Impact of Project Variables on Tariffs Required for Economic Development of Geothermal Projects

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ABSTRACT

The author participated in 2015 in a World Bank/ADB funded study of Indonesia's geothermal sector, aimed at advising on revised tariff setting procedures. The study identified a lack within the government sector of a definitive financial model to cater for the very wide variation in parameters that could potentially affect the tariff required for economic development. EBTKE subsequently requested assistance in the preparation of a suitable model to support development of a variable tariff system. This model was prepared by the author and colleagues, with initial inputs from Arup of UK, but subsequently by the NZ team alone. The model has been recognized as realistic by EBTKE, Ministry of Finance, INAGA and the World Bank, although the corresponding tariff system was not eventually adopted by the government, who preferred a fixed tariff system based on PLN's avoided generation costs. The model has subsequently been further developed and used to examine the impacts of technical, subsidy and other potential regulatory changes.

The developers have now used the model to examine the impact on required tariffs of a number of project parameters, including resource quality, project size in terms of total MW capacity and generating unit configuration, costs of drilling to various depths, the use of slim hole exploration techniques, who is carrying exploration risk, development by SOEs or private sector etc. While the specific model was developed for Indonesia, the principles should be valid for all areas provided suitable input variables and financial factors are used. Although the actual derived tariffs will require the underlying cost database to be revised to reflect post-COVID costs, the ratio of the various required tariffs, as presented in this paper, is expected to remain relevant and will provide guidance to developers and regulators of the areas which need the most consideration in planning development.

1. PRODUCTION COST MODEL

The UNFC classification of geothermal resources, which is being increasingly used as an international standard, is founded on a project-specific basis. Financial models are usually prepared by project developers or lenders, specific to a particular project. Although these models can be adjusted to examine a very limited number of sensitivity cases, they are not usually flexible enough to look at a wide range of project structures or variables.

Following the publication of a joint report by the World Bank and ADB ("Unlocking Indonesia's Geothermal Potential"), in which it was noted that the Ministry did not have a reliable financial model with which to estimate the cost of production of geothermal energy from the wide range of possible project variables, the Geothermal Directorate of the Indonesian Ministry of Energy, General Directorate of Renewable Energy and Energy Conservation (EBTKE) requested the assistance of the author, via NZ MFAT, to generate such a model.

The model developed by the author, Mr Jim Lawless and Mr Bart van Campen, was specifically designed to consider a very wide range of projects and to arrive at a tariff required to make a project economically viable for the developer. It includes a complete sheet in which to set up the key project parameters, and automatically develop a project timeline and construction capex cash flow (see Figure 1), and a separate sheet with an extensive estimating data base covering drilling requirements (common assumptions, well costs and number of wells required, the later based on variations in resource quality), civil & infrastructure works, power plant and steamfield costs, exploration and development overheads, O&M costs, various escalation indices and financial data (including equity and debt requirements plus tax and depreciation).

Tariff is then determined using an in-built macro to "goal seek" the tariff required to generate either the Equity IRR for the project (for a private sector developer) or the Project IRR (or WACC, for an SOE developer). See Figure 2.

Provision has also subsequently been made to input and examine the impact of a number of government incentives such as tax relief, concessionary finance and some potential Indonesian government and World Bank exploration and delineation support schemes.

Inputs to the model were sought from the Indonesian Ministry of Finance (especially for equity and project rates of return and cost of finance for SOEs), lenders and the International Finance Corporation (for private sector debt parameters) and private sector industry players (for equity return requirements). The model was subsequently presented to and endorsed by the Indonesian Geothermal Industry Association (INAGA) and the World Bank.

Unfortunately, the Ministry of Energy did not proceed with the tariff setting scheme that EBTKE was intending to adopt, which would have used this model as the basis for adopting and subsequently adjusting tariffs for individual projects. The model has, however, been successfully used to examine a number of development incentive options, and also for students at the Geothermal Institute to obtain a better understanding of the impact of various parameters on the economic cost of geothermal generation.

