AN ASSESSMENT OF THE ECONOMIC FEASIBILITY OF ELECTRICITY GENERATION FROM PUMPED WELLS TAPPING LATERAL OUTFLOWS OF LIQUID DOMINATED GEOTHERMAL SYSTEMS

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ABSTRACT

Conventional liquid dominated geothermal systems can be considered as undergoing idealised convective processes. Hot fluid up flows from depth and boils into a liquid and steam mixture as it rises and the pressure reduces. The liquid is cooled by boiling and often some mixing with cooler in-situ water. Near surface topography and the presence of high permeability geological layers in the upper 1000m of many systems can enable the development of productive moderate temperature reservoirs above and partly isolated from deeper high temperature reservoirs. Lateral outflow zones of hot liquid water, often with temperature reversals beneath are found in many fields and in some fields these outflows are extensive and have prolific flow rates.

Line shaft or electrical submersible pumps can be used to pump fluid from relatively shallow depths (< 1000m) tapping these lateral outflows which provide the high permeability required to achieve high well productivity without excessive power lost in pumping. Electricity can be produced from energy extracted from the pumped brine using the Organic Rankine Cycle (ORC) process in a binary geothermal power plant. It is envisaged that 100% of geothermal brine is reinjected further down gradient along the outflow and at depth providing an option for power generation that has minimal environmental impact.

Numerical models representing engineering processes of pumped well flow, fluid flow in pipework, and electrical power generation have been developed and applied to the typical conditions encountered in outflow type systems. These models are presented and are used to establish net power, and annualised power generation as a function of geothermal resource conditions.

Considering indicative costs for capital plant and project development the Return on Investment (ROI) has been evaluated using a financial project development model. The ROI for a pumped outflow development is compared to conventional geothermal generation (deep self discharging wells to condensing steam turbine, binary, or combined cycle power plant) options. The sensitivities of outflow temperature, depth of drilling, flow rates, and well productivity to project economics are then discussed.

1. INTRODUCTION

Conventional high temperature (volcanic hosted) liquid dominated geothermal systems can be considered as undergoing idealised convective processes. Figure 1 depicts this process for a flat terrain (i.e. continental or basin and range) setting, whilst Figure 2 depicts a high-relief system in a volcanic setting.

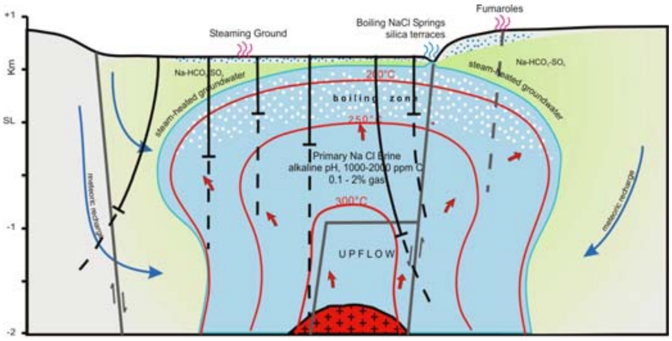

Figure 1: Conceptual Model Schematic for a Liquid Dominated Geothermal System in a Flat Terrain Setting

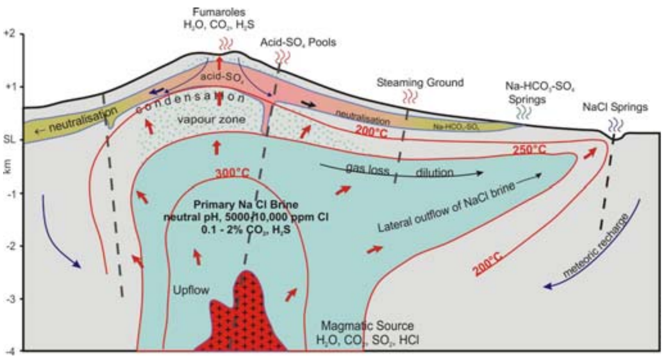

Figure 2: Conceptual Model Schematic for a Liquid Dominated Geothermal System in a High-Relief Volcanic Setting

In both models, hot fluid convects from depth and, as the pressure reduces, will start to boil. The liquid may also cool with some mixing of in-situ water.

