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FINANCIAL ASSESSMENT OF COMMERCIAL EXTRACTION OF SULPHUR AND CARBON DIOXIDE FROM GEOTHERMAL GASES IN MENENGAI, KENYA

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ABSTRACT

This study presents a financial viability assessment of commercial extraction of elemental sulphur and carbon dioxide (CO_2) from non-condensable gases (NCG) in Menengai geothermal field, Kenya. A brief overview of the geothermal gases in geothermal production and technology options for sulphur removal and carbon dioxide purification and liquefaction suitable for the field are presented. An Excel based profitability assessment model was applied to determine the profitability using gas chemistry data from 11 production wells and budget information received from technology suppliers. It is found that the capital cost of setting up the plant with annual production capacity of 5,655 tons of elemental sulphur and 17,382 tons of industrial liquid CO_2, equivalent 5%, is approximately US$9,779,415. The project´s Net Present Value (NPV) and NPV of Net Cash Flow are $2,033,178 and $2,028,446, respectively, while the equity Internal Rate of Return (IRR) is 31%. These numbers indicate that extraction is viable from the financial point of view and would provide a second option for the power company to generate an additional stream of revenue, and also eliminate the environmental effects of hydrogen sulphide (H_2S) and CO_2. It is found that production of sulphur as a single product is financially unattractive. Market analysis carried out indicates that Kenya is a net importer of sulphur and the Menengai production could provide an alternative local supply source. According to a risk assessment analysis the biggest risk that the production faces is the significantly high sensitivity of IRR to changes in prices both of sulphur and CO_2.

1. INTRODUCTION

Geothermal power production in high-temperature geothermal fields releases non-condensable gases (NCG) as by-products. The concentrations of these non-condensable gases in the geothermal steam can range from less than 0.2% to over 25% depending on the reservoir characteristics. The composition of NCG is mainly carbon dioxide (CO_2), hydrogen sulphide (H_2S), ammonia (NH_3), methane (CH_4), hydrogen (H_2), nitrogen (N_2) and argon (Ar); CO_2 and H_2S being the largest components (Rodríguez et al, 2014).

Carbon dioxide significantly contributes to the global greenhouse effect. Globally, CO_2 emission from geothermal power plants in high temperature fields are about 120 g/KWh^{-1} by weight on average (Ármannsson et al, 2005). Hydrogen sulphide (H_2S) on the other hand is known for its toxic effect and for being a possible cause of acid rain (Padilla, 2007). The environmental effect of these two gases, albeit being significantly lower in comparison to traditional fossil fuels, have led to increased interest in developing alternative methods not only for eliminating them but also creating valuable products that can be of economic value. There exist various abatement methods and processes for eliminating and treating these gases with the re-injection method being currently the most popular abatement scheme in several geothermal producing countries (Rodríguez et al, 2014, Padilla, 2007).

The conversion of NCG into valuable products that can generate a market value is an alternative approach that has gotten more important over the last decade. The key attraction of this method is that it allows primary production of geothermal power to continue without contributing significantly to greenhouse warming as well as providing an additional revenue stream for the company. The hydrosulphide can be removed and converted into mercantile elemental sulphur while the resulting CO_2 is purified and liquefied for sale either as liquid or as dry ice.

Examples of geothermal fields that are currently converting these gases into marketable products include a 500 kg/h liquid CO_2 production plant in South Iceland (Ragnarsson, 2015, and personal comm.), a 120,000 tons/year liquid CO_2 plant in Kizildere, Turkey (Mertoglu et al., 2015; Şimşek et al., 2005) and George Olah renewable methanol plant in Iceland utilizing CO_2 from the Svartsengi geothermal power plant (technology.com, 2015). In addition, two wells in Armenia produce CO_2 for supplying it to a mineral water bottling company and a factory producing dry ice (Lund and Boyd, 2015).

Tests carried out by Geothermal Development Company (GDC) in Menengai to ascertain the gas chemistry of the steam found out that the proportion of NCG in the steam is 5.9% by weight on average. The CO_2 and H_2S components in the NCG are 98% and 1.59% by weight on average, respectively. A potential problem in this field therefore, is the downstream elimination of these gases without disregarding their economic importance. There are several options under consideration including using H_2S as a raw material for elemental sulphur production and further purifying and liquefying CO_2 to produce industrial or food grade liquid CO_2. This strategic option would minimize the environmental effect associated with these gases but also provide an avenue to optimize the utilization of the resources.

Elemental sulphur and liquid CO_2 extracted from a geothermal field can be used for a number of industrial applications as discussed in Section 2.5. However, before the option is considered, a technical, financial and economic assessment is required in order to determine the capital and operational cost of extraction, technological availability as well as the sustainability and profitability of the production.

The objective of this study is to determine financial viability of retrofitting a sulphur recovery and CO_2 purification plant into the 105 MW (3×35MW) Menengai geothermal plants. The aim of the financial assessment is to identify the project capital and investment requirements, the production and operation costs and specifically to assess whether the project will generate acceptable financial returns. This study will also carry out a market analysis to identify the market for the products as well as carry out a risk assessment to identify the effects of various parameters on the profitability of the project.

In Section 2, this report includes a brief discussion of geothermal gases and the chemical characteristics and composition of geothermal gases at the Menengai wells. It gives an overview of the technology options available on the market for sulphur recovery and CO_2 purification and liquefaction in Section 3; the methodology of financial assessment including the market analysis are discussed Section 4, together with the results of the modelling and of the risk analysis. Conclusion are provided at the end.

1.1 Reviewed literature

A few studies have been conducted so far on available technologies and cost estimates for CO_2 extraction in the geothermal industry. However, the cost data which is available are not complete enough for investment decision making. A study by Bogarín Chaves (1996) found out that it is technically feasible and financially viable to produce commercial liquid CO_2 to maximize the geothermal resource in the value chain. The study is however, not backed by financial assessment of the cost of production.

Rodríguez et al. (2014) reviewed the methods available for H_2S abatement in geothermal power plants including the development of a screening tool for technology selection based on field chemistry and type of the geothermal power plant. The study generally describes costs of the different abatement methods but makes no financial assessment of the commercialization of the CO_2 and sulphur production process.

Padilla (2007) carried out a preliminary study on the emission abatement and utilization of geothermal gases for commercial uses in El Salvador. Different methods of abating H_2S and subsequent process of cleaning CO_2 from the Berlin geothermal power plant are discussed. Cost estimation of sulphur and CO_2 production using costs data indexed from 2000 prices from the Svartsengi power plant is also done. Although the study is comprehensive, it lacks more recent information based on the current cost and development in the geothermal industry. This paper will therefore, expand and bring up to date this information on the current costs as well as the financial soundness of commercializing the production processes.

2. GASES IN GEOTHERMAL PRODUCTION

2.1 General background of Kenya's geothermal market

Globally, Kenya is ranked among the leading countries with geothermal potential of between 7,000 and 10,000 MW (Onyango, 2012). The high-temperature geothermal fields are located in the Rift Valley. As in September 2015 the country's total installed electricity generation capacity was 2,177 MW with geothermal power generation contributing 630 MW (27% of installed capacity), mainly from the Olkaria geothermal field. Geothermal Development Company (GDC) is currently developing 105 MW in Menengai geothermal field, 200 MW in Baringo - Silali and 150 MW in Suswa.

2.2 The Menengai geothermal field

Menengai is a high-temperature field located within the Kenyan Central Rift Valley, north of Lake Nakuru and south of Lake Bogoria. The field is the third field to be developed outside of the Olkaria prospects. Nakuru is Kenya´s fourth largest city and a major agricultural and manufacturing town. Menengai is located within a region of intra-continental crustal triple rift junction with the complex dominated by a central volcano approximately 12 km in diameter. The field measures approximately 850 km^2 with an estimated potential of over 700 MW (Onyango, 2012; Omenda and Simiyu, 2015).

The Menengai field is located in the Menengai caldera formed in the Quaternary and built of trachyte lavas and associated intermediate pyroclastic. Resurgent post-caldera activity (< 0.1 Ma ago) occurred on the caldera floor with an eruption of thick piles of trachyte lavas from various centres. Seismology indicates seismic wave attenuation at < 6 km depth underneath Menengai Caldera suggesting the existence of shallow magma bodies which are believed to be associated with the heat sources for the geothermal system.

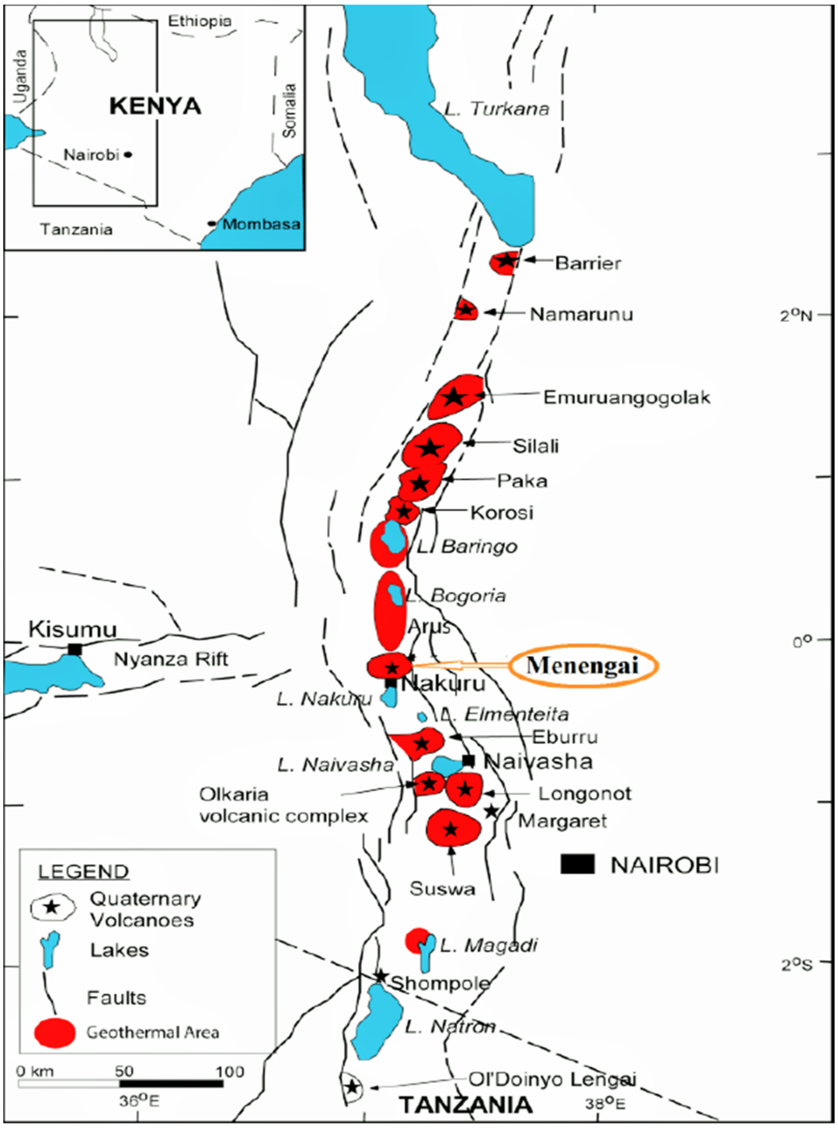

FIGURE 1: Geological map of Kenya showing the location of Menengai

The gas geothermometry based on H_2S and CO_2 indicates that the reservoir temperatures are greater than 250°C. The volcano has been active since about 0.8 Ma ago (Omenda and Simiyu, 2015). The location of Menengai geothermal fields is shown in Figure 1.

