Proceedings World Geothermal Congress 2010
Bali, Indonesia, 25-29 April 2010

Economic Analysis of CO_2 Thermosiphon

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Keywords: CO2, Thermosiphon, EGS, Enhanced Geothermal Systems, Carbon Dioxide

ABSTRACT

The use of CO_2 to extract heat from engineered geothermal systems (EGS) is of interest due to the possibility of generating power at a lower cost than when using water. This lower cost would arise from its ease of flow through the geothermal reservoir, strong innate buoyancy which permits the use of a thermosiphon rather than a pumped system, and lower dissolution of substances that lead to fouling. Here we develop a costing/pricing methodology as a step towards estimating the economic potential of using CO_2 as a heat extraction fluid instead of water. This costing methodology is applied here to a base case to give a general estimation of the price range for a CO_2-based EGS. The impact on economics of changes in injection temperature, wellbore size, and recompression systems are addressed, and found to be significant. In general, the CO_2-based system is found to be very sensitive to both assumptions in the pricing model (particularly well costs), and to process operational parameters. This work provides a starting point for optimisation of CO_2-based EGS for economic performance.

1. INTRODUCTION

Prior analysis of CO_2-based EGS has focused on the heat or energy extraction in comparison to water (Brown 2000; Pruess 2006; Gurgenci, Rudolph et al. 2008; Pruess 2008; Atrens, Gurgenci et al. 2009), with some additional attention to the geochemical interactions between CO_2, H_2O, and the reservoir rock (Pruess and Azaroual 2006). Ultimately the value of the concept depends on its economic efficiency.

This work explores the likely cost components and levelised cost of electricity of a CO_2 thermosiphon, with a general aim to provide a framework for more detailed and comprehensive economic analyses in the future. The purpose of this work is to provide an estimate of the range of likely costs of a CO_2-based EGS, and insight into the key characteristics for economic optimisation. Additionally, this work will provide some insight into the approach towards economic optimisation of a CO_2-based design, including an approximation of the cost-optimal operating conditions, and process modifications that may provide significant economic benefits to the project.

2. THERMODYNAMIC METHODOLOGY

The basis for this analysis is the major components of a CO_2 thermosiphon – the turbine, heat exchanger/cooling system, and the injection and production wells. The layout of the system is shown in Figure 1. The approach for calculation of the thermodynamic process conditions is as follows. Injection temperature and pressure are set, and the injection flow rate into the geothermal system is calculated based on reservoir conditions, in a manner similar to that outlined in previous works (Atrens, Gurgenci et al. 2009).

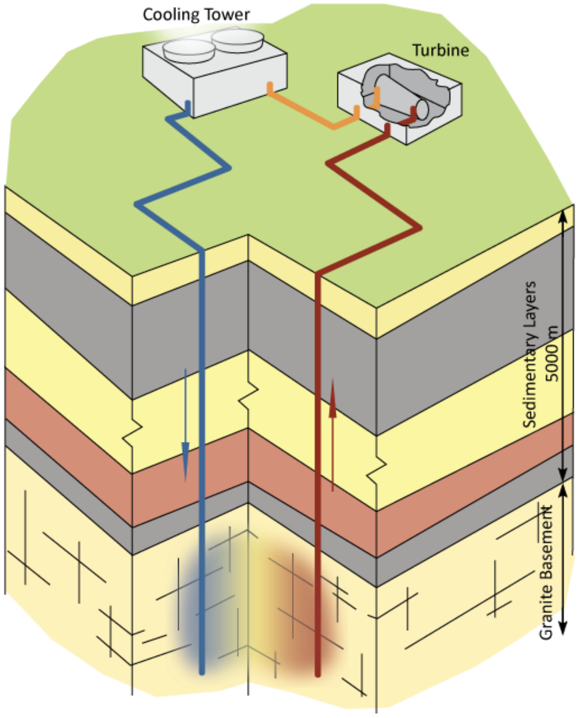

Figure 1: CO_2 thermosiphon configuration

Mass flow rate injected into the reservoir is calculated from the following set of equations:

$$\Delta P = \rho g \Delta z - \Delta P_{f,well} \quad (1)$$

$$\Delta P_{f,well} = f \frac{\Delta z}{D} \rho \frac{V^2}{2} = f \frac{8\pi^2 m^2 \Delta z}{\rho D^5} \quad (2)$$

$$f = \left[-1.8 \log \left[\frac{6.9}{\mathrm{Re}} + \left(\frac{\varepsilon}{3.7D} \right)^{1.11} \right] \right]^{-2} \quad (3)$$

$$\Delta h = g \Delta z - \frac{V^2 \Delta z}{\frac{P}{\rho g} - 2\Delta z} \quad (4)$$

$\Delta P_{f,well}$ is the frictional pressure drop along the wellbore, ρ is density, g is the gravitational constant, Δz is the change in height, D is the well diameter, ε is the wellbore roughness, Re is the Reynolds number, f is the friction factor, Δh is the change in enthalpy, and V is the velocity.

With the mass flow-rate known, and conditions at the base of the production well known (equal to the reservoir pressure and the reservoir temperature), the change in properties in the production well can be calculated.

Each of the calculations for change in thermodynamic properties in the injection well, reservoir, and production well are calculated in a stepwise manner, at intervals of 50 m in the wells, and 10 m in the reservoir.

The production pressure and temperature are the inlet conditions for the turbine. The outlet conditions are determined by the entropy of the fluid entering the turbine, and the injection pressure required. Therefore it is defined by the equations:

$$\Delta s = 0 \quad (5)$$

$$P_{out,turb} = P_{inj} \quad (6)$$

$$W_T = m\eta_{isen}\Delta h_{turb} \quad (7)$$

where W_T is the electricity generated by the turbine, and Δh_{turb} is the change in enthalpy between the inlet and outlet of the turbine, and η_{isen} is the isentropic (or second law) efficiency of the turbine. An isentropic efficiency of 85% is used for all calculations in this work. This calculation method does not directly calculate the actual turbine outlet conditions, as they are not required to calculate electrical generation and heat exchanger load. In cases where it is necessary, they are trivial to calculate.

