Economics of Developing Hot Stratigraphic Reservoirs

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ABSTRACT

Stratigraphic geothermal reservoirs at 3 – 4 km depth in high heat-flow basins are capable of sustaining 100 MW-scale power plants at about 10 c/kWh. This paper examines the impacts on the levelized cost of electricity (LCOE) of reservoir depth and temperature, reservoir productivity, and drillhole/casing options. For a reservoir at 3 km depth with a moderate productivity index by hydrothermal reservoir standards (about 50 L/s/MPa, 5.6 gpm/psi), an LCOE of 10c/kWh requires the reservoir to be at about 200°C. This is the upper temperature limit for pumps. The calculations assume standard hydrothermal drilling costs, with the production interval completed with a 7 inch liner in an 8.5 inch hole. If a reservoir at 4 km depth has excellent permeability characteristics with a productivity index of 100 L/s/MPa (11.3 gpm/psi), then the LCOE is about 11 c/kWh assuming the temperature decline rate with development is not excessive (< 1%/y, with first thermal breakthrough delayed by about 10 years). Completing wells with modest horizontal legs (e.g. several hundred meters) may be important for improving well productivity because of the naturally high, sub-horizontal permeability in this type of reservoir. Reducing the injector/producer well ratio may also be cost-effective if the injectors are drilled as larger holes.

Introduction

Stratigraphic formations with naturally high permeability at depths of 3 – 4 km have the potential to provide a bridge between traditional hydrothermal systems that have dominated geothermal development to date, and enhanced geothermal systems in the future (Allis et al., 2013, 2012; Ziagos et al., 2013; Jeanloz and Stone, 2014). At 3 – 4 km depth, the temperatures can be in the range of 150 to more than 200°C for heat flows of more than 80 mW/m^2, making large areas of the western U.S. potential geothermal development targets. The large areas of basins (~ 10^2 to 10^4 km^2) with similar stratigraphy and heat flow indicate that developments of at least 100 MWe are possible. In a companion paper, Allis and Moore (2014) show that a 100 MWe geothermal development requires significant cooling of 10 to 20 cubic kilometers of reservoir volume over a 30+ year economic life. If the reservoir has a sub-horizontal, stratigraphic geometry with a thickness of about 300 m, then the reservoir area needs to be at least 30 km^2. Reservoir modeling of layer-cake stratigraphy with production and injection confirms that if the high permeability is distributed as several layers in a reservoir-seal "sandwich," a 300-m-thick sandwich will sustain a 100 MWe binary power plant for more than 30 years (Deo et al., 2014; assumes 200°C initial temperature and a cumulative reservoir transmissivity of 3 – 10 Darcy-meters).

Most geothermal production wells around the world are between 1 and 3 km depth. Drilling for a reservoir at 3 to 4 km depth is presently considered overly risky. The two major uncertainties hindering deeper exploration and development are 1: doubt that production wells will have the required permeability and flow rate at these depths; and 2: concern that the well field will be capable of producing economically attractive power (< 10 c/kWh) using today's development costs. The first uncertainty is the subject of the companion paper (Allis and Moore, 2014), and the second is the subject of this paper.

Our economic analysis uses two approaches. Initially we used default settings in the economic modeling tool GETEM (Geothermal Electric Technologies Evaluation Model; Mines and Nathwani, 2013; Entingh and Mines, 2006) and used Monte Carlo techniques to investigate the sensitivity of the levelized cost of electricity (LCOE) to varying reservoir (well) depth, temperature, average well flow rate, and the rate of reservoir temperature decline with development. We then used GETEM to investigate in more detail the cost components for the most attractive target stratigraphic reservoirs, similar to "the prize" characteristics identified in Allis et al. (2013) and Allis and Moore (2014). These reservoirs have temperatures of 175 - 200°C, they range in depth between 3 – 4 km, and are developed with pumps on all production and injection wells, with the well field supplying an air-cooled binary power plant. The 200°C upper limit is due to present temperature constraints for pumps. Air-cooled binary plants are required because of the need to return all production water to the reservoir to sustain pressure, and the typically arid conditions over much of the western U.S. also usually prevent water-cooled plants.

Phase 1: Monte Carlo Modeling Coupled to GETEM

GETEM is a tool developed by the U.S. Department of Energy Geothermal Technologies Office to estimate the power generation costs from geothermal energy. It estimates the costs to develop and operate a geothermal facility, as well as the size of the power plant and well field required to support a specified level of power sales. The capital cost estimates include those for exploration and confirmation phases of development, the well field completion (including surface piping and geothermal pumps), well stimulation costs (if necessary), power plant costs, permitting, and make-up well costs. Generation costs are determined as an LCOE using a methodology that replicates a discounted cash flow analysis. It provides for using varying discount rates and time periods for the different project phases, including the operational life of the plant (default value of 30 years). The model's estimate includes a 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule; it does not account for inflation. Cost correlations used in GETEM to predict drilling, plant, and equipment costs are referenced to specific years. GETEM brings those costs to the present using Producer Price Indices (PPI's) published by the U.S. Department of Labor's Bureau of Labor Statistics. These PPI's are currently updated annually.

GETEM estimates the impact of a declining resource temperature on power production from the plant and includes this impact in its projected LCOE. If the fluid temperature decrease exceeds a defined threshold, the model provides for total replacement of the well field provided 1) sufficient resource potential is found during the exploration and discovery phase, and 2) the replacement does not occur in the last 5 years of the project life. Both the rate at which the resource temperature declines and the maximum allowable temperature decline can be revised.

