Integration of Distributed Energy Resources (Solar PV)

A Revenue Impact Study & Tariff Optimisation Analysis for EThekwini Municipality

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In fulfilment of the degree of Masters of Science, College of Agriculture, Engineering and Science, University of KwaZulu-Natal

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Examiner's Copy

As the candidate's supervisor, I agree with the submission of this dissertation.

Signed on 14/07/2020

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Signed on 14/07/2020

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DECLARATION 1 - PLAGIARISM

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DECLARATION 2 - PUBLICATIONS

Publication 1

L Moodliar, A.G. Swanson and F Ghayoor. *Integration of Distributed Energy Resources (DER's). A Revenue Impact Study & Tariff Optimization Analysis for EThekwini Municipality*. 9th Cigre Southern African Regional Conference, Johannesburg, 2019

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Leshan Moodliar

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ABSTRACT

The South African energy generation sector is naturally evolving from a traditionally vertically integrated structure to a more liberalised one via the promotion of local generation. The main drivers of such a transition are the rapid drop in generation technology prices, especially solar photovoltaic (PV) and the corresponding increase in electricity prices. While this transition is unconventional for South Africa, it does bring fresh opportunities for local economic stimulation and job creation. However, as the generation becomes more localised, customers reduce their energy dependency from the network due to their ability to self-consume generated electricity. This self-consumption creates an imbalance in the recovery of network-related charges for the municipality, i.e. creating a revenue loss. The rate of localisation of energy generation will dictate the magnitude of loss for the municipality.

To better understand the level of revenue loss associated with customers migrating to solar PV, a solar techno-economic model was designed and analysed with eThekwini Municipality's unique loading and generation data.

The model showed that customers were deemed feasible if their projects met the minimum Internal Rate of Return (IRR) of 15% and a maximum Simple Payback Period (SPBP) of ten years. Based on the number of feasible customers migrating to PV under various scenarios, the municipal revenue loss was quantified. The potential renewable energy (RE) that could be introduced onto the grid for each scenario was also quantified. The electricity tariff structures were optimised for each customer category within eThekwini Municipality to mitigate revenue losses. The optimised tariff structures were focussed on introducing fixed network access charges, based on the PV inverter size and a buy-back tariff for energy exported onto the grid.

In instances where customers adopt a long term view for solar PV investing, and accept to calculate the IRR over 25 years, 37% of customers met the feasibility criteria. This resulted in the municipality potentially losing R1.041 billion and gaining 1343 MW of RE, should all feasible customers install solar PV. Applying generation limits as per NRS 097-2-3, resulted in a municipal revenue loss of R959 million and a RE gain of 1251 MW. Introducing RE tariffs to counteract the revenue loss, in conjunction with the generation limits resulted in only 3.9% of customers remaining feasible, with a reduced RE gain of 722 MW.

Applying the NRS 097-2-3 generation limits and calculating the IRR over 10 years, resulted in 31% of customers meeting the feasibility criteria. Under these conditions, the municipality could potentially lose R 397 million and gain 684 MW of RE should all feasible customers install solar PV. Introducing RE tariffs to counteract the revenue loss resulted in zero customers meeting the feasibility criteria.

The revenue losses were introduced because the current municipal tariffs recover fixed network charges via variable energy rates. Each unit of electricity offset due to self-consumption via solar PV results in fixed network costs incorrectly being offset as well, due to the nature of the current tariff design.

RE tariffs were designed to remedy this anomaly. They incorporated fixed network charges and a buy-back energy rate, priced at the avoided cost. The RE tariffs have been optimised to position the municipality in a revenue neutral position as solar PV is introduced, resulting in no windfall gain or inadvertent revenue losses to the municipality.

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ACRONYMS

No.	Term	Description
1	SPBP	Simple Pay Back Period
2	IRR	Internal Rate of Return
3	SSEG	Small Scale Embedded Generation / Generator
4	NPC	Net Present Cost
5	ROI	Return on Investment
6	SARS	South African Revenue Service
7	NERSA	National Energy Regulator of South Africa
8	LCOE	Levelized Cost of Energy
9	PV	Photo-Voltaic
10	RE	Renewable Energy
11	REIPPP	Renewable Energy Independent Power Producer Program
12	kW	Kilowatt
13	MW	Megawatt
14	GW	Gigawatt
15	IBT	Inclining Block Tariff
16	FiT	Feed-in Tariff
17	ERA	Electricity Regulation Act
18	MFMA	Municipal Finance Management Act
19	MSA	Municipal Systems Act
20	NMP	Net Metering Policy
21	IE	Import Energy
22	EE	Export Energy
23	DOE	Department of Energy
24	R&D	Research & Development
25	BRICS	Brazil, Russia, India, China, South Africa
26	IRP	Integrated Resource Plan
27	NEDLAC	National Economic Development and Labour Council
28	VOS	Value of Solar
29	AW	Annual Worth
30	PW	Present Worth

INTERCHANGEABLE TERMS

No.	Term	Interchangeable Term
1	Utility	Municipality
2	Distributed Energy Resources (DERs)	Small Scale Embedded Generator (SSEG)
3	Solar photovoltaic (PV)	Photovoltaic (PV)
4	Electricity Grid	Electricity Network
5	Distribution	Reticulation
6	Feed-in Tariff (FiT)	Export Tariff or Buy Back Tariff
7	Consumption Tariff	Import tariff
8	Customer	Consumer or Prosumer

1 CHAPTER 1: OVERVIEW

1.1 Introduction

Small Scale Embedded Generation (SSEG), specifically solar PV, is fast becoming a more financially feasible option when compared to grid-supplied electricity. Within eThekwini, there has been widespread activity around the installation of PV systems and generation of electricity for their own use. Generation of electricity for own use has led to reduced consumption of grid electricity. The high cost of technology and regulatory uncertainty in South Africa have historically hindered the widespread rollout of PV systems. The cost of technology has seen a decline in the past ten years, and the amendment of Schedule 2 of the Electricity Act in 2017 has positively influenced the uptake of PV systems. The uptake of PV is further enhanced by the higher than inflationary electricity increases over the past ten years.

Amendment to Schedule 2 of the Electricity Regulation Act (ERA) allows for generation and trading of electricity up to one Megawatt (MW) via a regulatory registration process as opposed to a licensing process [1]. The newly introduced registration process can be viewed as a partial liberation of the generation and retail sector on small and medium scale generation.

The South African Revenue Service (SARS) is lending a hand to the economic case of localised generation installed by businesses. The current tax incentive (12B), allows for the full depreciation of the generation asset in year one [2]. The benefit is gained by reflecting the total depreciation value as an expense, reducing the yearly tax burden. The introduction of the carbon tax will further strengthen the economic case for the adoption of localised generation.

While the notion to promote RE is welcomed, municipalities now find themselves competing against local generators and traders of electricity while operating as a regulated distribution entity. The impact of this regime will bring about reduced electricity sales for the municipality and ultimately revenue losses. Reduced sales will mainly be experienced due to the self-consumption of generated electricity. The extent of the revenue loss and the mitigation actions thereof will dictate the future sustainability of the municipality. Graffy and Kihm [3] described the phenomenon as disruptive competition that will erode the natural monopoly of network service providers.

The current trend within eThekwini municipality highlights the declining nature of electricity sales. Declining sales is a worrying trend against a backdrop of a growing customer base and an increasing capital and maintenance budget. The current declining sales trend is not solely attributed to the increase in localised generation; it does, however, indicate the plausible reality as higher levels of self-generation materialise.

The current municipal distribution business is a capital-intensive one with long-term cost recovery models. Failure to secure long-term continuous network usage or stable network pricing will lead to financial difficulty for eThekwini Municipality. Governments throughout the world are still trying to figure out the real impact that renewable generation will have on traditional utility revenue models [4].

In trying to understand the impacts of RE better, the study focused on quantifying the revenue losses applicable to eThekwini municipality, as PV generation systems materialise. Various factors were considered for modelling purposes. These included the application of generation limits in accordance with NRS 097-2-3 [5] as well as investment horizons, by considering the IRR calculation over ten years and 25 years. The study further attempted to propose realistic tariff optimisation options that mitigated the revenue losses while promoting the uptake of PV.

1.2 The strategic importance of the study and contribution

The introduction of solar PV within the electricity distribution and reticulation sector is bound to disrupt the traditional operation of the sector. Disruption will introduce risks as well as opportunities. This study sought to unpack the level of financial risk associated with PV introduction to eThekwini Municipality. Further, the study has sought to understand the potential of harnessing the opportunities that such disruption would introduce.

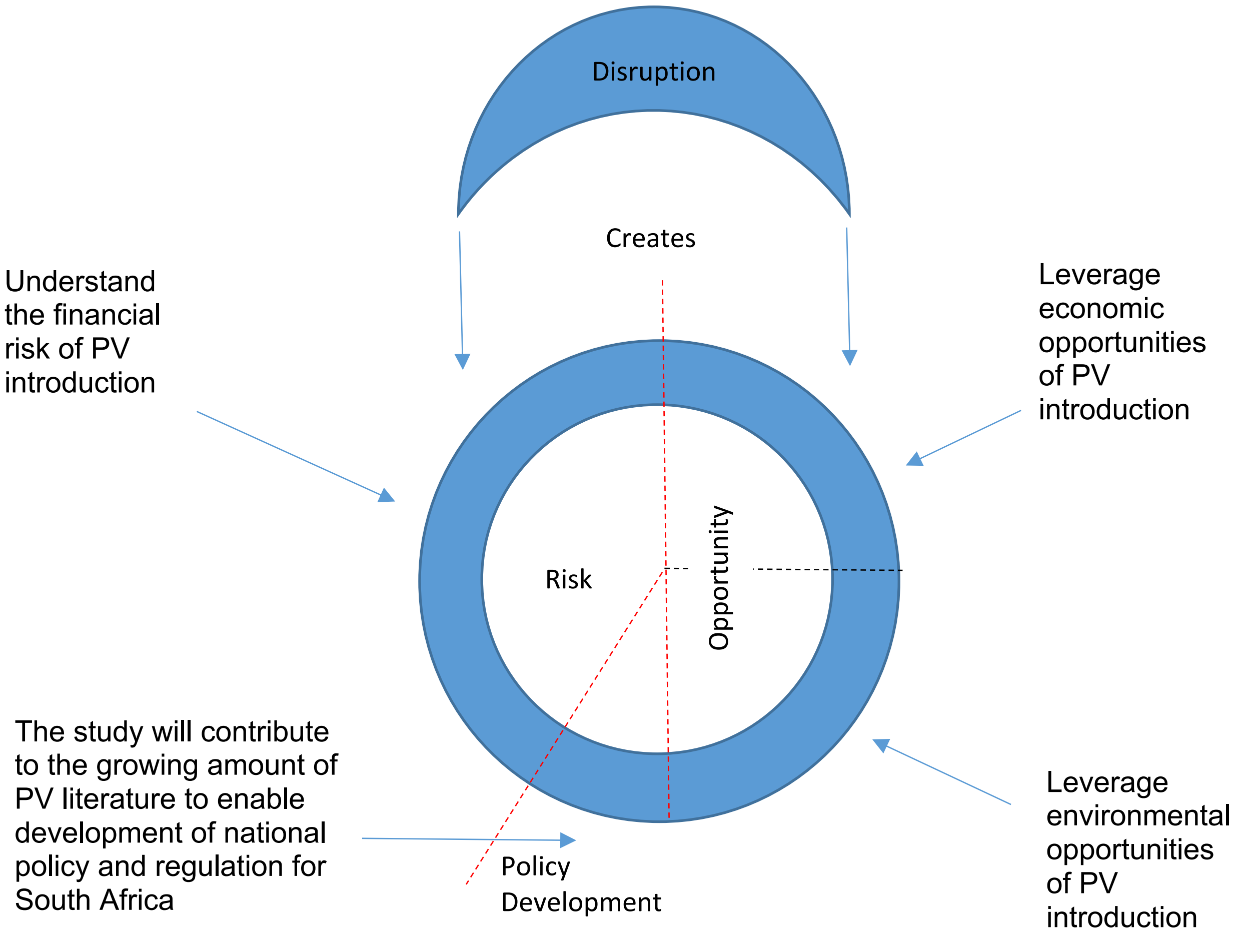


Figure 1 Risk and opportunities of solar PV introduction to eThekwini Municipality

1.2.1 Understanding the financial risks

Electricity reticulation and distribution are some of the core functions of eThekwini Municipality as endorsed by its distribution licencing criteria. These functions allow the municipality to build and operate a distribution grid. Further duties include the provision of electricity to customers, which drives the social program of uplifting the lives of the people through the provision of essential services.

Any factor that could negatively affect the provision of electricity services must be thoroughly understood, assessed and mitigated to ensure continuity of essential services to the people. The study allows for an in-depth understanding of the financial impacts of solar PV introduction and a proposal for mitigating any financial losses. Mitigating and management of financial losses will allow for the continuity of the social service provision and sustained electricity grid operations.

1.2.2 Regulatory and policy development

There are currently limited regulatory guidelines available to municipalities on renewable generation tariffing principles. The lack of regulation creates uncertainty and places eThekwini Municipality at risk. The study quantifies the financial risk elements and portrays plausible mitigation options for the municipality. The learning principles of the study could further be used to aid the introduction of solar PV tariff regulations and benchmarks at a national level.

1.2.3 Economic stimulation and job creation

Solar PV brings the opportunity for the introduction of new technology and development. When scaled correctly, this has the potential of accelerating direct job creation, contributing to GDP growth, the emergence of new services/sectors and business innovation [6]. The study presents the economic/financial case for PV projects as distribution electricity tariffs are optimised. Knowing the economic/financial parameters of each customer's project ensures that eThekwini Municipality can make the most favourable decision of PV deployment while levering its relevant economic potential of job creation and GDP growth.

The City of Johannesburg was able to create 68 job opportunities when it rolled out a solar PV project for three sites totalling approximately 0.91 MW [7].

The South African Renewable Independent Power Producer Program (REIPPP) almost doubled its job opportunities from 17800 jobs in 2014 to 36500 jobs in 2018. 85% of all jobs were created in the construction phase, while the balance of the 15% was created in the operational period [8].

Understanding the relationship between GDP growth and RE requires complex studies and evaluations. However, studies indicate that GDP and RE in most cases are linked via a positive relationship that has long term benefits for a country [9].

1.2.4 Accelerated contribution to RE targets

Creating an enabling platform to promote PV will allow for the contribution to the RE targets of eThekwini Municipality. Contributing to RE targets will also add to a reduced carbon emission profile for the municipality. Routhier and Honsberg [10] agreed that one way to combat the release of carbon dioxide into the atmosphere is to install large amounts of RE resources like PV.

This study presents the relevant financial impact assessment of PV deployment against the contribution to RE targets. The attainment of this information allows eThekwini Municipality to make optimum decisions on PV deployments while levering its contribution to RE targets and a reduced carbon footprint.

1.3 Dissertation focus

The focus of the dissertation was to understand the impact that customer initiated solar PV projects would introduce to eThekwini Municipality. This included focussing mainly on the financial aspects with a view of mitigating any negative impacts via the introduction of RE tariffs. Further emphasis was placed on understanding how the deployment of PV by customers would contribute to the RE targets of eThekwini Municipality. In line with the dissertation focus, the following hypothesis and research questions were applicable:

1.3.1 Hypothesis

The hypothesis is that the electricity tariffs can be optimised, such that the revenue of the municipality is preserved as PV is introduced, and that customers can benefit from the PV installation.

1.3.2 Research questions

a) What percentage of customers within eThekwini Municipality meet favourable investment criteria to install PV systems, considering the current retail tariffs and optimised RE tariffs designed to protect municipal revenue?

b) What level of revenue loss would PV projects initiate for eThekwini Municipality, considering the current retail tariffs and optimised RE tariffs designed to protect municipal revenue?

c) What level of contribution would customer installed PV systems make, towards the 2030 and 2050 RE targets of eThekwini Municipality, considering the current retail tariffs and optimised RE tariffs designed to protect municipal revenue?

1.4 Limitations and assumptions of the study

a) The study focuses on calculating the optimum generation size (i.e. least NPC) based on the customer loading irrespective of the availability of roof (or generation) space. It, therefore, excludes plausible generation in cases where there is space available, however no loading and vice versa.

b) Customers on obsolete tariffs have been excluded from the study. Customers with zero consumption or account anomalies were excluded from the modelling.

c) The study assumes that solar irradiation data is constant throughout eThekwini and ignores the effects of shading. The study further assumes PV systems are correctly installed with optimum panel orientation.

d) The study assumes that all residential and business customers consume electricity in accordance with typical loading profiles, respectively.

e) Generation capacities for all customers were limited to 1000 kW at maximum and 1 kW at minimum.

f) Medium Voltage (MV) generators were assumed to be sufficiently dispersed within the network, without breaching any supply parameters, including NRS 097-2-3 as applicable. In the absence of a fully connected network diagram, the assumption was deemed fair and reasonable as medium voltage customers accounted for 0.005% of the total modelled customer base.

g) High Voltage (HV) generators were assumed to be sufficiently dispersed within the network, without causing any negative impacts nor breaching any supply parameters of the network. In the absence of a fully connected network diagram, the assumption was deemed fair and reasonable as high voltage customers accounted for 0.002% of the total modelled customer base.

1.5 Dissertation structure

The dissertation can be broadly categorised into six chapters, as depicted below.