The topography near the surface, coupled with the presence of high permeability geological layers in the upper 1000m of many systems can enable the development of productive moderate temperature reservoirs (> 160°C) above and partly isolated from deeper high temperature reservoirs.

Lateral outflow zones of hot liquid water, often with temperature reversals beneath are found in some fields. In some cases these outflows are extensive with prolific flow rates.

These outflows can be developed for electricity generation using established and proven technology. In certain situations this type of development can be attractive compared to conventional deep drilling and steam flash condensing plant.

The key factors to develop these kinds of systems are:

- Depth to drill to intersect target formations;
- Temperature of the outflow;
- Well productivity and injectivity;
- Natural outflow rate;
- Life of the pump.

Considering a green-field exploration scenario and a location where power prices are high, the exploration risk can significantly be reduced taking into consideration of the alternative of developing a low temperature (<240°C) and shallow (<1000m) resource. In addition, the lower relief terrain that typically prevails in outflow areas enables easier and more cost effective site access and associated project infrastructure (e.g. piping and transmission).

For a well characterised brown-field site, the outflow of the field is commonly indirectly well-defined laterally and at depth through production and delineation drilling of the deep reservoir. Therefore, development of the outflow or shallow resource can be considered as a low risk expansion option.

2. ENERGY CONVERSION TECHNOLOGY

The geothermal power plant envisaged is an air-cooled binary ORC plant. This is suitable for the low-medium (100 - 215ºC) temperatures expected in the lateral outflows under consideration. Air-cooled plant heat rejection is assumed here because it can be located in most environments (i.e. it does not require a source of supplementary cooling water). If a source of cooling water is available this would provide an incremental performance and economic benefit to the project.

A simple schematic is shown in Figure 3, supplied by shallow pumped wells.

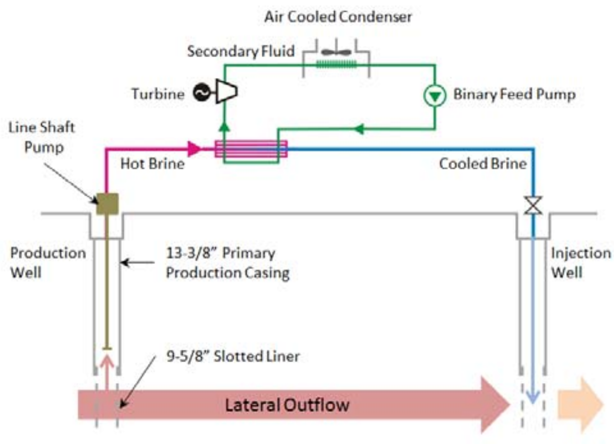

Figure 3: Schematic of a Simple Hot Water Binary ORC Power Plant, pumped from a Lateral Outflow. Figure not to scale.

It is envisaged that 100% of the geothermal brine is re-injected further down-gradient along the outflow. The spacing between the production and injection wells would practically be determined on a case-by-case basis and as a balance between cost of piping and supplementary pressure support for the production wells.

Injection pumps may be required depending on the injectivity encountered. Often the production well head pressure (WHP) is sufficient to drive the flow through the power plant heat exchangers and into the injection wells.

3. DOWNHOLE PUMP TECHNOLOGY

There are two main types of downhole pumps currently used in geothermal applications. These are lineshaft vertical turbine pumps (LSP) and electrical submersible pumps (ESP).

3.1. Electrical Submersible Pumps

With an ESP, the motor is located down-hole below the pump and is exposed to the temperature of the fluid. Power is supplied via a specially protected cable from the surface. A variable speed drive is often used to provide flow control. The pump discharges into a 'riser' pipeline within the well casing which brings the fluid to the surface.

ESPs have had wide-spread use in the petroleum industry.

While less prevalent in geothermal fields they have been used in fields like Lihir (Papua New Guinea), the Soultz EGS Pilot Plant (France), the Steamboat II and III sites (Reno, Nevada) and at Unterhaching (Germany).

