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FINANCIAL VIABILITY OF DEVELOPING 35 MW OF GEOTHERMAL POWER AT MENENGAI FIELD, KENYA

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ABSTRACT

Developing a geothermal project from the initial stage to the operation stage is difficult, complex, expensive and time consuming. Most investors and independent power producers in the geothermal sector prefer a viability assessment to be undertaken and a decision made based on the assessment's results which include investment advantages and the risks involved in the project.

Currently, the Geothermal Development Company (GDC) is developing a 105 MW (3 x 35 MW) geothermal project in the Menengai geothermal field in Kenia. The purpose of this study is to present a financial viability assessment for the development of a 35 MW single unit at the Menengai geothermal field by using an Excel based profitability model.

The calculated internal rate of return obtained from the model for the total cash flow and net cash flow are more than the total marginal attractive rate of return of 10% and the equity discounting rate of 15%, respectively. That fulfils the criteria that the internal rate of return should be greater than the marginal attractive rate of return. Based on the results of the model, the project is viable and worth investing.

1. INTRODUCTION

1.1 Background

Kenya is endowed with a vast geothermal resource potential. Most of these resources are located along the Kenyan Rift that transects the country from north to south. Studies reveal that the geothermal potential in the country exceeds 10,000 MWe. Detailed surface studies have been done in most of the country's prospects which comprises of Suswa, Longonot, Olkaria, Eburru, Menengai, Bogoria and Baringo-Silali prospects and their geothermal systems identified as summarised by Omenda (2012).

Currently, the country's installed generation capacity adds up to 2,295 MWe, the geothermal share is about 630 MW and is mainly produced from the Olkaria geothermal field which is operated by Kenya Electricity Generating Company (KenGen).

To fast track and accelerate the development of geothermal prospects in the country, the Government of Kenya formed the Geothermal Development Company (GDC). The company has the task to accelerate the development of geothermal energy in the country by prospecting, exploring, assessing, developing and marketing geothermal energy in Kenya and to support the government initiative to raise the requisite development funds.

Through GDC the Government of Kenya has assumed its responsibility to prepare bankable projects that will be eligible to receive financing from financial institutions and also to address the various issues to fulfil the criteria for financial approval.

In the long term, GDC is mandated to develop 5,000 MWe from geothermal resources in accordance to the country's development blueprint, Vision 2030. In the short term, the government has set up an acceleration program to generate over 5,000 MW of electricity from various energy sources in the country. Under this program, the Government of Kenya recognizes geothermal as the lowest cost source of power and has mandated GDC to develop a total of 810 MW from geothermal resources in the country.

1.2 Project objective

The main aim of this study is to analyse and present a financial viability assessment for the development of a 35 MW single flash geothermal power plant unit at the Menengai geothermal field using a Microsoft Excel-based profitability assessment model developed by Jensson (2016). The model is made up of different spreadsheets, each with different specific functions and all the spreadsheets are interconnected. The tasks in the spread sheets in the model include project cost breakdown, summary, investment, operations, cash flows and profitability sheets.

The financial viability assessment model will help determine the following:

- Project investment requirements;
- Working capital requirements;
- Net present value;
- Internal rate of return;
- Risk assessment of the project.

The profitability model will specifically assess whether the project will generate acceptable financial returns. Also, sensitivity impact analysis is done to determine the effects of change on energy sales price, sales quantity, cost of equipment and operation and maintenance cost of the project to the overall project profitability.

1.3 Existing energy policy framework in Kenya

1.3.1 Feed-in-tariff

In January 2010, the Kenyan government published its new feed-in-tariffs (FIT) to provide investment security to renewable electricity generators, reduce administrative and transaction costs, and encourage private investors. The 2010 feed-in-tariff was revised and became effective in 2012 indicating a tariff of 0.0088 USD/kWh for power plants with installed capacity ranging from 35-70 MW. Some of the revisions in the policy include standardization of Power Purchase Agreements (PPAs), connecting small scale renewables and change in feed-in-tariff levels. The policy document addressed the need for a long term PPAs between generators and off-takers (Ministry of Energy, 2012).

1.3.2 Energy act

Kenya's energy policy of 2004 encourages implementation of indigenous renewable energy sources to enhance the country's electricity supply capacity. The policy is implemented through the Energy Act of 2006, which provides for mitigation of climate change through energy efficiency and promotion of renewable energy (Government of Kenya, 2016).

1.3.3 Public Private Partnerships (PPP) Framework

The Government of Kenya recognizes that the required funds that are needed to fully support the country's development agenda and to meet the infrastructure deficit will require involvement of the private sector, hence Public Private Partnerships (PPP). PPP arrangements offer an opportunity for the country to attract enhanced private sector participation in financing, building and operating infrastructure services and facilities (National Council for Law Reporting, 2013).

1.3.4 Least Cost Power Development Plan (LCPDP)

Kenya's power industry generation and transmission system planning is undertaken on the basis of a 20 year rolling Least Cost Power Development Plan (LCPDP) which is updated every year. The plan reviews the load forecast based on changed pertinent parameters, commissioning dates for committed projects, costs of generating plants and transmission system requirements. It incorporates key lessons learnt and the need to incorporate population, urbanization and efficiency gains and technology in undertaking the demand forecast and capturing of potential new demand arising from the vision 2030 flagship projects and other investor projects (Energy Regulatory Commission, 2013).

1.3.5 Land policy

The national land policy was formulated to provide an overall framework and define the key measures required to address the critical issues of land administration, access to land, land use planning, restitution of historical injustices, environmental degradation, conflicts, unplanned proliferation of informal urban settlements, outdated legal framework, institutional framework and information management. It also addresses constitutional issues such as compulsory acquisition and development control as well as tenure (Ministry of Lands, 2009). It recognizes the need for security of tenure for all Kenyans (all socio-economic groups, women, pastoral communities, informal settlement residents and other marginalized groups).

1.3.6 Environmental policy

The goal of the environmental policy is to improve the quality of life for present and future generations through sustainable management and use of the environment and natural resources with the objective of providing a framework for an integrated approach to planning and sustainable management of Kenya's environment and natural resources (Ministry of Environment, Water and Natural Resources, 2013).

1.4 Project location

The Menengai geothermal field is a high temperature field and the third geothermal field to be developed in Kenya after Olkaria and Eburu geothermal fields. Menengai is a large caldera volcano inside a rift valley. The project is located in Nakuru County, about 10 km north of Nakuru town and 180 km from Nairobi, Kenya (Figure 1).

GDC is currently developing the first 105 MW power plant generating geothermal electric power from the Menengai field which is expected to be made of three units of each 35 MW. GDC has already