Table 1 Dissertation structure summarised per chapter

Chapter	Description
1. Overview	The problems of solar PV integration to a municipal environment is broadly discussed, creating a platform for the formulation of the research questions and hypothesis.
2. Literature review	An overview of the growth of solar PV, the shift in electricity usage topologies and methods of recovering costs via tariffs are discussed. Principles highlighting the concept of a continuous declining revenue stream for municipalities as consumption decreases is also discussed. The chapter concluded with plausible tariff optimisation strategies based on global experiences. Learnings from these experiences aided the tariff optimisation process to mitigate the adverse financial effects of PV introduction.
3. RE tariff design	In line with the learnings of the literature review, a solar techno-economic modelling tool was designed and implemented to balance the negative financial impacts of PV integration while promoting their uptake. This chapter further elaborates on the inputs/outputs parameters of the model and provides an overview of the execution and calculation methodology.
4. Scenario modelling	Various scenarios were modelled utilising the solar techno-economic modelling tool to understand the factors influencing the economic parameters and uptake of PV projects.
5. Results and recommendations	Key results are presented with optimal RE tariff recommendations to avoid municipal revenue losses. The results and tariff recommendations are portrayed per customer category (i.e. residential, business and industrial).
6. Conclusion	The key objectives of the dissertation are correlated against the key findings. Further, the results for each customer category is summarised based on the various modelled scenarios. The summary included economic criteria and realisation of potential RE generation per scenario. Two essential areas of study for future improvements were highlighted to ensure a sustained and continued approach for PV integration. One area focussed on evaluating the technical impacts of solar PV integration to the municipality while the other focussed on impacts of battery storage on future tariff design.

2 CHAPTER 2: LITERATURE REVIEW

2.1 Aim of review

The primary objective of the literature review is to:

2.1.1 Provide a broad overview of the impact that SSEG has within various aspects within the distribution and reticulation environment. Specific focus was placed on understanding the financial impact on municipal revenue.

2.1.2 Evaluate existing literature and reach consensus on the need to augment the existing tariff revenue recovery model for eThekwini Municipality due to the introduction of PV.

2.1.3 Evaluate existing literature and reach consensus on the need to construct optimised RE tariffs while promoting the uptake of PV.

2.2 Method of review

The global research, views and opinions of various authors were used to highlight the concerns surrounding the introduction of PV to the local municipal environment. These concerns were contrasted to the actualities of eThekwini Municipality to give context and applicability to the arguments and resolutions. The review was conducted based on local, national and international information spanning across 27 years (i.e. 1992 to 2019) to ensure a comprehensive outline.

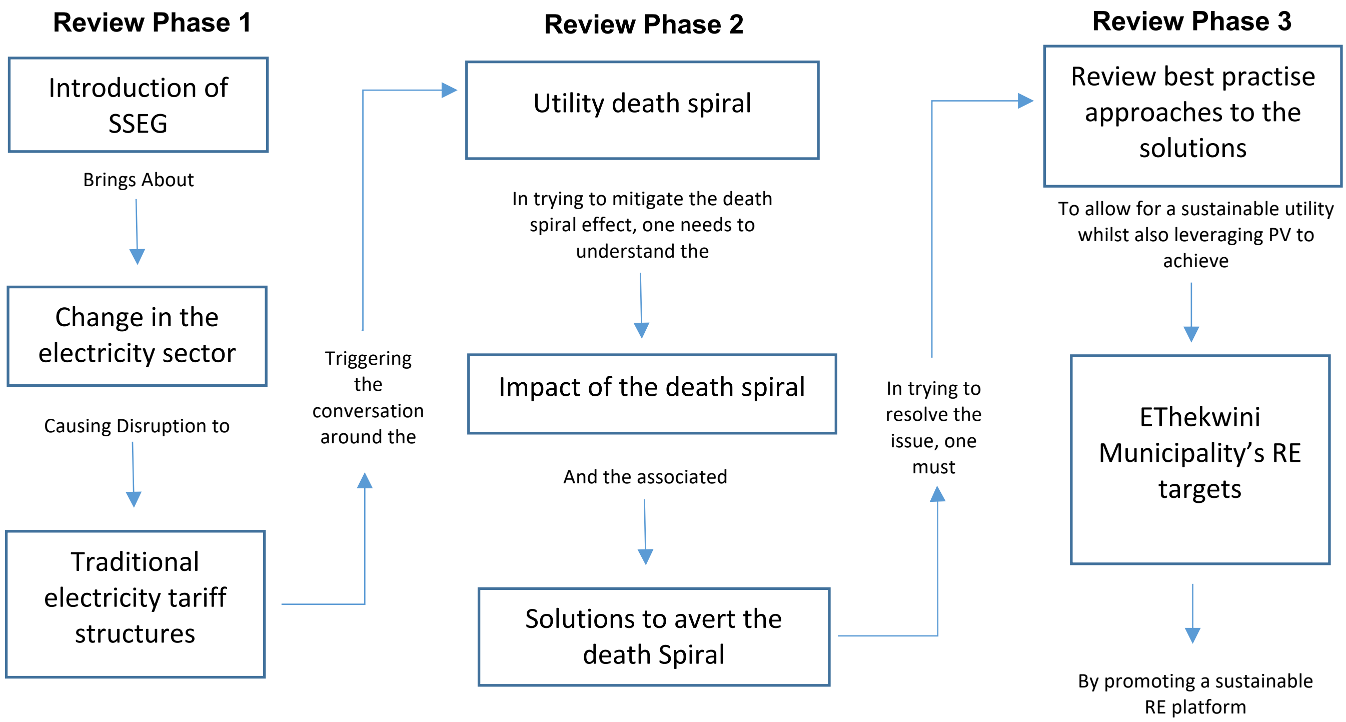


Figure 2 Understanding the literature review

Table 2 Breakdown of literature review per section

Review Phase	Description of Section	Key Outcome:
Literature Review Phase 1	**The growth of solar PV** Highlighting the rate at which solar PV is being developed and embraced globally.	To understand the rate at which solar PV is growing globally
	The reasons for the growth of solar PV Highlighting typical and plausible reasons promoting the adoption rate of solar PV.	To understand the reasons for the newfound interest in PV.
	The shift in electricity usage and generation topologies Highlighting typical shifts in the electricity usage topologies as a result of more RE and storage options being available	To understand how electricity generation and usage are being disrupted, leading to the creation of a new era of generation and usage topologies.
	Traditional electricity tariff structures Highlighting conventional electricity tariff structures and their means of revenue recovery.	To understand how electricity costs were traditionally recovered and the standard tariff structures.
Literature Review Phase 2	**Definition of the death spiral** **Impact of the death spiral** **The shift in the revenue recovery mechanism** These sections provide an overview of the realities of maintaining traditional tariff structures in an era of PV introduction, declining sales and rising costs.	To understand the potential impacts on municipalities as the growth of PV materialises.
	The solutions to avert the death spiral Highlighting plausible solutions that could be implemented to avoid municipalities losing revenue as PV is introduced to the grid. Highlighting plausible business model diversification ideas to ensure municipalities remain sustainable.	To understand the possible mitigation scenarios in avoiding negative financial impacts to municipalities as PV is introduced.
Literature Review Phase 3	**Principles of RE tariff design** **Types of RE tariff mechanisms** **Applicability of RE tariff mechanisms in eThekwini Municipality** These sections provide an overview of the best practise approaches in redesigning the current electricity tariff structures and rates for eThekwini Municipality to cater for the dynamics of PV.	To understand the options available to municipalities in implementing RE tariffs.
	Carbon emissions and RE targets This section provides an overview of RE targets and their contribution to reducing carbon emissions.	To understand the RE and carbon reduction targets of eThekwini Municipality.

2.3 The growth of solar PV

The global solar landscape has shown signs of significant growth over the years. The world total solar PV capacity is estimated at 505 GW with BRICS countries contributing 214 GW and EU countries contributing 115 GW. The balance of the 176 GW is spread across the world. The top 10 countries for solar PV capacity and additions as of 2018 are highlighted below [11]:

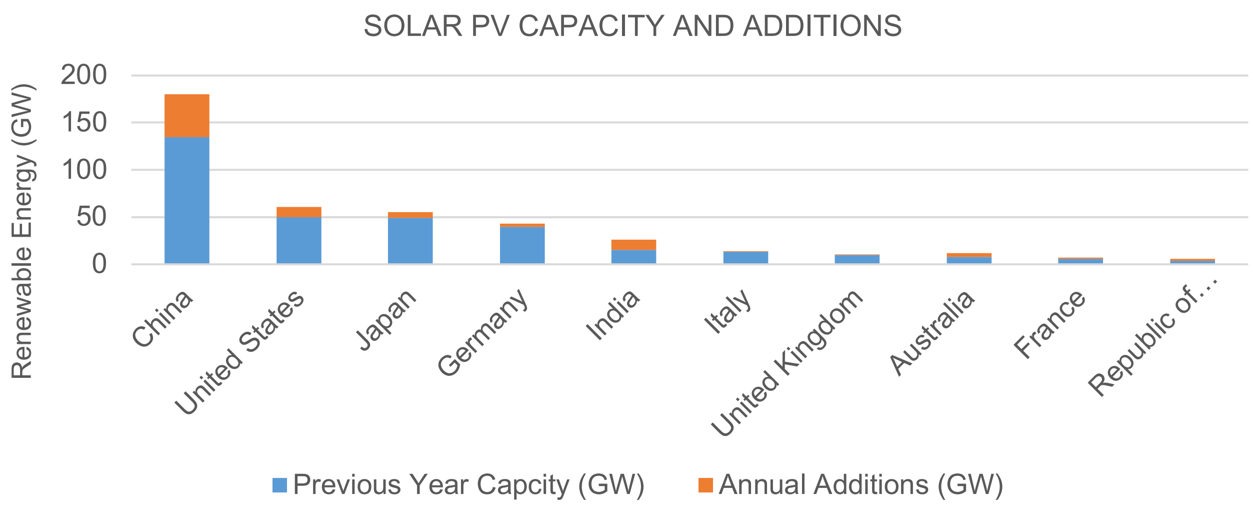


Figure 3 Top 10 countries for solar PV capacity & additions

The installed capacity of PV and the annual additions are dynamic and vary per country. The leading three countries with the highest concentration of solar PV in the world is China, the United States and Japan. Growth rates have been phenomenal. China has expanded its solar PV capacity by 35% in 2018 alone.

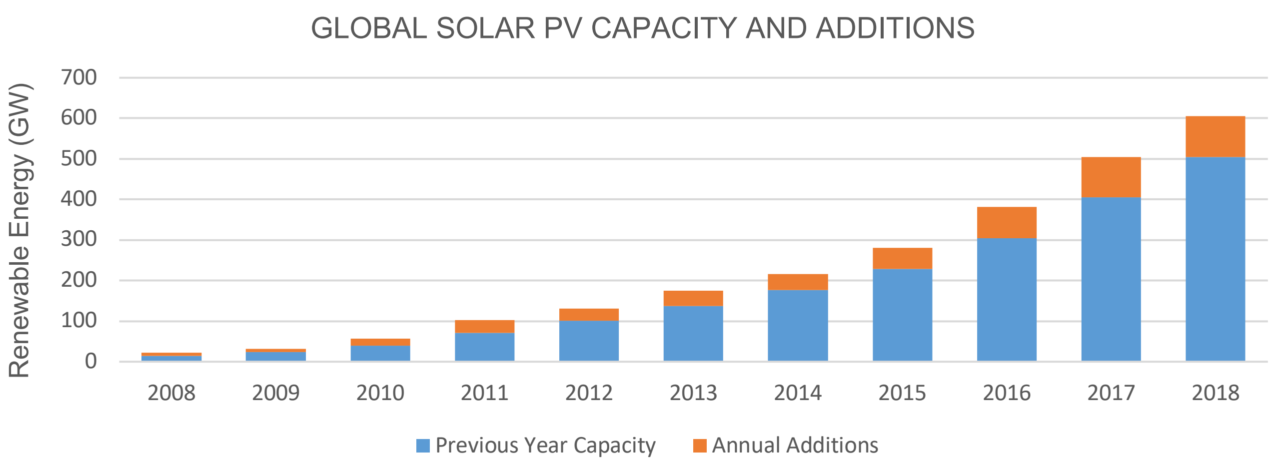


Figure 4 Global solar PV capacity & additions

The global account for solar PV was at 15 GW in 2008. Ten years later, this increased by 3267% to 505 GW. There is no doubt that that the global transition to make solar-powered generation a part of the generation mix has commenced and will be continuing. This shift in the adoption of generation technologies is sure to bring about change in the electricity sector.

2.4 Reasons for the growth of solar PV

The global solar PV uptake growth rate of 3267% over the past ten years indicates that electricity generated via solar is fast becoming a more preferred option when compared to grid-supplied electricity. Within eThekwini, there has been widespread activity by customers around the installation of PV and generation of electricity for their own use.

This self-consumption has led to reduced consumption of grid electricity. The high cost of technology and regulatory uncertainty in South Africa have historically hindered the widespread rollout of PV.

The cost of PV technology has continuously been declining. There has been a decline of PV installed residential system costs in the United States over the last eight years [12]. General cost reductions are attributed to higher efficiency modules and inverters largely attained due to focussed research and development (R&D). Further cost reductions were achieved due to economies of scale, enhanced manufacturing processes and by the principle of learning by doing [13].

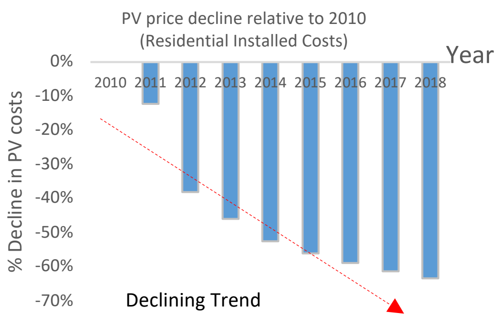


Figure 5 PV Price decrease relative to 2010

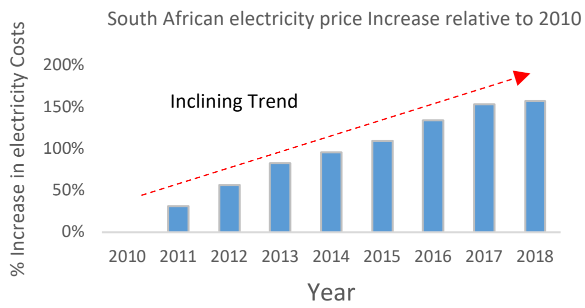


Figure 6 Electricity price increase relative to 2010

Contrary to the declining cost curve of PV technology, the national electricity prices in South Africa have been continuously rising. The sharp increasing price trend is because of the debt-laden national supplier, trying to reach the plateau of the actual cost of supply pricing.

Amendment to Schedule 2 of the Electricity Regulation Act (ERA) allows for generation and trading of electricity up to one megawatt (MW) via a regulatory registration process as opposed to a licensing process. This can be viewed as a partial liberation of the generation and retail sector for small and medium scale generation [1].

The South African Revenue Service (SARS) is lending a hand to the economic case of localised generation installed by businesses. The current tax incentive (12B), allows for the full depreciation of the generation asset in year one [2]. The benefit is gained by reflecting the total depreciation value as an expense, reducing the yearly tax burden. The looming introduction of the carbon tax will further strengthen the economic case for the adoption of localised generation [14]. The carbon tax was also cited as a feasible accelerator for PV systems in Qatar [15].

The draft Integrated Resource Plan (IRP) 2018 update for National Economic Development and Labour Council (NEDLAC) energy task team was developed to respond to the rapid changes in technology advancements that were creating uncertainty on how that would affect the generation trajectory of the country. 200 MW per annum was allocated to embedded generation technologies to try to harmonise greater certainty in generation capacity for the next decade [16]. This introduction into the draft IRP has formally recognised the embedded generation sector and gave certainty to its continued existence in South Africa. The IRP 2019 made allowance for 500 MW of embedded generation annually from 2023 until 2030 [17].

2.5 The shift in electricity usage & generation topologies

Due to the enabling environment for PV and developing storage options, there will be a shift in the topology on how electricity is consumed by customers, which will be different from legacy methodologies. The diagram below provides a summary of the changing landscape and potential technology uptakes within the electricity sector [18].

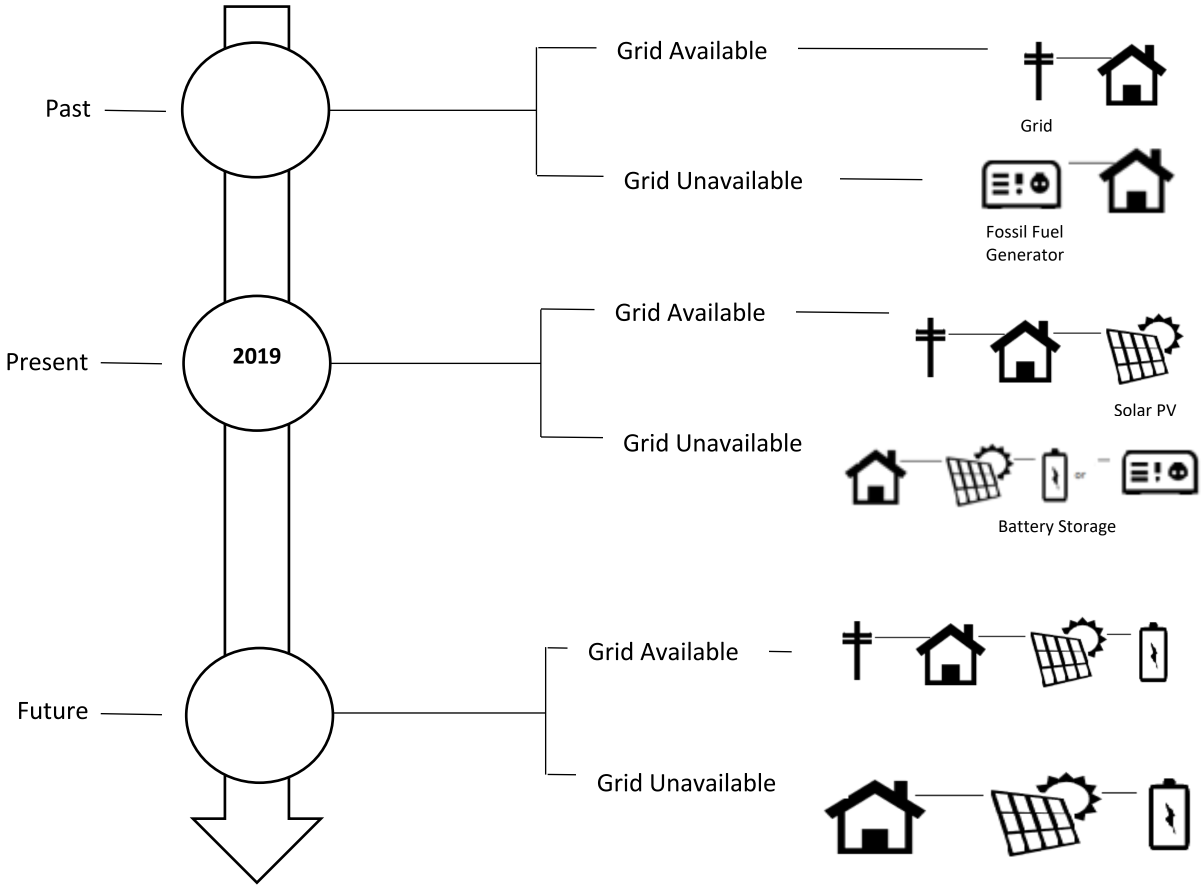


Figure 7 Change in electricity supply topology – Own elaboration based on [18]

2.5.1 The past

The cheapest form of electricity was grid electricity. As an alternate during grid failure, fossil fuel-fired generation was a suitable alternative. RE technologies were considered expensive and unreliable. There was also low social acceptance and lack of commoditisation of panels, inverters and associated equipment, which made it unpopular.

