Feasibility study of utilizing surplus energy from Landsvirkjun for the production of Substitute Natural Gas

by

Vignir Bjarnason

Thesis

Master of Science in Sustainable Energy

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Thesis submitted to the School of Science and Engineering
at Reykjavík University in partial fulfillment
of the requirements for the degree of
Master of Science in Sustainable Energy

January 2013

Supervisor:

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Examiner:

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Abstract

Over 80% of the energy used in Iceland today comes from domestic renewable energy sources. Around 70% of the energy produced from domestic renewable energy comes from hydro power. The largest producer of renewable hydro power in Iceland is Landsvirkjun. At present there is a substantial part of that hydro power energy which goes to waste during parts of the years when water flows over the spillways of full reservoirs. This research thesis proposes a solution to utilizing this energy. The main idea is to utilize the surplus or unsecured energy generated by Landsvirkjun to produce a renewable synthetic fuel or Substitute Natural Gas. This is to be done using the Sabatier reaction process. The equipment that is referred to in this research is being developed by SolarFuel GmbH in Germany. The research focuses mainly on what is needed to make the production described work and whether it can be considered feasible, both technically and financially. In order to get a sense of any economies of scale three scenarios are set up of different sizes for the SNG plant. The conclusion to the research is that the project is technically possible but at best marginally financially feasible. Future development of the technology could change the outcome of the project as well as possibly higher fossil fuel prices.

Key words:

Substitute Natural Gas, Surplus Energy, Feasibility, CO_2 Capture

Möguleg nýting umframorku Landsvirkjunar til framleiðslu Metangass - Arðsemismat

Útdráttur

Yfir 80% af þeirri orku sem nýtt er á Íslandi í dag er framleidd með innlendum og endurnýjanlegum auðlindum. Yfir 70% af orkunni sem framleidd er á Íslandi er frá vatnsafli og er framleitt af stærstum hluta af Landsvirkjun. Sem stendur fer töluverður hluti af vatnsaflinu til spillis á þeim tíma árs þegar öll lón eru full og vatn rennur yfir yfirföll stíflna. Í þessari rannsóknarritgerð er lögð fram tillaga að lausn á þessu. Meginhugmyndin er að nýta þessa orku sem er umframorka og ótryggð orka til þess að framleiða metan gas. Til þess að framleiða metan gasið er notaður svokallaður „Sabatier Reaction Process“. Sá búnaður sem miðað er við í þessari rannsókn er frá SolarFuel GmbH í Þýskalandi. Rannsóknin snýr að mestu að því hvaða þættir þurfa að vera til staðar og hvort að hægt sé að framkvæma þetta á bæði tæknilega og fjárhagslega hagkvæmann hátt. Til þess að fá hugmynd um hvort það sé einhver stærðar hagræðing til staðar þá eru sett upp þrjú tilvik sem eru mismunandi að stærð. Niðurstaða rannsóknarinnar er að þessi framleiðsla er tæknilega framkvæmanleg en í besta falli tæplega fjárhagslega hagkvæm. Hugsanlegar tækniframfarir sem og hugsanlegar hækkanir á olíuverði í framtíðinni geta haft mikil áhrif á framtíðarmöguleika þessa verkefnis.

Lykilorð:

Substitute Natural Gas, Surplus Energy, Feasibility, CO_2 Capture

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List of Abbreviations

NG – Natural Gas

SNG – Substitute Natural Gas

CNG – Compressed Natural Gas

LNG – Liquefied Natural Gas

BMG – Bio Methane Gas

SEGC – Surplus Energy Generation Capacity

H_2 - Hydrogen

CO_2 – Carbon Dioxide

O_2 – Oxygen

DCC – Direct Contact Cooler

FGD – Flue Gas Desulphurization

MEA – Monoethanolamine

SOFC – Solid Oxide Fuel Cell

PEM – Polymer Electrolyte Membrane

TPD – Tons per Day

LLCR – Loan Life Coverage Ratio

NPV – Net Present Value

IRR – Internal Rate of Return

CR – Capital Ratio

MARR – Marginal Attractive Rate of Return

EUR – Euros

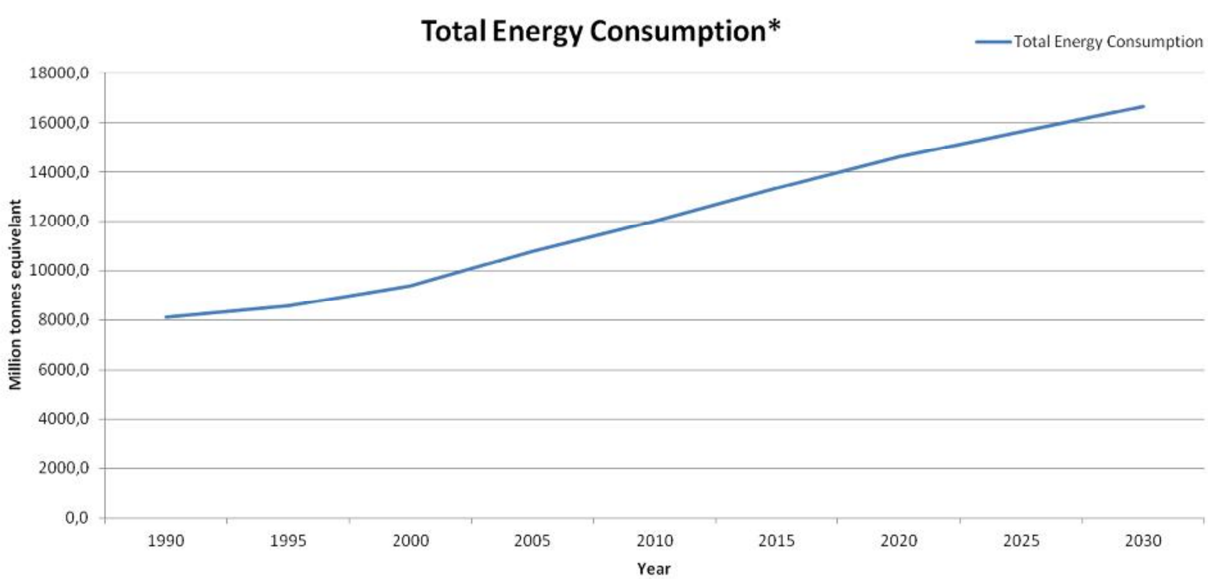
KEUR – Thousand Euros

MEUR – Million Euros

1. Introduction

1.1. Main research motives

Most aspects of the modern lifestyle have some connection to energy. Whether it entails travelling to and from work, cooking lunch or vacuuming the living room floor, people use energy in one form or another for most things. This reality creates a huge demand for energy of all types. The demand for energy can have many aspects ranging from using electricity for space heating to using fuel to transport goods. Global energy consumption has been on the rise for decades and does not seem to be diminishing. This trend is clearly visible when the global consumption of primary energy is examined as can be seen in Graph 1-1 (BP Statistics, 2012).

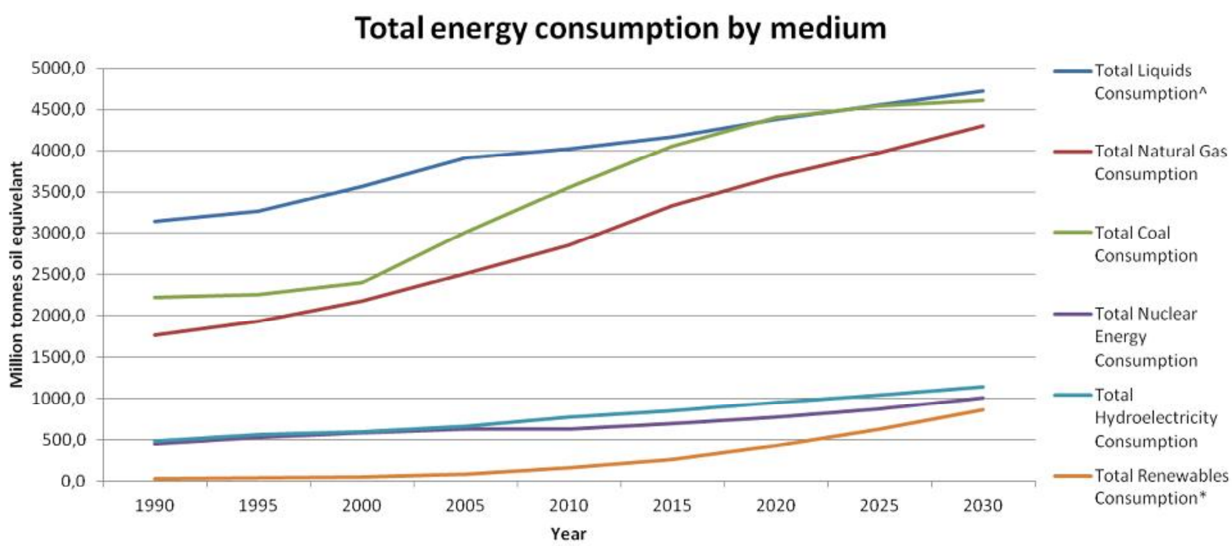


*Energy consumption comprises commercially traded fuels, including modern renewables used to generate electricity.

Graph 1-1 Total Global Energy Consumption (BP Statistics, 2012)

Energy can be harnessed from various sources. Most common means of energy production are fossil fuels, i.e. oil, gas and coal. Other means of energy production are nuclear energy, hydroelectric energy, geothermal energy, wind energy, solar energy and other sources. Fossil fuels can both be used for electricity production for base load requirements as well as a fuel for transportation and shipping. Nuclear energy, hydroelectric energy, geothermal energy and the other mediums can for the most part only be used for electricity production and not as a fuel.

As Graph 1-2 (BP Statistics, 2012) shows, fossil fuels count for the most part of the total global energy consumption. Renewable sources as well as nuclear energy count for a small amount of the total energy consumption compared to fossil fuels.



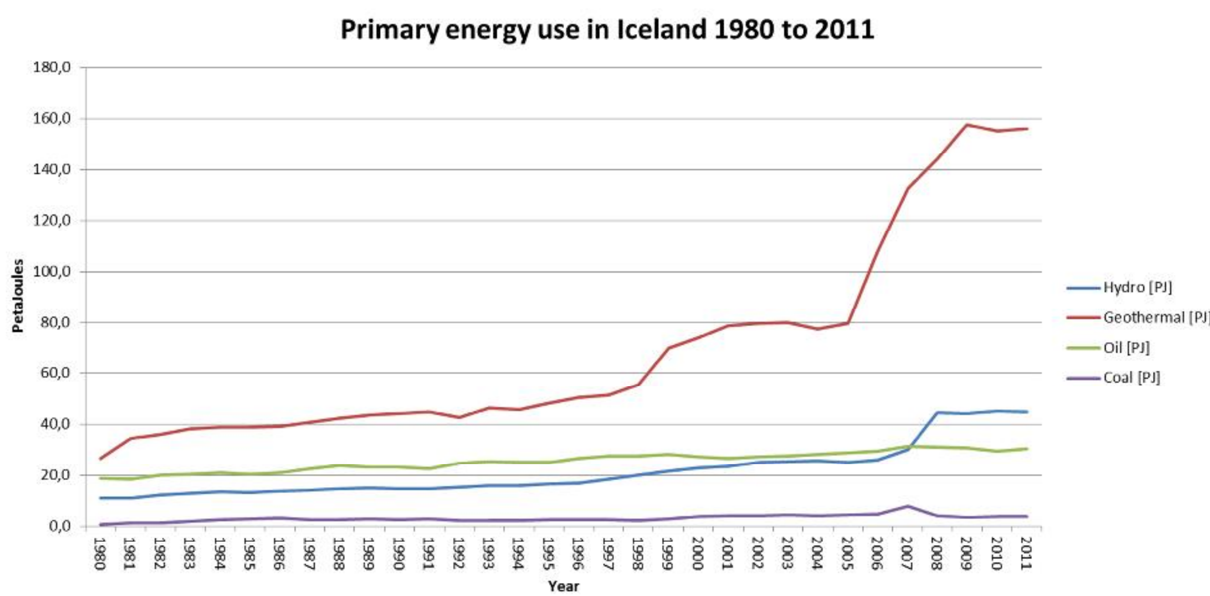
^ Includes oil, biofuels, gas-to-liquids and coal-to-liquids.
* Includes wind power, solar electricity and other renewables.

Graph 1-2 Total Global Energy consumption by medium (BP Statistics, 2012)

Fossil fuels do however have the drawback of polluting when used in combustion, whether it is for electricity production or for use in transportation. CO_2 emissions are considered among the worst pollutants today. According to the IPCC, fossil fuel use accounts for 57% of the total global greenhouse gas emissions (IPCC, 2007).

With the ever increasing awareness of the impact pollution from the use of fossil fuels has on the environment, the search and development of alternative means of energy production is increasing. The effort to reduce dependency on fossil fuel for energy production is in full swing and governments as well as companies are trying hard to reduce carbon emissions.

Iceland is one of the countries that can be considered fortunate in this respect whereas most of its domestic energy is produced from renewable sources such as hydroelectric sources and geothermal sources (The National Energy Authority, 2012). The country is rich in possible sources for both hydroelectricity and geothermal energy. As mentioned above Iceland gets 80% of its primary energy supply from renewable sources. The remaining 20% is from imported fossil fuels, which are mostly used in the transportation and fisheries sectors. Iceland is completely dependent on other nations for its supply of fossil fuels. There is no domestic production of fossil fuels in Iceland. This means that the country has to import all of its fuel for transportation and industries from abroad at great cost (European Commission, 2011).



Graph 1-3 Primary energy use in Iceland (The National Energy Authority, 2012)

Graph 1-3 shows the total energy use in Iceland. Geothermal energy is used extensively in Iceland for space heating as well as for industrial processes. If the electricity production in Iceland is examined, it becomes apparent that of all the electricity produced around 73% is produced by hydro power and around 27% by geothermal sources (Hagstofa Íslands, 2012).

Renewable energy can be considered to be a possible way forward in the quest to reduce the overall dependency on fossil fuels and to reduce the related CO_2 emissions. Renewable energy is generated using energy from the environment, i.e. hydroelectricity, wind energy, geothermal energy, wave energy or other similar means. Not all countries possess natural resources that can be harnessed for renewable energy.

Renewable energy sources battle a few flaws, among which are the security of supply. Security of supply is one of the most important aspects of energy generation, i.e. to be able to predict how much energy can be produced in the future is essential for any energy producer that intends to plan ahead. Solar power and wind power are very unstable by nature, wind is sometimes high and sometimes low, and sunshine isn't always readily available especially in a country like Iceland.

The steady nature of hydroelectric energy and geothermal energy has made the two the favorite form for electricity production in Iceland. The demand for energy is also quite flexible and can be high at certain times as well as it can be low at other times. Hydroelectric energy generation is considered quick to respond to changes in demand and it is possible to vary energy production in line with demand. It is however not possible to store endless amounts of water. If energy production is slowed down, water builds up to the point where the water starts to flow into the spillways of the dams, this inevitably leads to energy being wasted.

There is also a tendency to build power plants bigger than absolutely necessary in order to cope with years where there is a shortage of water. This creates a surplus energy generation capacity (SEGC) in the years with plenty of water. This surplus energy production capacity is in essence wasted energy, i.e. when the reservoirs fill up, the water flows over the spillways without producing any work.

1.2.Energy storage

The SEGC brings up the topic of energy storage, because the surplus capacity could be put to use if the energy could by stored somehow. There are several methods of storing energy. These methods include:

Thermal energy storage refers to the method of storing heat directly in solids or fluids. This method is ideally suited for applications such as space heating, where low quality, low temperature energy is needed (Ter-Gazarian, 2011).

Flywheel storage refers to the method of storing energy in the form of mechanical kinetic energy in flywheels. This method has the drawback of only being able to release energy for a comparatively short time period (Ter-Gazarian, 2011).

Pumped hydro storage refers to the method of pumping water into reservoirs during low load hours of the day and utilizing the pumped water for energy generation during high load hours. Pumped storage requires a reservoir and access to plenty of water. Since pumped hydro requires such specific geographical conditions it can be difficult to realize.

Compressed air storage refers to a method developed by Stal Laval in 1949, which uses underground caverns as pressure vessels for compressed air. The air is then routed under high pressure trough a generator to produce energy (Ter-Gazarian, 2011).

Hydrogen and other synthetic fuels refers to the energy storage method of using energy to power a chemical process that produces a synthetic fuel that can be stored and later be used for combustion or other means of energy generation (Ter-Gazarian, 2011).

Capacitor bank storage refers to the method of storing energy in the form of an electrostatic field (Ter-Gazarian, 2011).

Electrochemical energy storage refers to the method of storing energy in primary batteries, secondary batteries and fuel cells. Here the energy is stored as chemical energy and later converted to electrical energy (Ter-Gazarian, 2011).

Superconducting magnetic energy storage refers to the experimental method of storing significant quantities of energy in magnetic fields (Ter-Gazarian, 2011).

For this feasibility study the selected method of energy storage is synthetic fuel or Substitute Natural Gas (SNG).

The reason for using SNG rather than any of the other technologies has to do with the interesting possibilities it presents. Storing SNG uses the same technology as storing Natural Gas (NG) and therefore the potential of storing large quantities of reserve gas is a possibility. The flexibility of SNG is also very appealing. In fact SNG can be used for electricity generation using Gas Turbines, used as fuel for combustion engines with minor mechanical changes and be burned directly for space heating, cooking and more.