Vendor claims of five years mean time run to failure are typical. However, pump operating performance in the field can be significantly less depending on the operating environment, with temperature and salinity being key resource factors.

The maximum working fluid temperature claimed by current ESP vendors is around 250°C. We are not aware of pumps operating in these temperatures for geothermal projects. Pump performance decreases at high temperatures and practical limits such as available power output are lower.

ESPs can be theoretically set very deep and are not depth limited to the same level as LSPs (see section 3.2 for detail).

3.2. Lineshaft Vertical Turbine Pumps

A LSP consists of a surface vertical shaft electric motor, and down-hole pump mounted on a line-shaft. An oil lubrication system is required to lubricate the shaft bearings.

Downhole LSPs have been used over the last 30 years in the USA for geothermal applications. They have been derived from water well pumps. The first application was in the East Mesa field (California) in the 1970s.

LSPs must be installed in relatively vertical wells and are limited to depths of approximately 730m (Frost, 2010). Previous work by others (Sanyal, et. al., 2007) discussed a limitation of 457m depth for LSPs, although it appears that more recent advances in LSPs have surpassed this earlier limitation.

The LSP requires a large diameter (13-3/8") primary production casing to house the unit. Generally LSPs have a lower capital and operations and maintenance costs compared to ESPs. They typically operate at lower speeds with consequently lower wear rates.

Historically, pumps in abrasive installations with constant load have lasted for 1-3 years (refurbishment through to full replacement), but may last up to 8-10 years depending on the operating conditions and environment. LSPs have field experience up to about 215°C (Frost, 2010). The practical lower temperature limit for electricity generation from pumped wells will be dictated by the ORC power cycle not the pump itself.

LSPs are preferable for this type of development. They are suited for relatively shallow, hot and highly productive wells.

4. MODEL DESCRIPTION

4.1. Model Overview

A simple Microsoft Excel based hydraulic pumped well and power plant model is presented in this section. It represents the process in Figure 3 from the production feedzone to the injection feedzone.

For a given flow-rate and well configuration the model calculates:

- pressure drops in the system;
- required set depth of the down-hole pump;
- gross and net power at the plant;

The model can be used to establish the maximum flow rates possible within the operating limits of the pump and the specified well geometry.

When the model results are analysed in conjunction with capital cost estimates, optimum pump types and flow rates can be determined.

Additional commentary on this model is provided in Clotworthy et. al. (2010) and Groves et. al. (2012).

4.2. Calculating Pump Set Depth and Pump Power

The required lift is the difference between the required pressure at the wellhead and the dynamic (operating) water level in the well plus pressure losses in the vertical suction and delivery piping.

The wellhead pressure is set as a model input to overcome pressure losses in the surface piping, plant equipment, and reinjection system, prevent flashing of the fluid, and to limit deposition of mineral scale on internal surfaces of the piping system.

For a given flow rate, the dynamic water level is a function of the pressure at the well feed zone (with allowance for long term changes) and the well Productivity Index (PI), which describes the well draw-down under flow.

The SKM pump model explicitly calculates for required minimum pump set depth, h, by first calculating the pressure drop between the primary production casing shoe and the pump impeller bowl. This pressure drop is referred to as ΔP_{c1p} in Figure 4 and is calculated as:

$$\Delta P_{c1p} = P_{res} - (Q/PI) - \Delta P_c - \Delta P_l - (P_{NPSH} + P_{sm} + P_{sat}) \qquad (1)$$

The variables in (1) are defined as:

P_{res} = static reservoir pressure;
Q = pumped mass flow rate;
PI = well productivity index;
ΔP_c = hydrostatic and frictional pressure drop in secondary casing strings (if any);
ΔP_l = hydrostatic and frictional pressure drop in liner sections or in open hole;
P_{NPSH} = required pump net positive suction head (NPSH);
P_{sm} = additional safety margin to avoid cavitation;
P_{sat} = fluid saturation pressure at production temperature;

The flow into the well is assumed to be governed by Darcy's law and can be expressed as a linear drawdown relationship:

$$Q = PI\,(P_{res} - P_{wf}) \qquad (2)$$

where:

P_{wf} = flowing wellbore pressure;