To characterize the general sensitivity of the LCOE to reservoir characteristics, Phase 1 used a GETEM model that was updated and modified by V. Gowda at the Energy & Geoscience Institute in 2010. In order to generate the trends in LCOE for varying constraints such as pump flow rate, rate of temperature decline, wellhead temperature, well depth, and drilling costs, GETEM was coupled with @Risk, allowing Monte Carlo simulations. Between 5,000 and 10,000 simulations were run for each scenario. Results were then filtered to find the combinations of well depth and reservoir temperature that produce the required trends of LCOE (constrained to less than ± 0.2 c/kWh). Key results are plotted here in temperature-depth space to allow easy comparison with likely geotherms (temperature trends with constant heat flow) beneath high-heat-flow basins (i.e., 80 – 100 mW/m^2.)

Our modeling assumes a 100 MWe plant capacity, and pumps for production and injection wells. An important component of the LCOE for the relatively deep reservoirs being considered here is the cost of drilling. GETEM assumptions for the cost of drilling with increasing depth (Figure 1) were compared to estimates supplied by Bill Rickard of the Geothermal Resources Group (2011, pers. comm. to EGI) and found to be similar. Figure 1 shows the standard drilling cost curve used in this phase of the modeling, and curves for ± 20% variance from the standard cost curve. These trends imply that a production well that is 3 km deep costs $5 ± 1 million. Drilling costs can be highly variable, so the 20% cost variable allowed consideration of possible savings when drilling numerous identical wells into known conditions of 2 – 3 km of unconsolidated sediments overlying the bedrock reservoir section, or unexpected difficult drilling conditions or inflating drilling costs over time. The more detailed cost analysis in Phase 2 of this modeling uses 2010 drilling cost curves supplied by Sandia National Laboratories and incorporated into GETEM. Phase 1 models incorporate drilling costs at the wildcat exploration stage (20% success rate), and a resource confirmation stage (120% normal drilling costs) to allow for the costs of well testing and reservoir analysis. Another important assumption is an injector/producer well ratio of 1, based on the reservoir modeling of Deo et al. (2014), and the need to disperse injection water throughout the production well field.

Varying well productivity (i.e., reservoir permeability) was handled by models that assume the pump rates of the wells range between 500 and 2000 gallons per minute (gpm; 31 – 127 L/s), and are constant with time for a given scenario. The upper pump rate is considered the maximum feasible with today's technology. Lower pump rates require more production wells for a power plant of fixed capacity, and these increase the LCOE. The effect of pump rate on the pumping power is handled in GETEM both by a productivity or injectivity index, and by calculated friction losses in the well. Pump rates that are too high for the default productivity index (about 5.7 gpm/psi or 52 L/s/MPa) cause excessive reservoir pressure decline and more expensive pump power.

The rate of temperature decline of production wells was handled by a constant decline rate in percent per year. A rate of 1 %/year with an initial reservoir temperature of 200°C results in a temperature of 181°C after 10 years, and a temperature of 148°C after 30 years. This is in the middle of the range for the

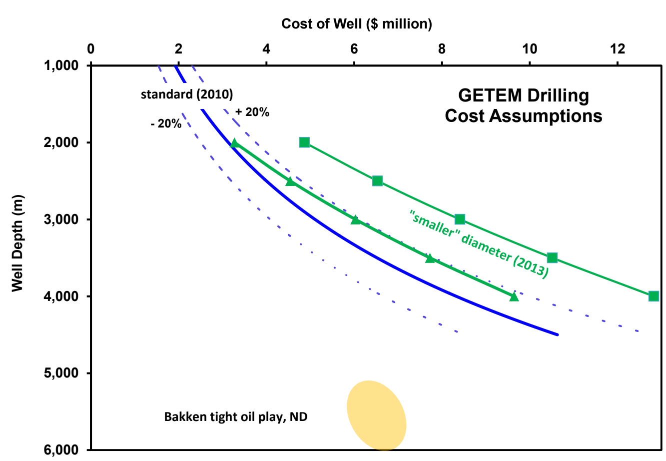

Figure 1. Cost curves used in the GETEM modeling. Phase 1 models used the 2010 curves (blue lines); Phase 2 uses the two 2013 trends for "smaller" and "larger" wells (green lines; Mines, 2013). The cost of typical Bakken (North Dakota) tight oil wells (3 km vertical, 3 km horizontal) is from Hicks (2013).

five reservoir models that were simulated by Deo et al. (2014). GETEM assumes the well field is replaced after the production temperature declines by 25 to 30°C for initial reservoir temperatures of 175 to 200°C. Development strategies could include temporarily resting producers and introducing new producers on a decadal timescale, so it may be possible to achieve temperature decline rates significantly less than 1%/year.

