Energy Conversion and Management 243 (2021) 114335

Contents lists available at ScienceDirect

Energy Conversion and Management

journal homepage: www.elsevier.com/locate/enconman

Evaluating the feasibility of geothermal deep direct-use in the United States

Koenraad F. Beckers[a,b,*], Amanda Kolker[a], Hannah Pauling[a], Joshua D McTigue[a], Devon Kesseli[a]

[a] National Renewable Energy Laboratory, Golden, CO, USA
[b] Heateon, Gent, Belgium

ARTICLE INFO

Keywords:
Geothermal deep direct-use
Geothermal district heating
Reservoir thermal energy storage
Heating
Cooling
Thermal storage

ABSTRACT

This paper investigates the techno-economic feasibility of geothermal deep direct-use for heating, cooling, and thermal energy storage in the United States. The six 2017–2019 deep direct-use projects funded by the U.S. Department of Energy are reviewed and evaluated using the simulation tool GEOPHIRES, and results are compared with prior studies, existing geothermal district heating systems in Europe and the United States, as well as non-geothermal centralized and non-centralized heating, cooling, and thermal energy storage systems. Analysis indicates that deep direct-use feasibility varies widely, depending on subsurface characteristics, system design, and financial conditions. Project base case levelized cost of heat values ranged between $13 and $350/MWh; key drivers lowering the levelized cost of heat include higher reservoir temperatures, shallower reservoir depths, higher well flow rates, higher utilization rates, lower drilling costs, and lower discount rates. Incentives such as grants and an investment tax credit resulted in small improvements in project economics. Base case levelized cost of heat values for four projects fell within the range of levelized cost values for existing systems in Europe and the United States, and were comparable to values found in previous studies, including the 2019 *GeoVision* study. The lowest-cost projects for district heating had comparable levelized cost of heat values to existing fossil-fuel-driven district heating systems, and lower values than decentralized heating with natural gas boilers or heat pumps. Chilled water production with absorption chillers driven by a high-quality geothermal resource obtained attractive levelized cost of cooling values, in line with values from typical centralized cooling production facilities and lower than domestic decentralized cooling with air-conditioning units. Also, thermal energy storage is a potential deep direct-use application, where levelized cost of storage values can be obtained that are comparable to those of other thermal storage techniques such as borehole thermal energy storage and hot water storage tanks. Other aspects of deep direct-use, which are not captured in a standard levelized cost of energy metric, include the ability to decarbonize the heating and cooling supply, and provide reliability and resiliency to the energy infrastructure. These attributes are gaining increased attention and improve overall project feasibility. Finally, this paper identifies technical, market, policy, and social barriers for deep direct-use development in the United States, and provides potential approaches for reducing these barriers.

1. Introduction

The United States—like many other countries—uses a large fraction of its primary energy consumption for heating and cooling in the residential, commercial, and industrial sector. According to the U.S. Energy Information Administration, in 2019, the total U.S. primary energy consumption was about 105.7 EJ, with 31% used for direct fossil fuel combustion (mostly for heating) in the residential, commercial, and

Abbreviations: ATES, Aquifer Thermal Energy Storage; BTES, Borehole Thermal Energy Storage; CAPEX, Capital Expense; CHP, Combined Heat and Power; DC, District Cooling; DDU, Deep Direct-Use; DOE, U.S. Department of Energy; EGS, Enhanced Geothermal System; GDH, Geothermal District Heating; GEOPHIRES, GEOthermal energy for Production of Heat and electricity ("IR") Economically Simulated; ITC, Investment Tax Credit; LCOC, Levelized Cost of Cooling; LCOE, Levelized Cost of Electricity; LCOH, Levelized Cost of Heat; LCOS, Levelized Cost of thermal Storage; O&M, Operations and Maintenance; OPEX, Operating Expense; NREL, National Renewable Energy Laboratory; PSU, Portland State University; PTES, Pit Thermal Energy Storage; RTES, Reservoir Thermal Energy Storage; Sandia, Sandia National Laboratories; TES, Thermal Energy Storage; TTES, Tank Thermal Energy Storage; TI, Technology Improvement; UIUC, University of Illinois at Urbana-Champaign; UNEP, United Nations Environment Program; UTES, Underground Thermal Energy Storage; WVU, West Virginia University.

* Corresponding author at: National Renewable Energy Laboratory, Golden, CO, USA.
E-mail address: koenraad.beckers@nrel.gov (K.F. Beckers).

https://doi.org/10.1016/j.enconman.2021.114335
Received 29 March 2021; Accepted 24 May 2021
Available online 6 June 2021
0196-8904/

industrial sector, 37% for electricity generation, and 28% for transportation [1]. Fox et al. [2] calculated using 2011 data that about 25% of primary energy is used in the United States for heating and cooling applications under 120 °C. Most of the thermal energy demand is supplied using fossil fuels—including natural gas, propane, benzene, heating oil, and diesel—corresponding to significant levels of greenhouse gas emissions. In 2018, fossil fuel combustion in the residential, commercial, and industrial sector (mostly for heating) represented 21% of the total U. S. greenhouse gas inventory, while electricity generation was 26% and transportation 27% [3]. With aggressive greenhouse gas reduction targets enacted by almost 30 U.S. states [4] (e.g., 90% reduction from 2005 levels by 2050 in Colorado), decarbonizing the energy supply for heating and cooling should be considered.

Options for providing low-carbon heating and cooling include geothermal, solar thermal, biomass, nuclear, as well as heat pumps driven by low-carbon electricity. Each of these options have their pros and cons, and suit certain applications better than others. Solar thermal can produce high temperatures (i.e., >500 °C, required for certain industrial heating applications), but it is variable and has low resource quality in certain key regions with high thermal demand (e.g., northeastern United States in the winter). Nuclear can provide megawatt- to gigawatt-scale heating with a small land footprint, but siting issues and public perception may prevent any large-scale development in the United States. Limitations on food, water, land, and nutrient resources may prevent biomass from supplying all U.S. heating needs [5]. However, for smaller-scale and more rural applications, biomass may be a cost-competitive resource that can sustainably be produced and harvested. Heat pumps can provide heating and cooling efficiently, and millions of heat pump systems have been installed in the United States. However, relying on heat pumps alone would result in a significant increase in electricity consumption, in addition to the anticipated increase for electrifying the transportation sector, and may not be the lowest cost option.

1.1. Geothermal energy for direct-use

Geothermal energy is an attractive low-carbon energy option gaining renewed interest in the United States for heating and cooling applications, as it is scalable, available 24/7, has a small land footprint, and has proven to be cost-competitive in many heating projects around the world. Geothermal energy refers to the thermal energy stored in subsurface rocks and fluids. Using injection and production wells, which may go several kilometers deep, a geothermal reservoir can be developed and exploited to transfer heat to the surface. The produced geothermal fluid can be used to generate electricity with a power plant or directly as heat—also called *direct-use*—in various applications such as heating for buildings (stand-alone or in a district), greenhouses, fish farming, food drying, snow melting, and industrial processes. With absorption chillers, the geothermal heat can also provide cooling, refrigeration, and freezing. Key challenges for geothermal development include finding suitable resources, high upfront costs, and sometimes long development timelines.

Geothermal direct-use systems in the United States have historically been limited to utilizing relatively shallow resources, from hot springs at the surface to wells typically not deeper than 1–2 km. These shallow, higher-grade resources tend to occur in the western United States, where practically all of the current ~100 direct-use systems are located [6]. More recently, deeper resources have been considered for direct-use applications, referred to as *deep direct-use* (DDU) (see Fig. 1). There is no universally agreed upon depth that makes the direct-use system *deep,* but 2 km may be a fair threshold. Such systems allow for development in regions with lower geothermal gradients (e.g., in the eastern United States; see Fig. 2), where deeper drilling depths are required to reach the same target temperatures. Several direct-use applications such as greenhouses, building heating, and food processing can be supplied with relatively low geothermal temperatures in the range of 50–100 °C. Such

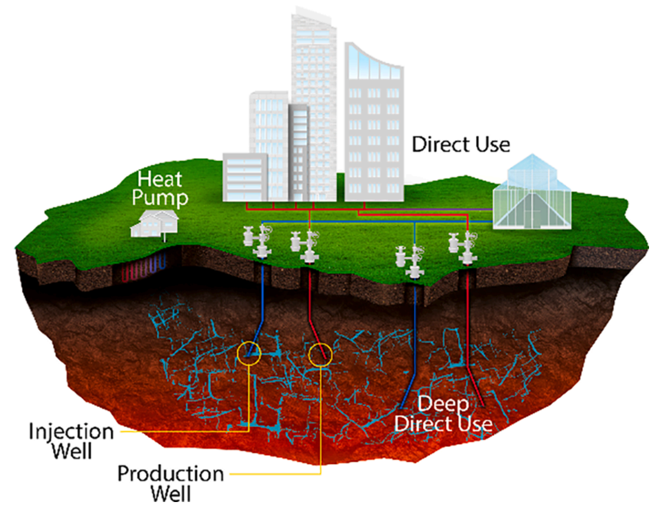

Fig. 1. Geothermal direct-use. Heat from the subsurface provides direct heating to two applications at the surface: building heating and greenhouse heating. Other geothermal heating applications (not shown in this figure) are possible. For comparison, a heat pump system is included, connected to an array of shallow boreholes providing heating and cooling to an individual house. Figure by Joelynn Schroeder, NREL.

temperatures are widespread across the country at low to moderate subsurface depths. Electricity production requires relatively high geothermal temperatures (generally >120 °C), typically limiting such systems to higher-grade resources, found in the western United States.

The U.S. Department of Energy (DOE) 2019 *GeoVision* study [7] calculates the economic potential for geothermal district heating (GDH) systems at more than 17,500 installations nationwide—totaling 320 GW_{th} of heating capacity. Despite the large potential, only about 400 MW_{th} of geothermal direct-use heat systems [6] are currently in operation in the United States. Of the direct-use sites, there are 23 GDH systems, representing about 100 MW_{th} in installed capacity in the United States [8]. While limited in the United States, geothermal direct-use development has been significant in several European countries as well as in China. As of 2019, Europe has 327 geothermal district heating and cooling systems, representing about 5.5 GW_{th} of installed capacity, of which almost 2.2 GW_{th} is in Iceland where nearly all the country's space-heating demand is supplied using GDH systems [9]. Other European countries with significant direct-use development are Turkey, France, Hungary, Germany, and the Netherlands. Over the last decade, about 10 geothermal direct-use plants are commissioned each year in Europe [9]. Lund and Toth [10] report 7 GW_{th} of GDH capacity in China as of 2020.