2. VARIABLES CONSIDERED FOR THIS STUDY

The number of variables potentially associated with a geothermal development is obviously very large. However, based on the author's experience, a smaller number of parameters are either well known as having a significant

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impact on the required tariff, or are known to have particular interest for developers and lenders, who believe that they should have an impact. The key parameters which have been considered are:

a. Variations in resource enthalpy
b. Variations in generating plant capacity and configuration
c. Drilling variations including use of slimholes
d. General capex variations
e. Opex variations
f. Finance and timing variations

A base case project (2 x 50 MW power plant being developed on a medium-high enthalpy resource) has been used against which to compare the impact of these variables. Details of the variable inputs for this model are shown in Figure 3 (overleaf).

Project Data and Capex Spread

Project Description

Unit Capacity (MW)	50	**Number of Units**	2	**Accessibility**	Moderate
Resource Quality	Medium-High	**Type of Units**	Conventional		
Developer	IPP	**Type of Development**	Greenfield		
Financing Details	16.5% Equity IRR, 70 % Debt at 7.65% Loan Interest Margin, 12years Tenure, 4 years Grace Period. FID occurs 6 months after 65% of rated capacity has been delineated.				
Exploration By	Developer				
Exploration Method	Standard				
Additional Comments	For Brownfield or No-Drill Enhancement, the Exploration By input has no significance. For all Greenfield developments, the Exploration Method must be selected, and in the case of Government exploration, the repayment point must be provided (in cell U14).				
COD Date	Aug/30	Initial O&M Rate	1.63	c/kWh	
Financial Close	Dec-27	Project Duration	27	quarters	
Project Start Date	Jan/24	MUR Drilling Frequency	6	years	
Govt Exploration Starts					

Figure 1: Project description section of the Project Data Sheet in the Production Cost Model.

Key Metrics

Uses (USD '000)

	USD '000	%
Construction Costs	421,945	92.5%
IDC (Snr Debt & Appraisal Support)	29,292	6.4%
Commitment Fee + Appraisal Risk Fee	-	-
Initial Working Capital	5,000	1.1%
Total	456,237	100.0%
Recognised Prior Expenditure	-	
Total Uses & Sunk Costs	456,237	

Sources (USD '000)

	USD '000	%
Equity	136,871	30.0%
Senior Debt	319,366	70.0%
Total	456,237	100.0%
	(Exc. Prior Expenditure)	

Returns

	NPV		
	Disc Rate	USD '000	IRR
Project (Geared)	10.0%	97,052	13.2%
Equity	10.0%	125,869	16.5%
		Target Equity IRR	16.5%

Debt Ratios

	Min	Min Date	Average
DSCR	1.21 x	31-Dec-31	1.45 x

Base Electricity Tariff (US¢ / kWh) 12.25

Optimise Debt & Calculate Tariff

Generation (MWh - First 20 Years)

	Total	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031
Phase 1 Net Generation	11,439,360	-	-	-	-	-	393,120	790,560	788,400
Total	11,439,360	-	-	-	-	-	393,120	790,560	788,400

Prices (USD / MWh - First 20 Years)

	Escal. Portion	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031
Base Tariff		-	-	-	-	-	-	122.53	122.53
Escalation (Indonesia)	-	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.04
Escalation (USA)	25.00%	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.01
Current Tariff	25.00%	-	-	-	-	-	-	122.53	122.93

Cash Opex per MWh (USD - First 20 Years)

	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031
Variable O&M Costs	-	-	-	-	-	-	4.10	16.50
Plant Overhauls	-	-	-	-	-	-	-	0.06
Total	-	-	-	-	-	-	4.10	16.57

EBITDA (USD '000 - First 20 Years)

	Total	FY 2024	FY 2025	FY 2026	FY 2027	FY 2028	FY 2029	FY 2030	FY 2031
Revenue	1,365,033	-	-	-	-	-	-	25,291	100,699
OpEx	(227,323)	-	-	-	-	-	-	(4,009)	(16,081)
EBITDA	1,137,710	-	-	-	-	-	-	21,282	84,618

Figure 2: A section of the Production Cost Model output sheet. The sheet includes basic parameters from the first 20 years of the project's life, the cash waterfall and several graphical outputs.