2.5.2 The present

The fast decline in PV prices has brought upon grid parity for PV technology. Grid parity now brings about a new feasible supply configuration of including PV while the grid is available. New feasible supply configurations allow a customer to occasionally become a prosumer and provide energy back to the network. PV will be the primary source of energy while the grid will be a backup supply. When the grid is unavailable, depending on technology costs, a combination of battery storage and fossil fuel-fired generation will be an alternate source of energy.

2.5.3 The future

With the widespread installation of PV expected and the declining trend of battery costs, the future supply configuration includes battery storage solutions, when the grid is available and when unavailable. Complete grid independence can only be possible with an extensive storage system, which is subject to significant capital costs and unfeasible at this stage. Based on economics, permanent disconnection from the grid is not envisaged; however, there will be a substantial decline in energy consumption from the network.

The change in supply topology will ultimately bring change in the way customers would interact with the grid. Past interactions were limited to the unidirectional flow of electricity from the producer to the consumer. However, future interactions would allow for a bidirectional flow of electricity via the grid, making the customer a producer of electricity at times and a consumer at other times [18].

The transition from past to present, as highlighted above, is in line with the real-life scenarios that are being currently experienced by eThekwini Municipality. There is a growing number of applications for solar PV systems to connect to the grid.

2.6 Traditional electricity tariff structures

Traditional business models include centralised generation that follows a one-way energy flow with network costs being recovered via variable energy rates (i.e. volumetric tariffs). The total cost of delivering energy to the customer, including maintenance costs, is essentially converted into a per-unit rate. Any increase or decrease in kWh sales that differs from the initial forecast will create an imbalance between the utility costs and expected revenues. Volumetric rates are straightforward to administer; however, they create the erroneous perception that network charges only exists when energy flows through the network [19].

During the time of electricity growth, volumetric pricing is the preferred method of recovering fixed network charges as higher volumes leading to a lower average price per unit. However, declining sales will have the opposite effect of increasing the average price per unit.

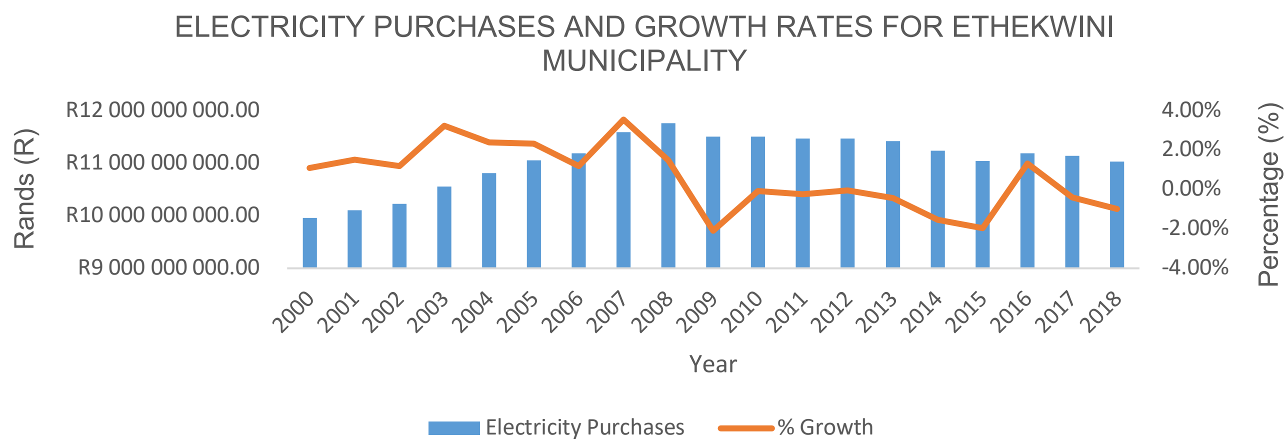


Figure 8 EThekwini electricity usage and growth trend

From the year 2000 until 2008, there has been progressive growth in the sale of electricity. Recovering fixed charges via the volumetric rates was advantageous as it allowed for a lower average unit price. Year on year electricity growth has been negative for eThekwini since 2009 with the exception being 2016, which displayed an increase of 1.37% when compared to 2015. The declining sales will have the unintended consequence of rising electricity prices where volumetric electricity pricing is enforced.

Castello and Hemphill [20] illustrated a similar argument surrounding volumetric charges and indicated that a variety of utilities recovered a substantial share of the fixed costs in the volumetric charge. When there is a drop in sales (kWh), there will be a corresponding decline in the recovery of fixed costs. This principle is further illustrated by the following equation representing the customer's total electricity bill [20]:

$$TB = \alpha F + Q[\frac{(1-\propto)F}{Q_{ty}} + v] \quad (1)$$

TB	= Total Bill	(R)
F	= Utility’s fixed costs allocated to customer	(R)
Q	= Actual Sales	(kWh)
Q_{ty}	= Test year sales	(kWh)
v	= variable cost per kWh	(R)
$\hat{\alpha}$	= Share of utilities fixed cost recovered in fixed charge	

With a higher share of fixed costs recovered in the volumetric charge (i.e. lower α), the utility earnings fluctuate more for a given increase or decrease in sales. There is a strong incentive to increase sales. On the other side, the utility suffers a higher earnings loss per unit decline in sales.

The following represent the higher earnings loss:

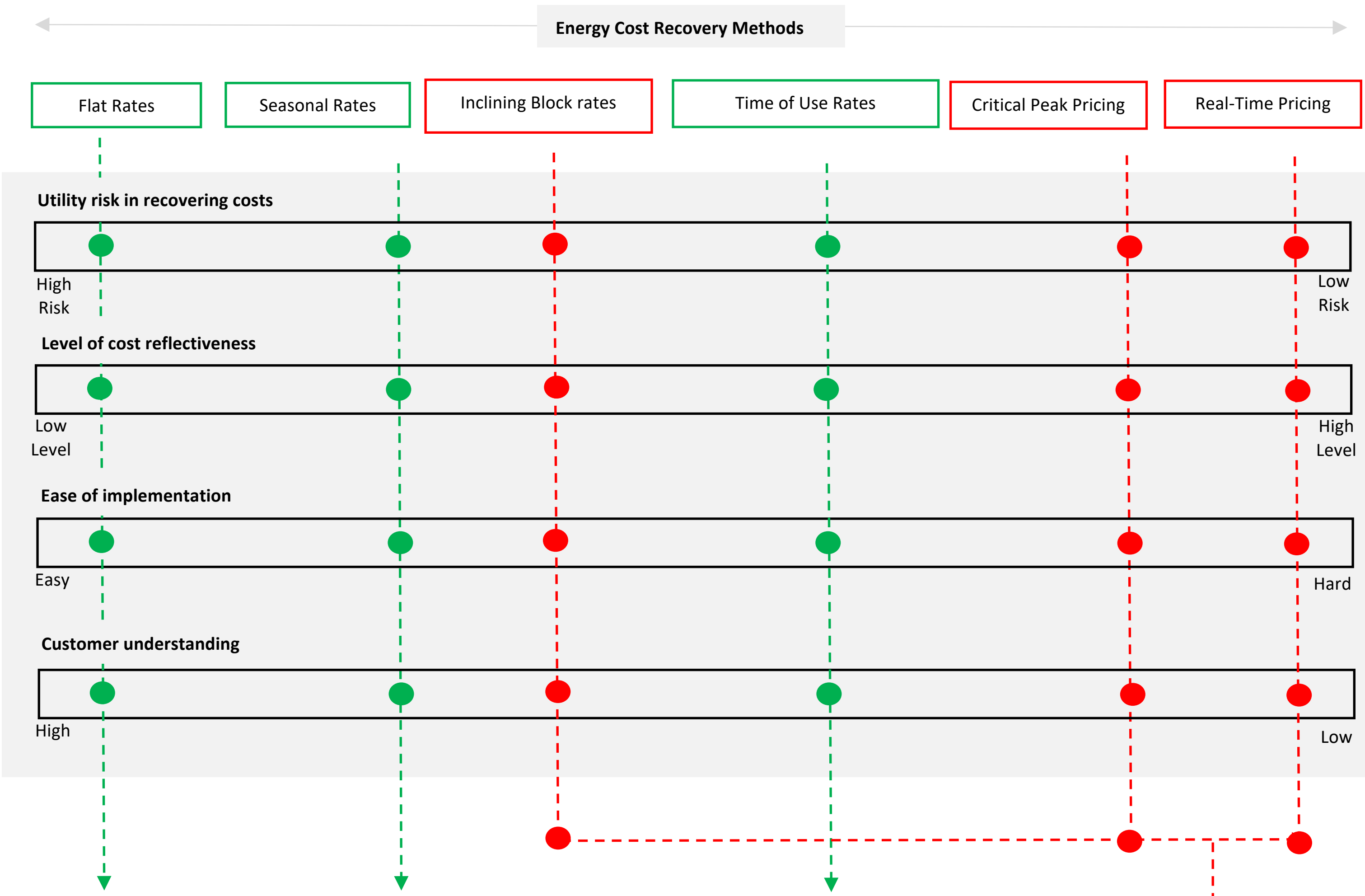
$$\frac{\partial TB}{\partial Q} = \frac{(1-\alpha)F}{Q_{ty}} + v \quad (1a)$$

Setting total cost $TC \ = \ F + vQ$ then $\frac{\partial TC}{\partial Q} = v$ (1b)

Thus for each unit decline in sales, Earnings (E) would drop by: $\frac{\partial TB}{\partial Q} - \frac{\partial TC}{\partial Q} = \frac{(1-\alpha)F}{Q_{ty}}$ (1c)

2.7 Tariff method of recovering energy costs

Numerous tariffs structures can be used to recover energy costs. The adoption of a tariff structure by a utility will depend on the level of significance placed on the following factors: utility risk in recovering costs, customer understanding, level of cost reflectiveness and ease of implementation [21], [22], [23], [24], [25].



The flat rate tariff is a simple tariff structure. It is popular as it is easy for customers to understand and easy for utilities to implement. Single register meters could be used in conjunction with simple billing systems.

However, the flat rate tariff is not cost reflective, as it cannot pass on signals of price variations due to time and seasonality. This increases the risk to the utility in terms of cost recovery.

Within eThekwini, 100% of residential costs and 96% of business costs are recovered via flat rate charges. There are no industrial customers purchasing electricity on a flat rate tariff.

Seasonal tariffs have the ability to vary the prices due to a change in season. This is particularly useful in areas where there is large discrepancies in the generation of energy costs between seasons.

The tariff is considered simple to implement and can be done with simple metering and billing systems. Customer understanding is deemed high.

The seasonal tariff is unable to pass on price variations due to time differences and is considered high utility risk with low levels of cost reflectivity, albeit better than flat rate tariffs.

Within eThekwini, only industrial/commercial tariffs are designed around seasonality.

The Time of Use tariff is able to vary the energy prices based on the time of usage. There are generally three distinct time period, in the case of eThekwini, they are categorised as Peak, Standard and Off-Peak.

Due to the time based charging, the metering infrastructure is more complex and the bill is a more complicated as there are more energy charges with varying energy rates. A high level of customer understanding is required.

Due to its ability to vary prices on a time basis, it can better pass on the varying prices of generation to the end customer making the tariff highly cost reflective. It also lowers the utilities cost recovery risk.

Within eThekwini, only industrial /and commercial Tariffs are designed around Time of Use rates.

Residential Time of Use is currently not available.

Currently not implemented in eThekwini

Figure 9 Tariff method of recovering energy costs - Own Elaboration referencing: [21], [22], [23], [24], and [25].

Table 3 Electricity Tariffs not applicable in eThekwini Municipality

Critical peak pricing	During times of extremely high demand and constrained generation (i.e. critical period), more expensive generation options are called upon. Critical peak pricing will reflect these costs.
Real-time pricing	Real-time pricing varies electricity prices as costs of generation vary in real-time, generally on an hourly basis.
Inclining block tariff	The tariff structure is divided into blocks, and the rate usually increases as consumption increases.

None of the above-tabulated tariffs are being implemented in eThekwini. The inclining block rate tariff (IBT) was introduced into South Africa in February 2010. The NERSA has recommended that the tariff become integrated within the municipal suite of tariffs. The aim was to ensure the protection of the poor (via low consumption) against the higher than inflationary electricity tariff increases.

EThekwini Municipality did not implement the tariff structure, as it would have had the opposite effect, as many customers were living in combined households with a single meter. This does not support the theory indicating that low-income customers consume a reduced amount of electricity, and high-income customers consume more. Further, the cross-subsidy requirement was large.

Real-time pricing and critical peak pricing are driven mainly by the costs of generation. EThekwini is not a generator; it only experiences energy costs via Eskom Transmission Department through the tariff structure. The only feasible time to introduce these tariffs in eThekwini (i.e. real-time/critical peak pricing) is when Eskom introduces these tariffs to the municipality. In the interim, the city should continue to align its sales tariffs with its purchasing tariffs. The alignment will ensure there is minimal mismatch between how electricity is bought and how it is sold.

2.7.1 Electricity tariff structures applicable in eThekwini Municipality

The electricity tariffs per category are shown below [26] :

Table 4 eThekwini Municipality electricity tariffs per category

Residential Tariff Structure	***Scale 3,4,8,9***
Energy Charge	197.14 c/kWh
Service Charge (R/Month)	R 0.00

Business Tariff Structure	***Scale 1***
Energy Charge	222.61 c/kWh
Service Charge (R/Month)	R 291.29

Industrial Tariff Structure			***Industrial Time of Use (ITOU)***		
Summer September to May (c/kwh)			***Winter June to August (c/kWh)***		
Peak :	*Standard:*	*Off-Peak:*	*Peak :*	*Standard:*	*Off-Peak:*
128.42	*91.62*	*61.88*	*372.46*	*120.04*	*69.87*

Network Access (R/kVA)	*Network Demand (R/kVA)*	*Service Charge R/pm*	*Voltage Surcharge (%) (Applicable to all costs except the service charge)*		
R 36.51	*R 111.15*	*R 5175.00*		*275kV*	*0.00*
				132kV	*2.25*
				33kV	*3.00*
				11kV	*10.50*
				6.6kV	*12.75*
				0.4kV	*22.50*

2.8 Tariff method of recovering network costs

Network costs can be recovered in a variety of ways from customers. As the method of recovery becomes more reflective, it does become more complex to implement. It also poses a high risk of customers not understanding it. However, it does lower the municipal risk in terms of recovering costs. Each grid operator would have to analyse their circumstances and set their method of recovering grid costs [27], [28], [29], [30], [31].

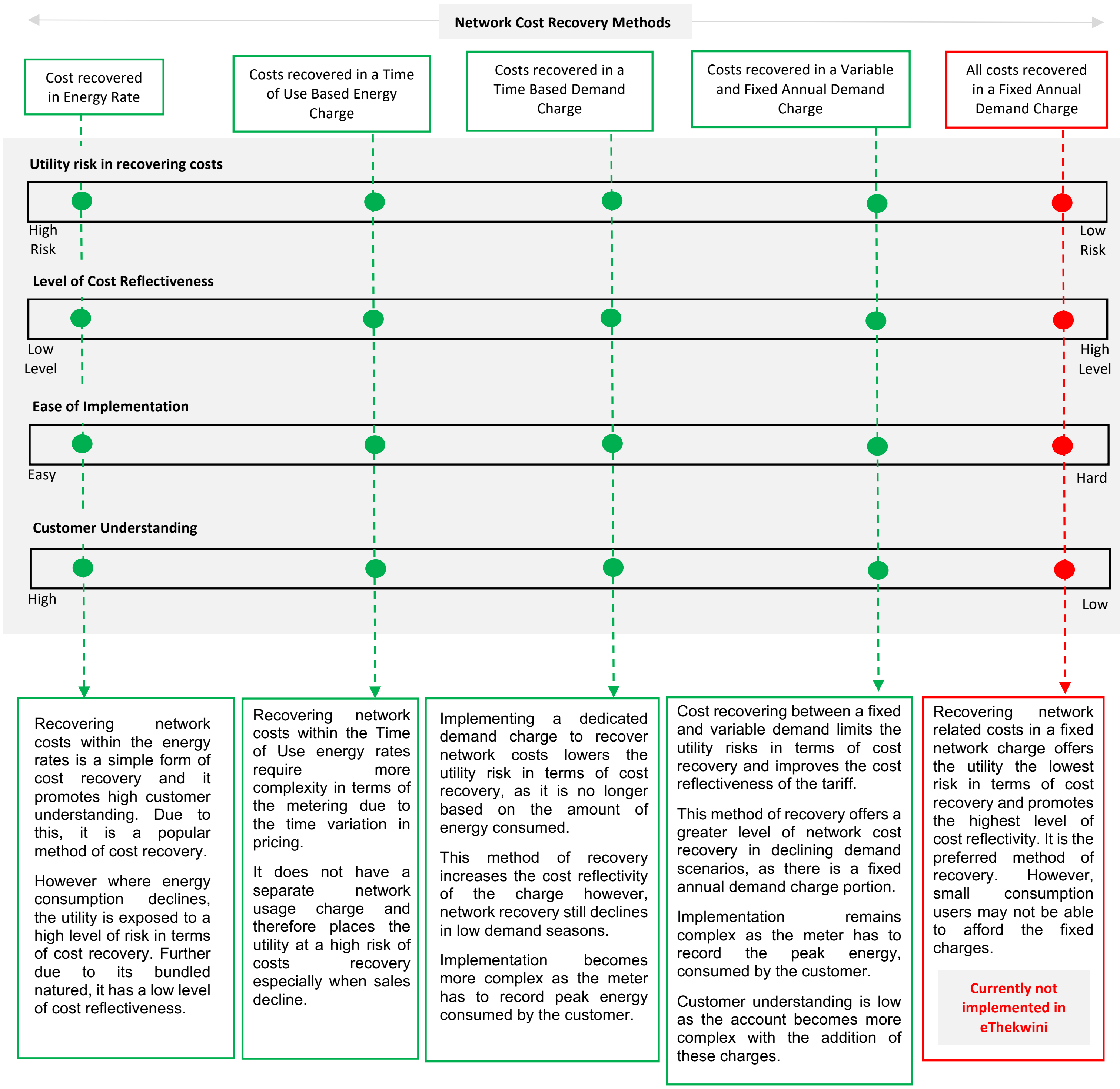


Figure 10 Tariff method of recovering network costs – Own elaboration referencing: [27], [28], [29], [30], [31].

