UNIVERSITY OF CAPE TOWN
Department of Chemical Engineering

An Update on the Process Economics of Biogas in South Africa based on Observations from Recent Installations

Dissertation submitted in fulfilment of the requirements of the degree of Master of Science in Engineering by

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Date: 9 February 2019

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Synopsis

Anaerobic Digestion (AD) of organic waste and subsequent usage of energy extracted from biogas can contribute toward the mitigation of three key environmental issues created by the South African economy - organic waste is treated in a non-polluting way, while producing renewable energy and reducing Green House Gas (GHG) emissions. Although this appears to be a clear step in transitioning toward a low-carbon economy, the South African AD sector has not yet achieved the exponential growth required to realise its full potential.

In the absence of a national technology-specific support programme, an AD facility can only be established if it is able to stand its ground as a viable business proposition, as opposed to a social and environmental intervention. The slow growth of the sector can therefore be partly attributed to the perceived lack of financial viability, or marginal viability which is highly sensitive to fluctuations in internal and external variables.

Although the process economics of biogas projects have been widely described internationally, there are very few published studies in SA, especially where the installation costs of completed projects are analysed and documented. Seeing that the cost of establishing a plant in a developing country will differ from what is observed in developed countries based on several internal and external factors, there exists a need for an improved understanding of the process economics of AD, based on observations from locally constructed biogas plants. Another topic which has been widely documented internationally but only to a limited extent locally, is the relative financial merits of utilising biogas for electricity generation vs. upgrading to biomethane for application as a vehicle fuel. Lastly, there is a need to demonstrate the financial viability, or lack thereof, of biogas projects under current conditions in SA, taking realistic variability and risks into account.

This study sets out to create an improved understanding, in the context of SA, of financial viability of biogas plants valorising a single income stream, by addressing the following three research objectives:

- **<u>Objective 1</u>**: To document and analyse the costs associated with biogas technology in SA and to evaluate how these compare with costs observed internationally, specifically in countries where the sector has developed to maturity. This entailed the following:
    - Gathering of financial data on biogas plants through a public media search, followed by interviews with local project developers and requests to complete questionnaires. Data was sourced on 17 local electricity generating plants and 3 biomethane plants, as well as 42 international plants.

- Analysis of data, followed by regression analysis to obtain prediction models for capital cost, as well as operational and maintenance costs.
- Calculation of a Lang factor observed for biogas plants in SA, to relate the cost of major equipment to the associated costs for an entire production plant.
- Calculation of the Levelised Cost of Energy (LCOE) provided by biogas and comparison between what is observed in SA and documented internationally.

- **Objective 2:** To compare the relative financial merits of two biogas usage pathways: biogas-to-electricity and biogas-to-biomethane. This entailed the following:
  - A review of the trends in electricity and fuel prices in SA, which served as a benchmark for product prices.
  - Creation of 42 biogas plant scenarios, and estimation of plant capital and running costs based on results from objective 1.
  - A Discounted Cash Flow (DCF) analysis of each scenario.
  - Comparison of the Net Present Value (NPV), as well as other financial indicators to identify the most promising scenario.
- **Objective 3:** To evaluate the investment risk posed on the business case by incorporating realistic variability in key parameters into the abovementioned results. This entailed the following:
  - Identification of key parameters and assigning probability distributions in line with expected fluctuations to them.
  - A Monte Carlo simulation to incorporate these fluctuations into the DCFs created in objective 2, and an evaluation of the results.
  - Identification of the parameters with the greatest influence on each project's NPV, and evaluating what that influence is.

For the South African and International biogas plants combined, three cost trends were observed – high-, medium-, and low-cost. This was strongly influenced by the type of feedstock, the amount of pre-treatment required, and the amount of post-treatment applied to the biogas. The majority of South African plants analysed were among the low-cost range, with only two plants in the medium-cost range and no plants in the high-cost range. This indicates that, in general, plants are being built at a lower cost locally than internationally –

especially in Europe where the sector is more mature. This can potentially be linked to a warmer climate and less strict building regulations in SA.

The data gathered on existing plants in SA were sufficient to create a locally based cost estimation model for electricity-generating plants. However, for biomethane plants there were only three data points and hence a combination between local and international cost values was used.

Regression analysis revealed that a capacity-cost factor of 0.68 is observed for biogas-to-electricity and a Mean Magnitude of Relative Error (MMRE) of 33% can be expected on cost estimations. For biogas-to-biomethane, a capacity-cost-factor of 0.57 was observed and, as the data set had more variability, a MMRE of 45% can be expected on cost estimations. Statistical hypothesis testing proved that both values are significantly smaller than 1, which indicates that economies of scale are observed in both cases.

A Lang factor of 1.81 was determined, based on cost data from 20 medium- to large scale biogas plants in South Africa. This indicates that the plant cost is dominated by the cost of purchased equipment.

A higher and lower cost range were observed for Operational and Maintenance (O&M) costs, which vary between R2.6 – R4.6 per Nm^3 (Normal cubic metres) biogas produced where significant feedstock sorting and/or transport costs are present and R0.3 – R1.4 per Nm^3 biogas produced where minimal feedstock sorting and/or transport costs are present.

The Levelised Cost of Energy (LCOE) was observed to be within the same range, but generally lower in SA than what is documented internationally. Energy can be recovered from Combined Heat and Power (CHP) biogas plants at an LCOE of 0.5 – 2 R/kWh in SA, compared with the range of 1.8 – 2.8 R/kWh documented internationally. For a biomethane plant, the expected range of costs is between 0.4 R/kWh and 3.5 R/kWh, or 111 R/GJ and 972 R/GJ, with insufficient data to draw a distinction between costs observed in SA and internationally.

Based on a financial analysis, there are typically two plant scenarios that can be financially viable in the South African context: A small-scale plant, built at the low-cost range, typically producing electricity for self-consumption. In order to build such a plant, very specific, and limiting, project conditions would have to be met.

For a medium-cost CHP plant where only electricity is utilised as income stream, a positive Net Present Value (NPV) is possible from 1 MW_e upward, with greater returns at higher plant capacities. For a biomethane plant, a positive NPV can be attained at plant capacities of 4 MW_{eq} and higher.

It was observed that a biomethane plant will generally cost more to build and operate than an equivalent capacity CHP plant. However, the income-generating ability will be greater because it competes with fuel prices instead of electricity prices. Based on this, a biomethane plant has greater potential profitability than a CHP plant at capacities greater than 5 MW_{eq}, whereas at smaller capacities, a CHP plant would yield better returns.

The most attractive investment scenario evaluated was a 6 MW_{eq} biomethane plant, where a Return on Investment (ROI) of 18% could be attained with a payback period of 8 years for a plant lifetime of 20 years. However, at greater scales, project uncertainties also increase, and a risk analysis making use of Monte Carlo simulation revealed that such a project would have a 91% chance of obtaining a positive NPV, just falling short of the 95% benchmark typically set in the engineering and construction industry. Considering the high up-front capital investment associated with a large scale biogas project, it is anticipated that the financial risks associated with such a project would be unacceptably high for most investors at current conditions in South Africa.

The parameters whose range of fluctuation had the greatest effect on achievable NPV were annual revenue for larger plants, while capital investment and operational cost fluctuations had the greatest effect on smaller scale plants.

This dissertation concludes that, in order for the biogas sector in SA to develop to its full potential, the financial risks associated with the projects have to be mitigated. This can be done by reducing the observed variability in key parameters, or alternatively by increasing profit margins.

Typical mitigation measures from project developers could include valorising an additional income stream, selling the product at a higher price, investigating additional income streams based to the non-monetary benefits which the technology brings to society, or identifying projects that could be constructed at the low-cost range.

From a regulatory point of view, the risks associated with the technology could typically be addressed by imposing building regulations specifically aimed at biogas projects, which would make the costs and plant performance more predictable, or implementing stricter regulations regarding the disposal of organic waste and GHG emissions, which would force the private sector to consider investing in AD not just as a renewable energy source, but based on environmental considerations.

Acknowledgements

I would firstly like to thank my Lord and Saviour Jesus Christ, who, through his Holy Spirit helps and empowers me to conquer every mountain I face.

But he said to me, "My grace is sufficient for you, for my power is made perfect in weakness." Therefore, I will boast all the more gladly of my weaknesses, so that the power of Christ may rest upon me.

2 Corinthians 12:9-10

To my supervisor, Prof. Harro von Blottnitz, your patience, dedication, valuable suggestions and continual guidance really meant a lot to me – I am sincerely grateful.

To my husband, Tymen, you have been a pillar of constant support, encouragement, and help to me through this challenging journey.

To my daughters, Clara-Belle and Ariela, your arrival in my life has – and will continue to – encourage me to be the best version of myself.

To my parents - Jan & Mariana de Bruin, my siblings – Susan, Elize, and Jana, and my extended family – thank you so much for your constant love and support.

I extend my gratitude to Carrol Carr for going the extra mile to support and help me with administration, which was very challenging at times.

I would also like to thank Marisel Smit for going the extra mile to help with Clara-Belle so that I could finish my dissertation.

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List of Acronyms and Abbreviations

AACE	American Association of Cost Engineers
AD	Anaerobic Digestion
ANOVA	Analysis of Variance
Capex	Capital Expenditure
CEPCI	Chemical Engineering Plant Cost Indices
CHP	Combined Heat and Power
CNG	Compressed Natural Gas
COD	Chemical Oxygen Demand
CTL	Coal-To-Liquids
DBSA	Development Bank of South Africa
DCF	Discounted Cash Flow
DEA	Department of Environmental Affairs
DoE	Department of Energy
DPBP	Discounted Payback Period
ENR	Engineering News Record
EU	European Union
GHG	Greenhouse Gas
GTL	Gas-To-Liquids
HPWS	High Pressure Water Swing
IDC	Industrial Development Corporation
IRENA	International Renewable Energy Agency
IRR	Internal Rate of Return
LCOE	Levelised Cost of Energy

LSBF	Least Squares Best Fit
M&S	Marshall & Swift
MARR	Minimum Attractive Rate of Return
MDDFT	Metrobus Diesel Dual Fuel Technology
MMRE	Mean Magnitude of Relative Error
MRE	Magnitude of Relative Error
NBC	National Biogas Conference
NBMMP	National Biogas and Manure Management Programme
NBP	National Biogas Platform
NDP	National Development Plan
NERSA	National Energy Regulator of South Africa
NGV	Natural Gas Vehicle
NPV	Net Present Value
O&M	Operational and Maintenance
OFMSW	Organic Fraction of Municipal Solid Waste
PPI	Producer Price Index
REIPPP	Renewable Energy Independent Power Producer Procurement Programme
ROI	Return on Investment
r^2	Coefficient of determination
SA	South Africa
SABIA	South African Biogas Industry Association
SSEG	Small-Scale Embedded Generation
VFA	Volatile Fatty Acids
WWTW	Waste Water Treatment Works

CHEMICAL FORMULAS

C	Carbon
C_2H_6	Ethane
C_3H_8	Propane
CH_4	Methane
CO_2	Carbon Dioxide
H	Hydrogen
H_2S	Hydrogen Sulphide
N_2	Nitrogen
NH_3	Ammonia
O_2	Oxygen

1. Introduction

1.1 Background

In South Africa's (SA)'s first National Development Plan (NDP), the vision of transitioning toward a low-carbon economy and improving environmental sustainability was stated (RSA National Planning Commission, 2012). If the nation is to progress toward this vision, sustainable waste management, Greenhouse Gas (GHG) emission reduction, and renewable energy generation are among the key sectors that would need to be prioritised.

Anaerobic Digestion (AD) of organic wastes and subsequent usage of biogas for electricity generation or upgrading to biomethane could – to some extent – simultaneously address these issues by treating organic waste to produce a biologically stable substrate with reduced pathogens, while producing renewable energy and reducing GHG emissions.

Although this appears to be a promising and clear solution to some of the environmental problems created by SA's economy, the AD sector has not yet achieved the exponential growth required to realise its full potential. In 2016 there were around 38 commercial projects established in SA, growing to around 46 in 2018 - unfortunately not all previously established projects are currently operational (Altgen Consulting, 2016), (Goemans, 2017).

To put this into perspective, AD is a mature technology which has been widely implemented worldwide. There are more than 10 000 biogas producing digesters in Europe, of which approximately 4500 AD facilities were reported seven years ago in Germany, the European technology leader (Goulding, 2012). Additionally, there are more than 2000 AD facilities in the USA (Serfass, P, 2012), and millions of household scale digesters in India and China. SA is therefore lagging behind several developed and developing countries in this regard.

In South Africa, the renewable energy strategy has since 2011 selected wind and solar power for programmatic, competitive bidding, leaving an unattractively small window for biomass and biogas contributions. At the same time, waste management reforms have considered but not implemented new regulations to stop the disposal of untreated organic wastes to landfill. Consequently, the local establishment of AD plants have so far been driven by individual project developers - with isolated, privately funded, projects being the norm. This stands in contrast to field leaders like Germany and Sweden, where national support programmes have enabled far reaching implementation of the technology.

In the absence of a technology-specific support programme, an AD facility can only be established if it is able to stand its ground as a viable business proposition, as opposed to a social and environmental intervention. Therefore, a key hurdle to the large scale implementation of the technology has been a perceived lack of financial viability, or marginal viability which is highly sensitive to fluctuations in internal and external variables.

In order to evaluate the extent of this hurdle, an understanding of the underlying trends in installation costs and product revenues associated with the technology, in the context of South Africa, is required.

1.2 Problem Statement

Although the process economics of biogas projects have been widely described internationally, there are very few published studies in SA, especially where the installation costs of completed projects are analysed and documented.

Seeing that the cost of establishing a plant in a developing country will differ from what is observed in developed countries based on several internal and external factors including differences in legislation, cost of labour, local availability of specialised equipment and knowledge, industrial capacity, political and economic stability etcetera (Amigun B. , 2008), a need exists for local plant cost intelligence.

There are a few local publications which have partially addressed this matter. This includes a study by (Amigun & Von Blottnitz, 2009) which evaluated the capacity-cost factor for biogas plants in Africa. However, the focus was on small or institutional scale plants. An evaluation of the business case for biogas plants was carried out by (Greencape, 2017) – here the focus was specifically on the Western Cape, for plant sizes up to 1.5 MW_e. Two additional studies based their costing data on single project scenarios (Shmulevich, 2015), (Goosen, 2013).

Based on the limited information provided in these studies, there exists a need for an updated and expanded compilation of medium to large scale biogas plants costs, and a subsequent cost prediction model which reflects observations across South Africa, and can therefore be applied for first level estimations during feasibility studies on future projects.

Another topic which has been widely documented internationally but not locally, is the relative financial merits of utilising biogas for electricity generation vs. upgrading to biomethane for application as a vehicle fuel.

One local publication, commissioned by the Department or Environmental Affairs (DEA), carried out this analysis. However, in the absence of a local plant cost prediction model, this study did not include a biogas plant costing analysis (DEA, 2016). A need therefore exists to verify and update this study based on locally observed plant costs.

The absence of an established and proven knowledge base, as well as a large fraction of constructed biogas plants that are currently non-operational or were never commissioned, have resulted in hesitation from financing institutions and investors to put down the proportionally large capital investment required to establish a biogas plant. Furthermore, feasibility studies performed are frequently based on optimistic assumptions of what could be achieved, instead of verified parameters from operational digesters in SA.

Based on abovementioned observation, there is further a need to demonstrate the financial viability, or lack thereof, of biogas projects under current conditions in SA, taking realistic variability and risks into account.

One of the biggest challenges associated with biogas projects, is that there simply is no generic solution or plant configuration. This is a very variable technology, accepting feedstock from a wide range or sources, with a wide range of possible plant scales and different biogas usage pathways.

It is therefore anticipated that, at a specified scale, a range of project costs can be expected, for a range of biogas plant configurations, resulting in a range of financial viability outcomes.

1.3 Objective

The objective of this study is to contribute to the knowledge base regarding the process economics of biogas plants in the South African context, based on data from existing, local, biogas plants.

It is the author's hope that this dissertation will serve as a tool to stimulate investment into the South African biogas sector, while highlighting pitfalls to avoid.

The research approach followed can be broken down into three objectives:

- **Objective 1**: To develop an understanding of the costs associated with establishing a biogas plant in the context of South Africa and to evaluate how these compare with technology costs observed internationally, specifically in countries where the sector has developed to maturity. This objective will also update and expand on a previous study (Amigun & Von Blottnitz, 2009) by evaluating the capacity-cost factor and Lang factor observed for medium-large scale biogas projects.

- **Objective 2:** To evaluate the revenues obtainable from a biogas-to-electricity plant in comparison with a biogas-to-biomethane plant. Furthermore, taking the respective technology costs into account, to determine the financial indicators achievable and thereby to evaluate which of the two options is more financially viable in the South African context. This objective will update and expand on a previous study carried out (DEA, 2016), by including local plant costs.

- **Objective 3:** To incorporate risks and variability into the abovementioned results in order to evaluate how sensitive the financial indicators are to expected variations in key parameters, and to verify whether the achievable business case for biogas is robust enough to merit large-scale investment in the absence of a formal incentivisation programme.

1.4 Research Questions

This dissertation sets out to answer the following research questions:

What capital and operational costs are associated with biogas plants in South Africa, and how do these compare to international values?

Which biogas usage pathway is more financially viable? Electricity or biomethane for fuel?

What financial indicators can be expected from a typical biogas project in SA?

How sensitive are the findings to variations in key parameters? And which parameters matter most?

1.5 Dissertation Structure

The structure of this dissertation is summarised in Figure 1-1 and described in the section below.

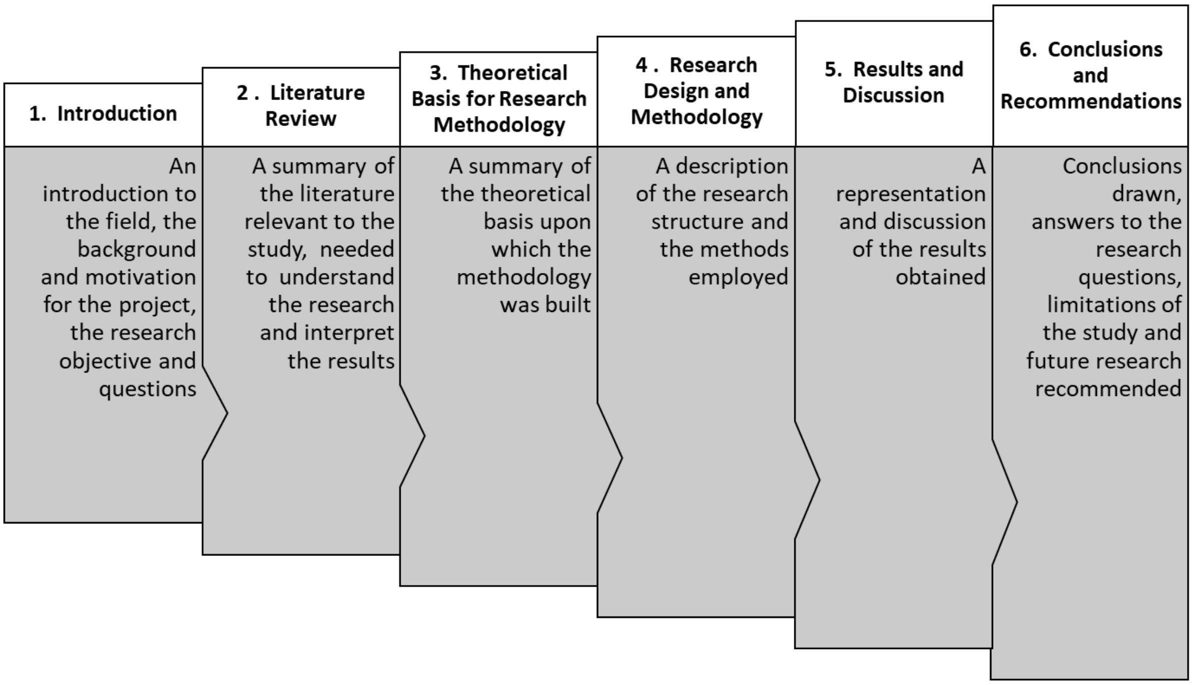


Figure 1-1: Thesis structure summary

<u>Chapter 2</u>: This chapter reviews the context and related studies, discussing the following:

- 2.1: Key aspects of the anaerobic digestion process and different biogas usage pathways.
- 2.2: The current status of the South African and international biogas sectors, and how these sectors have grown over the last two decades.
- 2.3: The biogas potential of feedstocks available in South Africa.
- 2.4: A look at past research carried out on the techno-economics of biogas plants in South Africa and internationally – the research gap, and therefore the merit for this dissertation, is defined.

<u>Chapter 3</u>: This chapter provides the theoretical basis for the research methodology by listing the methods, as available in scientific literature, that were employed in carrying out this dissertation:

- 3.1: The different stages of plant cost estimation and associated levels of accuracy – the methods applied in industry to carry out early level plant cost estimations are discussed.
- 3.2: A basis for the statistical methods applied is provided.
- 3.3: Methods of presenting plant costs in a standardised way are discussed.
- 3.4: The potential income streams obtainable from a biogas plant, and how to quantify them for different plant configurations are discussed.
- 3.5: The methods employed in analysing the financial viability of different biogas plants are presented, as well as short descriptions of different financial indicators.
- 3.6: A basis for the analysis of risk and uncertainty is provided.

Chapter 4: A description of the research methodology applied in this dissertation is provided as follows:

- 4.1: The methodology employed in achieving objective 1 are presented: evaluating the cost of biogas production in South Africa, and comparing it with internationally observed costs.
- 4.2: The methodology employed in achieving objective 2 are presented: comparing the financial viability of biogas-for-electricity with that of biogas-for-fuel at different plant capacities.
- 4.3: The methodology employed in achieving objective 3 are presented: evaluating the risks and variability that could be expected based on fluctuations in key variables.

Chapter 5: The results obtained are presented in this chapter, as follows:

- 5.1: The observed costs are presented and discussed.
- 5.2: The financial indicators for fuel and electricity production are presented and discussed.
- 5.3: The variability of costs is presented and discussed.

Chapter 6: The main conclusions and recommendations from this research are presented in this chapter as follows:

- 6.1: The research questions stated in section 1.4 are answered based on the research findings.

- 6.2: A summary of key conclusions drawn from the research is provided.
- 6.3: The limitations of this study are discussed.
- 6.4: Recommendations for future research are presented.
- 6.5: Recommendations for the advancement of SA's biogas industry are made.

1.6 Scope, Assumptions, Limitations

This dissertation focuses on the capital and operating cost of biogas plants in South Africa. Only projects of 10 kW electrical capacity (or equivalent bio-methane output) and greater are analysed.

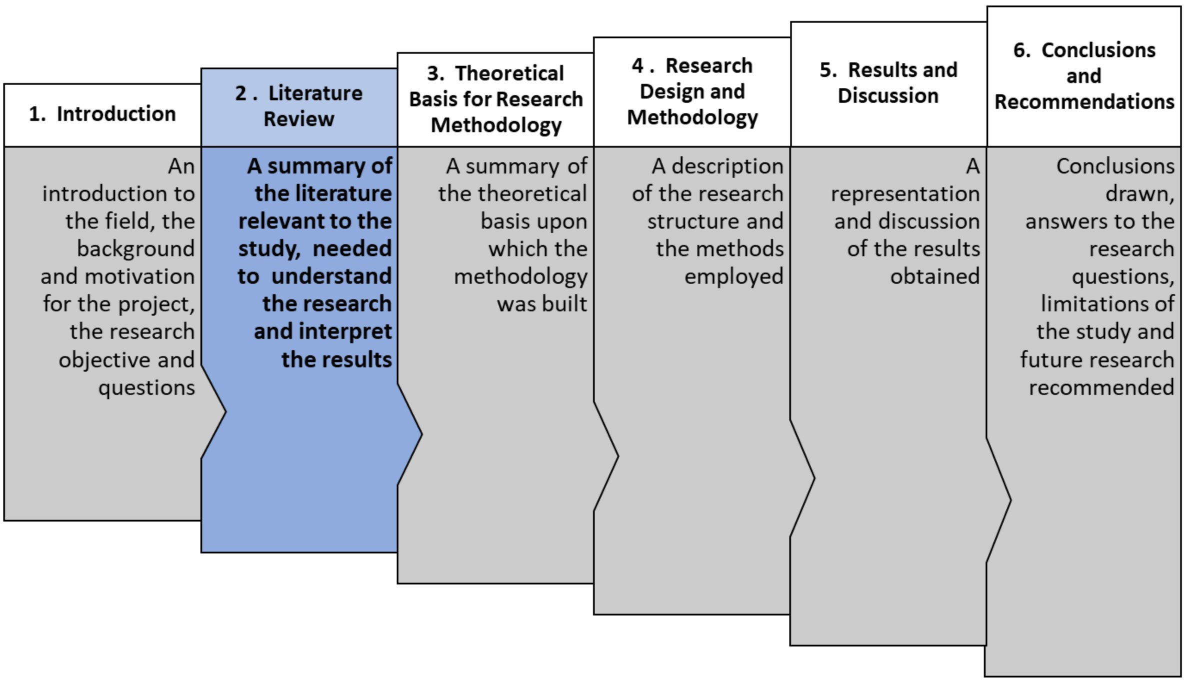
There is only a small number of existing biogas projects in SA, taking in various feedstocks, and producing biogas for various usage pathways. Therefore, the quantitative cost data used in financial modelling remains exemplary rather than representative of what can be expected in the future. The potential incomes from two biogas usage pathways are analysed, namely electricity production, and upgrading to biomethane.

The AD process can generate a variety of income streams including waste as a feedstock for which a gate fee can be charged, a nutrient rich effluent and substrate which can be applied as an organic fertiliser or soil conditioner, and heat recovered from the electricity generation process, which can also be converted into cooling through combined heat and cooling technologies. However, only the primary energy product produced from the biogas was considered within the scope of this dissertation. The implication is that biogas projects could be more profitable than described in this financial analysis, and therefore, further studies which also include the valorisation of additional income streams are recommended.

This dissertation only considered the process economics of biogas plants and excluded non-monetary benefits like the treatment of organic waste and the reduction of GHG emissions.

2. Literature Review

This chapter provides the technical background to the study and discusses and reviews relevant studies and publications. It is meant to provide the foundational knowledge and inform the reader of the state of the art, required to understand the research and interpret the results



Biogas is produced by the microbial degradation of organic matter in a damp, anaerobic environment, in a process referred to as anaerobic digestion, which occurs widely throughout nature - for example in swamps and wetlands, as well as in the digestive tracks of ruminants. The primary product is a flammable gas (biogas) consisting mainly of Methane (CH_4) 50-75%, and Carbon Dioxide (CO_2) 25 – 45%, as well as traces of Hydrogen Sulphide (H_2S), Nitrogen (N_2), and other residual compounds.

Biogas plays a unique part among renewable energy technologies because of its flexibility and multiple benefits:

- It is suitable for applications generating electricity, domestic or industrial heat, or vehicle fuel, and can substitute or be mixed in with natural gas.
- The scale and complexity of a biogas plant can vary from extremely small and simple household or rural sanitary digesters, to fully automated, industrial scale chemical plants.
- The storage and transport of biogas are relatively simple, which means that temporal and spatial separation between biogas production and usage are possible.
- Matter considered as waste can successfully be used as feedstock. For this reason, AD can have a positive impact on GHG emissions, waste management and energy supply at the same time (FNR, 2013).
- Apart from biogas, the AD process yields a second product, a digestate, which can be applied as an organic fertilizer with lower pathogen levels and improved nutrient availability compared to raw manure (Browne, 2011).

AD is an old and proven technology (yet characterised by frequent innovations) which has been implemented successfully across the world for the treatment of biological waste and production of biogas. The first documented biogas plant was a sewage sludge digester built in the United Kingdom to fuel streetlamps in the 1890s (Bond, 2011). Since then, the biogas sector has developed well in several countries worldwide, and a renewed interest in the technology has emerged during the last few decades – a strong driver being international commitments to reduce GHG emissions as well as more stringent waste management regulations.

Germany is currently leading the world biogas market, with 28% of the world's installed biogas capacity, followed by the USA with 20% and the United Kingdom with 15.5% (Yousuf, 2016). Other European countries at the technical forefront include Austria, Italy, Denmark and Sweden (Al Seadi, 2008). Implementation of the technology is still expanding, and it has been predicted that the world biogas market will reach over $ 50 billion annually by 2030 for plant constructors, operators, service providers and suppliers (Yousuf, 2016).

Although the AD process has been widely implemented in these developed and developing countries, application of the technology has been said to be still in its infancy in Africa, including South Africa (Roopnarain, 2016).

The following sections provide an overview of AD as a technology and its development in SA and internationally within the context of this dissertation.

2.1 AD Process

AD is a multistep biochemical process where complex organic matter is decomposed in the absence of oxygen by various types of anaerobic microorganisms, as shown in Figure 2-1 below. Inputs to the process are bio-degradable mass and water, and outputs are biogas, digestate slurry, and a nutrient rich effluent.

These four processes occur simultaneously in an anaerobic digester, and when functioning properly, the conversion of products from the first three steps into biogas is almost complete, so that the concentrations of intermediate products are low at any given time (USDA, 2018).

- During the first step, hydrolysis, insoluble complex molecules like carbohydrates, proteins and fat are broken down into their monomeric building blocks by hydrolytic bacteria or fungi.
- During the second step, Acidogenesis, fermentative bacteria convert these monomeric products into Volatile Fatty Acids (VFAs), alcohols, carbon dioxide and ammonia.
- During the third step, acetogenic bacteria and hydrogen scavengers convert the VFAs to acetic acid.
- The final step is methanogenesis, where methanogens, a sub-class of archaea, form Methane from the products of acetogenesis, as well as from some intermediate products from the previous steps.

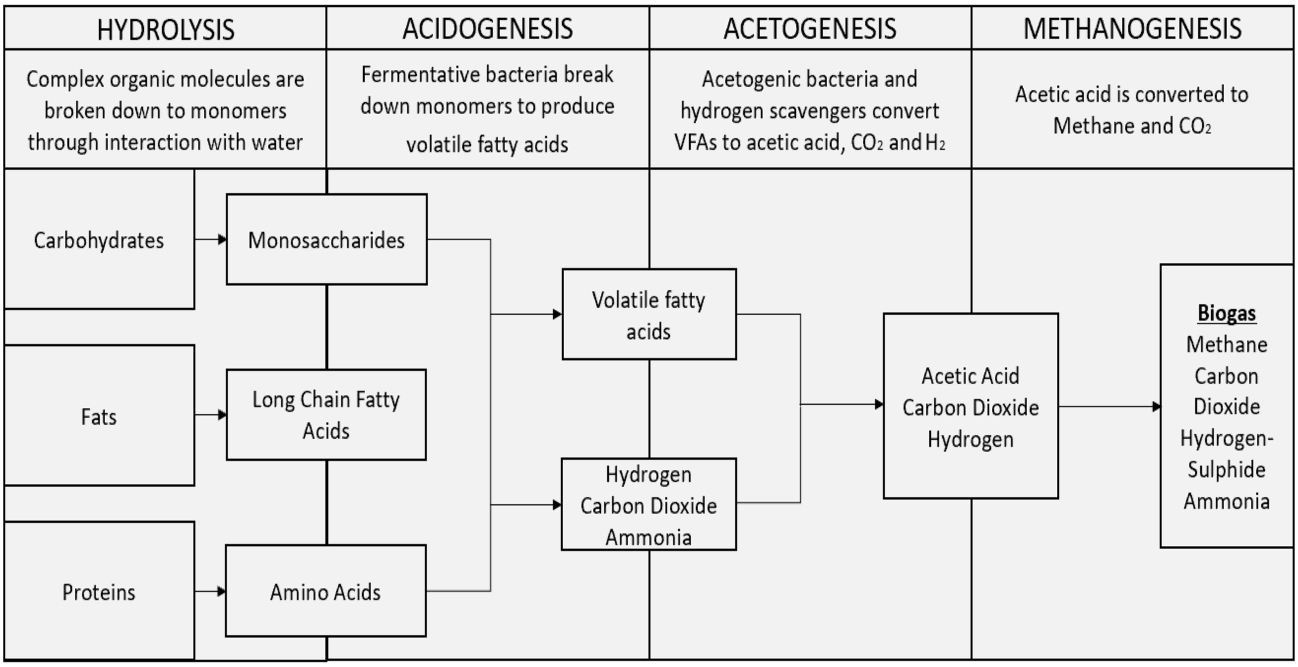


Figure 2-1: Diagram of Anaerobic Digestion Process: Adapted from (Al Seadi, 2008), (Jha, 2016)

2.1.1 Biogas Characteristics

Biogas is the most significant product of AD, and its economic value lies in its main constituent – Methane – which possesses economic potential because of its energy content. Biogas can be applied for cooking, heating, cooling, electricity generation or even vehicle fuel If upgraded to biomethane. However, apart from its economic potential, the capture of biogas also has an important positive environmental impact because it prevents Methane emission, which is a powerful greenhouse gas, 28 times more potent than CO_2 over a 100 year time frame (Starr, 2012).

Although the composition of the biogas and hence the calorific capacity will vary based on the feedstock and the bio-digester design, some typical calorific values that can be expected from biogas are shown in Table 2-1 below *(Al Seadi, 2008), (FNR, 2013).*

Table 2-1: Energy Potential from Biogas

Parameter	Unit	Value
Typical biogas calorific value	kWh/m^3	6
Typical biogas calorific value	MJ/m^3	21 - 24
Methane calorific value	kWh/m^3	9.97
Methane calorific value	MJ/m^3	35.9

2.1.2 Biogas Plant Classification

A system wherein AD is facilitated by establishing a suitable controlled environment is referred to as a biogas plant, as shown schematically in Figure 2-2 below.

The biogas plant receives input in the form of bio-degradable waste or energy crops, AD takes place in the reactor or biodigester, with biogas and digestate as output streams.

Apart from biogas, the digestate could also have economic value through its application as fertiliser. Traditionally, organic wastes like manure or compost are used directly as a fertiliser, however, this can have negative effects on the environment because of Methane and Carbon dioxide emissions during storage, as well as pollution of nearby water bodies. Putting organic waste through a biodigester will reduce odours and pathogens, while increasing the bio-availability of nutrients (Scarlat, 2018). However, depending on the type of waste, sterilisation could still be necessary to remove certain resistant pathogens, helminths etcetera (FNR, 2013).

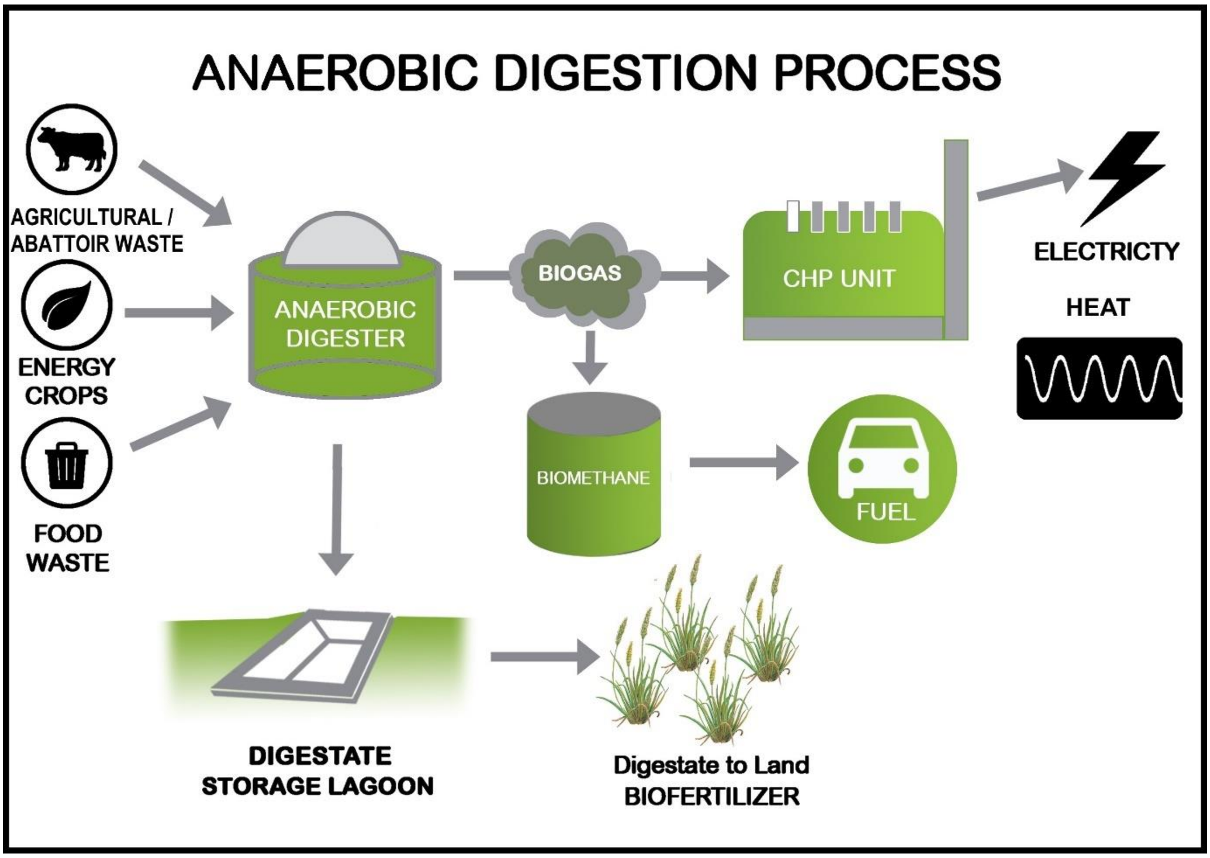


Figure 2-2: Biogas plant diagram: Adapted from (Geoline Ltd., 2018).

Although Biogas plants are not conventionally categorised, due to the wide variety of settings, applications, and financial structures that could apply, the following broad range of size categories are defined. For the purpose of this dissertation, the larger three of the five scale classes will be analysed (Amigun B. P., 2012), (Altgen Consulting, 2016), (Greencape, 2017):

- Domestic (< 20 m^3 digester volume)
- Institutional (20 - 500 m^3 digester volume)
- Small scale (10 - 250 kW_e): Typical applications include larger institutional, community, small manufacturing and smaller farm settings.
- Medium scale (>250 kW_e; <1 MW_e): Typical applications include abattoirs or commercial farms, producing energy mostly for own use.
- Large scale Biogas (> 1 MW_e): Typically, biogas, electricity and/or other energy products are produced for sale to others.

AD systems can be characterized based on their solids content as follows (Angelonidi, 2015):

- Wet system: total solids of 10% - 20%
- Dry system: total solids of 20% - >40%

Feeds for a bio-digester can come from a wide variety of sources. For the purpose of this dissertation, feedstock will be grouped into the following categories:

- Agricultural or abattoir waste
- The Organic Fraction of Municipal Solid Waste (OFMSW)
- Sewage sludge
- Industrial waste
- Food and beverage waste
- Energy crops or plant residues

These feedstock streams can be fed separately or mixed into a single digester, which is termed co-digestion (Al Seadi, 2008).

There are various parameters that can have a significant effect on the stability and efficiency of a biodigester, some of the key parameters are listed in Table 2-2 below.

Table 2-2: Key parameters affecting biodigester stability and efficiency

Parameter	Description	Influenced by	Effects	Optimum Value	Reference
Temperature	Three temperature zones have been defined: • Psychrophilic: below 25ºC • Mesophilic: 25ºC - 45ºC • Thermophilic: 45ºC – 70ºC	• Climatic conditions • External heating • Insulation	• Pathogen destruction • Higher gas yield and conversion rate at higher temperatures • Higher risk of ammonia formation • Solubility of inhibiting substances increases at increased temperature	Dependent on system	(Al Seadi, 2008)
pH	pH has an Influence on the growth of methanogenic microorganisms and on the dissociation of Inhibitory substances	• Type of Waste • Buffer capacity of CO_2 in the system	• For Acidogenesis: 5.5 – 6.5 • For Methanogenesis: 7.8 – 8.2	6.5 – 8.0 for both organisms to co-exist	(Al Seadi, 2008)
Carbon (C): Nitrogen (N) Ratio of waste	The carbon-to-nitrogen (C: N) ratio is one of the most important parameters for optimal functioning of the bio-digester, and is influenced by the type of waste fed to the digester.	Type of Waste	• Too much N: Ammonia is produced • Too much C: Acid generation resulting in pH drop	C: N = 20: 30	(Naik, 2012)

Parameter	Description	Influenced by	Effects	Optimum Value	Reference
Presence of Volatile Fatty acids	VFAs are intermediate products of the AD process which will accumulate in an unstable system	Stability of the system	Excess VFAs can be produced from easily hydrolysed substrates such as food waste, and could inhibit methanogenesis by lowering pH		(Zhang, 2016)
Presence of Ammonia	NH_3 can be produced by the degradation of proteins or other nitrogen-containing materials in the feed stream (as found in urine). This process releases ammonia-nitrogen largely in the less toxic ionized form (NH_4+) at acidic to neutral pH. However, with increasing pH (>7) the toxic non-ionized form (NH_3) increases.	Temperature Type of waste	Ammonia is an essential nutrient for the growth of microbes involved in AD but acts as inhibitor at high concentrations. NH_3 starts to be toxic at pH values higher than 7.	Continually below 80 mg/L	(Al Seadi, 2008) (Niyobuhungiro, 2016) (Jha, 2016)
Hydrogen Sulphide (H_2S)	Sulphur-containing compounds in the feedstock could be converted to sulphide in an anaerobic environment	Temperature Type of waste	Excess Sulphide could inhibit methanogenesis	As low as possible.	(Zhang, 2016)

Parameter	Description	Influenced by	Effects	Optimum Value	Reference
Retention Time	The average time spent inside the reactor by substrate	Volume and flow rate	Longer retention time results in higher conversion rates	Depends on other system parameters with a minimum of 10 days	(Al Seadi, 2008)

2.1.3 Biogas Usage: Combined Heat and Power

With the exception of household scale bio-digesters, the most widely implemented biogas application has traditionally been electricity generation, heat generation, and Combined Heat and Power (CHP) generation (Scarlat, 2018), regardless of its limited electrical efficiency which is typically around 35 - 40%. Electricity can be used on-site, fed into the grid at the municipal feed-in rate, or distributed through the grid and sold to a remote consumer via a municipal wheeling agreement. Waste heat can also be recovered, resulting in a combined efficiency of around 80 – 85% (Horvath, 2016).

In countries where district heating systems are in place, the heat can be sold to remote consumers, which can result in excellent economic and efficiency results. However, in the absence of district heating, if there is no on-site off taker for the heat, it needs to be dissipated which renders the business case significantly less attractive. In certain instances, the heat can also be used for heating the digester to mesophilic or thermophilic conditions, or drying the digestate to produce a sellable fertiliser (Budzianowski, 2015).

A CHP unit consists of a system where high temperature heat first drives a gas or steam powered generator. The resulting low-temperature waste heat is then captured through a heat exchanger (GTZ, 1988).

Electricity generation can be achieved over a vast range of scales and complexity levels, ranging from a very simple gas engine, able to tolerate high levels of biogas impurities, to a highly complex multi-fuel generator, running on upgraded biogas or biomethane.

Even though a CHP system generally does not require extensive biogas upgrading, and can therefore run with very limited infrastructure, H_2S which is very corrosive, needs to be removed from biogas before injection into any type of engine, (Goulding, 2012).

There is furthermore a range or emerging technologies for generating electricity from biogas like micro gas turbines and fuel cells. However, these technologies also require biogas purification and have not yet reached maturity. Some typical electrical and thermal efficiencies are shown in Table 2-3 below.

Table 2-3: Biogas Conversion Efficiencies Obtainable from Different Technologies Source: (FNR, 2013).

Technology	Electrical Efficiency (%)	Thermal Efficiency (%)	Total Efficiency (%)
CHP	33 - 45	35 - 56	~ 85
Micro gas turbines	26 - 33	None	26 - 33
Fuel cells	40 - 55		40 - 55
Simple gas engines (Pilot Injection, Gas-Otto)	30 - 44		30 - 44

2.1.4 Biogas Usage: Biomethane

A second, more efficient use of biogas has been demonstrated in countries like Germany, Sweden, and Switzerland - to upgrade the biogas to biomethane, and then to compress it, obtaining a product which is chemically similar to Compressed Natural Gas (CNG) (Browne, 2011). This biomethane consists mostly of Methane (97+% purity), and can be sold for heating purposes, where it can be used as a replacement for Liquid Petroleum Gas (LPG) or applied as vehicle fuel. The application of biomethane blended with natural gas in a 50% ratio, or BioCNG is also increasing. The major advantage of upgrading biogas to biomethane is that it enables spatial and temporal separation between biogas production and biogas usage. The energy dissipated during the upgrading process is around 10% of the energy of raw biogas, while about 1.5% Methane loss can be assumed. This means that energy losses of 10% - 20% can be expected with this method (Budzianowski, 2015), (Murphy J. &., 2009).

The upgrading of biogas to biomethane is increasing internationally, influenced by factors like advancements in biogas upgrading technologies and the poor economics of electricity producing biogas plants (Scarlat, 2018).

In countries like SA, where there is no national gas grid, the transport sector can serve as an excellent entry market for biomethane with great potential based on its size. This application of biomethane will be the focus of this dissertation. The development of biomethane for fuel is at different levels for different countries across the world, being influenced by various factors like infrastructure, national support systems etcetera – the main pre-requisite being an established Natural Gas Vehicle (NGV) fleet.

NGVs were first implemented as trucks during and after World War II in a number of European cities. It was relaunched in the early 1990's, and its implementation has since increased in popularity all over the world (Thran, 2014). Brazil was also an early adopter of the technology with biofuels for transport being implemented in the 1970's after the first oil crisis (Scarlat, 2018).

As of 2015, there were approximately 18 million vehicles running on natural gas around the world. Countries with a strong market for NGVs include Iran, Pakistan, China, Argentina and Brazil. An increase is also observed in European countries where, as of 2013, biomethane as automotive fuel was available in 13 countries (Thran, 2014). Sweden is at the head of this European trend with approximately 44 000 operational NGVs including buses and refuse collection trucks, 195 NGV refuelling stations, and 60 biogas upgrading plants (Gutierrez, 2018). Figure 2-3 below shows a graphical representation of biogas upgrading plants across the world, as of 2012.

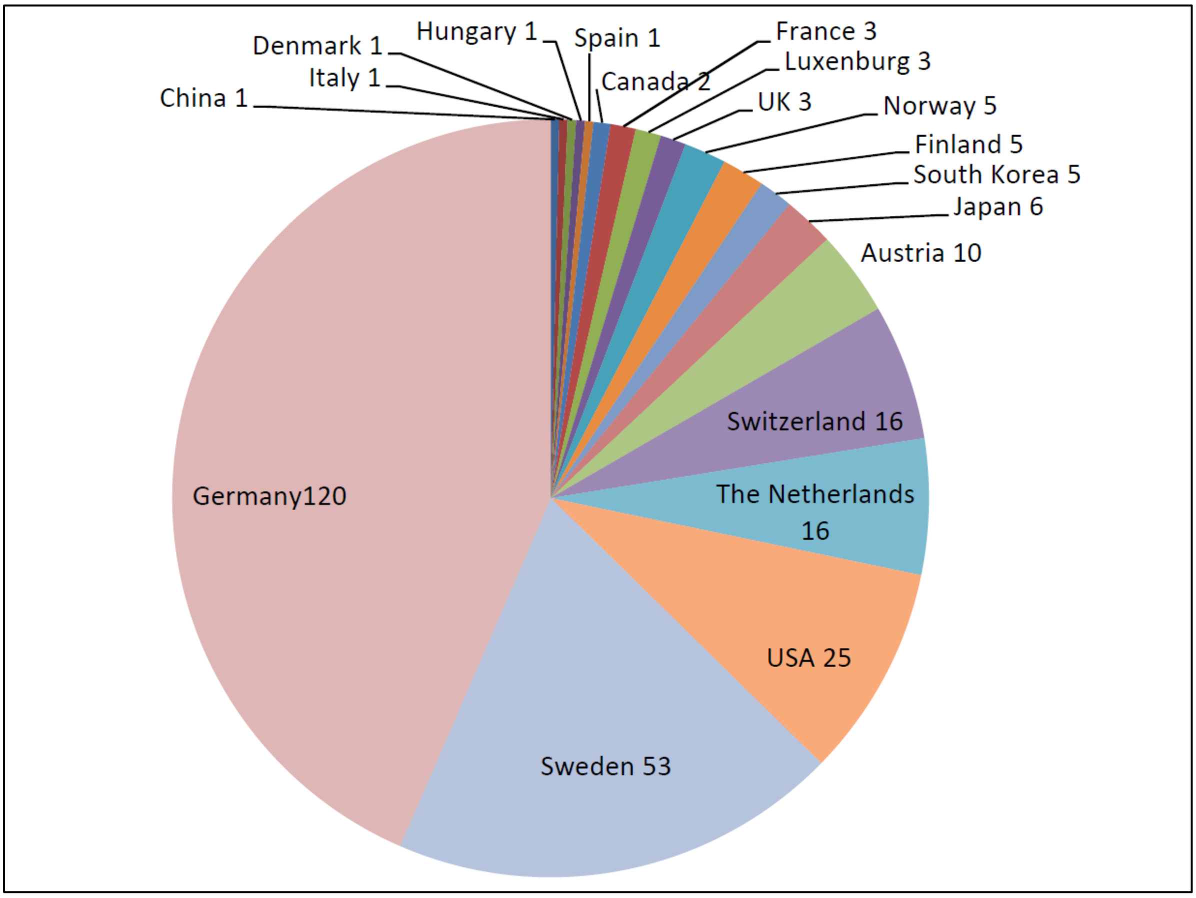


Figure 2-3: Biogas upgrading plants across the world in 2012. Source: (Thran, 2014).

The application of biomethane for vehicle fuel holds the potential to bring about significant reductions in GHG emissions due to the cleaner combustion process compared to conventional fuel, as a result of the higher Hydrogen (H): Carbon (C) ratio, and therefore reduced CO_2 emissions per energy equivalent of fuel (DEA, 2016). It is, however, a process that needs to be stringently controlled, as contaminants in sub-standard biomethane could have a destructive effect on a vehicle's engine (Goulding, 2012).

A study commissioned by the DEA found that, in the absence of a technology-specific support programme, a positive business case for biogas in the South African transport sector does not yet exist. Such a support programme should be based on the non-monetary benefits which the technology brings to society since biomethane from AD is currently not commercially competitive enough to overcome the barriers of implementation as a transport fuel.

A typical support programme could take the form of subsidies, taxation and/or regulation. When looking at international experiences of government support for the uptake of different types of biofuels, it is observed that most countries typically rely on tax-incentive schemes (DEA, 2016). This dissertation will evaluate, based on quantitative cost data from existing biogas plants in SA, whether this finding still holds true under the current market conditions.

2.1.4.a Conversion of Petroleum-Based Engines to Enable Biomethane Usage

A vehicle which normally runs on petrol or diesel can be converted to a dual-fuel (petrol/biomethane) vehicle. However, even in its compressed state, the volumetric energy density obtainable from biomethane is only 25% that of diesel. This means that the vehicle would have to be fitted with a larger fuel tank, and, due to the pressurised state of the gas, the tank would be more expensive than a conventional fuel tank (DEA, 2016). Apart from that, biomethane delivers almost the same performance and efficiency as diesel, and a typical range for a bio-fuel car is 400 - 500 km (IRENA, 2018). The following options for converting vehicle engines to biogas exist (Linkd Environmental Services, 2015):

- A dedicated gas engine: The vehicle will run exclusively on biomethane/CNG. This applies well to vehicles with fixed routes, and where access to refuelling stations can be planned and guaranteed.
- A mixed fuel engine: This vehicle will use a relatively small amount of petrol/diesel, and run primarily on biomethane/CNG. The same limitations as for an exclusive gas engine apply.

- A dual fuel engine: This vehicle will have the option to run on both petroleum-based fuel and biomethane/CNG, or exclusively on petroleum-based fuel.

Because the biomethane market is still immature in SA, previous studies have focused on dual fuel systems thereby lowering associated risk.

2.1.4.b Biogas Upgrading Technologies

Methane is the only component of biogas that can be used for energy generation, and therefore other gas components should be removed. The required CH_4 content depends on the desired application. As can be seen in Table 2-4 below, purification of biogas for vehicle fuel applications requires removal of around 90% of the CO_2, as well as N_2, Oxygen (O_2), H_2S and other impurities.

Table 2-4: Typical composition of biogas, biomethane and natural gas Source: (DEA, 2016), (Rasi, 2009), (Sun, 2015).

Component	Quantities present in -		
	Raw Biogas	**Biomethane for fuel applications**	**Natural Gas**
Methane (CH_4)	45 - 75% vol	97 - 99% vol	93 - 98% vol
Carbon Dioxide (CO_2)	20 – 40% vol	< 2.5% vol	1% vol
Water vapour (H_2O)	2 - 7%	-	-
Nitrogen (N_2)	1 - 5% vol	< 3% vol	1% vol
Oxygen (O_2)	< 2% vol	Maximum 100 ppm	-
Hydrogen (H_2)	Trace	Trace	-
Hydrogen Sulphide (H_2S)	3000 - 5000 ppm	< 10 ppm	-
Ammonium (NH_3)	< 100 ppm	Trace	-
Ethane (C_2H_6)	-	-	< 3%
Propane (C_3H_8)	-	-	< 2%
Others including: Siloxanes, Aromatic and halogenated compounds, Volatile organic compounds, Sulphides, disulphides and thiols, Metals	Trace	-	-

The largest fraction that needs to be removed is CO_2, and for that the following five technologies, as set out in Table 2-5, can be applied.

