Proceedings World Geothermal Congress 2020+1
Reykjavik, Iceland, April - October 2021

Attractiveness of Kenya's Geothermal Electricity Generation Investments; A Risk Perspective

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Keywords: Risk, coefficient of variance, internal rate of return, debt service coverage ratio, hurdle rate

ABSTRACT

The study sought from a risk perspective to answer the question as to how financially attractive Kenya's geothermal electricity generation investments would be given the private sector risk appetite, prevailing electricity tariff, representative geothermal resource characteristic, typical industrial costs and financing opportunities within the financial market. Alternatively stated is whether Kenya will raise private sector capital for its geothermal sector that lies underutilized despite a sizeable potential.

Monte Carlos simulation was used in the study. Expected (mean) internal rate of return based on free cash flow to equity was computed for different combination of inputs. Inputs included a range of values of development costs such as infrastructure costs, drilling costs and drilling success rate, steam gathering system, consultancy fees and cost of power plant, typical field characteristics including average well yield and field production decline, project design factors such as plant size and project development period, commercial issues such as power purchase agreement period, bulk power tariff and prevailing tax rate, operation and maintenance issues including load factor, parasitic load, and financing variables including interest on debt, and financial leverage. The probability of success of exploration was also incorporated in the simulation. For each of the variables an appropriate probabilistic function was assigned to each of the variables. Two measurements were used to measure risk. Type I measurement measured the coefficient of variance of computed internal rate of return and Type II measurement measured risk by probability that the computed internal rate will exceed a hurdle rate required by investors. Literature showed that the investors set the hurdle rate at internal rate of return not less than about 10% but could span as high as 30%. In recognizing the role of debt in the success of the investment, debt service coverage ratio (DSCR) and payback period were computed as measures indicating lenders willingness to finance the projects. Literature further showed that lenders would require a DSCR whose minimum would range between 1.4 and 1.7. The foregoing analysis was undertaken assuming private sector entry at exploration, appraisal, and production drilling phases or at power plant construction phase.

The study outcomes for the mean internal rate of return were -36%, 7.7%, 10% and 8.7%, ranging from -55.6% to 10.5%, and from 0.05% to 15.2% and from 6% to 14.6% and from -3.6% to 18.7% assuming private sector entry at exploration, appraisal, production drilling and power plant construction phases respectively. In addition dispersion of the internal rate of return about the mean as measured by coefficient of variance was 0.64, 0.26, 0.13 and 0.33, for the probability that the various outcomes would at least be or exceed 10% were 0.08%, 11.92%, 47.87 and 31.6% and average DSCR 1.23, 1.51, 1.69 and 1.47 assuming private sector entry at exploration, appraisal, production drilling and power plant construction phases respectively. From the result, Type I risk measurement indicate that the investment have very high risk at exploration and generally but significantly reduce as the project progress. This would imply investors would be attracted to the projects after exploration. On the other hand, the results showed that the probability that the simulated outcomes for all entry cases fell below a threshold of about 80% probability of success that would interest investors. This imply that investors would not take up every project but would be very cautious and selective on the project they take. Further, lenders would most likely avoid funding exploration phase of development but may consider financing subsequent phases. From the study, the exploration phase should be a preserve for a public entity as the risk is too high and the super profit to entice the private sector to this phase are non-existence. On the other hand, appraisal phase has a high chance of trailing thresholds set by private investors. Investors at production drilling phase will require to select projects and cut costs especially drilling cost to make the projects pass the investment hurdle. Power plant phase will attract investors who are not excessively risk averse. The general conclusion is that risk reduction using Type I measurement does not in every case result to investment grade projects and the country might be forced to address offered tariff otherwise the public sector will continue to dominate the geothermal sector.

1. INTRODUCTION

Competitively priced electricity has been identified as one of the key enablers to propel Kenya into a newly industrializing middle–income country providing a high quality of life to its citizens by 2030. The country seeks to develop between 2000 and 5000 MW additional capacity from geothermal sources. Without the private sector participation in the development thus partly raising the requisite capital requirements, the Government recognizes that by itself it impossible to achieve this objective at the desired pace due to the substantial financial capital requirement estimated at between US$ 13 billion and US$ 31 billion.

This paper seeks to answer the question that given the desired tariff which is low and is desired to be lower for national economic competitiveness, various applicable Kenya policies, Kenyan typical geothermal resource characteristics, commercial terms that independent power producers would access debt capital for geothermal projects in Kenya, and given the risk/ reward appetite for the private sector, how attractive is the prospect of investing in the geothermal sector in Kenya and at what stage of development within the cycle of geothermal project development would the independent power producers profitably be willing to take up projects. The secondary question in respect of the above is whether Kenya will raise private sector capital for its geothermal sector that lies underutilized despite a sizeable potential.

2. MEASURE OF PROFITABILITY

Kenya will raise the desired infrastructure capital to expand geothermal development from the private sector only if the offered investment are attractive to prospective investors. Maximization of shareholders' wealth largely outlines the financial goal of a firm. In committing funds to any investment, as a minimum, the investors hope that the investment will be profitable such that it will pay back capital deployed both equity and debt and generate returns that compensate them for the risk taken and where possible generate surplus funds which increase the wealth of the shareholders (Pandey, 2009). Profitability is the ultimate defining factor in deciding attractiveness of an investment.

