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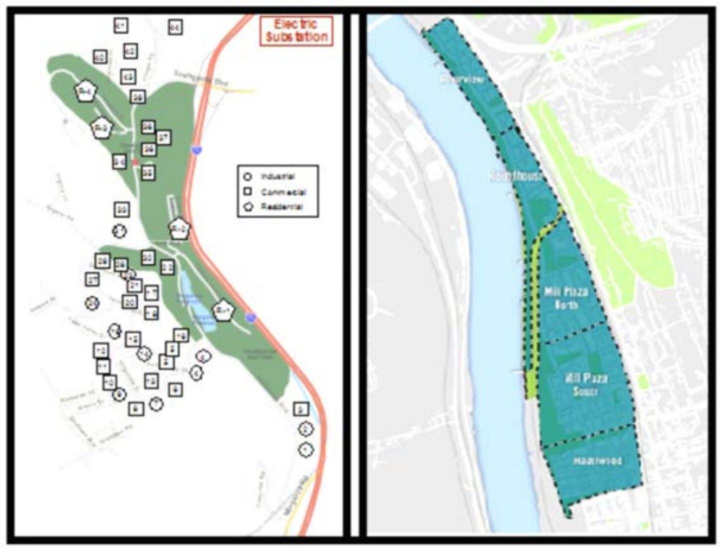

Southpointe Business Park and City of Pittsburgh's Almono District: Case Studies in Deep Direct Use of Geothermal Energy

25 February 2020

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Office of Fossil Energy

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Cover Illustration: Plan views of the Southpointe Business Park (left) and Almono Energy District (right), courtesy (TIAX, 2004) and (Regional Industrial Development Corporation (RIDC), 2015), respectively.

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Southpointe Business Park and City of Pittsburgh's Almono District: Case Studies in Deep Direct Use of Geothermal Energy

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Acronyms, Abbreviations, and Symbols

Term	Description
AHU	Hydronic air handling units
BTO	Building Technologies Office
DDU	Deep Direct Use
DHW	Domestic hot water
DOE	U.S. Department of Energy
EGS	Enhanced geothermal systems
GTO	Geothermal Technologies Office
LCOH	Levelized cost of heat
NETL	National Energy Technology Laboratory
NG	Natural gas
NREL	National Renewable Energy Laboratory
PDE	Partial differential equations
RIDC	Regional Industrial Development Corporation
SMU	Southern Methodist University
WVNG	West Virginia National Guard

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EXECUTIVE SUMMARY

Geothermal energy is a domestic energy resource that leverages the earth's heat to supply clean and renewable energy with a minimal environmental footprint. At present, this resource remains largely untapped due to high exploration costs, resource characterization uncertainty, and operational challenges.

The U.S. Department of Energy's (DOE) Geothermal Technologies Office (GTO) is working to reduce the costs and risk associated with developing geothermal resources through innovative technologies and systems analysis. One area of research is Deep Direct Use (DDU) geothermal energy (https://www.energy.gov/eere/geothermal/downloads/energy-department-explores-deep-direct-use), which employs lower temperature geothermal resources found at depths exceeding 1,000 meters for space heating and cooling in buildings. The potential resource is vast due to favorable resource conditions throughout the U.S. and the widespread need for heating and cooling buildings.

The National Energy Technology Laboratory (NETL) investigated the feasibility of developing deep geothermal resources for space heating for two Pittsburgh, Pennsylvania commercial development sites: a greenfield application, referred to as the Almono redevelopment district in the City of Pittsburgh; and a retrofit of an existing business park, known as the Southpointe Business Park, located near Canonsburg, Pennsylvania. Additionally, the use of a conventional natural gas-fueled heating system was also evaluated to understand comparative cost and performance differences between the "business as usual" case and the DDU system. In the application of DDU to both sites, several scenarios involving DDU system size, where the DDU system provided 70%, 91%, and 100% of heating requirements, were studied to better understand the sensitivity of DDU-based heating cost to this variable.

This work found that geothermal heat resources suitable for space heating (e.g., temperatures in the range 150–180°F) are expected to reside at depths between 9,000–14,000 ft for the two sites evaluated. While these depths are accessible technically and the resource was found to be adequate for 50-year project lifetimes, capital costs and project risks must be reduced to allow DDU heating systems to compete economically with conventional heating systems.[1]

Specific findings of this study include:

- The greenfield and retrofit DDU systems had similar levelized cost of heat (LCOH) - $86/MMBTU and $78/MMBTU, respectively. These cost estimates, while preliminary, are inclusive of all DDU system components and costs, both above and below ground.
- The greenfield application's geothermal solution was found to be substantially more competitive than the retrofit solution. In this greenfield study, the LCOH was 26% higher for the geothermal case than for the conventional natural gas-fueled system, whereas the geothermal case LCOH in the retrofit scenario was over four times higher as compared to

[1] The capital costs are primarily associated with drilling and the heat distribution system, while project risks are often associated with resource uncertainty in new areas of development.

the conventional system. These cost estimates assume 2018 natural gas prices, and the differences between the costs at the two locations primarily result from the fact that in the analysis of the Southpointe retrofit, the NG pipeline already existed and therefore was "pre-paid."

- Capital costs drive the LCOH for a DDU system: approximately 90% of the LCOH comes from capital-related costs in the greenfield system, compared to 80% in the retrofit scenario. By comparison, the capital costs for the conventional, in-building forced-air solutions burning NG constituted 78% and 8% of the LCOH for the greenfield and retrofit scenarios, respectively.

From these findings, it is observed that to lower the cost of accessing geothermal energy in the eastern United States, developers must lower the costs of drilling and distribution systems, which comprise most of the capital costs. Similarly, the greatest project risk for DDU systems occurs during the drilling phase, where significant project costs are incurred, and resource viability remains unknown. Work to reduce these risks and costs would allow DDU heating systems to better compete with conventional heating systems. Additional opportunities to improve the economic competitiveness are described below and warrant further study.

While the results reported here represent only a preliminary assessment to determine feasibility and rough estimates for the cost of using deep geothermal heat for space heating, the results provide valuable information on current development opportunities and areas of research and development that can reduce costs and project risks. Prior to pursing a geothermal energy solution at either of these two sites, NETL expects additional analyses would be done to more accurately assess resource availability along with true project costs and feasibility. This would likely involve performing more detailed modeling of a potential geothermal energy site, drilling a test well to help reduce project risk, or evaluating other technology and configuration options such as "enhanced geothermal systems (EGS)," heat pumps, subsurface heat storage, space cooling, or the potential for production of electricity.

Sensitivity Scenarios

A number of opportunities exist to optimize DDU systems to both reduce cost and generally improve competitiveness. While some of these opportunities will be broadly applicable to all DDU systems, others may be specific to a climactic region, load profile, or system application (e.g., space heating for a building, thermal-storage enabled systems, hybrid systems, etc.).

Two of these opportunities for cost reduction were evaluated as part of this study, including re-sizing the geothermal system to meet only a portion of the annual heating load (with a conventional system for peak loads) and the use of higher-efficiency or lower-temperature space heating technologies in combination with optimized geothermal wells. The results of those investigations are detailed below, as is a comparison to another commercially available geothermal space heating and cooling system. Other opportunities, notably "EGS," heat pumps, subsurface heat storage, or the potential for production of electricity, to name a few, were not investigated in the sensitivity studies but may warrant further study.

The two investigations in this study focused on ways to reduce the well size and depth (and hence cost) by lowering the peak energy required from the geothermal source. First, the use of high-efficiency, low-temperature HVAC systems, such as hydronic in-floor heating was evaluated to reduce feedwater temperature requirements and to increase thermal mass in the buildings. Early in the study these systems were found to incur relatively high capital costs, resulting in a LCOH roughly three times the LCOH of conventional forced-air HVAC building systems burning natural gas.

Second, smaller DDU systems were evaluated to determine the impact of system size on LCOH. In this scenario, two cases were evaluated where the DDU systems served as a majority of the site heating demand, either 70% or 91%, and a natural gas-fired system was used to meet the peak loads. This investigation found that:

- LCOH was relatively inelastic to system size in cases where the natural gas backup system receives a certain level of utilization. Notably, the LCOH for the 70% case was nearly the same as the 100% heating demand case for both cases: $78/MMBTU for the greenfield 70 % and 100% cases; and essentially the same in the retrofit cases: $88/MMBTU for the 70% case versus $86/MMBTU for the 100% case. This suggests that for both retrofit and greenfield scenarios residing within the same environmental region, both will have the same DDU cost comparisons across different fractional DDU heat solutions.
- However, substantial price increases were seen in the 91% cases: to $115 and $134 per MMBTU for the greenfield and retrofit cases respectively. The results also suggest that the additional cost of installing a peaking system (due to its infrequent use) will not be warranted from an economic viewpoint over the range of fractional DDU supply analyzed here (70% to 100%). That is, it appears that a DDU system can be designed to meet peak needs at close to the same or less cost as a system using a smaller DDU system that employs an NG boiler for meeting infrequent peaking needs.

Finally, the DDU system cost was compared to another type of geothermal energy system, a ground-sourced geothermal heat pump (GSHP), at the greenfield site. In this scenario, cost and performance data from a prior analysis conducted for the greenfield site was leveraged, where circa 500 shallow wells would be installed for using ground-sourced geothermal heat pumps. In this scenario it was found that the GSHP was likely to be only about 15% less costly than using a DDU approach as investigated here (considering only space heating needs). Given that geothermal heat pump systems are now common and the technology far more mature than DDU geothermal systems, one can expect the learning curve is greater for DDU, which means the cost of DDU has a strong potential for further reduction. It also suggests that DDU demonstration projects should be considered to help further mature the DDU technology and options. Doing so, along with efforts to reduce the cost of drilling DDU systems, should make DDU technology economically viable and a worthy option to consider over much of the eastern United States.

NETL is actively looking for funding opportunities and is open to collaborating with external organizations on further research and deployment projects for DDU systems.

1. INTRODUCTION

Direct use of geothermal energy has been ongoing for some time, but within the United States, use has been mainly in the western states (Lienau et al., 1994). Recently, the U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) was funded by DOE's Geothermal Technologies Office (GTO) to further assess the potential for direct use of geothermal energy from deep sources in the eastern United States. Studies by Cornell University (Reber, 2014) show that there are numerous locations throughout Pennsylvania and New York where Deep Direct Use (DDU) of geothermal energy may be viable (Figure 1). As evident in their report, one notable candidate is the area of Pittsburgh. They show that the geothermal resource and regional thermal energy demands align well to possibly offer low Levelized Cost of Heat (LCOH = $20/MMBTU) that is comparable to current residential costs using NG furnaces/boilers—when not including natural gas (NG) pipeline distribution costs. However, the report also shows a wide range of results, where some points in the Pittsburgh area show as high as > $52/MMBTU, which suggests that more detailed studies be pursued for given cases of interest.

One specific study recently conducted as part of the above-mentioned GTO-sponsored work as well as NETL's Fossil Energy Program, was a study to assess the on-site resource potential and options for use of both geothermal energy and NG at a West Virginia National Guard (WVNG) training site in West Virginia called Camp Dawson (Means et al., 2017). The study showed potential for DDU utilization for Camp Dawson having a lifetime of well over 60 years. Guard officials are now considering pursuing more detailed analyses. To further assess the potential for DDU resources in the eastern United States, NETL has recommended that two additional case studies be conducted: 1) DDU within the Southpointe Business Park; and 2) DDU within the City of Pittsburgh. The study within the City of Pittsburgh will support the goals of a Memorandum of Understanding signed between NETL and the City of Pittsburgh to "provide Pittsburgh with socially responsible, clean, reliable, and resilient energy generation and distribution."

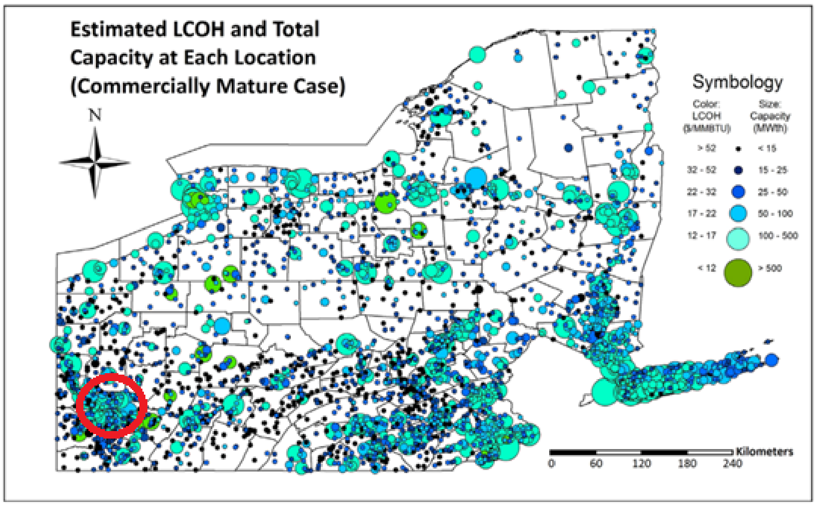

Figure 1: Levelized cost of heating in Pennsylvania and New York (Reber, 2014). The chart shows the Pittsburgh area (red circle) to have great potential for deep direct use of geothermal energy, but the wide range of conditions (>$52/MMBTU to $12/MMBTU) show that site-specific conditions require their own close assessment.

In general, DDU applications of geothermal energy lend themselves to large, commercial operations that optimize the value stream of lower temperature resources through a cascade of uses, from electricity generation to direct heating and cooling, industrial and commercial applications, and agricultural uses (Anderson, 2015). Western states within the United States have notably higher-temperature geothermal resources, and those resources tend to be more readily accessible (less deep) compared to those in eastern states; however, even in the East, certain regions have sufficient temperature gradients to support direct use in such applications as space heating and process heating. Further, district heating infrastructure in many places across the states needs upgrading, so there is an opportunity to transition from NG to geothermal energy as part of those upgrades.

The basic application of deep geothermal energy (whether to serve in power generation or for directly meeting heating/cooling needs) is well developed and understood. For space heating of buildings, a system of heat exchangers, pumps, and controllers is used for managing water flow and heat transfer between one or more deep wells and the hydronic heating systems inside the buildings. Current industry drilling capabilities allow access to geothermal resources at considerable depths—wells as deep as 20,000 ft have been drilled to date—and those resources can be further engineered to optimize flow rates and temperatures via such methods as directional drilling and resource fracturing. However, given present industry capabilities and understanding on specific resource targets, the design and ultimate technical and economic viability of a given project is not 100 percent understood until after well drilling and flow testing are performed. As a result, the primary risks and costs of implementing deep geothermal energy currently involve below-ground issues such as knowing the exact depth of resource to access/drill, as well as resource strata geography and its structural and material properties.

Given the state of industry capability and understanding, costs for DDU applications can be high, especially within the eastern United States. In the eastern United States, to get acceptable DDU temperatures for purposes of space heating (often > 180°F depending on demand and supply characteristics), well depths of 10,000 ft or deeper may be required. At these depths, single-well drilling costs alone can reach $5 million (Lukawski et al., 2014) or more. Depending on the configuration of the well, well completion, well testing, and other well related costs, an exploratory well may cost as much as $10 million. Hence, for a typical doublet system, the total well costs alone can reach circa $16 million–$20 million. For systems requiring well-laterals to improve access to the thermal energy in the formation, there is an additional cost. To justify this level of capital investment, the lifetime costs of the geothermal system would need to be the same or lower than that of alternative heating methods, such as NG boiler systems. As an example, with current commercial NG costs of $9.65/MMBTU (EIA, 2017) the available geothermal energy would need to be on the order of 2.5×10^{15}J (2.4×10^{6} MMBTU) just to offset well costs. Hence, for payback on the cost of the geothermal wells alone, approximately 60 years of thermal energy supply will be required for the *entire* Almono or Southpointe sites.

This study offers a documented assessment of the opportunity for direct use within the Pittsburgh area, technical challenges that require further research, and potential barriers to development. In the next section, an overview of the two sites studied here is given—Southpointe Business Park (often simply referred to as "Southpointe" in this report) and Almono. The section then reviews two methods for potentially reducing the cost of DDU—employing auxiliary heat for helping with peak loads and building thermal mass. Section 3 is devoted to assessing the geothermal resources at the two sites and providing estimates for the temperatures at various depths. Section 4 provides a detailed analysis of the application of DDU heat for meeting the heating needs for about half of the Southpointe site and estimates the cost for providing such a solution to Southpointe. Section 5 performs the same level of study, but for the full Almono[2] site. And finally, Section 6 provides a summary of the entire study and proposes potential next steps for consideration by Southpointe and Almono developers.

[2] Toward the end of this study, the development plans changed along with the development name, which is now Hazelwood Green. While detailed plans for the new development are still in development, it is assumed for this study that overall energy loads, especially for heating, will remain similar as both prior and current expectations are to employ high-performance buildings. Hence, while the exact results from the Almono case study will now be different from current development plans, the authors expect that through appropriate extension, the results here could apply to the new development as well.

2. OVERVIEW OF PROJECT SITES

As noted in the introduction, the purpose of this study is to help assess the potential for DDU geothermal energy in the eastern United States. Toward that end, the following two case studies were conducted: 1) DDU within the Southpointe Business Park; and 2) DDU within the City of Pittsburgh at the Almono redevelopment district. While the study will directly apply to both these sites, it is expected that it can also serve as a representative analysis for many other sites in the eastern United States; and given the relatively lower thermal gradients determined for the present two locations, it is expected that other sites will likely have improved economics over what has been determined here.

2.1 SOUTHPOINTE BUSINESS PARK

The development of Southpointe as a business park dates to the 1980s, and the first industrial and commercial buildings were completed in 1993 (Pittsburgh Post-Gazette, 2013). It spans approximately 800 acres and hosts several major resource-holding companies, such as Range Resources, Chesapeake Energy, Consolidated Natural Gas, Noble Energy, Rice Energy, and Columbia Gas. Figure 2 shows the layout of the Southpointe community, which surrounds a golf course.

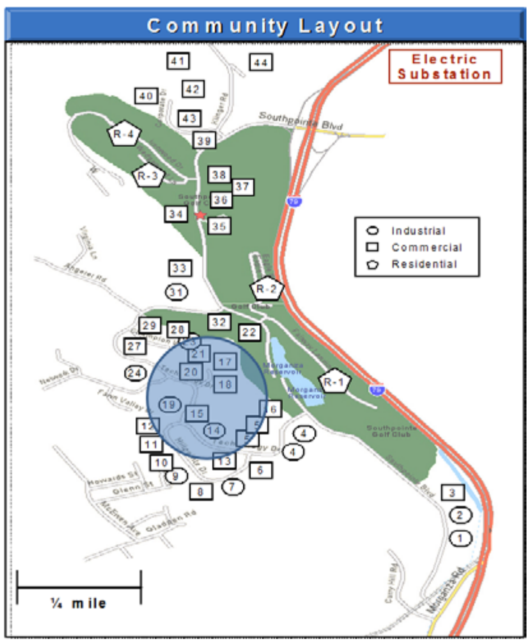

Figure 2: Southpointe community (TIAX, 2004). The blue circle denotes the targeted portion of the site being used for this study. See Section 4.

There are approximately 70 commercial and small industrial businesses (TIAX, 2004) located in mostly "medium-sized" office buildings (ca. 50,000 ft^2 (Katipamula, 2012)):

- Commercial buildings
  - 9 large office buildings, ~1 million ft^2 total, 1,200 employed
  - 13 medium office buildings, ~550,000 ft^2, 1,300 employed
  - 11 small office buildings, ~200,000 ft^2, 300 employed
  - 1 hotel, 135,000 ft^2, 100 employed

  - 3 public assembly buildings, 128,000 ft^2, 200 employed
- Industries, 9 companies
  - Printing, fabricated metal products, surgical equipment manufacturers, office equipment manufacturers
  - ~ 450,000 ft^2 total, 800 people employed
- Residences
  - 40 single-family homes, 1,700 ft^2 per home
  - 79 townhouses, 1,000 ft^2 per home
  - Luxury apartments, 120,000 ft^2 total

The community has a summer peak electric load of 12.4 MW and a winter peak of 7.6 MW. Base-load power consumption is 2.4 MW. Sixty-six percent of the community's 46 GWh annual electricity consumption is consumed by commercial buildings (mostly office buildings), 31 percent by light industry, and 3 percent by residential buildings. Figure 3 shows the NETL-simulated hourly profiles for electricity use and daily profiles for gas use for one year (2003), as used in the TIAX report. During the summer months, electric demand is greatest and has its greatest short-term (week to week) variability, while during the winter, gas consumption (mainly for heating) has a peak (ca. 1,200 MMBTU/day (15 MW) in January), along with its greatest week-to-week variability. Total gas use through the year was estimated to be ca. 41,000 MMBTU (12 million kW-hr). It is the primary goal of this study to determine how geothermal energy can best meet all or a portion of this variable heat load.

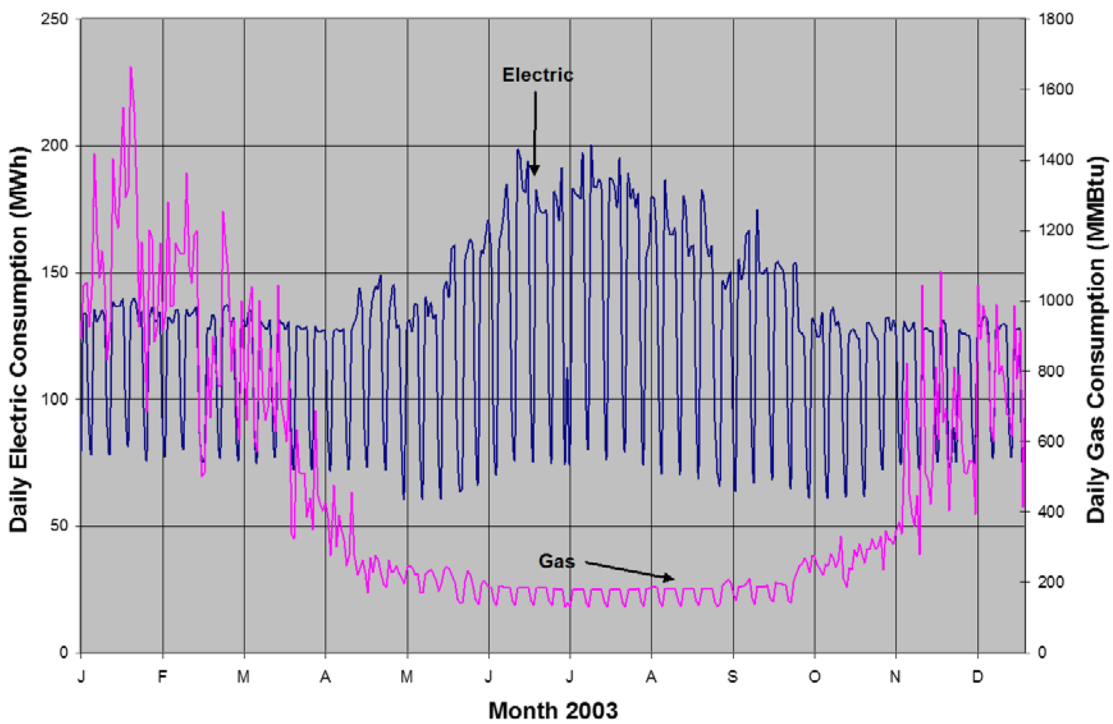

Figure 3: Daily electric and gas consumptions in 2003. (Simulated loads—see TIAX (2004)).

2.2 CITY OF PITTSBURGH - ALMONO

At the beginning of this study, Almono was one of seven energy districts within the City of Pittsburgh. It was in early-stage development with a goal of providing mixed-use space for residential, light industrial and commercial uses over a 178-acre riverfront region (City of Pittsburgh, 2016) previously used to support the local steelmaking industry. The planning documents (Regional Industrial Development Corporation (RIDC), 2015) call for five distinct neighborhoods within Almono (Figure 4) with their own features, mix of uses and population density.

