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Economic Valuation of Directional Wells for EGS Heat Extraction

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ABSTRACT

The purpose of this research is to investigate the potential of Enhanced Geothermal Systems (EGS) heat extraction using directional wells. Our previous research demonstrates that the performance of vertical wells is greatly affected by the well separation distance, the thickness of the injection interval, the permeability, and fracture properties and orientation. The near-vertical orientation of fractures often found in EGS environments means that vertical wells cannot optimally exploit the geothermal resources. In addition, vertical well performance can be impacted by density differences that cause the colder injected water to sink to the bottom of the injection interval, reducing the long-term thermal performance of the reservoir. The potential of directional well drilling to overcome these problems is being investigated by simulating their thermal and economic performance across a variety of well configurations and EGS environments. This paper/presentation presents the economic performance piece of the investigation (the thermal performance results are being presented by the same authors as a separate paper – Kalinina et al. 2014).

In our analysis we use a Fracture Continuum Method (FCM) coupled with the Finite Element Heat and Mass (FEHM) model to perform high-resolution simulations of injection and production well pairs at three different orientations: vertical, 45^0 inclination, and horizontal. A total of 30 simulations were run by varying the injection interval, reservoir permeability, and fracture orientation with respect to the well-pair plane. The thermal performance of each simulation is used as input to the GT-Mod system dynamics model to simulate the full-system performance and to estimate the levelized cost of electricity (LCOE) over an assumed 30 year project lifespan. The well design specifications and costs were developed for Sandia National Laboratories as part of a separate study by Baker Hughes, Inc. (unpublished). The LCOE is estimated through a dynamic link between GT-Mod and a modified version of the Geothermal Electricity Technology Evaluation Model (GETEM).

1. INTRODUCTION

Physical performance within an enhanced geothermal system (EGS) refers to the operational conditions that are controlled by the underground environment such as the thermal drawdown over time, the ability to stimulate the reservoir and circulate fluid, and the pressure losses across the reservoir. These conditions control the amount of energy that can be produced, the number of wells needed, the pumping requirements, and ultimately, the cost of producing that energy. Thus, one could argue that uncertainty in knowing the physical performance of an EGS reservoir is the limiting factor for developing EGS generating facilities. However, it has been shown that the thermal performance of directional wells for EGS is relatively insensitive to conditions in the underground environment (Kalinina et al., 2014), meaning that the use of directional drilling technology could significantly reduce physical performance uncertainty. This analysis represents the second of a two-part analysis that explores the physical and economic viability of using directional wells for EGS power generation.

Directional drilling technology achieved commercial viability during the late 1980's (EIA, 1993). This technology has significantly advanced over the past decades driven by a large demand within the oil and natural gas extraction industry. Directional wells provide access to formations that are not accessible with vertical drilling and can provide a significant increase in reservoir productivity. In addition, technological advances in directional drilling has allowed for achieving larger horizontal displacements and higher build-up rates resulting in faster and more efficient access to a formation. These technological advances along with the economics of scale have resulted in lower drilling costs as compared to even a few years ago. While directional wells are generally more expensive than vertical wells directed to the same target horizon, their costs are now low enough that their use in other applications, such as geothermal energy extraction, can be considered. The question is whether the improvement in thermal drawdown over time and the reduction in uncertainty provided by directional wells economically offsets the additional drilling costs. This work is a first estimate to answering that question.

2. PROBLEM SETUP

To address this question, we utilize the work completed by Kalinina et al. (2014) to provide thermal drawdown curves for a set of different well-pair configurations and geologic environments. The drawdown curves are used as input into GT-Mod (Lowry et al., 2010, 2011), which along with a set of well drilling cost estimates and other system performance inputs is used to calculate the levelized cost of electricity (LCOE) for each configuration and geologic environment. Developed at Sandia National Laboratories, GT-Mod simulates the interdependent behavior of the various systems, sub-systems, and components that make up an EGS production facility. It addresses the issues of dynamic dependency, uncertainty, and risk and provides a means to simulate and assess the integrated physical and economic performance of an EGS system. GT-Mod includes the ability to simulate:

- Heat extraction across a range of EGS reservoir conditions
- Heat loss/gain in the production and injection wells
- Power production from binary power plants
- Pressure losses in the production and injection wells, the EGS reservoir, the surface delivery systems, and the power plant

- Parasitic losses
- Costs and the LCOE

A dynamic link between GT-Mod and a modified version of the Geothermal Electricity Technology Evaluation Model (GETEM) (Entingh et al., 2006) is used to do the final economic analysis and LCOE determination. For this analysis, the thermal and hydraulic drawdown curves from Kalinina et al. (2014) are read into GT-Mod via a lookup table where the calculations proceed as normal within the model.

The well cost estimations were developed for Sandia National Laboratories by Baker Hughes, Inc. (B-H), who provided proprietary cost estimates for several different well configurations using current drilling, labor, and material rates. While the design specifications and cost estimates mainly rely upon industry best practices and, as such, are preliminary, they do provide a good starting point for comparing the economics of different well-pair set-ups.

The well designs proposed by Baker Hughes are based on the following assumptions:

- The EGS reservoir is located within a depth interval of 1,600 m to 3,200 m.
- The reservoir rock is either granite, granodiorite, or basalt with a rock density of 2,850 kg/m^3.
- The overlying formation is either claystone, siltstone, or sandstone with a rock density of 2,650 kg/m^3.
- Reservoir temperature is 200 ^{o}C.
- The directional control is maintained while drilling through hard and possibly fractured igneous rocks.
- Well designs consist of vertical, 45° directional, and 90° directional (horizontal) with production/injection liners up to 1,400 m long.