The expected benefits are measured in net cash received against criteria that sets the minimum acceptable benefits .The opportunity cost of capital is set as the cut-off, or hurdle or the required rate of return expected by investors on investment of equivalent risk. A number of investment criteria are in use in practice including net present value (NPV), internal rate of return, (IRR), profitability index (PI), payback period (PB), discounted payback period and accounting rate return (ARR). The NPV is ranked superior as it consistent with the objectives of the investor. A positive NPV means that the investment has met the minimum threshold and is therefore acceptable. IRR is like NPV and are related to NPV. It is a popular criterion because it measures profitability as a percentage and can be easily compare with the opportunity cost of capital. IRR greater than opportunity cost of capital indicates that the investment is acceptable. By comparing IRR of an investment with its opportunity cost of capital, we in fact are ascertaining whether the NPV of the investment is positive. In the case where IRR is greater, the NPV is positive and adds to the investors' wealth (Pandey, 2009). If IRR equals the opportunity cost, the investment leaves the wealth of the investor at the same level.

3. FACTORS AFFECTING PROFITABILITY

3.1 Risk

Investors consider geothermal projects to be risky (Bank, 2012). Risk has been defined in various ways. In investment, risk may be defined as the variability of expected return where return could be a sequence of cash flow, net present value (NPV) or internal rate of return (IRR) of an investment project. Risk exists because of the inability of the decision makers to make perfect forecast. Forecast cannot be made with perfection or certainty, since the future events on which they depend are uncertain.

Standard deviation and the coefficient of variation are most common measure of risk. A single factor forecast (i.e. the expected value) is viewed as having limitation to the extent that the probability of it occurring is not known (Pandey, 2009). Consequently rather than use a single factor to make decisions, an array of all possible outcomes with their associated probability of occurrences are used. Following this argument, risk may be defined as probability or likelihood of occurrence of losses relative to the expected return. In common language risk means a low probability of an expected outcome (Dwivedi, 2010). Risk is said to have been quantified if all the possible outcomes are determined and the probability of occurrence of each value (Palisade, 2005).

The rational investors are generally risk averse and will avoid risky investments. For investors to allocate financial resources to the geothermal sector, they need to be convinced that the expected returns are sufficient to compensate for the associated risk that is the risk premium offered by the sector is adequate to make the investors indifferent to sector risks.

Investors may take up projects at different stage of development; undeveloped/greenfield, appraisal/delineation, production drilling or power plant construction. Bank (2012) qualitatively exhibit (Figure 1) the probability of a successful project at each successful stage of development.

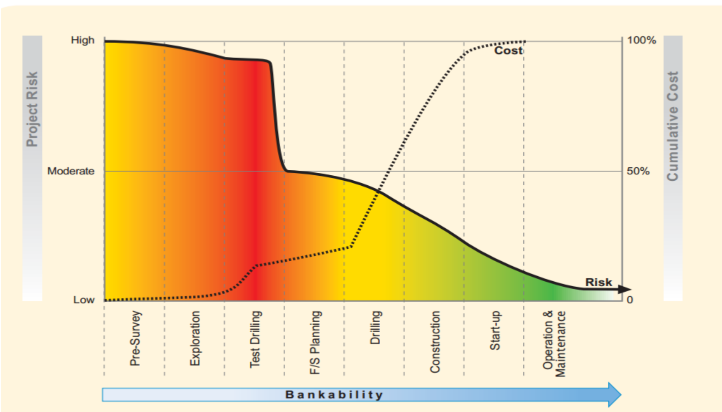

Figure 1: Project risk at different phases of development ((Bank, 2012)

According to them relatively high risk exists at exploration stage which reduce to moderate after drilling of a few test wells and is relatively low at commissioning of the plant. Bernett, Randle, & Fikre-Mariam (2003) evaluating the probability of achieving a viable geothermal projects at different stages of geothermal value chain finds that there is only about 20% probability for viable project at detailed surface study (including geophysics), 40% probability after test drilling and 80% probability after delineation drilling.

Bank (2012) indicates that the required return could be as high as 20 to 30% while Hance (2005) indicates that investors would require 17% but more for the exploration phases. Quinlivan, et al. (2015) indicates that for undeveloped prospects investors would require 22 to 30% and 18 to 22% at appraisal stage. They have further indicated that the opportunity cost of capital to be typically 10%. Merz (2007) state that equity return aster tax would be about 8% to 20%. Salmon, Meurice, Wobus, Stern, & Duaime (2011) show that investors require a minimum of 10% but prefer 13% or more.

