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Feasibility of Deep Direct-Use for District-Scale Applications in a Low-Temperature Sedimentary Basin

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ABSTRACT

A feasibility study of using deep direct-use (DDU) geothermal energy to heat agricultural research facilities (ARFs) was conducted at the University of Illinois at Urbana-Champaign (U of IL) and its similar application to military facilities in the Illinois Basin (ILB). The geothermal energy system (GES) investigated utilizes low-temperature (30–90°C; 90–190°F) geothermal fluid (i.e., brine) from an extraction well that is part of a deep, two-well (doublet) system that extends to the bottom of the ILB. The geothermal reservoir modeled, the Mt. Simon Sandstone (MSS), is about 1,280 m (4,200 feet) deep and 457 m thick (1,500 feet) beneath the U of IL. The DDU GES surface infrastructure includes heat exchangers connected in-parallel to pipelines carrying the geothermal fluid and fresh cold and hot water. Analysis of the GES indicated that the MSS can provide a baseload of 2 MMBtu/hr to heat the ARFs by extracting 954 m³/d (6,000 barrels/day [bbl/d]) of geothermal fluid that has a temperature of 44–46 ℃ (111–115 ℉).

In addition to analyzing the levelized cost of heat (LCOH) and life cycle costs, the environmental effects of the DDU GES were evaluated, including reduced greenhouse gas (GHG) emissions and water consumption. Multiple system designs were evaluated and then ranked based on their maximum heating performance, energy efficiency, and cost recovery. This study addressed the major issues associated with DDU implementation in the ILB and met the following objectives: (1) reduce geologic uncertainty, (2) minimize drilling risk, (3) optimize system performance and flexibility with reliable fluid delivery, and (4) support task expertise through established partnerships.

1. INTRODUCTION

Academic campuses and military installations are aggressively pursuing targets to significantly reduce their carbon footprints and enhance operational resiliency. As such, renewable energy generation and distribution options are being considered to provide an uninterruptible source of energy, increase resilience to extreme weather conditions, reduce U.S. fossil fuel dependency, and offset carbon dioxide equivalent GHG emissions. While the primary motivation of universities may be to reduce GHG emissions, many are finding that on-campus, renewable energy initiatives create 1) significant economic advantages, 2) provide new educational opportunities, 3) support energy security, and 4) create jobs in the “green” renewable energy sector.

Of the low carbon, renewable energy sources available to universities—including solar, wind, biomass, and geothermal—it is geothermal energy that offers the greatest dependability to supply a constant thermal load and least impact to the energy grid (Cross et al., 2011). Geothermal resources offer an efficient, competitive, and renewable energy alternative for heating and cooling classroom and research buildings like the ARF. Additionally, geothermal resources are found in virtually all parts of the U.S., and developing them is regarded as a smart environmental and economic investment. Of the many advantages offered by utilizing geothermal energy resources, the relatively short return on investment and longevity of GES are considered most favorable compared with other sources of renewable energy (Cross et al., 2011). The cost of installation is recouped by significant energy cost savings over the lifespan of the GES. Its long-term environmental benefits are very attractive to universities, especially since the heating, cooling, and dehumidification of buildings are their largest emitters of GHG and require significant energy loads.

The flexibility associated with installing GES in district-scale energy systems is another major advantage. Whether constructing new buildings or renovating older structures, the GES can be designed to provide all or part of an end-user’s heating and cooling requirements. Also, the systems are built belowground, and therefore do not compete for limited space, especially in congested urban environments. Moreover, unlike solar panels or wind turbines, geothermal boreholes and piping are hidden, and out of sight, such that the aboveground can be utilized for other purposes. Although its belowground location is advantageous, as a result, owners looking to demonstrate their environmental and economic benefits will likely need to provide some type of education.

At the U of IL, the administration and students are pursuing an aggressive strategy towards a sustainable campus environment and becoming carbon neutral by entirely eliminating or offsetting GHG emissions as soon as possible, and no later than 2050 (iCAP, 2015). To achieve this goal, the U of IL established the first "Illinois Climate Action Plan" (iCAP) in 2010, which is currently being updated for the third time. The latest revision will be released sometime in late 2020. The iCAP lays out a pathway for reaching the "zero carbon target", which considers a range of objectives, including energy generation, distribution, and conservation. There is a growing consensus at the U of IL that electricity generation by solar and wind systems alone cannot meet the "zero carbon target", and that geothermal energy is an important resource to explore to complement the existing renewable energy portfolio. Of particular interest to the U of IL is installing DDU GES, particularly at facilities not connected to the campus district energy system (e.g., ARF in the South Farm) or places where a it can replace a large heating and/or cooling load or provide thermal storage for a multi-building complex. Strategic use of geothermal energy can be a key component of a climate action plan. While improving energy efficiency and reducing demand are essential approaches to cutting a campus carbon footprint, using low carbon renewables like geothermal energy can provide additional reductions fossil fuel usage that contributes to the long-term environmental and economic benefits.

The objective of this feasibility study is to evaluate the application of a DDU GES to extract thermal energy from the ILB to heat six ARF. The ILB is a low-temperature (30–90 °C; 90–190 °F) sedimentary basin (cf., Williams et al., 2015; Akar and Turchi, 2016) covering ~155,000 km^2 (~60,000 square miles) of Illinois and adjacent states (Figure 1). *In-situ* temperature and fluid volume are the two key parameters involved in calculating the available geothermal resources. The ILB contains the prolific, water-bearing MSS that is the focus of the geothermal resource assessment conducted as part of this feasibility study, which constitutes the first assessment of geothermal resources in the ILB. The MSS is an extensive unit found across the ILB (Frailey et al., 2011). Within its lower part lies an arkosic sandstone with the highest formation porosity, known as the Lower Mt. Simon Sandstone (LMSS). The LMSS geology exemplifies exceptional reservoir qualities. Much of the original, primary porosity in the lower part of the LMSS is preserved, also creating a high-quality reservoir rock. Besides this work for the ARFs, the total geothermal resource in the *entire* ILB was also estimated (Figure 1).