The thermal performance modeling conducted by Kalinina et al. (2014) followed these configurations and assumptions as closely as possible to maintain consistency between the thermal performance and the drilling cost estimates. Variations in fracture strike (i.e. the relationship between the well-pair plane and the fracture strike), fracture dip, mass flow rate, and screened interval length were used to test each well-pair set-up across a variety of geologic environments. Details of their approach and set-up can be found in Kalinina et al. (2014). Table 1 lists the well-pair set-up and the geologic conditions used for input to GT-Mod and nomenclature for identifying the different scenarios in the economic analysis. The thermal performance simulations were based on a non-stimulated condition with an effective permeability of 2x10^{-13} m^2. The effective permeability value is derived from a set of fracture parameter distributions based on values found in the literature (Cladouhos, 2011; Murphy et al., 1980; Kosack et al., 2011a&b; McClure, 2009; Saito and Hayashi, 2002; Tenma et al., 2008, Huenges et al., 2011, and Wyborn, 2011; Kalinina et al., 2012a and 2013).

Table 1 – List of different well orientations and mean fracture properties used in the economic analysis.

PARAMETER	VALUES	OTHER PARAMETER VALUES	SCENARIO #
Well Separation Distance	390, 600, 800 m	Fracture Strike = 80° Fracture Dip = 18° Prod. / Inj. Interval = 250 m Mass Rate = 120 kg/s	W390, W600, W800
Fracture **S**trike	10°, 80°	Fracture Dip = 18° Prod. / Inj. Interval = 250 m Mass Rate = 120 kg/s Well Separation Distance = 800 m	S10, S80
Fracture **D**ip	5°, 18°, 75°	Fracture Strike = 80° Prod. / Inj. Interval = 250 m Mass Rate = 120 kg/s Well Separation Distance = 800 m	D5, D18, D75
Mass Flow Rate	60, 90, 120, 150, 200 kg/s	Fracture Strike = 80° Fracture Dip = 75° Prod. / Inj. Interval = 250 m Well Separation Distance = 800 m	M60, M90, M120, M150, M200
Well Configuration*	**H**orizontal, **I**nclined, **V**ertical		Scenario # + -H, -I, -V e.g. W390-H is well separation distance 390 m for horizontal well configuration

*Well orientations: H = horizontal (90° from vertical), V = vertical, I = inclined (45° from vertical)

Kalinina et al. (2013, 2014) showed that the thermal drawdown performance for all well orientations is insensitive to production and injection interval lengths > 250 m, so the intervals are held constant at that length across all the scenarios. For the economic analysis, any scenario that dropped below the minimum generating temperature of 170.2 ^{o}C was deemed unrealistic and thrown out.

Figure 1 shows a plot of the 3 well orientations and the relationship between the well spacing and screened interval length from configurations in the B-H report. Due to the limited number of well cost estimates, the inclined cases are directly offset in the horizontal direction as opposed to the preferred configuration in which the offset would be perpendicular to the incline angle.

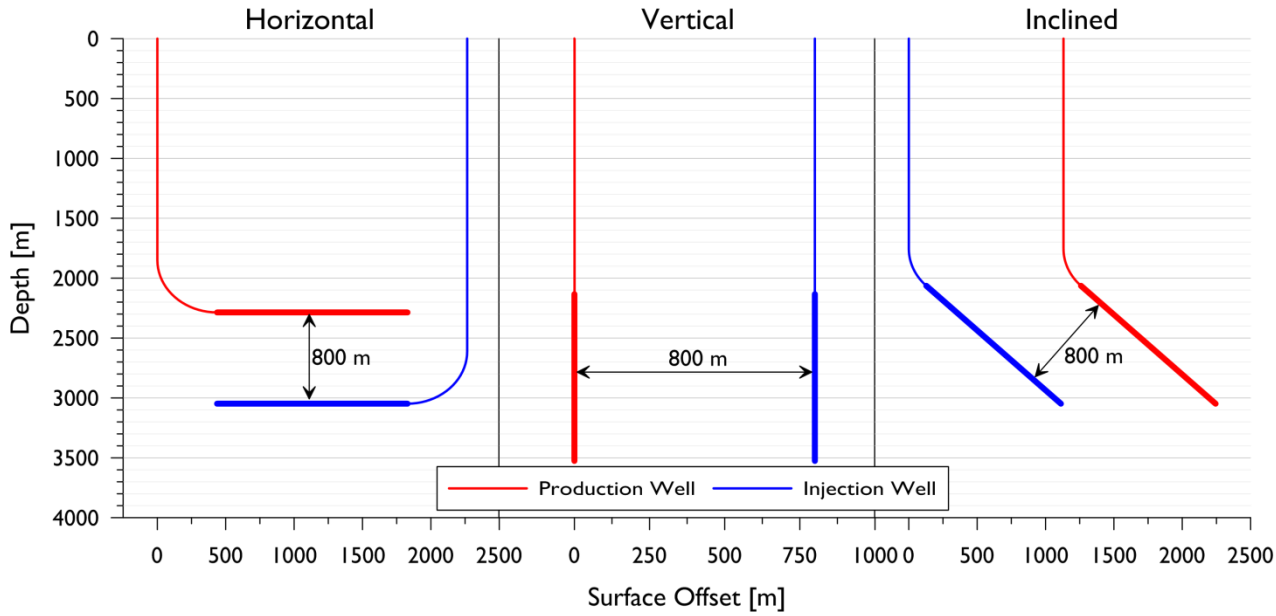

Figure 1 – Well configurations for the three orientations showing the production and injection wells with 800 m separation distance and a 1400 m screening interval.