Table 2-5: Biogas upgrading technologies sources: (Starr, 2012), (Sun, 2015).

Unit Operation	Technology	Description of process	Energy usage	CH_4 loss
Absorption	High pressure water scrubbing (HPWS)	Water absorbs CO_2 under high pressure conditions and is regenerated by depressurising.	0.2 - 0.32 kWh/Nm^3 raw gas	>2 %
	Chemical scrubbing	An Amine solution absorbs CO_2 and is regenerated by heating.	0.1 - 0.15 kWh/Nm^3 and 0.5 - 0.75 kWh/Nm^3 (heat) raw gas	8 - 10%
	Organic physical scrubbing	Polyethylene glycol absorbs CO_2 and is regenerated by heating or depressurising.	0.2 - 0.3 kWh/Nm^3 and 0.2 kWh/Nm^3 (heat) raw gas	2 - 13%
Adsorption	Pressure swing adsorption	Pressurised biogas is passed through a medium such as activated carbon, which is then regenerated under lowered pressure.	0.25 kWh/Nm^3 raw gas	2 - 9%
Membrane	Membrane separation	Pressurised biogas is passed through a membrane which is selective for CO_2.	0.15 - 0.22 kWh/Nm^3 raw gas	0.5 - 20%
Cryogenic	Cryogenic separation	Biogas is cooled until the CO_2 enters a liquid or solid phase while the methane remains a gas, thereby enabling separation.	0.2 - 0.28 kWh/Nm^3 raw gas	< 1%

HPWS is the least complex, and therefore the most economical and most frequently employed system in Europe – it will therefore be used as the default upgrading technology in this dissertation. HPWS does not require heat input, operates on approximately 0.25 kWh$_e$/m^3 of raw biogas, and operates at an expected Methane loss of approximately 1.5%. HPWS functions on the principle that CO_2 has a higher solubility in water than Methane (Browne, 2011). It should, however, be noted that due to the high purity requirements for vehicle fuel applications, chemical absorption or cryogenic separation could be more suitable upgrading technologies, depending on the level of contaminants in the feedstock. (Sun, 2015).

2.2 The Global and South African Biogas Sectors

One of the greatest environmental challenges faced by modern societies is the reduction of GHG emissions and hence the prevention of further climate change. The replacement of fossil fuels with renewable sources such as biogas plays an integral role in mitigating these occurrences. For this reason, there has been increased interest in AD across the world over the past two decades (Horvath, 2016). This section describes the developments observed in the biogas sector world-wide and in South Africa.

2.2.1 The Global Biogas Sector

Over the past two decades, there has been a significant growth in the implementation of renewable energy worldwide, with 19% of the global final energy demand being met by renewable sources in 2014. This growth is driven by policy support as well as decreasing prices in technology – especially wind and solar energy (Scarlat, 2018). Bioenergy was contributing approximately 9.6% to the global energy mix in 2015. Biogas currently constitutes a small portion of the total bioenergy, but its contribution increased from 2.7% in 2005 to 7.8% in 2015, showing the highest growth in the bioenergy sector. The increase in biogas plant installed capacity worldwide can be seen in Figure 2-4 below.

The European Union (EU) is currently the world leader in biogas production, with more than 10 GW installed capacity and around 17 400 biogas plants, compared to the global biogas capacity of 15 GW in 2015. Other major role players include the USA with 2.4 GW installed capacity, Asia with 711 MW, South America with 147 MW, and Africa with 33 MW.

China had an estimated 100 000 modern biogas plants and 43 million residential-scale digesters in 2014, and India had approximately 4.75 million farm size biogas plants in 2014 (Scarlat, 2018).

In the USA, there were approximately 2100 biogas plants in 2017, of which 250 were farm-based with animal manure as feedstock, 654 were recovering biogas from landfill sites, and 1240 were situated at Waste Water Treatment Works (WWTWs).

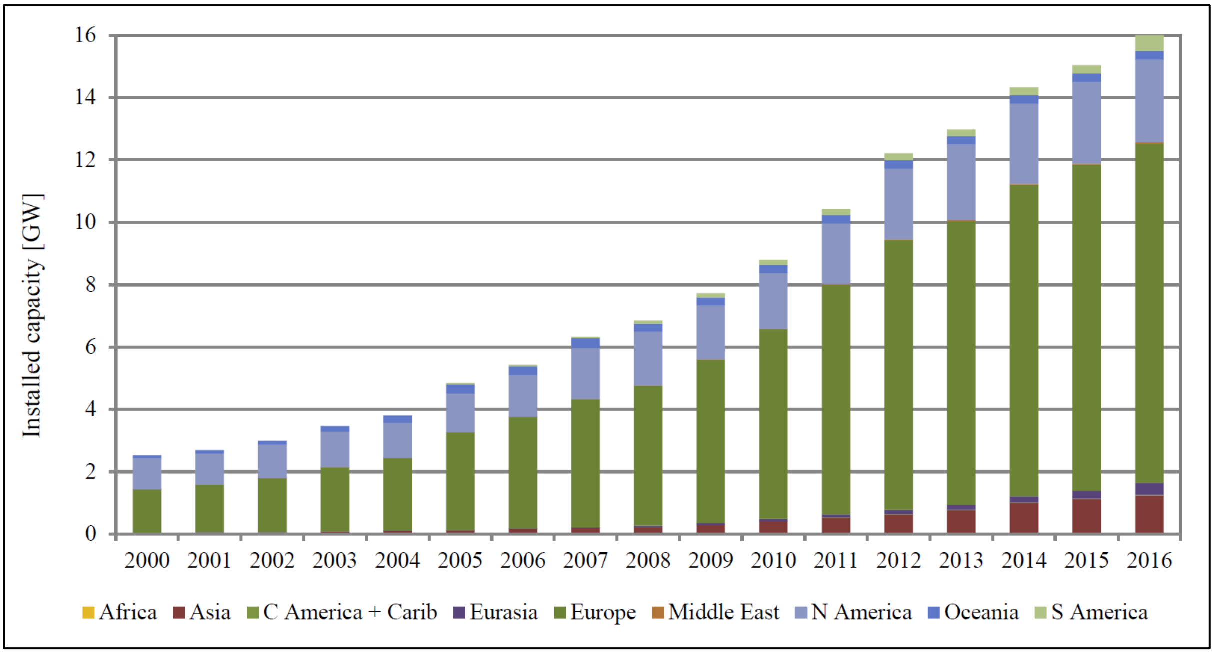


Figure 2-4: Global increase in biogas plants observed Source: (Scarlat, 2018).

2.2.1.a Biogas Applications Observed Worldwide

In developed countries, biogas is used primarily for electricity-only or electricity-and-heat, with small amounts used in heat-only plants, although an increase in biogas upgrading to biomethane has been observed. The EU is also the world's leading producer of biomethane, with 1.2 billion Nm^3 of biomethane produced in 2015 (Scarlat, 2018).

In developing countries, biogas is mainly produced in household scale or small community scale digesters and biogas is used mostly for cooking and lighting.

2.2.2 The South African Biogas Sector

South Africa was one of the early role players in the global biogas sector, with its first documented anaerobic digester being built in 1957 by British fighter pilot, L. John Fry on his pig farm (Munganga, 2013). Since then, however, the biogas sector has been slow to develop both commercially and rurally and is currently still small compared to other developed and developing countries (Altgen Consulting, 2016). Although AD has been applied as an effluent treatment method for decades, on an industrial scale, the focus has been on Chemical Oxygen Demand (COD) reduction and not on energy generation (Ross, 1989). It is estimated that there are currently around 500 bio-digesters in SA, of which around 200 are at municipal and industrial WWTWs - only a small fraction of which are capturing the biogas produced. Of the remaining 300, the majority are small scale digesters, and almost all the functioning bio-digesters were established through private funding (Altgen Consulting, 2016).

SA possesses great potential for a flourishing biogas sector because of its mild climate and abundant supply of bio-degradable waste streams, combined with electricity supply shortfalls and consistent electricity and fuel price increases. In spite of these attractive conditions, the sector is currently not thriving. Table 2-6 below provides a summary of medium and large-scale biogas projects in South Africa for which data is available in the public domain – the operational status of many of these plants are unclear.

To promote the growth of the renewable energy sector in SA, the government implemented the Renewable Energy Independent Power Producer Procurement Programme (REIPPP) in 2011. This program especially stimulated wind and solar energy sectors. While biogas projects were included in the programme’s design, no biogas projects have been developed as part of the programme, with the closest being the Johannesburg landfill gas to electricity project (Goemans, 2017). In 2013, the first National Biogas Conference (NBC) was held in Gauteng. It was facilitated by the Department of Energy (DoE), the South African Biogas Industry Association (SABIA), and the Development Bank of South Africa (DBSA) (Goemans, 2017). The purpose of the conference was to remove barriers and to identify research gaps. As a key resolution of the conference, the National Biogas Platform (NBP) was established. The second NBC was held in Gauteng in 2015, and the third NBC in 2017.

Table 2-6: Biogas plants implemented in SA

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
1	SAB Miller: Rosslyn	SAB Miller	2006	Rosslyn, Pretoria	2.28	18	Brewery organic waste
2	PetroSA	MetchCap	2007	Mosselbay	4.2	N/A	Refinery waste water
3	SAB Newlands	SAB Miller	2007	Newlands	1.42	14	Brewery organic waste
4	SAB Miller: Alrode	SAB Miller	2009	South of Johannesburg	2.63	N/A	Brewery organic waste
5	iBert Jan Kempdorp	M2M Abattoir	2012	Jan Kempdorp, Northern Cape Province	0.28	6.4	Slaughter waste
6	Manjoh Ranch	Farmsecure Carbon and Manjoh Ranch	2012	Nigel	N/A	23	N/A

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
7	Joburg Northern works refurbished facility	Johannesburg Water	2013	Johannesburg	0.855	20	Sewage sludge
8	Cape Flats WWTW	Cape Town Flats WWTW City of Cape Town	2014	Cape Town	2.8	83	Sewage sludge
9	Uilenkraal Dairy Farm	Uilenkraal Dairy Farm	2014	Darling	0.5	11	Waste: Bovine manure – lined lagoon digester
10	Morgan Abattoir Digester	Morgan Abattoir	2015	Springs, Gauteng	0.4	N/A	Abattoir waste
11	Bio2Watt Bronkhorstspruit	Bio2Watt	2015	Bronkhorstspruit	4.6	150	Cattle manure and other mixed wastes

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
12	Elgin fruit juices	Elgin Fruit Juice	2015	Grabouw	1.077	20	Fruit waste
13	iBert – Peninsula	Peninsula Piggery	2015	Queenstown	0.37	6.7	Pig manure
14	Bayside Mall	Bayside Mall	2015	Table view, Cape Town	0.031	2.5	Organic waste from retailers
15	RCL Foods	RCL Foods	2015	Worcester	N/A	N/A	N/A
16	Botala Energy: Greenway Farms Biogas	Greenway Farms - Rugani food processing facility	2015	Krugersdorp	3.5	15	Vegetable residue from food processing and grass silage
17	iBert: Riversdale	Hessequa Abattoir	2015	Riversdale	0.093	5.3	Abattoir waste

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
18	Distell Biobulk	Veolia, Distell	2016	Stellenbosch, Western Cape	N/A	N/A	Distillery waste water
19	iBert: Zandam	Zandam +IBert	2016	Durbanville Cape Town	0.167	9.5	Pig manure
20	Botala energy: Tshwane Food and Energy Centre	Tshwane Food and Energy Centre	2016	Close to Bronkhorstspruit	0.08	2.8	Sweet sorghum grass silage, discarded vegetables & other farm residues
21	New Horizons Athlone	Clean Energy Africa and Waste Mart	2017	Cape Town	6.5	450	OFMSW
22	Botala Energy: Lukhanyiso Bio-CNG Facility	Lukhanyiso Food and Energy Centre	2017	Free State	5.41	73	Energy crops of sweet

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
							Sorghum grass silage
23	iBert: SucroPower	SucroPower	2017	Mandini	0.043	3.8	Napier grass and cow manure
24	Ceres fruit farm	Ceres	1998 – refurbished in 2015	Ceres	N/A	N/A	Fruit waste
25	Distell Worcester	Distell	Expected in 2019	Worcester	N/A	N/A	Distillery waste
26	Bio2Watt Vylvlei Dairy	Bio2Watt & Vylvlei	In Process	Malmesbury	4.8	N/A	Cow manure
27	Reliance Composting	Reliance Composting	In Process	Klipheuwel	N/A	N/A	N/A
28	Arcelor Mittal	Saldanha Bay Municipality	In Process	Saldanha Bay	N/A	N/A	N/A

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
29	Drakenstein Municipality	Drakenstein Municipality and Interwaste	Planned for 2019 but cancelled	Wellington	10.07	99	OFMSW
30	Faircape	New Horizons Energy	Planning Stage	Kuiperskraal	N/A	N/A	N/A
31	SAB Miller: Prospection	SAB Miller	N/A	Prospection	1.68	N/A	Brewery organic waste
32	SAB Miller: Ibhayi	SAB Miller	N/A	Ibhayi	0.76	N/A	Brewery organic waste
33	iBert: Cavalier Abattoir	iBert: Cavalier Group	2016	Cullinan	0.747	25	Slaughter waste
34	Driefontein WWTW	Johannesburg Water	2014 completed not commissioned	Johannesburg	2	29	Waste water sludge

Ref. No	Project Name	Project Owner	Year Commissioned	Location	Energy Capacity (Combined) MW	Capital Cost (R Million)	Feedstock Description
35	Farmsecure Carbon	Farmsecure	N/A	N/A	0.25	13	bovine manure,
36	Farmsecure Carbon	Farmsecure	N/A	N/A	0.4	N/A	N/A
37	Selectra: Harmony BioEnergy Project	Selectra	2016	Free State	N/A	N/A	Purpose grown silage
38	WindhoeK AD	CAE	N/A	N/A	0.5	N/A	N/A
39	Humpries	CAE	N/A	Bela-Bela, Limpopo	1.2	N/A	N/A

2.2.3 The Potential for Electricity from Biogas in SA

In SA, there is a program termed Small-Scale Embedded Generation (SSEG), which allows for electricity to be fed into the national grid by power generation facilities located at residential, commercial or industrial sites. Electricity can be generated through solar photovoltaic, wind, biogas or other technologies. Although this system is still in its infancy, there is an upward trend of municipalities adopting the SSEG system. As of 2017, 21% of municipalities allowed SSEG installations, 13% of municipalities had an official application system and 11% of municipalities had SSEG tariffs. The Western Cape is leading the initiative by allowing SSEG in more than 70% of its municipalities (SALGA, 2017).

The obstacles associated with feeding electricity into the grid include the requirement to apply for an energy generation licence with the National Energy Regulator of South Africa (NERSA), the limited amount of South African municipalities allowing electricity feed-in, and the tariffs offered, which are frequently not competitive.

In light of these obstacles, the simplest and most economically beneficial use of electricity and heat from biogas is self-consumption on-site which implies that heating and electricity savings equal to Eskom's retail price can be achieved. Alternatively, if a remote consumer is willing to pay a premium for the electricity purchased based on environmental considerations, a feasible business case may also exist for a wheeling agreement. Unfortunately, reaching a wheeling agreement with a municipality also typically involves substantial obstacles and delays in project execution (Thomas, 2018).

2.2.4 The Potential for Biomethane from Biogas for the SA Transport Sector

The transport sector forms the backbone of South Africa's socio-economic activities. It is crucial to the economic development of the country as it facilitates the movement of people and products. It is, however, contributing 13% to South Africa's GHG emissions, making it the fastest growing source of GHG emissions, and the second largest source, apart from the electricity sector (Linkd Environmental Services, 2015).

Oil is the main resource that fuels the world economy. It supplies about one third of the global primary energy requirements and supplies around 95% of the energy required by global transport systems. Similarly, the South African transport sector, which consumes around 28% of SA's energy, relies heavily on petroleum fuels, with more than 80% of our petroleum fuels consisting of petrol and diesel (Department: Energy Republic of South Africa, 2014).

As SA has very limited crude oil reserves and production, we rely heavily on the importation of crude oil and refined petroleum products. SA's local refining capacity to petroleum products is approximately 703 000 barrels per day, about 72% of which consists of imported and domestic crude oil and about 28% consists of coal-to-liquids (CTL) synthetic fuels as well as gas-to-liquids (GTL) synthetic fuels (Department: Energy Republic of South Africa, 2014).

Gas is currently playing a small marginal role in the South African energy mix, and therefore, there is very limited gas transport and retail infrastructure in place (DEA, 2016). There is, however, a rapid expansion in the natural gas industry with gas reserves in Mozambique and Namibia being exploited, as well as the possibility of shale gas exploitation in SA (Linkd Environmental Services, 2015).

Historically, the applications of biogas in South Africa, excluding residential use, have been limited to the generation of heat and electricity. Biogas as transport fuel has been tested on a few occasions, but no substantial projects have been established to date (DEA, 2016).

2.2.4.a SA's Annual Spending on Importation of Petroleum Products and the Cost of Fuel

SA's local production of petrol and diesel has not been increasing dramatically, from 20.2 billion litres in 2002 to 21.3 billion litres in 2016. Fuel consumption has, however, been increasing at approximately 3% per year, which resulted in about 5.7 billion litres of petrol and diesel being imported in 2016 (Department: Energy Republic of South Africa, 2017).

In 2016, SA spent $ 6.5 billion on the importation of crude oil, $ 2.6 billion on processed petroleum oils and $ 268 million on petroleum gases. They further spent $ 204 million on the importation of coal and solid fuels made from coal. The importation of petroleum related products grew steadily from 2009 to 2016, and the mineral fuels sector represents the second largest component of SA's imports, comprising 13.4% which shows that there is a strong and growing demand for fossil fuel related products (Workman, 2017).

It is known that there are sufficient oil resources to last up to 2030, after which, it is not clear how oil production will develop (Linkd Environmental Services, 2015).

2.2.4.b Greenhouse Gas Emissions from Vehicles

South Africa is the largest emitter of GHG in Africa (Global Carbon Project, 2017), and is ranked the 12th largest CO_2 emitter in the world (Goemans, 2017). Of the greenhouse gases emitted, CO_2 forms the largest component, and the greatest contributor to emissions is the electricity industry with the transport industry in second position. Methane emissions form the second largest component, of which the greatest contributors are the livestock and waste sectors (DEA, 2014).

It is further known that emissions from petrol and diesel used in road transport account for 93% of the GHG emissions related to the transport sector, which contributes 13% of South Africa's overall emissions (Linkd Environmental Services, 2015).

2.2.4.c Gas Powered Vehicle Developments in SA: Municipal Bus Fleets

The Industrial Development Corporation (IDC) has launched a pilot project to determine the feasibility of converting metrobuses to gas or ethanol. The project operated on urban drive cycles for more than a year with the aim of determining the payback period and financial viability. The study found that operational costs for dual-fuel buses are lower than for petroleum buses, which led to the launching of pilot projects in Johannesburg and Pretoria (Linkd Environmental Services, 2015). The results from this pilot project has led to the Metrobus Diesel Dual Fuel Technology (MDDFT) initiative, which, to date, includes 30 converted buses and 150 newly purchased buses in Johannesburg and 40 dedicated CNG buses in Tshwane (Liedtke, 2017).

Based on these pilot projects, it has been shown that municipalities can achieve savings of 20% on fuel as well as reduced vehicle maintenance costs and GHG emissions.

2.2.4.d Gas Powered Vehicle Developments in SA: Minibus Taxis

In 2013, the IDC commissioned a pilot project of converting minibus taxis to run on CNG. Average fuel savings of 35 cents/km were observed, which translates into a 24% saving in fuel costs compared to petrol. This program has since been extended, with an estimated 1000 CNG taxis currently running in Johannesburg, Pretoria and Ekurhuleni (Linkd Environmental Services, 2015).

2.2.5 Drivers for a Growing Biogas Sector

The primary driver for a growing biogas sector is its economic viability. Based on the fact that the business case for biogas plants is not very attractive on its own, those biogas sectors across the world that have shown significant growth have all been underpinned by national support schemes (Scarlat, 2018).

For instance, the leadership of the EU in the biogas sector is primarily based on ambitious energy and climate policies adopted by them, which have resulted in various national support schemes for biogas (Scarlat, 2018).

Developing countries where biogas support programmes have been implemented to develop household biogas systems have also seen significant growth of their biogas sectors. This includes China, Thailand, Nepal, Vietnam, Bangladesh, Sri Lanka, and Pakistan (Scarlat, 2018). This is also demonstrated by India, where the National Biogas and Manure Management Programme (NBMMP) continues to promote the construction of family size biogas plants, with the aim of increasing the number of biodigesters by 100 000 between 2014 and 2019 (Scarlat, 2018).

In South Africa, there is currently no national biogas support programme, however, there are other factors that could drive the acceleration of the biogas sector. These include (Goemans, 2017), (Greencape, 2017):

- Gradual improvement in regulatory frameworks which promote renewable energy, and which makes the landfill of hazardous biological waste costlier and more difficult.
- Waste disposal costs, which are currently relatively low in South Africa, but increasing for certain types of wastes such as abattoir waste, as tighter disposal regulations are being enforced.
- Green project funding and incentives.
- Unreliable energy supply from the national grid, combined with electricity and fuel prices that are consistently rising above inflation.
- Widely available, untapped feedstock sources, e.g. landfill sites reaching their capacity, a significant agriculture sector and numerous wastewater treatment plants nationally.
- Government’s commitment to cleaner energy sources.
- Stricter legislation toward the disposal of animal waste and liquid waste (waste with a moisture content >40%) to landfill, as described in the National Norms and Standards for the Disposal of Waste to Landfill (GN R 636 of 23 August 2013), as well as the newly drafted National Norms and Standards for Organic Waste Composting (GN1135 of 2019), which aims to divert organic waste from landfills.

2.2.6 Barriers to a Growing Biogas Sector

The development of the NBP has made a great contribution to the growth of the biogas sector in SA, however, the following barriers still curb sector growth (Goemans, 2017), (Greencape, 2017), (Unterlecher, 2018), (Thomas, 2018).

- Biogas projects in South Africa are often found to be insufficiently financially feasible. This relates to project costs, market conditions and a lack of funding opportunities.
- The regulatory environment is not conducive the development of biogas projects – environmental and other legal requirements can be very expensive and lengthy.
- The biogas supply chain is not sufficiently developed in South Africa, frequently expensive equipment needs to be imported from Europe.
- A lack of alignment between different tiers of government regarding the approval of biogas projects.
- A lack of local experience in designing, constructing and operating biogas plants.
- A lack of support from government in the form of subsidies and incentives.
- An unwillingness of commercial banks to support biogas projects – this is exacerbated by the large amount of non-operational biogas projects in SA.
- A general lack of understanding of the biogas process, especially at the municipal level.
- A lack of information sharing on existing biogas projects.

2.3 AD Feedstock Potential in SA

Based on a report released by the (DEA, 2016), SA has enough bio-degradable waste sources to produce around three million Nm^3 of biogas per day, which translates into approximately 300 MW electricity generation capacity or 500 million litre equivalent of diesel production annually. The majority of potential biodigester feedstock sources are located in urban areas around SA’s largest metropoles in the Gauteng, Western Cape, and Natal provinces.

As can be seen in Figure 2-5 below, the largest potential feedstock source lies in the municipal solid waste sector, where the vast majority of waste is currently landfilled. This sector has enormous potential for AD as many landfill sites throughout the country are currently approaching maximum capacity. However, a challenge associated with the OFMSW is that the waste is generally not separated at source, and sorting at the AD site can have significant cost implications.

The sugar production and agriculture sectors also have great potential, however, a challenge here is that many single point sources do not have enough waste to achieve significant economies of scale, which means the transport of waste would be necessary, resulting in higher biogas production costs.

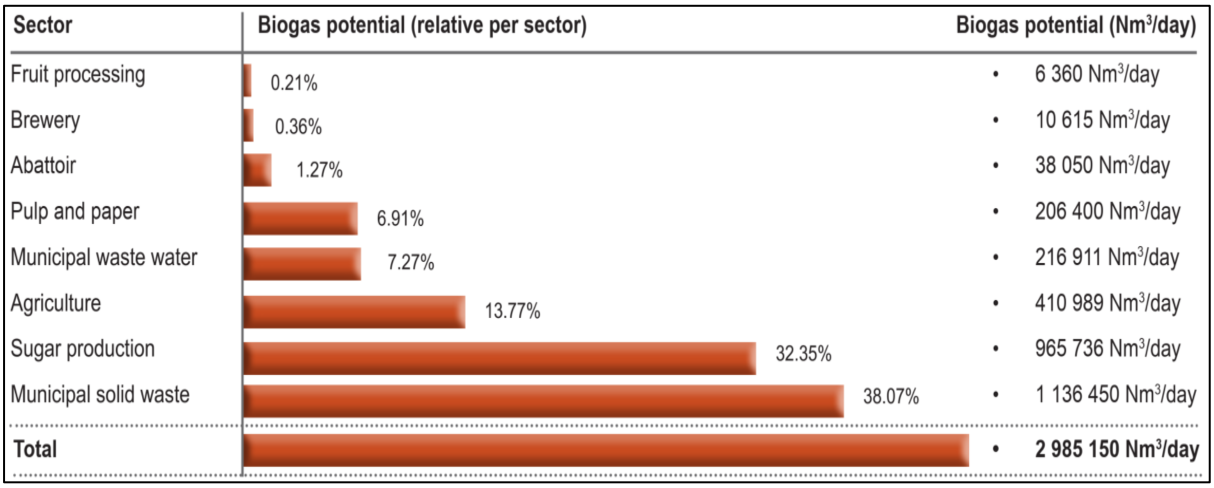


Figure 2-5: Biodigester feedstock potential in SA Source: (Department: Transport, RSA, 2016)

A sector that specifically holds great potential for AD in SA is the municipal wastewater treatment sector, where AD has been implemented to stabilise the sludge before disposal since the 1960’s. Many of the treatment plants still have functioning digesters, however, the biogas is generally not captured for energy recovery, but flared (WEC Projects, 2016), while about 0.5 million tons of sewage sludge is landfilled per annum (Altgen Consulting, 2016). There exists therefore an untapped potential for extracting gas from these existing plants and using it for energy generation. A study to estimate the biogas potential from WWTW’s across SA was carried out by GIZ in 2016 (WEC Projects, 2016).

The project identified 129 WWTW’s with existing bio-digesters and capacities greater than 10ML/day for the assessment. Feasibility was based on the potential of the biogas produced to supply the treatment works with its required energy based on CHP units. Of the assessed plants, 87 were found to have biogas potential, and 39 were identified as being feasible for a CHP project. Feasible plants were those that could recover the capital investment, operational and maintenance costs over the 15-year lifespan of an upgraded bio-digester through savings in electricity costs.

The main advantages for the WWTW sector are that the digesters have already been built and there is a constant supply of slurry at no extra cost. The main challenges associated with this scenario is finding a workable solution between municipalities and AD project developers. Additionally, in order to maintain a stable digestion process, co-digestion with manure is highly recommended, which means that additional waste would have to be accepted into the municipal WWTW facility.

2.4 Key Findings from Past Research

Biogas production through AD is a mature and well documented technology internationally, although research on economics of biogas plants carried out in SA is still limited. This also applies to the conversion of biogas to electricity and heat through a CHP system, as well as conversion to biomethane (Al Seadi, 2008), (FNR, 2013).

2.4.1 Research in South Africa

There is a limited body of published research on the economics of biogas plants, in the context of South Africa.

(Amigun & Von Blottnitz, 2010) indicated that diseconomies of scale are present for small scale biogas plants in Africa, while economies of scale are present for large scale plants, with a capacity- cost factor of 0.8. However, for large scale plants this factor could not be verified as significantly different from 1 with f- and t-test statistical analyses. An international study by (Boldrin, 2016) agrees that economies of scale are observed for biogas plants.

A study by (Malla, 2011), found that a large scale biogas plant could generate an IRR of 20.5% under the Renewable Energy Feed-In-Tariff (REFIT) model if electricity can be sold at R0.96 R/kWh. This model also included heat and fertilizer sales as revenue streams. Heat sales can, however, not be guaranteed in the absence of a national heat distribution network.

(Greencape, 2017) conducted a study on the financial viability of biogas plants based on cost data from case studies, particularly in the Western Cape. The study found that the business case is highly site specific. It further found that small scale (< 50 kW_e) biogas plants would not be financially viable under current conditions, whereas medium scale digesters (>50 kW_e; <1 MW) would be financially viable only if high waste management costs would be saved through the plants, and if the full amount of energy produced could be used on-site. The main focus of this study was for plant sizes up to 1 MW.

A study by the DEA investigated the feasibility of large scale biogas plants for vehicle fuel in comparison with electricity generation. Even though this study did not include an analysis of local biogas plant costs, it found that fuel production is the most attractive option, since the higher cost for upgrading and compression is compensated for by the higher price paid for fuel than for electricity per kWh. The study further found that, although biomethane has the potential to be more profitable than CHP, a positive business case does not yet exist in the South African context without some form of government support (DEA, 2016).

A study by (Shmulevich, 2015) evaluated the financial viability of a specific large-scale AD project, studying project capacities varying from 2 MW to 10 MW. A basic design was carried out for each scenario, and costing was based on estimations by a local technology service provider. All scenarios were found to be financially feasible with payback periods < 10 years. The 5 MW scenario was found to be the most economically attractive with a payback period of 5.2 years and an IRR of 23%. This study included both electricity and heat as revenue streams, used by an on-site off taker.

A dissertation involving various case studies by (Goemans, 2017) concluded that biogas projects in SA have insufficient financial feasibility for implementation without government support.

Based on these studies, there are conflicting findings about the financial viability of biogas plants in the South African context. The results seem to indicate that, in the absence of a government support programme, biogas plants can only be economically viable if a combination of very specific project conditions are met.

Economies of scale are observed for medium and larger plants, and therefore larger plants tend to have more attractive financial indicators than smaller plants. However, the risk of financial loss if the plant fails to achieve projected returns will be greater.

There is potential for fuel-from-biogas applications to be more financially attractive based on higher revenue per energy unit generated. However, this study needs verification based on locally observed plant costs.

Although this was done internationally, no South African study could be found comparing the financial indicators for different biogas usage pathways at different plant capacities (biogas-for-fuel vs. biogas-for-electricity).

In contrast to the small body of research in SA, the economics of biogas plants are well described Internationally, as discussed below.

2.4.2 International Research

A study by (Boldrin, 2016) found that keeping plant costs to a minimum by excluding purpose-grown energy crops from the feedstock made financial sense, even though this decreased the specific biogas yield. This was confirmed by findings by (Gutierrez E. W., 2018), who found that an urban biomethane plant with capacity above 60,000 t/year can have a positive Net Present Value (NPV) without subsidies if sewage sludge is used as feedstock. However, if pig slurry is added, subsidies are required, even though the Methane yield increases.

(Budzianowski, 2015) found that conventional CHP plants can be profitable under current policy conditions in Poland, as opposed to biomethane plants that would require incentivisation. This was also found by (Cucchiella, 2016), who confirmed that the profitability of biomethane plants in Italy are strongly linked to subsidies.

Several comparative studies have been carried out between biogas-for-fuel and biogas-for-electricity. (Goulding, 2012) found that biomethane production as a transport fuel is the optimum biogas technology for Ireland at present. CHP would be more profitable if a market for the heat could be found, which would rarely be the case due to the lack of a national heat distribution programme.

This is in contrast with (Gutierrez E. X., 2016), who found that biogas-for-electricity applications could be profitable under current conditions in Mexico, depending on the feed-in tariff. However, biomethane production would require incentivisation, and would not be viable without government support.

(Gutierrez E. X., 2016) also found that biomethane from biogas would not be feasible at a scale smaller than $150Nm^3/h$ (approximately 0.5 MW_{eq}). (Patrizio, 2015) highlighted the important effect of how easily the plant can be connected to existing gas infrastructure on financial viability.

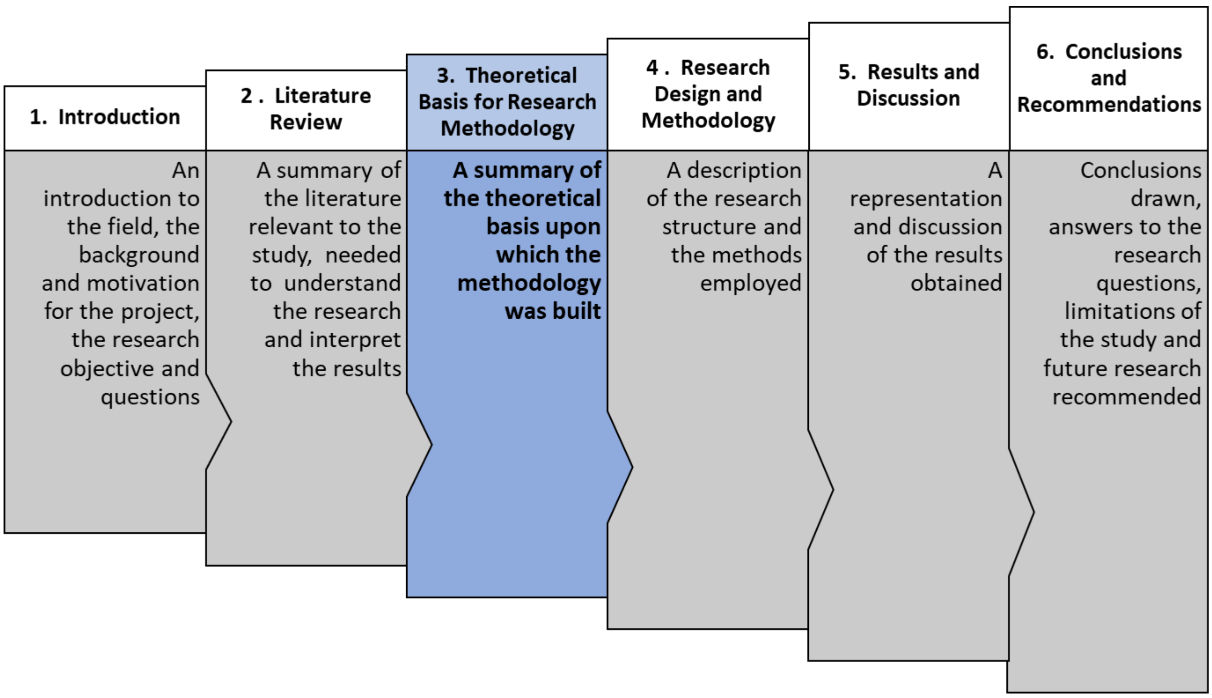
Similar to what was observed in South African publications, while several studies demonstrated a lack of profitability without incentivisation - (Boldrin, 2016), (Gebrezgabher, 2010), (Gutierrez E. X., 2016), other studies found that a biogas plant can be profitable, but it is strongly influenced by factors like plant size, feedstock cost, transportation and pre-treatment requirements on the feedstock, and biogas yield (Murphy J. &., 2009), (Akbulut, 2012), (Mel, 2015).

The following general summary of key conclusions was provided by (Börjesson, 2012) – "Results seem to indicate that a small portion of the biogas sector potential can be cost-effectively utilised without subsidies or larger infrastructural investments. Comparably low subsidies would enable significant increases in cost-effective biogas utilisation levels, but utilisation close to the full technical potential would require significant subsidies."

From a techno-economic perspective, studies indicate that, except in the rare instances where an off-taker for heat and electricity is available, biogas is best used as vehicle fuel at higher plant scales. However, the high cost barriers and associated financial risks can prevent this usage pathway from being implemented without incentivisation.

3. Theoretical Basis for Research Methodology

This chapter provides the basis, as found in literature, upon which the methodology was built.



3.1 Plant Cost Estimation Methods

A good understanding of the costs associated with establishing a biogas plant, as well as the availability of cost estimation models, are important aspects in the growth of the local biogas sector and provides a basis from which first level feasibility studies can be carried out.

The capital and operational costs associated with a project are initially estimated to determine the potential financial viability, and it is then continuously refined throughout the stages of development. The accuracy of the cost estimation increases as project planning becomes more detailed.

According to the American Association of Cost Engineers (AACE), there are five estimate classes based on the maturity level of the project, divided as follows:

- **Class 5**: 0 - 2% of project definition deliverables reached, corresponding cost estimations should be accurate within -50% to +100%.
- **Class 4**: 1 - 15% of project definition deliverables reached, corresponding cost estimations should be accurate within -30% to +50%.
- **Class 3**: 10 - 40% of project definition deliverables reached, corresponding cost estimations should be accurate within -20% to +30%.
- **Class 2**: 30 - 70% of project definition deliverables reached, corresponding cost estimations should be accurate within -15% to +20%.
- **Class 1**: 70 - 100% of project definition deliverables reached, corresponding cost estimations should be accurate within -10% to +15%.

A rapid estimation method is typically used for a class 4 or class 5 estimation, and a possible error of approximately 30% can be expected (Perry, 1997). The two rapid estimation methods that were considered in this dissertation are described in the sections below.

3.1.1 Capital Expenditure Estimation

Biogas plants are characterized by high Capital Expenditure (Capex) followed by relatively low operational costs (Amigun & Von Blottnitz, 2009). Lower plant costs are expected where systems are based on waste or sewage - where feedstock costs are non-existent and capital costs are low compared to energy crops (IRENA, 2018).

In the South African context, the capital expenditure is generally dominated by the digester, the generator and peripheral equipment, a large part of which needs to be imported due to a lack of local availability (Greencape, 2017). The capital expenditure can be estimated as described below.

3.1.1.a Capacity-Cost Factor

A good understanding of the relationship between capital cost and plant size can provide valuable information for the assessment of economic viability of a biogas plant, and is a useful decision making tool during the early phases of developing a new project (Amigun & Von Blottnitz, 2010).

A rapid capital cost estimate can be made by capacity-ratio exponents based on existing cost data. If the cost of a plant of capacity Q_1 is represented by C_1, then the cost of a similar plant of size Q_2 can be calculated from Equation 3-1 as follows (Perry, 1997):

$$C_2 = C_1\left(\frac{Q_2}{Q_1}\right)^n$$

Equation 3-1: Capacity Cost Factor

The value of the capacity-cost factor, *n,* depends on the type of plant and would, in the case of this dissertation, first need to be determined for typical biogas plants in the South African context. As a rule of thumb, a typical value of 0.6 is used in industries where economies of scale are observed. Other publications have assumed that a factor of 0.6 can be applied to biogas plants within the size range of 0.1 – 1 MW (Sgroi, 2015), However, (Amigun & Von Blottnitz, 2009) have determined that, for large-scale biogas plants in Africa, the capacity-cost factor should be 0.8.

The capacity-cost factor can be derived as the gradient of a linear line between the natural logarithm of the capacity and cost of two plants, as shown in Equation 3-2 below. In order to derive the capacity factor from a data set, the natural logarithms of capacity and cost can be plotted, and a linear regression analysis can be carried out on the plot (Clayton, 2014).

$$n = \frac{Ln\left(\frac{C_2}{C_1}\right)}{Ln\left(\frac{Q_2}{Q_1}\right)}$$

Equation 3-2: Capacity cost factor derivation

Economies of scale arise from the fact that certain elements of a plant can function more efficiently at a larger scale based on certain fixed costs that are not proportionally dependent on the plant output. A capacity cost factor that is equal to unity indicates that capital investment increases proportionally with size, without any scale effects, a factor smaller than 1 indicates that economies of scale are present, and a factor larger than 1 indicates that diseconomies of scale are present. This is a useful measure in determining the optimum size for a project but should be used with caution since economies of scale will typically not be present over the entire range of possible project sizes (Amigun & Von Blottnitz, 2010).

3.1.1.b Factorial Method: Lang Factor Approach

The Lang factor method was developed by the engineer Hans J. Lang, after the end of World War II. It suggests a simplified method to obtain the approximate capital cost of a process plant, based on the purchase price for major equipment items delivered to site. The method was originally developed following a study of fourteen process plants of different sizes and types.

Because the Lang factor is a ratio of the total plant cost to the main equipment cost, the assumption is made that the ratio is free from the effects of escalation, and therefore it can be compared with similar ratios for other projects implemented at other time periods (Sinnot, 2004).

The total capital cost associated with the project is given as a function of the purchased equipment by Equation 3-3 below:

$$C_{cp} = f_L(\sum C_{MPE})$$

Equation 3-3: Lang Factor

Where:

C_{cp} = Complete plant cost

f_L = Lang Factor

C_{MPE} = Main plant equipment costs

In literature, the Lang factor typically varies from 3.10 for a predominantly solids processing plant to 4.70 for a predominantly fluids processing plant (Sinnot, 2004). However, a more accurate factor can be derived for a specific technology based on historical costs. In an industry where the major equipment costs comprise the bulk of the total plant investment, a lower Lang factor can be expected.

The greater the uncertainties associated with capital cost; the more cautious investors are likely to be. It is therefore important to determine factors that are accurate and that reflect the specific conditions relating to where the project is being established (Amigun & Von Blottnitz, 2009).

Over the years, many authors have elaborated on the Lang factor approach, making contributions to improve accuracy – for that reason individual cost factors are considered separately rather than compounding them into a single factor. There exist many combinations of factor groupings in literature. The input is usually the base cost, which can be determined from a material balance. The following additional costs should be considered:

- The cost of major pieces of equipment
- The cost of complete installation of equipment
- Auxiliary equipment necessary to make the process work
- Engineering and field expenses
- Contractors' fees and contingencies

For the purpose of this dissertation, and based on available data, the groupings shown in Table 3-1 were used (Sinnot, 2004), (Marouli, 2005):

Table 3-1: Lang factor calculation groupings

Description	Main Plant Equipment Cost (C_{mpe})	Civil Works Cost (C_{cw})	Mechanical and Electrical Cost (C_{me})	Indirect Cost (C_{id})
Items included	• Waste preparation system • Digester • Biogas conditioning system • Generator including heat recovery system • Equipment installation	• Site improvements • Foundations • Buildings • Structural work	• Piping, instrumentation and control • Electrical services	• Design and engineering costs • Procurement • Site supervision • Environmental authorisations • Contingency allowance

Based on the table above, the complete plant cost (C_{cp}), can be calculated as shown in Equation 3-4:

$$C_{cp} = C_{mpe} + C_{cw} + C_{me} + C_{id}$$

Equation 3-4: Project cost components

The separate factors are then calculated as shown in Equation 3-5 to Equation 3-7:

$$C_{cw} = f_{cw} . C_{mpe}$$

Equation 3-5: Civil works cost factor

$$C_{me} = f_{me}.C_{mpe}$$

Equation 3-6: Mechanical and electrical cost factor

$$C_{id} = f_{id}.C_{mpe}$$

Equation 3-7: Indirect cost factor

The cost relationships described above can then be represented by

$$C_{cp} = (1 + f_{cw} + f_{me} + f_{id}).C_{mpe}$$

Equation 3-8: Total plant cost in relation to cost factors

C_{cp} represents the complete cost of establishing the biogas plant, including equipment and auxiliary services needed to bring it to the point of start-up. Each of the factors can be estimated separately, based on historical values, as the relationship between the relevant portion of the investment cost and the main plant equipment cost, and the Lang factor is then calculated as shown in Equation 3-9.

$$f_L = 1 + f_{cw} + f_{me} + f_{id}$$

Equation 3-9: Lang factor calculation

According to (Amigun & Von Blottnitz, 2009), a value of 1.78 can be expected for a centralized biogas plant in Africa.

3.1.1.c Cost Indices

Cost indices are dimensionless numbers used to update and compare the capital costs required to erect chemical plants at different periods in time by incorporating changes in the time value of money. The cost index is the ratio of the price at the time of construction and that at a selected base period. This serves as a generic rate to compare chemical plant costs, considering the composite effects of changes in the costs of equipment, construction labour, buildings, engineering and supervision. To update an item cost from period A to Period B, the following equation can be used (Amigun B. , 2008):

$$Cost\ at\ B = Cost\ at\ A\ .\frac{Index\ at\ B}{Index\ at\ A}$$

Equation 3-10: Cost index to calculate time adjustment

The following cost indices are widely applied:

- Chemical Engineering Plant Cost Indices (CEPCI)
- Engineering News Record (ENR)
- Marshall and Swift Equipment Cost Index (M&S)

In the absence of access to these indices, and in order to incorporate effects specific to SA, the final manufactured goods Producer Price Index (PPI) was used in this dissertation.

3.1.2 Operational and Maintenance Cost Estimation

The Operational and Maintenance (O&M) costs include the daily running and maintenance costs of the plant. These costs are further divided into fixed O&M costs or the costs that stay constant every month, and variable O&M costs, or the costs that vary depending on feedstock load, electricity usage or other variable factors.

Typical fixed O&M costs include (Cucchiella, 2016):

- Substrate related costs: This depends on the type of feedstock and is often zero or even an income if the feedstock is a waste stream and a gate fee is charged. However, this cost also includes the sorting and preparation of waste. In the case of energy crops, the fixed costs associated with growing the crops are included.

- Transport costs
- Overheads
- Land lease: This is rarely applicable since a biogas plant is typically added to additional operations with land already available.
- Insurance
- Salaries
- Depreciation fund for electrical and mechanical components

Typical variable O&M costs include:

- Feedstock
- Maintenance
- Energy consumption

For cost estimation purposes, the fixed and variable O&M costs can be grouped together into monthly O&M costs, and expressed as a fraction of the capital costs. Sources in literature have estimated O&M costs for biogas plants to vary from 2.5% for small scale plants to 20% for larger projects (Karellas, 2010). A study by the International Renewable Energy Agency (IRENA) provided a summary of expected O&M costs as shown Figure 3-1. It can be seen that the specific operational costs decrease with increasing plant size, and the costs associated with energy crops are significantly higher that the costs associated with waste. A previous study carried out by (Greencape, 2017) estimated operating costs for biogas plants in SA to be around R1700.year^{-1}.kW$_e$.$^{-1}$.

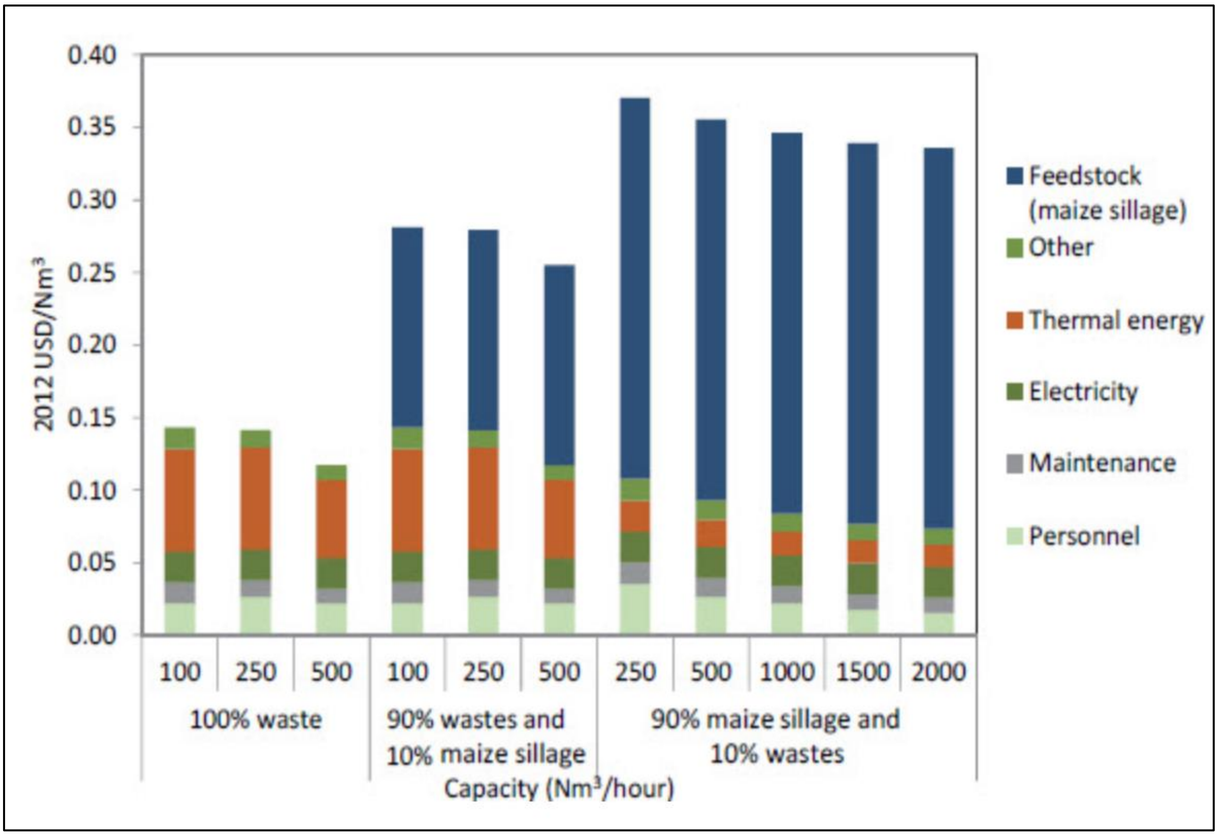


Figure 3-1: Operational costs of biogas plants Source: (IRENA, 2013).

3.2 Statistical Methods

Statistical methods are employed in order to build an empirical model based on observed data, which can then be used to predict outcomes and facilitate decision making (Montgomery, 2004).

The statistical methods applied as a basis for this dissertation are described in the section below.

3.2.1 Regression Analysis

A regression model is an equation which can be used to describe the relationship between a given variable (termed the dependent variable – for example capital expenditure) and another variable (termed the independent variable – for example plant capacity). Such a relationship can either be linear or non-linear. A linear regression model can be expressed as shown in Equation 3-11. Regression analysis is a collection of statistical methods used to estimate the parameters of the regression model. The fitted regression model can then be used to predict future values of the dependent variable.

$$Y = \beta_0 + \beta_1 . x + \epsilon$$

Equation 3-11: Linear regression model expression

Where:

Y = dependent variable

β_0 and β_1 = regression parameters

x = independent variable

ϵ = random error term

Where the regression model is significant, the error term will form a normal distribution with a mean of zero and a variance of σ^2.

The regression model can be fitted to the observed data by means of the Least Squares Best Fit (LSBF) approach, which implies that a model is fitted so as to minimise the sum of the squares of the vertical deviations from the observed values. For a sample of size, n, solving the normal equations below result in the least squares estimates of the regression parameters.

$$n\hat{\beta}_0 + \hat{\beta}_1 \sum_{i=1}^{n} x_i = \sum_{i=1}^{n} y_i$$

Equation 3-12: Least squares normal equation

$$\hat{\beta}_0 \sum_{i=1}^{n} x_i + \hat{\beta}_1 \sum_{i=1}^{n} x_i^2 = \sum_{i=1}^{n} y_i \, x_i$$

Equation 3-13: Least squares normal equation

The least squares normal equations can be solved by computer software packages like Microsoft Excel.

3.2.2 Determining the Goodness-of-Fit

There are several ways of evaluating the accuracy of a statistical estimation. One such way is to evaluate the coefficient of determination (r^2) as well as the residuals and residual plots.

The residuals are defined as the difference between each predicted and actual value, as shown in Equation 3-14 below. If the model provides a good prediction of the observed values, the residual plot should be randomly scattered, which indicates that the observed error is consistent with stochastic error. The residuals should further be centered around zero for the entire range of values fitted (Minitab, 2018).

$$e_i = y_i - f_i$$

Equation 3-14: Formula for residuals in regression analysis

Where:

e_i = residual value

y_i = observed value

f_i = predicted value

The r^2 value is a statistical measure of how well the linear estimation fits the observed data, and therefore provides an indication of the strength of the relationship between the independent variable and the dependent variable. The r^2 value is calculated as shown in Equation 3-15 below. The r^2 value will be a percentage, with values closer to 100% indicating a good fit and values closer to 0% indicating a poor fit (Minitab, 2018), and can be interpreted as the percentage of variation in the dependent variable that is explained by the fitted relationship with the independent variable (Amigun & Von Blottnitz, 2010).

$$r^2 = 1 - \frac{SS_{res}}{SS_{tot}}$$

Equation 3-15: Calculation of r^2 in regression analysis

Where:

r^2 = the coefficient of determination

SS_{res} = the sum of squares of residuals over the sample range

SS_{tot} = the sum of the differences between each value and the mean value for the data range.