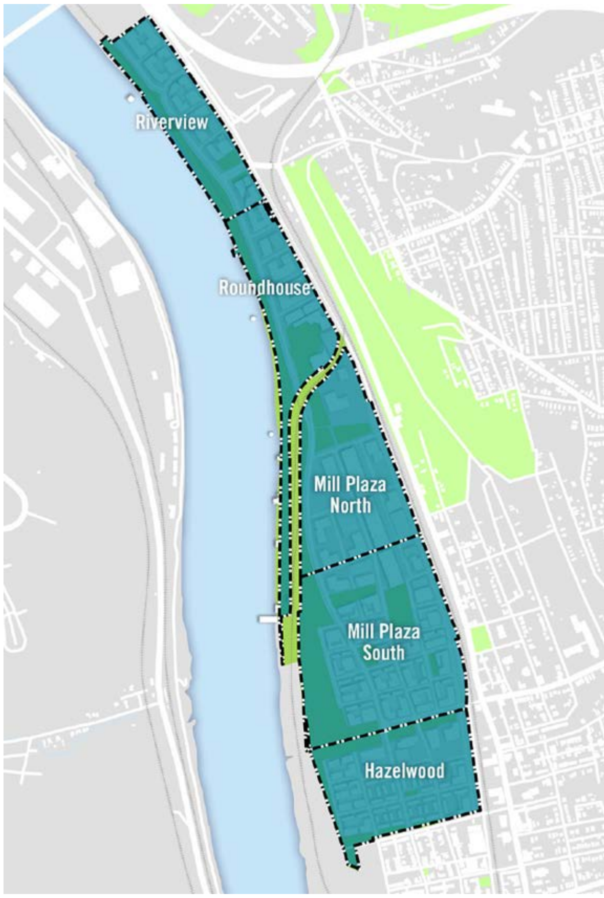

Figure 4: Almono neighborhoods—Riverview, Roundhouse, Mill Plaza North, Mill Plaza South, Hazelwood (RIDC, 2015). Also see: https://www.rdcollab.com/sketchbooks/almono/.

Almono Development Phases

There are four major phases to the development, beginning with the Mill Plaza district, which is associated with the repurposed historic Mill 19 to support retail activity. Hazelwood will follow as Phase 2, followed by higher-density Roundhouse and Riverview districts. Various building controls are planned to support residential development with a population density of 20,000 people per square mile. The plan calls for a variety of housing typologies and sizes (townhomes in low-rise and high-rise formats, affordable/market-rate condominiums, etc.); energy efficiency, including envelope heat recovery and other high-efficiency building methods to limit both energy intensity and water-use intensity; off-site wind power and on-site photovoltaic energy systems, green-gas for cooking, and shallow geothermal heat-pump systems for heating and cooling. The currently planned geothermal heat-pump system, Figure 5, is comprised of 300 wells, each 500 ft deep, and includes integration with river thermal energy (i.e., energy storage/thermal energy recharge in summer). In 2016, the developer's estimated costs for this system were $3.8 million for the district loop costs (likely to be higher in this estimation), $28 million to develop the geothermal field, and $2.8 million for metering = $34.6 million total (Johnson, 2016).

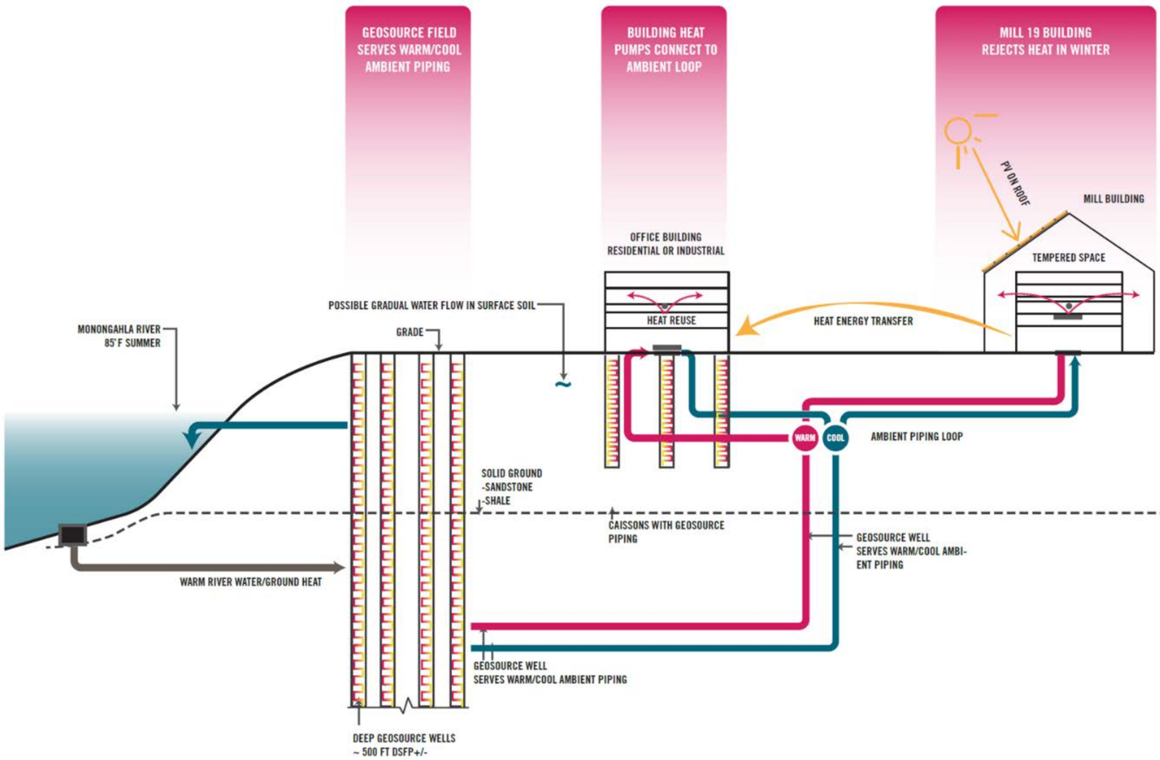

Figure 5: Schematic of the planned shallow geothermal heat pump system (RIDC, 2015).

Current planning documents call for the total square footage of conditioned space to be 6,369,541 ft^2. The residential and non-residential thermal demand loads are given as follows:

- Residential thermal demand
  - Annual space heating thermal load = 5,607,591 kWh
  - Annual space cooling thermal load = 4,125,124 kWh
  - Annual domestic hot water (DHW) thermal load = 2,341,867 kWh
- Non-residential thermal load demand
  - Annual space heating thermal load = 5,405,265 kWh
  - Annual space cooling thermal load = 5,165,007 kWh
  - Annual DHW thermal load = 3,736,836 kWh

The total thermal load for Almono (11 million kWh) is about the same as that of the entire Southpointe Business Park, making both roughly comparable in terms of overall load size. The site area (which defines the amount of available deep geothermal energy) is much larger for Southpointe, which allows a longer resource lifetime for Southpointe. Finally, it can also be expected that the climate conditions are largely the same at the two sites, and, as a result, the annual load variations such as given in Figure 3 for Southpointe will be similar.

2.3 STRATEGIES TO MINIMIZE GEOTHERMAL DDU SYSTEM SIZE AND COST

As shown above in Figure 3, supplying the thermal demands throughout the year will mean sizing the system to deliver energy for peak demand rates. A reduction in the size of the geothermal system (such as well diameters, pipe diameters and heat exchangers) can be obtained, along with a respective reduction in overall system cost, by limiting the peak capacity of the geothermal system. This can be achieved by adding an **auxiliary heat supply** (e.g., electrical backup heat or NG-fueled boilers) within the building system so that a portion of the instantaneous heat demand can be met with such alternative supply (see Figure 6). Additionally, internal building **thermal storage** (e.g., radiant floor systems using thick concrete floors to hold thermal energy) can be used advantageously to smooth the short-term fluctuations in demand such that low-temperature hydronic heating systems can better meet the demand. And finally, perhaps equally effective as thermal mass is on a single building through district-style agglomeration of independently controlled buildings, hourly load fluctuations can be smoothed but will still reflect daily and weekly demand variations driven by fluctuations in the environmental temperature, wind, etc.

Using Auxiliary Heating for Peaking

Figure 7 shows EnergyPlus™ modeled hourly heating rates during a year for a system of five medium-sized buildings using Pittsburgh-area weather data, and so has relevancy to both Southpointe and Almono applications. Details on the use of EnergyPlus™ for Southpointe are given in Section 4. Figure 8 shows the probability distribution of those hourly heating rates. Ninety percent of all hourly heating rates occur at less than 1.25E+9 J/hr or 1.19 MMBTU/hr (green arrows on chart), which is about 25% of the peak demand of 5E+9 J/hr, or 4.7 MMBTU/hr. For a geothermal heating sub-system designed having a range of heating capacity from 0 to 2.5E+9 J/hr, i.e., up to 50% of peak, 85% of the total annual heat energy requirement (total joule energy) will be met (if it is operated **only** to meet the hourly heat rate demand **below** 2.5E+9 J/hr) as shown in Figure 9. For heat rate demands above 2.5E+9 J/hr, an infrequent but significant load requirement must be met (i.e., the remaining 15% of annual energy). To meet this upper-end heat rate demand, the geothermal sub-system can be operated at its full capacity, thereby meeting up to 2.5E+9 J/hr of the heat rate demand, with the balance above 2.5E+9 J/hr met using a suitably sized auxiliary heating system. For this scenario, the geothermal system would cover not only the 85% of annual demand that occurs below 2.5E+9 J/hr, but also a sizeable portion of the annual demand occurring at the upper end. In fact, most of the upper-end demand occurs near 2.5E+9 J/hr, and analysis shows that the geothermal system will in fact cover as much as 97% of the total annual heat energy requirement for the site. It is possible then to design a geothermal system that can operate to serve well over half the annual heat energy requirements of a building or buildings and run nearly constant with a more limited turndown (0 to 50% of the peak heat rate), while letting a conventional auxiliary system (e.g., electrical heating) support the much less frequently occurring 50% to 100% heat rate (J/hr) needs. If the geothermal system is sized to meet 0 to 25% of peak heat rate demand, further capital cost reductions can occur, and more of the annual load can be supported by the currently lower cost auxiliary heating system. Doing so will allow the geothermal energy resource lifetime to be extended as well. The result of such a strategy is shown in Figure 7 (orange profile) where the geothermal source provides the building demand up to 25% of peak. Such an approach is applicable to "small building districts," where smoothing of the peaks due to random loads imposed on the system by independently operated buildings is not effective; this has been recommended by others pursuing the direct use of geothermal energy (Lund, 2015).

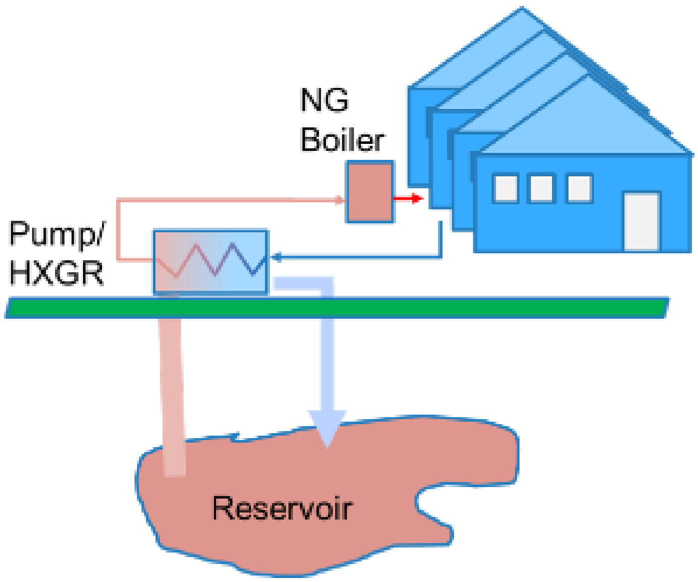

Figure 6: DDU heat supply to buildings with NG boiler auxiliary heat system.

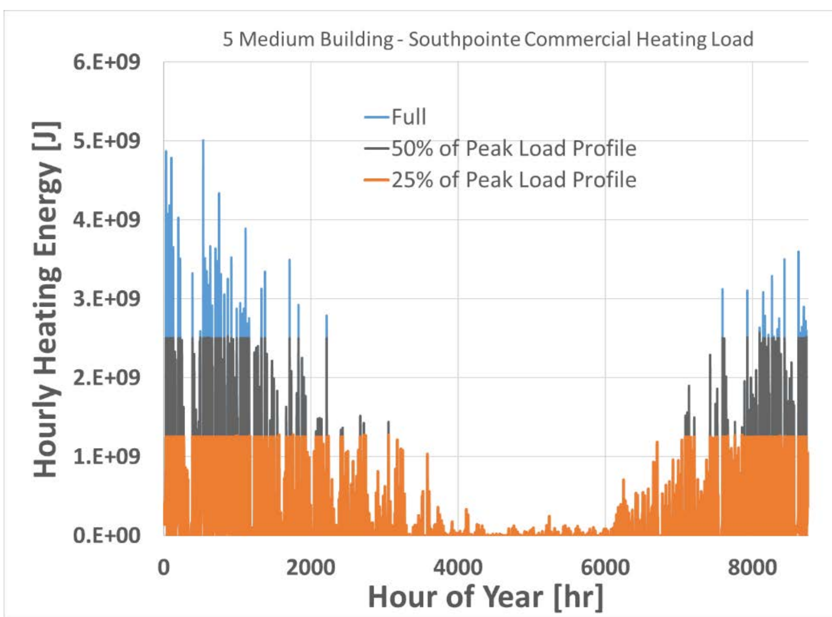

Figure 7: Modeled five medium-sized building annual heat demand (joule of heat over given hour of the year). Blue profile spans full range of demand. Black profile clips geothermal load at 50% of peak. Orange profile clips geothermal load at 25% of peak.

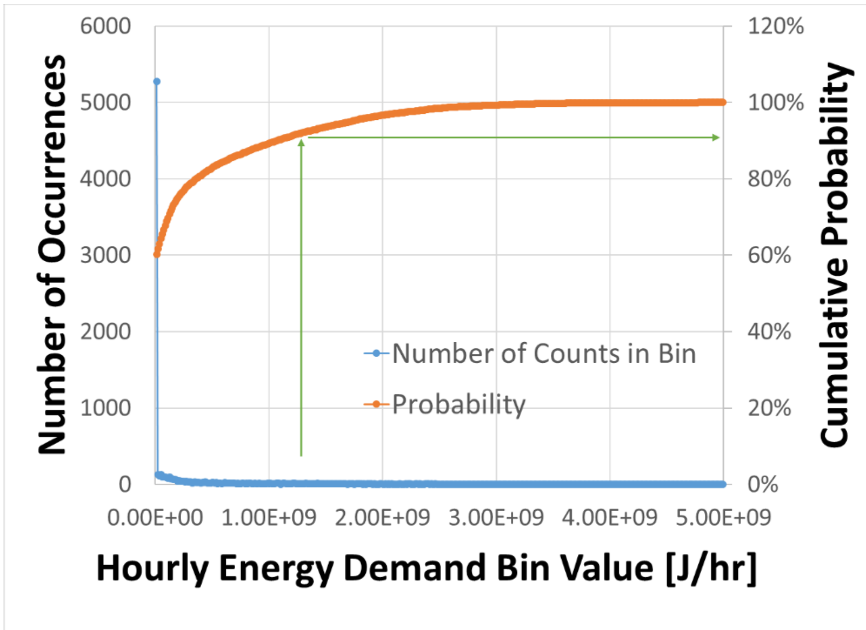

Figure 8: Distribution of heat rate demands for full profile in Figure 7. The most frequently occurring heat rate demands (in J/hr) are at the lower end of the demand range, with over 90% of the heat rate demands occurring below 1.25E+9 J/hr (25% of peak).

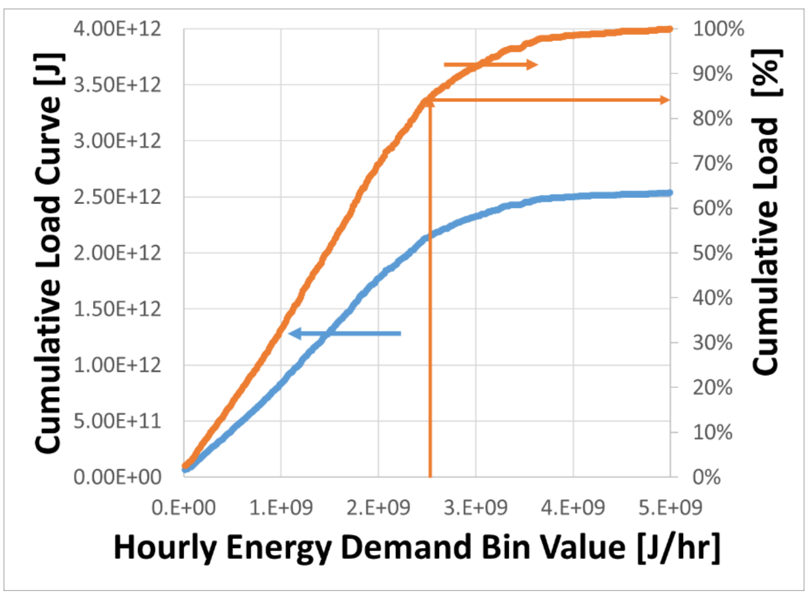

Figure 9: Cumulative heat energy demand for full annual profile in Figure 7. Over 85% of the entire annual demand occurs with hourly heating rates below 2.5E+9 J/hr (50% of peak).

Using Within-Building Thermal Mass

Figure 10 shows the results of a modeled medium-sized building where heat loss to the environment occurs with a cycle controlled by a 20ºF diurnal environmental temperature variation—a common temperature swing for month of January in the Pittsburgh region. A 3-inch thick radiative concrete floor was assumed for the building's heat distribution system. The model was calibrated to provide the same average daily heat loss as that given by EnergyPlus™ for a medium-sized office building given a Pittsburgh climate. As shown in Figure 10, there is a 13% reduced peak heating capacity needed by the geothermal system relative to that of the instantaneous building heat demand (loss) to the environment. The balance is, of course, being met by the thermal mass within the building, which is charged during the warmer (lower heat loss) portions of the day. The lowered peak heating capacity needed by the geothermal system will mean a smaller-sized system can be used, which implies a lower overall capital and operational (maintenance) cost.

Finally, it is also well known that to the extent that a large number of buildings operating with independent HVAC control systems are supplied through DDU application (e.g., as a district-managed system), the statistical nature of their independent action will result in a smoothing of the load, as illustrated in Figure 7, such that while the total annual demand increases proportionally to the number of buildings, the peak load on the district heating system will increase by some factor less than the number of buildings. Given an expected minimum of 40 buildings to be served for Southpointe (and even more for Almono given the assumption of high-efficiency construction), this additional smoothing that results from independent HVAC control will be considered effective for this analysis when sizing and costing the proposed system components.

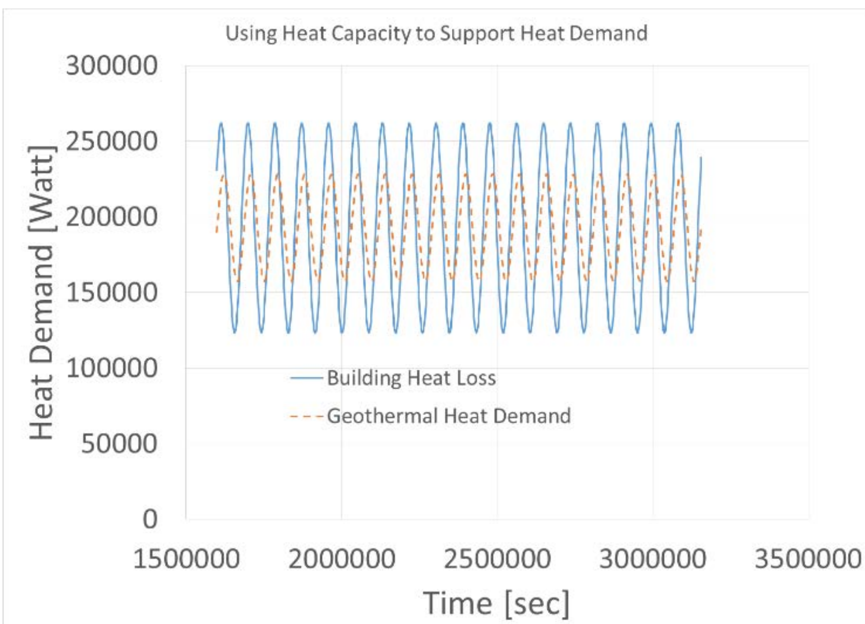

Figure 10: Medium-sized building heat demand—use of building heat capacity ("thermal mass"). Model results show that the peak geothermal heat demand requirement can be reduced relative to the building's instantaneous heat demand through use of the building's heat capacity (thermal mass). Here, 13% lower geothermal peak capacity is needed relative to the building's instantaneous demand requirement. Hence, a smaller (less expensive) system size can be used.

2.4 DISTRICT HEATING DESIGN FOR SOUTHPOINTE AND ALMONO

The conceptual design shown in Figure 6 is assumed for supplying heat to a group (district) of buildings in both the Southpointe and Almono studies. The basic piping layout for the above-ground district heat distribution is shown in Figure 11.

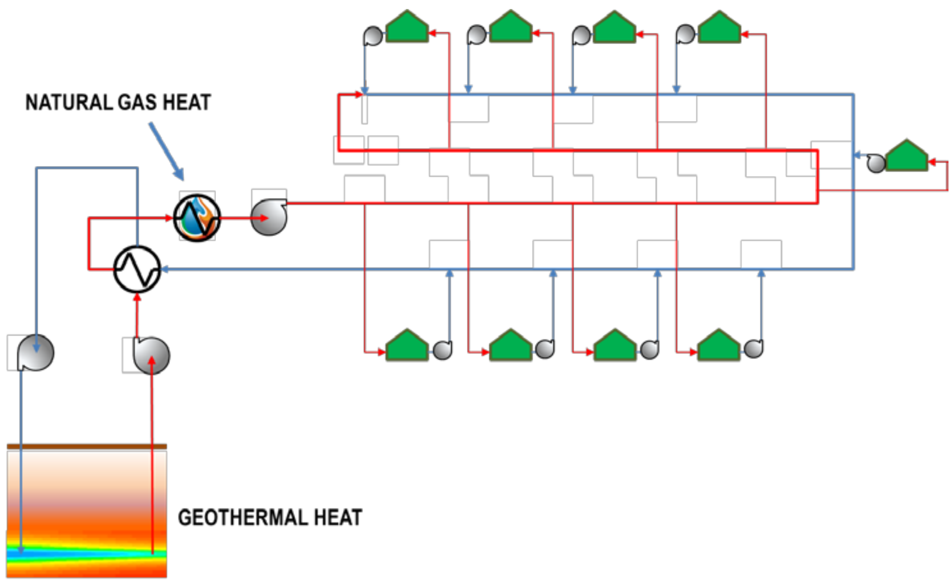

Figure 11: District piping scheme where central NG boiler is used to meet peak heating needs. District buildings pull off needed flow rate from district loop to meet their specific heat demand.

Heat from the geothermal resource is pumped to an above-ground heat exchanger that provides the DDU heat to a district hydronic loop delivering geothermal heat to all buildings. Within each building, the design employs a hydronic-to-air heat exchanger, which then allows heated air to circulate through the buildings. To help manage load variations and to reduce the size of the below-ground system (thereby reducing the overall levelized cost of heat from this design), auxiliary NG heating unit(s) (as shown in Figure 6) assist in heating the hydronic loop water during peak heat demand. Hydronic air handling units (AHU) for Southpointe and Almono have specifications shown in Table 1. The Southpointe assessment assumed a heating system retrofit for the buildings. Therefore, the hydronic-to-air heat exchangers were specified to heat rooms using a relatively high-temperature airflow compared to those specified in high-efficiency new builds seen today. This required a higher water-inlet temperature for the Southpointe air heaters than for the Almono air heaters—160º F versus 120º F, respectively. These temperatures are the minimum needed to operate each system effectively.