The heat exchanger heat load is calculated from:

$$\Delta P = 0 \quad (8)$$

$$T_{out,hx} = T_{inj} \quad (9)$$

$$Q_{HX} = m\Delta h_{hx} + (1 - \eta_{isen})W_T \quad (10)$$

where Δh_{hx} is the change in enthalpy within the heat exchanger, and Q_{HX} is the heat rejected from the heat exchanger to the coolant fluid.

Note that pressure drop within the heat exchanger is assumed to be zero. While this will not in reality the case, pressure drop will be small compared to absolute pressures involved, and will mostly be negligible compared to pressure difference within the turbine.

Knowledge of the heat exchanger heat flow requirements allows calculation of the area required for heat exchanger, from the equation:

$$Q_{HX} = UA\Delta T_{lm} \quad (11)$$

where A is the bare outside area for heat exchange (doesn't include area of fins), U is the overall heat transfer coefficient, and ΔT_{lm} is the log-mean temperature difference, or the average driving force behind heat transfer. Normally, a standardised function can be used to the log-mean temperature difference, but as the heat capacity of CO_2 is not constant over the range of heat transfer conditions (it is near the critical point), this value is calculated numerically based on the CO_2 inlet and outlet conditions, and those of the coolant fluid.

Calculation of U is not discussed in detail in this work, as it is dependent on a complex range of factors. A base value of 100 $Wm^{-2}K^{-1}$ is used for calculation of the heat exchanger area required, but there is significant uncertainty related to this value (in is a mostly conservative estimate).

Reference parameters used for calculations in this work are given in Table 1. Unless otherwise specified, reference values are used.

Table 1: Reference parameters

Depth (m)	5000
Reservoir Length (m)	1000
Reservoir Temperature (°C)	225
Injection Temperature (°C)	25
Reference Temperature (°C)	25
Min. Reservoir Width (m)	0.73
Max Reservoir Width (m)	250.73
Impedance (MPa.s/L)	0.2
Corresponding $K.h$ (m^3)	8.603e-11
Reservoir Pressure (MPa)	49.05
Wellbore roughness, ε (m)	0.0004
Wellbore Diameter (m)	0.231
Isentropic Efficiency, η_{II}	0.85

3. ECONOMIC/COSTING METHODOLOGY

Economic analysis of the project is conducted based on standard process engineering cost methodologies. Where necessary, some extrapolation of traditional costing factors is used, to allow for the unconventional operating conditions or equipment involved.

This is necessary due to the limited economic and costing information available for three specific considerations of the CO_2-based system: the high pressures likely in surface heat exchange equipment, the high densities likely in CO_2-based turbomachinery, and the larger-diameter wells that provide increases in thermodynamic performance for CO_2-based EGS.

Where appropriate, upper and lower bounds for cost estimates are used to provide insight into costing results. Upper bounds represent a range where all uncertainties in cost estimation are taken as the unfavourable. Lower bounds represent the favourable end of cost uncertainties (of note here is a reduction in well costs beyond the current average for EGS). The 'most likely' value used in the economics results section represents a conservative estimate, where the lower bound estimates are used for process equipment, but increased costs are considered likely for larger-diameter wells.

3.1 Heat Exchanger Costs

The base costs of the heat exchangers are estimated from standard costing methods (Turton, Bailie et al. c2003). The approach is reproduced here for clarity. Costing is based on air-cooled heat exchangers; in some cases water cooling will be available. In these cases, the cost of cooling systems will be significantly reduced. The cost of heat exchangers is estimated from:

$$C_{BM,HX} = \left(B_1 + B_2 F_M F_P\right) C_p^0 \tag{12}$$

where $C_{BM,HX}$ is the bare module cost, B_1, and B_2 are constants for an equipment type, F_M is the material factor, F_P is the pressure factor, and C_p^0 is the cost for the same equipment made from carbon steel operating at ambient pressure. The constants used in this cost analysis (for Stainless steel equipment) are given in Table 2.

Table 2: Constants for heat exchanger costs

Exchanger Type	B_1	B_2	F_M
Air-Cooled	0.96	1.21	2.9

The base cost for carbon steel equipment is given by:

$$C_p^0 = 10^{\left(K_1 + K_2 \log A + K_3 \log[A]^2\right)} \tag{13}$$

where K_1, K_2 and K_3 are constants for the heat exchanger type, and A is the area of the heat exchanger. The constants are given in Table 3.

Table 3: Constants for heat exchanger base costs

Exchanger Type	K_1	K_2	K_3
Air-Cooled	4.0336	0.2341	0.0497

Area for these estimations is limited to 10,000 m^2 for the air-cooled heat exchanger. Above these sizes of equipment, costs will be linearly extrapolated from an equipment size of 10,000 m^2.

Pressure factors are given by the equation:

$$F_P = 10^{\left(C_1 + C_2 \log P + K_3 \log[P]^2\right)} \tag{14}$$

where C_1, C_2 and C_3 are constants for the heat exchanger type, and P is the design pressure (in bar) of the equipment. The values of these constants are given in Table 4.

Table 4: Constants for heat exchanger pressure factors

Exchanger Type	C_1	C_2	C_3
Air-Cooled	-0.1250	0.15361	-0.02861

The range of pressure factor estimation is specified as limited to below 100 bar for air-cooled heat exchangers. As some design pressures for the CO_2 thermosiphon may be slightly above this range, a small extrapolation of these pressure factors is used. The extrapolation is derived from the fit of a power law to the higher-pressure region (i.e. 50-100 bar) of the pressure-factor calculation, which is then extrapolated. The resulting equation for the extrapolation is:

$$F_P = 0.9396 P^{0.04759} \tag{15}$$

The result of this is shown in Figure 2.