3.2 Resource Factors

The amount of fluid flowing from a well at a certain temperature and pressure signify the amount of energy extractable from a well for electricity generation. The extractable energy is measured in units of energy usually megawatts (MW). The higher the MW yield of a well the lower the unit cost of making that energy available through drilling and the higher the profitability. IFC (2013), studying 2613 wells in 57 field and 14 countries, have reported the well yields ranges between 1 to 53 MW. In addition they have established that 3 MW is the most common yield and a histogram peaks between 3 and 6 MW but the average well yield is 7.3 MW. Hance (2005) providing data from the USA, indicate that the average well output ranges between 3 and 5 MW. GeothermEx (2010) reviewing 215 Indonesian wells observe that yield for commercial wells range between 3 and 50 MW while the mode being 9 MW. They have further indicated that the mode for Japanese wells is between 4 and 5 MW. SKM (2007) indicate the yield for New Zealand wells to be between 0 and 30 MW with the average productivity being between 4 and 5 MW. In Kenya, shallowly drilled fields have shown average yields between 2.5 and 3.5 MW while fields drilled deeper have indicated yield averaging between 6 and 8 MW.

Non condensable gases (NCG) of magmatic origin in particular carbon dioxide and hydrogen sulfide are entrained in the fluids extracted from a geothermal reservoir. Direct condensing steam turbine probably the most thermally efficient plants are affected by the amount of NCG in the steam. Addition steam is used to evacuate the gases from the condenser using steam ejectors or alternatively pumps are used to create vacuum in the condenser. This therefore require additional capital to provide steam for the ejectors or alternatively use the generated electricity (parasitic load) to power pumps thus reducing available power for sale thus impacting revenues to the investment.

Dissolved solids are part of the extracted fluids. Ground water under pressure and temperature dissolves rock materials which are extracted from the wells. As pressure falls within the surrounding well formation, within the wellbore and on surface steam processing infrastructure, the dissolved solids may be released from solution forming solid substances. The solid substance inhibit flow of fluid from the well affecting electricity generation. Besides affecting sales where they negatively impact generation, the deposits increase operational cost in mitigating their presence. Mitigating measures could include acidization, drilling makeup wells, mechanical removal (work-over) or use of anti-scalants all of which increase capital and operation and maintenance costs without increasing sales.

Geothermal power production is highly dependent on the underground water to transport the energy contained within the reservoir rock to surface. Overtime and in particular if the extracted water is not replenished naturally or by re-injection, the wells yields decline in both pressure and flow thus affecting level of generation. SKM (2007) have indicated that for a 50 MW plant, a decline of about 3% is expected subject to plant size relative to resource capacity while Hance (2005) has provide a decline of 5%. Quinlivan, et al. (2015) has used figures between 2 and 6%. In Kenya, rate of decline of up to 4% has been recorded although not on a year to year basis.

3.2 Plant Size

Economies of scale has been established for geothermal power plants where larger plants have a lower unit capital cost as well as lower operation and maintenance cost. Fixed cost such as geotechnical works, roads, water supply, electricity supply during development have higher negative impact on profitability for a smaller plant than for a larger one. Kenya has commissioned about 280 MW plant within the same field and 100 MW for a green filed. Bank (2012) indicates that the geothermal is best developed in sizes of 30 to 60 MW and alludes that this is the best international practice. GEA has indicated that investors develop plants between 10 and 50 MW. SKM (2007) has indicated that private sector may not be interested with projects less than 50 MW. Oversizing the plant relative to the reservoir sustainable capacity is a major consideration in limiting the size of the plant. SKM (2007) have pointed out that large Green field projects are not likely to attract financing until the experience with particular resource was gained and the risk associated with large development were able to be well quantified.

3.4 Development Costs

Development costs range from geotechnical work associated with prospecting for the geothermal resource, infrastructure costs including access roads, drilling water supply, project offices, access to land lease or outright purchase, drilling services cost, well logging and measurements, feasibility study, steam gathering and power plant construction. These cost will vary from project to project and from one geographical location to another.

3.5 Financing Factors

Geothermal investments may be financed with equity or equity and debt. Figure 2 shows a whole array of sources from where investors can obtain funds from.

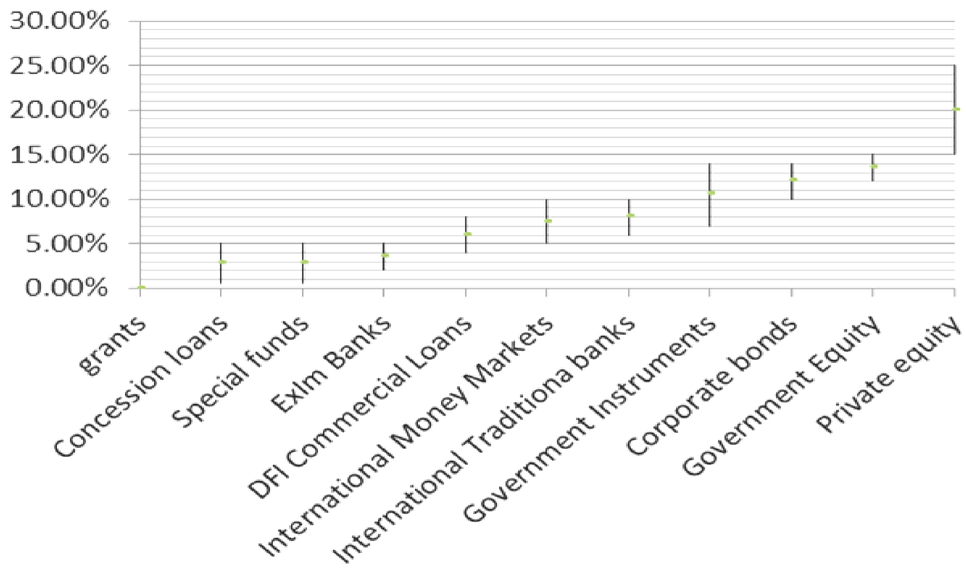

Figure 2: indicative interest rate for various sources of funds

Different sources will provide funds at different terms. The key terms include interest for debt or return on equity, loan period, grace period, financial ratio that must be assured in particular debt coverage services ratio (DCSR). Proof of a certain at least 25% of steam requirement may also be made a condition of lending. Further probability of success as high as 80% might also be required before lending can be firmed up. All this affect profitability.