2.3 Composition of non-condensable gases (NCG) from Menengai field

By July 2015, 130 MW of steam equivalent had been measured on the well heads in the Menengai field and three companies Sosion Energy, Quantum East Africa and Orpower 22 contracted to operate a 35 MW modular power plant each for a period of 20 years from 2017. These geothermal plants are expected to release non-condensable gases as by-products and measuring them and monitoring is important because these gases can affect the performance of a power plant as well as have environmental effects.

Discharge test results carried out by GDC show that the average share of the NCG in steam from the Menengai field is about 5.9% by weight out of which 98% is CO_2 while 1.59% is hydrogen sulphide (see Table 1). This data was used to determine the quantities of hydrogen sulphide and CO_2, and also as a basis for obtaining budget information from the technology suppliers which is used to estimate the cost (see Section 4).

TABLE 1: Composition of NCG from Menengai field

NCG component	Gas content (%wt)
CO_2	97.9
H_2S	1.59
H_2	0.37
CH_4	0.16
Total	100

2.4 Direct application of non-condensable geothermal gases

In Kenya, commercial direct use applications of geothermal energy are only carried out by the Oserian Development Company where 50 hectares of greenhouses are being heated using geothermal energy from an exploration well. Other small scale applications can be found at the Eburru area where the local community uses 95°C hot steam from a borehole to dry pyrethrum and the condensate as domestic water. Lake Bogoria hotel located near the L. Bogoria geothermal prospect uses water from a nearby warm spring to heat its spa pool (Omenda and Simiyu, 2015).

Besides thermal energy, non-condensable gases and other geothermal by-products geothermal fluids contain can be captured and used for a number of industrial applications in order to achieve a holistic approach. CO_2 and H_2S in particular are the prime gases that can be harnessed for commercial use in the Menengai field.

2.5 Use of elemental sulphur

Elemental sulphur from the Menengai field can be used in the following potential market areas:

- *Chemical production* – Sulphur is the primary source for the production of sulphuric acid. Elemental sulphur can be sold to industries involved in making sulphuric acid. The size of the market of sulphuric acid is discussed in Section 5.
- *Fertilizer manufacturing* – Sulphur is used in the fertilizer manufacturing as one of the essential plant nutrients, along with nitrogen, phosphorous and potassium.
- *Industrial uses* – Potential industrial uses of elemental sulphur includes non-ferrous metals, textile, rubber making such as tyres and boots, pharmaceuticals, agricultural pesticides, personal care products, cosmetics, synthetic rubber vulcanization, water treatment, detergents, paper and carpet making.

2.6 Use of liquid CO_2

CO_2 from the field can be used for a number of applications including the following:

- *Food and beverage industry:* CO_2 can be supplied to food and beverage industry as a key food additive and acidity regulator. CO_2 is also used in carbonate soft drinks, beers, wine and soda/mineral water and to prevent fungal and bacterial growth (modified atmosphere packaging). CO_2 provides fizz to the beverages.
- *Agricultural and biological applications:* Potential customers under his category include large horticultural farms in Nakuru. Plants require CO_2 for photosynthesis and the yields of plants grown in green houses can increase by 20% when air inside the green house is enriched with CO_2. The target level for enrichment is typically a CO_2 concentration of 1000 ppm.
- *Refrigeration (freezing and chilling):* Liquid and solid CO_2 are important refrigerants, especially in the food industry where they are used during the transportation and storage of frozen foods to protect the taste and texture of food products by maintaining proper temperature control.
- *Methanol:* CO_2 can be used as a feed stock and converted into renewable methanol (RM) for usage as fuel, in the production of biodiesel, making of plywood, paints and other products.
- *Medical applications:* In health care, CO_2 is used for insufflation and is often mixed with oxygen or air as a respiratory stimulant to promote deep breathing.
- *Firefighting:* Liquid CO_2 under pressure is used to extinguish small flames from flammable liquids and electrical fires.

3. TECHNOLOGY OPTIONS FOR SUPHUR AND CO_2 RECOVERY

3.1 Overview

This section discusses briefly the main methods that currently exist for the removal of sulphur and purification of CO_2. Independent of the technology type chosen, the process of extracting elemental sulphur and CO_2 from geothermal gases for commercial purposes always involves two main stages. The first stage is the removal of H_2S from the streams of NCG and converting it into elemental sulphur, the second stage involves the purification and liquefaction of the remaining CO_2 (Padilla, 2007). The two-staged production process is briefly discussed here below.

3.2 Stage 1: Removal of hydrogen sulfide (H_2S)

There exist various methods and processes in the geothermal industry for removing H_2S from the stream of NCG exiting the condenser. These processes include liquid redox methods (Stretford, Unisulf, Sulferox and LO-CAT), AMIS, NCG gas injections, the Peabody-Xertic process, the Fe-C1 hybrid method, the Selectox process, biological or THIOPAQ, the Burner-scrubber process, re-injection, the H_2O_2 process, the BIOX process, the copper sulphate process, the steam reboiler process, the alkali scrubbing process, catalytic oxidation, steam stripping, the burner-scrubber process and the Claus process (Bogarín Chaves, 1996; Rodríguez, et al., 2014, Padilla, 2007; Sanopoulos and Karabelas, 1997). The selection of the appropriate process depends on several factors including the condenser type, the gas chemistry, the expected quality of sulphur and regulatory policies regarding gas emissions.

Using the decision tool developed by Rodríguez et al. (2014) for selection of appropriate methods for hydrogen sulphide (H_2S) removal in different geothermal conditions, Table 2 outlines commercial processes that can be applied in the Menengai field. Other processes have not been considered due to their inapplicability (condenser type, gas chemistry, the expected quality of sulphur, economics and regulations for gas emissions) in the Menengai conditions.

The removal of H_2S from NCG from the power plants should involve the application of one of the methods listed above. Price information received from one of the vendors indicated that the capital costs for the full equipment package (including cost for equipment, engineering, initial chemical supply, training and start up support services) for the LOCAT system for the recovery of 15.3 metric tons of sulphur per day is approximately \$16M excluding installation costs of approximately \$4M. The operating expenses per day on a power plant for chemical purchase are about \$2.5M annually. The electricity required totals 4,200 kW for both the equipment electricity load (1100 KW) and the inlet compressors (3100 kW). This process was therefore, eliminated as an option due to its high capital costs, high operating costs associated with the chemicals purchase and high electricity consumption. For the purposes of this study, Thiopaq desulphurization unit has been selected based on economics and budget information received from vendors.

The THIOPAQ process was originally developed by Paques B.V. for the treatment of biogas. The process was further improved by Paques in co-operation with Shell Global Solutions (2008) for the application in the oil and gas industry. The first application of the process was in 1993 in Netherlands and over 100 systems have been installed since. The THIOPAQ process involves the use of naturally occurring bacteria/microorganisms to oxidize the H_2S to elemental sulphur that can be used in the fertilizer production. The process of removing H_2S from the NCG through the THIOPAQ process consists of three stages as shown in the Figure 2 below.

The first stage is the absorption stage/section where hydrogen sulphide is absorbed in a packed tower. The washing liquid from the aerobic reactor is sprayed downwards from the top of the tower. The washing fluid exits the tower at the bottom and is directed to the aerobic reactor. The second stage is the aerobic reactor stage where the microorganisms contained in the aerobic reactor oxidizes absorbed

TABLE 2: H_2S removal processes suitable for the Menengai field

Process type	Brief process description	Pros, cons and costs
1. BIOX process	The BIOX is a downstream process where the off-gases are compressed and mixed with the condensate before entering the cooling tower. An oxidizing biocide is used for biological growth control in the cooling tower which, in combination with oxygen, converts dissolved H_2S to soluble sulphates.	• Eliminates at least 95% of the H_2S in the NCG and at least 98% of the H_2S in the portion of condensate used as cooling tower makeup water • It is suitable for both large and small power plants • The process can be used in both surface and direct contact condenser • Low capital and operational cost
2. THIOPAQ process	The Process involves the use of microorganisms for oxidizing the H_2S to elemental sulphur. The gas containing H_2S is absorbed in an alkaline solution under pressure in a first absorption step. The dissolved sulphide is then oxidized into elemental sulphur in a reactor. The elemental sulphur slurry in the reactor can be separated in a centrifuge to different purities.	• Final H_2S removal of up to 99,99% efficiency with a reactor oxidation to amorphous sulphur between 95 and 98% • Used mostly in the gas industry • Minimal chemical consumption relative to other processes • Low capital costs • The biological sulphur cake can be used for agricultural use
3. Fe-CI hybrid	This method utilizes a highly acidic iron solution through which the off-gas from the condenser is bubbled. The solid sulphur precipitates with nearly 100% turndown of H_2S at solution temperature between 70 and 75°C. The separation of elemental sulphur is done using a rotary drum vacuum filter. Sulphur is obtained as a by-product.	• It has only been laboratory tested and is still under development • The process has potential to generate profit • The iron solution is highly acidic and would require an appropriate selection of materials. • Low capital cost and operational cost
4. Amine/Claus process	Amine/Claus process is a two stage process involving oxidation of stream of gas with air at high temperature to produce sulphur, water and SO_2 followed by a catalytic reaction of H_2S and SO_2 to produce sulphur and water. The liquid sulphur obtained in the process is collected.	• Sulphur recovery of 97% can be achieved • High heat required • No experience in geothermal power plants
5. Wet gas sulphuric acid process (WSA)	WSA is a catalysis process based on diatomaceous earth silica carrier impregnated with vanadium-pentoxide and sodium/potassium pyrosulphates to obtain commercial quality sulphuric acid.	• High quality sulphuric acid (97%) obtained • 95-99% H_2S removal efficiency achieved • Sulphuric acid can be sold commercially • Proper material selection must be done (corrosion) • Low capital costs
6. XERGY process	The XERGY process is still a new technology applicable for HS sulphur recovery in a sour gas stream. There are two different versions of the process, the sub sulphur dew point and the above sulphur dew point. Sulphuric acid is recovered through condensation.	• Sulphur obtained can be sold commercially • There are no stream emissions • The process can be adopted to different H_2S abatements requirements
Sources: Rodríguez et al., 2014; Bogarín Chaves, 1996; Padilla, 2007; Sanopoulos and Karabelas, 1997		

