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Utilization of Geothermal Waters for Mining Processes in the Andes Mountains

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ABSTRACT

It is well known that most mines located in the Andes Mountains are limited by the availability of water, and much effort is applied to delivering water supplies from surface, sometime using costly water dams, and groundwater sources, as desalted and seawater is also being considered at elevated costs. A large number of geothermal resources have been identified in the vicinity of existing and planned mines, and some of these geothermal systems have been assessed to have potential to provide large volumes (925 l/s) of industrial water.

The areas of the Andes Mountains that are marked by geological alteration, including volcanic activity, also host many geothermal systems. Magma emplaced close to the surface (5-7 km depth) can induce a convective regimen in the deep groundwater creating a geothermal reservoir. These systems may have localized upflow zones covering a few km^2 located above the heat source, and may also have outflow aquifers that extend as long as 20 km.

The fluid which typically circulates through these hydrothermal systems is dilute brine of near-neutral pH, having salinity of one-tenth to one quarter of seawater and some dissolved gases, as well as large energy reserves. These geothermal reservoirs are usually isolated from shallower meteoric ground waters by a deep clay layer (smectite-illite/smectite) created by thermal alteration within and above the geothermal system. Therefore, geothermal wells are drilled much deeper than most ground water wells and specifically case off shallow ground waters to depths of typically 500 to 1000m. Effectively, these wells tap into aquifers which are not currently utilized and almost certainly have not been accounted for by the mine operators and local communities.

1. INTRODUCTION

It is well known that most mines located in the Andes Mountains are limited by the availability of water, and much effort is applied to delivering water supplies from surface and groundwater sources, as desalted and seawater is also being considered at elevated costs. A large number of geothermal resources have been identified by different authors in Chile and Peru (Hauser, 1997; Steinmüler et al., 1997; Vargas et al., 2009). Some of these resources are classified as high temperature fields and are located in the vicinity of existing and planned mines. Some of these geothermal systems have been assessed in this paper to have the potential to provide large amounts of industrial water (about 400 to 925 l/s).

This paper provides an introduction to geothermal resources discussing the main characteristics of a geothermal field in a volcanic setting (e.g., depth of the reservoir, chemistry, temperature). In addition, it presents a preliminary assessment of the costs involved in the production of large volumes of geothermal water that could be used in mining processes.

2. BASICS OF HYDROTHERMAL SYSTEMS

Most of the hydrothermal systems in the Andes Mountains are all related to magmatic activity (Figure 1). This is the type of hydrothermal system that usually supports economic geothermal energy developments in countries without subsidies on power prices. In this environment magmatic intrusions are emplaced high enough in the crust that they induce convective circulation of groundwater.

There are a number of sub-types of volcanic-related hydrothermal systems, but this paper will review the most relevant to those located in the Andes. In these kinds of systems, the heat source is an intrusion or intrusions. The depth of emplacement varies depending on the geology, but is usually in the range of 2 to 5 km (SKM, 2008). The host rocks may be of any type, but given that these systems form in volcanic areas, the most common host rocks are volcanic.

The size of a typical hydrothermal system depends on the local geology and topography. In general terms, the hot “upflow” zone may be in the range of 1 to 3 km2 (Figure 1). The “outflow” zones can be as long as 20 km, though these will usually be preferentially channeled in certain directions rather than surrounding the whole system radially (Figure 1). In geothermal terminology, “upflow” refers to the zone where geothermal fluids ascend more or less vertically from the deeper, hotter parts of the geothermal field, and “outflow” refers to the zone(s) where fluid flow is predominantly horizontal (Cumming, 2009). Drilling in an upflow zone will yield increasing temperature with depth (typically ≥240°C), whereas drilling in an outflow zone will initially yield increasing temperature at intermediate depth, but a reversal of temperature or “inversion” at greater depth, beneath the outflow aquifer (e.g., <240°C).

The fluid at the depth of economic exploitation is predominantly meteoric water that has accumulated in a geological time scale, although the input of a certain percentage of magmatic water and associated volatiles can be chemically important (Figure 1). It is expected that in most Andean systems, the typical fluid which circulates through the bulk of the hydrothermal system is a dilute brine, perhaps one-tenth to one quarter of the salinity of seawater (arising from the interaction of hot fluids with the host rocks). It has a near-neutral pH, and a significant content of dissolved gases. At productive reservoir levels (1 to 2 km) CO_2 is the most important and H_2S is the next most common (Figure 1).