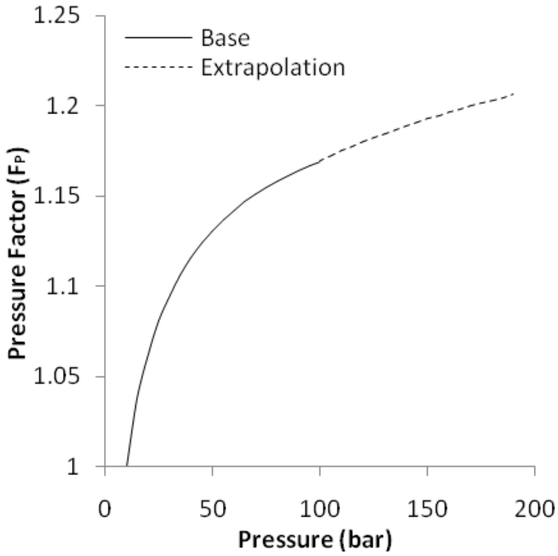

Figure 2: Pressure factor for air-cooled heat exchanger versus pressure

3.2 Turbine Costs

A method of estimating the costs of CO_2 turbines was formulated in an earlier work (Atrens, Gurgenci et al. 2009). That method accounted for the higher density of CO_2 under the thermodynamic conditions within the turbine, leading to lower equipment size. To apply the results of that method directly in an easy-to-calculate manner, the following equation for the turbine cost was formulated:

$$C_{BM,T} = \alpha W_T F_S = \alpha W_T^{\beta} \rho_{out}^{\gamma} \tag{16}$$

where $C_{BM,T}$ is the bare module cost of the turbine, W_T is the turbine work output, α and β and γ are constants, and F_S is the size factor, and is dependent on turbine outlet density (ρ). This equation was fitted to the costs of steam turbines and CO_2 turbines estimated in the previous work (Atrens, Gurgenci et al. 2009). The quality of the fit is presented in Figure 3.

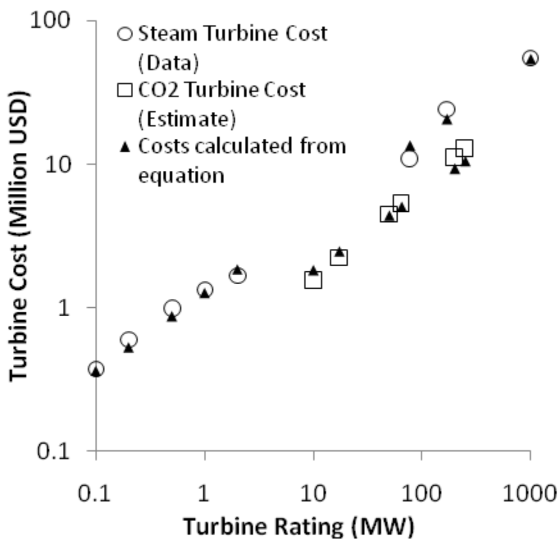

Figure 3: Turbine costs estimated from equation 16

The minimisation of least squares to provide this fit of data resulted in constants for equation 16 as given in Table 5.

Table 5: Turbine cost equation constants

α	β	γ
1.066	0.5439	-0.1472

This provides an estimate for the cost of CO_2 turbines that fits reasonably with the understanding of the equipment and the fluid conditions involved. The cost of CO_2 turbines estimated from equation 16 supplies values used for most likely economic estimates and the lower bound on cost. Upper bound costs use estimates of prices based on generic steam turbine costs for the same turbine power output.

3.3 Well Costs

The cost of EGS wells is still uncertain. Methodologies for estimating costs generally involve a function of depth. As mentioned previously and discussed further in section 4, the diameter of CO_2-based EGS wells is of thermodynamic importance, but diameter is generally not considered as a component in cost estimation.

For this analysis, the dependence of cost on depth is not the key issue of importance. Instead, the influence on cost of drilling wells of larger diameter is the topic of significance. This is a relatively unexplored cost consideration, and is not generally included as a major factor in cost estimates for geothermal wells (or indeed for oil and gas wells).

Below is formulated a methodology for estimating EGS well costs from the cost and depth data from past EGS wells, and a function for adjusting for changes in diameter. Note that the purpose of this costing estimate is not to provide a fundamental approach to costing EGS wells (which is complex and dependent on many characteristics), but to provide a general approach to estimating the change in costs from a change in diameter.

The cost associated with an increase in well diameter is likely to be dependent on three major considerations:

- Increased time requirements for drilling
- Costs associated with changes in well casing
- Changes in overall well design or configuration

3.3.1 Effect on drilling speed

The standard oil and gas well cost estimation methods (e.g. the Joint Association Survey, or the Mechanical Risk Index) take into account many different factors, but do not include well diameter.

To estimate the base increase in costs from drilling larger diameter holes, a concept known as the ‘Mechanical Specific Energy’ is used (Kaiser 2007). This is the measure of energy required to destroy a volume of rock, and can be correlated with rate of penetration in the following manner:

$$ROP = \frac{2538 W_{RIG}}{MSE.D^2} \tag{17}$$

where ROP is the rate of penetration (in ft/hr), W_{RIG} is the power of the drilling rig (in horsepower), MSE is the mechanical specific energy (in ksi), and D is the well diameter (in in.). From this equation, it can be seen that to drill two holes through the same type of rock, and with the same drilling rig, the time taken for each hole would be proportional to the square of the diameter. From that relationship, a base estimate for the dependence of costs on diameter can be made, where the costs increase by a proportion of the diameter squared multiplied by the proportion of time spent drilling.

3.3.2 Effect of casing costs

With any increase in well diameter, there will also be an increase in diameter of well casing and tubing. This will generally be associated with an increase in casing cost. This increase in cost is not derived particularly from an increase in steel volume of the casing, as the change is proportionally quite small, but instead due to the lack of economies of scale for larger casing sizes. This is particularly true for the surface casing, and initial and secondary intermediate casings, as these are more likely to increase into size ranges beyond the established convention (where the large volumes produced keep prices low).

Developing a more comprehensive method of estimating this effect is a work in progress, however for this preliminary study, the cost of casing is considered to increase linearly with increasing diameter.

3.3.3 Changes to well design and configuration

It is important to note that wells design is not as simple as a matter of depth and diameter, and other factors come into play during design, particularly with respect to cost-optimal solutions. Where a well of larger overall production diameter is the goal, there may be opportunities to use a design that consists of fewer, longer, intermediate casing intervals, instead of simply increasing the diameter of all casing intervals, for example. This may result in higher risks during drilling, but could keep the costs of increasing diameter low. While this topic will not be dealt with in detail here, other examples of design changes include the use of rigs of higher power, or different drilling equipment.

Changes to the well design and configuration are complex and difficult to model at a preliminary stage. They are mentioned here to clarify that the topic is more complex than can be discussed appropriately in this preliminary work, and to indicate that despite the negative effects of diameter increase on drilling speed, there are changes to configuration which may significantly reduce the cost of large diameter wells.