Development Basis	
Resource Quality	Medium-High
Capacity Per Well (7")	8.0 MW
Capacity Per Well (9-5/8")	10.0 MW
Injection Wells per Producer	30%
Rate of Decline	4%
Units	
Number of Units	2
Capacity per Unit	50
Technology	Conventional
Development	
Type of Development	Greenfield
Developer	Private (IPP)
Exploration by	Developer
Exploration Technique	Standard Wells
Timing	
Project Start Date	Jan-24
COD	Aug-30
Costs	
Drilling	
No of Exploration Wells	3
No of Production Wells	15
No of Injection Wells	3
Depth (m) (Exploration/Inject'n)	2,000
Depth (m) (Delineation/Prod'n)	2,500
Contractor Mob/Demob	$ 1,500,000
Cost per Standard Well (7")	$ 6,000,000
Cost per Large Well (9-5/8")	$ 7,000,000
Well Testing	$ 1,860,000
MUR Drilling Campaigns	6 years
Civil & Infrastructure	
Contractor mob/demob	$ 800,000
Roading (25 km upgrading)	$ 1,500,000
Laydown & Support Areas	$ 1,000,000
Well Pads & Access Roads	$ 11,700,000
Water Supply	$ 4,400,000
Land Acquisition	$ 635,000
Surface Facilities	
Power Plant	$ 165,000,000
Steamfield	$ 43,500,000
Overheads	
General plus P/Management	6.5%
O&M Costs	
Variable	1.50 ¢/kWh
Major Overhaul (every 5 years)	$ 500,000
MUR Drilling (per campaign)	$ 25,000,000
Finance	
Debt:Equity Ratio	70%/30%
Cost of Debt	7.65%
Term of Debt	12 years
Equity Return	16.50%

Figure 3: Input variables for the Base Case model.

The tariff calculated for this base case model was 12.25 US¢ per kWh. This value would probably be reasonably indicative of a likely tariff required in Indonesia for an IPP greenfield project starting next January 2024. However, a number of parameters and escalation indices have seen changes over the last 24 months, resulting from both COVID and the Ukranian/Russian conflict, leading to significant changes in finance costs, and economic updating is required to re-validate the input parameters. The reported results are therefore being expressed as percentages of the base case tariff in order to demonstrate the degree of impact that variation of the various parameters will likely have.

2.1 Variations in Resource Quality

Definition of resource quality is implict in the UNFC approach, and is a fundmantal necessity for any project analysis, but is not always made explicit. Resource quality is often referred to simply in terms of temperature, although that is not an accurate term to use when considering the overall project thermodynamic and process design. Our model used a number of different resource quality groupings, defined as follows:

Low: The lower limit is that the wells can self-discharge. That will depend both on temperature and pressure, since there are artesian wells which discharge at low temperature without flashing. For this reason it is better in this range to define a temperature as well as an enthalpy, therefore "low quality" is defined as reservoir fluid temperature between 180°C and 225°C and less than 10% excess enthalpy compared to reservoir temperature when measured in a discharging well with at least 5 barg WHP.

Medium-Low: Between 225°C and 260°C, and less than 10% excess enthalpy compared to liquid saturation at reservoir temperature when measured in a discharging well with at least 5 barg WHP.

Medium-High: Over 260°C, and less than 10% excess enthalpy compared to liquid saturation at reservoir temperature when measured in a discharging well with at least 5 barg WHP.

High: Over 10% excess enthalpy compared to reservoir temperature when measured in a discharging well with at least 5 barg WHP, thus up to and including dry steam.