3.2.3 Calculation of the Magnitude of Relative Error

Another indicator of the likely accuracy of a cost estimate based on the regression analysis is the Magnitude of Relative Error (MRE), which is the degree of error in an estimation, and can be calculated by Equation 3-16 as a percentage (Anandhi, 2013).

$$MRE = \frac{|Estimate - observed|}{observed} \; x \; 100$$

Equation 3-16: Magnitude of relative error calculation

The Mean Magnitude of Relative Error (MMRE) can also be calculated. The MMRE is an indicator of the degree of variance that can be expected between the observed values and the predicted values, and is calculated as the mean MRE over the sample size, as shown in Equation 3-17 (Anandhi, 2013):

$$MMRE = \frac{1}{n}\sum_{i=1}^{n} MRE_i$$

Equation 3-17: Calculation of the mean magnitude of relative error

3.2.4 Hypothesis Testing in Linear Regression Analysis: t-test, ANOVA

Hypothesis testing can be carried out on the slope and intercept of a linear regression model as well as on the normality assumption of errors. In order to carry out a hypothesis test on whether the slope equals a constant, the appropriate hypotheses are:

$$H_0\!: \ \beta_1 = \beta_{1,0}$$

$$H_1\!: \ \beta_1 \neq \ \beta_{1,0}$$

Equations 3-18: Hypotheses statements

Where H_0 = The null hypothesis and H_1 = the alternative hypothesis

The responses, Yi are normally distributed which means the test statistic, T_0, can be calculated by solving Equations 3-19:

$$T_0 = \frac{\hat{\beta}_1 - \beta_{1,0}}{\sqrt{\frac{\hat{\sigma}^2}{S_{xx}}}} = \frac{\hat{\beta}_1 - \beta_{1,0}}{se(\hat{\beta}_1)}$$

Equations 3-19: Equation for t-test

Where:

σ^2 = sample variance

se (β_1) = the standard error of the slope

S_{xx} = the sum of squares or the difference between each x and the mean x value

We can reject the null hypothesis if the t_0 is greater than the critical t-value at the specified confidence level (α) and degrees of freedom. A similar analysis can also be carried to test the hypothesis about the intercept, β_0.

These analyses, also referred to as the t-tests, test the significance of the regression. If the null hypothesis cannot be rejected, it means that there is no linear relationship between x and y, or that x is of insignificant value in explaining the variance observed in y. If the null hypothesis can be rejected, it implies that x is of value in explaining the variations observed in y, and that the straight-line model is adequate.

A second method of verifying the significance of the regression analysis is through an analysis of variance (ANOVA). The ANOVA identity is given by Equation 3-20.

$$SS_T = SS_R + SS_E$$

Equation 3-20: ANOVA identity equation

Where:

SS_T = the total sum of squares

SS_R = the regression model sum of squares

SS_E = the residual sum of squares

The relevant hypotheses are:

$$H_0:\ \beta_1 = 0$$

$$H_1:\ \beta_1 \neq\ 0$$

Equation 3-21: ANOVA hypotheses

The mean square of the regression model (MS_R), and mean square of the residual (MS_E), are given by:

$$MS_R = \frac{SS_R}{1}$$

$$MS_E = \frac{SS_E}{n-p}$$

Equation 3-22: ANOVA mean square equations

The test statistic, F_0, should be calculated and compared with the critical value of F at the chosen confidence level and degrees of freedom. If F_0 is greater than the critical value of F, the null hypothesis can be rejected. If the null hypothesis cannot be rejected, it means that the slope of the regression line is equal to zero and therefore the mean of the observed values will give a better fit than the regression model.

3.2.5 Prediction Interval on Future Observations

An important application of regression models is to predict future observations which correspond to the determined regressor variables. In order to do this with confidence, the prediction interval on a future observation for simple linear regression should be determined, as is shown in Equation 3-23:

$$\hat{y}_0 \pm t_{\frac{\alpha}{2},n-2} \cdot s_\epsilon \sqrt{1 + \frac{1}{n} + \frac{(x_0 - \bar{x})^2}{S_{xx}}}$$

With $$S_{xx} = \sum x_i^2 - \frac{1}{n}\left(\sum x_i\right)^2$$

Equation 3-23: Prediction interval on a future observation for simple linear regression

Where:

y = dependent variable

$t_{\frac{\alpha}{2},n-2}$ = the 100(1-α/2) percentile of the t- distribution with n-1 degrees of freedom

x = independent variable

$\bar{x}$ = sample average

s_ϵ = sample standard deviation

α = level of uncertainty

n = sample size

The output is a 'band' of values around the regression line – the prediction can then be made with α as confidence level that future values will fall within that band. The band becomes wider for higher values of α.

3.3 Standardised Costs

Frequently, different project options need to be compared with each other in order to find the project with the most benefits at the lowest cost. In order to do this, the cost-comparison methods described in the section below can be used.

3.3.1 Annualised Project Cost

The annualised project cost is calculated as a single number which incorporates both capital and operating costs and can be used to compare the costs of different plant options. It is the same for each year of the plant's lifetime and consists of the annuity or annualised capital cost, fixed operating cost and variable annual operating cost. The annualised capital cost is calculated by Equation 3-24:

$$A = \frac{KrD^n}{(D^n - 1)}$$

Equation 3-24: Annualised capital cost

Where:

A = annualised capital cost

K = capital expenditure at time = 0

r = discount rate

D = (1+r)

n = number of years in project's financial lifetime

The total annualised cost is calculated based on the assumption that the operating and maintenance costs stay constant over the financial lifetime of the project, and is calculated by Equation **3-25**:

$$AC = A + O$$

Equation 3-25: Total annualised cost

Where:

Ac = total annualised cost

A = annualised capital cost

O = annual fixed operation and maintenance costs + annual variable operating costs

The specific annualised cost is the annualised cost per unit of production. It is calculated based on the assumption that the production rate is constant each year throughout the financial lifetime of the project, and is calculated based on Equation 3-26:

$$AC_s = \frac{AC}{P}$$

Equation 3-26: Specific annualised production cost

Where:

AC_s = the specific annualised project cost

AC = total cost

P = the product of interest – which, in this dissertation, is one of the following:

- kwh electricity
- kwh heat
- Nm^3 raw biogas
- Nm^3 biomethane
- GJ energy product
- L_{eq} of petrol or diesel

3.3.2 Levelised Cost of Energy

In order to compare the total cost of energy product from different sources with each other, the Levelised Cost of Energy (LCOE) can be calculated over the economic lifetime of the plant.

LCOE is calculated as the sum of the total present values of all the outgoing cash flows of the project divided by the total energy produced by the plant over its lifetime. In other words, it is the price, per unit of energy, which a developer/investor needs to charge in order to achieve an NPV of zero over the lifetime of the project (O'Shea, 2016).

The LCOE is calculated as the total annualised plant cost over the lifetime of the plant, divided by the energy produced over the lifetime of the plant, as described in the following sections.

3.4 Energy Product from a Biogas Plant

It is important to note that biogas yield and quality determined in laboratory-based measurements are likely to differ substantially from yields obtainable in full scale plants. This was demonstrated in a study by (Kowalczyk, 2011) on the performance of differently sized bio-digesters. The study found that, although there is a clear correspondence in performance, the difference in biogas yields across differently scaled digesters are statistically significant. For this reason, the data used in this study was based on long term yields obtained from operational, full-scale biogas plants.

In order to calculate the revenue obtainable from a biogas plant, the net equivalent energy capacity is used as a basis in this dissertation and is calculated as set out in the sections below.

3.4.1 Equivalent Power from a Biogas Plant with CHP Unit

A CHP unit refers to an electricity generator coupled with a heat exchanger, which can be connected to an anaerobic digester in order to generate electricity and heat from biogas.

In situations where an off-taker for the heat is available on-site, or where a heat distribution network is present, the heat can be sold to a third party.

However, if none of these two requirements are met, the heat will be dissipated, or can alternatively be applied to heat the digester to the desired temperature or to dry the substrate.

The combined energy produced from a CHP plant can be calculated based on biogas yield as shown in Equation 3-27.

$$E_i = F_{bg} \,.\, C_{bg}.\, H.\, \mu_e + F_{bg} \,.\, C_{bg}.\, H.\, \mu_h$$

Equation 3-27: Sellable energy generated by a biogas CHP unit

Where:

E_i = Annual net equivalent energy in kWh/yr

F_{bg} = Production rate of biogas in Nm^3/h

C_{bg} = The calorific value of biogas in kWh/Nm^3

H = Annual productive hours of the biogas plant

μ_e= The electrical efficiency of the CHP unit

μ_h= The thermal efficiency of the CHP unit

3.4.2 Net Equivalent Energy from a Biomethane Plant

The net equivalent energy from a biomethane plant can be calculated based on biomethane yield as shown in Equation 3-28:

$$E_i = F_{bg} \,.\, x_{bg} \,.\, C_{bm}.\, H.\, \mu$$

Equation 3-28: Net equivalent energy generated by a biomethane plant

Where:

E_i = Annual net equivalent energy – for a biomethane plant this is the calorific value of the biomethane produced kWh/annum

F_{bg} = Production rate of biogas in Nm^3/h

X_{bg} = Fraction of Methane in the biogas

C_{bm} = The calorific value of biomethane

H = Annual productive hours of the biogas plant

μ = The Methane capturing efficiency obtainable through a biogas upgrading unit.

3.4.3 Revenue from Electricity Sales Generated by a CHP Plant

In order to estimate the revenue that could be generated from a biogas CHP plant, the assumption can be made that electricity generated through AD can be sold to an off-taker at a price equal to the commercial price of electricity in South Africa. This assumption will entail the prediction of future electricity prices based on historical prices. As can be seen in Figure 3-2 below, there has been a drastic upsurge in the annual electricity price increase ever since the electricity supply shortage crisis which took place in 2008.

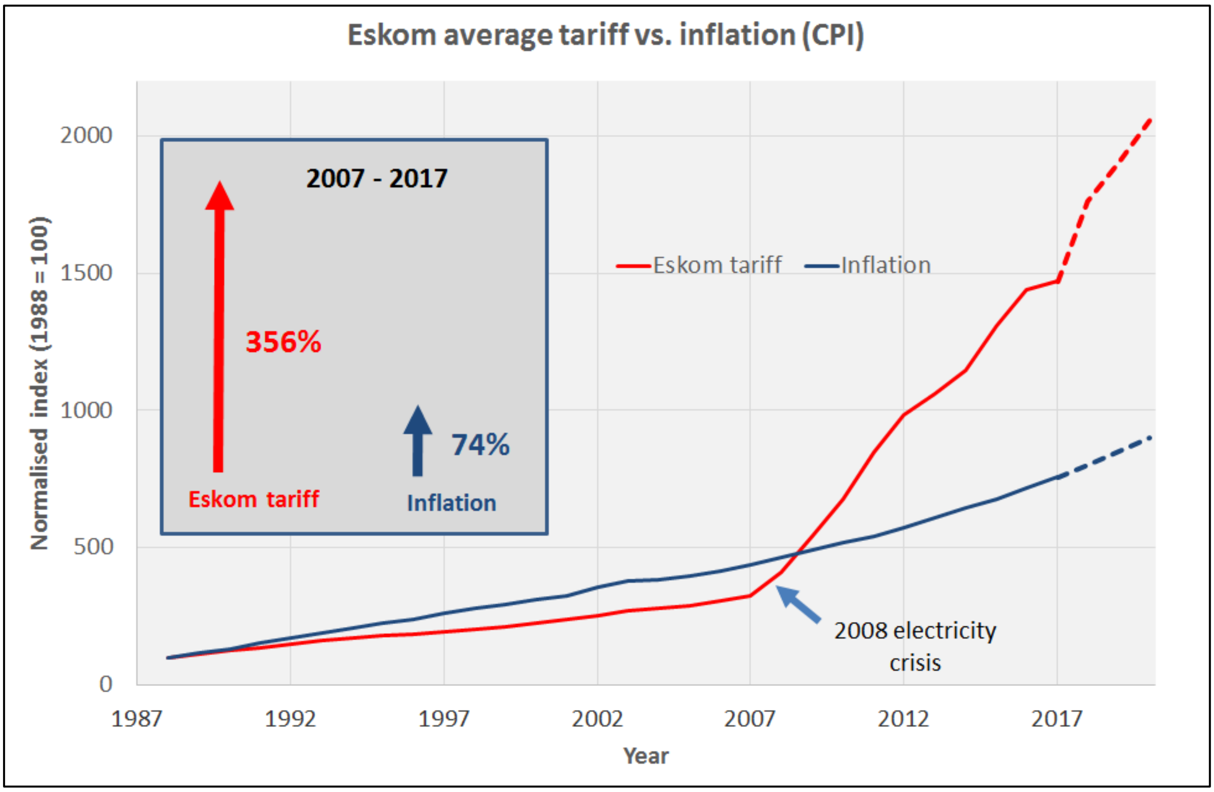


Figure 3-2: Eskom electricity tariff increase over the past three decades. Source: (Moolman, 2018).

The commercial electricity price over the past decade is shown in Table 3-2 below. The average year-on-year increase over this period is 16%.

Table 3-2: Commercial electricity price for businesses over the past decade – source: (Motiang, 2017)

Year	Commercial electricity Price: c/kWh excl. vat	Year-on-year increase (%)
2008	24.85	5.9%
2009	31.61	27%
2010	40.97	30%
2011	52.63	28%
2012	65.92	25%
2013	73.24	11%
2014	82.67	13%
2015	89.16	8%
2016	100.07	12%
2017	109.09	9%
2018	117.82	8%

3.4.4 Revenue from Fuel Sales Generated by a Biomethane Plant

Currently, the South African government supports the uptake of CNG, which is similar in properties to biomethane from AD, as a transport fuel via unregulated exemption on the fuel levies and taxes that are placed on petrol and diesel.

If the calorific value of petrol is taken as 32.4 MJ/L, the factors making up the price of 95 unleaded petrol in R/MJ are shown in Figure 3-3 below. It is important to note that, for biomethane, the only imposed tax is 15% VAT at the pump. This is because the gas for transport sector in SA is not yet developed and the government is yet to determine how taxing for this sector will be structured.

This absence of fuel taxes and levies on biomethane fuel, but applicable to petrol and diesel, can be considered an 'informal tax incentive' (DEA, 2016). In addition, the IDC provides a subsidy in the form of a soft loan for the conversion of petrol and/or diesel vehicles to gas engines. It is uncertain how long this lack of taxing will persist, but the department of transport did include tax incentives for biofuels in the private sector as part of their green transport strategy for 2016-2021 (Department: Transport, RSA, 2016).

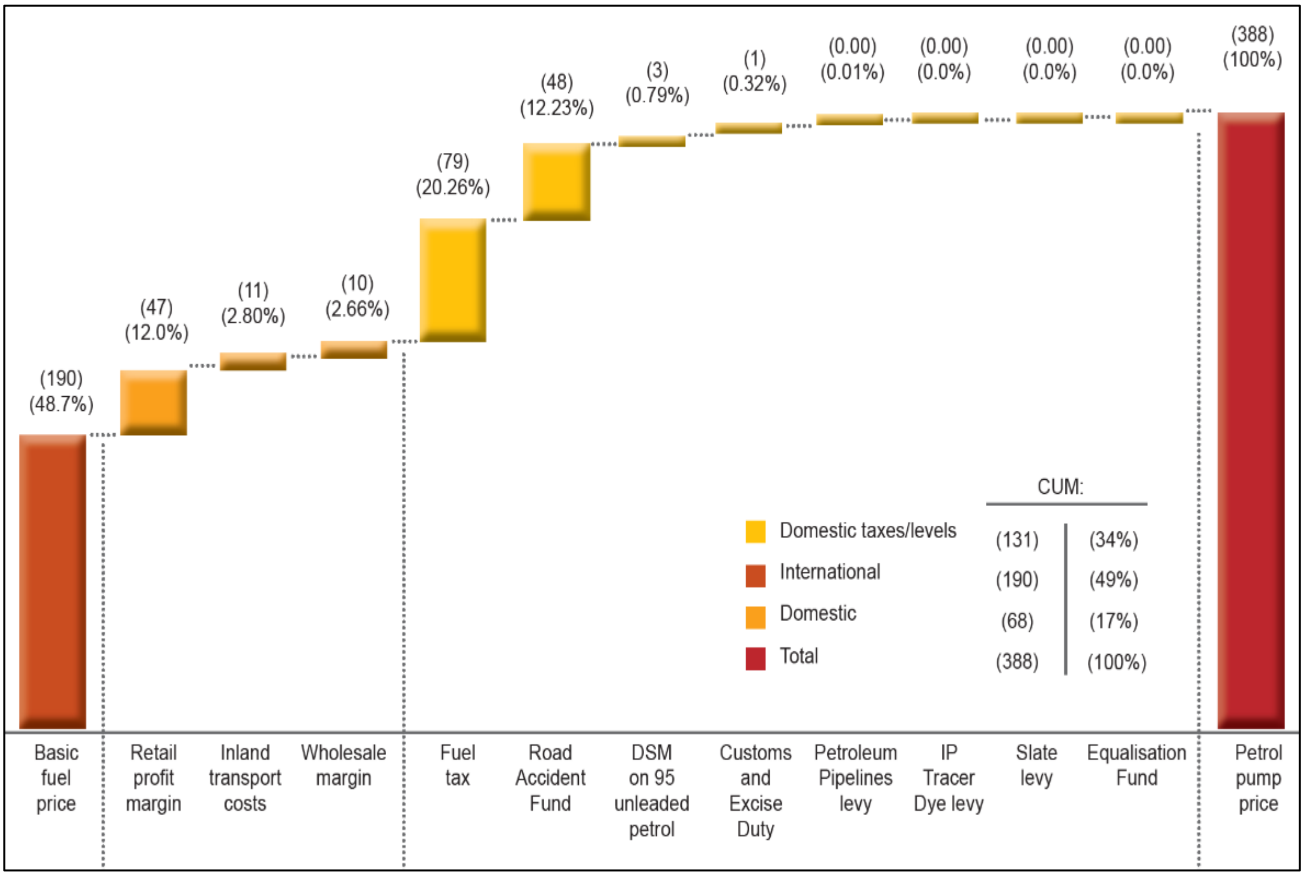


Figure 3-3: Fuel taxes in South Africa Source: (DEA, 2016)

Based on this 'informal tax incentive', the revenue that could be generated from a biomethane plant for fuel can be calculated based on the assumption that biomethane from upgraded biogas can be sold for a price equal to the retail price of diesel in South Africa, excluding 15% VAT. This assumption will entail the prediction of future fuel prices based on historical prices.

The retail petrol and diesel prices over the past decade are shown in table 3-3 below. The average year-on-year increase over this period is 9% for both fuels.

Table 3-3: Retail fuel prices in SA over the past decade – source: (Automobile Association of South Africa, 2018)

Year	Petrol price (R) 93 octane	Year-on-year increase (%)	Diesel price (R) 50ppm Sulphur	Year-on-year increase (%)
2008	R8.86		R9.38	
2009	R7.19	-19%	R6.70	-29%
2010	R8.10	13%	R7.39	10%
2011	R9.82	21%	R9.18	24%
2012	R11.37	16%	R10.61	15%
2013	R12.70	12%	R11.92	12%
2014	R13.74	8%	R12.81	7%
2015	R12.22	-11%	R11.13	-13%
2016	R12.35	1%	R10.74	-4%
2017	R13.42	9%	R11.58	8%
2018	R15.21	13%	R13.54	17%

3.5 Analysing Economic Viability

In this dissertation, the techno-economic viability refers to the potential to implement the technology at a positive NPV, when considering the cost of implementation and product prices. Non-technology-related economic aspects, for example a lack of information, financing problems, sociological problems, or effects on the macro-economic level, also play a very important role, but fall outside the scope of this dissertation (Börjesson, 2012).

For a biogas project to be financially viable, the cost of the heat, electricity or biomethane produced must be comparable to the selling price of energy produced by an alternative, fossil fuel-based plant. If it is higher, then some form of grant or subsidy will be necessary for the project to be implemented (Ricardo Energy and Environment, 2017).

3.5.1 Discounted Cash Flow Analysis

A Discounted Cash Flow (DCF) analysis is an economic appraisal tool that is especially valuable where different project options need to be compared in order to make decisions based on economic viability. A DCF can be used to answer the following questions for a proposed project:

- Are there better ways of meeting the objectives set by the project?
- Are there better uses for the resources required to execute the project?
- DCF is a forecasting technique which necessarily involves predicting the future. This is inherently difficult as it carries the risk of false accuracy, which is why good data gathering and justified assumptions are of extreme importance. The basic elements of a DCF include (CEEU, 2012):
    - Project definition: This includes defining the project scope – what is included, what is excluded, what is assumed. This also includes specification of the project time frame, which is typically the economic lifetime of the plant.
    - Identification of costs and benefit streams: All cost and benefit stream associated with the specific project need to be identified and quantified.
    - Selection of a suitable discount rate: The discount rate is very important as it affects the NPV of the project. A higher discount rate will reduce the NPV while a lower discount rate will increase it. The discount rate should be specified to reflect the effects of inflation, and should take the risks associated with the project into account.
    - Account for the time value of money: Because costs and benefits occur at different points in the life of the project, it is important that the present values if all costs and benefits be calculated.

The DCF quantifies future cash flow projections discounted to the present time. The Discounted Present Value (DPV) of a cash flow stream at a specific time period (n) in the project lifetime can be calculated by Equation 3-29 and Equation 3-30.

The sum of the net cash flow DPVs over the lifetime of the project is the NPV of the project (Cucchiella, 2016).

$$DPV = FV.df$$

Equation 3-29: Discount factor application

$$df = \frac{1}{(1+r)^n}$$

Equation 3-30: Discount factor calculation

Where:

DPV = Discounted present value

FV = Future value

df = discount factor

r = discount rate

n = time period

3.5.2 Net Present Value

The NPV is the sum of a project's cash inflows and outflows, discounted at a rate that is consistent with the project's risks, over the project lifetime (Goosen, 2013). NPV takes the time value of money into account, thereby expressing the project's total value in current terms. It is calculated as shown in Equation 3-31 below:

$$NPV = \sum_{t=0}^{N} \frac{(NCF)_t}{(1+r)^t}$$

Equation 3-31: Calculation of NPV

Where:

NPV: Net Present Value

$(NCF)_t$: The Net cash flow at time t

t: The project period in years

r: The discount rate in percentage

The NPV decision rule states that an organization can consider investing if the NPV is greater than zero (Goosen, 2013). This implies that the sum of discounted benefits exceeds the sum of discounted costs (CEEU, 2012).

3.5.3 Discounted Payback Period (DPBP)

The DPBP is the time necessary to regain the funds invested into the project, and is calculated as the number of years needed to balance the cumulative discounted cash flows with the initial investment (Cucchiella, 2016). A short payback period is an indication of a financially attractive project. The payback period should be evaluated together with other financial indicators as it does not indicate the profitability of the project, but only the time it will take to recover investment. The DPBP can be calculated by Equation 3-32:

$$DPBP = \ln\left(\frac{1}{1 - \frac{O_1 . r}{NCF}}\right) \div \ln{(1 + r)}$$

Equation 3-32: Discounted payback period calculation

Where:

O_1 = Initial investment

r = discount rate

NCF = annual net cash flow

3.5.4 Internal Rate of Return (IRR)

The IRR identifies the discount rate at which the present value of all future cash flows equals the initial investment. The IRR is therefore an indication of the growth rate of the investment capital over a specified period of time, and can be used to compare different projects. Its calculation is shown in Equation 3-33 below, which is similar to

Equation 3-31, where NPV = 0, meaning that the NPV equals the net present value of the investment.

In essence, the IRR is an indication of the maximum rate of interest that a project can afford to pay for the resources used to implement it. In general, a project with an IRR that is greater than the cost of capital is attractive.

$$0 = \sum_{t=0}^{n} \frac{(NCF)_t}{(1 + IRR)^t}$$

Equation 3-33: Calculation of IRR

Where:

$(NCF)_t$: The net cash flow at time t

t: The project time in years

IRR: The internal rate of return in percentage

If the IRR exceeds the project discount rate, then the project is financially feasible. The higher the IRR, the more financially attractive the project is.

3.5.5 Return on Investment (ROI)

ROI is the annual net profit divided by the initial investment and is an indication of the performance of the investment. The ROI can be calculated as shown in

Equation 3-34 below:

$$ROI = \frac{Average\ annual\ nett\ profit}{Initial\ investment}$$

Equation 3-34: Calculation of ROI

The higher the ratio, the greater the benefit earned. The ROI can be compared to the Minimum Attractive Rate of Return (MARR), which will vary for each company based on the cost of capital, the risks associated with the investment etcetera. The MARR can also be determined by comparing the returns receivable for a specific project with returns that could be achieved by investing money somewhere else.

3.6 Evaluating Risk and Uncertainty

An inherent problem with financial feasibility studies is that it attempts to forecast the future based on currently available information. A feasibility study that neglects uncertainty only provides point estimates of key parameters when, in fact, these variables are probability distributions that quantify the likelihood of economic success or failure (Amigun B. P., 2011).

Only considering the values of traditional financial indicators like NPV and IRR puts investors at the risk of overlooking the volatility of the project, based on uncertain events. Risk-based decision criteria can aid in identifying and mitigating the most influential risks (Kim, 2018).

It is therefore of utmost importance that a risk analysis be carried out which incorporates parametric uncertainty and enables the evaluation of financial indicators like NPV and ROI as probability distributions instead of point values.

The technique used for risk analysis in this dissertation is Monte Carlo analysis. This method was first used by scientists working on the atom bomb during world war II and was named after the resort town Monte Carlo in Monaco, which is famed for its many casinos (Palisade, 2018). The technique is described in more detail in the section below.

3.6.1 Monte Carlo Analysis

Monte Carlo analysis is a simulation technique that allows us to account for risk in quantitative analysis and decision making by calculating a range of possible outcomes and their probabilities of occurring.

The technique builds a model of possible outcomes by assigning a probability function to each parameter with inherent uncertainty. The results are then calculated over and over, each time with a different set of random values, which are taken from a pool of probability functions.

In investment decision-making for engineering projects, the most commonly used probability distributions applied to input variables include uniform distribution, triangular distribution, normal distribution, logarithmic normal distribution and Bernoulli distribution (Liu, 2017).

The parameters evaluated in this dissertation are represented by normal distributions and triangular distributions, which are described in the sections below.

3.6.1.a Normal Distribution

Normal distribution is the typical "bell curve" where a mean value and standard deviation are defined. Values in the middle, or proximity to the mean, are most likely to occur. This distribution is symmetric around the mean and can be used to describe many natural phenomena. Figure 3-4 below shows a normal distribution.

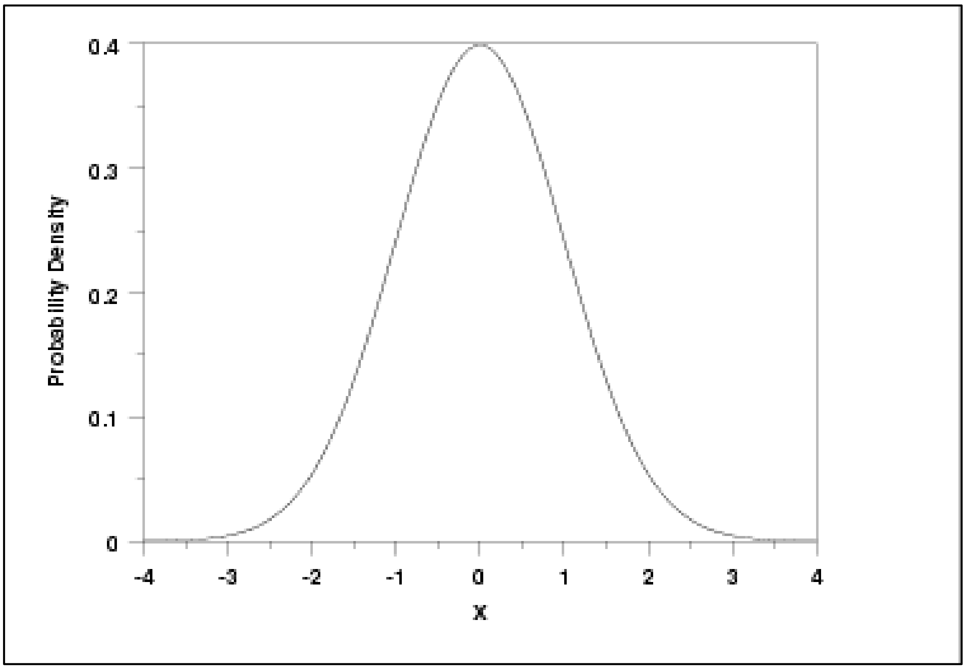


Figure 3-4: Diagram of normal probability distribution Source: (NIST/SEMATECH, 2018).

3.6.1.b Triangular Distribution

This distribution consists of a minimum, a mode, and maximum value, with the highest probability for the mode value to occur. Figure 3-5 below shows a triangular distribution.

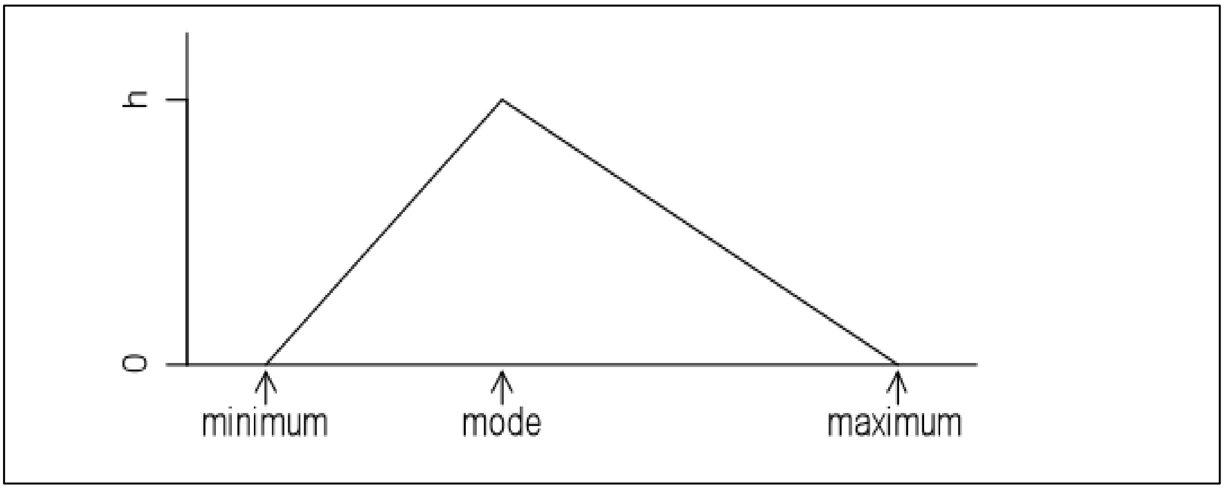


Figure 3-5: Diagram of triangular probability distribution Source: (NIST/SEMATECH, 2018)

3.6.2 Acceptable Levels of Risk

The output from the Monte Carlo simulation is then a probability distribution of possible financial indicators like NPV, as shown in Figure 3-6 below (Palisade, 2018).

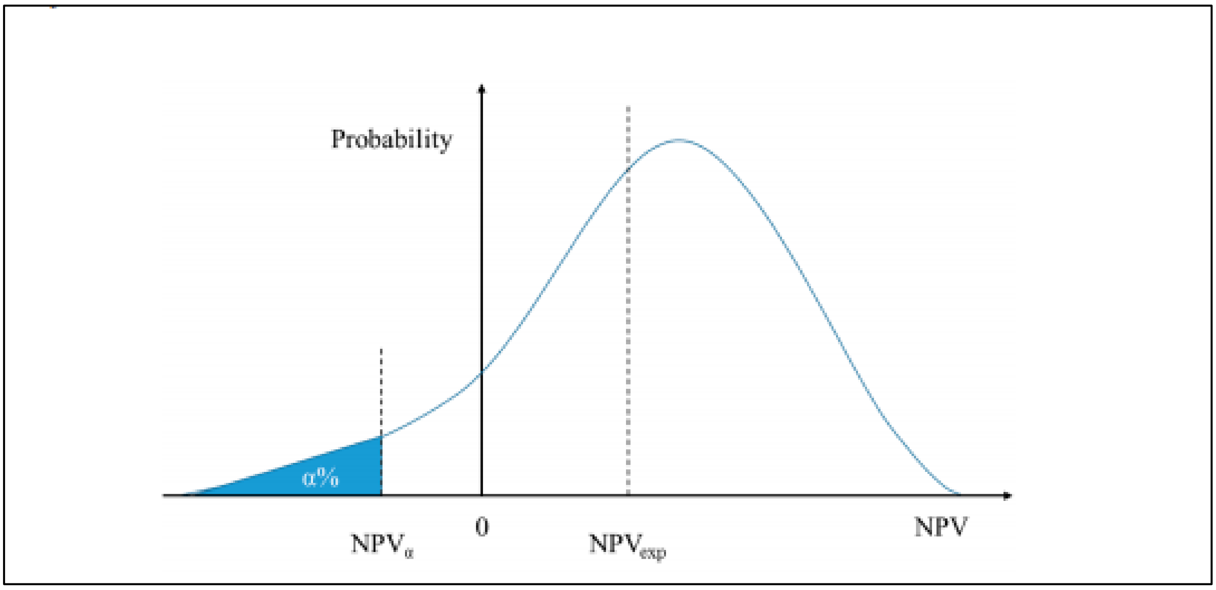


Figure 3-6: Probability distribution of the NPV Source: (Kim, 2018)

Where:

NPV_{exp} = The most probable NPV value that the project will achieve

α = The critical level of risk

In order to decide whether the risk associated with the project is low enough to merit the required investment, the probability of the project achieving a positive NPV has to meet a pre-defined decision criterion, which is: $NPV_{\alpha} > 0$.

The critical level of risk (α) needs to be determined based on specific project attributes. Sources in literature have used 40%, which corresponds with a confidence level 60%, (Liu, 2017) and even 50% which corresponds with a confidence level 50% (Zaman, 2017).

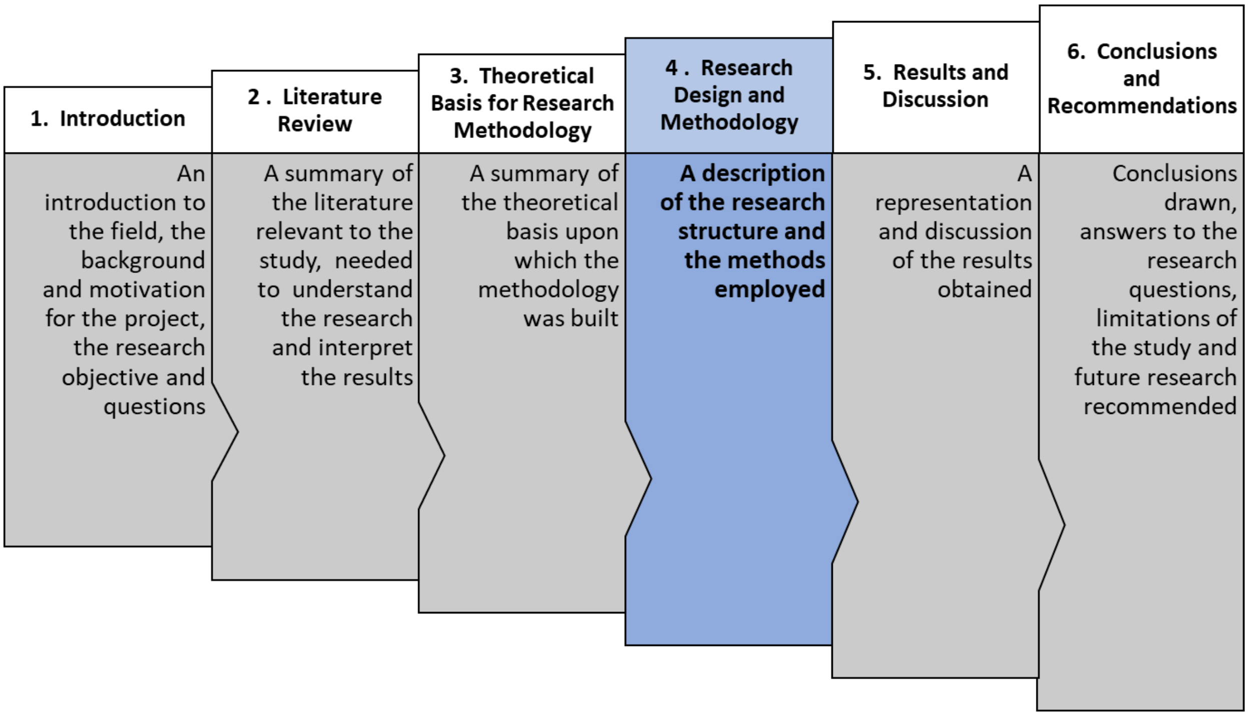
A very low critical risk level corresponds to a project that is likely to succeed under all conceivable circumstances. However, if a project is rejected based on the critical risk level being too low, the possibility exists that a risk-sensitive investor would erroneously miss a suitable investment opportunity.

This dissertation, in line with various other authors, adopted a critical risk level of 5%, which corresponds with a confidence level of 95% (Kim, 2018), (Ye, 2000) (Caron, 2007).

The decision-making process can be improved, as described by (Kim, 2018), by identifying which input variations have the greatest effect on the outcome, and then including risk mitigation measures into the project design, followed by re-evaluation of the project.

4. Research Design and Methodology

This chapter summarises the research approach followed, and presents the research planning and methodology.



The methodology followed to achieve the research objectives, and answer the research questions stated in section 1.4 are described in the following sections, and illustrated in Figure 4-1 below.

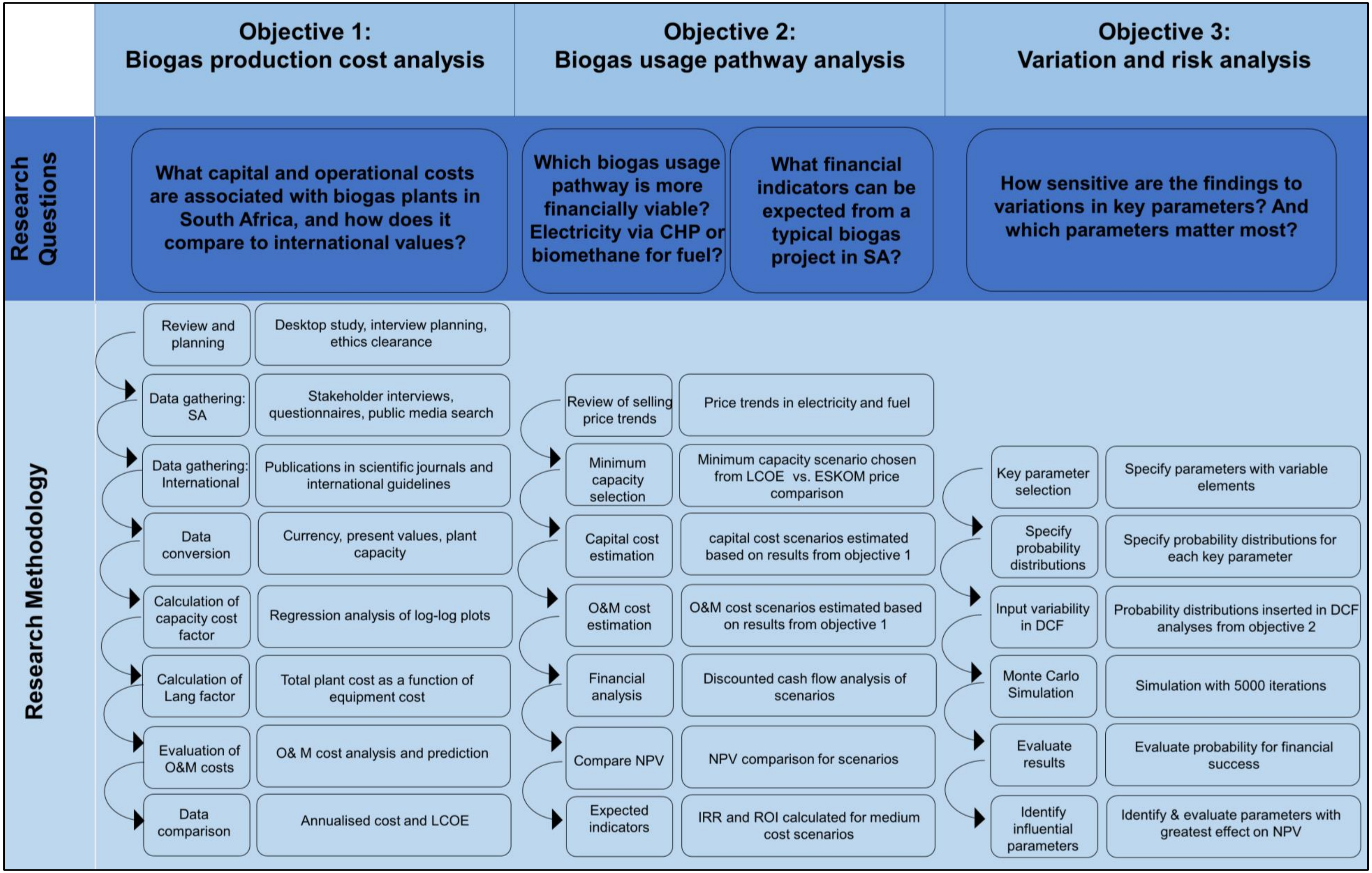


Figure 4-1: Research Methodology outline

4.1 Objective 1: Observed Costs of Biogas Production

This section set out to answer the following research question:

What capital and operational costs are associated with biogas plants in South Africa, and how does it compare to international values?

In order to answer this question, a survey was carried out on existing biogas plants in SA, obtained cost data was classified and then compared to published costs of existing biogas plants in other countries, particularly where the biogas sector is more mature. This data had to be manipulated, compared and extrapolated for prediction of future values.

Because of the wide range of biogas plant configurations, feedstock type and gas usage technologies – which can have a significant impact on costs observed, the biogas plants were evaluated based on the portion of the output that can definitely be sold. This is, for the scope of this dissertation, either electricity produced or biomethane produced.

The biogas plants analysed receive feedstock from a wide range of sources, including agricultural-, slaughterhouse-, industrial-, municipal- and WWTW waste, as well as energy crops.

The goal was therefore to obtain a range of observed and expected costs rather than single values.

4.1.1 Review and Planning

As a first step, data was gathered on existing biogas projects in South Africa – this was done by means of a desktop study through which information available in the public domain was collected. Based on the data observed in literature, the structure of capital and operating costs for biogas projects was developed and used to plan for interviews with developers. Ethical principles were considered and applied in the planning of interviews and ethical clearance was applied for and obtained. Ethical clearance is attached in Annexure A.

4.1.2 Data Gathering

Next, project developers and industry stakeholders were contacted and interviewed where possible or asked to fill in a questionnaire on the financial aspects of their projects. Based on interviews with seven project developers, financial and technical data on 20 biogas plants in SA were sourced and the data was assembled into an Excel spreadsheet which served as a basis for the financial analysis that followed. Questionnaires supplied to project developers are attached in Annexure B. The raw information supplied by project developers are not disclosed, due to confidentiality agreements undertaken with them.

In order to obtain data on international projects, a desktop study was carried out where financial data for 43 biogas plants were sourced from peer reviewed scientific journals as well as industry stakeholder publications. Based on the fact that the EU is currently the world leader in medium to large scale AD facilities, the majority of the international projects evaluated were based in the EU, with a minority of projects in the USA, Turkey, Mexico and Malaysia also included in the analysis.

The sources for international plant costs used are provided in Annexure C.

4.1.3 Data Conversion

To compare different biogas plants with one another, the data had to be converted to accommodate differences in currency exchange rates, time of project commissioning and plant capacity. This was carried out as described below.

4.1.3.a Currency

To compare published data from biogas plants outside SA with local data, the published currency was converted to Rand in 2018. In order to incorporate the effect of a fluctuating Rand, an average conversion value was calculated over the past 12 months by summing the highest and lowest values for each month and dividing it by 24, as shown in Table 4-1 below. Based on the observations shown, a conversion factor of 13.1 Rand / USD and 15.6 Rand / Euro were used, while a potential variation of 18% upward and 12% downward were assumed and inserted as error bars in a cost - comparison graph.

Table 4-1: Fluctuations in Rand/USD and Rand/Euro over the past year

Description	Rand /USD	Rand /Euro
Highest value observed in the past 12 months	15.4	17.9
Lowest value observed in the past 12 months	11.5	14.2
Average value observed over the past 12 months	13.1	15.6
% upward fluctuation from average (2018) value in the past year	18%	15%
% downward fluctuation from average (2018) value in the past year	12%	9%

4.1.3.b Capital Cost Escalation to Present Time

The capital cost was escalated to 2018 using the change in PPI for final manufactured goods as documented by Statistics SA for the years between 2006 and 2018. The PPI is a measure of the average change in prices received by domestic producers for their outputs in a given time period. It is based on selling prices reported by establishments of all sizes, with probability of selection proportionate to size. The PPI values used are shown in Table 4-2 below (Statistics SA, 2018).

Table 4-2: Production Price Index for South Africa and for Europe from 2006 to 2018 Source: (Statistics South Africa, 2018), (OECD, 2018).

Year	PPI for final manufactured goods South Africa Base: 2016=100	PPI for Europe Base: 2015=100	PPI for USA Base: 2015=100
2006	52.8	91.8	84.6
2007	58.5	93.9	87.8
2008	64.6	97.3	94.7
2009	67.0	93.1	90.1
2010	68.6	96.3	94.6
2011	72.4	100.8	101.9
2012	77.4	102.6	104.1
2013	82.01	102.2	104.5
2014	88.1	101.3	105.3
2015	91.3	100.0	100.0
2016	100.0	98.7	98.1
2017	102.5	101.3	101.6
2018	106.8	103.6	106.6

4.1.3.c Plant Capacity

Different sized biogas plants can be compared based on a variety of variables like feedstock flow rate, digester tank volume, biogas production rate etcetera. From a financial analysis perspective this can be deceptive because two similar sized digesters can have differing biogas yields based on different waste types, and furthermore, two plants with identical biogas yields can have differing energy yields based on different biogas compositions and generator efficiencies.

Therefore, the financial analysis was carried out based on the sellable end-product produced by each biogas plant. This was defined as the electrical capacity for a CHP system in MW_e or kWh/yr respectively, and the equivalent calorific capacity for a biomethane production plant in MW_{eq} or kWh/yr respectively, which were calculated based on the methodology discussed in section 3.4, and expanded below. The biogas production for each plant was based on the average long-term biogas yield and methane content, as supplied by plant owners and/or operators.

Energy product from a CHP plant:

In countries like South Africa, where no national heat distribution is present, the assumption cannot be made that there will always be an on-site off taker for the produced heat. Therefore, income streams from heat generated were excluded from the financial model, and Equation 3-27 is therefore simplified to Equation 4-1:

$$E_i = F_{bg} \,.\, C_{bg} . H . \mu_e$$

Equation 4-1: Simplified formula for energy from a CHP plant

Where:

E_i = Annual sellable energy in kWh/yr

F_{bg} = Production rate of biogas in Nm^3/h

C_{bg} = The calorific value of biogas, which was taken as: 6 kWh/Nm^3 (FNR, 2013).

H = Annual productive hours of the biogas plant. This was taken as 24 hrs, 365 days of the year, 90% of the time, which results in 7884 operational hours per annum.

μ_e= The electrical efficiency of the CHP unit, which was taken 40% unless otherwise specified.

Energy product from a biomethane plant:

Although the energy content of fuel is conventionally evaluated in Joule, it was converted to kWh for comparison with CHP systems. The net equivalent energy from Methane was further expressed in GJ/ annum for comparison with other fuel types, and as L_{eq} of diesel for comparison with petroleum fuel in SA, based on the following conversion:

$1Nm^3$ Methane = 9.97 kWh = 35.9 MJ = 0.93 L_{eq} of diesel

This was evaluated based on Equation 3-28 as follows:

$$E_i = F_{bg}\,.\,x_{bg}\,.\,C_{bm}.\,H.\,\mu$$

Equation 3-28: Energy from a biomethane plant

Where:

E_i = Annual net equivalent energy – for a biomethane plant this is the calorific value of the biomethane kWh/annum

F_{bg} = Production rate of biogas in Nm^3/h

X_{bg} = Fraction of methane in the biogas – based on values shown in section 2.1.1, methane content of 65% is assumed unless otherwise specified.

C_{bm} = The calorific value of biomethane, which is assumed to be 9.97 kWh/Nm^3.

H = Annual productive hours of the biogas plant. For the purpose of this dissertation – it is assumed that the plant operates 24 hrs, 365 days of the year, 90% of the time, which results in 7884 operational hours per annum.

μ = The Methane capturing efficiency obtainable through a biogas upgrading unit, which is assumed to be 80% for this dissertation, based on values given in section 2.1.4.

4.1.4 Capacity Cost Factor

As discussed in section 3.1.1.a, the capacity-cost method can be used to make early project stage predictions of capital expenditure, and captures the effect of economies of scale on capital investment. The objective of this part of the study was to determine a capacity cost factor that corresponds with the data for existing biogas plants in South Africa.

A regression analysis was carried out as described in section 3.2.1. The natural logarithms of the capital investment as well as the natural logarithms of the plant capacity were determined and plotted, and a linear regression analysis was carried out on the data. The slope of the resultant linear regression line was determined.

The data was validated based on the following statistical methods as described in sections 3.2.2 to 3.2.4:

- Goodness of fit by evaluating r^2
- Calculation of the MMRE
- Hypothesis testing (t-test)
- ANOVA verification (f-test)
- Lastly, the prediction intervals on future observations were calculated at a confidence level of 95% as described in section 3.2.5. These prediction intervals were used to determine the high cost and low cost estimations which formed the basis for objective 2.

The statistical analysis was carried out by means of the “data analysis” add-in to Microsoft excel software.

4.1.5 Lang Factor

The Lang factor calculation was based on data from fourteen existing biogas plants in SA. The cost data was divided into the following groups, as discussed in section 3.1.1.b:

- Main plant equipment cost (C_{mpe})
- Civil works cost (C_{cw})
- Mechanical and electrical cost (C_{me})
- Indirect cost (C_{id})
- Each factor was calculated by dividing the cost of that grouping by the cost of the main plant equipment, as shown in Equation 4-2, (Sinnot, 2004):

$$f_i = \frac{C_i}{C_{mpe}}$$

Equation 4-2: Lang group factor calculation

The total Lang factor was then calculated by summing all factors plus unity, as described in section 3.1.1.

4.1.6 O& M Costs Estimation

The annual O&M costs observed in SA were compared with international published and expected values in terms of actual value and as a percentage of capital cost. A regression analysis was carried out on the data, based on the LSBF method described in section 3.2.1. the observed data was validated against values reported in literature.

4.1.7 Data Comparison Based on LCOE and Annualised Cost

The cost data for biogas plants in SA was compared to international cost data. This was done based on the total annualised cost (R), as well as the LCOE (R/kWh).

LCOE (R/kWh) was calculated as the summed present values of all plant costs, per unit of energy, over the lifetime of the project (taken as 20 years) for an NPV of zero, with a discount rate of 8% (O'Shea, 2016). This is also equal to the total annualised cost (as described in section 3.3.1, divided by the sellable energy produced in a year.

Based on the outcome, a cost prediction curve for biogas plants in SA was constructed, and compared to international published costs.

4.1.8 Assumptions Made

The assumptions made in carrying out objective 1 are summarised in Table 4-3 below.

Table 4-3: Assumptions made for objective 1

Parameter	Value assumed	Unit	Additional notes
Average Methane content in raw biogas	65	%	It is known that biogas can have a methane content of approximately 50 – 75%. However, for calculation purposes, the assumption was made that raw biogas has an average methane content of 65%.
Average Methane content of biogas	97	%	This assumption was made for calculation purposes – in reality the concentration can range from 95% to 99.5%.

Parameter	Value assumed	Unit	Additional notes
upgraded to bio-methane			
CHP unit electrical efficiency	40	%	For the economic evaluation of CHP units, only the portion converted to electricity was used because of constraints associated with recovering financial value from localized recovered heat. In cases where no efficiency was specified for the project, and efficiency of 40% was used.
CHP unit thermal efficiency	40	%	
Overall efficiency for biogas upgrade to biomethane	80	%	HPWS was used as the default upgrading technology, for which a parasitic energy demand of 0.32 kWh_e/m^3 of raw biogas can be assumed (Browne, 2011). Parasitic energy demand was combined with 2% Methane losses during the scrubbing process. Assuming the parasitic energy can be supplied by a small CHP unit operating at 40% efficiency, an overall plant efficiency of 80% was assumed.
Calorific value of biomethane	35.9	MJ/m^3	This assumption was made for calculation purposes – in reality, the energy content of biomethane can vary from 34.02 MJ/Nm^3 to 37.78 MJ/Nm^3
Calorific value of biomethane	9.97	kWh/m^3	It was therefore observed that 1,075 Nm^3 of biomethane has the equivalent energy potential to 1L of diesel, which has an energy content of approximately 9.8 – 11 kWh/L (Browne, 2011), (FNR, 2013).
	35.9	MJ/Nm^3	
Calorific value of diesel	38.6	MJ/L	

Parameter	Value assumed	Unit	Additional notes
Plant operational hours per year	7884	Hours/yr	Assuming a plant is operational 24 hrs/day, 365 days/yr, 90% of the time
Plant operational lifetime	20	years	Based on the typical lifetime of major equipment pieces.

4.2 Objective 2: Comparing CHP with Biogas-to-Biomethane

This section set out to answer the following research questions:

Which biogas usage pathway is more financially viable? Electricity or biomethane for fuel?