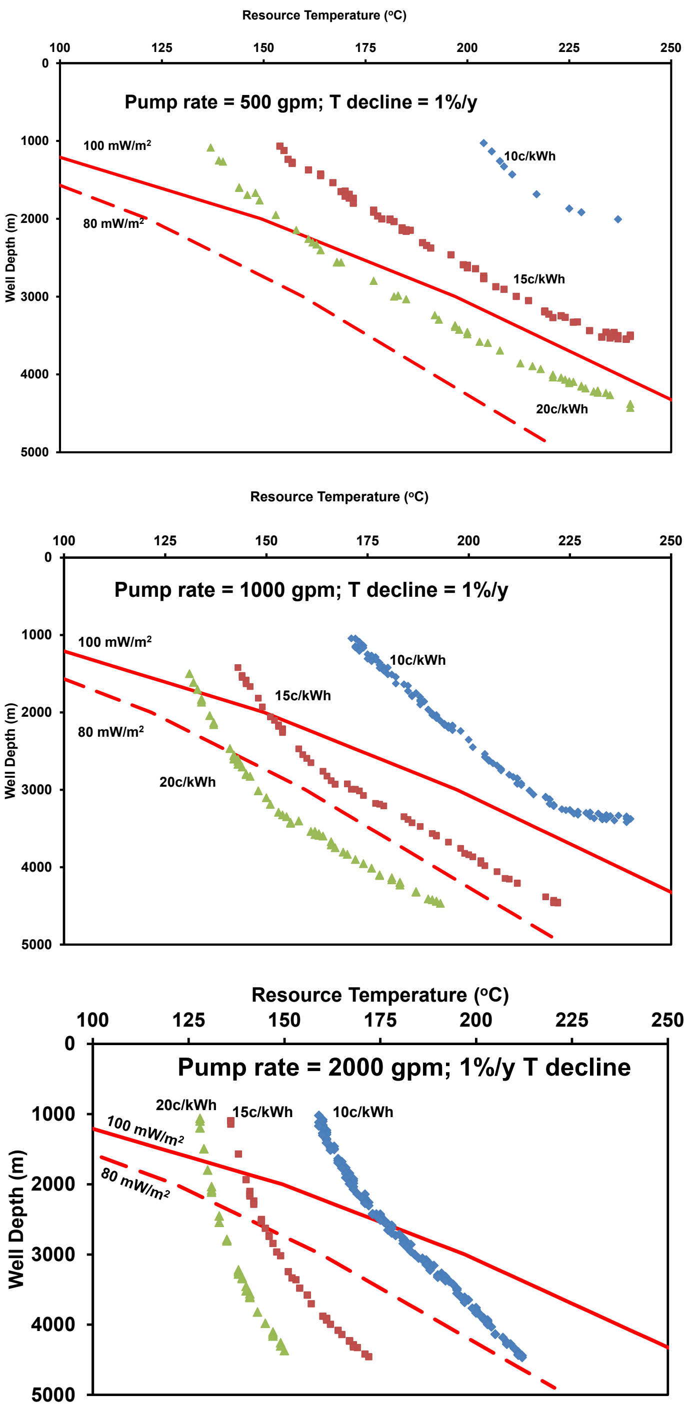

Figure 2. LCOE trends (10, 15, and 20 c/kWh) with initial resource temperature and depth for pump rates of 500, 1000, and 2000 gallons per minute (gpm). Note assumptions of a 1%/year decline rate, and 100 MWe air-cooled binary plant. The two geotherms assume thermal conductivities typical of a basin setting.

Phase 1 Model Results

All results are compared to 80 and 100 mW/m^2 geotherms assuming basin characteristics for thermal conductivity and the heat flows typical for large areas of the Great Basin. Figure 2 shows three LCOE trends (10, 15, 20 c/kWh) for developments with pump rates at 500, 1000, and 2000 gallons per minute (32, 63, 126 L/s respectively). At a pump rate of 1000 gpm, the minimum LCOE on the 100 mW/m^2 geotherm is close to 12 c/kWh with the reservoir at about 3km depth and at an initial temperature of 200°C, the upper temperature limit of present pump technology. At the technical maximum pump rate of 2000 gpm, and a target LCOE of 10c/kWh, the reservoir constraints range between 175°C at 2.6 km depth (100 mW/m^2) and 200°C at 4 km depth (80 mW/m^2). The LCOE is higher at cooler temperatures because additional wells are required as a result of the reduced potential to do work (available energy), and is also higher at greater depth due to increased drilling costs. The slope of the constant LCOE trends in Figure 2 steepens as the pump rate increases. This indicates the influence of reservoir depth decreases as the pump rate increases.

The effects of the temperature decline rate are shown in Figure 3 for a 1000 gpm pump rate. If the decline rate is 0.3 %/y compared to the 1%/y rate shown in Figure 2 (i.e., reservoir temperature declines from 200°C to 180°C in 30 years compared to 12 years), then the 10 c/kWh curve is lowered by about 25°C. This means the 10c/kWh LCOE curve intersects the 100 mW/m^2 geotherm at 175°C and 2.7 km, and the 200°C temperature limit is reached at 3.2 km depth.

A composite graph of the 10 c/kWh LCOE trends for varying pump rate and temperature decline rate is shown in Figure 4. If the regional heat flow is between 80 and 100 mW/m^2 (assuming typical basin thermal conductivity trends), then the range of viable reservoir and pump characteristics are given by the LCOE trends lying between these two geotherms, and for temperatures less than the 200°C upper constraint from pumps. Clearly, pump rates near the maximum of 2000 gpm are desirable, and temperature decline

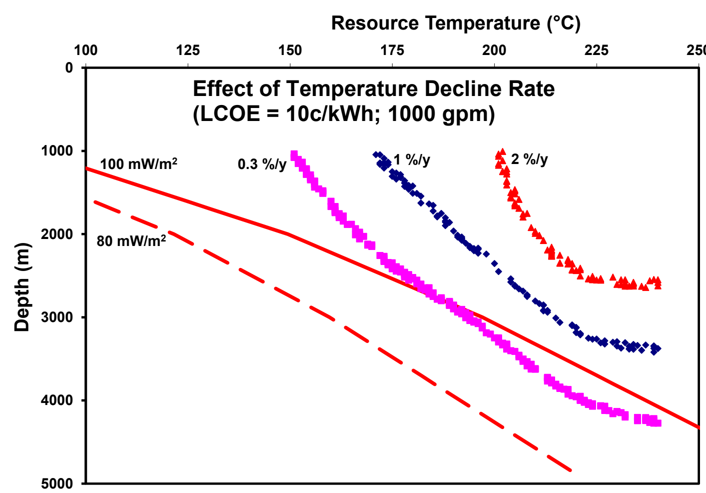

Figure 3. Effect of varying reservoir temperature decline on the 10 c/kWh LCOE trends for a pump rate of 1000 gpm.