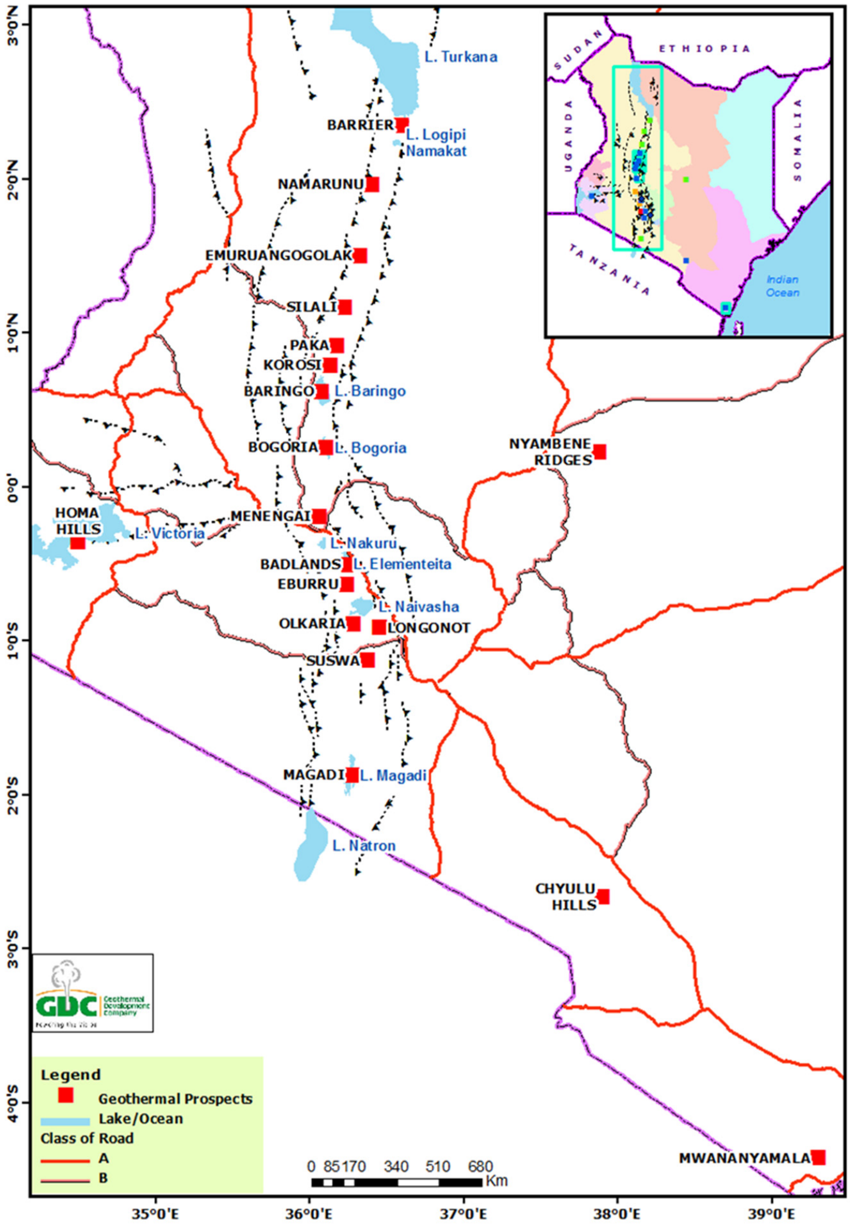

FIGURE 1: Location of Menengai geothermal field

procured three Independent Power Producers (IPPs) to develop and operate 35 MW modular power plants for a period of 25 years each.

The development of the 105 MW power plant project is guided by Kenya's current institutional and legal framework within the sector. The guidelines include the Vision 2030, Feed in Tariff (FiT), Least Cost Power Development Plan (LCPDP), Kenyan laws and the Public Private Partnerships Framework among other laws.

For the realization and acceleration of geothermal development in Kenya, the Government of Kenya is in the process of developing geothermal prospectors which will act as a guide in determining the development and implementation models for the various undeveloped geothermal fields in the country.

1.5 Project scope and timelines

1.5.1 Project scope

The scope of my study will involve estimating the cost components of each project phase, analyse the investment required and determine financial viability of the project using the profitability model.

Mwangi (2005) describes that a geothermal project consists of successive development phases that aim at locating the resource, confirming the capacity of the reservoir, drilling of wells, construction of the steam gathering system, and building of the power plant and its associated structures.

The 35 MW Menengai project is developed in five main development phases and each phase´ activities are described in Table 1.

TABLE 1: Project detailed description

Project phase	Detailed description
Reconnaissance	Involves collecting information from previous geological, geochemical or geophysical studies made in an area and which relate to mapping of volcanic activities, hot springs, steam jets, groundwater boreholes and even known traditional utilization of geothermal resources.
Detailed surface exploration	The main purpose of undertaking detailed surface exploration program is to cost-effectively minimize risks related to resource temperature, depth, productivity, and sustainability prior to appraisal drilling. Successful drilling of exploration and appraisal wells would culminate to bankable feasibility study report which is a key document required when seeking project financing.
Infrastructural development	It involves construction of main access roads, establishment of waterline system (pipeline and pump stations), well pads and drilling fluid recirculation pond.
Steam field development	In this stage, three to four exploration wells are drilled to prove the presence of steam. The drilling of the exploration wells is followed by the drilling of appraisal wells after which a feasibility study is carried out. Positive outcomes of the feasibility studies lead to drilling sufficient production wells for the project.
Power plant construction and its auxiliaries	This stage involves design, tendering, manufacturing and installation of the power plant. The steam from the wells will be connected to a 35 MW single flash power plant through a steam gathering system. The power from the 35 MW project will be evacuated through a 132 kV transmission line to the nearest national grid.

2. LITERATURE REVIEW

A viable project is a project that is able to generate income and is in a position to meet its operating and investment costs over its operation lifetime and generate an acceptable rate of return. Most of the investors/Independent Power Produces (IPPs) in the geothermal business prefer project assessment to be done to determine its financial viability and to estimate if the investment advantages outweigh the risks involved in the project before making an investment decision.

Determining project profitability assessment is important for investors, government institution and financiers in the geothermal business in order to make critical project decisions on either to accept or reject a project.

Some previous studies have been done to determine the financial viability of developing geothermal power projects.

Bloomquist (2004) presented a study on economic factors impacting direct use geothermal development viability and indicated that economic factors that ultimately determine the viability of a geothermal project are extremely complex and highly variable. The study proposed that each and every project should be evaluated at every stage based on the results obtained as more and more information becomes available.

Kiptanui (2015) presented a study on financial assessment of commercial extraction of sulphur and carbon dioxide from geothermal gases in Menengai geothermal field in Kenya. The study focussed on the commercial extraction of elemental sulphur and carbon dioxide (CO_2) from non-condensable gases (NCG) and applied an excel based profitability assessment model to determine the profitability of the project by using gas chemistry data from 11 production wells in Menengai with the main objective of generating an additional stream of revenue to the Geothermal Development Company (GDC) and also eliminate the environmental effects of hydrogen sulphide (H_2S) and CO_2.

Geirdal (2013) developed a method which is using wellhead technology to generate early revenues during the construction phase of geothermal projects. The study presented the importance of wellhead power plants being utilized at early stages of the development and showed how this can increase the Net Present Value (NPV) of the project and make the project viable and attractive.

Hance (2005) presented a study on factors affecting costs of geothermal development. The study explains how the capital costs of a geothermal project are very site and resource specific. The resource temperature, depth, chemistry and permeability are major factors affecting the cost of the power project. The study showed further how the resource temperature of a geothermal system will determine the power conversion technology (steam vs. binary) as well as the overall efficiency of the power system. Other factors which affect the capital costs include site accessibility and topography, local weather conditions, land type and ownership are additional parameters affecting the cost and time required to bring the power plant online.

3. PROJECT VIABILITY ASSESSMENT

The primary objective of investing in a project is to earn profit. In geothermal project development, profits are normally directly related to the set electricity price per kWh and the quantity of energy sales delivered in comparison with the cost of producing it.

Other factors that influence the cost of production include project financing structure, initial capital investment required and loan costs which are normally directly related to the money interest rate and the length of the repayment period.

Therefore, before investors engage in a geothermal project, a viability assessment is advisable. That means that the capital invested in a project must have a potential to generate an economic return to investors, at least in comparison to other similarly risky investments, i.e. the return on investment needs to be equal or higher.

The financial viability analysis is important because it helps to evaluate the economic viability of an investment and guides investors in making prudent investment decisions. The financial model used in this project is mainly based on the lectures notes of the profitability assessment and financing lectures at the UNU-GTP (Jensson, 2006). The model is used to evaluate financial conditions of project, operating performance of the investment and forecasting its future condition of the investment.

3.1 Methodology and data used

In order to assess project viability, project cost components were broken down according to project phases and factors influencing these costs were considered at each project phase. This study defines the various project phases according to the sequence of development including the various parameters that contribute to its costs. Most of the costs used in the analysis were obtained from existing literature, vendors, geothermal developers/experts, own estimates, and UNU-GTP training notes. The detailed description of the project phases is outlined below.