Table 1: In-Building Air Handling Unit Requirements

	Air Flow	Exiting Air Temperature	Water Flow	Water Temperature at Inlet	Water Temperature at Outlet
	[m^3/min]	[°C]	[lpm]	[°C]	[°C]
Southpointe	17	58	8	71	47
Almono	17	43	11	49	40

Note. *Other design options for managing building heating are available as well, and one high-efficiency system considered early in this study was the use of hydronic in-floor heating systems. Such an approach, which allows lower-temperature heat to be delivered efficiently into the building, offers high system efficiency and the use of lower temperature resources (i.e., either less depth for the wells or smaller well diameters and hence lower drilling costs), but the capital cost (see Section 4.3) of such building hydronic systems were found to be more expensive. For this reason, this approach was not reported in detail in this report.*

3. GEOTHERMAL RESOURCE ASSESSMENT FOR SOUTHPOINTE AND ALMONO

3.1 OVERVIEW OF THE GEOLOGICAL STRUCTURE AND SEDIMENTARY ROCK STRATA NEAR SOUTHPOINTE AND THE CITY OF PITTSBURGH'S ALMONO DISTRICT

Both the Southpointe and Almono study areas lie with the Appalachian Basin, just outside the western extent of the northeast-to-southwest-trending Rome Trough (Figure 12), which is a very broad down-dropped region bound by normal faults that extend down into the granitic and metamorphic rock of the Earth's crust (the "basement"). The shallower strata consist of a thick sequence of sedimentary rock layers, containing mostly shales, sandstones, limestones, and dolomites. Locally, these strata dip gently to the southeast. To the east of Southpointe and Almono, the sedimentary strata dip more steeply and are slightly more folded within the Rome Trough. To the west of both sites, the strata are less folded. Maximum sediment thickness in this part of the basin is 14,000 to 16,000 ft (Figure 13).

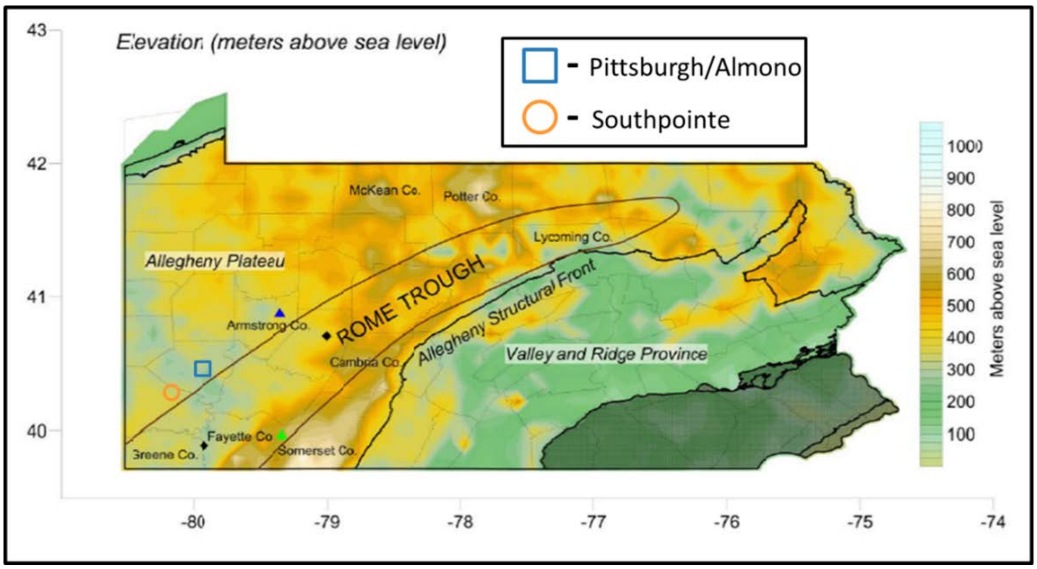

Figure 12: Elevation map in meters (Shope et al., 2012) showing the approximate locations of Pittsburgh and Southpointe relative to the locations of the major geologic provinces in Pennsylvania.

A geologic cross section (Figure 13) shows the various names, approximate depths and thicknesses, and general structure of the rock layers beneath Southpointe and Almono. The subsurface structure beneath both sites is relatively simple down to basement rock (Figure 14), as there is one normal basement fault extending up into the Gatesburg Formation beneath a gentle syncline structure. Figure 15 displays a map of basement faults and folds within the vicinity of both sites, where the nearby syncline structures can be seen. To reduce uncertainty about the subsurface structures beneath both study areas, an interpreted seismic survey should be acquired by geothermal developers to help identify and predict folds, faults, directions of open natural fractures, and zones of more intense fracturing.

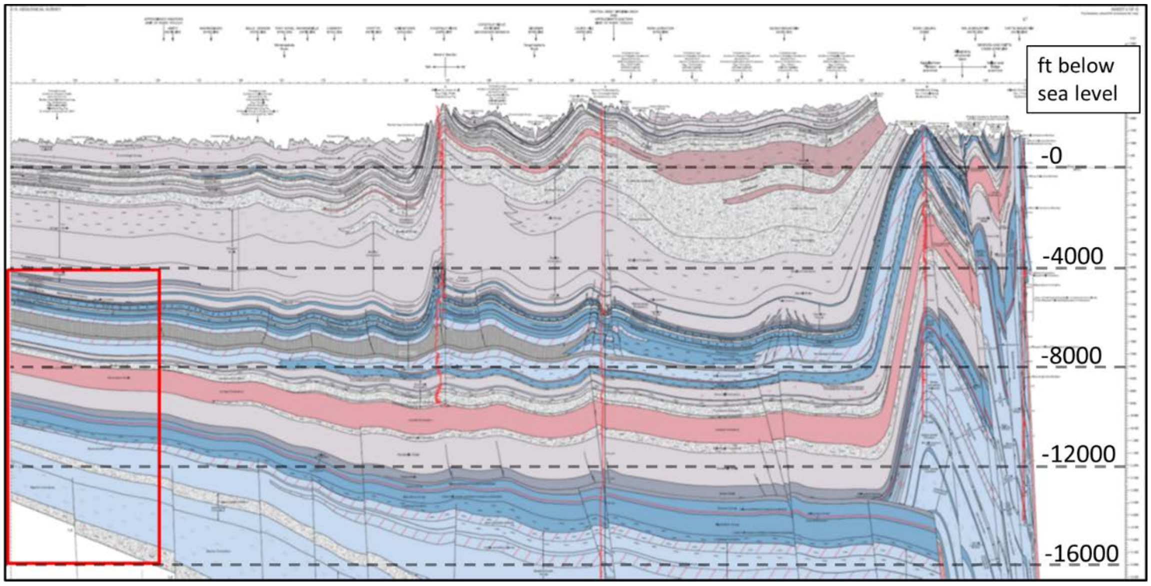

Figure 13: Geologic cross section near Almono and Southpointe study areas (Ryder et al., 2012). Cross section area of interest outlined by red rectangle is nearest the two study sites and is expanded in Figure 14 below.

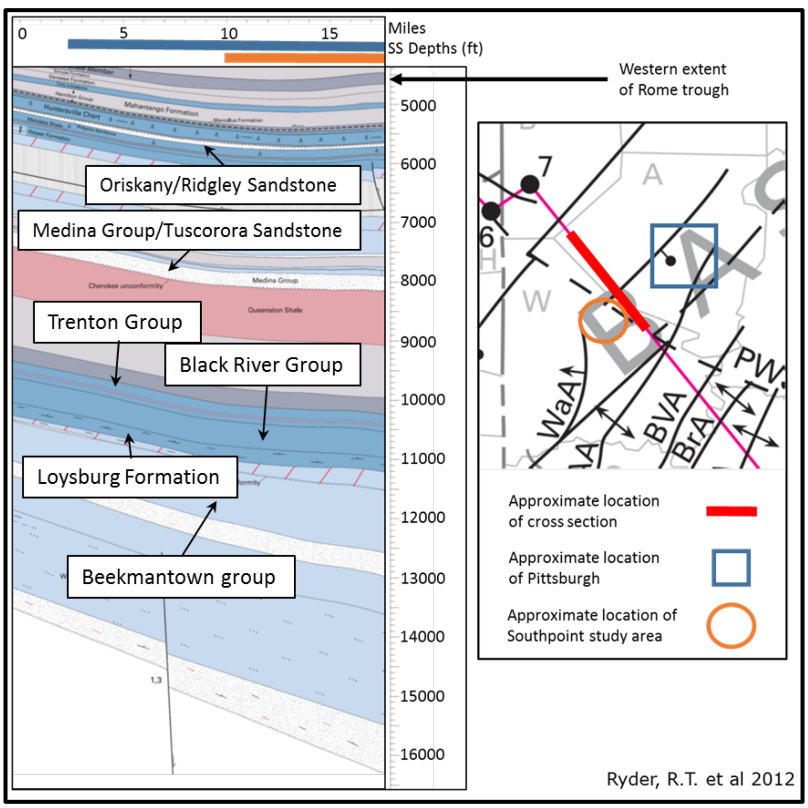

Figure 14: Approximate cross section (left) and its location near Almono (Pittsburgh) and Southpointe study areas (right).

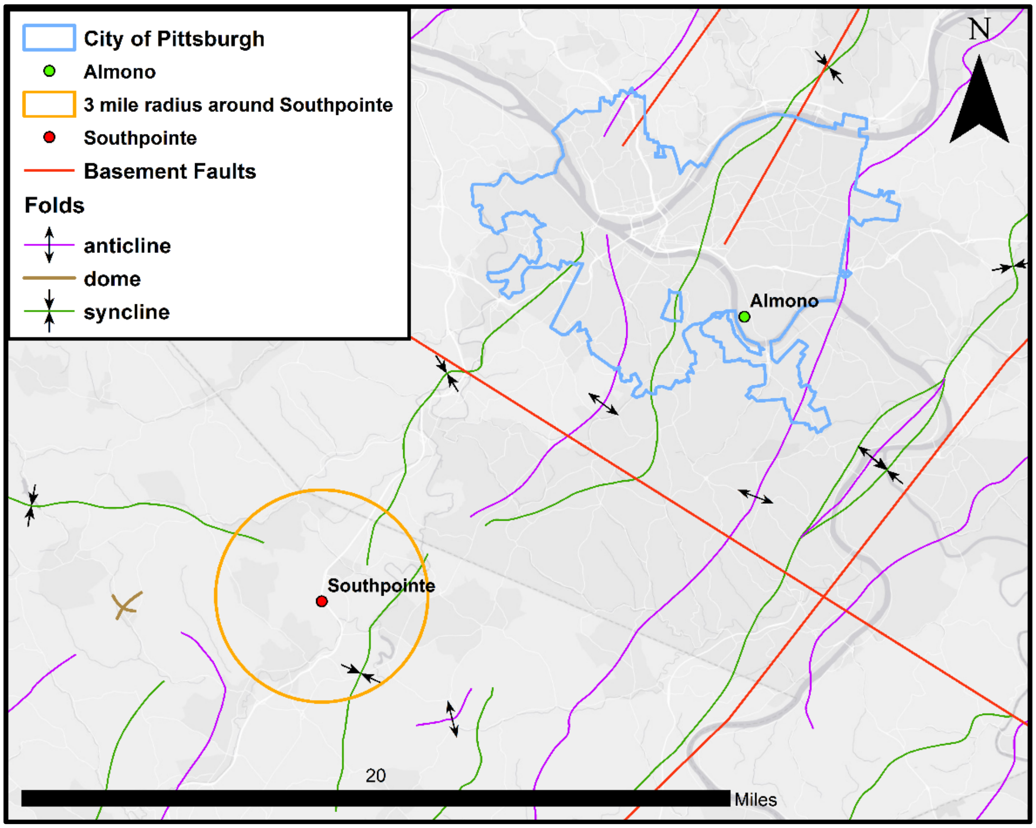

Figure 15: Map displaying basement faults and various folds in the vicinity of Southpointe and Pittsburgh.

3.2 ROCK PROPERTIES, GEOTHERMAL GRADIENT ESTIMATES AND GEOTHERMAL PRODUCTION POTENTIAL

Information on the relevant properties of rocks is not available for the immediate vicinity of Southpointe and Almono; therefore, information was sought from regional studies. Typical bulk properties for sedimentary strata within the Rome Trough were reported by Shope et al. (2012) and are presented here in Table 2.

Table 2: Typical Values for a Volume of Sedimentary Rock Buried at Depth within a Sedimentary Basin (Shope et al., 2012)

Parameter	Notation	Typical value	Units
Rock volume density	ρ_r	2500	kg m^{-3}
Rock volume bulk thermal conductivity	K_r	3	W m^{-1} K^{-1}
Rock volume heat capacity	c_r	1×10^3	J kg^{-1} K^{-1}
Pore fluid density	ρ_f	1000	kg m^{-3}
Pore fluid heat capacity	c_f	4.185×10^3	J kg^{-1} K^{-1}
Pore fluid velocity*	v_f	10^{-13}- 10^{-9}	m s^{-1}
Rock volume porosity	Φ	0.1	
Internal heat generation	A	1.25×10^{-6}	W m^{-3}
Formation and pore fluid temperature	T	373	K

The average thicknesses (ft) and thermal conductivity values (W/m-K) for various formations within the Rome Trough are displayed in Table 3. In general, sandstone, limestones, and dolomites have higher thermal conductivity than shales and therefore make better geothermal heat sources (i.e., reservoirs). Thickness and thermal conductivity values are used to help evaluate the potential of various reservoirs beneath a project site. Formation names shown in this Table correlate with widely recognized formation names elsewhere in the Appalachian Basin: the "Ridgeley," as shown in this table, is another name for the Oriskany Sandstone, and the "Antes Formation" correlates with rock referred to as the Utica Shale; the Coburn, Salona and Nealmont formations are equivalent to the Trenton limestones, whereas the Benner through the Hatter limestones are considered to be Black River Group equivalents. The Tuscarora Formation is indicated to have a very high thermal conductivity, but its utility as a geothermal reservoir may be limited by its notorious hardness, which derives from silica cements between the sand grains, making it extremely costly to penetrate while drilling horizontal wells.

Table 3: Stratigraphy for the Rome Trough (Shope et al., 2012) with Average Thicknesses and Thermal Conductivity Values for Various Formations.

Units in Stratigraphic Order		
Unit Names	Average Thickness (ft)	Thermal Conductivity (W/m-K)
Unnamed sandstone	722	3.34
Monogahela OR Uniontown/Pittsburgh	299	2.22
Conemaugh OR Casselman/Glenshaw	866	1.6
Allegheny	279	2.91
Pottsville	194	3.25
Mauch Chunk	456	2.15
Greenbrier	118	3.1
Burgoon/Rockwell OR Shenango	636	2.91
Venango OR Catskill OR Hampshire	1,545	3.17
Chadakoin/Bradford OR LockHaven	1,739	3.05
Brallier	2,884	2.25
Harrell	459	1.02
Tully	66	2.45
Mahantango	240	1.98
Marcellus	121	1.52
Selinsgrove	16	2.45
Huntersville	105	2.33
Needmore	23	2.12
Ridgeley	98	3.42
LickingCreek OR Shriver	85	2.08
Mandata	23	1.43
Corriganville	10	2.45
New Creek	10	2.45
Keyser Formation	89	2.45
Tonoloway	69	2.31
Wills Creek	577	2.26
Lockport OR McKenzie	164	1.9
Clinton Group	531	2.51
Tuscarona Formation	292	4.6
Queenston OR Juniata/Bald Eagle	1,276	3.34
Reedsville	764	2.15
Antes Formation	177	1.72
Coburn Formation	246	2.5
Salona Formation	128	2.01
Nealmont	256	2.5

Table 3: Stratigraphy for the Rome Trough (Shope et al., 2012) cont.

Units in Stratigraphic Order		
Unit Names	Average Thickness (ft)	Thermal Conductivity (W/m-K)
Benner	148	2.7
Snyder	89	3.35
Hatter	157	3.35
Loysburg	141	3.35
Beekmantown Group	2,224	3.35
Gatesburg	948	3.35
Warrior Formation	440	3.35
Pleasant Hill	794	2.31
Waynesboro	994	2.51
Tomstown	1,640	3.4
Unnamed sandstone	1,640	3.4

Note. *Sandstones are in yellow, shales in grey, dolomites in light blue, and limestones in blue.*

Some typical specific heat values for the relevant types of dry geologic materials are listed in Table 4. The important thing to notice is that these values do not differ much between the different types of Earth materials listed. Therefore, these values may be useful when estimating values of heat capacity for each stratum at depth, after accounting for porosity and pore fluid types to get representative values.

Table 4: Specific Heat Values for Different Dry Geologic Materials

Product	Specific Heat
	(kJ/kg K)
Clay	0.92
Dolomite rock	0.92
Limestone	.84 - 0.908
Sandstone	0.92
Source: http://www.engineeringtoolbox.com/specific-heat-solids-d_154.html	

To better estimate and reduce uncertainty in formation thicknesses in the immediate vicinity of the Southpointe and Almono sites, cross sections were created using well log data purchased from I.H.S. Markit (see https://ihsmarkit.com) (Figures 16 and 17). Although tops of certain formations could be readily identified (such as the Onondaga Limestone or the Oriskany Sandstone), well logs did not extend below the Helderberg Limestone or its equivalent (Licking Creek Limestone) to get information on deeper strata. Figure 17 shows another cross section for the Almono site that highlights the lack of data for the two wells closest to the site, which do not have well logs.

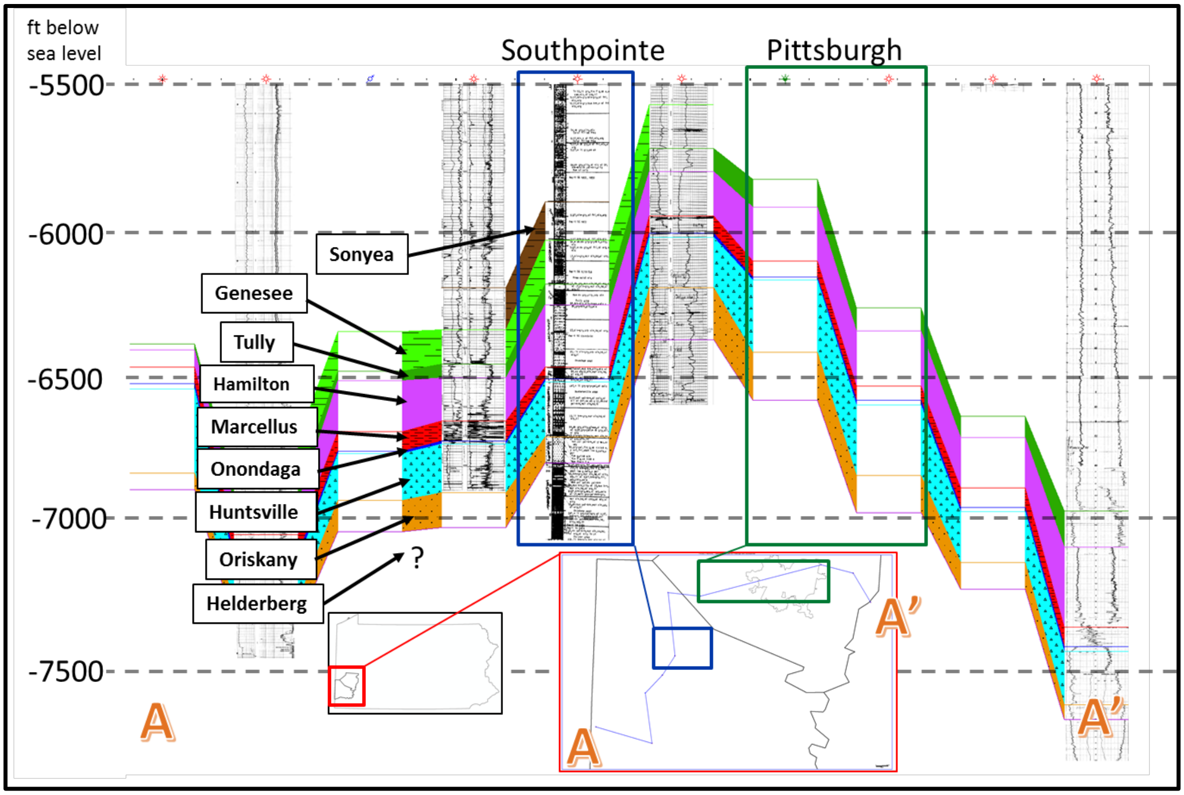

Figure 16: Cross section A-A' through Southpointe (blue rectangle) and Pittsburgh (green rectangle). Formation tops were picked from well logs (source: I.H.S. Markit, data purchased from: https://ihsmarkit.com) to estimate thicknesses.

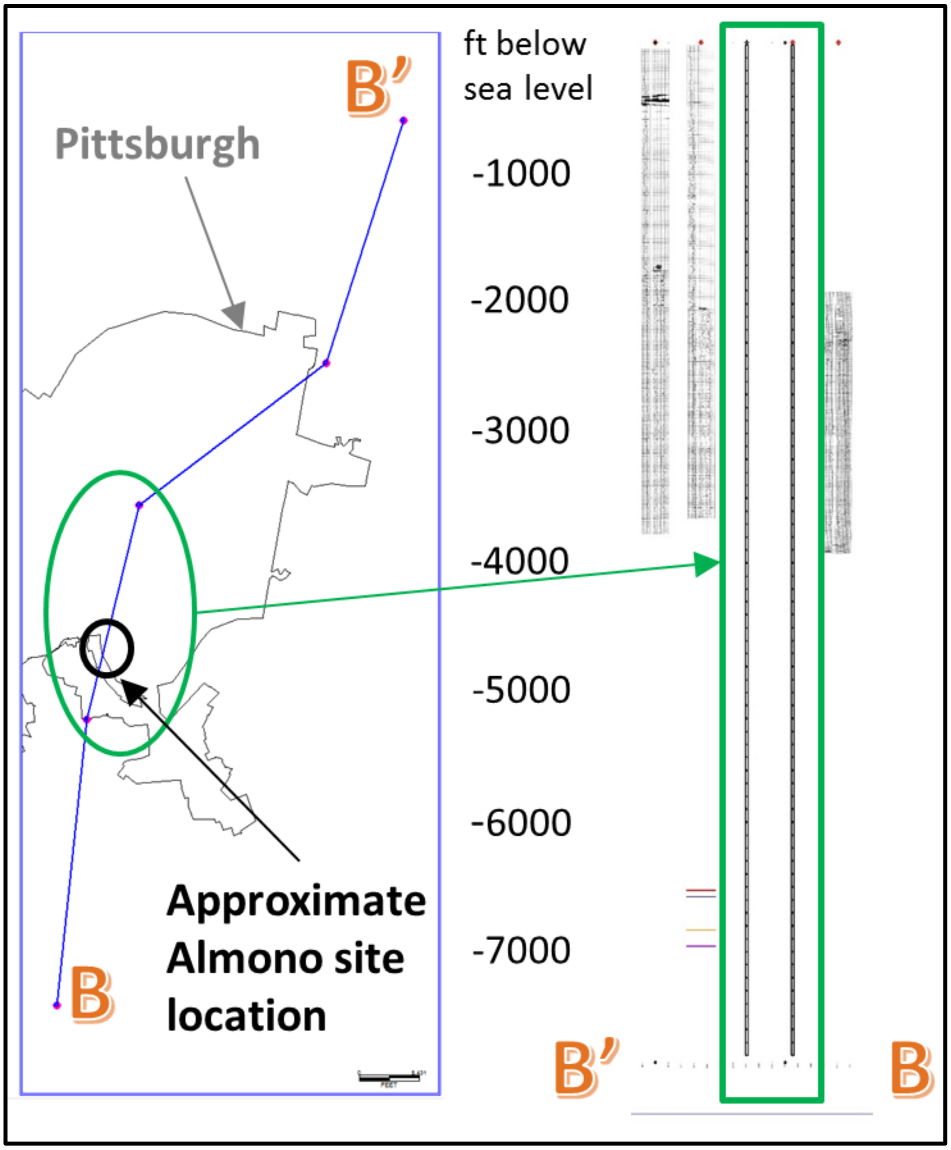

Figure 17: Cross section B-B' through Almono site (black circle), highlighting the lack of well log data at depths of interest in the vicinity and the absence of available data for the nearest wells in the I.H.S. Markit database (see green ellipse and rectangle).

