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Probabilistic Flow Modelling of Geothermal Wells in Sedimentary Aquifers

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ABSTRACT

Economic assessment of the development prospects for production of moderate temperature geothermal brine from a deep sedimentary aquifer is aided by a statistical analysis of information from existing petroleum or other wells. A statistical distribution of formation permeability, thickness, temperature and pressure is combined with a simplified wellbore model to produce an estimate of the flow from a submersible pump with a fixed maximum discharge head. Monte Carlo simulation of the pump discharge flow can then be used to produce a probability distribution of well output for economic analysis.

Estimates of the levelised electricity cost probability distribution can be obtained by using the output from the probabilistic flow model as one of the inputs to a Monte Carlo model of major cost. A preliminary financial model was created to investigate the potential economic viability of various options for low temperature geothermal developments in a sedimentary basin.

Using probabilistic modeling of the expected range of parameters affecting the flow from wells tapping low temperature sedimentary formations produces a model output of expected production well flow rate that can be used for economic assessment of project viability.

For low temperatures geothermal developments the production well flow rate and temperature are the major factors affecting the economic viability of projects.

1. INTRODUCTION

Development of low temperature geothermal reservoirs hosted in deep sedimentary basins requires high production well flows to achieve economic viability for moderate temperature geothermal brines. The formation temperatures in these systems is usually known quite reliably as a function of depth. The average formation permeability and thickness are more variable.

Economic assessment of project viability requires estimates of well flow rates. The economic assessments have typically used a limited rate of fixed flows. A probabilistic flow distribution is more useful for economic analysis.

2. NUMERICAL MODEL

A simple 3-D numerical model of a sandstone formation was set up to confirm the theoretical dependence of well flow on formation thickness and porosity using TOUGH2 geothermal modeling software. The numerical model also enabled estimates of the changes in productivity with time and the likely interference between wells.

The model consisted of three layers with a length of 20 km in each direction (Figure 1) with a single production well at the centre. In order to accurately record the pressure gradient near the well, the grid dimension reduced to 10 m near the central well. In theory smaller blocks should be added immediately around the wellbore, but generally in geothermal wells the near-wellbore permeability is enhanced during drilling (negative skin effect) or can be enhance later by acidizing or fracturing. Therefore a distance of 5 m to the inner block boundary was considered appropriate.

The upper layer was 3000 m thick and impermeable, corresponding to the overlying cap rock. The formation was split into two layers of equal thickness to enable the effective thickness to be varied. The middle layer could be either impermeable to simulate a thin formation thickness or the same permeability as the bottom layer to simulate a thicker aquifer. Two models were set up Layer 2 and 3 being either 100 m or 400 m thick, which enabled 4 thickness values to be modeled - 100, 200, 400 and 800 m.

The hot layer underlying the formation was not included in this simple model to save time setting up and running the model. Instead flows of hot water were injected at the boundary blocks of the production layers and extracted at the top. The cross flow of hot water kept Layer 2 and 3 at a near-constant temperature. To simulate the connection to the rest of the aquifer in the basin the blocks at the base of Layer 3 had a substantially larger volume. This model was not a perfect representation of the actual formation because of conductive heat loss to the upper layer which had an average temperature of 70°C at 1500 m depth.

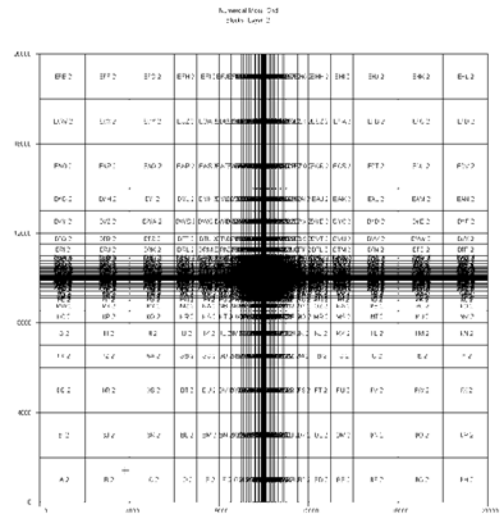


Figure 1: Grid for numerical model (dimensions in metres)

Adding more layers would have improved the temperature match but this was not felt to be important as the temperature at the production well remained almost constant during production. Pressure profiles perpendicular to the flow direction were used and drawdown was calculated as the difference from the boundary element at 20 km.

