required flow rate

To model the thermal deliverability, a rock matrix of homogeneous thermal conductivity was assumed. Calculations were performed under a condition of steady-state, which enabled the utilization the steady state heat equation and Fourier's Law (ME 2018). This situation models a constant temperature gradient established by the depletion of local heat energy through contact with cold injected water and heat replenishment via natural conductivity in the subsurface. The model incorporates isothermal cylindrical shells extending from the edge of the wellbore into the reservoir. The initial temperature of these shells is taken to be the midpoint of their depth. The heat flux is set by a given flow rate of cold injected water. Temperatures of each shell are iterated until heat flow rates converge across the entire system. This generates temperature distributions extending radially from the wellbore (**Fig. 6**). The temperature changes are small at far distances from the wellbore and temperatures predicted there reflect the initial conditions of the reservoir. Consequently, for a given flow rate, the approximate required temperature of the granite can be determined, and, with the aid of a temperature gradient, the necessary wellbore depth can be calculated. **Fig. 6** obviously demonstrates that the ambient temperature required for the magnitude of heat transfer necessitated by the ORC unit is extremely impractical to attain; even a flow rate above 1 L/s would require cost-prohibitive depths to furnish the required temperature of over 200 degrees Celsius.

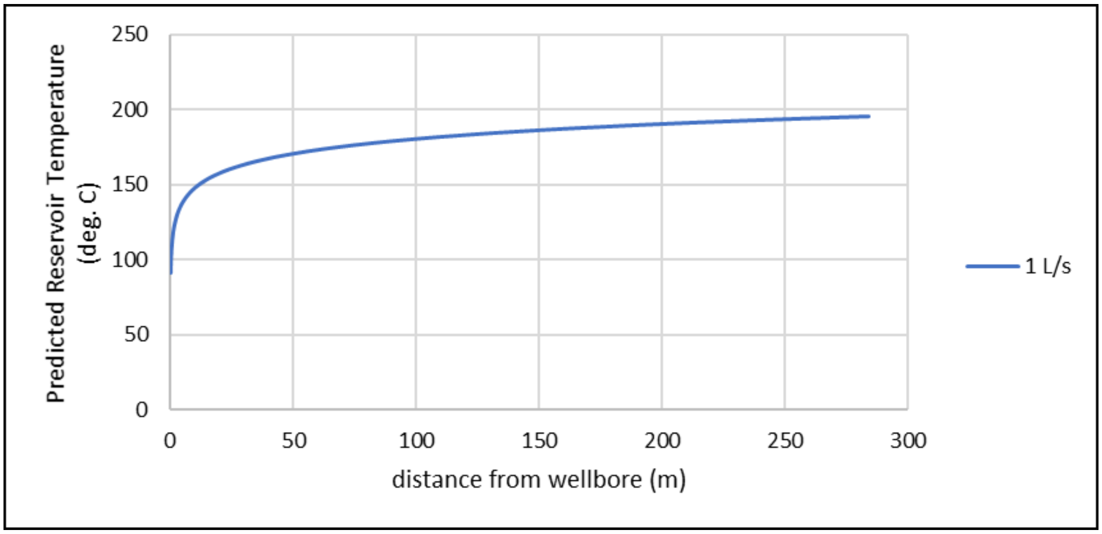


Figure 6: Temperatures predicted by the heat transfer model increase as distance from the wellbore increases and approach the initial geothermal reservoir temperature required for a system at a particular flow rate

Based on informal interviews with industry professionals, we assume the bit life is 50 hrs/bit at a rate of $5,000 per day. The rate of penetration through sandy shale is assumed to be 60 ft/hr, but that rate drops to 7 ft/hr, according to research from Baumgartner et al. 1995 An efficient crew can trip approximately 2,500 ft/hr. The rig rate is assumed to be $20,000 per day. To get to the top of the granite, we estimate approximately 28 hours, and it will need another 360 hours to get to 13,000 ft. The costs of drilling to 13,000 ft can be found in **Table 3**. Please note that the prices are estimate as of 2018 and reality may be different.