Within GETEM, the LCOE is calculated as a function of several cost categories that together, make up the entire project costs. Those categories are:

1. Resource Exploration
2. Resource Confirmation
3. Well Field Development
4. Operations and Maintenance
5. Power Plant

For an EGS, GETEM requires that at least two wells be confirmation wells and uses the cost of the production well for the cost of the confirmation wells. This is slightly problematic for the directional wells since confirmation wells for an EGS site would likely be drilled as vertical wells and then later developed as production or injection wells. In addition, for the horizontal well case, the production well is shallower and thus less expensive than the injection well. However, with no simple method of over-riding this behavior, the default cost of the production well was used in calculating the resource exploration costs for all scenarios and well configurations. Table 2 lists the major assumptions used within the analysis for each cost category.

Because the FEHM simulations were based on a single production-injection well pair the ratio of injection to production wells for the economic analysis was kept at 1:1. A somewhat arbitrary number of six well pairs was used, which fulfilled the need to have at least two confirmation wells and produced a total power generating capacity at the default mass flow rate of 120 kg/s of ~70 MW. Sensitivity analysis of the LCOE to the number of well pairs' show that the LCOE is fairly insensitive to the number of well pairs and that the variability is the same across the three well configurations, thus all scenarios were run using six well pairs.

Adjustments to the well drilling costs provided in the B-H report were made to match the actual well configurations used in the FEHM simulations. The most notable difference was the FEHM configurations used smaller injection and production intervals and shallower depths. For each well configuration, the B-H report lists estimates for drilling time, rig time costs, mobilization/demobilization costs, casing costs, wellhead construction costs, rental tool costs, inspection costs, logistics, labor costs for engineering and project management, and costs for consumables, such as drill bits, fluids, cement, and the like. Costs for well completion and well logging were also provided in the B-H report.

To scale the B-H estimates to match the FEHM configurations the estimates from the B-H report were broken into three categories: time dependent, depth dependent, and fixed. For the FEHM simulations, a central elevation of 2400 m below ground level was assumed for the mid-point elevation of the vertical and inclined wells and the average elevation of the injection and production wells for the horizontal configuration. With this set-up, the 13 scenarios listed in Table 1 were able to be simulated with single well designs for the vertical and inclined orientations and three different well designs for the horizontal orientation. The three designs for the horizontal orientation were due to the need to adjust the depth of the production and injection wells to maintain the mid-point depth of 2400 m when the well spacing was changed.

Table 3 lists the well configurations and costs from the B-H report, as well as the adjusted costs and configurations used in this analysis. The striking difference between the two cost sets is the similarity between the vertical well costs and the directional well costs for the adjusted values as compared to the original values. This is mostly due to the assumed 250 m injection / production screen interval and the additional assumption that the directional portion of both the inclined and horizontal wells consisted of just the screen interval. One interesting note is the off-setting effect of the costs of the production and injection wells for the horizontal case. As the distance between the wells narrows, the cost for the production well goes up while the cost for the injection well goes down.

Table 2 – List of cost categories and major assumptions.

CATEGORY	ITEM	VALUE / SOURCE	COMMENT
Economic Parameters	All	GETEM defaults	2010 scenario estimate year
Resource Definition	Resource type	EGS	
	Temperature	200 ^{o}C	
	Depth	2000 – 2800 m	Match Baker-Hughes report configurations
	Mass flow rate	Fixed for each scenario	From FEHM runs
	Thermal drawdown	FEHM simulations	
	Hydraulic drawdown	FEHM simulations	
	Water losses	None	
Resource Exploration	Drilling costs	Not included	
	Non-drilling costs	$790k	GETEM default values
Resource Confirmation	Well drilling costs	2 x production well drilling cost	
	Non-drilling costs	$3.050 mil	Incl. well testing
	Stimulation costs	None	
Well Field Development	Surface equipment costs	$350k / well	
	Pump costs	*f*(pump size, etc.)	GETEM calculation
	Non-drilling costs	5% of WFD costs	GETEM default
	Drilling costs	Baker-Hughes Report	Scaled to match FEHM well configurations
	Stimulation costs	None	
Operations & Maintenance	Labor & Non-labor costs	GETEM default	
Power Plant	Type	Binary	
	Transmission costs	$94 mil	GETEM default assumes 5 miles
	Plant equipment costs	*f*(plant size, etc.)	GETEM default calculation
	Plant construction costs	*f*(capital costs, plant size, etc.)	GETEM default calculation

Table 3 - List of well costs and major design parameters from the Baker-Hughes report and the adjusted values used in the economic analysis.

ESTIMATION SOURCE	#	WELL TYPE	TOTAL DEPTH [m]	TOTAL LENGTH [m]	DIRECTIONAL LENGTH [m]	HORIZONTAL OFFSET [m]	COST
Baker-Hughes	1	Vertical	2286.0	2286.0	NA	NA	$5,703,860
	2		3048.0	3048.0	NA	NA	$6,712,706
	3	Inclined	2286.0	2949.8	2149.7	1647.8	$6,544,002
	4		3048.0	3333.1	856.3	733.6	$7,533,910
	5		3048.0	4090.6	3442.9	2562.4	$8,100,921
	6	Horizontal	2286.0	3927.4	1392.2	1828.8	$9,287,933
	7		3048.0	3775.0	477.8	914.4	$9,168,790
	8		3048.0	5603.8	2306.6	2743.2	$12,653,170
Adjusted Baker-Hughes	All	Vertical	2525.0	2525.0	NA	NA	$6,115,017
	All	Inclined	2488.4	2595.8	76.2	485.5	$6,038,385
	W800*	Horizontal Production	2000.0	2250.0	76.2	686.6	$6,121,491
	W600		2100.0	2350.0	76.2	686.6	$6,323,571
	W390		2205.0	2455.0	76.2	686.6	$6,535,756
	W800*	Horizontal Injection	2800.0	3050.0	76.2	686.6	$7,738,135
	W600		2700.0	2950.0	76.2	686.6	$7,536,054
	W390		2595.0	2845.0	76.2	686.6	$7,323,870