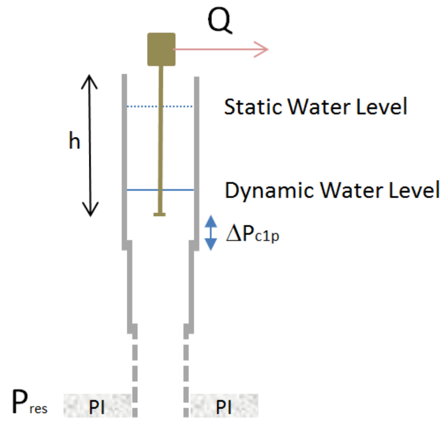

Figure 4: Schematic of pumped well under flowing conditions showing pump set depth (h). Figure not to scale.

The required set depth of the pump is then calculated as:

$$h = z_{c1} - \Delta P_{c1p} / (\rho g + 2\rho f U^2/D) \qquad (3)$$

where:

z_{c1} = vertical depth of primary production casing shoe;
ρ = fluid density;
g = gravitation acceleration;
f = Moody friction factor;
U = fluid velocity;
D = primary production casing inner diameter;

The required discharge pressure of the pump is calculated as the sum of the required production wellhead pressure (WHP) plus hydrostatic and frictional pressure drop in the pump riser.

$$P_{dis} = WHP + (\rho g h + 2\rho h f U^2/D) \qquad (4)$$

The required hydraulic pump power is then:

$$E_h = (P_{dis} - (P_{res} - (Q/PI) - \Delta P_{c1p} - \Delta P_c - \Delta P_l))\,(Q/\rho) \qquad (5)$$

And the required pump shaft power is:

$$E_s = E_h/\eta_{pump} \qquad (6)$$

Where η_{pump} is overall pump efficiency and includes electrical losses in the motor. The pump stage efficiency is in of the order of 68-78% however, once efficiency losses in power cables and other electrical losses are considered, a lower a figure of 65% is more conservative, and it is the one we used in this model.

Injection pump parasitic losses are calculated in a similar way but consider the injection WHP required to inject the fluid.

4.3. Estimating Power Plant Efficiency

The gross efficiency of the plant is calculated simply as a function of resource and ambient temperatures and has been obtained empirically from analysis of reference binary power plant performance. The efficiency calculation is:

$$\eta_{gross} = (2.1 - 0.144T_{amb} + 0.0862T_{res})/100 \quad (7)$$

Where:

η_{gross} = gross efficiency;
T_{amb} = ambient dry bulb temperature (in ºC);
T_{res} = brine temperature at plant interface (in ºC);

Equation (7) is suitable to use for air-cooled binary plant in temperate climates.

The power plant parasitic load factors used for auxiliary equipment are given in Table 1. These factors are used to calculate the net efficiency and power. In practice the loads for binary fluid pumps and condenser fans are expected to vary with ambient temperature. This level of detail has not been included in this model.

Table 1: Power Plant Parasitic Factors

Auxiliary Load	Parasitic Factor [%]
Binary Feed Pump	4.0
Air Cooled Condenser Fans	5.5
Miscellaneous Electrical Loads	1.0
Transformer Losses	1.0

Tester et. al. (2006) presented a correlation for ORC cycle net thermal efficiency as a function of geothermal fluid.

$$\eta_{net} = (0.0935T_{res} - 2.3266)/100 \quad (8)$$

Equation (8) is based on ten existing binary plants across a range of geothermal fluid temperatures. It gives comparable answers to equation (7) although does not include the dependency on ambient dry bulb temperature. Equation (7) was used in the case study presented in section 5.

Other heat rejection systems can be used with binary ORC power plants. These include wet evaporative cooling and once through cooling systems. The parasitic factors and energy conversion efficiency will vary depending on the particular plant configuration selected.

5. CASE STUDY – MOKAI, NEW ZEALAND

A number of geothermal fields appear suitable for further consideration of outflow development with shallow pumped wells.

The Mokai system is examined here as a case study. All information discussed in this section on Mokai has been sourced from the public domain.