3.1.1 Exploration costs

Exploration is the initial development phase in any geothermal development. This phase seeks to locate a geothermal resource that can provide sufficient energy to run a geothermal power plant and produce electricity. In order to explore geothermal subsurface resources, several scientific studies have to be done and these include geological, geochemical, and geophysical studies. The scientific studies help to determine the subsurface thermal structure of the geothermal system and use the information obtained to estimate the temperature of the reservoir as well as the source of the fluid and to locate active up flow zones.

The cost of geothermal surface exploration varies considerably from one geothermal field to the other. These variances are attributed to the size of the geothermal area to be explored, geological settings of the field, accessibility of the area, and availability of previous studies.

3.1.2 Number of wells required

To determine the number of wells to generate 35 MW of net electricity, several assumptions were made to fill data gaps and to simplify the analysis. All the assumptions are based on conservative estimates. To do the analysis, a percentage success rate probability was assumed on exploration appraisal and production drilling. The simplified calculated analysis is based on the assumption that each well will yield 5 MW of average net electricity production and well success rate are assumed as shown in Table 2.

TABLE 2: Number of wells required for the project
Author's estimates and assumptions

Activity	Success rate	Well productivity (MW)	No of wells	Power output (MW)
Exploration wells	50%	5	3	8
Appraisal wells	75%	5	3	11
Production wells	80%	5	4	16
Subtotal (MW)				35
Excess steam	10%			3
Total power output				**38**
Reinjection wells			2	
Total number of wells			**12**	

As the table above shows, an estimated 10 wells are required for the 35 MW project and 2 additional wells are dedicated to reinjection purposes.

3.1.3 Drilling plan and strategy

The main aim of drilling is to determine geothermal resource availability, hydrothermal capacity and chemical characteristics of the resource. To access the resource, drilling must be done to a certain depth. The costs of drilling vary from one region to the other. This is attributed to some drilling parameters which include hard formation, loss of circulation during drilling, loose formation and changing lithology in the wells at various depths. According to Kipsang (2013), the cost of drilling geothermal wells is estimated to be about 40% of the total investment cost for a new high temperature geothermal field.

To mitigate delays and other challenges in drilling, the following assumptions, strategies, and plans were prepared to keep the drilling program on track during the scheduled drilling period:

Drilling days

- Drilling of one well is expected to take 80 days which is includes the moving of the rig.
- A Project Implementation Team (PIT) will be formed to closely supervise drilling operations and monitor the services rendered by drilling contractors to ensure that the drilling operations run smoothly and according to plan.
- There will be technical meetings (weekly, monthly, quarterly and as need arises) between GDC and the service contractor to address drilling challenges/issues.

Drilling costs

- The drilling cost considered per well for this project is GDC's average drilling expenses of 3.5 M USD (Million US Dollars). The assumption is that GDC will use its own rigs. The cost can be higher if hired rigs are used.

Supply of drilling materials

- GDC ensures sufficient provisions of drilling consumables i.e. drilling diesel and cement. The procured hardware goods will be stored in GDC stores, from where the material will be transported to the drill sites when required. This will ensure that the supply contractor has control on the supply to eliminate delays.

Drilling services contractors

- GDC will use its own rigs for the drilling operation of this project.
- In order to mitigate delays in the drilling operations, GDC will hire a contractor which will be responsible for providing the following services:
  - Directional drilling
  - Cementing
  - Fishing
  - Air drilling

3.1.4 Steam pipeline system

The location of the wells determines the length of the steam pipeline system to be constructed. Other parameters which dictate the length of the steam gathering system including site conditions such as environmental conditions, flowing pressure, topography, chemistry of the fluids and pipeline layout greatly affect the selection of a pipeline system.

The costs of the steam gathering system vary depending on the distance from the production and injection wells to the power plant. In the 35 MW Menengai project, most of the wells are located within a radius of approximately 0.5-1 km from the proposed power plant site. A reinjection pump is not required since the flow of brine will be facilitated by gravity.

3.1.5 Power plant

In order to determine the size of the power plant, the reservoir capacity of the field should first be evaluated. This is achieved by undertaking a field feasibility study to obtain information on the resource availability and to estimate if it can sustain the required power generation.

The U.S. Department of Energy (2008) Geothermal Market Report indicates that the cost of geothermal power production is very capital-intensive with high first-cost and risk, with fairly low operating and maintenance costs and a high capacity factor which makes the geothermal energy technology one of the most economical base load power generation options available. The report estimated developmental costs for a typical 50 MWe geothermal power plant at USD1700 per kW. In this study, power plant costs and other project costs were calculated based on the available literature, UNU-GTP training notes, own communication with turbines developers/experts and own estimations.

The power plant technology type considered for the project is a single flash type since Menengai is a high temperature geothermal field. The assumption in the analysis is that GDC will undertake the project development all the way from exploration to power plant construction.

3.1.6 Transmission availability and nearness to the grid

The power generated from the 35 MW Menengai project will be relayed to switchyard using a 132 kV single circuit transmission line network. The switchyard will be interconnected with a switchyard at a bay installed with the controls, protection and supervisory facilities – including communication systems. A substation will be put up for the purpose of boosting power before joining the national pylon grid. The substation will be mounted with equipment such as transformers, circuit breakers, isolators, and switchgears and a transmission line constructed to evacuate from the proposed power station through Rongai to connect to the Olkaria-Lessos transmission line which lies approximately 15 km from the proposed 35 MW Menengai power plant.

3.1.7 Project permitting costs

According to the Ministry of Environment, Water and Natural Resources (2013), geothermal projects have to comply with existing project legislative requirements related to environmental and construction issues. In Kenya, the National Environmental Management Authority (NEMA) was established as the principal institution of government charged with the implementation of all policies relating to the environment, and to exercise general supervision and coordination over all matters relating to the environment. In consultation with the lead agencies, NEMA is empowered to develop regulations, prescribe measures and standards and to issue guidelines for the management and conservation of natural resources and the environment.

The act provides for environmental protection through environmental impact assessment, environmental audit and monitoring, environmental restoration orders, conservation orders and easements. According to NEMA, the cost of an Environmental Impact Assessment (EIA) is prescribed at a fee of the total cost of the project and with no upper capping required for the processing of an EIA license. Apart from an EIA, other project permits include feasibility studies, generation license, and geothermal and land lease which are part of other permitting requirements in geothermal development.

3.2 Project cost breakdown

To estimate and determine the costs of the project, the project phases were further broken down into its related activities and the cost of each activity was computed as in Table 3.

In order to use the costs estimates above in the model, the cost breakdown is divided into three main project components which are buildings, equipment and others costs:

i. Buildings: Access roads, well pads and wells, water storage tanks and supply system, and resettlement;
ii. Equipment: Power plant, steam gathering system and transmission line and substation;
iii. Others: Detailed surface studies, environmental studies, feasibility study and other permits and licenses.

The calculations indicated the average cost of developing 35 MW to be **USD**3,865/Kw, this includes connection to the grid. The percentage cost breakdown of the project per phase is as shown in Figure 2.

