PROCEEDINGS, Thirty-Eighth Workshop on Geothermal Reservoir Engineering
Stanford University, Stanford, California, February 11-13, 2013
SGP-TR-198

INTRODUCING GEOPHIRES V1.0: SOFTWARE PACKAGE FOR ESTIMATING LEVELIZED COST OF ELECTRICITY AND/OR HEAT FROM ENHANCED GEOTHERMAL SYSTEMS

Koenraad F. Beckers[1,2,*], Maciej Z. Lukawski[1,2], Timothy J. Reber[1,3], Brian J. Anderson[4], Michal C. Moore[5], Jefferson W. Tester[1,2]

[1]Cornell Energy Institute, Cornell University, Ithaca, NY 14853, USA
[2]School of Chemical and Biomolecular Engineering, Cornell University, Ithaca, NY 14853, USA
[3]Earth and Atmospheric Sciences, Cornell University, Ithaca, NY 14853, USA
[4]Department of Chemical Engineering, West Virginia University, Morgantown, WV 26506, USA
[5]School of Public Policy, University of Calgary, Calgary, Alberta, Canada
*Corresponding author: kb447@cornell.edu

ABSTRACT

A new computer-based model has been developed to evaluate the levelized cost of electricity and/or direct-use heat from Enhanced Geothermal Systems (EGS). This software upgrades and expands the “MIT-EGS” model used in the 2006 “Future of Geothermal Energy” study. The upgrades include implementation of the latest geothermal well drilling and power plant cost submodels as well as incorporation of production wellbore heat losses. The main expansion consists of implementing different end-uses, i.e. electricity, direct-use, or combined heat & power (CHP). The new model “GEOthermal energy for the Production of Heat and Electricity Economically Simulated” (GEOPHIRES) can be used either as a stand-alone program or as a subroutine to be called from another program, e.g. MATLAB. GEOPHIRES has the option to either simulate an EGS reservoir and power plant for given parameters, or optimize their design, operating parameters and drilling depth to yield minimum levelized cost. Two case studies were analyzed. The first one provides an estimate of the levelized cost of electricity and direct-use heat with EGS, which is compared with predictions from the widely used GETEM (Geothermal Electricity Technology Evaluation Model). The second case study develops a supply curve for geothermal energy district heating using EGS for the states of New York and Pennsylvania – which are representative areas for low-enthalpy geothermal energy resources in the U.S.

1. INTRODUCTION

In order to assess the economic feasibility of an Enhanced Geothermal System (EGS), a software tool was developed which combines reservoir and surface plant simulations with capital and operation & maintenance (O&M) cost predictions to estimate the levelized cost of electricity (LCOE) and/or heat (LCOH) with an EGS. This software tool is built upon the “MIT-HDR” model, developed at the MIT Energy Laboratory (Tester and Herzog, 1990 and 1991; Herzog et al., 1997); in 2000 upgraded into the “EGS Modeling for Windows” program (Kitsou et al., 2000) and in 2006 upgraded into the “MIT-EGS” model for the “Future of Geothermal Energy” study (Tester et al., 2006). The upgrades and expansions from the “MIT-EGS” model include (1) the evaluation of direct-use heat and combined heat & power (CHP) in addition to electricity; (2) inclusion of a standard discounted cash flow economic model besides a fixed annual charge rate model (FCR), and the BICYCLE model (Hardie, 1981); (3) the option to specify thermal drawdown with an annual percentage temperature decline besides the parallel fractures model, the 1-D linear heat sweep model and the $\dot{m}/A$ thermal drawdown parameter model; (4) the simulation of production and injection wellbore heat transmission using Ramey’s model (Ramey, 1962); (5) updated drilling and surface plant costs; and (6) the conversion of the GUI programming language from Visual Basic 6 into the .NET framework environment.

In order to reflect the major changes with respect to previous versions, the software tool has been renamed GEOPHIRES (“GEOthermal energy for the Production of Heat and Electricity Economically Simulated”). Our software tool differs from the widespread GETEM (Geothermal Electricity Technology Evaluation Model) program (Mines, 2008). It builds in system optimization capabilities, simulates direct-use heat or CHP utilization, and can be used either as stand-alone software or as subroutine in a larger user-developed program.