However, even defining enthalpy does not fully assist in determining the economics of the project. What is required is an assessment of the power production to be expected from different sized wells, the injection requirements relative to production and hence the number of wells needed to be drilled. The assumed average parameters as used in the model are given in Figure 4, which also indicates the assumed rate of linear resource decline (a linear decline rate is easier to handle within the model, though in reality it may follow an exponential, harmonic or other function). Note that the rate of decline applies to the development as a whole: some individual wells may in reality decline faster or slower. The rate of decline can also be expected to depend on the size of the development relative to the resource capacity (however defined). If a devolopment is over-sized relative to the resource (as for example at the peak total development at the The Geysers in California), the decline rate will be faster. If the development(s) are small compared to the capacity of the resource (as in the case of Kawerau in New Zealand), the decline rate will be less. However, this has not been explicitly taken into account in this study.

	Capacity (MW) per slim hole	Capacity (MW) per 7" hole	Capacity (MW) per 9-5/8" hole	Injection wells for each equivalent COD well capacity	Annual rate of decline (assumed linear
High	1.5	10.0	12.0	15%	5%
Medium-High	1.5	8.0	10.0	30%	4%
Medium-Low	1.0	6.0	8.0	60%	3%
Low	0.0	5.0	7.0	90%	3%

Figure 4: Assumed impact of various resource qualities.

With a base case resource of Medium-High quality, the impact of High and Medium-Low options has been considered in this study.

2.2 Variations in Plant Configuration

The cost of geothermal power plant is actually highly variable, based on the market conditions prevailing at the time of ordering the plant. However, it has also been noted over a long period of time that there is a very significant economy of scale that has to be recognized. The individual parameters that together cause this impact include both unit size and the number of units installed at about the same time on each plant site (multiple plant sites being more expensive than multiple units grouped onto a single site). This has been examined by using a 2 x 50 MW configuration for the base case and comparing with a 1 x 50 MW (i.e. same unit size, smaller total output capacity) and a 1 x 100 MW (i.e. same output capacity but only one unit).

The advent of smaller modular and binary units has resulted in a step change in the cost characteristics for smaller units, resulting from the use of standardized existing designs and a simpler approach to the provision of ancillary equipment and buildings. This has been examined by looking at a 5 x 20 MW modular/binary plant (same overall output, increased number of units, but with a different basis for costing).

2.3 Drilling Variations

It is generally assumed that drilling will require around 30% or more of the total cost of a geothermal development. Obviously, this will be significantly influenced by the quality of the resource, which in turn dictates the actual number of wells required, both for appraisal/production and injection (see Figure 4 above). Note that exploration is always regarded in the model as requiring 3 wells. Budgeting for less than three wells will usually lead to delays in the program and associated standby costs while permission is obtained from the shareholders for the extra expenditure, whilst if the resource has not been located after three wells it is probably not there. However, an independent variable is the required depth of drilling. The model considers exploration and injection wells and appraisal/production wells to be drilled to different depths, with the first usually somewhat shallower than the later (2,000 m and 2,500 m for the base case). The impact of having to drill 20% deeper (2,400 m and 3,000 m respectively) has been considered in this study.

The impact of a 15% increase in the cost of drilling has also been considered. Drilling costs can be country specific (Indonesia was generally higher than other countries, despite large geothermal and petroleum sectors, mainly because of problems with importation and subsequent re-exportation of rigs making rig availability somewhat restrictive).

Additionally, the number of rigs mobilized can make a difference, especially during appraisal when trying to save on rig mob/demob costs can result in deploying a single rig only and hence delaying completion of appraisal drilling and hence financial close. In general, it is easier to justify using more rigs during production drilling as the schedule is then driven by the usual 2-year completion time for the power plant EPC contract.

Finally, the impact of exploration using deep slim holes has been considered. Although deep slim hole drilling has long been recognized as a useful exploration tool, it has often been expressed that this must result in increased development costs because the slim holes will not be usefully productive and so the same original number of wells will have to be drilled in addition to the slim holes. In the model, limited production from the slim holes has been assumed, though they can in some cases also be used for reinjection. A further, unquantifiable but real benefit is that slim holes may later provide useful reservoir monitoring points.

2.4 General Capex Variations

As an indicator of the impact of general infrastructure capex variations, the cost of constructing well pads has been looked at with an assumed cost increase of 20% for sites with more difficult topographical or geotechnical conditions.