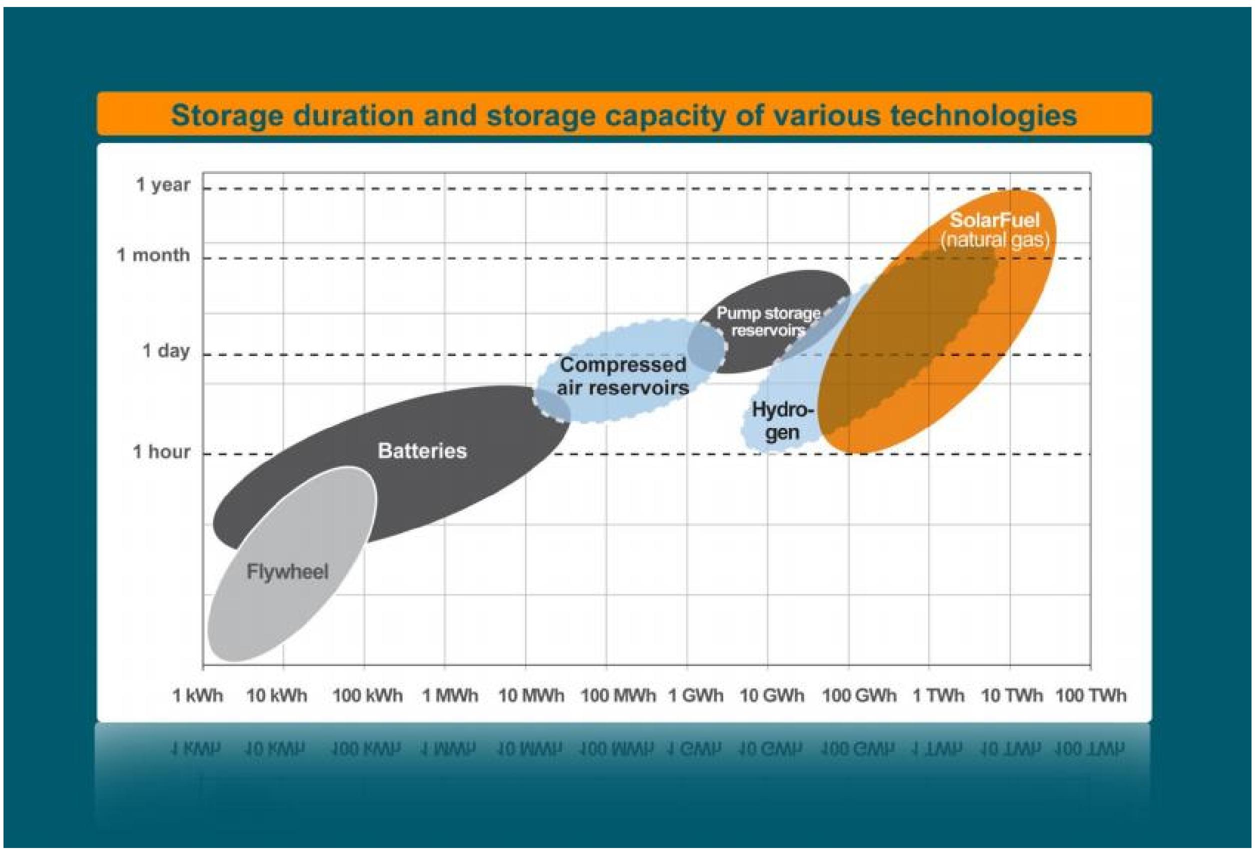


Figure 1-1 Capacities and storage duration of various technologies (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012)

As can be seen from Figure 1-1 the potential of SNG is great. The possibility of storing large quantities opens up the option of having large reserves of gas to be used at a later date.

The fact that SNG can be used as a fuel for transportation with only minor changes to the vehicles engines is a huge benefit (M. Mozaffarin, 2004). As stated before, Iceland is completely dependent on fossil fuel imports to serve its needs. A domestic production of SNG opens up the possibility of supplying the demand for fossil fuel in Iceland partially or fully with SNG. In all aspects this would be a great benefit for Iceland. It would reduce Iceland’s dependency on foreign fossil fuel imports as well as generate revenue inside the country’s economy instead of having capital flowing out of the economy.

1.3. Main research questions

The Surplus Energy Generation Capacity (SEGC) in Iceland is the spark that ultimately led to this project. The question is: Is it possible to have a production cycle that utilizes the SEGC to produce fuel, so that it can be shut off in the dry periods or high demand periods where all the water is needed for the already existing customers?

The technology used in the proposed solution is a production cycle which utilizes the SEGC for the production of Substitute Natural Gas (SNG) or Methane gas. This cycle is also known as the Sabatier reaction process.

The possibility of using the SEGC for the production of alternative fuel instead of electricity to the grid is intriguing. This could change Iceland's dependency on fossil fuel imports as well as making the country partly self-sufficient with regards to fuel for its transportation and fisheries sectors.

So the main research questions are:

- Is the proposed solution economically feasible?
- How much SNG could theoretically be produced using the proposed solution?
- How might the domestic production of SNG impact Iceland's dependency on fossil fuel imports?

The answers to these questions might help predict the future of SNG production in Iceland, i.e. if it could serve as a viable alternative fuel.

1.4.Thesis structure and approach

The first chapter serves as the introduction into the inspiration behind the project as well as a broad description of the project itself and the main research questions.

In the second chapter the main sources of literature used as a basis for this thesis are reviewed. The significance of each source will be stated and how it affects the topic of the thesis.

In chapter 3 the technological aspects of the projects are explored. The technology used for the generation of the SNG is explained as well as a careful rundown of all the systems used in the process from electricity to SNG. There will also be a mention of the possible uses of SNG as well as storage, distribution, etc... The possible sources of CO_2 will also be discussed.

In chapter 4 the proposed plant/s will be discussed. The three different scenarios (5MW, 20MW and 40MW) will be laid out and explained before using the information as a basis for the financial assessment.

In chapter 5 the financial aspects of the project will be explored. Where the revenue is to come from etc… The possibility to exploit some of the carbon capture schemes such as Cap n Trade, European Union Emission Trading Scheme (ETS) and more will be examined.

In chapter 6 the information that has been gathered will be used to build a profitability assessment which will then establish whether the project can be considered feasible or not. All assumptions will be stated clearly and the methodology explained. The results of the assessment will be explained.

In chapter 7 the risk analysis of the project will be performed. This is done to see how the projects financials will react to different scenarios of revenue and cost. This helps to determine if the project is in fact a safe option for investment.

In chapter 8 the main results of the project will be summarized and discussed. The possible impact of the project will also be a topic along with a discussion on the significance of the project.

In chapter 9 the conclusions of the paper will be discussed.

2. Literature Review

The main sources of literature that were used in the process of this project will be addressed and explained here.

Storing Renewable Energy in the Natural Gas Grid – Methane via Power-to-Gas (P2G): A Renewable Fuel for Mobility

M. Specht, U. Zuberbuhler, F. Baumgart, B. Feigl, V. Frick, B Sturmer, M. Sterner, G. Waldstein

Centre for Solar Energy and Hydrogen Research (ZSW), Fraunhofer Institute for Wind Energy and Energy System Technology (IWES), SolarFuel GmbH

This report talks about the possibility of producing SNG, using wind and solar power, for storage in the German gas grid. It is one of the papers which sparked interest in this topic and ultimately led to the topic selection of this thesis project.

Hybrid PV-Wind-Renewable Power Methane Plants – An Economic Outlook

Ch. Breyer, S. Rieke, M. Sterner, J. Schmid

Reiner Lemoine Institute, Kassel University, Q-Sells SE, SolarFuel GmbH, Fraunhofer IWES

This report highlights the economic outlook of the SNG production and sparked interest in the topic of this thesis project.

Fluor's Econamine FG Plus^{SM} Technology for CO_2 Capture at Coal-Fired Power Plants

S. Reddy, D. Johnson, J. Gilmartin

Power Plant Air Pollutant Control Symposium, Baltimore

This report provides valuable information about the CO2 capture process used in this thesis project. The Econamine FG Plus process is a proven process which is used around the world.

Energy Storage for Power Systems, 2nd Edition

A.G. Ter-Gazarian

The Institution of Technology and Engineering, 2011 London

There are several methods that can be used to store renewable energy. The book points out available ways of storing energy and the pros and cons of each technology.

The method that was selected is, storing renewable energy as a synthetic fuel. There are even several synthetic fuels that can be used. Probably the best known method is to use Hydrogen (H_2) as a medium. The decision was made to use the method of storing renewable energy as methane gas or as Substitute Natural Gas (SNG) for the purposes of this project.

Bioenergy and renewable power methane in integrated 100% renewable energy systems – Limiting global warming by transforming energy systems

Doctoral Dissertation by Dr. Michael Sterner

2009, Kassel University

The main focus of the doctoral dissertation is the use of SNG (a synthetic fuel) to store the surplus energy produced by solar power and wind power in Germany. The means of storing the gas is the Natural Gas (NG) infrastructure of Germany, which has a real storage capacity of 217 TWh (Sterner, 2009). The SNG is to be produced at times of high production capacity with low demand for energy and then stored in the NG pipelines.

The main topic used from the dissertation is the use of the Sabatier reaction process for the production of SNG. This part of the dissertation is adapted to suit the proposed solution in this project. The main difference is that the energy available in Iceland is generated by hydro power and that there is no infrastructure with regard to NG.

3. Technological Aspects

This chapter discusses the different technological aspects and how these aspects affect the project and its outcome.

The SNG production requires a few things to run. The SNG production itself uses CO_2 and H_2 for the production of SNG. The CO_2 is processed from the flue gas of some industrial process and the H_2 is produced via electrolysis of water. Electricity is used to power these processes. The requirements of the SNG plant dictate where the plant can be set up, these factors are discussed here.

3.1. Possible locations

When the possible locations for the SNG production plant are being considered, the process itself has to be assessed. The process requires energy in the form of electricity, plus CO_2 and water for the electrolysis. Other factors such as proximity to the highway system have to be taken into account as well.

Since CO_2 is in many cases a byproduct of industry, industrial sites seem to be a logical place to start. The most common heavy industry in Iceland is Aluminum smelting and Ferrosilicon production. These industrial processes produce CO_2 in great quantities. Another benefit is that these processes require large industrial sites that could possibly accommodate the synthesis plant. Logistics at these sites are also easier with close proximity to both the highway system as well as large harbors for transportation. Both Aluminum smelting and Ferrosilicon production requires large quantities of electricity which means that the High Voltage grid at these industrial sites are very good and can be modified to accommodate the SNG production.

The Ferrosilicon plant at Grundartangi is the CO_2 source that is going to be used for the purposes of this project. The CO_2 source for the project is a deciding factor in determining where to place the SNG plant and therefore Grundartangi is the site where the SNG plant will operate for the purposes of this project.

The benefits of setting up the SNG plant at Grundartangi are obvious. With a large scale Aluminum smelter and a Ferrosilicon plant already in operation, Grundartangi is already a wellestablished industrial site. With close proximity to the highway network of Iceland and a harbor which can accommodate bulk carriers and container vessels, it is an ideal site with regards to transportation connections. Also with two large consumers of electrical energy the site has high capacity high voltage connections which reduce the cost of connecting to the grid. Water is also readily available at the site. So all in all, Grundartangi provides the ideal location for the SNG plant.

Figure 3-1 Aerial photograph of Grundartangi industrial site, Elkem Ferrosilicon plant showing (Google Maps, Google Corporation, 2012)

Figure 3-1 shows a theoretical plant location for the SNG production plant. The figure shows a building location denoted in yellow and the flue gas pipe routing is denoted in red. The main purpose of the figure is to show a possible plant location and not to taken as an accurate representation.

As can be seen in Figure 3-1 there is plenty of room in the vicinity of the Elkem Ferrosilicon plant. This makes it easier to find a suitable location for the plant with full reference to the production and work that already exists on the industrial site.

3.2.Energy

Landsvirkjun supplies the Ferrosilicon plant at Grundartangi with electricity and therefore grid connections are readily available.

The main driver behind this research project is to find a use for the off peak and unsecured energy which Landsvirkjun has available. The main electricity production of Landsvirkjun is through hydroelectric installations. These hydroelectric installations are very good at supplying both base load and peak load energy. The main driver behind the available off peak and unsecured energy is the different demand. Demand for electricity can vary quite a bit with regard to time of year and even with regard to time of day.

In the long term, Landsvirkjun assumes that its energy production capacity is fully utilized or to the point where secure supply is reached. There are periods where the energy production capacity is not fully utilized, but this surplus is categorized as unsold energy rather than surplus energy generation capacity which can be had at a lower price (Björnsson, 2012).

The electricity that Landsvirkjun is generating is defined into three categories.

Category 1 – Base load energy – This category is for regular base load energy with delivery as close to 8760 hours per year as possible. Price and quantity is negotiated with Landsvirkjun. The quantity available is determined by the quantity of unsold energy available in the generation system of Landsvirkjun (Björnsson, 2012).

Category 2 – Surplus energy – This category is for surplus energy available in the generation system. This energy has flexible delivery and Landsvirkjun has the authority to reduce delivery during dry years to a maximum of 50%. The probability of 100% delivery is approximately for 50% of years. For approximately 5% of years the possible reduction in delivery is close to the agreed upon limit of 50%. Readily available energy is close to 70 MW (Björnsson, 2012).

Category 3 – Unsecured energy – This category is for the real surplus energy, i.e. this energy has seasonal availability and there is the possibility of years where there is no available energy in this category. This might happen in one of every ten years. The months of the year where this energy is available, are July, August, September and October. The available quantity is close to 50 MW (Björnsson, 2012).

The energy is as stated above divided into three separate categories. These categories are base load energy, surplus energy and unsecured energy. The difference between the energy in each category is availability. The availability also affects the price of the energy as will be discussed in Chapter 4.

The energy which is the most appealing to use for an SNG plant is the category 2 – surplus energy. The quantity of energy is around 70 MW and that is quite enough for all the scenarios proposed for this project. The only issue with the surplus energy would be the security of supply. As stated above, the availability is 100% delivery for approximately 50% of years. So for a 10 year period there would be 100% delivery for 5 years, between 100% and 50% for 4-5 years and close to 50% delivery for 0,5-1 year.

The use of the category 3 – unsecured energy will also be explored and as well as the impact of more downtime vs. the lower energy price.

3.3. CO_2 capture technology

The technology used to capture the CO2 which is one of two gases used for the production of SNG is very important to the process. Whereas the availability of a source for pure CO2 is very limited, a chemical process is used to capture CO2 from flue gas.

3.3.1. CO2 Capture using Econamine FG plus

There are a number of methods used for capturing CO_2 from various sources. These methods are Post-combustion capture, Pre-combustion capture, Oxy-fuel combustion and Direct-air capture. Of these methods, only Post-combustion capture and Direct-air capture can be used in this project. This is because both Pre-combustion and Oxy-fuel combustion are used to modify the fuel before combustion or to affect the combustion itself (Sarah M. Forbes, 2008). Since the CO_2 source used in this project is a Ferrosilicon plant using electric arc furnaces, there is no combustion to modify. Direct-air capture technology has been used in industry for over 70 years, although on a much smaller scale than proposed in this project. The main drawback of Direct-air capture is its high costs (Manya Ranjan, 2011).

Post-combustion capture refers to a method that removes CO_2 from flue gas of industrial processes. Usually Post-combustion capture systems can be built into existing industrial plants and power stations without heavy modifications to the original plant. There are several methods of Post-combustion capture of CO_2. The most commonly used method is passing the flue gas through filters where the CO_2 is absorbed into amine based solvents. A change in temperature or pressure is then used to release the CO_2 from the solvent.

The Econamine FG Plus process is one of the premier commercially proven Post-combustion processes for the recovery of CO_2 from flue gases (Dan G. Chapel, 1999). It uses an inhibited 30 wt. % Monoethanolamine (MEA) solution. The features of the process allow the use of carbon steel instead of stainless steel as well as lower stripper reboiler steam demand, which translates into more competitive costs. The process can recover 85-90% of the CO_2 in flue gas and produces 99,95%+ pure CO_2. The process can be used on SO_X containing flue gas after SO_2 scrubbing. The additional SO_2 scrubbing returns an environmental benefit (Dan G. Chapel, 1999).

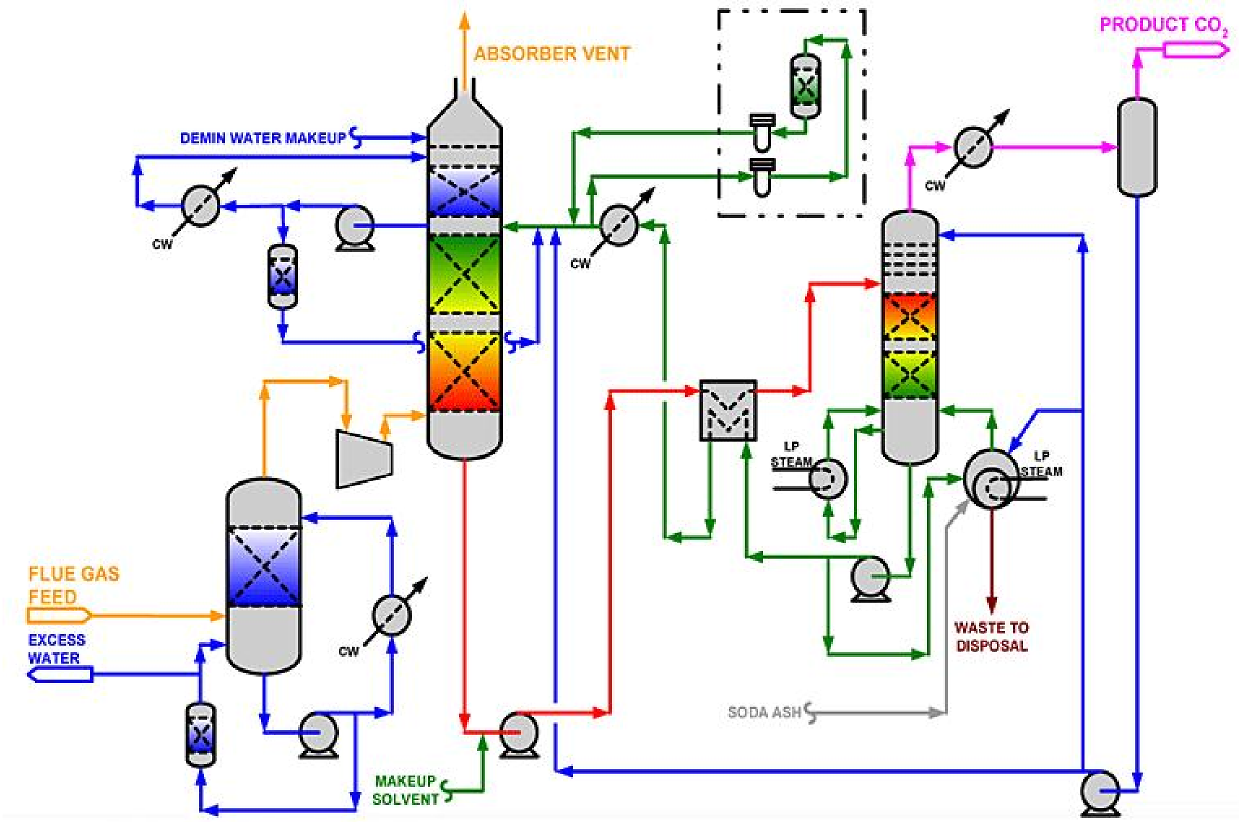


Figure 3-2 Schematic drawing of the Econamine FG Plus CO_2 capture process (Econamine FG Plus Process, 2012)

Figure 3-1 shows a schematic drawing of a typical Econamine FG Plus CO_2 capture flow sheet. The flue gas feed is in yellow where it enters the Direct Contact Cooler (DCC) which also serves as a Flue Gas Desulphurization (FGD) unit. The SO2 has to be removed whereas it contributes to the degradation of the MEA solution if left in the flue gas. The flue needs to be cooled down to below 50°C before it enters the absorber unit. Lower heat of the flue gas increases the absorption performance of the MEA solution. Then the flue gas travels to the CO_2 absorber unit. Hereafter the CO_2 is denoted in red. From the absorber the CO_2 travels through a heat extractor which generates low pressure steam for the process. From the heat extractor the CO_2 is denoted in purple as Product CO_2 (Satish Reddy, 2008).