A modified list of potential geothermal reservoirs is presented in Table 5. All depth and thickness values were estimated from the U.S. Geological Survey cross section (Ryder et al., 2012)—see Figure 14. Uncertainties in formation tops and average thicknesses result from the approximation of the location of Southpointe and Almono along the cross section. Southpointe is just to the south of the cross section and Almono to the north. Values for thermal conductivity are from Table 5 and not calibrated for estimated thicknesses and other factors.

Table 5: List of Potential Geothermal Reservoirs Beneath Southpointe and Almono (modified from Shope et al. (2012))

Favorable Geothermal Lithologies in depth order	Approximate Formation Top Depth range (ft)	Approximate average thickness (ft)	Approximate Thermal conductivity (W/mK) (within Rome Trough)
Tully Limestone	5600 – 6070	81	2.45
Onondaga Formation	5930 - 6400	14	2.45
Huntersville Chert	5950 - 6430	220	2.33
Ridgley/Oriskany Sandstone	6,190 - 6650	127	3.42
Licking Creek Limestone (Cherty)	6,300 - 6,700	63	2.08
Corriganville and New Creek Formations	6,480 - 6,850	20	2.45
Keyser Formation	6,500 - 6,920	140	2.45
Keefer Formation (Clinton group)	8,000 - 8,450	30	2.51
Medina Group/Tuscorora Formation	8,300 - 8,750	225	4.60
Trenton Group(Salona, coburn, nealmont)	10,500 - 11,300	295	2.01-2.50
Black River Group(Snyder/hatter)	10,800 - 11,720	400	3.35
Loysburg Formation	11,200 - 11,750	225	3.35
Beekmantown Group	11,400 - 13,200	1010	3.35
Upper Sandy Member (gatesburg formation)	12,300 - 13,300	280	3.35
Warrior Formation	13,150 - 14,300	1475	3.35
Waynesboro Formation	14,500 - 16,050	500	2.51

Note. *Estimates are approximate for depths of formation tops, average thicknesses, and thermal conductivities. Sandstones are in yellow, dolomites in light blue, and limestones in blue. Cells highlighted in green are estimates from the well log cross sections, and orange are estimates from the USGS cross section (Ryder et al., 2012).*

To determine the temperature gradients and heat flow at both Southpointe and Almono, wellbore data modified and presented by Southern Methodist University (SMU) was used (Figure 18). To obtain values for the temperature gradient and heat flow in the vicinity of both sites, the natural neighbor interpolation method was used because it accounts for spatial irregularity of the data points and is ideal for varying data densities (Shope et al., 2012). To estimate the geothermal gradient, a linear geothermal gradient was assumed over the depths of interest with an average surface temperature of 12°C or 53.6°F (estimated from Figure 19).

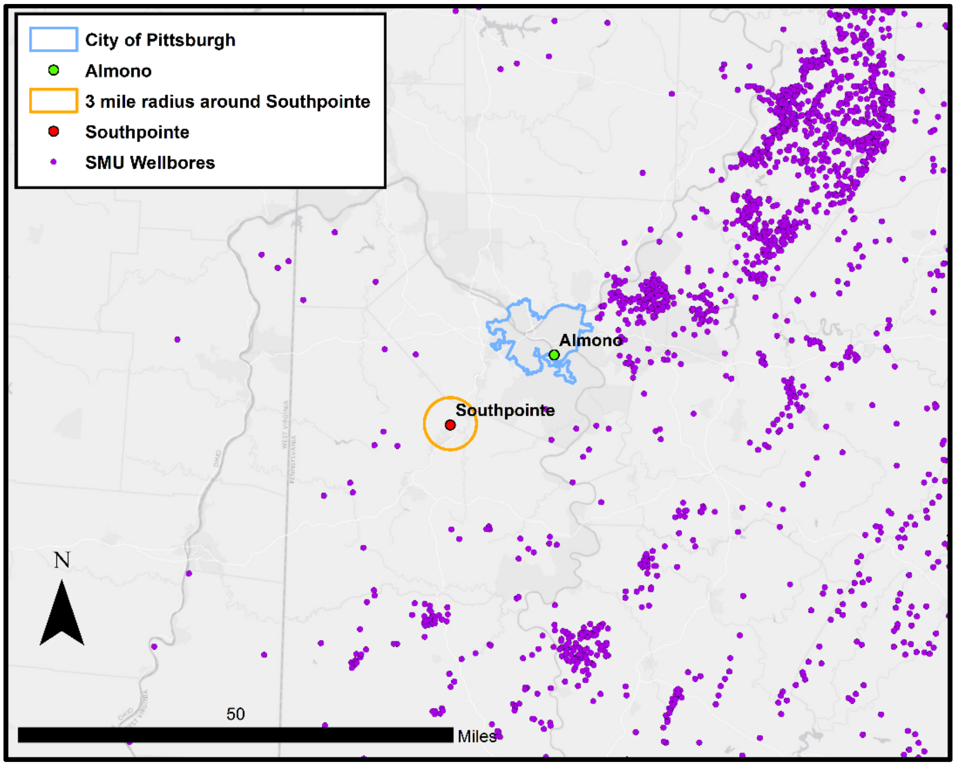

Figure 18: Locations of wells in SMU's database used for interpolations of temperature gradient and heat flow.

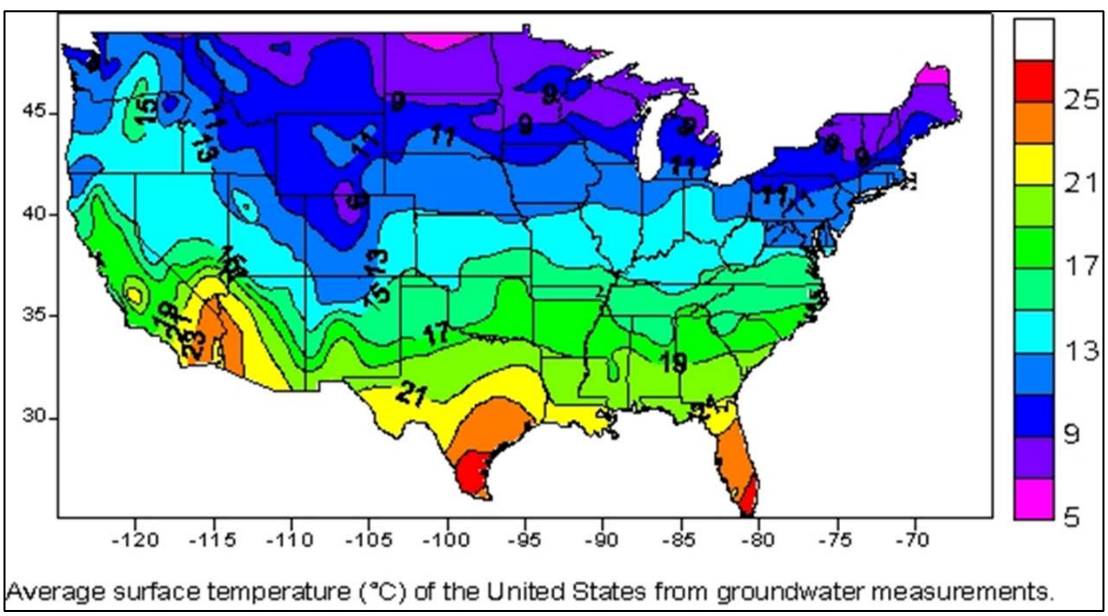

Figure 19: Average surface temperature (°C) of the United States from shallow groundwater measurements (Gass, 1982) used in this study to determine geothermal gradients and approximate depth to temperature suitable for a geothermal reservoir.

The interpolated results for temperature gradient and heat flow are displayed in Figures 20 and 21, respectively. These estimates of the geothermal gradient have not accounted for terrain effects that could result in slightly steeper gradients and slightly higher temperatures in the candidate rock formations. In general, as you move in a southwesterly direction from Almono to Southpointe, both temperature and heat flow are increasing. The average temperature gradient estimated at Almono is approximately 16.2 °C/km (0.89°F/100 ft) and at Southpointe is 20.0 °C/km (1.10°F/100 ft). The average heat flow estimated at Southpointe is approximately 58.3mW/m² and at Almono is 46.0mW/m².

The results presented above can be compared to the maps produced by Stutz et al. (2015), as presented in Figures 22 and 23. As summarized in Table 6, both the temperature gradient and heat flow interpolation results from Stutz et al. (2015) are slightly higher than the estimates presented here, which were derived from the SMU data and natural neighbor interpolation. Although Stutz et al. (2015) used the kriging interpolation method rather than the natural neighbor method, it is likely that much of the differences derive from the data sets used. Differences between the two studies indicate that uncertainties remain relatively significant, given that modest differences in the temperature of the resource can be very important for low-temperature district heating applications.

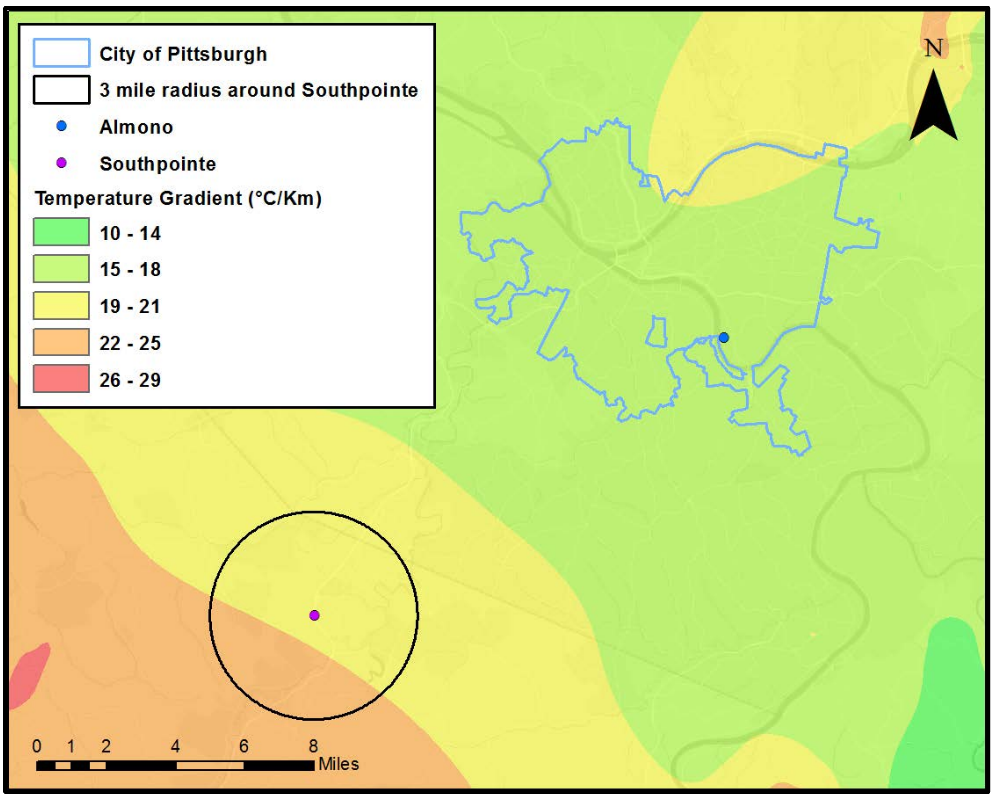

Figure 20: Interpolation estimate for temperature gradient (°C/km) in and around Southpointe and Almono study areas.

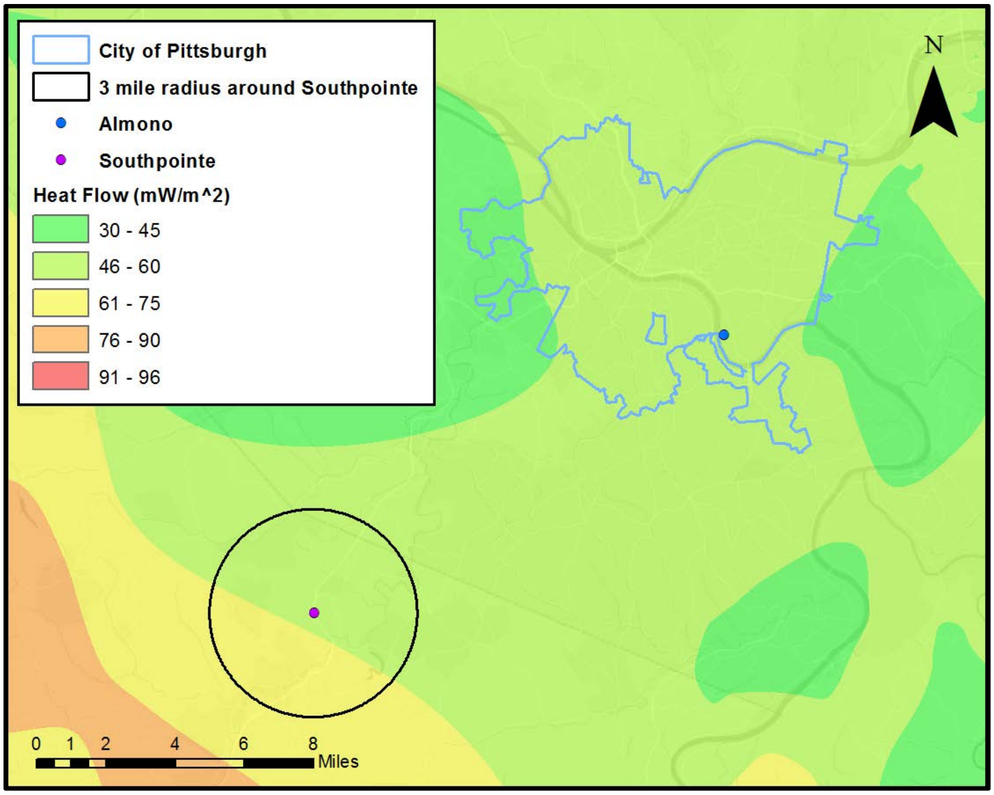

Figure 21: Interpolation estimate for heat flow (mW/m^2) in and around Southpointe and Almono study areas.

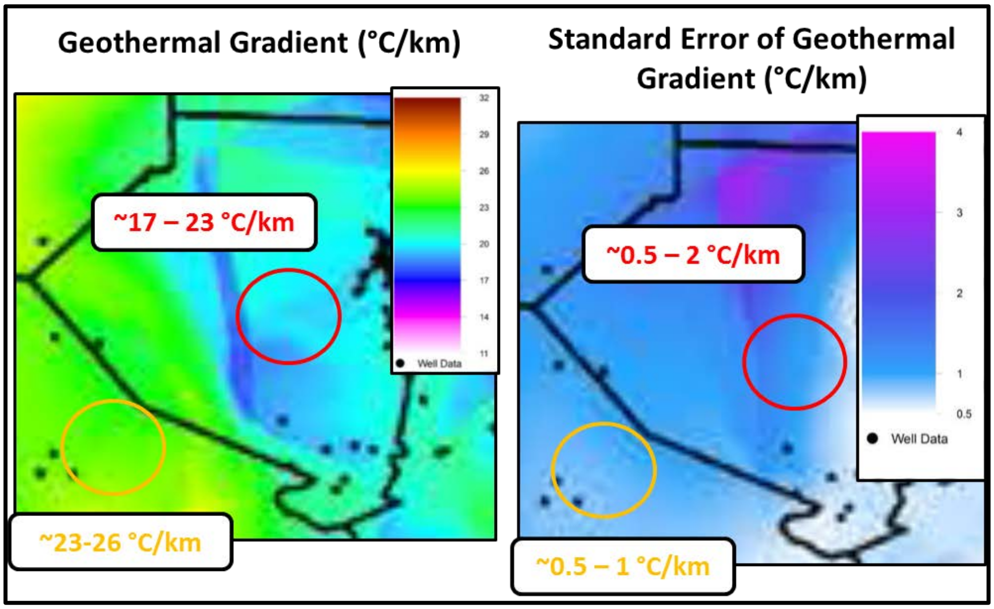

Figure 22: Interpolation estimates for temperature gradient (C/km) and standard error of temperature gradient (C/km) by Stutz et al. (2015) in and around Southpointe (orange circle) and Almono (red circle) study areas.

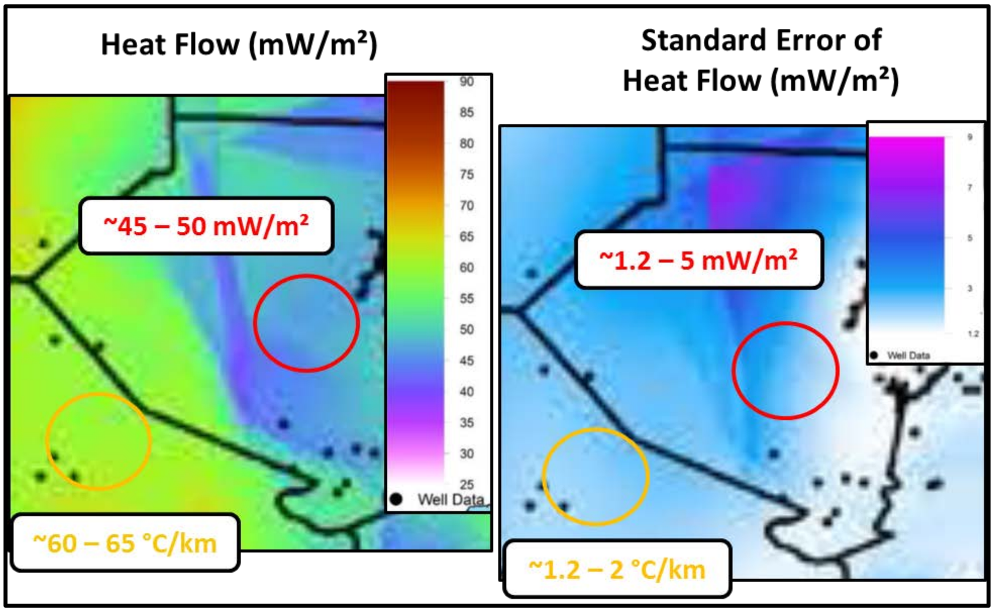

Figure 23: Interpolation estimates for heat flow (mW/m^2) and standard error of heat flow (mW/m^2) by Stutz et al. (2015) in and around Southpointe (orange circle) and Almono (red circle) study areas.

Table 6: Comparisons of Estimated Average Temperature Gradient and Heat Flow (this study) with Approximate Ranges of Temperature Gradient and Heat Flow, Including Standard Error Ranges, from Stutz et al. (2015)

	Estimated Average Temperature Gradient (C/km)	Approximate Temperature Gradient Range (C/km)	Approximate Standard Error of Temperature Gradient (C/km)	Estimated Average Heat Flow (mW/m^2)	Approximate Heat Flow Range (mW/m^2)	Approximate Standard Error of Heat Flow (mW/m^2)
Almono	16.2	17-23	0.5-2.0	46.0	45-50	1.2-5.0
Southpointe	20.0	23-26	0.5-1.0	58.3	60-65	1.2-2.0

Using the temperature gradient map, the respective approximate depths needed to reach 150°F (65.6°C) and 180°F (82.2°C), are 10,900 ft and 14,276 ft for Almono and 8,790 ft and 11,513 ft for Southpointe (Figures 24 and 25). These depths would be less if the actual temperature gradients are closer to the values estimated by Stutz et al. (2015). At these depths, potentially all the targets from the Tuscarora Formation downward could meet the needs for geothermal heat, depending on the desired life of the system, the configuration of the wells and the permeability characteristics of the chosen target rock formation. Sandstones usually have higher thermal conductivities and may therefore offer an advantage over limestone formations, if other factors (e.g., permeability and fracture characteristics) are the same.

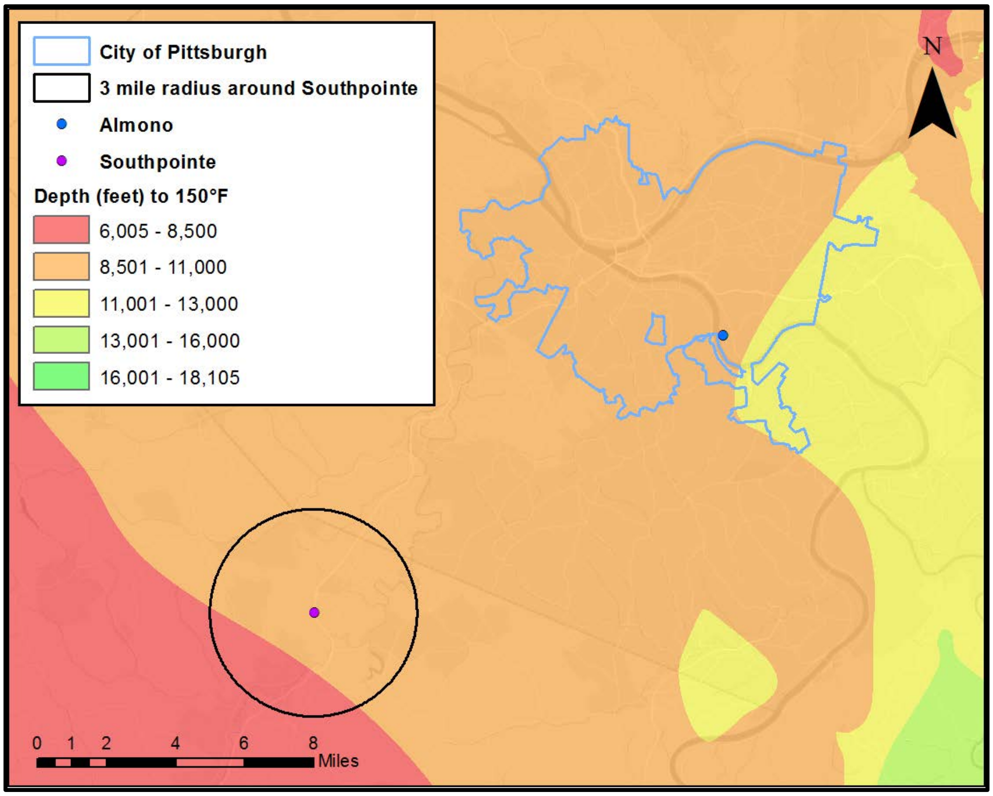

Figure 24: Interpolation estimate for depth needed to reach 150°F/65.6°C.

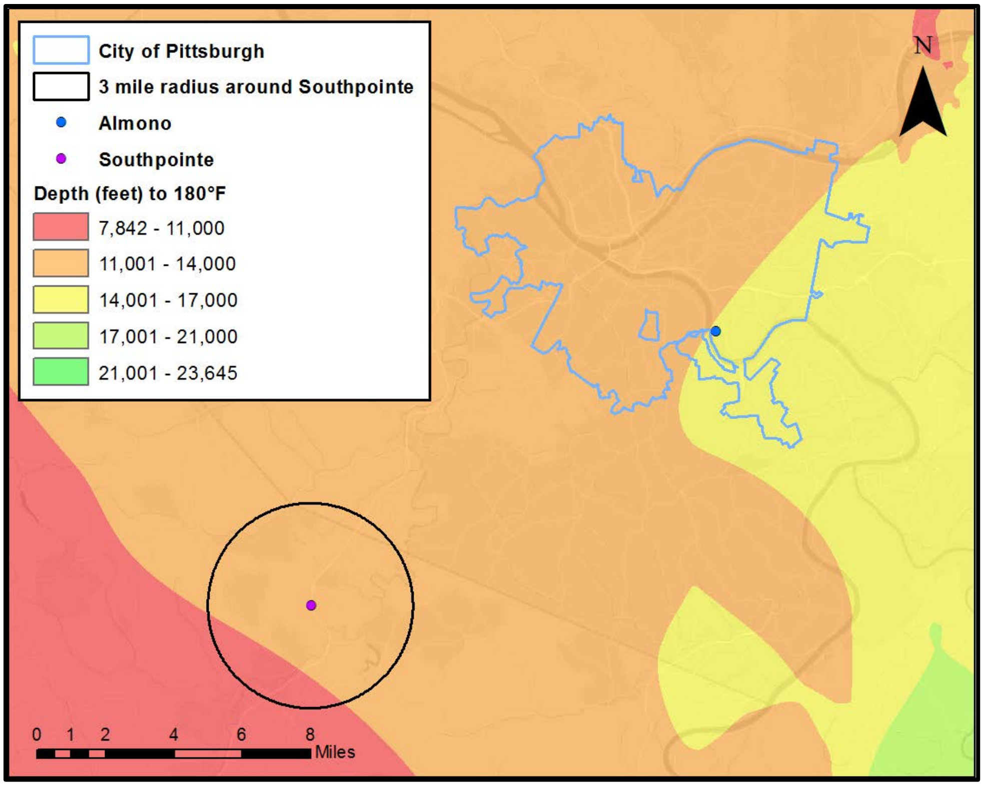

Figure 25: Interpolation estimate for depth needed to reach 180°F/82.2°C.