This question required a discounted cash flow analysis to be carried out for the two biogas usage pathways considered. The costs for a range of biogas plant scenarios at different power output capacities could be estimated based on the outcomes from section 1.

In order to calculate the revenues, the selling price that a typical off-taker would have to pay for a similar product of fossil fuel origin was taken as benchmark.

This formed the basis for an NPV calculation over the lifetime of various project scenarios.

What financial indicators can be expected from a typical biogas project in SA?

This question could be answered by evaluating the DCF scenarios defined above, calculating the ROI, and comparing it to a MARR or hurdle rate, which was defined as the average returns that could be obtained from a low-risk investment elsewhere – 18% was defined as the benchmark.

4.2.1 Review of Selling Price Trends

As described in section 2.1.2, there are multiple biogas usage pathways. However, only two of these were analysed in this dissertation, namely electricity generation through a CHP unit or upgrading to biomethane for application as vehicle fuel.

4.2.1.a Electricity Sales from Biogas

The electricity generated by a CHP plant can either be sold at a price similar to Eskom's commercial electricity price, or would alternatively result in an electricity bill saving at said price. Therefore, in order to do a cash flow prediction, the future electricity price in SA had to be estimated. This was done by evaluating and extending the price trends over the last decade. As discussed in section 3.4.3, the average year-on-year increase in electricity prices over the last decade has been 16%.

However, considering that a potential off-taker would have to enter into a long-term agreement (15 years +) with the biogas producer, it was deemed unrealistic to incorporate a 16% price increase annually. For that reason, the annual selling price increase was specified at 5%, in line with inflation. The initial price was set at R1.01 /kWh, based on Eskom's current commercial electricity price of R1.18 /kWh, excluding 15% VAT.

4.2.1.b Biomethane Sales

As discussed in section 3.4.4, in the absence of fuel taxes imposed on biomethane, it can either be sold at a price similar to SA's retail vehicle fuel price, or would alternatively result in fuel savings at said price. Therefore, in order to do a cash flow prediction, the future fuel price in SA had to be estimated. This was done by evaluating and extending the price trends over the last decade. The average year-on-year increase the fuel price over the last decade has been 9%, which is not deemed realistic for a long term off-taker agreement. For that reason, an annual price increase of 5% was specified.

The initial diesel price was set at R14.20 /L, which corresponds to the average fuel price for 2018 of R16.40 excluding 15% VAT, with one Litre-equivalent of diesel corresponding to 1.08 Nm^3 biomethane produced. The initial selling price per Nm^3 of biomethane produced was therefore set at R13.2 R/Nm^3, which translates into approximately R1.42 /kWh potential energy.

4.2.2 Scenario Selection

Based on previous studies reporting that CHP plants become financially viable at smaller scales than biomethane plants, the minimum plant capacity for the analysis was based on the minimum capacity at which a CHP plant can be financially viable.

This was deducted from an LCOE vs plant capacity curve, evaluated against Eskom's electricity price over the last decade. Based on this analysis, the minimum plant capacity for evaluation was identified as 0.3 MW_e, however, to be conservative, the minimum capacity for financial analysis was chosen as 0.5 MW_e. The highest capacity was chosen as 6 MW_e, based on limited accuracy of cost data at higher plant scales. The plant capacity scenarios are shown in Table 4-4, which resulted in 42 analyses.

Table 4-4: Scenario selection for biogas plant financial modelling

Plant size (MW_e or MW_{eq})	**Low Cost: CHP**	**Medium cost: CHP**	**High Cost: CHP**	**Low Cost: Biomethane**	**Medium cost: Biomethane**	**High Cost: Biomethane**
0.5	0.5a	0.5b	0.5c	0.5d	0.5e	0.5f
1	1a	1b	1c	1d	1e	1f
2	2a	2b	2c	2d	2e	2f
3	3a	3b	3c	3d	3e	3f
4	4a	4b	4c	4d	4e	4f
5	5a	5b	5c	5d	5e	5f
6	6a	6b	6c	6d	6e	6f

Based on observations from objective 1, high cost scenarios correspond to plants where waste needs to be transported, pre-sorted and/or treated, or purpose-grown, or where there are high levels of contaminants that need to be removed from the product gas.

Low-cost plants correspond with waste produced on-site, with minimal or no pre-treatment required. Manure dominated feedstocks typically result in a low-cost plant.

4.2.3 Capital Cost Estimation

The capital cost for each project scenario was estimated from the results in section 5.1.2. Based on the prediction intervals calculated, a high cost value, low cost value, and medium cost value were calculated. This can be interpreted as follows: The medium cost estimate has the highest probability of being accurate. Based on statistics, there is a 95% chance that the cost will not be higher than the “high” value or lower than the “low” value.

Due to a lack of data points for local biomethane plants, the cost estimations for had to be based on a combination between local and international plant costs.

4.2.4 Operational and Maintenance Cost Estimation

The O&M costs were estimated from the results obtained in outcome 1. The O&M costs as a percentage of capital cost were calculated based on the curve fitted to the data, as shown in Figure 5-7.

For the NPV calculation, the O&M costs were increased with 5% each year to account for inflation.

4.2.5 Financial Analysis

The financial analysis was carried out by calculating the income from energy sales for each scenario, as well as the expenses based on the initial capital investment and the annual O&M costs. The NPV for each scenario was calculated as discussed in section 3.5.2, based on a project lifetime of 20 years.

4.2.6 Comparison and Further Financial Indicators

The NPV for biomethane and CHP projects of the same size were compared with each other in order to identify the most attractive project option. The following additional financial indicators were calculated only for projects with a positive NPV:

- Discounted payback period – as discussed in section 3.5.3
- Internal rate of return – as discussed in section 3.5.4
- Return on investment – as discussed in section 3.5.5. For this dissertation, the MARR, which is the minimum acceptable rate or return on investment, was specified as 17%.

4.2.7 Assumptions Made

The assumptions made in carrying out objective 2 are summarised in Table 4-5.

Table 4-5: Assumptions made for objective 2

Parameter	Value assumed	Unit	Additional notes
Discount rate for NPV calculation	10	%	In order to calculate the NPV of the various biogas plant scenarios, a discount rate of 10% annually was assumed over the lifetime of each project.
Tax	28	%	Taxes were specified at 28% of net profit
Depreciation	50 30 20	%	Depreciation was carried out on main plant equipment at 50% in year one, 30% in year two, and 20% in year three, as allowed by section 12B of the South African income tax act.
Wheeling and legal costs	0		The costs of wheeling agreements and environmental authorisations were not included in the analysis because these costs don't apply to all projects
Costs associated with fuel distribution	0		The costs associated with fuel distribution will be highly project specific, and were therefore excluded from this analysis.
Fuel taxes	15	%	For fuel applications, the assumption was made that the government levies and taxes on petroleum fuels will not apply to the biomethane produced, and only VAT at the pump will apply (DEA, 2014)
Land purchase	0		The assumption was made that the project developer is already in possession of, or has access to the project site and therefore no land purchase or lease costs were included in the analysis

4.3 Objective 3: Evaluating Risk and Variability

This section set out to answer the following research question:

How sensitive are the findings to variations in key parameters? And which parameters matter most?

In order to answer this question, the effect of random, and often unforeseen fluctuations in projected parameters had to be determined. This was done by carrying out a Monte Carlo analysis on the project scenarios defined in objective 2, but by replacing certain key parameters, which were "constant values" in the previous analysis, with probability distributions over a range of potential values, which resembles reality more closely.

The theory behind the Monte Carlo analysis is discussed in section 3.6. The analysis was carried out with @Risk [1]software, as an add-in to the existing financial model which was built in Microsoft Excel. A previous study carried out by (Amigun B. P., 2012) was used as a baseline for comparing methodology and results.

4.3.1 Key Parameter Selection and Probability Distribution Assignment

Fluctuations can either be caused by external factors like exchange rate, inflation rate, labour and transport cost variations, political instability etcetera, or internal factors like feedstock supply rate, biogas yield, operational failures, drops in product sales etcetera. In order to evaluate the effect of such variations on project outcomes, probability distributions were assigned to the following key parameters:

- **Project discount rate:** the discount rate reflects the rate at which capital can be made available for the project. South Africa's current market rates vary between 7.18% and 9.68% for bonds of 10 years and longer (South African Reserve Bank, 2018). Therefore a triangular distribution was used, with values shown in Table 4-6 below.

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[1] @Risk is a sub-product of Palisade products and services, and forms part of the Decision Tools Suite. It is installed as an add-on to Microsoft excel, and enables risk analysis using Monte Carlo simulation. A trial version of the software was used, which was downloaded from their website: www.palisade.com.

- **Investment cost:** Variations in investment costs were already calculated in the regression analysis described in section 4.1, where prediction interval calculations were carried out at a 95% confidence level, and therefore these values were used.
- **Annual revenue:** The annual revenue is determined by the design production rate and the product selling price:
    - The production rate can vary because of unplanned maintenance or plant shut-downs, impurities in the feedstock not considered during the design phase, an unstable AD process based on insufficient process control, feedstock composition or supply interruptions etcetera. The AD process is inherently susceptible to production interruptions because of its dependence on healthy bacterial communities which are, by nature, sensitive to fluctuations in the feedstock stream. This is exasperated by feedstock streams that are frequently variable in nature, especially if it originates from a combination of sources. A study on the performance of 8 manure-based digesters in the USA was used as guideline to estimate expected downtimes. The audited digesters operated, on average, at 56% of their full capacity which was specified as 0% downtime, with a standard deviation of 23% (Western United Resource Development Inc., 2009). Because the costing model was already based on data from operational digesters, the fluctuation in production rate was modelled as a normal distribution with mean at the specified production rate and a 20% standard deviation.
    - Based on the inherent nature of a biogas plant, the product selling price and supply rate would usually be fixed by a long term, pre-determined contract with an off-taker, failure by the off-taker to meet their commitments would be detrimental to the project's success. Fluctuations can also occur based on external parameter variations. For the purpose of this dissertation, the assumption was made that the off-taker will honour a long term agreement, at the pre-determined selling price. As determined in sections 3.4.3 and 3.4.4, the selling price for electricity and biomethane produced were set equal to the commercial price of electricity and the retail price of diesel in SA. These prices have respectively increased with 16% and 9% annually over the past decade. It is, however, not sustainable to assume that the biogas selling price will be able to increase at the same rate. For this reason, the assumption was made that the price will increase annually in line with inflation, which is currently 5-6%.

- **<u>Annual operating costs:</u>** Variations in the operational and maintenance costs were already included in the regression analysis prediction interval calculations previously carried out. Therefore, the high, medium, and low values from the scenarios in outcome 2 were used.

Table 4-6: Probability distributions used for key parameters in Monte Carlo simulation

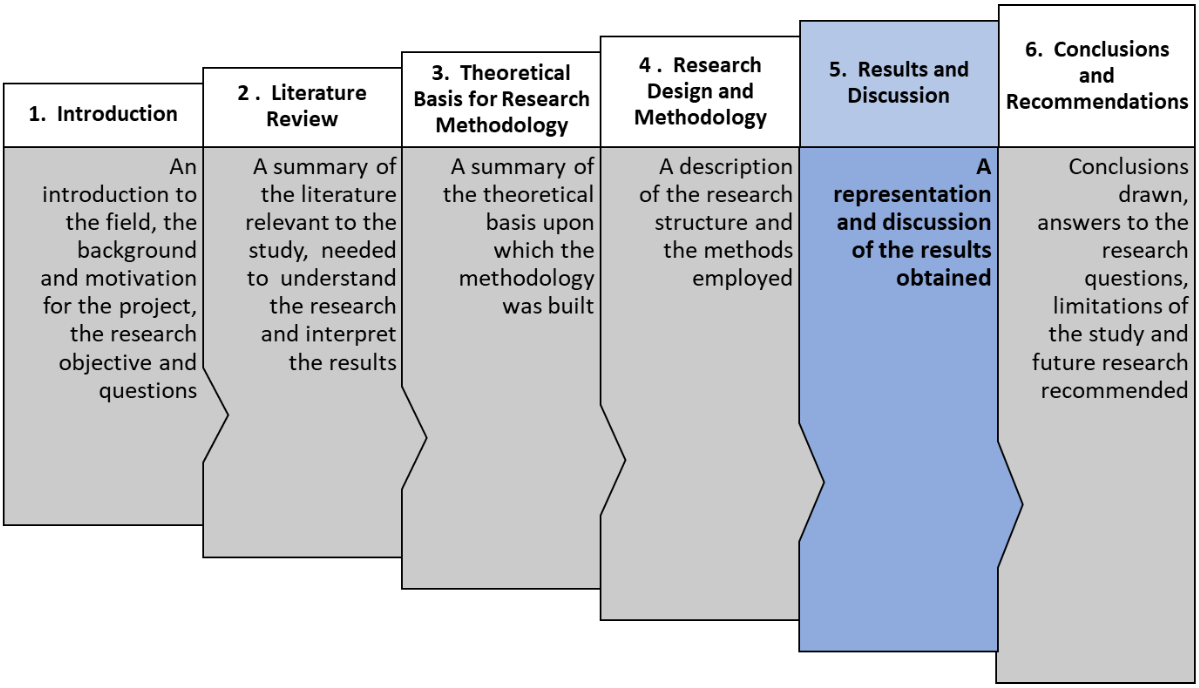
Parameter	Project discount rate	Investment cost	Annual revenue	Annual operational costs	Annual revenue growth rate
Probability distribution applied	Triangular distribution	Triangular distribution	Normal distribution	Triangular distribution	Normal distribution
Description of distribution	• Min. value = 7%, Probable value =10%, • max value = 13%	High, medium and low values as presented in table 5.3	• Mean = design capacity • Std. deviation =20%	High, medium and low values as presented in table 5.3	• Mean = 5% • Std. deviation = 2%

4.3.2 Baseline Financial Analysis and Monte Carlo Simulation

A baseline financial analysis was carried out similar to the one described in section 4.2, but now with the key parameters set as probability distributions of values instead of single values. Next, a Monte Carlo simulation was carried out on the financial model with 5000 iterations. This means that 5000 different project scenarios were calculated, each time substituting a random value for each key variable from the probability distributions specified.

5. Results and Discussion

This chapter presents and discusses the results and findings



5.1 Observed Costs

The aims of this first part of the investigation were to evaluate the costs observed in the South African biogas industry, to deduct a model for predicting the costs and to evaluate how these compare with internationally published values. The study included data from 17 SA-based CHP plants, 3 SA-based biomethane plants, and 43 international plants. The findings from this first outcome can be used to answer the first research question, and are presented in the section below. All calculations are attached in Annexure D

5.1.1 Observations on the Capital Cost of Biogas Plants

The capital cost data for the various biogas plants evaluated are shown in figure 5.1 below. A broad range of costs are observed, especially at larger plant capacities (>1 MW). This is, however, not unexpected but rather a representation of the inherently variable nature of biogas technology.

The observed capital costs for a biomethane plant broadly fall within the same range as a CHP plant of similar power output. It is, however, important to note that the equivalent biomethane plant would physically be smaller than the corresponding CHP plant, having about half the biogas production rate, but with increased energy recovery.

Three cost trends can be observed in the data, resulting in a low-cost, medium-cost and high-cost regression line. Although there were outliers, the data points on these cost lines generally corresponded with the following conditions related to feedstock:

- Low cost: Waste produced on-site as feedstock – with no or limited pre-treatment requirements.
- Medium cost: A combination of feedstocks with a portion requiring pre-treatment or transport.
- High cost: Feedstock requiring transport, significant treatment, or cultivation – like sorting of municipal solid waste, or energy crop cultivation.

The following factors, related to biogas usage, also contributed to cost variations:

- The required purity of the biogas or biomethane.
- Different feedstock types which introduce different contaminants into the biogas – and whether these contaminants need to be removed.
- The biogas upgrading technology or alternatively electricity generation technology applied.
- Location of the plant – rural, urban or coastal.

These observations correspond to a “low” and “high” cost trend that was also observed in literature (Budzianowski, 2015), (Rajendran, 2019), and stakeholder interviews (Unterlecher, 2018).

It was further noted that the majority of South African biogas plants evaluated correspond to the low-cost curve, with only two plants corresponding to the medium-cost curve and no plants on the high-cost curve.

This can possibly be ascribed to the absence of incentives or subsidies, the construction of higher cost plants has simply not been feasible in SA, and hence such project scenarios remain un-exploited.

Furthermore, the warmer climate and hence less insulation requirements in SA play a role, seeing that the majority of international plants evaluated are located in Europe or the USA.

Lastly, South Africa does not yet have strict building legislation applicable to biogas projects, as opposed to certain first world countries where large margins in digestate tank storage capacity, ground protection, snow protection etcetera are specified (Unterlecher, 2018).

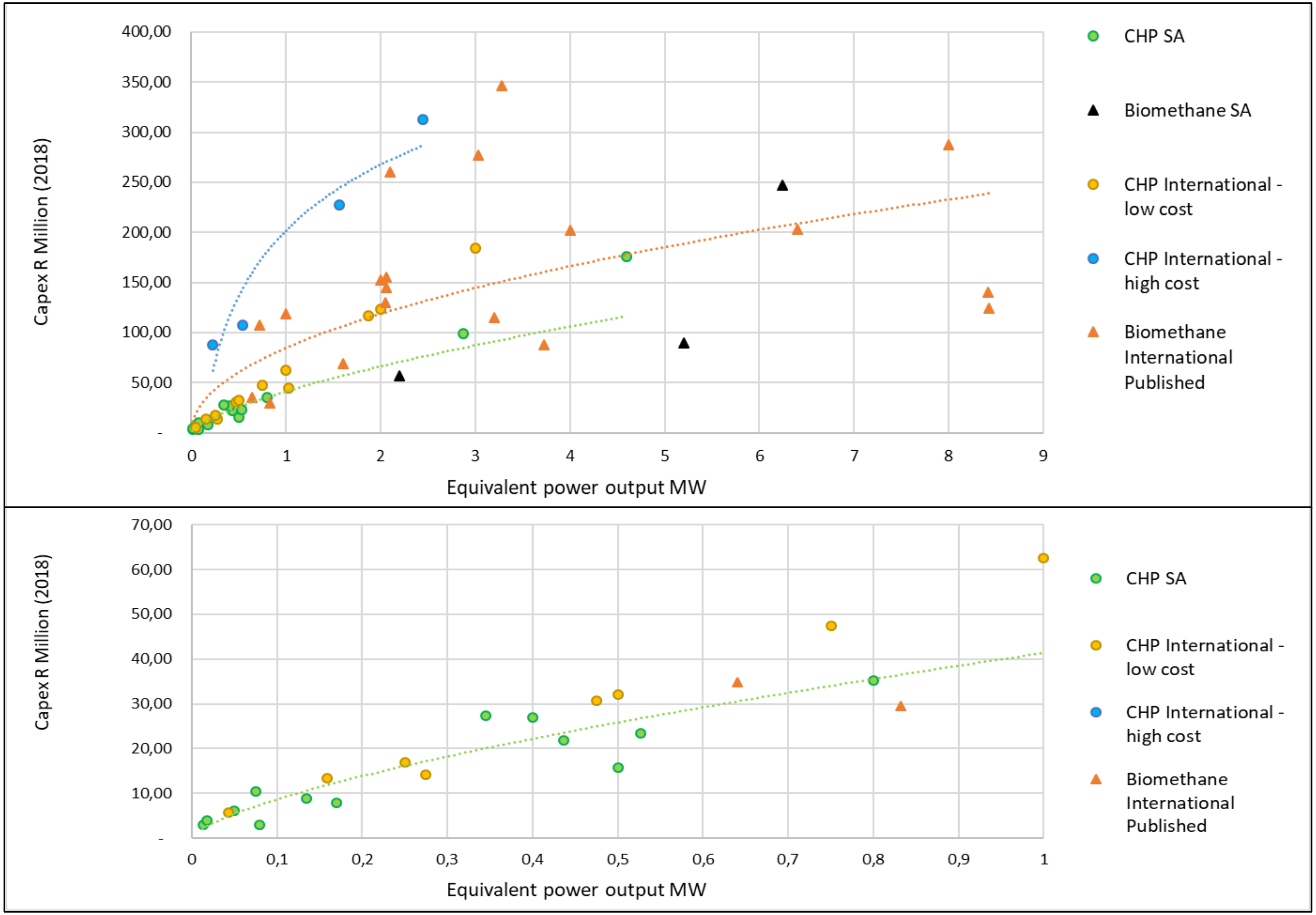


Figure 5-1: Large and zoomed-in view of capital expenditure vs equivalent power output observed in SA and internationally

5.1.2 Capacity Cost Factor

The capacity cost factor was calculated separately for CHP and biomethane systems. The results obtained are discussed in the section below.

5.1.2.a CHP System Capacity Cost Factor

Because there is a sizeable amount of data on CHP plants in SA and based on the observed difference in cost values between SA and internationally, the capacity cost factor for CHP plants was calculated based on local values alone.

It was determined to be 0.68 for biogas plants with CHP facilities, as shown in Figure 5-2. It is observed that the capacity cost factor is less than 1, which indicates that economies of scale are present at the range or plants investigated. This corresponds well with the value of 0.8 previously reported (Amigun & Von Blottnitz, 2010).

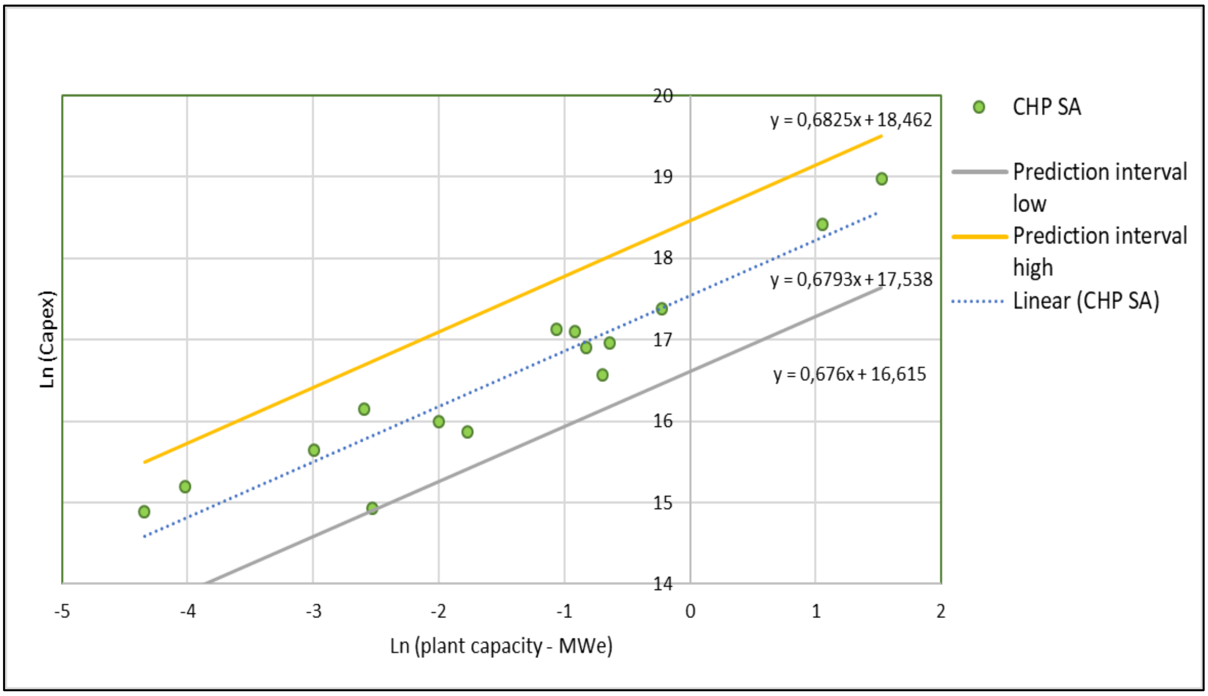


Figure 5-2: Capacity cost factor for biogas plants in SA with prediction intervals at 95% confidence level

<u>Prediction interval for future observations:</u>

The prediction intervals for future observations at a confidence level of 95% were also calculated over the range of x- values evaluated in order to get a graphical representation of low and high future predictions – this is shown as solid lines in Figure 5-2.

Statistical analysis of data:

The residual plot shows a random dispersion with equal amounts of positive and negative residuals, which indicate a good fit, as can be seen in Figure 5-3. The coefficient of determination, r^2, has a value of 89.8% which means that 89% of the variation in the capital investment cost is accounted for by the fitted relationship with the capacity. The magnitude of relative error was calculated; the largest negative relative error in the data set is -33% and the largest positive relative error is + 143%. The MMRE is 33% - this means that, on average, a 33% error can be expected in the data. This error is slightly larger than, but still deemed acceptable for a class 5 cost estimate as described by the American Association of Cost Engineers as described in section 3.1.

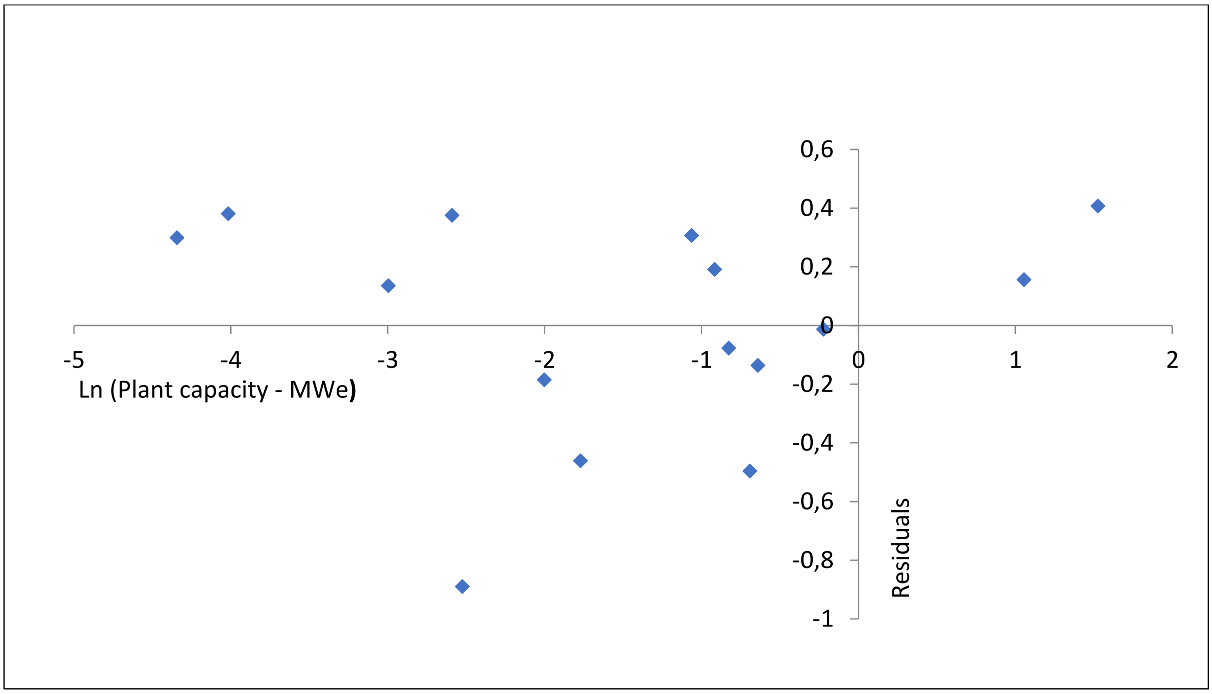


Figure 5-3: Residual plot: regression analysis for SA biogas plant capex: CHP

Hypothesis testing: t-test of regression analysis:

Hypothesis tests were carried out on the regression analysis (Figure 5-2) as described in section 3.2.4. At a confidence level of 95% and with 28 degrees of freedom (15 observations for a two-tailed t-test), the critical t statistic is equal to 2.05. The following t-tests were carried out on the slope of the fitted regression line:

- **Test 1:** Hypothesis - the slope is constant and hence there is a linear relationship between the independent and dependent variables.

- Zero hypothesis: the slope is not constant.
- For this test the t-statistic was computed as 10.74.

- **Test 2:** Hypothesis - the slope is not equal to 0 and hence the model is better at describing the response variable than simply using the mean.
  - Zero hypothesis: the slope is equal to 0 and hence the mean is a more accurate description of the response than the model.
  - For this test the t-statistic was computed as 127.18.
- **Test 3:** Hypothesis - the slope is significantly less than 1 compared to the observed error, and hence, economies of scale are observed.
  - Zero hypothesis: the slope is not significantly less than 1.
  - For this the t – statistic was computed as 5.1.

All three t-statistics were greater than the critical t-value of 2.05, which means that the null hypothesis could be rejected in all three cases.

Analysis of Variance (ANOVA) approach:

These results were also verified with an ANOVA approach on the significance of the regression. The F- value was calculated to be equal to 115.2. This is greater than the critical F- value of 2.5 which means that the null hypothesis can be rejected therefore there is a linear relationship between the independent and dependent variables.

The results from the hypothesis tests indicate that the null hypothesis could be rejected for all cases, which can be interpreted as follows:

The relationship between the independent and dependent variables is indeed linear, the regression model is better at describing this relationship than the mean of the response variable, and economies of scale are observed.

5.1.2.b Biomethane System Capacity Cost Factor

Because only three data points could be obtained for biomethane plants in SA, these values were combined with internationally reported values for the regression analysis.

The capacity cost factor was determined to be 0.57 for biogas plants with upgrading facilities to biomethane, as shown in Figure 5-4. This factor is less than 1, which indicates that economies of scale are present at the range of plants investigated. Although fuel energy capacity is conventionally expressed in Joule/hr, it was evaluated in MW_{eq} for comparison purposes with CHP plants, based on the calorific value of biomethane.

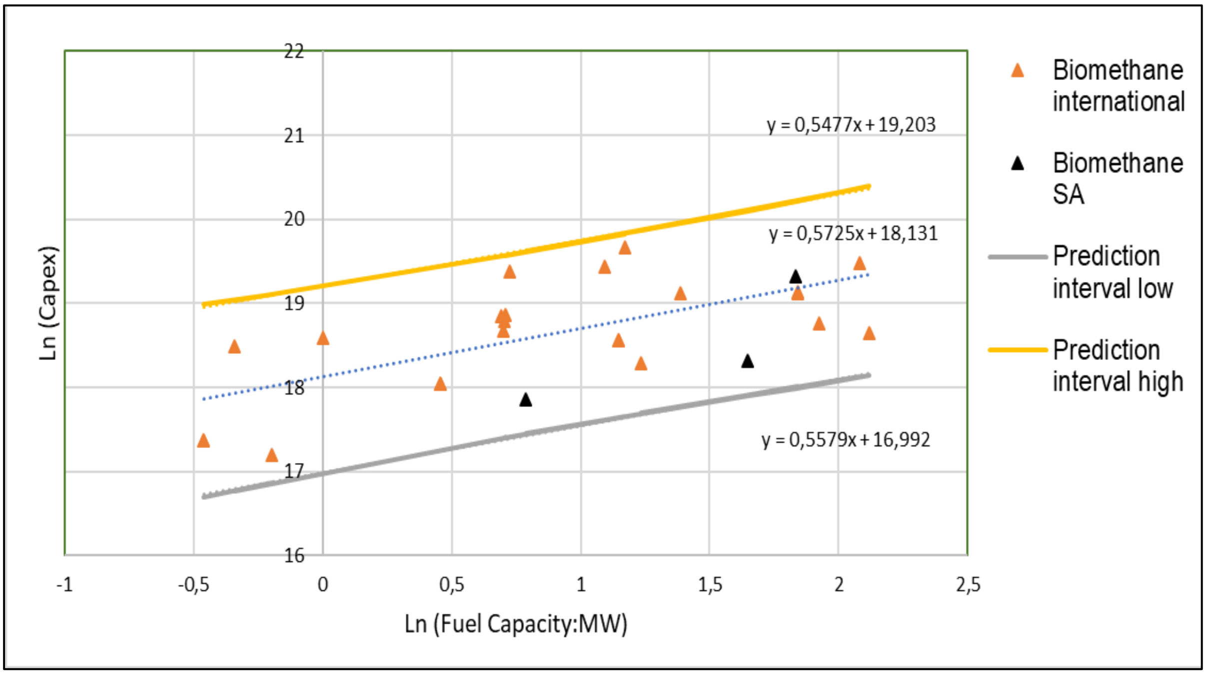


Figure 5-4: Capacity cost factor for biomethane: data from SA and international plants with prediction intervals

<u>Prediction interval for future observations:</u>

The prediction intervals are shown in Figure 5-4 above. Because the international data set was used in the absence of sufficient local data, it is anticipated that local values will fall in the low- or medium cost range and not in the high-cost range. For this reason, the higher prediction interval was calculated at 80% confidence level, and the lower prediction interval at 95% confidence level.

Statistical analysis of data:

The residual plot shows a random dispersion with equal amounts of positive and negative residuals, which indicate a good fit, as can be seen in Figure 5-5. The coefficient of determination, r^2, has a value of 42.9% which means that 43% of the variation in the capital investment cost is accounted for by the fitted relationship with the capacity. The magnitude of relative error was calculated; the largest negative relative error in the data set is -60% and the largest positive relative error is +120%. The MMRE is 45% - this means that, on average, a 45% error can be expected in the data. This error acceptable for a class 5 cost estimation as described by the American Association of Cost Engineers.

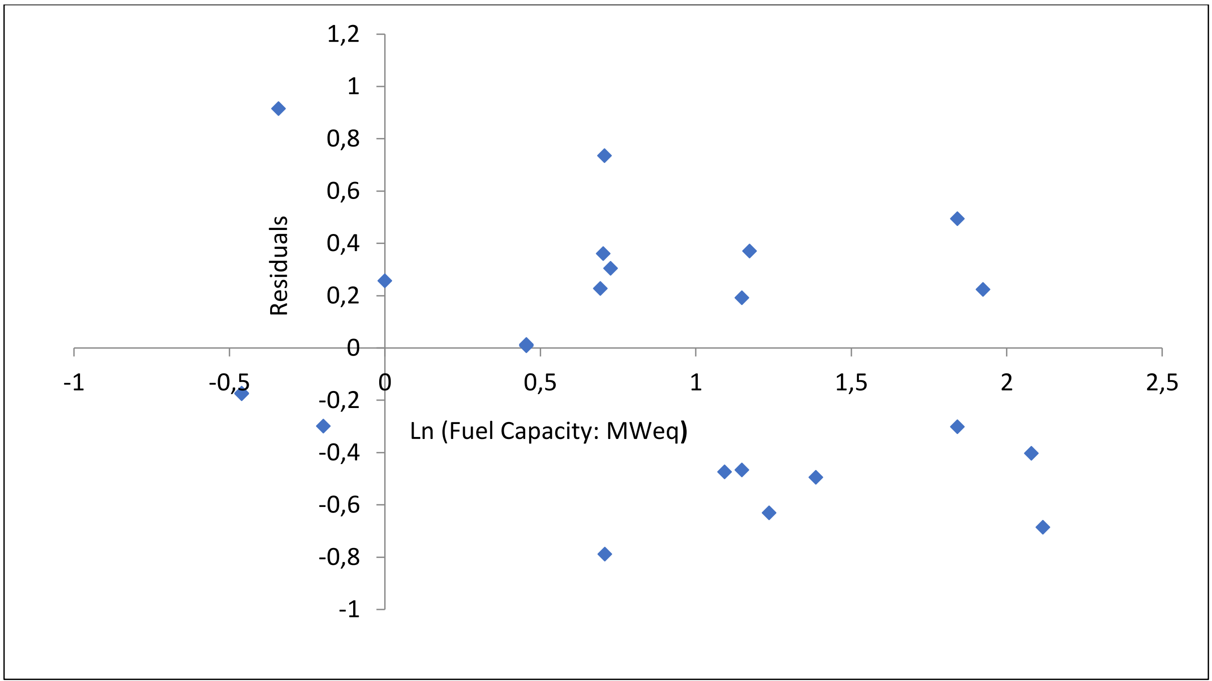


Figure 5-5: Residual plot: regression analysis for SA and international biomethane plant capital expenditure

Hypothesis testing: t-test of regression analysis:

Hypothesis tests were carried out on the regression analysis (Figure 5-4) as described in section 3.2.4. At a confidence level of 95% and with 24 degrees of freedom, the critical t statistic is equal to 2.06. The following three t-tests were carried out on the slope of the fitted regression line:

- **Test 1**: Hypothesis - the slope is constant and hence there is a linear relationship between the dependent and independent variables.

- Zero hypothesis: the slope is not constant.
- For this test the t-statistic was computed as 4.24.

- **Test 2:** Hypothesis - the slope is not equal to 0 and hence the model is better at describing the response variable than simply using the mean.
  - Zero hypothesis: the slope is equal to 0 and hence the mean is a more accurate description of the response than the model.
  - For this test the t-statistic was computed as 114.5.
- **Test 3:** Hypothesis: the slope is significantly less than 1 compared to the observed error, and hence economies of scale are observed.
  - Zero hypothesis: the slope is not significantly less than 1.
  - For this the t – statistic was computed as 3.4.

All three t-statistics were greater than the critical t-value of 2.06, which means that the null hypothesis could be rejected in all cases.

Analysis of Variance (ANOVA) approach:

The ANOVA approach was also used to test the significance of the regression. The F- value was calculated to be equal to 17.99. This is greater than the critical F- value of 2.5 which means that the null hypothesis can be rejected therefore there is a linear relationship between the dependent and independent variables.

The results from the hypothesis tests indicate that the null hypothesis could be rejected for all cases, which can be interpreted as follows:

The relationship between the dependent and independent variables is indeed linear, the regression model is better at describing this relationship than the mean of the response variable, and economies of scale are observed.

5.1.3 Lang Factor

Based on the data gathered, a Lang factor of 1.81 was determined for biogas plants in SA, as discussed in section 3.1.1.b. This corresponds well to the value of 1.78 determined by a previous study (Amigun & Von Blottnitz, 2009). This is lower than the expected value for predominantly solids processing plants of 3.1, and indicates that the plant cost is dominated by the main equipment costs (Sinnot, 2004). This further indicates that the total plant cost can be estimated as 1.81 multiplied by the equipment costs. A summary of the cost factors determined is shown in Table 5-1.

Table 5-1: Lang factor results

Civil Works Cost Factor (F_{cw})	0.37
Mechanical and Electrical Cost Factor (F_{me})	0.27
Indirect Cost Factor (F_{id})	0.17
Lang Factor (f_L) (= 1 + sum of individual factors)	**1.81**

5.1.4 Operational and Maintenance Costs

Figure 5-6 below shows biogas O&M costs as observed in SA. It is presented in USD / Nm^3 raw biogas produced on one axis, for comparison purposes with Figure 3-1 as shown in section 3.1.2, and in Rand/Nm^3 biogas on the other axis[2]. It can be observed that, where waste with significant sorting and/or transport costs are involved or where energy crops are involved, the O&M costs observed in SA are in the same order as expected costs listed by the International Renewable Energy Agency (IRENA, 2013). However, where waste produced on-site is used as feedstock, the costs are generally lower in SA than what has been documented internationally.

For this reason, a higher and lower O&M cost range can be deducted. The higher range varies between 0.2 – 0.38 USD/Nm^3 biogas produced, which translates into R2.6 – R4.6 /Nm^3, and the lower cost range varies between 0.02 – 0.09 USD/Nm^3 biogas produced, which translates into R0.3 – R1.4 /Nm^3.

[2] Based on an exchange rate of 1USD = R12.50 in May 2018

These rates can be translated into a lower cost range of R 750 – R 1900. kWe^{-1}.year and a higher cost range of R 2400 – R 8000 .kW_e^{-1}.year depending on the feedstock source and biogas applications.

The lower cost range corresponds to a previous estimation by (Greencape, 2017), which reported R 1700. $kW_e^{-}1$.year for biogas plants in SA.

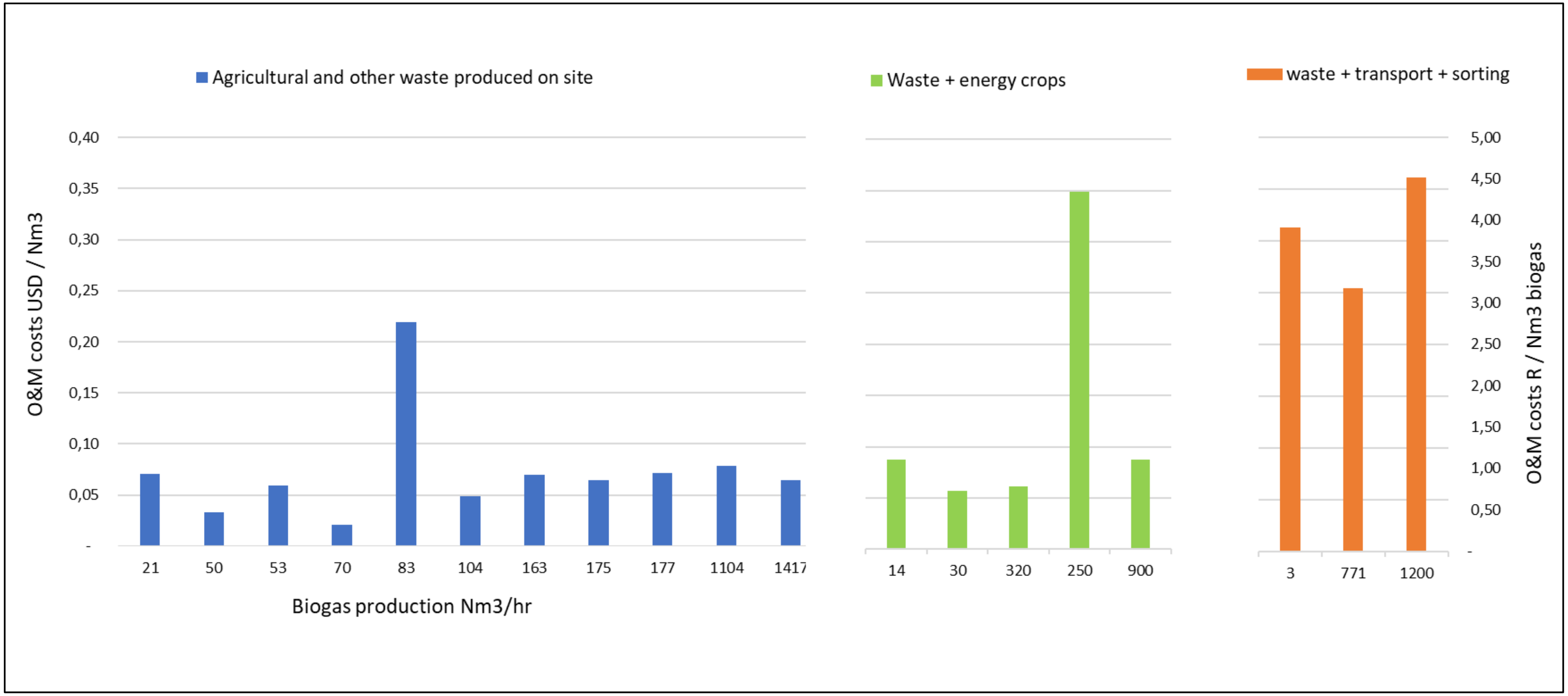


Figure 5-6: O&M costs observed for biogas plants in SA: biomethane and CHP combined

Operational and maintenances costs were also evaluated as a percentage of capital investment, as shown in Figure 5-7.

Based on this data, the observation was made for South African CHP plants that, for plant capacities < 1 MW_e, annual O& M costs vary between 2%-10% of capital investment.

For plants with capacities >1 MW_e, annual O&M costs vary between 10% and 20% of capital investment. The range of observed values for biomethane plants is wider than what is observed for CHP plants, which means there is more uncertainty.

This corresponds to values of 2.5% for smaller plants and 20% for larger plants that were reported in literature (Karellas, 2010).

This observation is in line with the inherent nature of biogas technology, which can range from a very low technology farm scale installation, to a complex industrial plant. Smaller plants can generally be fed by a waste stream generated on-site, and biogas purity requirements would typically be minimal. Lastly, there would be no administration related to biogas sales and transport - consequently only a small amount of staff is necessary. Whereas a large-scale plant would require complex process control, waste pre-treatment, and more staff.

A regression analysis was carried out on the O&M costs for CHP plants, with the equation shown on Figure 5-7 below. However, for biomethane plants in SA the data was too limited for regression analysis.

Lastly, a histogram was drawn to present the data of all the biogas plants evaluated. This is shown in Figure 5-8 - it is observed that, in 90% of the cases, the O&M costs is between 3% and 25% of the capital expenditure. However, as noted above, for plants with capacity > 1 MW, the annual O&M costs will generally be greater than 10% of capital expenditure.

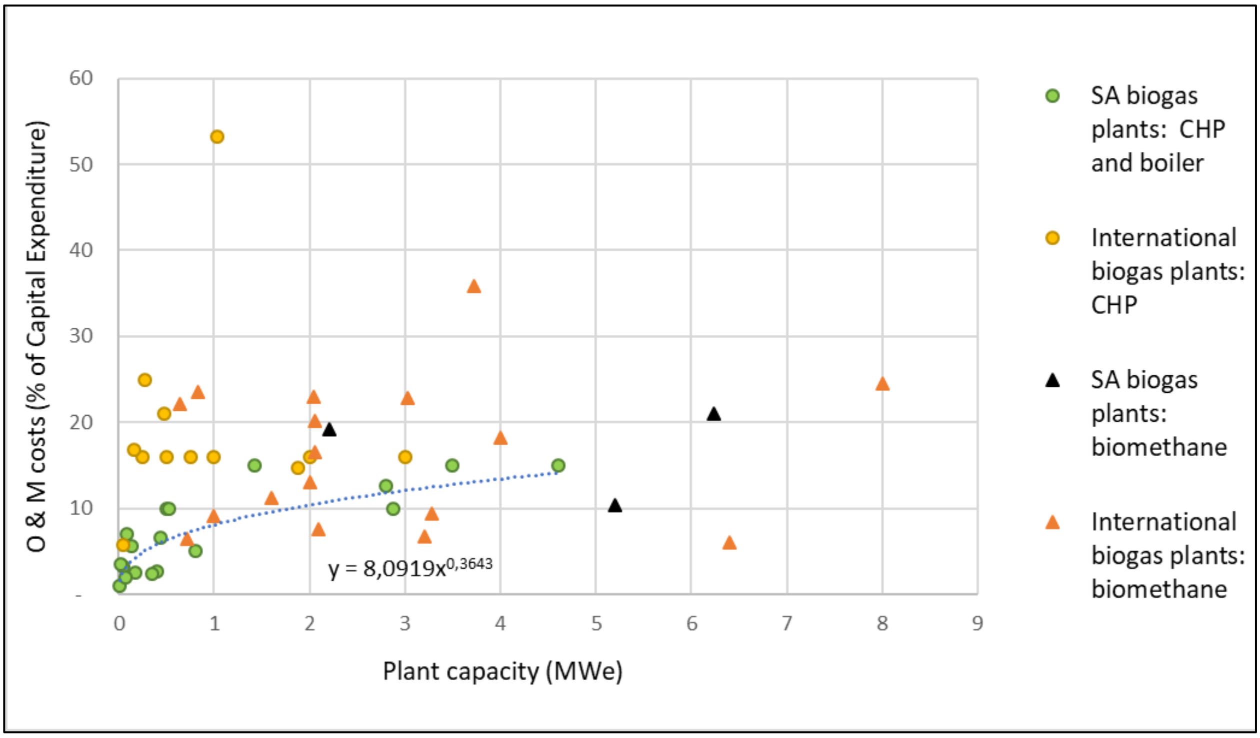


Figure 5-7: Annual O&M costs observed in SA and internationally as a percentage of capital expenditure

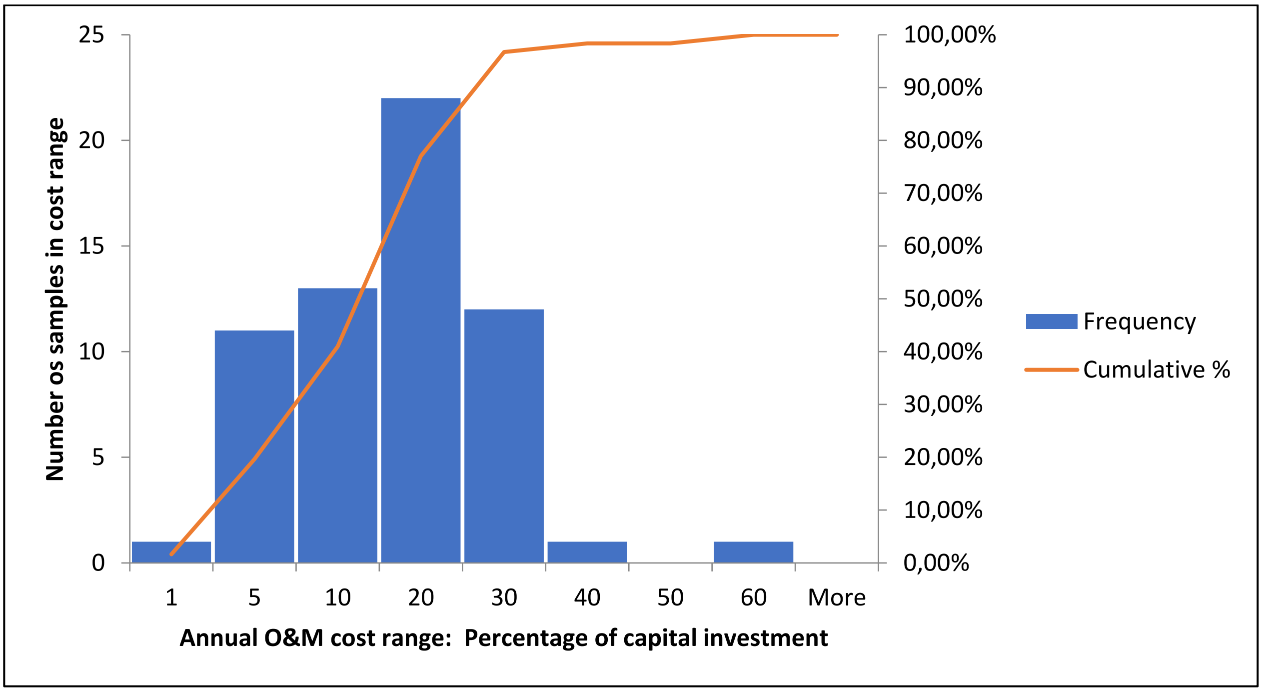


Figure 5-8: Histogram of O&M costs as percentage of capital cost with cumulative percentage line

5.1.5 Data Comparison Based on Levelised Cost of Energy

In this section, the data gathered from existing biogas plants in SA was compared to published values for biogas plants in Europe, USA, Mexico and Turkey, based on combined capital expenditure and operational costs. The LCOE was calculated for each plant as the present annual plant cost per unit energy produced. For CHP plants, the following observations were made, as shown in Figure 5-9:

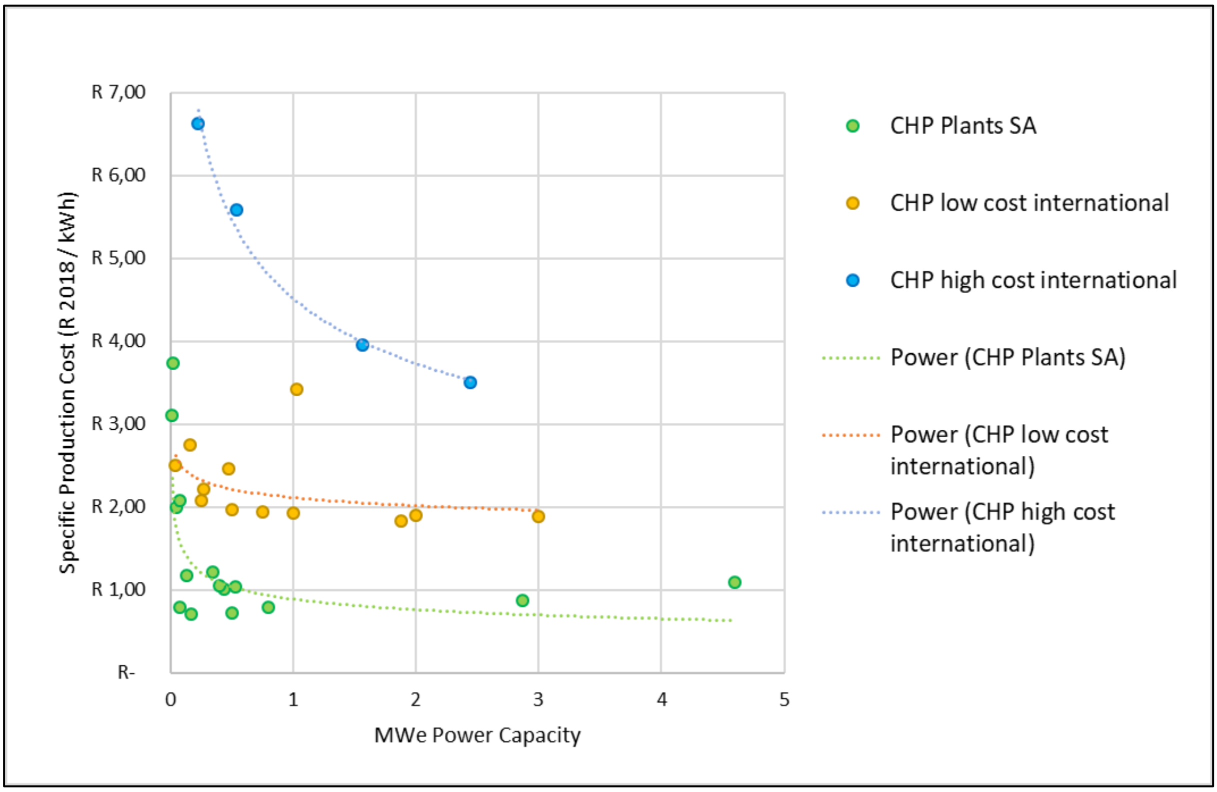


Figure 5-9: LCOE vs plant capacity for CHP plants in SA and internationally

Except for the smallest plant scales, the LCOE observed for biogas plants in SA were lower than what was documented internationally. Furthermore, two cost trends are observed for international biogas plants – the higher costs are associated with energy crops and unsorted OFMSW, while the lower costs are associated with manure dominated plants.