3.3.2. CO_2 Source Characteristics

The CO_2 source is very important for this project. The effort required for capturing CO_2 from flue gas depends a lot on the composition and characteristics of the flue gas in question. For this project the flue gas of the ELKEM Ferrosilicon plant in Grundartangi, Iceland is used.

The ELKEM Ferrosilicon plant exhausts around 400.000 tons of CO_2 every year (Hannesson, 2012).

Basic Flue Gas Composition						
		Mol % of Flue Gas				
Furnace	**Vol. Nm3/klst**	**CO_2**	**SO_2**	**O_2**	**N_2**	**Ar**
1	180.000	3,99	0,013	19,29	74,87	0,89
2	180.000	3,99	0,013	19,29	74,87	0,89
3	240.000	3,82	0,013	19,32	75,00	0,89

Table 3-1 ELKEM Ferrosilicon Flue gas basic composition (Hannesson, 2012)

The Econamine FG plus CO_2 capture process is specifically engineered to work with flue gases which have very low CO_2 partial pressures. Usual percentages of CO_2 in flue gas are around 3-13%. The process can process CO_2 from flue gas with a CO_2 percentage of as low as 3%. With the flue gas stream of the ELKEM Ferrosilicon plant containing just under 4%, it is within the range of the Econamine FG plus CO_2 capture process (Econamine FG Plus Process, 2012).

Other criteria for CO_2 capture is the ratio of O_2 in the flue gas. If the flue gas contains high levels of O_2 in the flue gas the use of stainless steel or other corrosion resistant metal is needed. The Econamine FG plus CO_2 capture process uses an inhibitor to both protect the metal and inhibit amine solution degradation. This inhibitor allows for the use of carbon steel instead of corrosion resistant metals, which is a big benefit from a cost standpoint. The inhibitor used requires at least a O_2 ratio of 1,5% to maintain activity. The Econamine FG plus CO_2 capture can operate with flue gas O_2 levels of up to 20%. The flue gas from the ELKEM Ferrosilicon plant meets these requirements with a small margin, i.e. the O_2 percentage is 19,29% which is close to the maximum of 20% (Econamine FG Plus Process, 2012).

3.4. Synthesis technology

The proposed plant solution is to use the Sabatier reaction process for the purpose of methanation. This production of SNG via the Sabatier reaction has three core processes. The first core process is the electrolysis, which converts hydroelectricity and water into O_2 and H_2. The second core process is a source of CO_2, which can be had from various industrial and natural sources. The third core process is the Sabatier reaction process, this is where the H_2 and CO_2 are converted to SNG with water as a byproduct (Ch. Breyer, 2011).

The source for the information on the SNG production plant is SolarFuel GmbH in Germany. SolarFuel, in collaboration with German research institutes, has successfully developed technology which enables the conversion of electricity into SNG. This in turn allows SNG to be stored. SolarFuel has already built and is successfully operating an alpha plant which uses 25 kW with an overall power-to-gas efficiency of 40% (Ali-Oettinger, 2012). The power-to-gas efficiency of larger SNG plants is going to be in the range of 60-63% not utilizing waste heat. When utilizing waste heat the plant efficiency could reach 80% (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012).

The equipment which constitutes the SolarFuel SNG production plant is an Electrolysis reactor and a Methanation reactor. The proposed plant also uses a Econamine FG plus CO_2 capture process to supply the CO_2 needed for the Methanation.

3.4.1. Electrolysis

Electrolysis has a conversion efficiency of electricity to hydrogen in the range of 62-80% (Sterner, 2009). Electrolysis uses electricity to decompose water into H_2 and O_2. The most widely used technology for electrolysis in industry is alkaline electrolysis. This method uses caustic potassium hydroxide at a process temperature of 70-140°C. Alkaline electrolysis equipment uses a working pressure of 1-200 bars and are available and widely used in capacities of >0,1MW_{el}. Two other methods are available for electrolysis, these are polymer electrolyte membrane (PEM) and solid oxide fuel cell (SOFC). These methods have drawbacks such as high costs, small capacities and limited membrane lifetime (Sterner, 2009).

3.4.2. Methanation

Methanation is a standard technology used in coal gasification and has been developed for use in biomass gasification. Approximate efficiency that can be reached in methanizing SNG is 75%-85% (Sterner, 2009). Methanation is a catalytic exothermal process at temperatures of 180-350°C and pressure of 1-100 bars. CO_2 methanation (equation 3.4.2-1) is a combination of reversed endothermal water-gas-shift-reaction (equation 3.4.2-2) and an exothermal CO methanation (equation 3.4.2-3). This reaction is called the Sabatier process and was discovered in 1913, but has not been applied to energy systems until recently (Sterner, 2009).

$$4H_2 + CC_2 \leftrightarrow CH_4 + 2H_2O \quad \Delta H_R = -164{,}9\, kJmol^{-1} \quad (equation\, 3.4.2-1)$$

$$H_2 + CC_2 \leftrightarrow CO + H_2O \quad \Delta H_R = 41{,}5\, kJmol^{-1} \quad (equation\, 3.4.2-2)$$

$$3H_2 + CO \leftrightarrow CH_4 + 2H_2O \quad \Delta H_R = -206{,}4\, kJmol^{-1} \quad (equation\, 3.4.2-3)$$

Pure CO_2 methanation is not yet a state-of-the-art technology and is currently under research by SolarFuel GmbH. Prototype tests as well as laboratory tests show a CO_2 methanation rate of up to 95% at 6-7 bar pressures and 280°C (Sterner, 2009).

3.4.3. Basic Concept of SNG Production

The outline of how the SNG plant is to operate needs to be clear. Resources for the SNG plant, such as its energy, CO2 and water.

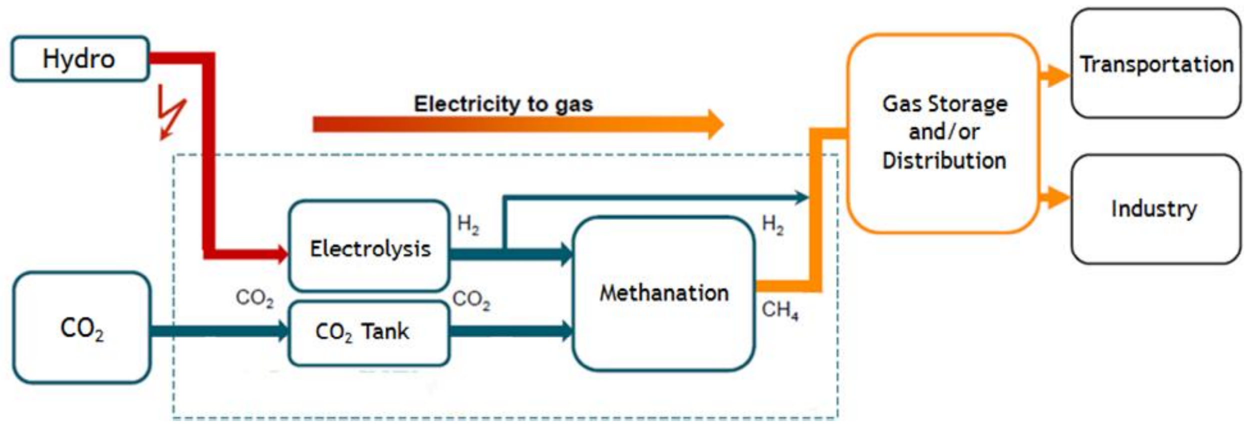


Figure 3-3 Basic concept of renewable power to SNG plant (Source: Own compilation)

Figure 3-3 shows a basic concept drawing of the proposed SNG plant and connected systems. The electricity, as stated before is produced by Landsvirkjun and is generated using hydropower. The CO_2 is captured from the flue gas of ELKEM Ferrosilicon plant at Grundartangi and piped to the SNG plant where it is compressed before entering the process. Water for the electrolysis is readily available at the Grundartangi industrial site through the local water pipeline.

The SNG exits the plant at close to atmospheric pressure and is in a continuous stream. The SNG is then compressed for storage or distribution. There is also the possibility of constructing a pipeline from the SNG plant to the possible customers.

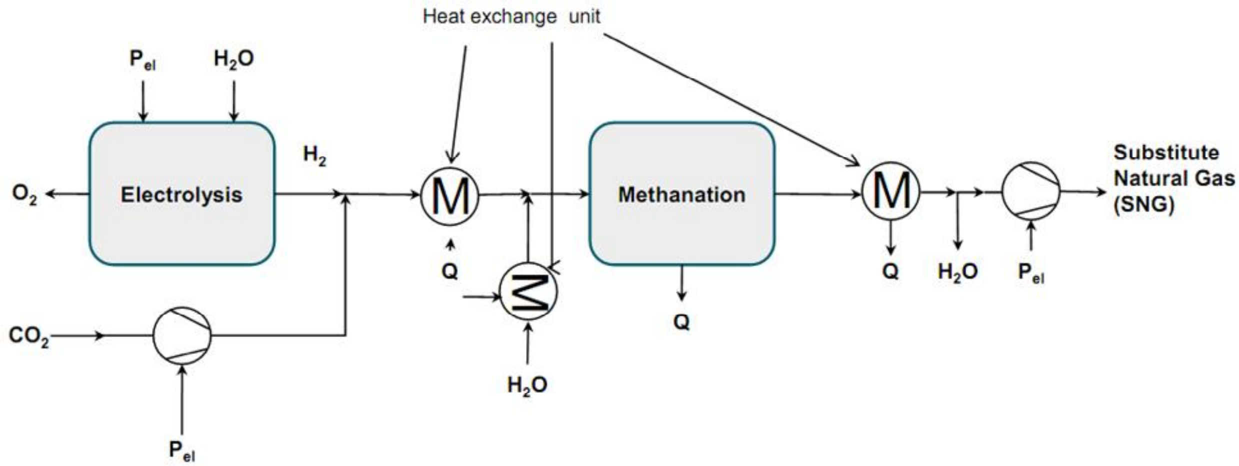


Figure 3-4 Drawing of SNG plant in more detail (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012)

Figure 3-4 shows the constituent parts of the SNG plant. It also shows what is needed for the production and what is produced. For example, the electrolysis reactor needs electricity (P_{el}) and water (H_2O) and it produces oxygen (O_2) and hydrogen (H_2). There are heat exchangers at various points in the process, these are used to add to the efficiency as well as utilizing waste heat for steam generation (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012).

Steam is used to heat up the gases entering the methanation reactor as well as being added to the gas stream in front of the methanation reactor to avoid carbon deposits and catalyst deactivation (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012).

There are pumps at both ends of the process. The pump in front of the process is used to get the CO_2 up to working pressure for the methanation process. The working pressure of the methanation unit is at a maximum of 10 Bar (Sterner, 2009). The pump at the end of the process is used to compress the SNG before it goes into distribution or storage.

3.4.4. Efficiency

Efficiency is very important. It is one of the most important criteria for success of a process such as the proposed SNG plant. The efficiency of the SNG plant basically refers to how much of the initial electricity which is put into the process comes out in the form of SNG and as useful heat. Since SNG is the main product of the process the efficiency of converting electricity into SNG is the main concern. Useful heat from the process is a byproduct, which can be used for space heating or generation of electricity from a steam powered turbine (useful heat >300°C).

Figure 3-5 Drawing which shows the efficiencies of the SNG process (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012)

Figure 3-5 shows how the electrical energy which enters the process is used and how much of that energy is converted to SNG. As can be plainly seen the efficiency of converting electricity into SNG is, according to this drawing, 61,6% (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012).

The combined efficiencies electrolysis and methanation in SNG generation is in the range of 46-75%, on average 63%. The SNG to electricity efficiency is around equal to standard gas power generating technologies and combined heat and power plants with an efficiency of up to 60% in combined cycle power plants (Sterner, 2009).

Figure 3-5 does not take into account the electricity used for the process of CO2 capture. It only accounts for the electricity used in the operation of the SolarFuel SNG plant.

3.4.5. Gas Conversion

The whole idea of SNG production revolves around conversion of gases. The process is basically converting H_2 and CO_2 into CH_4. The conversion rate and the properties of the Product Gas are very important to the success of the process.

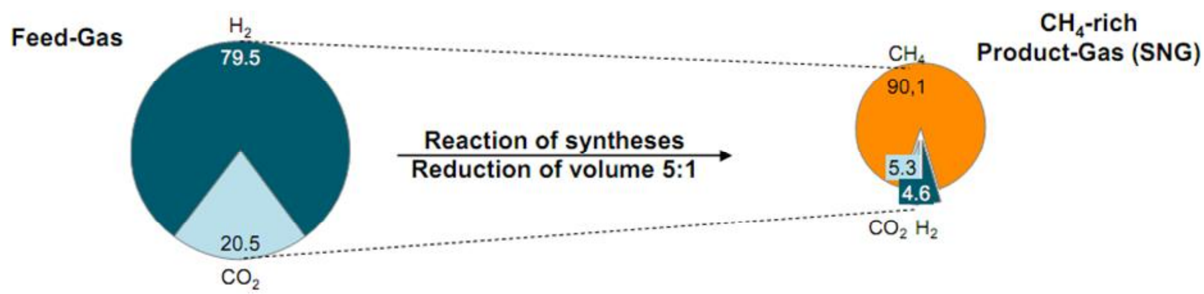


Figure 3-6 Drawing which shows the actual conversion of gases (Rieke, Power-to-gas technology-the missing link in renewable energy systems, 2012)

Figure 3-6 shows the ratio between H_2 and CO_2 when entering the methanation reactor. 79,5% of H_2 versus 20,5% of CO_2. The product gas leaving the system is 90,1% pure CH_4 with a ratio of 5,3% of unconverted CO_2 and 4,6% of unconverted H_2. The unconverted CO_2 and H_2 in the SNG do not affect the SNG's quality and the SNG is sold without further separation (Rieke, Engineer at SolarFuel Gmbh, 2012).

There is also another big benefit to converting H_2 and CO_2 to CH_4, besides fuel production, and that is the overall reduction in volume. The volume of H_2 is in essence reduced to form a more energy dense gas, CH_4. If the input is roughly 5 m^3 of gas, 1 m^3 of CO_2 and 4 m^3 of H_2, the output is 1 m^3 of SNG product gas. So in a way the production of SNG is a way to more efficiently store H_2.

3.5. Transportation and storage methods

It is assumed that the SNG production plant will only be a wholesale company, supplying the SNG as a continuous stream of gas at atmospheric pressure or as a compressed gas.

This assumption is made because natural gas (NG) has not been used to a great extent in Iceland and therefore there is very little in the form of infrastructure for NG. The only available method for transportation and storage of gas in Iceland is in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). Both CNG and LNG use high pressure containers to store the SNG, with LNG using cryogenic cooling as well. Liquefied gas is stored at around 200 bar pressure and at a -162°C. At this pressure and temperature the SNG takes up approximately 600 times less space than at atmospheric pressure. CNG is natural gas compressed to 200 bar – 275 bar of pressure and stored in thick steel, aluminum or composite containers. The liquefaction of the SNG is expensive and storage difficult due to the need to keep the liquefied gas cold. CNG is also expensive but considerably cheaper than LNG.

4. Proposed Plant/s

It is necessary to set up scenarios in order to be able to figure out variables and calculate costs. For the purposes of this project, three scenarios are set up. The main variable used to distinguish between the three set ups is the energy requirements of the SolarFuel SNG plant. This variable controls the size and production of the project.

The energy requirements for this project are 5 MW, 20 MW and 40 MW. These scenarios are set up to be able to estimate if there is any economy of scale present in the project and to be able to get an idea of how big the project needs to be in order to make profit. These energy requirements are also chosen because they fit into the available supply of category 2 – surplus energy from Landsvirkjun.

A key component of the financial calculations is the available annual running time or how many hours per year the plant is going to be able to produce SNG. When the annual running time is figured out the production capacity of each of the three scenarios can be calculated.

It is assumed for all three scenarios that the location of the SNG plant is Grundartangi industrial site. Access to enough water is assumed to be available. Electricity is assumed to be coming from Landsvirkjun.

4.1. Annual Running Time

The energy that can be used from Landsvirkjun is the category 2 – surplus energy and the category 3 – unsecured energy. Possible down time due to energy shortage presents the problem of the possibility of having to reduce production during some years. For the purposes of this project, instead of calculating each year and building in shortage the decision is to use an average for the available running time.

4.1.1. Category 2 Available Running Time

From the information from Landsvirkjun, it is stated that the probability of 100% delivery is in approximately 50% of years and in approximately 5% of years the reduction is likely to be close to the agreed upon limit of 50% (Björnsson, 2012).

So in order to figure out how many hours per year the SNG plant can operate it is necessary to make assumptions. For the purposes of this project it is assumed that, for a 10 year period, there is 100% delivery for 5 years, 75% delivery for 4 years and 50% delivery for 1 year.

So: $(5 \cdot 1) + (4 \cdot 0{,}75) + (1 \cdot 0{,}5) = 8{,}5 => \frac{85}{10} = 0{,}85\ or$ 85% delivery can be assumed

There are 8766 hours in one year, which means that it can be assumed that the SNG plan can operate for 85% of those 8766 hours

So: $8766 \cdot 0{,}85 = 7451{,}1$

For the purposes of this project it is assumed that the SNG plant can operate at full capacity for 7400 hours per year.

4.1.2. Category 3 Available Running Time

For the category 3 energy it is assumed that the energy delivery is close to 50% for 5 years out of 10 and 35% for 5 years out of 10.

So: $(5 \cdot 0{,}5) + (5 \cdot 0{,}35) = 4{,}25 => \frac{425}{10} = 0{,}425\ or$ 42,5% delivery can be assumed

So: $8766 \cdot 0{,}425 = 3725{,}55$

For the purposes of this project it is assumed that the SNG plant can operate at full capacity for 3725 hours per year.