Table 3: Drilling costs for extending the depth of OU 24-1

COSTS	TO TOP OF GRANITE (1,640 FT)	INTO GRANITE (2,500 FT)	TOTAL DRILLING COST
RIG RENTAL	$23,500	$300,000	
BIT RENTAL	$5,000	$75,000	
TRIP TIME	$3,000	$60,000	
TOTAL	$31,500	$435,000	$466,500

An important consideration that holds true for both options 3 and 4 is the pumping costs associated with injecting water at a rate of 30 L/s to a depth of 13,000 feet. Every liter of hot water utilized by the ORC unit to produce electricity will incur an operational expense as a result of pumping. The margin of these values provides the financial justification for pursuing options 3 and 4. To consider the maximum potential of this value, 100% pumping efficiency and no reservoir temperature drawdown were assumed. Realistically, the pumping efficiency will be lower, and the reservoir temperature would be drawn down prohibitively in order to supply the minimum required fluid flow to operate the ORC unit. Despite these optimistic assumptions, the operating margin is already negative, as shown in Fig. 7.

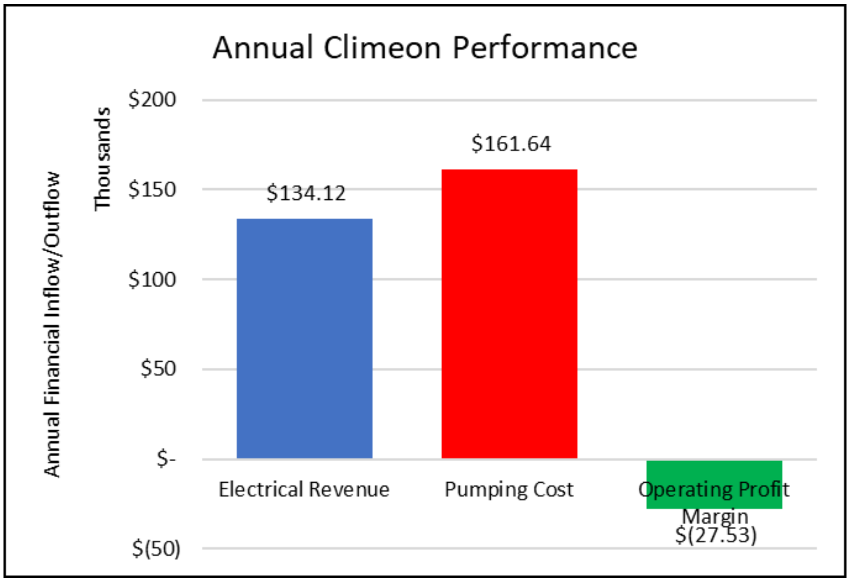


Figure 7: The electrical revenue generated from injected water is offset by its pumping cost; the negative operating margin is actually an optimistic assumption of value for options 3 and 4. These values are valid for a temperature differential of 70 degrees Celsius and a flow rate of 5 L/s.

Technically, option 3 is essentially impossible to implement under current technology availability. The minimum heat flow required by the ORC unit simply cannot be provided through conduction from a granite matrix into a single producer/injector wellbore located next to WCTC building. The depths that would support the required temperatures are deep. Financial calculations were made assuming that the granite matrix at 13,000 feet could effectively support the required heat flow and consistently provide 5 L/s of fluid at the minimum temperature differential of 70 degrees Celsius; even with this assumption the NPV of the project is clearly negative, in part due to the extensive capital expenditures required (Table 4), and in part due to the negative incremental value associated with operating the selected ORC system.