There is a downward trend in LCOE as plant capacity increases. Although the trend is not strong enough for reliable regression analysis, the following observations were made: A LCOE of R 0.5 – R 2 /kWh can be expected for biogas plants in SA, with higher costs expected for plants with capacities <0.1 MW_e. For international biogas plants, a LCOE of R 1.8 – R 2.8 /kWh can be expected for lower cost plants, or R 3.5 – R 6.5 /kWh for higher cost plants.

The LCOE was also evaluated for biomethane plants, as shown in Figure 5-10 below. The same trend is observed than for CHP plants, with costs in SA being lower than costs internationally. Based on the combination of South African and international plants, a general range of costs between R 0.4 /kWh and R 3.5 /kWh or R 111 /GJ and R 972 /GJ can be expected. There is a slight decrease in LCOE as plant capacity increases, however, this is not a strong enough relationship for significant regression analysis. This can be seen in Figure 5-10 below.

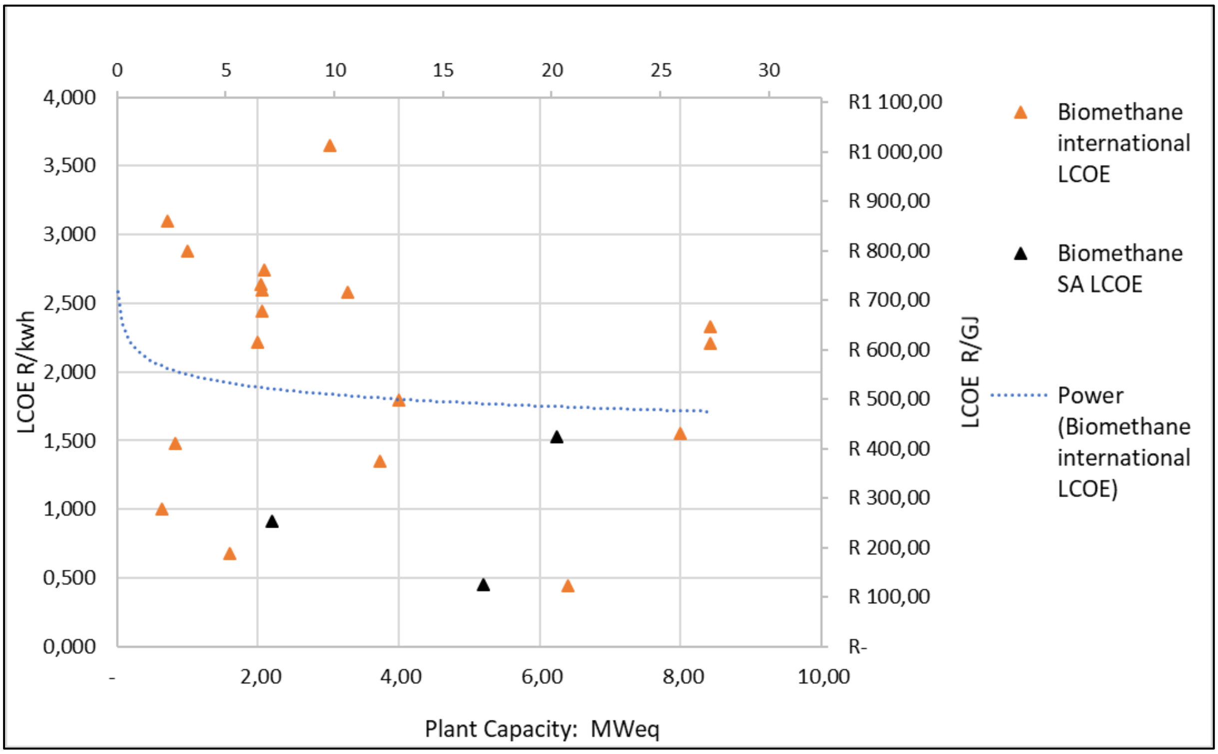


Figure 5-10: LCOE vs plant capacity for biomethane plants in SA and internationally

In practical terms, the high- medium- and low- cost scenarios observed would typically correspond to the project parameters set out in table 5.2 below:

Table 5-2: Factors that influence biogas plant cost

Low cost plant	High cost plant
Sufficient and constant feedstock stream available on-site	Waste needs to be transported to AD site
Cheap or free feedstock source, or income generated through gate fee. No pre-treatment requirements, for example manure	Expensive feedstock stream like energy crops, unsorted municipal waste, seasonal waste like fruit and vegetables

Low cost plant	High cost plant
Waste with high specific biogas yield, or co-digestion where a smaller plant size is required	Low yielding feedstock like slurry which would require an excessively large plant
Biogas usage on-site is achievable	Biogas is generated and used at different locations
Low levels of contaminants in feedstock, and/or low purity requirements in product stream	High levels of contaminants in feedstock, and/or high purity requirements in product stream
Importing low-cost equipment from developing countries or manufacturing equipment locally	Importation of high-cost, specialised equipment from first world countries.

5.1.6 Data Comparison Based on Annualised Cost

Finally, to demonstrate the effect of fluctuations in currency over a year period, the various plants were compared based on their total annual cost with error bars inserted for the variations observed between South African and the internationally currencies over a 12-month period. These error bars actually apply to all the graphs plotted but were only inserted here to keep the data presentation as uncluttered as possible.

It can be seen in Figure 5-11 below that even through the cost data can fluctuate substantially, the patterns observed earlier still prevail.

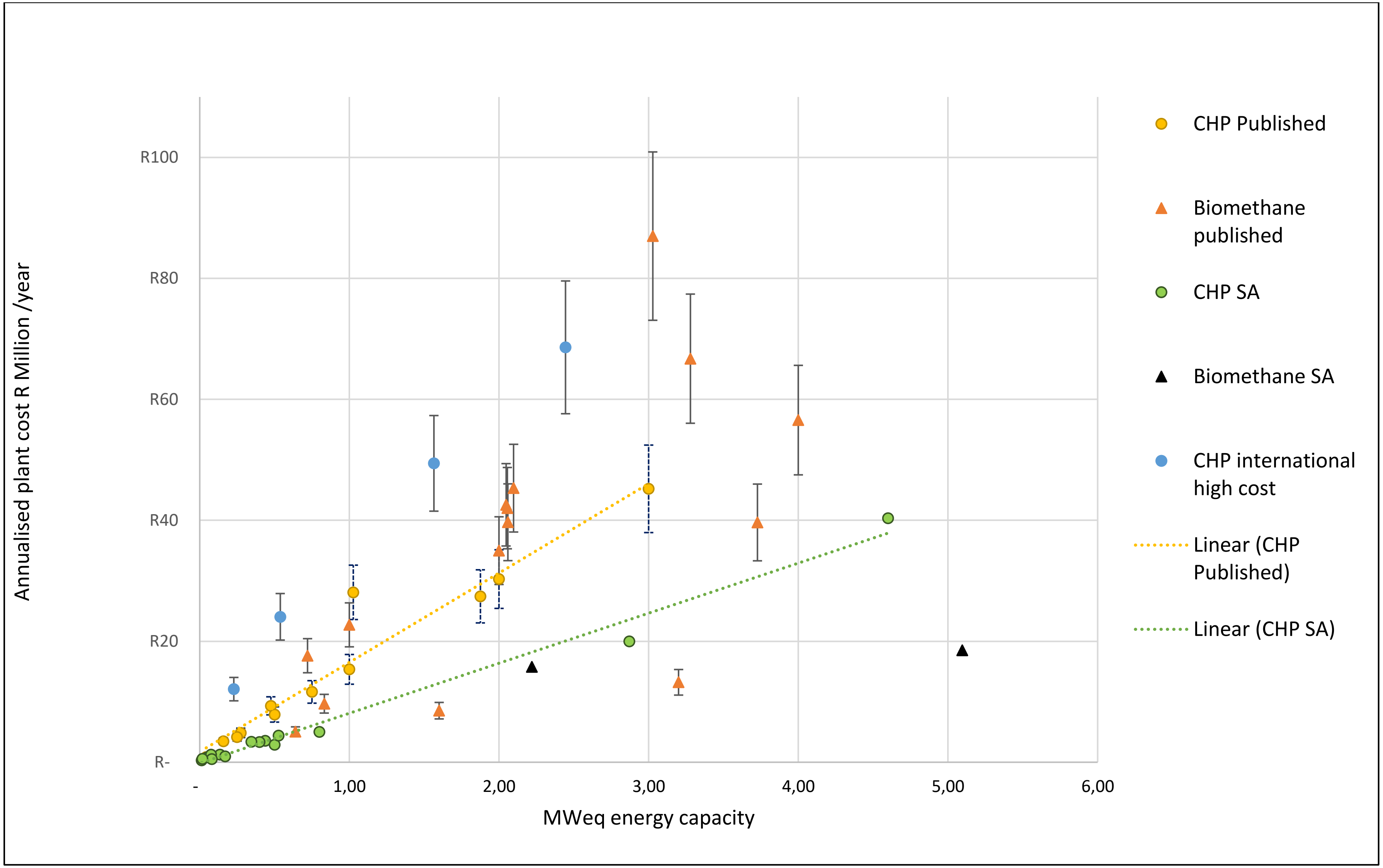


Figure 5-11: Annualised cost for SA and international biogas plants incorporating currency fluctuations

5.2 Financial Indicators of Electricity and Fuel Production

The aims of this part of the investigation were to evaluate whether the biogas-to-electricity or the biogas-to-biomethane for fuel applications are more financially attractive in the South African context, and further to estimate the financial indicators that could be obtained by a typical biogas project. The findings from this second outcome can be used to answer the second and third research questions, and are presented in the sections below.

5.2.1 Scenario Selection

In order to identify the lowest capacity scenario for evaluations, a comparison of LCOE for existing CHP plants in SA was carried out against Eskom prices over the past decade – this is shown in Figure 5-12 below. From this diagram is it can be seen that a positive business case for electricity from biogas only became possible from 2013 onward. As of 2018, a positive business case could potentially exist for plants with capacity greater than 0.3 MW_e. Based on this observation, eight biogas plant scenarios were chosen with capacities ranging from 0.5 MW_{eq} to 6 MW_{eq} for further evaluation.

It can further be observed that, if Eskom prices continue to rise at its current rate of 16% per annum, the business case for an electricity generating biogas plant could potentially become very attractive within the next few years.

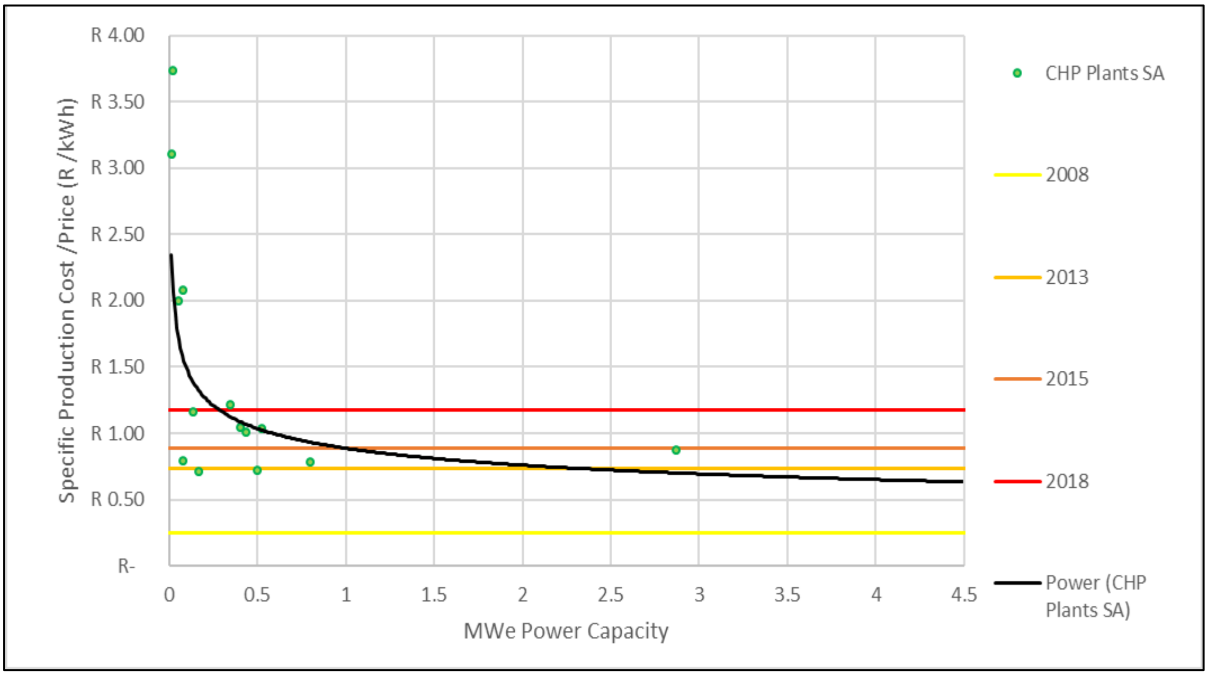


Figure 5-12: LCOE of electricity from biogas vs Eskom prices over the last decade

5.2.2 Cost Estimation for Plant Scenarios

For this evaluation, it is assumed that plant costs will form a triangular distribution as discussed in section 3.6.1.b, with high, medium or low-cost plants being observed.

A low-cost plant is without doubt the most attractive option, however, it would not often be practically achievable except at very small scales, since it would require a reliable and constant waste source, generated on-site throughout the year, at a feedstock rate corresponding to on-site energy requirements.

Medium-cost plants have the highest probability of being achievable. This would typically refer to a scenario where some partial form of either waste pre-treatment or transport, biogas storage or distribution costs are required. Furthermore, where an acceptable specific biogas yield is achieved, resulting in an average sized plant. The plant scenarios and associated cost estimations are shown in Table 5-3.

Table 5-3: CHP and biomethane capital and operational costs for low, medium, and high-cost scenarios

	Biogas plant with CHP for electricity generation (R million)						Biogas plant with upgrading to biomethane (R million)					
Plant size (MW_e or MW_{eq})	Low Capex	Medium (probable) Capex	High Capex	Low annual O&M	Medium (probable) annual O&M	High annual O&M	Low Capex	Medium (probable) Capex	High Capex	Low annual O&M	Medium annual (probable) O&M	High annual O&M
0.5	10.2	25.8	64.9	0.6	1.6	2.9	16.3	50.3	85.0	1.6	7.5	17.0
1	16.4	41.3	104.2	1.3	3.3	5.9	23.9	74.8	122.9	2.4	11.2	24.6
2	26.2	66.3	167.2	2.7	6.9	12.2	35.2	111.3	177.6	3.5	16.6	35.5
3	34.5	87.3	220.6	4.2	10.5	26.6	44.2	140.4	220.3	4.4	21.0	44.0
4	41.9	106.1	268.4	5.6	14.2	36.0	51.9	165.5	256.7	5.1	24.8	51.3
5	48.8	123.5	312.6	7.0	17.9	45.0	58.8	188.0	289.0	5.9	28.2	57.8
6	55.2	139.8	354.0	8.6	21.7	55.0	65.1	208.8	318.4	6.5	31.3	63.7

5.2.3 Financial Analysis of CHP Plants

Figure 5-13 below shows the NPV for the various CHP plant scenarios. It can be seen that the low-cost plant scenario had a positive NPV from 0.3 MW_e upward, as expected. The medium cost plants had a positive NPV from 1 MW_e upward, whereas the high cost plants had a negative NPV in all cases. It was further observed that, higher NPVs can theoretically be achieved at greater capacities, which is expected because of economies of scale.

Although the low-cost plant scenarios had the highest NPV, it would correspond to a very specific set of project parameters which are not likely to be achievable in the majority of cases. For that reason, further modelling was based on the medium-cost scenarios only.

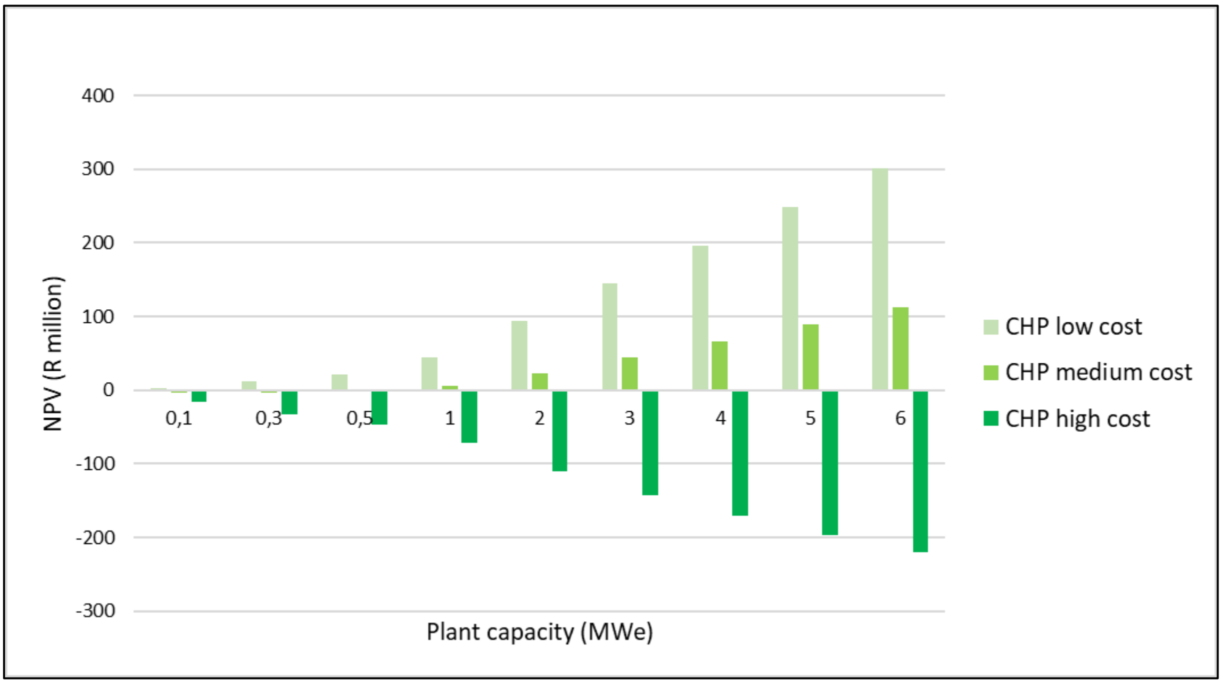


Figure 5-13: NPV for biogas plant scenarios with CHP unit

5.2.4 Financial Analysis for Biomethane Plants

Figure 5-14 below shows the NPV for the various biomethane plant scenarios. The following observations were made:

- The low-cost scenario had a positive NPV across the whole range or plant sizes
- The medium-cost scenario had a positive NPV from 4 MW_{eq} upward
- The high-cost scenario had a negative NPV across the whole range or plant sizes

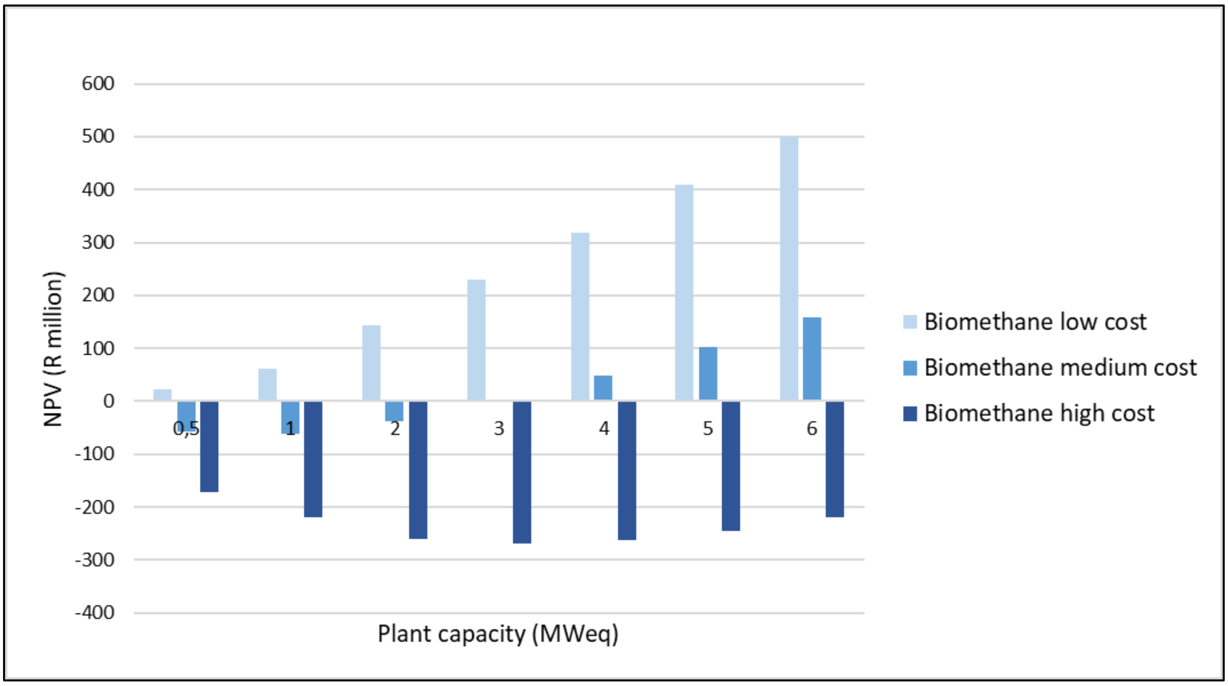


Figure 5-14: NPV for biogas plant scenarios with upgrading unit to biomethane

5.2.5 Comparative Financial Indicators

A comparison of the achievable NPV through different usage pathways can be seen in Figure 5-15 below. For this comparison, only the medium cost values, which are the most likely to be realistic were used. The following observations can be made:

At smaller plant capacities (below and up to 4 MW_{eq}) the CHP plant scenarios have comparatively higher NPVs, however, at larger plant capacities (5 MW_{eq} and greater) the biomethane plants have larger NPVs.

It is further noteworthy that at a capacity of 6 MW_e, both usage pathways had their greatest potential NPV, which is a result of economies of scale.

It can be seen that biomethane plants are more cost-sensitive but also more profitable at larger plant capacities

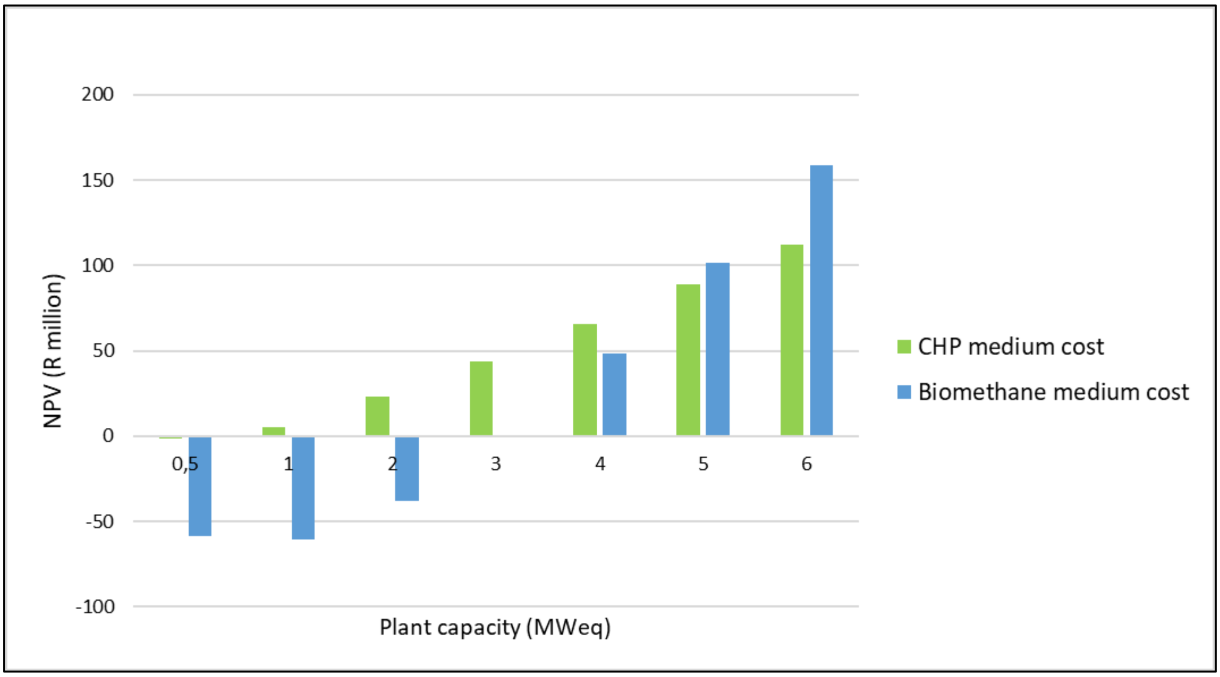


Figure 5-15: NPV comparison between biomethane and CHP plants: Only medium cost plants

Additional financial indicators were calculated only on the ‘medium cost’ plants as this is the most realistic scenario; these are presented in Table 5-4 and discussed below.

For a CHP plant, the MARR or hurdle rate of 17% is exceeded for plants with 4 MW_e capacity or greater, where a corresponding payback period of 9 years can be achieved and a 17% ROI. For biomethane plants, the MARR is exceeded at plant capacities of 5 MW_{eq} or greater, where a corresponding payback period of 10 years can be achieved and a 16% ROI.

At the largest capacity evaluated, which was 6 MW_{eq}, the two usage pathways had similar payback periods of 8 years, corresponding to IRR values of 19%, and ROI values of 19% and 18%.

	CHP plant: Medium cost scenarios			Biomethane plant: Medium cost scenarios		
Plant size (MW_e or MW_{eq})	**Discounted payback period (years)**	**IRR Internal rate of return (%)**	**ROI Return on investment (%)**	**Discounted payback period (years)**	**IRR Internal rate of return (%)**	**ROI Return on investment (%)**
0.5	N/A	9%	9%	N/A	N/A	N/A
1	23	12%	11%	N/A	N/A	3%
2	13	15%	14%	N/A	5%	6%
3	10	16%	15%	N/A	10%	10%
4	9	17%	17%	15	14%	13%
5	8	18%	18%	10	17%	16%
6	8	19%	19%	8	19%	18%

Table 5-4: Financial indicators for biogas plant medium cost scenarios

5.2.6 Further Discussion of Results

Over the range of plant capacities evaluated (0-6 MW_{eq}) biogas plants smaller than 1 MW_e will generally not be financially viable in the South African context, regardless of the feedstock used or the usage pathway followed. Unless the plant is constructed in the low-cost range, or, unless additional income streams are valorised.

The effect of a second income stream is demonstrated by the difference in results for this study and a study by (Shmulevich, 2015) which included heat sales. For the CHP plant scenario, the results obtained for the 5 MW plant were less positive than results reported by (Shmulevich, 2015), who calculated a payback period of 5.3 years as opposed to 8 years according to this study, and an IRR of 23% as opposed to 18% according to this study.

At plant capacities >2 MW_e for electricity generation and >4 MW_{eq} for biomethane, a biogas plant can be financially viable based solely on electricity or fuel sales. However, this only holds true for low or medium cost plants, which excludes expensive plants with energy crops or high volume- low yielding slurry as feedstock.

If “inexpensive” waste like pre-sorted municipal waste, food waste, industrial waste or abattoir waste is available at these scales, the business case could be viable, with an ROI of up to 19% for CHP or 18% for biomethane, and a payback period as low as 8 years at the highest scales. There may, however, be challenges associated with sourcing biological waste at such a large scale while still keeping costs low, as multiple waste sources may be required.

Lastly, CHP plants have a higher NPV at capacities below 5 $MW_{eq,}$ while, from 5 MW_{eq} or higher, biomethane plants have a higher NPV. However, as the investment costs for biomethane plants are generally also higher, the IRR and discounted payback periods for the two usage pathways are very similar at these larger scales.

These result correspond to the earlier study by (DEA, 2016), which concluded that the business case for biomethane has the potential to be more profitable than for electricity production through CHP – however, the results indicate that this is only true at larger plant capacities (> 5 MW_{eq}).

5.3 Variability of Costs

As shown in section 5.1 variations in key parameters are sure to occur – these can be caused by external or internal fluctuations. The third objective of this dissertation is therefore to evaluate whether such fluctuations will render a seemingly viable project unviable or not. The findings obtained by Monte Carlo simulation are presented in the sections below. The risk assessment programme files are attached in Annexure E.

A comparison between the NPVs for CHP and biomethane projects at capacities ranging from 0.5 MW to 6 MW are presented in figure 5.16 to figure 5.19. The variabilities as described in section 4.3.1 were applied. The results correspond well with what was determined in the previous section. The following observations can be made:

- At capacities up to 3 MW_{eq}, the CHP system has a higher probability of achieving a positive NPV.
- At the largest capacity evaluated, 6 MW_{eq}, the biomethane system has the highest probability of achieving a positive NPV.
- The CHP system forms a narrower bell curve than the biomethane system. This corresponds with the results from section 5.1, where the cost distribution for CHP plants was narrower than what was observed for biomethane plants. Biomethane plants as a relatively new technology therefore correspond with higher levels of uncertainty than CHP plants, which is a mature and proven technology.

From figure 5.16 it can be seen that, at 0.5 MWeq, the CHP plant has 62% chance of resulting in a negative NPV while the biomethane plant has a 96% chance. The probability for financial success is therefore unattractively small for both options if only one revenue stream is valorised.

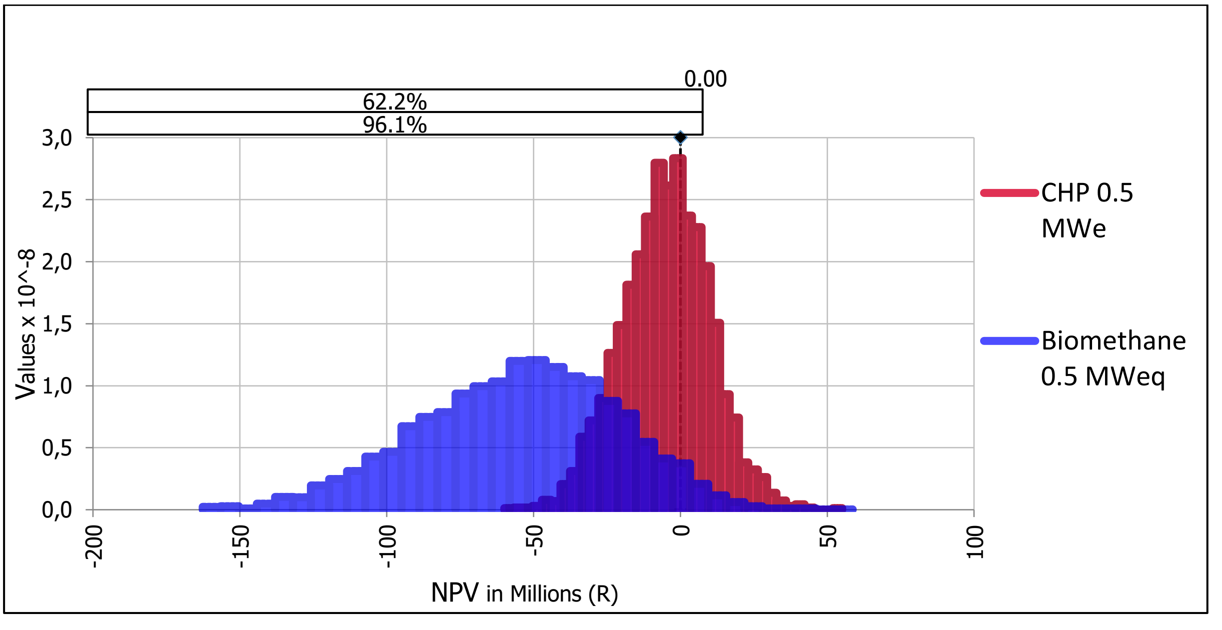


Figure 5-16: Comparison between NPV for CHP and biomethane at 0.5 MWeq

From Figure 5-17 it can be seen that, at 1 MW_{eq}, the CHP plant has 53% chance of achieving a positive NPV while the biomethane plant has a 17% chance. The probability for financial success is therefore unattractively small for biomethane plants and marginal for CHP plant.

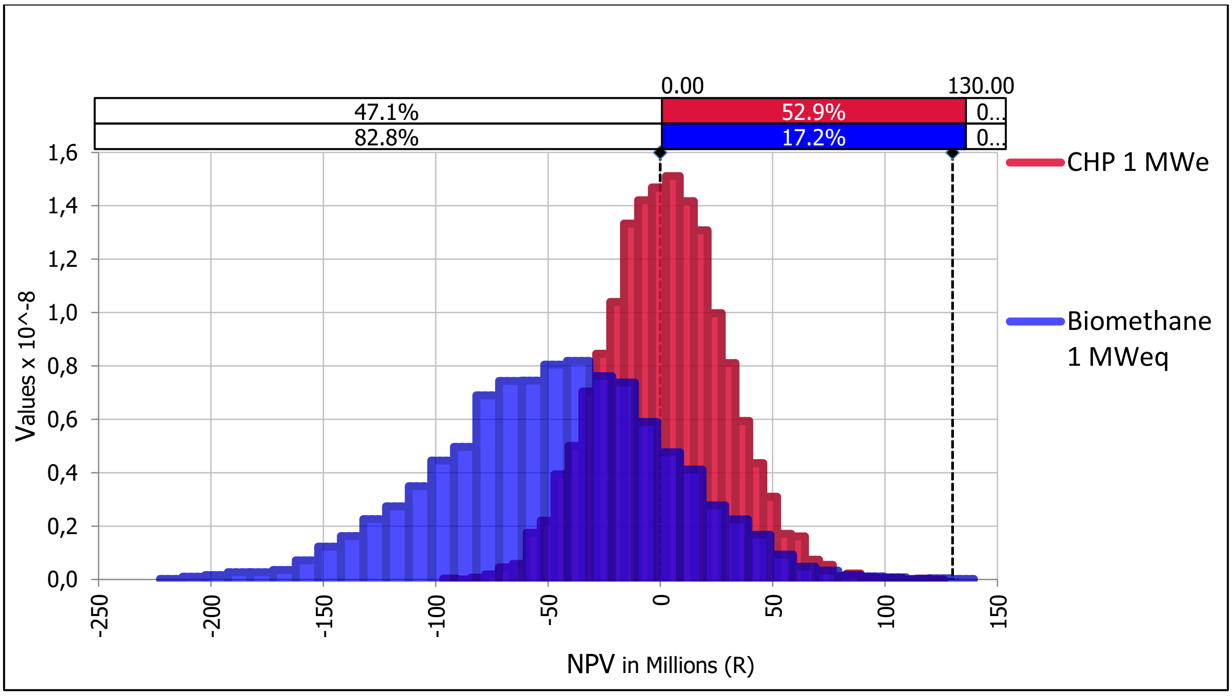


Figure 5-17: Comparison between NPV for CHP and biomethane at 1 MW_{eq}

From Figure 5-18 it can be seen that, at 3 MW_{eq}, the two scenarios look very similar with the CHP plant having 74% chance of achieving a positive NPV while the biomethane plant has a 68% chance. The probability for financial success is therefore marginal but positive for both cases.

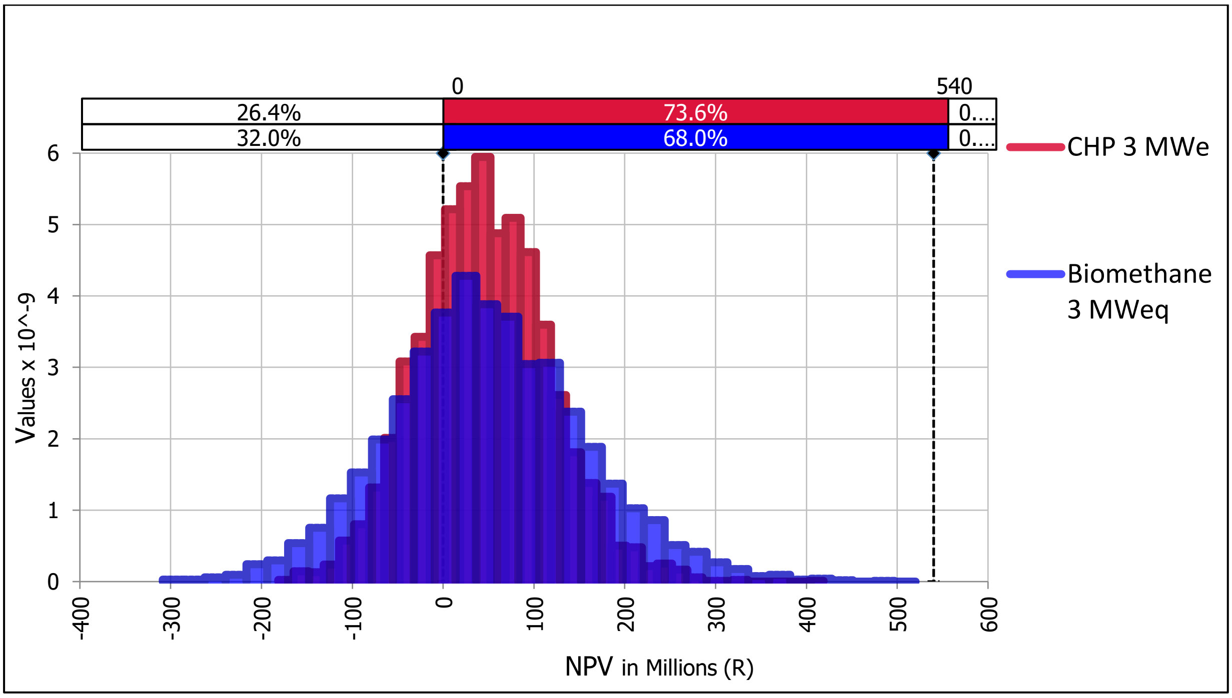


Figure 5-18: Comparison between NPV for CHP and biomethane at 3 MW_{eq}

From Figure 5-19 it can be seen that, at 6 MW_{eq}, the biomethane plant has the most attractive probability of achieving a positive NPV at 91%, while the CHP plant has an 83% chance. The probability for financial success is more attractive than other scenarios, but is still less than the specified level of 95%, as explained in section 3.6.2.

It can therefore be concluded, in line with findings by (DEA, 2016), that the business case for biomethane has greater potential for profitability than CHP if only one income stream is beneficiated. However, the variation and hence risks are also greater for the biomethane scenario.

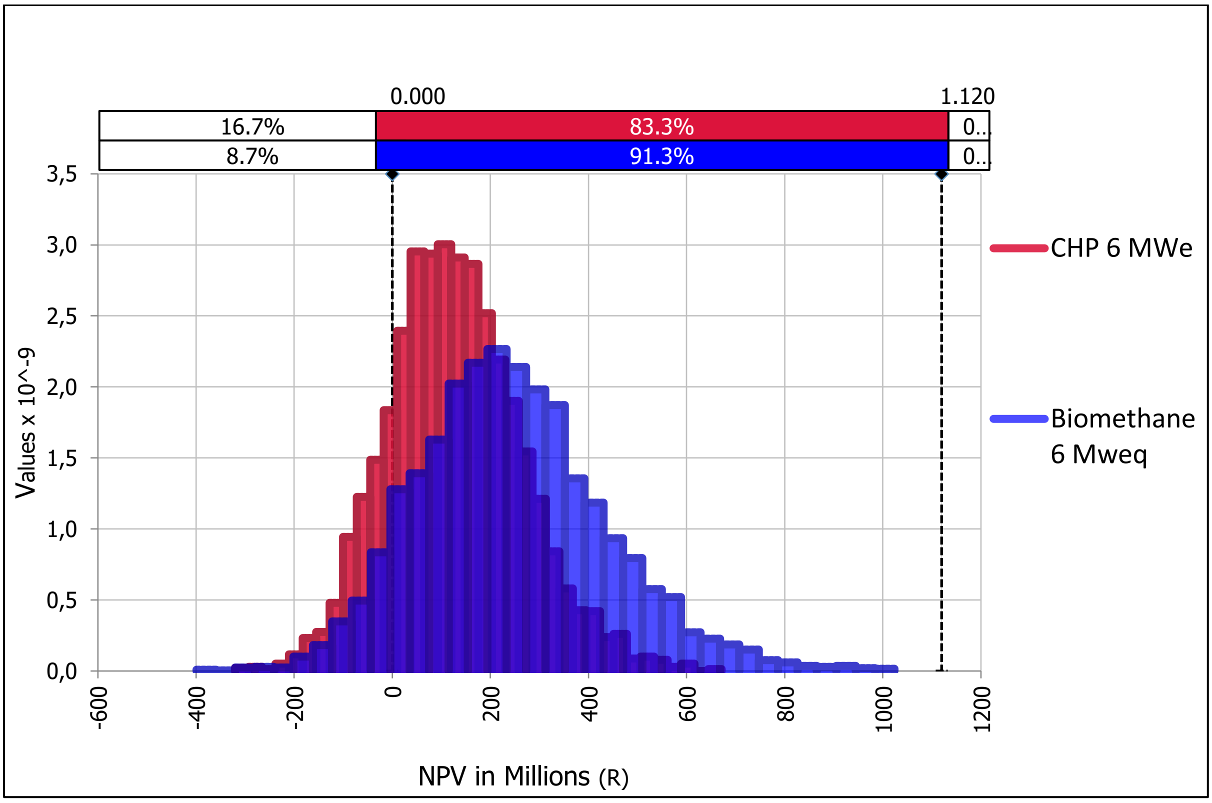


Figure 5-19: Comparison between NPV for CHP and biomethane at 6 MWeq

The probability for financial success across the range of capacities was also evaluated separately for CHP and biomethane plants, as can be seen in Figure 5-20 and Figure 5-21.

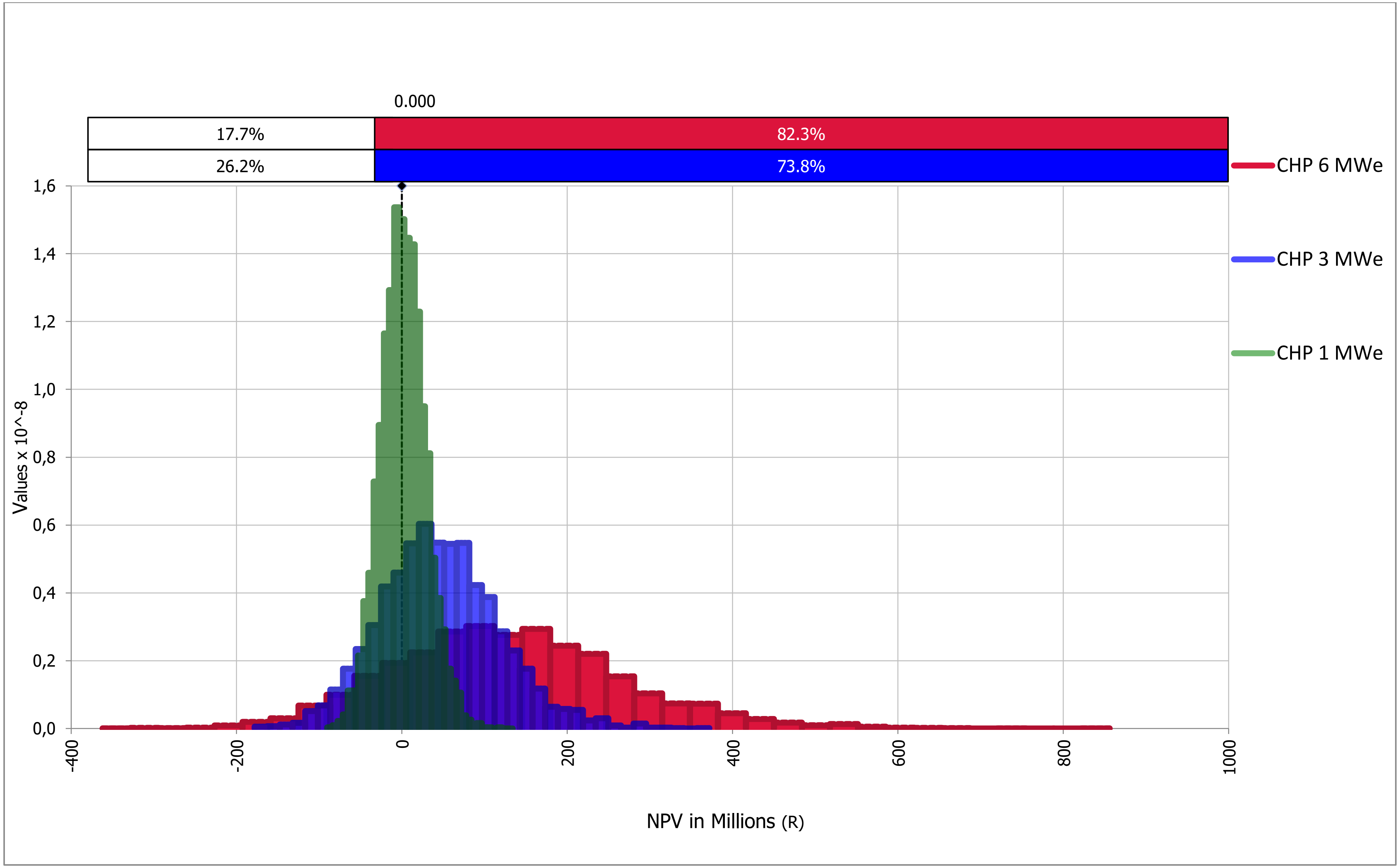


Figure 5-20: NPV variation analysis for CHP plants

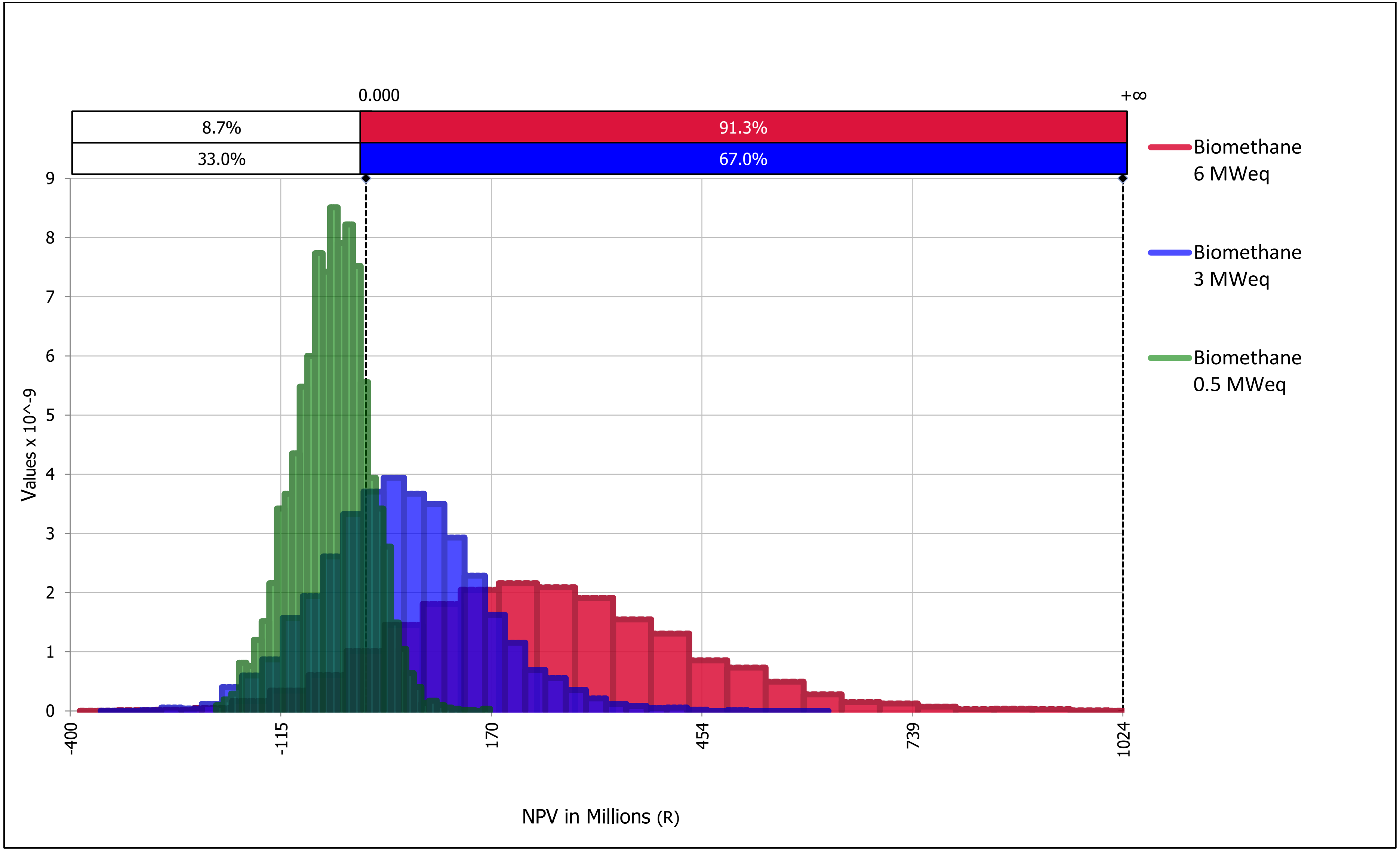


Figure 5-21: NPV variation analysis for biomethane plants

The following observations were made from the figures above:

- **<u>The normal distribution moves to the right at larger capacities:</u>** The results indicate that, for both biogas usage scenarios, as the plant capacity increases, the probability of financial success also increases, and furthermore, the value of the median NPV also increases – this is expected as larger sales volumes will result in larger revenues while unit costs decrease because of economies of scale.
- **<u>The normal distribution becomes broader at larger capacities:</u>** In order to explain this phenomenon, a look was taken at the parameter distributions with the greatest effect on the project NPV, as described below.

5.3.1 Parameters with Greatest Effect

Figure 5-22 to Figure 5-25 show the ranked effect of parameter fluctuations on the 0.5 - 6 MW_{eq} CHP plants. From these graphs it can be seen that the financial risk of larger plants (> 3MW) is dominated more by revenue while for the smaller (0.5 MW_{eq} and 1 MW_{eq}) plants it is dominated more by investment costs.

This effect is fully coherent with the observed scale factors derived in section 5.1, which confirm that the investment costs become relatively less important for larger plants.

This effect can also be seen for biomethane plants, as shown in Figure 5-26 to Figure 5-29.