3.3 A MATHEMATICAL MODEL FOR RESERVOIR LIFETIME ASSESSMENT

The basic problem under analysis is shown in Figure 26, with the focus here on the heat extraction from the geothermal reservoir where water flows through the reservoir from the injection well to the production well. To predict the lifespan over which a geothermal doublet is capable of providing a specified amount of the heat for the buildings of interest, a mathematical model has been created. The calculations completed by this model are based on a simple linear model involving a number of parallel, equidistant, vertical fractures of uniform aperture. The fractures are separated by blocks of homogeneous, impermeable rock. The volume of the fractures is assumed to be negligible compared with the volume of the rock. The water is injected into a layer of thickness h through a well lateral of length L_w and produced from a parallel well lateral of equal length spaced a distance d from the injector. The model assumes that flow is distributed uniformly from bottom to top of the layer. Details of the water flow are not modeled. It is assumed that the water flow rates required to meet the energy demand may be obtained with an acceptable pressure drop. If the fractures are spaced distance s apart, then L_w/s fractures are assumed to intersect each of the laterals and the flow is distributed evenly among these fractures. With these assumptions, the model reduces to a spatially two-dimensional model in which the solution yields a rock temperature, $T_r(t, x, z)$, and the water temperature, which is assumed at quasi-equilibrium with the rock, $T_w(x, z)$, where x is the horizontal distance from the injector and z is the vertical distance measured downward from the surface.

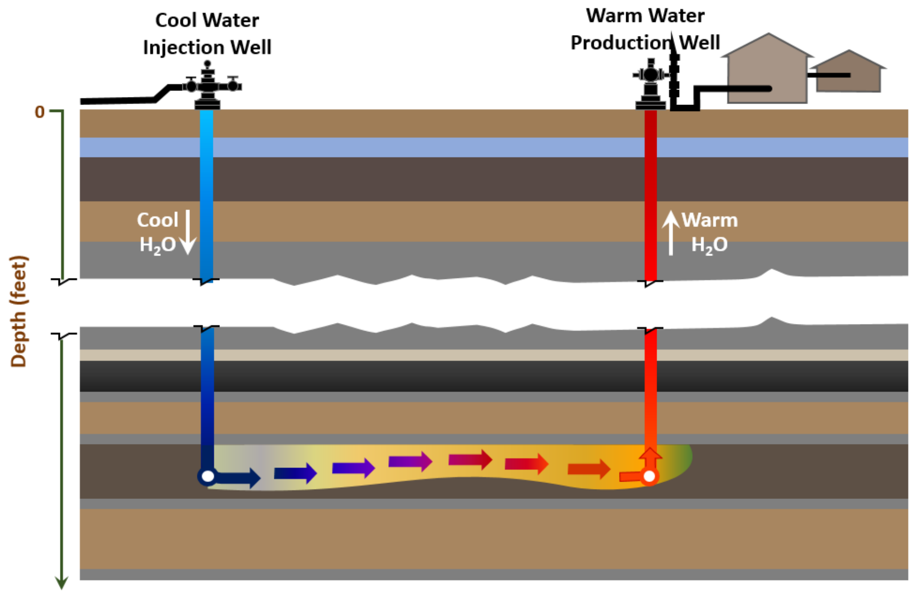

Figure 26: Cross section of the geometry analyzed.

The following simplifying assumptions are made:

- The water and rock specific heats and densities are constant. The heat capacity of the water-saturated rock can be calculated from the respective rock and water heat capacities and the porosity of the rock.
- The rock thermal conductivity is constant and the same in both the x and z directions.
- Heat transfer via circulated water occurs by forced convection alone, and heat transfer in the rock is by means of conduction alone.
- The volume of the fractures is so small compared to that of the rock that it can be neglected when writing the energy balance for the water in the fractures.
- The water and rock temperatures are initially the same and are computed from a specified thermal gradient and surface temperature.

The energy balance for mobile water flowing in fractures yields the following equation

$$v_S \rho_W C_{V,W} \frac{\partial T_W}{\partial x} + H(T_W - T_R) = 0 \, ,$$

where v_s is the superficial velocity of water, ρ_w is the density of water, $C_{v,w}$ is the specific heat of water, and H is the volumetric heat transfer coefficient. For the purpose of this calculation, H is approximated as 4 k/s^2, where k is the thermal conductivity of the rock and *s* is the fracture spacing.

The energy balance for the rock along with the immobile water contained within its pores is

$$\left[(1-\varphi)\rho_R C_{V,R} + \varphi\rho_W C_{V,W}\right]\frac{\partial T_R}{\partial t} - k\left(\frac{\partial^2 T_R}{\partial z^2} + \frac{\partial^2 T_R}{\partial x^2}\right) - H(T_w - T_R) = 0\ ,$$

where φ is porosity, ρ_R is the density of the rock, and $C_{V,R}$ is the specific heat of the rock.

The boundary conditions are:

$T_w(0, z) = T_{in}$

$T_r(t, x, 0) = T_{surface}$ and the gradient of T_r is equal to the natural thermal gradient at a depth below the injection, z_{max}, that is set to be sufficiently distant from the bottom of the reservoir, z_{bottom}, to be negligibly affected by the project.

The rock equation applies for: $0 < x < d$ where d is the spacing of the wells, and $0 < z < z_{max}$, to account for thermal energy conducted into the reservoir by surrounding rock. The water equation applies only in the region: $0 < x < d$ and $z_{top} < z < z_{bottom}$ where z_{top} and z_{bottom} are the depths of the top and bottom of the injection zone respectively.

The partial differential equations (PDE) for the water and rock were discretized by finite difference/finite volume methods, and the resulting set of algebraic equations was solved numerically using Gauss elimination. The prescribed flow velocity appearing in the PDE for water was calculated based on a monthly energy demand schedule (MMBtu vs. month) and the current water temperature at the production well. The spatial discretization in the x direction was uniform while variable gridding was used in the z direction. The z increments were constant in the injection zone and were increased geometrically above and below the injection zone. The temperature of the outlet water from the injection zone was averaged to obtain the outlet water temperature.

Using the above model, a detailed calculation is performed in the following Southpointe and Almono studies to determine the lifetime of a given multi-building (district) heating system using their available geothermal resources and HVAC design requirements.

4. SOUTHPOINTE DDU CASE STUDY

As noted above, the Southpointe Business Park comprises a variety of building types. While there is a significant amount of geothermal resource available to the site to supply these buildings, a first-order assessment of the total heat demand for all buildings shows that the demand is likely to be greater than what can be accessed via a single pair of wells (a "duplex well system") using today's technologies. Hence, for the present study future pursuits for DDU by Southpointe are anticipated to begin with a single duplex system, even though multiple such systems might be accommodated on or near their 800-acre site. As a result, a subset of buildings will be targeted for the proposed DDU geothermal solution studied here. Specifically, half the site's demand will be considered in this analysis. This number of buildings provides the best opportunity for achieving a cost-share arrangement that is feasible given the capital requirements for such a project. This will also keep well pipe diameters and pressure drop through the resource within tolerable limits.

As detailed below, two different NG base cases and three different geothermal cases were considered. The base cases were used to best reflect current operations of the Southpointe site as well as present an alternative "district" heating system employing centralized NG boilers. For the three geothermal cases, it is assumed that different proportions of annual heat demand are supplied from the geothermal resource (70%, 91%, and 100%) with the balance provided by a centralized NG boiler.

4.1 ENERGYPLUS™ – A MODEL FOR ANALYZING THE HEAT DEMAND OF OFFICE BUILDINGS

The analysis to determine heat demand began with the investigation of which modeling system to use for analyzing the energy requirements for a building. NETL settled upon use of the EnergyPlus™ model to simulate year-round heating conditions. While the model has the capability of analyzing the cooling requirements for buildings, cooling is not considered at this time. EnergyPlus™ is a whole-building energy simulation program for heating, cooling, ventilation, lighting, and plug-and-process loads. It was developed for the U.S. DOE's Building Technologies Office (BTO) by the National Renewable Energy Laboratory (NREL) (DOE-EERE, 2016).

As an initial study, a generic, medium-sized office building was analyzed, and the results are presented here. This case study is based on the example provided in EnergyPlus™ for a medium-sized building using current building technology with documented energy efficiency values. The building has a total usable floor space of 4,982.19 m^2 (43,608.36 ft^2), with an aspect ratio of 1.5 and a general layout of 49.911 m x 33.274 m (163.76 ft x 109.17 ft), and three stories tall. General construction is steel frame walls, built-up flat roof, slab-on-grade floor, and window-to-wall ratio of 33%. Windows are permanent, non-opening fixtures, with a U-value of 3.241 W/m^2-K. A heat sizing factor of 1.33 was used to account for infrequent, severe weather conditions.

The building has electric coil resistance heating in the majority of zones, with gas heating via forced air systems at building entrances. These are added together to determine the total heating requirement of a given building system modeled in this study. A crude wire frame of the three-story structure can be seen in Figure 27, where the core of office space is in the rectangular areas in the center of the building, and the trapezoidal shapes to the outside are plenums for hall space.

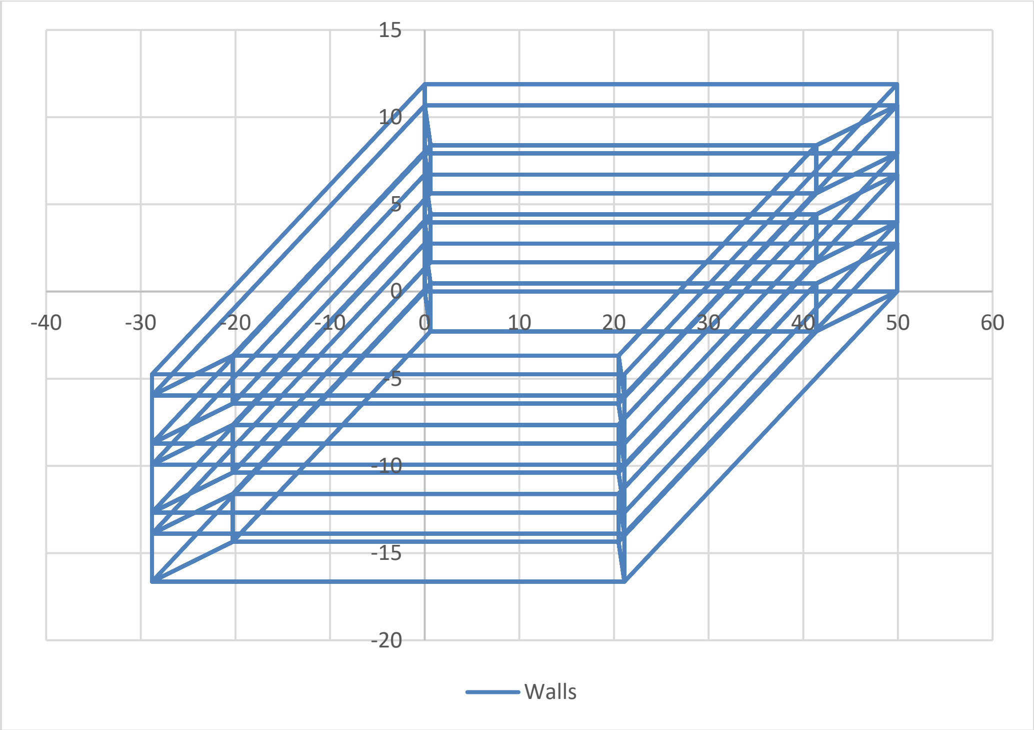

Figure 27: Wire frame of the three-story structure under analysis in the example case study. Building structure in blue line, windows not shown.

As mentioned above, only space heating was analyzed with the model. The software allows input of a weather profile; this study used the weather for Allegheny County, PA for the Southpointe and City of Pittsburgh areas. The weather profile allows EnergyPlus™ to generate a year-round utility demand table, with hourly data. This is reflected in Figure 28, showing the much larger amount of electric heating used over gas heating. Other heat sources, such as from lighting, personnel, equipment, etc., were included as internal sources.

Total heat demand for a given year for one building of this design would require 381 GJ (361 MMBTU) of electricity use and 119 GJ (113 MMBTU) of NG use, totaling to about 500 GJ of heat demand. This equates to 474 MMBTU of energy use throughout the year for heating. When similar analysis was performed for *all buildings* at Southpointe, the total heat demand for the commercial buildings can be determined as shown in Figure 29, which is ~44,000 GJ (41,000 MMBTU)—this data has been smoothed to account for the random nature of the instantaneous heat demand for any one building, thereby providing site-wide peak demand of only 11 MW (38 MMBTU/hr).

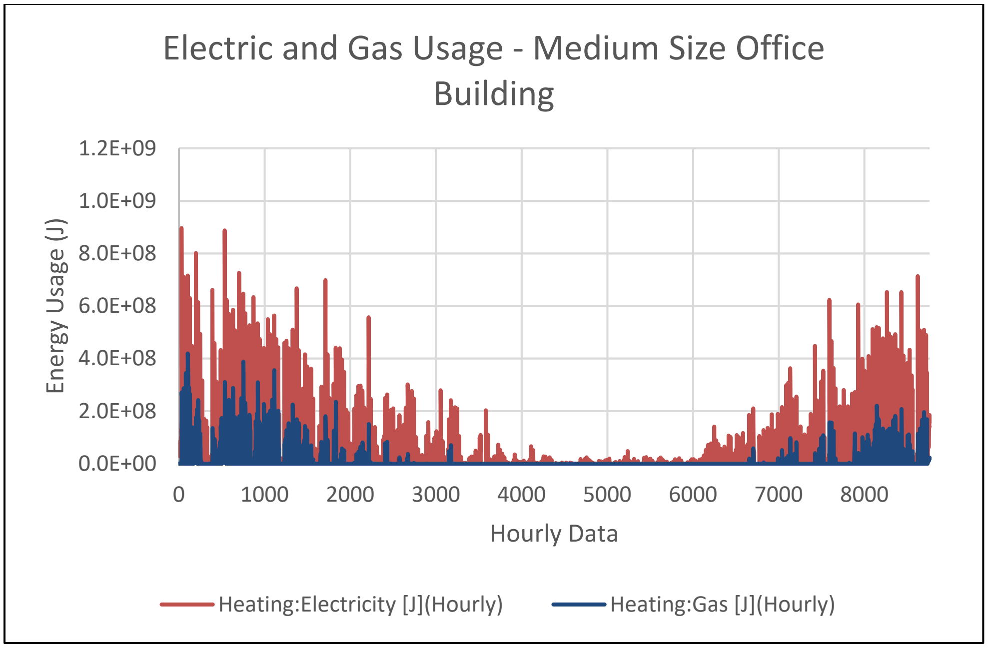

Figure 28: Year-round utility hourly demand data for single medium-sized building. Model assumes electric heating is much larger than gas heating.

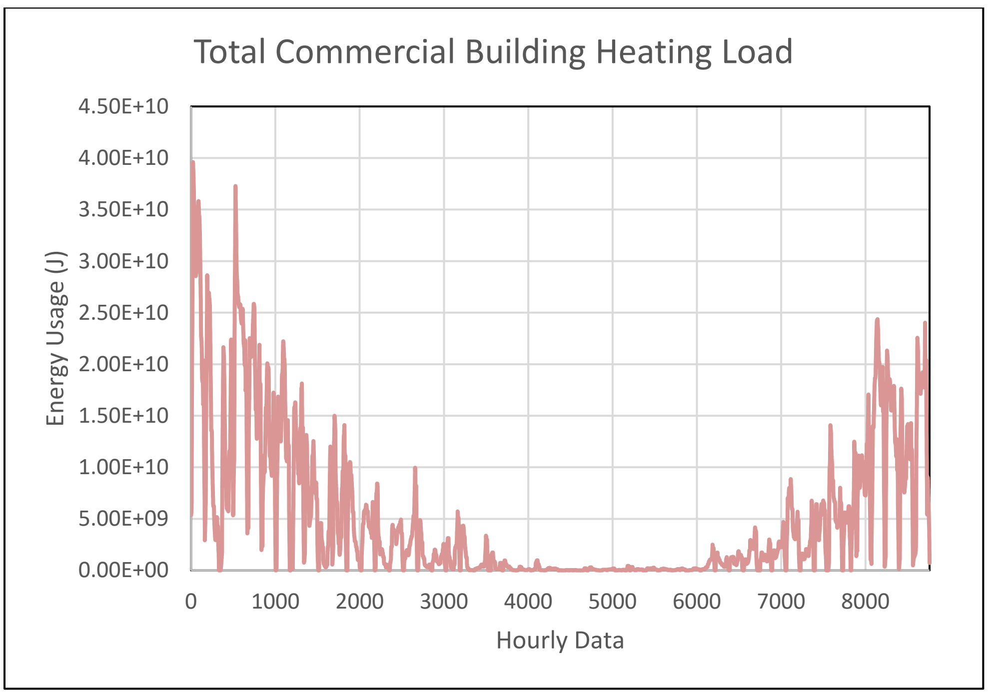

Figure 29: Full-site, total heat demand at Southpointe as estimated by EnergyPlus™ model and smoothed using a box-car running average over a 20-hr period. Data is given in terms of amount (i.e., joules) of energy required in a given hour. Based on the data, peak heat load is 11 MWth (38MMBTU/hr). For all cases analyzed except the Stand-Alone Base Case, this smoothed profile was used. For the Stand-Alone Base Case, no smoothing due to "random building district heat demand" was performed.

4.2 CALCULATED RESOURCE LIFETIME GIVEN SOUTHPOINTE BUSINESS PARK DISTRICT HEAT DEMAND

The model presented in Section 3 was used to perform detailed calculations for mining of geothermal energy from a targeted formation under Southpointe to determine the lifetime of the resource given a specific thermal demand. As noted, two different base cases and three different geothermal cases were considered. One base case, referred to as the Stand-Alone Base Case, assumed that each building separately employed its own NG, forced-air heating system to provide its annual load. This case was used to best reflect current operations of the Southpointe site. The other base case assumed a central hydronic boiler unit was used to manage the "district" heating needs. This case can be compared with the "geothermal district" concept under study here. For the three geothermal cases, it is assumed that different proportions of annual heat demand are supplied from the geothermal resource (70%, 91%, and 100%). These geothermal contributions were obtained by capping the peak thermal energy supply from the geothermal resource at 4.7 and 8.5 MMBtu/hr for the 70% and 91% cases, respectively. The balance of heat then came from a centrally located NG boiler. With this approach, a LCOH can be achieved if the well's diameter and other geothermal system parameters can be reduced, given a much-reduced flow rate required for the 70% and 91% cases. To deliver the heat energy from the subsurface to the buildings, a district hydronic loop was assumed (Figure 11), with the central boiler system located at the geothermal pump and heat exchanger building. The hydronic loop delivered the needed thermal energy to each building via a hydronic-to-air heat exchanger operated at 160ºF.

In the analysis of each geothermal case, the geothermal resource lifetime was set at 50 years, since this is the typical service life for a given well doublet (personal communication, Altarock, 1/11/2018). After 50 years, the wells would require some form of major maintenance to continue producing at their design performance, but since such major well maintenance actions are not well known at present, no consideration was given toward doing so here. To achieve the prescribed lifetime of 50 years, the horizontal well length of each case was appropriately sized—this length defines the volume of resource accessed and hence the total amount of thermal energy available to extract over 50 years. All model parameters used for each Southpointe case are shown in Table 7. For all geothermal load cases (70%, 91%, and 100% of annual demand), the monthly <u>total</u> district energy use in the model (as calculated using the building energy model presented in Section 4.1) is presented in Table 8. And to be clear, for two of the geothermal cases (70% and 91% cases), only a portion of this total demand was served by the geothermal resource—the remainder being provided by an NG boiler. Also, during construction, the length of the well laterals would be adjusted from the presently assumed values to reflect that true reservoir's bulk permeability (i.e., both fracture permeability and intergranular permeability), along with the other factors addressed in this study.

Given the above operating conditions, and a demand for only half of Southpointe, it was found that only the Trenton Black River Group formation would be viable having resource temperatures starting at 180ºF (ca. 11,500 ft) and able to provide a targeted 50-year lifetime (Figure 30). Hence, only that resource is considered in the following analysis.

Table 7: Table of Values Used for the Southpoint Site Model.

Southpointe – Trenton Black River Formation				
Geothermal contribution to heating	**[%]**	**100%**	**91%**	**70%**
Density of water	[lb/ft^3]	62.4	62.4	62.4
Specific heat of water	[Btu/lb.F]	1	1	1
Density of rock	[lb/ft^3]	171	171	171
Specific heat of rock	[Btu/lb.F]	0.217	0.217	0.217
Thermal conductivity of rock	[Btu/ft.F.hr]	1.94	1.94	1.94
Porosity of rock	[-]	0.1	0.1	0.1
Length of lateral	**[ft]**	**2,120**	**1,930**	**1,660**
Distance between laterals	[ft]	1,000	1,000	1,000
Thickness of injection zone	[ft]	100	100	100
Spacing between fractures	[ft]	10	10	10
Thermal gradient	[F/ft]	0.011	0.011	0.011
Surface temperature	[F]	53.6	53.6	53.6
Depth to top of formation	[ft]	11,500	11,500	11,500
Initial reservoir temperature (target)	[F]	180	180	180
Water injection temperature	[F]	118.7	118.7	118.7
Minimum water production temperature	[F]	162	162	162
Number of grid points	[-]	40	40	40
Number of grid points in injection zone	[-]	10	10	10
Number of grid points below injection zone	[-]	20	20	20
Number of grid points above injection zone	[-]	54	54	54
Required lifetime	**[yr]**	**50**	**50**	**50**

Note. *The length of the well laterals was iterated upon until each case provided a lifetime of 50 years. Model employed 180°F starting temperature and 162°F ending temperature to provide needed temperature to building HVAC units assuming a 2°F pinch point on the district heat exchanger—see Section 2.4.*

Table 8: Table of Monthly Energy Usage for Half Southpointe Site—Heat Demand of all Buildings Served in this Study

Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Southpointe [MMBtu]	6,259.38	3,717.84	1,800.33	831.91	414.53	67.98	18.10	33.53	201.94	799.50	1,842.39	4,610.99

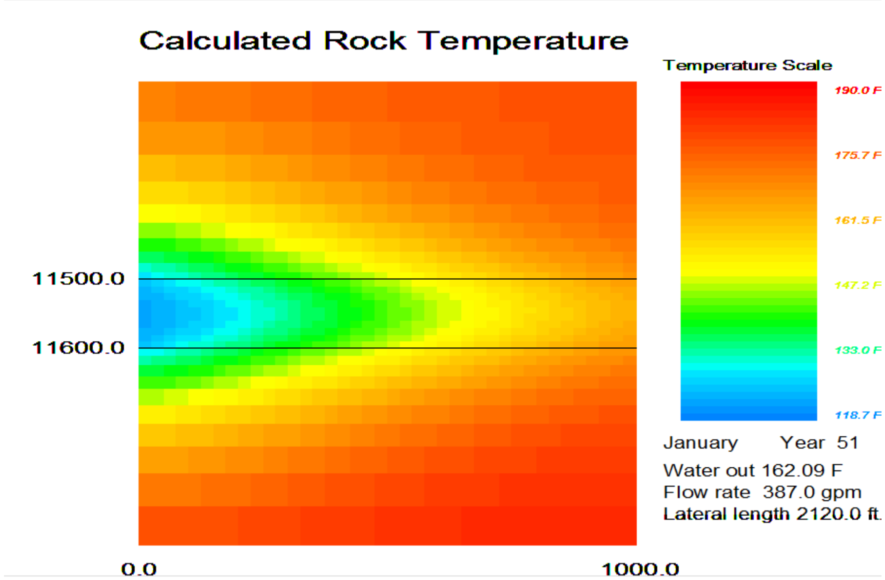

Figure 30: Formation temperature profile of the 100% geothermal case for the Southpointe site, Black River Group Formation. Time = Year 50.