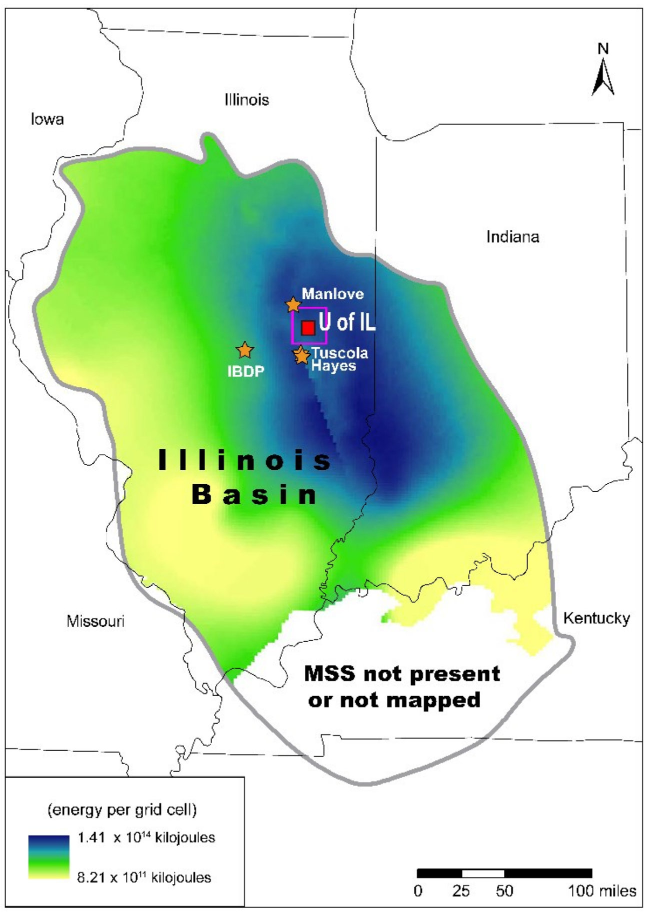

Figure 1. Location of the study site in the ILB. The pink box delineates the extent of geologic, geocellular, and reservoir models that were completed; an area covering 93 km^2 (36 square miles). Also, the orange stars denote the Manlove and Tuscola natural gas (NG) storage fields, the Illinois Basin–Decatur Project (IBDP), and the Hayes oil field. The geothermal resources available in the MSS is represented by the colored shading.

The breadth of previous, geologic-based research conducted in the ILB supported a thorough estimation of the geothermal resources in the MSS. Estimating the geothermal resources involved a rigorous evaluation of borehole and laboratory data, geologic and geocellular modeling, and geothermal reservoir and wellbore simulations. The data used came from geologic records, wireline logs, and petrophysical analyses of core samples obtained drilling oil fields and natural gas (NG) and CO_2 storage wells. The majority of the data came from work conducted at Manlove NG storage field, Illinois Basin Decatur Project (IBDP), Tuscola NG storage field, and Hayes oil field (Figure 1).

The top of the Lower Mt. Simon Sandstone (LMSS) is ~1,750 m (5,745 feet) beneath the U of IL. To harness its thermal energy, geothermal fluid extracted from the LMSS is circulated through aboveground infrastructure and injected back into the reservoir at the same extraction depth (Figure 2). The belowground and aboveground components of the DDU GES are designed to meet the required heating baseload of 2 MMBtu/hr for the ARFs, and fluid flow through the system was simulated using an integrated, multi-disciplinary approach. The evaluation of the basin's geology, hydrogeology, and thermogeology was used to assess the feasibility of applying this DDU technology and GES at other types of facilities (e.g., military installations, hospital complexes, and university campuses) located elsewhere in the ILB and in other midcontinent sedimentary basins. For these facilities, the DDU GES can secure a long-term supply of heating and cooling, consequently reducing GHG emissions while simultaneously increasing energy security and improving energy resiliency.

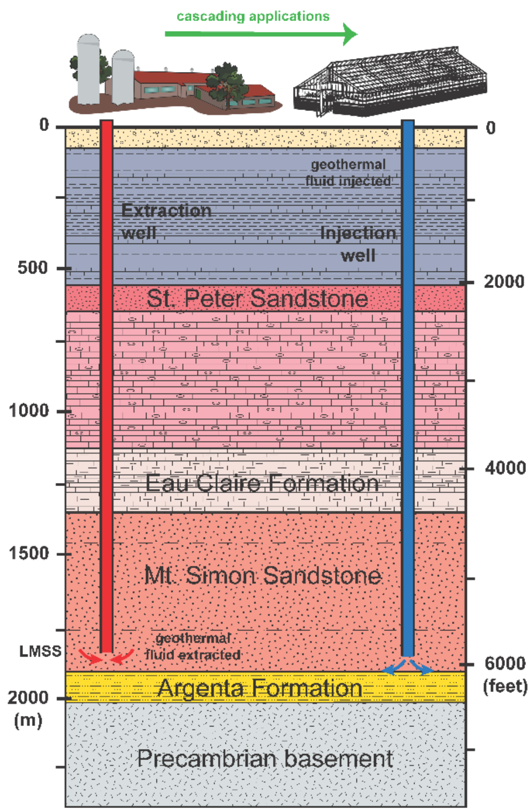

Figure 2. Schematic diagram of the two-well (doublet) system designed for the DDU GES at the U of IL.