3.3.4 Overall well cost model

There is uncertainty related to both the depth of EGS wells and increases in diameter. As well costs provide a significant proportion of the total cost of an EGS power plant, the overall economics are very sensitive to the well costs used. The economic considerations chosen reflect this sensitivity. The lower bound on economics used in this work is the JAS oil and gas well average – while EGS wells to-date have on average costed twice this amount, there have been a small number drilled, and it is not inconceivable that as technology and knowledge improve, costs may trend towards the same average seen in the oil and gas sector. The upper bound of costs is for the case where wells cost as per the EGS average, with increasing cost from diameter change due to both drilling time and casing costs as discussed in section 3.3.1 and 3.3.2, and without any benefits from design changes as discussed in section 3.3.3. The most likely estimate used is the same as the upper bound, except the cost of increases in casing size is assumed to be offset by design changes.

The equation used to calculate likely cost of a well for the latter case is based on a standard exponential function for depth, and an adjustment for increased drilling speed at larger diameters:

$$C_{well} = Ke^{bz}(1-\zeta) + \left(\frac{D}{D_0}\right)^2 \zeta K e^{bz} \qquad (18)$$

where C_{well} is the cost of the well, *z* is the well depth, D is the well diameter, D_0 is a standard diameter used as a baseline (in this case taken to be 0.2313 m), ζ is the fraction of time spent drilling out of total time, and *K* and *b* are constants from the relationship between cost and depth. Proportion of time spent drilling is used as a factor here instead of the fraction of drilling costs out of total cost, as there are drilling components and services that will be unaffected by change in time spent.

Table 6: Well cost equation constants

K	*b*	ζ
0.554	0.000613	0.25

ζ is of course variable, and depends on the characteristics of the rock, amount of difficulties, etc. For this analysis, it is kept at a base value of 25%, as this is similar to estimates for geothermal wells (Polsky, Mansure et al. 2009).

For the upper bound, an additional increase to the well cost from an increase in casing cost linearly with respect to diameter is included:

$$C_{well,upper} = C_{well} + 0.2\left(\frac{D-D_0}{D_0}\right)Ke^{bz} \qquad (19)$$

Values for the constants *K* and *b* are derived from an exponential fit of well cost and depth for geothermal wells (Augustine, Anderson et al. 2006). The fit versus data for geothermal wells is presented in Figure 4.

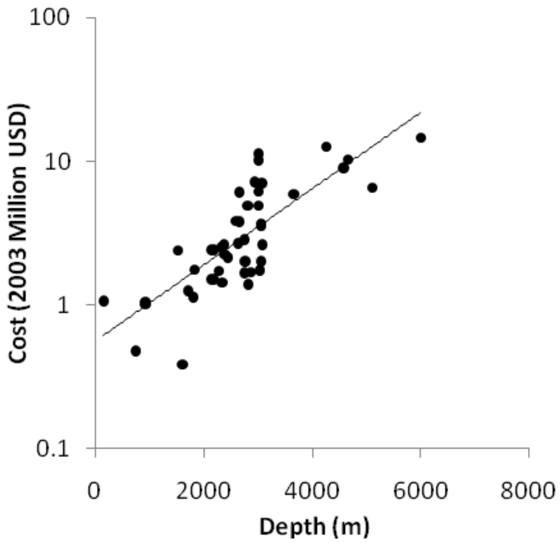

Figure 4: Well cost (2003 $M) versus depth (m), with fit line

From the data in figure 4, we see that the likely cost, on-average, or an EGS well drilled with current knowledge and technology is approximately 12 MM USD (2006). This is compared to the previously discussed cost scenarios in Figure 5.

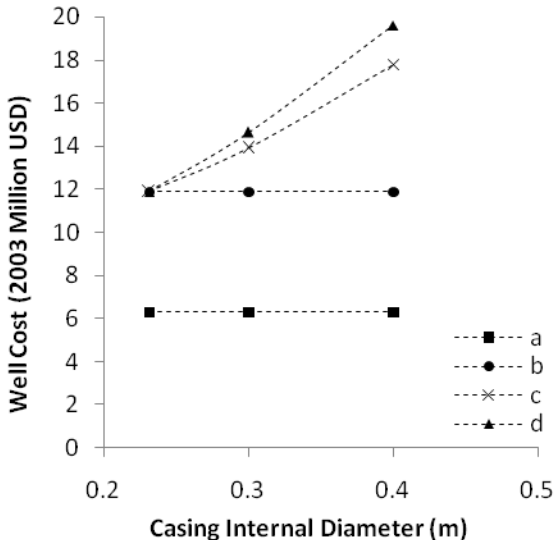

Figure 5: Cost estimates for different costing scenarios versus well diameter for a well of 5000 m depth; (a) costs equivalent to JAS estimates (used for lower bound estimates); (b) costs equivalent to EGS average; (c) costs equivalent to EGS average, with costs increased for drilling time increase (used for most likely estimates); (d) costs equivalent to EGS average with costs increased for both drilling time and casing cost increase (used for upper bound estimates)

As is visible here, there is a significant range of uncertainty (which increases at larger diameter). This is typical of drilling wells in general (as can be seen from the spread of data in Figure 4), but also from an unconventional change in design.

3.4 Total Capital cost

The total capital cost of the power plant is estimated from the equation:

$$C_{TOT} = \omega\left(C_{BM,HX} + \lambda C_{BM,T}\right) + \sum_{i}^{n} C_{well,i} \qquad (20)$$

where C_{ON} is the total capital cost, ω is a constant to take into account the cost increase of building a green-fields facility, λ is a constant to scale up the turbine cost with additional piping, control, freight, labour, and other overheads, and *n* is the number of wells. The values of the two constants are given in Table 7. Well costs are increased by a factor of 1.093 to account for inflation from 2003 to 2006 (due to lack of a geothermal drilling cost index for 2006).

Table 7: Constants used in overall cost estimation

ω	λ
1.8	2.4

3.5 Levelised Cost of Electricity

The costing methodology discussed above leads to a cost estimate of the capital cost of the power plant. This can be translated into a levelised cost of electricity, by annualising costs and dividing total electricity produced over the lifetime of the power plant by the annualised cost.