The Mokai geothermal field is located about 30 km NW of Taupo, in the western part of the Taupo Volcanic Zone in New Zealand. The power station is currently owned and operated by Tuaropaki Power Company (25% by Mighty River Power, and 75% by Tuaropaki Trust).

A 55 MW_e combined cycle geothermal power station, Mokai 1, was commissioned on the field in 2000. A 39 MW_e expansion of similar design, Mokai 2, was commissioned in 2005. A further 17 MW_e binary plant was then installed at the station in 2007 to accommodate changing reservoir fluid composition caused in response to the initial development. The current annual generation is about 930 GWh.

The production reservoir has been delineated by at least two MT/TDEM (magnetotelluric/time-domain electromagnetic) surveys which suggest a 4-5 km^2 surface extent (Figure 5).

Based on the available well information, it is proposed that the system up-flows within the production area and outflows to the north reaching MK1 and the Waikato River.

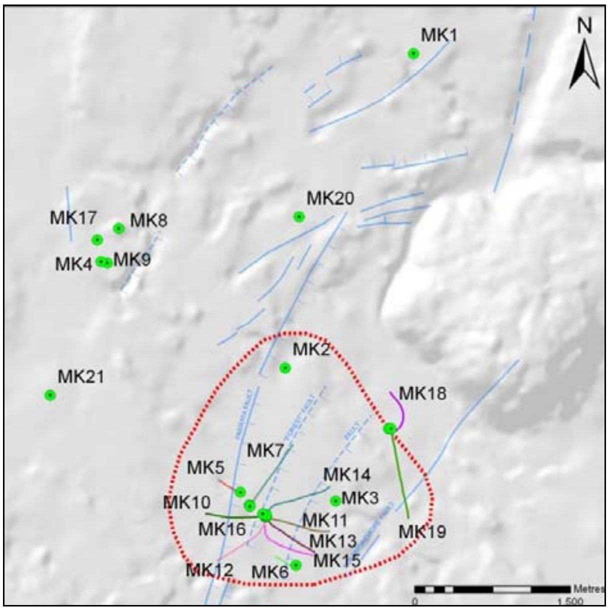

Figure 5: Plan view of Mokai geothermal field. Production wells are located within the reservoir, defined by the dashed red line. Injection wells are located to the north and north-west, outside the deep production reservoir area (Ramirez et. al., 2009)

In the deep reservoir, the geothermal wells have encountered temperature ranging between 240°C and 300°C (Ramirez et al, 2009). Figure 6 shows the stable temperature profiles for three of the injection wells in Mokai. These profiles suggest that the injection wells MK17 and MK20 have encountered a shallow permeable aquifer (200 to 400m) reaching temperatures of 200°C (Figure 2).

Considering the potential extension of the aquifer (MK17 to MK20), and the high temperature indicated by the profiles it is suggested that this shallow aquifer represents a prospective target for development by relatively shallow pumped wells.

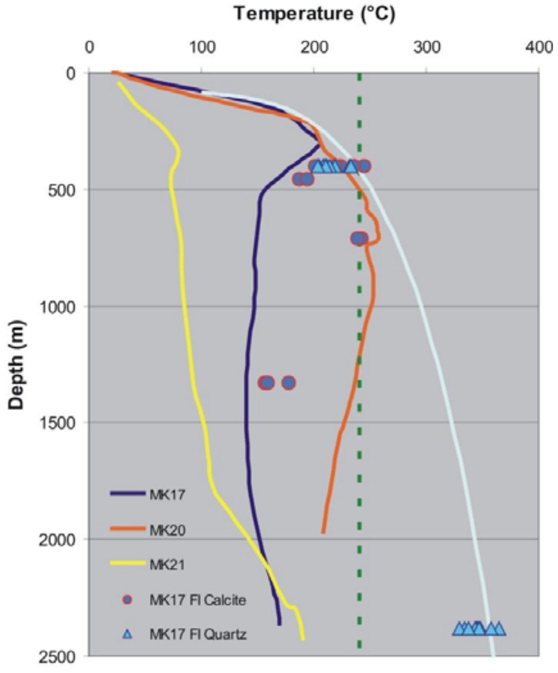

Figure 6: Stable temperature profiles of injection wells MK17, MK20, MK21. The pale blue curve is the boiling point for depth curve for pure water. (Ramirez et. al. 2009)

5.1. Input Assumptions

While the expected temperature can be inferred from Figure 6, many of the other parameters listed are speculative. They serve to illustrate a plausible development scenario but would require further work and data collection to verify.