4.2. Production Information for Each Scenario

For each scenario the following assumptions are made:

- Annual running time is 7.400 hours
- The conversion efficiency from electricity to SNG is 60%
- The energy content of m^3 of SNG is 39Mj/m^3 or 10,8 Kwh/m^3
- The efficiency of the electrolysis is 75%
- The volume of gas from 1 liter of electrolyzed water is: H_2 = 1018,7 liters & O_2 = 509,3 liters

Scenarios - Cat 2 Energy		5 MW	20 MW	40 MW
SNG plant size in KWel		5.000	20.000	40.000
Running time		7.400	7.400	7.400
KWh/year		37.000.000	148.000.000	296.000.000
SNG KWh/year		22.200.000	88.800.000	177.600.000
SNG M^3/year		2.055.556	8.222.222	16.444.444
Gas used for the production of CH_4	CO_2 Nm^3/year	2.106.944	8.427.778	16.855.556
	H_2 Nm^3/year	8.170.833	32.683.333	65.366.667
Water usage	Water t/year	8.021	32.083	64.165
	Water l/m	15	61	122
Production gas - Actual sales product				
	SNG Nm^3/year	2.055.556	8.222.222	16.444.444
	O_2 Nm^3/year	4.084.514	16.338.057	32.676.115

Table 4-1 Calculated numbers for each scenario as derived from sourced information ((Rieke, Engineer at SolarFuel Gmbh, 2012)

Table 4-1 shows the calculated production capacities as well as how much of each component gases and water is needed for the production. This table only accounts for the energy demand of the SolarFuel SNG plant and not the energy demanded by the CO_2 capture system.

Scenarios - Cat 3 Energy		5 MW	20 MW	40 MW
	SNG plant size in KWel	5.000	20.000	40.000
	Running time	3.725	3.725	3.725
	KWh/year	18.625.000	74.500.000	149.000.000
	SNG KWh/year	11.175.000	44.700.000	89.400.000
	SNG M^3/year	1.034.722	4.138.889	8.277.778
Gas used for the production of CH_4	CO_2 Nm^3/year	1.060.590	4.242.361	8.484.722
	H_2 Nm^3/year	4.113.021	16.452.083	32.904.167
Water usage	Water t/year	4.037	16.150	32.299
	Water l/m	8	31	61
Production gas - Actual sales product				
	SNG Nm^3/year	1.034.722	4.138.889	8.277.778
	O_2 Nm^3/year	2.056.056	8.224.225	16.448.450

Table 4-2 Calculated numbers for each scenario as derived from sourced information (Rieke, Engineer at SolarFuel Gmbh, 2012)

The scenarios in Table 4-2 are using all the same values and information as Table 4-1, with the only variable changed being the number of available running hours per year.

For the cost calculations it is critical to be able to see if it is indeed financially viable to invest in this kind of SNG plant in order to run it using the category 3 – unsecured energy. All cost information for the scenarios will remain the same with only the available running time changed.

5. Financial Aspects

Primary concerns for any kind of project are its financial aspects. How much is it going to cost and which are the main sources of revenue? These are the questions that need answering before a decision is made to go forward with the project or not. This chapter is an attempt to answer these questions.

5.1.Costs

The costs are the starting point of any financial analysis. To find the cost information for this project, some help was needed. Companies which design and produce the equipment needed were helpful in most cases and provided cost information for the purposes of this project. With the information from chapter 3 and 4 it is possible to calculate the costs incurred by each of the three scenarios.

5.1.1. Building

In Iceland the weather can become rather extreme at times. In winter there are high winds with rain, snow and sleet. All this can present a problem for fragile industrial equipment. The only option is to house the equipment in a building. For this project, a simple steel frame industrial building is needed.

The CO_2 capture equipment is designed to be outside and withstand the elements and therefor the only equipment which needs to be housed is the SolarFuel methanation equipment, i.e. the electrolysis reactor and the methanation reactor.

The building only needs to be a simple, industrial building and the space requirements for the SolarFuel SNG plants are as follows (Rieke, Engineer at SolarFuel Gmbh, 2012).

- For an installation of 5 MWel: 1200 m^2 is required
- For an installation of 20 MWel: 3000 m^2 is required
- For and installation of 40 MWel: 5000 m^2 is required

To get a realistic idea of the building cost in Iceland today, real world examples are an option. The examples chosen were from two very recently finished industrial projects in Iceland. One was for a building of 1000 m^2 and the other for a building of 4000 m^2. These should give a realistic figure for the cost of the required buildings. Both buildings are very simple industrial structures which meet the criteria set forth (Þorfinnsson, 2012).

The 1000 m^2 building cost was approximately 144.000 ISK/m^2 and the building cost for the 4000 m^2 building cost was approximately 110.000 ISK/m^2. These numbers are for a finished building with all needed components for work to be started (Þorfinnsson, 2012).

Using the ISK to EUR exchange rate of 164,1 ISK to 1 EUR.

This means, that the cost of construction for the buildings is as follows.

- For 5 MWel at 1200 m^2 it is 1.053.016 EUR
- For 20 MWel at 3000 m^2 it is 2.010.968 EUR
- For 40 MWel at 5000 m^2 it is 3.351.614 EUR

5.1.2. Power Lines and Flue Gas Piping

The need to pipe the flue gas to and from the CO2 capture system calls for added costs. For the purposes of this project the cost of the flue gas piping and the piping for CO2 from the CO2 capture system into the SNG plant are assumed to be included in the price of the systems. This is possible due to the small size of the industrial site and the close proximities of the SNG plant and the CO2 capture system.

The SNG plant requires a 20 Kv connection to the grid (Rieke, Engineer at SolarFuel Gmbh, 2012). The transformer station that supplies Grundartangi industrial site with energy is approximately 5 km away. The cost of a 25 Kv power line is in the range of 3,2 – 4,2 MISK/Km or 19500 -25600 EUR/KM (Haraldsson, 2002), adjusted using inflation percentages for Iceland (Hagstofa Íslands, 2012).

Transmission Line Cost			
Scenarios	**5 MW**	**20 MW**	**40 MW**
Distance	5	5	5
€/KM	19500	23000	25000
Cost	97.500	115.000	125.000

Figure 5-1 Calculated cost of the transmission lines needed for the SNG plant (Haraldsson, 2002).

5.1.3. CO_2 Capture Equipment

There was a lot of difficulty in getting real numbers for the capital and operation and maintenance cost of CO_2 capture. This is due to the heavy industrial secrecy on the systems used as well as the proprietary nature of the solvents and inhibitors so critical to the efficiency of the systems. Due to this, the numbers used for the cost analysis of the CO_2 capture have a level of uncertainty and need to be viewed with that in mind.

There is no information available regarding the CO_2 capture from the flue gas of a Ferrosilicon plant and because of that a close approximation was needed. The flue gas characteristics of a Natural Gas Combined Cycle plant (NGCC) are a very close approximation, in key areas, to that of the Ferrosilicon plant. These areas are the low CO_2 content of the flue gas and the relatively high O_2 content. So for the purposes of this cost estimation, the modular cost numbers for a NGCC plant are used (Dan G. Chapel, 1999).

The initial capital cost of a NGCC plant is in the range of 973 €/Kw to 1834 €/Kw *(adjusted numbers from 2008 to 2012, using OECD Consumer Price index for inflation in Germany)* of installed capacity (Tzimas, 2009) (OECD.StatExtracts, 2012). The three scenarios are for an installation of an SNG plant of the size of 5 MW, 20 MW and 40 MW. Using the quantities of CO_2 given in Table 4-1 it is calculated that the needed CO_2 quantities are 15 tpd/CO2 and 45 tpd/CO_2 and 90 tpd/CO_2, respectively. In terms of the technology in CO_2 capture today, these quantities can be considered small. Sizes of CO_2 capture range from a few hundred tons per day into several thousand tons per day. Because of the small size of the plant and the fact that the system needs to be retrofitted to the Ferrosilicon plant, it is assumed that the overnight capital cost is to be in the high range for that of the NGCC plants, or 1700 €/Kw.

The energy needed for CO_2 capture is in the range of 0,297 Kwh/kg and 0,354 Kwh/kg (Howard Herzog, 2004). For the purposes of this project the assumption is made that since the CO_2 capture is small scale, it does not benefit from economies of scale and therefore uses more energy than larger operations. It is therefore assumed that the energy requirements are 0,35 Kwh/kg of CO_2 captured.

CO$_2$ Capture			
Scenarios	**5 MW**	**20 MW**	**40 MW**
tons/year	4.000	15.500	30.500
Kwh/kg	0,35	0,35	0,35
Kwh/year	1.400.000	5.425.000	10.675.000

Table 5-1 Energy requirement calculations for the CO2 capture system (Howard Herzog, 2004)

Table 5-1 shows how much energy each scenario requires for its CO_2 capture needs. This energy is not included in the 5 MW, 20 MW or 40 MW and will be added to the overall energy need of the SNG plant.

Cost of CO$_2$ Capture			
Scenarios	**5 MW**	**20 MW**	**40 MW**
€/Kw	1700	1700	1700
Kw Capacity	160	620	1.250
Initial Capital Cost	272.000	1.054.000	2.125.000

Table 5-2 Calculated initial capital cost of CO2 Capture using Econamine FG plus (Tzimas, 2009)

Table 5-2 describes the initial capital cost of the Econamine FG plus CO2 capture system. The values given for the cost of the system have a certain degree of uncertainty and need to be assessed with that in mind.

5.1.4. SolarFuel Methanation Equipment

By far the biggest single cost item in this project is the SolarFuel SNG production plant. This plant includes the water electrolysis reactor and the Methanation reactor along with all the miscellaneous equipment needed to operate the plant.

SolarFuel is one of very few companies developing this technology and the technology is still in early stages of development. This means that the numbers given are with a certain degree of uncertainty and need to be assessed with that in mind.

The initial capital cost for the 5 MW SNG plant is 2000 EUR/Kw and for the larger plants (20 MW and the 40 MW) the overnight capital cost is 1200 EUR/Kw (Rieke, Engineer at SolarFuel Gmbh, 2012).

SolarFuel SNG Plant Cost			
Scenarios	**5 MW**	**20 MW**	**40 MW**
SNG plant size in KWel	**5.000**	**20.000**	**40.000**
Cost €/Kwel	**2.000**	**1.200**	**1.200**
Initial Capital Cost €	10.000.000	24.000.000	48.000.000
O&M Cost per year €	150.000	600.000	1.200.000

Table 5-3 Cost of building and running SolarFuel SNG plant (Rieke, Engineer at SolarFuel Gmbh, 2012)

Table 5-2 shows the calculated overnight capital costs for each of the three scenarios. The operation and maintenance costs are 30 EUR/Kw of installed power (Rieke, Engineer at SolarFuel Gmbh, 2012).

The O&M costs include all labor and material costs. The labor which is needed to run the SNG plant is capable of overseeing the CO_2 capture equipment without problem (Rieke, Engineer at SolarFuel Gmbh, 2012).

5.1.5. Price of Energy

The price of energy from Landsvirkjun is divided into the same three categories as the energy based on the security of delivery. The energy generation of Landsvirkjun is divided into these categories, i.e. base load energy, surplus energy and unsecured energy. Each category has enough available energy and the price per Kwh for each category is as follows (Björnsson, 2012):

Using the ISK to EUR exchange rate of 164,1 ISK to 1 EUR.

- **Category 1** – Base Load Energy costs 3,4 ISK/Kwh or 0,021 EUR/Kwh
- **Category 2** – Surplus Energy costs 2,4 ISK/Kwh or 0,015 EUR/Kwh
- **Category 3** – Unsecured Energy costs 1,7 ISK/Kwh or 0,01 EUR/Kwh

From the energy price it would seem to be most economical to use the category 3 energy. But with heavy delivery restrictions during some years it could be impossible to make the investment pay off.

The method used for determining if the delivery restrictions are too heavy for the investment to be viable is to lower the available running time of the SNG plant but keep all investment costs at the same level.

5.2. Revenue

Similarly important as the cost of a project is the possible revenue stream of the project. For this project there are a few possible ways to earn revenue. The main revenue stream is the product SNG but there are other ways as well.

The electrolysis reactor generates O_2 from the electrolysis of water. This O_2 can be used in a variety of industries and might be a sellable product.

The same is also true for CO_2. CO_2 is used in a variety of industries and could also be a sellable gas, but with restrictions in quantity as it is one of two main components of SNG.

Another point of interest is the possibility of utilizing the waste heat created by the methanation process.

5.2.1. SNG

Substitute Natural Gas or SNG is the main product and main revenue earner of this project. The emphasis is on the efficient production of SNG using the methods described in the previous chapters. That is why the most important price of any product from this project is the price of SNG.

In Iceland the closest substitute to SNG is Bio Methane Gas (BMG). The CH_4 or Methane gas is the major gas in both SNG and BMG. That is why the price of BMG will be used as the price that could possibly be had for SNG (Hermannsson, 2012).

Today BMG is sold through two pump stations to the general public for transportation. It is being sold by a company called Sorpa and a subsidiary called Metanorka. These companies sell gas which is captured from municipal waste sites (Hermannsson, 2012).

The price of BMG and by extension the price for SNG is in the range of 80 – 100 ISK/M^3. It is assumed that for the purposes of this project that the price for SNG is 100 ISK/m^3 or 0,61 EUR/m^3 (Hermannsson, 2012).

5.2.2. O_2

Selling O_2 for industrial or commercial use is possible. O_2 has very diverse applications and is used in industrial processes from metallurgy to fish farming. In Iceland the main use for O_2 is for fish farming, where it is used to oxygenate the water (Rafnsson, 2012).

Isaga is the largest producer and seller of industrial gases in Iceland and as such was considered to be a likely buyer for the O_2 produced by the electrolysis (Rafnsson, 2012).

After reviewing the proposed plants and the data the result is that it would prove too expensive to use the O_2 from the SNG plant. This is mainly due to the fact that the O_2 would be provided at atmospheric pressure. The O_2 would either have to be liquefied or compressed for use in steel cylinders (Rafnsson, 2012).

Liquefaction of the O_2 requires cooling the gas to a very low temperature for more efficient storage but liquefaction uses huge amounts of energy as well as having high capital costs.

Compressing the O_2 is another possibility but in this case was considered too expensive to be viable. The compression would require the gas to be compressed onto steel cylinders which then are transported to the consumer. The transportation cost coupled with the cost of the filling station make this possibility difficult (Rafnsson, 2012).

There is however the possibility that with increased activity at the Grundartangi industrial site there could be on site buyers for the O_2 produced by the SNG plant. There are two metallurgy plants in construction, at Grundartangi, which could possibly be buyers of O_2 and CH_4 in the future. The gas would be piped to the plants and they would use the gas as it is produced, with a storage/buffer unit in between the SNG plant and the consumer (Rafnsson, 2012).

These plants are however not going to be a reality in the near future and can therefore not be considered buyers at this point in time. This could however change the economics of the project in the future (Rafnsson, 2012).

5.2.3. CO_2

Isaga is also interested in buying CO2 gas, which is another big part of their commercial sales. Today they produce CO2 by capturing it from the atmosphere which is inherently expensive and energy intensive (Rafnsson, 2012).

The possibility of selling the excess CO2 to Isaga is interesting. This would only be the quantity of CO2 which isn't used in the production of the SNG gas.

However the same difficulties were found with CO2 as were found with the O2, i.e. the expense of compression, cooling and storage of the gas is simply too high. This means that it is not financially viable for Isaga to buy the gas at atmospheric pressure and compress it onto tanks for distribution to customers (Rafnsson, 2012).

5.2.4. Waste Heat

Waste heat is another possible source of revenue. The process can, as stated before, yield some waste heat. This waste heat comes in both high grade heat (>300°C) and low grade heat (<80°C).

The low grade heat might be useful for space heating or other such utilization. However, since Grundartangi is situated in an area with large geothermal reservoirs which are utilized for space heating at a low price, it is not considered financially viable to utilize the small low grade heat potential of the SNG plant.

The high grade heat could be used to produce steam. This kind of steam generation might prove beneficial in reducing the CO_2 capturing costs, whereas the CO_2 capture system uses steam to boil the CO_2 out of the MEA solution. Using the steam could reduce the energy demand of the system to some degree and thereby increase the financial viability.

For the purposes of this project the steam generation is assumed to be too small to be of any real value in reducing the energy requirements of the CO_2 capture system.

6. Profitability Model

The three scenarios need to be calculated for profitability in order to figure out the viability of the project.

Each of the three scenarios are put through the model using two different energy prices and annual running time. This makes the scenarios six in total.

The main focus is on Scenario 3. This is because Scenario 3 showed the most positive numbers for financial feasibility. Scenario 1 is not viable and will be covered briefly. Scenario 2 shows some positive numbers and will also be covered briefly.

6.1. Assumptions

As with any model calculations, some assumptions regarding the model have to be made. The assumptions made for the profitability model are stated here.

The planning horizon of the project is set at 20 years.

Discount rate or Marginal Attractive Rate of Return (MARR) is set at 6% (real terms).

The construction time of the SNG plant is assumed to be 1 year (2014) and operation could start the following year (2015).

The financing for this project is considered to be 30% equity and 70% loan. The loan has a payoff period of 20 years with the repayment of principal starting in 2016. The interest rate for the loan is 5% per year (real terms) with loan management fees of 2% of the principal of the loan. The working capital is adjusted according to each scenario and is to cover the initial phase of the project, i.e. to cover operating expenses, loan management fees and interest before the project starts to earn revenue.

The depreciation is assumed to be 10% for the SNG plant and CO_2 capture system. Depreciation for the Building is assumed to be 5%. Income tax is 20% in Iceland.

It is assumed that each m3 of SNG is priced at 100 ISK or 0,61 EUR at wholesale (Hermannsson, 2012). It is also assumed that there is sufficient demand for SNG to sell the whole quantity of produced SNG.

