Techno-Economic Analysis for a Potential Geothermal District Heating System in Tuttle, Oklahoma

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Keywords

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ABSTRACT

Geothermal deep direct use (DDU) has potential across a wide swath of the United States but is underutilized due to challenging project economics associated with developing a deep geothermal resource for a large-scale and variable heat demand. The National Renewable Energy Laboratory (NREL) and University of Oklahoma evaluated the feasibility of a geothermal district heating (GDH) and cooling system in two schools and 250 houses by utilizing existing oil and gas (O&G) wells in Tuttle, Oklahoma. Heating and cooling demand in the two schools and a typical single-family house were modeled using EnergyPlus™ building energy simulation software. The modeling results indicated that annual heating demand in two schools and 250 houses is approximately 2.61 GWh_{th}, and cooling demand in the two schools is approximately 2.65 GWh_{th}. In this scope, the techno-economic analysis (TEA) was conducted using the GEOPHIRES tool combined with the TOUGH2 reservoir simulator. The reservoir performance, including geothermal heat production capacity, was modeled by the reservoir simulator TOUGH2. Then, levelized cost of heat (LCOH) was calculated using GEOPHIRES version 3.0, which includes new features such as hourly heat load optimization and peak performance evaluation. Geothermal reservoir temperature was estimated as 90.5°C at a total depth of 3.3 km by the regional average temperature gradient of 22.8°C/km and validated by cation geothermometer calculations. Four production scenarios with two different well configurations and two different heat load profiles have been developed for well flow rates ranging between 3.1 kg/s and 9.3 kg/s. The LCOH of the district heating and cooling system was calculated between $95 and $210/MWh ($28/MMBtu to $62/MMBtu) for four different production scenarios. Typical natural gas prices for residential customers in Oklahoma have ranged from 9 to 19 $/MMBtu over the past decade, which indicates a challenge for deployment of such a GDH system.

1. Introduction

Geothermal district heating (GDH) systems are mature and have been utilized in several countries as a primary source of district heating, namely in China, Türkiye, Iceland, Germany, and 25 other countries. There are 23 active GDH systems in the United States, but more than two-thirds (~82%) are over 30 years old (Kolker et al., 2021). Only four systems were installed after 2000, in

California and Oregon (Robins et al., 2021). Unlike Europe, GDH systems in the United States are small systems, ranging from 0.1 MW_{th} to 20.6 MW_{th}, with an average capacity of 4 MW_{th} (Robins et al., 2021). The most recent installation was in 2017 at the Modoc County Joint Unified School District in Alturas, California, which has an installed capacity of 0.4 MW_{th}. Another new GDH system was installed in 2014 at Lakeview District hospitals and schools in Oregon with a capacity of 4.4 MW_{th} and annual generation of 4.4. GWh_{th}/yr. Larger GDH systems are in Boise, Idaho (20.6 MW_{th} and 42.3 GWh_{th}/yr), and San Bernardino, California (12.8 MW_{th} and 22 GWh_{th}/yr).

Between 2017 and 2019, six deep direct use (DDU) projects were funded by the U.S. Department of Energy (DOE) to increase the understanding of DDU technical performance and cost-competitiveness, and to foster development of such systems in the United States (Beckers et al., 2021a). Four of the six DDU projects were modeling a geothermal district heating system and/or absorption cooling systems ranging between 6 MW_{th} and 32 MW_{th} with levelized cost of heat (LCOH) values between $13/MWh and $60/MWh (Table 1). Key drivers for lowering the LCOH include higher reservoir temperatures, shallower reservoir depths, higher well flow rates, higher utilization rates, lower drilling costs, repurposing existing wells, and lower discount rates.

Table 1. Summary of key parameters and LCOH of four district heating and absorption cooling case studies out of six DDU projects between 2017 and 2019 (modified from Beckers et al., 2021a)

Project	**Sandia (Hawthorne, NV)**	**Cornell University (Ithaca, NY)**	**West Virginia University (Morgantown, WV)**	**NREL (Longview, TX)**
Application	**District Heating**	**District Heating**	**District Heating + Absorption Cooling**	**Absorption Cooling**
Drilling Depth (km)	0.3	2.5	2.9	2.7
Reservoir Temperature (°C)	100	72	88	120
Geothermal Gradient (°C/km)	27.2	27.5	25.8	37.5
Flow Rate (kg/s)	36	50	40	125
System Size (MW_{th})	6	13 (with HP)	32 (with HP)	11
Utilization Factor (%)	48	98	95	90
Heat Production (GWh/yr)	26.1	115	267	119
Total CAPEX ($)	$8.9M	$16.3M	$102.5M	$11.7M
Total OPEX ($/yr)	$450k/yr	$1.23M/yr	$8.8M/yr	$780k/yr
LCOH ($/MWh)	41	17	60	13
LCOH ($/MMBtu)	12	5	17.5	3.7

One of four modeled cases was the Cornell University campus deep geothermal system, which indicated subsurface temperatures ranging between 70° and 90°C, at around 2.5 to 3 km depth (Beckers et al., 2021b). Techno-economic analysis (TEA) suggests that integrating Earth Source Heat (ESH) into the existing district energy campus infrastructure and coupled with centralized heat pumps would provide cost-competitive heating at an LCOH of $5/MMBtu (Beckers et al., 2021b). The Cornell University district heating system is also modeled with hybrid configurations of solar thermal systems combining a flat plate collector solar system with a parabolic trough collector system via a heat exchanger and coupled with thermal energy storage yielding a natural gas offset reaching up to 204,000 MMBtu, which corresponds to 25% of the annual heating demand (Akar et al., 2023)

Estimated LCOH for the U.S. GDH systems ranges from $15 to $105/MWh ($4.4/MMBtu to $31/MMBtu), with an average of $54/MWh or $16/MMBtu (Robins et al., 2021). The average utilization factor of the GDH systems in the United States is 23% (Kolker et al., 2021). The utilization factor is the percent ratio of geothermal heat utilized by the district heating system divided by the geothermal heat that can be extracted from the reservoir at a specified flow rate and well configuration. In other words, it defines total heat deployed compared to the theoretical amount of heat that the system can generate at full capacity for every hour of the year.