2. GEOTHERMAL RESERVOIR CHARACTERIZATION

2.1 Geologic and Geocellular Modeling

Geologic and geocellular models were developed to characterize the *in-situ* sedimentary architecture and inherent hydraulic and thermal properties of the MSS. The models were based on a geologic framework built around a stratigraphy that includes the recent Quaternary glacial deposits down into the Precambrian basement (Lin et al., 2020). The stratigraphy contains updated information about the bedrock geology of Champaign County (Nelson, in press); the county where the U of IL is located.

Hydraulic and thermal properties of all geologic formations were compiled from existing datasets held at the Illinois State Geological Survey (ISGS), and used to determine thermal gradients for the major geologic formations at the U of IL. The formation-specific thermal gradients were based primarily on continuous distributed temperature sensing (DTS) measurements taken at the IBDP (Schlumberger Carbon Services, 2012). The thermal gradients were fitted to the bottomhole temperatures (BHT) at the Manlove and Tuscola NG storage fields and in wells at Hayes oil field, as well as DTS measurements in a geothermal monitoring well at the U of IL Energy Farm (Lin et al., 2019; Stumpf et al., 2018). This detailed analysis using formation-specific thermal gradients yielded temperatures between 44℃ and 46°C (111 °F and 115 °F) for the LMSS.

Information on the heterogeneity and spatial distributions of the LMSS (reservoir rock), Eau Claire Formation (caprock), Argenta Formation, and Precambrian basement in the ILB, and the geostatistical analysis performed as part of the reservoir characterization, informed development of the geocellular model (Okwen et al., 2020). Within the model, three subzones were differentiated in the Precambrian basement. Each of the formations were assigned average hydraulic and thermal properties published in various books and reports (e.g., Waples and Waples, 2004; Freiburg et al., 2014). The LMSS was assigned a porosity of 15.1 %.

2.2 Geothermal Reservoir Modeling

The geocellular model was used to perform geothermal reservoir simulations of the LMSS in order to determine changes in reservoir temperature for 50 years while operating the GES. In designing the doublet well system, simulations were run to evaluate the sensitivity of reservoir temperature to variations in several parameters: well spacing, extraction and injection rates, injection temperature, and changes in seasonal (ambient) ground surface temperature.

Temperature changes at the ground surface caused subsurface temperatures near the injection well to fluctuate, seasonally, between 2.8 ℃ and 5.6 ℃ (5.0 ℉ and 10.0 ℉). Higher injection temperatures only increased the temperature near the injection well; there was no significant impact on the movement of the cold temperature front towards the extraction well (Okwen et al., 2020). To avoid thermal breakthrough at the extraction well, only well spacings >0.8 km (0.5 miles) were simulated.

Reservoir simulations predicted a maximum extraction rate of 3,339 m^3/d (21,000 bbl/d) and a maximum injection rate of 1,431 m^3/d (9,000 bbl/d) (Okwen et al., 2020). Due to its hydraulic properties, the LMSS can provide flow rates which exceed those needed to meet the ARFs' maximum energy demand: 954 m^3/d (6,000 bbl/d). The DDU GES was designed to achieve these flow rates, although the reservoir simulations demonstrate that circulating fluids at the higher flow rates is technically feasible.

2.3 Wellbore Modeling

Wellbore modeling was conducted to simulate temperature changes (i.e., heat loss) during extraction. The extraction and injection rates and formation-specific thermal properties were varied during the simulation. As a result, the temperature change along the wellbore was greater as the extraction rate decreased because, as flow rate decreases, more heat is conducted between the wellbore and surrounding geologic formations. It is possible to control the temperature and maintain a minimum or acceptable magnitude of change (i.e., <0.56 °C; 1.0 °F) by increasing the throughput flow rate or by insulating the wellbore (Okwen et al., 2020).

For the extraction well, applying a coating of silicate foam around the tubular that is 0.952 cm (0.375 inch) thick lowered the expected temperature change more than installing vacuum-insulated tubing. Variations in thermal capacity of geologic formations was not a significant factor in controlling temperature along the extraction wellbore because geothermal fluid temperatures at ground surface eventually stabilized within a narrow temperature range (44–46 °C; 111°–115 °F).

Simulations for the injection wellbore were carried out by varying the flow rate and wellbore diameter (Okwen et al., 2020). Simulation results showed that formation temperature increased at the bottom of the injection wellbore when flow rate remained constant. As the wellbore diameter was increased, the formation temperature at the bottom also increased. In other words, with decreased flow rate in a larger wellbore, more heat is exchanged (i.e., temperature change grew). However, the resulting temperature increase along the injection wellbore remained constant as injection temperatures were varied.

3. ENERGY END-USE MODELING

Establishing heating demands requirements for the ARFs was accomplished using an end-use load analysis and assessing the design capacity of the GES. The energy analysis required averaging the ARFs' historical fuel consumption data (either propane [LPG] or NG), which was available for the period fiscal year (FY) 2015 to FY2017. A preliminary aboveground piping network for the DDU GES design was developed connecting the extraction well, ARFs, and injection well. Simulations of fluid flow through the piping and pumps returned data that was used to determine the required pipe size and insulation materials, pump type, and electrical power requirements (energy consumption included in the annual operating and maintenance [O&M] costs).

Two DDU GES cases were simulated to compare design capacities against the ARFs' current heating loads supplied by their existing, conventional energy systems. Specific components of the energy system, including the heating, ventilation and air conditioning (HVAC) equipment and configuration of hot- and cold-water piping were evaluated to determine the relative compatibility with the expected range in geothermal fluid temperature (44–46 °C or 111–115 °F) and flow rate (954 m^3/d or 6,000 bbl/d).