4.3 SYSTEM COMPONENT COSTS AND LEVELIZED COST OF HEAT ESTIMATE

In the following analysis, the LCOH when using DDU geothermal energy for the Southpointe site was determined using a financial model developed by NETL. For reasons given in the above sections, half of the Southpointe site was selected for initial implementation of geothermal heating. The LCOH values are determined given estimates for system capital cost, performance, service data, and assumptions on how the project is financed. For all cases studied, it is assumed that 60% of the capital cost is covered through loans and an expected return on investment is 12%. Inflation rates on general operations and escalation rates for heat and/or electricity were the same for all cases—2% and 3%, respectively. Every case includes the capital costs associated with above-ground building requirements (e.g., district-level hydronic heating system, auxiliary heating system, etc.), the capital cost for well drilling and completion, as well as operating costs. It is assumed that new wells would be drilled instead of repurposing old gas wells given the costs of repurposing are much less certain than the costs of drilling new wells. While attempts were made to be as complete and accurate as possible, given the level of geologic information available and the conceptual nature of this study, this economic study is considered *informational*, and additional detailed engineering designs and cost analyses would be needed to more accurately assess the benefits of using on-site energy resources, before committing resources for constructing such a system. Given these considerations, an anticipated cost uncertainty of greater than +/- 30 percent should be expected.

Building Requirements and Above-Ground Infrastructure for Geothermal Heating System

Building retrofits – Part of the initial study considered retrofitting the existing buildings for in-floor hydronic heating as that technology is more energy efficient. However, the costs to do so were too great (ca. $16 million), making that approach infeasible. Instead, for Southpointe, this study assumed the use or retrofitting of hydronic-to-air heat exchangers in each building, to use existing building HVAC infrastructure as much as possible. In reality, some buildings may have other HVAC systems, but at the level of this analysis a more detailed building-by-building assessment was not warranted. Table 9 shows the number of buildings being served by this design and the number and cost of their hydronic-to-air units.

Table 9: Cost for Targeted District Building Hydronic-to-Air Heat Exchangers

Hydronic Air Handling Units		
AHU capacity	[Btu/hr]	43,300
AHUs needed per medium building	[-]	22
AHU installed cost per medium building	[$/med.bldg]	70,290
Number of buildings (medium) that can be served	[-]	43
AHU installed cost for site	[$]	$3,055,243

Site hydronic water distribution network – Given that half of the site is targeted for analysis in this study and given Southpointe's layout of buildings, several different groups of buildings could be served by the planned geothermal system. To keep project costs to a minimum for the present study, the area of Southpointe with greatest building density was identified. In this way, distribution piping to the buildings (and costs) could be kept to a minimum. Based on the available site data used in this study, the greatest building density is found in the south end of the business park (see Figure 2). Half of the business park's buildings can be covered by a circle with a diameter of 0.31 mile, and this length was used to define the integrated supply/return distribution pipe system (here, both hot supply and cold return are integrated as one installed unit). Including the pipe length needed to move water between the buildings and this distribution loop, the entire pipe network length is estimated to be 1-mile long. It is assumed that within this loop resides the heat exchanger needed to exchange heat between the geothermal fluid and above-ground hydronic water (i.e., between the "geofluid loop" and the "district loop"). The annual flow-rate profile used for sizing the distribution piping for this system is calculated by applying a 24-hour running average to the heat-demand history from the EnergyPlus™ building response discussed above. This smoothing simulates the combined effect of hydronic system heat capacity along with the asynchronized heat demand of a district building system, where each building operates independently from the others as was described in Section 2. Discussing such boiler applications with HVAC vendors indicated that such a daily average demand is a more typical specification for boiler capacity in this context (Delval, 2018). The pipe diameter of the above-ground district loop is 6 inches to match the down-hole pipe diameter. This results in a maximum pressure drop through the district loop of 236 psi. This pressure is similar to that used by Farralon in a geothermal district heating study for the City of Courtenay (Salter, 2013). Given the large range of flow rates during operations, it is assumed that two pumps are employed on the supply (one to cover the high range and one to cover the low range). The same setup is assumed on the return line. The cost for installing this pipe is determined using installation cost as a function of diameter as given by (Rafferty, 1996), but is adjusted to account for the more recently experienced installation cost of Farralon. By this method, including inflation between 2013 and 2018 (Inflation Calculator, 2018), the material and installation cost for the Southpointe loops was calculated to be $392/ft; and a cost for the main distribution loop was calculated to be $2 million. Branch pipe to deliver hot water to each building is similarly analyzed, but with a total cost of $2.6 million. Given all the above, the total capital cost for the pipe network and pumps (including one spare pump) is around $4.6 million.

Pumping power for district hot water distribution – To calculate the annual pumping energy required to circulate heated water through the district loop, a power-versus-flowrate curve was calculated and then used to determine the power needed to provide the necessary flow throughout the year using the site's annual building heat demand data. Given that heat loss can become relatively large at low flow rates, a minimum pressure drop of 1 bar/km for the district loop was assumed. This design minimum prevents water from losing large amounts of heat to the soil over the time it takes to be delivered to its use point (Yildrim et al., 2010). Also included in this flow calculation is a 20-psi pressure drop within the heat exchanger. Table 10 shows the resultant kilowatt-hours required to circulate this hydronic fluid throughout a given year. The local electricity price of 3.72 cents per kW-hr was applied to this energy requirement (ElectricityLocal, 2018), and arrived at $2,597 for the annual operating cost. This total recognizes that 1,917 hours of the year show zero heat demand (see Figure 31).

Table 10: District Loop Pumping Requirements and Annual Costs

Energy to Circulate the Loop for a Year		
Pump efficiency	[-]	0.59
Energy	[kWh/yr]	69,830

Well Hardware Installation and Operation

Well costs – As presented in Section 4.2 and summarized in Table 7, only one geothermal rock formation was considered for Southpointe—Trenton Black River Group. The cost for boring the wells was calculated using values from the literature and from industry, where it is often seen that the first (exploratory) well costs slightly more than the second (production or injection) well due to having different objectives, additional formation testing, and costs of converting an exploration well into a production or injection well. The geometrical inputs for the well calculations include casing diameter, vertical depth, radius of the curve drilled to initiate the horizontal bore-hole, and the length of the horizontal bore-hole. Costs estimates are presented in Tables 11 and 12.

Geofluid-to-hydronic water heat-exchanger system installation cost – The hot geofluid from the production well must be routed to a heat exchanger to deliver heat to the district water loop described above and then back through the subterranean reservoir. This study assumed 1,000 ft each of pipeline *to* and *from* the heat exchanger connecting to the production and injection well, respectively. The diameter of pipe used for these connections matches the well casing or production tubing diameter (I.D.): 8.75 inches. Using the same type of installation as assumed for the district loop, the installed price for the geofluid loop is about $274/ft. This makes the total install cost of the pipe of 2 x $274/ft x 1,000 ft=$548,000.

The cost of the geofluid to district-loop-water heat exchanger is based on the estimate used in the earlier techno-economic assessment of geo-heating Camp Dawson (Means et al., 2017). To generate a cost for the Southpointe heat exchanger, the price of the Camp Dawson heat exchanger was normalized by the peak heat transfer rate for which it was designed—giving $9,857 per MMBtu/hr. A heat exchanger cost of about $185,000 was determined by applying Southpointe's peak of 18.8 MMBtu/hr. In the same way, the price of the submersible geofluid circulation pumps is estimated from a scaling of the pump costs in the Camp Dawson report (Means et al., 2017). Assuming a pump each for injection and production wells, plus a spare, the cost for the Southpointe project was about $182,000 for all pumps for the 70% geothermal source case, where peak loads are met by the boiler system, and as much as $725,000 for the 100% geothermal case, where the geothermal subsystem alone must meet the winter peak load conditions.

Geofluid system operation – Electric water pumps are used to move the geofluid through the reservoir system comprising: vertical injection well; permeable geothermal reservoir; vertical production well; surface piping (i.e., geofluid loop); and heat exchanger. As with the district loop, piping pressure drops are calculated using the Darcy Weisbach approach via an online calculator (Schmitz, 2018). Note, buoyancy effects were ignored while the static pressures in the vertical and injection wells were assumed to cancel out for the system. Darcy's equation was used for the geothermal reservoir, employing the same permeability, 15 md, assumed in the Camp Dawson report (Means et al., 2017). Also, from the Camp Dawson study (Means et al., 2017), the same style of heat exchanger was assumed, having a design pressure drop of 20 psi at max flow. The pressure drop in the heat exchanger for other flow rates was then scaled according to the pressure drop that appears in the piping system. To account for the change of the reservoir temperature over its use life and the consequent changes in required flow rate and in geofluid viscosity, the overall system pressure drop for initial production temperature (year 1) and final production temperature (year 60) was calculated along with their associated electric pumping power. The electric power purchased costs from initial and final years were then averaged for use in estimating levelized cost of heating for the entire project. For the Black River Group cases, the operating cost estimate is less than $35,000/yr (Table 12). This annual cost is obtained in part due to the assumed smoothing of the heat load as a result of the statistical nature of the district buildings' instantaneous heat demands.

Table 11: Summary of Well Capital and Operating Costs for Half Southpointe Site and 50-yr Lifetime

Case	Lateral Length	Initial (Injection) Well	Second (Production) Well	Pump-power	GeoHeat Share	Max pump-flow	NG Peak Contribution
	[ft]	[$MM]	[$MM]	[$/yr]		[gpm]	[MMBtu/hr]
Trenton Black-River Resource 70% DDU Heat Load	1660	$ 9.35	$ 6.15	$ 33,557.09	70%	222	14
Trenton Black-River Resource 91% DDU Heat Load	1930	$ 9.81	$ 6.27	$ 32,363.81	91%	405	10
Trenton Black-River Resource 100% DDU Heat Load	2120	$ 10.13	$ 6.48	$ 35,051.06	100%	887	0

Table 12: Summary of Well Capital and Operating Costs for Half Southpointe

Case	Well Pumps	Heat Exchanger	Surface Geofluid Pipe	Capital Subtotal	Annual, Variable, Non-fuel O&M
	[$]	[$]	[$]	[$1000]	[$]
Trenton Black-River Resource 70% DDU Heat Load	181,913	185,021	548,086	16,415.12	33,557.09
Trenton Black-River Resource 91% DDU Heat Load	331,066	185,021	548,086	17,141.94	32,363.81
Trenton Black-River Resource 100% DDU Heat Load	725,385	185,021	548,086	18,067.90	35,051.06

Natural Gas Peak Heating

For two of the geothermal cases, it is assumed that a portion of the heating load (so called peak load) is supported through natural-gas-fueled boilers. Also, these geothermal DDU scenarios were compared with two different assumed 100% NG boiler district heating solutions: (1) district-level NG heating and (2) NG heaters (either hydronic or forced air) within each building. The capital and operating costs of these systems are covered in this section.

Capital cost of NG boilers – Given the 24-hr smoothed load curve due to thermal mass of each building, the hydronic system, and the assumed independent heating controls on the "district" buildings, the geothermal system under study here was able to contribute up to 25% of the peak heat load required by the targeted site for the 70% of annual load case, and 45% for the 91% of annual load case. Beyond this capped heat/flow rate, the balance of heat demand is provided by NG hot-water "boilers." The maximum hourly demand for the 70% case gives a boiler capacity requirement of 14 MMBtu/hr; and for the 91% case, the boiler requirement would be 10 MMBtu/hr; and for the stand-alone boiler cases, it would be 19MMBtu/hr. This assessment assumed that a set of boilers (~2 MMBtu/hr capacity each and a cost of $32,400 each) will provide the balance of the heat demand. The 70% geothermal case would require eight boilers; the 91% case would require six boilers; and for the non-geothermal district heating case would use 10 boilers. The multiple boilers allow a highly variable system with very little loss in efficiency. They also give high redundancy, which will lead to high availability in any given year. Figure 31 shows the majority of this boiler bank can be offline most of the year.

Table 13: Summary of Southpointe Boiler Capital Cost

Boiler Capital Cost					
Quoted boiler capacity	[MMBtu/hr]	1.9060			
Quoted boiler price	[$/boiler]	32,422			
Quoted boiler efficiency	[frac.]	0.953			
Calculated heat rate	[BtuNG*/MMBtuHW**]	1,049,318	*NG=Natural Gas **HW = Hot Water		
Hydronic Case			**Trenton Black-River Resource 91% DDU Heat Load**	**Trenton Black-River Resource 70% DDU Heat Load**	**District Boiler Hydronic Heating**
Required boiler capacity	[MMBtu/hr]		10.3	14.1	18.8
Number of boilers needed	[-]		6	8	10
Max Capacity	[MMBtu/hr]		11.436	15.248	19.06
Cost for Boilers	[$]		194,532	259,376	324,220
Cost for Boilers	[$1000]		194.53	259.38	324.22

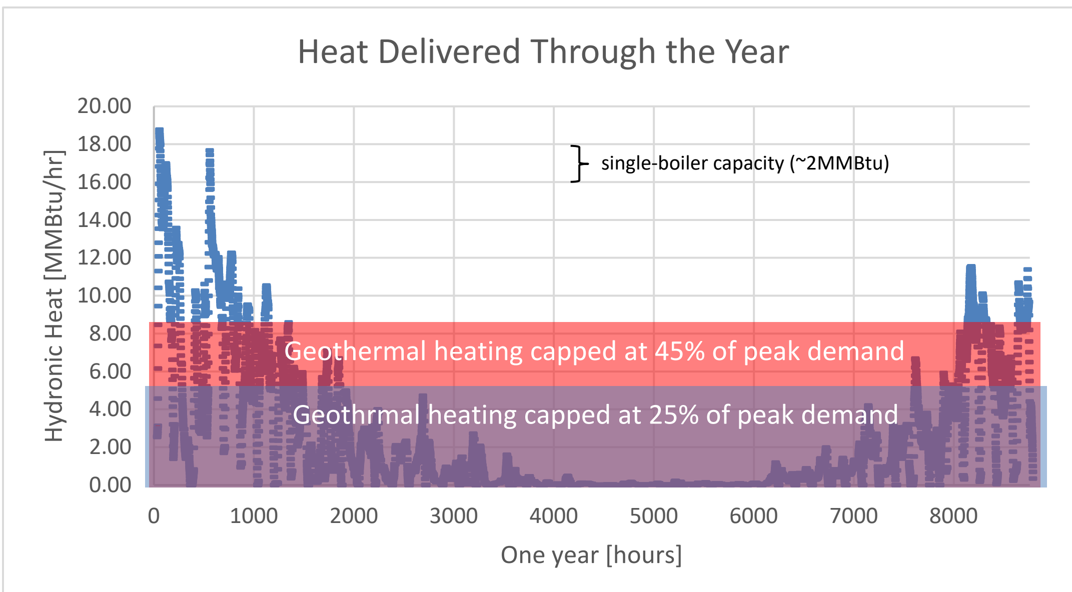

Figure 31: Heat supplied by geothermal resource for the three different cases, with color bars showing respective the cap in supply. The 70% case is shown with the purple bar. 91% case is shown with the red bar. The 100% case is shown with no cap.

Operating cost of NG boilers – To capture the cost of NG used for peak heating in the financial model, this study considered NG as a secondary energy source and adjusted the heat rate applied to the boilers to show the amount of NG used, on average, when meeting the total thermal demand. This is accomplished in the model by multiplying the boiler nameplate heat rate by the annual fraction of heat, which is provided by the boiler. This has the effect of "improving" the heat rate (thereby reducing the amount of NG required) given that the boiler is being supported by the geothermal system. In cases where NG is the sole energy source for heating, the boiler heat rate remains, of course, unadjusted and is calculated from the published efficiency of the boiler.

It is assumed that the boilers have a 95% efficiency (i.e., a heat rate of 1,049,319 Btu from NG vs. ideal 1 MMBtu to heat water) and that the boilers will need to be replaced three times through the 50-yr service life of the geothermal couplet and its associated reservoir, given that the useful life of a boiler is on the order of 10–15 years, (FannieMae, 2014; Wohlfarth, 2012). To account for these replacements at year 13, year 26, and year 39, a fixed savings rate for replacement must be added to the annual operating cost. This savings rate is calculated as the levelized total cost of boilers purchased throughout the 50-yr life. Inflation is considered for the replacement boilers. For the 70% geothermal load case, the annual cost is $12,200, while for the 91% geothermal load case the annual cost is $9,200. For the stand-alone building furnace base case, the annual cost is $48,000. And for the NG district boiler base case, the annual cost is $34,000.

Other Capital and Operating Costs

Capital costs of boiler building, heat-exchanger building and well houses – An estimated $20/ft^2, Means et al. (2017), is used for the cost of a structure housing the NG boilers and geothermal hydronic heat exchanger. The width of the structure is assumed to be 50 ft, and the length of the building is set to accommodate the number of boilers in each case (boilers alone or boilers assisting). Additionally, well houses are assumed constructed at the same cost per square foot and with an assumed 25-ft-by-25-ft size. Overall capital costs are shown in Table 14 below.

Table 14: Capital Cost of Buildings

	Boilers and Hydronic Pumps House			HX House	2 Well-Houses
	Boiler-powered Hydronic Heating	Trenton Black-River Resource 91% DDU Heat Load	Trenton Black-River Resource 70% DDU Heat Load		
	10 boilers	6 boilers	8 boilers	1HX House	
Length [ft]	95	65	80	20	25
Width [ft]	50	50	50	20	25
Area [sqft]	4,800	3,300	4,050	400	1,250
Cost [$/sqft]	20	20	20	20	20
[$]	**96,000**	**91,000**	**106,000**	**33,000**	**25,000**

General operating costs – Labor salary costs to maintain the operations of this system are scaled from the data reported for the geothermal district heating system at the City of Courtenay (Salter, 2013). In Salter's report, employment costs are $18.41/MMBtu. Scaled to the heating demand in this study, employee salaries would total about $180,000/yr or three jobs at approximately $60,000.

Levelized Cost of Heat

Given the above assumed financial data, capital costs, and operating costs, a levelized cost of heat was determined via the NETL cost model, which is reported for each case studied in Table

15. A more detailed presentation of the data and input parameters is given in Appendix B. As can be seen in the Table 15, among the cases studied in this report, the lowest-cost approach for heating at the Southpointe Business Park is to use individual NG boilers located at each building. It would cost nearly twice as much to provide heat using a district-style heat management solution using central boilers, so unless current space used for HVAC systems within buildings can be reduced by going to a district heat loop (and thereby free up space for other business needs), it may not be desirable to pursue such a solution.

For the targeted Black River Group formation, despite having a 50-yr lifetime, the cost of a complete DDU geothermal heating system is about three times greater than that of stand-alone NG boiler systems. As the table shows, the high capital costs of a geothermal system drive the high LCOH—over 80% of the COH results from the capital cost component for a geothermal system, whereas only 8% results for the stand-alone NG boiler systems. In short, considerable progress toward reducing the cost to develop the well system will need to occur in order make DDU geothermal energy at Southpointe competitive, given today's low costs of NG.

Table 15: Levelized Cost of Heat for Southpointe: Stand-Alone Building Furnaces, District NG Boiler and Three Geothermal Cases

Case Description	Natural-Gas, Forced Air	District Boiler Hydronic Heating	Trenton Black-River Resource 70% DDU Heat Load	Trenton Black-River Resource 91% DDU Heat Load	Trenton Black-River Resource 100% DDU Heat Load
RESULTS					
Total Overnight Capital, $1,000	**$456.43**	**$8,104.01**	**$24,489.28**	**$25,136.26**	**$25,809.69**
Escalated Total Overnight Capital, 1000$	**$464.65**	**$8,249.88**	**$24,930.09**	**$25,588.71**	**$26,274.26**
Debt, $1,000	**$292.12**	**$5,186.71**	**$15,673.57**	**$16,087.64**	**$16,518.65**
Equity, $1,000	**$185.86**	**$3,299.95**	**$9,972.04**	**$10,235.48**	**$10,509.70**
Interest During Construction	**$13.34**	**$236.78**	**$715.51**	**$734.42**	**$754.09**
Investment Tax Credit	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Total As-Spent Capital (TASC) $1,000	**$477.98**	**$8,486.66**	**$25,645.60**	**$26,323.13**	**$27,028.36**
Cost of Heat (CoH)					
COP Units	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
Dollar Year / Base year	**2018**	**2018**	**2018**	**2018**	**2018**
Constant, Levelized COH	**$25.02**	**$54.24**	**$78.13**	**$115.98**	**$78.02**
Capital Component of COH	$1.89	$33.59	$64.00	$104.19	$67.46
Variable O&M Component of COH	$0.00	$0.13	$1.76	$1.70	$1.83
Fixed O&M Component of COH	$11.07	$10.39	$9.33	$9.18	$8.74
Primary Fuel/Feedstock Component of COH	$12.06	$10.13	$0.00	$0.00	$0.00
Secondary Fuel/Feedstock Component of COH - $1,000	$0.00	$0.00	$3.04	$0.91	$0.00
Effective Annual Cost for Above Supplied Energy	**$515,426**	**$1,117,202**	**$1,609,348**	**$2,389,072**	**$1,607,130**

5. CITY OF PITTSBURGH ALMONO DDU CASE STUDY

5.1 HEAT DEMAND FOR ALMONO

Figure 32: Photo of the Almono development site (https://revitalization.org).

The Almono development is a brownfield area, housing a former steel production facility along the Monongahela River southeast of downtown Pittsburgh (Figure 32). The name Almono is derived from the three-river system meeting in downtown Pittsburgh; the Allegheny, the Monongahela, and the Ohio Rivers. The entire site is being refurbished into a combined residential/commercial/ industrial site for workforce use. The analysis presented here models *a portion of Phase 1* of development, namely remodeling of a portion of what is known as the Mill 19 building, as well as an analysis of the heat load for the entire Almono development.

Phase 1 for Almono is to rework a section of the existing Mill 19 building into a multifunction space, with a mix of light industry and commercial stores. The Mill 19 building is about 1,300 ft. long, but only a 300-ft section is being developed for use in Phase 1. The footprint of the new development is 75 ft by 300 ft and three stories tall, all fitting within the mill building footprint. Each floor has two wings, with separate tenants for each wing, which are separated by a small commons area, along with restrooms and mechanical/electrical rooms. A solar photovoltaic array, covering 44,000 ft^2 of roof space located above the developed end of Mill 19, will be erected over the top of the existing mill building. This study used a strip mall configuration, already present as a building option in EnergyPlus™, for each floor of the layout. This gave the best representation of a commercial space as it was planned by the Almono planners. The model is based on a 75 ft x 300 ft layout, same as Phase 1, with 10 separate store areas on each floor. Using EnergyPlus™'s editing feature, model parameters as called out by the developers for their "optimized envelope" and improved lighting systems were adjusted. The model results are then compared to information supplied by the Almono developers for expected heat loads. Note: Some of the further developments called out by Almono, such as energy recovery, heat pumps, and ground source heat rejection are not easily modeled in EnergyPlus™ and were not handled at this time. The final set of building parameters utilized in the model is given in Table 16.

Table 16: EnergyPlus™ Model Parameters for the Mill Building

Parameter	Value	Units
Envelope Parameters		
Exterior Walls U	0.040	Btu/hr-ft^2-F (R-25)
Roofs U	0.028	Btu/hr-ft^2-F (R-35)
Windows U/SHGC	0.28/0.27	Btu/hr-ft^2-F
Internal Load Parameters		
Lighting	0.6	W/ft^2
Exterior Lighting	5,800	W
Outside Air Parameters		
Outside Air Flow	8,000	cfm
Equipment Loads		
Occupancy	100	ft^2/person
Equipment	1.0	W/ft^2

Assuming a similar level of building performance in other future site buildings, the predicted annual thermal load for the Mill building was scaled using data provided by the developers that showed anticipated total thermal demand (kWh) for the entire development. Table 17 shows data for both residential and commercial applications, broken out by heating, cooling and domestic hot water (DHW). The EnergyPlus™ model providing hourly data was scaled to meet this number for total space heating thermal demand for the Almono layout, which provides the heating load profile in Figure 33.