Natural gas price is an important parameter that indicates a challenge for deployment of such GDH systems. Figure 1 shows the historic annual average natural gas price in Oklahoma over the last decade. Typical natural gas prices have ranged from 9 to 19 $/MMBtu for residential customers and 2 to 8 $/MMBtu for industrial use over the past decade (EIA, 2023). There was a significant increase in residential natural gas prices in 2022, with a historic high of 34 $/MMBtu in the month of October (EIA, 2023).

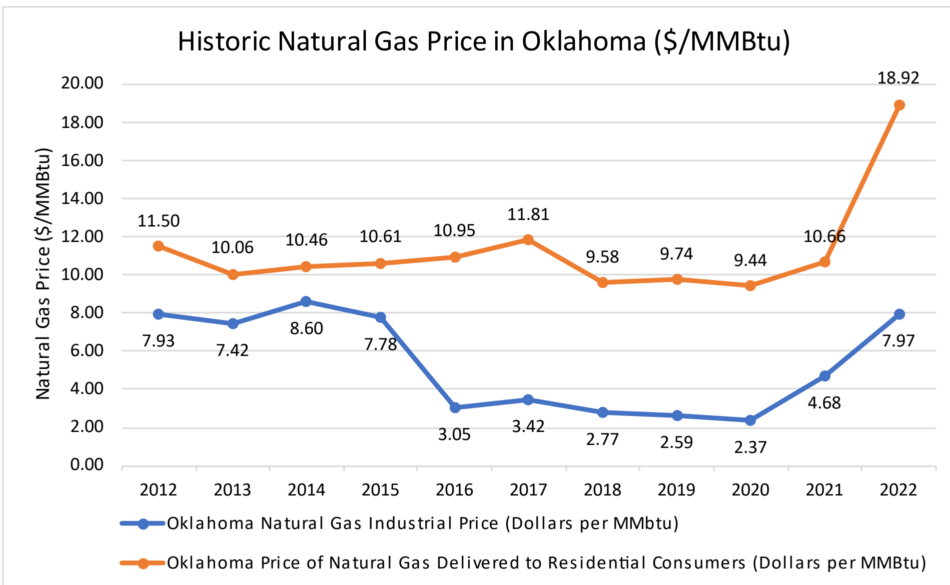

Figure 1: Historic annual average natural gas prices for industrial and residential customers in Oklahoma between 2012 and 2022* (Data source: EIA, 2023) *2022 data is the average of 9 months.

In addition to heating, geothermal resources can provide cooling for buildings. Ammonia water- or lithium bromide water-based absorption chiller technologies are compatible with low-temperature geothermal heat sources between 60°C and 90°C (Liu et al., 2015). An ammonia-water-based absorption chiller has been operational since 2005 at the Aurora Ice Museum at Chena Hot Springs, Alaska. The chiller runs on 73°C geothermal heat and provides 15 tons of -29°C chilling, allowing the Ice Museum to stay frozen year-round (Erickson and Holdmann, 2005). A recent study conducted by NREL investigated the techno-economic feasibility of a 12-MW_{th} capacity absorption chiller system that uses geothermal heat to produce 86 GWh of cooling per year for a chemical plant in East Texas (Turchi et al., 2020).

In Europe, many GDH systems use hydrothermal resources in sedimentary basins, utilizing doublet well configuration with a pair of injection and production wells for heat extraction (GeoDH, 2014). Sedimentary basins are also potential areas for geothermal heat production in the United States with Anadarko basin being the highest expected geothermal heat capacity (Augustine, 2014; Porro et al., 2012). Total beneficial heat available from geothermal resources below 150°C in sedimentary basins of the United States is estimated as 46,500 MW_{th} (DOE, 2019). The city of Tuttle is located at the southeastern edge of the Anadarko basin blue region, where the extent of the region has estimated temperatures ranging from 100°C to 150°C at depths between 4,000 m and 5,000 m (Figure 2).

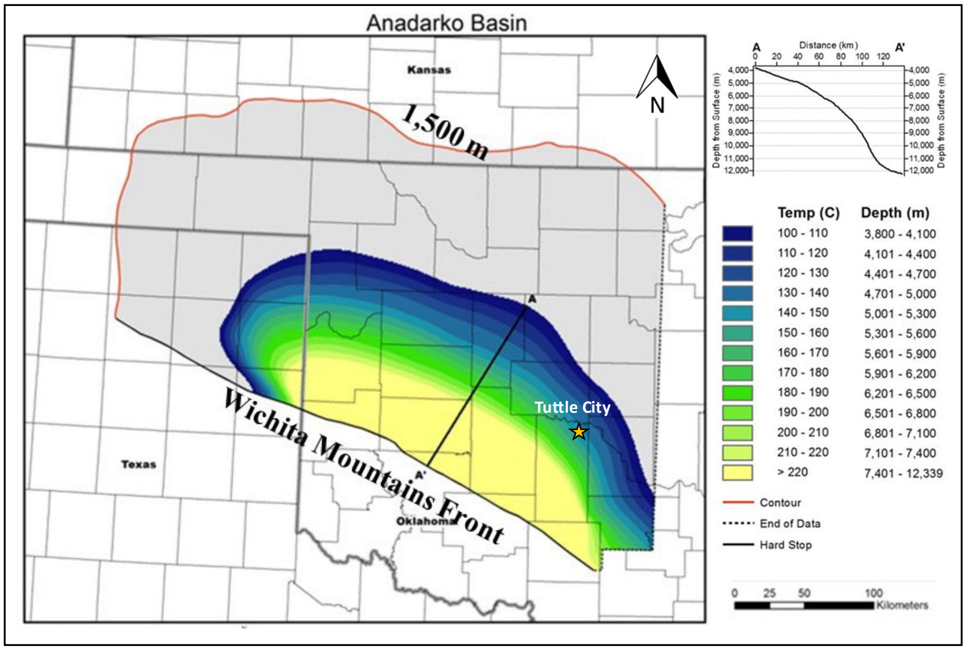

Figure 2: Location of Tuttle in the Anadarko basin and estimated reservoir temperatures greater than 100°C delineated by 10°C temperature increments (modified from Porro et al., 2012).