2. MODEL IMPLEMENTATION

In GEOPHIRES, the EGS resource, reservoir, and surface plant are characterized by a set of 96 parameters (although not all are used simultaneously). They are grouped into 7 different categories:

1. Resource parameters (geothermal gradient segments, rock thermal conductivity, rock density, …)
2. Engineering parameters (well depth, well diameter, end-use product, …)
3. Reservoir parameters (well separation, reservoir impedance, drawdown model, …)
4. Financial and operating parameters (project lifetime, capacity factor, interest rate, …)
5. Capital cost parameters (drilling costs, reservoir stimulation costs, …)
6. O&M cost parameters (wellfield O&M costs, make-up water costs, …)
7. Optimization parameters (initial guess and lower and upper limit for a total set of 9 parameters when GEOPHIRES is used in optimization mode)

Using these parameters, GEOPHIRES first simulates the production wellhead temperature over the lifetime of the plant, then calculates the annual generation of the end-use product and finally, combined with the capital and O&M costs, estimates the levelized cost of electricity and/or heat.

The model is written primarily in FORTRAN 90, with some legacy parts of the code in FORTAN 77. The GUI is implemented in VB 9.0 under the .NET Framework 3.5. Currently, GEOPHIRES v1.0 is only available for the Microsoft Windows platform.
Figure 1 shows a screenshot of GEOPHIRES with the input screen for the engineering parameters. The following subsections explain in detail how specific components of the model work.

2.1 Geothermal Energy End-Use Options

In GEOPHIRES, the user can choose from 3 end-use applications: electricity, direct-use heat and CHP. For the electricity option, all the geothermal heat is converted into electricity. The levelized cost of energy is calculated as the levelized cost of electricity (LCOE) in cents/kWh.

For the direct-use heat option, no heat-to-power conversion takes place at the surface and the levelized cost of energy is expressed as levelized cost of heat (LCOH) in $/MMBTU.

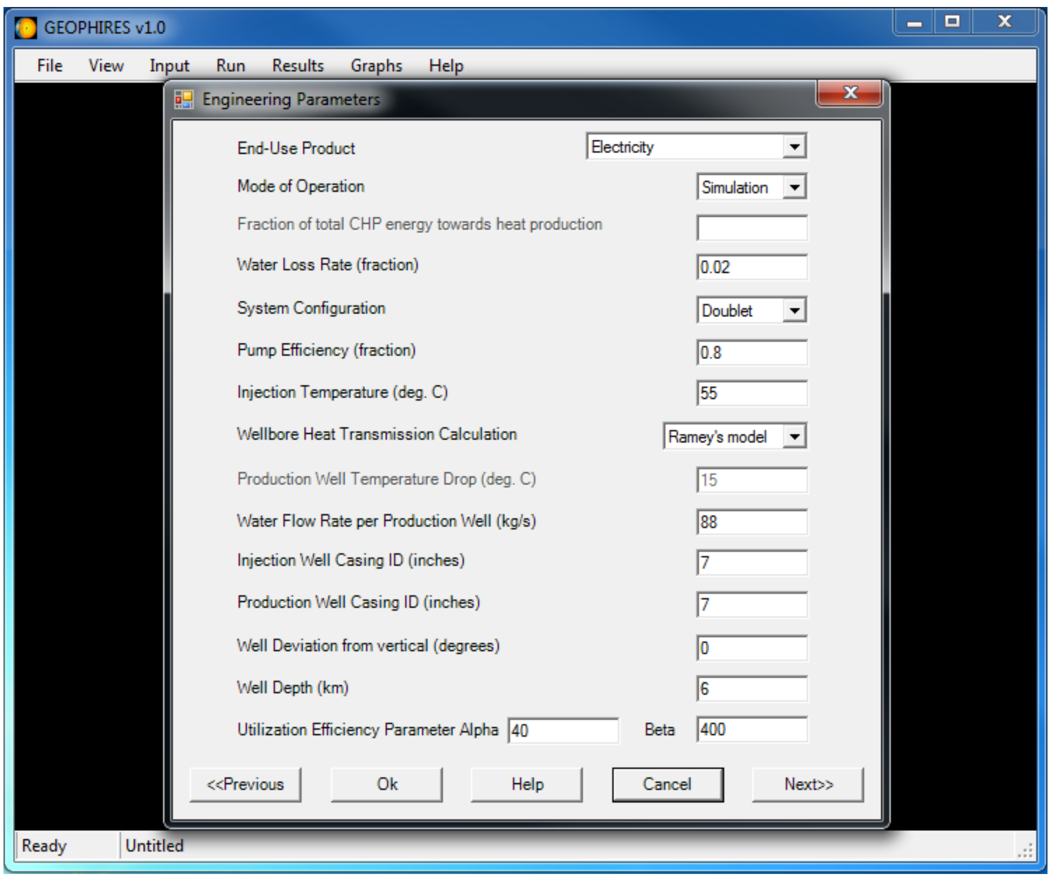

Figure 1: Screenshot of GEOPHIRES Graphical User Interface with engineering parameters input screen.