3.6 Operation and Maintenance Factors

Geothermal plants have a high load factor especially because they are used as base loads. In Kenya it is typical to sign a PPA with a load factor of 95%. However, the factor may vary between 86% and 95%. Quinlivan, et al. (2015) has used 88% to 92%. Deloitte (2008) has indicated load factor range of 86-95%.

GEA has indicated that the operational cost would be about US$ 7 / MWh, power plant maintenance cost of about US$ 9 /MWh and steam field maintenance and make-up wells drilling cost of about US$ 8/ MWh. ESMAP has indicated that the steam field maintenance cost ranges between US$1 and 4 million for a 50 MW plant

3.7 Commercial Factors

Kenya feed in tariff (FiT) policy provides a geothermal tariff at US 8.8 MWh for a plant not exceed 70 MW. Tariff for plants exceeding 70 MW are to be negotiated and are expected to be lower than the FiT rate. The duration of the FiT power purchase agreed as stated in the policy is 20 years. The geothermal act, under a permit, provides that an investor could have up to 5 years to prove commercial viability of a project. Subsequently and investor may be issued with a geothermal license for a period of 30 years that may be extended for a period of five years. Conventional geothermal power plants economic life is estimated at 25 to 30 years (Hance, 2005). Bank (2012) has indicated that the typical range of tariff is between US$ 4 to 10 MWh for a 50 MW plant.

3.8 Taxes and Incentives

Kenya provides tax exemption for generation equipment. In addition, the country provides an accelerated depreciation. For capital projects invested in the capital city of above US$ 2, the investors are allows 100% capital deduction allowance within the first year and are allowed to carry losses for a maximum of nine years. Similarly, for projects outside of the capital city, the investors are allowed a 150% capital deduction allowance within the first year and again carry losses for a maximum of nine years. Although generation equipment is tax exempt, hired drilling services is not. Rigs mobilized from across the border are required to pay a 20% withholding tax on drilling cost in addition to a 16% value added tax. Tax exemption and capital deduction allowances improve project profitability but tax on hired drilling services increase the well cost. Income tax rate for corporation registered in Kenya is set at 30%.

Risk mitigation in the form of a grant has been available in Kenya but provided by international organizations. In addition, green funds have been also accessible in the form of carbon credits as well as concession loans.

4. ANALYTICAL METHOD

4.1 Monte Carlos Simulations

This study sought to estimate the overall investment risk. Risk is quantified if all possible outcomes arising from an event or events and their relative likelihood of occurrence are determined (Palisade, 2005). The study used the numerical (Monte Carlo) simulation. Monte Carlos simulation is an analytical technique that performs a large number of iterations using samples randomly generated to model the probability of occurrence of different outcomes that cannot easily be determined. The technic considers the interaction among variables and probabilities of the changes in variables (Pandey, 2009) that produces alternative outcomes (Dwivedi, 2010). It is a suitable method because a large number of unpredictable factors have to be taken into consideration in evaluating a geothermal investments and their interaction results into a range of returns. Consequently, there is risk in judging how the real life situation will react to various situations (Keating & Wilson, 2003).

The simulation analysis is a four step process including (Pandey, 2009, Dwivedi, 2010):

i. Identification of the independent variables
ii. To establish the probability function of each of the independent variable
iii. Build a mathematical model that relates the variables
iv. Use an appropriate computer program to generate a large number scenarios and simulate the dependent variables

4.2 Mathematical Model

The free cash flow to equity mathematical model was used but revised to reflect the prevailing tax regime in Kenya. The FCFE is computed as follows:

$$FCFE = Rev - Exp - Dep - Int - Tax + Dep - Capex - \Delta WC + Net\ borrowing$$

While Tax is computed as

$$Tax = Rev - Exp - Int - ICDA - Loss$$

Where Rev, Exp, Int, Dep, Tax, Capex, ΔWC, ICDA and Loss are revenue, expenses, interest on debt, annual taxes, capital expenditure, change in working capital, investment capital deduction allowance and losses carried forward from the previous year

4.2 Assumption

The assumption made are:

- All option are being evaluated at the same point in time
- Technology employed is single flush conventional steam turbine
- Private sector don't have to repay infrastructure cost where it is put in place by public entity
- Though feed in tariff allows price escalation, operation costs also will escalate probably cancelling out the benefit of escalation
- Inflation is also excluded. Often times power purchase agreements have a correction factor to ensure investors value is maintained
- Exchange rate factor is excluded. Bulk power tariff is dollar based
- Grace period marched to development period
- Transmission line cost excluded.