2. District Heating System in Tuttle, Oklahoma

The city of Tuttle, located in Grady County, Oklahoma, is home to 7,413 people living in 2,563 housing units, based on 2020 decennial census data (USCB, 2020). Monthly average air temperature during winter months varies between 3°C and 10°C, with a low of -1°C; monthly average air temperature during summer months varies between 15°C and 28°C, with a high of 34°C (Weatherspark, 2023). The potential district heating system in Tuttle includes one elementary school, one middle school, and 250 single-family houses (SFHs). Figure 3 shows the location of wells, two schools, and the potential extent of the GDH system that can serve up to 250 SFHs in Tuttle, Oklahoma. Heating and cooling demand in the two schools and SFHs was modeled using EnergyPlus™, a building energy simulation software. The annual heating demand of one SFH is calculated as 9.47 MWh_{th}, which corresponds to a heat demand of 2.37 GWh_{th} for 250 SFHs. Annual heating demand of the two schools is calculated as 0.24 GWh_{th}, which is a total annual heating demand of 2.61 GWh_{th} for the total GDH system. In addition to heating demand, annual cooling demand in the two schools is calculated as approximately 2.65 GWh_{th}.

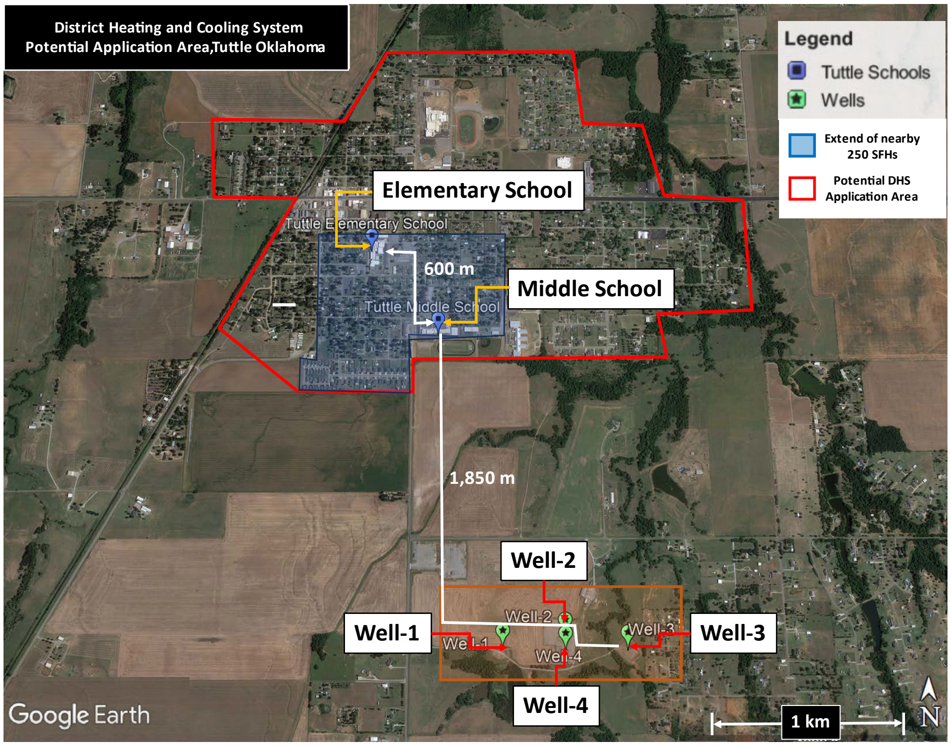

Figure 3: Location of wells, two schools, and potential extent of GDH system that can serve up to 250 SFHs in Tuttle, Oklahoma

2.1 Heating and Cooling Demand Analysis

The total heating demand in the two schools and 250 houses (outlined with red) and cooling demand in the two schools (outlined in blue) are represented in Figure 4. The TEA assumes the given heating demand is supplied by a direct-use heating application (e.g., radiator for space heating), while the cooling demand is supplied by an absorption chiller. While it is assumed that the thermal energy produced from the Tuttle wells is directly supplying the heating demand (1:1), the cooling demand incorporated the coefficient of performance (COP) of the absorption chiller, which is typically less than 1 for a single-stage absorption chiller at low temperature below 150°C. That is, higher thermal energy is needed to supply the cooling demand. For example, if the daily cooling demand is 1 MWh, the thermal energy to supply the 1-MWh cooling demand is 1.25 MWh with a COP of 0.8. The total annual heating demand in two schools and 250 houses used for Scenarios 1 and 2 was calculated as 2.61 GWh_{th}, and cooling demand for two schools was calculated as 3.31 GWh_{th} with COP of 0.8., which sums to 5.92 GWh_{th} in Scenarios 3 and 4, combining heating and cooling loads. GEOPHIRES takes the hourly heat load as input and calculates the share of geothermal heat that can compensate for the heat demand of the district heating system (DHS). Then, it calculates the heat required for the peak hours that the geothermal system cannot meet the demand (i.e., additional heating and/or cooling system to fully cover the given demand). Annual production and utilization factor calculations of the DHS will be discussed in Section 5.