For this procedure, the general approach used by MIT in a report on nuclear power (MIT 2003) is used. A detailed description of the method can be found in that source. The assumptions used for that model are given in Table 8.

Table 8: Levelised cost of electricity parameters

Parameter	Value
Capacity Factor	90%
Inflation Rate	3%
Operating Costs	1 c/kWh
Interest Rate	8%
Equity Rate	15%
Equity Proportion	50%
Debt Proportion	50%
Debt Payback Period	10 yrs
Plant Lifetime	30 yrs
Depreciation Schedule	MAR ACH 15 year accelerated
Operating cost escalation rate	1%
Tax Rate	38%

This methodology is used in preference to simpler methods of calculating levelised cost to provide confidence in the conversion. When applied to the CO_2-based EGS (due to lack of ongoing fuel costs), however, it effectively is the same as multiplying by a conversion factor of 0.00247 ¢/kWh and adding 1.14 ¢/kWh. Most results in this work use capital costs directly; levelised cost of electricity is used to provide a frame of reference against other power generation systems.

4. THERMODYNAMIC RESULTS

Results from the thermodynamic analysis of the system provide the underlying basis for cost calculations. In the following sections, the effect of injection temperature, well diameter, and addition of recompression are discussed in terms of their thermodynamic effect on the process.

4.1 Effect of injection temperature

Exergy production versus injection pressure is shown for a number of injection temperatures in Figure 6.

Exergy production increases with injection pressure, but the rate of increase slows with increasing pressure. The produced exergy is not shown beyond the asymptotic point; in that range of process operation the production pressure is less than the injection pressure, preventing operation of the thermosiphon from buoyancy forces alone. Furthermore, at higher injection pressures, exergy production decreases below the maximum values shown here.

The relationship between electricity produced by the turbine and injection pressure is shown in Figure 7.

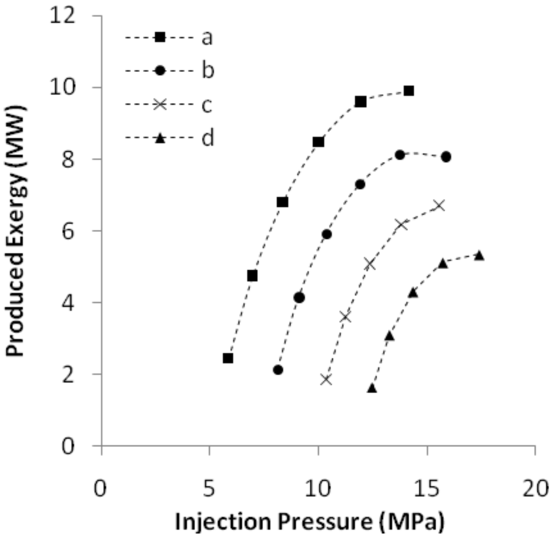

Figure 6: Exergy produced at the surface and available for power conversion versus injection pressure, for different injection temperatures; (a) 15 °C; (b) 25 °C; (c) 35 °C; (d) 45 °C

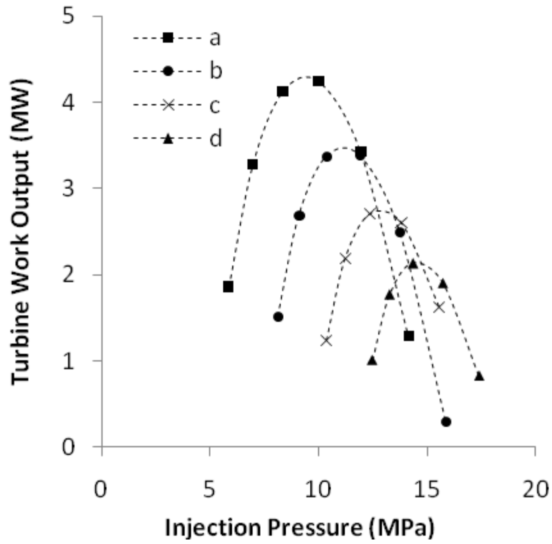

Figure 7: Electrical generation versus injection pressure for different injection temperatures; (a) 15 °C; (b) 25 °C; (c) 35 °C; (d) 45 °C

The peak for electricity production occurs at a lower injection pressure than the peak for exergy available at the surface. At higher injection pressures, there is increased fluid flow extracting more energy from the reservoir, but also decreases in production pressure, reducing the ability to convert energy in the produced fluid into electricity.

Corresponding to the decreased conversion to electricity, energy extracted from the reservoir of the EGS has to be rejected from the system as heat in the cooling equipment. This leads to the dependence of heat exchanger load on injection pressure and injection temperature is given in Figure 8.

To clarify the overall effects on the system and the interaction between injection pressure, mass throughput, exergy available, electricity produced, and heat exchanger load, these characteristics are shown in Figure 9.

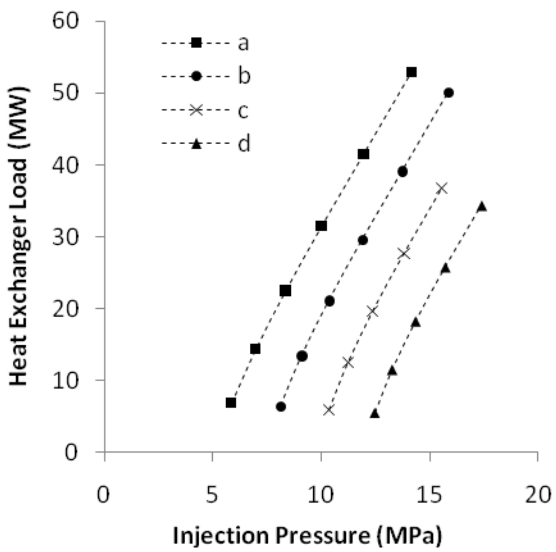

Figure 8: Heat rejected from the power plant versus injection pressure for different injection temperatures; (a) 15 °C; (b) 25 °C; (c) 35 °C; (d) 45 °C