rates ideally should not exceed 1%/y. Using mainly the 2000 gpm pump rate and the 1%/y decline rate curve, the target depth range for these stratigraphic reservoirs is confirmed to be between about 2.5 and 4 km. If the heat flow is higher than 100 mW/m^2, then there is more flexibility for lower pump rate scenarios, or shallower reservoir options.

The ± 20% variance on the standard drilling cost curve shown in Figure 1 causes the 10c/kWh LCOE curve to be displaced by about ± 10°C (Figure 5; higher reservoir temperature required for increased drilling costs). This is a smaller effect than the temperature decline rate shown in Figure 3.

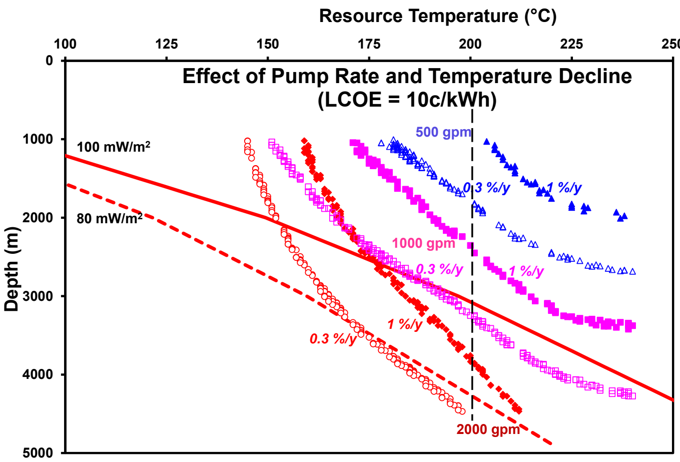

Figure 4. Composite graph of 10 c/kWh LCOE trends showing the combined effects of the reservoir decline rate and the pump rate with varying reservoir temperature and depth. The dashed line at 200°C marks the upper limit for pumps. The shaded ellipse highlights the target zone for economic stratigraphic reservoirs assuming the basin-wide heat flow is in the range 80 – 110 mW/m^2.

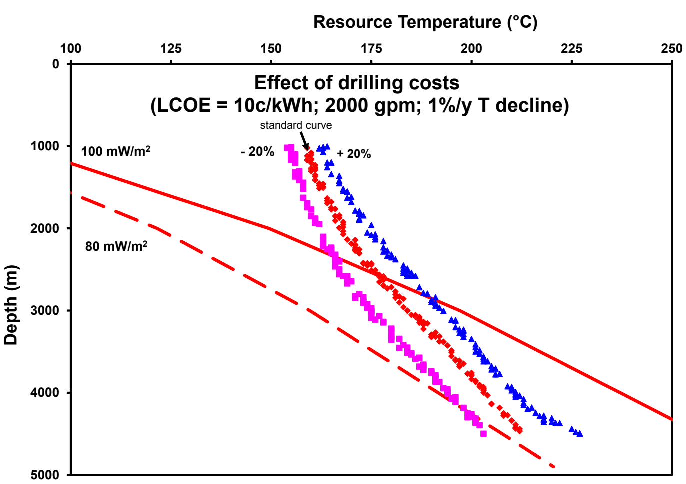

Figure 5. Effect of varying drilling costs on the LCOE trends. Refer to Figure 1 for the drilling cost curves.

Phase 2: Detailed Economic Models of Potential Reservoirs

Model Assumptions

In this phase we examine the breakdown of the cost components of the LCOE for scenarios that are considered to be most representative of development of stratigraphic reservoirs. Based on Phase 1 trends and the findings reviewed in Allis et al. (2014), the initial reservoir temperature is assumed be in the range of 175 to 200°C, and the depth range is 3 – 4 km. Sanyal and Butler (2009) evaluated the economics of sedimentary basins, but their focus was biased towards conditions in the Gulf Coast, where the temperatures are cooler at a given depth, and their analysis used 2003 costs for wells ($4 million for 3 km depth well).

Our modeling assumes that the basic exploration to identify regional heat flow, knowledge of the basin fill thickness (for example, from gravity interpretations), and the inferred stratigraphic reservoir target are already known. The LCOE calculation includes permitting and all subsequent development costs, but does not include transmission costs. Nor do the calculations include any exploration costs beyond the estimated costs for the project leases ($10 per acre). Two wells are assumed for initial confirmation of the temperature and permeability or productivity of the reservoir, and the subsequent well field drilling is assumed to have an 80% success rate. The confirmation phase is assumed to last 1 year; 2 years are assumed for completing the development of the well field. The wells are assumed to encounter sufficient natural permeability so there are no stimulation costs and all wells can be pumped at 2000 gpm. The discount rate for financing the confirmation drilling and well field development is 15%, and that for the power plant is 7%. During operation, revenues and costs are discounted at a rate of 7%. A contingency of 10% is included for all capital costs incurred prior to startup. The models all assume a 100 MWe air-cooled binary power plant. Also assumed is that 250 MW of resource potential is discovered, allowing for one replacement of the well field (if necessary). Default GETEM settings are used for most other inputs.

