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Introducing GEOPHIRES v2.0: Updated Geothermal Techno-Economic Simulation Tool

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ABSTRACT

This paper presents an updated version of the geothermal techno-economic simulation tool GEOPHIRES (**GEO**thermal energy for **P**roduction of **H**eat and electricity ("**IR**") **E**conomically **S**imulated). GEOPHIRES combines engineering models of the reservoir, wellbores, and surface plant facilities of a geothermal plant with an economic model to estimate the capital and operation and maintenance costs, lifetime energy production, and overall levelized cost of energy. The available end-use options are electricity, direct-use heat, and cogeneration. The main updates in the new version include conversion of the source code from FORTRAN to Python, the option to import temperature data (e.g., measured or from stand-alone reservoir simulator), updated cost correlations, and more flexibility in selecting the time step and number of injection and production wells. In this paper, we provide an overview of all the updates and two case studies to illustrate the tool's new capabilities.

1. INTRODUCTION

From 2012 to 2014, one of the authors developed the computer software GEOPHIRES (Beckers et al., 2013; 2014) to perform techno-economic simulations of deep geothermal energy systems. GEOPHIRES is an acronym that stands for **GEO**thermal energy for the **P**roduction of **H**eat and electricity ("**IR**") **E**conomically **S**imulated. The "IR" represents electric current and resistance and refers to the electricity mode. The simulation tool incorporates reservoir, wellbore, and surface plant models to calculate the heat and/or electricity output over the lifetime of the plant. The tool has built-in capital and operation and maintenance (O&M) cost correlations, as well as economic life-cycle models to estimate the overall required investment and levelized cost of electricity and/or heat (LCOE and LCOH). Different end-uses (i.e., direct-use heat, electricity, or cogeneration) can be evaluated for different resource grades and technology assumptions. Ground-source heat pump systems are not included.

Various scenarios exist that require performing these types of simulations to assess the technical and economic performance of a geothermal plant. Examples of these scenarios include selecting the best location of a new plant, determining the best end-use for a certain resource, comparing with other energy sources, modeling inherent uncertainty in subsurface parameters (e.g., permeability, geothermal gradient, and reservoir volume) with a sensitivity analysis, developing an optimal reservoir management strategy, estimating future behavior using historical operating data, or predicting the impact on future revenue of a system upgrade (e.g., drilling a new well, stimulating the reservoir, or replacing a heat exchanger).

Other techno-economic tools are available to simulate deep geothermal energy systems, such as the Geothermal Energy Technology Evaluation Model (GETEM) (DOE, 2016) and the Hot Dry Rock economic (HDRec) model (Heidinger et al., 2006). However, the focus of these and other prior models is solely on the generation of electricity, which may not be the target end-use. Having the capability to assess other end-uses, such as direct-use heat in district heating systems or industrial processes or combined heat and power (CHP), was the original reason for developing GEOPHIRES.

GEOPHIRES has been upgraded over the last several months, and this work will continue throughout 2018. This paper presents the current status and planned future changes. At the time of publication, the drilling, labor, and surface plant cost correlations in the model have been updated to reflect present-day trends. Additionally, the source code has been converted from FORTRAN to Python to enhance code readability and improve accessibility for external developers, as part of a greater effort to release an open-source version of the model. This refactoring of the source code also allows for implementing new capabilities, such as advanced time-stepping control and coupling to external reservoir simulators. A discussion on these and other GEOPHIRES upgrades is provided in Section 2, along with a detailed description of the model structure and a history of the tool. Section 3 presents two case studies—one electricity and one direct-use—to demonstrate GEOPHIRES and its capabilities.