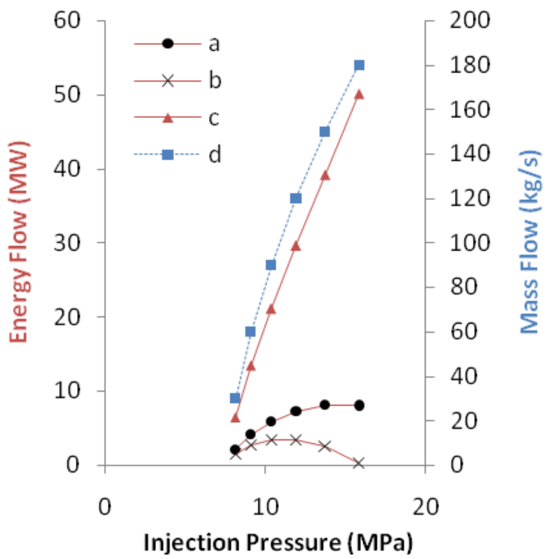

Figure 9: Fluid properties versus injection pressure for the reference case CO_2-based EGS; (a) Exergy available; (b) Electricity generated; (c) Heat exchanger load; (d) Mass throughput

4.2 Effect of well diameter

A prior work (Atrens, Gurgenci et al. 2009) reported significant increase in exergy produced from increases in wellbore diameter. Shown in Figure 10 is the electricity generation versus injection pressure for different sizes of well diameter. The increased exergy produced at larger well diameters leads directly to increased electricity generation in the turbine.

4.3 Effect of recompression

As discussed in section 4.2, operating the CO_2-based EGS at higher injection pressures leads to higher exergy production, but eventually also leads to reduced ability to convert that exergy into electricity. This is largely due to a decrease in the different between the production and injection pressures. The reduction in conversion efficiency (i.e. second-law efficiency) of the power conversion system with increasing production pressures is shown in Figure 11.

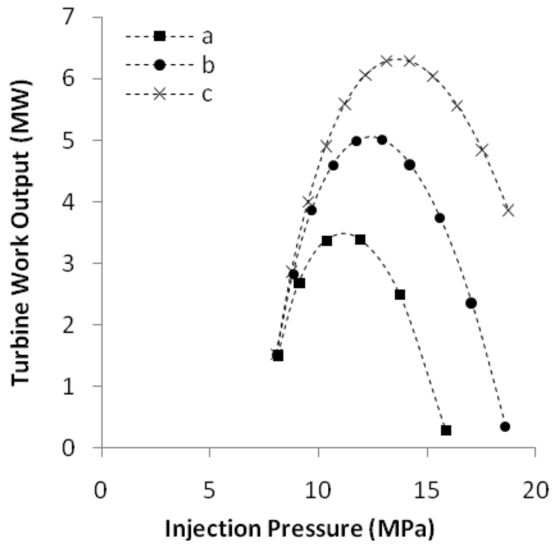

Figure 10: Electrical generation versus injection pressure for different well internal diameters; (a) ID of 0.23 m; (b) ID of 0.3 m; (c) ID of 0.4 m

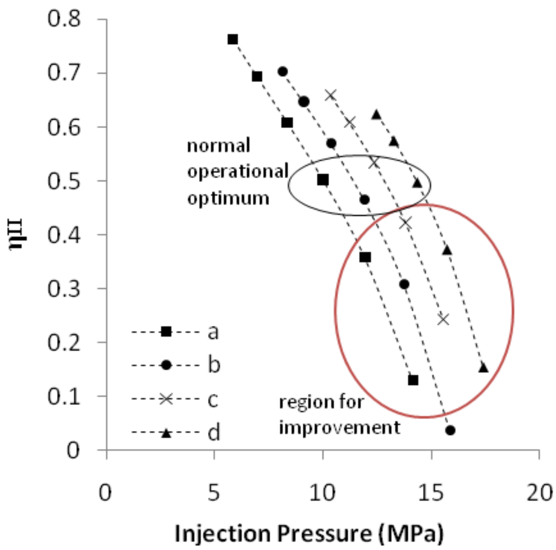

Figure 11: Second law efficiency versus injection pressure for different injection temperatures; (a) 15 °C; (b) 25 °C; (c) 35 °C; (d) 45 °C

The reduction in second law efficiency at higher operating pressures, in conjunction with the higher exergy available at these pressures (as visible in Figure 6) indicates that there is potential for process modifications to significantly improve conversion of exergy to electricity.

One possible modification to the process would be a recompression step. In this scenario, the turbine exhaust pressure would be lower than the pressure at the injection wellhead. The turbine effluent would, after being cooled in the cooling system, be recompressed to the injection pressure (and likely also re-cooled down to the desired injection temperature). This allows the turbine exit pressure to be significantly lower than otherwise, improving the ability of the system to convert energy available in the produced geothermal fluid into electricity when operating at high injection pressures (and therefore high throughput).

The effect of this process modification to the thermodynamic operation of the system is shown in Figure 12. Point (1) indicates the injection wellhead and heat exchanger outlet, point (2) indicates the base of the injection well and the entry to the reservoir, point (3) indicates the base of the production well, point (4) indicates the production wellhead and turbine inlet, and point (5) indicates the turbine exhaust and cooling system inlet. Point (5') indicates the turbine exhaust with recompression modification, point (6) indicates the compressor inlet, and point (7) indicates the compressor outlet.

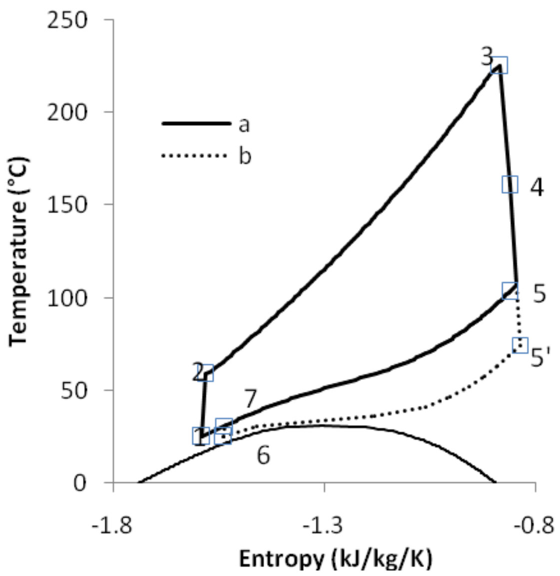

Figure 12: Temperature-entropy diagram of a CO2-based EGS system; (a) reference case (without changes); (b) with recompression modification (for turbine exhaust pressure of 8 MPa)

The pressure chosen for the turbine exhaust when recompression is used is a case where optimization is necessary. The optimum operating conditions will depend on the production pressure, injection pressure, and injection temperature desired. Optimisation of this parameter will not be discussed in detail here, although in general it should be noted that the exergy converted to electricity can be generally improved significantly for most process conditions, allowing conversion efficiency (i.e. second-law efficiency) of the power generation system to be increased.