For the CHP option, the user can choose between three configurations: (1) topping cycle (high temperature electricity production in series with low temperature direct-use heat utilization), (2) bottoming cycle (high temperature direct-use heat utilization in series with low temperature electricity generation) or (3) parallel cycle (production fluid splits into two parts to meet direct-use heat and electricity cycle requirements at same temperature).

For the levelized cost of energy in CHP mode, GEOPHIRES has the option to either consider the produced heat as operating income and calculate the LCOE, or to consider the electricity as operating income and calculate the LCOH, or to calculate both the LCOH and LCOE with each end-use product attributed their fraction of the shared capital and O&M costs based on the energy consumption of the geothermal fluid.

Geothermal fluid pumping power is subtracted from the total produced electricity in the electricity and CHP mode, and it is considered an operating expense with a user-defined electricity price in direct-use heat mode.

2.2 Reservoir Thermal Simulation Models

Four models are available in GEOPHIRES to simulate the reservoir thermal drawdown: (1) The user defines the thermal drawdown in percentage temperature drop per year. This option is equivalent to the reservoir thermal simulation model in GETEM; (2) The reservoir is modeled using the 1-D linear heat sweep model (Hunsbedt et al., 1984) which assumes 1-D uniform flow through a fractured reservoir; (3) The reservoir is modeled as an infinite series of parallel, equidistant, and planar fractures with 1-D thermal conduction in the rock and 1-D uniform fluid flow in the fractures (Gringarten et al., 1975); (4) The user defines a thermal drawdown parameter as mass flow rate per unit area of an individual fracture. This model was utilized in early HDR reservoir modeling as reported by Armstead and Tester (1987).

2.3 Levelized Cost Economic Models

The user can choose between 3 economic models in GEOPHIRES to calculate the levelized cost of energy: (1) The fixed annual charge rate (FCR) model assumes a constant charge rate on the capital costs and no time-dependant value (discount) for invested capital. Different methods exist to estimate the FCR based on several economic parameters including rates of return on equity capital, debt interest rates, and depreciation (Edwards et al., 1982); (2) The standard levelized cost model is utilized, discounting future expenses and income back to the present and assumes a constant discount rate. The LCOE or LCOH is calculated with the following equation (OECD NEA, 2010):

$$LCOE \text{ or } LCOH = \frac{\sum_{t=1}^{n} \frac{C_t + OM_t - I_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}}, \qquad (1)$$

with C_t the capital investment in year t, OM_t the operating and maintenance costs in year t, I_t the extra income by heat or electricity sales in CHP mode in year t, E_t the energy (electricity or heat) produced in year t, r the discount rate and n the lifetime of the plant; (3) The BICYCLE model, developed at Los Alamos National Laboratory (Hardie, 1981), allows the user to define a debt-equity ratio, debt and equity interest rates, an inflation rate, and tax rates in order to more closely approximate real market conditions. Both the first and second model are available in GETEM.

2.4 Power Plant Utilization Efficiency

Electricity generation using the thermal energy from the geothermal fluid is rigorously estimated by calculating the exergy of the geothermal fluid and multiplying by the following correlation for the utilization efficiency for an optimized geothermal binary or flash power plant (Tester, 1991):

$$\eta_u = 0.21 + 0.41 \cdot \left(\frac{1}{1 + \exp\left(-\frac{T(t) - \beta}{\alpha}\right)} \right). \qquad (2)$$

In this empirical correlation, $T(t)$ is the production temperature and α and β are adjustable parameters. The standard values for α and β in GEOPHIRES are 40 and 400 (with $T(t)$ in Kelvin) but the user can choose their own values to match a specific power plant conversion cycle. No performance degradation is assumed.

2.5 Capital Cost Correlations

The user has three options to estimate the capital costs: (1) use the GEOPHIRES built-in capital cost correlations; (2) multiply a specific built-in correlation by a certain factor; or (3) input their own costs.

The capital costs are calculated as the sum of the geothermal well drilling and completion costs, power plant costs, reservoir stimulation costs, fluid distribution costs and exploration costs:

$$\begin{gathered} C_{cap} = C_{cap,well} + C_{cap,pp} + C_{cap,stim} \\ + C_{cap,distr} + C_{cap,expl}. \end{gathered} \qquad (3)$$

The following sections discuss the GEOPHIRES built-in correlations for each of the capital costs components.