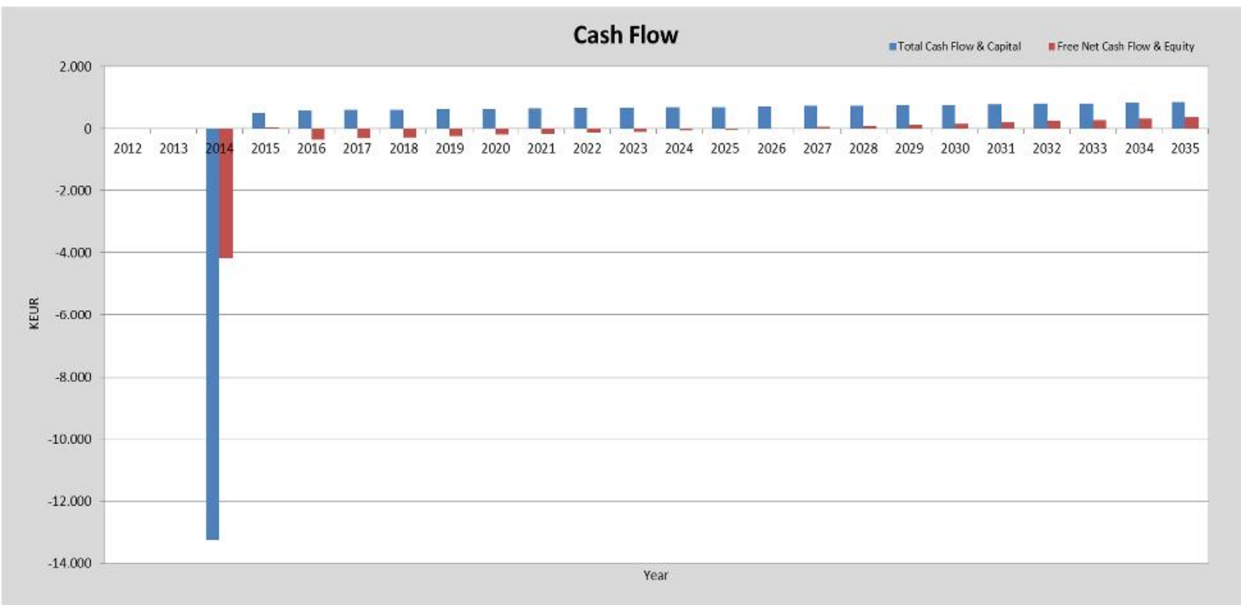
6.1.1. Cost Calculations – Three Point Method

The cost of each component as quoted by the producers is used as the Most Likely number in the calculations. The Pessimistic number is 15% higher and the Optimistic number 10% lower.

The cost numbers are then calculated using the three point method (Lichtenberg, 2000). The method uses a 95% confidence interval.

6.2. Scenario 1: 5 MW SNG plant – Cat 2 Energy

As with most new projects there are considerable investment costs at the beginning. When the construction is finished, the project starts to generate income.

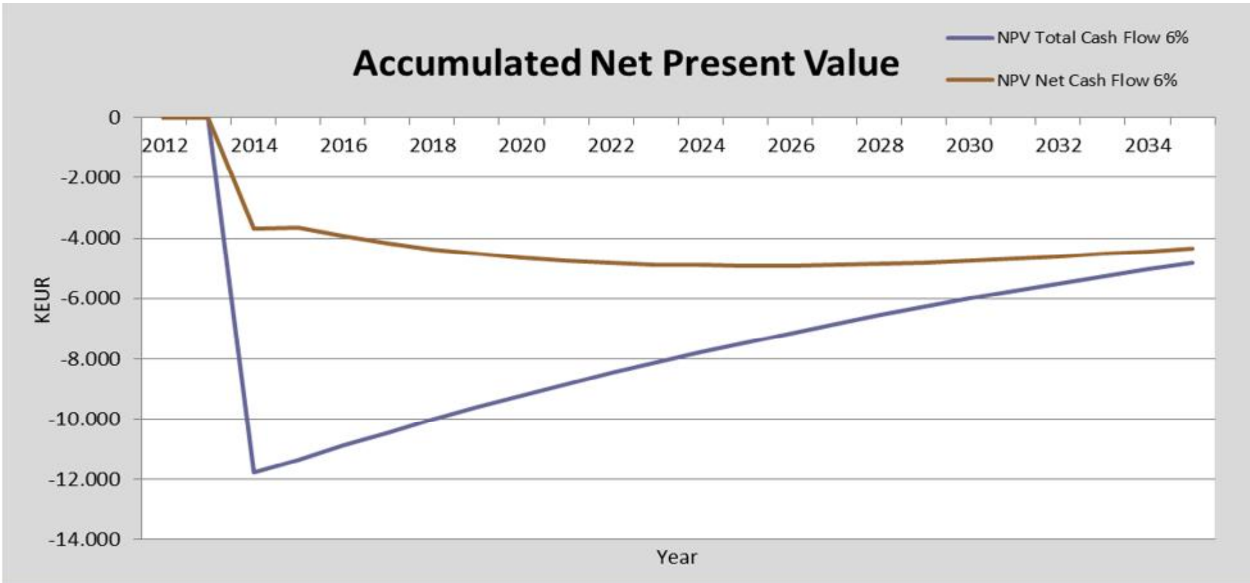


Graph 6-1 Cash Flow Graph for Scenario 1 – 5 MW SNG plant using Cat 2 energy.

Graph 6-1 shows the initial capital investment in 2014 and the revenue generation for the following years. The capital investment is substantial or 13,23 MEUR.

The project does not start to generate net profits until 2024 but due to the accumulated losses the project is still in the red at the end of the planning horizon. The losses at the end of the planning horizon amount to just over 3,01 MEUR.

The repayment of the principal of the loan starts in 2016 and that explains the dip that occurs in the free net cash flow and equity from 2015 to 2016.



Graph 6-2 Accumulated NPV for Scenario 1 – 5 MW SNG plant using Cat 2 energy

Graph 6-2 shows the Accumulated NPV of the project over the planning horizon. The graph shows how the project increases its NPV over the planning horizon without ever reaching the positive side. At the end of the period the NPV of Total Capital is -4,8 MEUR and NPV of Equity is -4,3 MEUR.

The IRR on Equity and Total capital are 0,0% and 0,9%, respectively. Since the discount rate is set at 6% this project is a long way from covering the Marginal Attractive Rate of Return.

Both Cash Flow Ratios and Financial Ratios for Scenario 1 show that based on these results there is not much foundation for investment. The ratios are all lower than the preset Acceptable Minimum and therefore indicate that the project would have difficulty meeting its obligations with regard to repayment of loans and other financial obligations.

6.2.1. Results – Scenario 1

The graphs showing the financial indicators for Scenario 1 all lead to the same conclusion, Scenario 1 is in no way a financially feasible option.

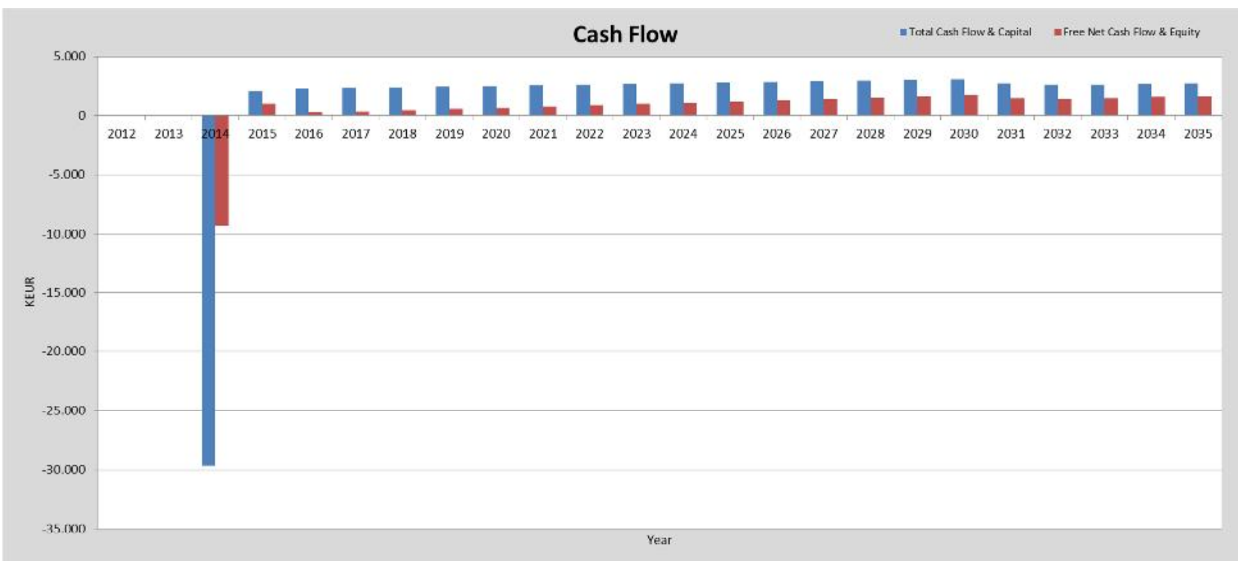
The IRR of Equity is 0,0% and the NPV of Equity is -4,3 MEUR, these two numbers should be enough to put Scenario 1 aside.

The minimum cash account of Scenario 1 using 1 MEUR as working capital is just over -1 MEUR. The cash account of Scenario 1 did not get any more positive than -122.000 EUR and that was using 8 MEUR as working capital. It can be said that the economics of Scenario 1 are not going to improve without some reductions in price of equipment or other large factor/s.

The salvage value of the Total Capital for Scenario 1 at the end of the planning horizon is only 109.000 EUR, which means that the Salvage Value of the project does not even help justify the investment.

6.3.Scenario 2: 20 MW SNG Plant – Cat 2 Energy

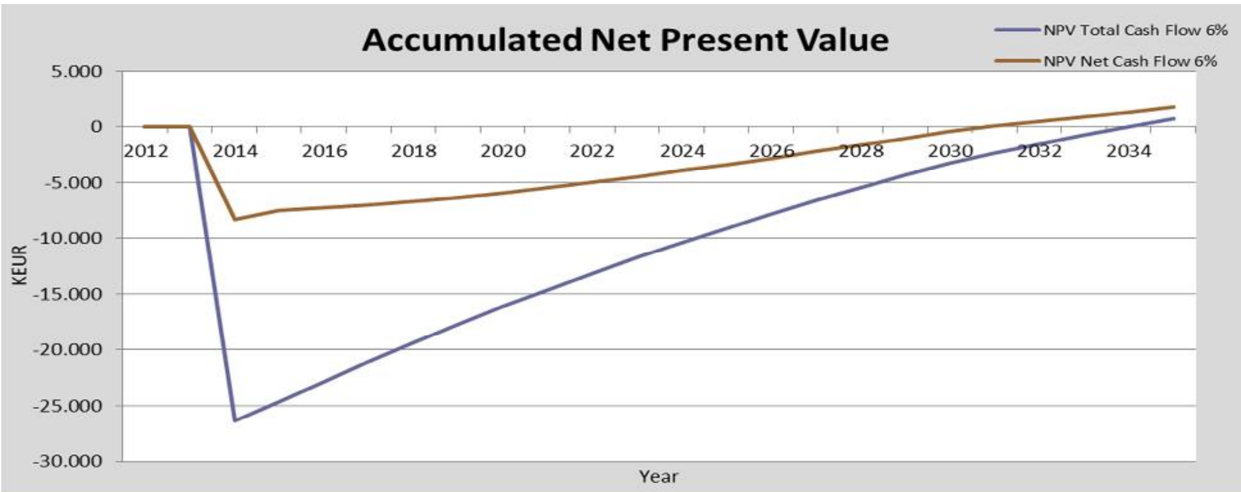
The initial capital investment of Scenario 2 is just over 29,6 MEUR. This sizeable investment can be seen in Graph 6-6 below.



Graph 6-3 Cash Flow Graph for Scenario 2 – 20 MW SNG plant using Cat 2 energy.

Graph 6-6 shows the cash flows of Scenario 2 and how theses cash flows are dispersed throughout the planning horizon. The project starts to generate revenue in 2015 and then the repayments on the loan start in 2016, which explains the dip in Free Net Cash Flow & Equity in 2016.

The project does not earn profits until the year 2025. These profits go towards paying up the accumulated losses. The accumulated losses are paid up in 2029, which means that in 2030 the project starts to pay taxes.



Graph 6-4 Accumulated NPV for Scenario 2 – 20 MW SNG plant using Cat 2 energy

Graph 6-7 shows the accumulated NPV over the planning horizon of the project. The NPV of Net Cash Flow becomes positive in the year 2031 and the NPV of Total Cash Flow in the year 2034. The value of the NPV of Total Cash Flow is 0,7 EUR and the value of NPV of Net Cash Flow is 1,7 MEUR. Since the NPV numbers are positive the project could be considered viable.

The IRR of Total Cash Flow becomes positive in the year 2025 and reaches a peak of 7,9% in 2035. The IRR of Net Cash Flow becomes positive in the year 2026 and reaches a peak of 6,3% in 2035. This means that the project could be considered marginally investable whereas the IRR is higher than the Marginal Attractive Rate of Return.

The Debt Service Coverage Ratio is at 1,9 in 2015 before dropping to 1,1 in 2016 and then rising steadily to reach the Acceptable minimum of 1,5 in 2022 and then reaching 2,4 at the end of the planning horizon.

The Loan Lifetime Coverage Ratio starts out at 1,5 in 2015 and rises steadily throughout the planning horizon of the project before reaching its peak at 5,1.

The Liquid Current Ratio of Scenario 2 is very good so the project can be considered to have good short term financial strength. The Liquid Current Ratio is at 0 in 2014 due to construction and in 2015 it is 1,2 and covers the acceptable minimum in 2017 at 1,7 and reaches 27,8 at the end of the planning horizon. The Net Current Ratio is the same as the Liquid Current Ratio because there is no inventory buildup.

The Internal Value of Shares starts out at 1 and then slowly decreases to -0,8 in 2024 but rises after that to peak at 2,6 in 2035. The ratio only reached the Acceptable Minimum of 1,5 in 2032.

The Capital Ratio starts out at 0,3 in 2014 and never exceeds the Acceptable Minimum of 1,5 during the planning horizon. The Capital Ratio is at 1 in at the end of the planning horizon.

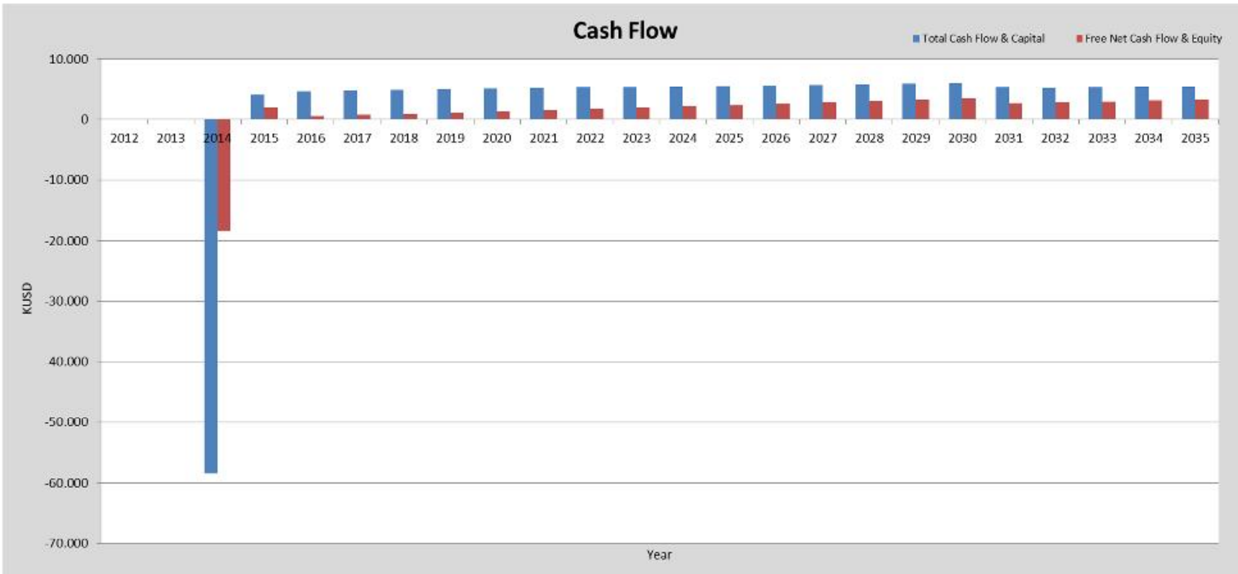
6.3.1. Results – Scenario 2

The IRR of Total and Net Cash Flows suggest that Scenario is marginally profitable. The same can be said for the NPV of Total and Net Cash Flows. These figures suggest that Scenario is profitable but only just so. The IRR is only slightly higher than the discount rate or MARR. The Minimum Cash Account is at 85.000 EUR in 2014 and the Working Capital is at 500.000 EUR.

The Salvage Value of Total Cash Flow is 22,8 MEUR.

6.4.Scenario 3: 40 MW SNG Plant – Cat 2 Energy

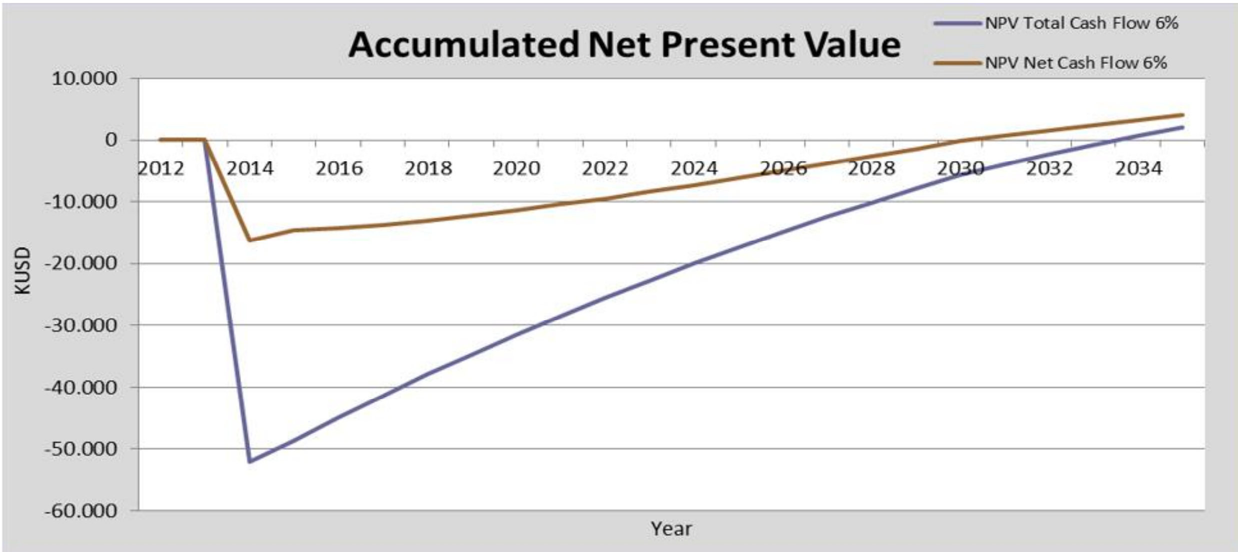
As with Scenario 1 and 2, Scenario 3 has a considerable initial investment. The investment is to the amount of 58,4 MEUR.



Graph 6-5 Cash Flow Graph for Scenario 3 – 40 MW SNG plant using Cat 2 energy.