The effect of cost increases for power plant (as distinct to cost adjustments required for changes in unit size and configuration) has been considered, again with a 20% increase in the reference unit cost (i.e, cost per MW installed as established in 2018 USD). Similarly, the impact of a 20% increase in steamfield costs has separately been assessed.

2.5 Opex Variations

Generally, developers and lenders regard annual O&M costs as an important variable. Normal O&M costs for geothermal are in fact constant, although they are often presented as a cost per kWh, usually about 1.50 US¢/kWh. The study has looked at a 15% increase in this value.

Another major plant O&M variable is the cost and frequency of major plant overhauls. With the development of better steam quality control (especially the reduction of brine carry-over), power plant outages have been slowly increasing in periodicity and are now often undertaken at 5 year intervals. The impact of a reduction of this time back to 3 years has been included as a possible variable.

Make-Up and Replacement (MUR) drilling is a third major opex factor (although it may be treated in accounting terms as an additional capex cost). The requirement for MUR drilling is driven by the estimated reservoir run-down characteristic, which is very difficult (or impossible) to accurately predict before operations commence. The base case model has assumed for a medium-high enthalpy resource that run-down will be at 4% per annum (linear) and for comparison purposes a run-down rate of 5% has also been assumed. Even this figure assumes a prudent resource operator. Much higher decline rates have occurred at projects which have adopted, for example, inappropriate reinjection strategies.

2.6 Timing Variations

From a project scheduling perspective, and probably the hardest to predict, is the time taken from completion of delineation or appraisal drilling to financial close (also termed final investment decision, FID). This period requires that all development contracts should be finalized (especially the plant EPC contract and the steamfield construction contract), plus all permitting etc. be finalized in accordance with the planned development configuration, which cannot be realized until the completion of a full project feasibility study following completion of exploration drilling, and that all financing arrangements are finalized and signed. The base case model assumes a time lag of 12 months from completion of well testing to FID for an IPP developer. In the case of an SOE, the time lag is reduced to 6 months to reflect the (hopefully) easier requirements for institutional financing of a government entity. For the purpose of this analysis, the time lag has been revised down to 6 months and also increased to 18 months.

2.7 Finance Variations

Clearly, the cost of finance is a critical consideration. As is usual for this type of project finance structure, the debt:equity ratio has been set at 70%/30% - the model assumes that if the initial equity requirement prior to debt drawdown exceeds 30%, then the surplus equity will be preplaced by debt following drawdown.

The expected equity IRR was originally determined by discussion with the Indonesian Ministry of Finance and several IPP developers, and was set at a total of 16.50% for return on a greenfield project with exploration being undertaken by the developer. The impact of increasing this by 10% (to 18.15%) has been examined in this study.

Similarly, the cost of debt has been gauged from a market survey, including inputs from IFC, as 7.65% per annum, with a debt tenure of 12 years and a grace period of 4 years from drawdown (to allow for completion of construction and generation of sufficient income to meet the debt repayment requirements). This analysis has looked at the impact of an increase of 10% in the cost of debt finance, to 8.42%. It has also separately looked at an increase in debt tenure from 12 to 15 and 20 years. The 12 year tenure is seen as being typical for fully commercial debt, whilst the longer tenures may be available from institutions such as IFC.

Finally, given the current uncertainty regarding international financial markets, the combined impact of a 10% reduction in both equity IRR (to 14.85%) and debt interest rate (to 6.89%) has been (optimistically) modelled.

3. RESULTS

The results of this analysis are stated in Figure 5 and shown graphically in Figure 6, with the results being grouped in accordance with the type of variables discussed in Section 2 of this paper.

As previously discussed, the economic tariff for the base case has been assessed as 12.25 US¢/kWh. This figure is probably reasonable for a project of this size commencing in January 2024, with COD in August 2030. However, the actual magnitude of the tariff may be subject to revision following updating of a number of economic factors, including escalation projections, that have not been validated at this time. For that reason, the following analysis of impacts of project variables are expressed in percentages of the base case tariff, rather than actual tariffs, thus also making the results more readily applicable under different jurisdictions other than Indonesia.