1.2. Deep direct-use projects in the United States

The DOE Geothermal Technologies Office recently awarded $4 million to six DDU projects to increase the understanding of DDU technical performance and cost-competitiveness, and to foster development of such systems across the country [11]. A list of the projects identifying the leading and partnering institutions and short project description is provided in Table 1. The locations of the six projects are shown in Fig. 2; they are labelled with the name of the leading institution researching each project. Four of the six projects investigated GDH at a university campus or community. The University of Illinois at Urbana-Champaign (UIUC) considered geothermal energy hybridized with electric heaters to provide heating to their new agricultural research facility [12]. Sandia National Laboratories (Sandia) researched a GDH system for the Hawthorne Army Depot, the city of Hawthorne and Mineral Country in Nevada [13]. Cornell University (Cornell) researched a geothermal system coupled with centralized heat pumps

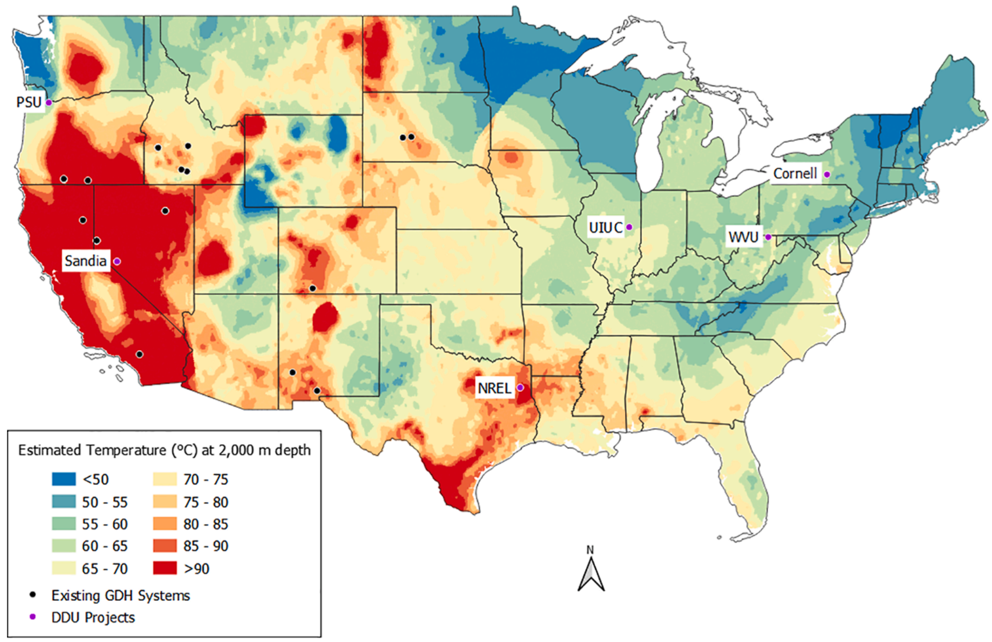

Fig. 2. Location of existing GDH systems (black dots) [8] and DDU projects (purple dots) overlaying estimated temperature at 2000 m depth [18].

for providing heating to their main campus in Ithaca, New York [14]. West Virginia University (WVU) investigated using geothermal energy for heating and cooling—in some scenarios hybridized with natural gas boilers—to their main campus in Morgantown, West Virginia [15]. The National Renewable Energy Laboratory (NREL) investigated utilizing geothermal energy for providing turbine inlet cooling using absorption chillers at a chemical plant in Longview, Texas [16]. Portland State University (PSU) researched seasonal thermal storage in a geothermal reservoir of heat collected with solar thermal panels for a hospital campus in Portland, Oregon [17]. Fig. 2 illustrates that several projects are located in regions with lower-grade geothermal resources, where no prior GDH systems have been developed.

1.3. *Deep direct-use literature review, research gap, and study objectives*

Few studies have been conducted on feasibility of DDU in the United States. McCabe et al. [19] for the *GeoVision* study found competitive levelized cost of heat (LCOH) values in the range $50 to $100/MWh and economic nationwide potential of 17,500 installations [7]. However, they assumed a generic GDH system, and did not consider integrating with heat pumps or other applications such as cooling and thermal storage. Beckers et al. [20] calculated attractive LCOH values for deep enhanced geothermal systems (EGS) for direct-use applications, in the range $12 to $49/MWh. However, they did not investigate specific surface applications and assumed a generic surface capital cost of only $150/kW$_{th}$. Reber in 2013 [21] investigated performance of deep EGS for GDH and found LCOH values in the range $40 to $115/MWh. Reber focused only on New York and Pennsylvania, and did not consider applications other than district heating. The 2021 geothermal market report [8] estimates competitive LCOH values for existing GDH systems in the United States in the range $15 to $105/MWh. However, most current GDH systems in the United States consider relatively shallow resources and would not qualify as DDU. In addition, most of them were developed in the 1980′s, when geothermal drilling costs and policies were different than today. The six DOE DDU projects (see Section 1.2) provide recent estimates on LCOH, and consider diverse applications and detailed site-specific designs. However, the teams typically did not compare performance with other technologies, and assumed a wide range in cost and financing conditions.

In general, the reviewed studies report competitive LCOH values for DDU. However, current DDU feasibility in the United States is unclear, as studies typically did not compare with other technologies or existing systems, in some cases assumed cost correlations and incentives that are now outdated, or only considered shallow resources, generic district heating systems, or overly generous or conservative financing conditions. The objective of this paper is to investigate the feasibility of DDU for heating, cooling, and thermal storage in the United States by analyzing the technical and economic performance of the six DDU projects under different scenarios, and by comparing the results with prior studies and existing geothermal and non-geothermal systems in the United States and other countries. The six DDU projects have recently been completed, and their final reports provide detailed and publicly available information allowing for a careful review of U.S. DDU feasibility. This paper presents novel findings and results from the DDU review analysis, informing the geothermal community and the district energy community on latest cost-competitiveness, technical performance, barriers and enablers, and status of DDU in the United States. Techno-economic simulations were performed for each DDU project under various scenarios using the software tool GEOPHIRES (GEOthermal energy for Production of Heat and electricity ("IR") Economically Simulated), as outlined in Section 2. An overview of the DDU project parameters and results of the review of DDU projects and of the GEOPHIRES simulations are provided in Section 3. Discussion of results is presented in Section 4, which includes a comparison of DDU with alternative heating, cooling, and thermal storage systems, as well as a review of DDU barriers and enablers. Project conclusions are provided in Section 5.

2. Methods

In this paper, techno-economic feasibility of geothermal DDU in the United States was investigated by analyzing the six recent DOE-funded DDU projects using the software tool GEOPHIRES v2.0, and comparing results with prior studies and existing GDH systems in the United States and other countries, as well as alternative heating, cooling, and thermal storage technologies. GEOPHIRES is a geothermal techno-economic modeling tool, originally developed in 2013 by Beckers et al. [20] for estimating performance of geothermal direct-use and power production from EGS reservoirs. The tool was recently upgraded at NREL [22] by converting the code to Python, making the software

Table 1
List of DOE DDU project teams with partnering institutions and project description. The first four projects investigated GDH, while NREL investigated geothermal for providing chilled water and PSU investigated seasonal thermal storage.

Principal Investigating Institution	Partnering Institutions	Project Description
University of Illinois at Urbana-Champaign	• University of Wisconsin, Madison • Loudon Technical Services • U.S. Army CER Laboratory • MEP Associates • Illinois Geothermal Engineering • Trimeric	GDH for agricultural research facility at University of Illinois at Urbana-Champaign campus near Champaign, Illinois
Sandia National Laboratories	• U.S. Navy Geothermal Program • Power Engineers Inc • University of Nevada, Reno	GDH for Hawthorne Army Deport, City of Hawthorne and Mineral County in Nevada
Cornell University	*No partners were listed on the Cornell DOE DDU project report, but partners for their umbrella Earth-Source Heat project include:* • Engie • ICDP • University of Iceland	GDH for Cornell University campus in Ithaca, New York
West Virginia University at Morgantown	• West Virginia Geological & Economic Survey • Lawrence Berkeley National Laboratory • Cornell University	GDH for West Virginia University campus in Morgantown, West Virginia
National Renewable Energy Laboratory	• Southern Methodist University • Eastman Chemical • TAS Energy • Electric Power Research Institute	Geothermal heating to provide chilled water using absorption chiller for turbine inlet cooling
Portland State University	• AltaRock Energy • City of Portland, Oregon • Oregon Health & Science University • U.S. Geological Survey	Geothermal reservoir for seasonal storage of solar heat. Focus was on subsurface analysis and not on surface equipment cost optimization, as other (lower cost) heat sources could be considered

open-source, and coupling the tool to the stand-alone reservoir simulator TOUGH2 to allow for more advanced modeling of the heat production from various types of reservoirs. For this project, modifications were implemented in GEOPHIRES for each DDU project to account for specific components and configurations considered by the teams, such as centralized heat pumps, solar collectors, etc.

Eleven scenarios were developed and simulated in GEOPHIRES for each DDU project to allow for a fair comparison of the techno-economic results between the projects, as well as to investigate the impact of financial incentives and technological improvements. Reservoir simulations were not replicated in GEOPHIRES. Instead, the production temperatures and pumping requirements found by the six DDU project teams were directly provided as input. One scenario is included for quality control by keeping all parameters identical to the project team assumptions to ensure the model is set up correctly in GEOPHIRES and matches the results obtained by the teams. A set of scenarios investigate the impact of financial conditions and incentives (e.g., grants and investment tax credit [ITC]) on the system's cost-competitiveness. One scenario is run for a subsurface-only system to allow comparing the subsurface system independent from the surface application. Another set of scenarios explores impact of drilling cost and utilization factor on system performance. Several teams utilized GEOPHIRES for part of their analysis, including Cornell, WVU, NREL and Sandia. GEOPHIRES input files were obtained from some of these teams (either downloaded from the Geothermal Data Repository or directly sent by the project investigators), which were used as a starting point for setting up some of the GEOPHIRES models. All GEOPHIRES models (input files, scripts and output results) that were developed in this study were uploaded to the Geothermal Data Repository [23]. Sharing all models provides transparency and allows the reader to investigate other scenarios. Example scenarios that could be of interest include a different number of injection and/or production wells, different wellbore depths and reservoir temperatures, cascading of direct-use heat applications, and hybrid operation of electricity generation and direct-use heat production if reservoir temperatures are sufficiently high.