2.9 The electricity revenue recovery model

The tariff revenue model for the eThekwini Electricity unit is hinged on three major tariff revenue streams, i.e. residential, business and industrial. The number of customers, proportionality of income and the method of recovery is shown below [32]:

Table 5 Key parameters defining the revenue model for eThekwini Municipality: Electricity Unit

Residential **Annual income: R 4.3bn**	**Business** **Annual income : R 3.0bn**	**Industrial** **Annual income : R 4.9bn**

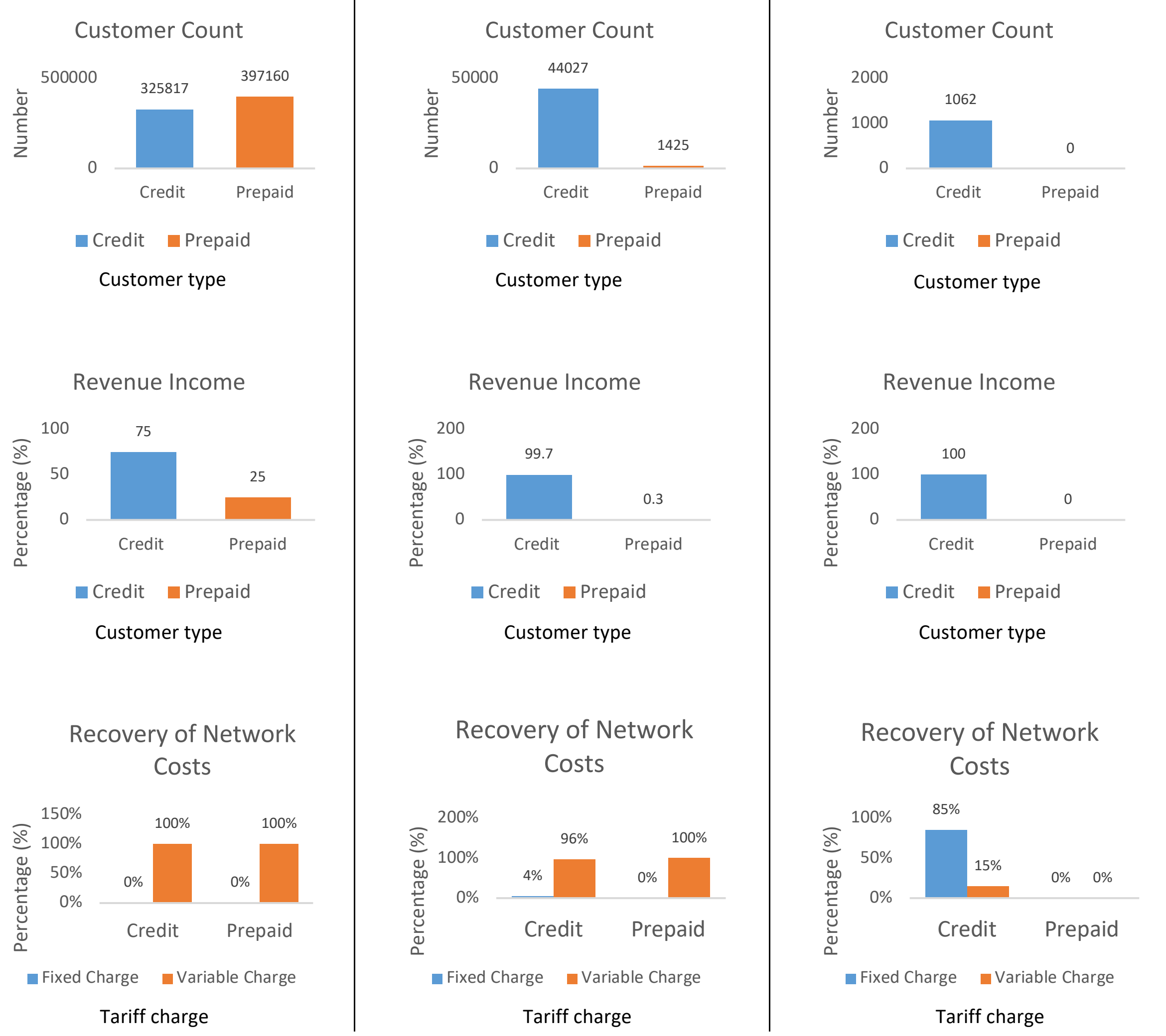


Figure 11 EThekwini Municipality revenue recovery model

The current revenue model is based on recovering fixed (network & service) and variable (energy) charges. The cost causation drivers should determine the proportionality of fixed to variable charges [33]; however, legacy tariff design within eThekwini has set the current status quo.

2.10 Network cost recovery

2.10.1 Network cost recovery for residential customers

All network costs are recovered via the energy rate for the residential sector. The retail price per unit of electricity (kWh) for residential customers is 197 c/kWh. The cost attributed to municipal related costs is 90 c/kWh. The energy purchase cost (Eskom) is 107 c/kWh. The retail energy rate per kWh consists of energy and network costs in the following proportions:

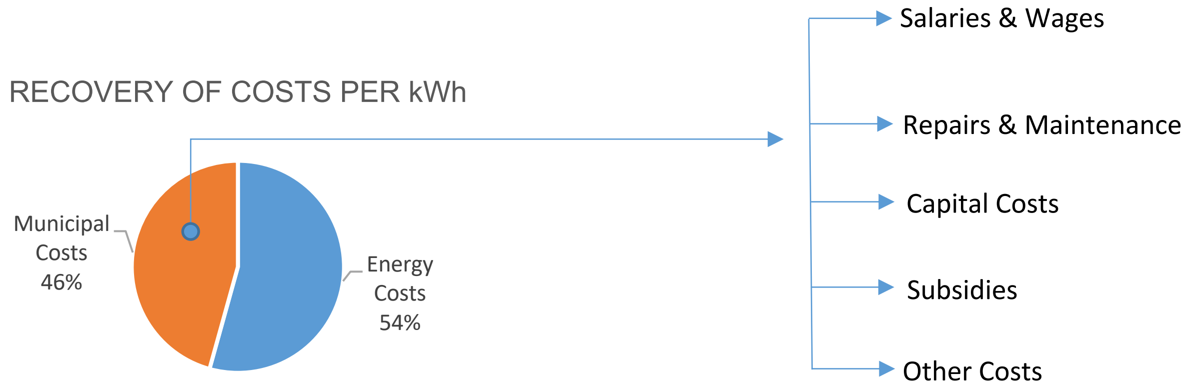


Figure 12 Recovery of costs per kWh: Residential category

2.10.2 Network cost recovery for business customers

Within the business sector, 96% of the network costs have been recovered via the energy rate. The retail price per unit of electricity (kWh) for business customers is 222 c/kWh. The contribution to municipal related costs is 110 c/kWh. The energy purchase cost (Eskom) is 112 c/kWh. The retail energy rate per kWh consists of energy and network costs in the following proportions:

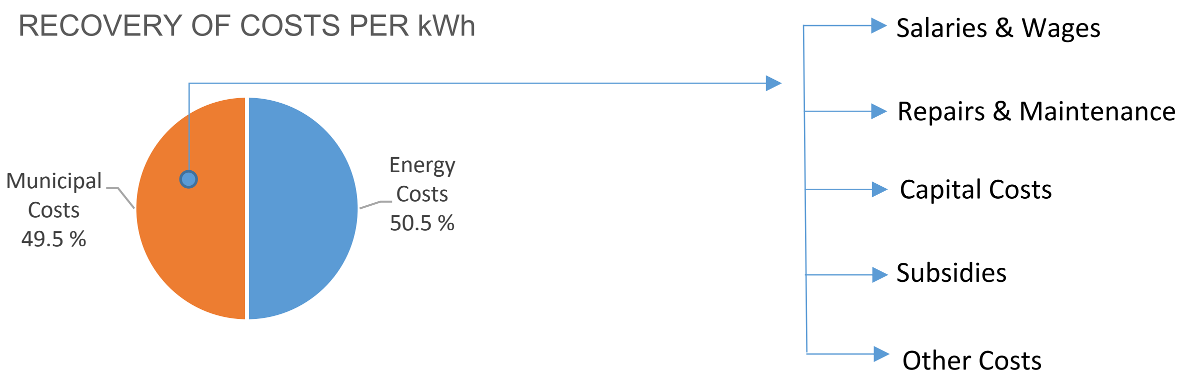


Figure 13 Recovery of costs per kWh: Business category

2.10.3 Network cost recovery for industrial customers

Within the Industrial sector, only 15% of the Municipal costs are recovered via the energy rate. The retail price per kWh for Industrial customers vary depending on their time of use.

2.11 Definition of the utility death spiral

The recent trend of declining electricity sales against a rising cost structure is not unique to eThekwini Municipality. It seems to be a common tendency amongst many countries. This phenomenon has been labelled the "death spiral" [19].

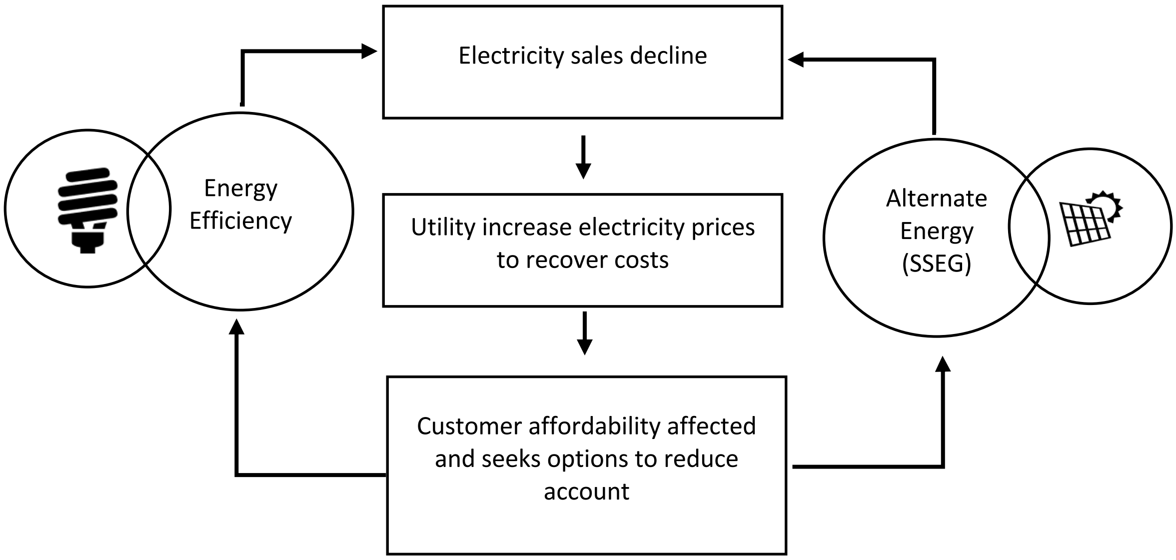


Figure 14 Understanding the cycle triggering the utility death spiral. Own elaboration referencing: [18], [19]

Felder and Athawale [19] defined the start of the death spiral when additional small scale embedded generators lead to the electricity grid becoming more expensive for non-generating customers. In the process, they make self-generation further financially viable. As a result, utilities have been compared to dinosaurs and labelled as "shockingly stupid". The death spiral is not necessarily due to shortsighted utility management or disruptive competition but rather due to poor tariff design.

Castello and Hemphill [20] highlighted the death spiral concept dating back to the oil embargo in 1973, after which the industry faced a significant reduction in electricity sales and increased expenses via operating and capital costs. Despite the realities of increased costs against decreasing sales, the authors believe that the spiral effect is overstated. It was concluded that the manifestation of the death spiral is based on idealistic circumstances about customer reaction to prices and incentives and further argues that the regulatory nature of the sector would not allow for the deterioration of the utility finances to the extent that leads to a death spiral. While the author acknowledges the realities of a death spiral, the author is of the view that it will and can be avoided by taking appropriate action.

Laws et al. [34] agreed that the death spiral occurs with both high PV adoption rates and high utility costs. Castaneda et al. [35] agreed that the swift uptake of SSEG, particularly photovoltaic deployment, threatens the current utility business models that may challenge the reliability of electricity systems and societal welfare. A death spiral is possible where the vicious cycle is triggered. Essential variables that drive the cycle include reduced PV costs and higher electricity tariff rates.

Khalilpour and Vassallo [18] highlight that there has been a wave of social and academic discussions of migrating away from the grid because the recent decline in PV prices has brought grid parity, or near grid parity for PV in many countries. This, if uncontrolled, has been termed the "death spiral" for utility companies.

2.12 Impact of the utility death spiral

Khalilpour and Vassallo [18] highlighted that the death spiral would threaten cost recovery due to reduced electricity sales. The platform for SSEG is well crafted to promote the goal of cleaner energy. As a result, the current volume-based electricity tariff design will not sustain adequate revenue recovery for network costs. The death spiral will also affect local governments where taxes and societal benefit charges are levied. Either the revenue has to decrease, or the government will have to collect more from fewer customers. This problem is exaggerated if higher energy usage customers install SSEG and do not pay for the grid via a fixed charge.

The authors further highlighted that the critical societal concern of leaving-the-grid is the consequent escalation of retail electricity prices for those remaining connected. When some of the customer bases are transformed to prosumers and leave the grid, the network cost will be distributed over fewer customers, and thus the network charge will increase. The consequent rise of electricity prices will further improve the economic attractiveness of leaving the grid for any remaining customers and will expedite grid deflection. This loop will continue like a spiral until collapsing the utility industry.

Laws et al. [34] described the impact of the utility death spiral as being a decline in electricity demand. This is caused due to the implementation of SSEG or efficiency measures resulting in increased retail electric prices. The increased prices drive more customers to reduce their demand until the utility becomes an unsustainable business.

Castaneda et al. [35] acknowledged that the death spiral would affect utilities in the medium to long term. The consequences of the death spiral include sales decreases as the result of greater PV adoption and higher revenue losses for utilities. Further grid users with solar PV systems will experience benefits, while others will face very high tariffs. In addition to the utilities traditional business model being affected, the entire system sustainability and further contributions to societal welfare is threatened. If a significant amount of customers starts to generate their own electricity, network reliability will start to reduce, and all customers connected to the network will be at risk as electricity distribution becomes unsustainable.

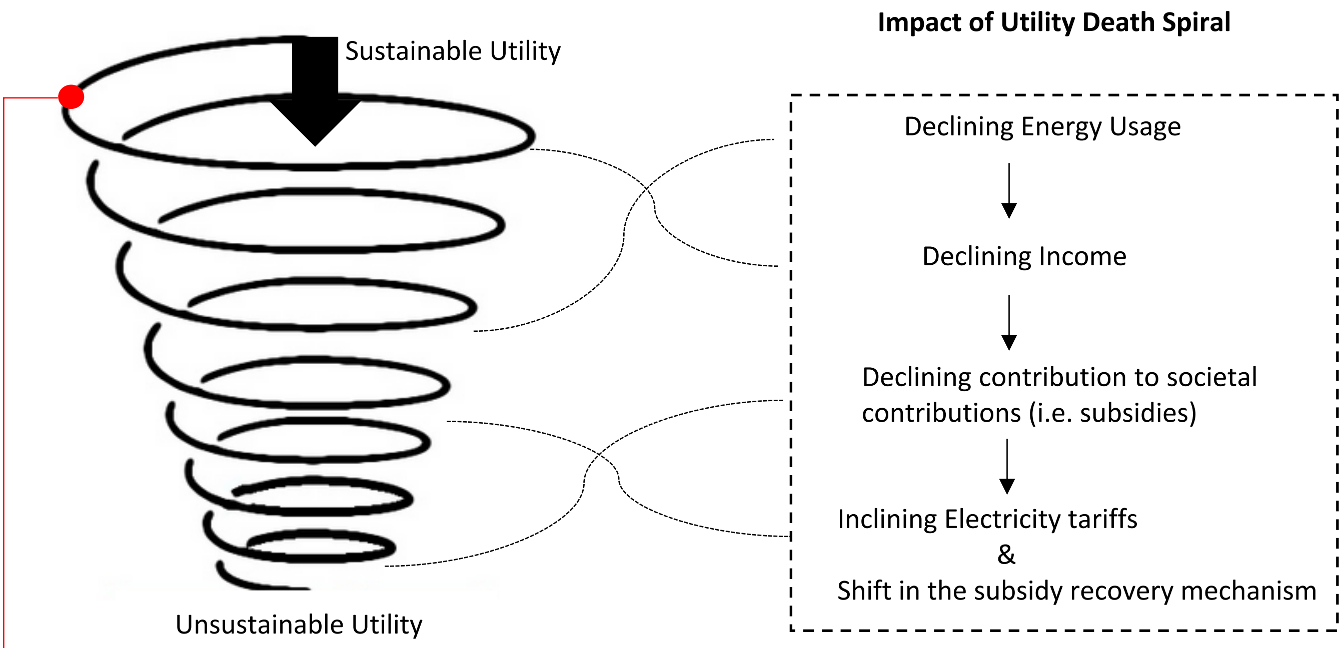


Figure 15 Impacts of the utility death spiral

Due to the low number of SSEG installations, eThekwini Municipality is currently closer to the sustainable utility point as opposed to the unsustainable utility point. This bodes well for the municipality as it still has an opportunity implement mitigation strategies to prevent it from spiralling towards the unsustainable point.