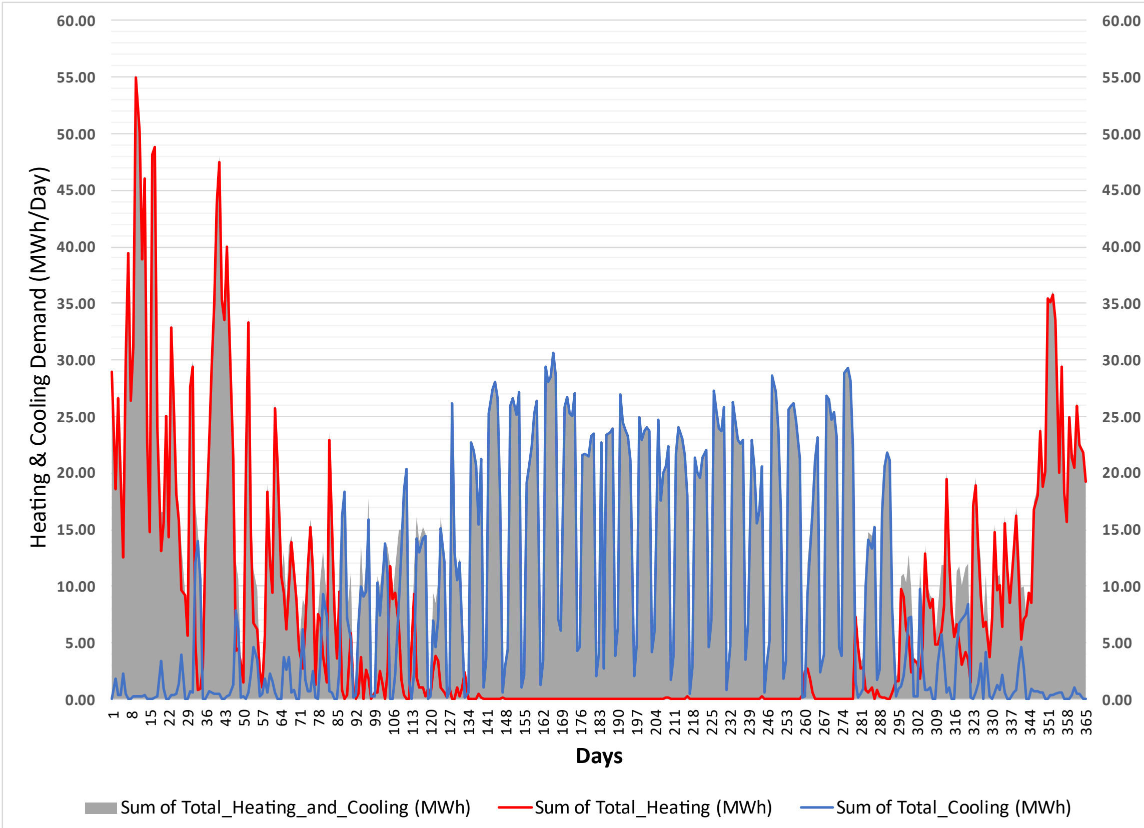

Figure 4: Daily heating demand of two schools and 250 SFHs, and cooling demand of two schools in Tuttle, Oklahoma, for a typical year

3. Model Development

3.1 Methodology

Version 3.0 of GEOPHIRES allows the users to perform techno-economic simulations for geothermal energy systems with possible end-use options such as electricity generation, direct-use heat, cogeneration, absorption chiller, heat pump, and district heating. The district heating option includes hourly heat load optimization and peak performance evaluation. We have used both the direct-use heat and district heating options to compare the annual generation and impact of surface equipment to LCOH. Because the wells are repurposed for geothermal heat production, all subsurface costs such as drilling, stimulation, and well completion are omitted in both cost models. While the direct-use cost model only includes surface cost associated with the geothermal brine gathering system and well head pumps, the district heating system cost model includes all costs, including heat exchangers, absorption chillers, network pipes, storage tanks and other components that are discussed in Section 4. GEOPHIRES allows users to specify a utilization factor and thermal efficiency factor of the direct-use heat application. The direct-use option estimates the heat production with a user-provided utilization factor; the district heating option calculates the utilization factor based on heat demand profile and geothermal installed capacity. For a given set of input parameters, the tool simulates the subsurface reservoir, wellbore, and surface plant by using built-in models. TOUGH2 incorporated with GEOPHIRES is originally designed to model a doublet well configuration with one production and one reinjection well. For the specific layout of the Tuttle case study, the TOUGH2 model is modified to model a quartet well configuration at given spacing between wells. In a quartet well configuration, the model works on three production wells and one reinjection well. The simulated output includes the reservoir production temperature and instantaneous and lifetime surface plant heat production combined with capital and operation and maintenance (O&M) cost correlations. Then, the LCOH of the system is calculated based on the standard levelized cost model.

3.2. Reservoir Modeling with TOUGH2

TOUGH2 geothermal reservoir simulator is for non-isothermal multiphase flow in fractured porous media. The reservoir pressure drop is calculated by specifying an overall reservoir impedance or productivity index (Beckers and McCabe, 2019). When specifying a productivity and injectivity index, a reservoir hydrostatic pressure is calculated using the built-in modified Xie–Bloomfield–Shook equation. To account for production wellbore heat losses, the built-in transient Ramey's wellbore heat transmission model is used.