Well drilling capital costs

Geothermal well drilling and completion costs ($C_{cap,well}$) are estimated using the following correlation:

$$C_{cap,well} = 1.65 \cdot 10^{-5} \cdot MD^{1.607} \quad 1600 < MD < 9000\text{m} \tag{4}$$

where $C_{cap,well}$ is expressed in M$ and MD is the measured depth of the well in meters. This correlation is plotted in Figure 2.

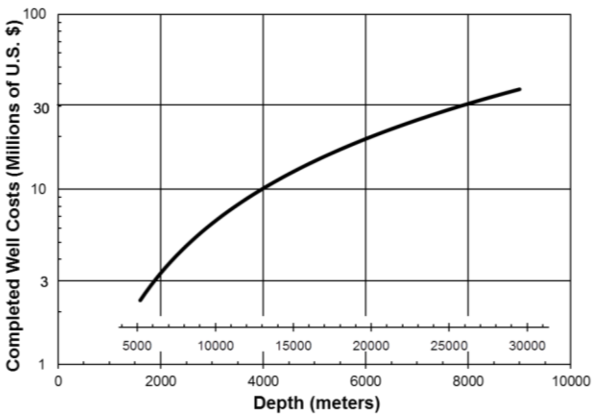

Figure 2: Average drilling and completion costs of geothermal wells.

Multiple sources were used to infer the cost-depth correlation for geothermal wells. To estimate the cost of shallow and medium depth (<3000 m) wells, we used WellCost Lite model results (Livesay, 2012) for 2440-3050 m (8000-10000 ft.) boreholes in conjunction with a cost database we assembled from twenty hydrothermal wells with depths ranging from 1500-2800 m (4900-9200 ft.), drilled between 2008 and 2012. The WellCost Lite wells were modeled as non-optimal and trouble-free. Costs of deep EGS wells were based on WellCost Lite model results (GEECO et al., 2012). The functional form of the correlation was chosen based on analysis of over 27,000 oil and gas wells drilled in the US in 2009 (API, 2011) and regressed to the actual and predicted geothermal well costs.

The presented cost correlation is intended to represent average drilling and completion costs. We do not recommend using this correlation to predict drilling costs of individual wells in specific locations. Geothermal well costs vary significantly depending on geologic setting and trouble time. Even similar wells drilled in the same formation may have significantly different costs.

Power plant capital costs

In electricity mode, the power plant capital costs are estimated by multiplying the correlations from the "Future of Geothermal Energy" report (Tester et al., 2006) by a Power plant Index (*PI*) to bring the costs from 2004 to 2012. For a production wellhead temperature T below 190ºC, the power plant is assumed a binary cycle power plant and the power plant capital costs (C_{PP}) are estimated as (in \$/kWe):

$$C_{cap,pp} = \begin{cases} PI \cdot \left(1000 + 575e^{-\frac{T-150}{69}}\right), T < 150°\text{C}, \\ PI \cdot \left(1000 + 575e^{-\frac{T-150}{550}}\right), T \geq 150°\text{C}. \end{cases} \tag{5}$$

This correlation updates the estimate cost data in Figure 7.4 in the "Future of Geothermal Energy" report by incorporating the *PI* factor. Equation (5) is applicable to binary power plants with nominal capacity of 1 to 5 MWe (Tester et al., 2006).

For a geothermal fluid temperature above 190ºC, the power plant is assumed to be a single- or double-flash power plant. The power plant capital costs are estimated by using the flash system capital cost correlation from the "Future of Geothermal Energy" report (Equation 7-6 in (Tester et al., 2006)) multiplied by the Power plant Index (*PI*):

$$C_{cap,pp} = PI \cdot \left(750 + 1125e^{-0.006115(P-5)}\right) \tag{6}$$

with P the total capacity of the plant in MWe and the result in \$/kWe.

The *PI* in these correlations is calculated using Producer Price Index (PPI) data from the Bureau of Labor Statistics (BLS PPI, 2013). Assuming that the turbine-generator set PPI is representative for the total power plant PPI, the *PI* used in the power plant capital cost correlations in GEOPHIRES is 1.30.

For direct-use heat, the surface plant capital costs are strongly correlated to the end-use application. The built-in correlation in GEOPHIRES is 150\$/kWth, however, we encourage the user to specify more accurate capital costs for the intended application.

In CHP mode, the aforementioned correlations are used for both the electricity component and the direct-use heat component.