TABLE 3: Project cost breakdown

	Activities	Units	Unit Price (USD)	Total Price (USD)	USD/kW	%
1	**Preparation Work:**					
	Access roads	20	40,000	800,000		
	Well pad site preparation	12	90,000	1,080,000		
	Water pipeline system (approx. 20 km)	20	60,000	1,200,000		
	Water pump station and storage tanks	1	380,000	940,000		
	Subtotal:			**4,020,000**		
	Engineering, supervision and commissioning	10%		402,000		
	Contracting and other fees	15%		663,300		
	General contingency	10%		508,530		
	Total Preparation Cost			**5,593,830**	**160**	**4%**
2	**Drilling**					
	Exploration wells	3	3,500,000	10,500,000		
	Appraisal wells	3	3,500,000	10,500,000		
	Production wells	4	3,500,000	14,000,000		
	Re-injection wells	2	3,500,000	7,000,000		
	Total Drilling Cost			**42,000,000**	**1,200**	**31%**
3	**Steam pipeline system:**					
	Piping (12*500 m)	6,000	1,000	6,000,000		
	Separator and vent stations (piping, vessels, earthworks and foundation)	1	3,500,000	3,500,000		
	Electrical and control equipment for well field	1	100,000	100,000		
	Reinjection System:					
	Piping system	1000	700	700,000		
	Reinjection pumping	0	800,000			
	Subtotal:			**10,300,000**		
	Engineering, supervision and commissioning	10%		1,030,000		
	Contracting and other fees	15%		1,699,500		
	General contingency	10%		1,302,950		
	Total pipeline cost			**14,332,450**	**409**	**11%**
4	**Power plant:**					
	Mechanical:					
	Turbine-generator, incl. lube oil unit, control etc.	1	16,000,000	16,000,000		
	Mechanical balance of plant	1	12,000,000	12,000,000		
	Compressed air system, cranes, platforms etc.	1	600,000	600,000		
	Electrical & Control					
	Main transformer and aux transformers	1	3,000,000	3,000,000		
	Local connection to the grid	15	250,000	3,750,000		
	Control & Instrumentation	1	1,800,000	1,800,000		

	Activities	Units	Unit Price (USD)	Total Price (USD)	USD/kW	%
	Electrical balance of plant	1	7,000,000	7,000,000		
	Civil works					
	Earthworks	1	1,500,000	1,500,000		
	Buildings and building services	1	5,000,000	5,000,000		
	Subtotal:			**50,650,000**		
	Engineering, supervision and commissioning	10%		5,065,000		
	Contracting and other fees	15%		8,357,250		
	General contingency	10%		6,407,225		
	Total Power Plant Costs			**70,479,475**	**2,014**	**52%**
5	**Other Permitting Cost**					
	Generation license	1	2,000	2,000		
	Feasibility study	1	1,000,000	1,000,000		
	Resettlements	20	25,000	500,000		
	Detailed surface studies	1	1,000,000	1,000,000		
	ESIA licenses for drilling and power plant	2	200,000	400,000		
	Total			**2,902,000**	**82**	**2%**
	TOTAL PROJECT COST			**135,307,755**	**3,865**	**100%**

In order to obtain total cost of project activities, some other additional costs were calculated in Table 3 and calculated as shown below:

- Engineering: 10% of the total cost
- Contracting fees: 15% of (total cost + engineering)
- Contingency: 10% of (total cost + engineering + contracting fees)

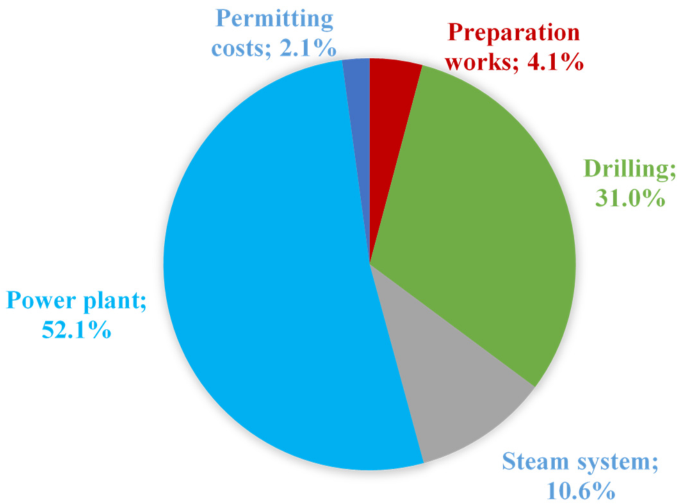

FIGURE 2: Project cost representation

3.3 Operation and maintenance (O&M) costs

Operation costs include all the expenses related to the operation of the power plant, steam gathering, and transmission line. Maintenance costs are related to labour costs and all expenses related to the maintenance of all the equipment i.e. steam gathering system pipes, pumps, turbines, vehicles, buildings, etc. Therefore, operation and maintenance costs of a geothermal power plant correspond to all expenses needed to keep the power system in good working condition. According to Paul Ngugi (2012), the rate of operation and maintenance is fairly low for geothermal, given the operation and maintenance costs are 0.00763 USD per kWh in other Kenyan power plants. Therefore, the cost of O&M considered for this project is calculated based on the country's Least Cost Development Plan.

3.4 Market factors, such as electricity sell price, raw material and drilling material costs

According to the Power Africa (2015) report, Kenya's economy has been growing at a rate of approximately 5.1% per year over the last 10 years with 2,295 MW of installed capacity (March 2015). The country's economic growth however has been constrained by an insufficient supply of electricity. In order increase the current power capacity in the country, the Kenyan electricity sector investment framework was set up. The framework offered an investment enabling environment to investors/IPPs by providing protections and fiscal incentives:

- The Feed-In-Tariff projects guarantees a FIT (USD/kWh) that eliminates pricing risk;
- A priority purchase obligation by Kenya Power and guaranteed access to the national grid;
- A 20 year FIT, providing an amortization period sufficient to raise long-term project financing;
- An obligation for Kenya Power to enter into a Power Purchase Agreement (PPA) with the project company to meet the criteria required by the FIT program.

3.5 Rationale for assessment

Before an investment decision is made in a project, it is prudent to determine whether or not the planned investment idea is feasible and viable. This is only achieved by carrying out a financial assessment to determine whether the project is worth investing. The analysis is a critical and important step in the project decision-making process.

The assessment considers all project costs development parameters in the entire phases of the project i.e. from initial surface exploration to power plant construction and commissioning stages. The assessment will also help to determine the project investment requirements and assess the project profitability.

3.6 Project assumptions

This study based some of the costs and results on actual costs obtained from surface exploration studies, exploration, appraisal and production drilling by GDC in the Menengai geothermal field. Other costs were based on the current market prices and literature as well as experts' opinions.

In order to use the profitability model to determine the financial viability of the project, economic, technical and financial inputs assumptions have to be determined and accepted as true so as to be used in the model while others assumptions vary from one country to another i.e. income tax rate. The project assumptions used for this project are as shown in Table 4.

3.7 Project financing

Geothermal project financing varies from one project to the other depending on the type of the investment, the risk level of the investment, and the credit rating of the project owner. Lenders would normally require an equity percentage to ensure the sponsor's or project owner´s continued commitment. In this case, the 35 MW projects financing arrangement will assume financing arrangement of 30% from equity and 70% debt.

TABLE 4: Other project assumptions

Project Parameter	**Unit**
The power plant type	Single flash
Net electricity output	35 MW
Capacity factor	95%
Construction time	8 years
Planning horizon (operations)	25 years
Loans	70%
Loan interest rate (no inflation)	6%
Income tax rate	30% of profit
Loan repayment	20 years
Operating & maintenance costs	2.3 MUSD
Electricity price	0.088 USD/kWh (FIT)
Sales quantity	291.3 (MWh/yr)
Depreciation buildings	4%
Depreciation equipment	15%
Depreciation other	10%
Loan management fee	0.8%
Discounting rate (MARR) total	10%
Discounting rate (MARR) equity	15%

3.8 Revenue estimation

To calculate estimate revenues from net power output, the power output results are converted to energy produced during one year using a capacity factor as follows:

$$\text{Revenue Per Year} = 365 * 24 * \text{NPO} * \text{C.F.} * \text{E.P.} \tag{1}$$

where 365 = Days in a year;
24 = Hours in a day;
NPO = Net Power Output;
C.F. = Capacity Factor; the capacity factor considered for this study is 95%;
E.L. = Electricity Price; the electricity price is considered 0.088 USD/kWh (as given by the FIT policy).

4. MAIN RESULTS OF THE PROFITABILITY MODEL

In this section, the main focus is to analyse the results obtained from the profitability model. Based on the results from the model, an indication of the financial conditions of the investments, capital investment requirements of the project, the net present value, internal rate of return, and forecast future performance of the investment is determined as described in the subsequent sections.