Table 17: Thermal Demand for the Entire Almono Site Over one Full Year Based on Developer-Provided Data

Thermal Demand (kWh)	Residential	Commercial	Total
Space Heating	5,607,591	5,405,265	**11,012,856**
Space Cooling	4,125,124	5,165,007	**9,290,131**
DHW	2,341,867	3,736,836	**6,078,703**
Total	**12,074,582**	**14,307,108**	**26,381,690**

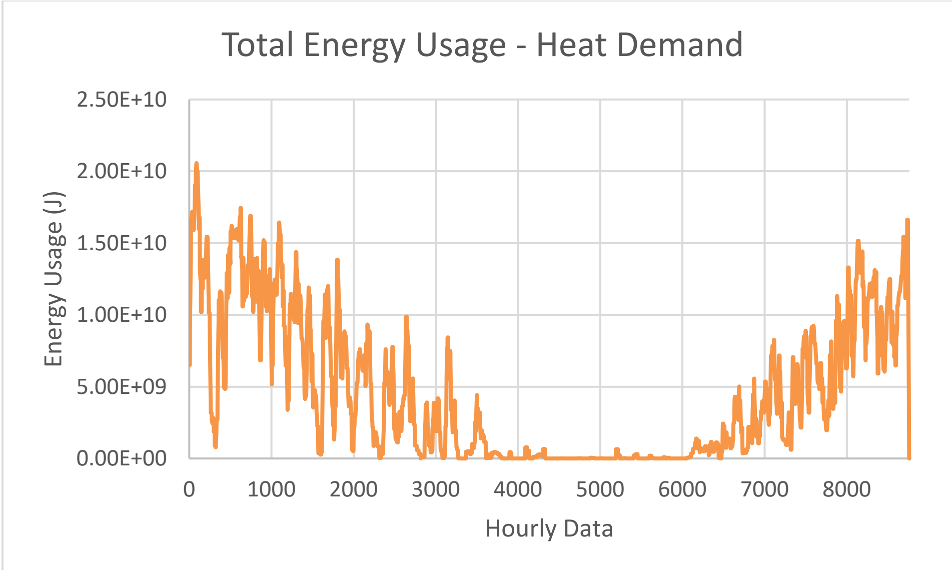

Figure 33: Anticipated annual heat demand profile for Almono. Data is given in joules required in a given hour. Based on this data, site peak thermal demand is estimated at 5.7 MW (19.5 MMBTU/hr).

5.2 CALCULATED RESOURCE LIFETIME GIVEN ALMONO DISTRICT HEAT DEMAND

As for Southpointe, the model presented in Section 3 was used to perform detailed calculations of the mining of geothermal energy from a targeted formation to determine the lifetime of the resource given a specific thermal demand for Almono. For the Almono site, the Warrior Formation with starting temperatures of about 180°F (at a depth of about 14,200 ft), was the only formation that could provide the necessary heat energy over a 50-yr life of a planned system. Hence, the results from the Warrior Formation are all that will be presented in detail here.

As in the Southpointe study, two different *base cases* and three different *geothermal cases* were examined for the size of geothermal resource required for a 50-yr project life. One base case assumed that each building separately employed its own NG forced-air heating system to meet its annual demand. This case was used to best reflect the lowest-cost heating option for the Almono site. To have the most meaningful comparison, included in the costs for this case was the installation of the NG lines needed throughout the site. The rationale for this is that Almono is essentially a new development, and one can therefore decide if a DDU strategy for heating would be used versus NG ahead of development. If the former, then one could (potentially) forego the need to distribute NG throughout the site, and instead only direct NG to the central district boiler. In the LCOH analysis for this base case, it was assumed that the length of the pipe needed to deliver NG to each building would be the same as the length of pipe needed to deliver district hydronic water to each building. The other base case assumed a central hydronic boiler unit is used to manage the "district" heating needs. It too only included the cost to deliver NG to the central boiler. This case can be compared with the "geothermal district" concept under study here.

For the three geothermal cases, it was assumed that different proportions of annual heat demand are served by the geothermal resource (70%, 91%, and 100%). These geothermal contributions coincide with capping the peak thermal energy supply from the geothermal resource at 6.3 and 10.2 MMBtu/hr for the 70% and 91% cases, respectively. The balance of heat would come from a centrally located NG boiler. Aside from allowing for smaller diameter piping in the district loop and geofluid loop, the smaller geothermal load cases (70% and 91%) allow for a reduced size wellbore (and reduced well cost) and/or longer resource lifetime.

The parameters used for all Almono cases are shown in Table 18. Monthly energy use as calculated using the building energy model presented in Section 5.1 can be seen in Table 19. As for Southpointe, the length of the well lateral was adjusted to obtain a 50-yr life for the DDU well system. Again, this is the anticipated lifetime prior to major maintenance needed on a well system. The model ran until the temperature of the produced water dropped below the minimum required temperature, which for Almono was 124°F, as it reflects newer, more efficient technology options available to new developments. Figure 34 shows the resulting temperature profile at the end of life for the 100% geothermal load case.

Table 18: Table of Values Used for the Almono Subsurface Model

Almono -- Warrior Formation (180 °F Starting Temp.)				
Geothermal contribution to heating	[%]	100%	91%	70%
Density of water	[lb/ft^3]	62.4	62.4	62.4
Specific heat of water	[Btu/lb.F]	1	1	1
Density of rock	[lb/ft^3]	171	171	171
Specific heat of rock	[Btu/lb.F]	0.217	0.217	0.217
Thermal conductivity of rock	[Btu/ft.F.hr]	1.94	1.94	1.94
Porosity of rock	[-]	0.1	0.1	0.1
Length of lateral	**[ft]**	**2,250**	**1,680**	**1,550**
Distance between laterals	[ft]	1,000	1,000	1,000
Thickness of injection zone	[ft]	100	100	100
Spacing between fractures	[ft]	10	10	10
Thermal gradient	[F/ft]	0.009	0.009	0.009
Surface temperature	[F]	53.6	53.6	53.6
Depth to top of formation	[ft]	14,200	14,200	14,200
Initial reservoir temperature (target)	[F]	180	180	180
Water injection temperature	[F]	104.8	104.8	104.8
Minimum water production temperature	[F]	124	124	124
Number of grid points	[-]	40	40	40
Number of grid points in injection zone	[-]	10	10	10
Number of grid points below injection zone	[-]	20	20	20
Number of grid points above injection zone	[-]	54	54	54
Required lifetime	**[yr]**	**50**	**50**	**50**

Note. The length of lateral piping was adjusted to meet the 50-yr life expectancy of the well.

Table 19: Table of Monthly Energy Usage—Base Case

Month	1-Jan	1-Feb	1-Mar	1-Apr	1-May	1-Jun	1-Jul	1-Aug	1-Sep	1-Oct	1-Nov	1-Dec
Almono (MMBtu)	8,530.28	6,909.03	4,302.62	2,265.49	1,330.69	120.45	2.63	40.18	341.52	2,086.85	4,067.16	7,517.92

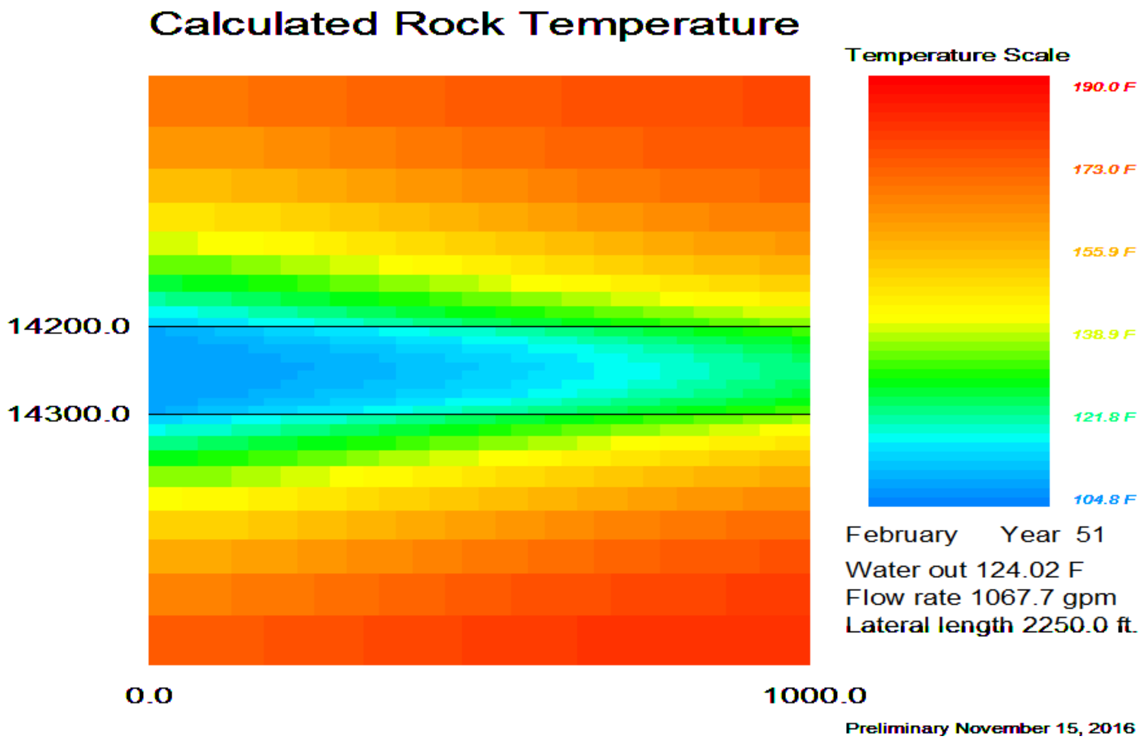

Figure 34: End-of-life temperature distribution in the Warrior Formation—serving the 100% heat demand of Almono.

5.3 SYSTEM DESIGN COST AND LEVELIZED COST OF HEAT ESTIMATE

The same cost model and financial parameters used for the Southpointe LCOH calculations are used here for the Almono study. The same level of uncertainty can be expected for this analysis as for Southpointe (ca. +/- 30%).

Above-Ground Infrastructure for Geothermal Heating System

Building HVAC design – As for Southpointe, this study assumed hydronic-to-air heat exchangers in each building to use standard building HVAC infrastructure as much as possible. Table 20 shows the number of buildings being served by this design and the number and cost of their hydronic-to-air units. The AHU capacity employed corresponds to the lower end of the range of register temperatures specified for forced-air heating. This assumes high-efficiency buildings, commensurate with new buildings being planned for Almono. An estimate for the number of medium-sized buildings (ca. 50,000 ft^2) that can be served was calculated based on the total square footage currently planned by Almono developers (see Section 1). As a result, the total cost of all space heating equipment (specific to the DDU system under consideration) is estimated to be $6.1 million.

Table 20: Cost for Planned District Building Hydronic-to-Air Heat Exchangers

Hydronic Air Handling Units		
AHU capacity	[Btu/hr]	25,800
AHUs needed per medium building	[-]	15
AHU installed cost per medium building	[$/med.bldg]	47,925
Number of buildings (medium) that can be served	[-]	127
AHU installed cost for site	[$]	$6,086,475

Site district water distribution network – The final site plan for Almono (Hazelwood Green) is still to be developed. However, one concept for a district system can be conceived here. Using architectural sketches of Almono (see Figure 4), a district loop may be laid along the streets. This maximizes the accessibility to the district loop for measurements and maintenance. The district loop to be considered here makes up a slightly bent rectangle along the length of Almono; its width matches the narrow end of the Almono site, and its length approximately matches the full length of the site. It is assumed that within this district loop resides the heat exchanger needed to exchange heat between the geothermal fluid and above-ground hydronic water (i.e., between the "geofluid loop" and the "district loop"). The annual flow-rate profile used for sizing the distribution piping for this system is calculated by applying a 24-hr running average to the heat-demand history from the EnergyPlus™ building response discussed above. The pipe diameter of the above-ground district loop is 8.75 inches to match the down-hole pipe diameter. This results in a pressure drop through the entire district loop of 927 psi. Given the large range of flow rates during operations, it is assumed that two pumps are employed on the supply (one to boost pressure for the high range and one to cover the low range). The same setup is assumed on the return line. The cost for installing this pipe is determined using installation cost as a function of diameter as given by (Rafferty, 1996), but is adjusted to account for the more recently experienced installation cost of Farralon. By this method, including inflation between 2013 and 2018 (Inflation Calculator, 2018), the material and installation cost was calculated for the Almono loops to be $419/ft. This brings the cost for the main distribution loop to $7.7 million. Branch pipe to deliver hot water to each building is similarly analyzed, but with a total cost of $13.7 million. Given all of the above, the total capital cost for the pipe network and pumps (including one spare pump) is around $21.5 million.

Pumping power for district hot water distribution – To calculate the annual pumping energy required to circulate heated water through the district loop, the same assumptions and calculations were performed as for Southpointe. Table 21 shows the resultant kilowatt-hours required to circulate this hydronic fluid throughout a given year. The local electricity price of 3.72 cents per kW-hr was applied to this energy requirement (ElectricityLocal, 2018), and resulted in $63,700 for the annual operating cost.

Table 21: District Loop Pumping Requirements and Annual Costs

Energy to Circulate the Loop for a Year		
Pump efficiency	[-]	0.59
Energy	[kWh/yr]	1,713,883

Well Hardware Installation and Operation

Well costs – As presented in Section 5.2 and summarized in Table 18, only one geothermal rock formation was considered for Almono—the Warrior Formation. The cost for boring the wells was calculated using values from the literature and from industry, where it is often seen that the first (exploratory) well costs slightly more than the second (production or injection) well due to having different objectives, additional formation testing, and costs for converting an exploration well into a production or injection well. The geometrical inputs for the well calculations include casing diameter, vertical depth, radius of the curve drilled to initiate the horizontal bore-hole, and the length of the horizontal bore-hole. Cost estimates are presented in Tables 22 and 23.

Geofluid-to-hydronic water heat-exchanger system installation cost – The hot geofluid from the production well must be routed to a heat exchanger to deliver heat to the hydronic water in the surface piping network described above and then back through the subterranean reservoir. This study assumed 1,000 ft each of pipeline *to* and *from* the heat exchanger connecting to the production and injection well, for a total pipe installation of 2,000 ft. The diameter of pipe used for these connections matches the well casing or production tubing diameter (I.D.): 6 inches. Using the same type of installation as assumed for the district loop, the installed price for the geofluid loop is about $419/ft. This makes the total install cost of the pipe of 2 x $419/ft x 1,000 ft = $839,000.

The cost of the geofluid-to-hydronic water heat exchanger is based on the price of the Camp Dawson heat exchanger as normalized by the peak heat transfer rate for which it was designed—$9,857 per MMBtu/hr. Applying Almono's peak of 19.5 MMBtu/hr, this study arrived at a heat-exchanger cost of about $192,000. In the same way, the price of the below-ground geofluid circulation pumps is estimated from a flow normalization of the pump costs in the Camp Dawson report (Means et al., 2017). Assuming a pump each for injection and production wells, plus a spare, this study arrived at a cost for the Almono project of about $405,000 for all pumps for the 70% geothermal source case, where peak loads are met by the boiler system, and as much as $1,120,000 for the 100% geothermal case, where the geothermal subsystem alone must meet the winter peak load conditions.

Geofluid system operation – Following the calculation for Southpointe to determine the Geofluid pumping costs, Almono's operating cost estimate is less than $42,000/yr (Table 23).

Table 22: Summary of Well Capital and Operating Costs for Almono

Case	Lateral Length	Initial (Injection) Well	Second (Production) Well	Pump-power Cost	GeoHeat Share	Max pump-flow	NG Peak Load
	[ft]	[$MM]	[$MM]	[$/yr]		[gpm]	[MMBtu/hr]
Warrior Resource 70% DDU Heat Load	1550	$ 13.83	$ 8.43	$ 23,926.94	70%	744	13
Warrior Resource 91% DDU Heat Load	1680	$ 14.13	$ 8.60	$ 41,161.31	91%	1203	9
Warrior Resource 100% DDU Heat Load	2250	$ 15.44	$ 9.36	$ 36,319.80	100%	2054	0

Table 23: Summary of Well Capital and Operating Costs for Almono

Case	Well Pumps	Heat Exchanger	Surface Geofluid Pipe	Capital Subtotal	Annual, Variable, Non-fuel O&M
	[$]	[$]	[$]	[$1000]	[$]
Warrior Resource 70% DDU Heat Load	405,622	192,185	838,888	23,693.14	23,926.94
Warrior Resource 91% DDU Heat Load	656,102	192,185	838,888	24,416.19	41,161.31
Warrior Resource 100% DDU Heat Load	1,120,100	192,185	838,888	26,952.21	36,319.80

Natural Gas Peak Heating

For two of the geothermal cases, it is assumed that a portion of the heating load (so-called peak load) is supported through natural-gas-fueled boilers. Also, this study desired to compare these geothermal DDU scenarios with two different NG boiler district heating solutions: (1) district-level NG heating, and (2) NG heaters (either hydronic or forced air) within each building. The capital and operating costs of these systems are covered in this section.

Capital cost of NG piping – As noted in the introduction to this section, a notably different site situation exists for Almono versus Southpointe. Almono is a new development whereas Southpointe is a retrofit where (per this assumed analysis) currently all buildings already employ NG heating units. As a result, for Almono, the base case in which all buildings use their own NG boiler needs to include the cost of distributing NG to each building. For the cases where an NG boiler is used as backup to geothermal heating, or where a district boiler supplies all heat to the site, just the cost of NG pipe used to supply the central boiler is included. For the 100% DDU case, no NG pipe is assumed required for the site and so the cost is zero. (Note: There may be other reasons to distribute NG through the site, but such needs are not considered for this study.) The capital cost for these two different cases is summarized in Table 24.

Table 24: Capital Cost of NG Distribution Pipe for Almono

	Stand Alone Natural-gas Forced Air	District Boiler Hydronic Heating	Warrior Resource 70% DDU Heat Load	Warrior Resource 91% DDU Heat Load	Warrior Resource 100% DDU Heat Load
Installed Cost of NG Pipe	$ 21,435,277.19	$ 2,565,126.62	$ 2,565,126.62	$ 2,565,126.62	$ -

Capital cost of NG boilers – Given the 24-hr smoothed load curve due to thermal mass of each building, the hydronic system, and the assumed independent heating controls on the "district" buildings, the geothermal system under study here was able to contribute up to 32% of the peak heat load required by the targeted site for the 70% of annual load case, and 53% for the 91% of annual load case. Beyond this capped heat flow rate, the balance of heat demand is provided by NG hot-water "boilers." The maximum hourly demand for the 70% case gives a boiler capacity requirement of 13 MMBtu/hr; for the 91% case, the boiler requirement would be 9.2 MMBtu/hr; and for the stand-alone boiler cases, it would be 19MMBtu/hr. This assessment assumed that a set of boilers (~2 MMBtu/hr capacity each and a cost of $32.4k each) will provide the balance of the heat demand. The 70% geothermal case would require seven boilers; the 91% case would require five boilers; and the non-geothermal district-heating case would use 11 boilers. The requirements for the different cases are summarized in Table 25. The multiple boilers allow a highly variable system with very little loss in efficiency. They also give high redundancy which will lead to high availability in any given year. As for the Southpointe study, it was expected that the majority of this boiler bank can be offline most of the year—see Figure 34.

Table 25: Summary of Almono Boiler Capital Cost

Boiler Capital Cost				
Quoted boiler capacity	[MMBtu/hr]	1.9060		
Quoted boiler price	[$/boiler]	32,422		
Quoted boiler efficiency	[frac.]	0.953		
Calculated heat rate	3tuNG*/MMBtuHW*	1,049,318	*NG=Natural Gas **HW = Hot Water	
Hydronic Case		**Warrior Resource 91% DDU Heat Load**	**Warrior Resource 70% DDU Heat Load**	**District Boiler Hydronic Heating**
Required boiler capacity	[MMBtu/hr]	9.3	13.2	19.5
Number of boilers needed	[-]	5	7	11
Max Capacity	[MMBtu/hr]	9.53	13.342	20.966
Cost for Boilers	[$]	162,110	226,954	356,642
Cost for Boilers	[$1000]	162.11	226.95	356.64

Operating cost of NG boilers – As for Southpointe, it is assumed that the boilers have a 95% efficiency and that the boilers will need to be replaced three times through the 50-yr service life of the geothermal wells and its associated reservoir, given that the useful life of a boiler is on the order of 10–15 years (FannieMae, 2014; Wohlfarth, 2012). To account for these replacements at year 13, year 26, and year 39, a fixed savings rate for replacement is required to be added to the annual operating cost. This savings rate is calculated as the levelized total cost of boilers purchased throughout the 50-yr life. Inflation is considered for the replacement boilers. For the 70% geothermal load case, the annual cost is $10,600, while for the 91% geothermal load case, the annual cost is $7,900. For the stand-alone building-furnace base case, the annual cost is $56,000. And for the NG district boiler base case, the annual cost is $37,500.

Other Capital and Operating Costs

Capital costs of boiler building, heat-exchanger building and well houses – An estimated $20/ft^2, (Means et al., 2017), is used for the cost of a structure housing the NG boilers and geothermal hydronic heat exchanger. The width of the structure is assumed to be 50 ft, and the width of the building is set to accommodate the number of boilers in each case (boilers alone or boilers assisting). Additionally, well houses are assumed constructed at the same cost per square foot and with an assumed 25-ft-by-25-ft size. Overall capital costs are shown in Table 26 below.

Table 26: Capital Cost of Buildings

		Boilers & Hydronic Pump House						HX House	2 Well-Houses
		Boiler-powered Hydronic Heating		Warrior Resource 91% DDU Heat Load		Warrior Resource 70% DDU Heat Load			
		11 boilers	20ft added for HX and piping	5 boilers		7 boilers		1 HX House	
width	[ft]	83	103	38	58	53	73	20	25
depth	[ft]		50		50		50	20	25
area	[sqft]		5,150		2,900		3,650	400	1,250
cost	[$/sqft]		20		20		20	20	20
	[$]		**103,000**		**83,000**		**98,000**	**33,000**	**25,000**

General operating costs – Labor salary costs to maintain the operations of this system are scaled from the data reported for the geothermal district heating system at the City of Courtenay (Salter, 2013). In Salter's report, employment costs are $18.41/MMBtu. Scaled to the heating demand in this study, employee salaries would total about $180,000/yr or three jobs at approximately $60,000.

Levelized Cost of Heat

Given the above assumed financial data, capital costs, and operating costs, a levelized cost of heat was determined via the NETL cost model, which is reported for each case studied in Table 27. A more detailed presentation of the data and input parameters is given in Appendix B. As can be seen in the table, among the cases studied in this report, the lowest-cost approach for meeting the heat demand at Almono is to use individual stand-alone NG boilers located at each building. This approach costs about 28% less than providing heat using a district-style heat management solution using central boilers.

The lowest-cost deep direct use geothermal approach would be to use DDU for 100% of the site demand (although the 70% DDU load case with backup using central boilers is certainly within the margin of error for this analysis). This approach is only 26% more than the stand-alone base case studied. As the table also shows, the higher capital costs of a geothermal system drive the higher LCOH—over 91% of the COH results from the capital cost component for a geothermal system, whereas only 73% results for the stand-alone NG boiler systems. These results for a "new development" are very different from what was seen for the retrofit study of Southpointe. For the Almono study, including the cost of distributing NG throughout the site for the stand-alone case is appropriate so long as there is no other need for NG besides heating. For the retrofit Southpointe study, the NG pipe is assumed to be a "sunk cost," and so is not included in that analysis. While from the present study the cost of DDU heating for Almono is about 26% greater than stand-alone NG heating, it is expected that considerable progress will be made going forward toward reducing the capital cost of this approach—in particular, the cost to develop the well and district systems. This will make DDU geothermal energy more competitive even with today's low costs of NG.