3.1 End-User Energy Demand

The energy demand was estimated for the six ARFs, which included three existing facilities—the Energy Farm, Poultry Farm, and Beef & Sheep Research Field Laboratory—and three planned facilities—the Feed Technology Center, Imported Swine Research Laboratory (ISRL), and Dairy Farm. At the Energy Farm, the sole fuel source for space heating and making hot water is LPG. The ISRL uses NG and LPG for heating. All the other ARF burn NG to generate heat and make hot water. Since LPG costs reported for the Energy Farm and ISRL only reflect the total amount of gas *delivered*, not necessarily the gas *combusted*, this data was therefore converted into energy consumption by cross-referencing the LPG units of storage with "daily degree days", values that reflect heating (and cooling) demand and provide an estimate of energy consumption (cf., Erbs et al., 1983).

From FY2015 to FY2017, the IRSL used the highest amount of energy, accounting for ~38 % of total consumption at the ARFs (University of Illinois, 2019). The Poultry Farm and Dairy Farm used the lowest amount of energy, consuming <10 % of total consumption. The relatively smaller space heated at the Poultry Farm and the relatively lower heating demand (i.e., lower temperatures) required at the Dairy Farm explain why their overall energy consumption was lower. Typically, NG and LPG consumption at the ARFs is highest in the heating season (late October to early May, and peak energy consumption occurs in the winter months, December to March.

3.2 Hourly Heating Load

Monthly fuel consumption data from FY2015 to FY2017 and hourly climate data from a nearby National Weather Service station (Willard Airport) was used to predict hourly heating demand and hourly peak heating loads. The “degree days” from FY2015 to FY2017 were estimated using a nominal, generally accepted temperature of 18 ℃ (65 ℉). When the ambient air temperature falls below this threshold, then heating is needed. Heating requirements were estimated by summing the “degree days”.

Nearly 90 % of the “degree days” from June to September are negative, signaling a reduction in heating demand. Therefore, the four months of summer are not part of the heating season. During this time, NG and LPG are used primarily for making domestic hot water. Positive degree days, mostly from October to May, with maximums in January and February, are consistent with temporal changes in monthly energy use. The amount of energy used for space heating was determined by subtracting the baseload heating from total energy use. The hourly energy usage for space heating is directly correlated with the seasonal air temperatures. For the ARFs, heating is required for 5,832 hours annually.

3.3 Peak Load

Hourly peak heating at the ARFs reached 5.86 MMBtu/hr in FY2015, 4.42 MMBtu/hr in FY2016 and 5.04 MMBtu/hr in FY2017; averaging 5.68 MMBtu/hr over the three years. Peak heating demand was an important design parameter for the DDU GES. To ensure peak heating load was not underestimated, another approach based on “degree days” (cf. Althouse et al., 2017) was used.

The peak heating load required for the three years was as high as ~6 MMBtu/hr, but only lasted for a short period of time. Heating loads above 5 MMBtu/hr on average are only required for 16 hours per year. Therefore, a baseload of 2 MMBtu/hr satisfies 80% or more of the total annual heating demand.

3.4 Geothermal Fluid Handling

As part of designing the DDU GES, a “virtual” piping system was developed in a geographic information system (GIS) to demonstrate how geothermal fluid and clean water would be circulated between the wells and ARFs (Figure 3). The entire piping system, including the main pipeline carrying the geothermal fluid, will be insulated and buried underground. Insulating the pipeline is necessary to prevent a decrease in fluid temperature that may lead to scaling or precipitation in the pipes. Based on results from the reservoir simulation, the preferred design includes two wells spaced 2.3 km (1.4 miles) apart and located as close as possible to the ARFs to take advantage of the existing electrical grid. A small outbuilding at the extraction well would house the process and control systems, including a surface pump. Positioning the pump at the extraction well allows for immediate heat transfer between the geothermal fluid and clean water. A second outbuilding at the injection well would house a second surface pump that regulates fluid injection, along with control system components.