4.1 Marginal Attractive Rate of Return (MARR)

According to Salas (2012), the Marginal Attractive Rate of Return (MARR) is the discount rate that an investor or project owner most appreciates compared to other financial investment of an equivalent risk. It is the rate of return which provides the most preferred investment alternatives. Usually, MARR for equity is the same as investors cost of capital. According to Paul Ngugi (2012), the rate of return on equity (ROE) in Kenya is 15% and above. The Government requires a ROE of 15% while private investors would normally charge between 18% and 23% but sometimes this can be higher.

In this project, the minimum acceptable rate of return on the total and equity project is 10% and 15%, respectively.

4.2 Net cash flows

As shown from Figure 3, the cash flow in the first 8 years shows a negative trend, resulting from the outflow of cash during the construction of the project. At this stage most of the high costs are related to drilling operations, construction of the steam pipeline system and power plant construction.

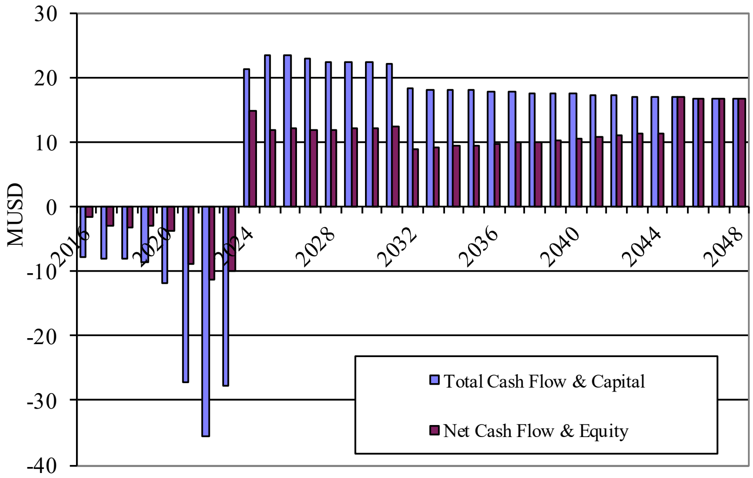

FIGURE 3: Cash flow

The cash flow becomes positive in 2024, this is when the power plant begins commercial production of electricity and cash flow is generated from electricity energy sales.

The difference between the total cash flow, capital, the net cash flow and equity in the first 8 years (project construction period) is the loan part of the capital requirement while the difference after 2024 (the positive part) is the loan repayment and the interest rate. Also, it can be observed that after 20 years the total cash flow and capital is equal to the net cash flow and equity. This is because the loan repayments and interests have been concluded.

4.3 Net Present Value

The Net Present Value is defined as the value of future cash flows minus the present value of the cost of investment. Investments require initial capital. The initial capital go into cash outflow payments for the project at the initial stage of development which is followed by cash inflows in form of revenue during the operation stage of development.

The Net Present Value is a tool used for the evaluation of an investment and represents the sum of all the years discounted cash flows. For a project to be attractive and to generate returns on an investment, the NPV should be positive. In order to determine the profitability of this project, the Net Present Value was calculated and compared with regard to the future cash flows resulting from the investment to other investment alternatives. Therefore, the NPV is calculated using the following formula (Salas, 2012):

$$NPV = \sum_{i=0}^{k} \left(\frac{C_i}{(1+r)^{\,i}} \right) \tag{2}$$

where
- r = The discounting rate;
- i = The time of the cash flows, i.e. the return that could be earned per unit of time on an investment with similar risk;
- C_i = The net cash flows, i.e. cash inflow – cash outflow, at time *i*;
- k = Tthe service life of the project.

- When the project Net Present Value is greater than zero, accept the project.
- When the project Net Present Value is less than zero, reject the project.

As can be seen in Figure 4, the accumulated NPV for the total capital with discounting rate of 10% is 7 M USD while the accumulated NPV for equity with discounting rate of 15% is 5 M USD. The accumulated NPV for the net cash flows turns positive after 11 years of operation while the accumulated NPV for the total cash flows turns positive after 17 years of operation. Given that the NPV turns positive, the project is therefore profitable and economically viable.

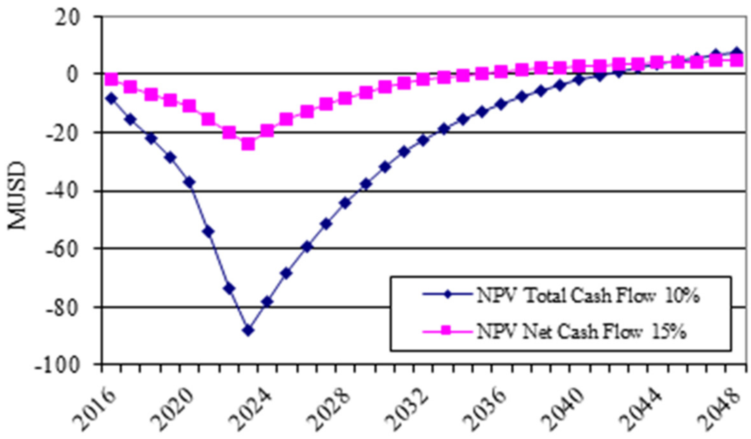

FIGURE 4: Accumulated net present value

4.4 Internal Rate of Return

To determine the profitability of an investment, the internal rate of return (IRR) is calculated to evaluate the profitability potential of an investment. Internal rate of return is a discount rate that makes the net present value (NPV) of all cash flows from a particular project equal to zero. It is a measure to determine the level of annual return (profitability) over the life span of an investment.

According to Salas (2012), the IRR is defined as the compound rate of return r that makes the NPV equals to zero and it is expressed as:

$$\sum_{i=0}^{k}\left(\frac{C_i}{(1+r)^{\,i}}\right)=0 \tag{3}$$

For a decision to be made either to go on with the project or not, the basic investment rule can thus be described as:

- When the project IRR is greater than MARR, accept the project.
- When the project IRR is less than MARR, reject the project.

As shown in Figure 5, the model indicates that the internal rate of return of total cash flow is 11% while the internal rate of return of net cash flow (equity) is 17% which is more than the total discounting rate (MARR) of 10% and equity discounting rate (MARR) of 15%, respectively. This analysis meets the criteria that for a project to be viable, IRR should be greater than (>) MARR as shown in Equation 3. Based on the analysis above, the project is financially viable and worth investing.

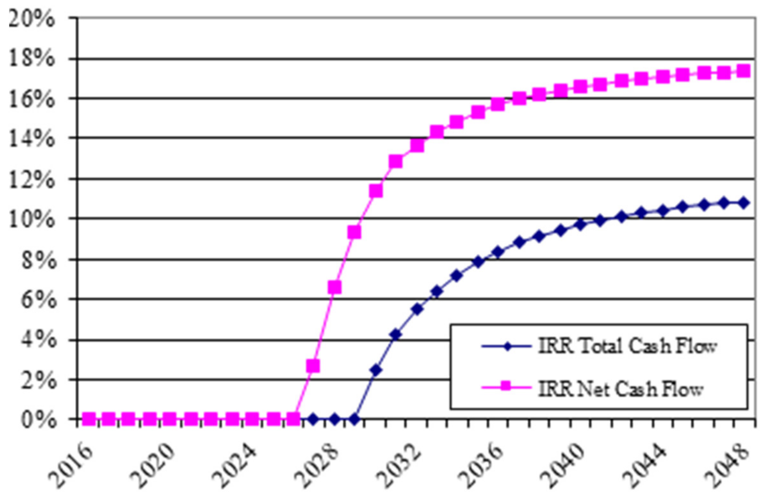

FIGURE 5: Internal rate of return

4.5 Debt service coverage ratio

The debt service coverage ratio refers to the amount of cash that is available to meet annual interest and principle payment on debt and is therefore used to calculate the debt service ratio. This is calculated by dividing the net operating income (NOI) by the annual debt as expressed in the formula below (Jensson, 2006):

$$\mathrm{DSCR} = \frac{\text{Net operating income}}{\text{Total debt service (Principal \&Interest payments)}} \tag{4}$$

The debt service coverage represents the amount of the project's free cash flow that is expected to be available for debt service over the loan repayment period.