Base case input data for GEOPHIRES simulations were extracted from the final technical reports submitted by the six DDU project teams. Some of the DDU project teams investigated multiple cases, including hybridizing geothermal technologies with natural gas or coal-fired boilers, heat pumps, and other variations; this analysis focused on the geothermal-only system—if applicable—for each project. Some teams varied reservoir parameters including number of wells, reservoir depth and well flow rate. The scenario put forward by each team as base case, generally the scenario that lowers the LCOH, was selected as base case for this study. Missing or ambiguous data were obtained by reaching out directly to the project investigators. Assumptions for financial incentives and technology improvements are based on assumptions by McCabe et al. [19] and Beckers and Young [24] for the *GeoVision* study, scenarios in a GDH study by Reber [21], and conditions for GDH development in Europe as documented in the database of case-studies [25] and final report [26] of the GeoDH project. Cost comparison of DDU systems for district heating was performed with cost figures for Europe using data from the GeoDH project [25] and with cost figures for existing U.S. GDH systems using data collected for the forthcoming Geothermal Market Report [8]. Various papers and reports were reviewed for assessing costs of non-geothermal centralized and de-centralized heating, cooling, and storage systems. These references are cited in the corresponding discussion (Section 4).

The LCOH was selected as a key techno-economic metric for evaluating the feasibility of each DDU project. This metric combines technical, economic, and financial parameters to calculate a single metric that reflects the breakeven heat price for the supplied heat over the considered project lifetime. The LCOH in this project is calculated as:

$$LCOH = \frac{C_o + \sum_{i=1}^{t} \frac{C_i}{(1+r)^i}}{\sum_{i=1}^{t} \frac{E_i}{(1+r)^i}}$$

with C_0 as the project's initial investment cost ($M), C_i as the annual operating and maintenance cost in year i ($M/year), E_i as the annual heat production (MWh/year), r as the discount rate (%), and t as the project lifetime (years). In this paper, the LCOH is generally reported in $/MWh, but in a few cases it is also converted to $/MMBtu, a common unit to express heat prices in the United States. Calculating an LCOH allows for comparison of cost-competitiveness among projects, between scenarios, and with other heating technologies. The LCOH is analogous to the levelized cost of electricity (LCOE) for electricity generation systems. A levelized cost of cooling (LCOC) for the NREL project and a levelized cost of thermal storage (LCOS) for the PSU project are calculated using a similar approach.

Although the six DDU projects provide detailed information to study the technical and economic performance of their system, teams have indicated that their design is not necessarily optimized for lowest cost. For this paper, redesigning the proposed systems to obtain a minimum LCOH was not attempted. Instead, the analysis considered the application and conditions as assumed by the teams, and investigated the reasons why certain projects are cost-competitive and others are not. For some projects, it is highlighted how certain changes in their system design would lower the LCOH. It is recommended to carefully interpret and compare DDU project LCOH results, keeping in mind that different teams considered different applications and made different assumptions for subsurface and surface conditions.

3. Results

This section presents results from review of the DDU projects and simulations with GEOPHIRES. Base case assumptions and reported LCOH for each DDU project are provided in Section 3.1. A wide range in base case project LCOH is observed, with Section 3.2 exploring underlying reasons. Section 3.3 provides a description and corresponding results of eleven scenarios simulated for each DDU project with GEOPHIRES. Results for other levelized cost metrics as well as other aspects of the DDU projects that impact project feasibility (such as environmental and socio-economic benefits) are presented in Section 3.4.

3.1. Deep direct-use projects' base case input parameters and levelized cost of heat

The six DDU projects vary widely in subsurface characteristics, surface equipment, and financial conditions (Table 2). Drilling depths ranged from 0.3 to 2.9 km. Drilling depths from Sandia and PSU are only 0.3 km, probably too shallow to officially designate these projects as *deep* direct-use projects. Anticipated target reservoir temperatures ranged from 45 °C for UIUC to 120 °C for the NREL project. The PSU project used the reservoir as a storage medium, with initial temperature of 12 °C but heating up to 80 °C over time after charging with solar heat. Most projects only considered a doublet (i.e., one injection well and one production well), but WVU considered a system with five injection wells and ten production wells as base case. Well flow rates considered ranged from only 11 kg/s for UIUC to more than 125 kg/s for NREL. Project system sizes were between 0.5 MW_{th} and 32 MW_{th}, and utilization factors between 45% and 98%. All projects assumed a 30-year lifetime, except UIUC which considered a 50-year lifetime. Discount rates ranged between 2.5% and 7.5%, with some teams considering a nominal discount rate and others a real discount rate (and correspondingly reporting the LCOH as either nominal or real). WVU was the only team that considered a tax rate (at 30%). Exploration costs ranged between $0M and $4.2M. Surface applications were broad, including district heating, absorption cooling, and hybrid systems with heat pumps, electrical heaters, and solar thermal collectors, resulting in a wide range of surface capital cost—from $381/$kW_{th}$ to $6,500/$kW_{th}$. Drilling costs reported by each team were often based on quotes obtained from local drilling companies. Different well designs (e.g., well depth and well diameter), prior knowledge of the subsurface, local drilling experience, and availability of regional drilling companies resulted in a wide range in total and specific drilling costs. The broad range in reservoir temperature, reservoir depth, and system size is illustrated in Fig. 3. Reported base case LCOH ranged from only $13/MWh for the NREL project to $345/MWh for the UIUC project.

3.2. Base case levelized cost of heat drivers

The wide range in input parameter values resulted in a wide range in LCOH values (see Table 2). Key system parameters driving the LCOH of the DDU projects are shown in Figs. 4 and 5. Fig. 4 groups key parameters for which an increase in value lowers the LCOH: geothermal gradient, reservoir temperature, well flow rate, system size, and utilization factor. Fig. 5 groups key parameters for which a decrease in value lowers the LCOH: surface cost, drilling cost, and discount rate. Sensitivity analysis in previous works, including the GeoVision Direct-Use Task Force Report [19], a general study on EGS for direct-use and electricity [20], and a study on ESG for GDH in New York and

Table 2
Key parameters for each DDU project base case system. inj = injection well; prod = production well.

	UIUC	Sandia	Cornell	WVU	NREL	PSU
Geothermal System Technical Parameters						
Drilling Depth	1.9 km	0.3 km	2.5 km	2.9 km	2.7 km	0.3 km
Reservoir Temperature	45 °C	100 °C	72 °C	88 °C	120 °C	Initially 12 °C; after charging, 80 °C
Geothermal Gradient	16.5 °C/km	272 °C/km	27.5 °C/km	25.8 °C/km	37.5 °C/km	N/A
Number of Wells	1 inj + 1 prod	1 inj + 2 prod	1 inj + 1 prod	5 inj + 10 prod	1 inj + 1 prod	1 inj + 1 prod
Well Flow Rate	11 kg/s	36 kg/s	50 kg/s	40 kg/s	125 kg/s	50 kg/s
Surface System Technical Parameters						
Surface Equipment	District heating plus electrical heating	District heating	District heating plus heat pumps	District heating plus absorption cooling in buildings	Absorption Cooling	Building solar thermal energy storage
System Size	0.6 MW_{th}	6.2 MW_{th}	13 MW_{th} (incl. HP)	32 MW_{th} (incl. HP)	15 MW_{th} heating; 11 MW_{th} cooling	0.5 MW_{th}
Utilization Factor	~45%	48%	98%	95%	90%	N/A for thermal energy storage
Heat Production	2.34 GWh/year	26.1 GWh/year	115 GWh/year	267 GWh/year	119 GWh/year (heating)	1.8 GWh/year
Cost Parameters						
Surface Capital Cost	$5,000/$kW_{th}$ (includes piping)	$785/$kW_{th}$	$560/$kW_{th}$ (incl. heat pump plus district heating connection)	$1,300/$kW_{th}$ (incl. piping)	$381/$kW_{th}$ (incl. only piping)	$6,500/$kW_{th}$ (includes solar array at $6,100/$kW_{th}$)
Well Drilling Cost	$2,115/m	$3,232/m	$1,585/m	$1,310/m	$1,042/m	$2,241/m
Exploration Cost	$0	$1.02M	$0	$4.2M	$3.4M	$0
Stimulation Cost	$0	$0	$1.25M	$0	$0	$0
Total CAPEX	$11.2M	$8.9M	$16.3M	$102.5M	$11.7M	$4.53M
Total OPEX	$240k/year	$450k/year	$1.23M/year	$8.8M/year	$780k/year	$30k/year
Financial Parameters						
Project Lifetime	50 years	30 years	30 years	30 years	30 years	30 years
Discount Rate	5% (nom.)	7% (nom.)	2.5% (real)	7.5% (nom.)	5% (real)	0.8% (real)
Tax Rate	0%	0%	0%	30%	0%	0%
Levelized Cost of Heat (LCOH)						
Base Case LCOH	$345/MWh ($101/MMBtu)	$41/MWh ($12/MMBtu)	$17/MWh ($5/MMBtu)	$60/MWh ($17.5/MMBtu)	$13/MWh ($3.7/MMBtu)	$116/MWh ($34/MMBtu)

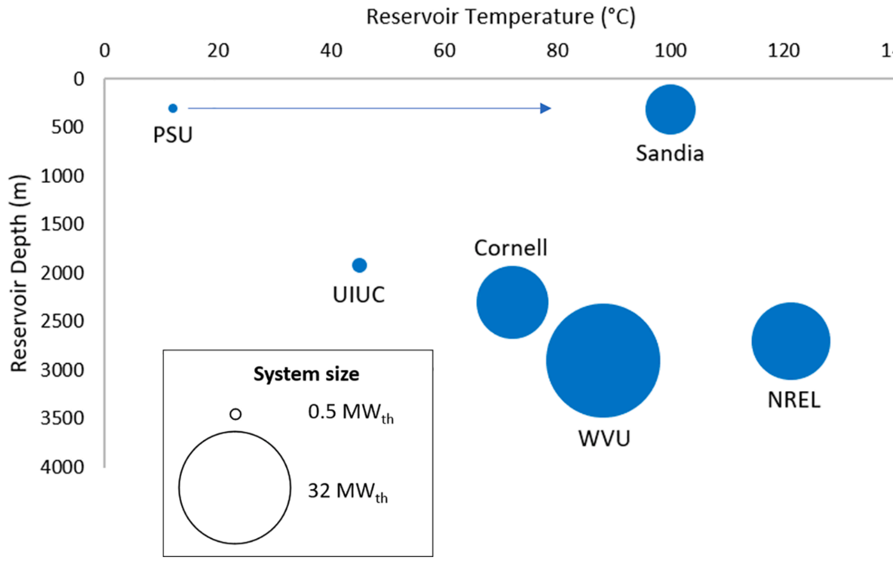

Fig. 3. Reservoir depth (0.3 km to 2.9 km), reservoir temperature (12 °C to 120 °C), and system size (0.5 to 32 MW_{th}) of DDU projects. The PSU project considered storage of solar heat in an initially cold reservoir, resulting in increase of reservoir temperature from 12 °C to about 80 °C.