*This is the horizontal well configuration used for the other scenarios

3. RESULTS

The thermal performance of each scenario as simulated using FEHM is shown in Figure 2 thru Figure 5. The important lesson from those figures is the consistent performance of the horizontal well orientation across the different fracture orientations and set-ups as compared to the vertical and inclined well orientations. The two lowest temperature plots in Figure 2 and Figure 4 are less than the minimum operating temperature of the plant and are not used in the economic evaluation.

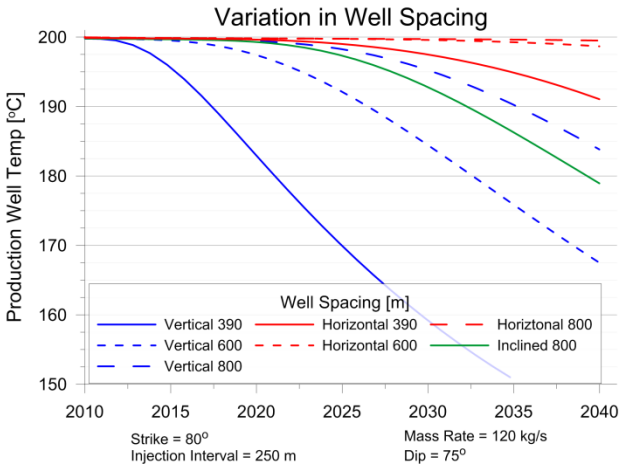

Figure 2 – Thermal performance as a function of well spacing.

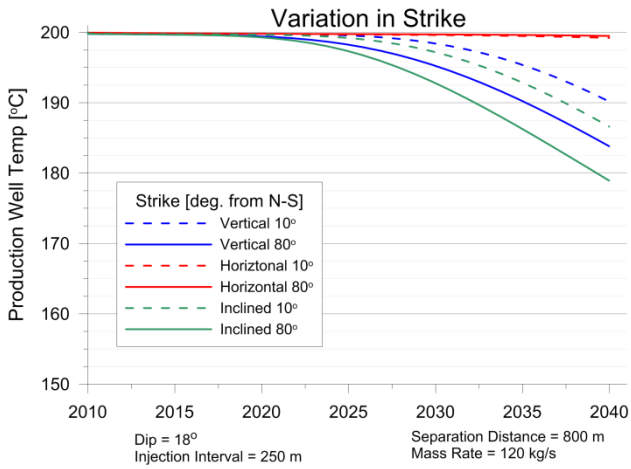

Figure 3 – Thermal performance as a function of fracture strike.

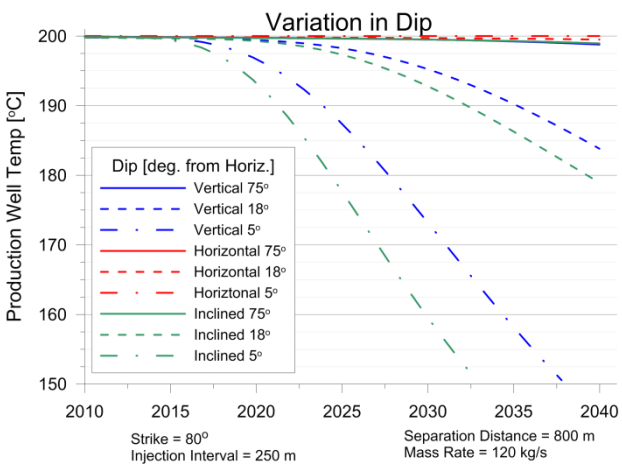

Figure 4 – Thermal performance as a function of fracture dip.

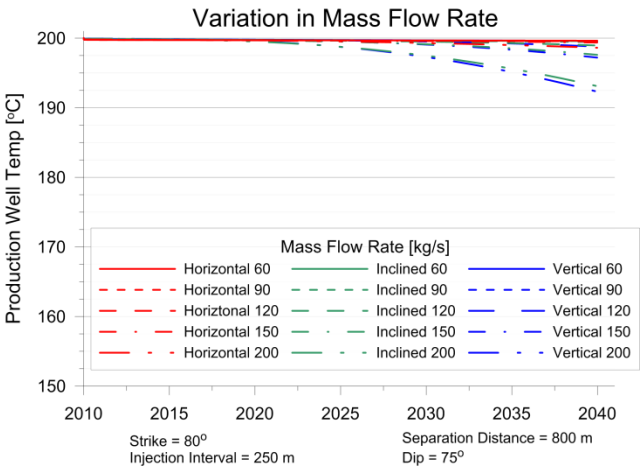

Figure 5 – Thermal performance as a function of mass flow rate.