For the production simulations the mass flow from the well was kept at a constant value for 30 years. This enabled the pressure drawdown in the formation to be determined for a range of flows, with varying permeability and layer thicknesses. If two layers were active there was a well in each layer with half the total flow.

For this preliminary model a single production well was used, but a production-injection doublet can also be simulated or multiple pairs if the geometry is symmetric.

2.1 Numerical Modeling Inputs

A full range of values of thickness and permeability for Layers 2 and 3were used for model runs with a high flow of 200 kg/s. A limited number of combinations of thickness and permeability were then used for modelling with well flows of 100, 50 and 25 kg/s. The total of 28 runs was made.

2.2 Numerical Modeling Results

It is expected that the pressure drawdown in the formation is proportional to the flow and inversely proportional to the formation thickness and permeability product, kh (permeability-thickness product).

$$\Delta P \propto \left(\frac{Q}{k.h}\right) \qquad (1)$$

where ΔP = pressure drawdown (bar)

Q = flow (kg/s)

k = permeability (milli-darcy)

h = formation thickness (m)

This relationship (or the apparent productivity index) changes with time. For the study the long term productivity after 20 years was required.

The results of formation pressure drawdown at the block containing the production well were cross plotted in the form of (flow rate / pressure drawdown at 21years) versus kh. The fitted line through the origin had a coefficient of regression of 0.9991, indicating a good fit. There was more scatter of values at lower values of kh (lower permeability) but the variation was small.

The long-term pressure decline can be estimated with little error using the equation : $\Delta P = \dfrac{CxQ}{kh}$

where 1/C is the coefficient from the linear fit.

For a multiple-well model with production-injection doublets the long term relationship would still be expected to be linear, but a different fit could be used if necessary. The short term relationship may also be non-linear.

This equation is used in the Monte Carlo simulation to relate well productivity to formation permeability-thickness.

3. PROBABILISTIC MODEL OF WELL OUTPUT

A Monte Carlo model was run with the following parameters having a probabilistic input range :

Table 1. Flow Model Input Estimates.

PARAMETER	PROBABILITY DISTRIBUTION
Formation permeability (k)	Exponential
Formation thickness (h)	Triangular
Formation pressure	Logistic
Formation temperature	Triangular

For a given pump head the expected flow rate is calculated as probability density function.

3.1 Flow Calculation

Using the equation derived above relating formation pressure drawdown as a function of well flow rate, formation permeability and thickness a probabilistic estimate of well output at a particular pump head can be calculated.

Because the frictional pressure drop in the wellbore restricts the available flow when the formation permeability and thickness are high, the calculated flow from the well is determined by finding the flow at which the drawdown in the formation equals the available head from the pump.

The available head from the pump is calculated as follows :

Pump Head(available) = (Max. Pump Head) – Formation drawdown – (frictional loss in wellbore)

Strictly, the pump delivery curve should be used to calculate the maximum pump head but in practice the pump will be sized for the well characteristics. Therefore a fixed Max.PumpHead of 20 bar was used. The formation drawdown is described in section 2.2.

The frictional pressure drop was calculated assuming a 13-3/8” casing down to 2500 m and a 9-5/8” slotted liner with a length of 800m. The frictional pressure drop as a function of flow was accurately fitted by a quadratic equation.

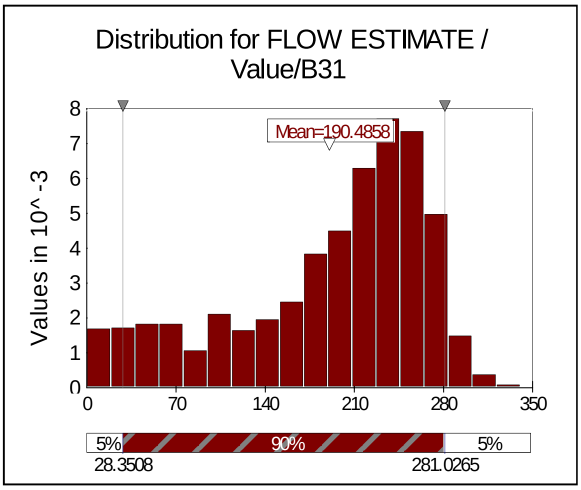
When the available pump pressure is equated to the formation pressure drawdown the resulting quadratic equation can be solved for the flow.