An important assumption is the type of well that is drilled, so that the productivity (PI; or injectivity, II) of the wells is maximized. Frictional effects and therefore additional pump power requirements can be important if the diameter of the casing gets too small for the pump rates of 2000 gpm. Most models assumed the "smaller" well design shown in Figure 6, with the cost curves labeled as 2013 on Figure 1. A few models assumed the "larger" design, also shown in Figures 6 and 1. The possibility of directional mud motors being used for the last part of the well to give a horizontal leg of up to 1 km was also investigated with both types of well. This was to examine the costs of an extra length of hole within the stratigraphic reservoir, which would allow for increased transmissivity (permeability times length of open section), or in effect, well productivity. All scenarios shown here have the reservoir section with a slotted or perforated liner. Although open hole reservoir sections result in an LCOE lowered by about 7%, we felt the investment in getting the hole to 3 – 4 km depth was excessively at risk due to hole collapse or blockage if the production zone did not have a liner.

Two values were assigned for the initial productivity and injectivity indices: a "moderate" value of 5.7 gpm/psi (52 L/s/MPa), and a "high" value of 11.4 gpm/psi (104 L/s/MPa; Figure 7). The two indices were assumed to be the same in each scenario, although there is evidence that reservoir injectivity is systematically higher than the productivity, which is attributed to thermal contraction and fractures opening around injection wells (Grant et al., 2013).

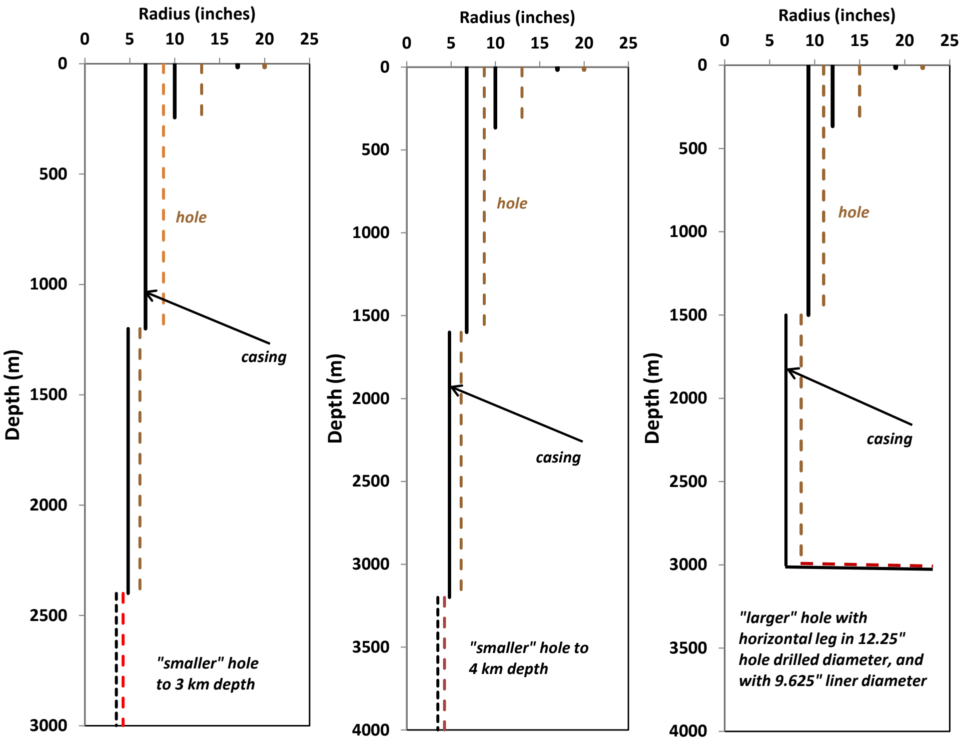

Figure 6. Examples of the “smaller” and “larger” hole and casing configurations assumed in this modeling. The smaller design has a 7 inch production liner in an 8.5 inch hole. The example of a larger design has the horizontal leg drilled at 12 ¼ inches with a liner of 9 ⅝ inches.

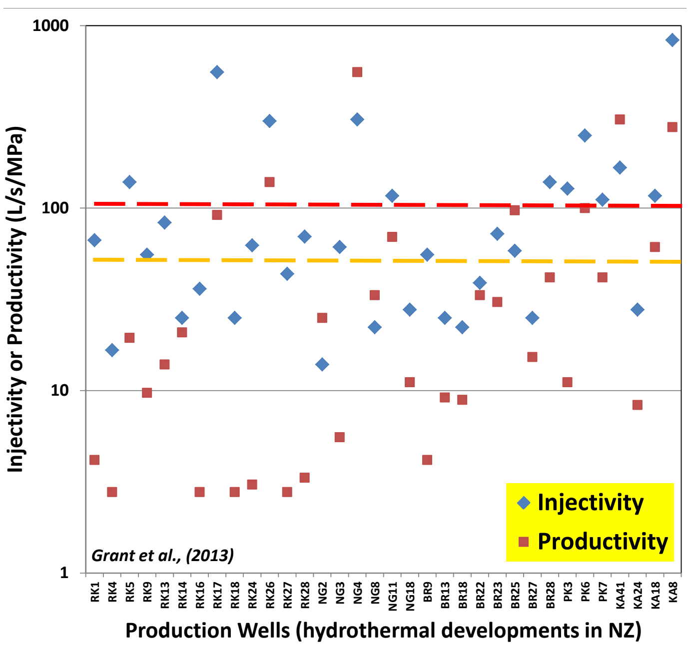

Figure 7. The GETEM models use two options for values of the initial well productivity and injectivity (both assumed to be the same.) The moderate value of 52 L/s/MPa (5.7 gpm/psi) and the high value of 104 L/s/MPa (11.4 gpm/psi) are shown superimposed on productivity and injectivity data from five production well fields in New Zealand (modified from Grant et al., 2013).