Results for the economic analysis as a function of well distance are shown in Table 4 and Figure 6 and Figure 7. Recall that the strike is 80°, the dip is 75°, and the mass flow rate is 120 kg/s for these scenarios. There is very little variability in the LCOE for the horizontal well orientation across the three separation distances mainly due to the very slight difference in thermal performance between the scenarios (Figure 2). The vertical and inclined cases were unable to maintain the minimum generating temperature at the 390 m and 600 m separation distances and thus only appear as points in Figure 7. Scenario W800-V has the lowest LCOE, due to the smaller capital costs associated with the vertical wells and pumping requirements that are less than half of the other well orientations.

Table 4 - Economic analysis results for variation in well distance. Power sales' is gross power minus pumping power. The power figures are yearly averages for the 30 year lifespan of the project.

SCENARIO #	CAPITAL COSTS [$/kW]	O&M [$/kW/yr]	PUMPING POWER [MW]	POWER SALES [MW]	LCOE [¢/kW-hr]
W390-H	$5,055.79	$145.68	4.604	64.068	7.437
W600-H	$5,043.84	$145.23	4.732	64.713	7.371
W800-H	$5,038.56	$145.06	4.699	64.823	7.356
W800-I	$5,141.69	$151.70	7.475	60.202	7.394
W800-V	$4,725.56	$135.37	2.023	65.423	7.129

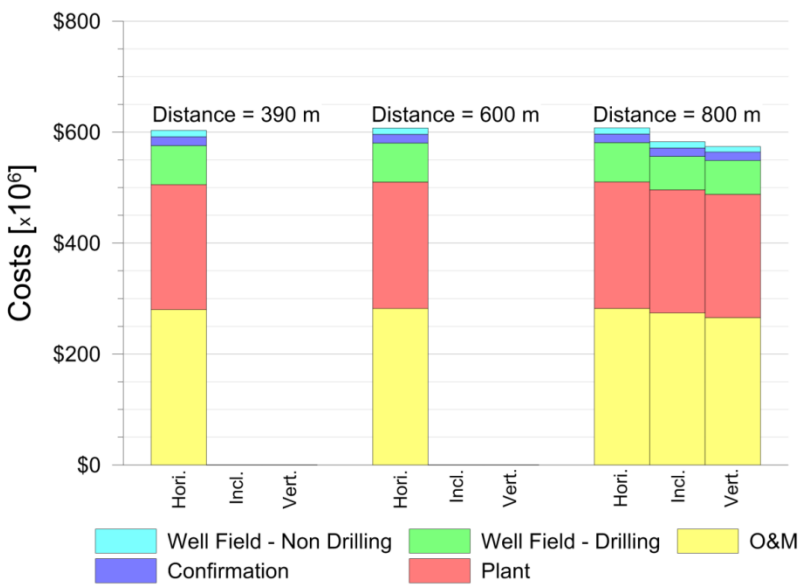

Figure 6 - Cost categories for each well configuration and valid scenario as a function of well separation distance.

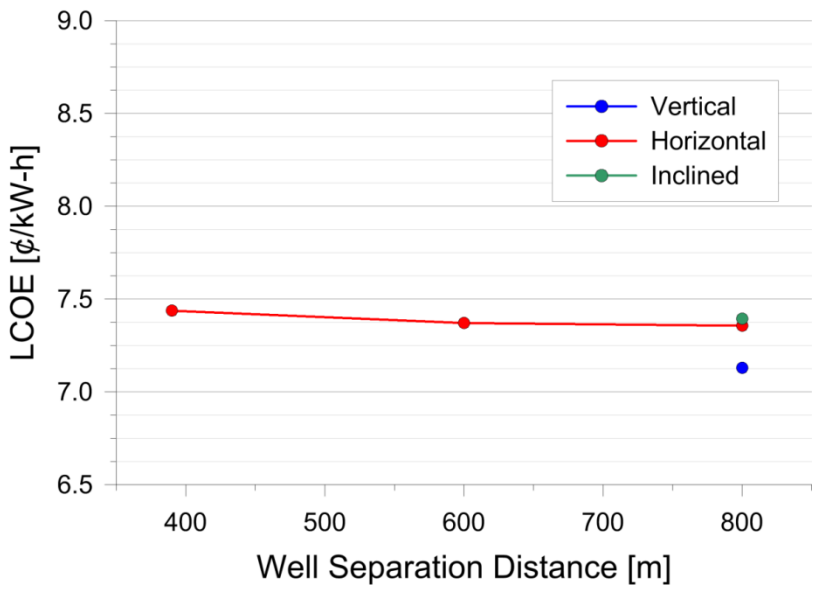

Figure 7 - The LCOE as a function of well separation distance.

Results for the economic analysis as a function of fracture strike are shown in Table 5 and Figure 8 and Figure 9. Recall that the dip is 18°, the separation distance is 800 m, and the mass flow rate is 120 kg/s for these scenarios. There is very little variability in the LCOE across all well orientations. Even though the total costs shown in Figure 8 are higher for the horizontal well orientations as compared to the inclined orientations, the LCOE is slightly lower, due to the high pumping requirements for the inclined wells. This is reflected when the costs are expressed on a per-kilowatt basis as listed in Table 5. The vertical wells have the smallest LCOE mainly due to the smaller pumping requirements as compared to the other well orientations.

Table 5 - Economic analysis results for variation in fracture strike. Power sales' is gross power minus pumping power. The power figures are yearly averages for the 30 year lifespan of the project.