As described above the formation thickness, permeability and local pressure drawdown have been fitted by probability density functions and these are used to run a Monte Carlo simulation using @Risk software with Excel.

Each simulation was run for 2000 iterations.

2.2 Results of Monte Carlo Modeling

An example of the expected flow distribution for an aquifer with good permeability and known thickness is shown in Figure 3. The flow distribution is dominated by the permeability distribution at lower flows and by the frictional pressure drop in the wellbore at high permeability values. For high flow rates the output from the well is pump-limited. Using a different maximum available pump head would increase the mean flow value.



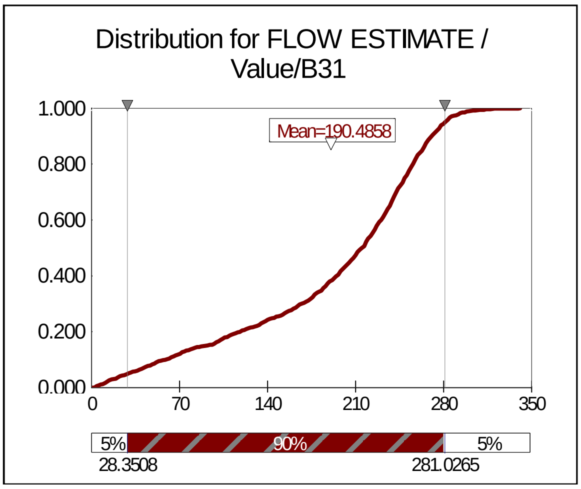


Figure 2: Distribution for flow estimate from Monte Carlo model

4. PROBABILISTIC ECONOMIC EVALUATION

A preliminary financial model was created to investigate the potential economic viability of various options for low temperature geothermal developments in a sedimentary basin. The results given in this model are based on best estimates given the size and location of the developments and therefore maybe subject to some variation. For this reason a Monte Carlo simulation has conducted to determine the sensitivity of these results to the various ‘estimates’ for the given parameters.

A comprehensive spreadsheet based model was created to calculate the levelised electricity cost (LEC, USD$/MWh) from the total capital and operational and maintenance (O&M) costs with respect to the annual power generation for each of the four power plant options, using the reservoir parameters from the flow model.

The LEC can be described as the minimum selling price that a product, in this case electricity, requires for the project to break even, i.e. it is the selling price that returns zero net present value over the asset life (Σ(PV costs – PV income) = 0). It uses the NPV of both the combined capital and O&M costs and the NPV of the annual power generation over the economic life of the asset in order to generate the LEC. This is done via equation 2:

$$LEC = \frac{NPV_{TV}\,(USD)}{NPV_{PG}\,(MWh)} \qquad (2)$$

Where;

$$NPV_{TV} = \sum_{i=1}^{n} \frac{(CAPEX + O\&M)}{(1 + real\ disc\ rate)^{i}} \qquad (3)$$

and

$$NPV_{PG} = \sum_{i=1}^{n} \frac{(annual\ energy\ generation)}{(1 + real\ disc\ rate)^{i}} \qquad (4)$$

The LEC analysis was carried out using a real discount rate of 6.8% (nominal discount rate of 10% and inflation rate of 3%) over an economic lifetime of 20 years. Other economic indicators expressed in this model are the return on equity (ROE), after tax NPV and after tax DPI. These require assumptions to be made on various parameters as defined below.

4.1 Plant Configuration

The financial model was based on several available options for technical plant development. Due to the nature of the resource (low temperature, saturated liquid) only binary geothermal power plant options have been considered.