The project´s debt service coverage ratio rises from 0.9 in 2023 to 3 in 2044. For a project to meets its debt obligation, the debt service ratio should be greater than the minimum critical value of 1.5.

As shown in Figure 6, the lowest debt service coverage ratio realized during the operation period of the plant is 1.9, This shows that the project´s cash flow is sufficient to meet its debt service obligations over the plant operation lifetime.

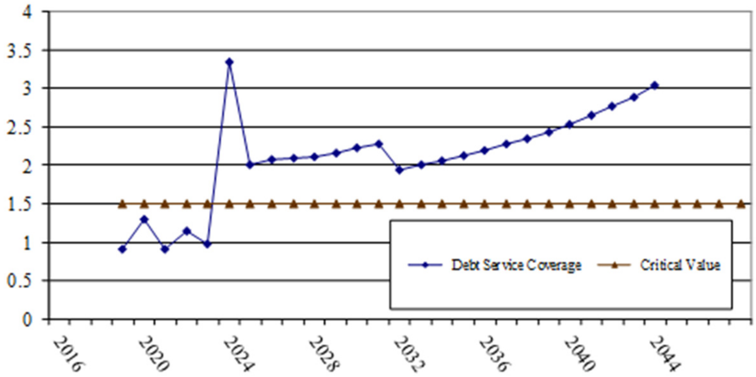

FIGURE 6: Debt service coverage ratio

4.6 Risk assessment analysis

The purpose of performing sensitivity analysis is to help to identify key variables which influences the project cost and benefit of stream of the project. It includes electricity sales price, sales quantity and operation and maintenance costs of the project.

Therefore, sensitivity analysis is conducted by determining how much the IRR changes relative to a given change in input parameters i.e. electricity price, sales quantity and operation and maintenance costs. Firstly, a base case is defined from the most likely values for each variable (pessimistic, most likely and optimistic). One variable at a time is changed by a specified percentage. In this case, we have used values from -50% to + 50% while other variables are held constant at the base case value. The output is then calculated for the new value. In this case the output is the IRR of equity and the results are shown in Table 5.

TABLE 5: Impact analysis

		Price		**Sales quantity**		**Equipment**		**O & M**
		17%		**17%**		**17%**		**17%**
-50%	50%	**2%**	50%	**4%**	50%	**23%**	50%	**18%**
-40%	60%	**6%**	60%	**7%**	60%	**22%**	60%	**18%**
-30%	70%	**9%**	70%	**10%**	70%	**21%**	70%	**18%**
-20%	80%	**12%**	80%	**13%**	80%	**19%**	80%	**18%**
-10%	90%	**15%**	90%	**15%**	90%	**18%**	90%	**18%**
0%	100%	**17%**	100%	**17%**	100%	**17%**	100%	**17%**
10%	110%	**19%**	110%	**19%**	110%	**16%**	110%	**17%**
20%	120%	**21%**	120%	**21%**	120%	**15%**	120%	**17%**
30%	130%	**23%**	130%	**22%**	130%	**14%**	130%	**17%**
40%	140%	**25%**	140%	**24%**	140%	**13%**	140%	**17%**
50%	150%	**26%**	150%	**25%**	150%	**12%**	150%	**16%**

Based on Table 5, the project sensitivity assessment indicates that increasing the electricity price and sales quantity of the project increases the IRR, hence making the project more profitable while decrease in sales price and quantity by more than 10% will make the project unprofitable.

5. CONCLUSIONS AND RECOMMENDATIONS

To determine geothermal project viability, it is important to take into consideration all the necessary parameters that enable the successful development of the project. Some of these parameters include the country's existing supporting policy framework on geothermal development, development of a bankable project document, and project financing structure.

It is important to note that in all the cost components such as engineering, supervision and commissioning, general contingency and contracting fees were added in order to cover for unforeseen costs in the project. In this study, it is assumed that GDC will use its own rigs which ultimately reduced the cost of drilling, ultimately reducing the cost of the project. The costs can be higher if hired rigs are used.

The analysis of the result obtained from the profitability model, considering the data used and the assumptions made in the project, leads to the following conclusions:

- The planning horizon considered in the viability assessment of the project is 25 years.
- The calculated IRR obtained from the model for the total cash flow and net cash flow are more than the total discounting rate (MARR) of 10% and equity discounting rate (MARR) of 15%, respectively, which meets the criteria that the IRR should be greater than (>) the MARR. That indicates that, based on the analysis above, the project is viable and worth investing.
- The project debt service coverage ratio analysis shows that the minimum DSCR ratio obtained is 1.9 which is more that the critical value of 1.5 (Figure 6). Therefore, the project cash flow is sufficient to meet its debt service obligations over the lifetime of the project.
- It is advisable to undertake Project financial viability studies at early stages of project development in order to reduce risks involved in the project before making financial commitment.

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Appendix I: Summary Results

	Assumptions and Results				Discounting Rate(MARR) Total				10%		Planning Horizon		25	years	
Assumptions:					Discounting Rate(MARR) equity				15%						
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	Total
Investment:	MUSD														MUSD
Buildings		7	8	7	9	4	7	7	0	0	0	0	0	0	48
Equipment	100%	0	0	0	0	8	20	28	28	0	0	0	0	0	85
Other		1	1	1	0	0	0	0	0	0	0	0	0	0	3
Total		8	8	8	9	12	27	35	28	0	0	0	0	0	135
Financing:															
Working Capital (Inv from Op)		1	0	0	1	2	2	4	5	0	0	0	0	0	15
Total Financing		8.93	8	8	10	14	29	39	33	0	0	0	0	0	150
Equity	100%	30%													
Loan Repayments	100%	20	Years												
Loan Interest	100%	6%													
										OpStart					
Operations:		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
Sales Quantity	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	291	291	291	291	291	000mwh/
Sales Price	100%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.088	0.088	0.088	0.088	0.088	0.088USI
Variable Cost	100%	0	/USD/Kwh												
O & M Costs	100%	2	IUSD/year												
Inventory Build-up (MUSD)															

Other Assumptions:		
Debtors	1/12	of turnover
Creditors	1/12	of variable cost
Dividend	0%	of profit
Income Tax	30%	of Taxable profit
Depreciation Building	4%	
Depreciation Equipm	15%	
Depreciation Other	10%	
Loan Management Fe	0.8%	

Main Results:		
	Total Cap.	Equity
NPV of Cash I	7	5
Internal Rate	11%	17%
Internal Value of Shares		6.8
after 25 years		
Minimum Cash Account		0

Breakdown of Costs:		
Variable Cost	0	0%
O & M Costs	58	9%
Paid Taxes	105	16%
Repayment	105	16%
Interest	87	13%
Paid Dividend	0	0%
Cash Account	298	46%
	654	100%

Appendix II: Investment

Investment

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Investm and Financing		0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Investment:		0.0	0.0														
Buildings		6.53	8	7	9	4	7	7	0	0	0	0	0	0	0	0	0
Equipment		0.00	0	0	0	8	20	28	28	0	0	0	0	0	0	0	0
Others		1.40	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
		7.93	**8**	**8**	**9**	**12**	**27**	**35**	**28**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Booked Value of Fixed Assets																	
Buildings		6.53	14	21	30	34	41	48	48	46	45	43	41	40	38	37	35
Equipment		0.00	0	0	0	8	29	57	85	76	67	55	42	30	17	4	4
Other		1.40	2	3	3	3	3	3	3	3	2	2	2	1	1	1	1
Total Booked Value		**7.93**	**16**	**24**	**33**	**45**	**72**	**108**	**135**	**125**	**114**	**100**	**86**	**71**	**56**	**42**	**40**
Depreciation:																	
Depreciation Buildings	4%	0	0	0	0	0	0	0	0	1.6238	1.4138	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538
Depreciation Equipm.	15%	0	0	0	0	0	0	0	0	8.4557	9.7105	11.503	12.722	12.722	12.722	12.722	0
Depreciation Other	10%	0	0	0	0	0	0	0	0	0.2902	0.29	0.29	0.29	0.29	0.29	0.29	0.29
Total Depreciation		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**10.37**	**11.41**	**13.35**	**14.57**	**14.57**	**14.57**	**14.57**	**1.844**
Financing:																	
Equity	30%	2.68	2.4	2.5	2.9	4.2	8.8	11.8	9.8	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Loans	70%	6.25	5.7	5.7	6.8	9.7	20.5	27.6	22.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total		**8.93**	**8**	**8**	**10**	**14**	**29**	**39**	**33**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Loans:																	
Drawdown		6.3	5.7	5.7	6.8	9.7	20.5	27.6	22.9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Repayment	20										5.3	5.3	5.3	5.3	5.3	5.3	5.3
Principal	0	6.3	11.9	17.7	24.5	34.2	54.7	82.3	105.2	105.2	100.0	94.7	89.4	84.2	78.9	73.7	68.4
Interest	6%	0	0.4	0.72	1.1	1.5	2.1	3.3	4.9	6.3	6.3	6.0	5.7	5.4	5.1	4.7	4.4
Loan Managem. Fees	1%	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