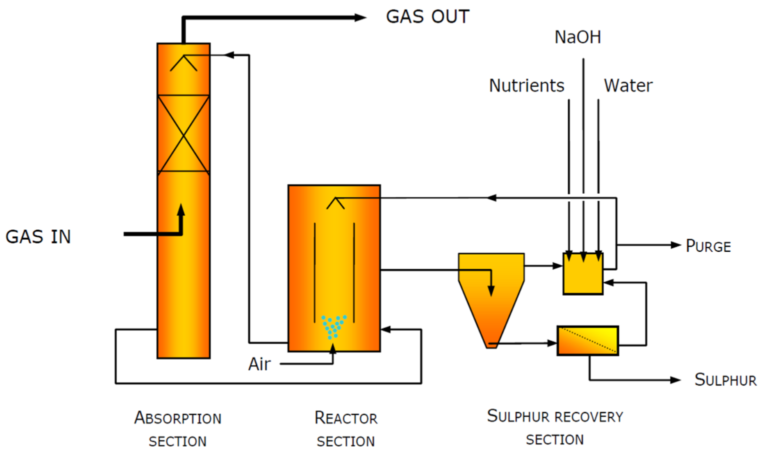

FIGURE 2: THEOPAQ desulphurization process

sulphide into elemental sulphur. The reactor effluent is recycled in the absorber column. The conversion process requires nutrients for good operation. Salt is also required for biomass growth and maintenance.

At the last stage of sulphur recovery, a settling unit is used to separate the produced sulphur from the liquid. The elemental sulphur slurry in the reactor can be separated in a centrifuge to obtain dry-solid concentration of about 60%. The THIOPAQ system will reduce the level of H_2S in the NCG to less than 22 ppm on average.

3.3 Stage 2: Purification of CO_2

After the removal of hydrogen sulphide (H_2S) is completed in stage 1, the remaining CO_2 is purified in order to make it suitable for commercial and industrial use. There is no single standard process designed for the process of recovering and purifying CO_2 after elimination of hydrogen sulphide. Currently, there are five main downstream technologies of removing CO_2 from various gas streams that are available on the market. The five technologies are: chemical solvents, physical solvents, membrane separation, cryogenic separation and adsorption/desorption. The final pressure, temperature and concentration of the CO_2 in the non-condensable gases stream as well as the purity of the final product will determine which technology is most suitable for the extraction process. Most of these technologies are mainly applied in the separation and capturing of CO_2 from coal and gas fired power plants. The purification method most commonly used is the treatment with potassium permanganate, potassium dichromate or active carbon. A typical CO_2 purification process includes the following operational steps (Quintero, 1987; Bogarín Chaves, 1996; Padilla, 2007):

Step i: Compression: After the elimination of H_2S, the next step is compression. The compression stage is a two or more step process which allows the liquefaction of some condensable gases mixed with the CO_2..

Step ii: Phases separation: At this stage, differentiation is carried out based on the gases densities, liquid and gas content.

Step iii: Scrubbing: After differentiation, water or potassium permanganate is normally used to remove some soluble compounds from the gas.

Step iv: Filtration: The next process is the removal of a variety of inorganic impurities by the use of adsorbents such as carbon activated or absorbent compounds.

Step v: Dehumidification: Dehumidification is done using desiccant material in order to reduce the moisture content in the gas.

Step vi: Condensation and liquefaction: During this stage, a refrigerant is used to cool and condense the gas into a liquid form by decreasing the temperature (to approximately -30°C) in combination with high pressure.

Step vii: Storage: The purpose of the storage tank, insulated and with a cooling system, is to contain the liquid CO_2 at high pressures of 15 bar-g and a temperature of approximately -30°C. The cooling could be provided by the CO_2 produced in the process or supplied by an independent cooling device.

The purity of the CO_2 recovered by the process following these steps makes it suitable for usage in the food and beverage industry, agricultural applications and other industrial ones including methanol production and medical applications. The product can be sold liquefied, or solidified as dry ice.

3.4 Current separation of elemental sulphur and CO_2 from geothermal plants

Sulphur is obtained from different sources including coal, gas power plants, crude petroleum, tar sands, oil shale, coal and geothermal brines, metal sulphides such as pyrites, sulphate materials or traditionally mined in native and volcanic deposits (Padilla, 2007). Currently, there are no known documented sources on the production of mercantile sulphur from geothermal power plants.

3.4.1 The Haedarendi CO_2 plant

The power plant at Haedarendi in Grímsnes, South Iceland, has been commercially producing liquid CO_2 food grade (99.99% purity) from two geothermal boreholes since 1988 (Ragnarsson, 2015). The Haedarendi geothermal field is a medium-temperature geothermal field with a temperature of 160°C and a gas content of 1.4% by weight. The plant produces liquid CO_2 for commercial use by utilizing the high concentration of CO_2 gas discharged from the wells which is almost pure CO_2 (Bogarín Chaves, 1996).

The concentration of hydrogen sulphide in the CO_2 gas is approximately 380 ppm, reducing the complex purification process of eliminating it (Bjarnason, 2005). The plant uses approximately 6 l/s of fluid and produces approximately 4,500 tons annually (525 kg/h) of liquid CO_2 (Orkustofnun, 2015; AGA, personal communication).

The production from this facility is sufficient to supply 75% of the total Icelandic CO_2 market requirements of 6,000 tonnes annually. The supply gap is met by imports. The plant was set up at investment costs of $4.7 million. The liquid CO_2 from the power plant is mainly used in green houses, carbonating beverages and in the food industry. The plant is shown in Figure 3.

The production process involves four cleaning stages: cleaning, compression, dehumidification and storage. The cleaning of the gas is performed by a water dispenser where the condensation of some gas takes place at low temperatures. The removal of the remaining portion of H_2S is done using an active carbon filter.

The next stage is a two-stage compression process where cooling and condensate trapping is done at every stage before the final compression is done applying 15 bar-g. At the dehumidification stage, the drying process is carried out in a packed column with silica gel, using a second column for regeneration cycle.

The purified final product (liquid CO_2) is kept in a storage tank with a cooling system to keep the temperature close to -26.5°C. The plant has 225,000 litre capacity storage tanks installed at the site from where liquid is picked up for delivery to customers all over Iceland. The plant itself consumes 17 m^3 of cooling water per hour (AGA, personal communication).

FIGURE 3: Haedarendi carbon dioxide plant in S-Iceland

3.4.2 The CO_2 production from Kizildere field, Turkey

Geothermal resources with high enthalpy in Turkey contain high concentrations of non-condensable gases, especially CO_2. The CO_2 concentration from these fields is probably the highest in the world, ranging from 1 to 2.5% by weight of the geothermal fluid. The Kizilder geothermal field, located at the eastern end of the E-W trending Buyuk Menderes Graben in Western Anatolia, Turkey, is a high-temperature field with a total current production of 95 MWe and 50 MWt. The Kizildere-Denizli power plant was the first geothermal power plant to be built in Turkey in 1984 with an initially installed capacity of 15 MW (Serpen et al., 2015).

In addition to electricity generation, part of the non-condensable gases discharged from Kizildere power plant condenser is piped and passed to a commercial dry ice production plant integrated to the power plant which produces dry ice and liquid CO_2. The CO_2 is filtered through a chemical adsorption process in order to remove minor amounts of sulphur compounds, hydrocarbons and other potential contaminants. Since 1986, the CO_2 plant operated with an initial dry ice and liquid CO_2 production of 40,000 tons per year of clean gas. The production capacity of the plant was increased in 2000 to 120,000 tons per year (Şimşek et al., 2005). Currently, the plant supplies more than 90% of the food grade CO_2 demand required by the Turkey carbonated soft drink market (Simsek et al., 2015). Through this process, the facility is able to generate with zero emission and is at the same time benefiting from the income from commercial sale of CO_2 and through carbon emission trade. Green houses also consume 4,000 tons of CO_2 per year from geothermal resources (Aksoy et al., 2015).

3.4.3 George Olah CO_2 to renewable methanol (RM) plant, Iceland

The George Olah methanol plant located in Grindavík, Reykjanes Peninsula, SW-Iceland, is the world's first commercial CO_2 to methanol plant (see Figure 4). It is the first plant in the world to demonstrate a commercially viable way of generating a synthetic liquid fuel (i.e. liquid electricity for cars) directly from CO_2. The pilot plant started operating in 2007 with a capacity of 50,000 litres per year while an industrial plant began operating in 2011 (Carbon Recycling International, 2015).

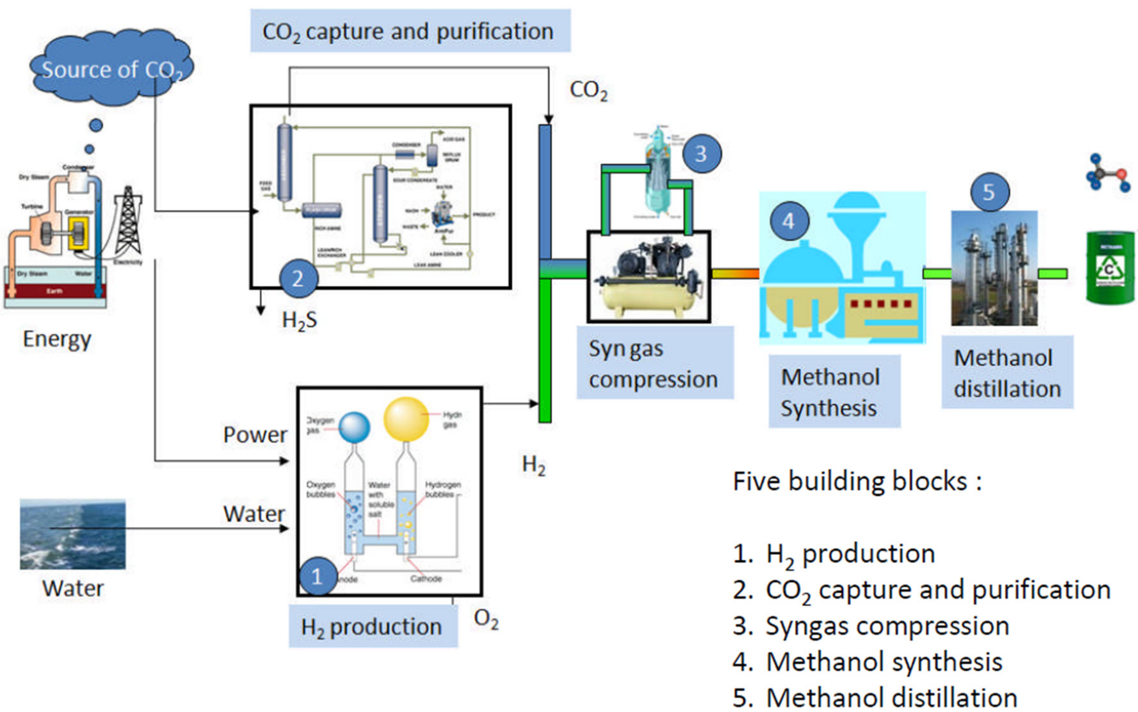

FIGURE 4: Simplified scheme showing the carbon dioxide to fuel process

The industrial plant developed at an investment cost of \$8 million uses CO_2 in steam from the Svartsengi geothermal power plant and hydrogen as feed stock and converts this into renewable methanol (RM) for use as a fuel and for making plywood, paints and other products. The water provides the required hydrogen to convert CO_2 to methanol. The only by-product from this process is oxygen (Chemicals-Technology.com, 2015).