Costs for transmission and distribution lines for either electricity or district heating are not included in the power plant capital costs calculations.

Stimulation capital costs

The reservoir simulation costs are estimated in GEOPHIRES as M$0.75 per well, based on assumptions by Sanyal et al. (2007).

Fluid distribution capital costs

The costs for the "gathering system" or surface piping from wells to plant are accounted for by the fluid distribution costs. Although they are largely case-specific, a rough estimate of $50/kWth geothermal fluid output is assumed.

GEOPHIRES does not include a built-in correlation for the piping costs in a district heating system. Case Study 2 (Section 3.2) gives an example where the user has manually provided these costs.

Exploration capital costs

The built-in correlation to estimate the exploration costs is based on the method used in GETEM (GETEM Manual, 2011):

$$C_{cap,pp} = 1.12 \cdot (\text{M}\$1 + 0.6 \cdot C_{1\,well}). \qquad (7)$$

This correlation assumes one exploratory slim-hole well is drilled at 60% of the cost of a normal well. The M$1 is assumed to cover non-drilling related exploratory work such as field work, remote sensing, and geophysical surveys. The factor 1.12 accounts for technical and office support (GETEM Manual, 2011).

2.6 O&M Cost Correlations

The annual O&M costs are calculated as the sum of the power plant, wellfield and make-up water O&M costs:

$$\begin{aligned} C_{O\&M} = {} & C_{O\&M,plant} + C_{O\&M,wellfield} \\ & + C_{O\&M,water}. \end{aligned} \qquad (8)$$

In calculating these O&M costs, the GEOPHIRES built-in correlations rely on the same method as used in GETEM (Entingh, 2006). Alternatively, the user can input their own costs or multiply a built-in correlation by a certain factor.

Power plant O&M costs

The power plant O&M costs are estimated as the sum of 75% of total labor costs and 1.5% of the power plant capital costs:

$$C_{O\&M,plant} = 0.75 \cdot C_{labor} + 1.5\% \cdot C_{cap,pp}. \qquad (9)$$

The annual labor costs for an electricity production case are based on the labor costs used in GETEM (Entingh, 2006), multiplied by 1.14 (based on employment cost index for utilities (BLS ECI, 2013)) to bring the costs from 2006 to 2012 (with P the total electricity output in MWe):

$$C_{labor} = \begin{cases} 266k\$, & P < 5\text{MWe} \\ 876k\$, & 5\text{MWe} \le P < 10\text{MWe} \\ 1192k\$, & 10\text{MWe} \le P < 20\text{MWe} \\ 1769k\$, & 20\text{MWe} \le P < 40\text{MWe} \\ 2107k\$, & 40\text{MWe} \le P. \end{cases} \qquad (10)$$

In direct-use or CHP mode, the labor costs are estimated as (with P the total geothermal energy output in MWth):

$$C_{labor} = \begin{cases} 266k\$, & P < 25\text{MWth} \\ 876k\$, & 25\text{MWth} \le P < 50\text{MWth} \\ 1192k\$, & 50\text{MWth} \le P < 100\text{MWth} \\ 1769k\$, & 100\text{MWth} \le P < 200\text{MWth} \\ 2107k\$, & 200\text{MWth} \le P. \end{cases} \qquad (11)$$

Wellfield O&M costs

The wellfield O&M costs are estimated as 25% of total labor costs and 1% of the well capital costs:

$$C_{O\&M,wellfield} = 0.25 \cdot C_{labor} + 1\% \cdot C_{well}. \qquad (12)$$

Water O&M costs

The make-up water O&M costs are estimated using a water rate of $660/ML ($2.5/1000 gallons).

3. CASE STUDIES

3.1 Case Study 1 – EGS for Electricity or Direct-Use Heat

In the first case study, we estimate the LCOE for electricity production and the LCOH for direct-use heat with an EGS. The parameter values are given in Table 1. A geothermal gradient of 40°C/km can be found in a few areas in New York State and Pennsylvania (Shope et al. 2012). All capital and O&M costs are calculated with the correlations given in section 2. The results from the GEOPHIRES model are shown in Table 2. The LCOE was 25.8 cents/kWh and the LCOH was 9.6 $/MMBTU, both expressed in 2012$. The LCOE found with GETEM was 31.4 cents/kWh for the same set of assumptions summarized in Table 1 (electricity case) and using the medium drilling cost curve and a single-flash plant.