		2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	Total
Investm and Financing		16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	
Investment:																			
Buildings		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**48**
Equipment		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**85**
Others		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3**
		0	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**135**
Booked Value of Fixed Assets																			
Buildings		34	32	31	29	27	26	24	23	21	20	18	17	15	13	12	10	9	
Equipment		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	
Other		0	0	0	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	-1	
Total Booked Value		**38**	**36**	**35**	**33**	**31**	**29**	**28**	**26**	**25**	**23**	**22**	**20**	**18**	**17**	**15**	**14**	**12**	
Depreciation:																			
Depreciation Buildings	4%	1.5538	1.5538	1.5538	1.5538	1.5537532	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	**38.77**
Depreciation Equipm.	15%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**80.56**
Depreciation Other	10%	0.29	0.29	0.29	0.29	0.29	0	0	0	0	0	0	0	0	0	0	0	0	**3.77**
Total Depreciation		**1.844**	**1.844**	**1.844**	**1.844**	**1.84375**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**1.554**	**123.1**
Financing:																			
Equity	30%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**45.09**
Loans	70%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**105.2**
Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**150.3**
Loans:																			
Drawdown		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Repayment	20	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	0.0	0.0	0.0	0.0	**105.2**
Principal	0	63.1	57.9	52.6	47.3	42.1	36.8	31.6	26.3	21.0	15.8	10.5	5.3	0.0	0.0	0.0	0.0	0.0	
Interest	6%	4.1	3.8	3.5	3.2	2.8	2.5	2.2	1.9	1.6	1.3	0.9	0.6	0.3	0.0	0.0	0.0	0.0	**86.5**
Loan Managem. Fees	1%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0.8**

Appendix III: Operation

Operations

Operations Statement		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Sales		0	0	0	0	0	0	0	0	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3
Price		0	0	0	0	0	0	0	0	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088
Revenue		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**
Variable Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
O&M Costs	2	0	0	0	0	0	0	0	0	2	2	2	2	2	2	2	2	2
Diverse Taxes																		
Operating Surplus (EBITDA)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
Inventory Movement		0	0	0	0													
Depreciation		0	0	0	0	0	0	0	0	10.37	11.414	13.347	14.566	14.566	14.566	14.566	1.8438	1.8438
Operating Gain/Loss (EBIT)		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**13**	**12**	**10**	**9**	**9**	**9**	**9**	**21**	**21**
Financial Costs		0.0	0.4	0.76	1.1	1.5	2.2	3.5	5.1	6.3	6.3	6.0	5.7	5.4	5.1	4.7	4.4	4.1
Profit before Tax		**0.0**	**-0.4**	**-0.76**	**-1.1**	**-1.5**	**-2.2**	**-3.5**	**-5.1**	**6.6**	**5.6**	**4.0**	**3.1**	**3.4**	**3.7**	**4.0**	**17.0**	**17.4**
Loss Transfer	0	0.0	-0.5	-1.22	-2.3	-3.9	-6.1	-9.6	-14.7	-8.1	-2.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Taxable Profit		0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.5	3.1	3.4	3.7	4.0	17.0	17.4
Income Tax	30%	0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.9	1.0	1.1	1.2	5.1	5.2
Profit after Tax		**0.0**	**-0.4**	**-0.76**	**-1.1**	**-1.5**	**-2.2**	**-3.5**	**-5.1**	**6.6**	**5.6**	**3.5**	**2.1**	**2.4**	**2.6**	**2.8**	**11.9**	**12.1**
Dividend	0%	0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Net Profit/Loss		**0.0**	**-0.4**	**-0.76**	**-1.1**	**-1.5**	**-2.2**	**-3.5**	**-5.1**	**6.6**	**5.6**	**3.5**	**2.1**	**2.4**	**2.6**	**2.8**	**11.9**	**12.1**

Operations Statement		2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	Total
Sales		291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	291.3	**7283**
Price		0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	0.088	
Revenue		**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**25.63**	**641**
Variable Cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**
O&M Costs	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	**58**
Diverse Taxes																		
Operating Surplus (EBITDA)		**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**583**
Inventory Movement																		
Depreciation		1.8438	1.8438	1.8438	1.8438	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	1.5538	**123**
Operating Gain/Loss (EBIT)		**21**	**21**	**21**	**21**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**22**	**459**
Financial Costs		3.8	3.5	3.2	2.8	2.5	2.2	1.9	1.6	1.3	0.9	0.6	0.3	0.0	0.0	0.0	0.0	**87**
Profit before Tax		**17.7**	**18.0**	**18.3**	**18.6**	**19.2**	**19.5**	**19.9**	**20.2**	**20.5**	**20.8**	**21.1**	**21.4**	**21.8**	**21.8**	**21.8**	**21.8**	**372**
Loss Transfer	0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Taxable Profit		17.7	18.0	18.3	18.6	19.2	19.5	19.9	20.2	20.5	20.8	21.1	21.4	21.8	21.8	21.8	21.8	
Income Tax	30%	5.3	5.4	5.5	5.6	5.8	5.9	6.0	6.1	6.1	6.2	6.3	6.4	6.5	6.5	6.5	6.5	**112**
Profit after Tax		**12.4**	**12.6**	**12.8**	**13.0**	**13.5**	**13.7**	**13.9**	**14.1**	**14.3**	**14.6**	**14.8**	**15.0**	**15.2**	**15.2**	**15.2**	**15.2**	**261**
Dividend	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
Net Profit/Loss		**12.4**	**12.6**	**12.8**	**13.0**	**13.5**	**13.7**	**13.9**	**14.1**	**14.3**	**14.6**	**14.8**	**15.0**	**15.2**	**15.2**	**15.2**	**15.2**	**261**

Appendix IV: Cash flows

Cash Flow

		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Cash Flow																	
Operating Surplus (EBITDA)		**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**
Debtors	0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Debtor Changes			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-2.1**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Greditors	0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Creditor Changes			**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Financing - Expenditure		1.00	0	0	1	2	2	4	5	0	0	0	0	0	0	0	0
Cash Flow before Tax		**1.00**	**0**	**0**	**1**	**2**	**2**	**4**	**5**	**21**	**23**	**23**	**23**	**23**	**23**	**23**	**23**
Paid Taxes			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.9	1.0	1.1	1.2
Cash Flow after Tax		**1.00**	**0**	**0**	**1**	**2**	**2**	**4**	**5**	**21.17**	**23.3**	**23.3**	**22.86**	**22.39**	**22.29**	**22.2**	**22.1**
Interest & Loan Man Fee		0.05	0.4	0.8	1.1	1.5	2.2	3.5	5.1	6.3	6.3	6.0	5.7	5.4	5.1	4.7	4.4
Repayment		0.00	0	0	0.0	0.0	0.0	0.0	0.0	0.0	5.3	5.3	5.3	5.3	5.3	5.3	5.3
Net Cash Flow		**0.95**	**-0.4**	**-0.8**	**-0.1**	**0.5**	**-0.2**	**0.5**	**-0.1**	**14.9**	**11.7**	**12.0**	**11.9**	**11.8**	**12.0**	**12.2**	**12.4**
Paid Dividend			0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Cash Movement		**1**	**0**	**-1**	**0**	**0**	**0**	**1**	**0**	**15**	**12**	**12**	**12**	**12**	**12**	**12**	**12**