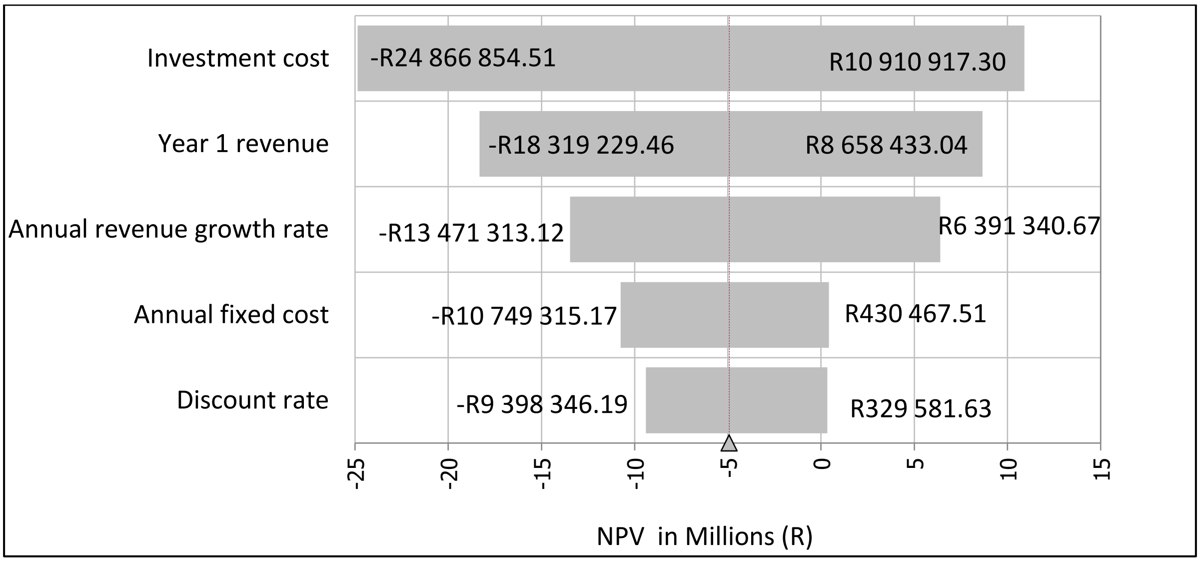


Figure 5-22: Inputs ranked by effect: CHP 0.5 MWe

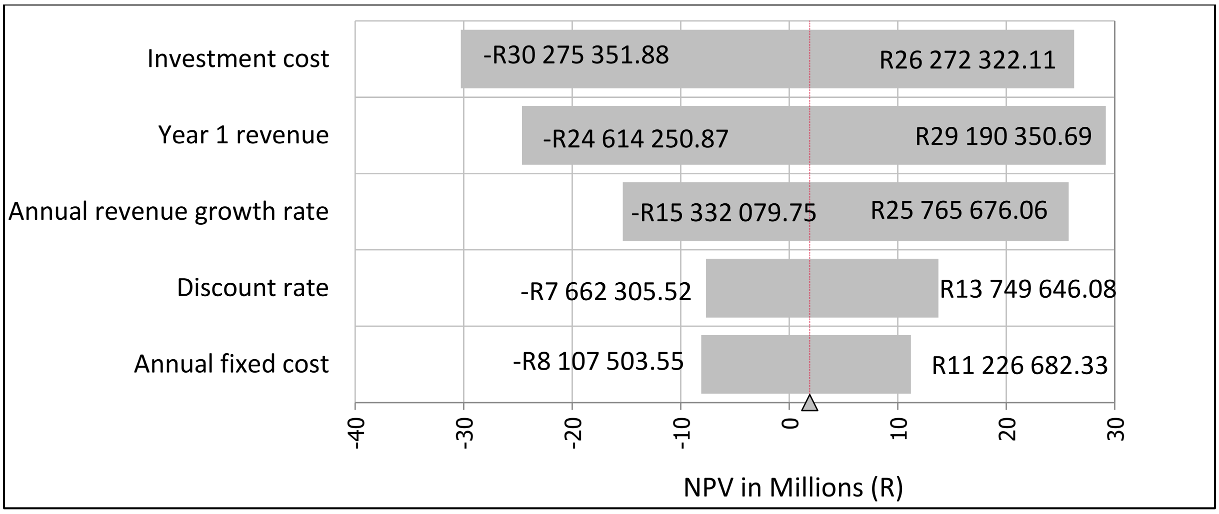


Figure 5-23: Inputs ranked by effect: CHP 1 MWe

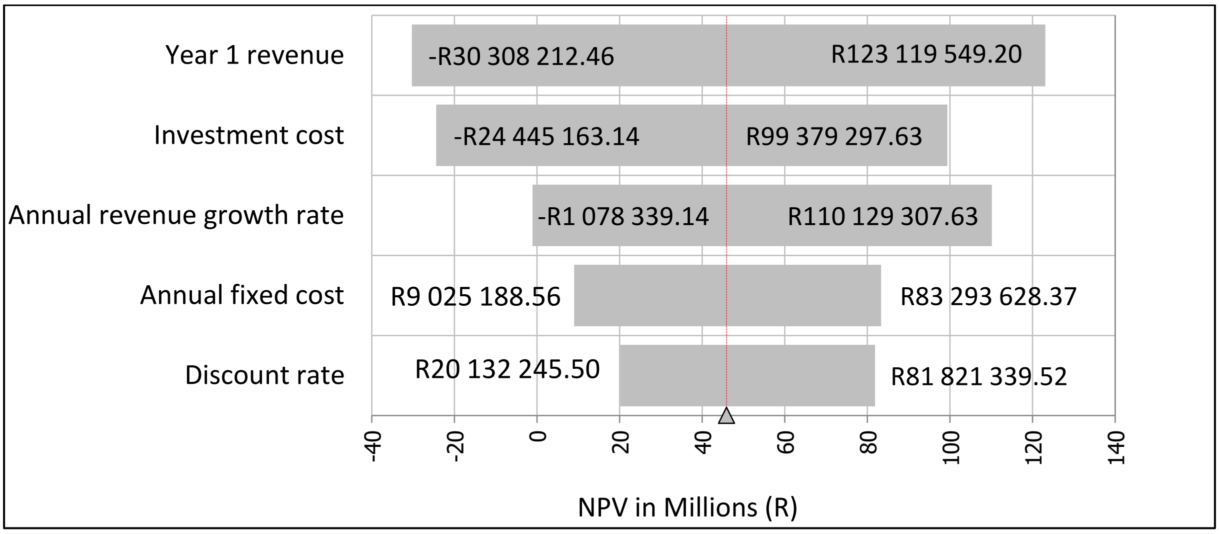


Figure 5-24: Inputs ranked by effect: CHP 3MWe

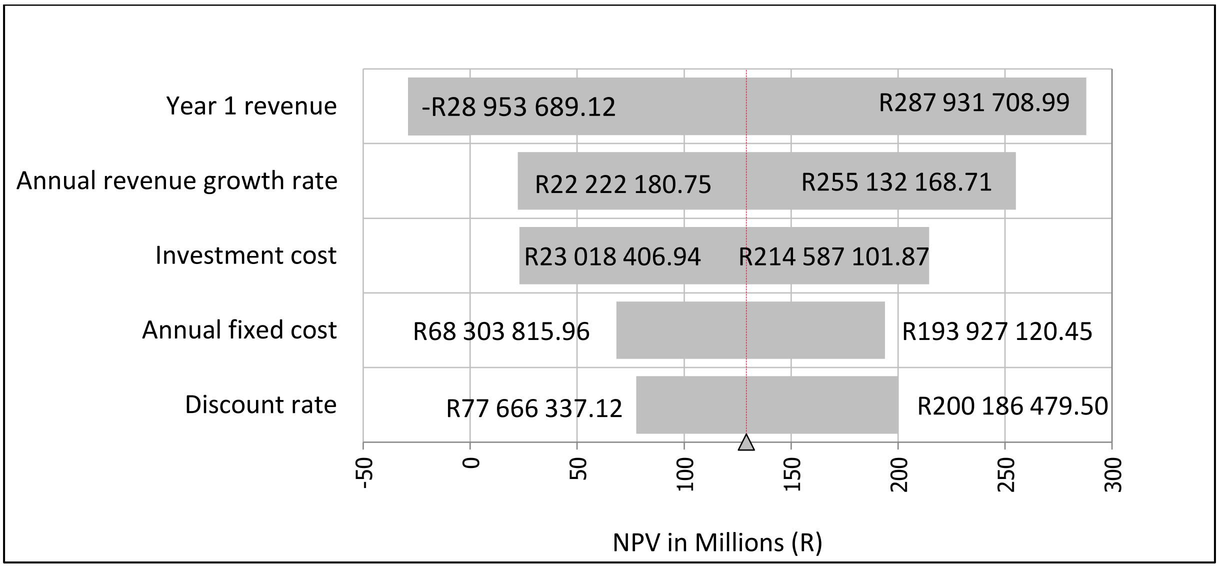


Figure 5-25: Inputs ranked by effect: CHP 6 MWe

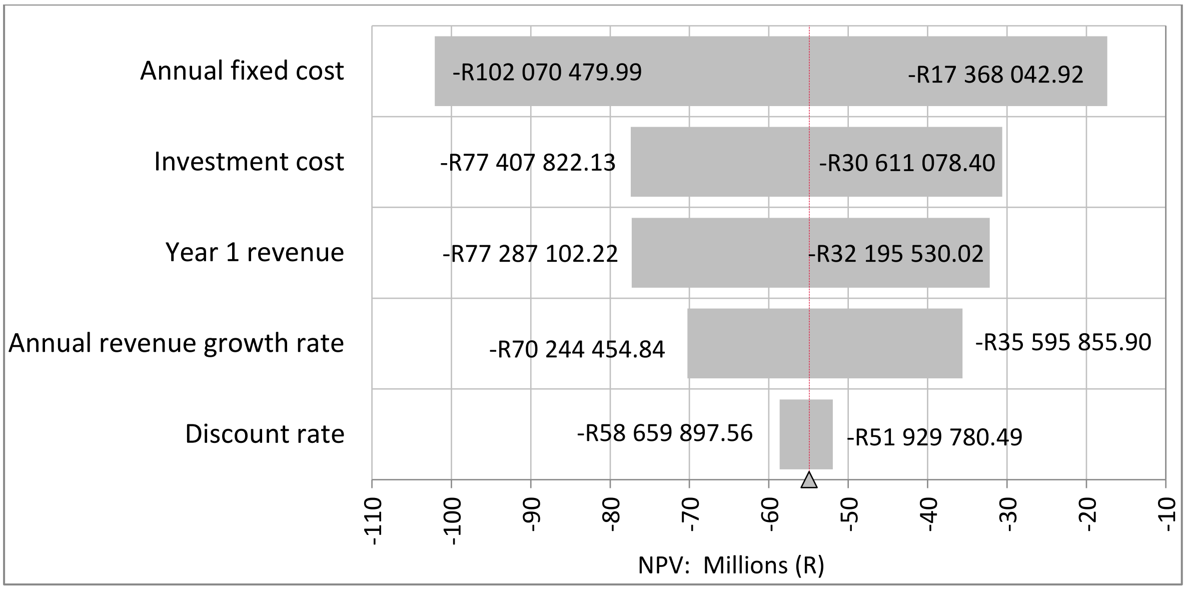


Figure 5-26: Inputs ranked by effect: biomethane 0.5 MWeq

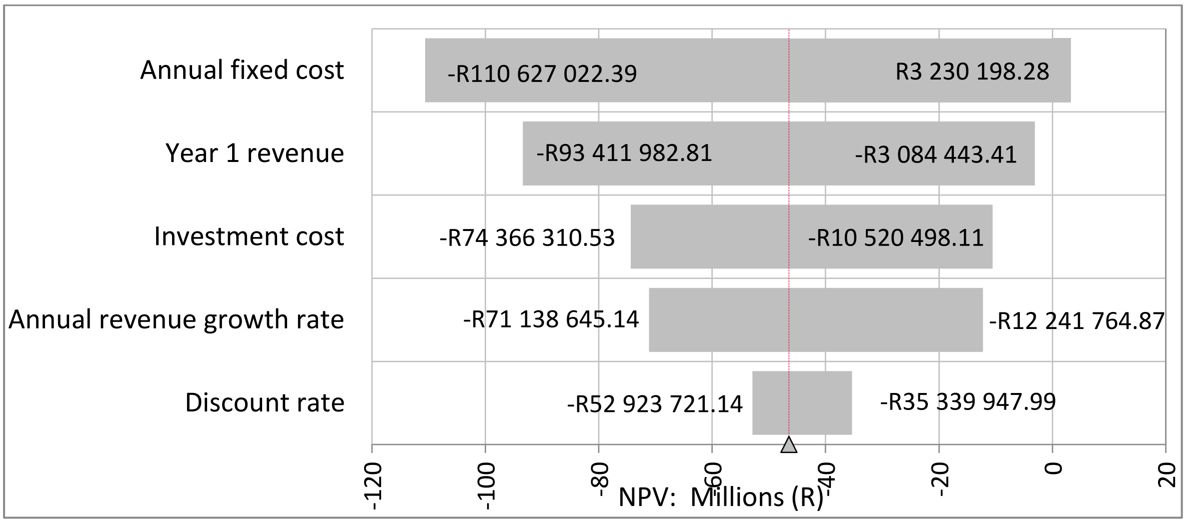


Figure 5-27: Inputs ranked by effect: biomethane 1 MWeq

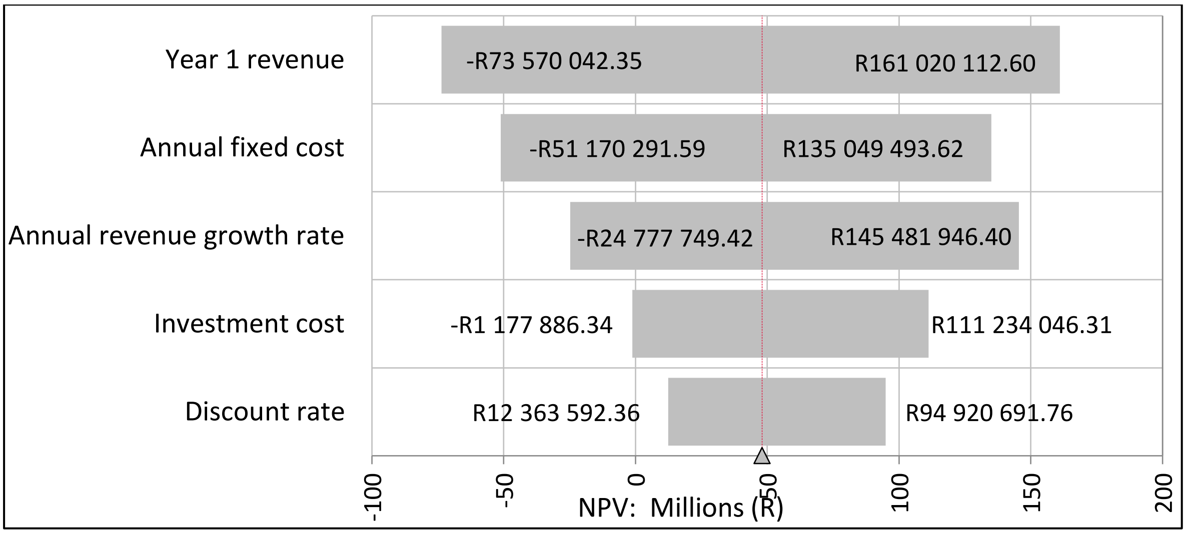


Figure 5-28: Inputs ranked by effect: biomethane 3 MWeq

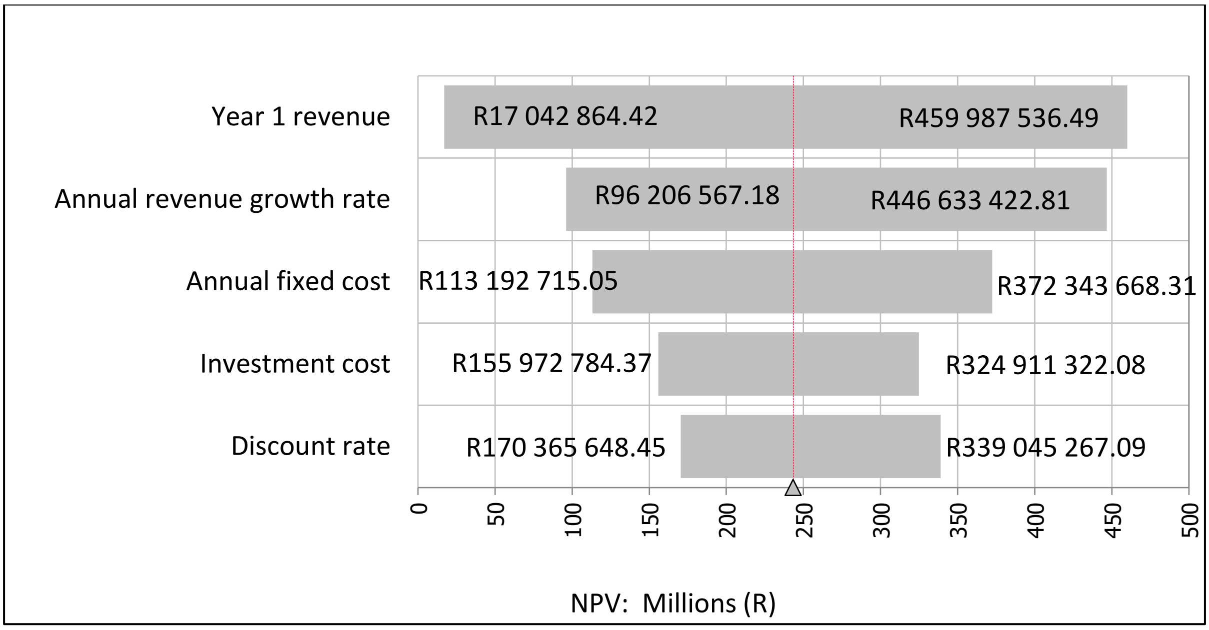


Figure 5-29: Inputs ranked by effect: biomethane 6 MWeq

In order to get a better understanding of why the NPV distribution curves become broader at larger plant capacities, the effects of the three most influential parameters were further evaluated as described below.

<u>Variations in annual revenue:</u>

This parameter was specified as a normal distribution with median at the design rate and a variance of 20% of the annual income. In order to evaluate the effect of this assumption, this value was shifted from 5%, to 20%, to 40% variance. For illustration purposes, this test was only carried out on the biomethane, 6 MW_{eq} scenario. The results are shown in Figure 5-30 below – it can be seen that, as the amount of variance in annual revenue increase, the bell curve broadens out, which means that the uncertainty in achievable NPV, as well as the probability of financial failure increases.

It can therefore be seen that additional research into the expected variations in a typical biogas project's annual revenue would be valuable.

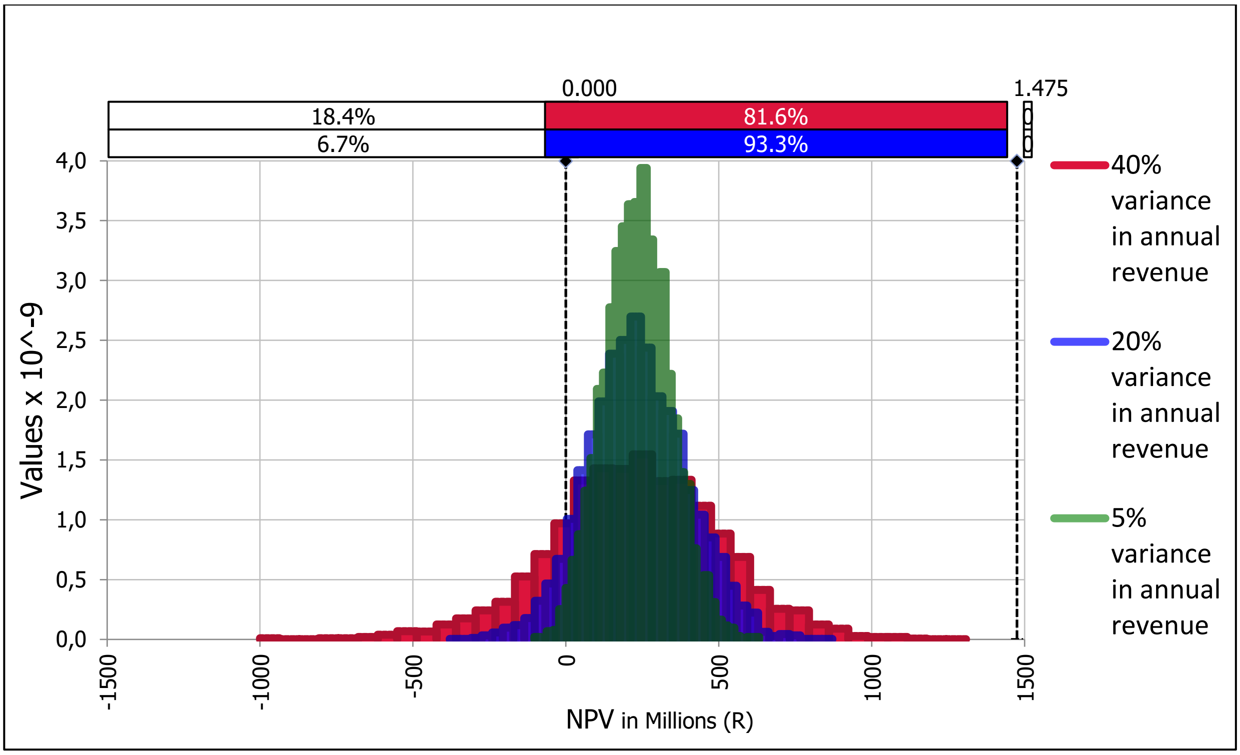


Figure 5-30: The effect of variations in annual revenue on NPV

<u>Variations in annual fixed cost and investment costs:</u>

These variations were based on observations of existing plant costs and are therefore quantitatively fixed. The variation in annual fixed plant cost with increasing plant capacity is shown in Figure 5-31 and the variation in capital expenditure with increasing plant capacity is shown in Figure 5-32 below.

It can be seen that, as the plant capacity increases, the range of possible cost values also increases – this is linked to limited data availability at larger plant scales. These two parameters therefore contribute to increased uncertainty on actual plant cost at larger plant capacities.

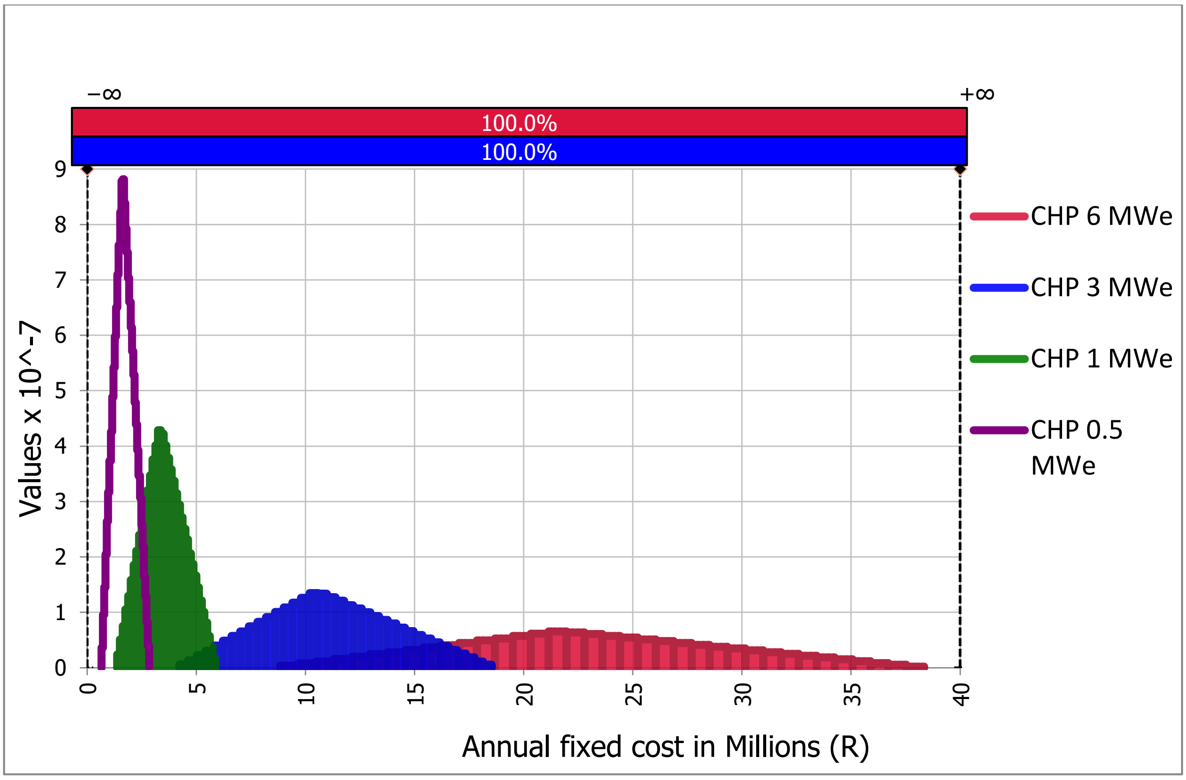


Figure 5-31: Variations in annual plant cost for CHP scenarios

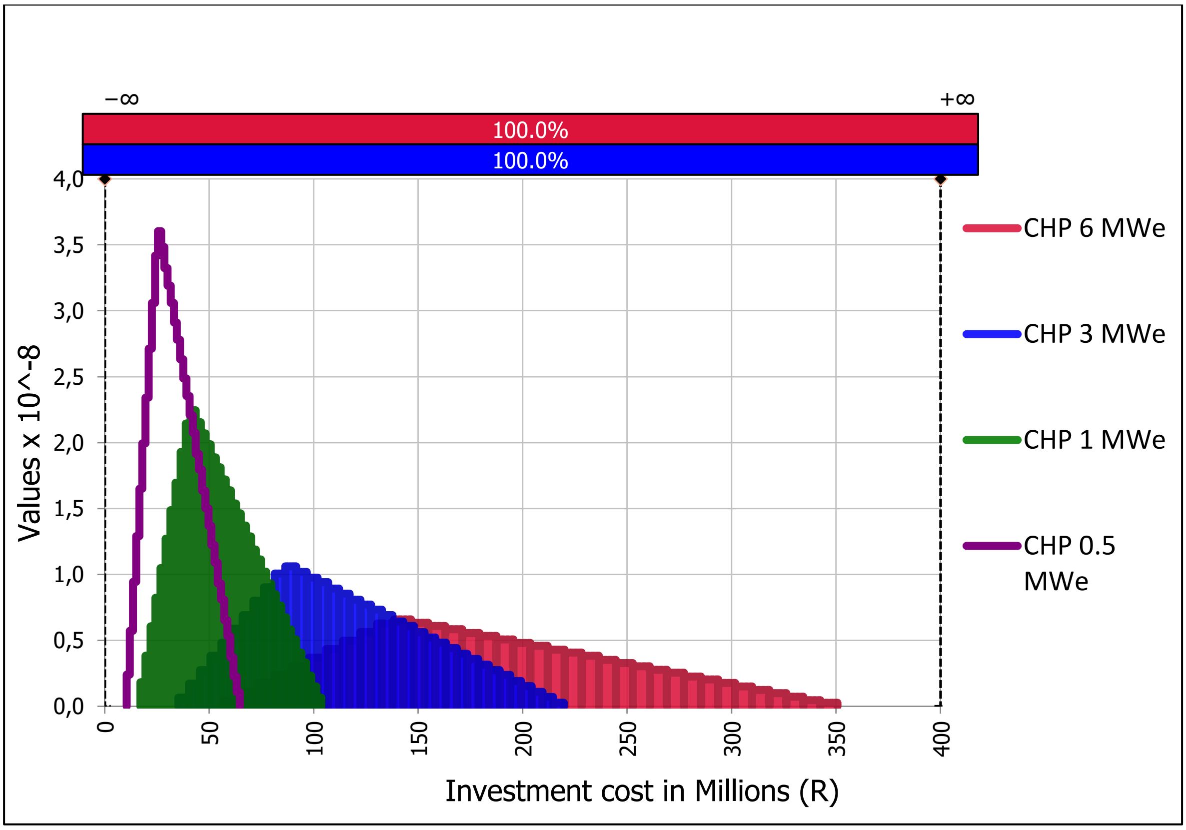


Figure 5-32: Variations in capital investment for CHP scenarios

5.3.2 Decision Support Tool

Based on the results presented in the sections above, two flow diagrams were created to serve as a first-order decision making tool in determining the potential feasibility of a biogas project. These diagrams are by no means exhaustive but can provide some guidance in differentiating between potentially feasible and non-feasible projects. The decision for a smaller scale project should be focused on establishing and running the plant at a minimal cost, as shown in Figure 5-33 and the decision for a large scale project should be focused on maximising plant revenue and minimising downtime as shown in Figure 5-34.

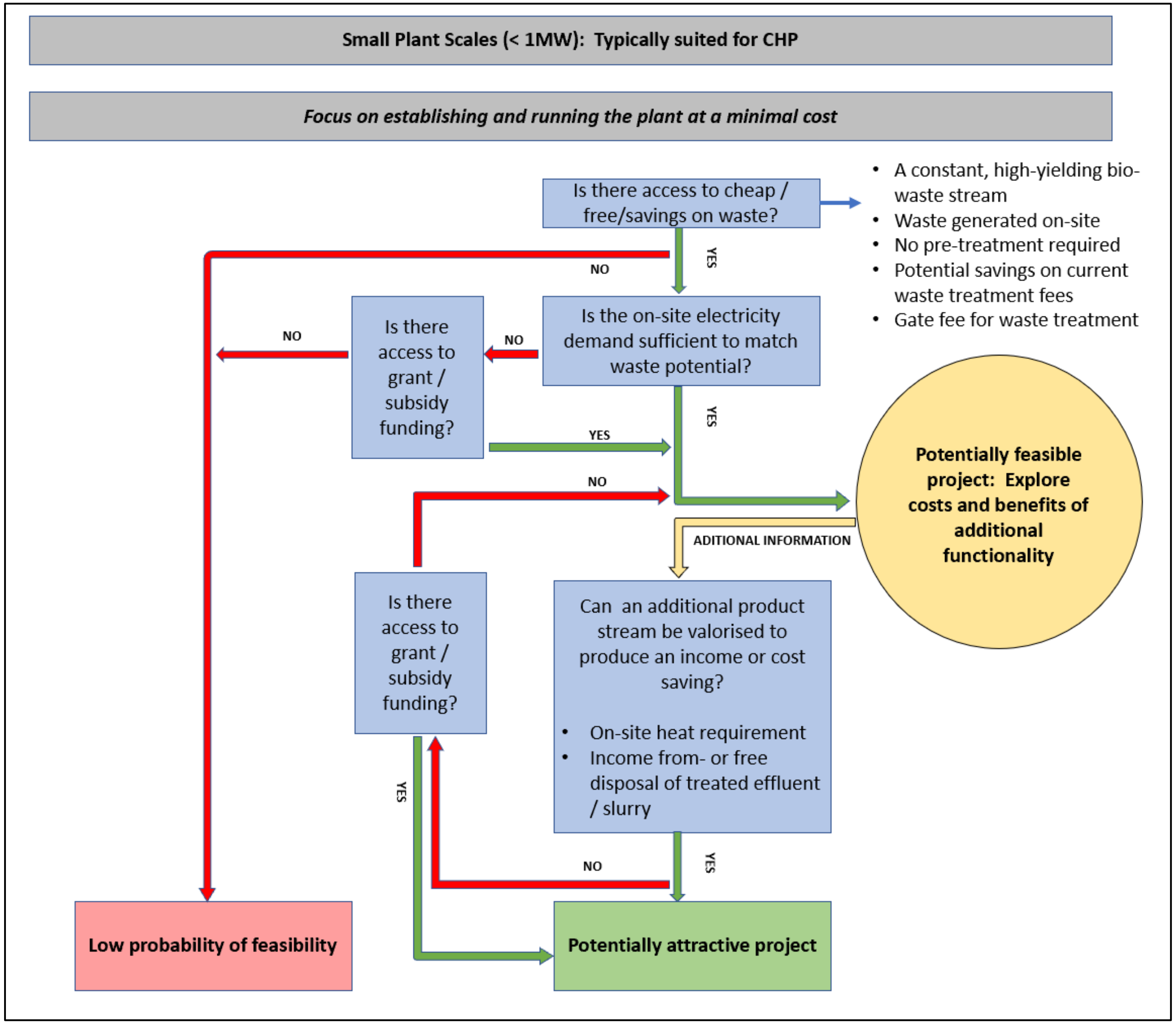


Figure 5-33: Decision support tool to evaluate feasibility of smaller scale AD projects

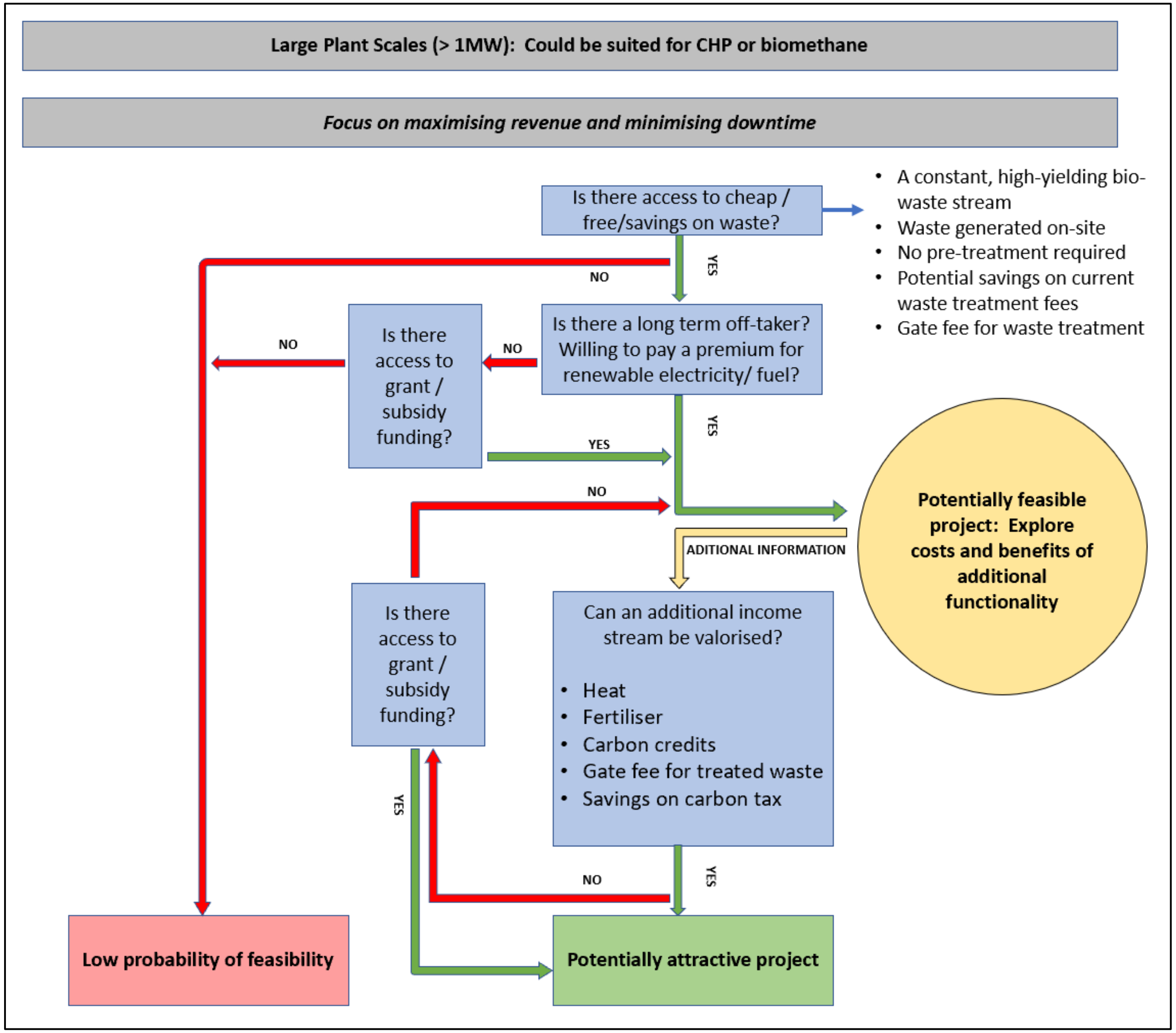
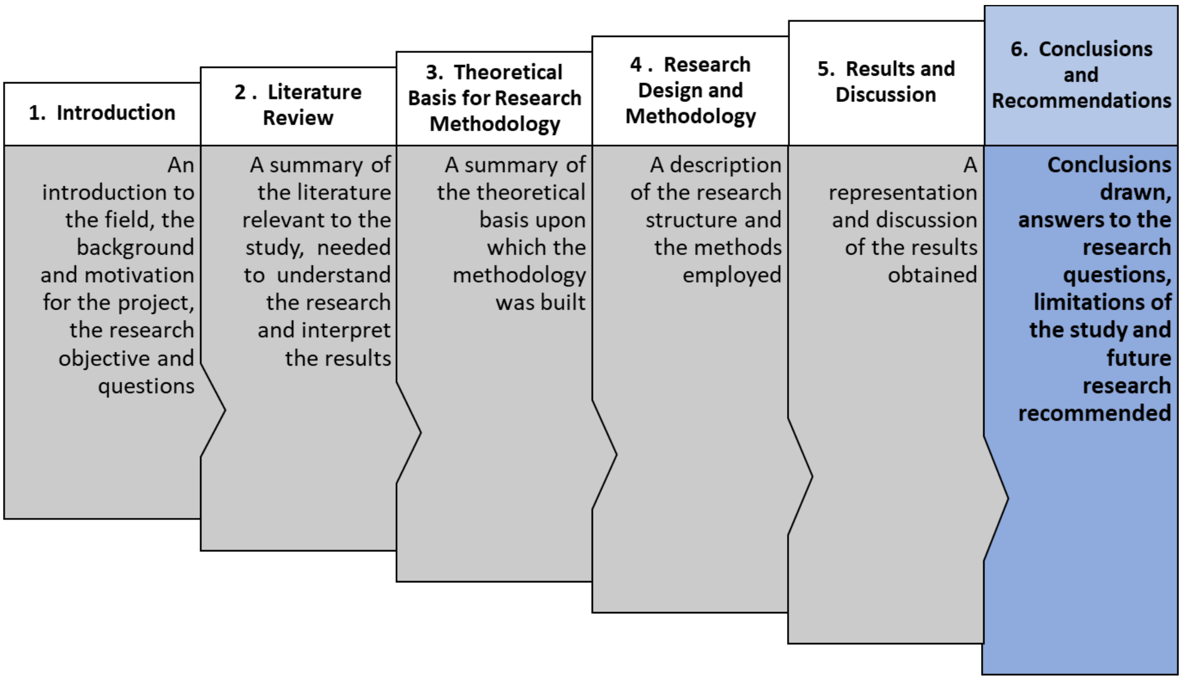


Figure 5-34 Decision support tool to evaluate feasibility of larger scale AD projects

6. Conclusions and Recommendations

In this chapter the presents the main conclusions drawn from the results, as well as recommendations for the South African biogas sector and for future research



This dissertation set out to create an improved understanding of the process economics of medium to large scale biogas plants in SA based on data from recently built, local plants, and thereby to answer the research questions stated in section 1.4 – these answers are presented in the first section of this concluding chapter. Conclusions, limitations and recommendations are presented in the sections that follow.

6.1 Answers to Research Questions

What capital and operational costs are associated with biogas plants in South Africa, and how do they compare to international values?

The first question is answered based on results from section 5.1.

For the South African and international biogas plants combined, three cost trends were observed – high-, medium-, and low-cost. This was strongly dependent on the type of feedstock, the amount of pre-treatment required, and the amount of post-treatment applied to the biogas.

Compared to international plants, the SA-based plants were mostly among the low-cost plants, with only two plants falling in the medium-cost range and no plants in the high-cost range. This is expected, as high-cost plants would typically not be viable in the absence of an incentive programme.

- **Capex for CHP plants**: The data gathered on existing plants in SA were sufficient to create a local based cost estimation model by regression analysis for prediction of high- medium- and low-cost plants, as shown in Figure 5-2. Hypothesis tests confirmed that the data followed a straight line on a log-log scale, and that economies of scale are observed. A capacity cost factor of 0.68 is observed, and a Mean Magnitude of Relative Error (MMRE) of 33% can be expected on cost estimations. It is expected that CHP plant costs would typically lie in the low-cost to medium-cost range, which is as follows:
    - 0.5 MWe plant: R 10 – R 26 million
    - 1 MWe plant: R 16 – R 41 million
    - 2 MWe plant: R 26 – R 66 million
    - 3 MWe plant: R 34 – R 87 million
    - 4 MWe plant: R 42 – R 106 million
    - 5 MWe plant: R 49 – R 123 million
    - 6 MWe plant: R 55 – R 140 million

- **Capex for biomethane plants:** With only three data points for existing, local plants, there was insufficient information to deduct a cost model for local biomethane plants. However, a regression analysis was carried out on international plant costs, including the local data – this resulted in a wider range of possible costs and hence more uncertainty than what was determined for CHP plants. A capacity cost factor of 0.57 was determined, and a MMRE of 45% can be expected on cost estimations. It is expected that biomethane plant costs would typically lie in the low-cost to medium-cost range, which is as follows:
    - 0.5 MWe plant: R 16 – R 50 million
    - 1 MWe plant: R 24 – R 75 million
    - 2 MWe plant: R 35 – R 111 million
    - 3 MWe plant: R 44 – R 140 million
    - 4 MWe plant: R 52 – R 165 million
    - 5 MWe plant: R 59 – R 188 million
    - 6 MWe plant: R 65 – R 209 million
- **Lang Factor:** A Lang factor of 1.81 was determined for SA-based biogas plants. This indicates that, on average, the total plant cost will be 1.81 multiplied by the total installed equipment cost. This value corresponds well with a previous study which reported 1.78 (Amigun & Von Blottnitz, 2009).
- **Operational and Maintenance costs:** A higher and lower cost range were observed, depending on the amount of transport and feedstock pre-treatment required. The higher cost range lies between R 2.6 and R 4.6 /Nm^3 raw biogas produced, and corresponds with what was reported internationally (IRENA, 2013). The lower cost range lies between R 0.3 and R 1.4 /Nm^3 raw biogas produced, which corresponds well with a previous estimation by (Greencape, 2017). A cost prediction model is provided in Figure 5-7. It was further observed that, for plant capacities < 1 MW_e, annual O & M costs vary between 2% - 10% of capital investment, while for capacities >1 MW_e, annual O&M costs between 10% and 20% of capital investment can be expected.
- **Levelised cost of energy for CHP plants:** The levelised cost of energy, which was taken as a combination of capex and O&M costs over the lifetime of the plant per unit energy produced, was determined to be lower in SA than internationally. A LCOE of R 0.5 – R 2 /kWh can be expected for biogas plants in SA, with higher costs expected

for plants with capacities <0.1 MW. For international biogas plants, a LCOE of R 1.8 - R 2.8 /kWh can be expected for lower cost plants, or R 3.5 – R 6.5 /kWh for higher cost plants.

- **Levelised cost of energy for biomethane plants:** Even though there are too few data points to draw a definite conclusion, a general range of costs between R 0.4 /kWh and R 3.5 /kWh, or R 111 /GJ and R 972 /GJ can be expected in SA and internationally.

  It can therefore be seen that a wider range of costs is observed for biomethane than for CHP in SA. This indicates that there is more uncertainty, as there is a lack of local experience with the implementation of the technology.

Which biogas usage pathway is more financially viable? Electricity via CHP or biomethane for fuel?

The second and third questions are answered based on results from section 5.2

It was observed that a biomethane plant will generally cost more to build and operate than an equivalent capacity CHP plant. However, the income generating ability will be greater for a biomethane plant than for a CHP plant, because it competes with fuel prices (R1.42 /kWh) instead of electricity prices (R1.01 /kWh), and because the levies and taxes payable on petroleum do not currently apply to biomethane in SA. This confirms the findings of the study commissioned by the DEA (2016).

This resulted in the biomethane scenario being more scale dependent than the CHP scenario. At smaller scales, <4 MW_{eq}, CHP plants had a higher NPV than biomethane plants. However, at larger scales, >5 MW_{eq}, biomethane plants had a higher NPV than CHP plants.

What financial indicators can be expected from a typical biogas project in SA?

Modelling indicates that biogas plants built within the low-cost range have the highest potential NPVs. However, these plants have a limited scope as implementation would only be viable if very specific project conditions are met, and usually only at small scales with energy produced for self-consumption.

At larger plant capacities, where a plant of medium-cost range is most likely to be viable, plant capacities >1 MW_e for electricity generation and >4 MW_{eq} for biomethane can be financially viable based solely on electricity or fuel sales. This excludes high-cost plants with energy crops or high-volume low-yielding slurry as feedstock.

This result runs contrary to the observation that the majority of recently built plants in SA were at scales < 1MW_e. it would thus appear that project developers and owners valued the electricity generated at a higher price and/or planned their investments to extract additional income streams.

The most attractive plant scenario for CHP as well as biomethane plants were at the highest capacity investigated, which was 6 $MW_{eq.}$ At this capacity, the following financial indicators can be achieved:

- **6 MW_e CHP plant financial indicators:**

  NPV: R110 Million

  DPBP: 8 years

  IRR: 19%

  ROI 19%

- **6 MW_{eq} biomethane plant financial indicators:**

  NPV: R160 Million

  DPBP: 8 years

  IRR: 19%

  ROI 18%

How sensitive are the findings to variations in key parameters? And which parameters matter most?

The fourth research question is answered based on results from section 5.3

Fluctuations in key parameters had a significant effect on the project outcome. If a 95% probability of achieving financial success is taken as the benchmark, none of the plants evaluated have a high enough probability of positive NPV to merit investment. The most promising plant scenarios were at 6 MW_{eq} capacity, with a 91% and 87% probability for positive NPV for biomethane and CHP plants respectively. This is in line with the earlier observation that economies of scale are present (the NPV distribution curve moves to the right with increasing plant capacity).

The parameters with the greatest effect were found to be the annual revenue for larger plants (> 3 MW_{eq}) while annual fixed cost, as well as investment costs had a greater influence on smaller scale plants (0.5 MW_{eq} and 1 MW_{eq}).

The range of possible NPVs increased as plant scale increased (the normal distribution became broader). In order to explain this, a look was taken at the three parameters with greatest effect on NPV across all scenarios:

- **Annual revenue:**

For the purpose of this dissertation, the assumption was made that this parameter will follow a normal distribution with variance of 20% the design value. This variance has a direct effect on the variance of the NPV curve, which becomes more pronounced at larger plant scales. Accurate quantification of this variance is therefore identified as a limitation of this study, and further research is advised.

- **Capital expenditure**

The capital expenditure scenarios were based on the results mentioned above. It was noted that the range of possible cost values becomes broader at higher plant capacities. This indicates that uncertainties increase with larger plant capacities and corresponds to less available cost data at these scales.

- **Annual O&M costs:**

Plant running costs were based on the results mentioned above and calculated as a percentage of capital investment – the same trend in variability was therefore observed.

6.2 Conclusions Drawn from the Research

Based on the results obtained, the following conclusions are drawn:

- Biogas plants with a single income stream can potentially be constructed and operated at a positive NPV in South Africa. As of 2013, electricity from large biogas plants (>0.5 MW_e) can potentially be generated at a cost below Eskom's retail price. As of 2018, a biogas plant of 0.3 MW_e and greater can achieve grid parity.
- In the absence of fuel levies and taxes imposed on biomethane, it can be produced from biogas at greater profit margins than electricity, which becomes apparent at large scale plants. On the other hand, biomethane plants will also cost comparatively more to build and operate, and are associated with more cost uncertainty than CHP plants.
- Even though both biogas usage pathways investigated show potential for a positive business case, the large variations observed in technology costs, as well as uncertainties around plant revenue, resulted in unacceptably large investment risks which could, in part, clarify why the biogas sector in SA is not developing at its full potential.
- The main contributing parameters relating to high levels of project risks were identified as annual revenue, capital expenditure, and plant running costs. It is therefore noted that mitigation of these risks could result in improved project viability.
- If the electricity and fuel prices paid in SA continue to rise at the rates observed over the past decade, it will lead to a higher achievable profit margin and hence smaller revenue related risks, which could result in a more attractive business case for biogas.
- For the plant scenarios evaluated, profitability increased with increasing plant capacity as economies of scale are observed. However, so did uncertainties in key parameters and therefore in achievable NPV.
- The most attractive plant scenario evaluated was a biomethane plant at 6 $MW_{eq.}$ However, a 95% probability of positive NPV could not be demonstrated. This study therefore agrees with the conclusion drawn by (Börjesson, 2012), and (DEA, 2016), that

although the business case for biomethane from biogas holds great potential, the barriers-to-entry may be too great to overcome under current conditions in South Africa.

6.3 Limitations of This Study

The following limitations were identified and encountered during this study:

- Additional income streams that could be generated by biogas plants were excluded from this analysis. For example, a gate fee chargeable for waste treatment or avoided waste disposal costs, recovery and sale of heat, fertilizer sales, subsidies, grants etcetera. The reason for the exclusion was that frequently, the required infrastructure or a suitable off-taker are not present and hence these incomes cannot be guaranteed. The results demonstrate, however, that under current local conditions, biogas plants have a very small chance of being viable in the absence of such additional income streams.
- The costs of biomethane plants in the South African context could not be predicted with the desired accuracy due to the limited implementation of the technology. The predictions were therefore based on plants across different countries and this resulted in a wide range of possible plant costs.
- The scope for this dissertation was up to the point of final product production. Distribution costs were excluded from the analysis due to limited available data. Such costs could typically include an electricity wheeling agreement for a CHP system, or a fuel distribution network for a biomethane system.
- The scope of the investigation was to determine costs suitable for a class 5 estimation according to the American Association of Cost Engineers (AACE). This means that the estimations are expected to be accurate within -50% to +100%. It is advisable that a financial evaluation be carried out at a higher level of detail before deciding whether a project is feasible or not.
- This dissertation only considered biogas projects from an economic point of view. It is, however, known that micro-technical elements will also play an important part in project selection, but this was outside the scope of this study. Future research that incorporates technology related aspects into the financial evaluations is recommended.
- The effects of variations in key parameters were mostly based on verifiable sources, except for fluctuations in income generated. This is identified as a limitation of this study and further investigation is recommended on typical expected variations.

6.4 Recommendations for Future Research

The following recommendations are proposed for future research:

- Although the financial indicators could potentially be attractive, the risks associated with investing in large scale biogas projects in SA are currently at a level that would not be acceptable to most investors. It is therefore recommended that actual income streams of plants already built, as well as additional incomes such as fertiliser sales, selling of heat or cooling be investigated. Furthermore, alternative incomes like grants or subsidies based on the non-monetary benefits which the technology brings to society (like reductions in GHG emissions and improved waste management) should be investigated.
- If the commercial electricity and fuel prices in SA continue to increase at historical trends, it is advised that the findings from this study be revised.
- There is a range of innovative technologies emerging that could decrease losses and thereby increase profitability. Investigation of these technologies was outside the scope of this dissertation, but research on their suitability to the SA biogas sector is recommended. This includes, for example:
    - Electricity generation through fuel cells or other mechanisms,
    - Biogas upgrading with power-to-gas, where the CO_2 in the biogas is also converted to Methane,
    - Cryogenic and other biogas upgrading methods that could results reduced losses and improved product purity.
- A study on the effect of the distance which feedstock and substrate need to be transported on project costs was outside the scope of this dissertation. This can, however, play an important role in the economics of a biogas plant and is recommended for future research.

6.5 Recommendations for Advancement of SA's Biogas Industry

This study concludes that one of the significant barriers against the large-scale development of the South African biogas sector is financial risk based on parametric uncertainty and marginal profitability of the technology. Nonetheless, the sector has great potential that could be unlocked by a combination of stakeholders. The following recommendations are made to biogas project developers:

- Because the parameters with the greatest effect on financial risk are the annual revenue for larger plants (> 3 MW_{eq}) while annual fixed cost, as well as investment costs have a greater influence on smaller scale plants (0.5 MW_{eq} and 1 MW_{eq}). It is recommended that, for a small-scale plant, the greatest focus should be on minimising risks associated with investment cost and operational costs – this can be done by:

  - Identifying a project site with a waste stream that matches energy requirements available on-site at no or minimal costs.

  - Identifying simple and low-cost technology options, and building a plant that requires minimal process control and staff.

  On the other hand, for large scale plants, the greatest focus should be on minimising the risk of lost revenue, for example by identifying a long-term off-taker that would pay a premium for carbon-neutral energy, identifying a waste stream that is fairly constant in supply rate and composition, taking measures to minimise plant down-time.

- It is recommended that increased knowledge sharing around existing operational and non-operational biogas plants be implemented, as access to more information on the costs, operating conditions, revenue streams, and pitfalls encountered could aid in the advancement of the sector.

The following recommendations are made to government and other regulating bodies:

- Building regulations, standards and guidelines that apply specifically to biogas plants should be implemented. This will result in improved predictability of plant performance and plant costs.

- The implementation of stricter regulations regarding the disposal of organic wastes to landfill and/or GHG emissions are recommended, as this will make AD more attractive compared to other alternatives.

- It was noted in section 2.3 that the municipal solid waste sector has the greatest biogas potential in SA, however, sorting of municipal waste increase plant costs which could render it financially non-viable. It is therefore recommended that pre-sorting of waste be imposed on the public in order to unlock the potential of this waste source.

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Annexure A: Ethical Clearance

APPLICATION FORM

Please Note:
Any person planning to undertake research in the Faculty of Engineering and the Built Environment (EBE) at the University of Cape Town is required to complete this form **before** collecting or analysing data. The objective of submitting this application *prior* to embarking on research is to ensure that the highest ethical standards in research, conducted under the auspices of the EBE Faculty, are met. Please ensure that you have read, and understood the **EBE Ethics in Research Handbook** (available from the UCT EBE, Research Ethics website) prior to completing this application form: http://www.ebe.uct.ac.za/ebe/research/ethics1

APPLICANT'S DETAILS		
Name of principal researcher, student or external applicant		Mrs Brigette Nagel
Department		Chemical engineering
Preferred email address of applicant:		Brigette.db@gmail.com
If Student	Your Degree: e.g., MSc, PhD, etc.	MSc.
	Credit Value of Research: e.g., 60/120/180/360 etc.	180
	Name of Supervisor (if supervised):	Prof. Harro Von Blottnitz
If this is a researchcontract, indicate the source of funding/sponsorship		NRF
Project Title		Evaluating the Potential of Biogas from South African Waste Water Treatment Works as Transport Fuel

I hereby undertake to carry out my research in such a way that:

- there is no apparent legal objection to the nature or the method of research; and
- the research will not compromise staff or students or the other responsibilities of the University;
- the stated objective will be achieved, and the findings will have a high degree of validity;
- limitations and alternative interpretations will be considered;
- the findings could be subject to peer review and publicly available; and
- I will comply with the conventions of copyright and avoid any practice that would constitute plagiarism.