The renewable methanol which is sold under the brand Vulcanol is used in bio diesel production, blended with normal gasoline and used as transport fuel for cars both in Iceland and internationally. The renewable facility has a production capacity of fifty million litres of renewable methanol per year which is sufficient to meet approximately 2.5% of the Iceland's gasoline demand. The approximately 5 MW of electricity which the plant requires for its production and electrolysis processes is obtained from the same CO_2 feed stock supplier, the Svartsengi geothermal power plant (Tran, 2010). The facility reclaims approximately 5,500 tons/year of CO_2.

The separation and subsequent conversion process of CO_2 into the final products is based on emission to liquid (ETL) technology, developed by and proprietary of Carbon Recycling International (CRI). The process simply involves splitting of water into hydrogen and oxygen using electricity (electrolysis) and combining CO_2 (feed stock) extracted from the geothermal steam in a ratio of 1:3 to produce renewable methanol (Tran, 2010; Chemicals-technology.com, 2015). A simplified CO_2 to fuel schematic process is shown in Figure 4 above.

3.4.4 Gas separation at the Hellisheidi power plant, Iceland (SulFix and CarbFix Processes)

Reykjavik Energy, in a bid to tackle the gas emission effects at its Hellisheidi Power Plant, has developed a gas abatement method for lowering the H_2S and CO_2 emissions. This method aims at dissolving the geothermal gases in effluent water from the power plant based on their solubility and re-inject them back into the geothermal reservoir. Carbfix involves the isolation of the CO_2 and re-injecting it back into the basaltic formation while SulFix involves reinjection of CO_2 into the geothermal system. A pilot scale gas separation station was operated at the field to determine the commercially feasibility of separating the gases into streams of H_2S and CO_2 rich gas and a stream of less soluble geothermal gases i.e. H_2, N_2, CH_4 and Ar prior to the reinjection of the gases into the reservoir. The company is currently implementing an industrial scale gas injection system based on the success of the pilot project (Júlíusson, 2015; Gunnarsson et al., 2015).

During the pilot phase, three technologies where being tested for their viability; a membrane system for H_2S removal, a system comprising of adsorption and desorption towers for separating soluble gases CO_2 and H_2S from the rest of the geothermal gases and a distillation column to separate CO_2 from H_2S. The pilot scale gas separation is carried out in two steps. The first step involves the separation of soluble gases, CO_2 and H_2S, from the rest of the insoluble geothermal gases (H_2, N_2, CH_4, and Ar) using an absorption/desorption or membrane system. In the second step a distillation column is used to separate CO_2 from H_2S based on the difference in their physical properties (Júlíusson, 2015; Gunnarsson et al., 2015).

There is an interest in developing alternatives of utilizing the resource in the most sustainable and energy efficient way and creating valuable products from all available sources. The stream of purified CO_2 which is separated in the process is a valuable product and can be used in greenhouses to increase the production of crops in Iceland, particularly for tomatoes, algae production, bio fuel production and aquaculture (Júlíusson, 2015). A study to assess the feasibility of the production of renewable methanol and sulphuric acid from hydrogen sulphide and CO_2 emissions from the Hellisheidi geothermal power plant was carried out in 2014 and found that the Icelandic market for sulphur and sulphuric acid was too small, and exporting it was not feasible economically (Júlíusson, 2015; Gunnarsson et al., 2015).

The projects described above demonstrate examples of areas where commercial CO_2 emitted from geothermal plants is captured and converted into marketable products.

4. FINANCIAL ASSESSMENT

4.1 Methodology and model framework

The main criteria for estimating the financial feasibility (profitability) of the investment are the Net Present Value (NPV) and the Internal Rate of Return (IRR) of cash flows. A modified Microsoft Excel-based profitability assessment model developed by Jensson (2006) was applied. The model which consists of different spreadsheets for investment, operations, cash flows and profitability is a simulation model based on an initial investment and subsequent operations of the plant over a determined period of time. The model is set up including a twenty-five year planning period in line with the assumed lifetime of the plant. Using this model, other parameters like the capital requirement, working capital, cash flow, financial ratios and charts can be deduced.

The profitability model is based on the premise that sulphur removal and CO_2 purification plant is a downstream process and will involve retrofitting into the 105 MW Menengai power plants. The model is based on given assumptions (see Section 4.4) which are deterministic but allows random variables to be added. The model´s key input which is costs for the desulphurization unit are based on budget information from the THIOPAQ process supplier. The cost estimates for the CO_2 purification and liquefaction unit are based on budget information presented by a technology supplier in 2012 for the production of 1,000 kg/h liquid in Iceland. The purification costs have been indexed to 2014 prices using the Chemical Engineering Plant Index (CEPCI).

Other model input including the cost for civil works and site preparation, land purchase, labour, utility costs, licences and permitting have been estimated for the Kenyan case. The estimated values used in the modelling might not be the most optimal, but will nevertheless provide a preliminary estimate with a probable accuracy of within ± 20% and be sufficient for decision making.

The key outputs from the model are the discounted NPV and IRR of cash flow and profitability yard sticks for the project. Risk assessment using sensitivity analysis was also carried out to evaluate and compare the effects of various parameters on the profitability (IRR) of the plant. For simplicity, we assume that the prices for elemental sulphur and liquid CO_2 are the same over the modelling time span.

4.2 Data

Gases chemistry data from eleven production wells from the Menengai field and normalized at 7 bar-a (165°C) using WATCH 2.4 program were collected and used to obtain budget quotation from commercial vendors and/or manufacturers for the desulphurization unit. This approach was adopted to ensure that the estimates reflect the present market cost and that they are as realistic as possible.

The THEOPAQ process was selected for this study based on budget information received, plant economics and the suitability of the process in the field. Data on prices of nutrients, sulphur and liquid CO_2 was obtained from secondary sources including market reports, United Nations Commodity Trade Statistics Database and the U.S Geological Survey. Additional data for the purification and liquefaction of CO_2 were obtained via personal communication with AGA, Orka Náttúrunnar (ON) and Carbon Recycling International staff, Iceland.

4.3 Rational for financial assessment

The primary objective of the financial assessment is to determine the net financial impact of the elemental sulphur and CO_2 production plant on GDC. The assessment has been performed from GDC's perspective as the project developer and owner, and hence considers the cash flows that have a direct impact upon GDC or are directly attributed to the development or operation of the plant. The results from the model should provide an indication on whether it is economically viable or not to invest in the project.

4.4 Technological, cost and financial assumptions

The input data for the model includes information on the expected annual production of elemental sulphur and liquid CO_2 in tons, associated annual expenses, estimated capital costs, operational costs, the Marginal Attractive Rate of Return (MARR) for the project and equity, dividend payments and other technical and financial assumptions.

4.4.1 Technological and production assumptions

- Project start date - January 1, 2017 with one-year construction period.
- Full commercial operation start date - January 1, 2018.
- The desired final compression pressure of the purified liquid CO_2 is 15 bar-g and a temperature of -30°C.
- The planning horizon is 25 years (PPA period).
- Four people are needed to operate the plant (2 engineers per shift).

4.4.2 Cost estimation assumptions

- Total equipment costs are the combined costs for plant and equipment, piping and piping installation, instrumentation, controls, electrical system and installation, cooling tanks, storage tanks for the sodium hydroxide, insurance and freight from the vendor's country to Menengai, engineering, supervision and commissioning. Storage tanks with the capacity to hold NAOH, Paques nutrients and liquid CO_2 for 14 days were considered.
- Cost for buildings and services including the costs for site and yard improvements (fencing, grading, roads, sidewalks, landscaping), as well as auxiliary facilities and service (water, electricity connection, fire protection). These costs have been estimated for Kenya.
- Others investment costs include costs for contracting, licensing and permits and general contingency. Costs for licenses and permits are real values from Kenya (National Environmental Management Authority fees (licenses Environmental and Social Impact Assessment for the plant and site excavation) of 0.1% of the total project costs), royalties of 0.5% of gross sales value and construction levy of 0.5% of the total contract value of the project.
- Fixed costs includes the annual maintenance and repair cost estimated to be 5% of total capital costs, annual plant overhead and administrative expenses estimated to be 6% and 15%, respectively, of the sum of annual operating labour and maintenance and repair costs (Peters and Timmerhaus, 1991; Towler, and Sinnott, 2012). Annual operating labour costs are estimated for Kenya.
- Price of caustic NAOH (20%) estimated to be $ 300 /ton CFR (Cost and Freight) in Kenya. NAOH requirements are 792 litres/hour.
- The Paques nutrient solution's (Nutrimix 34/32) standard price is € 1.699 /litre or $ 1.911 /litre (Shell Global Solutions, 2008). The nutrients requirement is assumed to be 381 litres/day. Indexed to 2014 prices.
- Demineralized water (1.0 $\$/m^3$) estimated 2 m^3/ton of CO_2.
- Cost for land acquisition is not included in cost estimates as it is already owned by the company.
- Kenya´s corporate tax of 30%.
- Electricity to be supplied from the nearby power plant at US Cents 7 for kWh.
- Cooling water costs are not considered, have to be obtained from the condenser.
- Cost for transportation of liquid CO_2 to the customer premises and storage facilities, costs at the clients' yard, are not included in the estimates.