SCENARIO #	CAPITAL COSTS [$/kW]	O&M [$/kW/yr]	PUMPING POWER [MW]	POWER SALES [MW]	LCOE [¢/kW-hr]
S10-H	$4,764.61	$137.22	4.408	68.492	7.343
S10-I	$5,071.24	$149.29	10.367	62.095	7.399
S10-V	$4,542.99	$133.43	3.102	68.952	7.181
S80-H	$4,786.64	$137.81	4.699	68.235	7.356
S80-I	$4,884.61	$144.11	7.475	63.370	7.394
S80-V	$4,489.28	$128.60	2.023	68.866	7.129

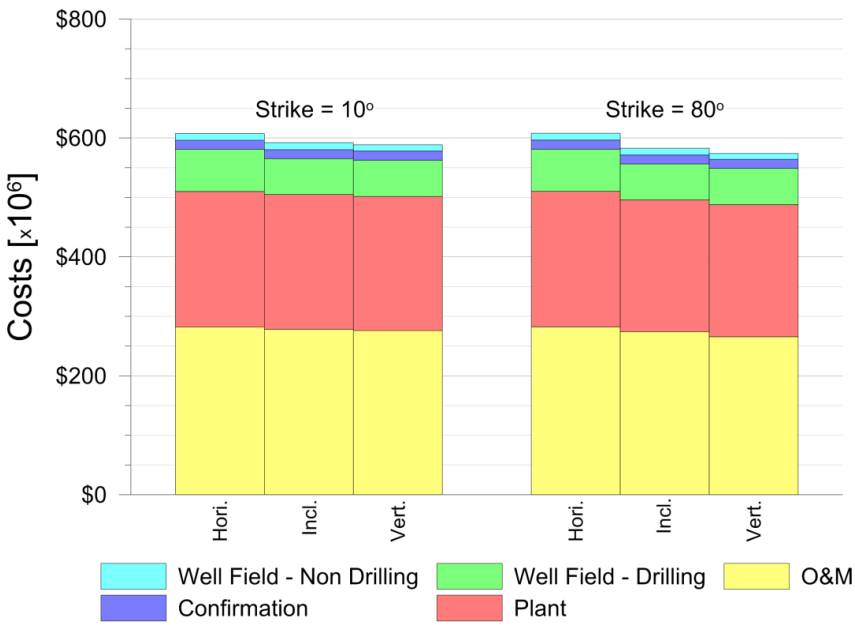

Figure 8 - Cost categories for each well configuration and valid scenario as a function of fracture strike.

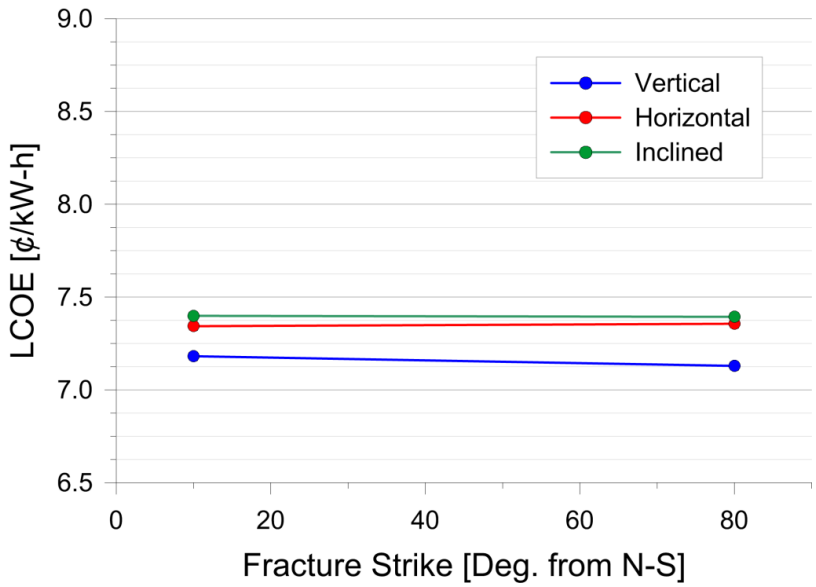

Figure 9 - The LCOE as a function of fracture strike.

Results for the economic analysis as a function of fracture dip are shown in Table 6 and Figure 10 and Figure 11. Recall that the strike is 80°, the separation distance is 800 m, and the mass flow rate is 120 kg/s for these scenarios. From Figure 11 one can see that the LCOE improves for the horizontal well configuration as the dip steepens due to a drop in the pumping requirements. As the dip angle increases, the vertical permeability decreases causing the pumping requirements to decrease also. There is very little variability in the LCOE for the other orientations.

Table 6 - Economic analysis results for variation in fracture dip. Power sales' is gross power minus pumping power. The power figures are yearly averages for the 30 year lifespan of the project.

SCENARIO #	CAPITAL COSTS [$/kW]	O&M [$/kW/yr]	PUMPING POWER [MW]	POWER SALES [MW]	LCOE [¢/kW-hr]
D18-H	$4,786.64	$137.81	4.699	68.235	7.356
D18-I	$4,884.61	$144.11	7.475	63.370	7.394
D18-V	$4,489.28	$128.60	2.023	68.866	7.129
D75-H	$4,737.87	$127.43	0.796	68.503	6.979
D75-I	$5,029.53	$148.14	7.084	63.134	7.143
D75-V	$4,678.16	$133.55	1.925	67.230	6.971