SIGNED BY	Full name	Signature	Date
Principal Researcher/ Student/External applicant	Brigette Mariana Nagel		**29 Sep 2017**

APPLICATION APPROVED BY	Full name	Signature	Date
Supervisor (where applicable)	Harro von Blottnitz		
HOD (or delegated nominee) Final authority for all· applicants who have answered NO to all questions in Section1; and for all Undergraduate research (Including Honours).	Click here to enter t:Jxt		Click h1-)e to enter c1date.
Chair : Faculty EIR Committee For applicants other than undergraduate students who have answered YES to any of the above questions.			i8

Annexure B: Questionnaires to South African biogas plant developers

BIOGAS PROJECT RESEARCH INTERVIEW QUESTIONS

Person interviewed:

Represented Company:

Project name:

Interview location and Date:

PROJECT OVERVIEW

1. Please provide a general overview of the project by filling in the table below:

In which year was the project commissioned?	
What type of Feedstock is used?	
What is the feed rate of the feedstock (kg/day)?	
What form of digester is used? (i.e. cigar, CSTR, etc.)	
What is the volumetric capacity of the digester? (M^3 tank volume)	
What was the total capital cost of the project?	
What are the approximate O & M costs / year? (please specify as either an amount or as % of capital cost)	
What biogas yield is obtained? (m^3/hr)	
What is the biogas used for?	
Approximate methane content of raw biogas? (%)	
What technology is used to upgrade and compress biogas to CBG?	
What is the purity level of the CBG?	
What is the volumetric yield of the CBG produced? (m^3/ hr @ what pressure)	

2. Capital Cost Break Down: Please supply approximate values for the following capital cost components:

Percentage of capital cost toward:

- Waste preparation and sorting: ___________
- Biogas production: ___________________
- Biogas upgrading and compression: _______________

Total capital cost breakdown:

- Total purchased Equipment:
- Mechanical:
- Electrical:
- Engineering and Supervision:
- Piping Instrumentation and control:
- Civil and earth work:
- Environmental authorisations:
- Preliminary and General costs:
- Other:

3. Running Cost Break Down: Please supply (if possible) an estimate of the Operational and Maintenance Costs

Fixed O&M costs:

Land lease, Insurance, Salaries, Depreciation etc.

Variable O&M costs:

Feedstock, Maintenance, Energy consumption etc.

4. What are the main challenges you experienced with this project?

5. Was the capital cost of your project within budget? If not, how far did it over shoot?

6. **Please identify the project revenue streams?**

7. **Is the project currently running?**

8. **Was the equipment manufactured locally or internationally? If internationally, what percentage was imported? From where?**

9. **What was the duration from inception to implementation?**

Annexure C: Sources of international biogas plant cost data

International Research papers used to establish biogas plant costs.

Table A-1: International publications on the economics of biogas plants

Topic investigated	Reference
A techno-economic evaluation of electricity and heat generation, based on a case study of an existing farm scale biogas plant in Turkey.	(Akbulut, 2012)
An integration of energetic, GHG emission reduction and economic analysis to develop a model for optimised biogas production from the co-digestion of pig slurry and sugar beet pulp. The costing was based on existing biogas plants in Denmark.	(Boldrin, 2016)
A case study based on existing biomethane facilities in Europe, to assess the economics of producing biomethane from various bio-resources for use as transport fuel in Ireland. The relationship between increased penetration of biomethane in the transport sector and production costs was assessed.	(Browne, 2011)
An economic analysis was carried out, comparing biomethane and bio-electricity generation from biogas in Poland, the plants' economic performance were evaluated using different government support schemes and plant configurations.	(Budzianowski, 2015)
This study evaluated the economic performance of biomethane AD plants in Italy. A mathematical model was developed to predict the financial feasibility as a function of plant size and feedstock used. The study is based on 356 case studies of existing biogas plants.	(Cucchiella, 2016)
An analysis was carried out to evaluate the financial performance for a given biogas plant in the Netherlands. The basis of linear programming was used to optimize electricity production and determine the optimal application of digestate.	(Gebrezgabher, 2010)
The energy that can be generated from human and animal waste in Spain was estimated. AD was compared to other energy generation methods based on energy generation potential and cost.	(Gomez, 2010)
An integrated analysis compared AD to other waste treatment options on the basis of energy savings, technology cost, and logistic consequences. An optimisation tool was developed to identify an optimal waste treatment system. A case study was carried out based on Dutch biomass and waste treatment systems.	(Dornburg, 2006)
A study to determine the optimum use of biogas for small to medium scale applications in Ireland, and to evaluate the impact that the technology can have on Ireland's energy directives.	(Goulding, 2012)
An economic and carbon analysis of biomethane production through anaerobic digestion of food waste was carried out for application as transport fuel in Mexico.	(Gutierrez, 2018)
An economic evaluation of AD to treat agricultural waste and generate electricity was carried out. The process was simulated based on biogas plant costs in Malaysia.	(Mel, 2015)
A feasibility study was carried out for biogas integration into waste treatment plants in Ghana.	(M. Mohammed, 2017)
A technical and economic analysis was carried out on biogas production from three different energy crop rotations. The aim of the study was to determine the optimal crop rotation for biomethane production through AD in Ireland.	(Murphy J. M., 2004)
This study set out to determine the effect of plant location, waste source and incentives on the financial viability of biogas plants in Ireland. Cost data was sourced from the UK biomethane plant database and results were based on mathematical modelling.	(O'Shea, 2016)

Topic investigated	Reference
A spatially explicit simulation framework was used to identify optimal locations and biogas utilization pathways for agricultural biogas plants in Northern Italy.	(Patrizio, 2015)
This study investigated the required policy support to overcome techno-economic barriers for the utilization of biogas in the transport and district heating sectors in Sweden. A quantitative energy model was used to evaluated what portion of biogas potential can be utilised in the absence of formal subsidies.	(Börjesson, 2012)
An evaluation of biogas plant costs based on variations in feedstock type, plant installation and transport requirements. The analysis was based on giant reed as feedstock in Italy.	(Sgroi, 2015)
A systematic review of different biogas upgrading technologies based on obtainable product purity, methane recovery, upgrading efficiency and system costs, based on costs observed in Sweden.	(Sun, 2015)
An investigation of the costs of electricity production from biogas with maize silage as feedstock. The optimum plant size for Austria was determined.	(Walla, 2008)

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Sgroi, F. F. (2015). Economic evaluation of biogas plant size utilizing giant reed. *Renewable and Sustainable Energy Reviews*, 403-409.

Sun, Q. L. (2015). Selection of appropriate biogas upgrading technology - a review of biogas cleaning, upgrading and utilisation. *Renewable and sustainable energy reviews*, 521-532.

Walla, C. S. (2008). The optimal size for biogas plants. *Biomass and Bioenergy*, 551-557.

Annexure D: Biogas plant process economics calculations

SA biogas plant database

Ref. No	Project Name	Project Owner	Project Developer	Year Commissioned	Location	Energy Capacity (Combined) MW	Energy Capacity (Electrical) MW	Energy Capacity (Thermal) MW	Volumetric Capacity (Cumulative digester volume m3)	Capital Cost (R Million)	O& M Cost (R / Year)	Notes	Feedstock Description	Feedstock Flowrate (kg/day)	Biogas Yield (m3/day)	Biogas Energy Potential (Gjoule/hr)	Usage	Reference
1	SAB Miller : Rosslyn	SAB Miller	SAB Miller	2006	Rosslyn, Pretoria	2.28	2.28			18		CDM Registered project	Brewery organic waste					
2	PetroSA	MetchCap	Biotherm	2007	Mosselbay	4.2						Waste: Refinery waste water. (1.4 kW e x3)	Refinery Waste water		45 600		CHP	www.biothermenergy.com
3	SAB Newlands	SAB Miller	SAB Miller	2007	Newlands	1.42		1.42	4500	14		CH4 content = 70%	Brewery organic waste	6 000	2000	5.3	Electricity and heat	R35. Energy From Waste Water , Interview with Sean Power
4	SAB Miller: Alrode	SAB Miller	SAB Miller	2009	South of Johannesburg	2.63						The gas is used in a boiler that produces 3 tons of steam/hr	Brewery organic waste	25 000	9000			www.digivu.co.za
5	iBert Jan Kempdorp	M2M Abattoir	Jan Kempdorp	2012	Jan Kempdorp, Northern Cape Province	0.28	0.12	0.16	600	6.4	360 000		Slaughter Waste	22 000	1276		CHP	Interview with Horst Unterlecher
6	Manjoh Ranch	Farmsecure Carbon and Manjoh Ranch	Joint between FSC and Manjoh Ranch	2012						23	1 396 352	Potato, grain and cattle farm						CDM Application - PDD available on www.energy.gov.za
7	Joburg Northern works refurbished facility	Johannesburg Water	WEC Projects	2013	Johannesburg	0.855	0.437	0.418	1000	20	1 305 724	Budget was R20 Million	Sewage Sludge	9 600	3 911		CHP	Biogas tool obtained from Jason Gifford
8	Cape Flats WWTW	Cape tTown Flats WWTW City of Cape Town	City of Cape Town	2014	Cape Town	2.8		2.8	18000	83	10 440 000	AD has been used since the commissioning of the plant, but the methane gas has not been utilized. 20 Year lifetime assumed	Sewage Sludge	77 000	34 000		The biogas produced is used as fuel for drying the sludge	R43. CDM Application
9	Uilenkraal Dairy Farm	Uilenkraal Dairy Farm	CAE	2014	Darling		0.5		7000	13			Waste: Bovine manure – lined lagoon digester	260000	4200		chp	www.engineeringnews.co.za, www.farmersweekly.co.za, R13. Green Cape Business Case www.constructionreviewonline.com
10	Morgan Abattoir Digester	Morgan Abattoir	Biogas SA / WEC Projects	2015	Springs, Gauteng	0.4	0.4			22	605 000	Eskom SOP rebate provided approximately 30% of the capex of the project	Abattoir Waste				CHP	R06. Goemans Thesis, Interview with Mark Tiepelt R90
11	Bio2Watt Bronkhorstspruit	Bio2Watt	Bosch Projects	2015	Bronkhorstspruit	7.6	4.6	3	26000	150	22 500 000	Energy off taker is BMW Rosslyn, Major Challenge was the tedious environmental approval process. 35 days retention time. Heat energy not used although it is available	Cattle manure, chicken, abattoir, waste,, vegetable, and fruit market waste, paper sludge and dairy waste +-375	500 000.00	18 500	16.60	BMW Wheeling agreement electricity (+- 60km away)	R02. Job Potential, mail & guardian africa Questionnaire by Sean thomas
12	Elgin fruit juices	Elgin Fruit Juice	GCX	2015	Grabouw	1.077	0.527	0.55	2700	20		Plant is managed by GCX	fruit waste	57000			chp	R13. Business case, GCX Website
13	iBert - Peninsula	Peninsula Piggery	iBert	2015	Queenstown	0.37	0.17	0.2	600	6.7	168000		Pig manure	30 000	1680		CHP	www.biogascentral.net, iBert interview
14	Bayside Mall	Bayside Mall	JG Africa - WEC Projects	2015	Table view, Cape Town	0.031	0.013	0.018		2.5			Organic Waste from Retailers	570	83.56		CHP	R13 -Greencape business Case
15	RCL Foods		Trigen	2015	Worcester													
16	Greenway Farms Biogas	Greenway Farms - Rugani food processing facility	Botala Energy	2015	Krugersdorp	3.5		3.5	4000	15	377100	85% of equipment was imported from china	Vegetable residue from food processing and grass silage		7680		Steam boiler	Peet Steyn interview and www.botala.co.za
17	iBert: Riversdale	Hessequa Abattoir	iBert	2015	Riversdale	0.093	0.05	0.072	400	5.3	168 000		Abattoir Waste	9500	500		CHP	iBert interview
18	Distell Biobulk	Veolia, Distell	Distell	2016	Stellenbosch, Western Cape							8.6 tons COD/day	Distillery waste water	1000			www.veoliatechnologies.co.za	
19	iBert: Zandam	Zandam +Ibert	Ibert	2016	Durbanville Cape Town	0.167	0.075	0.092	500	9.5	189 000		Pig manure	45 000.00	1196		CHP	Greencape Business Case R13, R37 Zandam case study

Ref. No	Project Name	Project Owner	Project Developer	Year Commissioned	Location	Energy Capacity (Combined) MW	Energy Capacity (Electrical) MW	Energy Capacity (Thermal) MW	Volumetric Capacity (Cumulative digester volume m3)	Capital Cost (R Million)	O& M Cost (R / Year)	Notes	Feedstock Description	Feedstock Flowrate (kg/day)	Biogas Yield (m3/day)	Biogas Energy Potential (Gjoule/hr)	Usage	Reference
20	Tshwane Food and Energy Centre	Tshwane Food and Energy Centre	Botala Energy	2016	Close to Bronkhorstspruit	0.08			500	2.8	71 437	The facility is off-grid. Everything was made locally excedpt for the generator, which was imported from China at about 20% of the Project cost	Sweet Sorghum grass silage, Discarded Vegetables & other farm residue		720		Electricity	Peet Steyn interview and www.botala.co.za
21	New Horizons Athlone	Clean Energy Africa and Waste Mart	Athlone, new horizons energy NHE	2017	Cape Town				15800	450	99 600 000	Feed is 500-600 ton/day of general waste. 1200Nm3/hr biogas, purified to 760nm3/h Bio-Methane	OFMSW	560 000.00	28800	28.002	Compressed Methane and liquefied CO2	R13. Business Case, R38, R39, interview
22	Lukhanyiso Bio-CNG Facility	Lukhanyiso Food and Energy Centre	Botala Energy	2017	Free State	5.10		5.10	15000	73	1 500 000	Funded by DBSA, Green fund - 85% of eqipment budget is for imports. (60% from Europe and the rest from other countries)	Energy Crops of sweet Sorghum grass silage		24000		CNG Compression sold to gas transporter	Peet Steyn interview and www.botala.co.za
23	iBert: SucroPower	Sucropower	iBert	2017	Mandini	0.043	0.018	0.025	200	3.8	135000	Financed by finland, austria and UK	Napier grass and cow manure	4500	324		CHP and cooking	Interview with iBert
24	Ceres fruit farm	Ceres	Veolia	1998 – refurbished in 2015	Ceres													
25	Distell Worcester		Veolia	Expected in 2019	Worcester													
26	Bio2Watt Vylvlei Dairy		Bio2Watt	In Process	Malmesbury	4.8												
27	Reliance Composting	Reliance Composting	Reliance Composting	In Process	Klipheuwel													
28	Arcelor Mittal	Saldanha Bay Municipality	West coast Power Solutions / Optimus Investments	In Process	Saldanha Bay													
29	Drakenstein Municipality	Drakenstein Municipality and Interwaste	Interwaste and MBHE African Power	Planned for 2019	Wellington	10.07	2.87	7.2	7200	99		All values are estimates as the project is still in planning phase. 40% cycle efficiency is estimated for thermal energy	OFMSW	197000	26490		CHP	R46 EIA documents
30	Faircape	New Horizons Energy	New Horizons Energy	Planning Stage	Kuiperskraal													
31	SAB Miller: Prospection	SAB Miller	SAB Miller		Prospection	1.68							Brewery organic waste					
32	SAB Miller: Ibhayi	SAB Miller	SAB Miller		Ibhayi	0.76							Brewery organic waste					
33	iBert: Cavalier Abattoir	iBert: Cavalier Group	iBert	2016	Cullinan	0.747	0.3	0.447	1000	25	585 000		Slaughter Waste	48000	2500		CHP	iBert interview
34	Driefontein WWTW	Johannesburg Water	WEC Projects	2014 completed not commissioned	Johannesburg	2	0.8	1.2	5000	29	1 450 000	Costs in 2011, building completed in 2014 - however it was never commissioned	Waste water sludge		4250		CHP	Questionnaire filled by Jason Gifford
35	Farmsecure Carbon	Farmsecure				0.25			12000	13			bovine manure,	5000				
36	Farmsecure Carbon	Farmsecure				0.4												Mr Rudi Kriese farmsecure carbon: rudi@farmsecure.co.za
37	SA3	SA3	SA3	2016		2.22	0	2.22	4000	52	10000000		Purpose grown silage	16000	6000		Heating	
38	Reliance - Corona Farm				Corona Farm Paarl													
39	Rhodes Food Group				Stellenbosch, Franschoek													
40	WindhoeK AD	CAE				0.5									3000			
41	Humpries	CAE			Bla-Bela, Limpopo	1.2												

SA Plant cost calculations

Ref No	Project Name	Energy Capacity (Combined) MW	Energy Capacity (Electrical) MW	Energy Capacity (Thermal) MW	GJ/hr	Capital Cost (R Million)	PPI Index	Current Capex 2018 R Million	Annualised Capex R	O& M Cost (R / Year)	Current O&M Cost (2018)	O&M R/year/kWe	Total annual cost R	Specific production cost R/kwh electricity / LCOE	Specific production cost R/GJ fuel / LCOE	Feedstock Feed rate (kg/day)	Biogas Yield (Nm3/hr)	Methane Yield (m3/hr)	Electricity produced from CHP / year kWh	Methane Yield (m3/yr)
	CHP																			
6	iBert Jan Kempdorp	0.28	0.135	0.16		6.4	77.41	8.83	R 899 005	360 000	R 496 494	2 666.67	R 1 259 005	R 1.17		22000	53		1 080 000	-
8	Joburg Northern works refurbished facility	0.855	0.437	0.418		20	97.78	21.84	R 2 224 124	1 305 724	R 1 425 640	2 987.93	R 3 529 848	R 1.01		9600	163		3 496 000	-
10	Uilenkraal Dairy Farm	0.5	0.5			13	88.13	15.75	R 1 603 979	1 300 000	R 1 574 810	2 600.00	R 2 903 979	R 0.73		260000	175		4 000 000	-
11	Morgan Abattoir Digester	0.4	0.4	0.35		23	91.31	26.89	R 2 738 978	605 000	R 707 368	1 512.50	R 3 343 978	R 1.04					3 200 000	-
12	Bio2Watt Bronkhorstspruit	4.6	4.6	3		150	91.31	175.38	R 17 862 899	22 500 000	R 26 307 086	4 891.30	R 40 362 899	R 1.10		500000	771		36 800 000	-
13	Elgin fruit juices	1.077	0.527	0.55		20	91.31	23.38	R 2 381 720	2 000 000	R 2 338 408	3 795.07	R 4 381 720	R 1.04		57000			4 216 000	-
14	iBert - Peninsula	0.37	0.17	0.2		6.7	91.31	7.83	R 797 876	168 000	R 196 426	988.24	R 965 876	R 0.71		30000	70		1 360 000	-
15	Bayside Mall	0.031	0.013	0.018		2.5	91.31	2.92	R 297 715	25 000	R 29 230	1 923.08	R 322 715	R 3.10		570	3		104 000	-
18	iBert: Riversdale	0.093	0.05	0.072		5.3	91.31	6.20	R 631 156	168 000	R 196 426	3 360.00	R 799 156	R 2.00		9500	21		400 000	-
20	iBert: Zandam	0.167	0.075	0.105		9.5	97.78	10.37	R 1 056 459	189 000	R 206 358	2 520.00	R 1 245 459	R 2.08		45000	50		600 000	-
21	Tshwane Food and Energy Centre	0.08	0.08			2.8	97.78	3.06	R 311 377	196 000	R 214 000	2 450.00	R 507 377	R 0.79			30		640 000	-
24	iBert: SucroPower	0.043	0.018	0.025		3.8	102.54	3.96	R 402 967	135 000	R 140 556	7 500.00	R 537 967	R 3.74		4500	14		144 000	-
30	Drakenstein Municipality	10.07	2.87	7.2		99	106.76	99.00	R 10 083 369	9 900 000	R 9 900 000	3 449.48	R 19 983 369	R 0.87		197000	1104		22 960 000	-
34	iBert: Cavalier Abattoir	0.747	0.345	0.475		25	97.78	27.30	R 2 780 155	585 000	R 638 726	1 695.65	R 3 365 155	R 1.22		48000	104		2 760 000	-
35	Driefontein WWTW	2	0.8	1.2		29	88.13	35.13	R 3 578 106	1 450 000	R 1 756 519	1 812.50	R 5 028 106	R 0.79			177		6 400 000	-
	Boiler																			
3	SAB Newlands	1.42	1.42	1.42	5.112	14	58.52	25.54	R 2 601 463	2 100 000	R 3 831 231	1 478.87	R 4 701 463	R 2.99	R 116.65	6000	83		1 573 880	-
9	Cape Flats WWTW	5.6	2.8	2.8	20.16	83	88.13	100.55	R 10 240 787	10 440 000	R 12 646 935	3 728.57	R 20 680 787	R 0.77	R 130.12	77000	1417		26 755 960	-
17	Greenway Farms Biogas	1.225	3.5	3.5	4.41	15	91.31	17.54	R 1 786 290	2 625 000	R 3 069 160	750.00	R 4 411 290	R 0.75	R 126.88		320		5 858 688	-
	CNG																			
22	SA1	6.2	6.2	6.5	22.464	450	102.54	247.27	R 25 185 427	49 800 000	R 51 849 503	7 980.77	R 74 985 427	R 1.52	R 423.39	560000	1200	624.0	49 196 160.00	4 992 000.00
23	SA2	5.2	5.20	5.10	18.72	73	106.76	90.00	R 9 166 699	9 360 000	R 9 360 000	1 800.00	R 18 526 699	R 0.45	R 125.53		900	468.0	40 996 800.00	3 744 000.00
38	SA3	2.2	2.2	2.22	7.92	52	97.78	56.78	R 5 782 722	10 000 000	R 10 918 388	4 545.45	R 15 782 722	R 0.91	R 252.76	16000	250	130.0	17 344 800.00	1 040 000.00

International plant database

Biomethane

Lead author	Year of Data (Publication yr - 1)	Country	Methane capturing efficiency		Feedstock	Feedstock flow rate ton/an	Biogas flow rate Nm3/hr	GJ/Yr	CH4 concenctration in biogas	Fuel energy generated/ yr (kWh) bio-methane	Bio-Methane production Nm3/hr	GJ/hr	equivalent generator size (MW)	Bio-methane produced per year (Nm3)	Capital cost biogas production (R)	% of total capex	Capital cost upgrading unit (ZAR)	% of total capex	Total Capex	PPI Index	Current Capex 2018	Current Capex 2018 R Million	Annualised Capex R	O&M Costs Annual (ZAR)	% of capex	Total annual cost R	Specific production cost R/kwh potential energy / LCOE	LCOe R/GJ	R/Leq. diesel
Boldrin	2015	Denmark	0.9	CSTR	Pig slurry	110 000	158.00	20 448.95	0.57	5 680 264	72	3	0.72	576 384.00	R 101 295 480	0.98	R 2 471 040	0.02	103 766 520.00	100.00	R 107 502 115	R 107.50	R 10 949 328	6 662 619.60	6.42	R 17 611 947	3.101	861.264	R 33.24
Boldrin	2015	Denmark	0.9	CSTR	Pig slurry	320 000	460.00	59 534.92	0.57	16 537 478	210	8	2.10	1 678 080.00	R 211 560 960	0.84	R 39 486 720	0.16	R 251 047 680	100.00	R 260 085 396	R 260.09	R 26 490 272	R 18 825 840	7.50	R 45 316 112	2.740	761.169	R 29.38
Boldrin	2015	Denmark	0.9	CSTR	Pig slurry	500 000	719.00	93 055.67	0.57	25 848 798	328	12	3.28	2 622 912.00	R 295 152 000	0.88	R 39 312 000	0.12	R 334 464 000	100.00	R 346 504 704	R 346.50	R 35 292 269	R 31 434 312	9.40	R 66 726 581	2.581	717.061	R 27.68
Browne	2010	Ireland	0.9	CSTR	Grass silage & animal slurry	50 000	467.16	58 339.94	0.55	16 205 539	206	7	2.06	1 644 397.65	R 99 840 000	0.74	R 35 100 000	0.26	R 134 940 000	96.30	R 145 169 097	R 145.17	R 14 785 793	R 27 227 079	20.18	R 42 012 872	2.593	720.139	R 27.80
Browne	2010	Ireland	0.9	CSTR	Slaughter house waste	50 000	468.00	58 445.04	0.55	16 234 733	206	7	2.06	1 647 360.00	R 109 200 000	0.76	R 35 100 000	0.24	R 144 300 000	96.30	R 155 238 629	R 155.24	R 15 811 397	R 23 867 528	16.54	R 39 678 925	2.444	678.910	R 26.21
Browne	2010	Ireland	0.9	Dry batch	OFMSW	50 000	688.00	85 919.20	0.55	23 866 445	303	11	3.03	2 421 760.00	R 218 400 000	0.85	R 39 000 000	0.15	R 257 400 000	96.30	R 276 912 150	R 276.91	R 28 204 114	R 58 786 150	22.84	R 86 990 264	3.645	1012.466	R 39.08
Budzianowski	2015	Poland	0.9	?	Maize silage & cattle manure	15 218	182.46	23 614.44	0.57	6 559 567	83	3	0.83	665 608.00	R 24 336 000	0.86	R 4 102 800	0.14	R 28 438 800	100.00	R 29 462 597	R 29.46	R 3 000 831	R 6 674 741	23.47	R 9 675 571	1.475	409.731	R 15.82
Cucchiella	2015	Italy			OFMSW		178.57	18 164.74	0.56	5 045 760	80	2	0.64	640 000.00	R 24 336 000	0.72	R 9 360 000	0.28	R 33 696 000	100.00	R 34 909 056	R 34.91	R 3 555 564	R 1 486 867	22.06	R 5 042 432	0.999	277.595	R 10.72
Cucchiella	2015	Italy			OFMSW		446.43	45 411.84	0.56	12 614 400	200	6	1.60	1 600 000.00	R 49 140 000	0.74	R 17 550 000	0.26	R 66 690 000	100.00	R 69 090 840	R 69.09	R 7 037 055	R 1 486 867	11.15	R 8 523 922	0.676	187.703	R 7.25
Cucchiella	2015	Italy			OFMSW		892.86	90 823.68	0.56	25 228 800	400	12	3.20	3 200 000.00	R 93 600 000	0.84	R 17 550 000	0.16	R 111 150 000	100.00	R 115 151 400	R 115.15	R 11 728 424	R 1 486 867	6.69	R 13 215 292		145.505	R 5.62
													-																
Cucchiella	2015	Italy			Maize+Manure		1 923.08	181 647.36	0.52	50 457 600	800	23	6.40	5 760 000.00	R 172 263 000	0.88	R 23 400 000	0.12	R 195 663 000	100.00	R 202 706 868	R 202.71	R 20 646 142	R 1 486 867	6.08	R 22 133 009	0.439	121.846	R 4.70
Goulding	2012	Ireland	0.90	CSTR	Energy crops + slurr: Grass silage	39 585	492.01	58 092.30	0.52	16 136 750	205	7	2.05	1 637 418	128 252 904	1.00		-	R 128 252 904	102.60	R 129 502 932	R 129.50	R 13 190 160	29 373 708	22.90	R 42 563 868	2.638	732.694	R 28.28
UK Govt	2014	UK			Different wastes		230.77	28 382.40	0.65	7 884 000	150	4	1.00	1 200 000	R 104 400 000	0.90	R 11 700 000	0.10	R 116 100 000	101.30	R 118 736 032	R 118.74	R 12 093 527	R 10 620 000	9.15	R 22 713 527	2.881	800.268	R 30.89
	2014	UK					461.54	56 764.80	0.65	15 768 000	300	7	2.00	2 400 000	R 132 120 000	0.89	R 17 100 000	0.11	R 149 220 000	101.30	R 152 608 016	R 152.61	R 15 543 463	R 19 440 000	13.03	R 34 983 463	2.219	616.288	R 23.79
	2014	UK												-	R 154 080 000	0.88	R 21 240 000	0.12	R 175 320 000	101.30	R 179 300 612	R 179.30	R 18 262 163	R 25 740 000	14.68	R 44 002 163			
	2014	UK					923.08	113 529.60	0.65	31 536 000	600	14	4.00	4 800 000	R 172 440 000	0.87	R 25 020 000	0.13	R 197 460 000	101.30	R 201 943 297	R 201.94	R 20 568 371	R 36 000 000	18.23	R 56 568 371	1.794	498.270	R 19.23
	2014	UK												-	R 188 820 000	0.87	R 28 260 000	0.13	R 217 080 000	101.30	R 222 008 766	R 222.01	R 22 612 083	R 44 100 000	20.32	R 66 712 083			
	2014	UK												-	R 208 080 000	0.87	R 31 320 000	0.13	R 239 400 000	101.30	R 244 835 538	R 244.84	R 24 937 040	R 52 200 000	21.80	R 77 137 040			
	2014	UK												-	R 226 620 000	0.87	R 34 200 000	0.13	R 260 820 000	101.30	R 266 741 876	R 266.74	R 27 168 249	R 60 300 000	23.12	R 87 468 249			
	2014	UK					1 846.15	227 059.20	0.65	63 072 000	1 200	29	8.00	9 600 000	R 244 440 000	0.87	R 36 900 000	0.13	R 281 340 000	101.30	R 287 727 779	R 287.73	R 29 305 710	R 68 760 000	24.44	R 98 065 710	1.555	431.895	R 16.67
Truc	2017	Ireland	0.75	CSTR	Grass silage and slurry	53064	716.67	105 771.74	0.65	29 381 040	430.0	13	3.73	3 440 000	34 320 000	0.89	4 180 800.00	0.11	R 85 581 600	101.30	R 87 524 716	R 87.52	R 8 914 586	30 732 000	35.91	R 39 646 586	1.349	374.832	R 14.47
	2017	Ireland						238 896.00		66 360 000	829.5	30	8.42	5 308 800	137 436 000				R 137 436 000	101.30	R 140 556 462	R 140.56	R 14 315 986	140 088 000		R 154 403 986	2.327	646.323	R 24.95
	2017	Ireland						239 112.00		66 420 000	830.3	30	8.42	5 313 600	121 836 000				R 121 836 000	101.30	R 124 602 267	R 124.60	R 12 691 016	134 160 000		R 146 851 016	2.211	614.152	R 23.71

International plant database

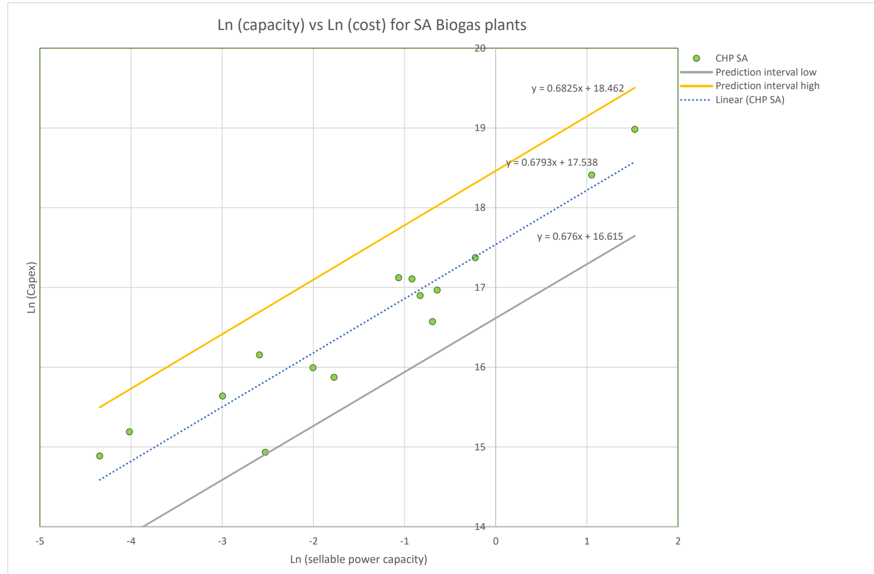
CHP

Literature source	Lead author	Year of Data (Publication yr - 1)	Biogas application	Location	Generator efficiency	Reactor type	Feedstock	Feedstock flow rate ton/an	Biogas flow rate Nm3/hr		CH4 concenctration in biogas	Electricity generated / yr (kWh)	Generator size MW	Generator size energy crops + OFMSW	heat generated / yr (kWh)	Electricity over plant lifetime (kWh)	Capital cost biogas production (R)	%	Capital cost CHP unit & Cleaning (ZAR)	%	Total Capex	PPI Index	Current Capex 2018	Current Capex 2018 R Million	Annualised Capex R	O&M Costs Annual R	% of capex	Total annual cost R	Specific production cost R/kwh electricity / LCOE
R.93	Akbulut	2011	CHP	Turkey	0.39	CSTR	Cow manure	29 200	129.6		0.55	2 191 689	0.27		1 966 900	43 833 779	R 7 849 608	0.57	R 5 878 080	0.43	R 13 727 688	100.80	R 14 109 013	R 14.11	R 1 437 034	R 3 416 186	25	R 4 853 220	2.214
R.94	Boldrin	2015	CHP	Denmark	0.45	CSTR	Pig slurry & sugar beet	110 000		173.25	0.7	4302594.45		0.54	4 015 755	86051889	R 101 295 480	0.97	R 2 779 920	0.03	R 104 075 400	100.00	R 107 822 114	R 107.82	R 10 981 921	R 13 064 809	13	R 24 046 729	5.589
R.94	Boldrin	2015	CHP	Denmark	0.45	CSTR	Pig slurry & sugar beet	320 000		504	0.7	12 516 638		1.56	11 682 196	250 332 768	R 211 560 960	0.96	R 8 087 040	0.04	R 219 648 000	100.00	R 227 555 328	R 227.56	R 23 177 013	R 26 240 947	12	R 49 417 960	3.948
R.94	Boldrin	2015	CHP	Denmark	0.45	CSTR	Pig slurry & sugar beet	500 000		787.5	0.7	19 557 248		2.44	18 253 431	391 144 950	R 295 152 000	0.98	R 6 864 000	0.02	R 302 016 000	100.00	R 312 888 576	R 312.89	R 31 868 393	R 36 731 565	12	R 68 599 958	3.508
R.96	Budzianowski	2015	CHP	Poland	0.416	?	Maize silage & cattle manure	15 218	182		0.57	3 800 000	0.48		3 900 000	76 000 000	R 24 336 000	0.82	R 5 210 400	0.18	R 29 546 400	100.00	R 30 610 070	R 30.61	R 3 117 703	R 6 208 800	21	R 9 326 503	2.454
R.102	Gebrezgabher	2009	CHP	Netherlands	0.37		pig manure, poultry manure, energy maize, food waste, flower bulbs	70 000				15 000 000	1.88			300 000 000	R 105 300 000	1.00		-	R 105 300 000	93.10	R 117 175 940	R 117.18	R 11 934 628	R 15 490 800	15	R 27 425 428	1.828
R.103	Gomez	2009	CHP	Spain	0.33		OFMSW, Sewage sludge, livestock manure					2 000 000	0.25			40 000 000	R 15 233 743	1.00		-	R 15 233 743	93.10	R 16 951 835	R 16.95	R 1 726 582	R 2 437 399	16	R 4 163 981	2.082
R.103	Gomez	2009	CHP	Spain					173.25			4 000 000	0.50			80 000 000	R 28 883 743	1.00		-	R 28 883 743	93.10	R 32 141 308	R 32.14	R 3 273 663	R 4 621 399	16	R 7 895 062	1.974
R.103	Gomez	2009	CHP	Spain					504			6 000 000	0.75			120 000 000	R 42 533 743	1.00		-	R 42 533 743	93.10	R 47 330 782	R 47.33	R 4 820 745	R 6 805 399	16	R 11 626 144	1.938
R.103	Gomez	2009	CHP	Spain					787.5			8 000 000	1.00			160 000 000	R 56 183 743	1.00		-	R 56 183 743	93.10	R 62 520 256	R 62.52	R 6 367 826	R 8 989 399	16	R 15 357 225	1.920
R.103	Gomez	2009	CHP	Spain								16 000 000	2.00			320 000 000	R 110 783 743	1.00		-	R 110 783 743	93.10	R 123 278 150	R 123.28	R 12 556 152	R 17 725 399	16	R 30 281 551	1.893
R.103	Gomez	2009	CHP	Spain								24 000 000	3.00			480 000 000	R 165 383 743	1.00			R 165 383 743	93.10	R 184 036 045	R 184.04	R 18 744 478	R 26 461 399	16	R 45 205 877	1.884
R.105	Goulding	2012	CHP	Ireland	0.38	CSTR	Energy crops + slurr: Grass silage	39 585	492.01		0.52	8 212 050	1.03		8 428 000	164 241 000	R 44 217 342	1.00			R 44 217 342	102.60	R 44 648 310	R 44.65	R 4 547 529	R 23 542 007	53	R 28 089 536	3.421
R.106	Gutierrez	2016	CHP	Mexico	0.25	HDPE Covered lagoon	Pig slurry	19 357	72.00		0.61	1 268 000	0.16			25 360 000	R 12 668 323	1.00			R 12 668 323	98.70	R 13 297 247	R 13.30	R 1 354 354	R 2 125 500	17	R 3 479 854	2.744
R.110	German solar energy society	2006	CHP	Germany			Agricultural waste	800				344 000	0.04			6 880 000	R 4 992 000	0.70		0.30	R 4 992 000	91.80	R 5 633 673	R 5.63	R 573 802	R 286 744	6	R 860 546	2.502
R.111	Murphy	2006	CHP	Ireland	30-40	DRANCO prc	OFMSW	5 000				1 825 000		0.23		36 500 000	R 78 000 000	1			R 78 000 000	91.80	R 88 026 144	R 88.03	R 8 965 657	R 3 120 000	4	R 12 085 657	6.622
R.115	Patrizio	2015	CHP	ITALY	0.3 - 0.36		mix									-						100.00		R -	R -			R -	

Capacity cost factor for SA CHP plants

biogas plants in SA - CHP

		Capex 2018 ZAR		electrical. Capacity (MW)	ln capex	ln capacity	y low	y high
	iBert Jan Kempdorp	R	8 826 559.88	0.135	15.9932759	-2.002480501	15.29467	17.06152
	Joburg Northern works refurbished facility	R	21 836 776.44	0.437	16.8991061	-0.827822084		
	Uilenkraal Dairy Farm	R	15 748 099.40	0.5	16.57223024	-0.693147181	16.1807	17.95422
	Morgan Abattoir Digester	R	26 891 687.66	0.4	17.10732779	-0.916290732		
	Bio2Watt Bronkhorstspruit	R	175 380 571.68	4.6	18.98246887	1.526056303	17.60394	19.54577
	Elgin fruit juices	R	23 384 076.22	0.527	16.96756585	-0.64055473		
	iBert - Peninsula	R	7 833 665.53	0.17	15.8739411	-1.771956842		
CHP	Bayside Mall	R	2 923 009.53	0.013	14.8881243	-4.342805922	13.62435	15.55251
	iBert: Riversdale	R	6 196 780.20	0.05	15.63954039	-2.995732274		
	iBert: Zandam	R	10 372 468.81	0.075	16.15466562	-2.590267165		
	Tshwane Food and Energy Centre	R	3 057 148.70	0.08	14.93299324	-2.525728644	14.9305	16.71486
	iBert: SucroPower	R	3 956 387.75	0.018	15.19084198	-4.017383521		
	Drakenstein Municipality	R	99 000 000.00	2.87	18.41063041	1.05431203	17.30888	19.19996
	iBert: Cavalier Abattoir	R	27 295 970.55	0.345	17.12224965	-1.064210862		
	Driefontein WWTW	R	35 130 375.58	0.8	17.37457672	-0.223143551	16.48999	18.28343



Capacity-cost factor & residual plots for SA & international biomethane plants

			biogas plants in SA - CHP C Capex 2018 ZAR	Q electrical. Capacity (MW)	y C ln capex	x Q ln capacity	y low	y high	
International plants	Boldrin	R	107 502 114.72	0.71	18.49302108	-0.342443775	16.77303706	19.04205123	18.47078969
	Boldrin	R	260 085 396.48	2.07	19.37652058	0.726187682	17.417366	19.5827292	18.99524733
	Boldrin	R	346 504 704.00	3.23	19.66340695	1.17282255	17.66443844	19.8309308	19.23600287
	Browne	R	145 169 096.57	2.03	18.7934098	0.705911543	17.40583141	19.57177956	18.98462617
	Browne	R	155 238 629.28	2.03	18.86047403	0.707711405	17.40685642	19.57275042	18.98556791
	Browne	R	276 912 149.53	2.98	19.43921086	1.093031947			
	Budzianowski	R	29 462 596.80	0.82	17.19863211	-0.198516971	16.86398102	19.1107079	18.53738666
	Cucchiella	R	34 909 056.00	0.63	17.36825684	-0.460893255	16.69728471	18.98645478	18.41686114
	Cucchiella	R	69 090 840.00	1.58	18.05093272	0.455397477			
	Cucchiella	R	115 151 400.00	3.15	18.56175834	1.148544657	17.6513527	19.81709474	19.2225819
	Cucchiella	R	203 636 160.00	6.31	19.13184543	1.841691838			
	Cucchiella	R	35 151 480.00	0.63	17.37517728	-0.460893255			
	Cucchiella	R	68 929 224.00	1.58	18.0485908	0.455397477	17.26105743	19.43875813	18.85559539
	Cucchiella	R	114 908 976.00	3.15	18.55965086	1.148544657			
	Cucchiella	R	202 706 868.00	6.31	19.12727149	1.841691838	18.00968946	20.22738986	19.62056817
	Goulding	R	129 502 932.30	2.02	18.67921408	0.701657766	17.40340804	19.5694859	18.98240133
	UK Govt	R	118 736 031.59	1	18.59241337	0			
	UK Govt	R	152 608 015.79	2	18.8433832	0.693147181			
	UK Govt	R	201 943 297.14	4	19.12349751	1.386294361	17.77780665	19.95428178	19.35565332
	UK Govt	R	287 727 778.87	8	19.47752538	2.079441542	18.12555605	20.37516425	19.76390933
	Truc	R	87 524 716.29	3.44	18.28743178	1.235471471	17.69802393	19.86681678	19.27081227
	Truc	R	140 556 461.99	6.8	18.76111983	1.923571171			
	Truc	R	124 602 266.54	8.3	18.64063735	2.116556674	18.14333515	20.39854218	19.78658592
SA plants	SA1	R	247 274 234.45	6.24	19.32600854	1.830980182	17.99436733	20.20843102	19.60217809
	SA2	R	90 000 000.00	5.2	18.31532023	1.648658626	17.90277474	20.09784697	19.49491156
	SA3	R	56 775 618.74	2.2	17.85461754	0.78845736	17.45261732	19.61652882	19.02803296

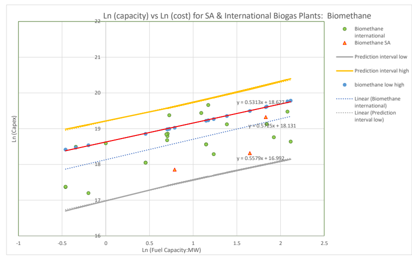
bio-methane

Sxx 4.755220263

18.1793 1

		slope	0.552688	18.09819441	interc	
		SE slope	0.130539	0.158088787	SE interc.	
		RSQ	0.427559	0.51453122	SE y	
		F	17.9257	24	DF	
		Ssregr	4.745692	6.353817037	Ssres	
	t crit	**t.95**	**2.063899**			
		std deviation of x values	0.800576			
	DEVSQ of x values	Sxx	15.53604			
o2	variance in x values	Smple variance	0.64	tstat agains slope = 1		-3.429481263
o		std. dev	0.8	t stat against slope = 0		4.23737673

ln capex		*ln capacity*	
Mean	18.62841	Mean	0.868275043
Standard Error	0.14003	Standard Error	0.166931548
Median	18.67921	Median	0.726187682
Mode	#N/A	Mode	-0.460893255
Skewness	-0.69815	Skewness	-0.144373561
Range	2.464775	Range	2.577449929
Minimum	17.19863	Minimum	-0.460893255
Maximum	19.66341	Maximum	2.116556674
Sum	428.4534	Sum	19.97032598
Count	23	Count	23
Confidence Level(95.0%)	0.290405	Confidence Level(95.0%)	0.346194842



SUMMARY OUTPUT

Regression Statistics	
Multiple R	0.654602513
R Square	0.428504451
Adjusted R Square	0.404692136
Standard Error	0.514106015
Observations	26

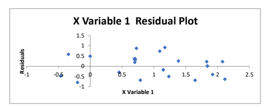
ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	1	4.756188908	4.756188908	17.9950777	0.000285353
Residual	24	6.343319862	0.264304994		
Total	25	11.09950877			

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	18.09741233	0.157996717	114.5429646	2.21537E-34	17.77132314	18.42350153	17.77132314	18.42350153
X Variable 1	0.554450701	0.130703156	4.242060549	0.000285353	0.284692646	0.824208756	0.284692646	0.824208756

RESIDUAL OUTPUT

	y : Ln Capex		Y									
Observation	*Predicted Y*	*Residuals*	*observed value (Ln Capex)*	*MRE*	*Preidcted (Capex R)*	*observed (Capex R)*	*residual*	*MRE*	*MRE %*	*abs MRE*	*MMRE*	
1	17.90754414	0.585476935	18.49302108	3.165934501	59861501.44	107502114.7	-47640613.28	0.44316	44.31598	44.31597779		44.9797747
2	18.5000476	0.876472981	19.37652058	4.523376511	108260141.1	260085396.5	-151825255.4	0.583752	58.37516	58.3751558		
3	18.74768462	0.915722334	19.66340695	4.656987146	138680685	346504704	-207824019	0.599773	59.97726	59.97725763		
4	18.48880548	0.304604321	18.7934098	1.620803909	107049883.4	145169096.6	-38119213.22	0.262585	26.25849	26.25849035		
5	18.48980342	0.370670617	18.86047403	1.96533033	107156765.5	155238629.3	-48081863.8	0.309729	30.97287	30.9728732		
6	18.70344466	0.735766201	19.43921086	3.784959207	132679189.4	276912149.5	-144232960.1	0.520862	52.08618	52.08617981		
7	17.98734446	-0.788712348	17.19863211	-4.585901615	64834242.77	29462596.8	35371645.97	-1.20056	-120.056	120.0561044		
8	17.84186975	-0.473612908	17.36825684	-2.726887977	56056448.24	34909056	21147392.24	-0.60579	-60.5785	60.57852793		
9	18.34990778	-0.298975065	18.05093272	-1.656285965	93167339.5	69090840	24076499.5	-0.34848	-34.8476	34.84759991		
10	18.73422372	-0.172465381	18.56175834	-0.929143555	136826426.9	115151400	21675026.9	-0.18823	-18.8231	18.8230685		
11	19.11853966	0.013305766	19.13184543	0.069547742	200944571.4	203636160	-2691588.649	0.013218	1.321764	1.321763605		
12	17.84186975	-0.466692465	17.37517728	-2.685972391	56056448.24	35151480	20904968.24	-0.59471	-59.4711	59.47108981		
13	18.34990778	-0.301316987	18.0485908	-1.669476526	93167339.5	68929224	24238115.5	-0.35164	-35.1638	35.16377247		
14	18.73422372	-0.174572864	18.55965086	-0.940604244	136826426.9	114908976	21917450.9	-0.19074	-19.0738	19.07375008		
15	19.11853966	0.00873183	19.12727149	0.045651205	200944571.4	202706868	-1762296.649	0.008694	0.869382	0.869381815		
16	18.48644697	0.192767109	18.67921408	1.031987256	106797702.6	129502932.3	-22705229.68	0.175326	17.5326	17.53259889		
17	18.09741233	0.495001032	18.59241337	2.662381811	72377955.83	118736031.6	-46358075.76	0.39043	39.04297	39.04297216		
18	18.48172827	0.36165493	18.8433832	1.919267502	106294943.4	152608015.8	-46313072.35	0.303477	30.34773	30.34773246		
19	18.86604421	0.257453295	19.12349751	1.346266786	156105748.9	201943297.1	-45837548.19	0.226982	22.69823	22.6982271		
20	19.25036015	0.227165225	19.47752538	1.16629408	229258364.2	287727778.9	-58469414.7	0.203211	20.32109	20.32108784		
21	18.78242036	-0.494988573	18.28743178	-2.70671453	143582502.2	87524716.29	56057785.96	-0.64048	-64.0479	64.04794935		
22	19.16393772	-0.402817886	18.76111983	-2.147088713	210277304.9	140556462	69720842.91	-0.49603	-49.6034	49.60344186		
23	19.27093866	-0.63030131	18.64063735	-3.381329179	234025037.3	124602266.5	109422770.8	-0.87818	-87.8176	87.81764074		
24	19.10139917	0.224609366	19.32600854	1.16221291	197529633.4	247274234.4	-49744601.08	0.201172	20.11718	20.11717929		
25	19.00031086	-0.68499063	18.31532023	-3.739987189	178537792.3	90000000	88537792.32	-0.98375	-98.3753	98.3753248		
26	18.53457307	-0.679955526	17.85461754	-3.808289502	112063145.5	56775618.74	55287526.76	-0.97379	-97.379	97.3789947		



Lang Factor Calculation

INPUTS									CALCULATIONS				
	PLANT NAME	CONSTRUCTION YEAR	CAPEX	I_f (Installed Plant Cost)	C_{MPEC} (Delivered to site Purchased equipment cost)	C_{CW} (Civil Work Cost) Includes Site improvements, buildings, structures	C_{ME} (Mechanical and Electrical Costs) Equipment installation, piping, instrumentation, control, electrical equipment,)	C_{ID} (Indirect Cost) - Design and Engineering, Procurement, Site Supervision, Environmental Authorisations, Contingencies, engineering supervision	F_{CV} (Factor for Civil Works)	F_{ME} (Factor for Mechanical and Electrical)	F_{ID} (Factor for Indirect Costs	FI (Sum of all factors +1)	TOTAL PLANT COST
1	A1	2007	13 800 000.00	12 000 000	4 762 500	3 159 243	341 500	3 802 481	0.663	0.072	0.798	2.533	R 12 065 724.00
2	A2	2012	7 360 000.00	6 400 000	3 200 000	1 920 000	1 280 000	368 000	0.600	0.400	0.115	2.115	R 6 768 000.00
3	A3	2013	595 125.00	517 500	320 000	50 000	95 000	52 500	0.156	0.297	0.164	1.617	R 517 500.00
4	A4	2015	3 286 125.00	2 857 500	2 200 000	250 000	300 000	107 500	0.114	0.136	0.049	1.299	R 2 857 500.00
5	A5	2015	6 095 000.00	5 300 000	2 650 000	1 590 000	1 060 000	304 750	0.600	0.400	0.115	2.115	R 5 604 750.00
6	A6	2015	7 705 000.00	6 700 000	3 350 000	2 010 000	1 340 000	385 250	0.600	0.400	0.115	2.115	R 7 085 250.00
7	A7	2015	22 041 667.05	19 166 667	13 033 334	958 333	3 833 333	1 542 917	0.074	0.294	0.118	1.486	R 19 367 917.00
8	A8	2016	17 346 600.00	15 084 000	10 200 000	2 300 000	1 300 000	1 284 000	0.225	0.127	0.126	1.479	R 15 084 000.00
9	A9	2016	59 915 000.00	52 100 000	36 850 000	5 000 000	2 500 000	7 750 000	0.136	0.068	0.210	1.414	R 52 100 000.00
10	A10	2016	10 925 000.00	9 500 000	4 750 000	2 850 000	1 900 000	546 250	0.600	0.400	0.115	2.115	R 10 046 250.00
11	A11	2016	28 750 000.00	25 000 000	12 500 000	7 500 000	5 000 000	1 437 500	0.600	0.400	0.115	2.115	R 26 437 500.00
12	A12	2017	69 000 000.00	60 000 000	46 366 000	8 500 000	3 300 000	1 834 000	0.183	0.071	0.040	1.294	R 60 000 000.00
13	A13	2017	4 370 000.00	3 800 000	1 900 000	1 140 000	760 000	218 500	0.600	0.400	0.115	2.115	R 4 018 500.00
14	A14	2011	33 350 000.00	29 000 000	18 850 000	1 450 000	5 800 000	3 335 000	0.077	0.308	0.177	1.562	R 29 435 000.00
								average	0.373	0.270	0.169	1.812	