2. GEOPHIRES

2.1 History of GEOPHIRES

The original GEOPHIRES (v1.0) tool evolved out of previous research and models developed by Jeff Tester and co-workers that date back to the 1970's Fenton Hill Hot Dry Rock (HDR) project at Los Alamos National Laboratory. The work in that project resulted in the thermo-economic HDR model, which was presented in detail in "Heat Mining" by Armstead and Tester (1987). In the late 1980s, the HDR model was updated to the MIT-HDR model (Tester and Herzog, 1990), and in the 1990s, it was modified into a Windows version to make it accessible to the wider geothermal community (Kitsou et al., 2000). That model formally became known as the MIT-EGS model and was used in the "Future of Geothermal Energy" study (Tester et al., 2006).

From 2012 to 2014, the MIT-EGS model was modified extensively by Beckers and other members of the Tester research group at Cornell Univeristy to develop GEOPHIRES v1.0. In addition to incorporating different end-uses beyond electricity production (direct-use and CHP), the built-in capital and O&M cost correlations were updated and a new economic model (standard discounted levelized cost model), reservoir model (percentage thermal drawdown model), and wellbore model (Ramey's heat transmission model) were implemented. Also, new power plant conversion efficiency correlations for subcritical binary cycle and double flash power plants were developed and integrated based on simulations in AspenPlus and MATLAB. GEOPHIRES v1.0 was introduced at the Stanford Geothermal Workshop (Beckers et al., 2013) and later described in detail in a journal article (Beckers et al., 2014) and dissertation (Beckers, 2016). Various simulation examples are included in these papers. Other case studies using GEOPHIRES v1.0 include an analysis of the potential for deep geothermal district heating in New York and Pennsylvania (Reber et al., 2014) and at Cornell University (Tester et al., 2015), and an assessment of a hybrid geothermal-biomass cogeneration system for Cornell University (Beckers et al., 2015).

2.2 GEOPHIRES Model Structure

Figure 1 shows the updated GEOPHIRES (v2.0) operating scheme. The components simulating the reservoir, wellbore, and power plant, as well as the cost and economic models, are implemented in Python and represented by the green rectangles. GEOPHIRES v2.0 requires about 80 input parameters grouped into six categories: resource parameters, engineering parameters, reservoir parameters, financial and operating parameters, capital cost parameters, and O&M cost parameters. If a parameter is not provided by the user, a default value is assumed. The default techno-economic output result is the LCOE (in ¢/kWh_e) or LCOH (in $/MMBTU), depending on the end-use type selected. To facilitate providing the input parameters and reading the output, a graphical user interface (GUI) for Windows (written in VB 9.0) is available. The GUI and Python code communicate through an input and output file in ".txt" format. The user can bypass the GUI, for example, to perform batches of simulations for optimization purposes, Monte Carlo statistical analysis, or parameter sensitivity analysis. GEOPHIRES v2.0 also has the option to bypass the built-in reservoir models and read in the temperature profile from an external reservoir simulation or actual geothermal plant data.