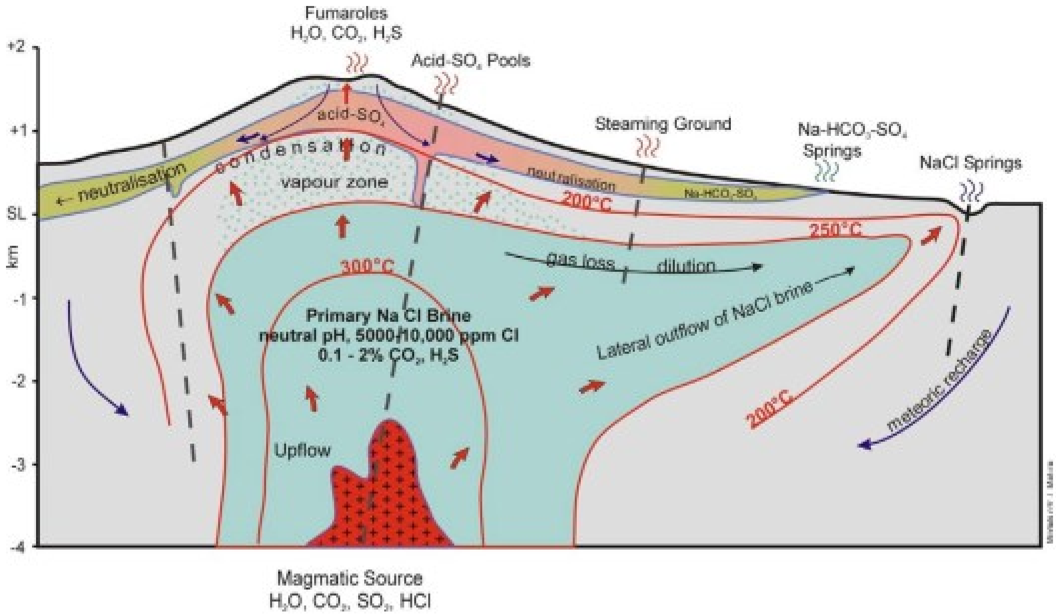

Figure 1 Schematic of a volcanic terrain geothermal system. This diagram is typical of volcanic geothermal fields in the Andes (e.g., El Tatio-Chile, Borateras-Peru), with exploitable upflow and outflow.

In most cases at depth, close to the heat source, the geothermal fluid is effectively isolated from the surface by a deep clay layer (smectite-illite/smectite) created by thermal alteration within and above the geothermal system (Ussher et. al., 2000; Gunderson et al., 2000). Consequently, very high fluid pressures can build up, to reach lithostatic, or temporarily even greater pressures. Above this level, the fluid is in pressure connection with surficial water (albeit remotely), and pressures are controlled by hydrostatic effects. At this level and above, the fluid is not stationary or else it would cool conductively. Hot water is less dense than cold water therefore it is displaced upward by surrounding colder water. The system is thus a large convective cell located at 1-5km depth. There is a central upflow zone, and a corresponding downflow or inflow zone of recharge fluid. If the pressure gradients and topography are suitable, there may be long lateral outflow zones as illustrated in Figure 1.

Geothermal wells are usually cased to at least 500m and often much greater depth. A casing depth of 1-1.5 km is not uncommon. The maximum drilling depth is limited by cost with few geothermal wells drilled to greater than 3 km vertical depth.

3. METHODOLOGY: BASICS OF GEOTHERMAL ENERGY EXPLOITATION

Mankind has used geothermal energy for centuries, for bathing, heating, and cooking. In Tuscany, at Larderello in 1904 the first electricity was generated using dry steam that naturally occurs in the area. Commercial electricity generation started in Italy from 1913 using the same dry steam resources. Many other countries, such as New Zealand, Mexico, and Japan were early adopters of geothermal power production from wet steam (liquid dominated) resources. Currently, the total installed generating capacity of geothermal power plants exceeds 10,000 MW (Bertani, 2010), indicating that geothermal fluid and energy production is a well-established technical endeavour.