The rate of cooling of the production wells during the life of the power plant was included by assuming an annual percent rate of temperature decline. Comparisons with the reservoir modeling of Deo et al. (2014) for the response of different types of stratigraphic reservoirs to production and injection show a delay in the thermal breakthrough is common, and its magnitude depends on many factors including the distance between injectors and producers, the reservoir volume being swept, and the rate of production (Figure 8). This has an important influence on the LCOE because of the delayed rundown of the power plant output, and delays in the requirement for makeup wells (Figure 8). Here we assumed either a fixed rate of decline of 1%/year from the start of power generation, or a 10 year delay in the 1%/year decline rate. The replacement of wells occurs after a temperature decline of 25°C for reservoirs with an initial temperature of 175°C, and 30°C for a 200°C reservoir.

Model Results

Numerous scenarios were run to examine the most important factors influencing the LCOE; a selection of results is discussed here.

Reservoir temperature has a large effect. The LCOE decreases by about 30% as the reservoir temperature increases from 175 to 200°C for moderate PI/II or for high PI/II, all else being the same (Figure 9). The effect of using the delayed thermal decline

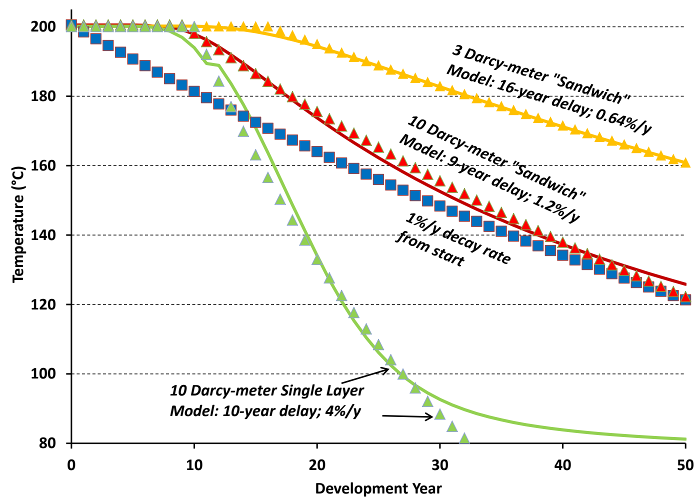

Figure 8. In many of the GETEM models a 1%/y decline rate is assumed for the production well temperature beginning from the start of production and injection (blue squares for initial reservoir temperature of 200°C). However, the reservoir modeling of a stratigraphic layer “sandwich” (Deo et al., 2014) shows that a better representation of the thermal decline is with a delayed thermal break-through, followed by a constant decline rate in the production temperature. The reservoir models of Deo et al. (2014) assume a 5-spot well spacing (i.e., producers/injectors = 1; well spacing = 500 m) and wells pumped at 1000 gpm. A few GETEM models shown in this paper have a 10-year delay followed by a 1%/y decline rate. Three of the stratigraphic reservoir models of Deo et al. (2014) are shown here (smooth lines); the fits to delayed decline curves are shown as triangles.