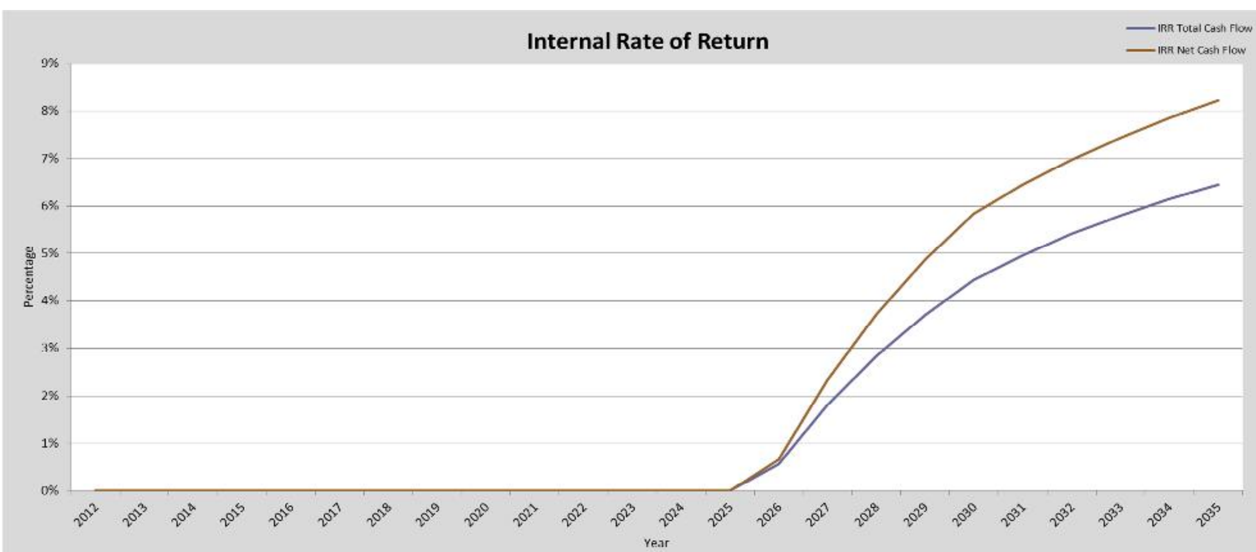
Graph 6-11 shows the Cash Flows for Scenario 3. The initial investment is only over one year and not spread out. This means that the lead time is short, i.e. the investment starts to generate revenue soon after the initial investment. In this case, the project earns revenue in the following year or 2015. As with the previous scenarios, Scenario 3 starts to pay the principal of the loan in the year 2016, which explains the dip in Free Net Cash Flow & Equity.

The project starts to earn profits in the year 2025 and it takes until the year 2029 to pay the accumulated losses. In the year 2031 the first taxes are paid.



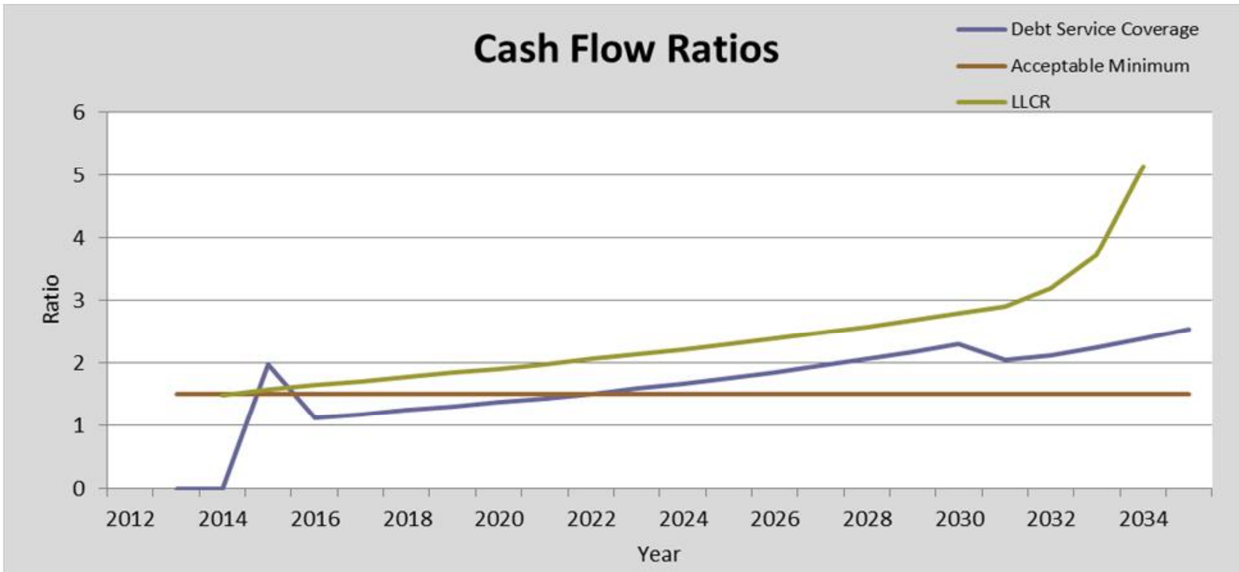
Graph 6-6 Accumulated NPV for Scenario 3 – 40 MW SNG plant using Cat 2 energy

Graph 6-12 shows the Accumulated NPV of Total Cash Flow and Net Cash Flow for Scenario 3. The NPV of Net Cash Flow is just over 4,1 MEUR and the NPV of Total Cash Flow is just over 2 MEUR. This means that Scenario 3 can be considered a profitable investment.



Graph 6-7 Internal Rate of Return (IRR) for Scenario 3 – 40 MW SNG plant using Cat 2 energy

Graph 6-13 shows the IRR of Total Cash Flow and of Net Cash Flow for Scenario 3. The IRR for Net Cash Flow is 6,4% and the IRR for Total Cash Flow is 8,2%. Since the IRR of Total Cash Flow is 8,2% and therefore higher than the discount rate of 6% this can be considered an investable project.

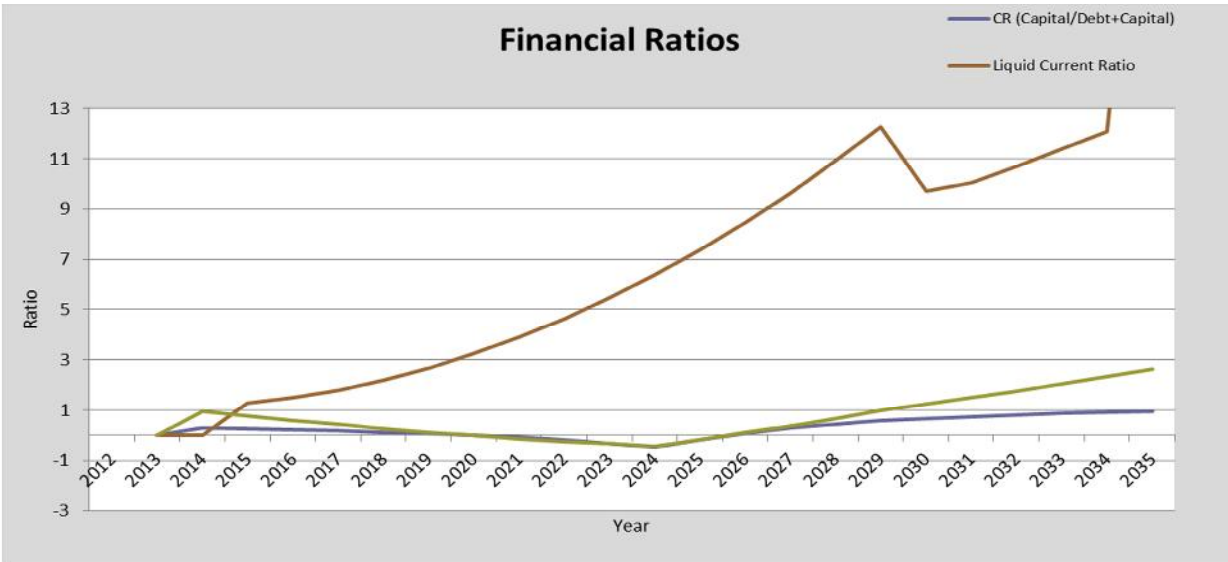


Graph 6-8 Cash Flow Ratios for Scenario 3 – 40 MW SNG plant using Cat 2 energy

Graph 6-14 shows the Cash Flow Ratios for Scenario 3.

The LLCR starts out at 1,5 and at the end of the planning horizon it is at 5,1. With the Acceptable Minimum at 1,5 the LLCR is only around that at the beginning of the planning horizon.

The Debt Service Coverage Ratio starts at 2 in 2015, goes down to 1,1 in 2016 and ends up at 2,5 at the end of the planning horizon. It covers the Acceptable Minimum in the year 2022. There is a drop in the Debt Service Coverage Ratio in 2030 and that is because the project starts to pay taxes of the profits earned.



Graph 6-9 Financial Ratios for Scenario 3 – 40 MW SNG plant using Cat 2 energy

The Liquid Current Ratio of Scenario high so the project can be considered to have good short term financial strength. The Liquid Current Ratio starts at 1,3 in 2015 and it covers the Acceptable Minimum in 2016 at 1,5 and reaches 28,2 at the end of the planning horizon. The Net Current Ratio is the same as the Liquid Current Ratio because there is no inventory buildup. There is a dip in 2030 due to the project starting to pay taxes.

The Internal Value of Shares starts out at 1 and then slowly decreases to -0,4 in 2024 before rising to a peak at 2,6 in 2035. The ratio only reached the Acceptable Minimum of 1,5 in 2031.

The Capital Ratio starts out at 0,3 in 2014 and is at its highest, at 1, in 2035. The Capital Ratio never exceeds the Acceptable Minimum of 1,5 during the planning horizon.

6.4.1. Results – Scenario 3

The numbers for Scenario 3 are to a certain extent positive and show that the project is indeed profitable. The IRR of Total and Net Cash Flows are higher than the MARR of 6%. The NPV of Total and Net Cash Flows is also positive. This all means that the project is profitable and feasible.

The Minimum Cash Account is at 182.000 EUR in the year 2014 with the Working Capital set at 1 MEUR. The Salvage Value of Total Cash Flow is 46,3 MEUR.

6.5. Scenario 4, 5 And 6 – Using Cat 3 Energy

The original idea behind this project was to use the unsecured energy or Category 3 energy of Landsvirkjun. This energy is cheaper than both base load energy and surplus energy but with much restricted delivery. The price of this energy is 1,7 ISK/Kwh or 0,01 EUR/Kwh. The calculated available annual running time, according to information from Landsvirkjun, is 3.725 hours per year.

The numbers for Scenarios 1, 2 and 3 were put into the profitability model using the price of energy and available annual running time of the Category 3 energy, the unsecured energy. These scenarios are numbered as 4, 5 and 6 and use the cost of 5 MW, 20 MW and 40 MW, respectively.

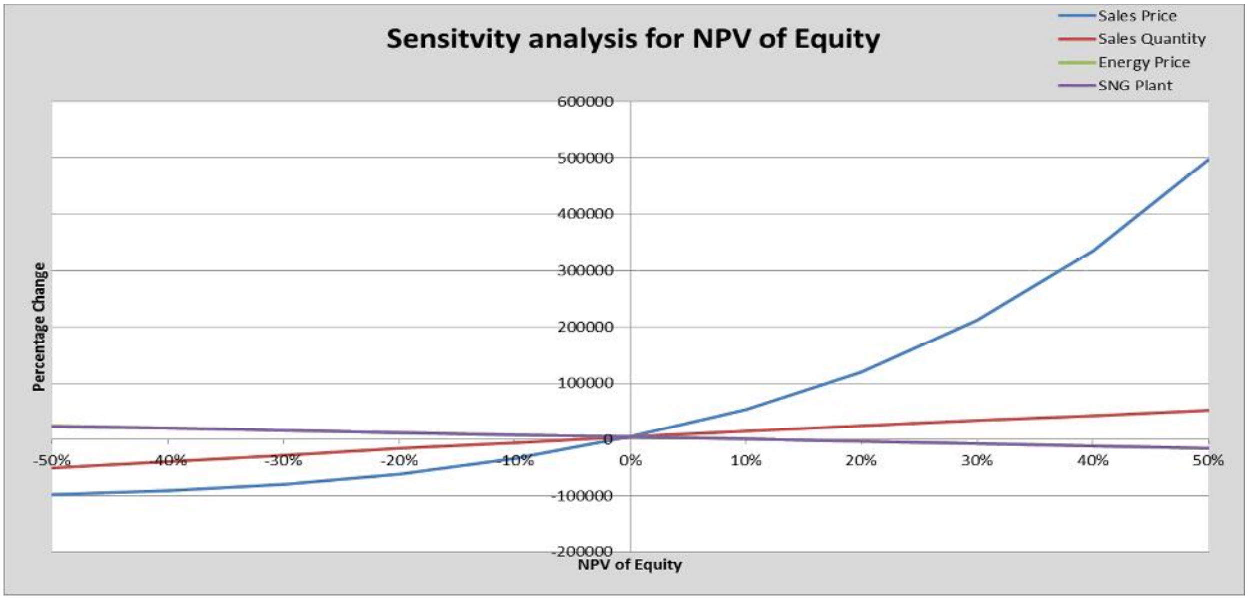
The objective is to figure out if the lower price of energy was enough to offset the limited available running time.

In short, the answer is NO. The limited available running time costs much more in lost production than the expenditure that is avoided with the lower energy price.

The scenarios were all calculated using the profitability model. The model results showed that there was no way, using the Category 3 energy with the limited available running time, can be considered feasible for any of the three scenarios.

7. Sensitivity Analysis

Since Scenario 3 is the only scenario showing half descent results, there is only need to look at the sensitivity analysis regarding Scenario 3.



Graph 7-1 Sensitivity analysis for NPV of Equity using Scenario 3 numbers

Graph 7-1 shows that the Sales Price of SNG is the factor that affects the outcome of the project the most, i.e. a relatively small rise in Sales Price would affect the outcome of Scenario 3 for the better. The beginning status of Graph 7-1 is a NPV of Equity of 4,1 MEUR and 0%. The rise in Sales Price of 10% would mean that the NPV of Equity would go up to 52,9 MEUR, which is a substantial increase.

The Energy Price and the cost of the SNG Plant investment have a very similar impact on the NPV of Equity. The lines follow almost exactly the same path. If the Energy Price would go down 10% the NPV of Equity would be at 8 MEUR and if the SNG Plant could be had for a 10% lower price the NPV of Equity would be at 8 MEUR.

The Sales Quantity has an effect on the profitability of the project but is completely dictated by the available energy. The profitability assessment assumes that the SNG Plant is run at full capacity at all times when there is available energy. This means that production of SNG is unlikely to rise but it could in fact go down. If the Sales Quantity were to be reduced by 10% the NPV of Equity would be at -5,8 MEUR.

8. Discussion

The idea of producing Substitute Natural Gas for domestic use in Iceland is very interesting and after an extensive data collection and discussions with professionals, the result is that this is a technically possible solution. There are however a few issues that have to be considered.

When reviewing the results of the profitability model from Scenarios 1, 2 and 3, it is apparent that there is some economy of scale. The Scenarios get more profitable as the scope of the projects get bigger. In fact, economy of scale is something that can be expected with large industrial projects. From the cost quotes for the SNG plant this is obvious, the cost for a small plant is about 800 EUR/Kwh higher than that of the larger plant.

The technology used for the production of SNG is in fact in the early stages of development and needs to be proven at an industrial scale before the uncertainty of the project can be set aside. Although the main concept of the Sabatier reaction process has been known for several decades, there has not been any real development of the technology for industrial scale synthetic fuel production until recent years. So, future developments of the technology might make it more economical.

There is also the issue of greenhouse gases and the quotas on CO_2, which companies such as Elkem will soon have to purchase to cover their own emissions. This could be an opportunity for the production of SNG. Since the production of SNG requires a source of CO_2 for its production, it could help reduce the emissions of industrial processes and minimize the need to buy the emissions quotas. Instead of emitting CO_2 into the atmosphere the gas would be used to produce sustainable fuel. This could change the economic outlook of the SNG production.

The sensitivity analysis for the Sales Price of SNG shows that a relatively modest increase in price could change the financial side of the project. So if the price of SNG could be raised from the current 80 – 100 ISK/m^3 the economics of the project could change significantly. The only way however for the price to change is either by government subsidy or for the fossil fuel prices to rise to allow the increase in price. Both these options are very uncertain and can’t be taken for certain.

What also affects the outcome of the Scenarios is the fact that none of the suggested revenue streams could be used aside from the sales of SNG. The additional revenue which could possibly be generated from sales of O_2, CO_2 or waste heat could change the outcome significantly. The problem with theses revenue streams is that, in Iceland, there is a limited market for them today and that is probably not going to change in the near future.

Using the Category 3 energy as was planned at the start of the research proved to be very difficult. This is mainly due to the limited annual availability of energy. The energy is only available for around 5 months a year and that means that the big investment that goes into the SNG plant, building and CO_2 capture equipment is idle for 7 months out of the year. Scenarios 4, 5 and 6 were calculated by this criterion and did not show any positive financial signs.

Scenario 1 does not present a profitable or viable investment. Scenarios 2 and 3 show signs of being profitable but only marginally and most likely they are not profitable enough to warrant taking the inherent risk that comes with such a project. Scenarios 2 and 3 both show signs of weakness through their Financial and Cash Flow Ratios.

The Financial and Cash Flow Ratios show signs of issues, which mean that even with a positive IRR and NPV there still could be trouble. The Acceptable Minimum is there for a reason and none of the ratios should be below the value of 1,5. But many of the ratios are under that for most of the planning horizon or even the entire time. This suggests that the projects could have trouble covering debt, financing operations etc. These inherent weaknesses make it difficult to recommend investment.

9. Conclusion

The main goal of this research project was to find out whether or not there is a financial and technological foundation for the production of SNG using the surplus energy generated by Landsvirkjun. All the components of the system already exist. CO_2 capture is a proven technology that has been used in industry for many years. Substitute Natural Gas production is also a technology that has existed for decades and is being developed for use in today's energy market.

The big issue is cost. The technology of SNG production is still in early stages of development and therefore costs too much to be a viable solution to the problem posed in this research project. With further development and refinement the viability of SNG production could change for the better in the future.

Most of the methane produced in Iceland today is from municipal waste and the annual production is in the range of 1,5 to 2 million m^3 of gas (Hermannsson, 2012). The profitability model came up with a marginally feasible result for the largest SNG production scenario, Scenario 3. The SNG production quantity of Scenario 3 would increase today's production of methane gas by a factor of 9 or 10. This means that in order for Scenario 3 to be successful in the real world the demand for SNG in Iceland would have to increase dramatically.

Iceland relies on fossil fuel imports to satisfy the needs of its transportation and fishing fleet. Since SNG can be used as fuel for most internal combustion engines, it could change Iceland's dependency on fossil fuel imports. There is however a problem with infrastructure. There are only two filling stations for methane gas in Iceland. One filling station is in Reykjavik and one under construction in Akureyri (Hermannsson, 2012).