2.13 The shift in the revenue recovery mechanism

Apart from triggering the death spiral, the uptake of PV will lead to a shift in the recovery mechanism of utility costs. This unintended consequence will lead to other users paying more and PV customers paying less [18].

2.13.1 Impact on subsidy mechanism: no PV installed

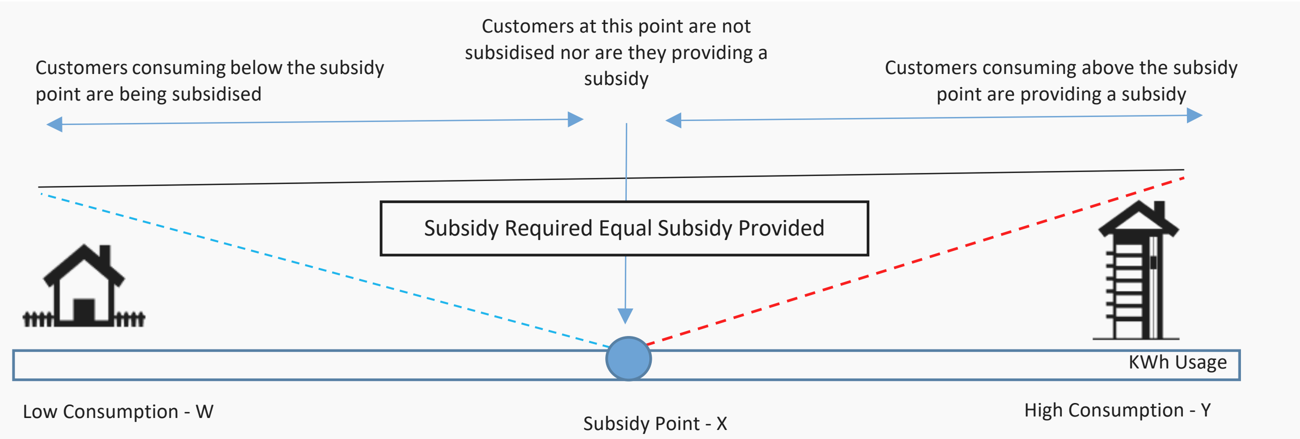


Figure 16 Balanced subsidy mechanism

The further away (right) from the subsidy point, the higher the contribution to subsidies. The further away (left) from subsidy point, the higher the subsidy required.

Subsidy required by low consumption users = X - W
Subsidy provided by high consumption users = Y - X
Currently, the amount of subsidy required and the amount of subsidy provided is balanced.

2.13.2 Impact on subsidy mechanism: PV installed by high consumption customer

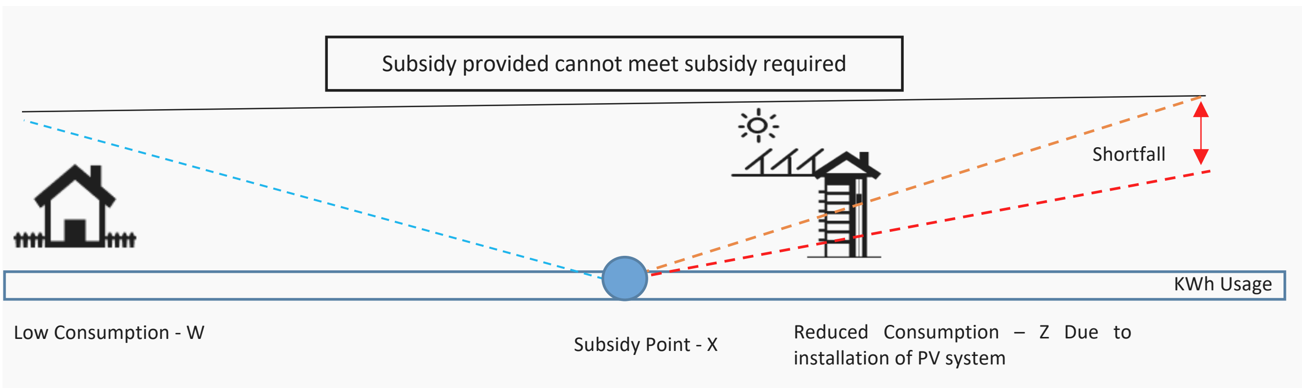


Figure 17 Unbalanced subsidy mechanism due to high consumption consumers installing PV

As high consumption customers start to install PV systems, they consume less electricity and move closer to the subsidy point. This has the effect of reducing the subsidy provided (red line) and leads to a shortfall. The amount of subsidy required and the amount of subsidy provided is no longer in balance. To counteract this, the prices of other customers must increase (orange line).

2.13.3 Impact on subsidy mechanism: more PV installed by high consumption customer

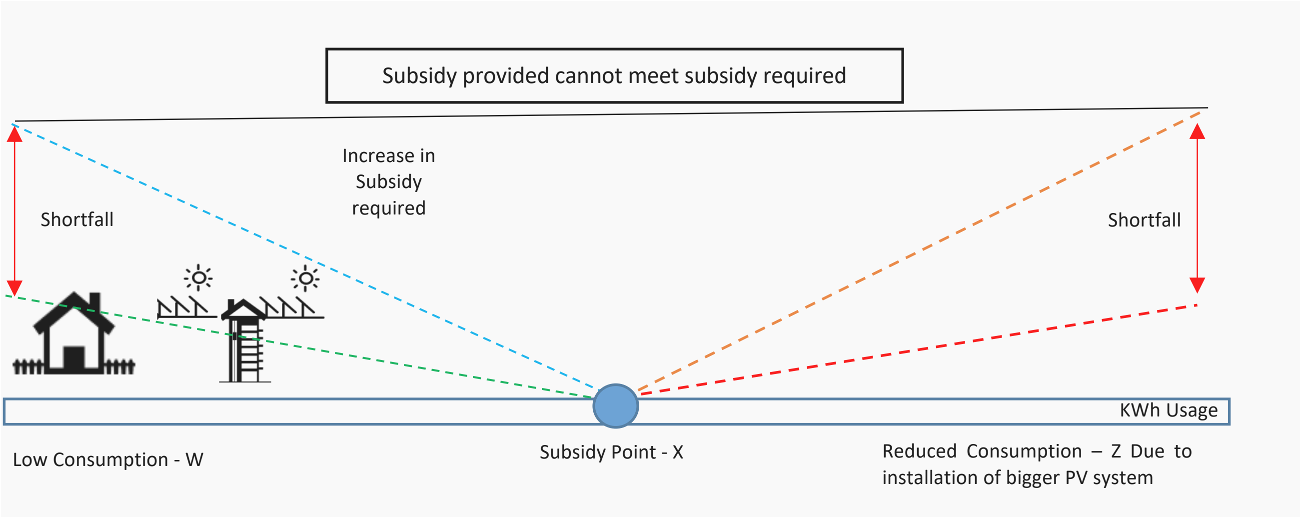


Figure 18 Unbalanced subsidy mechanism due to high consumption consumer installing PV

The imbalance becomes more pronounced, leading to a more significant shortfall in the subsidy provided when a bigger PV system is installed (or more people install PV). The high consuming customer that was providing the subsidy is now receiving a subsidy. The amount of subsidy required and the amount of subsidy provided is no longer in balance. To counteract this, the prices of other customers must increase (orange line).

2.13.4 Impact on subsidy mechanism: PV installed by low & high consumption customer

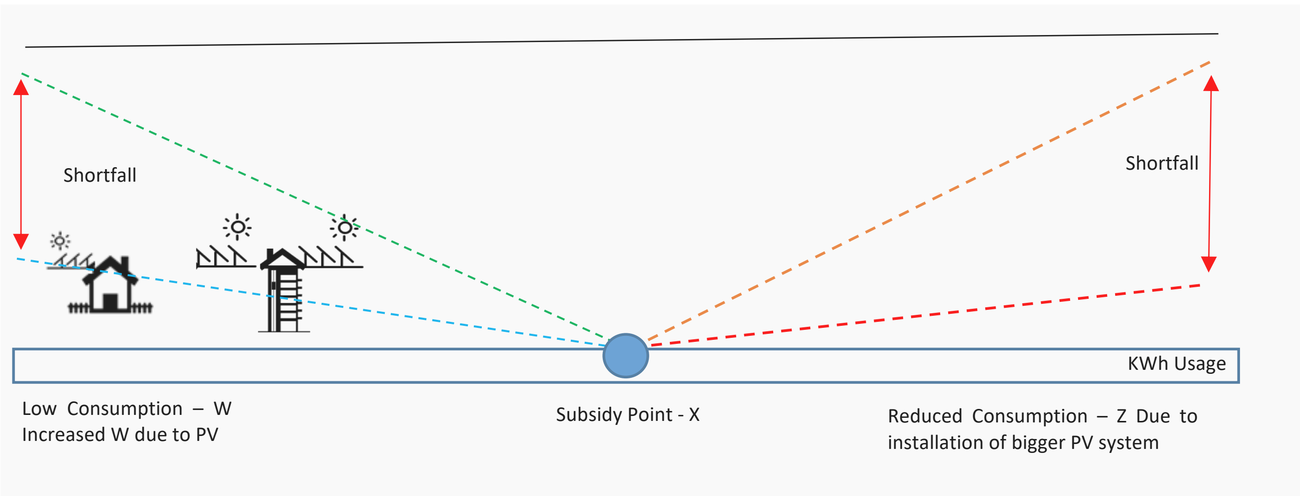


Figure 19 Unbalanced subsidy mechanism due to high consumption customer and low consumption customer installing PV

The problem becomes even more pronounced as small consumption users start to install PV in conjunction with high consumption customers. The subsidy providers are now contributing less (red line), and the subsidy receivers require more (green line). There is a growing subsidy need and a declining subsidy provision.

Aggressive climate change policy is leading to the rapid uptake of RE technologies. Rapid RE technology uptake is leading to a change in the way revenue is collected from customer classes. A study in Japan has highlighted that incentive provision for RE has harmed low-income class customers and negatively impacts on equity [36]. The issue at hand questions the impact of social equity as renewable and climate change policies are enforced. The effect of RE incentive tariffs and social equity have been extensively studied in Germany [37] and the United Kingdom [38]. Careful consideration must be applied in the tariff designs to ensure that low-income customers are not adversely affected by the introduction of PV.

2.14 The solutions to avert the death spiral

Felder and Athawale [19] proposed that the solution to avoid the death spiral is to correct the anomaly in electricity rate design. This entailed separating the fixed and variable costs within a tariff. The customer will, therefore, be charged separately for network usage and energy consumption.

The separation of charges is referred to as straight fixed, variable rate design. The author raised concerns that the proposed solution would result in cost-shifting from high consumption customers to low consumption customers. This cost shift between customers might be conflicting to the objectives of the regulators who consider low-income assistance as part of their mandate. The author suggested that a straight fixed, variable rate only be applied to SSEG customers; however, noting that this would reduce the attractiveness of the SSEG investment.

Felder and Athawale [19] further concurred that the death spiral is not due to disruptive competition. SSEG competes with the generation of electricity, and in the absence of storage capabilities, it is a compliment and should not be perceived as a competitor to the network. In moving forward, the author was of the view that no business can survive if it is unable to charge the appropriate fees to recover its costs and electric utilities are no exception.

Laws et al. [34] stated that a death spiral could be averted by adjusting the business models and pricing structure to avoid grid deflection.

Castaneda et al. [35] agreed that the impacts of the death spiral could be averted by implementing a series of interventions. These interventions will facilitate the safeguarding of the utility's profitability and maintain network reliability and social welfare. Interventions include tariff reforms to include back-up fees, adopting net billing methodology of charging and increasing the fixed charges within traditional tariffs.

Khalilpour and Vassallo [18] stated that conventional grids are one-directional networks. Future grids will be a bidirectional network of prosumers that are sometimes producers and some-times consumers. The authors were of the view that policies could be devised to help utilities develop other sources of revenue by designing smart tariffs and Demand Side Management (DSM) mechanisms rather than only increasing the energy prices assumed to be the driver of the death spiral.

Castello and Hemphill [20] were optimistic that the death spiral could be averted based on hindsight. Previous threats have been significantly overstated. Although utilities did experience severe financial conditions in the past, the utility management teams in conjunction with electric regulators responded to the challenges by taking the appropriate action avoiding a financially unsustainable situation. The authors summarised that utilities worry that as SSEG uptake rates increase; there would be cost-shifting, free riding and grid integrity issues. To overcome these issues, the authors recommended new rate and tariff designs incorporating net metering and the levying of standby charges for SSEG.

In further averting the spiral effects, the author stated that there is an expectation for the utility to price discriminate in favour of those customers who are most price elastic and seek government and regulatory protection to avert severe financial problems.

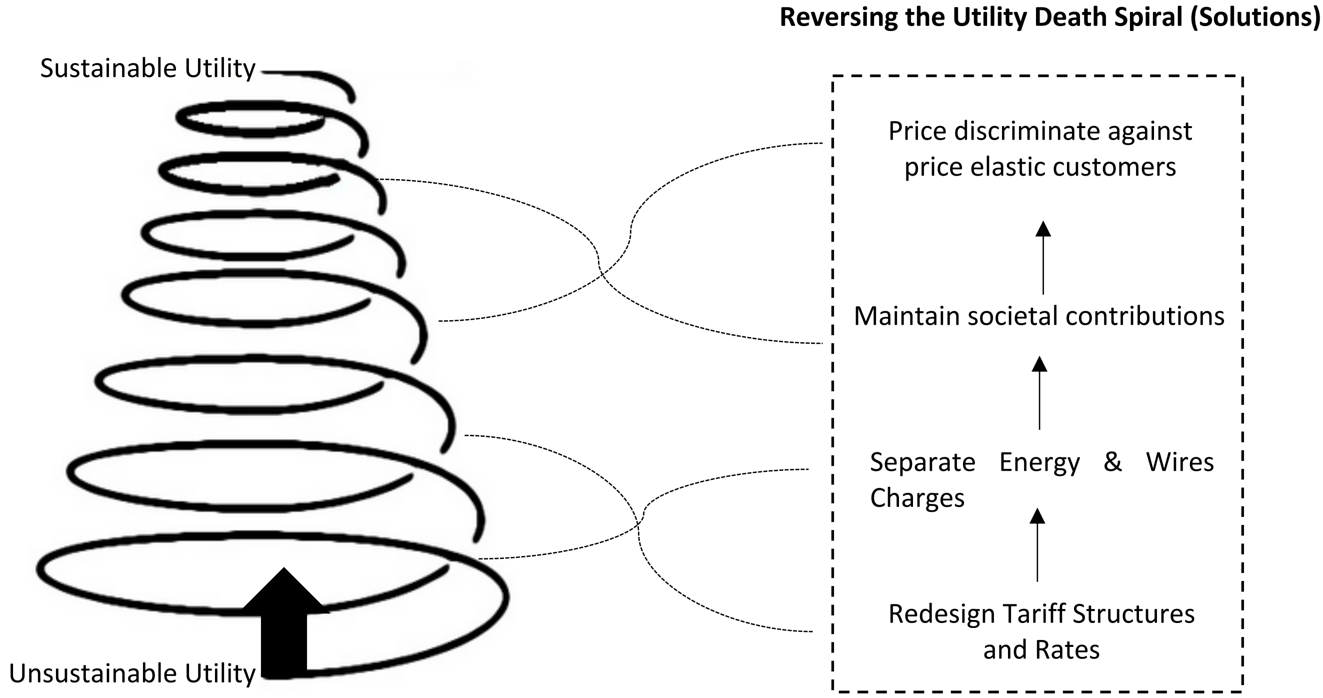


Figure 20 Reversing the effects of the utility death spiral

2.15 Concluding remarks on the utility death spiral

All reviewed authors were in general agreement of the definition of the death spiral, noting that it will occur in the electricity sector when there are rising utility costs and declining electricity sales.

Table 6 Summary of authors view on the utility death spiral

Author(s)	*Agreed that the death spiral can occur when costs escalate and sales decline*	*Agreed that the death spiral can be triggered by the rapid uptake of SSEG*	*Agreed that the impact of the utility death spiral will lead to higher tariffs*	*Agreed that the effects of the utility death spiral will lead to reduced revenue*	*Agreed that the solution in preventing a utility death spiral is to amend/adapt the tariff structures to accommodate the dynamics of SSEG*
Khalilpour and Vassallo *[18]*	●	●	●	●	●
Felder and Athawale *[19]*	●	●	●	●	●
Costello and Hemphill *[20]*	●	●	●	●	●
Laws, et al. *[34]*	●	●	●	●	●
Castaneda, et al. *[35]*	●	●	●	●	●

There was agreement that the uptake of SSEG in an environment with heavily loaded volumetric tariff charges will trigger the spiral. There was also consensus on the impacts of the death spiral, noting that it led to higher electricity rates as electricity sales further decline. There was unanimous agreement that to prevent the death spiral, a change in rate/tariff design was required. The key recommendations were to amend the current tariff structures to make it more reflective by moving away from recovering fixed network costs via volumetric energy rates.

There was also a general view amongst the authors that the death spiral can occur, but will not in the electricity sector as the regulated nature of the sector will allow for the implementation of various interventions to prevent the spiral. Further, they were of the view that the spiral will occur gradually allowing utilities and regulators enough time to review the problem and implement suitable changes.

2.15.1 EThekwini Municipality in context of the utility death spiral

EThekwini Municipality is currently facing a decline in electricity sales, a rise in utility costs and anticipating an increase in the uptake of PV systems. With a large proportion of its costs recovered via variable energy charges, the municipality is naturally being positioned to trigger the death spiral as the uptake of PV systems materialises.