For the reservoir modeling in TOUGH2 with four Tuttle wells, we developed four production scenarios with two different well configurations and two heating/cooling load profiles. We used flow rates ranging between 3.1 kg/s and 9.3 kg/s to achieve minimum seismic risk. In addition to seismic activity risks, there are other regulatory restrictions for utilization of the resource at a certain depth of the reservoir due to O&G coproduction. The information on reservoir properties, such as density, thermal conductivity, and porosity, was collected from the literature review in collaboration with the University of Oklahoma and incorporated in the reservoir modeling (Table 2). The four case scenarios are:

- **Scenario-1**: Doublet well configuration with 1 production well at 9.3 kg/s flow rate and 1 injection well for heating of two schools and 250 houses.
- **Scenario-2:** Quartet well configuration with 3 production wells at 3.1 kg/s flow per well and 1 injection well for heating of two schools and 250 houses.
- **Scenario-3:** Doublet well configuration with 1 production well at 6.2 kg/s flow rate and 1 injection well for heating and cooling load for two schools and heating load for 250 houses.
- **Scenario-4:** Quartet well configuration with 3 production wells at 6.2 kg/s flow per well and 1 injection well for heating and cooling load for two schools and heating load for 250 houses.

Figure 5 shows the temperature drawdown for all four scenarios for a 30-year lifetime. Scenario-1 with a doublet well configuration has the most stable production temperature, which stabilizes around 75°C where the absorption chiller can be operated without heat boost from peaking boiler b, for cooling end use. Scenario-4 with a quartet well configuration is the least stable for production temperature, which peaks at 65°C then drops to 43°C during the first 15 years of production.

Table 2: Reservoir model parameters for TOUGH2 simulation

Models	Scenario-1	Scenario-2	Scenario-3	Scenario-4
Reservoir model	TOUGH2	TOUGH2	TOUGH2	TOUGH2
Model geometry	Doublet	Quartet	Doublet	Quartet
Wellbore heat transfer model	Ramey	Ramey	Ramey	Ramey
Number of production wells	1	3	1	3
Number of injection wells	1	1	1	1
Well depth (m)	3,300	3,300	3,300	3,300
Production well diameter (inch)	8	8	8	8
Injection well diameter (inch)	8	8	8	8
Flowrate per production well (kg/s)	9.3	3.1	6.2	6.2
Geothermal gradient (°C/km)	22.8	22.8	22.8	22.8
Maximum reservoir temperature (°C)	95	95	95	95
Injection temperature (°C)	15	15	15	15
Reservoir density (kg/m^3)	2,700	2,700	2,700	2,700
Reservoir thermal conductivity (W/m/K)	5	5	5	5
Reservoir heat capacity (J/kg/K)	930	930	930	930
Reservoir porosity (%)	12	12	12	12
Reservoir permeability (m^2)	5E-14	5E-14	5E-14	5E-14
Reservoir thickness (m)	100	100	100	100
Reservoir width (m)	2,300	2,300	2,300	2,300
Well separation (m)	540	270	540	270

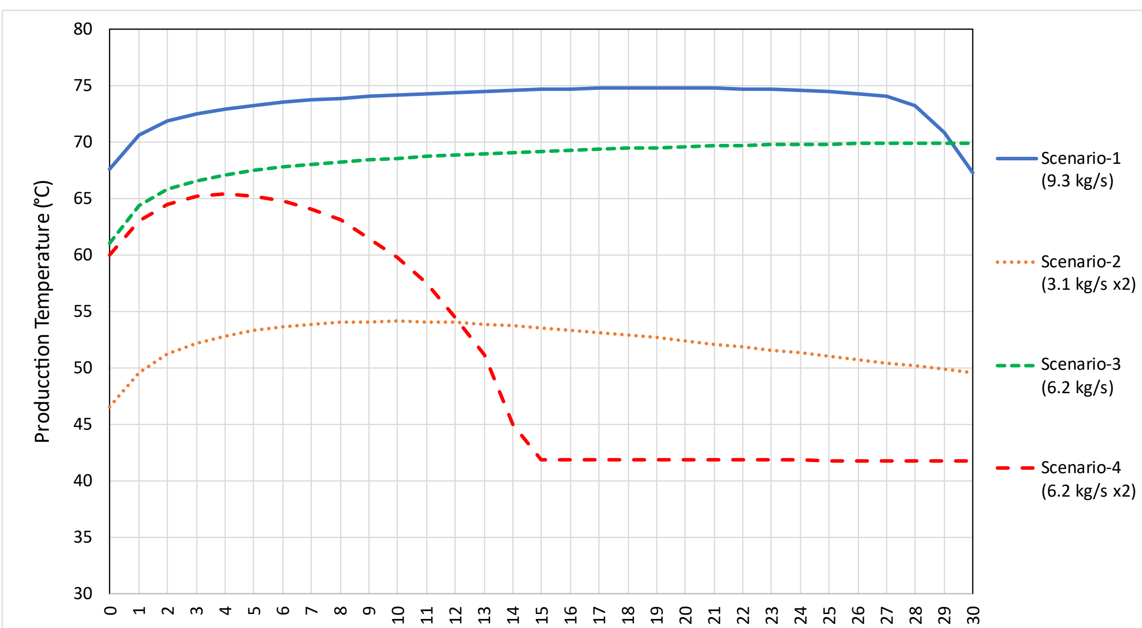

Figure 5: Production temperature drawdown for a 30-year lifetime of four different production scenarios

4. Techno-Economic Analysis

Capital expenditures (CAPEX) associated with the necessary components, including heat exchangers, air handlers, fluid surcharge tanks, peaking natural gas boilers, circulation pump, and trenching, were collected from the University of Oklahoma. Absorption chiller cost is scaled based on DOE`s combined heat and power technology fact sheet (DOE, 2017). Engineering and operations costs are taken from industry examples and previous studies (Turchi et al., 2020). Utilizing existing O&G wells reduced the LCOH significantly because drilling cost was omitted from CAPEX. Well repurposing costs including pre-evaluation and completion cost, such as well logs, permitting, landowner royalty fees, and other soft costs are covered under EPC overhead. The district heating option includes CAPEX based on two systems: 1) heating system only and 2) heating and cooling system with an absorption chiller (Table 3).