Although an LCOE of 25.8 cents/kWh is not very economically attractive, an LCOH of approximately 10$/MMBTU can be competitive. This case study highlights the potential of medium-grade geothermal resources for direct-use applications.

Table 1: Parameter values for Case Study 1.

Parameter	Value for Electricity	Value for Direct-Use
Geofluid flow rate	60 kg/s	60 kg/s
Geothermal gradient	40 °C/km	40 °C/km
Well depth	5 km	3km
Temperature drawdown rate	1.5 %/year	1.5 %/year
System configuration	Doublet	Doublet
Average surface and ambient temperature	15 °C	15 °C
Impedance per well-pair	0.15 MPa s/L	0.15 MPa s/L
Temperature loss in production well	10 °C	10 °C
Water loss/total injected	2 %	2 %
Geofluid pump efficiency	80 %	80 %
Capacity factor	95 %	75 %
Fluid temperature drawdown threshold before rework	21 %	21 %
Injection temperature	40 ºC	40 ºC
Well casing inner diameter	0.18 m	0.18 m
Fixed annual charge rate	10 %	10 %
Plant lifetime	30 years	30 years

Table 2: GEOPHIRES Results for Case Study 1. All results in 2012$.

Parameter	Value for Electricity	Value for Direct-Use
Generating capacity	3.8 MWe	17.0 MWth
LCOE/LCOH	25.8c/kWh	9.6 $/MMBTU
Drilling and completion costs per well	M$ 14.5	M$ 6.4
Total capital costs	M$ 57.0	M$ 23.5
Total annual O&M costs	M$/yr 2.4	M$/yr 1.3

3.2 Case Study 2 – Supply Curve for EGS Direct-Use Heat for District Heating Systems in New York State and Pennsylvania

In addition to its capabilities as a stand-alone modeling program, GEOPHIRES can be coupled with other programming or modeling tools to further enhance its functionality. In this example GEOPHIRES was used to perform a regional evaluation of geothermal district heating (GDH) options in the states of New York and Pennsylvania (Reber, 2013). Temperature data, Residential and Commercial Buildings Energy Survey data from the Energy Information Administration, and building and economic data from the U.S. Census Bureau were used to estimate the yearly space and water heating demand profile in each town or community within New York State and Pennsylvania, totaling 2894 individual places. The Census Bureau's TIGER dataset for GIS applications was then laid over a newly developed geothermal resource map of New York and Pennsylvania (Shope et al. 2012) to estimate the geothermal gradient at each location. A proportion of the total length of roads in each town (from the TIGER dataset) was used as proxy to estimate the length of distribution piping required for a district heating network for specific conceptual designs.

A MATLAB shell code was written that reads in all variable inputs and performs necessary preliminary calculations, such as the size and cost of surface distribution piping and heat exchangers. Other key variables such as the unit cost of equipment and maintenance, the maximum well flow rate, the desired production temperatures to be investigated, and the secondary fluid operating temperature are defined by the user. These values, along with the geothermal gradient, are passed from MATLAB to GEOPHIRES, which then performs all required subsurface reservoir, power, and cost modeling for a single geothermal doublet system. The results are printed to file and read back into MATLAB where the LCOH of each doublet and the number of doublets required for each town are calculated and stored. This process is iterated for each location in the dataset and for each production temperature (a user-defined list).

Once all places and temperatures are examined, MATLAB identifies the optimal production temperature for each place and prints the results. These results can then be plotted in the form of a supply curve showing the cumulative GDH capacity in the study area vs. the associated LCOH. In effect, this shows how much geothermal district heating capacity can be developed and at what cost. Three GDH supply curves are presented in Figure 3. They correspond to three different levels of EGS technology maturity. The results show that an LCOH of 15$/MMBTU should be achievable in the mid-term for up to 20GWth in GDH development. Note that each location along the curve has a unique gradient and has been individually optimized, meaning each location may have a different production temperature, drilling depth, capacity factor, and surface plant cost in addition to other variables.