A summary of cost components for the desulphurization and the CO_2 is given in Tables 3 and 4 below:

TABLE 3: Desulphurization unit

Cost item	Component	Cost ($
Capital investment		
Buildings	Buildings & civil works, auxiliaries and installation	259,701
	Land purchase	-
	Buildings Total	**259,701**
Equipment	Plant and equipment, piping and piping installation, instrumentation and controls, electrical system and installation, engineering, supervision and commissioning, insurance and freight, storage tank for NAOH & cage ladder on scrubber tank	6,197,684
	Equipment total	**6,197,684**
Other investment	Contracting and other fees	230,334
	Licensing, permits, other fees	63,868
	General contingency	645,739
	Other investment total	**939,941**
Total capital investment		**7,397,326**
Production costs		
Fixed costs	Maintenance and repairs ($/yr.)	322,869
	Operating labour and supervision ($/yr.)	45,714
	Plant overhead ($/yr.)	221,150
	Administrative expenses ($/yr.)	55,288
	Fixed costs total	**645,021**
Variable costs	Caustic (NAOH) 20% and Paques nutrient solution (Nutrimix 34/32) ($/yr.)	3,461,387
	Electricity ($/yr.)	807,672
	Water ($/yr.)	-
	Variable costs total	**4,269,059**

TABLE 4: CO_2 purification and liquefaction unit

Cost item	Component	Menengai cost ($)
Capital investment		
Buildings	Buildings & civil works, auxiliaries and installation	129,850
	land purchase	
	Buildings total	**129,850**
Equipment	Plant and equipment, piping and piping installation, instrumentation and controls, electrical system and installation, engineering, supervision and commissioning, CO_2 storage tank	1,887,471
	Total equipment costs	**1,887,472**
Other investment	Contracting and other fees	23,033
	Licensing and permits	
	General contingency	201,732
	Total other investment	**224,767**
	Total capital	**2,242,089**
Production cost		
Fixed costs	Maintenance and repairs ($/yr.)	100,866
	Operating labour and supervision ($/yr.)	45,714
	Plant overhead ($/yr.)	87,948
	Administrative expenses	21,987
	Total fixed costs	**256,516**
Variable costs	Electricity	180,708
	Demineralized water ($/M3)	36,593
	Total variable	**217,300**
	Total production	**473,816**

4.4.3 Project financing

- The project financing is 30% equity and 70% debt
- Loan repayment period is 8 years
- Interest rate on the loan is 6%

5. MARKET ANALYSIS FOR ELEMENTAL SULPHUR AND CO_2

5.1 Elemental sulphur demand, supply and price

In 2014, the global sulphur production was about 72.4 million tonnes, with production from oil and gas contributing 97%. China, the United States and Canada are the biggest producers with their production accounting for approximately 15%, 13% and 11% respectively of the global supply. Africa produces paltry less than 1% share of the global production (U.S. Geological Survey, 2015a). The world sulphur production from all sources is expected to grow at an average annual rate of between 4-6% from 2014 to 2019 with elemental sulphur growing by 6% (IHS, 2014) with the highest growth expected in the Middle East and Canada. Kenya´s known sources of sulphur are small and uneconomical and therefore, the country relies mostly on imported sulphur. In 2013, Kenya produced 23,000 metric tons of sulphuric acid.

The global demand for sulphur in 2014 was dominated by fertilizer production (56%) while base metals and industries consume 32%. Phosphate fertilizer production consumed about 85% of the 56% consumed in fertilizer production, followed by ammonium sulphate production (IHS, 2014). Global consumption increased by 38% from 2000 to 2014 and is expected to grow by 11% per year until 2019 depending on the stability of the world economy and growth in demand for sulphuric acid (IHS, 2014). A surge in demand from major end-use industries is also projected to positively influence growth in global sulphur demand. China is the largest consumer of sulphur. Africa is expected to continue to import high levels of sulphur for phosphate production (U.S. Geological Survey, 2015a).

In 2013, Kenya imported 5,335 metric tons of sulphur in all forms from Russia, Saudi Arabia, United Arab Emirates, India, Jordan and other countries with a trade value of $1.393 million and exported 28 tons valued at $12,964 (United Nations Commodity Trade Statistics Database, 2015).

Kel Chemicals, a sulphuric acid producing plant in Nairobi, produces 14,600 metric tons of sulphuric acid mainly from imported sulphur (Yager, 2015).

Kenya has a total fertilizer demand of 500,000 tonnes annually but only produces 300,000 tonnes. All sulphur required for the manufacturing process is imported. To bridge the demand-gap a new factory with a production capacity of 100,000 tonnes of fertilizer is being set up in Nakuru (15 km away from Menengai field) and is expected to start operation in November 2016. A second factory owned by Toyota Tshusho Corporation is also being built in Eldoret (150 km away from Nakuru). The two companies could provide a locally available demand for the Menengai by-product.

The average contract price for exported elemental sulphur in the U.S in 2014 was $ 157 (FOB) per ton and $ 169 (FOB) per ton between January and June 2015 (U.S. Geological Survey, 2015b). According to Gordon (2015) the price of sulphur between January and March 2015 has been ranging from $ 155 to $ 175 per ton as shown in Figure 5. In September 2015, the Free On Board prices for elemental sulphur in China and the Middle East ranged between $ 120-130 and $ 123-135 /ton respectively (Meehan, 2015).

The average price of imported sulphur in Kenya for the fertilizer production is $150 (personal communication with a fertilizer manufacturing company).

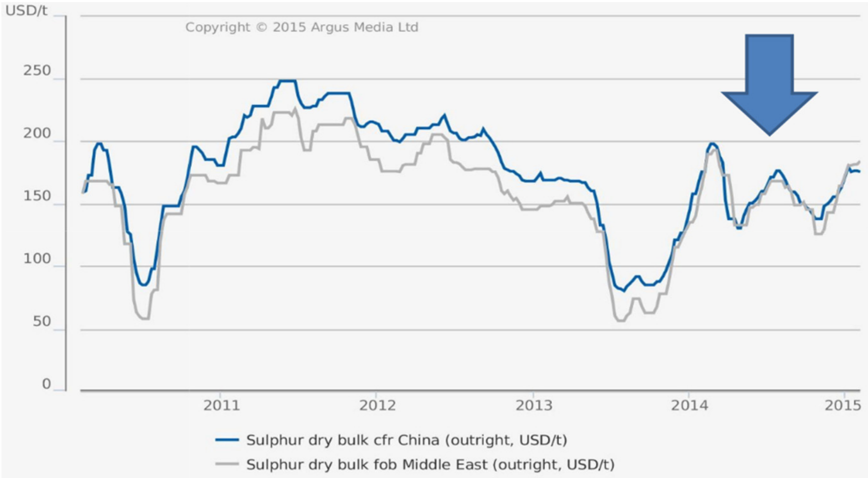

FIGURE 5: Trend of sulphur prices (Gordon, 2015)

5.2 Carbon dioxide demand, supply and price

The market for commercial liquid CO_2 is driven today by demand of the food and beverage industry. The beverage industry has been a consistent consumer of high purity CO_2 for decades with a consumption of more than 300 million tons worldwide. The food and beverage industries consumed almost half of this amount while metal production markets consumed about 15%. China is the leading user with a consumption of almost 34% of the global CO_2 produced in 2014. It is then followed by North America with a demand of 23%, Asia/Oceanic with 16% and the Middle East is accounting for 8% (IHS, 2015).

During the years 2014 to 2019, the total global liquid CO_2 market is expected to grow annually by 2.6% with the average growth rates forecasted to be the highest in Africa with a rate of 9.6%, followed by Latin America and the Middle East at a rate of 5.3% and China at a rate of 4.5% (IHS, 2015; Klemes et al., 2007).

The market for CO_2 in Kenya is an oligopolistic supply, mainly coming from Carbacid (CO_2), Ltd., BOC Kenya, Ltd. (BOC), Chemigas, Noble Gases, Welgas, Crown Gases and Synergy Gas. The industry is divided into a tonnage supply scheme composed of large volumes producers supplying directly via gas pipelines from the on-site production facility, merchant or bulk liquid market where suppliers fill the cryogenic tanks at the customers' sites and cylinder gas deliveries involving small scale supply using gas cylinders.

Carbacid, Ltd. is the biggest CO_2 trading company and controls the majority share of pure CO_2 and other gases market in the East African region. The biggest and major market is the food industry, drink bottlers and breweries in Kenya, Uganda, Tanzania, Rwanda, Burundi, Ethiopia, Uganda, Zambia, Southern Sudan and Somali. The company obtains its natural CO_2 by mining from its underground reservoir wells, 70 km from Nairobi. In 2013, Carbacid´s annual production from its plant in Nairobi was 35,000 tons while the annual production of CO_2 from natural sources was 18,900 tons. Due to increasing regional and local demand for the product, the company increased its capacity in 2014 by 10,000 tons at its mining site at Kereita Forest (Yager, 2015).

BOC Kenya, Ltd. (BOC) sells its CO_2 in the East Africa Region in bulk food grade liquid form, bulk industrial grade liquid CO_2, compressed CO_2, dry ice pellets or as industrial gas in cylinders. In 2013, Kenya exported 12,371 tons of food grade and industrial CO_2 valued at $5,323,477 (equivalent to $430/ton) and imported 9,821 tons valued at $17,781 (United Nations Commodity Trade Statistics

Database, 2015). Information on the actual size of the CO_2 market in Kenya is very scanty due to the nature of the market but this study estimates that the production is approximately 50,000 tons per year.

Currently, the major consumers of CO_2 are the food and beverage industries (beer, wine, fizzy drinks and bottled juices). Some of the biggest consumers include regional bottlers particularly in the East Africa Region including Uganda, Nile, Braliwa and East Africa breweries, Coca Cola, Keroche Industries and flavoured juice manufacturers who use it as a preservative or products enhancer. Demand for the product is further expected to rise parallel with the growth in the soft drinks industry in the East African Region. The carbonated drink production increased by 19.1% in the year 2013.

The price of liquid industrial CO_2 in Iceland is approximately 26-28 ISK/kg (202 to 218 $/ton, exchange rate September, 2015) (AGA Iceland, personal communication in September 2015). For some industries the price is 50 ISK/kg. For this analysis, a price of 393 $/ton was used.

6. MAIN RESULTS OF PROFITABILITY MODEL

This section presents results from the profitability assessment model. From the model results, this study is able to deduce the financial conditions and operating performance of the investment and forecast the future performance of production. The results are based on an annual production of 5,287 tons of elemental sulphur and 17,382 tons of liquid CO_2. This amount of CO_2 is equivalent to 5% of the CO_2 released from the 105 MW power plant as roughly estimated in this study. The prices for elemental sulphur and liquid CO_2 are assumed to be $ 150 and $ 393 per ton, respectively, as indicated in Section 5).

6.1 Project capital requirements

The capital investment required for the project is $ 9,639,415 to be allocated as follows: $ 389,552 for buildings, $ 8,085,156 for equipment and $ 1,164,707 for other investment cost. The project would also require an additional investment in working capital during the first year of the project. From the model, the project´s estimated working capital requirement is $ 140,000. A fixed cost and variable cost of approximately $ 901,537 annually and 198 $/ton will be required throughout the operation period. See Appendix I for detailed information on the financial model of the project.