There has to be a review of the impacts of PV on the current revenue recovery model to avoid triggering the spiral and the shift in cost contributions. Once completed, there would need to be a review and redesign of the current electricity tariff structures and rates to allow for a self-adapting tariff model that prevents revenue losses as the uptake of PV systems materialise.

2.16 Municipal business model diversification

The Electricity department within eThekwini Municipality operates under a distribution licence issued by the National Energy Regulator of South Africa (NERSA). As a result, the core of its operations and adopted business model is centred on distribution activities.

With sales declining as RE is introduced, the first step in becoming more sustainable is to correctly price for the grid via appropriately designed tariffs. This will avoid the death spiral as highlighted in section 2.15. This study attempts to optimise and realign the tariff structures to correctly charge for grid infrastructure and related recoveries.

With the rapid developments in technology, there may be an opportunity to diversify the current municipal business model, which could contribute positively to the future financial sustainability of the municipality. A few explorative ideas are briefly highlighted below.

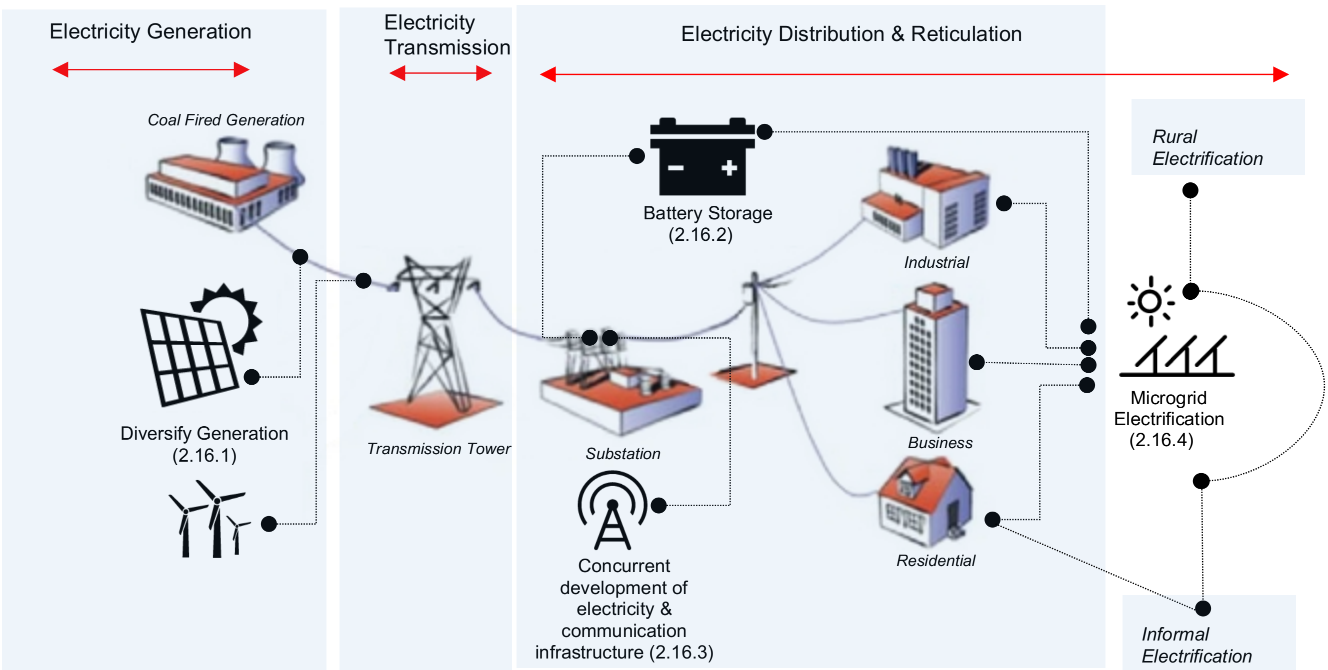


Figure 21 Diversification of current municipal business model [39]

2.16.1 Diversification of electricity generation

The electricity generation and transmission costs are levied to municipalities via a bulk tariff from Eskom. This cost is generally 75% of the total budget of the Electricity Unit within the municipality [40]. The remaining 25% of the budget resembles the cost of municipal distribution and related expenses. The bulk tariff is, therefore, an important cost that influences the retail price of electricity. Other than municipalities seeking internal efficiencies, they could reduce their costs by exploring alternate and cheaper electricity generation options.

Large scale PV and wind have proven their ability to contribute positively to the energy diversification mix of many countries. Solar PV, in many cases, is able to make the contribution at a lower price than that the conventional cost of electricity [41]. Due to the reduced operating costs of RE sources and the absence of a fuel source, their yearly escalations are usually indexed to inflation or a similar level of increase. In South Africa, bulk electricity prices have been escalating above inflation for a number of years [42]. The graph below illustrates the impact of the above inflationary increases.

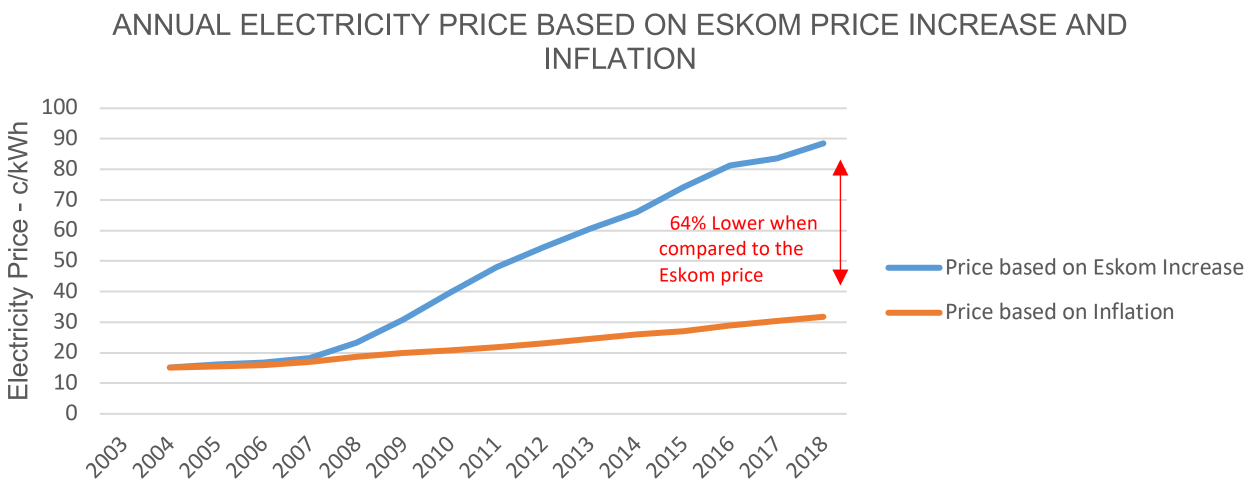


Figure 22 Annual electricity price based on Eskom Increase and inflation

Municipalities that are able to secure long-term arrangements for electricity, hedged at inflationary increases (or lower), will be able to better manage their costs and better control the cost of electricity to the end customer.

2.16.2 Battery storage

Integrating batteries into the network can substantially improve network performance [43]. There is also the potential to leverage the storage capabilities of batteries to generate revenue. This is done by the bulk time shifting of electricity. Batteries have proved to be successful in generating revenue in a market, highly penetrated by intermittent RE sources like solar PV [44]. While penetration rates of solar PV are currently low within eThekwini, there may exist an opportunity to generate revenue utilising batteries, by exploring the principle of arbitrage.

The current ratio of peak energy to off-peak energy in winter is 5:1 (refer to table 4). The current ratio of peak to off-peak energy in summer is 2:1. Each kilowatt-hour shifted in winter would generate 302.59 cents while each kilowatt-hour shifted in summer would generate 66.54 cents. There is also an opportunity to capitalise on the pricing differential between standard and off-peak times as well as weekend and weekday energy price differentials. Strategically positioning and operating optimally, sized batteries could also reduce demand charges by reducing the simultaneous maximum demand drawn from the network.

2.16.3 Concurrent development of electricity and communication infrastructure

Wei et al. [45] portrayed the advantages of integrating and concurrently developing energy and information networks in the Pan Arctic region. While the circumstances vastly differ between eThekwini and the Pan Arctic region, the advantages and synergies of such collaboration must be appreciated.

Tahon et al. [46] supported a joint roll out of utility and telecommunication infrastructure, within the European context, and calculated that the network operator could benefit from a cost saving of 17% per household, that is connected to the communication network.

EThekwini Municipality has an integrated communication fibre-optic cable network that keeps growing as new electricity infrastructure is installed. Whilst the fibre-optic cable is primarily installed to facilitate the Supervisory Control and Data Acquisition (SCADA) within the network, expanding on the number of cores can easily allow for other forms of communication. Fibre-optic cable is also being installed as electricity cables are being replaced. Concurrent installation of communication infrastructure with electricity infrastructure drastically reduces the installation costs, as the communication infrastructure installation free rides the trenching (and related) costs of the electricity cable installation.

This favourably positions the municipality, as it can now diversify its electricity offering with that of a communication offering, in the form of connectivity via its fibre-optic cable networks. Endorsing strategic public private partnerships can make this a reality. Further, electricity streetlight poles and overhead line infrastructure can also be an ideal rental platform, for those wanting to introduce a local area wireless network technology (e.g. Wi-Fi) or similar communication to communities. These poles contain a source of electricity, generally high enough for good communication area coverage while deterring theft.

Kenya Power has embraced the utility-telecommunications model since 2010 and has developed a telecommunications business unit called “U-Telco” to manage its fibre-optic business that is primarily installed within the electricity transmission and distribution networks. Despite being a traditional distribution network operator, they are also licensed as a Telecommunications Network Facility Provider (TNFP). Their current fibre offering includes Indefeasible Rights of Use (IRU) of its fibre-optic network, via lease agreements with telecommunication operators for periods ranging from five years up to 20 years [47] .

2.16.4 Microgrids for electrification

Decentralised generation and microgrids are gaining popularity, and it may be the trigger of another industrial revolution [48],[49]. Microgrids can offer great advantages for developing countries, especially those experiencing generation scarcities, network constraints and a large electrification backlog [50]. EThekwini Municipality has approximately 290000 households (approximately 37%) that are not electrified. The rate of urbanisation is outstripping the rate of electrification, resulting in an increasing number of households queuing to be electrified annually.

The traditional approach is to extend the network and provide a connection; however, with the introduction of commercially viable solar PV and battery storage systems, there may be an opportunity to meet the electrification needs via a more cost effective hybrid solution. Introducing solar PV in conjunction with grid extensions can minimise new investments in transmission and distribution infrastructure as well as reduce distribution losses [51].

2.16.5 EThekwini Municipality in context of business model diversification

There are different techniques for adapting the distribution grid business to generate revenue by considering organisational hybridity. While plausible, it may require a substantial change in regulation, legal frameworks and strategic policy to become a reality. Further, it would require the support of staff, political leadership and management.

2.17 Principles of tariff design

A generalised pricing method to cater for the dynamics of RE does not exist. Each utility uses a different way of tariffing and pricing, dependant on the desired objectives of the utility [52]. Despite the lack of commonality amongst the tariffing and rate designs; there are essentially ten principles (P1-P10) that should be considered to justify tariffs and prices [53].

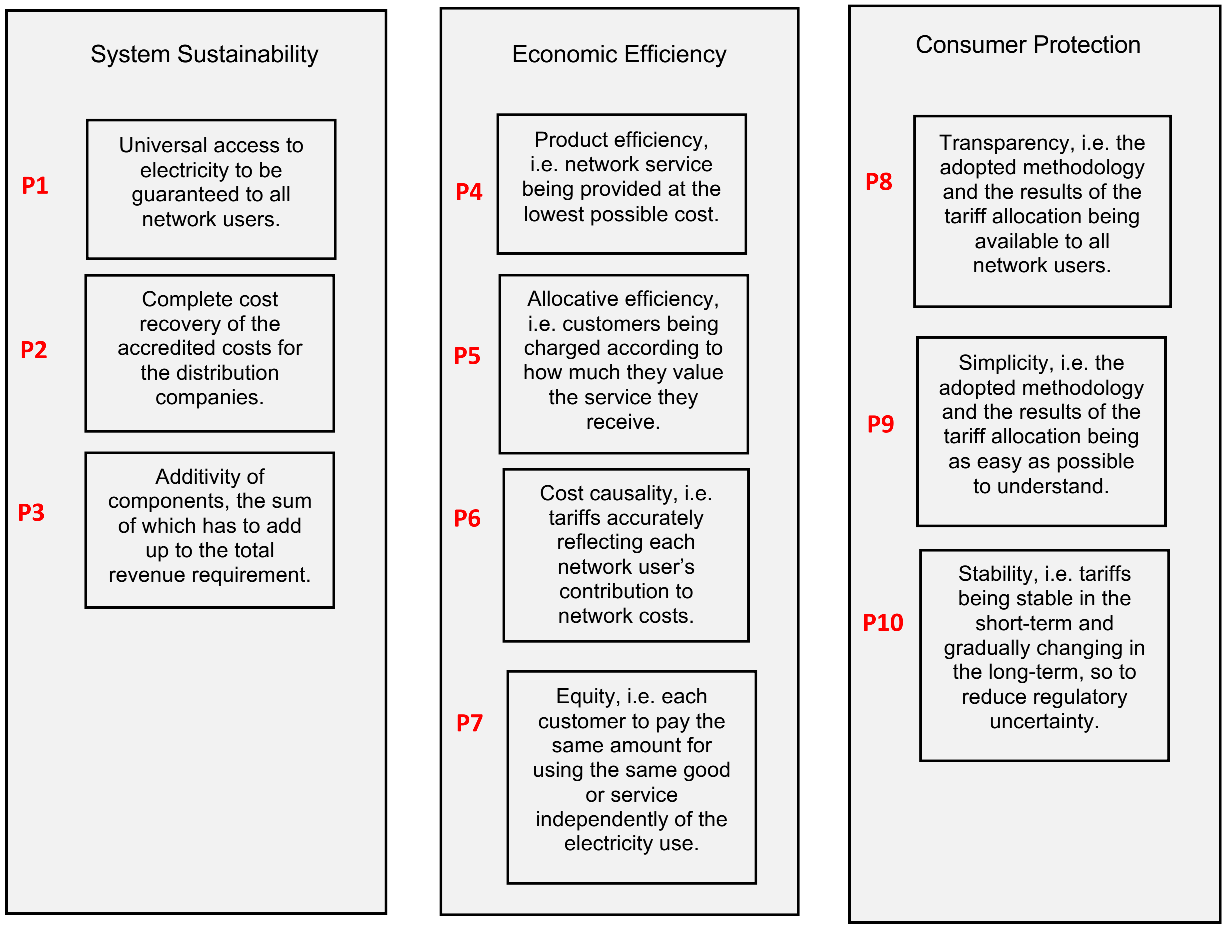


Figure 23 Tariff design principles [53]

While these principles create a precise platform for pricing, they do, however, conflict with each other when applied in practical situations. Simplicity and cost causality are complicated to achieve at one time. Economic efficiency and sustainability are also challenging to balance on the same scale. Within eThekwini, all residential customers (urban & rural) pay the same rate for electricity, while this supports the equity principle, it does not support the policy of passing on costs due to cost causality.

Therefore, rate designs have to prioritise some of these principles over others. It is, therefore, imperative to understand the context of the utility, the main objective of the rate-making process and the desired outcome [53].

2.18 Types of RE tariff mechanisms

Policy variations, regulatory differences and energy circumstances vary per country. Further tariff rates, tariff structures and socio-economic conditions also vary. Because of these variabilities, there is a diverse range of RE tariffs across countries. However, the design principles of the diverse range of RE tariffs can be narrowed down to a few. In this section, four of the most popular RE tariff designs are discussed.

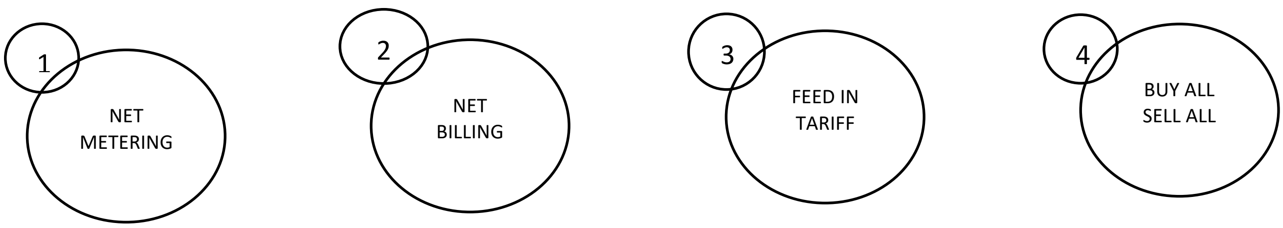


Figure 24 Popular RE tariff design options

2.18.1 Net Metering

In net metering there is only one meter which can turn in the forward direction or the reverse, measuring the imported minus exported energy in kWh. In net metering, the energy exported onto the grid has the same value as the energy imported from the network. They are financially equal [54].