4.3 Simulation Scenarios and Runs

Several runs were undertaken assuming an entry point for the investor as follows:

i. A1 Green field development
ii. A2 Green field development with tax excluded from drilling cost
iii. B1 Appraisal stage of development
iv. B2 Appraisal stage of development with tax excluded from drilling cost
v. C1 Production drilling stage of development
vi. C1(a) Production drilling stage of development with tax excluded from drilling cost
vii. C2 Production drilling stage of development – best case parameter case
viii. C2(a) Production drilling stage of development – best case with tax excluded from drilling cost
ix. D1 Power Plant construction

4.4 Input Data

Table 1 below shows the values of various variables used in the simulation and the probability density function utilized for each of the variables as they apply to each simulation runs.

Table 1: Simulation data input

Category	Input variable	Units	Best Estimate	Probability Distribution		
				Type	Min	Max
Success of Exploration						
A1 and A2	Exploration success	%		Rectangular	0%	25%
All other except A1, A2	Exploration success		100%	Fixed		

and D1						
Drilling and Resource Characteristics						
All others except C2, C2(a) and D1	Average well output	MW/ Well	5	Triangular	3	8
C2 and C2(a)	Average well output	MW/Well	7	Triangle	6	8
All others except C2, C2(a) and D1	Drilling Success rate	% of wells drilled	80	Triangular	60	90
C2 and C2(a)	Drilling Success rate	% of wells drilled	85	Triangular	75	90
All others C2, C2(a) and D1	Ratio of re-injection to production wells	%	30%	Triangle	20%	50%
C2 and C2(a)	Ratio of re-injection to production wells	%	20%	Fixed		
All others D1	Ratio of unsuccessful exploration and production wells used as reinjection wells	%	30%	triangular	0%	30%
All others D1	% excess steam at startup	%	10%	fixed		
	Steam decline	%	3%	triangular	0	6%
Project Design and investment decision						
All others except C2 and C2(a)	Plant size	MW	50	Triangular	20	70
C2 and C2(a)	Plant size	MW	70	Fixed		
All others except D1	Construction Period	Years	7	Triangular	5	10
D1	Construction Period	Years	3	Fixed		
Operation and maintenance						
All	Operation and Maintenance cost (plant)	US$ / KWh	0.012	Triangular	0.007	0.017
All except D1	Operation and Maintenance cost (steam field excluding makeup)	% of initial capital cost	2%	Triangular	1%	2%
All except C2 and C2(a)	Parasitic Load	% of generation	3.5%	Triangular	2%	7.5%
C2 and C2(a)	Parasitic Load	% of generation	3.5%	Fixed		
All	Load factor/ Average generation	% plant capacity	90%	Triangular	86%	95%
Commercial Issues						
All except C2 and C2(a)	Power purchase period	Years	25	Triangular	20	30
C2 and C2(a)	Power purchase period	Years	30	Fixed		
All	Bulk Tariff	US$	0.0885	Fixed		

All	Tax rate	% of profit	30%	fixed		
Investment Costs						
	Land acquisition	MUS$/ KM2				
	Project site development costs	MUS$/ Project		Triangular		
	Drilling and well testing cost	MUS$/ Well	6.5	Triangular	6	7
All except D1	Steam Gathering	MUS$/ MW	0.45	Triangular	0.35	0.6
All except C2 and C2 (a)	Power Plant Cost	MUS$	2.3	Triangular	1.45	2.8
C2 and C2 (a)	Power Plant Cost	MUS$	2.3	Fixed		
All	Consultancies, feasibility and insurance	%of total project cost	5%	triangular	5%	10
All	Contingency	%of total project cost	5%	Triangular	5%	10%
Financing						
All except C2 and C2(a)	Leverage / Debt equity ratio	% of investment	70%	Triangular	55%	75%
C2 and C2(a)	Leverage / Debt equity ratio	% of investment	75%	Triangular	70%	75%
All except C2 and C2(a)	Interest on debt	% of debt	6%	Triangular	3.5%	12%
C2 and C2(a)	Interest on debt	% of debt	4%	Triangular	3.5%	6%
All except C2 and C2(a)	Tenure of debt	years	15	Triangular	7	18
C2 and C2(a)	Tenure of debt	years	18	Triangular	15	20

5. RESULTS AND DISCUSSION

The government wish is for the private sector to increasing take up financing of future geothermal electricity power projects which is currently public dominated. However, the government also seeks to lower tariff as much as possible as it has a significant impact on the economic competitiveness of the country. The country seeks 2000 to 5000 MW additional generation capacity from the geothermal sector. To realize this objective, the government is offering green field concessions and brown field investment opportunities to the private sector. The government recognizes that upfront risk is a deterrent to private sector investment in the sector and through a public entity has invested to carry out early development that are known to be most risky and avail brown field opportunities. Simulation shows that of successful exploration project the capital cost will range between US$ 4.7 million to US$ 9.5 million per MWe. The average capital cost is estimated at US$ 6.23 million per MWe. Figure 3 shows the frequency distribution of the capital cost.