Table 2 details a number of input assumptions used in the technical model described in section 4. In addition a simple economic model has been run using the outputs of the technical model plus estimates of capital and operational costs. For simplicity, the financial modelling has assumed a balance sheet funded investment with the whole of life investment cash flows discounted at a post-tax nominal discount rate of 10%.

An average power price for the Mokai grid injection point from 2010 to 2012 has been calculated at NZD 71/MWh. This price has been adjusted to US dollars using an exchange rate of USD 0.8:1 NZD, resulting in an indicative power price of USD 57/MWh applied to all scenarios.

All capital and operational estimate costs referenced here are on an order of magnitude 2013 pricing basis. The level of accuracy is no better than +/- 40 % and the estimates here should be taken as indicative only.

Well costs reflect large bore (13-3/8") primary production casing to 300m with 9-5/8" slotted liner to target depth.

The power plant capital cost is dependent on factors such as brine temperature, size of plant, and market competition. It has been estimated as a function of gross output and has considered existing published information on similar equipment procured using an Engineering-Procurement-Construction (EPC) contracting model. The power plant component is about 70% of the capital cost for the assumptions in Table 2 and a competitive tendering process engaging multiple equipment suppliers could be expected to achieve positive commercial outcomes.

For simplicity, financial modelling has assumed a balance sheet funded investment with the whole of life investment cash flows discounted at a post-tax nominal discount rate of 10%.

Table 2: Base Case Input Assumptions

Parameter	Unit	Value
Depth to Drill	m	350
Outflow Temperature	ºC	200
Plant Rejection Temperature	ºC	70
Productivity Index (PI)	t/hr.b	25
Injectivity Index (II)	t/hr.b	25
Production Wells	-	6
Injection Wells	-	3
Total Brine Mass Flow Rate	kg/s	282
Gross Power	MW_e	26.4
Net Power (excl. pumps)	MW_e	23.4
Net Power (incl. pumps)	MW_e	22.5
Well Cost	USD	800k
Pump Cost	USD	450k
Pump MTBF	Years	3
Piping Cost (per Dimension Inch Foot)	USD/DIF	20
Plant Cost (factored price by gross MW)	USD	48M
Power Price	USD/MWh	57
Discount Rate	%	10
Debt:Equity	Ratio	0:100
Investment life	Years	25
Depreciation	%	4 (straight line)
Inflation	%	2
Taxation	%	28

6. MODEL RESULTS

6.1. Base Case Results

Results from the financial modelling base case suggest a levelised electricity cost (LEC) of approximately USD 76/MWh (NZD 95/MWh), with a project internal rate of return (IRR) of approximately 5.5%. Although the base case IRR is less than the 10% hurdle rate, suggesting the desired investment returns will not be achieved, it is considered that there is the potential to address this.

Noting the assumed capital structure of the investment is 100% equity, an adjusted debt to equity ratio of 70% debt to 30% equity was also tested. Assuming a loan life of 10 years at an interest rate of 8% per annum, the effect on the LEC is a reduction by approximately 20%. This is due to the applied discount rate reducing from 10% to approximately 7% when the assumed debt is factored in.

In combination with an effective investment capital structure, further positive refinement of capital costs and geothermal resource inputs appear to position the pumped well investment option competitively against conventional geothermal developments.

The following section discusses the base case sensitivity to resource temperature, well productivity, drilling depth and the timing of pump replacements.

6.2. Sensitivity Analysis

The 'base case' outputs are highlighted in red in the following graphs.

6.2.1 Resource Temperature

Relative to the 'base case' the sensitivity of the LEC to brine temperature is shown in Figure 7.

The flow mass flow rate has been held constant in this analysis. There is potential for further optimization of the pump for the lower temperature cases. The pump could be set deeper for a higher flow rate at the expense of additional pumping parasitic load.