3.1 Resource Quality

This has generally the greatest impact on the required tariff for economic performance of the project, which is interesting given that many financial analyses do not explicitly consider this as a variable. We consider that it is much better to do so than to vaguely assume it falls into the category of "resource risk". Differences in enthalpy result in significant changes in the number of wells required to be drilled, and in fact it has a double impact because not only are more production wells required for lower enthalpy fields, but also more injection wells.

A medium-low enthalpy will result in an economic tariff of 113% the base case tariff, whilst a high enthalpy resource will require an economic tariff of only 94% of the base case. It should be noted that a low enthalpy resource, not shown in Figure 5, would require a tariff of 128% of the base case. The model also has the ability to consider low enthalpy resources with pumped wells, although that case has also not been included in this study.

Base Case		Tariff Variation
	2 x 50 MW, Medium-High Resource Quality (12.25 US¢/kWh)	100%
Resource Quality		
	Medium Low Enthalpy	113%
	High Enthalpy	94%
Power Plant Configuration		
	Single 50 MW Unit	111%
	Single 100 MW Unit	96%
	Multiple Unit Binary	96%
Drilling		
	+15% Well Costs	105%
	+20% Well Depth	104%
	Single Drilling Rig	101%
	Slim Hole Exploration	100%
Capex Variations		
	+20% Well Pad Costs	101%
	+20% Power Plant Cost	106%
	+20% Steamfield Cost	102%
Opex Variations		
	+15% Variable O&M	102%
	Major Plant Overhauls Reduced from 5 to 3 Years	100%
	Reservoir Rundown Increased from 4% to 5%	102%
Timing Variations		
	Increased Time Lag to FID from 12 to 18 months	105%
	Reduced Time Lag to FID from 12 to 6 months	96%
Finance		
	+10% Equity IRR	108%
	+10% Debt Interest Rate	102%
	-10% Equity IRR & Debt Interest	91%
	Debt Tenure Extended from 12 to 15 years	98%
	Debt Tenure Extended from 12 to 20 years	95%

Figure 5: Impact of project variables on economic tariff.

3.2 Power Plant Configuration

Changes in power plant configuration have the second greatest potential impact on the tariff required for economic development of the project. This is a reflection of the known economy of scale effect, which has been seen in many projects world-wide. Installation of a single 50 MW unit would have a tariff requirement of 111% that of a double unit installation because mainly of the sharing of civil and structural works and switchyard costs over the two units (provided they are on the same site) and also engineering costs. However, replacing 2 x 50 MW units with a single 100 MW unit has the effect of bringing the required tariff down to only 96%.

It is interesting to note that the use of multiple small binary or other small modular units also has the effect of significantly reducing the required tariff because of the lower unit cost of small, modular type units. This lower unit cost is probably due to being able to use existing, common and often simpler, engineering designs and faster manufacturing time.

3.3 Drilling Variations

Although drilling costs represent a significant part of the overall development cost (typically of the order of 1/3rd of the overall capital cost), variations in the average cost per well and depth of drilling do not have such a significant impact on the required tariff (105% and 104% respectively). The bigger concern will probably lie with the potential for the costs of an individual well to rapidly increase due to sub-surface conditions. Our model in fact includes provision for well success (50% in exploration, 65% in appraisal and 80% in production drilling), based on international experience, rather than trying to accommodate individual failures. Also, depth variation is not so very significant in most volcanic based resources, with well depths being typically between 1,500 m and 2,500 m (extending to 3,000 m more recently, especially in the Rift Valley in Africa). Obviously, this is a rather different situation to that being experienced in non-volcanic systems currently being currently examined in Europe and elsewhere.

The impact of multiple rig mobilization is interesting. For a modest sized project such as the base case project in this study (which requires a total of 9 wells to be drilled before FID), reducing to a single rig does not greatly reduce the time required for appraisal compared with parallel activities. The impact when drilling in a lower quality resource will be much greater and generally rigs should be mobilized to keep appraisal drilling duration to less than 12 or 18 months duration.