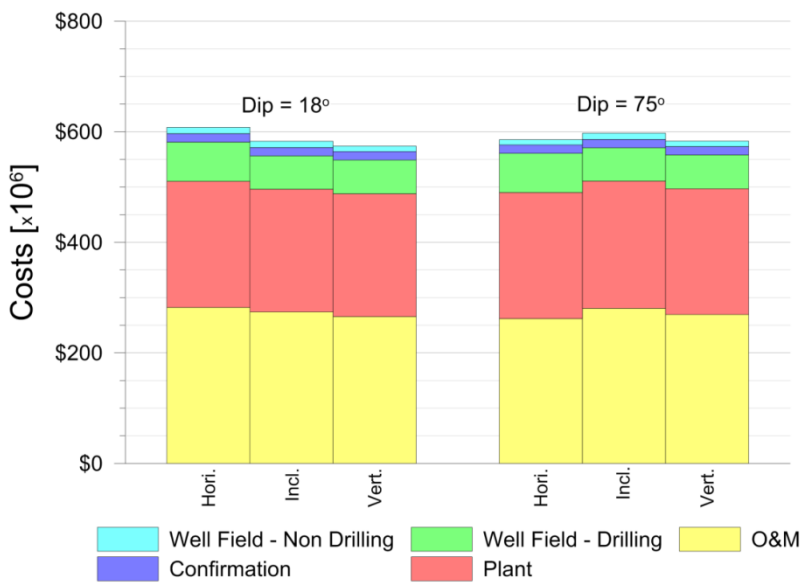

Figure 10 - Cost categories for each well configuration and valid scenario as a function of fracture dip.

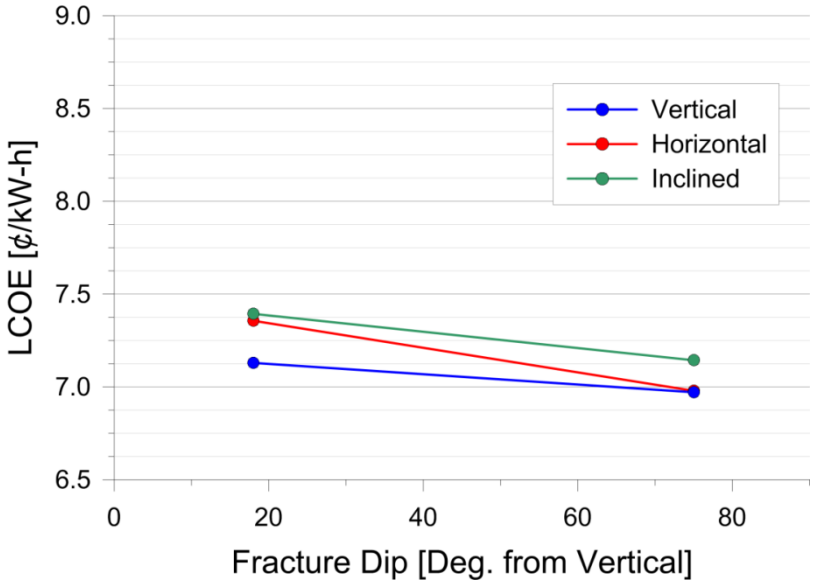

Figure 11 - The LCOE as a function of fracture dip.

Results for the economic analysis as a function of mass flow rate are shown in Table 7 and Figure 12 and Figure 13. Recall that the fracture strike is 80°, the separation distance is 800m, and the fracture dip is 75° for these scenarios. Because the thermal drawdown over time is relatively small for all scenarios, the main difference in the LCOE from the different mass flow rates comes from the change in the capital costs and the pumping requirements. At the lowest mass flow rates of 60 and 90 kg/s, the capital costs on a per-kilowatt basis are higher than the other scenarios, resulting in high LCOE values for those scenarios across all well orientations. As the mass flow rate increases, the gross power produced and pumping requirements also increase. For the 120 and 150 kg/s scenarios, the power production is increasing faster than the pumping requirements, reducing the LCOE. However, for the 200 kg/s scenarios, the pumping requirement increases faster than the power production, resulting in a higher LCOE.

Table 7 - Economic analysis results for variation in mass flow rate. Power sales' is gross power minus pumping power. The power figures are yearly averages for the 30 year lifespan of the project.

SCENARIO #	CAPITAL COSTS [$/kW]	O&M [$/kW/yr]	PUMPING POWER [MW]	POWER SALES [MW]	LCOE [¢/kW-hr]
M60-H	$6,198.84	$142.00	0.000	34.316	8.915
M60-I	$6,062.91	$159.45	1.258	33.765	8.658
M60-V	$5,912.86	$139.23	0.000	34.152	8.560
M90-H	$5,172.80	$125.04	0.000	51.790	7.487
M90-I	$5,306.07	$149.63	3.417	49.179	7.561
M90-V	$4,985.64	$125.79	0.011	51.615	7.280
M120-H	$4,737.87	$127.43	0.796	68.503	6.979
M120-I	$5,029.53	$148.14	7.084	63.134	7.143
M120-V	$4,678.16	$133.55	1.925	67.230	6.971
M150-H	$4,588.94	$132.55	3.768	83.135	6.839
M150-I	$4,971.82	$151.21	12.628	75.207	7.013
M150-V	$4,561.82	$137.41	5.347	81.286	6.862
M200-H	$4,598.69	$142.32	12.825	103.535	6.952
M200-I	$5,193.03	$164.65	27.045	89.799	7.213
M200-V	$4,676.80	$148.44	16.327	99.004	7.035