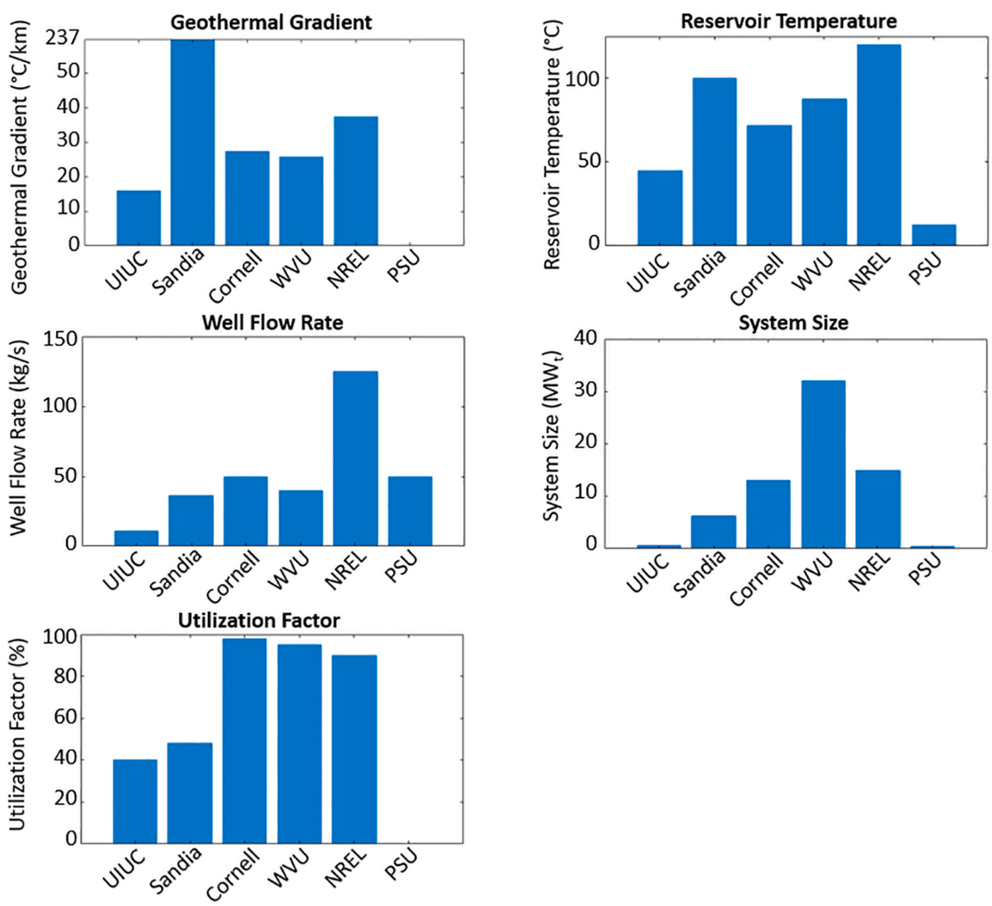

Fig. 4. Key parameters impacting LCOH, for which an increase in value lowers the LCOH. Parameter values correspond to those provided in Table 2.

Pennsylvania [21], has shown that of these parameters, the ones with the biggest impact on LCOH are geothermal gradient, drilling cost, well flow rate, and discount rate.

3.3. Techno-economic performance under various scenarios

Eleven scenarios were developed and simulated in GEOPHIRES to explore techno-economic feasibility of the DDU projects under different financial, economic, and reservoir conditions. Several scenarios explore the impact of incentives (low-cost financing, grants, and ITC) on project

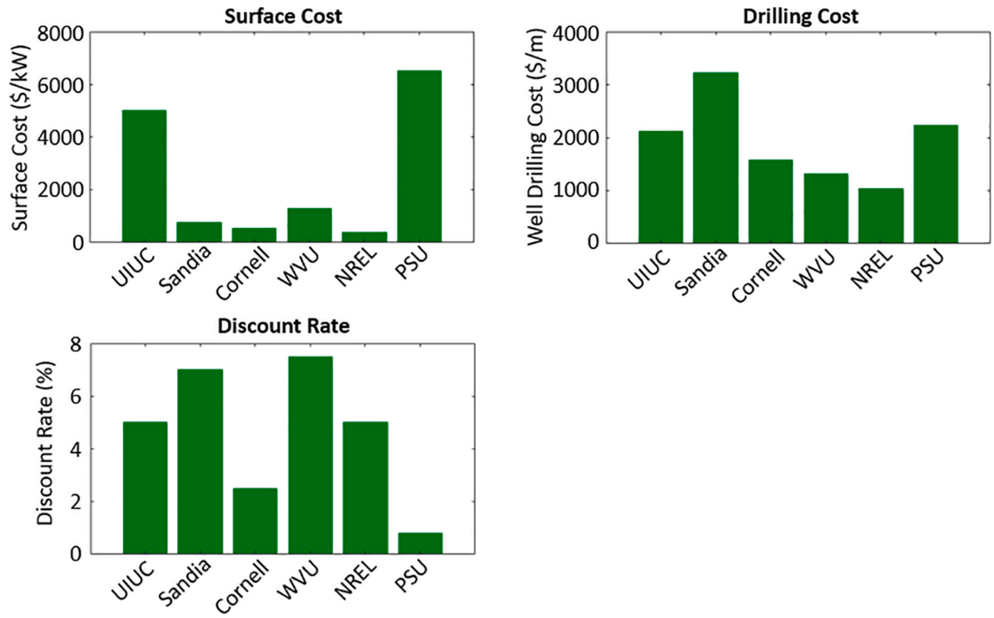

Fig. 5. Key parameters impacting the LCOH, for which a decrease in value lowers the LCOH. Parameter values correspond to those provided in Table 2.

performance. Other scenarios investigate the impact of technological improvements such as low-cost drilling and a high utilization factor. One scenario is included for quality control of the GEOPHIRES modeling setup. To allow for a fair cross-comparison of results among the DDU projects, default financial conditions (and in some scenarios also default costs) are assumed. The 11 scenarios are listed below:

- **Scenario 1 (Quality Control):** This scenario considers all parameter values as assumed by the project teams. This scenario is for quality control to ensure that the GEOPHIRES model for each DDU project is set up correctly and input parameters are provided correctly.
- **Scenario 2 (Default Financing)**: This scenario assumes identical financial conditions with a 30-year project lifetime, 5% discount rate, and 0% tax rate. This scenario allows exploring the impact of reservoir and surface equipment technical and cost aspects among projects by keeping financial conditions identical. The discount rate is assumed nominal, and the LCOH reported is nominal.
- **Scenario 3 (Default Cost and Financing)**: This scenario is identical to Scenario 2 (30-year project lifetime, 5% discount rate, and 0% tax rate) but with zero exploration costs, and drilling costs updated to be in line with recently published drilling costs by the Reservoir Maintenance and Development Task Force for the *GeoVision* study [27]. Similar to Scenario 2, by keeping financial conditions and certain cost assumptions identical among projects, the impact of other factors such as reservoir conditions and surface application can be investigated.
- **Scenario 4 (Investment Tax Credit [ITC] of 10%)**: This scenario is identical to Scenario 2 but also considers an ITC of 10%. This assumes all projects have a tax burden to apply the full 10%.
- **Scenario 5 (Grant of 20%)**: This scenario is identical to Scenario 2 with a subsidy or grant of 20% of the total capital cost. Several GDH systems in the United States and Europe have benefitted from grant funding through public agencies, often in the range of 10%–30% of investment cost [8].
- **Scenario 6 (Grant of 30%)**: This scenario is identical to Scenario 5 but with a subsidy or grant of 30% of the total capital cost instead of 20%.
- **Scenario 7 (Low Discount Rate)**: This scenario is identical to Scenario 2 but with a discount rate of 2.5% instead of 5%. A lower discount rate reflects cheaper financing conditions (e.g., as a result of public agency funding with low-cost bonds or as a result of obtaining a government loan guarantee).
- **Scenario 8 (High Utilization Factor)**: This scenario is identical to Scenario 2 (30-year project lifetime, 5% discount rate, and 0% tax rate), but with all projects having a high utilization factor of 95%. The utilization factor in GEOPHIRES refers to the percentage of time the geothermal system is operating and does not reflect thermal or hydraulic drawdown. A utilization factor of 95% means the geothermal wells are operating at their nominal flow rate for 95% of the time. Unlike electricity production, direct-use systems—particularly GDH systems—sometimes have relatively low utilization factors due to limited heat demand during the summer months. A high utilization factor lowers the LCOH because for the same well investment cost, more heat is produced and utilized at the surface. Reservoir simulations are not rerun in this scenario; it is assumed the reservoir can provide the same production temperatures with a high utilization factor as with the default utilization factor assumed by each team (Table 2). Typically, increasing the utilization factor would accelerate thermal breakthrough. However, there were only two projects (UIUC and Sandia) that considered a relatively low utilization factor (of about 50%) as default, and these teams also considered a relatively low well flow rate and system size. Hence, the inherent increase assumed in reservoir performance for these two projects under Scenario 8 is not considered unrealistic. Scenario 8 is not simulated for the PSU project: the dynamic operation of charging and discharging when utilizing the reservoir for thermal storage prevents producing heat from the reservoir 95% of the time.
- **Scenario 9 (Low Drilling Cost)**: This scenario is identical to Scenario 2 but with the drilling cost lowered by 30% as a result of technological improvements or a downturn in the drilling market.
- **Scenario 10 (dGeo TI)**: This scenario mimics the *GeoVision* dGeo Technology Improvement ("TI") scenario [19]. This scenario is identical to Scenario 2 (5% discount rate, 30-year lifetime, 0% tax rate) but also assumes a flat exploration cost of $3.5M, 50% discount on the drilling cost assumed by each team, and a surface heat exchanger efficiency of 80%.
- **Scenario 11 (Subsurface LCOH)**: This scenario is identical to Scenario 2 (30-year project lifetime, 5% discount rate, and 0% tax rate), but with no exploration cost and no surface costs. This scenario calculates the "wellhead LCOH," which considers the subsurface system only. All surface equipment such as heat exchangers, heat

pumps, and electrical heaters are removed, and the heat production is adjusted accordingly.