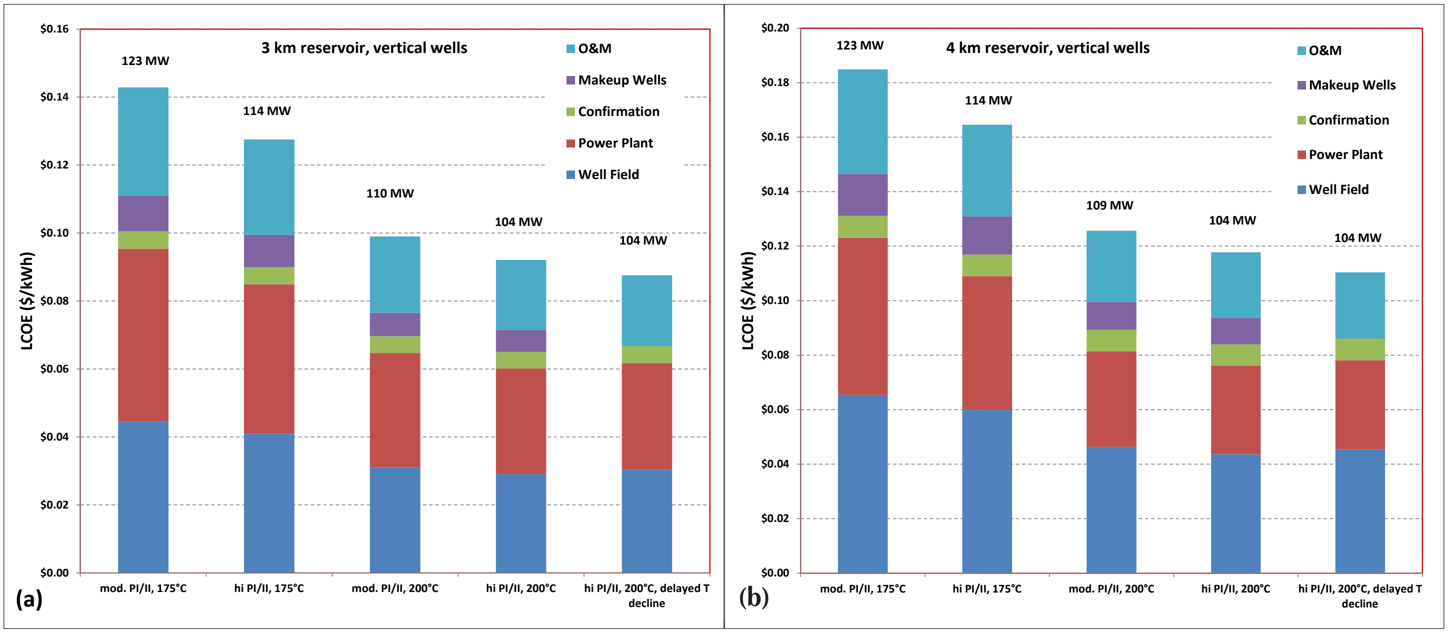

Figure 9. Effects on the LCOE of reservoir temperature and productivity/injectivity indices (PI/II) for vertical wells in a reservoir at 3 km depth (a), and 4 km depth (b). The top of each bar shows the total size of the power plant required to cover the parasitic load due to pump power. O & M refers to Operations and Maintenance.

relationship, in this case by 10 years with the 1%/y rate and the initial temperature at 200°C, reduces the LCOE by an additional 6%. Both factors highlight the importance of reservoir temperature on available energy and its conversion to power, and also the value of delaying drilling makeup wells.

Well field costs rise 48% going from a 3 km depth reservoir to a 4 km depth reservoir. With this depth increase, the associated LCOE rises from 14.3 to 18.5 c/kWh for a 175°C reservoir, and from 9.9 to 12.6 c/kWh for a 200°C reservoir (both with moderate PI/II indices; the increase in LCOE is about 28%).

Doubling the productivity and injectivity indices causes a decrease in LCOE of 11% with a 175°C reservoir, and a 7% decrease with a 200°C reservoir. The primary reason is decreased pump power with increased productivity and therefore a smaller power plant (23 to 14 MWe of pump power with a 175°C reservoir; 10 to 4 MWe for a 200°C reservoir). In all cases shown here, the required production pumping power greatly exceeds that for injection. Scenarios were not run lowering the productivity below the moderate value, but clearly this would increase pumping power leading to a larger plant and more production wells unless the rate at which wells could be pumped was decreased, which would also increase the number of production wells required. In either case the LCOE would increase. All models discussed here assume the inflow and outflow from the wells is distributed over the whole production and injection interval rather than the GETEM default of flow in and out of the wells at total depth. The reason is the stratigraphic permeability is assumed to be distributed over the interval, rather than as one or two fractures at the bottom of the wells. The effect of distributed inflow and outflow roughly halves the frictional pressure loss in the injection and production wells, and for the 185°C scenario with moderate PI/II (productivity index or injectivity index) the LCOE decreases by 1 c/kWh compared to high permeability only near the total well depth.

Most oil and gas wells drilled in the U.S. these days have horizontal legs once the "pay" horizon is reached. The horizontal legs provide an opportunity to enhance the permeability of low permeability source rocks through multi-stage hydrofracturing. In the case of stratigraphic reservoirs, the target formations already have good but perhaps spatially variable permeability. A horizontal leg within the producing zone offers the possibility of increasing the productivity index, but at increased drilling cost. In Figure 10 we show seven scenarios for a 200°C with the same high PI/II and varying length of horizontal leg, horizontal legs only on producers, and two scenarios with two production wells to every injection well. In reality, each scenario will have different well

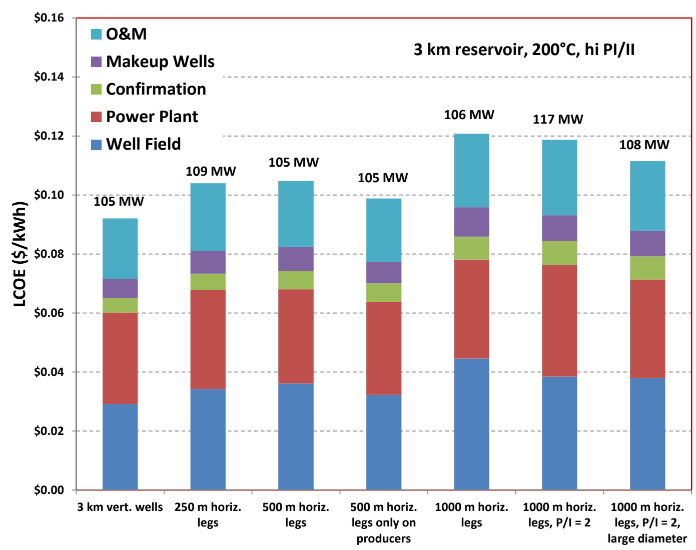

Figure 10. Effects on LCOE of adding horizontal legs to 3 km vertical wells; P/I = ratio producer to injector wells.

productivity, but rather than arbitrarily varying the PI/II indices, we only examine the effect of varying well field options. The cost of the additional length in the horizontal portion of the well is assumed to be the same as if it had been vertical (Figure 1).