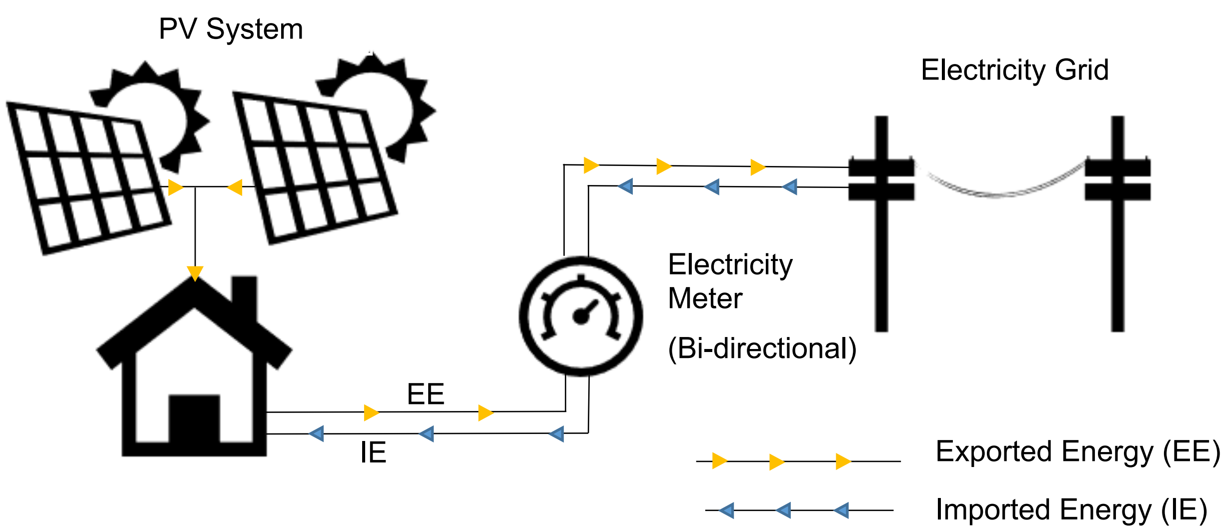


Figure 25 Net metering energy flow and metering topology. Own elaboration referencing [54]

Net metering can exist with a few variations [54] :

2.18.1.1 Net Metering: Simple

The meter will spin in the forward direction when energy is imported (IE) and the reverse direction (EE) when energy is exported.

Where IE - EE > 0: The customer owes money to the utility for energy consumed
Where IE – EE < 0: The customer is in credit, however, does not receive any compensation.

2.18.1.2 Net Metering: With buyback

Where IE – EE < 0: The customer is in credit and will receive compensation per billing cycle for the energy exported at the wholesale or avoided cost rate.

2.18.1.3 Net Metering: With rolling credit

Where IE – EE < 0: The customer is still in credit for that billing cycle after being compensated for the current cycle. The credit will be carried forward to the next cycle. The maximum rollover period is generally limited to one year. Any excess at the end is forfeited.

2.18.1.4 Net Metering: With rolling credit and buyback

Where IE – EE < 0: The customer is in credit for that billing cycle after being compensated for the current cycle. The credit will be carried forward to the next billing cycle. The maximum rollover period is generally limited to one year. Any excess at the end of the period is compensated for at the wholesale or avoided cost rate.

2.18.1.5 Applicability of Net Metering within eThekwini

Implementing net energy metering where customers are remunerated for excess generation at the full retail rate means that they receive an implicit subsidy where they are paid for distribution, transmission and related grid services that they do not provide [55].

The concept of net metering and any variation thereof is not supported within eThekwini. The main reason is that it is assumed that the generated energy has the same value as retail energy. This is incorrect. The retail rate includes a contribution to grid charges and subsidies. Netting off would give the generated energy a higher value than what it is worth. Further, the time of PV generation does not coincide with the peak prices paid for energy in eThekwini.

The diagram below illustrates the pricing imbalance during the *winter* season for a residential customer in eThekwini:

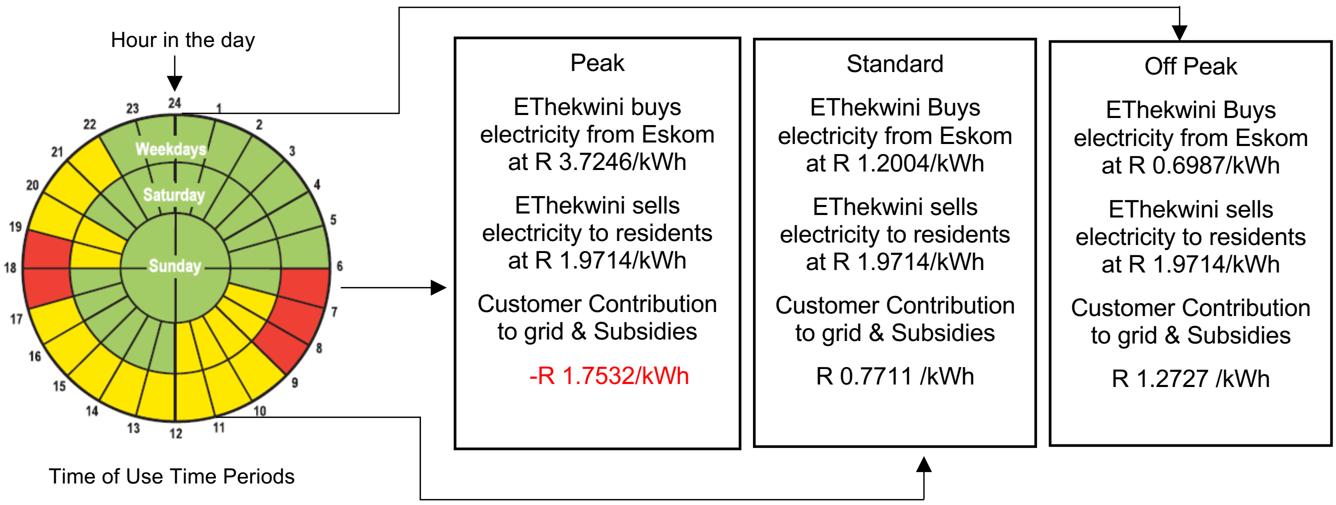


Figure 26 Pricing mismatch between purchasing and sales tariffs in eThekwini Municipality

There is a pricing imbalance between the cost of electricity from Eskom and the tariff being charged to residential customers. Therefore should a PV customer generate electricity during standard time

(R1.2004 /kWh) and consumes that electricity during peak time (R3.7246/kWh), the municipality will be incurring a loss of R2.524/kWh. Further, the customer would not be contributing to grid charges. Net metering is simple to administer and easy to understand; however, of late, it is coming under intense criticism for being unfair. Many utilities around the world are filing petitions to move away from net metering and towards fixed charges [56].

While net metering can quickly increase uptake rates of solar PV, there are many issues with the mechanism, and many nations are exploring alternatives. Policymakers are, therefore, being urged to analyse PV economics for a range of different compensation mechanisms and assess the impacts as PV penetration increases [57].

2.18.2 Net Billing

In net billing, there are usually two meters. One meter for measuring import energy and the other for measuring export energy. Import energy and export energy are measured using two separate meters, as there are different prices for import and export energy. Energy exchanges are expressed in financial terms [58]. A single electronic programmable electronic meter with dual registers can also be used.

In net billing, energy exported onto the grid is typically bought by the utility at the wholesale or avoided cost price while the electricity imported from the network is purchased at the retail price [59].

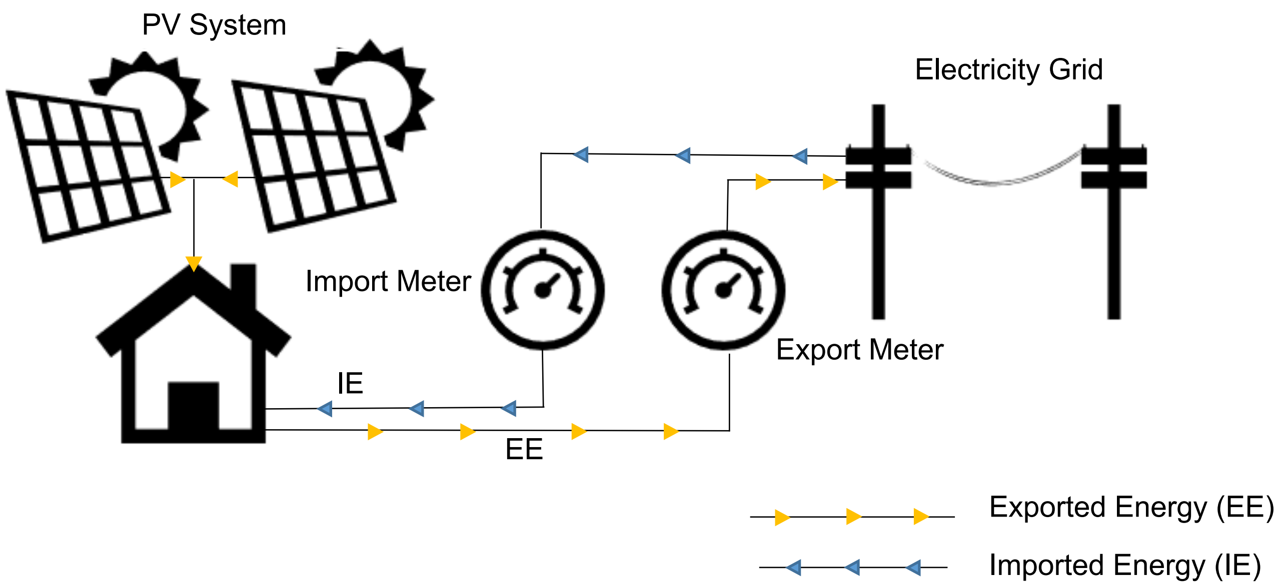


Figure 27 Net Billing energy flow and metering topology. Own elaboration referencing [54]

2.18.2.1 Net Billing: Simple

Energy Imported (IE) will be billed at the retail rate. Energy Exported (EE) will be credited at the avoided price.

Where IE - EE > 0 (in financial terms): The customer owes money to the utility for energy consumed
Where IE - EE < 0 (in financial terms): The customer is in credit however does not receive any compensation – i.e. all credit is forfeited.

2.18.2.2 Net Billing: With buyback

Where IE – EE (in financial terms) < 0: The customer is in credit and will receive compensation per billing cycle for the energy exported at the wholesale or avoided cost rate.

2.18.2.3 Net Billing: With rolling credit

Where IE – EE < 0: The customer is still in credit for that billing cycle after receiving compensation. The credit will be carried forward to the next billing cycle. The maximum rollover period is generally limited to one year. Any excess at the end of the period is forfeited.

2.18.2.4 Net Billing: With rolling credit and buyback

Where IE – EE < 0: The customer is in credit for that billing cycle after receiving compensation. The credit will be carried forward to the next billing cycle. The maximum rollover period is generally limited to one year. Any excess at the end of the period is compensated for at the wholesale or avoided cost rate.

2.18.2.5 Applicability of Net Billing within eThekwini

The concept of net billing and any variation thereof proves to be a workable solution in eThekwini if the purchase rate for energy exported is in line with the cost of energy (i.e. Eskom cost). Energy consumed will be sold at the retail tariff rate. Where this is the case, the municipality remains revenue neutral on the purchase of the electricity and agnostic in term of who supplies the electricity.
The net billing with a rolling credit is preferred as it would allow the exported energy to be offset against the municipal bill as credit and would avoid from providing a cash payment. The mechanism is also simple for customers to understand. However, the self-consumption of energy in this method will naturally be offset at the retail rate, and only the exported portion will be at the net billing rate. Due to the self-consumption of generated energy, the customer will be contributing less to the grid and subsidies. Therefore, a fixed network charge would be required to protect municipal revenue loss in terms of grid contributions only.

2.18.3 Feed-in tariff (FiT)

The FiT is similar to the net billing; however, there are no credits but rather payments. The FiT scheme has proven to catalyse the grid-connected PV installation in many countries. In 2015, FiT's were responsible for enabling almost 60% of the global share of total PV installations. There are variations in the FiT mechanism; however, generally, the scheme offers a payment guarantee and a stable contractual relationship for grid access (typically 20 years) [59]. FiT can be higher than retail rates where the objective is to promote higher penetration rates of RE. FiT's can also be priced on the Levelized Cost of Energy (LCOE) rate, which will vary per technology type.

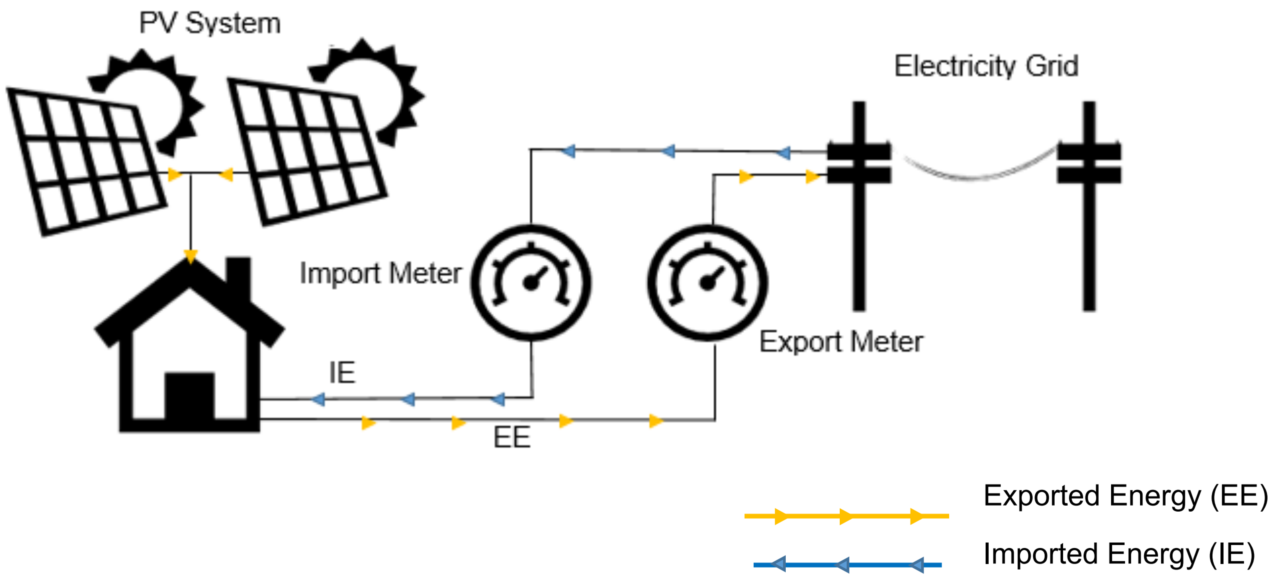


Figure 28 Feed-In Tariff energy flow and metering topology. Own elaboration referencing [54].

Germany was one of the pioneering countries to introduce feed-in tariffs in the early 1990s. The FiT was successful in promoting PV installations, and by the year 2004, Germany had increased its PV production thirtyfold. Apart from Germany, many countries in Europe, Asia and Australia use FiT's [60].

2.18.3.1 Applicability of feed-in tariffs within eThekwini

A form of the FiT has been implemented in South Africa via the Renewable Energy Independent Power Producer Program (REIPPP) and proved highly successful. However, the program was closed and not available for SSEG projects.

2.18.3.2 Long term contracting

The success of the FiT scheme is dependent mainly on long-term contractual arrangements. Long term contracting is, unfortunately, not an easy process within the local municipal supply chain framework specifically for electricity. It is, however, not impossible but rather a lengthy and administratively burdening process.

2.18.3.3 Purchasing of electricity

Municipalities are supplied bulk electricity via the national supplier, Eskom. Electricity pricing structures and price setting for organs of state supplying electricity to municipalities is monitored by National Treasury as prescribed by the Municipal Finance Management Act (MFMA) [61]. Price increases are further regulated via the National Energy Regulator of South Africa (NERSA). Because of this, municipalities are accustomed to buying electricity from organs of state and regulated accordingly. With the lack of procedures and guiding regulations to purchase electricity at a local level, it would be challenging to implement, especially where the export rate is higher than the avoided cost rate.

The FiT will be better suited to be implemented at a national level as the locus of control and decision-making around electricity generation, regulation and price setting is managed at that level.

2.18.4 Buy all - Sell All arrangement

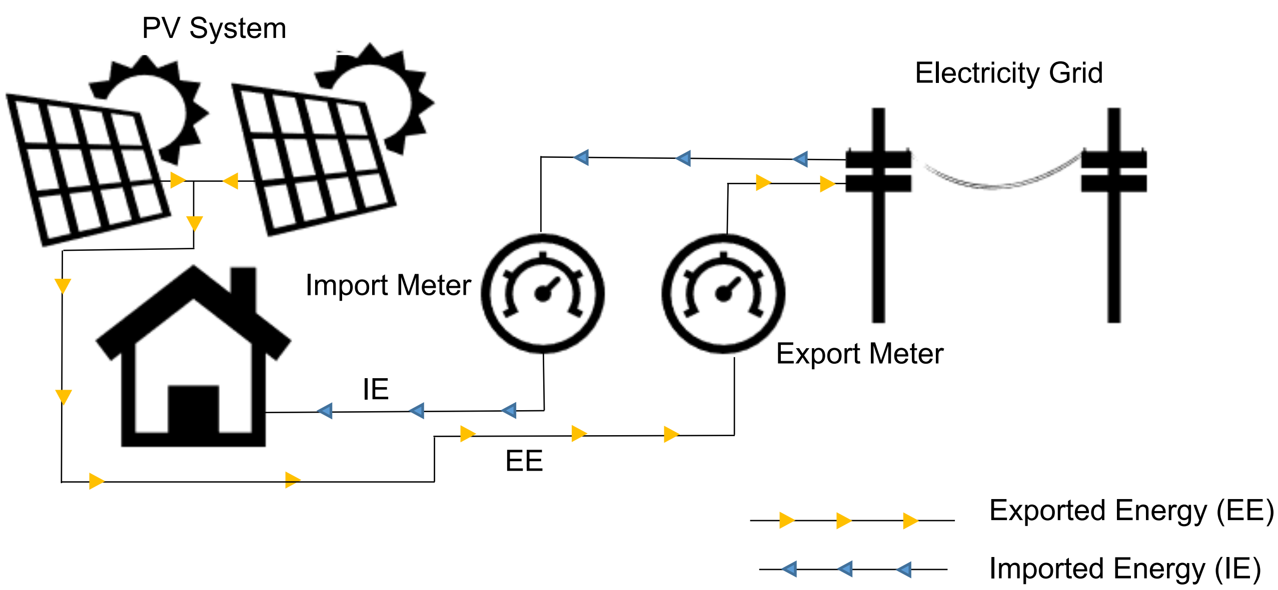


Figure 29 Buy All Sell All energy flow and metering topology. Own elaboration referencing [62].

In this method, all the energy imported or consumed from the grid is charged at the full retail rate. All the energy exported into the grid is remunerated at the export rate. There is, therefore, no self-consumption, and if the export rate were set at the avoided cost principle, then there would be no loss of revenue as is the case with net metering and net billing. There is no need to raise an additional network charge [62].