The corresponding financial, cost, and technical input parameters for each GEOPHIRES scenario are presented in Table 3. The LCOH for each scenario and each DDU project is presented in Fig. 6 and in Table 4. Scenarios 8 and 11 are not evaluated for the PSU project because of the need for solar collectors to store heat in the reservoir during the summer months.

3.4. Beyond levelized cost of heat: other metrics for evaluating deep direct-use feasibility

The LCOH metric applies to systems with geothermal heat as end-use application. For systems with other end-uses, such as cooling (NREL DDU project) and thermal storage (PSU project), different levelized cost metrics can be evaluated (see Section 3.4.1). Some aspects of DDU, including environmental and socio-economic benefits, are not captured in a standard levelized cost of energy metric, but can have an impact on project feasibility. These are presented for each DDU project in Section 3.4.2.

3.4.1. Deep direct-use for cooling and thermal storage

The NREL DDU project investigates the performance of utilizing geothermal heat solely for providing cooling using absorption chillers [16]. The NREL project in Table 1 refers to the geothermal heating system and does not include the absorption chiller or water storage tank. The geothermal system size is 15 MW_{th}, but only 11 MW_{th} of cooling is provided given that the absorption chiller operates with a coefficient of performance of 0.72. The annual cooling load is 86 GWh/year. The capital cost of the absorption chiller is $3.74M, bringing the total cost of the geothermally driven cooling system to $15.45M. The additional operations and maintenance (O&M) cost of the absorption chiller is $65k/year. Combining these results, the LCOC of the geothermal plus absorption chiller system for a 30-year lifetime and 5% discount rate is $21/MWh. Also, WVU considered utilizing geothermal heat for cooling during the summer months using absorption chillers. However, heating remained the dominant end use, and no separate analysis was conducted to estimate an LCOC.

The PSU DDU project analyzed the performance of using a shallow geothermal reservoir for thermal storage [17]. Solar heat is collected mainly during the summer and stored in the reservoir for ~ 6 months to be used during the winter months. The PSU project parameters presented in Table 1 are for the combined geothermal plus solar system. Other heating sources can be considered, which can lower the overall project cost. Assuming the case with heat available for free, the LCOH would drop to about $50/MWh. This limiting case only accounts for the thermal storage system, and the LCOH can be interpreted as the LCOS for this project. However, comparison with other LCOS values should be done carefully because the LCOS metric is an ill-defined metric. In literature, the calculation for LCOS sometimes includes the cost of the heat, and sometimes it does not (see Section 4.4).

3.4.2. Sustainability, socio-economic benefits, and resiliency

Several teams considered other aspects of DDU development, including sustainability, socio-economic benefits, and resiliency, to evaluate feasibility and attractiveness of their project. These aspects are generally not captured by the standard LCOH calculation and require a modified LCOH equation or other metrics to quantify and report.

The UIUC team conducted a full life-cycle analysis and found that the current greenhouse gas emissions (from heating with natural gas and propane) would be offset within 10 years of operation of the DDU system [12]. The team also identifies DDU's potential to increase energy security and energy resiliency. Sandia estimated that up to 2,248 metric tons of CO_2 emissions (from heating with diesel and propane) would be avoided annually by switching to DDU heating for the city/county and army depot at Hawthorne, NV [13]. The team also highlights reliability as another advantage of DDU as a heating source. Cornell calculated that the net avoided greenhouse gas emissions, depending on the case considered, is in the range 6,000 to 17,500 metric ton of CO_2-eq per year [14]. By assuming a social cost of carbon at $50/metric ton, they calculated that the avoided greenhouse gas emissions would result in a drop in LCOH on the order of 70%. When accounting for the regional economic impact value from local direct and indirect spending as part of the DDU project, Cornell calculated the LCOH to drop by about 50% from the baseline LCOH. Cornell has adapted DDU as a key pillar in their Climate Action Plan to decarbonize the campus heat supply and contribute to becoming a carbon neutral campus by 2035. The WVU

Table 3
GEOPHIRES scenarios and their input parameters. "As is" means the parameter is set to the value assumed by each project team. "*GeoVision*" refers to the drilling cost curves developed by the Reservoir Maintenance and Development Task Force for DOE's 2019 *GeoVision* study [27].

GEOPHIRES Scenario	Discount Rate	Project Lifetime	Tax Rate	Exploration Cost	Drilling Cost	Surface CAPEX and OPEX	Surface Equipment	Utilization Factor
Scenario 1 (Quality Control)	As is	As is	As is	As is	As is	As is	As is	As is
Scenario 2 (Default Financing)	5%	30 years	0%	As is	As is	As is	As is	As is
Scenario 3 (Default Cost + Financing)	5%	30 years	0%	$0	*GeoVision*	As is	As is	As is
Scenario 4 (Tax Credit: 10%)	5%	30 years	0%	As is	As is	As is	As is	As is
Scenario 5 (Grants: 20%)	5%	30 years	0%	As is	As is	As is	As is	As is
Scenario 6 (Grants: 30%)	5%	30 years	0%	As is	As is	As is	As is	As is
Scenario 7 (Low Discount Rate)	2.5%	30 years	0%	As is	As is	As is	As is	As is
Scenario 8 (High Utilization Factor)	5%	30 years	0%	As is	As is	As is	As is	95%
Scenario 9 (Low Drilling Cost)	5%	30 years	0%	As is	70%	As is	As is	As is
Scenario 10 (dGeo TI)	5%	30 years	0%	$3.5 M	50%	As is	80% end-use efficiency	As is
Scenario 11 (Subsurface LCOH)	5%	30 years	0%	$0	As is	$0	No heat pumps, heaters, heat exchangers, etc.	As is

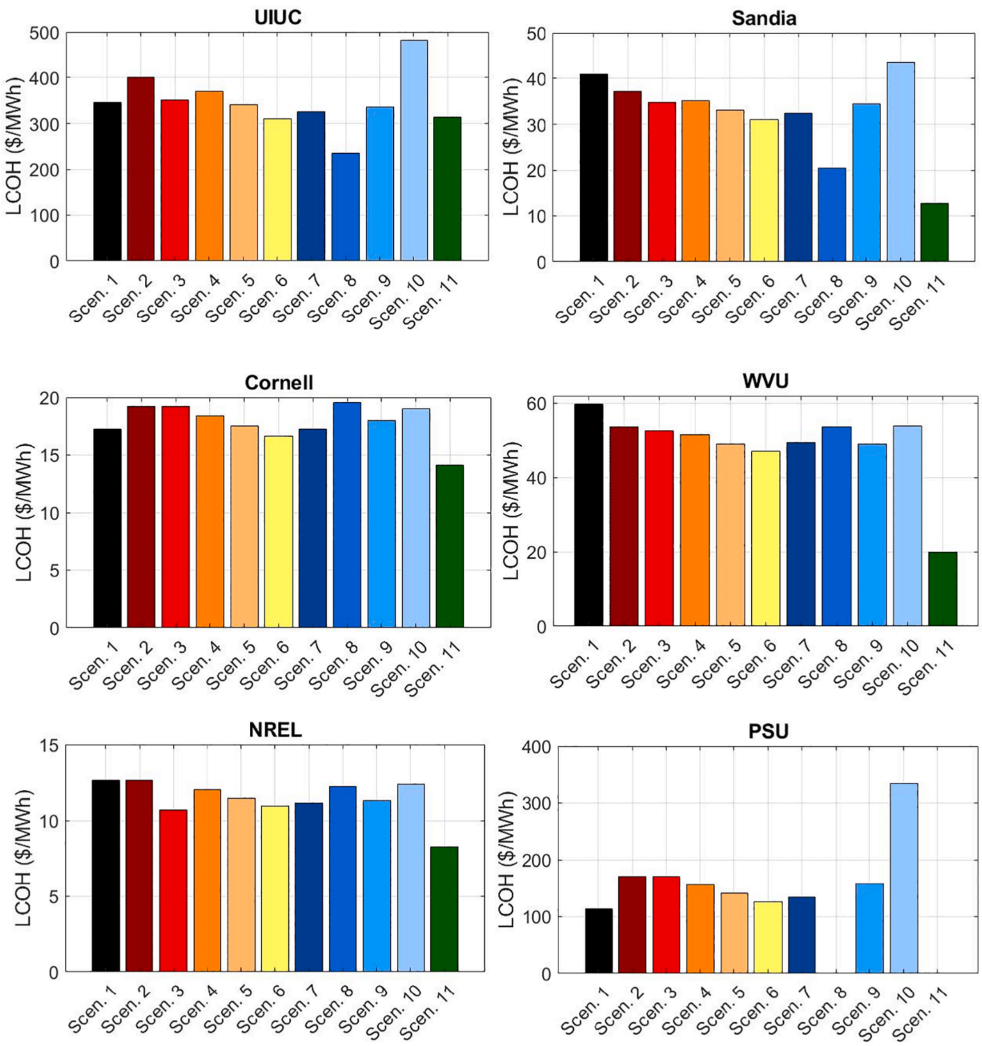

Fig. 6. LCOH simulation results for all 11 scenarios for each DDU project.

team calculated that heating with a DDU-based system would result in a reduction of 140–164 kg of CO_2 per MWh with respect to natural gas heating and a reduction of 239–260 kg of CO_2 per MWh with respect to coal-based heating [15]. WVU identifies DDU as a reliable and clean energy source that could contribute to the university's sustainability plan. The NREL project stated (but did not quantify) that turbine inlet cooling (the end-use application of DDU in their project) can reduce emissions of gas-combustion turbines and combined cycle power stations [16]. The PSU project did not calculate avoided greenhouse gas emissions but stated that DDU has significantly lower environmental impacts than natural gas and the average electricity generation mix, and highlighted that DDU for their application is highly reliable and highly resilient [17].