The benefit of this process modification is shown in Figure 13.

This allows the CO_2-based system to operate at relatively high thermodynamic efficiencies with what remains a relatively simple power conversion design. This does lead to additional costs, but they will be relatively insignificant due to the small size of compressor required. Generally the compression system will be justified for most process designs, although the choice of exhaust pressure is dependent on other process parameters.

A compression system is a likely component in a CO_2-based process regardless of the ability to extract additional electricity for control reasons. Where the process consists only of a turbine and cooling system, control of both the injection pressure and turbine operation is more difficult than if a compressor is available to adjust the process. Furthermore, a compressor is likely necessary during startup phases of a CO_2-based EGS.

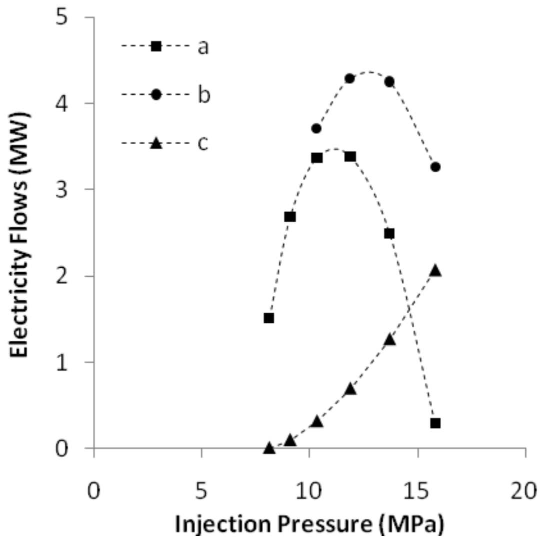

Figure 13: Electricity generated and consumed versus injection pressure; (a) electricity generated by turbine in reference case; (b) net electricity with recompression and turbine exhaust to 8 MPa; (c) Compression work in case [b]

4.4 Heat exchanger operating parameters

Cooling equipment is an important consideration for process design. For any given heat load and electrical conversion system, there is an optimum heat exchanger design. While this is fundamentally an economic optimisation, it is based on the underlying thermodynamic trade-off between air flow and required fan power. As fan power is increased, higher air-flow is supplied, improving heat transfer coefficients, and therefore reducing heat exchanger capital costs, but with a simultaneous increase in parasitic energy losses, leading to a reduction in net electricity generation.

The optimization of this component is not dealt with in this work, as it is almost identical to design of any air-cooled heat exchanger (economic optimization does depend on parameters with the remainder of the power system design). For this work, costing is based on conservative estimate of heat transfer coefficient 100 $Wm^{-2}K^{-1}$, and a mean temperature difference of approximately 10 (relatively low, to account for the generally low injection temperature of 25 ˚C used in the reference case of this work). For the upper bound of economic estimates, a lower heat transfer coefficient of 50 $Wm^{-2}K^{-1}$ is used. For all cases a parasitic load for powering fans of 11 kW per MW of heat removed

5. ECONOMIC RESULTS

For the reference case, the relationship between capital cost and injection pressure is shown in Figure 14. Note that costs are based off an approximately 50 MW power plant, to allow for economy of scale effects for process equipment compared to the doublets discussed in section 4.

These costs are relatively high – the likely cost range for normal operation under reference conditions is close to 7800USD per kW of capacity, equivalent to a levelised cost of electricity of approximately 20 ¢/kWh.

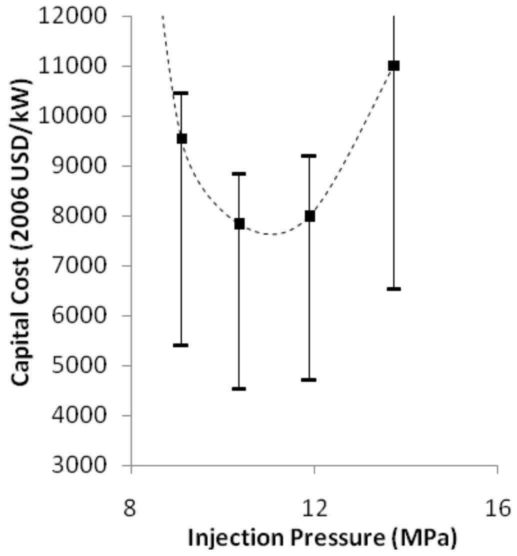

Figure 14: Capital cost versus injection pressure, with upper and lower bound estimates

5.1 Effect of injection temperature

The effect of injection temperature on the pseudo-optimal capital cost is shown in Figure 15. By pseudo-optimal, the minimum cost across the range of possible injection pressures at the given temperature is meant.

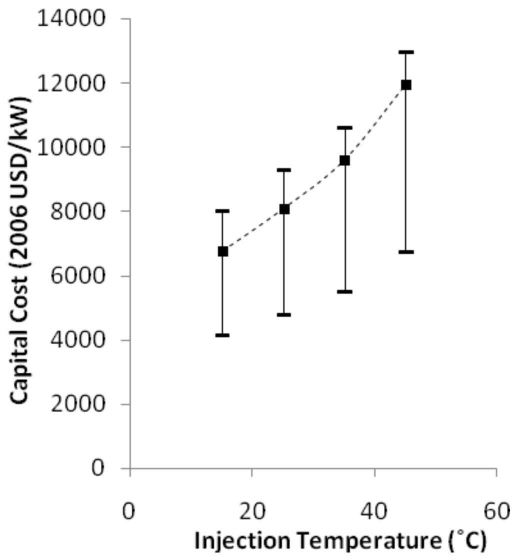

Figure 15: (Pseudo-optimal) Capital cost versus injection temperature, with upper and lower bound estimates

Injection temperature has a major effect on the capital cost of the CO_2-based EGS, primarily due to the large impact on electricity generation discussed in section 4.1.