It is interesting to see that the impact of deep slimhole drilling on required tariff is negligible. Although using slimholes will mean that more wells have to be drilled during appraisal or production drilling, the economic impact for the developer is that the quantum of equity exposure is significantly reduced during the earlier, higher risk stages of the project and that the bulk of the equity is therefore introduced later and for a shorter period than if using full sized wells during exploration. It is this reduced equity exposure that makes slimhole drilling so attractive to the commercial developer, provided that the information obtained is still valid for the purposes of data collection, remembering that it is data collection which is the prime reason for exploration drilling, not demonstration of actual production capacity.

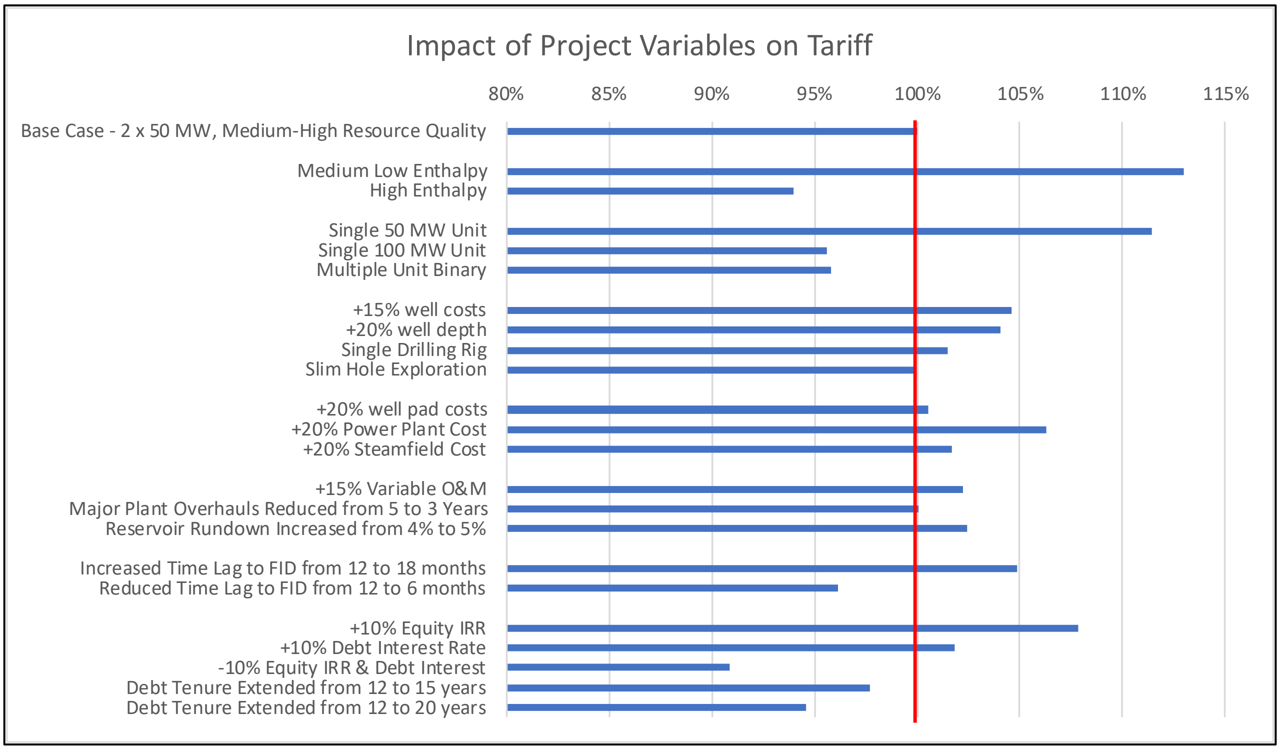

Figure 6: Impact of project variables on economic tariff.

3.4 General Capex Variations

As might be expected, variations in the cost of well pads (and similar infrastructure construction costs) do not result in a significant variation of the required tariff. Indonesian projects in particular may see a significant variation in capital cost due to developments in steep, heavily jungled terrain, although their higher capital cost may be offset in countries like Ethiopia, with easier terrain but significantly higher land compensation costs.