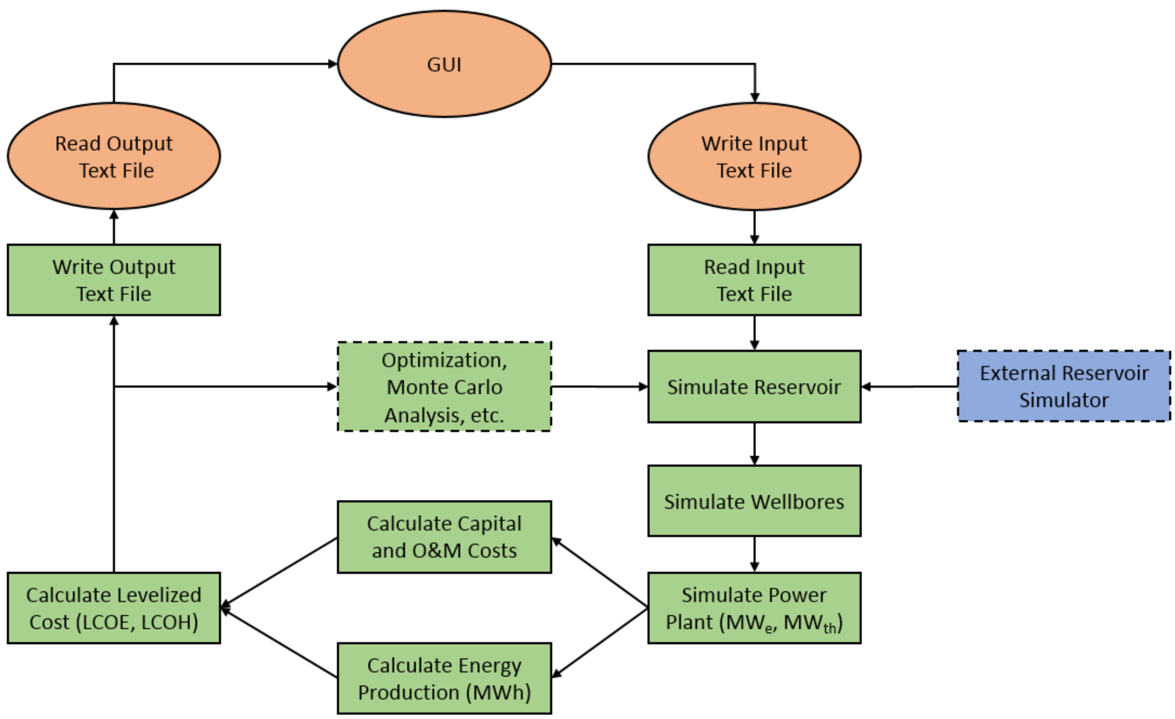

Figure 1: GEOPHIRES Model Structure. The Windows Graphical User Interface (GUI) components are shown with orange ovals. The underlying Python simulation components are shown with green rectangles. The blue rectangle shows the external reservoir simulator whose output can be used as input in GEOPHIRES v2.0.

2.3 Updates in GEOPHIRES v2.0

The model structure, built-in reservoir models, power plant conversion efficiencies, and economic models in GEOPHIRES v2.0 are mostly identical to those in GEOPHIRES v1.0. Those models and correlations are discussed in detail in Beckers (2016) and are not repeated here. An overview of the implemented upgrades in GEOPHIRES v2.0 vs. v1.0 is provided in Table 1 and summarized below.

The most significant update is the conversion of the source code from FORTAN 77 and 90 to Python 3.5. The reasons for this conversion are numerous: 1) the original FORTRAN code had poor readability, was prone to bugs, and difficult to modify due to having many GOTO statements ("spaghetti code"), ill-defined parameters, and global variables, 2) Python has a more active user community, is very well documented, and is supported by robust and not-for-profit compilers, 3) our goal of making the tool open-source and available to developers requires using a widely used program code such as Python, and 4) Python has several built-in libraries such as numpy and mpmath that make certain algorithms and calculations straightforward (e.g., inverse Laplace transform for calculating produced temperature with multiple parallel fractures reservoir model).

In GEOPHIRES v1.0, only built-in analytical models are available to simulate the reservoir. These models are the multiple parallel fractures model (Gringarten et al., 1975), the 1-dimensional linear heat sweep model (Hunsbedt et al., 1984), the single fracture thermal drawdown model (Armstead and Tester, 1987), and the percentage temperature drawdown model (Beckers, 2016). In GEOPHIRES v2.0, the option is implemented to import a generic reservoir production temperature profile. These temperature data are provided in column vectors in a text file and can be, for example, measured data from an operating geothermal plant or the output from a stand-alone reservoir simulator such as TOUGH2 (Pruess et al., 1999). Direct communication between GEOPHIRES v2.0 and TOUGH2 is currently being implemented (see below).

Other updates include bringing the cost correlations from 2012 to 2017 U.S. $. The latest data on drilling costs were obtained from the Reservoir Management and Development Task Force for the U.S. Department of Energy (DOE) GeoVision Study (Foris, 2017). The power plant cost correlations were indexed to 2017 using the IHS Markit North American Power Capital Costs Index (NAPCCI) excluding nuclear plants (IHS, 2018). Labor costs were indexed to 2017 using the Bureau of Labor Statistics (BLS) Employment Cost Index for utilities (BLS, 2018). The water cost to account for make-up water was updated to $3.5/1,000 gallons, a representative value obtained by surveying current industrial-scale water rates for the western United States.