Wells drilled into liquid dominated geothermal resources tap reservoirs of hot fluid (water or water and steam) that readily flows to the surface at pressures ranging from 5 to 30 bar and saturation temperature (150 to 230˚C). The enthalpy of the fluid quantifies its energy content, and reflects the proportions of steam and water at the wellhead; enthalpy can range from 1,000 kJ/kg to 2,000 kJ/kg or higher. The total energy delivered by a well is the product of enthalpy and flow rate, and the latter parameter can range from as low as 20 kg/s to 200 kg/s or more. These flow rates and enthalpy values equate to heat flows from individual wells of 20 to 400 MWth, or electrical power of 2 to 40 MW. In general, wells drilled in higher temperature reservoirs are self-flowing at favourable rates, but wells in lower temperature reservoirs can be pumped to enhance flow rate.

To set a context for the following sections, consider a geothermal project comprising seven production wells, each yielding 66.4 kg/s of fluid with an enthalpy of 1,250 kJ/kg.

- Total fluid flow = 7 x 66.4 = 465 kg/s
- Steam fraction at 13 bara = (1250 - hf)/(hg - hf) = (1250 - 815)/(2787 - 815) = 22.0%
- Steam flow = 465 * 22.0% = 102 kg/s; liquid (water) flow = 465 – 102 = 363 kg/s

These flows are sufficient to produce approximately 60 to 65 MW of power, using both the energy in the steam and the water phase. Steam is typically used in a steam turbine, and energy in the separated water (often called "brine") is utilized in an Organic Rankine Cycle (ORC) power plant. One form of this process is shown schematically in Figure 2, where the steam flow is fully condensed and could be recovered for supply of water for mining. It should be noted that Figure 2 depicts the reinjection of both steam condensate and the brine (water) component, which is usual in geothermal power projects. The brine component of the geothermal fluid may also be used for water supply, subject to treatment to remove dissolved solids that include sodium chloride and amorphous silica amongst other things.

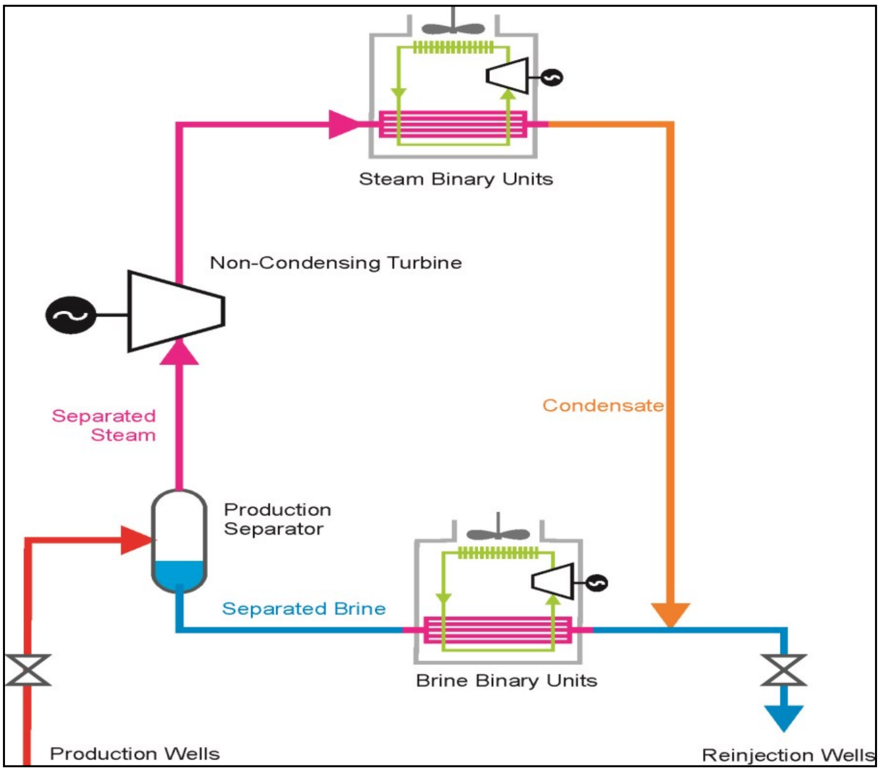

Figure 2 Schematic of Geothermal Power Cycle using Steam Turbine and Organic Rankine Cycle Units.

4. ESTIMATES OF POWER AND FLUID PRODUCTION

As a basis for estimates of power generation and fluid production from a typical geothermal field in the Andes an amount of steam of approx. 100 kg/s was assumed to be delivered. Depending on the fluid enthalpy (energy content), and the wellhead and steam system production pressure, the fraction of fluid delivered as steam can be calculated. Based on expected reservoir temperatures a typical enthalpy value was considered, namely 1,250 kJ/kg. A wellhead pressure of 15 bar (absolute) was also assumed, and a pressure drop of 2 bar was allowed between the wellhead(s) and the steam separation facility.