TEA has been conducted by using the GEOPHIRES standard levelized cost model (Beckers and McCabe, 2019). LCOH ($/MMBtu or $/MWh) is calculated by using CAPEX, O&M cost, and annual heat generation in (MWh/yr). The standard levelized cost model discounts future revenue and expenditures to today's dollars and calculates the levelized cost using the following equation.

$$LCOH = \frac{C_{capex} + \sum_{t+1}^{LT} \frac{C_{O\&M,t} - R_t}{(1+d)^t}}{\sum_{t+1}^{LT} \frac{E_t}{(1+d)^t}} \left(\frac{\$}{MMBtu} \ or \ \frac{\$}{MWh}\right) \tag{1}$$

with d as the real discount rate (unitless), LT as the plant lifetime (years), and $C_{O\&M,t}$, E_t , and R_t as the O&M cost (M$/yr), energy production (kWh or MMBtu), and secondary combined heat and power revenue stream (M$/yr), in year t , respectively. In Eq. (1), $C_{O\&M,t}$ and R_t are not corrected for inflation; therefore, d is the real discount rate, and the levelized cost is calculated in constant dollars (Short et al., 1995). Alternatively, LCOH is calculated with a nominal discount rate and accounts for inflation-adjusted cost. No tax incentives are considered in this levelized cost model.

Table 3: Preliminary system cost estimates for geothermal DHS with storage tank and heating/cooling system

	Scenario 1 & 2 Heating System	*Scenario3 & 4 Heating & Cooling[1] System.*	*Reference*
Equipment			
Absorption Chiller (120 ton/h)	$0	$111,600	0.42 MWth (PS)
Absorption Chiller (400 ton/h)	$0	$372,000	1.41 MWth (SS)
Heat Exchanger	$500,000	$500,000	(Kim et al 2017)
Air Handlers	$65,000	$65,000	AirFixture
Fluid Surge Tanks	$132,000	$132,000	National Thank Outlet
Peaking Boiler[2]	$57,500	$57,500	(Beckers and Young, 2017)
Inlet Pump	$82,000	$82,000	National Pump Supply
Distribution Pipes[3]	$750,000	$750,000	(Beckers and Young, 2017)
System Connection Cost[4]	$500,000	$500,000	(Beckers and Young, 2017)
Cold Water Tank (150 m^3)	$0	$222,800	EconExpert (for chiller)
Subtotal ($)	**$2,086,500**	**$2,792,900**	
Engineering & Operations			
Field Installation	$625,950	$837,870	(Equipment) * 30%
Start-Up	$52,163	$69,823	(Equipment) * 2.5%
EPC Soft Costs[5]	$208,650	$279,290	(Equipment) * 10%
EPC Contingency[6]	$104,325	$139,645	(Equipment) * 5%
Subtotal EPC	**$991,088**	**$1,326,628**	
Subtotal System	**$3,077,588**	**$4,119,528**	
Geothermal Surface Equipment Cost[7]	$970,000 (↑ $1,210,000)	$970,000 (↑ $1,210,000)	(↑) $340k ESP cost per well, add one more ESP for scenarios 2 & 4
Total CAPEX	**$4,047,588**	**$5,089,528**	
OPEX (Annual)			
Geothermal System O&M	$97,000	$97,000	(Subsurface System) * 1%
Surface Equipment O&M	$93,000	$123,000	(Surface System) * 3%
Total OPEX (Annual)	**$190,000**	**$220,000**	

[1] Absorption cooling is only for two schools; PS: Primary School, SS: Secondary School.
[2] Peaking natural gas boiler cost is taken as $50/kW (Beckers and Young, 2017).
[3] Distribution pipe cost, including trenching, is $750/m from dGeo study (Beckers and Young, 2017). Insulated surface pipes can be cheaper,
[4] System connection cost is ~$2,000/SFH from dGeo study (Beckers and Young, 2017).
[5] Well repurposing costs, including well completion, permitting, landowner royalty fees, and other soft costs are covered under EPC soft costs.
[6] EPC contingency is set as 5% for LCOH calculations. It can be up to 30% for deployment of actual system.
[7] Geothermal surface system cost includes electric submersible pump (ESP) 2,280 V, 100 HP with a max flow rate of 5,000 bbl/day and geothermal brine gathering system.

LCOH values are calculated for both direct-use and district heating end-use options in GEOPHIRES. The direct-use option represents the value of heat as fuel and does not take surface DHS equipment cost into account (Table 4). LCOH values vary between \$5/MMBtu and \$10/MMBtu, which is comparable to annual average natural gas price delivered to industrial customers; this totaled ~\$8/MMBtu in 2022 (EIA, 2023).

Table 4: Summary of GEOPHIRES TEA model results in four production scenarios for direct use

Models	Scenario-1	Scenario-2	Scenario-3	Scenario-4
Average Direct-Use Heat Production (MW_{th})	1.9	1.2	1.1	2.3
LCOH (\$/MMBtu)	10	8	5	6
LCOH (\$/MWh)	34	27	17	20
Average Annual Geothermal Heat Production (GWh_{th}/yr)	12.97	8.25	7.85	15.81
Initial Reservoir Temperature (°C)	90.5	90.5	90.5	90.5
Initial Production Temperature (°C)	69.9	46.7	61.8	61.8
Maximum Production Temperature (°C)	75.6	54.7	70.3	67.1
Average Production Temperature (°C)	74.5	52.8	69.1	51.3

The district heating application option optimizes geothermal heat production based on the heating demand of the DHS (i.e., the simulation is limited within the given demand), and the LCOH represent the full DHS system (Table 5). LCOH values vary between \$27/MMBtu and \$62/MMBtu, which is comparable to annual average natural gas price delivered to residential customers; this totaled ~\$19/MMBtu in 2022 (EIA, 2023).