Table 4: Estimated capital expenditures required to implement option 3

Capital Expense	Cost ($)
Drilling expense to deepen well	466,500
ORC generator unit	400,000
HVAC retrofit	380,000
Pump, insulated tubing	100,000
Total	**1,346,500**

Option 4 – Dual Well Enhanced Geothermal System (EGS). Our analysis of the heat flow requirements of the third option suggested that vastly more surface area is required for enough conduction to satisfy the drain of the ORC system on the heat energy of the rock matrix. Consequently, the final geothermal development option features a dual well system wherein an injector forces cold fluid through fractures in the granite matrix and into the producer well, which provides an insulated flow path to the ORC generator (Fig. 8).

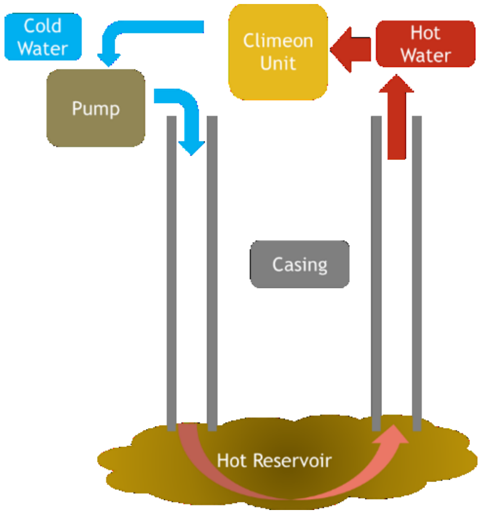


Figure 8: Cold fluid would be injected through one well into a fractured granite matrix. The fluid would gather heat energy and flow into an insulated producing wellbore. The hot fluid would enter the ORC generator, thereby generating electricity.

The OU 24-1 well would be extended to a TVD of 13,000 ft with a 2,500 ft lateral section. A new well would be drilled with a matching geometry, and both wells would be completed to provide a fracture flow path through the granite matrix between the wells. The wells would be spaced 500 ft apart and all perforations would be targeted toward the sister wellbore. A surface contact area of 10 million square feet was estimated based on the fracture geometries. The greater contact area facilitates heat transfer sufficiently to allow for a temperature differential of approximately 77 degrees Celsius at a depth of 13,000 ft for a flow rate of 5 L/s. Despite the higher temperature differential, the operating margin is still negative, meaning that the message of Fig. 7 doesn't meaningfully change and that the binary cycle system would still be losing money whenever it is operating. A breakdown of costs for this capital-intensive option are provided in Table 5.

Table 5: Estimated capital expenditures required to implement option 4

Capital Expense	Cost ($)
Deepening and extending OU 24-1	841,500
Drilling new well	2,325,000
Total completions cost	3,000,000
Climeon generator unit	400,000
HVAC retrofit	380,000
Pump, insulated tubing	100,000
Total	**7,046,500**

An important unknown factor in the performance of the proposed EGS design is the quantity of leakoff that will be experienced through the granite matrix. Economics run assuming a 0% leakoff (the base assumption in this report; values were previously presented in Table 1) feature negative NPVs, but even small leakoff values can make these values vastly more negative. A leakoff rate of 1%, for example, would almost double annual operating expenses from $155,000 to $260,000. These values assume a water cost of 25 cents per barrel of water.

Issues that plagued option 3 continue to create issues for option 4. Though the dual well EGS system has the potential to create vastly more contact area between the granite matrix and the injected water, the heat flow requirements of the ORC unit are still too demanding to satisfy in a cost-effective manner. Drilling deeper is the only way to mitigate the issues, at which point the low-temperature ORC system becomes irrelevant in a discussion of geothermal development, as more efficient, higher-temperature conversion options could be explored. An investigation of deeper, higher-temperature electricity generation was not conducted in this research; Oklahoma in general and Cleveland County in particular are not endowed with competitive geothermal gradients.