For the power plant units, based upon a steam combined cycle and brine binary scheme, certain (typical) assumptions were made regarding turbine isentropic efficiency and electro-mechanical losses for the non-condensing turbine. Additional (typical) assumptions were made about the conversion efficiencies of the binary units and the proportion of power needed to meet unit auxiliary loads such as cycle pumps and air cooled condenser fans. The steam combined cycle with bottoming brine unit was used as the basis of analysis because the amount of steam condensed is maximised by this cycle. The key parameters calculated are showed in Table 1.

The following observations should be kept in mind when considering the key parameters:

- The flow rate of individual wells can be increased by operating at lower wellhead pressure.
- Steam (and hence condensate) yield can be increased by reducing the separation pressure.
- Power output of the steam turbine decreases as separation pressure decreases.
- Power output of the brine binary unit can be increased by reducing the brine outlet temperature, but care must be exercised to avoid deposits of geothermal chemicals (notably amorphous silica) in the binary heat exchangers as brine temperature is reduced.
- Binary plant output is a function of both the heat load supplied by the geothermal fluid and the highest temperature in the cycle; this means that lower separation pressures reduce the amount of power able to be produced by the brine binary unit.

Due to the above counter-acting trends, optimisation of the power plant should be undertaken to either maximise power and/or condensate production. The amount of water that could be supplied to a mine process plant will depend on two main factors:

1) The first is whether the mine can accept only low total dissolve solids (TDS) condensate, or it can accept high TDS brine (or a mixture of the two). “High” means a TDS level of about 5,000 to 10,000 ppm, due to the nature of the geothermal fluids delivered by the wells. If the mine can accept high TDS liquid, then all of the recovered steam condensate, and the brine component would be available at the geothermal site. The water would need to be conveyed from the geothermal area to the mine, by canal or pipeline.

2) The second factor is the extent of development at the geothermal field. For example, in Case 1 (table above) the total amount of water is about 466 l/s for a power production of about 60 MW nett. If the size of development were increased to say 100 MW net, the amount of water available would increase pro-rata to approximately 765 l/s. doubling the size of the development to 120 MW nett would yield approx. 925 l/s.

Table 1. Calculated parameters for posterior calculations

Parameter	Units	Case 1
Well Flow Rate (NCGs 0.3%)	l/s	466
Fluid Enthalpy	kJ/kg	1250
Wellhead Pressure	bar (abs)	15
Separation Pressure	bar (abs)	13
Steam Flow (incl. NCGs)	kg/s	104.3
Steam Turbine Power*	MW	31
Condensate Temperature (outlet)	°C	70
Steam Binary Power (gross)	MW	23.1
Steam Binary Power (nett)	MW	20.3
Condensate Flow	l/s	100.4
Brine Flow	l/s	362
Brine Temperature (inlet)	°C	191
Brine Temperature (outlet)	°C	150
Brine Binary Power (gross)	MW	10.6
Brine Binary Power (nett)	MW	9.5
Total Power (gross)	MW	64.5
Total Power (nett)*	MW	60.5

* Note that a nett power value is not stated as the auxiliary power required for a back-pressure steam turbine generator is very minor.

5. COST ESTIMATES

5.1 CAPEX Option Water and Power

Based on the key parameters identified in the previous section (Table 1), estimates have been made of the project costs. It must be noted that these are very generalised, but are parametrically derived (e.g. $/kW for different power plant types, MW/well and $M/well, etc.). A loading has been included to account for anticipated high costs associated with the remoteness of the geothermal fields, the general climatic conditions, and relatively high altitude of the fields. Table 2 summarises the main cost components for the geothermal power project based on Case 1. The level of cost accuracy that is expected to apply is perhaps +40%, -25%.

5.2 OPEX (per year)

OPEX costs are estimated parametrically, using typical values from other geothermal projects, but with a margin of 25% reflecting potential difficulties associated with the field sites. Geothermal power project O&M costs are typically about 1.5 to 2 USc/kWh, so it would be prudent to allow 2.25 USc/kWh, plus the cost of make-up well connections required to sustain the fluid and power production rates as the field is gradually depleted. Again a parametric approach is considered suitable at this stage for estimating make-up well requirements; a rundown of 5% per annum is assumed. Wells are assumed to cost USD 10M each, with a further 15% added for interconnecting piping and valves.