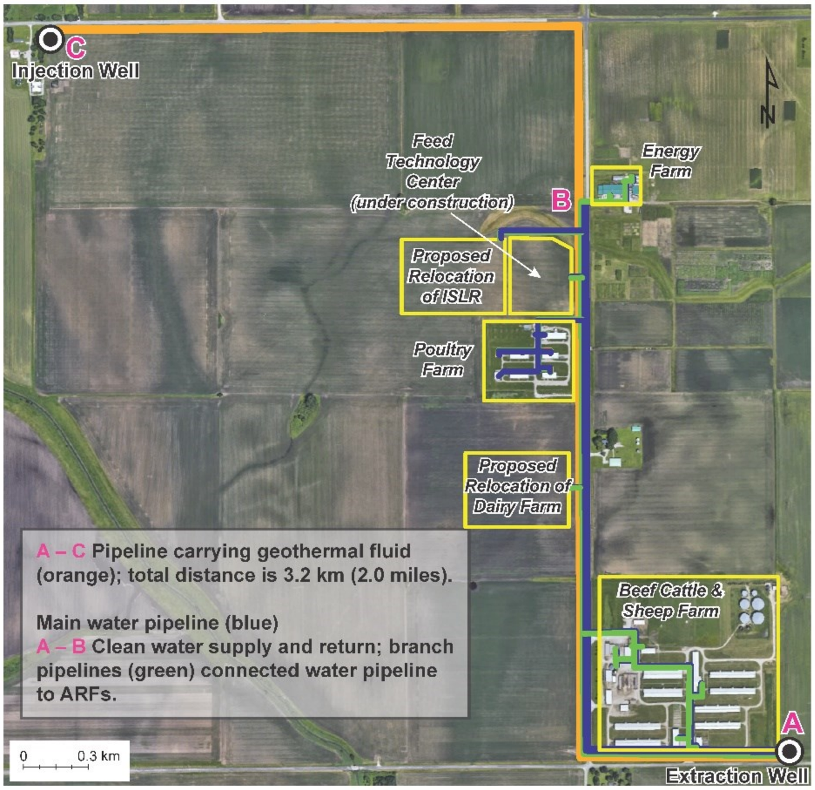

Figure 3. The piping routes for circulating geothermal fluid and clean water. The orange lines delineates the route of the main pipeline carrying the geothermal fluid between the extraction well (A) and injection well (C). The blue and green lines delineate the pipes carrying clean cold and hot water to and from the ARFs.

Three trench systems will be constructed for the pipes carrying geothermal fluid, deliver the clean water supply, and return the rejected clean water. The main pipeline will be 3.2 km (2.0 miles) long running between the extraction well and injection well (Figure 3). The clean water supply and return pipelines are both 1.6 km (1.0 mile) long, running from the heat exchanger at the extraction well to the Energy Farm. Multiple branch lines will supply the heated water from the main supply line to the ARFs and return the cooled water to the main return line.

3.5 Military End-Users in the ILB

While no specific feasibility study or DDU GES design based on the ILB geothermal resource assessment was completed for a military installation, the application of the DDU technology was evaluated for three military installations in the ILB: Rock Island Arsenal (IL), Fort Campbell (KY), and Fort Knox (KY). These installations have annual heating loads of 668,361 MMBtu, 352,499 MMBtu, and 751,452 MMBtu, respectively.

Commercialization strategies should focus on installations with the highest energy requirements and those that have space heating and cooling systems that can fully take advantage of the DDU GES capacity. The feasibility of implementing and commercializing the DDU technology should be based on a holistic analysis that considers issues such as energy security and energy resilience, rather than only focusing on single attributes (e.g., project economics).

4. INFRASTRUCTURE SCHEME

Design parameters and components of the DDU GES include well design (i.e., wellbore size, casing and cement, and tubing), water handling procedures (i.e., pumps, chemical additives, corrosion inhibitors, and temporary fluid storage), and the heating equipment (e.g., heat pumps and heat exchangers). Other design parameters include well spacing and placement with respect to the ARFs and the temperature of the extracted geothermal fluid. Two GES configurations (Cases 1 and 2) were modeled and compared based on their design capacity, energy efficiency, and cost.

4.1 Well Design and Fluid Handling

Changes in the subsurface fluid temperature resulting from reservoir pressure and formation temperature, flow rates (extraction and injection), and geothermal fluid composition influenced the selection of tubular (i.e., casing and tubing) sizing, casing metallurgy, and wellbore insulation materials. To ensure regulatory compliance, the U.S. Environmental Protection Agency (USEPA) and Illinois Environmental Protection Agency (IEPA) were consulted on the type of deep geothermal wells permitted in Illinois by their Underground Injection Control (UIC) programs.

Information about geothermal fluid composition, including salinity or total dissolved solids (TDS) and total suspended solids (TSS) was reviewed to determine the fluid handling requirements. The compatibility of geothermal fluid with DDU GES infrastructure informed which chemical additives were required to prevent scaling, fouling, corrosion, and blockage. Furthermore, the equipment requiring corrosion protection (i.e., heat exchangers and related fluid handling equipment) was identified. Heat transfer modeling was conducted to estimate temperature change along the pipeline that connects the extraction well and the ARFs.

Extraction Well

The extraction well is screened in the LMSS, the deepest part of the MSS, which, coincidentally, has the formation's best hydraulic properties and highest temperature. The extraction well is designed to deliver geothermal fluid from a screened interval in the wellbore between 1,860 m and 1,905 m (6,100 feet and 6,250 feet). The extraction well was designed such that: (1) the casing is wide enough to install a downhole submersible pump with the capacity to meet the required flow rate of 954 m^3/d (6,000 bbl/d) and (2) a cost-effective wellbore insulation can be installed. These two design parameters informed the type and size of the downhole submersible pump as well as tubular sizing.

The pump chosen has a diameter of 0.14 m (5.63 inches); this size requires an extraction well casing with an outer diameter of 0.18 m (7.0 inches). The well design includes intermediate and production casing, which is cemented all the way to the ground surface to prevent leakage from the wellbore into the adjacent geologic formations. The extraction well tubing has an internal plastic lining to prevent corrosion. A packer is used so that the insulating fluid can be placed in the tubing-casing annulus and protect the casing from corrosion. To further maintain the casing integrity in the LMSS, the joints will be made of chrome alloy. The estimated cost of drilling and completing the extraction well is $4.3 million.

Injection Well

The injection well was designed such that: (1) all casing strings (surface, intermediate, and injection) are cemented all the way to the ground surface and (2) all components of the injection well are constructed of materials that will prevent corrosion when exposed to the geothermal fluid. Chemical additives (e.g., phosphonate-based scale inhibitor) would be added to the geothermal fluid to reduce corrosion and prevent precipitation as the temperature falls during injection. The injection zone was established in the wellbore between 1,890 and 1,935 m (6,200 feet and 6,350 feet). Similar to the extraction wellbore, the injection wellbore would be constructed with a chrome alloy intermediate casing placed across the LMSS. The tubular size in the injection wellbore is 0.14 m (5.5 inches) and the injection tubing size is 0.07 m (2.9 inches). A packer is installed to prevent the casing from being corroded by the high salinity geothermal fluid. The estimated cost of drilling and completing the injection well is $3.8 million.