6.2 Profitability of the project

Net Cash Flows and Pre-Tax Cash Flows: In 2017, the total net cash flow is negative since this is the period where the initial investment is made and construction of the production plant is taking place. This is also the year where funding is required for the purchase of equipment, buildings, civil works as well as installation of the plant. A working capital of $ 140,000 is also required to cover other expenditures.

In 2018, the first full year of operation, pre-tax and net cash flows are forecasted to be approximately $ 2,236,123 and $ 952,877.

As seen in Figure 6, the net cash flows increase until 2027 from where it stabilizes at $ 1,569,961 after the clearing of the loans. This project could generate net cash flow of $ 32,389,601 in its entire 25 year lifetime. If the company decides to produce sulphur only, the pre-tax and net cash flows will be negative.

Net Present Value (NPV): The Net Present Value is a valuable indicator recognizing the time value of money. It is a common tool for evaluating an investment and represents the sum of the discounted cash flows from a given time period. Projects whose NPV is positive are attractive because they are profitable.

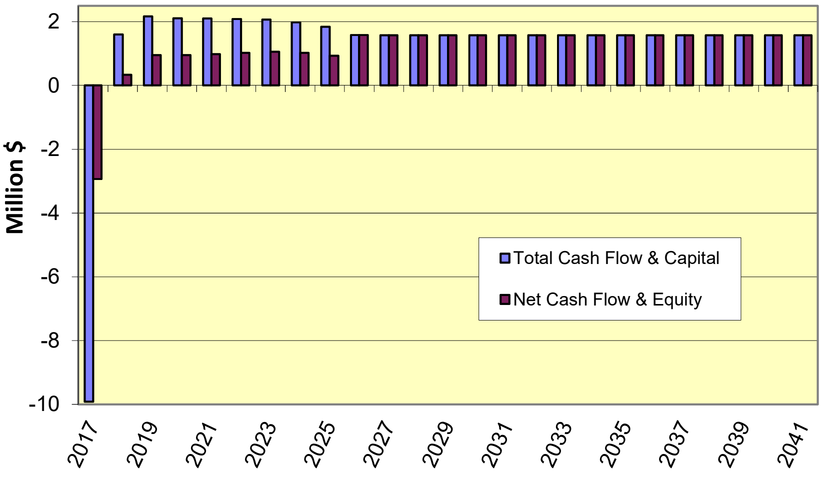

FIGURE 6: The total cash flow and net cash flow

The Net Present Value was calculated for this project to determine profitability of the project and to compare the future cash flows resulting from the investment with other investment alternatives (marginal attractive rate of return or MARR).

In this project, the NPV for total capital with discount rate (MARR) of 15% is $ 2,033,178 while NPV for equity with discount rate (MARR) of 20% is $ 2,028,446. The continued operation of the plant results in NPV of total cash flows and NPV of net cash flows being positive. As the trend of accumulated NPV shows in Figure 7, the NPV for total capital turns positive after ten years while NPV for equity turns positive after five years. In this case, a discount rate of 15% for the total project and 20% for equity was used.

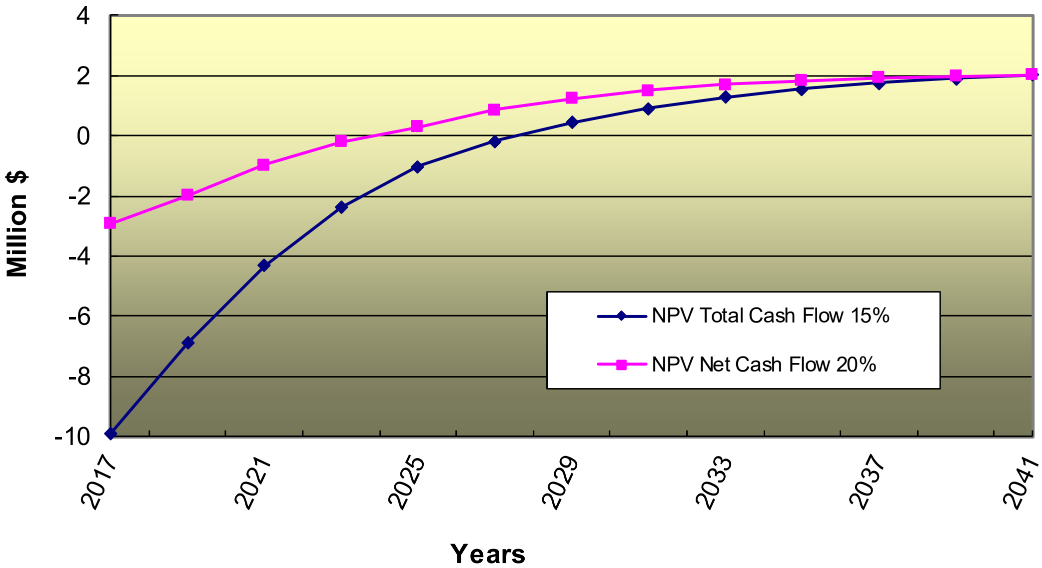

FIGURE 7: Net Present Value of total and net cash flow for the project

Internal Rate of Return (IRR): The Internal Rate of Return is defined as the discount rate at which the after tax NPV is equal to zero. It is a measure of determining the level of annual return (profitability) over the lifespan of an investment. The higher the IRR of a project, the more attractive and viable it is to invest in. This study calculated internal rate of return of the cash flow stream of the project to determine if the IRR meets the marginal attractive rate of the return (MARR) criterion which requires that the lowest acceptable limit for IRR should be greater than MARR or WACC or the hurdle rate.

In this study, the IRR of total cash flow and IRR of net cash flow are 19% and 31%, respectively (Figure 8). These values are higher compared to the total project MARR and equity MARR of 15% and 20%, respectively.

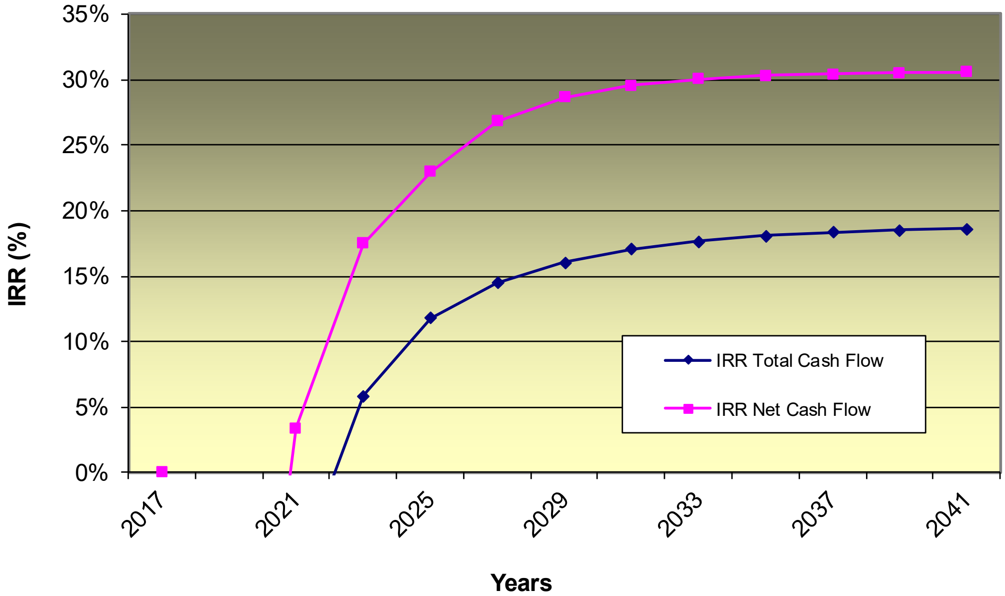

FIGURE 8: Internal Rate of Return (IRR) for the project

6.3 Financial indicators/ratios

The debt service coverage (DSCR) of the project was computed for this project to determine the after tax cash flow of the project on a year-to-year basis relative to the amount of money for loan repayment (principal and interest). The debt service coverage rises from 1.8 in 2018 to reach a stable high of 2.0 in 2023.

Similarly, the loan life cover ratio (LLCR) was also computed to show the number of times the after tax cash flow throughout the life time of the project can be able to repay the outstanding debts. The loan life cover ratio is 2.5 on average and hence higher than the minimum acceptable threshold of 1.5 (Figure 9).

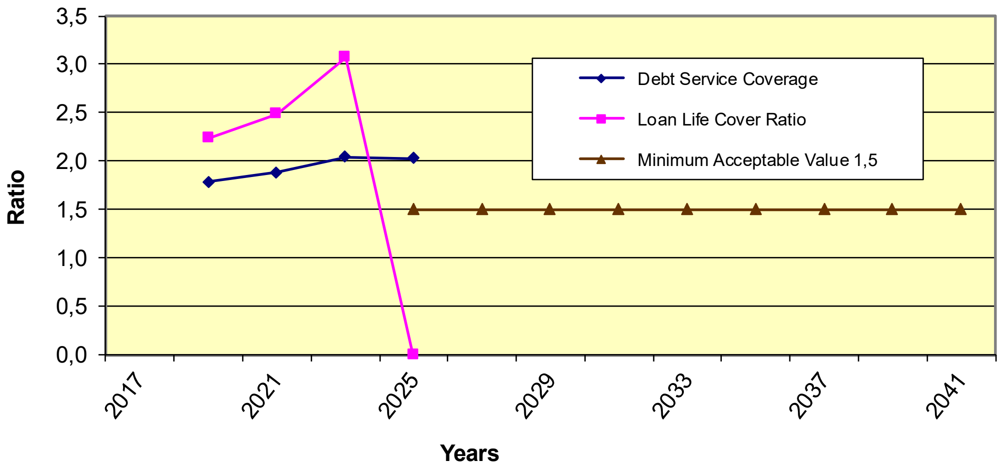

FIGURE 9: Debt service coverage ratio and loan life cover ratio

6.4 Risk assessment analysis

Impact analysis: As part of the financial assessment, risk assessment using sensitivity analysis was carried out to determine the sensitiveness of equity IRR relative to a given change in input parameters. The sensitiveness and size of impact of prices and sales quantities of both elemental sulphur and liquid

CO_2, and buildings and equipment costs on the project IRR was carried out. One variable at a time was changed by a specified percentage, both above and below the most-likely value, while the other variables were held constant at the base case value. The output was then calculated for the new value; in this case the output being IRR of equity. The results of the one-way sensitivity analysis for all variables are as shown in Figure 10 below.