Power plant cost increases, represented here by increases in basic unit cost rather cost variations due to different plant configurations, have a greater impact, simply because they represent a greater proportion of the overall capital cost of the project (typically around 40% to 45% of the total capex). For similar reasons, the impact of variations in steamfield costs (typically more like 10% of project capex) is smaller.

3.5 Opex Variations

The impact of variations in operating cost are generally quite small (up to 102% of required tariff). This may surprise operators, and certainly the developer's accountants who often see this as an area to focus on when preparing a project, probably because they think that they understand them. However, the fact of the matter is that these are costs which are incurred relatively late in the project, i.e. after the period of major capital expenditure and the impact on overall project cash flow, when considered in terms in terms of net present value, is actually very small.

The small impact of these costs is actually a reflection of one of the advantages of geothermal power production for inclusion in the grid. The cost of power from geothermal generation is actually very stable, with very high availability and minimal requirements for escalation over time. The initial tariff may be relatively high, but it will rapidly decline in real terms compared with projects that carry a high loading for a market sourced fuel supply.

3.6 Timing Variations

The impact of time lags during the development of a project is found to be quite significant (105% for increased delays, 96% for accelerated action during the negotiation and commercial discussion period before financial close). This is a very difficult period to predict as it depends on both market appetite for investment in this type of project and also the technical experience of both lenders and developers in assessing the viability and economic risks of the project.

Experience shows that it is vital to select a lead bank that has plenty of experience in such projects, as they will have to act to bring in other investors and provide leadership to the lender team. Small lenders with no experience are prone to require unreasonable assurances before releasing funding, including requiring the developer to have demonstrated in excess of 100% start-up steam requirement at the wellhead, compared with the normal range of 60% to 75% capacity. In turn this will require more drilling, often initiated at a late stage in the appraisal program when it would be unreasonable to mobilize a second rig.

3.7 Finance Variations

The cost of equity is a significant parameter in determining an economic tariff for a project. An increase in equity demand from the developers from the 16.5% base in the model by 10% to 18.15% (just 165 basis points) results in a required tariff increase to 108%. However, the 16.5% assumed rate was very much a judgement made at the time of the model development, based on quite different approaches by several private sector developers. A further review of current economic conditions is required to assess whether this is actually still appropriate. The current push towards green energy projects and concerns about global warming may in fact allow this rate to be reduced.

The impact of debt interest is rather less than equity IRR, mainly because the cost is lower to begin with and also because the return is required for only a limited period. Again, a review of current economic conditions is required to confirm the validity of the original assumption.

If the current economic environment were to permit an overall reduction in the cost of both equity and debt finance, then the impact on geothermal development could be most significant, with the required tariff being reduced to just 91% of the base case.

Finally, debt tenure is also a significant factor in determining the economic tariff. The base case model was using 12 years tenure as being representative of requirements from a number of smaller lending institutions. However, although organizations like the IFC are required to avoid reducing interest rates below those of the commercial lenders, they are able to extend loan tenures considerably with the sorts of impacts seen in this analysis (tariff reduced to 98% for a 15 year tenure and 95% for a 20 year tenure). This tenure extension may also be encouraged by current concerns about global warming and lenders responding to international pressures to support green energy projects. In fact, tenure extension may be much easier to arrange than interest rate reductions.

4. CONCLUSION

There are a very large number of parameters of which variation will impact on the required economic tariff of a geothermal development project. Some of those parameters are clearly within the direct control of the developer, whilst others will be impacted by resource, market and economic conditions outside of the developer's control.

However, this study does help to show the importance of considering these variables when establishing geothermal tariffs and the feasibility of specific projects. In particular, it should demonstrate to governments how important it is that, if they want to achieve lower power prices for their residents, they need to establish tariff regimes that are able to accommodate project differences in order to obtain the lowest tariffs. In general terms, simple comparisons to existing thermal regime tariffs will not permit this flexibility.

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