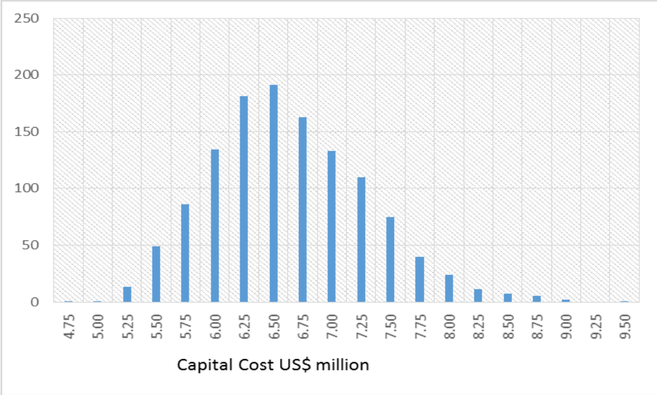

Figure 3: Capital cost (per MW installed) frequency distribution

Of the average cost analysis indicates that 12% will comprise cost of infrastructure (Figure 4), 12% cost of appraisal works 25% cost of production and 51% will comprise the cost of construction and installation of the power plant.

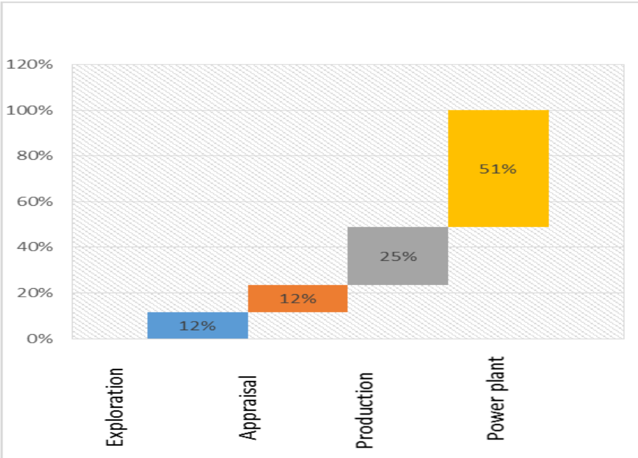

Figure 4: Ratio of capital cost (per MW installed) for each phase

The country is therefore seeking to raise about US$ 12.5 billion to US$ 31.2 billion to meet its projected geothermal power expansion.

The simulation result indicate that data dispersion (Type I risk measurement) generally reduce (Figure 5) if the investor enters at different stage of development. The investor faces the highest risk for a green field (exploration). At this point the investors enters only with a detailed surface exploration report, has to establish road infrastructure, water for drilling and drilling pads and drill exploration wells to prove that the resource exists, that its quality is suitable for further development and indicative well yields are encouraging. In addition, after successful exploration, the investors will undertake further drilling to establish the resource size (appraisal) followed by feasibility study to confirm that the resources is commercially viable. Thereafter the investors will undertake production drilling to avail sufficient steam and construct the power plant. The investor who enters after the discovery well has been drilled (at appraisal) faces significantly less risk. The investor finds roads in place and need not prove the existence of the resource. However, the investor will require to establish the resource area and commercial viability of the resource as well as provide adequate steam and build the power plant.

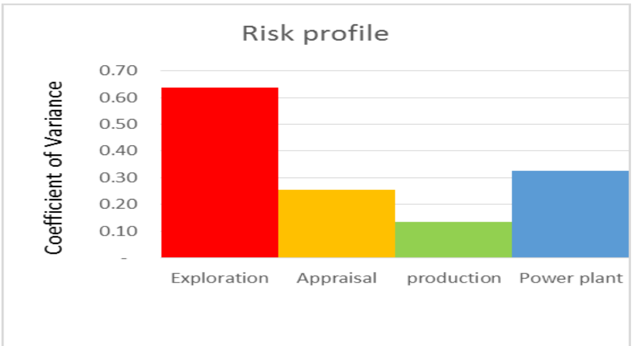

Figure 5: Coefficient of variance for expected internal rate of return at different phases of development

The investors who enter at the production drilling finds a commercially viable project because at this point feasibility of the projects is already established. Likewise the investor who only construct a power plant is further protected from the decline of the resource. Type I risk measurement arises from the formal definition of risk measured mainly by standard deviation and coefficient of variance from the mean or expected IRR. At exploration, geothermal resource characteristics are not known, whether the resource exist or not, the well reservoir fluid chemistry that impact operation and maintenance is not known and including the extent of its impact, the average yield of the wells are not known which by experience has a wide range, the size of the field is not known and resource decline is also unknown. The wide range of these unknown variable create uncertainty and hence the perceived risk. However, as successful development stages are undertaken, data that characterize the resource is obtained reducing and or eliminating the uncertainty and hence lowers the risk.

The simulation further shows (Table 2) the expected IRR at exploration, appraisal, production and power plant are (-ve) 36.16%, 7.69%, 9.98% and 8.66% respectively.