4. Discussion

Results from review of DDU projects and GEOPHIRES simulations (presented in Section 3) are interpreted and discussed in this section. The wide range in base case DDU LCOH and the performance of the DDU projects under the different scenarios studied are investigated in Section 4.1. DDU feasibility is evaluated by comparing with a reference heating price for each DDU project (Section 4.2), with prior studies and existing systems (Section 4.3), and with other heating, cooling and thermal storage technologies (Section 4.4). Impact of other aspects of DDU, including environmental and socio-economic benefits, on project feasibility is discussed in Section 4.5. Barriers for DDU development and options for reducing these barriers are presented in Section 4.6.

4.1. Analysis of levelized cost of heat drivers and scenarios

The base case LCOH for the DDU projects varies widely, from as low as $13/MWh (NREL) to $345/MWh (UIUC), as a result of a wide variety in project parameters. The base case parameters and results are listed in Table 2 and correspond to Scenario 1 in Table 3. Investigating the key parameters for each project (Table 2 and Figs. 4 and 5) reveals underlying reasons for obtaining either high or low LCOH:

- **UIUC**: The UIUC project has a high LCOH due to a combination of a low geothermal gradient (among the lowest in the country), low reservoir temperature, low flow rate, small system size, low utilization factor, high surface cost, and high drilling cost.
- **Sandia**: Despite a relatively low flow rate, low utilization factor, and high drilling cost (expressed in $/m), the Sandia project still obtained an attractive LCOH, mainly as a result of a very high geothermal gradient (among the highest in the country), low reservoir depth, high reservoir temperature, and low surface cost.
- **Cornell**: The Cornell project has a relatively low LCOH, mainly as a result of low surface cost (the district heating system is already in place), high utilization factor, high annual heat production, and low discount rate.

Table 4
GEOPHIRES LCOH results for all DDU projects for the 11 scenarios presented in Table 2.

GEOPHIRES Scenario	UIUC	Sandia	Cornell	WVU	NREL	PSU
Scenario 1 (Quality Control)	\$346/MWh	\$40.9/MWh	\$17.2/MWh	\$59.6/MWh	\$12.6/MWh	\$113/MWh
Scenario 2 (Default Financing)	\$400/MWh	\$37.2/MWh	\$19.2/MWh	\$53.6/MWh	\$12.6/MWh	\$171/MWh
Scenario 3 (Default Cost + Financing)	\$351/MWh	\$34.8/MWh	\$19.2/MWh	\$52.7/MWh	\$10.7/MWh	\$171/MWh
Scenario 4 (Tax Credit: 10%)	\$370/MWh	\$35.0/MWh	\$18.4/MWh	\$51.4/MWh	\$12.0/MWh	\$156/MWh
Scenario 5 (Grants: 20%)	\$341/MWh	\$32.9/MWh	\$17.5/MWh	\$49.2/MWh	\$11.4/MWh	\$141/MWh
Scenario 6 (Grants: 30%)	\$311/MWh	\$30.9/MWh	\$16.7/MWh	\$46.9/MWh	\$10.8/MWh	\$125/MWh
Scenario 7 (Low Discount Rate)	\$325/MWh	\$32.5/MWh	\$17.2/MWh	\$49.5/MWh	\$11.2/MWh	\$133/MWh
Scenario 8 (High Utilization Factor)	\$235/MWh	\$20.5/MWh	\$19.6/MWh	\$53.6/MWh	\$12.2/MWh	N/A
Scenario 9 (Low Drilling Cost)	\$335/MWh	\$34.4/MWh	\$18.0/MWh	\$49.1/MWh	\$11.3/MWh	\$158/MWh
Scenario 10 (dGeo TI)	\$482/MWh	\$43.7/MWh	\$19.0/MWh	\$53.9/MWh	\$12.4/MWh	\$333/MWh
Scenario 11 (Subsurface LCOH)	\$313/MWh	\$12.6/MWh	\$14.1/MWh	\$19.9/MWh	\$8.24/MWh	N/A

- **WVU**: The WVU project LCOH was average, because the high utilization factor, large system size, relatively high reservoir temperature, and relatively low drilling cost were offset by a relatively low geothermal gradient, only mediocre well flow rate, relatively high surface cost, and high discount rate.
- **NREL**: The NREL project obtains a low LCOH due to a combination of high reservoir temperature, high flow rate, high utilization factor, large system size, reasonably high geothermal gradient, low surface cost (only surface piping and pumps are accounted for), low drilling cost, and average discount rate.
- **PSU**: The PSU LCOH is relatively high, mainly as a result of very high surface cost for the solar array. Other factors contributing to a relatively high LCOH are a low utilization factor (this is inherent to seasonal thermal storage because heat is provided predominantly during the winter months, while reservoir charging occurs mainly during the summer months), small system size, and low annual heat production. The PSU team indicated that the project did not attempt to minimize cost but focused on researching the subsurface performance [17]. Larger systems or lower-cost heating sources would lower the LCOH. In the case of free heat (e.g., waste heat), the LCOH for this system would drop to \$50/MWh.

For all projects, the LCOH calculated in Scenario 1 (Quality Control) matches the reported LCOH by the project teams within 1%, indicating that the GEOPHIRES models and input parameters are set up correctly. Harmonizing the financial conditions and reporting the LCOH as nominal for all projects in Scenarios 2 and 3 resulted in a slight decrease in LCOH (less than 20%) for the NREL, Sandia, and WVU projects, a slight increase in LCOH (less than 20%) for the Cornell and UIUC projects, and a significant increase in LCOH (on the order of 50%) for the PSU project. This suggests that comparison should be done carefully among base case LCOH results reported by the teams, keeping in mind that generous financial conditions or reporting a real instead of a nominal LCOH lowers the LCOH value. Across all DDU projects, the 10% ITC (Scenario 4), 20% grant (Scenario 5), 30% grant (Scenario 6), and 2.5% discount rate (Scenario 7) resulted in a decrease in LCOH with respect to Scenario 2 in the range of 5% to 27%. This decrease is relatively small but non-negligible, and is sufficient to change the bottom line of a project (e.g., under Scenarios 4–7, the WVU project LCOH drops under the reference heating price [see Section 4.2]). A high utilization factor (Scenario 8) results in a significant decrease in LCOH (up to 50% with respect to Scenario 2) for those projects where the base case utilization rate was low (about 45%–50% for UIUC and Sandia). This indicates that operating with high utilization of the geothermal resource throughout the year—not just during the winter months—significantly improves the project economics. For most DDU projects, a decrease of 30% in drilling cost (Scenario 9) has a similar impact on the LCOH as a 20% grant. The dGeo TI scenario (Scenario 10) resulted in a relatively high LCOH for some projects due to its assumption of a flat exploration cost and relatively low end-use efficiency factor. Removing surface equipment and exploration cost to estimate a generic subsurface-only or wellhead LCOH (Scenario 11) resulted in a significant drop in LCOH for those projects that assumed high surface equipment cost (Sandia and WVU) or considerable exploration cost (NREL).

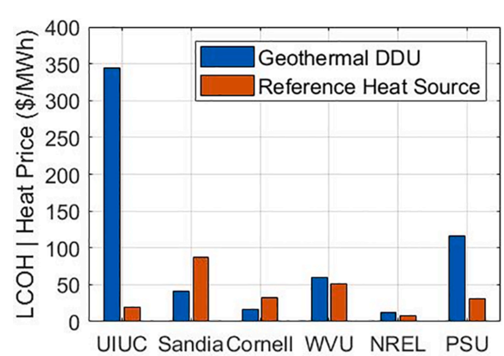

Fig. 7. Base case LCOH vs. reference heating price for each DDU project.

4.2. Comparison base case levelized cost of heat with reference heating price

Initial feasibility is assessed by comparing each DDU LCOH with a reference heating price (Fig. 7). The reference heat price is estimated by dividing the current fuel price by 85% for boiler efficiency, except for WVU where the cost is already reported as a campus heat price. The current fuel price is reported by the DDU teams or sourced from the U.S. Energy Information Administration [28]. The reference heat source for the Cornell, NREL, PSU, and UIUC projects is natural gas, with corresponding reference heat price of $32.1/MWh, $8.4/MWh, $31.3/MWh, and $20.1/MWh, respectively. The reference heat source for the Sandia project is diesel, with reference heat price of $86.7/MWh. The WVU campus heating fuel is coal with heat price of $51.2/MWh. Based solely on this comparison, the Sandia and Cornell projects appear cost-competitive, while the UIUC and PSU projects (and to some extent also the NREL project) appear not economically feasible. Even though the NREL project had the lowest LCOH of all six projects ($13/MWh), the LCOH was still higher than the reference heat price due to a very low industrial natural gas price in Texas ($6.6/MWh or $2.1/MMBtu). The WVU project has an LCOH of same order of magnitude as the reference heating cost.

Although revealing, this simple comparison only provides a first order feasibility analysis. The DDU projects are not necessarily optimized for lowest cost. For example, a different heating source or a larger system size could lower the LCOH of the PSU project. More surface thermal demand to allow for a higher well flow rate and higher utilization factor would significantly lower the UIUC project LCOH. Further, the reference heat prices listed (except for WVU) do not account for boiler cost, maintenance cost, discount rate, etc.—all factors that would increase the heat price (see also Section 4.4). This analysis also does not account for changing market conditions, and the natural gas prices are currently (as of 2020) historically low. Other factors such as environmental impact (including greenhouse gas emissions), socio-economic impact (including local job creation and local tax revenue), resiliency, and security of supply—all factors that would favor DDU project feasibility—are not incorporated into the LCOH (see also Sections 3.4.2 and 4.5).

4.3. Comparison of deep direct-use project levelized cost of heat with prior studies and existing systems

DDU project LCOH as reported by each team are compared with the LCOH for simulated and existing GDH systems in the United States and Europe in Fig. 8. Whereas Table 2, Fig. 6 (Scenario 1), and Fig. 7 only provide a single base case for each DDU project—selected for this study as "most representative"—most teams considered a range of system configurations and operating conditions (e.g., different number of wells, different pumping rates, different reservoir depths). The LCOH range as reported by each team is presented in Fig. 8, indicating a particularly wide LCOH range for the Sandia project, with the selected base case falling on the lower end of this range. The lower end of the PSU project LCOH range ($50/MWh) represents the PSU DDU system with zero cost for the heat (e.g., waste heat), while the upper end represents the system with heat provided by a solar array as considered by the team. The LCOH range for existing U.S. systems is based on 19 U.S. GDH systems, assuming a 5% discount rate, 30-year lifetime, and project capital cost, O&M cost, and annual heat production as reported in the NREL geothermal direct-use database [6], recently updated for the Geothermal Market Report [8], or as provided by Mattson and Neupane [29]. The range for existing GDH systems in Europe is based on heat prices for 11 GDH systems as provided by the GeoDH project [25], reported GDH heat prices in Iceland [30], and GDH LCOH estimates for Europe by Dumas and Angelino [31]. LCOH values for EGS-based GDH for communities in New York and Pennsylvania are based on simulations conducted by Reber [21]. The *GeoVision* GDH LCOH range is based on simulations with dGeo by McCabe et al. [19] for the *GeoVision* study [7] and includes both hydrothermal and EGS resources and the *business as usual* and *technology improvement* scenarios.