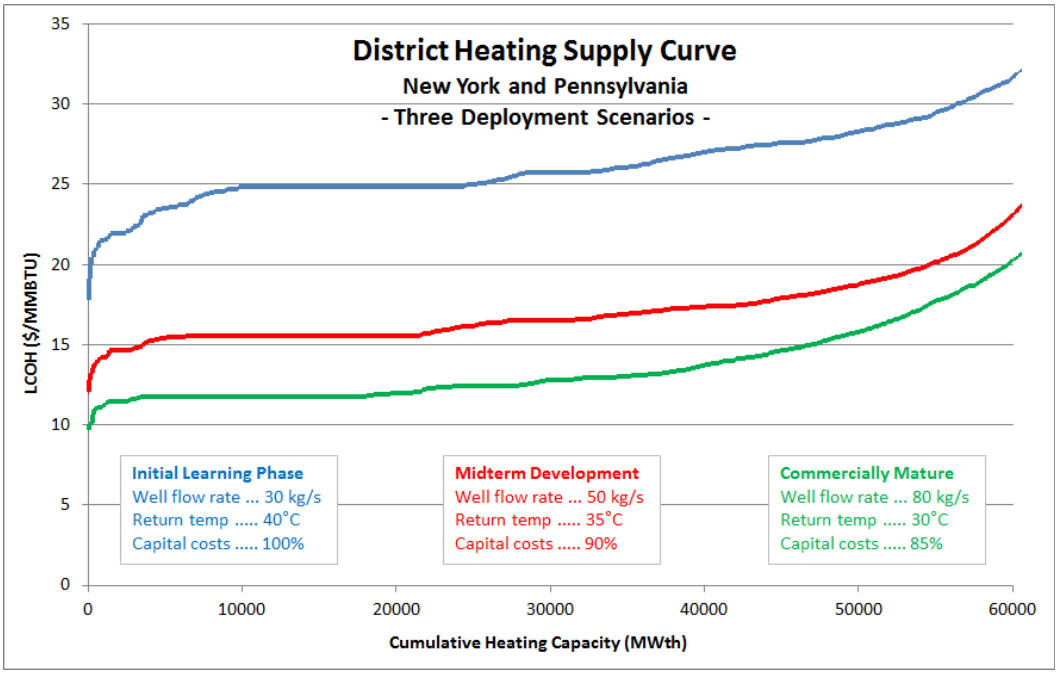

Figure 3: Supply curves for Geothermal District Heating Systems in New York State and Pennsylvania generated using GEOPHIRES in conjunction with a custom-built MATLAB shell.

4. CONCLUSIONS

In this paper we presented a new software tool, GEOPHIRES, to estimate the LCOE and/or LCOH of an EGS for electricity, direct-use heat or CHP. Reservoir simulators, economic models and built-in cost correlations have been discussed. Two case studies were given. In the first case study, we used GEOPHIRES as stand-alone program and calculated a currently unattractive LCOE but competitive LCOH for medium-grade EGS resources. These results highlight the potential of EGS for direct-use applications in the Eastern United States. In the second case study, we used GEOPHIRES as a subroutine to develop supply curves for geothermal district heating systems in New York State and Pennsylvania. We found that up to 20GWth of installed capacity of geothermal district heating systems can be provided in the mid-term with an LCOH around 15 $/MMBTU.

As expected, model results are clearly dependent on assumptions directly related to assumed reservoir performance, resource quality, and a wide range of economic parameters, including drilling and plant capital costs and financial parameters. A more in-depth analysis of the impact of the latest cost correlations on the economic feasibility of EGS for electricity and direct-use heat using GEOPHIRES will be presented in a future work. In addition, sensitivity studies will be used to explore the impact of parameter uncertainty and selected assumptions.

ACKNOWLEDGMENTS

The authors would like to thank the U.S. Department of Energy (contracts #DE-EE0002745 and #DE-EE0002852) and the Atkinson Center for a Sustainable Future for partial financial support of this work. We would also like to express our great appreciation to the researchers at our partner institutions involved in these projects: West Virginia University, Iowa State University, Southern Methodist University and University of Calgary.

REFERENCES

American Petroleum Institute (API, 2011), “Joint Association Survey on 2009 Drilling Costs”, Washington, DC, USA.

Armstead, H.C.H. and Tester, J.W. (1987), “Heat Mining”, E. & F.N. Spon Ltd., London and New York, 478 pages.

Bureau of Labor Statistics (BLS) Producer Price Index (PPI) (2013), “Turbine generator sets”,PCU33361133361101 at http://www.bls.gov/ppi/data.htm

Bureau of Labor Statistics (BLS) Employment Cost Index (ECI) (2013), “Private industry - Utilities”, CIS2014400000000I at http://www.bls.gov/ncs/ect/data.htm

Edwards, L.M., Chilingar, G. V., Rieke III, H. H. and Fertl, W. H. (1982), “Handbook of Geothermal

Energy”, Gulf Publishing, Houston, Texas, page 532-534.

Entingh, D. (2006), “DOE Geothermal Electricity Technology Evaluation Model (GETEM): Volume III – Detailed Technical Appendixes”.