Finally, it is noted that for the Almono site, one concept for the development considered the use of geothermal heat pumps to supply heat to the buildings (ca. 500 shallow wells), having an estimated capital cost of $34 million (district loop cost + geo-source field cost + metering). The annual costs for electricity + gas + maintenance + labor using this approach were estimated to be $2.93 million/yr. Using these values and the same cost model assumptions used in this DDU study, the LCOH was found to be $71.32. As shown in Table 27, this is about 15% less than the cost of the 100% DDU case studied here. So, while conventional geothermal heat pumps are a more mature technology and therefore have less risk, the overall cost of these two approaches can be expected to be similar.

Table 27: Levelized Cost of Heat for Almono: Stand-Alone Building Furnaces, District NG Boiler and Three Geothermal Cases

Case Description	Stand Alone Natural-Gas Forced Air	District Boiler Hydronic Heating	Warrior Resource 70% DDU Heat Load	Warrior Resource 91% DDU Heat Load	Warrior Resource 100% DDU Heat Load
Results					
Total Overnight Capital, $1,000	**$21,968.95**	**$30,856.53**	**$54,439.99**	**$55,083.19**	**$54,841.97**
Escalated Total Overnight Capital, 1000$	**$22,364.39**	**$31,411.95**	**$55,419.91**	**$56,074.69**	**$55,829.12**
Debt, $1,000	**$14,060.51**	**$19,748.72**	**$34,842.54**	**$35,254.20**	**$35,099.82**
Equity, $1,000	**$8,945.76**	**$12,564.78**	**$22,167.96**	**$22,429.87**	**$22,331.65**
Interest During Construction	**$641.88**	**$901.55**	**$1,590.60**	**$1,609.39**	**$1,602.34**
Investment Tax Credit	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
Total As-Spent Capital (TASC) $1,000	**$23,006.27**	**$32,313.50**	**$57,010.50**	**$57,684.08**	**$57,431.46**
Cost of Heat (CoH)					
COP Units	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
Dollar Year / Base year	**2018**	**2018**	**2018**	**2018**	**2018**
Constant, Levelized COH	**$68.36**	**$87.85**	**$88.60**	**$134.12**	**$86.17**
Capital Component of COH	$50.00	$70.23	$78.12	$125.37	$78.70
Variable O&M Component of COH	$0.00	$1.70	$2.34	$2.80	$2.67
Fixed O&M Component of COH	$6.29	$5.80	$5.08	$5.01	$4.80
Primary Fuel/Feedstock Component of COH	$12.06	$10.13	$0.00	$0.00	$0.00
Secondary Fuel/Feedstock Component of COH - $1,000	$0.00	$0.00	$3.05	$0.95	$0.00
Effective Annual Cost for Above Supplied Energy	**$2,564,403**	**$3,295,738**	**$3,323,667**	**$5,031,536**	**$3,232,529**

6. SUMMARY AND CONCLUSIONS

A first-order analysis was conducted for available deep geothermal energy at two eastern United States sites, one a business park and the other a new large-scale development. Results show that heat energy suitable for direct space heating exists at temperatures ca. 150°F–180°F. This heat energy, however, resides at depths ca. 9,000 ft–14,000 ft. While these depths are accessible technically, the present-day high costs of geothermal wells were found to be a limiting factor in providing a successful economic outcome. As part of this study, attempts were made to examine ways to reduce the well size and depth (and hence cost) by lowering the peak energy required from the geothermal source. This was done by considering high-efficiency, low-temperature HVAC systems, such as hydronic in-floor heating, and using auxiliary heating systems, such as NG-fired boilers, to meet the infrequently occurring peak demands. The former was found to still result in high capital costs that are not economically viable, resulting in about three times the levelized cost of conventional warm-air HVAC building systems for retrofit (e.g., Southpointe) scenarios. For greenfield scenarios (e.g., Almono), if NG distribution through the site can be avoided, then the cost of employing geothermal heating is much closer to conventional HVAC. Detailed technical and cost comparisons of several DDU cases at each site were conducted, and results are summarized in Table 28.

For the retrofit scenario (Southpointe), it was found that the overall LCOH for the best direct-use geothermal solution is about $78/MMBTU, which is about four times the cost of NG forced-air solutions. However, for the new development scenario (Almono), the overall LCOH for the best geothermal case is about $86/MMBTU, which is only about 26% above the conventional heating solution given that an NG pipe distribution would be incurred for the latter, whereas it can potentially be avoided when pursuing a DDU solution. Additional offsetting cost savings for Almono came from the fact that Almono is a greenfield project, and hence, could employ higher efficiency HVAC building solutions than the assumed retrofits required for Southpointe. Finally, it was found that both sites, given their respective DDU design, could accommodate a 50-yr lifetime using reasonable well lateral lengths.

For the Almono new development scenario using a DDU solution, approximately 90% of the LCOH comes from capital-related costs, whereas for conventional in-building forced-air solutions burning NG, it was about 78%. For the Southpointe retrofit scenario, the respective values were 80% and 8%. From this observation it is understood that to lower the cost of accessing geothermal energy in the eastern United States, focus will need to be put toward lowering the costs of drilling and distribution systems, which comprise most of the capital costs. For DDU, the greatest project risk occurs during the drilling phase, when significant project costs are incurred and resource viability remains unknown. Work to reduce these risks and costs would allow DDU heating systems to better compete with conventional heating systems.

Comparing the different DDU cases within a given site (70%, 91%, and 100% heat demand met with DDU), it is found that all had closely the same LCOH value ($78, $115, $78 per MMBTU for Southpointe; and $88, $134, and $86 per MMBTU for Almono, respectively). For both sites, the costs relative to 100% DDU were then roughly 100% and 150% for the 70% and 91% DDU cases, respectively. This suggests that, for both retrofit and greenfield scenarios residing within the same environmental region, both will have the same DDU cost comparisons across different fractional DDU heat solutions. The results also suggest that the additional cost of installing a peaking system (due to its infrequent use) will not be warranted from an economic viewpoint over the range of fractional DDU supply analyzed here (70% to 100%). That is, it appears that a

DDU system can be designed to meet peak needs at close to the same or less cost than a system using a smaller DDU setup that employs an NG boiler for meeting infrequent peaking needs. Finally, given these results for Almono (greenfield case) and given the DDU cases came within 26% of a conventional NG solution, it may be of interest in future studies to study lower fractional DDU scenarios to see if further cost reductions can be obtained to make DDU more comparable to conventional NG solution costs.

Finally, using cost data from a prior analysis conducted for Almono where ca. 500 shallow geothermal wells were to be deployed to meet site heating needs, it was found that such an approach was likely to be only about 15% less costly than using a DDU approach as investigated here. While such geothermal heat pump systems are now common and the technology far more mature than DDU geothermal systems, this result would suggest that DDU demonstration studies should be considered to help further mature these options as well. Doing so, along with efforts to reduce the cost of drilling DDU wells, could make such an approach an economically viable option to consider over the eastern United States.

Table 28: Summary of Key Parameters in This Study and Overall Results

Parameter	Almono	Southpointe	Note
Annual Heat Demand	37,500 MMBTU 40,000 GJ (full site—127 medium bldgs)	20,500 MMBTU 22,000 GJ (1/2 site—43 medium bldgs)	The Southpointe analysis assumed the need for a higher operating temperature for the in-building hydronic-to-air HXGRs due to need to accommodate a retrofit. Hence, ½ site for Southpointe is used in this study to obtain 50-yr life from a single well pair. Almono was viewed as a "greenfield" case and could accommodate a higher performance HVAC in the buildings.
Peak Heat Demand (smoothed)	20 MMBTU/hr 5.7 MWth (full site)	19 MMBTU/hr 5.5 MWth (1/2 site)	
Well and System Cost Summary			
Depth to access 150°F (65.6°C)	10,900 ft	8,790 ft	Lifetime model predicted < 50 years. Case not further analyzed.
Depth to access 180°F (82.2°C)	14,276 ft (Warrior Formation)	11,513 ft (Black River Formation)	*Depth found viable to reach max well lifetime of 50 years for both cases.
Lateral required for 50yr, 100% geothermal solution	2,240 ft	2,120 ft	
Lateral required for 50yr, 70% geothermal solution	1,550 ft	1,660 ft	
Total well and geofluid loop cost/Variable O&M cost, 100% geothermal solution	$26,900k (capital) $455k/yr	$18,100k (capital) $300k/yr	Operating costs excludes labor.

Parameter	Almono	Southpointe	Note
Well and System Cost Summary (cont.)			
Total well and geofluid loop cost / Variable O&M cost, 70% geothermal solution	$23,600k (capital) $399k/hr	$16,400k (capital) $288k/yr	Operating costs excludes labor.
Total air handling unit installed cost	$6,080k	$3,055k	
Total district hot water distribution piping installed cost	$21,700k	$4,600k	A larger area is served at Almono, leading to a longer hydronic loop and higher annual heat-demand. Also, lower hydronic loop temperatures for Almono mean higher flow-rates. Higher flow-rates lead to wider trunk-lines. Higher-efficiency buildings leads to more buildings being served on a given heat-demand. This leads to more branch-pipes.
Annual district hot water pumping costs	$63.7k	$2.6k	
Boiler capital cost for 70% geothermal solution/Operating cost	$226k (capital) $10.6k/yr	$259k (capital) $12.2k/yr	Though average demand at Almono is about twice that at Southpointe, peak demand is only slightly higher for Almono than for Southpointe.
Boiler capital cost for District Hydronic solution/Annual boiler replacement cost	$356k (capital) $37.5k/yr	$324k (capital) $34k/yr	District managed NG boiler heat solution. Assumes boiler replacement every 13 years.
Building costs: • **100%geo. therm.** • **70%geo. therm.**	• $58k • $123k	• $58k • $131k	
Labor costs	$180k/yr	$180k/yr	Same labor requirements assumed for all cases.
Levelized Cost of Heat Results			
Stand-alone NG base case	$68/MMBTU	$25/MMBTU	Assumes in-building NG forced air. For the Southpointe retrofit case, the site NG distribution costs were already a sunk cost so not included in the LCOH retrofit assessment.
District boiler heating	$87/MMBTU	$54/MMBTU	See above note for district hot water distribution.
70% DDU heating	$88/MMBTU	$78/MMBTU	
100% DDU heating	$86/MMBTU	$78/MMBTU	

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APPENDIX A. ABOVE GROUND DISTRICT PARAMETERS

Table A.1: Assumed District Thermal Loop Design Parameters for Southpointe and Almono

Parameter	Unit of Measure	Southpointe	Almono
Annual demand	[kJ/yr]	2.17 E10	3.96 E10
Max flow	[kg/hr]	196,612	514,124
Min flow	[kg/hr]	63,500	148,000
Trunk-loop perimeter	[m]	1,567	5,592
Trunk-line diameter	[in]	6	12.75
Average branch length	[ft]	165	300
Branch diameter	[in]	1.75	1.75
Number of branches	[-]	43	127

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APPENDIX B. COST MODEL INPUT VALUES AND RESULTS

Table B1: Detailed Financial Analysis for Southpointe Using NETL Cost Model

Case Description	Stand-Alone Natural-gas Forced Air	District Boiler Hydronic Heating	Trenton Black-River Resource 70% DDU Heat Load	Trenton Black-River Resource 91% DDU Heat Load	Trenton Black-River Resource 100% DDU Heat Load
Financial Inputs (see Note 2)					
Finance Structure Description	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**
Financial Methodology	Project	Project	Project	Project	Project
Debt Percentage Applied to TASC or TOC?	TOC	TOC	TOC	TOC	TOC
Enter Debt Percentage	60%	60%	60%	60%	60%
Equity Percentage	40%	40%	40%	40%	40%
Economic Life of Plant (Years)	50	50	50	50	50
Construction/Capital Expenditure Period (Years)	**2**	**2**	**2**	**2**	**2**
Debt Repayment Term (Years) for Project Financing	15	15	15	15	15
Base year (Year of Dollar value Entries)	2018	2016	2016	2016	2016
Investment Tax Credit (%TOC)	0%	0%	0%	0%	0%
Maximum Tax Credit ($1,000)	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Tax Rate	38%	38%	38%	38%	38%
Carbon Tax ($ per tonne of CO_2-e)	$0	$0	$0	$0	$0
Capital Depreciation Schedule (See Depreciation Table on Dep_CF_Tables Sheet)	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr
Number of years for Straight Line Depreciation if SL selected	0	0	0	0	0
Capital Depreciation number of years	15	15	15	15	15
Dollar Basis for Analysis type?	Nominal	Nominal	Nominal	Nominal	Nominal
Inflation Rate	2.0%	2.0%	2.0%	2.0%	2.0%
Real Escalation Rate for COP and All O&M (See Note 1)	1.0%	1.0%	1.0%	1.0%	1.0%
Nominal Escalation Rate for COP and All O&M (See Note 1)	3.0%	3.0%	3.0%	3.0%	3.0%
Nominal Cost of Debt /Interest Rate	4.5%	4.5%	4.5%	4.5%	4.5%
Real Cost of Debt /Interest Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Nominal Internal Rate of Return on Equity (IRROE)	12.0%	12.0%	12.0%	12.0%	12.0%
Real Required Internal Rate of Return on Equity (IRROE)	9.8%	9.8%	9.8%	9.8%	9.8%
Construction / Capital Expenditure Input					
Nominal Capital Cost Escalation During Capital Expenditure Period (annual rate)	3.6%	3.6%	3.6%	3.6%	3.6%
Real Capital Cost Escalation During Capital Expenditure Period (annual rate)	1.6%	1.6%	1.6%	1.6%	1.6%
Include Interest During Construction?	Yes	Yes	Yes	Yes	Yes
Capital Disbursements per year (for interest calculation)	12	12	12	12	12
Capital Distribution over expenditure period					
% First year	50%	50%	50%	50%	50%
% Second year	50%	50%	50%	50%	50%
% Third year	0%	0%	0%	0%	0%
TOTAL	100%	100%	100%	100%	100%
Results					
Total Overnight Capital, $1,000	**$456.43**	**$8,104.01**	**$24,489**	**$25,136.26**	**$25,810**
Escalated Total Overnight Capital, $1,000	$465	$8,250	$24,930	$25,589	$26,274
Debt, $1,000	$292	$5,187	$15,674	$16,088	$16,519
Equity, $1,000	$186	$3,300	$9,972	$10,235	$10,510
Interest During Construction	$13	$237	$716	$734	$754
Investment Tax Credit	$0	$0	$0	$0	$0
Total As-Spent Capital (TASC) $1,000	**$478**	**$8,487**	**$25,646**	**$26,323**	**$27,028**
TASC/TOC Ratio	1.0472	1.0472	1.0472	1.0472	1.0472
Analysis Dollar Type (Real = Constant dollars, Nominal = Current dollars)	**Nominal**	**Nominal**	**Nominal**	**Nominal**	**Nominal**
After-Tax Weighted Average Cost of Capital (ATWACC)	6.37%	6.37%	6.37%	6.37%	6.37%
Debt Percentage (TASC)	61.12%	61.12%	61.12%	61.12%	61.12%
Debt Percentage (TOC)	60.00%	60.00%	60.00%	60.00%	60.00%
Equity Percentage (TASC)	38.88%	38.88%	38.88%	38.88%	38.88%
Equity Percentage (TOC)	40.00%	40.00%	40.00%	40.00%	40.00%
Levelization Factor	1.5845	1.5845	1.5845	1.5845	1.5845
FCFF/Corporate Capital Charge Factor - based on constant/levelized capacity factor (see Note 3)	0.0538	0.0538	0.0538	0.0538	0.0538
Base Year FCFF Capital Charge Factor - based on capacity factor ramp (see Note 3)	0.0538	0.0538	0.0538	0.0538	0.0538
FCFE/Project Capital Charge Factor - based on constant/levelized capacity factor (see Notes 3, 5, & 6)	0.0854	0.0854	0.0854	0.0854	0.0854
Base Year FCFE Capital Charge Factor - based on capacity factor ramp (see Notes 3, 5, & 6)	0.0854	0.0854	0.0854	0.0854	0.0854

Case Description	Stand-Alone Natural-gas Forced Air	District Boiler Hydronic Heating	Trenton Black-River Resource 70% DDU Heat Load	Trenton Black-River Resource 91% DDU Heat Load	Trenton Black-River Resource 100% DDU Heat Load
Cost of Product (CoP)					
Financial Methodology	Project	Project	Project	Project	Project
COP Units	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
Dollar Year / Base year	**2018**	**2016**	**2016**	**2016**	**2016**
Constant, Levelized COP	**$25.02**	**$54.24**	**$78.13**	**$115.98**	**$78.02**
Capital Component of COP	$1.89	$33.59	$64.00	$104.19	$67.46
Variable O&M Component of COP	$0.00	$0.13	$1.76	$1.70	$1.83
Fixed O&M Component of COP	$11.07	$10.39	$9.33	$9.18	$8.74
Primary Fuel/Feedstock Component of COP	$12.06	$10.13	$0.00	$0.00	$0.00
Levelized COP	$39.65	$85.94	$123.79	$183.77	$123.62
First Year of Operation	**2020**	**2018**	**2018**	**2018**	**2018**
COP in First Year of Operation Dollars	**$26.55**	**$57.54**	**$82.89**	**$123.05**	**$82.77**
Effective Annual Cost for Above Supplied Energy	**$515,426**	**$1,117,202**	**$1,609,348**	**$2,389,072**	**$1,607,130**

Table B2: Detailed Financial Analysis for Almono Using NETL Cost Model

Case Description	Stand Alone Natural-gas Forced Air	District Boiler Hydronic Heating	Warrior Resource 70% DDU Heat Load	Warrior Resource 91% DDU Heat Load	Warrior Resource 100% DDU Heat Load
Financial Inputs					
Finance Structure Description	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**	**IPP from PSFM 8.0**
Financial Methodology	Project	Project	Project	Project	Project
Debt Percentage Applied to TASC or TOC?	TOC	TOC	TOC	TOC	TOC
Enter Debt Percentage	60%	60%	60%	60%	60%
Equity Percentage	40%	40%	40%	40%	40%
Economic Life of Plant (Years)	50	50	50	50	50
Construction/Capital Expenditure Period (Years)	**2**	**2**	**2**	**2**	**2**
Debt Repayment Term (Years) for Project Financing	15	15	15	15	15
Base year (Year of Dollar value Entries)	2018	2018	2018	2018	2018
Investment Tax Credit (%TOC)	0%	0%	0%	0%	0%
Maximum Tax Credit ($1,000)	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Tax Rate	38%	38%	38%	38%	38%
Carbon Tax ($ per tonne of CO_2-e)	$0	$0	$0	$0	$0
Capital Depreciation Schedule (See Depreciation Table on Dep_CF_Tables Sheet)	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr	SL15-1/2 yr
Number of years for Straight Line Depreciation if SL selected	0	0	0	0	0
Capital Depreciation number of years	15	15	15	15	15
Dollar Basis for Analysis type?	Nominal	Nominal	Nominal	Nominal	Nominal
Inflation Rate	2.0%	2.0%	2.0%	2.0%	2.0%
Real Escalation Rate for COP and All O&M (See Note 1)	1.0%	1.0%	1.0%	1.0%	1.0%
Nominal Escalation Rate for COP and All O&M (See Note 1)	3.0%	3.0%	3.0%	3.0%	3.0%
Nominal Cost of Debt /Interest Rate	4.5%	4.5%	4.5%	4.5%	4.5%
Real Cost of Debt /Interest Rate	2.5%	2.5%	2.5%	2.5%	2.5%
Nominal Internal Rate of Return on Equity (IRROE)	12.0%	12.0%	12.0%	12.0%	12.0%
Real Required Internal Rate of Return on Equity (IRROE)	9.8%	9.8%	9.8%	9.8%	9.8%
Construction / Capital Expenditure Input					
Nominal Capital Cost Escalation During Capital Expenditure Period (annual rate)	3.6%	3.6%	3.6%	3.6%	3.6%
Real Capital Cost Escalation During Capital Expenditure Period (annual rate)	1.6%	1.6%	1.6%	1.6%	1.6%
Include Interest During Construction?	Yes	Yes	Yes	Yes	Yes
Capital Disbursements per year (for interest calculation)	12	12	12	12	12
Capital Distribution over expenditure period					
% First year	50%	50%	50%	50%	50%
% Second year	50%	50%	50%	50%	50%
% Third year	0%	0%	0%	0%	0%
TOTAL	100%	100%	100%	100%	100%
Results					
Total Overnight Capital, $1,000	**$21,968.95**	**$30,856.53**	**$54,440**	**$55,083.19**	**$54,842**
Escalated Total Overnight Capital, $1,000	$22,364	$31,412	$55,420	$56,075	$55,829
Debt, $1,000	$14,061	$19,749	$34,843	$35,254	$35,100
Equity, $1,000	$8,946	$12,565	$22,168	$22,430	$22,332
Interest During Construction	$642	$902	$1,591	$1,609	$1,602
Investment Tax Credit	$0	$0	$0	$0	$0
Total As-Spent Capital (TASC) $1,000	**$23,006**	**$32,313**	**$57,011**	**$57,684**	**$57,431**
TASC/TOC Ratio	1.0472	1.0472	1.0472	1.0472	1.0472
Analysis Dollar Type (Real = Constant dollars, Nominal = Current dollars)	**Nominal**	**Nominal**	**Nominal**	**Nominal**	**Nominal**
After-Tax Weighted Average Cost of Capital (ATWACC)	6.37%	6.37%	6.37%	6.37%	6.37%
Debt Percentage (TASC)	61.12%	61.12%	61.12%	61.12%	61.12%
Debt Percentage (TOC)	60.00%	60.00%	60.00%	60.00%	60.00%
Equity Percentage (TASC)	38.88%	38.88%	38.88%	38.88%	38.88%
Equity Percentage (TOC)	40.00%	40.00%	40.00%	40.00%	40.00%
Levelization Factor	1.5845	1.5845	1.5845	1.5845	1.5845
FCFF/Corporate Capital Charge Factor - based on constant/levelized capacity factor (see Note 3)	0.0538	0.0538	0.0538	0.0538	0.0538
Base Year FCFF Capital Charge Factor - based on capacity factor ramp (see Note 3)	0.0538	0.0538	0.0538	0.0538	0.0538
FCFE/Project Capital Charge Factor - based on constant/levelized capacity factor (see Notes 3, 5, & 6)	0.0854	0.0854	0.0854	0.0854	0.0854
Base Year FCFE Capital Charge Factor - based on capacity factor ramp (see Notes 3, 5, & 6)	0.0854	0.0854	0.0854	0.0854	0.0854
Cost of Product (CoP)					
Financial Methodology	Project	Project	Project	Project	Project
COP Units	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu	$/MMBtu
Dollar Year / Base year	**2018**	**2018**	**2018**	**2018**	**2018**
Constant, Levelized COP	**$68.36**	**$87.85**	**$88.60**	**$134.12**	**$86.17**

Case Description	Stand Alone Natural-gas Forced Air	District Boiler Hydronic Heating	Warrior Resource 70% DDU Heat Load	Warrior Resource 91% DDU Heat Load	Warrior Resource 100% DDU Heat Load
Capital Component of COP	$50.00	$70.23	$78.12	$125.37	$78.70
Variable O&M Component of COP	$0.00	$1.70	$2.34	$2.80	$2.67
Fixed O&M Component of COP	$6.29	$5.80	$5.08	$5.01	$4.80
Primary Fuel/Feedstock Component of COP	$12.06	$10.13	$0.00	$0.00	$0.00
Levelized COP	$108.31	$139.20	$140.38	$212.51	$136.53
First Year of Operation	**2020**	**2020**	**2020**	**2020**	**2020**
COP in First Year of Operation Dollars	**$72.52**	**$93.20**	**$93.99**	**$142.29**	**$91.41**
Effective Annual Cost for Above Supplied Energy	**$2,564,403**	**$3,295,738**	**$3,323,667**	**$5,031,536**	**$3,232,529**

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