These are real world problems which could be solved with some determination and the will of the Government in Iceland. These problems stem from the small size of the Icelandic market.

Although the proposed solution has problems, Iceland being able to produce "Green" fuel for its domestic market is still an exciting prospect. The benefits of this kind of production are many and include a decreased dependency on fossil fuel imports, potentially reduced exchange deficit with foreign countries and increased domestic industrial production promoting work for Icelanders.

With SNG also being produced using captured CO_2 and renewable energy, it would not contribute to global warming and would be counted as zero emission fuel. The introduction of a domestically produced fuel could mean big changes in the economy of Iceland as well as improving its “Green” image.

The questions posed in this research project have been answered. It is technologically possible to produce SNG using surplus energy. It is however, at best, marginally profitable in the current economic climate.

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Appendix

The only scenario which showed any signs of being financially viable was Scenario 3. Scenario 3 was a 40 MW SNG plant running on Category 2 energy. The profitability model and calculations for Scenario 3 are included in this Appendix.

Investment Cost

Beta Distrebution:
Expected Value t= (a+4*m+b)/6
Standard Deviation s = (b-a)/6

CO2 Captur	Optimistic	Most Likely	Pessimistic	Expected V	Standard Dev	Variance
Equipment	**a**	**m**	**b**	**t**	**s** →	**V**
CO2 Unit	2.019	2.125	2.444	2.160	71	5.017
	2.019	**2.125**	**2.444**	**2.160**	**71** ←	**5.017**

Confidence Level	95%
Z Value	2
Cost Estimate for Equip.	2.277

Building	Optimistic	Most Likely	Pessimistic	Expected V	Standard Dev	Variance
Equipment	**a**	**m**	**b**	**t**	**s** →	**V**
Building	3.184	3.352	3.854	3.407	112	12.481
Power lines	119	125	144	127	4	17
	3.303	**3.477**	**3.998**	**3.535**	**112**	**12.499**
					←	

Confidence Level	95%
Z Value	2
Cost Estimate for Equip.	3.718

SNG Plant	Optimistic	Most Likely	Pessimistic	Expected V	Standard Dev	Variance
Equipment	**a**	**m**	**b**	**t**	**s**	**V**
SNG plant	45.600	48.000	55.200	48.800	1.600 →	2.560.000
	45.600	**48.000**	**55.200**	**48.800**	**1.600**	**2.560.000**
					←	

Confidence Level	95%
Z Value	2
Cost Estimate for Equip.	51.432

Assumptions and Results

All assumption and results are real therns

		2012	2013	2014	2015	
Investment:				KEUR		
Building				2.276,93		2.276,93
CO2 capture system	100%			3.718,45		3.718,45
SolarFuel SNG plant	100%			51.431,77		51.431,77
Total				57.427,14		57.427,14
Financing:						
Working Capital			0,00	1.000,00		1.000,00
Total Financing			0,00	58.427,14		58.427,14
Equity	100%	30%				
Loan Repayments	100%	20 years				
Loan Interest	100%	5,0%				
Operations:						
Sales Quantity SNG [M3/year]	100% M3/yr					
Sales Price [KEUR/M3]	100% KEUR/M3					
Sales Price increase (%)	100%					
Energy Purchased (Kwh)						
Variable Cost [EUR/Kwh]	100%	0,000014 KEUR/Kwh				
Fixed Cost	100%	1200,00 KEUR/year				
Inventory Build-up			0	0	0	
Debtors(account Recei)	9%	of turnover				
Creditors(Accounts Payable)	9%	of variable cost				
Dividend	0%	of profit				
Depreciation Building	10%					
Depreciation CO2 Capture Syste	10%					
Depreciation SolarFuel SNG Pla	10%					
Loan Managem. Fees	2%					
Income Tax	20%					

okey

Discounting Rate	6,0%	MARR
Planning Horizon	20	years

	Total Cap.	Equity
NPV of Cash Flow	2.080	4.136
Internal Rate Return	6,4%	8,2%
External Rate of Return	6,2%	7,0%

Minimum Cash Account 182

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Sales Quantity SNG [M3/year]		16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444
Sales Price [KEUR/M3]		0,000610	0,000616	0,000622	0,000628	0,000635	0,000641	0,000648	0,000654	0,000661	0,000667	0,000674	0,000681
Sales Price increase (%)			1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%
Energy Purchased (Kwh)		306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000
					2027	2028	2029	2030	2031	2032	2033	2034	2035
					16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444
					0,000687	0,000694	0,000701	0,000708	0,000715	0,000722	0,000730	0,000737	0,000744
					1%	1%	1%	1%	1%	1%	1%	1%	1%
					306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000	306675000

Salvage 46.320 55.076 62.531

0,00061
0,000671

Investment

Investment and Financing		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
			1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	
Investment																										
Building		0	0	2.277	2.049	1.822	1.594	1.366	1.138	911	683	455	228	0	0	0	0	0	0	0	0	0	0	0	0	
CO2 capture system		0	0	3.718	3.347	2.975	2.603	2.231	1.859	1.487	1.116	744	372	0	0	0	0	0	0	0	0	0	0	0	0	
SolarFuel SNG plant		0	0	51.432	46.289	41.145	36.002	30.859	25.716	20.573	15.430	10.286	5.143	0	0	0	0	0	0	0	0	0	0	0	0	
Booked Value		**0**	**0**	**57.427**	**51.684**	**45.942**	**40.199**	**34.456**	**28.714**	**22.971**	**17.228**	**11.485**	**5.743**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	
Depreciation:																										
Depreciation Building	10%		0	0	228	228	228	228	228	228	228	228	228	228	0	0	0	0	0	0	0	0	0	0	0	2.277
Depreciation CO2 Capture Systen	10%		0	0	372	372	372	372	372	372	372	372	372	372	0	0	0	0	0	0	0	0	0	0	0	3.718
Depreciation SolarFuel SNG Plan	10%		0	0	5.143	5.143	5.143	5.143	5.143	5.143	5.143	5.143	5.143	5.143	0	0	0	0	0	0	0	0	0	0	0	51.432
Total Depreciation			**0**	**0**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**5.743**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**57.427**
Financing:		**0**	**0**	**58.427**	**0**																					
Equity	30%	0	0	17.528	0																					
Loans	70%	0	0	40.899	0																					
Repayment	20			0	0	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	**40.899**
Principal		0	0	40.899	40.899	38.854	36.809	34.764	32.719	30.674	28.629	26.584	24.539	22.494	20.449	18.405	16.360	14.315	12.270	10.225	8.180	6.135	4.090	2.045	0	
Interest	5%		0	0	2.045	2.045	1.943	1.840	1.738	1.636	1.534	1.431	1.329	1.227	1.125	1.022	920	818	716	613	511	409	307	204	102	**23.517**
Loan Managem. Fees	2%	0	0	818	0																					**818**

Operations

Operations Statement		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Sales Quantity			0	0	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	16.444.444	345.333.324
Price index					1,00	1,01	1,02	1,03	1,04	1,05	1,06	1,07	1,08	1,09	1,10	1,12	1,13	1,14	1,15	1,16	1,17	1,18	1,20	1,21	1,22	
Price			0,000	0	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	
Revenue			**0**	**0**	**10.031**	**10.131**	**10.233**	**10.335**	**10.438**	**10.543**	**10.648**	**10.755**	**10.862**	**10.971**	**11.081**	**11.191**	**11.303**	**11.416**	**11.531**	**11.646**	**11.762**	**11.880**	**11.999**	**12.119**	**12.240**	**233.115**
Variable Cost KEUR/Kwh	0,000014		0	0	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	4.293	**90.162**
Fixed Cost	1200		0	0	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	1.200	**25.200**
Diverse Taxes																										**0**
EBITDA (Operating Surplus)			**0**	**0**	**4.538**	**4.638**	**4.739**	**4.842**	**4.945**	**5.049**	**5.155**	**5.261**	**5.369**	**5.477**	**5.587**	**5.698**	**5.810**	**5.923**	**6.037**	**6.152**	**6.269**	**6.386**	**6.505**	**6.625**	**6.746**	**117.752**
Inventory Movement			0																							**0**
Depreciation			0	0	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	0	0	0	0	0	0	0	0	0	0	0	**57.427**
Operating Gain/Loss			0	0	-1.205	-1.105	-1.003	-901	-798	-693	-588	-481	-374	-265	5.587	5.698	5.810	5.923	6.037	6.152	6.269	6.386	6.505	6.625	6.746	**60.325**
Financial Costs (Interest+LMF)		0	0	818	2.045	2.045	1.943	1.840	1.738	1.636	1.534	1.431	1.329	1.227	1.125	1.022	920	818	716	613	511	409	307	204	102	**24.335**
Profit before Tax		**0**	**0**	**-818**	**-3.250**	**-3.150**	**-2.946**	**-2.742**	**-2.536**	**-2.329**	**-2.122**	**-1.913**	**-1.703**	**-1.492**	**4.462**	**4.675**	**4.890**	**5.105**	**5.321**	**5.539**	**5.758**	**5.977**	**6.198**	**6.421**	**6.644**	**35.990**
Loss Transfer	0	0	0	-818	-4.068	-7.218	-10.164	-12.905	-15.441	-17.771	-19.892	-21.805	-23.508	-25.001	-20.538	-15.863	-10.973	-5.868	-547	0	0	0	0	0	0	
Taxable Profit		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	4.992	5.758	5.977	6.198	6.421	6.644	**35.990**
Income Tax	20%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	998	1.152	1.195	1.240	1.284	1.329	**7.198**
Profit after Tax		**0**	**0**	**-818**	**-3.250**	**-3.150**	**-2.946**	**-2.742**	**-2.536**	**-2.329**	**-2.122**	**-1.913**	**-1.703**	**-1.492**	**4.462**	**4.675**	**4.890**	**5.105**	**5.321**	**4.540**	**4.606**	**4.782**	**4.959**	**5.137**	**5.315**	**28.792**
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**
Net Profit/Loss		**0**	**0**	**-818**	**-3.250**	**-3.150**	**-2.946**	**-2.742**	**-2.536**	**-2.329**	**-2.122**	**-1.913**	**-1.703**	**-1.492**	**4.462**	**4.675**	**4.890**	**5.105**	**5.321**	**4.540**	**4.606**	**4.782**	**4.959**	**5.137**	**5.315**	**28.792**

Cash Flow

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Cash Flow																									
EBITDA (Operating Surplus)	0	0	0	4.538	4.638	4.739	4.842	4.945	5.049	5.155	5.261	5.369	5.477	5.587	5.698	5.810	5.923	6.037	6.152	6.269	6.386	6.505	6.625	6.746	117.752
Debtor Changes		0	0	870	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	11	1.061
Creditor Changes		0	0	372	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	372
Cash Flow before Tax	0	0	0	4.040	4.629	4.731	4.833	4.936	5.040	5.146	5.252	5.359	5.468	5.578	5.688	5.800	5.913	6.027	6.142	6.259	6.376	6.495	6.615	6.736	117.064
Paid Taxes		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	998	1.152	1.195	1.240	1.284	5.869
Cash Flow after Tax	0	0	0	4.040	4.629	4.731	4.833	4.936	5.040	5.146	5.252	5.359	5.468	5.578	5.688	5.800	5.913	6.027	6.142	5.260	5.225	5.299	5.375	5.452	111.194
Financial Costs (Interest+LMF)	0	0	818	2.045	2.045	1.943	1.840	1.738	1.636	1.534	1.431	1.329	1.227	1.125	1.022	920	818	716	613	511	409	307	204	102	24.335
Repayment	0	0	0	0	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	2045	40.899
Free(Net) Cash Flow	0	0	-818	1.995	539	743	947	1.153	1.359	1.567	1.776	1.985	2.196	2.408	2.621	2.835	3.050	3.266	3.484	2.704	2.771	2.948	3.126	3.305	45.960
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
Financing - Expenditure (Work Cap)	0	0	1000	0																					
Cash Account Movement	0	0	182	1.995	539	743	947	1.153	1.359	1.567	1.776	1.985	2.196	2.408	2.621	2.835	3.050	3.266	3.484	2.704	2.771	2.948	3.126	3.305	46.960

Source and Allocation of Funds

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Source of Funds																									
Profit before Tax	0	0	-818	-3.250	-3.150	-2.946	-2.742	-2.536	-2.329	-2.122	-1.913	-1.703	-1.492	4.462	4.675	4.890	5.105	5.321	5.539	5.758	5.977	6.198	6.421	6.644	35.990
Depreciaton	0	0	0	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	5.743	0	0	0	0	0	0	0	0	0	0	0	57.427
Funds from Operations	0	0	-818	2.493	2.593	2.797	3.001	3.207	3.413	3.621	3.830	4.040	4.250	4.462	4.675	4.890	5.105	5.321	5.539	5.758	5.977	6.198	6.421	6.644	93.418
Loan Drawdown	0	0	40.899	0																					40.899
Equity Drawdown	0	0	17.528	0																					17.528
Funds for allocation	0	0	57.609	2.493	2.593	2.797	3.001	3.207	3.413	3.621	3.830	4.040	4.250	4.462	4.675	4.890	5.105	5.321	5.539	5.758	5.977	6.198	6.421	6.644	151.845
Alloction of Funds																									
Investment	0	0	57.427	0																					57.427
Repayment	0	0	0	0	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	40.899
Paid Taxes	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	998	1.152	1.195	1.240	1.284	5.869
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
Total allocation	0	0	57.427	0	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	3.043	3.196	3.240	3.285	3.329	104.195
Changes Net Curr. Assets	0	0	182	2.493	548	752	956	1.162	1.368	1.576	1.785	1.995	2.206	2.417	2.631	2.845	3.060	3.276	3.494	2.714	2.781	2.958	3.136	3.315	47.649
Analysis of Changes																									
Current Assets																									
Cash at start of year	0	0	0	182	2.177	2.717	3.460	4.407	5.560	6.919	8.486	10.262	12.247	14.443	16.851	19.472	22.307	25.357	28.624	32.107	34.812	37.582	40.530	43.656	
Cash at end of year	0	0	182	2.177	2.717	3.460	4.407	5.560	6.919	8.486	10.262	12.247	14.443	16.851	19.472	22.307	25.357	28.624	32.107	34.812	37.582	40.530	43.656	46.960	
Changes in Cash	0	0	182	1.995	539	743	947	1.153	1.359	1.567	1.776	1.985	2.196	2.408	2.621	2.835	3.050	3.266	3.484	2.704	2.771	2.948	3.126	3.305	46.960
Debtor changes	0	0	0	870	9	9	9	9	9	9	9	9	9	10	10	10	10	10	10	10	10	10	10	11	1.061
Stock Movements	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
Changes in Current Assets	0	0	182	2.865	548	752	956	1.162	1.368	1.576	1.785	1.995	2.206	2.417	2.631	2.845	3.060	3.276	3.494	2.714	2.781	2.958	3.136	3.315	48.022
Liabilities																									
Creditor changes	0	0	0	372	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
Changes Net Curr. Assets	0	0	182	2.493	548	752	956	1.162	1.368	1.576	1.785	1.995	2.206	2.417	2.631	2.845	3.060	3.276	3.494	2.714	2.781	2.958	3.136	3.315	47.649
Error check	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	

Balance

Balance Sheet

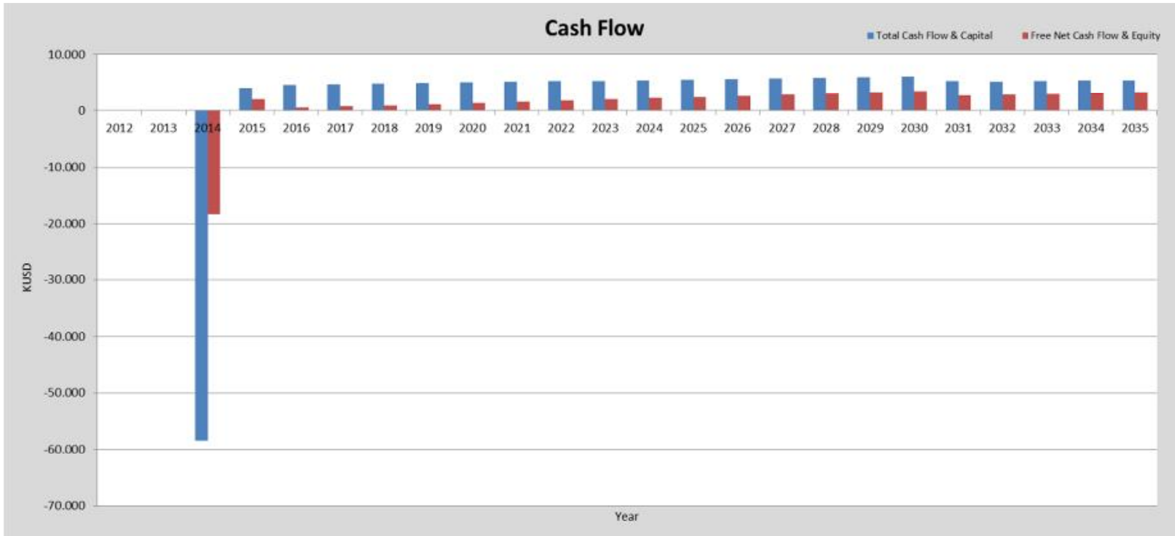
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Assets													
Cash Account	0	0	0	182	2.177	2.717	3.460	4.407	5.560	6.919	8.486	10.262	12.247
Debtors (Acc. Receivable)	9%	0	0	0	870	878	887	896	905	914	923	932	942
Stock	0	0	0	0	0	0	0	0	0	0	0	0	0
Current Assets		0	0	182	3.047	3.595	4.347	5.303	6.465	7.833	9.409	11.194	13.189
Fixed Assets		0	0	57.427	51.684	45.942	40.199	34.456	28.714	22.971	17.228	11.485	5.743
Total Assets		0	0	57.609	54.731	49.537	44.546	39.759	35.178	30.804	26.637	22.680	18.931
Debts													
Dividend Payable		0	0	0	0	0	0	0	0	0	0	0	0
Taxes Payable		0	0	0	0	0	0	0	0	0	0	0	0
Creditors (Acc. Payable)	9%	0	0	0	372	372	372	372	372	372	372	372	372
Next Year Repayment		0	0	0	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045
Current Liabilities		0	0	0	2.417	2.417	2.417	2.417	2.417	2.417	2.417	2.417	2.417
Long Term Loans		0	0	40.899	38.854	36.809	34.764	32.719	30.674	28.629	26.584	24.539	22.494
Total Debt		0	0	40.899	41.271	39.226	37.181	35.136	33.091	31.046	29.002	26.957	24.912
Equity		0	0	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528
Profit & Loss Balance		0	0	-818	-4.068	-7.218	-10.164	-12.905	-15.441	-17.771	-19.892	-21.805	-23.508
Total Capital		0	0	16.710	13.460	10.310	7.364	4.623	2.087	-243	-2.364	-4.277	-5.980
Debts and Capital		0	0	57.609	54.731	49.537	44.546	39.759	35.178	30.804	26.637	22.680	18.931
Error check		0	0	0	0	0	0	0	0	0	0	0	0