Fluid Treatment with Chemical Additives

The compilation of geochemistry data from existing wells in the MSS suggests the geothermal fluid contains >200,000 mg/L TDS. Solubility and relative saturation calculations at 25 °C (77 °F) indicate the formation fluid contains four main constituents: calcium carbonate, calcium sulfate, barium sulfate, and ferrous carbonate. All the constituents are near their solubility limits. Calcium carbonate and barium sulfate have the greatest scaling potential. Calcium sulfate dihydrate (gypsum), calcium sulfate (as anhydrite), ferrous carbonate, and silica have the greatest precipitation potential. Insoluble iron and manganese oxides may form and cause scaling if exposed to air. Using a phosphonate-based scale inhibitor, such as a derivative of diethylenetriamine penta-methylenephosphonic acid, would eliminate scaling. A typical application requires ~10 ppmw of inhibitor in water. At a flow rate of 954 m^3/d (6,000 bbl/d), ~0.001 m^3/d (~2.5 gallons/d) is required, which adds an additional ~$75/day to the annual O&M costs. Based on a 2 MMBtu/hr heating load, the inhibitor cost is ~$1.60/MMBtu.

4.2 DDU GES Technology

Process modeling estimated the design capacity, energy efficiency, and equipment costs for two DDU GES configurations. For Case 1, the GES provides a baseload of 2 MMBtu/hr (i.e., ~80% of the total annual heating load). Similarly, for Case 2, the system provides the 2 MMBtu/hr baseload heating, but the energy output is enhanced by heat recovered from electrical components running the surface pump. During periods of peak heating, an electrical heat pump provides an additional 2.3 MMBtu/hr (1.9 MMBtu/hr from the geothermal fluid and 0.4 MMBtu/hr from the electrical components), and the existing NG-fired heaters provide 1.7 MMBtu/hr. Consequently, for Case 2, the heat pump and NG-fired heaters provide the remaining 20% of the heating when >2 MMBtu/hr is required. Since the configuration for Case 1 does not include a supplementary heat source, the proposed GES would not meet peak loads at the ARFs. However, the GES for Case 1 would meet the entire heating demand when the seasonal temperatures rise above 3.3 °C (37.4 °F). The purpose of running the Case 1 simulation was to understand the capacity of a standalone DDU GES.

4.3 Surface Model

An economic valuation was made comparing the capital expenditures and O&M costs of operating the DDU GES. As more geothermal fluid is lifted from greater depths at higher flow rates, and water treatment procedures are implemented, the total cost would increase. Capital expenditures include the cost of surface facility equipment based on DDU GES design specifications (i.e., flow rate, heating requirements, and equipment sizing), and expenditures for the heat exchanger, surface pump, air handler, and heat pump may differ. The annual expenditures and O&M costs include 1) electricity needed to run the equipment, 2) amount of supplemental heating with NG, 3) any chemical treatment, and 4) ongoing, required maintenance.

Piping Sizing

The pipes carrying the geothermal fluid and clean water are sized to limit the fluid velocity to <1.5 m/s (4.9 ft/s), which will avoid having a larger pressure drop throughout the GES. The main, 3.2 km (2.0 miles) pipeline carrying geothermal fluid is 0.15 m (6 inches) in diameter and can accommodates the 954 m^3/d (6,000 bbl/d) flow rate. For Case 1, clean water flows through the same-sized pipe at ~954 m^3/d (~6,000 bbl/d), whereas for Case 2, the clean water is distributed through the same-sized pipe, but at a higher flow rate of 1,908 m^3/d (12,000 bbl/d). The increase in flow rate allows for an additional 1.9 MMBtu/hr of heat to be directly exchanged from the geothermal fluid when using a heat pump. The branch clean water lines running to the ARFs are sized smaller because the required flow rate is lower.

High-density polyethylene (HDPE) piping was chosen and is better suited to transport high-salinity geothermal fluid (PPI, 2019). HDPE is resistant to salinity-based corrosion and abrasion from suspended particulate and precipitates. All the pipes will be buried underground, insulated, and surrounded by a protective water barrier (jacketing) layer. Foamglass insulation will be used. Based on heat transfer calculations, the insulation will be at least 0.05 m (2 inches) thick to limit the temperature change along the pipeline to below 0.35 ℃/km (1.0 ℉/mile).

Surface Equipment Sizing and Costs

The heat exchanger, clean water surge tank, surge tank pump, and surface pump costs were estimated using the Aspen Capital Cost Estimator (v. 10). The surface facility equipment specifications, capital costs, and installation costs are shown in Table 1. The total cost for installing the surface infrastructure for Case 1 is $1.48 million, whereas for Case 2, it is slightly higher at $2.05 million. Piping and trenching costs increase the total cost to $3.1 million and $3.7 million, respectively. The cost differential between Case 1 and Case 2 can be attributed to the addition of a heat pump, which contributes to significantly higher thermal energy production. The larger temperature increase in the clean water between the inlet and outlet for Case 2 requires a larger heat exchanger, which also elevates the cost.

The cost difference is also impacted by the type of air handler installed. For Case 1, newly installed air handlers are sized to supply the 2 MMBtu/hr baseload, whereas for Case 2, the air handlers are sized to handle the baseload plus the peak load in the planned and/or relocated ARF. For planned and/or relocated ARF, new air handlers are sized according to the baseload requirement for Case 1, whereas for Case 2, during peak heating, the GES would provide heating through the existing air handlers; for Case 2, heating would be provided by the clean water that is circulated through a heat pump.