The primary factor causing the varying LCOE in Figure 10 is varying well field costs. This also causes smaller, flow-on costs for the make-up wells and O & M. The three scenarios with 1 km horizontal legs highlight the complex interplay between increased pump power because of frictional effects and decreased number of wells. When the number of injectors compared to producers is halved (P/I = 2), the pump power required for double flow into the injectors increases from 0.14 MW to 10 MW. The extra power then requires more producers and increased plant size. However, when the injectors are changed to the larger size (increasing their cost from \$9.6 million to \$12.8 million per well), the pump power for the injectors decreases to 1.64 MW, and there is a 0.7c/kWh decrease in the LCOE.

GETEM's well costs are those expected for drilling conventional hydrothermal resources. There is some expectation that drilling costs will be less when drilling into the sedimentary formations due to postulated higher rates of penetration and the expectation that drilling can be performed at regular spacing intervals with lower costs to move the rig between locations. Figure 11 shows the impact that well cost has on the LCOE for a given resource scenario for both the moderate and high levels of productivity/injectivity. Model results indicate that for every 10% change in the well costs the LCOE is impacted by ~ 0.6c/ kWh. Achieving a 20% reduction in well costs would produce ~11% decrease in the LCOE.

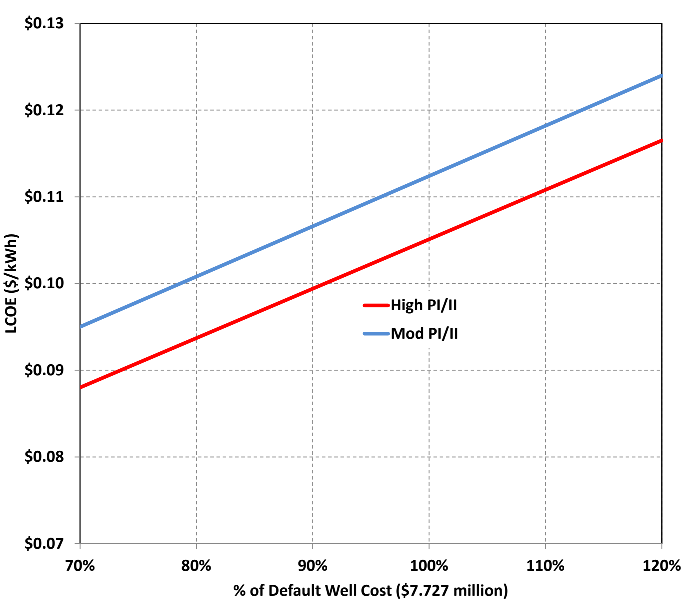

Figure 11. Effect of well cost on LCOE for 200°C resource, 3 km resource depth, and 500 m horizontal leg.

Conclusions

Economic modeling suggests deep stratigraphic resources have the potential to contribute significant geothermal power in the U.S. These resources can generate power with an LCOE of close to 10 c/kWh (without subsidies) on a 100 MW power plant scale, but there are several constraints that narrow down prospects that may be presently viable. The most attractive prospects will range between 150°C at 2 km depth, and 200°C at 4 km depth. This implies an average thermal gradient of at least 70°C/km down to 2 km depth, and an average 50°C/km down to 4 km depth, which for typical thermal conductivities in basin settings coincides with heat flows of 80 – 100 mW/m^2. Such heat flows are found in large areas (sub-basins) of the Great Basin.

A second requirement is the presence of a reservoir (that is, a stratigraphic formation) with naturally good productivity. For a reservoir at 3 km depth with a moderate productivity index by hydrothermal reservoir standards (about 50 L/s/MPa, 5.6 gpm/psi), an LCOE of 10c/kWh requires the reservoir to be at about 200°C. This is the upper temperature limit for pumps. The calculations assume standard hydrothermal drilling costs, with the production interval completed with a 7 inch liner in an 8.5 inch hole. If a reservoir at 4 km depth has excellent permeability characteristics with a productivity index of 100 L/s/MPa (11.3 gpm/psi), then the LCOE is about 11 c/kWh assuming the temperature decline rate with development is not excessive (< 1%/y, with first thermal breakthrough delayed by about 10 years). Completing wells with modest horizontal legs (e.g., several hundred meters) may be important for improving well productivity because of the naturally high, sub-horizontal permeability in this type of reservoir. Most of our scenarios had the same number of producers and injectors. Sometimes in water flood projects for secondary oil recovery the number of injectors per producer is reduced early in the project, and later in the project, infill injectors are included to more efficiently sweep out the remaining oil. Scenarios testing whether this might be a cost-effective heat sweep strategy produced mixed results. Although halving the number of injectors saves on drilling costs, the frictional effects from doubling the flow into injectors required increased pump power and resulted in minimal savings. However, a larger well design for these injectors (9 ⅝ inch liner in 12 ¼ inch hole) lowered the LCOE by 1 c/kWh.

In this study, we have assumed a conventional casing program to accommodate the need for pump discharge rates on the order of 2000 gpm. It is assumed that a seven inch slotted liner will be required for the production interval. Some cost savings may be possible by modifying the casing program once the initial (confirmation) wells are drilled and the drilling requirements are understood. Additional and significant savings are possible once well field development begins for a 100 MW power plant. These savings may be realized by purchasing drilling tools and casing in bulk, on-site bulk cement storage, reduced mobilization and demobilization costs, and an optimized well field design that includes collocated wellheads. Experience at the Bakken tight oil play in North Dakota has shown savings as well as decreased surface impacts by having as many as 6 wellheads on the same drilling pad and using "walkable" rigs (Hicks, 2013). Their target resource is at the same depth as being considered here for stratigraphic geothermal reservoirs.

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