The cost indications presented in Table 3 are for a power project that provides water as a by-product. Costs for delivering water from the geothermal area to the mine site have not been considered, and should be independently assessed. Furthermore, energy costs associated with fluid pumping (where necessary) have not been included, but this component of costs is primarily related to transporting the fluids from the geothermal field to the mine.

Table 2. Main cost components for the geothermal power project based on Case 1

Cost Component (USD Million)	Case 1
Exploration incl. Initial Well Drilling	40
Development Well Drilling	
Well Output	10 MW/well
Number of production wells*	6 + 1**
$M/well	10
Cost of Production Wells	70
Cost of Development Wells	70
Steamfield Works (USD750/kWnett)	45
Power Plant (USD2190/kWnett)	132
Transmission Line (USD10M+USD0.5M/km)	23
Misc Project Costs (Eng, Permitting, etc.)	25
Total Power Project Cost	335
Total Power (nett)	60.5
Installed Cost USD/kWnett	5,540

*No reinjection wells have been included as it is considered that the fluid will be directed to the mine. In addtion, it is considered that at least 2 wells of the exploration proramme could be used for reinjection or production if needed.

**6+1 = six wells + one spare well.

Table 3. OPEX costs for a power project that provides water as a by-product

Annual Cost (USD Million)	Case 1
O&M costs (Power Plant & Steamfield)	11.3
Make-up well costs	3.5
Total Annual Costs	14.8

5.3 Option Only Water

This option considers the possibility of simplifying the steam field works, and omits the power plant and electricity transmission line. This would make the geothermal development one that has the sole purpose of providing water supplies to the mine operation, and would have much reduced cost. To undertake such a development, in its simplest form, the geothermal fluid could be produced from the wells and discharged to ponds. The steam fraction would be lost entirely, as it would dissipate into the atmosphere, and even some of the brine would be lost as additional steam would flash to provide brine at atmospheric pressure. Of the total 466 kg/s produced, about 37% of it would be flashed, leaving only 293 l/s. This would be high TDS brine, due to the loss of the steam fraction (dissolved solids remain with the brine). The cost for the production of water only is estimated in Table 4, which is for 293 l/s of brine.

5.4 OPEX (per year)

As with the power plant OPEX costs, annual O&M costs are estimated parametrically, assuming that steam field related O&M costs are about one third of the total power project O&M figure. Additionally, the cost of make-up well connections required to sustain the fluid production rates as the field is gradually depleted are included by assuming a rundown rate of 5% per annum (wells are assumed to cost USD 10M each, with a further 15% added for interconnecting piping and valves.). The cost indications presented in Table 5 are for a project that provides water only.

Energy costs associated with fluid pumping have not been included, but this component of costs is primarily related to transporting the fluids from the geothermal field to the mine.

Table 4. Cost for the production of water only.

Cost Component (USD Million)	Case 1
Exploration incl. Initial Well Drilling	40
Development Well Drilling	
Well Output	10 MW/well
Number of production wells	6 + 1
$M/well	10
Cost of Production Wells	70
Cost of Development Wells	70
Steamfield Works (USD400/kWnett)	24
Misc Project Costs (Eng, Permitting, etc.)	13
Total Water Project Cost	147

Table 5. OPEX costs for the production of water only

Annual Cost (USD Million)	Case 1
O&M costs (Steamfield)	3.8
Make-up well costs	3.5
Total Annual Costs	7.3

6. CONCLUSIONS

The following conclusions can be drawn from this preliminary analysis:

- As geothermal wells are drilled much deeper than most ground water wells and specifically case off shallow ground waters to depths of typically 500 to 1000m. Effectively, these wells tap into aquifers which are not currently utilized and almost certainly have not been accounted for by the mine operators and local communities.
- High enthalpy geothermal fields in the Andes have the potential of delivering up to 925 l/s and 120 MW to nearby operating mines and upcoming mine process plant developments.
- The following nominal costs were obtained for a medium size geothermal development:

OPTION	**CAPEX**	**OPEX**
Option water + power 462 l/s or 60 MW nett	USD340M	USD 14.8M
Option only water 293 l/s	USD145M	USD 7.3M

- It is expected that production of geothermal water combined with geothermal power production would be significantly more attractive when revenues of power sells are taken into consideration in the total cost. This is particularly relevant in Peru, where recent renewable legislation seek to promote the development of geothermal energy (Renewable energy Law 1002 (May 2008); Authorization and Exploitation Law (2010)).

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