While converting the source code to Python, a few additional minor updates were implemented including: 1) allowing the user to choose the time step instead of fixing the value to 3 months, 2) allowing any number of injection and production wells, instead of pre-defined well configurations (doublet, triplet, or star), 3) using the Colebrook-White correlation to calculate the friction factor for a turbulent fluid in a pipe (Fox and McDonald, 2006) instead of using a constant value, 4) using a built-in, temperature-dependent correlation for water viscosity (NIST, 2017) instead of using a constant value, and 5) modifying the percentage thermal drawdown model from exponential to linear decline to better match temperature decline data observed in the field (Snyder et al., 2017).

Other upgrades planned for implementation over the next several months include direct coupling (at each time step) of GEOPHIRES v2.0 and TOUGH2, Ramey's wellbore model applied to injection wells (instead of just production wells) and formations with multiple segments, season-dependent surface plant operation (e.g., geothermal district heating only in winter), and the use of high-performance computing capabilities on the Peregrine supercomputer at the National Renewable Energy Laboratory (NREL). These and other upgrades will be presented in a future publication.

Table 1: Overview of upgrades from GEOPHIRES v1.0 to v2.0

	GEOPHIRES v1.0	GEOPHIRES v2.0
Source code language	FORTRAN 77 and 90	Python 3.5
Cost correlations	2012 U.S. $	2017 U.S. $
Reservoir simulator	Only built-in models available	Built-in models + Option to import reservoir temperature profile (e.g., from stand-alone simulator or measured data at operating plant)
Time step	Fixed time step of 3 months	User-defined time step
Wellbore configuration	Doublet, triplet, or star configuration only (1 injection well with 1, 2, or 4 production wells)	Any number of injection and production wells possible
Wellbore Darcy friction factor	Constant	Colebrook-White equation (Fox and McDonald, 2006)
Water viscosity	Constant	Temperature-dependent NIST correlation (NIST, 2017)
Percentage drawdown model	Exponential decline with annual temperature drop based on percentage of previous year production temperature	Linear decline with annual temperature drop based on percentage of initial production temperature

3. CASE STUDIES

Two case studies are presented to demonstrate the simulation capabilities (and constraints) of GEOPHIRES v2.0. All input parameters are listed in Table 2. Case Study 1 represents a hydrothermal resource at a depth of 2,000 m used for producing electricity with a subcritical dry-cooled binary cycle power plant. The wellhead production temperature starts at 145°C with annual drawdown of about 0.5%/year (see Figure 2). No seasonal ambient temperature changes are considered. This temperature output and decline are representative values for hydrothermal systems coupled to binary cycle plants in the Western United States (Snyder et al., 2017). A constant productivity and injectivity index is assumed of 20 L/s/bar (Snyder et al., 2017). Case Study 2 represents an enhanced geothermal system (EGS) resource used for supplying direct-use heat to an industrial application. The resource is at 150°C and 3,000 m depth, which corresponds to a geothermal gradient of about 45°C/km (assuming 15°C as ambient temperature). A gradient of 45°C/km represents a typical medium-grade resource widely available throughout the western United States (Tester et al., 2006). The reservoir output is based on a stand-alone TOUGH2 simulation by Fox et al. (2013) and is shown in Figure 2. This temperature profile is imported through a text file into GEOPHIRES v2.0. The wellhead temperature is calculated by applying Ramey's wellbore heat transmission model. The economic model is based on the built-in BICYCLE life-cycle levelized cost model developed at Los Alamos National Laboratory (Hardie, 1981). The financial input parameters (e.g., inflation rate, discount rate, and interest rate) are based on previous case studies conducted by Tester et al. (2006) and Beckers et al. (2016), as well as parameters used in the Geothermal Vision Study (Beckers and Young, 2017).