Table 5: Summary of GEOPHIRES TEA model results in four production scenarios for district heating

Models	Scenario-1	Scenario-2	Scenario-3	Scenario-4
Average Geothermal Heat Production (MW-th)	1.8	1.1	1.1	1.2
LCOH (\$/MMBtu)	62	58	28	31
LCOH (\$/MWh)	210	197	95	105
Average annual geothermal heat production (GWh-th/yr)	2.57	2.32	5.60	5.89
Average annual peaking fuel heat production (GWh-th/yr)	0.04	0.29	0.32	0.03
Initial Reservoir Temperature (°C)	90.5	90.5	90.5	90.5
Initial Production Temperature (°C)	68.3	43.8	61.1	60.1
Maximum Production Temperature (°C)	74.8	52.3	69.9	54.1
Average Production Temperature (°C)	73.7	50.7	68.6	52.2

TEA results indicated that:

- Scenario-1 has the highest annual average production temperature (~75°C), but the lowest utilization factor (~20%). The utilization factor can be increased to 33% by lowering the flow rate to 6.2 kg/s, or to 43% by keeping the flow rate at 9.3 and adding the absorption cooling load to the scenario, which would help make this scenario more feasible.
- Scenario-2 has low annual geothermal heat generation and the lowest production temperature (~47°C) due to fast thermal drawdown, resulting from a short distance between production wells in the quartet well configuration (~50 m).
- Scenario-3 gives the best results compared to the other three scenarios because it has the highest utilization factor (~71%) and lowest LCOH (~$28/MMBtu or $95/MWh), with ~69°C average production temperature. However, a 69°C production temperature is not high enough for absorption chiller application, thus a peaking boiler would be needed to boost the temperature to at least 75°C.
- Scenario-4 has the highest average geothermal heat production, but it is also impacted by thermal drawdown because of the short distance between production wells. Production temperature starts at 60°C and peaks at 65°C, and then gradually drops to 43°C during the first 15 years of production. This scenario also includes absorption cooling, but the production temperature is not suitable for that application.

4.3 Cost-Benefit Analysis

Figure 6 shows a comparison of the average annual geothermal heat generation and utilization factor via direct use and geothermal heat used in district heating systems. The utilization factor is the percent ratio of geothermal heat utilized by the district heating system divided by geothermal heat that can be extracted from the reservoir at a specified flow rate and well configuration. The highest utilization factor indicates better utilization of the resource for the specified district heating/cooling system. In this example, Scenario-3 has the highest utilization factor (Figure 6). In Scenario-3, geothermal heat can meet the heat demand up to 5.60 GWh/year and the peak hours summing up to 0.32 GWh/yr would be compensated by natural gas peaking boiler (Figure 7). In this case scenario, the utilization factor of the geothermal system would be as high as 71%.

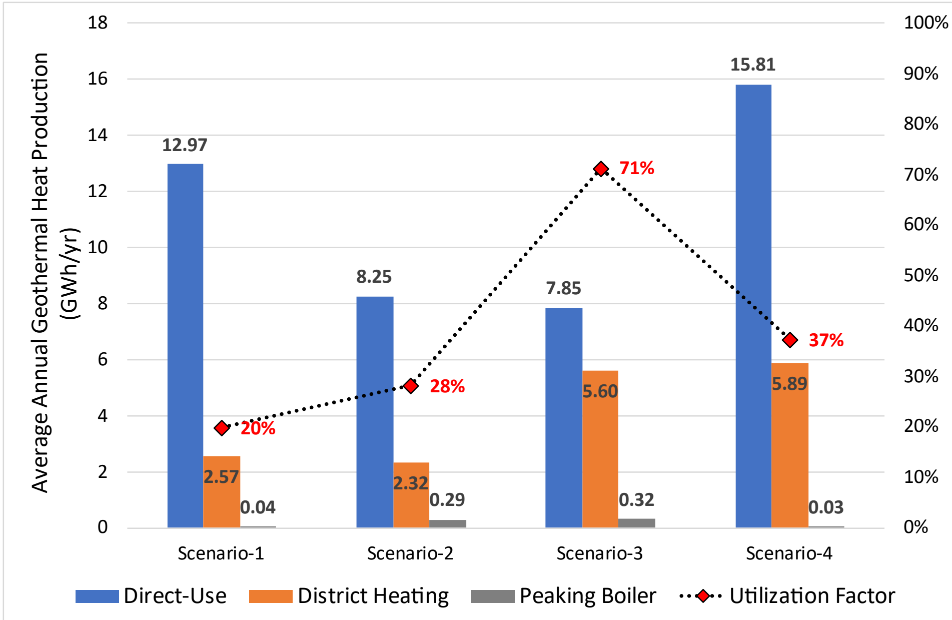

Figure 6: Comparison of average annual geothermal heat generation and utilization factor via direct use and geothermal heat used in district heating system.