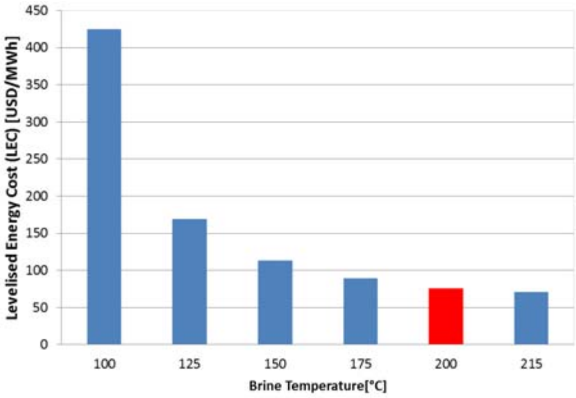

Figure 7: LEC Sensitivity to Brine Temperature

6.2.2 Well Performance

Relative to the ‘base case’ the sensitivity of LEC to well performance (productivity/injectivity) is shown in Figure 8.

The mass flow has been reduced for the low PI cases to ensure the pump can be set adequately within the primary production casing. A target pump set depth of 250 m was selected as a guideline in the adjustment of mass flow.

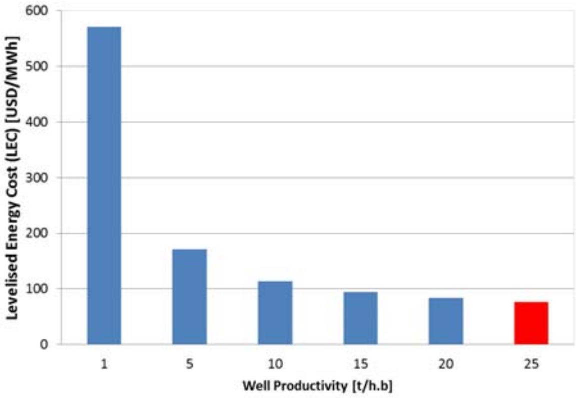

Figure 8: LEC Sensitivity to Well Productivity

6.2.3 Drilling Depth

Wells to 750 m and 1000 m have been estimated at USD 1.7 M and USD 2.25 M respectively. The sensitivity to LEC to drilling depth (and cost) has been examined and this is shown in

Figure 9.

The mass flow rate has been held constant here in this analysis. There is potential for further optimization of the pump flow rate to set in deeper wells (i.e. higher flow rates at the cost of higher parasitic load).

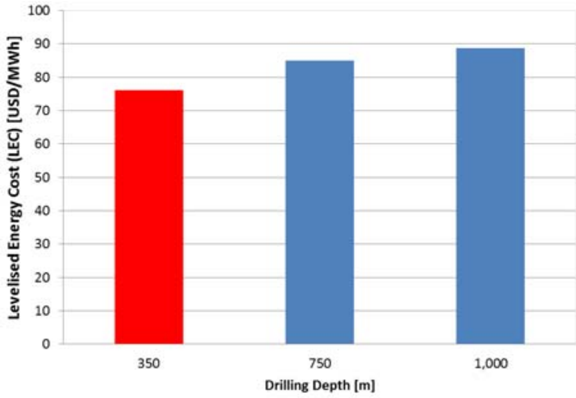

Figure 9: LEC Sensitivity to Drilling Depth

6.2.4 Pump Replacement Time

Relative to the ‘base case’ the sensitivity of LEC to pump mean time before failure (MTBF) is shown in Figure 10.

A full replacement of the pump has been assumed. This is conservative as some failures might be able to be addressed through an overhaul and repair.