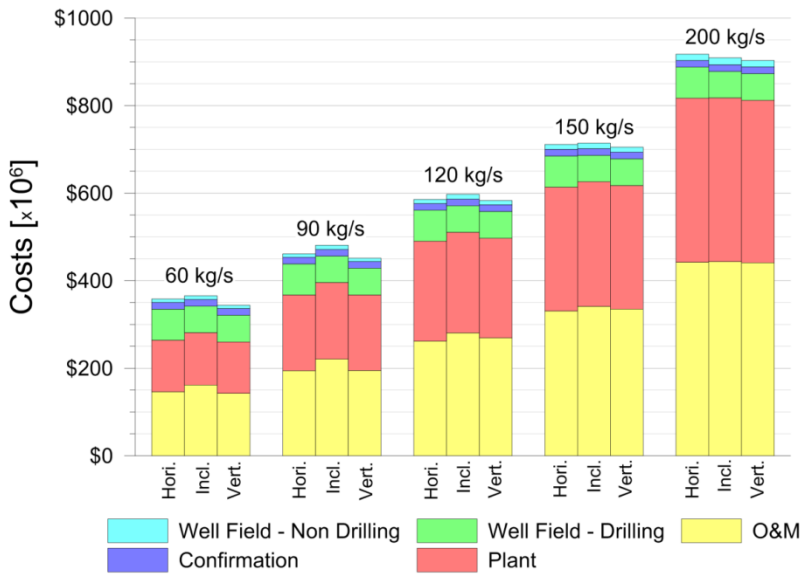

Figure 12 - Cost categories for each well configuration and valid scenario as a function of mass flow rate.

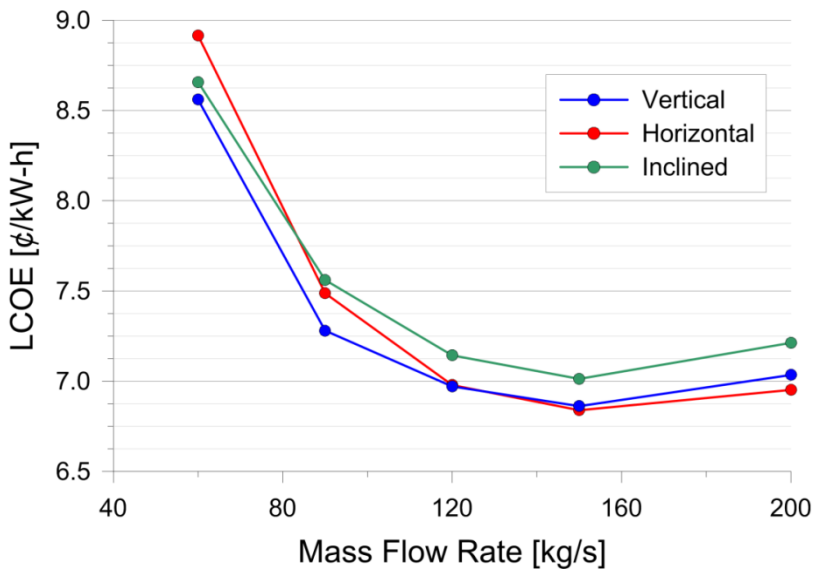

Figure 13 - The LCOE as a function of mass flow rate.

4. DISCUSSION

The key observation from this analysis is the reliance of the LCOE on the pumping requirements and how the geologic orientation affects those requirements. Generally, for well configurations where the mean flow direction between the injection and pumping wells are perpendicular to the fracture plane, the pumping requirements, and thus the LCOE are higher. For the scenarios where the geologic orientation is held steady (the 'W' and 'M' scenarios), the LCOE is almost solely dependent on the pumping requirement. With regards to EGS site development and design, this observation is important in that it indicates that there may be an optimal design that considers the orientation of the wells in relation to the main fracture plane, well separation distance, and the mass flow rate. This understanding now provides a means where EGS site design optimization can be explored.

With regards to the actual LCOE values, the differences between the different well orientations and scenarios were relatively small. However, three thermal drawdown simulations for both the vertical and horizontal cases were not used in this analysis because the production temperature for those scenarios dropped below the minimum generating temperature of 170.2 ^{o}C (scenario #'s D5-I, D5-V, W390-I, W390-V, W600-I, and W600-V). If one assumes that in order to reach the 30 year project lifespan for these scenarios a new reservoir would need to be developed along with a new set of wells, the LCOE could increase by 50-100% over a similar, but non-violating scenario. This would put the LCOE for those scenarios somewhere between 10.5 and 15.0 ¢/kW-hr, greatly increasing the variability in the LCOE for the inclined and vertical well orientations. While it is relatively easy to control the well spacing, knowing the thermal performance at that well spacing a priori is not. The same is true with regards to the fracture dip. Thus, the vertical and inclined wells introduce a significant amount of uncertainty, and thus risk, to the development of EGS. Conversely, the horizontal wells provide a relatively stable thermal drawdown profile across all the scenarios.

Combining the first point, that the LCOE is highly dependent on the pumping requirements, and the second point, that horizontal wells reduces uncertainty, the advantage of using horizontal wells becomes apparent. The EGS site design process could then consist of the following steps:

1. Site exploration: collect surface and sub-surface data about the site.
2. Data analysis: analyze the data to characterize the geologic environment for resource temperature, depth to resource, fracture plane(s), fracture aperture, permeability, and the like.
3. Site modeling and simulation: use the processed data to create a GT-Mod simulation of the site.
4. Design production-injection well sets by adjusting the mass flow rate and the orientation of the production and injection intervals to minimize the pumping requirements (or LCOE) and maximize power production.
5. Install the production-injection well set and field-test the set-up.
6. Update the simulation model and re-optimize the system. Install additional production-injection well sets as needed to achieve desired power production.

It should be noted that in the context of these steps, the horizontal well orientation is really a directional well orientation that is a function of the fracture plane angle and the resulting permeability field. Future efforts for this work will explore these six steps and further develop the criteria to find optimal well orientations and mass flow rate values over a wide range of geologic conditions.

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