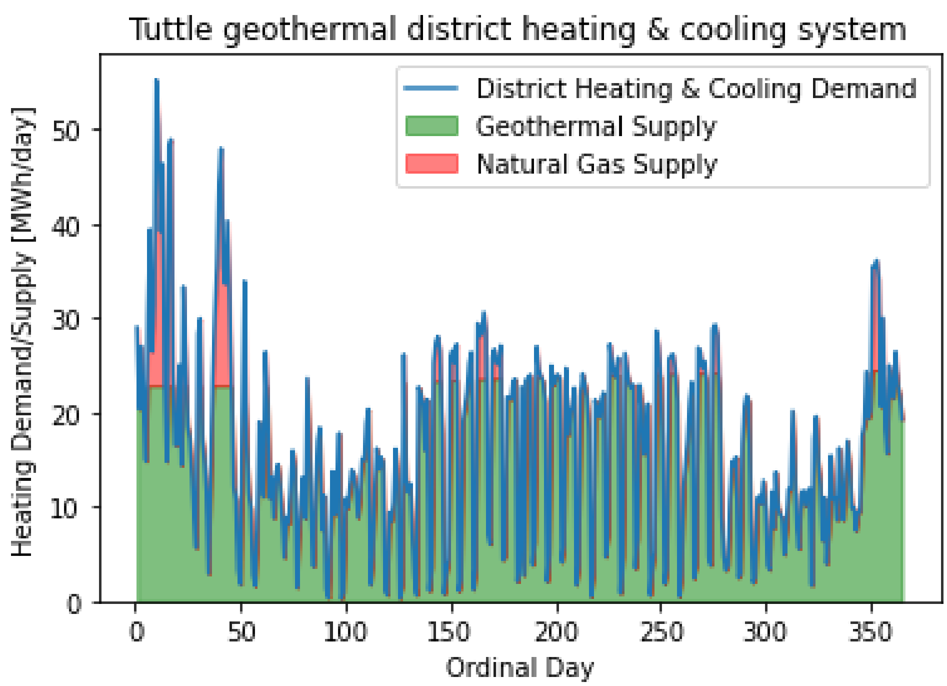

Figure 7: Daily geothermal heat supply and portion of natural gas boiler for peaking hours for Scenario-3 annual production at an average 1.1 MW_{th} capacity geothermal system (~26 MWh_{th}/day)

4. Conclusions and Discussions

NREL and the University of Oklahoma evaluated the feasibility of geothermal DDU for a district heating and cooling application in two schools and 250 houses by utilizing existing O&G wells in Tuttle, Oklahoma. Geothermal reservoir temperature was estimated as 90.5°C at a total depth of 3.3 km, assuming geothermal operation will be conducted closer to total depth. However, there are regulatory restrictions for utilization of the resource at a certain depth (~6,800 ft or 2,072 m) of the reservoir with a limited flow rate (~7,000 bbl/day or 9.3 kg/s) due to O&G coproduction and seismicity risk. For that reason, production temperatures between 65°C and 75°C would be more realistic. Repurposing existing O&G wells removed the drilling cost from CAPEX, thus lower LCOH values were expected when compared with other DDU projects. However, the LCOH values are at the high end when compared to other DDU projects. Scenario-3 gave the lowest LCOH (~$28/MMBtu or $95/MWh) and highest utilization rate (~71%) based on an average geothermal heat production capacity of 1.1 MW_{th}. However, the production temperature (~69°C) is not high enough for absorption chiller application, thus a peaking/additional boiler would be needed to boost the temperature to at least 75°C. Alternatively, Scenario-1 can be improved by lowering the flow rate to 6.2 kg/s or adding absorption cooling load to the scenario. This will increase the utilization factor of Scenario-1 to 33% and 43%, respectively. In the quartet well configuration (i.e., Scenario-4) with three production wells and one injection well 50 m and 270 m apart, production temperature starts at 60°C, peaks at 65°C, and then gradually drops to 43°C during the first 15 years of production. Thus, the doublet well configuration with one production well and one injection well separated by 540 m would help to minimize the temperature drawdown during 30 years of production. These results provide general ideas for pre-feasibility of a potential geothermal DHS through different production scenarios in Tuttle, Oklahoma. The LCOH values are at the high end when compared to other DDU projects. This can be lowered to a break-even LCOH ($19/MMBtu), equivalent to annual average natural gas price for residential customers in Oklahoma, by lowering down CAPEX by 30% and lowering OPEX by 25% (Figure 8).

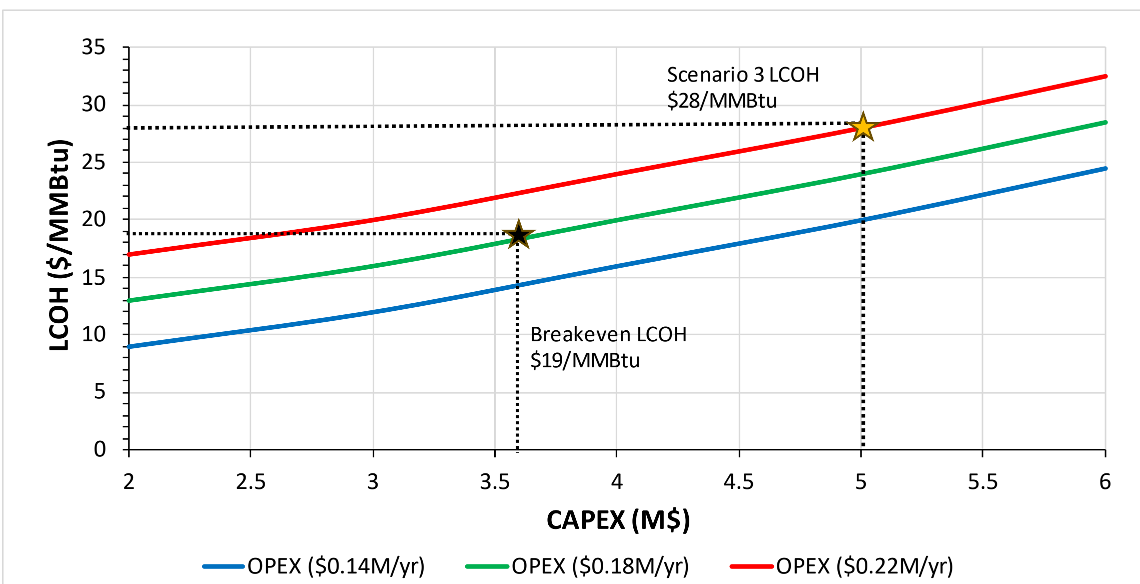

Figure 8: Sensitivity analysis for production Scenario-3 representing the impact of changes in CAPEX and OPEX to LCOH

Disclosure

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