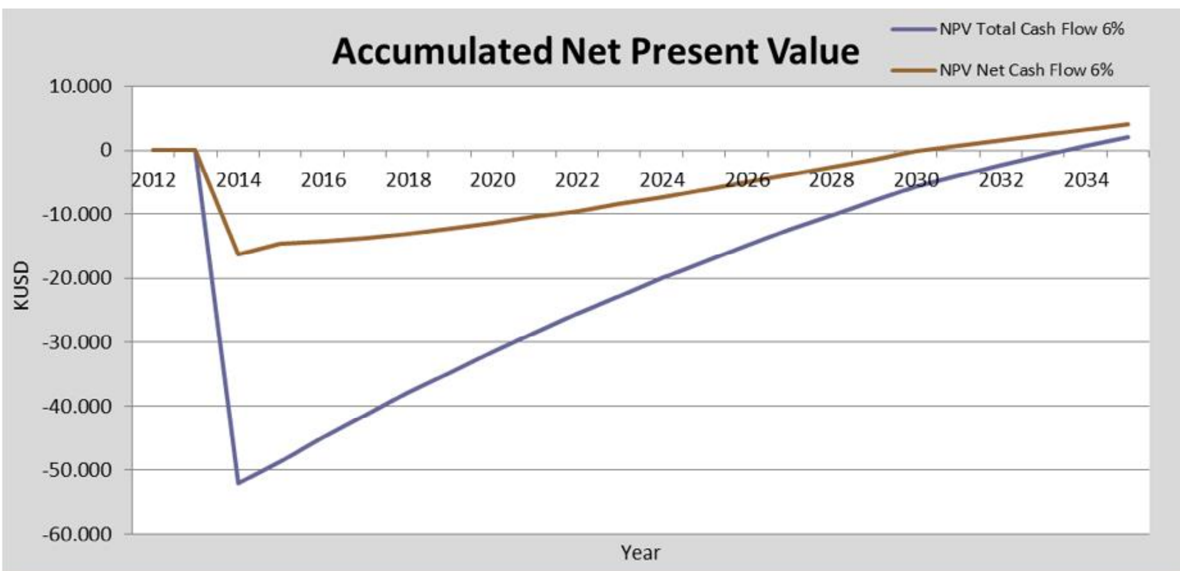
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Assets												
Cash Account	14.443	16.851	19.472	22.307	25.357	28.624	32.107	34.812	37.582	40.530	43.656	46.960
Debtors (Acc. Receivable)	951	961	970	980	990	1.000	1.010	1.020	1.030	1.040	1.051	1.061
Stock	0	0	0	0	0	0	0	0	0	0	0	0
Current Assets	15.394	17.812	20.442	23.287	26.347	29.623	33.117	35.831	38.612	41.570	44.706	48.022
Fixed Assets	0	0	0	0	0	0	0	0	0	0	0	0
Total Assets	15.394	17.812	20.442	23.287	26.347	29.623	33.117	35.831	38.612	41.570	44.706	48.022
Debts												
Dividend Payable	0	0	0	0	0	0	0	0	0	0	0	0
Taxes Payable	0	0	0	0	0	0	998	1.152	1.195	1.240	1.284	1.329
Creditors (Acc. Payable)	372	372	372	372	372	372	372	372	372	372	372	372
Next Year Repayment	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	2.045	0
Current Liabilities	2.417	2.417	2.417	2.417	2.417	2.417	3.416	3.569	3.613	3.657	3.701	1.701
Long Term Loans	20.449	18.405	16.360	14.315	12.270	10.225	8.180	6.135	4.090	2.045	0	0
Total Debt	22.867	20.822	18.777	16.732	14.687	12.642	11.595	9.704	7.703	5.702	3.701	1.701
Equity	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528	17.528
Profit & Loss Balance	-25.001	-20.538	-15.863	-10.973	-5.868	-547	3.994	8.600	13.382	18.340	23.477	28.792
Total Capital	-7.472	-3.010	1.665	6.555	11.660	16.981	21.522	26.128	30.910	35.869	41.005	46.320
Debts and Capital	15.394	17.812	20.442	23.287	26.347	29.623	33.117	35.831	38.612	41.570	44.706	48.022
Error check	0	0	0	0	0	0	0	0	0	0	0	0

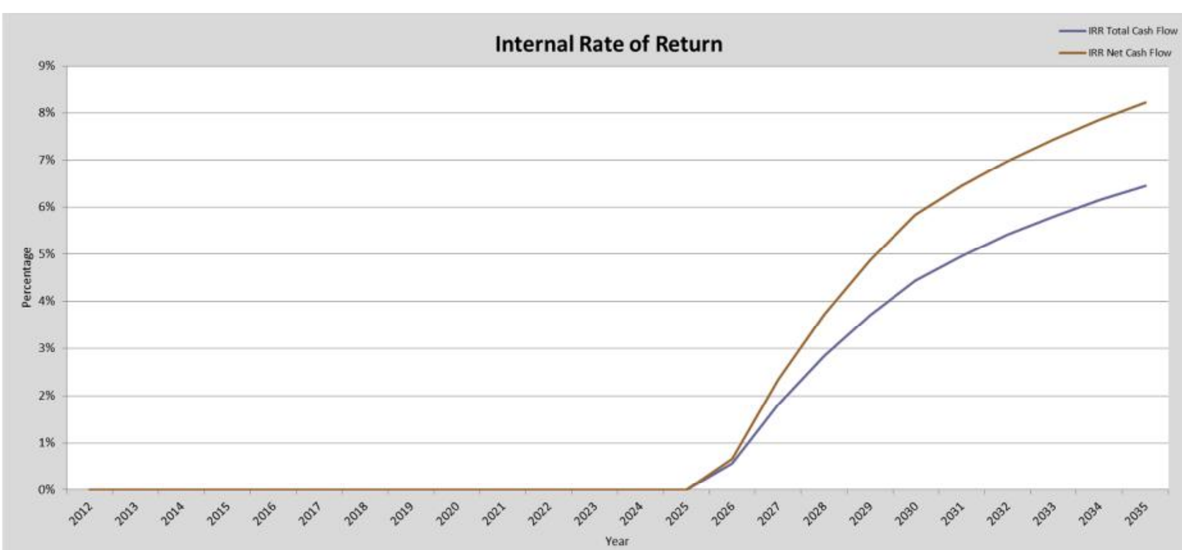
Profitability

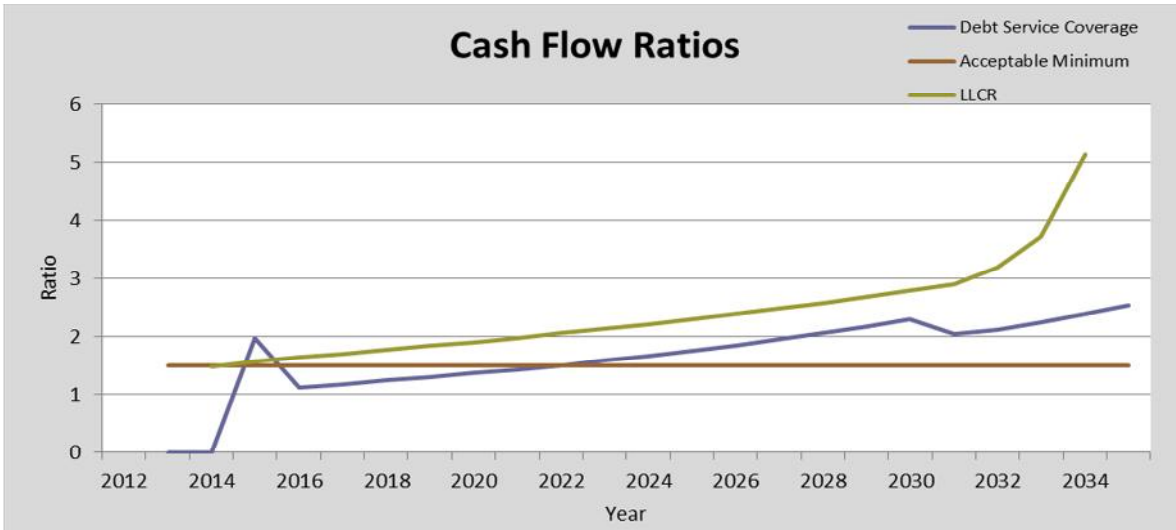
	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Profitability Measurements												
NPV and IRR of Total Cash Flow												
Cash Flow after Taxes	0	0	0	4.040	4.629	4.731	4.833	4.936	5.040	5.146	5.252	5.359
Loans	0	0	-40.899									
Equity	0	0	-17.528									
Total Cash Flow & Capital	0	0	-58.427	4.040	4.629	4.731	4.833	4.936	5.040	5.146	5.252	5.359
NPV Total Cash Flow 6%	0	0	-52.000	-48.608	-44.941	-41.406	-37.999	-34.716	-31.554	-28.508	-25.576	-22.752
IRR Total Cash Flow	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MIRR Total Cash Flow						-23%	-15%	-9%	-6%	-3%	-1%	1%
NPV and IRR of Net Cash Flow												
Net Cash Flow	0	0	-818	1.995	539	743	947	1.153	1.359	1.567	1.776	1.985
Equity	0	0	-17528									
Free Net Cash Flow & Equity	0	0	-18.346	1.995	539	743	947	1.153	1.359	1.567	1.776	1.985
NPV Net Cash Flow 6%	0	0	-16.328	-14.653	-14.225	-13.670	-13.003	-12.236	-11.383	-10.455	-9.464	-8.418
IRR Net Cash Flow	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
MIRR net cash flow				-50%	-37%	-26%	-19%	-13%	-9%	-5%	-3%	-1%
Financial Ratios												
ROI (Profit+Interest/Debt+Capital)		0,0	#DIV/0!	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0
ROE (Profit/Shareh. Capital)		0,0	#DIV/0!	-0,2	-0,2	-0,3	-0,4	-0,5	-1,1	8,7	0,8	0,4
TR (Revenue/Debt+Capital)		0,0	#DIV/0!	0,2	0,2	0,2	0,2	0,3	0,3	0,3	0,4	0,5
CR (Capital/Debt+Capital)		#DIV/0!	0,3	0,2	0,2	0,2	0,1	0,1	0,0	-0,1	-0,2	-0,3
Net Current Ratio		0,0	0,0	1,3	1,5	1,8	2,2	2,7	3,2	3,9	4,6	5,5
Liquid Current Ratio		0,0	0,0	1,3	1,5	1,8	2,2	2,7	3,2	3,9	4,6	5,5
Internal Value of Shares (Total Capital/Equity)		#DIV/0!	1,0	0,8	0,6	0,4	0,3	0,1	0,0	-0,1	-0,2	-0,3
Debt Service Coverage		#DIV/0!	0,0	2,0	1,1	1,2	1,2	1,3	1,4	1,4	1,5	1,6
Acceptable Minimum		1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5
Loan Life Cover Ratio												
NPV of Cash Flow remaining		57.324	60.764	64.410	63.992	62.924	61.685	60.264	58.647	56.823	54.778	52.498
Principal of Loans		0	40.899	40.899	38.854	36.809	34.764	32.719	30.674	28.629	26.584	24.539
LLCR			1,5	1,6	1,6	1,7	1,8	1,8	1,9	2,0	2,1	2,1
Salvage												
Total Capital		0	16.710	13.460	10.310	7.364	4.623	2.087	-243	-2.364	-4.277	-5.980
Free cash flow/MARR		0	-13.633	33.254	8.990	12.381	15.789	19.214	22.656	26.116	29.594	33.089
NPV NEXT 20 YRS/MARR												

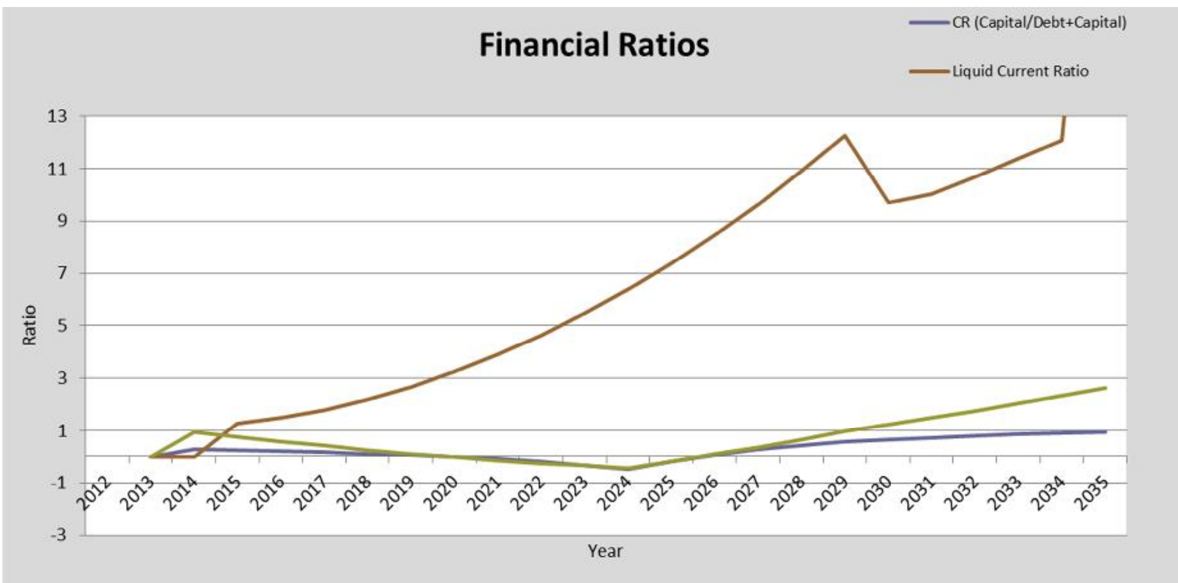
	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	Total
Profitability Measurements													
NPV and IRR of Total Cash Flow													
Cash Flow after Taxes	5.468	5.578	5.688	5.800	5.913	6.027	6.142	5.260	5.225	5.299	5.375	5.452	**111.194**
Loans													-40.899
Equity													-17.528
Total Cash Flow & Capital	5.468	5.578	5.688	5.800	5.913	6.027	6.142	5.260	5.225	5.299	5.375	5.452	52.767
NPV Total Cash Flow 6%	-20.035	-17.420	-14.904	-12.484	-10.156	-7.918	-5.766	-4.027	-2.398	-839	652	2.080	
IRR Total Cash Flow	0%	0%	1%	2%	3%	4%	4%	5%	5%	6%	6%	6%	
MIRR Total Cash Flow	2%	3%	3%	4%	5%	5%	5%	6%	6%	6%	6%	6%	
NPV and IRR of Net Cash Flow													
Net Cash Flow	2.196	2.408	2.621	2.835	3.050	3.266	3.484	2.704	2.771	2.948	3.126	3.305	**45.960**
Equity													
Free Net Cash Flow & Equity	2.196	2.408	2.621	2.835	3.050	3.266	3.484	2.704	2.771	2.948	3.126	3.305	
NPV Net Cash Flow 6%	-7.327	-6.198	-5.039	-3.856	-2.655	-1.442	-221	672	1.536	2.403	3.271	4.136	
IRR Net Cash Flow	0%	0%	1%	2%	4%	5%	6%	6%	7%	7%	8%	8%	
MIRR net cash flow	1%	2%	3%	4%	5%	5%	6%	6%	6%	7%	7%	7%	
Financial Ratios													
ROI (Profit+Interest/Debt+Capital)	0,0	0,4	0,3	0,3	0,3	0,2	0,2	0,2	0,2	0,2	0,2	0,2	
ROE (Profit/Shareh. Capital)	0,2	-0,6	-1,6	2,9	0,8	0,5	0,3	0,2	0,2	0,2	0,1	0,1	
TR (Revenue/Debt+Capital)	0,6	0,7	0,6	0,6	0,5	0,4	0,4	0,4	0,3	0,3	0,3	0,3	
CR (Capital/Debt+Capital)	-0,5	-0,2	0,1	0,3	0,4	0,6	0,6	0,7	0,8	0,9	0,9	1,0	
Net Current Ratio	6,4	7,4	8,5	9,6	10,9	12,3	9,7	10,0	10,7	11,4	12,1	28,2	
Liquid Current Ratio	6,4	7,4	8,5	9,6	10,9	12,3	9,7	10,0	10,7	11,4	12,1	28,2	
Internal Value of Shares (Total Capital/Equity)	-0,4	-0,2	0,1	0,4	0,7	1,0	1,2	1,5	1,8	2,0	2,3	2,6	
Debt Service Coverage	1,7	1,8	1,9	2,0	2,1	2,2	2,3	2,1	2,1	2,3	2,4	2,5	
Acceptable Minimum	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	1,5	
Loan Life Cover Ratio													
NPV of Cash Flow remaining	49.967	47.169	44.086	40.702	36.996	32.948	28.536	23.737	19.585	15.222	10.518	5.452	
Principal of Loans	22.494	20.449	18.405	16.360	14.315	12.270	10.225	8.180	6.135	4.090	2.045	0	
LLCR	2,2	2,3	2,4	2,5	2,6	2,7	2,8	2,9	3,2	3,7	5,1		
Salvage													
Total Capital	-7.472	-3.010	1.665	6.555	11.660	16.981	21.522	26.128	30.910	35.869	41.005	46.320	
Free cash flow/MARR	36.602	40.133	43.682	47.250	50.836	54.441	58.065	45.069	46.180	49.129	52.095	55.076	
NPV NEXT 20 YRS/MARR												62.531	


Cash Flow
Total Cash Flow & Capital
Free Net Cash Flow & Equity
KUSD
Year


Accumulated Net Present Value
NPV Total Cash Flow 6%
NPV Net Cash Flow 6%
KUSD
Year


Internal Rate of Return
IRR Total Cash Flow
IRR Net Cash Flow
Percentage
Year


Cash Flow Ratios
Debt Service Coverage
Acceptable Minimum
LLCR
Ratio
Year
0
1
2
3
4
5
6
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034


Financial Ratios
CR (Capital/Debt+Capital)
Liquid Current Ratio
Ratio
Year
13
11
9
7
5
3
1
-1
-3
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024
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2027
2028
2029
2030
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2035