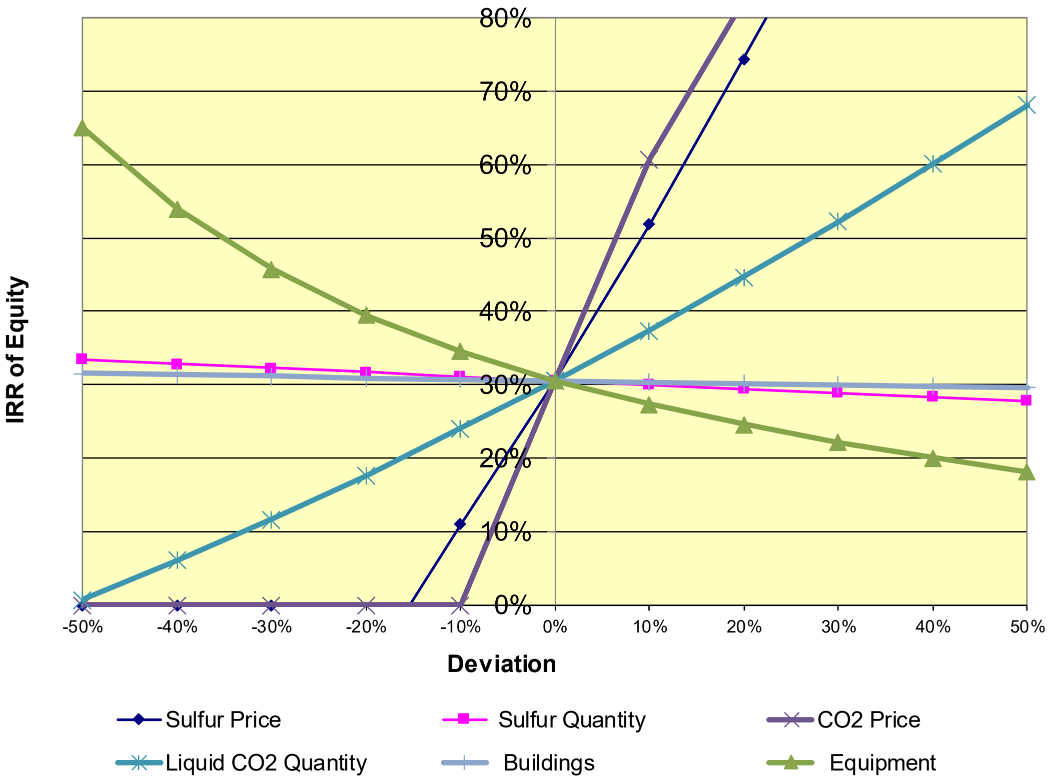

FIGURE 10: Impact analysis of the project

The line of CO_2 price is the steepest compared to others factors implying that the equity IRR is very sensitive to the selling price and quantities of CO_2. When the CO_2 price increases by 10% equity IRR increases by 61%.

On the contrary, GDC will lose profits if the sales price of CO_2 goes down by 5% which would result in a decrease of equity IRR of 14%. Equity IRR is also very sensitive to the sales price of sulphur. However, its impact is not as big as that of the price of CO_2. In addition, equity IRR is also sensitive to the cost of equipment. A 50% decrease in the cost of equipment will increase the equity IRR by 66%, while a 50% increase will increase equity IRR by 21%.

7. DISCUSSION

It is noted that the biggest component of the total capital investment (79%) is used for the desulphurization unit while the rest will be needed for the CO_2 purification and liquefaction unit.

The NPV of total cash flows and NPV for equity are both positive. The positive NPV demonstrates that the proposed project is acceptable or profitable. The production of elemental sulphur alone will not generate sufficient revenues for the project to break even. At a price of 150 \$/ton, the production of elemental sulphur will not be able to pay its variable cost of 198 \$/ton. A decrease in the demand below the capacity used in this study will make the project non-profitable.

The IRR of total cash liabilities and IRR of net cash flows of 19% and 34% are greater than the marginal attractive rate of return of equity (MARR) of 15% and 20%, respectively. The debt service coverage ratio and loan life cover ratio (LLCR) are also higher than the acceptable minimum acceptable threshold of 1.5. Consequently, on the basis of the results of the IRR and financial ratios the project is profitable enough to operate over the planned period.

Sensitivity analysis shows that the IRR of the project is significantly affected by changes in prices and quantity of liquid CO_2 and elemental sulphur. A drop in the price of sulphur and CO_2 by10% and16%, respectively, will make the IRR negative. A drop in the sales volume from the base value of 17,382 tons will make the investment uneconomical. This means that GDC's priority in the project will be to have long term contracts and assured markets for the 17,382 tons of CO_2 produced. Other parameters including the operational and maintenance, buildings and equipment costs have less impact on the profitability of the plant.

Revenue that may accrue to the project as a result of trading in the certified emission reductions (CERs) have not been taken into consideration in this study due to the recent collapse of the CERs markets and Kenya´s current ineligibility to trade its CERs in the European Union – Emission Trading Scheme.

8. CONCLUSIONS

This study demonstrates that the extraction of elemental sulphur and liquid CO_2 for commercial purposes is financially viable, i.e. results in positive NPV and IRR. Production of elemental sulphur alone is uneconomical but a combination of the two products can generate sufficient cash flows for meeting the project´s operational costs as surplus/profit. The surplus cash flows can significantly improve the economics of the project.

Through this project, Menengai field can provide alternative local elemental sulphur supply and reduce the country´s reliance on imports. Market analysis carried out in this study indicate that the two new fertilizer manufacturing factories being erected in Nakuru and Eldoret could provide a ready market for the 5,655 tons of elemental sulphur which are expected to be produced from the field.

To mitigate risks, further assessment on the accuracy and reliability of the demand for liquid CO_2 is proposed. This study also recommends identification of opportunities for further utilization of the remaining 95% CO_2 not considered. These large quantities could provide a source of potential revenues in the future.

Logistic and distribution chain requirements (costs and risks) for the two products are recommended before positioning the products in the market.

Protection of the environment is an increasingly important consideration in the current production of energy from geothermal sources. An avenue for minimizing the environmental impact of the harmful geothermal gases hydrogen sulphide and CO_2 is therefore, to convert them into marketable products. The emissions avoided during the extraction process as demonstrated in this study proves that the extraction process is an option that can be successfully applied in other geothermal fields in the world with high NCG concentrations. The net effect is the elimination of the effects of the two gases on the environment as well as improving the economics of geothermal power plants.

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APPENDIX I: Financial model of the project

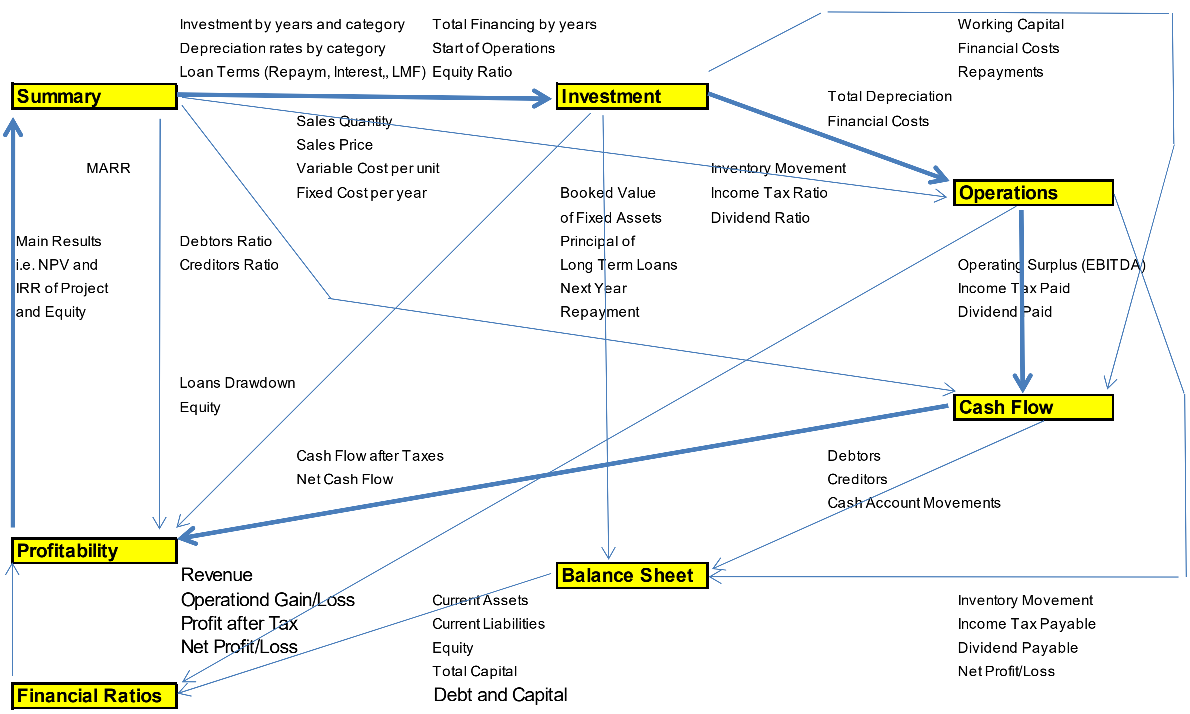

FIGURE 1: Profitability model summary

TABLE 1: Investment

Investment

Investm and Financing		2.017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039	2041	Total
		1	3	5	7	9	11	13	15	17	19	21	23	25	
Investment:															
Buildings		389.552	0	0	0	0	0	0	0	0	0	0	0	0	**389.552**
Equipment		8.085.156	0	0	0	0	0	0	0	0	0	0	0	0	**8.085.156**
Other		1.164.707	0	0	0	0	0	0	0	0	0	0	0	0	**1.164.707**
		9.639.415	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**9.639.415**
Booked Value of Fixed Assets															
Buildings		389.552	358.388	327.224	296.059	264.895	233.731	202.567	171.403	140.239	109.075	77.910	46.746	15.582	
Equipment		8.085.156	5.659.609	3.234.062	808.516	0	0	0	0	0	0	0	0	0	
Other		1.164.707	698.824	232.941	0	0	0	0	0	0	0	0	0	0	
Total Booked Value		**9.639.415**	**6.716.821**	**3.794.227**	**1.104.575**	**264.895**	**233.731**	**202.567**	**171.403**	**140.239**	**109.075**	**77.910**	**46.746**	**15.582**	**39.686.146**
Depreciation:															
Depreciation Buildings	4%	-	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	**342.806**
Depreciation Equipm.	15%	-	1.212.773	1.212.773	1.212.773										**5.659.609**
Depreciation Other	20%	-	232.941	232.941											**698.824**
Total Depreciation		**-**	**1.461.297**	**1.461.297**	**1.228.355**	**15.582**	**15.582**	**15.582**	**15.582**	**15.582**	**15.582**	**15.582**	**15.582**	**15.582**	**6.701.239**
Financing:															
Equity	0	2.933.824	-	-	- -	0 -	0								**2.933.824**
Loans	1	6.845.590	-	-	- -	0 -	0								**6.845.590**
Total		**9.779.415**	**-**	**-**	**- -**	**0 -**	**0**								**9.779.415**
Loans:															
Drawdown		6.845.590	0	0	0	0	0	0	0	0	0	0	0	0	
Repayment	8		**855.699**	**855.699**	**855.699**	**855.699**									**6.845.590**
Principal	-	6.845.590	5.134.193	3.422.795	1.711.398	-	0	0	0	0	0	0	0	0	
Interest	0	-	359.393	256.710	154.026	51.342	0	0	0	0	0	0	0	0	**1.848.309**
Loan Managem. Fees	2%	136.912	0	0	0	0	0	0	0	0	0	0	0	0	**136.912**