Table 2: Mean internal rate of return, coefficient of variance and probability that the data will exceed various hurdle rate at different phases of development

entry point	Mean IRR	std	Coefficient of deviation	Median	Px<0	Px>7%	Px>10%	Px>15%
Exploration	-36.16%	23.02%	0.64	-48.33%	76.48%	2.04%	0.08%	0.00%
Appraisal	7.69%	1.97%	0.26	7.69%	0.00%	64.31%	11.92%	0.02%
production	9.98%	1.33%	0.13	9.92%	0.00%	100.00%	47.87%	0.00%
Power plant	8.66%	2.83%	0.33	8.62%	0.08%	71.61%	31.59%	1.52%

Compared with what investors would be asking i.e. 10% to as high as 30%, the results shows that for all entry points, the investment opportunities would not meet the IRR that the investors would be asking (Type II risk measurement). For the 5000 data set, about 76% return a negative IRR at exploration with only about 2% exceeding 7% (risk free cost of capital for Kenya) or 98% would return IRR below 7%. This means that at exploration, there is a likelihood of about 76% that the investors will lose their invested capital (Px<0), and almost 100% that the investors will not be compensated for the risk taken. At appraisal, there is a 0% likelihood that the investors will lose their capital. In additional there is a 64% likelihood that they will at least exceed risk free rate of 7% indicating that the investors will be compensated for part of the risk they would take but there is only about 12% chance that the IRR will exceed 10%. At production the result shows that there is about 100% chance that the investors will be compensated part of their risk and about 48% that the IRR would exceed 10%. At power plant, there is a probability that about 72% will exceed the risk free rate and 32% that the IRR will exceed 10%.

The country could consider giving tax incentive in drilling services in additional to the generation equipment. If tax incentive was given for imported hired drilling services, drilling cost would decrease to about US$ 4.5 million from about 6.5 million. In this case, simulation indicates that the expected IRR would be (-ve) 25.64% (Table 3), 10.57%, 12.64% and 8.66% for entry at exploration, appraisal, production drilling and power generation respectively.

Table 2: Mean internal rate of return, coefficient of variance and probability that the data will exceed various hurdle rate at different phases of development considering drilling tax incentive

entry point	Mean IRR	std	Coefficient of deviation	Median	Px<0	Px>7%	Px>10%	Px>15%
Exploration	-25.64%	18.82%	0.73	-34.86%	73.65%	12.56%	1.76%	0.00%
Appraisal	10.57%	1.94%	0.18	10.57%	0.00%	96.64%	61.19%	1.42%
production	12.64%	1.34%	0.11	12.61%	0.00%	100.00%	98.24%	4.42%
Power plant	8.66%	2.83%	0.33	8.62%	0.08%	71.61%	31.59%	1.52%

Compared to the same cases under Table 2 there is a remarkable improvement on the expected return to investors. This imply that the model is sensitive to capital cost and that there is an inverse relationship between capital cost and IRR.

The projects may be financed by equity or both equity and debt. Simulation indicates that Type I risk measurement for entry at production drilling reduces from 0.133 (Table 2) to 0.076 if equity alone is used. This is attributed to the fact uncertainty relating to debt financing is eliminated and hence the risk is reduced. However, Type II risk measurement increases. The expected IRR reduces from 9.98% to 7.61%. This is interpreted to mean that use of equity only will reduce return to the investor but inclusion of debt improves the investors' return. This is a reasonable expectation because cost of debt is a deductible expense for tax purpose creating a tax shield. It therefore implies that debt is good for Kenyan geothermal projects as it increases return to the investors. Lenders under project finance arrangement will also share in the risk thus the investors is able to share out the risk. Lenders do however impose conditions for their participation. They would require the investor to contribute a significant portion of the required capital at least about 25 to 30%. They will further require that the investor prove existence of the resource and make available at least about 25 to 30% of the required steam. They will further ascertain that the project is potentially capable of generating adequate revenue to service debt repayment both principle and interest in addition to meeting operation and maintenance costs. Debt service coverage ratio (DSCR) is one of the financial ratio used to measure this capability. Lenders would require a DSCR of at least 1.4 and as much as 1.7. Simulation indicate that DSCR for exploration will average at 1.23 and range between 0.67 and 2.04 while that for appraisal will average at 1.51 and range between 0.89 and 2.47. For production, DSCR will average at 1.69 and range between 1.28 and 2.19 while that of the power plant will average at 1.47 and range between 0.76 and 2.45.

Lenders will also prefer projects with surplus cash flows. Payback is frequently used as a proxy for liquidity. Short payback period would indicate that the project is liquid while long payback period will indicate illiquidity. Simulation indicate that for exploration most of the outcomes will not payback (Figure 6).

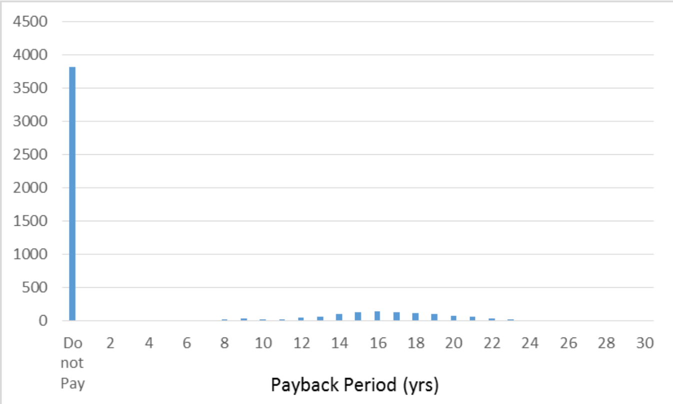

Figure 6: Payback period frequency distribution at exploration phase

For appraisal the payback period will average at about 10 years and range between 4 and 22 year (Figure 7). At production the payback will average at about 7 years and range between 4 and 16 years while generation will average at 11 year and range between 3 and 24 years. From the foregoing it will be relatively more difficult to raise debt for exploration than for the other stages of the development.