Table 2: Input parameters to the GEOPHIRES v2.0 case studies

	Case Study 1	Case Study 2
Resource type	Hydrothermal	EGS
End-use	Electricity with subcritical binary cycle power plant	Direct-use heat for industrial application
Reservoir temperature model	Percentage thermal drawdown model with annual drawdown of 0.5% (Figure 2)	Externally provided temperature profile (Figure 2)
Capacity factor	90%	90%
Reservoir depth	2,000 m	3,000 m
Bottom-hole temperature	150°C	150°C
Re-injection temperature	70°C	70°C
Well configuration	2 injection wells, 3 production wells	2 injection wells, 2 production wells
Injection well casing inner diameter	9-5/8" (0.2445 m)	9-5/8" (0.2445 m)
Production well casing inner diameter	9-5/8" (0.2445 m)	9-5/8" (0.2445 m)
Well flow rate	110 kg/s per producer	70 kg/s per producer
Pumping power	Calculated assuming constant productivity and injectivity index of 20 L/s/bar	Calculated assuming reservoir impedance of 0.1 GPa/(m^3/s) and built-in wellbore flow friction model
Electricity rate for pumping power	Pumping power is subtracted from total electricity production	Electricity is purchased at ¢7/kWh to power the pumps
Water loss rate	0%	2%
Economic model	BICYCLE model	BICYCLE model
Lifetime	30 years	30 years
Financing fraction through debt	65%	65%
Debt interest rate	7%	7%
Equity rate of return	12%	12%
Inflation rate	2.5%	2.5%

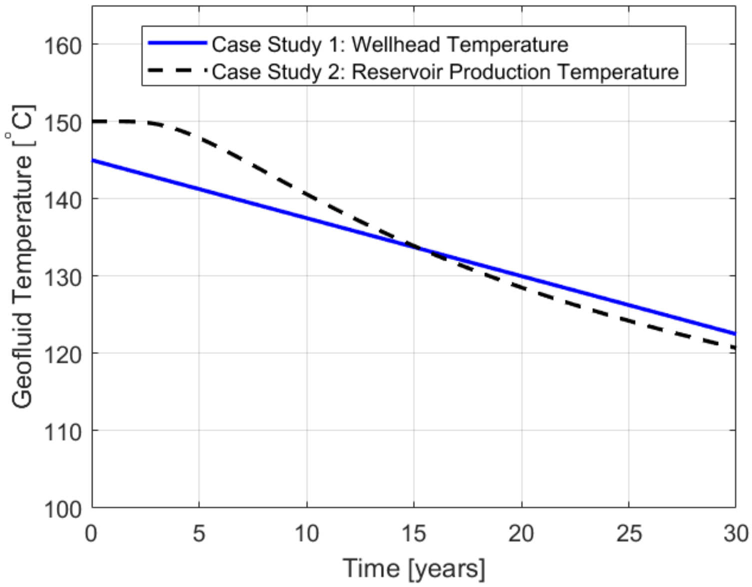

Figure 2: Geofluid production temperature for both case studies. Case Study 1 (hydrothermal resource) assumes wellhead temperature starting at 145°C and linearly declining at the rate of 0.5%/year. Case Study 2 (EGS resource) assumes temperature profile from Fox et al. (2013) for multiple fractures calculated with TOUGH2.

Table 3: Simulation results for GEOPHIRES v2.0 case studies

	Case Study 1	Case Study 2
Installed net capacity	8 MW_e	29 MW_{th}
Average annual energy production	46 GWh/year	187 GWh/year
Levelized cost	¢11.0/kWh	$7.1/MMBTU (= ¢2.4/kWh)
Capital cost	$46.4M	$34.5M
O&M costs	$1.6M /year	$1.9M/year (including pumping costs)

Table 3 provides the techno-economic results of the GEOPHIRES v2.0 simulations for the two case studies. Note that these results are not considered predictions of performance and costs of geothermal plants. Rather, they should be viewed as illustrative figures for generic geothermal plant conditions to demonstrate the capabilities of GEOPHIRES v2.0.