5.2 Effect of recompression

A comparison of process capital costs with and without recompression is given in Figure 16. Upper and lower bounds are not given for each data point; the ones given are representative.

There is a significant reduction in costs from addition of a recompression system. This derives both from an increase in the recovery of electricity, and therefore indirectly from a reduction in the number of wells required. This is shown for the reference case, but this is representative for a range of injection temperatures (and well diameters).

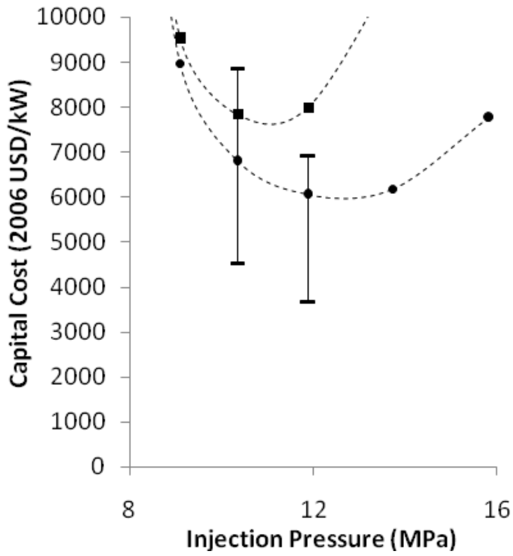

Figure 16: Design cost versus injection pressure for reference case, with and without recompression

5.3 Effect of wellbore diameter changes

Capital costs for the reference case and two larger wellbore diameters are shown in Figure 17. One set of representative upper and lower bounds are given for each size.

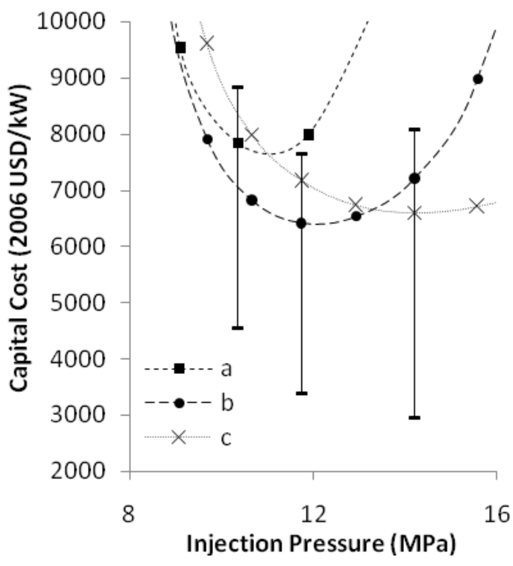

Figure 17: Expected capital costs versus injection pressure, with different wellbore sizes; (a) reference case; (b) 0.3 m internal diameter wells; (c) 0.4 m internal diameter wells

There is a significant cost benefit due to an initial increase in wellbore diameter; however the costs are not improved further through additional expansion in wellbore diameter. This result is sensitive to the assumptions behind this economic model, particularly the drilling costs. It is also dependent on the ability to convert electricity extracted from the EGS reservoir (i.e. the dynamic is changed for different surface temperatures or from the addition of a recompression component to the power generation system.

6. DISCUSSION

The costing models discussed here predict a relatively high cost for the reference case, although costing used here is in general relatively conservative.

Estimates rely on cost factors for adjustment of the base costs of process equipment. These factors are not arbitrary, but are typical of Greenfield process engineering projects. However, for EGS power generation systems, other values for these factors may be more appropriate.

Significant benefits in economics can be seen from addition of compression system and for use of larger well diameters – an decrease in capital cost of approximately 1600$/kW from diameter increases can be achieved, and approx $2000/kW decrease in capital costs from recompression systems. These process changes are expected to be additive, or in cases mutually beneficial. Due to this, the capital costs of an CO_2-based EGS utilising larger diameter wells and with optimised recompression and heat exchange systems wis expected to be cost-competitive where relatively low injection temperatures are achievable. This system design would also rely on negligible losses and assuming no effect of H_2O initially present in the reservoir.

The economic performance is reduced at higher injection temperatures, indicating that ambient temperatures may present a limitation to EGS using CO_2 directly as a heat extraction fluid. More detailed economic analyses are necessary to explore optimisation of heat exchange at higher ambient temperatures, as due to the significant effect of injection temperature on fluid injection, there may be more favourable economic operating points at higher temperature than those shown in the results of this work. Other innovative solutions, such as thermal storage, may result in significant impacts on the process economics at high ambient temperatures.

Well costs are the major component of the total plant cost (more than 70%). This is partly expected, due to the simplicity of the CO_2-based EGS power conversion system compared to binary systems, and due to the large costs involved in deep wells. The result of this is that economics of the process are highly sensitive to well costs. Because the estimates for well cost are conservative, there is significant room for improvement in economics from the likely cases given, either from reduction in costs as drilling technologies mature, or from lower-cost methods of creating larger-diameter wells.

7. CONCLUSIONS

For reservoirs of hydraulic permeability/impedance similar to Soultz-sous-Foret, where water is not present initially, in temperate (or cooler) climes, CO_2-based EGS becomes an attractive option with appropriate process modifications.

For hotter climates, the performance of CO_2-based EGS is reduced – to perform economically, either water cooling, innovative cooling techniques, or reductions in drilling cost would be required.

Fluid loss has not been explored here, but has the potential to significantly impact the economics (particularly where an income supplement is possible from CO_2 sequestration).

Compression systems and larger well diameters are economically justified modifications to the process, with significant beneficial impact under conservative assumptions. Compression is likely to be favourable for all process designs, with turbine exhaust pressure optimised based on other process parameters. Well diameters can be sized for a process economic optimum, however this optimum is highly sensitive to both base well costs and cost from changing well diameter.

Air-cooled heat exchanger operating conditions have been discussed in terms of their thermodynamic effect, but have not been fully characterised due to the conventional nature of the equipment. The inter-relation between heat exchanger operating conditions and the thermodynamics and economics of the process is an area for additional analysis.

The effect of initial water present in the system is an important topic for further analysis, and needs to be taken into account for more in-depth economic estimates.

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