The annual cost for supplemental electric power, heating with NG, chemical treatment, and required maintenance costs were estimated for both cases (Table 2). The $0.08/kWh unit cost of electricity is based on the current U of IL energy rate (University of Illinois, 2019b). The chemical treatment is estimated to be $30/gallon of geothermal fluid circulated. The cost of NG heating is estimated at $5/MMBtu. The annual maintenance cost reported is typically 4 % of the total capital cost of the installed surface facility (cf. Peters et al., 2003). Maintenance of the downhole submersible pump cost is $2,100/month, based on a pump life of 3 to 5 years. The total annual O&M cost for Case 1 and Case 2 are $239,732 and $272,868, respectively (Table 3). The majority of the cost is for purchasing electricity to operate the pumps. The pumps would have variable frequency drives that will reduce the overall electricity used for operation.

5. TECHNO-ECONOMIC FEASIBILITY MODEL

Models and tools were developed to integrate the geologic data and the geothermal resource assessment with energy demand at the ARFs in order to estimate the life cycle costs and benefits of the DDU GES. The market transformation plan includes mechanisms to expand use of the DDU technology in additional geographic regions of the ILB and other low-temperature sedimentary basins with similar end-user requirements (e.g., having large, district-scale residential, commercial, academic developments, and military installations). By combining the technical feasibility with project economics, multiple configurations of the aboveground infrastructure could be evaluated. Also, the economic criteria and project risk associated with GES deployment and implementation were evaluated as part of the techno-economic analyses. The techno-economic analyses identified the most economically and technically feasible application of the DDU technology.

Table 1. Surface Facility Capital Cost Estimates

DDU GES Equipment	Specifications			Equipment Costs	
	General Specifications	Case 1	Case 2	Case 1	Case2
Heat Exchanger	316SS tube/CS shell, max 100 psig	Area = 7,018 ft^2	Area = 12,759 ft^2	$149,500	$251,000
Surface Pump	Centrifugal, CS, 25/100 psig in/outlet	182 gpm/11 hp	390 gpm/23 hp	$9,200	$11,400
Air Handler	Total 20 handlers for six ARFs, 70/95 °F air inlet/outlet	Total capacity = 2.0 MMBtu/hr (all for baseload)	Total capacity = 4.6 MMBtu/hr (peak for new and base for old buildings)	$61,600	$124,000
Clean Water Preheater	Total 21 preheaters; 60–86 °F preheating			$37,700	$37,700
Heat Pump	Heat duty = 2.3 MMBtu/hr, 86/108 °F inlet/outlet			n/a	$116,000
Geothermal Fluid Surge Tank	3,900-gallon FRP tank, near atm pressure			$17,600	$17,600
Clean Water Surge Tank	160,000-gallon tank, near atm pressure			$168,000	$168,000
Injection Well Inlet Pump	Triplex (piston), 316SS, 50/1166 psig inlet/outlet, 169 hp			$285,800	$285,800
Surge Tank Pump	Centrifugal, 316SS casing, 5/100 psig inlet/outlet, 14 hp			$12,400	$12,400
Total Surface Facility – Purchased Equipment Cost (PEC)				**$742,000**	**$1,024,000**
Total Surface Facility Installed – Capital Cost				**$1,484,000**	**$2,048,000**
Piping Cost (Including Materials, Insulation, and Installation)				$801,000	$833,000
Trenching, Excavation, and Backfilling Cost				$777,000	$777,000
Total Installed Capital Cost				**$3,062,000**	**$3,658,000**

Table 2. Annual Electrical Usage and Expenses for Cases 1 and 2

Equipment Requiring Electricity	Electric Power Use (kW)		Electricity Cost ($/yr)	
	Case 1	Case 2	Case 1	Case 2
Electric submersible pump	254	254	$81,267	$81,267
Injection well inlet pump	126	126	$40,300	$40,300
Surge tank pump	11	11	$3,431	$3,431
Surface pump	8	17	$2,527	$2,687
Electric hot water heaters	22	22	$3,336	$3,336
Air handler power requirement	37	86	$11,842	$13,545
Heat pump	0	112	$0	$4,476
Total Electricity Usage and Cost	**458**	**628**	**$142,703**	**$149,042**

Table 3. Total Annual Operating Cost
(including electrical, chemical, supplemental energy, and maintenance for Cases 1 and 2)

Annual Operating Expenses	Case 1	Case 2
Total Electricity Usage and Cost	$142,703	$149,042
Chemical Treatment ($30/gal)	$12,490	$12,490
Supplemental Energy (NG)	$0	$4,247
Maintenance Cost*	$84,539	$107,090
Total Annual Operating Cost	**$239,732**	**$272,868**

* Note, the annual maintenance cost for the surface facilities is estimated at 4 % of the total project cost (cf. Peters et al., 2003), plus cost of monthly maintenance of the downhole submersible pump ($2,100/month), based on a life span of 3–5 years, before replacement.

5.1 Life Cycle Assessment

A life cycle assessment (LCA) spreadsheet tool was developed to quantify the overall environmental costs and benefits of the DDU GES. The LCA provided further insight into the environmental impacts associated with constructing, operating, and decommissioning the GES. The inventory of environmental impacts was compiled in the LCA spreadsheet tool using SimaPro version 8.5.2 and TRACI version 2.1 Impact Assessment Methodology. The list of possible environmental impacts includes: ozone depletion, global warming potential, smog, acidification, eutrophication, and fossil fuel depletion (Thomas et al., 2020). The impacts were applied to the following four life cycle stages of the GES: (1) extraction and manufacturing of raw materials; (2) construction of wells and aboveground infrastructure, including transportation of materials and equipment to the site; (3) operation of the pumps, heat exchangers, and heat pumps; and (4) removal of the aboveground infrastructure and equipment, and closure of the wells.