Case Study 1 represents a small geothermal power plant (only 8 MW_e installed electrical capacity) because the well field consists of only three production wells with moderate geofluid production temperatures (only ~140°C). A levelized cost of ¢11.0/kWh falls in the range of reported LCOE values for hydrothermal plants. The 2015 edition of the report *Projected Costs of Generating Electricity*, jointly published by the International Energy Agency (IEA), Nuclear Energy Agency (NEA), and Organization for Economic Co-operation and Development (OECD) (2015), estimates an average LCOE of ¢12/kWh for low-temperature binary-cycle geothermal plants in the United States. This value assumes a 10% discount rate, whereas our weighted discount rate is 8.8%. The transparent cost database (OpenEI, 2017) lists LCOE values for hydrothermal systems in the range 3 to ¢14/kWh. These values assume a 7% discount rate and are for binary and flash plants combined. Similar LCOE values were expected because no significant cost changes occurred over the last few years, and the assumed reservoir parameter values represent average hydrothermal conditions (Snyder et al., 2017).

With an installed thermal capacity of 29 MW_{th}, Case Study 2 represents a large geothermal direct-use facility. For comparison, average installed capacity values for geothermal direct-use facilities in the United States are about 5 MW_{th} for district heating and 3 MW_{th} for greenhouses (Snyder et al., 2017b). However, individual systems can be much larger. For example, the Boise district heating system has an installed capacity of more than 30 MW_{th} and continues to expand. Unlike electricity generation, the economics of a direct-use site depends heavily on the type of end-use application and the amount of surface infrastructure necessary, which complicates validating the LCOH values. For example, a residential district heating system requiring a large surface piping network and only operating for 50% of the time (i.e., winter), would have a significantly higher LCOH than a single industrial plant located near the wellhead using the heat year-round. In addition, Case Study 2 represents the use of an EGS resource, very few of which are in operation today. The most similar study was done by Beckers et al. (2014) who estimated LCOH values for industrial EGS applications using the previous version of GEOPHIRES (v1.0). They found values between 4.0 and 8.1 $/MMBTU, depending on the technology level assumed—the value in Case Study 2 is on the higher end of this range. Notably, Beckers et al. (2016) assumed a lower re-injection temperature of 50°C (vs. 70°C), a higher geothermal gradient of 50°C/km (vs. 45°C/km), and a lower discount rate of 7% (vs. 8.8%), all of which would lower the LCOH relative to Case Study 2.

4. CONCLUSIONS

This paper provided the latest updates to the geothermal techno-economic simulation tool GEOPHIRES. The original version of this tool, developed from 2012 to 2014, is undergoing upgrades throughout 2018. GEOPHIRES v2.0 combines built-in cost correlations, and reservoir, wellbore, surface plant, and economic life-cycle models to assess the technical and economic performance of a geothermal plant. The simulation outputs include the installed capacity, lifetime electricity, and/or heat production, upfront investment costs, and levelized cost of energy. The end-use options are electricity, direct-use heat, and combined heat and power. Major upgrades implemented so far include conversion of the source code from FORTRAN to Python, updates to various cost correlations, having the option to import measured or externally simulated reservoir output, and having more flexibility with respect to selecting the simulation time step and number of injection and production wells. Two case studies—one electricity and one direct-use—were presented to demonstrate the simulation capabilities of GEOPHIRES v2.0.

Several other upgrades to GEOPHIRES v2.0 are scheduled for implementation over the next several months. These upgrades include direct two-way communication between GEOPHIRES v2.0 and TOUGH2, Ramey's wellbore heat transmission model applied to multi-segment layers as well as injection wells, and high-performance computing capabilities (to handle computationally intensive subsurface simulations and batches of simulations). These upgrades and additional case studies will be presented in a future peer-reviewed paper.

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