4.1 Financial Modelling

Table 2 Financial model input estimates

INPUT PARAMETER	VALUE	UNIT
Nominal Discount Rate	10	%
Inflation rate	3	%
Power Plant FOB	2,000	US$/kW
Owners Engineering Costs	8	%
Transmission	40,000	US$/km
FCDS	100	US$/kW
Permitting	100,000	$
O&M	0.01	US$/kWh
Pipe Costs	20	US$/DIF
Steamfield Pre-development	1,000,000	US$
Production Wells	11,000,000	US$
Re-injection Wells	11,000,000	US$
Steam Decline Factor	0	%
Power Plant Load Factor	92	%
Other Owners Costs	3	%
Pipe Diameter	Option dependant	Inches
Tax rate	34	%
Depreciation Life	10	Years
Plant Life	20	Years
Electricity Sale Price	60	US$/MWh
Debt/Equity Ratio	0	%

The above parameters (where applicable) are based on prior knowledge of similar installations. Other factors such as plant life, debt/equity ratio, steam decline factor etc, have been assumed for the purpose of the financial model.

There is considerable variation in the parameters listed in Table 2. In a conventional cost estimate the ultimate cost is often presented with a ± contingency. This is limiting in that it provides a range of costs without giving an indication of the most likely value. A more analytical method is to assign an uncertainty to each input to the cost estimate and then run a Monte Carlo simulation.

The uncertainties applied to the inputs of the cost estimate are summarized in Table 3.

Table 3. Risk Analysis Input Estimates.

INPUT PARAMETER	DISTRIBUTION
Service capacity factor	PERT
Discount rate	PERT
Inflation rate	Normal
Mean flow	PERT
FCDS costs	PERT
Power plant costs (FOB)	PERT
Transmission costs	PERT
Transmission distance	PERT
Engineering costs	PERT
Permitting	PERT
‘Other’ project costs	PERT
Pipe Cost ($/DIF)	PERT
Steam field predevelopment	PERT
Production wells (drilled and tested)	PERT
Reinjection wells (drilled and tested)	PERT
Available temperature	PERT
Rejection temperature	PERT
Pipe length	PERT

The above variables were identified as having a direct effect on the value of the levelised electricity costs of the alternatives.

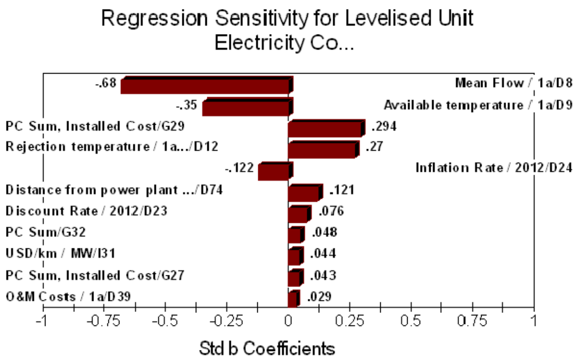


Figure 3: Tornado graph of relative effects of inputs

From Figure 3 for one of the power plant options it can be seen that the primary factor determining the sensitivity of the LEC is the mean flow rate of geothermal fluid. Other factors that have a dominant effect on the LEC are the available temperature and rejection temperature. The relative brine velocity (dependant on pipe diameter) has a large effect on the sensitivity of the analysis for all options other than the one shown in Figure 3. This indicates that optimization of pipe size is likely to improve profitability.

An example of the Monte Carlo output for one of the power plant options is shown in Figure 4.

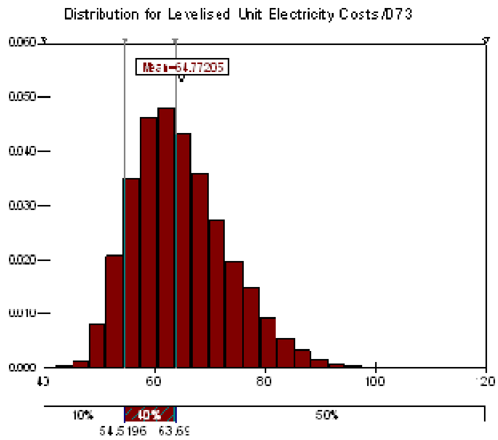


Figure 4: Levelised electricity cost distribution example

CONCLUSIONS

Using probabilistic modeling of the expected range of parameters affecting the flow from wells tapping low temperature sedimentary formations produces a model output of expected production well flow rate that can be used for economic assessment of project viability.

For low temperatures geothermal developments the production well flow rate and temperature are the major factors affecting the economic viability of projects.