Fig. 8 indicates that the UIUC project and several cases of the Sandia project are expensive outliers in comparison with the other DDU projects and existing and simulated systems in the United States and Europe. Utilizing solar heat as a heat source in the PSU project (upper end of LCOH range) appears expensive, while cheaper (or free) heat sources (lower end of LCOH range) would result in more cost-competitive LCOH values. However, given its thermal storage application, the PSU project is inherently different than the other projects, preventing a direct comparison with standard GDH systems. The WVU project and the more cost-competitive Sandia cases obtain LCOH values comparable with existing and simulated U.S. and European GDH systems. The Cornell and NREL DDU projects appear highly attractive in comparison with existing and simulated LCOH values for the United States and Europe. However, a direct comparison may not be fair because both DDU projects include limited surface equipment in their LCOH calculation. The Cornell project has an existing district heating system in place and capital costs for surface equipment only account for centralized heat pumps and a connection with the heating network. The NREL DDU project uses the geothermal heat not for district heating but for providing cooling with an absorption chiller. Their LCOH calculation only considers pumps, a 1-km transport pipeline, and a wellfield surface gathering system as surface equipment. Further, the Cornell project did not consider exploration costs, also lowering the LCOH value.

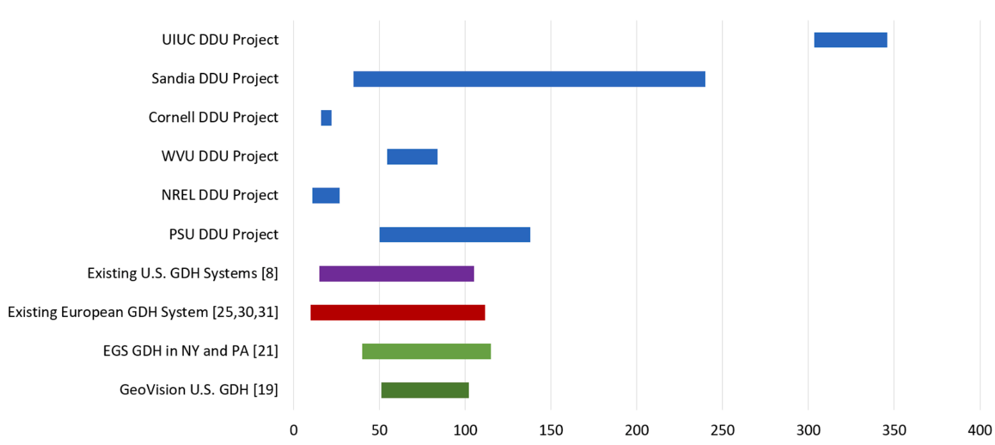

Fig. 8. Comparison of DDU project LCOH range as reported by each team with LCOH or heat price for existing U.S. and European GDH systems, and simulated LCOH for GDH in the United States by Reber [21] and by McCabe et al. [19] for the *GeoVision* study.

4.4. Comparison of deep direct-use projects with other heating, cooling, and storage systems

Worldwide, the number of GDH systems—on the order of several hundred—is only a small fraction (<1%) of the total number of district heating systems in operation (on the order of 100,000) [32]. The majority of district heating systems run on natural gas and combustible renewables, either through direct combustion, as waste heat, or as combined heat and power (CHP) [32]. The United Nations Environment Program (UNEP) in 2015 [33] estimates the LCOH for district heating systems (including the heating network cost) at $40/MWh when using waste heat as heat source, $60/MWh for combined cycle gas turbine CHP systems, $70/MWh for geothermal or natural gas boiler-based systems, and $90 to $130/MWh for woodchip CHP-based systems. For calculating the LCOH, they assumed a conservative discount rate of 10%, and a relatively high natural gas price (for the United States) of $38/MWh. For comparison, the LCOH for decentralized heating systems was estimated at $150/MWh for domestic natural gas heating (based on a natural gas price of $76/MWh), $220 for an air source heat pump system (with $203/MWh as electricity price), and $250/MWh for electric resistive heating [33]. With current residential natural gas and electricity prices in the United States roughly 50% lower than assumed in this report, the LCOH for decentralized natural gas heating would be on the order of $120/MWh, and for air-source heat pump heating on the order of $180/MWh. The base case Sandia, WVU, and Cornell DDU projects (with an LCOH in the range $17 to $60/MWh) appear cost-competitive in comparison with decentralized heating options and obtain comparable LCOH values as the lower cost centralized district heating systems. However, a direct comparison may not be correct, because the UNEP report assumes a high discount rate and relatively high natural gas price, and the Cornell DDU project does not account for the cost of a district heating network.

As studied by the NREL DDU project, geothermal can provide cooling with absorption chillers. Given the large U.S. cooling demand in the residential and commercial sector (including for space cooling, refrigerating, and freezing) [2], a potentially significant application for geothermal DDU is providing cooling to communities using district cooling (DC) networks or at specific sites with large local cooling load. Very few such systems are currently in place worldwide—one example is at Chena Hot Springs in Alaska—but a handful of case studies illustrate the potential, including a study on geothermal for space conditioning in commercial buildings in the U.S. [34], a study on geothermal cooling for a university campus in Australia [35], and modeling work of a single-stage [36] and two-stage [37] absorption chiller driven by geothermal heat. However, non-geothermal-based DC systems—potentially low-hanging fruit for implementing geothermal-based cooling—are widespread around the world. Around 44 GW of DC capacity is installed worldwide, 43% of which are in the Americas, 32% in Gulf Cooperation Council countries, 19% in Asia and Africa, and 5% in Europe [38]. These DC systems are typically supplied by electrically driven vapor compression systems or heat-driven absorption chillers. The LCOC for DC systems depends on many factors, such as load factor, fuel prices, installation costs, capacity, and development costs. Based on the UNEP report [33], typical values for LCOC for DC networks are on the order of $70/MWh for both systems running on absorption chillers and electric chillers (assuming steam price of $19/MWh, electricity price of $127/MWh and 10% discount rate). Roughly half of this LCOC is attributed to the network cost ($35/MWh) and the other half to the cooling production ($35/MWh). The LCOC for decentralized residential air-conditioning systems is estimated at $135/MWh (assuming an electricity rate of $203/MWh) [33]. For a more typical U.S. residential electricity rate ($100/MWh), this LCOH may drop to about $90/MWh. The LCOC estimated for the NREL DDU project ($21/MWh) appears attractive; however, that calculation assumed no DC network, only an absorption chiller as surface equipment and a lower discount rate of 5% instead of 10% in the UNEP report.

The PSU DDU project studied storing thermal energy in subsurface formations, referred to as reservoir thermal energy storage (RTES) [17]. RTES is one of several types of underground thermal energy storage (UTES) systems, with others including aquifer thermal energy storage (ATES), borehole thermal energy storage (BTES), and pit thermal energy storage (PTES) [39]. RTES and ATES are labelled as open UTES systems because the injected water penetrates the rock formations. While closely related, RTES typically uses more saline/brackish aquifers with slow-moving geochemically evolved fluids, whereas ATES systems utilize aquifers that typically have more significant regional ground water flow, potentially hindering storing thermal energy effectively [40]. This distinction is sometimes not made in literature, and ATES has been used to refer to both types of systems. Only about 3,000 ATES/RTES systems are in operation worldwide, about 2,500 of which are in the Netherlands, and only two in the United States [39]. One U.S. example is the ATES system at Stockton College, used for storage of chiller water [41]. BTES and PTES are examples of closed UTES systems because the injected/extracted fluid does not enter the subsurface formations. BTES uses sealed vertical boreholes for heat exchange with the surrounding rock, and PTES stores water in an excavated basin with a liner and an insulated lid. A common thermal storage system at the surface is utilizing large insulated tanks, also referred to as tank thermal energy storage (TTES). LCOS of thermal energy storage systems has been evaluated in multiple case studies, including a case-study on ATES in the Netherlands [42], a high-level review study on ATES, BTES, PTES and TTES [43], and a more detailed techno-economic review of different sensible thermal energy storage systems [44]. Bases on these three studies, a range of LCOS values for each technology is calculated: $15–$134/MWh for ATES, $24–$194/MWh for BTES, $91–$156/MWh for TTES, and $24–$108/MWh for PTES. However, multiple definitions are found in literature with sometimes the price of heat included in the LCOS value and sometimes not. The wide range in LCOS values is a result of a wide range in installation and O&M cost, storage volume, heat production, and cost of heat (sometimes zero). The PSU DDU project base case LCOS value without solar array ($50/MWh) falls in the middle of the LCOS range for ATES systems. Wesselink et al. [42] discuss how subsidies for geothermal heat in the Netherlands can lower the LCOS by almost 80%, explaining the relatively high number of ATES installations in that country.

4.5. Deep direct-use feasibility and attractiveness beyond levelized cost

Although calculating a DDU project levelized cost (LCOH, LCOC, LCOS) provides an initial assessment of cost-competitiveness and allows for easy comparison with other energy sources, several attributes of geothermal—that also impact project feasibility and attractiveness—are not captured in the levelized cost metric. These attributes include its potential for decarbonizing the heating/cooling supply, and providing resiliency and reliability to the energy infrastructure. In the context of a rapidly changing energy market, rapidly evolving policies with respect to climate change, and increased attention to the sustainability and resilience of energy systems, these attributes of DDU may become increasingly important when evaluating project feasibility. Several of the DDU project teams considered these additional measures and highlighted their positive contribution to project feasibility (see Section 3.4.2).

DDU's ability to provide megawatt-scale, baseload, and low-carbon heating positions it well to contribute to decarbonizing the energy supply in cities, campuses, and other communities across the country. With aggressive greenhouse gas reduction targets implemented by several U.S. states, cities, and universities, DDU may experience increased interest to assist with meeting these goals. Cornell for example has adopted DDU, referred to as Earth Source Heat, as their main technology for decarbonizing the campus heat supply in their Climate Action Plan in order to become carbon neutral by 2035. The university plans to drill a first test well during the second half of 2021. In Europe, geothermal has been identified as a key energy source for decarbonizing the heating and cooling sector in several countries, for example in Germany [45] and the Netherlands [46].