Discounted cash flow calculations

CHP

	electrical capacity	ln capacity	low capex	high capex	probable capex	Equipment cost	low annual O&M	high annual O&M	probable O&M	low annualised capex	high annualised capex	probable annualised capex	Low total annual cost	high total annual cost	probable total annual cost	kwh e produced per year	LCOE low	LCOE high	probable LCOE
low	0.1	-2.302585093	3 465 794.57	21 649 343.18	8 662 111.52	1 914 803.63	121 214.15	530 021.24	302 952.32	R 407 091	R 2 542 924	R 1 017 448	528 305.08	3 072 944.96	1 320 400.69	788400	0.67	3.90	1.67
med						4 785 696.97										788400			
high						11 960 963.09										788400			
low	0.3	-1.203972804	7 283 443.99	45 822 626.76	18 268 731.09	4 024 002.21	380 104.11	1 673 955.09	953 397.84	R 855 511	R 5 382 309	R 2 145 838	1 235 614.71	7 056 263.63	3 099 236.14	2365200	0.52	2.98	1.31
med						10 093 221.60										2365200			
high						25 316 368.37										2365200			
low	0.5	-0.693147181	10 287 421.63	64 936 930.01	25 846 345.55	5 683 658.36	646 683.56	2 857 426.53	1 624 742.07	R 1 208 357	R 7 627 467	R 3 035 902	1 855 040.24	10 484 893.96	4 660 644.12	3942000	0.47	2.66	1.18
med						14 279 748.92										3942000			
high						35 876 756.91										3942000			
low	1	0	16 436 252.97	104 218 477.62	41 387 936.19	9 080 802.75	1 330 005.15	5 903 278.49	3 349 070.41	R 1 930 596	R 12 241 463	R 4 861 411	3 260 601.26	18 144 741.77	8 210 481.86	7884000	0.41	2.30	1.04
med						22 866 263.09										7884000			
high						57 579 269.41										7884000			
low	2	0.693147181	26 260 264.37	167 262 158.47	66 274 795.36	14 508 433.35	2 735 362.12	12 195 833.07	6 903 417.35	R 3 084 521	R 19 646 550	R 7 784 613	5 819 882.92	31 842 383.45	14 688 029.95	15768000	0.37	2.02	0.93
med						36 615 909.04										15768000			
high						92 410 032.31										15768000			
low	3	1.098612289	34 541 149.39	220 587 034.01	87 288 771.87	19 083 507.95	4 170 638.67	18 644 202.08	10 539 600.84	R 4 057 190	R 25 910 070	R 10 252 906	8 227 829.11	44 554 272.32	20 792 507.23	23652000	0.35	1.88	0.88
med						48 225 840.81										23652000			
high						121 871 289.51										23652000			
low	4	1.386294361	41 956 125.03	268 442 125.57	106 126 299.21	23 180 179.58	5 625 696.94	25 195 888.10	14 229 969.92	R 4 928 151	R 31 531 111	R 12 465 555	10 553 847.65	56 726 999.45	26 695 525.20	31536000	0.33	1.80	0.85
med						58 633 314.48										31536000			
high						148 310 566.61										31536000			
low	5	1.609437912	48 787 272.57	312 602 000.42	123 494 935.12	26 954 294.24	7 095 644.02	31 825 488.06	17 961 161.83	R 5 730 535	R 36 718 114	R 14 505 669	12 826 178.75	68 543 601.74	32 466 830.58	39420000	0.33	1.74	0.82
med						68 229 245.92										39420000			
high						172 708 287.53										39420000			
low	6	1.791759469	55 186 526.77	354 024 202.62	139 776 128.63	30 489 793.80	8 577 566.03	38 517 846.75	21 725 211.61	R 6 482 189	R 41 583 550	R 16 418 052	15 059 754.75	80 101 396.75	38 143 263.23	47304000	0.32	1.69	0.81
med						77 224 380.46										47304000			
high						195 593 482.11										47304000			

Biomethane

	electrical capacity	ln capacity	low capex	high capex	probable capex	Equipment Cost	low annual O&M	high annual O&M	probable O&M	low annualised capex	high annualised capex	probable annualised capex	Low total annual cost	high total annual cost	probable total annual cost	kwh e produced per year	LCOE low	LCOE high	probable LCOE
low	0.5	-0.693147181	16 277 481.18	85 048 386.29	50 333 088.36	8 993 083.53	1 627 748.12	17 009 677.26	7 549 963.25	R 1 911 947	R 9 989 752	R 5 912 106	3 539 694.95	26 999 428.80	13 462 068.93	3942000	0.90	6.85	3.42
med						27 808 336.11										3942000			
high						46 988 058.72										3942000			
low	1	0	23 962 484.03	122 914 555.35	74 850 249.34	13 238 941.45	2 396 248.40	24 582 911.07	11 227 537.40	R 2 814 624	R 14 437 498	R 8 791 882	5 210 872.79	39 020 408.62	20 019 419.60	7884000	0.66	4.95	2.54
med						41 353 728.92										7884000			
high						67 908 594.12										7884000			
low	2	0.693147181	35 275 767.46	177 639 912.72	111 309 677.36	19 489 374.29	3 527 576.75	35 527 982.54	16 696 451.60	R 4 143 478	R 20 865 517	R 13 074 393	7 671 055.16	56 393 500.04	29 770 844.54	15768000	0.49	3.58	1.89
med						61 497 059.31										15768000			
high						98 143 598.19										15768000			
low	3	1.098612289	44 230 086.07	220 342 279.01	140 392 907.97	24 436 511.64	4 423 008.61	44 068 455.80	21 058 936.20	R 5 195 249	R 25 881 321	R 16 490 498	9 618 257.92	69 949 777.22	37 549 434.49	23652000	0.41	2.96	1.59
med						77 565 142.53										23652000			
high						121 736 065.75										23652000			
low	4	1.386294361	51 930 332.78	256 730 689.86	165 528 430.20	28 690 791.59	5 193 033.28	51 346 137.97	24 829 264.53	R 6 099 717	R 30 155 490	R 19 442 907	11 292 750.68	81 501 628.47	44 272 171.83	31536000	0.36	2.58	1.40
med						91 452 171.38										31536000			
high						141 840 160.15										31536000			
low	5	1.609437912	58 814 878.19	289 045 410.32	188 084 747.70	32 494 407.84	5 881 487.82	57 809 082.06	28 212 712.16	R 6 908 374	R 33 951 165	R 22 092 364	12 789 861.34	91 760 247.50	50 305 076.05	39420000	0.32	2.33	1.28
med						103 914 225.25										39420000			
high						159 693 596.86										39420000			
low	6	1.791759469	65 112 207.44	318 445 468.88	208 778 052.55	35 973 595.27	6 511 220.74	63 689 093.78	31 316 707.88	R 7 648 055	R 37 404 485	R 24 522 992	14 159 276.20	101 093 579.06	55 839 699.60	47304000	0.30	2.14	1.18
med						115 346 990.36										47304000			
high						175 936 723.14										47304000			

Discounted cash flow calculations

CHP

				Depreciation 1st 3 years																				
year	Revenue	Depreciation	Annual Gross Profit	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	NPV millionts
low	808 967	1 914 804	687 753		680 785	653 167	573 235	601 897	631 992	663 591	696 771	731 609	768 190	806 599	846 929	889 276	933 740	980 427	1 029 448	1 080 920	1 134 966	1 191 715	1 251 300	3
med	808 967	4 785 697	506 015	1 034 328	784 546	669 673	421 758	442 846	464 988	488 238	512 650	538 282	565 196	593 456	623 129	654 285	687 000	721 350	757 417	795 288	835 052	876 805	920 645	(3)
high	808 967	11 960 963	278 946	1 875 376	1 215 604	891 241	232 498	244 123	256 330	269 146	282 603	296 734	311 570	327 149	343 506	360 681	378 716	397 651	417 534	438 411	460 331	483 348	507 515	(16)
low	2 426 901	4 024 002	2 046 797	2 037 054	1 885 395	1 850 091	1 705 985	1 791 284	1 880 848	1 974 890	2 073 635	2 177 317	2 286 183	2 400 492	2 520 516	2 646 542	2 778 869	2 917 813	3 063 703	3 216 888	3 377 733	3 546 620	3 723 951	12
med	2 426 901	10 093 222	1 473 503	2 473 973	1 961 799	1 734 887	1 228 150	1 289 558	1 354 035	1 421 737	1 492 824	1 567 465	1 645 839	1 728 130	1 814 537	1 905 264	2 000 527	2 100 553	2 205 581	2 315 860	2 431 653	2 553 236	2 680 898	(3)
high	2 426 901	25 316 368	752 946	4 086 413	2 695 802	2 015 405	627 573	658 951	691 899	726 494	762 819	800 960	841 008	883 058	927 211	973 571	1 022 250	1 073 362	1 127 031	1 183 382	1 242 551	1 304 679	1 369 913	(33)
low	4 044 835	5 683 658	3 398 151	3 242 381	3 046 430	3 015 737	2 832 325	2 973 941	3 122 638	3 278 770	3 442 709	3 614 844	3 795 586	3 985 366	4 184 634	4 393 866	4 613 559	4 844 237	5 086 449	5 340 771	5 607 810	5 888 200	6 182 610	21
med	4 044 835	14 279 749	2 420 093	3 741 632	3 029 089	2 720 736	2 017 123	2 117 979	2 223 878	2 335 072	2 451 826	2 574 417	2 703 138	2 838 295	2 980 209	3 129 220	3 285 681	3 449 965	3 622 463	3 803 586	3 993 766	4 193 454	4 403 127	(1)
high	4 044 835	35 876 757	1 187 408	5 877 680	3 911 328	2 951 663	989 693	1 039 178	1 091 136	1 145 693	1 202 978	1 263 127	1 326 283	1 392 597	1 462 227	1 535 339	1 612 105	1 692 711	1 777 346	1 866 214	1 959 524	2 057 500	2 160 375	(46)
low	8 089 670	9 080 803	6 759 664	6 138 271	5 873 094	5 874 347	5 634 113	5 915 818	6 211 609	6 522 190	6 848 299	7 190 714	7 550 250	7 927 762	8 324 150	8 740 358	9 177 376	9 636 245	10 118 057	10 623 960	11 155 158	11 712 916	12 298 561	45
med	8 089 670	22 866 263	4 740 599	6 614 508	5 504 659	5 043 598	3 951 242	4 148 804	4 356 244	4 574 057	4 802 759	5 042 897	5 295 042	5 559 794	5 837 784	6 129 673	6 436 157	6 757 965	7 095 863	7 450 656	7 823 189	8 214 348	8 625 066	5
high	8 089 670	57 579 269	2 186 391	9 635 299	6 489 570	4 959 996	1 822 335	1 913 452	2 009 124	2 109 581	2 215 060	2 325 813	2 442 103	2 564 208	2 692 419	2 827 040	2 968 392	3 116 811	3 272 652	3 436 285	3 608 099	3 788 504	3 977 929	(71)
low	16 179 339	14 508 433	13 443 977	11 710 844	11 382 355	11 484 301	11 205 420	11 765 691	12 353 976	12 971 675	13 620 259	14 301 271	15 016 335	15 767 152	16 555 509	17 383 285	18 252 449	19 165 072	20 123 325	21 129 491	22 185 966	23 295 264	24 460 027	94
med	16 179 339	36 615 909	9 275 922	11 804 891	10 088 333	9 413 718	7 731 388	8 117 957	8 523 855	8 950 048	9 397 550	9 867 428	10 360 799	10 878 839	11 422 781	11 993 920	12 593 616	13 223 297	13 884 462	14 578 685	15 307 619	16 073 000	16 876 650	23
high	16 179 339	92 410 032	3 983 506	15 805 529	10 773 973	8 337 069	3 320 212	3 486 223	3 660 534	3 843 561	4 035 739	4 237 526	4 449 402	4 671 872	4 905 466	5 150 739	5 408 276	5 678 690	5 962 625	6 260 756	6 573 794	6 902 483	7 247 607	(110)
low	24 269 009	19 083 508	20 098 370	17 142 518	16 797 382	17 022 763	16 751 790	17 589 380	18 468 849	19 392 291	20 361 906	21 380 001	22 449 001	23 571 451	24 750 024	25 987 525	27 286 901	28 651 247	30 083 809	31 587 999	33 167 399	34 825 769	36 567 058	145
med	24 269 009	48 225 841	13 729 408	16 636 791	14 430 403	13 599 051	11 443 324	12 015 490	12 616 265	13 247 078	13 909 432	14 604 904	15 335 149	16 101 906	16 907 002	17 752 352	18 639 969	19 571 968	20 550 566	21 578 094	22 656 999	23 789 849	24 979 342	44
high	24 269 009	121 871 290	5 624 807	21 111 841	14 489 542	11 289 764	4 688 220	4 922 631	5 168 763	5 427 201	5 698 561	5 983 489	6 282 663	6 596 796	6 926 636	7 272 968	7 636 616	8 018 447	8 419 370	8 840 338	9 282 355	9 746 473	10 233 796	(142)
low	32 358 678	23 180 180	26 732 981	22 492 972	22 157 269	22 518 731	22 281 673	23 395 756	24 565 544	25 793 821	27 083 512	28 437 688	29 859 572	31 352 551	32 920 178	34 566 187	36 294 497	38 109 222	40 014 683	42 015 417	44 116 188	46 321 997	48 638 097	197
med	32 358 678	58 633 314	18 128 708	21 261 334	18 630 502	17 674 034	15 110 097	15 865 602	16 658 882	17 491 826	18 366 417	19 284 738	20 248 975	21 261 424	22 324 495	23 440 720	24 612 756	25 843 394	27 135 563	28 492 342	29 916 959	31 412 807	32 983 447	66
high	32 358 678	148 310 567	7 162 790	25 920 688	17 873 157	13 991 215	5 970 114	6 268 620	6 582 051	6 911 153	7 256 711	7 619 546	8 000 524	8 400 550	8 820 577	9 261 606	9 724 687	10 210 921	10 721 467	11 257 540	11 820 417	12 411 438	13 032 010	(171)
low	40 448 348	26 954 294	33 352 704	27 787 548	27 478 805	27 984 817	27 799 145	29 189 102	30 648 557	32 180 985	33 790 035	35 479 536	37 253 513	39 116 189	41 071 998	43 125 598	45 281 878	47 545 972	49 923 271	52 419 434	55 040 406	57 792 426	60 682 047	249
med	40 448 348	68 229 246	22 487 186	25 742 868	22 731 569	21 671 166	18 742 845	19 679 987	20 663 986	21 697 186	22 782 045	23 921 147	25 117 204	26 373 065	27 691 718	29 076 304	30 530 119	32 056 625	33 659 456	35 342 429	37 109 550	38 965 028	40 913 279	89
high	40 448 348	172 708 288	8 622 860	30 387 619	21 026 378	16 516 490	7 187 067	7 546 421	7 923 742	8 319 929	8 735 925	9 172 722	9 631 358	10 112 926	10 618 572	11 149 500	11 706 975	12 292 324	12 906 940	13 552 287	14 229 902	14 941 397	15 688 467	(196)
low	48 538 017	30 489 794	39 960 451	33 040 096	32 771 244	33 428 035	33 306 637	34 971 968	36 720 567	38 556 595	40 484 425	42 508 646	44 634 079	46 865 782	49 209 072	51 669 525	54 253 001	56 965 651	59 813 934	62 804 631	65 944 862	69 242 105	72 704 211	301
med	48 538 017	77 224 380	26 812 806	30 116 633	26 757 329	25 608 571	22 348 205	23 465 616	24 638 897	25 870 841	27 164 383	28 522 603	29 948 733	31 446 169	33 018 478	34 669 402	36 402 872	38 223 015	40 134 166	42 140 875	44 247 918	46 460 314	48 783 330	112
high	48 538 017	195 593 482	10 020 171	34 597 610	24 005 102	18 907 246	8 351 712	8 769 298	9 207 763	9 668 151	10 151 558	10 659 136	11 192 093	11 751 698	12 339 282	12 956 247	13 604 059	14 284 262	14 998 475	15 748 399	16 535 819	17 362 609	18 230 740	(220)

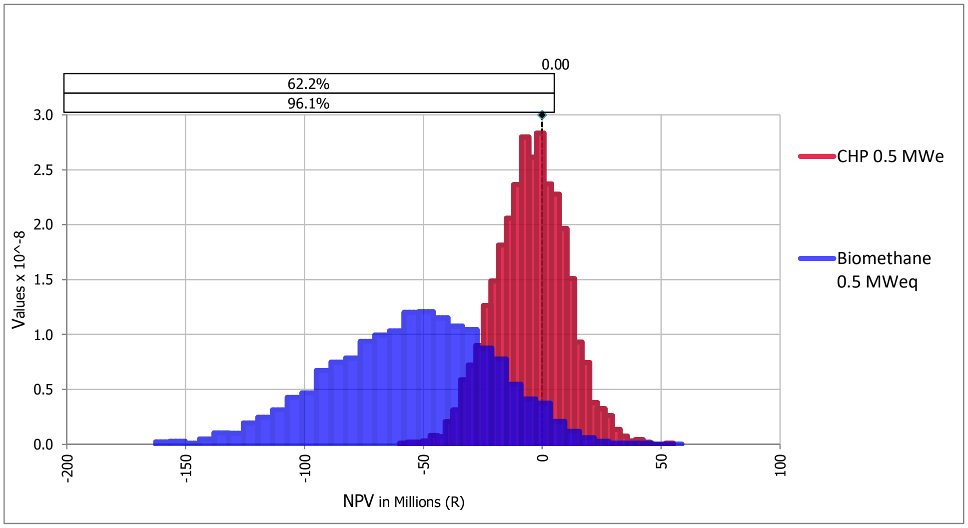
Biomethane

				Depreciation 1st 3 years																				
year	Revenue	Depreciation	Annual Gross Profit	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	NPV Millions
low	5 855 870	8 993 084	4 228 121	4 303 279	3 951 879	3 859 895	3 524 097	3 700 302	3 885 317	4 079 583	4 283 562	4 497 740	4 722 627	4 958 758	5 206 696	5 467 031	5 740 383	6 027 402	6 328 772	6 645 210	6 977 471	7 326 344	7 692 662	23
med	5 855 870	27 808 336	(1 694 094)	2 673 420	1 055 165	212 495	(1 412 010)	(1 482 611)	(1 556 741)	(1 634 578)	(1 716 307)	(1 802 123)	(1 892 229)	(1 986 840)	(2 086 182)	(2 190 491)	(2 300 016)	(2 415 017)	(2 535 767)	(2 662 556)	(2 795 684)	(2 935 468)	(3 082 241)	(58)
high	5 855 870	46 988 059	(11 153 808)	(1 452 413)	(4 485 282)	(6 222 561)	(9 296 587)	(9 761 417)	(10 249 487)	(10 761 962)	(11 300 060)	(11 865 063)	(12 458 316)	(13 081 232)	(13 735 293)	(14 422 058)	(15 143 161)	(15 900 319)	(16 695 335)	(17 530 102)	(18 406 607)	(19 326 937)	(20 293 284)	(171)
low	11 711 739	13 238 941	9 315 491	8 560 605	8 154 582	8 136 017	7 764 368	8 152 587	8 560 216	8 988 227	9 437 638	9 909 520	10 404 996	10 925 246	11 471 508	12 045 084	12 647 338	13 279 705	13 943 690	14 640 875	15 372 918	16 141 564	16 948 642	60
med	11 711 739	41 353 729	484 202	6 138 147	3 839 770	2 700 168	403 577	423 756	444 944	467 191	490 551	515 078	540 832	567 874	596 267	626 081	657 385	690 254	724 767	761 005	799 055	839 008	880 959	(61)
high	11 711 739	67 908 594	(12 871 172)	239 959	(4 026 284)	(6 414 255)	(10 727 993)	(11 264 393)	(11 827 612)	(12 418 993)	(13 039 943)	(13 691 940)	(14 376 537)	(15 095 364)	(15 850 132)	(16 642 638)	(17 474 770)	(18 348 509)	(19 265 934)	(20 229 231)	(21 240 693)	(22 302 727)	(23 417 864)	(219)
low	23 423 478	19 489 374	19 895 902	17 053 561	16 678 409	16 884 772	16 583 035	17 412 187	18 282 796	19 196 936	20 156 783	21 164 622	22 222 853	23 333 995	24 500 695	25 725 730	27 012 017	28 362 617	29 780 748	31 269 786	32 833 275	34 474 939	36 198 686	143
med	23 423 478	61 497 059	6 727 027	13 453 047	10 251 385	8 783 749	5 606 909	5 887 255	6 181 618	6 490 699	6 815 233	7 155 995	7 513 795	7 889 485	8 283 959	8 698 157	9 133 065	9 589 718	10 069 204	10 572 664	11 101 297	11 656 362	12 239 180	(38)
high	23 423 478	98 143 598	(12 104 504)	5 024 861	(906 943)	(4 112 514)	(10 088 983)	(10 593 432)	(11 123 104)	(11 679 259)	(12 263 222)	(12 876 383)	(13 520 203)	(14 196 213)	(14 906 023)	(15 651 324)	(16 433 891)	(17 255 585)	(18 118 364)	(19 024 283)	(19 975 497)	(20 974 272)	(22 022 985)	(260)
low	35 135 217	24 436 512	30 712 209	25 533 902	25 271 097	25 747 796	25 598 319	26 878 235	28 222 147	29 633 254	31 114 917	32 670 662	34 304 196	36 019 405	37 820 376	39 711 394	41 696 964	43 781 812	45 970 903	48 269 448	50 682 920	53 217 067	55 877 920	229
med	35 135 217	77 565 143	14 076 281	20 994 042	17 157 141	15 517 400	11 732 440	12 319 062	12 935 015	13 581 765	14 260 854	14 973 896	15 722 591	16 508 721	17 334 157	18 200 865	19 110 908	20 066 453	21 069 776	22 123 265	23 229 428	24 390 899	25 610 444	1
high	35 135 217	121 736 066	(8 933 238)	10 611 118	3 472 301	(273 985)	(7 445 765)	(7 818 053)	(8 208 956)	(8 619 404)	(9 050 374)	(9 502 892)	(9 978 037)	(10 476 939)	(11 000 786)	(11 550 825)	(12 128 366)	(12 734 785)	(13 371 524)	(14 040 100)	(14 742 105)	(15 479 210)	(16 253 171)	(269)
low	46 846 957	28 690 792	41 653 923	34 007 536	33 900 392	34 671 569	34 718 128	36 454 035	38 276 737	40 190 573	42 200 102	44 310 107	46 525 613	48 851 893	51 294 488	53 859 212	56 552 173	59 379 782	62 348 771	65 466 209	68 739 520	72 176 496	75 785 320	318
med	46 846 957	91 452 171	22 017 692	28 656 042	24 327 358	22 598 965	18 351 526	19 269 102	20 232 558	21 244 185	22 306 395	23 421 714	24 592 800	25 822 440	27 113 562	28 469 240	29 892 702	31 387 337	32 956 704	34 604 539	36 334 766	38 151 505	40 059 080	48
high	46 846 957	141 840 160	(4 499 181)	16 618 212	8 513 192	4 371 599	(3 750 023)	(3 937 524)	(4 134 400)	(4 341 120)	(4 558 176)	(4 786 085)	(5 025 389)	(5 276 659)	(5 540 492)	(5 817 516)	(6 108 392)	(6 413 811)	(6 734 502)	(7 071 227)	(7 424 789)	(7 796 028)	(8 185 829)	(262)
low	58 558 696	32 494 408	52 677 208	42 476 807	42 553 499	43 634 854	43 905 926	46 101 222	48 406 283	50 826 598	53 367 927	56 036 324	58 838 140	61 780 047	64 869 049	68 112 502	71 518 127	75 094 033	78 848 735	82 791 172	86 930 730	91 277 267	95 841 130	408
med	58 558 696	103 914 225	30 345 983	36 397 100	31 670 358	29 907 838	25 293 074	26 557 727	27 885 614	29 279 895	30 743 889	32 281 084	33 895 138	35 589 895	37 369 390	39 237 859	41 199 752	43 259 740	45 422 727	47 693 863	50 078 556	52 582 484	55 211 608	101
high	58 558 696	159 693 597	749 614	22 896 825	13 980 970	9 537 885	624 795	656 035	688 837	723 279	759 443	797 415	837 286	879 150	923 107	969 263	1 017 726	1 068 612	1 122 043	1 178 145	1 237 052	1 298 905	1 363 850	(244)
low	70 270 435	35 973 595	63 759 214	50 942 937	51 223 748	52 626 585	53 142 667	55 799 801	58 589 791	61 519 280	64 595 244	67 825 006	71 216 257	74 777 070	78 515 923	82 441 719	86 563 805	90 891 995	95 436 595	100 208 425	105 218 846	110 479 789	116 003 778	500
med	70 270 435	115 346 990	38 953 727	44 195 262	39 138 165	37 380 900	32 467 542	34 090 919	35 795 465	37 585 238	39 464 500	41 437 725	43 509 611	45 685 092	47 969 346	50 367 814	52 886 204	55 530 515	58 307 040	61 222 392	64 283 512	67 497 688	70 872 572	158
high	70 270 435	175 936 723	6 581 341	29 369 707	19 754 179	15 076 725	5 485 482	5 759 756	6 047 744	6 350 131	6 667 638	7 001 019	7 351 070	7 718 624	8 104 555	8 509 783	8 935 272	9 382 036	9 851 137	10 343 694	10 860 879	11 403 923	11 974 119	(219)

Annexure E: Risk assessment calculation files[3]

[3] These files can only be opened if @Risk software is installed

Risk Assesment - 0.5 MWe



Del X	Del Y
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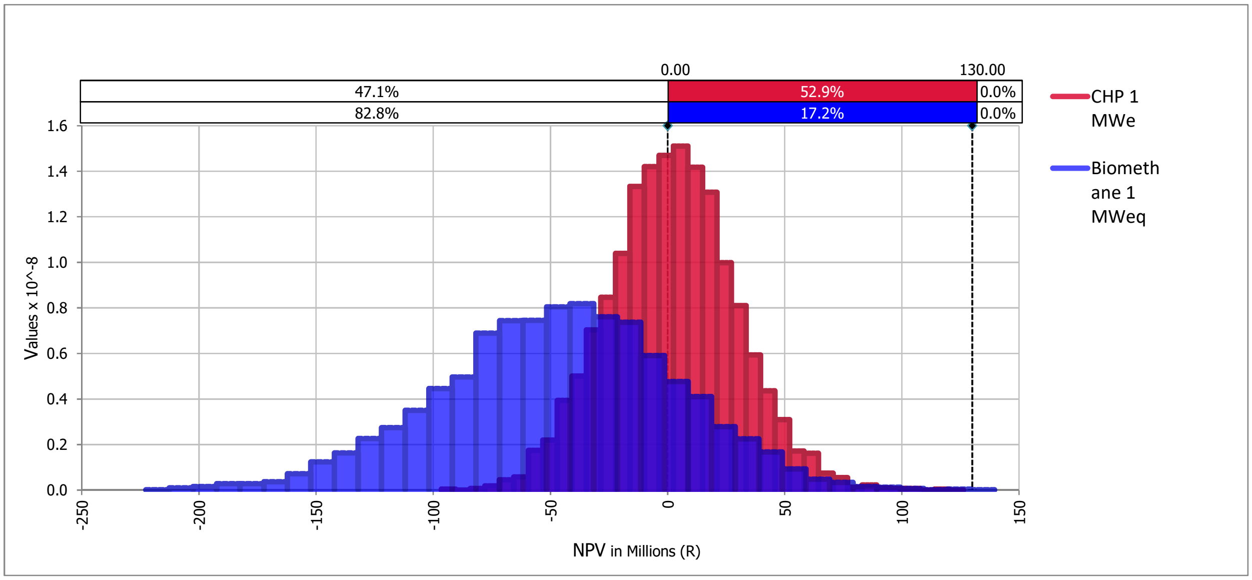
-400000000	0.00000003
580000000	0.00000003
280000000	0.00000003

X1	Y1	X2	Y2
-55828205.75	6.4025E-11	-769915265.2	1.16952E-11
-52704425.52	2.561E-10	-735713131.9	1.75428E-11
-49580645.28	2.561E-10	-701510998.5	5.84759E-12
-46456865.05	4.48175E-10	-667308865.2	1.16952E-11
-43333084.81	1.0244E-09	-633106731.9	3.50855E-11
-40209304.58	1.66465E-09	-598904598.5	4.09331E-11
-37085524.35	4.03357E-09	-564702465.2	4.67807E-11
-33961744.11	5.69822E-09	-530500331.8	5.84759E-11
-30837963.88	7.683E-09	-496298198.5	1.63732E-10
-27714183.64	9.66777E-09	-462096065.2	1.57885E-10
-24590403.41	1.31251E-08	-427893931.8	2.57294E-10
-21466623.18	1.74788E-08	-393691798.5	4.15179E-10
-18342842.94	1.77989E-08	-359489665.1	4.73655E-10
-15219062.71	2.11282E-08	-325287531.8	7.95272E-10
-12095282.47	2.42655E-08	-291085398.5	1.0935E-09
-8971502.24	2.45216E-08	-256883265.1	1.33325E-09
-5847722.006	2.63783E-08	-222681131.8	1.61393E-09
-2723941.773	2.66344E-08	-188478998.4	1.68995E-09
399838.4614	2.63143E-08	-154276865.1	2.1753E-09
3523618.695	2.33051E-08	-120074731.8	2.09344E-09
6647398.929	1.95916E-08	-85872598.42	2.4209E-09
9771179.163	1.41495E-08	-51670465.08	2.6782E-09
12894959.4	1.11403E-08	-17468331.74	2.81269E-09
16018739.63	7.55495E-09	16733801.6	2.47353E-09
19142519.87	4.8659E-09	50935934.94	2.11683E-09
22266300.1	4.0976E-09	85138068.28	1.3391E-09
25390080.33	2.49697E-09	119340201.6	1.01748E-09
28513860.57	1.98477E-09	153542335	6.90015E-10
31637640.8	8.32325E-10	187744468.3	4.32722E-10
34761421.04	4.48175E-10	221946601.6	3.74246E-10
37885201.27	3.8415E-10	256148735	1.9297E-10
41008981.5	3.8415E-10	290350868.3	9.35614E-11
44132761.74	2.561E-10	324553001.7	6.43235E-11
47256541.97	1.2805E-10	358755135	5.84759E-12
50380322.2	0	392957268.3	2.33904E-11
53504102.44	6.4025E-11	427159401.7	1.16952E-11
56627882.67	0	461361535	0

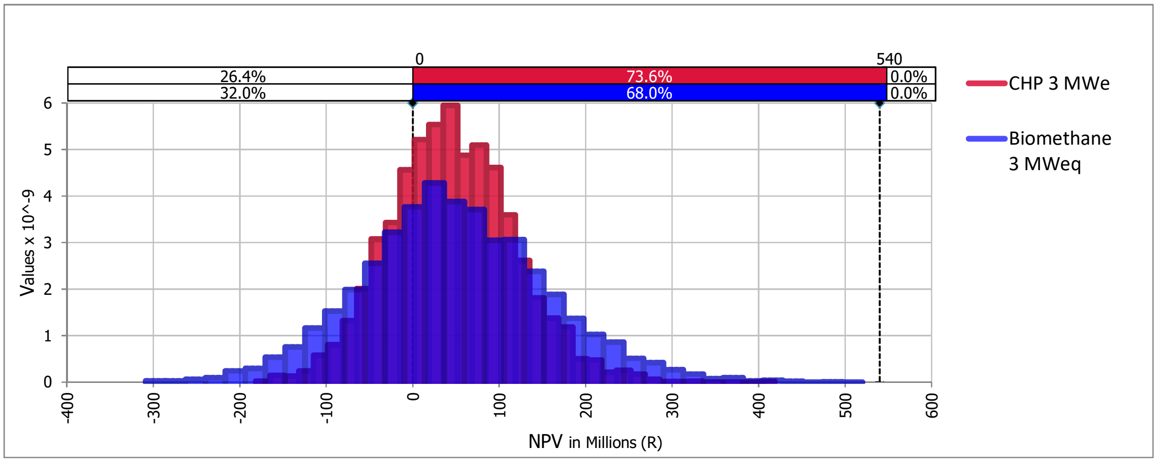
Risk Assessment 1MWe



Del X	Del Y
0	0.000000016
130000000	0.000000016
-125000000	0.000000016
140000000	0.000000016
65000000	0.000000016

X1	Y1	X2	Y2
-96631478.08	3.22948E-11	-222658760	1.98798E-11
-90438531.47	0	-212598319.4	9.93992E-11
-84245584.85	6.45896E-11	-202537878.7	1.59039E-10
-78052638.24	1.93769E-10	-192477438	2.78318E-10
-71859691.63	4.52127E-10	-182416997.3	2.78318E-10
-65666745.01	5.81306E-10	-172356556.7	3.57837E-10
-59473798.4	1.74392E-09	-162296116	7.15674E-10
-53280851.79	2.19605E-09	-152235675.3	1.23255E-09
-47087905.18	3.93997E-09	-142175234.6	1.63015E-09
-40894958.56	5.00569E-09	-132114794	2.2663E-09
-34702011.95	7.04027E-09	-122054353.3	2.74342E-09
-28509065.34	8.46124E-09	-111993912.6	3.49885E-09
-22316118.73	1.03989E-08	-101933471.9	4.45309E-09
-16123172.11	1.33378E-08	-91873031.27	4.96996E-09
-9930225.5	1.42097E-08	-81812590.6	6.89831E-09
-3737278.888	1.46941E-08	-71752149.93	7.43506E-09
2455667.725	1.5114E-08	-61691709.25	7.45494E-09
8648614.338	1.41774E-08	-51631268.58	8.05134E-09
14841560.95	1.30794E-08	-41570827.91	8.1905E-09
21034507.56	9.97909E-09	-31510387.23	7.61398E-09
27227454.18	8.106E-09	-21449946.56	7.37542E-09
33420400.79	5.94224E-09	-11389505.89	5.90431E-09
39613347.4	4.3598E-09	-1329065.215	4.77116E-09
45806294.01	3.1003E-09	8731375.458	4.11513E-09
51999240.63	1.71162E-09	18791816.13	2.78318E-09
58192187.24	1.61474E-09	28852256.8	2.24642E-09
64385133.85	7.42781E-10	38912697.48	1.66991E-09
70578080.47	5.49012E-10	48973138.15	9.34353E-10
76771027.08	1.29179E-10	59033578.82	4.77116E-10
82963973.69	2.26064E-10	69094019.5	3.37957E-10
89156920.3	9.68844E-11	79154460.17	1.59039E-10
95349866.92	6.45896E-11	89214900.84	1.19279E-10
101542813.5	6.45896E-11	99275341.52	7.95194E-11
107735760.1	0	109335782.2	1.98798E-11
113928706.8	3.22948E-11	119396222.9	3.97597E-11
120121653.4	0	129456663.5	1.98798E-11
126314600	0	139517104.2	0

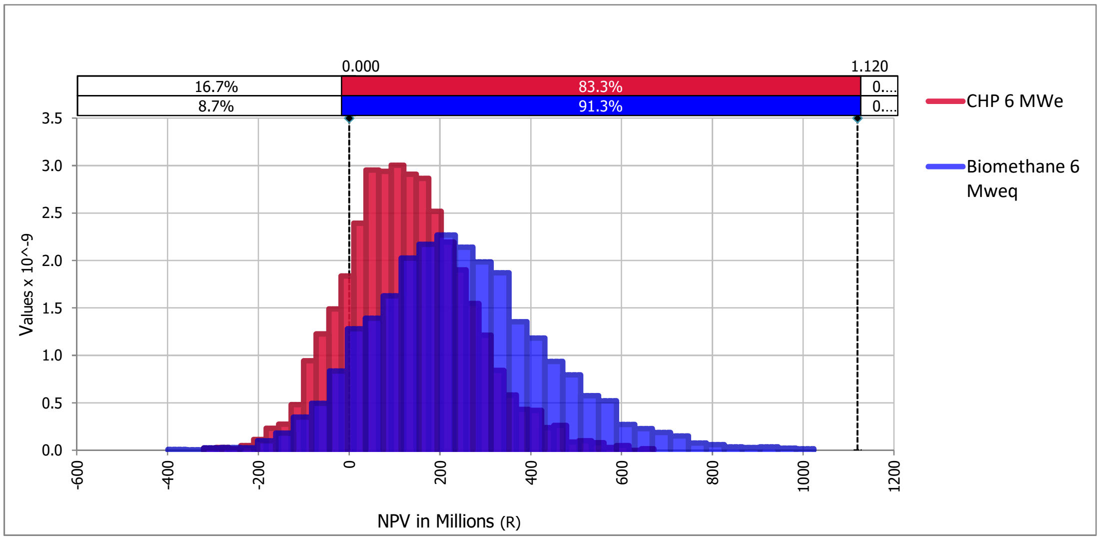
Risk Assessment 3 MWe



Del X	Del Y
0	0.000000006
540000000	0.000000006
-200000000	0.000000006
570000000	0.000000006
270000000	0.000000006

X1	Y1	X2	Y2
-181537275.7	2.398E-11	-308739241.8	2.60554E-11
-164856684.5	1.4388E-10	-285711405	2.60554E-11
-148176093.3	1.3189E-10	-262683568.2	6.0796E-11
-131495502.1	2.398E-10	-239655731.4	9.55365E-11
-114814910.9	5.75519E-10	-216627894.6	2.43184E-10
-98134319.72	8.03329E-10	-193600057.8	2.95295E-10
-81453728.52	1.3189E-09	-170572221	5.38479E-10
-64773137.32	2.01432E-09	-147544384.2	7.55607E-10
-48092546.12	3.08143E-09	-124516547.4	1.16381E-09
-31411954.92	3.42914E-09	-101488710.6	1.52858E-09
-14731363.72	4.56818E-09	-78460873.78	1.9889E-09
1949227.48	5.21564E-09	-55433036.98	2.55343E-09
18629818.68	5.53937E-09	-32405200.18	3.22219E-09
35310409.88	5.94703E-09	-9377363.382	3.76935E-09
51991001.08	4.87992E-09	13650473.42	4.28177E-09
68671592.28	5.09574E-09	36678310.21	3.88226E-09
85352183.48	4.61614E-09	59706147.01	3.70856E-09
102032774.7	3.59699E-09	82733983.81	3.04848E-09
118713365.9	2.61382E-09	105761820.6	3.06585E-09
135393957.1	1.81049E-09	128789657.4	2.37973E-09
152074548.3	1.37885E-09	151817494.2	1.88468E-09
168755139.5	1.18701E-09	174845331	1.37225E-09
185435730.7	5.03579E-10	197873167.8	1.02485E-09
202116321.9	4.79599E-10	220901004.6	8.59829E-10
218796913.1	2.1582E-10	243928841.4	5.12423E-10
235477504.3	2.5179E-10	266956678.2	4.16887E-10
252158095.5	1.6786E-10	289984515	2.69239E-10
268838686.7	5.99499E-11	313012351.8	1.73703E-10
285519277.9	1.199E-11	336040188.6	7.81663E-11
302199869.1	1.199E-11	359068025.4	9.55365E-11
318880460.3	2.398E-11	382095862.2	2.60554E-11
335561051.5	0	405123699	4.34257E-11
352241642.7	0	428151535.8	1.73703E-11
368922233.9	0	451179372.6	0
385602825.1	0	474207209.4	8.68514E-12
402283416.3	1.199E-11	497235046.2	0
418964007.5	0	520262883	0

Risk Assessment 6MWe



Del X	Del Y
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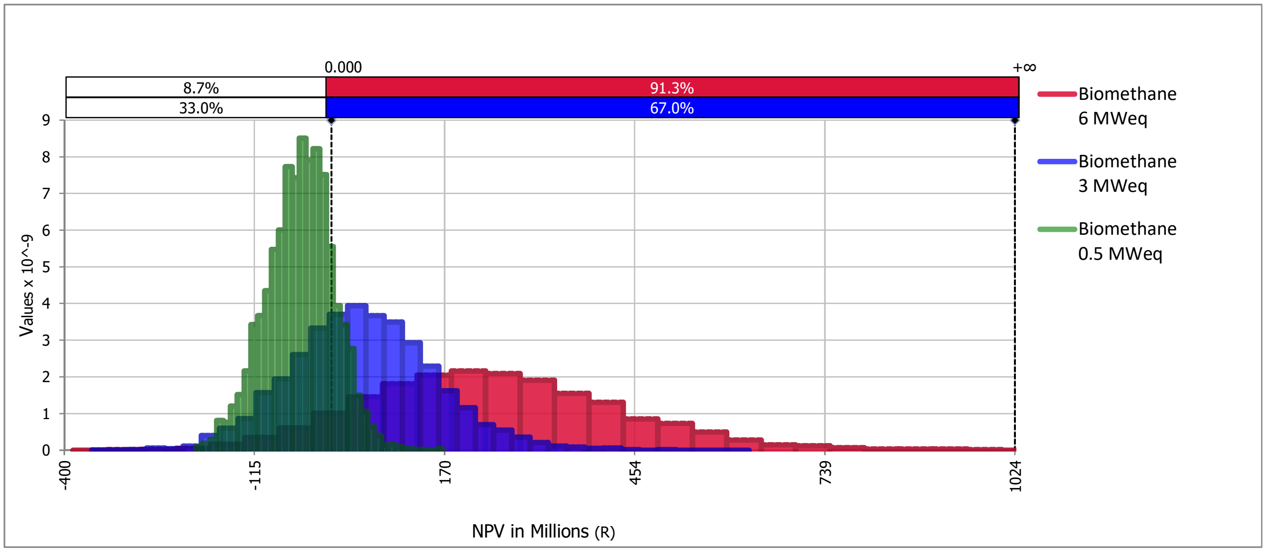
1120000000	3.5E-09
-300000000	3.5E-09
1160000000	3.5E-09
560000000	3.5E-09

X1	Y1	X2	Y2
-320642005.3	2.17722E-11	-399098885.6	1.01206E-11
-293083915.7	2.90296E-11	-359575348.1	5.06028E-12
-265525826.1	1.45148E-11	-320051810.6	2.53014E-11
-237967736.6	5.08018E-11	-280528273.1	3.03617E-11
-210409647	1.16118E-10	-241004735.6	2.53014E-11
-182851557.4	2.32237E-10	-201481198	1.01206E-10
-155293467.9	2.75781E-10	-161957660.5	1.8217E-10
-127735378.3	4.78988E-10	-122434123	3.49159E-10
-100177288.7	9.43462E-10	-82910585.47	4.95907E-10
-72619199.15	1.2265E-09	-43387047.95	8.34946E-10
-45061109.58	1.48777E-09	-3863510.428	1.28025E-09
-17503020.01	1.83612E-09	35660027.09	1.39158E-09
10055069.56	2.39494E-09	75183564.61	1.62941E-09
37613159.13	2.95376E-09	114707102.1	2.02411E-09
65171248.7	2.93925E-09	154230639.7	2.17086E-09
92729338.26	3.00456E-09	193754177.2	2.267E-09
120287427.8	2.91022E-09	233277714.7	2.1405E-09
147845517.4	2.86667E-09	272801252.2	1.98363E-09
175403607	2.51832E-09	312324789.7	1.8723E-09
202961696.5	2.19173E-09	351848327.3	1.35615E-09
230519786.1	1.90144E-09	391371864.8	1.1841E-09
258077875.7	1.54583E-09	430895402.3	9.36151E-10
285635965.2	1.21199E-09	470418939.8	7.94463E-10
313194054.8	8.41858E-10	509942477.3	5.76871E-10
340752144.4	5.80592E-10	549466014.9	5.21208E-10
368310233.9	4.28186E-10	588989552.4	2.73255E-10
395868323.5	4.20929E-10	628513089.9	2.27712E-10
423426413.1	2.39494E-10	668036627.4	1.8723E-10
450984502.7	2.61266E-10	707560164.9	1.51808E-10
478542592.2	8.70888E-11	747083702.5	7.59041E-11
506100681.8	1.01604E-10	786607240	6.07233E-11
533658771.4	7.98314E-11	826130777.5	3.54219E-11
561216860.9	2.90296E-11	865654315	3.03617E-11
588774950.5	5.08018E-11	905177852.6	3.54219E-11
616333040.1	0	944701390.1	2.02411E-11
643891129.6	1.45148E-11	984224927.6	1.51808E-11
671449219.2	0	1023748465	0

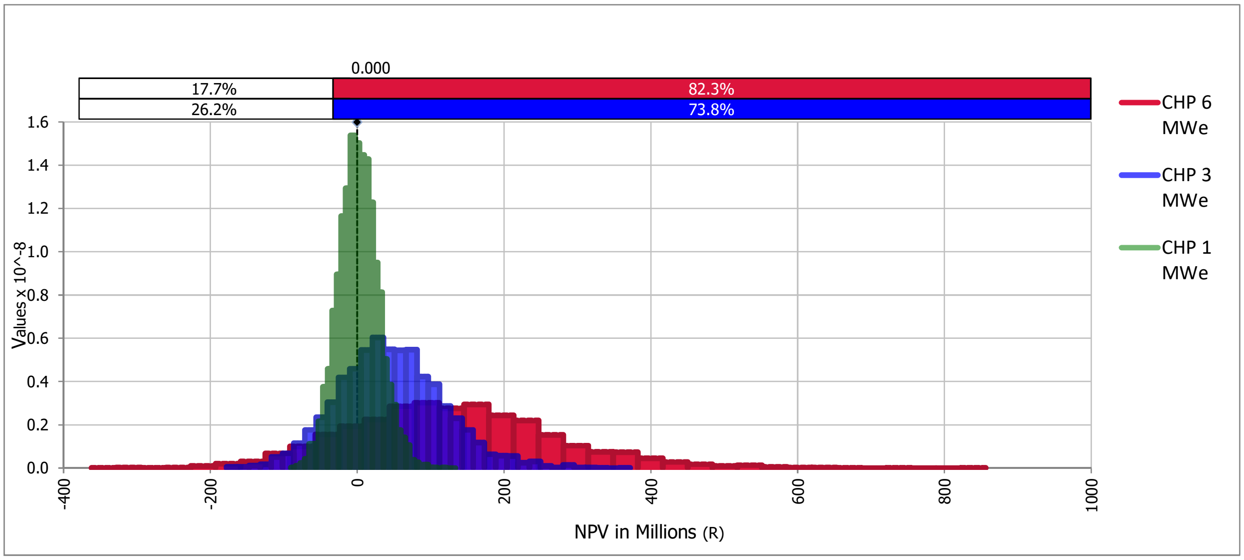
Comparative Risk Assessment - Biomethane



Del X	Del Y
0	0.000000009
1023750000	0.000000009
-200000000	0.000000009
1023750000	0.000000009
511875000	0.000000009

X1	Y1	X2	Y2	X3	Y3
-386879530.8	3.88258E-12	-358735865.4	7.31398E-12	-202794722.7	9.71456E-11
-335367329.1	1.55303E-11	-331390984.2	7.31398E-12	-192500893	1.94291E-10
-283855127.4	2.32955E-11	-304046103	1.4628E-11	-182207063.2	2.91437E-10
-232342925.7	5.04735E-11	-276701221.8	5.85119E-11	-171913233.4	8.16023E-10
-180830724	1.70833E-10	-249356340.6	4.38839E-11	-161619403.7	7.57735E-10
-129318522.3	3.45549E-10	-222011459.4	1.17024E-10	-151325573.9	1.20461E-09
-77806320.61	6.05682E-10	-194666578.2	4.02269E-10	-141031744.1	1.51547E-09
-26294118.92	1.01335E-09	-167321697	5.99747E-10	-130737914.4	2.15663E-09
25218082.78	1.45985E-09	-139976815.8	8.70364E-10	-120444084.6	3.41952E-09
76730284.47	1.80928E-09	-112631934.6	1.57251E-09	-110150254.8	3.6721E-09
128242486.2	2.05E-09	-85287053.45	1.93821E-09	-99856425.05	4.35212E-09
179754687.9	2.15871E-09	-57942172.26	2.61109E-09	-89562595.28	5.47901E-09
231266889.6	2.08883E-09	-30597291.07	3.32786E-09	-79268765.52	6.0036E-09
282779091.2	1.91023E-09	-3252409.875	3.70819E-09	-68974935.75	7.73279E-09
334291292.9	1.54915E-09	24092471.32	3.94224E-09	-58681105.98	7.42192E-09
385803494.6	1.30843E-09	51437352.51	3.67162E-09	-48387276.22	8.50995E-09
437315696.3	8.54167E-10	78782233.7	3.49608E-09	-38093446.45	7.90765E-09
488827898	7.33807E-10	106127114.9	2.93291E-09	-27799616.68	8.21852E-09
540340099.7	4.9697E-10	133471996.1	2.28928E-09	-17505786.92	7.51907E-09
591852301.4	2.79545E-10	160816877.3	1.6237E-09	-7211957.151	5.55673E-09
643364503.1	1.5142E-10	188161758.5	1.15561E-09	3081872.615	3.94411E-09
694876704.8	1.28125E-10	215506639.7	6.94828E-10	13375702.38	3.41952E-09
746388906.5	7.37689E-11	242851520.9	5.55863E-10	23669532.15	2.77836E-09
797901108.2	3.10606E-11	270196402	3.58385E-10	33963361.92	1.49604E-09
849413309.9	3.88258E-11	297541283.2	2.12106E-10	44257191.68	1.04917E-09
900925511.6	3.10606E-11	324886164.4	1.17024E-10	54551021.45	6.41161E-10
952437713.3	1.16477E-11	352231045.6	8.77678E-11	64844851.22	4.08011E-10
1003949915	3.88258E-12	379575926.8	5.11979E-11	75138680.98	1.36004E-10
1055462117	0	406920808	5.85119E-11	85432510.75	1.74862E-10
		434265689.2	2.19419E-11	95726340.52	9.71456E-11
		461610570.4	0	106020170.3	5.82873E-11
		488955451.6	1.4628E-11	116314000	3.88582E-11
		516300332.8	0	126607829.8	1.94291E-11
		543645214	0	136901659.6	1.94291E-11
		570990095.2	0	147195489.3	0
		598334976.3	0	157489319.1	3.88582E-11
		625679857.5	0	167783148.9	0

Comparative Risk Assessment - CHP



Del X	Del Y
0	0.000000016
1120000000	0.000000016
-200000000	0.000000016
1060000000	0.000000016
560000000	0.000000016

X1	Y1	X2	Y2	X3	Y3
-362063905.7	5.91056E-12	-178161427.8	5.23566E-11	-90370926.8	3.20898E-11
-328226146	1.77317E-11	-162881604.9	6.54458E-11	-84138424.66	9.62695E-11
-294388386.2	1.18211E-11	-147601781.9	1.17802E-10	-77905922.53	2.24629E-10
-260550626.5	2.36422E-11	-132321959	1.70159E-10	-71673420.39	4.17168E-10
-226712866.7	8.86584E-11	-117042136	5.10477E-10	-65440918.26	1.12314E-09
-192875107	1.95048E-10	-101762313.1	6.80636E-10	-59208416.13	1.12314E-09
-159037347.2	3.01438E-10	-86482490.13	1.15185E-09	-52975913.99	2.15002E-09
-125199587.5	6.73803E-10	-71202667.18	1.76704E-09	-46743411.86	3.75451E-09
-91361827.76	9.92974E-10	-55922844.23	2.34296E-09	-40510909.73	4.58885E-09
-57524068.01	1.55448E-09	-40643021.29	3.04977E-09	-34278407.59	7.28439E-09
-23686308.27	1.93275E-09	-25363198.34	4.18853E-09	-28045905.46	8.95307E-09
10151451.47	2.24601E-09	-10083375.39	4.59429E-09	-21813403.33	1.16486E-08
43989211.22	2.86071E-09	5196447.553	5.45818E-09	-15580901.19	1.29322E-08
77826970.96	3.02029E-09	20476270.5	6.0341E-09	-9348399.058	1.5371E-08
111664730.7	2.76023E-09	35756093.45	5.48436E-09	-3115896.924	1.5018E-08
145502490.4	2.93755E-09	51035916.39	5.44509E-09	3116605.209	1.44725E-08
179340250.2	2.44106E-09	66315739.34	5.47127E-09	9349107.343	1.428E-08
213178009.9	2.19873E-09	81595562.29	4.2278E-09	15581609.48	1.22904E-08
247015769.7	1.53674E-09	96875385.23	3.87439E-09	21814111.61	9.49859E-09
280853529.4	1.03435E-09	112155208.2	2.86653E-09	28046613.74	8.11873E-09
314691289.2	7.3882E-10	127435031.1	2.30369E-09	34279115.88	5.0381E-09
348529048.9	7.32909E-10	142714854.1	1.76704E-09	40511618.01	3.85078E-09
382366808.6	4.49202E-10	157994677	1.17802E-09	46744120.14	2.92018E-09
416204568.4	2.77796E-10	173274500	6.41369E-10	52976622.28	1.76494E-09
450042328.1	1.71406E-10	188554322.9	5.75923E-10	59209124.41	1.41195E-09
483880087.9	9.45689E-11	203834145.9	5.49745E-10	65441626.55	1.05896E-09
517717847.6	1.30032E-10	219113968.8	2.35605E-10	71674128.68	3.85078E-10
551555607.4	5.3195E-11	234393791.8	3.01051E-10	77906630.81	2.56719E-10
585393367.1	2.36422E-11	249673614.7	9.16241E-11	84139132.95	9.62695E-11
619231126.8	1.77317E-11	264953437.6	2.61783E-11	90371635.08	1.60449E-10
653068886.6	1.18211E-11	280233260.6	1.43981E-10	96604137.21	3.20898E-11
686906646.3	0	295513083.5	2.61783E-11	102836639.3	3.20898E-11
720744406.1	5.91056E-12	310792906.5	2.61783E-11	109069141.5	0
754582165.8	0	326072729.4	1.30892E-11	115301643.6	3.20898E-11
788419925.6	0	341352552.4	0	121534145.7	0
822257685.3	5.91056E-12	356632375.3	1.30892E-11	127766647.9	0
856095445	0	371912198.3	0	133999150	0