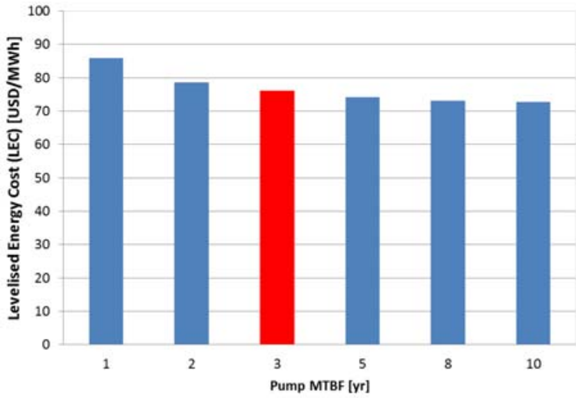

Figure 10: LEC Sensitivity to Pump MTBF

6.3. Other Comparisons

Gehringer et. al. (2012) report that high capacity geothermal (flash condensing, $50MW_e$ class) developments have a screening curve levelised cost of 50-60 USD/MWh.

Pumped systems will approach this figure with a combination of favourable technical parameters (i.e. productivity, shallow and cheap wells, hotter temperatures, and reliable pumps) and economic parameters (i.e. tax rates, discount rates, debt/equity ratio).

This assessment of the opportunity for Mokai is preliminary and intended as an illustration of how a development could target the appropriate parts of the system for lower temperature development. The case study could be refined with more complete understanding of resource conditions that is available publicly, optimisation of pumps, and a more rigorous and detailed assessment of project development costs.

7. DEVELOPMENT CONSIDERATIONS

The sensitivity analysis presented in section 6.2 illustrates that the economic feasibility of pumped outflow systems is dependent on temperature, well performance, drilling depth and pump reliability. Each geothermal field should be assessed on a case-by-case basis and consider the long-term behaviour of the outflow from a pressure perspective.

The drilling configuration should achieve a balance between the required depth of primary production casing to set a down-hole pump, intersecting the target formations, and the cost of drilling.

The production WHP should be set above the saturation pressure of the fluid. This is to ensure the geothermal fluid is kept in liquid phase, to avoid energy loss through flashing (latent heat of vaporization) and also to avoid any operational issues with scaling (such as calcite scaling in the well).

Pumped systems require adequate pressure support to ensure that draw-down in production wells is managed. High levels of draw-down will require pumps to be set deeper with higher parasitic load requirements. The majority of pressure support for these systems will be from the lateral outflow itself, with some secondary pressure support from the injection wells. A reservoir engineering/modelling assessment should be done on any prospective opportunity. This will inform the spacing of production and injection wells and flow rates/well to provide a sustainable development scheme matched to the extent and flow-rate of the outflow.

This type of project development is anticipated to provide 100% re-injection of fluid back in to shallow aquifers albeit at cooler temperatures. The environmental and community impact on surface features, such as springs, downstream of the fluid take and re-injection should be investigated and understood as part of any development, and appropriate mitigation options considered at an early stage.

In high-relief volcanic settings a pumped out-flow development can offer additional advantages over a conventional development. These include:

- access to a geothermal resource in gentler lower elevation areas where outflows are often found;
- reduced geohazard (volcanic and landslide) exposure to surface facilities;
- reduced infrastructure construction costs.

8. CONCLUSIONS

1) A simple Microsoft Excel based hydraulic pressure drop model for geothermal pumped-well flow to an ORC power plant has been developed.

2) The economic feasibility of these systems is primarily dependent on resource temperature, well productivity, depth to drilling, and pump reliability. In combination with an effective investment capital structure and capital cost of the power plant a pumped well development option from outflows can be competitive relative to conventional geothermal developments.

3) The spacing of production and injection wells and the flow rates/per well are determined by the casing configuration (to set the pump), the set depth limit of the pump, and an assessment of reservoir behaviour (through reservoir engineering assessment and/or modelling).

4) Production from lateral outflows can be a relatively low risk project development when compared to deep geothermal exploration. They can be explored cheaply through a combination of geo-scientific surveys and shallow core holes.

5) In high-relief volcanic settings developing an outflow presents advantages over a conventional geothermal development in terms of access, reduced geohazard exposure, and reduced construction costs.

6) For a well characterised brown-field site, the outflow of the field is commonly indirectly well-defined laterally and at depth through production and delineation drilling of the deep reservoir. Therefore, development of the outflow or shallow resource can be considered as a low risk expansion option.

7) Any development should consider potential environmental and community impacts of surface features downstream of the geothermal outflow, and identify suitable mitigation options.

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