4.6. Deep direct-use barriers and enablers

While LCOH of existing U.S. systems and some DDU projects appear cost-competitive and are comparable to LCOH values for systems in Europe, GDH development has been limited in the United States, with about 100 MW_{th} of current installed capacity. In contrast, installed capacity in Europe and China is several gigawatts, with dozens of systems currently under development. This section explores technical, economic, political, and social barriers for GDH development in the United States, as well as potential approaches for reducing barriers.

4.6.1. Technical barriers

Technical challenges arise in both the development of a subsurface resource and the installation of surface equipment. For geothermal systems, the geothermal resource quality (based on temperature, volume, depth, permeability, fluid chemistry, etc.) need to be quantified. Limited data and the cost of surveying and exploration contribute to uncertainty and risk in characterizing the subsurface and can adversely affect project timelines and finances [47]. Accessing a resource can affect the properties of the subsurface rocks and fluids—which may impact other users of the subsurface—and should be minimized, particularly if aquifer levels may be affected [48]. A successful geothermal reservoir requires sustainable high-temperature fluid production over its lifetime (e.g., 30 years) at economic flow rates (e.g., 50 kg/s per producing well). Stimulation techniques can enhance the reservoir permeability and increase fluid production rates, but may also lead to induced seismicity, causing disturbance and potentially damage at the surface. Minimizing induced seismicity requires evaluation of the uncertainty and impact of several risk factors, such as the rate and volume of fluid injection and withdrawal, injection pressures, depth of disturbance, state of stress in the crust, rock properties, and proximity to seismogenic faults [49].

A significant technical challenge for the surface equipment is transferring geothermal heat to the load. This typically requires the geothermal field to be located close to the load, to avoid long pipelines and rights-of-way issues and limit thermal losses. This co-location constraint may limit the potential deployment of geothermal direct-use [47]. An assortment of heating and cooling systems exist for a variety of applications, which, when coupled with a range of geothermal resource temperatures and flow rates, creates challenges for standardizing system designs, which leads to higher costs [7]. This is compounded by a limited knowledge base [50] which can lead to inadequate engineering, delays, reduced lifetime, and re-designs [48].

4.6.2. Market/policy barriers

Geothermal direct-use systems have high upfront costs and low operating and fuel costs, compared to conventional heating using fossil fuels. Significant costs are incurred early in the project to characterize the subsurface through pre-drilling activities such as geophysical and geological surveys, and test drilling [7]. Risks and costs are further increased the deeper and hotter the well is. Although geothermal wells typically have a small footprint, distributing heat to the load requires pipelines that can be complicated in urban environments, where rights-of-way will have to be obtained [17]. In the United States, geothermal development timelines are in the range of 7–10 years due to complex permitting processes and multiple stages of review [7]. As a result, financing costs are increased and return on investments are delayed.

High risks and long development timelines are unappealing to investors, while the costs may be too large for cities or municipalities to finance [8]. There are currently limited federal or state incentives such as subsidies or tax credits [7], and in some cases, renewable heating and cooling schemes may be ineligible [8]. A number of policy mechanisms currently in existence in the United States are meant to incentivize renewable power, mostly at the state level [8]. Most incentives specific to geothermal energy production are power-focused [8]. On the other hand, there are also a number of policy mechanisms in place to incentivize the use of geothermal heat pumps. The availability of any incentives can be unreliable, and there is a lack of risk mitigation schemes in the United States for geothermal (e.g., insurance), which presents further challenges for systems with long development periods [8].

The dominant energy source for heating in the U.S. residential sector is natural gas [51]. Natural gas currently has historically low prices in the United States, which makes DDU less cost-competitive. The residential natural gas price in the lower 48 U.S. states is currently in the range \$22 to \$73/MWh, with an average of \$39/MWh [52]. In contrast, European residential natural gas prices are much higher, in the range of \$38 to \$104/MWh for the EU27 countries, with an average of \$83/MWh [53].

4.6.3. Social barriers

Previous reports have claimed that compared to other renewable energy generators such as wind and solar, the relative invisibility of geothermal energy has led to a lack of public awareness, which is important to influence policy, incentives, and land access [8]. Outreach efforts during the early stage of a project can reduce opposition, which may result from "perceived" risks of induced seismicity [7]. Thus, openly communicating the seismicity risk evaluations is of paramount importance.

Geothermal direct-use systems require the cooperation of numerous stakeholders, such as landowners, government entities, utilities, communities, and end users. Negotiating the distribution of costs and benefits between these participants can create challenges [50]. The apparent shortage of geothermal professionals, consultants, and businesses may also limit the development of these networks.

4.6.4. Reducing barriers

Geothermal direct-use has been more widely deployed in Europe than the United States, and this has been attributed to higher natural gas prices, public availability of geological data, and financial tools including grants, loans, and insurance [8]. In Iceland, a government program was established in the 1940s to produce knowledge and data of the geothermal resources. The Icelandic Energy Fund was then established in 1967 to provide loans for the development of geothermal resources: risk was reduced by converting loans into grants if a resource was not found. As the industry developed, government finance was reduced, and exploration and development are now undertaken by utilities [48]. Other financial incentives that have been attributed to spur geothermal direct-use development in Europe include feed-in tariffs, tax rebates and reductions, risk mitigation schemes to provide insurance for short-term and long-term risks, and grants issued at the regional, federal, or European level. An overview of incentives and financing mechanisms in Europe has been documented as part of the GeoDH project [26] and by the European Geothermal Energy Council [54]. A recent update was provided by Dumas et al. in 2019 [55].

The geothermal direct-use industry could be developed in the United States by alleviating some of the barriers described above. For instance, technical barriers can be reduced by workforce development and technological innovation. Financial barriers can be reduced by initial government support through grants, loans, loan guarantee programs, risk mitigation schemes, and other incentives that recognize the unique attributes of geothermal direct-use, such as emissions reductions and continuous energy supply. Development times can be reduced with policies that streamline the process of obtaining permits, reviews, and rights-of-access. Increasing community involvement would increase awareness and reduce opposition. Successful DDU demonstration projects may also increase public awareness and reduce perceived risk.

5. Conclusions

This paper investigated the feasibility of utilizing deep geothermal resources for direct-use applications in the United States including for heating, cooling and thermal storage. Historically, U.S. geothermal development has focused on higher-grade resources in the western United States for electricity production. However, direct-use of geothermal heat avoids low conversion efficiencies and allows utilizing lower-temperature resources, which are more widespread. In addition, low-temperature heat demand in the United States is significant, and, while limited in the United States, several thousands of gigawatts-thermal of cost-competitive direct-use systems have been developed in Europe and China. Feasibility of DDU was assessed by reviewing results of six recently conducted DOE-funded DDU projects in the United States and running additional techno-economic simulations with the tool GEOPHIRES. Results were compared with prior studies, existing GDH systems in United States and Europe, and performance of non-geothermal centralized and non-centralized heating, cooling, and thermal storage systems.

DDU project base case LCOH ranged between $13 and $350/MWh. The wide range is a result of a wide variety of subsurface conditions, surface configurations, and cost and financing assumptions. Key LCOH drivers that increase DDU feasibility include higher reservoir temperatures, shallower reservoir depths, higher well flow rates, higher utilization rates, lower drilling costs, and lower discount rates. GEOPHIRES simulations indicated that comparison among reported LCOH values should be done carefully, as some teams assumed generous financing conditions, and some teams reported a real LCOH instead of a nominal LCOH. Other GEOPHIRES scenarios showed that, across all DDU projects, incentives such as the 10% ITC, a 2.5% discount rate, and a grant up to 30% of total capital cost, resulted in a decrease in LCOH in the range of 5% to 27%. For most DDU projects, a decrease of 30% in drilling cost resulted in a decrease in LCOH on the order of 10%, comparable to the impact of a 20% grant.

The base case LCOH values for four DDU projects fell in the range of LCOH values for existing GDH systems in Europe and the United States ($10–$110/MWh), and were comparable to values found in previous studies ($40–$115/MWh). Three DDU projects that investigated GDH had base case LCOH values in the range $17–$60/MWh, and appeared cost-competitive in comparison with a reference heating source at their site, in comparison with existing fossil-fuel-driven district heating systems reported in literature, and in comparison with decentralized heating with natural gas boilers or heat pumps. Also, an attractive LCOC value on the order of $20/MWh was obtained for producing chilled water with absorption chillers supplied by a high-quality geothermal resource. This LCOC value is comparable to those from typical centralized cooling production facilities and lower than domestic decentralized cooling with air-conditioning units. Investigating the DDU project for thermal storage revealed LCOS values in the range $50 to $130/MWh, comparable to other thermal storage techniques, such as borehole, aquifer, pit, and tank thermal energy storage, with LCOS values in the range $15 to $194/MWh.

The results show that DDU can be cost-competitive, in addition to offering benefits such as low environmental impact, high reliability, and high resiliency. However, various barriers for DDU development exist, including the need for exploration and test drilling, resulting in high upfront cost, long permitting timelines, limited financial incentives, low public awareness, and perceived risk of induced seismicity. Options are available for reducing barriers, such as workforce development, technological innovation, streamlining the permitting process, financial incentives such as grants and loan guarantee programs, and demonstration projects to increase public awareness and lower uncertainty and risk.

CRediT authorship contribution statement

Koenraad F. Beckers: Methodology, Formal analysis, Investigation, Visualization, Writing - original draft, Writing - review & editing. **Amanda Kolker:** Conceptualization, Formal analysis, Investigation, Writing - original draft, Writing - review & editing. **Hannah Pauling:** Formal analysis, Resources, Writing - original draft, Writing - review & editing. **Joshua D McTigue:** Writing - original draft, Writing - review & editing. **Devon Kesseli:** Writing - original draft, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgments

This work was authored in part by the National Renewable Energy Laboratory, operated by Alliance for Sustainable Energy, LLC, for the U. S. Department of Energy (DOE) under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Geothermal Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government. The U.S. Government retains and the publisher, by accepting the article for publication, acknowledges that the U.S. Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this work, or allow others to do so, for U.S. Government purposes. We would like to thank Jennifer Kurtz, Craig Turchi, Bud Johnston, and Deanna Cook for their review of the manuscript.

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