5. ECONOMICS

All future revenue and savings streams were discounted by 10%. Financial performance was evaluated based on 20-year NPV. Ultimately, none of the geothermal development options investigated in this report proved to be economically justifiable under the current energy prices of 2018. The best option from a financial perspective is to use the heat pump units. There are two points that should color the NPV values presented in this report. One is that the capital expenditures associated these geothermal projects are all high, especially for the deeper solutions. This implies that, even if positive NPVs could be obtained, the profit-to-investment ratio would still be modest, which is especially concerning considering the technical risks of a green field geothermal development. Secondly, it is difficult to quantify the value of implementing a more environmentally friendly energy supplying system at the WCTC building. Nevertheless, the sustainability benefits of a geothermal system are unlikely to justify the poor financial performance of the proposed geothermal solutions. Table 6 summarizes the calculated NPV and the estimated initial investment costs.

The performed economics, show that there is a high demand of novel technologies capable to efficiently harness the heat and make the economics of local small applications positive. Xin et al . (2012) have shown that if sufficient temperature and flowrate exists, ORC system may produce as much as 310 kWh electricity, however our focus was more on achieving a better large building heating in an environmental way.

Table 6: Economics of the geothermal development options considered for WCTC

Option	Description	Heat Savings	Electricity Generation	20-year NPV (thousand $)	Initial Investment (thousand $)
1	Shallow geothermal wells	Yes	No	-250	500
2	Resume production	Yes	No	-374	380
3	Single well producer/injector	Yes	Yes	-1,488	1,347
4	Dual well EGS	Yes	Yes	-7,064	7,047

6. DISCUSSIONS

Our study have revealed that under current energy prices in Oklahoma, most of geothermal solutions are not economically to be implemented. However, the same study have revealed some future research needs:

- classical heat pump systems cannot use high temperature input (typically over 80F) which could be beneficial in our case for heating purposes.
- we could not identify any small ORC units that can be used at lower flow rates (i.e. less than 5 l/s). Such units could be beneficial, as a combination of heat and power generation may increase the economics of such a project.
- the proposed case 2, does not consider the revenue of the produced oil, which can for a given time improve the economics.

For research purposes we have further looked into the time at which the NPV can become positive, and we identified that solution 1 and 2 could lead to a positive NPV after 30 years at a discount rate of 5% respectively 22 years at same discount rate (see table 7).

Table 7: Economics of the geothermal development options considered for WCTC location

Option	Description	Heat Savings	Electricity Generation	20-year NPV (thousand $) Uses 10% discount rate	Years to zero NPV Uses 5% discount rate	Initial Investment (thousand $)
1	Shallow geothermal wells	Yes	No	-250	30	500
2	Resume production	Yes	No	-374	20	380
3	Single well producer/injector	Yes	Yes	-1,488	>100	1,347
4	Dual well EGS	Yes	Yes	-7,064	>100	7,047

None of the studied scenarios do include the carbon footprint or any associated tax with CO2 emissions, nor any subventions that may be possible at the building location.

Falcone et al (2018) have shown that not all single well solutions may be economically although technically the solution could be a success. This encourage our team to further investigate new solutions for the well OU24-1. Our next step is to look into direct heat utilization for heating purposes, hence the well will be used only seasonal when heat is required for the building.

7. CONCLUSIONS

This research effort was spurred by the desire to generate energy savings at the WCTC through an environmentally sustainable, base load power providing system. Four geothermal applications were identified as potential solutions. These options were analyzed and financially compared in order to determine the optimal development at the WCTC.

Unfortunately, analysis demonstrated that the options were all financially problematic considering the 2019 level of energy costs; each scenario generated negative NPV, and payback periods were measurable in decades. Furthermore, some of the options proved to be technically unsound as a result of the prohibitive heat flow requirements of the ORC generator unit.

Though it is uncommon to recommend a negative NPV project, this report posits option 1 (drilling shallow geothermal wells) as the highest value-generating geothermal development that could be implemented at the WCTC while acknowledging that the financial rationale to undertake the project does not currently exist.

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