GEECO (Gas Equipment Engineering Corporation) et. al. (2012), “Baseline System Costs for 50 MW Enhanced Geothermal System - A Function of: Working Fluid, Technology, and Location”, Final Report for the U.S. Department of Energy, DE-EE0002742.

GETEM Manual (2011), <http://www1.eere.energy.gov/geothermal/pdfs/geothermal_electricity_technology_evaluation_model_may_2011.pdf >

Gringarten, A. C., Witherspoon, P. A. and Ohnishi, Y. (1975), “Theory of heat extraction from fractured hot dry rock,” Journal of Geophysical. Research, **80** (8), 1120–1124.

Hardie, R. W. (1981), “BICYCLE II: A Computer Code for Calculating Levelized Life-Cycle Costs”, LA-89089, Los Alamos National Laboratory, Los Alamos, New Mexico, November 1981.

Herzog, H. J., Tester, J. W., and Marcus, G. F. (1997), “Economic Analysis of Heat Mining”, *Energy Sources*, **19** (1), 19-33.

Hunsbedt, A., Kruger, P., and London, A. L. (1978), “Energy Extraction from a Laboratory Model Fractured Geothermal Reservoir”, *Journal of Petroleum Technology*, **30** (5), 712-718.

Hunsbedt, A., Lam, S. T. and Kruger, P. (1984), “User's manual for the one-dimensional linear heat sweep model”, Stanford Geothermal Program Technical Report No. 75 (1984).

Iregui, R., Hunsbeldt, A., Kruger, P. and London, A. L. (1978), “Analysis of Heat Transfer and Energy Recovery in Fractured Geothermal Reservoir”, Stanford Report SPF-TR-31, Stanford Geothermal Program, Stanford University, 1978.

Kitsou, O. I, Herzog, H, J and Tester, J.W. (2000), “Economic Modeling of HDR Enhanced Geothermal Systems”, *Proceedings World Geothermal Congress 2000*, Kyushu – Tohoku, Japan, May 28-June10, 2000.

Kuo, M. C. T, Kruger, P. and Brigham, WE (1977), “Shape- factor Correlations for Transient Heat Conduction from Irregular-shaped Rock Fragments to Surrounding Fluid”, *AIChE- ASME Heat Transfer Conference*, Paper 77-HT-54.

Livesay, B. (2012) Livesay Consultants, Personal communication, November.

Mines, G. (2008), “Geothermal Electricity Technologies Evaluation model DOE tool for assessing impact of research on cost of power”, *Proceedings, Thirty-Third Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 28-30, 2008, SGP-TR-185.

OECD NEA (2010) “Projected Costs of Generating Electricity: 2010 Edition”, OECD/IEA.

Ramey, H. J. Jr. (1962), “Wellbore Heat Transmission”, *Journal of Petroleum Technology* **225**, 427-435.

Reber, T. J. (2013), “Enhanced Geothermal System District Heating Opportunities in New York State and Pennsylvania”, *Master Thesis*, Cornell University, Ithaca, NY, USA.

Sanyal, S. K., Morrow, J. W., Butler, S. J. and Robertson-Trait, A. (2007), “Cost of electricity from Enhanced Geothermal Systems”, *Proceedings, Thirty-Second Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 22-24, 2007. SGP-TR-183.

Shope, E. N., Reber, T. J., Stutz, G. R., Aguirre, G. A., Jordan, T. E., and Tester, J. W. (2012) ”Geothermal Resource Assessment: A Detailed Approach to Low-Grade Resources in the States of New York and Pennsylvania.” *Proceedings, Thirty-Seventh Workshop on Geothermal Reservoir Engineering*, Stanford, University, Stanford, California, January 30 – February 1, 2012. SGP-TR-194.

Tester, J. W. and Herzog, H. J. (1990), “Economic predictions for heat mining: a review and analysis of hot dry rock”, Energy Laboratory, Massachusetts Institute of Technology, Cambridge, Mass.

Tester, J. W. and Herzog, H. J. (1991), “The Economics of Heat Mining: An Analysis of Design Options and Performance Requirements of Hot Dry Rock (HDR) Geothermal Power Stations”, *Sixteenth Workshop on Geothermal Reservoir Engineering*, Stanford University, Stanford, California, January 23-25, 1991.

Tester, J. W., et al. (2006), "The future of geothermal energy: Impact of enhanced geothermal systems (EGS) on the United States in the 21st century." Massachusetts Institute of Technology, DOE contract DE-AC07-05ID14517 final report.