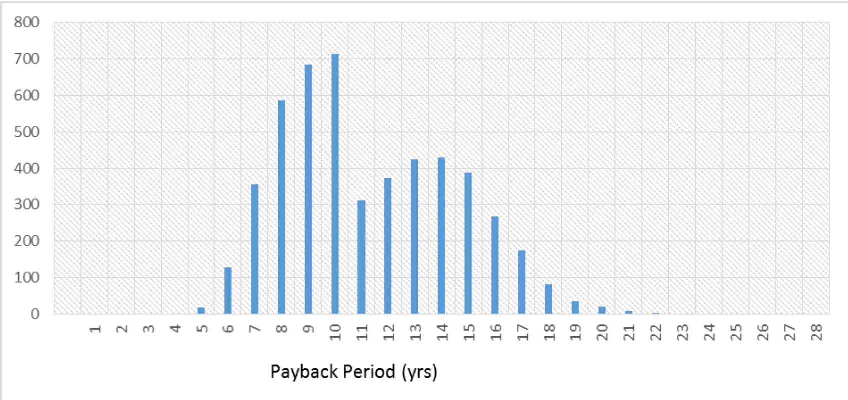

Figure 7: Payback period frequency distribution at appraisal phase

6. CONCLUSION

The private sector may enter a geothermal project at any point. However, there are four convenient points where they may enter a project; to prove the resource by drilling discovery well i.e. at exploration, after the resources is discovered, to drill delineation wells, sized the resource and established its commercial feasibility i.e. at appraisal, to provide adequate steam to run a specific size of a plant i.e. at production drilling or after all the steam is made available to construct and install the power plant to convert thermal energy to electrical energy i.e. at generation. The government would on an order of priority prefer that investors take up fields at exploration meaning zero cost to it, followed by at appraisal the least phase cost (12%) or at production drilling meaning medium capital expenditure (24%) by government or at the worst case at generation the government taking 49% of the capital cost.

Two types of risks are identified; Type I risk measurement that defines the dispersion of the various simulated outcomes about the expected return (mean) and Type II risk measurement which estimates the probability that these outcomes will meet the hurdle rate required by investors for them to decide to invest in the project. Type I risk measurement was measured by coefficient of variance while Type II was measured by ratio of simulated outcomes meeting or exceed the hurdle rate (probability). At exploration, Type I risk measurement was found to be comparatively very high. In addition about 100% chance exist that the expected return will be below 7%, the risk free rate for Kenya. This implies that the investors would not be compensated for the risk they take and will surely lose value of their investment. They would be better off investing in Treasury Bills or Kenyan Eurobonds. At appraisal, Type I risk measurement significantly reduces. However, Type II risk measurement shows that there is a 64% chance that the expected return will exceed the risk free rate and about 11% chance that the expected return will exceed the minimum hurdle rate of 10%. Probably this level of risk may continue to deter private sector from participating in the geothermal sector. At production drilling phase, Type I risk measurement is significantly low. Type II measurement risk indicate that there is about 100% chance that the expected return will exceed the risk free rate and 48% chance that the expected return will exceed 10% while at generation Type I risk measurement is relatively low and Type II risk measurement indicate that there is about 32% chance that the expected return will exceed 10%. From the foregoing, Kenyan investment are assess from a risk perspective to be of marginal return. Entry at production provides the best opportunity. Investor at exploration and to an extent appraisal face blind risk i.e. they need to invest to establish their level of risk while investors at production and generation face calculated risk i.e. there is adequate information to review without having to first invest. Simulation also shows that tax incentive on imported hired drilling services would reduce both Type I and Type II risk measurements and improve expected investors return making the investment more attractive.

Simulation showed that debt improves investor return and hence it is an essential component of financing of Kenyan investment. Ability to meet its financial obligations and have surplus cash as measured by debt service coverage ratio and payback period shows that it will be difficult or almost impossible to raise financing for the investors who enter at exploration phase. It will be relatively difficult to raise debt financing for the investor who enter at appraisal but will be rather easy for investors who take projects from production drilling and power plant construction and installation.

The overall assessment indicate that investors taking up green field projects will face very high risk without commensurate return for risk taken. Further, investors taking up projects at appraisal may find that the actual returns may fall way below the hurdle rate. Investors taking up projects at production drilling and at power plant construction will have to select between projects and be very frugal on capital employment. The general outcome is that although the risk is reduced as the project progresses, this is not synonymous to commercial viability and the country may have to consider to adjust tariff to make Kenyan investment more attractive else the public sector will continue to dominate development.

DISCLAIMER

This paper represents my personal opinion and does not exemplify the position of geothermal Development Company or Government of Kenya.

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