By and large, the use of steel pipe and concrete for well construction had the greatest environmental impact; CO_2 emissions attributed to the manufacturing of steel and the process of making iron were an order of magnitude higher than that for other materials. Taking actions, such as altering the design of the GES to implement instrumentation with lower electricity usage would lower total CO_2 emissions. Nevertheless, the GHG emissions from existing, conventional ARF energy systems could be entirely offset after operating the GES for just the first 10 years, assuming a 50-year lifespan.

This assessment indicates that the DDU GES is a comparable alternative to other renewable energy sources, and could improve annual energy and water consumption, heat and waste production, and environmental impacts at the U of IL. Considering the capacity of the doublet well system, between 14 and 23 additional buildings could be heated depending on the heat production rate used. The LCA shows that, while there are still notable environmental costs associated with operating the GES, there are still positive environmental benefits. Therefore, the GES should be considered at the U of IL to replace the existing, conventional energy systems at the ARFs.

5.2 GES Economics and Market Demand

The Life Cycle Cost Analysis (LCCA) for Case 1 and Case 2 were determined separately, and the analysis included the cost of goods and labor rates for installation. Capital and operating expenses were based on estimates from local vendors that were validated against similar drilling and energy projects previously completed at the U of IL; most of them the ISGS managed or supported.

The LCCA used a present value approach in constant $USD using the USDOE's value of 3 % for the real discount rate (excluding general price inflation), NIST energy price indices, and other discount factors (Lavappa and Kneifel, 2019). A 2 % escalation factor for non-fuel costs (e.g., annual maintenance and chemical treatment) was also used in the LCCA. The total capital cost, including constructing the extraction and injection wells and the fluid handling piping, ranges from $11.2 to $26.1 million for Case 1 and from $11.8 to $27.5 million for Case 2. The LCOH was calculated to be between $46.3 MMBtu/hr and $58.0 MMBtu/hr for Case 1 and between $41.1 MMBtu/hr and $50.9 MMBtu/hr for Case 2. Construction capital costs and LCOH estimates varied with different flow rates. Total construction and O&M costs were $11.4 to $27.1 million for Case 1 and $12.1 to $28.6 million for Case 2. Net Present Value and Savings to Investment Ratio were negative $18.9 million and 0.23 for Case 1 and negative $20.3 million and 0.27 for Case 2.

6. CONCLUSIONS

This study provides a detailed assessment of the feasibility of implementing the proposed DDU GES at the U of IL. The results provide a basis for evaluating geothermal resources in other midcontinent low-temperature sedimentary basins. The techno-economic analyses have demonstrated the potential of the DDU technology to access the ILB's untapped geothermal resources. This study led to addressing the broader objectives for the ILB: (1) reducing uncertainty in the geological characterization, (2) minimizing drilling risks, (3) optimizing DDU GES performance and flexibility, and (4) fostering geothermal expertise and collaborative partnerships. Furthermore, this feasibility study addresses the above concerns regarding the project at the U of IL, and returned the following findings that demonstrate the feasibility of installing a GES at the U of IL:

- MSS is the most productive geothermal resource. The ILB thermal gradient is based on high resolution DTS measurements at IBDP correlated with formation-specific properties.
- Current and recent drilling for ILB oil fields and for NG and CO_2 storage wells provides a realistic cost estimate for constructing the proposed doublet well system.
- LMSS geothermal fluid is highly saline, but normal oilfield precautions would inhibit corrosion and precipitation.
- Cool water (cold water front) emanating from the injection well will not impact the temperature of the extracted geothermal fluid for at least 50 years).
- Permeability variations in the MSS impact injection depth. To maintain a constant flow rate through the GES, the injection zone is established in the higher-porosity LMSS.
- Surface infrastructure provides the flexibility to meet the current heating demand at the ARFs. The available ILB geothermal resources would support future expansion in the South Farm and other large, district-scale energy systems in the ILB.

The results of the feasibility study provide end-users and policy makers in the ILB guidance for additional research on specific components of DDU technology so that its widespread use may provide (1) an uninterruptible energy source, (2) increased resilience from the extreme weather events, (3) a reduction in U.S. dependency on fossil fuels, and (4) a reduction in GHG emissions. The site-specific part of this study provides administrators at U of IL a realistic and pragmatic assessment of the financial resources necessary to install and operate the proposed GES and adopt the DDU technology in the campus renewable energy portfolio.

SOFTWARE CREDITS

Geocellular and geothermal reservoir modeling was completed using Landmark Graphics software via the University Donation Program and PetrelTM E&P software platform from Schlumberger, Limited, and HIS Markit's Petra geological interpretation software via the University Grant Program. The wellbore simulations were conducted in COMSOL Multiphysics® version 5.3 (COMSOI, 2017). Some economic calculations were completed using GEOPHIRES version 2.0 (Beckers et al. 2013; 2018). The LCCA tool "Building Life Cycle Cost (BLCC) Programs" version 5 (BLCC, 2019), developed by the National Institute of Standards and Technology (NIST), was used to calculate comparative economic measures for capital investments. A specialized LCA spreadsheet tool was developed by Thomas et al. (2020) to quantify the overall environmental impacts and co-benefits of the DDU GES. An inventory of impacts from the construction, use, and end-of-life phase of the DDU GES was created using SimaPro version 8.5.2 (SimaPro, 2018) and TRACI version 2.1 (Bare, 2012). The Aspen Capital Cost Estimator version 10 (AspenTech, 2016) was used to estimate some of the equipment costs.

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