	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	Total
Cash Flow																		
Operating Surplus (EBITDA)	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**23.3**	**583**
Debtors	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	
Debtor Changes	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**-2**
Greditors	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	
Creditor Changes	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0**
Financing - Expenditure	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Cash Flow before Tax	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**23**	**595**
Paid Taxes	5.1	5.2	5.3	5.4	5.5	5.6	5.8	5.9	6.0	6.1	6.1	6.2	6.3	6.4	6.5	6.5	6.5	**105**
Cash Flow after Tax	**18.19**	**18.1**	**18**	**17.91**	**17.81**	**17.72**	**17.54**	**17.44**	**17.35**	**17.25**	**17.16**	**17.06**	**16.97**	**16.87**	**16.78**	**16.78**	**16.78**	**490**
Interest & Loan Man Fee	4.1	3.8	3.5	3.2	2.8	2.5	2.2	1.9	1.6	1.3	0.9	0.6	0.3	0.0	0.0	0.0	0.0	**87**
Repayment	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	0.0	0.0	0.0	0.0	**105**
Net Cash Flow	**8.8**	**9.0**	**9.3**	**9.5**	**9.7**	**9.9**	**10.1**	**10.3**	**10.5**	**10.7**	**10.9**	**11.2**	**11.4**	**16.9**	**16.8**	**16.8**	**16.8**	**298**
Paid Dividend	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	**0**
																		0
Cash Movement	**9**	**9**	**9**	**9**	**10**	**10**	**10**	**10**	**11**	**11**	**11**	**11**	**11**	**17**	**17**	**17**	**17**	**298**

Appendix V: Balance

Balance

Balance Sheet		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Assets																	
Cash Account	0	0.95	1	0	0	0	0	0	0	15	27	39	51	63	75	87	99
Debtors		0.00	0	0	0	0	0	0	0	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362
Stock	0	0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current Assets		**0.95**	**1**	**0**	**0**	**0**	**0**	**0**	**0**	**17**	**29**	**41**	**53**	**65**	**77**	**89**	**101**
Fixed Assets		7.93	16	24	33	45	72	108	135	125	114	100	86	71	56	42	40
Total Assets		**8.89**	**17**	**24**	**33**	**45**	**72**	**108**	**136**	**142**	**143**	**141**	**139**	**136**	**133**	**131**	**141**
Debts																	
Dividend Payable		0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxes Payable		0.00	0	0	0	0	0	0	0	0	0	0	1	1	1	1	5
Creditors		0.00	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Next Year Repayment		0.00	0	0	0	0	0	0	0	5	5	5	0.0	0.0	0.0	0.0	0.0
Current Liabilities		**0.00**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5**	**5**	**6**	**1**	**1**	**1**	**1**	**5**
Long Term Loans		6.25	12	18	24	34	55	82	105	100	95	89	89	84	79	74	68
Total Debt		**6.25**	**12**	**18**	**24**	**34**	**55**	**82**	**105**	**105**	**100**	**95**	**90**	**85**	**80**	**75**	**74**
Equity	0	2.68	5	8	10	15	23	35	45	45	45	45	45	45	45	45	45
Profit & Loss Balanc	0	-0.05	0	-1	-2	-4	-6	-10	-15	-8	-2	1	3	6	8	11	23
Total Capital		**2.63**	**5**	**6**	**8**	**11**	**17**	**26**	**30**	**37**	**43**	**46**	**48**	**51**	**53**	**56**	**68**
Debts and Capital		**8.89**	**17**	**24**	**33**	**45**	**72**	**108**	**136**	**142**	**143**	**141**	**139**	**136**	**133**	**131**	**141**
Error Check														0.00	0.00	0.00	0.00

Balance Sheet	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
Assets																	
Cash Account	108	117	126	136	146	156	166	176	186	197	208	219	231	247	264	281	298
Debtors	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362	2.1362
Stock	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Current Assets	**110**	**119**	**129**	**138**	**148**	**158**	**168**	**178**	**189**	**199**	**210**	**221**	**233**	**250**	**266**	**283**	**300**
Fixed Assets	38	36	35	33	31	29	28	26	25	23	22	20	18	17	15	14	12
Total Assets	**148**	**156**	**163**	**171**	**179**	**187**	**195**	**204**	**213**	**222**	**232**	**241**	**251**	**266**	**282**	**297**	**312**
Debts																	
Dividend Payable	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Taxes Payable	5	5	5	5	6	6	6	6	6	6	6	6	6	7	7	7	7
Creditors	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Next Year Repayment	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Current Liabilities	**5**	**5**	**5**	**5**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**6**	**7**	**7**	**7**	**7**
Long Term Loans	63	58	53	47	42	37	32	26	21	16	11	5	0	0	0	0	0
Total Debt	**68**	**63**	**58**	**53**	**48**	**43**	**37**	**32**	**27**	**22**	**17**	**12**	**6**	**7**	**7**	**7**	**7**
Equity	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Profit & Loss Balanc	35	47	60	73	86	99	113	127	141	155	170	185	200	215	230	245	261
Total Capital	**80**	**92**	**105**	**118**	**131**	**144**	**158**	**172**	**186**	**200**	**215**	**230**	**245**	**260**	**275**	**290**	**306**
Debts and Capital	**148**	**156**	**163**	**171**	**179**	**187**	**195**	**204**	**213**	**222**	**232**	**241**	**251**	**266**	**282**	**297**	**312**
Error Check	0.00	0.00	0.00	0.00	0.00	0	0	0	0	0	0	0	0	0	0	0	0

Appendix VI: Profitability

Profitability

Profitability Measurements		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	Total
NPV and IRR of Total Cash Flow																																			
Cash Flow after Taxes		1	0	0	1	2	2	4	5	21	23	23	23	22	22	22	22	18	18	18	18	18	18	18	17	17	17	17	17	17	17	17	17	17	490
Total Capital		-9	-8	-8	-10	-14	-29	-39	-33	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-150
Total Cash Flow & Capita		-8	-8	-8	-9	-12	-27	-35	-28	21	23	23	23	22	22	22	22	18	18	18	18	18	18	18	17	17	17	17	17	17	17	17	17	17	340
NPV Total Cash Flow	10%	-8	-15	-22	-29	-37	-54	-74	-88	-78	-68	-59	-51	-44	-38	-32	-26	-22	-19	-16	-13	-10	-8	-6	-4	-2	0	1	2	4	5	6	7	7	
IRR Total Cash Flow		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	2%	4%	5%	6%	7%	8%	8%	9%	9%	9%	10%	10%	10%	10%	10%	11%	11%	11%	11%	
NPV and IRR of Net Cash Flow																																			
Net Cash Flow		1	0	-1	0	0	0	1	0	15	12	12	12	12	12	12	12	9	9	9	9	10	10	10	10	11	11	11	11	11	17	17	17	17	298
Equity		-3	-2	-2	-3	-4	-9	-12	-10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	-45
Net Cash Flow & Equity		-2	-3	-3	-3	-4	-9	-11	-10	15	12	12	12	12	12	12	12	9	9	9	9	10	10	10	10	11	11	11	11	11	17	17	17	17	253
NPV Net Cash Flow	15%	-2	-4	-7	-9	-11	-15	-20	-24	-19	-16	-13	-10	-8	-6	-4	-3	-2	-1	0	0	1	2	2	2	3	3	3	4	4	4	4	5	5	
IRR Net Cash Flow		0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	3%	7%	9%	11%	13%	14%	14%	15%	15%	16%	16%	16%	16%	17%	17%	17%	17%	17%	17%	17%	17%	17%	