TABLE 2: Operations

Operations

Operations Statement		2.017	2.019	2.021	2.023	2.025	2.027	2.029	2.031	2.033	2.035	2.037	2.039	2.041	Total
Operations Statement															
Sales Sulfur		-	5.287	5.287	5.287	5.287	5.287	5.287	5.287	5.287	5.287	5.287	5.287	5.287	**126.886**
Sales Liquid CO2		-	17.382	17.382	17.382	17.382	17.382	17.382	17.382	17.382	17.382	17.382	17.382	17.382	
Sulfur Price		-	150	150	150	150	150	150	150	150	150	150	150	150	
Liquid CO2 Price		-	393	393	393	393	393	393	393	393	393	393	393	393	
Revenue Sulfur		**-**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	**793.035**	
Revenue Liquid CO2		**-**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**6.830.985**	**163.943.649**
Revenue		**-**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**7.624.020**	**182.976.479**
Variable Cost	198		4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	4.486.360	**107.672.637**
Fixed Cost	901.537		901.537	901.537	901.537	901.537	901.537	901.537	901.537	901.537	901.537	901.537	901.537	901.537	**21.636.886**
Diverse Taxes															
Operating Surplus (EBITDA)		**-**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**2.236.123**	**53.666.956**
Inventory Movement		-	-												
Depreciation		-	1.461.297	1.461.297	1.228.355	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	15.582	**9.623.833**
Operating Gain/Loss (EBIT)		**-**	**774.826**	**774.826**	**1.007.768**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**44.043.124**
Financial Costs		136.912	359.393	256.710	154.026	51.342	0	0	0	0	0	0	0	0	**1.985.221**
Profit before Tax	-	**136.912**	**415.433**	**518.117**	**853.742**	**2.169.199**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**2.220.541**	**42.057.903**
Loss Transfer	0 -	136.912	-	-	-	-	-	-	-	-	-	-	-	-	
Taxable Profit		-	415.433	518.117	853.742	2.169.199	2.220.541	2.220.541	2.220.541	2.220.541	2.220.541	2.220.541	2.220.541	2.220.541	
Income Tax	30%	-	124.630	155.435	256.123	650.760	666.162	666.162	666.162	666.162	666.162	666.162	666.162	666.162	**12.617.371**
Profit after Tax	-	**136.912**	**290.803**	**362.682**	**597.619**	**1.518.439**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**29.440.532**
Dividend	0%	-	-	-	-	-	-	-	-	-	-	-	-	-	**-**
Net Profit/Loss	-	**136.912**	**290.803**	**362.682**	**597.619**	**1.518.439**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**1.554.379**	**29.440.532**

TABLE 3: Cash flow

Cash Flow

		2.017	2.019	2.021	2.023	2.025	2.027	2.029	2.031	2.033	2.035	2.037	2.039	2.041	Total
Cash Flow															
Operating Surplus (EBITDA)		-	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	53.666.956
Debtors	0	-	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	
Debtor Changes		-	-	-	-	-	-	-	-	-	-	-	-	- -	635.335
Greditors	0	-	-	-	-	-	-	-	-	-	-	-	-	-	
Creditor Changes			-	-	-	-	-	-	-	-	-	-	-	-	-
Financing - Expenditure (Wcap)		140.000	-	-	- -	0 -	0 -	0	-	-	-	-	-	-	140.000
Cash Flow before Tax		140.000	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	2.236.123	53.171.621
Paid Taxes		-	68.154	140.032	170.838	392.803	666.162	666.162	666.162	666.162	666.162	666.162	666.162	666.162	11.951.208
Cash Flow after Tax		140.000	2.167.969	2.096.091	2.065.286	1.843.321	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	41.220.413
Interest & Loan Man Fee		136.912	359.393	256.710	154.026	51.342	0	0	0	0	0	0	0	0	1.985.221
Repayment		-	855.699	855.699	855.699	855.699	-	-	-	-	-	-	-	-	6.845.590
Net Cash Flow		3.088	952.877	983.682	1.055.561	936.280	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	32.389.601
Paid Dividend			-	-	-	-	-	-	-	-	-	-	-	-	-
Cash Movement		3.088	952.877	983.682	1.055.561	936.280	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	32.389.601
Cash Flow ratios:															
Debt Service Coverage			1,8	1,9	2,0	2,0									
Loan Life Cover ratio:															
NPV of Cash Flow	6%		11.497.531	8.509.085	5.258.264	1.738.982	4.468.119	6.884.841	9.035.715	10.949.985	12.653.679	14.169.961	15.519.446	16.720.482	
Principal			5.134.193	3.422.795	1.711.398										
Loan Life Cover Ratio			2,2	2,5	3,1	-									
Minimum Acceptable Value	1,5					1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	

TABLE 4: Balance sheet

Balance

Balance Sheet		2017	2019	2021	2023	2025	2027	2029	2031	2033	2035	2037	2039	2041	
Assets															
Cash Account	0	3.088	1.290.319	3.221.745	5.296.927	7.254.825	10.410.150	13.550.071	16.689.993	19.829.915	22.969.836	26.109.758	29.249.680	32.389.601	
Debtors		-	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	635.335	15.248.040
Stock	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Current Assets		3.088	1.925.654	3.857.080	5.932.262	7.890.160	11.045.485	14.185.406	17.325.328	20.465.250	23.605.171	26.745.093	29.885.015	33.024.936	375.288.682
Fixed Assets		9.639.415	6.716.821	3.794.227	1.104.575	264.895	233.731	202.567	171.403	140.239	109.075	77.910	46.746	15.582	39.686.146
Total Assets		9.642.503	8.642.475	7.651.307	7.036.837	8.155.056	11.279.216	14.387.973	17.496.731	20.605.488	23.714.246	26.823.003	29.931.761	33.040.519	414.974.828
															-
Debts															-
Dividend Payable		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Taxes Payable		-	124.630	155.435	256.123	650.760	666.162	666.162	666.162	666.162	666.162	666.162	666.162	666.162	12.617.371
Creditors		-	-	-	-	-	-	-	-	-	-	-	-	-	-
Next Year Repayment		855.699	855.699	855.699	855.699	-	-	-	-	-	-	-	-	-	6.845.590
Current Liabilities		855.699	980.329	1.011.134	1.111.821	650.760	666.162	666.162	666.162	666.162	666.162	666.162	666.162	666.162	19.462.961
Long Term Loans		5.989.892	4.278.494	2.567.096	855.699	-	0	0	0	0	0	0	0	0	
Total Debt		6.845.590	5.258.823	3.578.230	1.967.520	650.760	666.162	666.162	666.162	666.162	666.162	666.162	666.162	666.162	
Equity	0	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	2.933.824	
Profit & Loss Balanc	0 -	136.912	449.828	1.139.252	2.135.493	4.570.471	7.679.229	10.787.986	13.896.744	17.005.502	20.114.259	23.223.017	26.331.774	29.440.532	
Total Capital		2.796.913	3.383.653	4.073.077	5.069.317	7.504.296	10.613.053	13.721.811	16.830.568	19.939.326	23.048.084	26.156.841	29.265.599	32.374.356	
Debts and Capital		9.642.503	8.642.475	7.651.307	7.036.837	8.155.056	11.279.216	14.387.973	17.496.731	20.605.488	23.714.246	26.823.003	29.931.761	33.040.519	

TABLE 5: Profitability

Profitability

Profitability Measurements		2.017	2.019	2.021	2.023	2.025	2.027	2.029	2.031	2.033	2.035	2.037	2.039	2.041	Total
NPV and IRR of Total Cash Flow															
Cash Flow after Taxes		-140.000	2.167.969	2.096.091	2.065.286	1.843.321	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	40.940.413
Total Capital		-9.779.415	-	-	-	-	-	-	-	-	-	-	-	-	-9.779.415
Total Cash Flow & Capital		-9.919.415	2.167.969	2.096.091	2.065.286	1.843.321	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	31.160.998
NPV Total Cash Flow	15%	-9.919.415	-6.888.129	-4.301.341	-2.373.991	-1.027.051	-188.321	442.568	919.611	1.280.324	1.553.075	1.759.314	1.915.260	2.033.178	
IRR Total Cash Flow			-44%	-8%	6%	12%	14%	16%	17%	18%	18%	18%	19%	19%	
NPV and IRR of Net Cash Flow															
Net Cash Flow		3.088	952.877	983.682	1.055.561	936.280	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	32.389.601
Equity		-2.933.824	-	-	-	0	0	-	-	-	-	-	-	-	-2.933.824
Net Cash Flow & Equity		-2.930.736	952.877	983.682	1.055.561	936.280	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	1.569.961	29.455.777
NPV Net Cash Flow	20%	-2.930.736	-1.990.388	-967.541	-204.273	298.590	859.402	1.246.781	1.515.795	1.702.610	1.832.342	1.922.434	1.984.998	2.028.446	15.035.359
IRR Net Cash Flow		0%	-37%	3%	18%	23%	27%	29%	30%	30%	30%	30%	31%	31%	
Financial Ratios															
Profit+Interest/Debt+Capital (ROI)			8%	10%	14%	31%	23%	17%	14%	12%	10%	9%	8%	7%	
Profit/Shareh. Capital (ROE)			9%	10%	13%	25%	17%	13%	10%	8%	7%	6%	6%	5%	
Asset Turnover Ratio			83%	94%	106%	105%	78%	59%	48%	40%	34%	30%	27%	24%	
Equity Ratio			39%	53%	72%	92%	94%	95%	96%	97%	97%	98%	98%	98%	
Net Current Ratio			2,0	3,8	5,3	12,1	16,6	21,3	26,0	30,7	35,4	40,1	44,9	49,6	
Liquid Current Ratio			2,0	3,8	5,3	12,1	16,6	21,3	26,0	30,7	35,4	40,1	44,9	49,6	
Internal Value of Shares			1,2	1,4	1,7	2,6	3,6	4,7	5,7	6,8	7,9	8,9	10,0	11,0	
Price/Earnings Ratio			11,6	11,2	8,5	4,9	6,8	8,8	10,8	12,8	14,8	16,8	18,8	20,8	