Due to its simplicity, it can be implemented with existing metering technology, does not require any detailed modelling before tariff implementation as the retail, and avoided cost rates are already known, and the municipality remains revenue neutral.

The drawback of this methodology is that the generation system would have to be metered, and this is embedded beyond the meter point (i.e. within the customer's property). This then subjects the export metering and supply to elements of tamper. Tampering would allow the customer to self-consume at the retail rate as opposed to selling at the avoided cost rate (lower).

2.18.4.1 Applicability of Buy All Sell All within eThekwini

The revenue neutrality of this methodology makes it an ideal mechanism for the municipality (i.e. no revenue loss). However, not allowing a customer to self-consume is the biggest drawback of this method. Offering the avoided cost price for all energy produced will not promote the rapid uptake of SSEG in the city. As the avoided costs increase in the future, it may become a more viable option.

2.18.4.2 Options for pricing the Export Rate

In each of the methodologies above, the export rate can be set based on different principles.

Generally, it is based on one of the following principles:

2.18.4.2.1 The bulk purchase price (avoided cost)

Pricing based on the bulk purchase price will apply in an instance where the municipality wants to remain revenue neutral. Buying the energy from the PV supplier or the Bulk supplier is immaterial.

2.18.4.2.2 A price higher than the retail rate

Pricing based on a higher than retail rate will apply in an instance where the utility wants to promote the generation of electricity and will remunerate customers at a higher rate for energy generated and exported to the grid.

2.18.4.2.3 The Levelized Cost of Energy (LCOE)

Upfront capital costs of RE are high while operational and maintenance costs are low. The means of pricing on a levelized base over the project lifespan (20 years) allows an all-inclusive remuneration to be paid to the generator based on the technology used to generate.

2.18.4.2.4 The Value of Solar (VOS)

In this method of pricing, value is awarded to solar energy generator based on its ability to save or reduced costs or enhance worth. Factors that are usually considered are avoided fuel cost, transmission and distribution losses, environmental impacts (non-release of greenhouse gases) and differed investment in infrastructure due to local generation. Value of solar rate is not necessarily set in relation to the retail tariff rate or the avoided cost rate [56].

2.19 Applicability of RE tariffs mechanisms in eThekwini Municipality

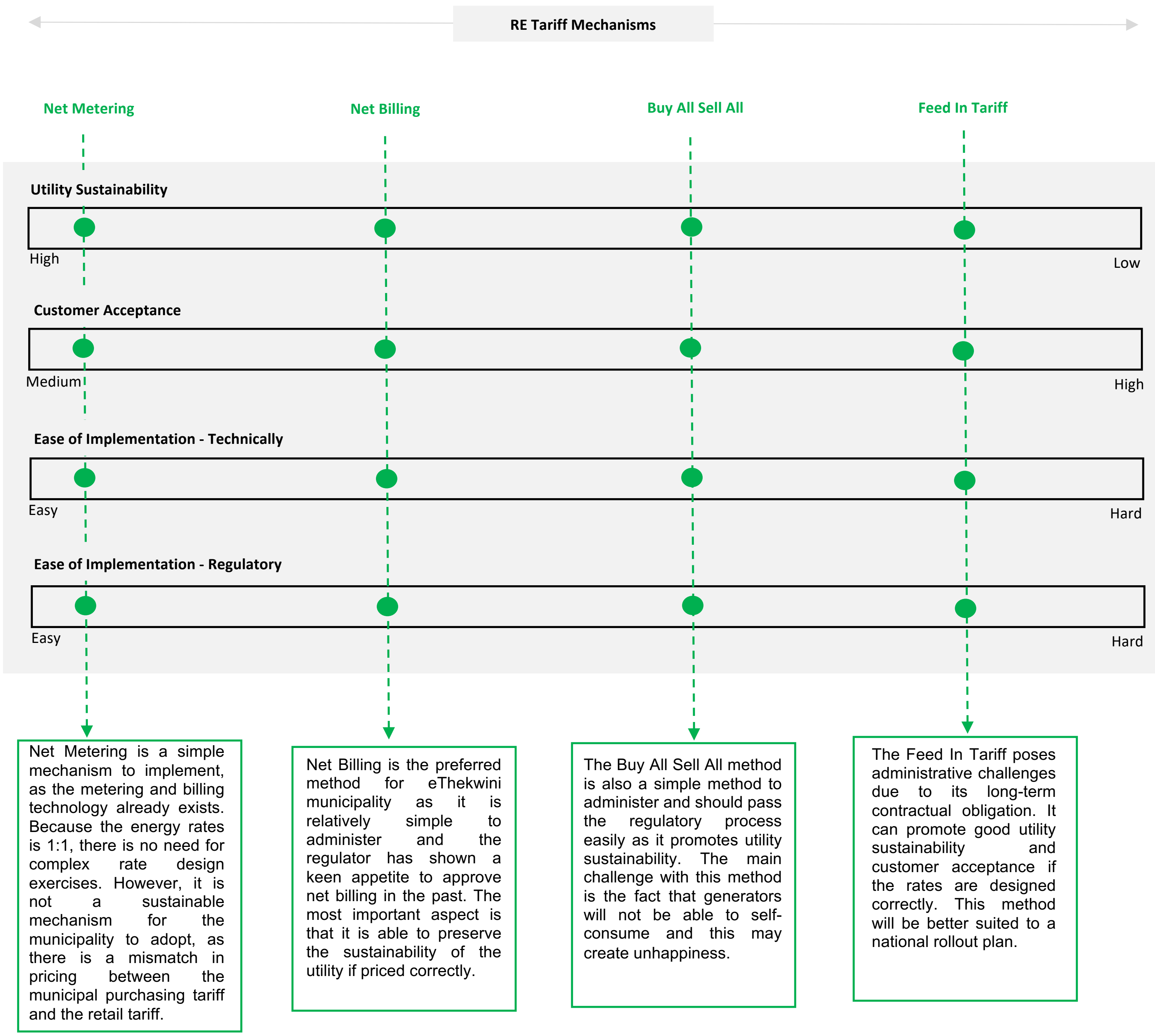


Figure 30 Applicability of RE tariff options for eThekwini Municipality

There are advantages and disadvantages to each method of tariffing. The approach to adopt must be situationally assessed and balanced based on the following:

- Priorities of the utility
- Maturity of customers and generators
- The attitude/appetite of the regulator

2.20 Carbon emissions and RE targets

Carbon dioxide (CO_2) is a greenhouse gas, and it is widely agreed that it is contributing to climate change. In 2015, world leaders signed the Paris Climate Agreement. The commitment by the world leaders was considered a significant stride in reducing carbon emissions throughout the world [10].

However five years earlier (in 2010), eThekwini Municipality became a signatory of the Global Cities Covenant on Climate – “Mexico City Pact”. As part of the agreement, the Municipality has committed to registering the Municipality’s greenhouse gas (GHG) emissions inventory, commitments, and climate mitigation/adaption measures in the carbon Cities Climate Registry [63].

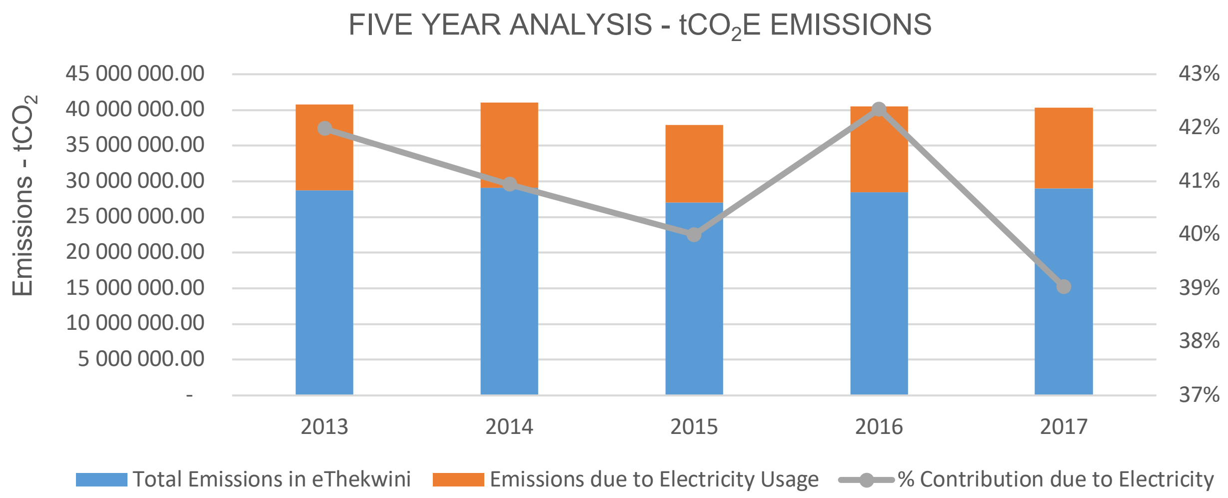


Figure 31 Carbon emissions for eThekwini Municipality: 2013 – 2017 [63]

Approximately 40% of all the CO_2 emissions for eThekwini Municipality is attributed to the usage of electricity. This has initiated the municipality to explore the role that RE can play to contribute to a reduced carbon emission profile in the future. EThekwini Municipality has set targets to have 40% of the electricity usage in the city generated from RE sources by 2030, and 100% of the electrical usage in the city generated from RE sources by the year 2050 [64].

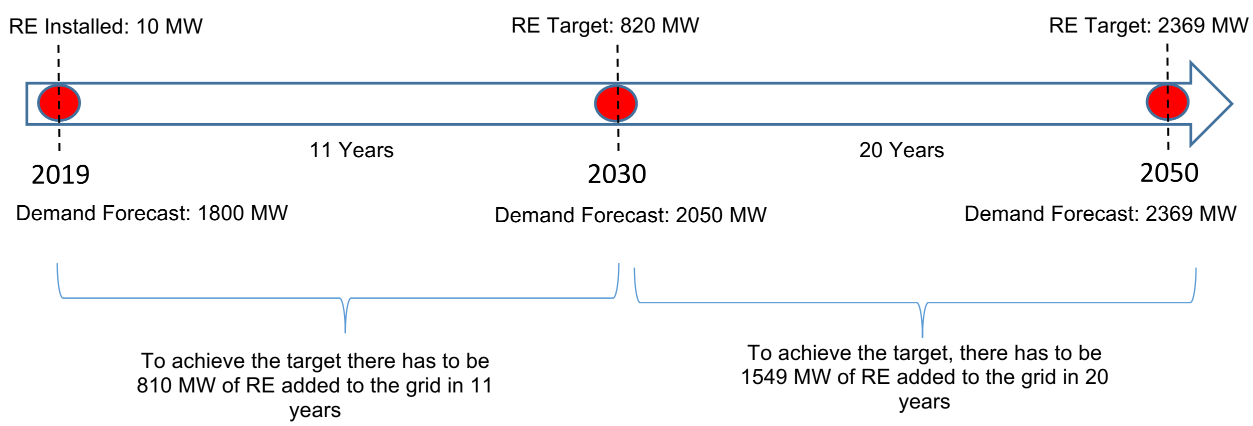


Figure 32 TimeLine: RE targets for eThekwini Municipality

To be able to achieve the ambitious goals of the city, there has to be a rapid uptake of RE installations in a limited space of time. While this is a mammoth task, significant progress can be achieved if the correct RE incentive mechanisms and tariff structures are adopted.

Greenhouse gas emissions from power generation plants are being criticised throughout the world. Clean energy technologies such as solar PV are being recognised as viable solutions to greenhouse gas emission mitigation. Due to their higher costs, various financial and tariff incentives are being made available to promote these cleaner technologies [60].

The ingenuity of the RE tariff framework adopted by eThekwini Municipality will play an influential role in dictating the rate at which RE will be adopted and carbon emissions reduced for the city going into the future.

3 CHAPTER 3: RE TARIFF DESIGN FOR ETHEKWINI MUNICIPALITY

3.1 Tariff design principles for RE tariffs

There are a wide variety of RE deployment options that have been implemented in various countries in the world. There have been many lessons learned, and valuable experience gained; however, there is no single deployment methodology for RE. The most appropriate approach in integrating RE to the grid will be dependent on the circumstances of the implementing city or municipality [59].

EThekwini Municipality is in the initial stages of RE integration, and therefore the principles of the RE tariff design, as highlighted in section 2.17, is based on the following order of priority:

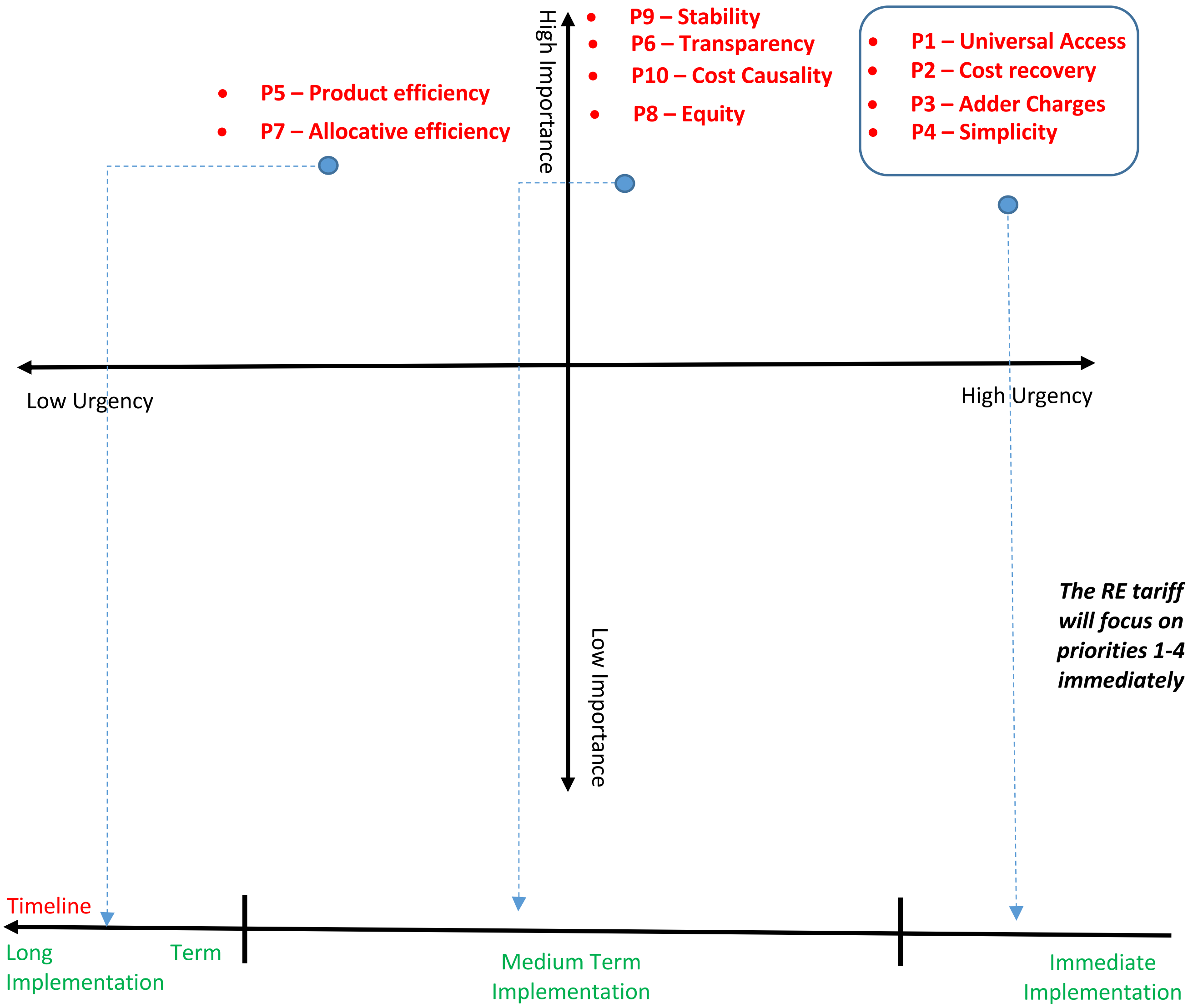


Figure 33 Timeline: Implementation of priority Indicators for RE tariff design in eThekwini Municipality

While all tariff priorities are important, they all cannot be introduced at once. This is the first attempt in eThekwini Municipality to introduce a suite of RE tariffs to cater for energy flowing in the reverse direction. There is also a learning customer base and a sparsely capacitated regulatory framework.

As an initial attempt, it is decided that the immediate RE tariff rollout would focus on the following four priorities - P1: Universal Access, P2: Cost Recovery, P3: Adder Charges and P4: Simplicity.

3.2 Evaluating tariff priorities with the proposed RE Tariffs

Universal Access (P1): The introduction of RE tariffs within eThekwini Municipality will formalise grid access to all PV generators.

Cost Recovery (P2): To maintain cost recovery, the proposed RE tariffs will be designed to prevent a drop in grid contribution when a customer installs PV and ensure there is no cost shifting within customer categories.

Adder Charges (P3): The introduction of additional network charges will ensure revenue stability.

Simplicity (P4): The proposed RE tariffs will have the same tariff structure as the purchasing tariff structure. This ensures a high level of simplicity and customer understanding.

Stability (P9): Introducing a suite of RE tariffs will bring about balance and structure within the solar PV sector in eThekwini. The sector is currently unstable and confused due to the lack of precise regulation.

Transparency (P6): The introduction of new RE tariffs will improve transparency, as network costs will now be explicitly shown.

Cost Causality (P10): The introduction of the new RE tariffs will not improve cost causality. The importance of cost causality is noted and will be introduced at a later stage as the generation market matures. At this stage, it is unclear exactly how PV will influence costs.

Equity (P8): The introduction of RE tariffs will not affect the equity aspect as it remains as per the existing tariffs.

Product Efficiency (P5): The introduction of RE tariffs will not affect the production efficiency aspect as it remains as per the existing tariffs.

Allocative Efficiency (P7): The introduction of RE tariffs will not affect the allocative efficiency aspect as it remains as per the existing tariffs.

3.3 Design method for RE Tariffs

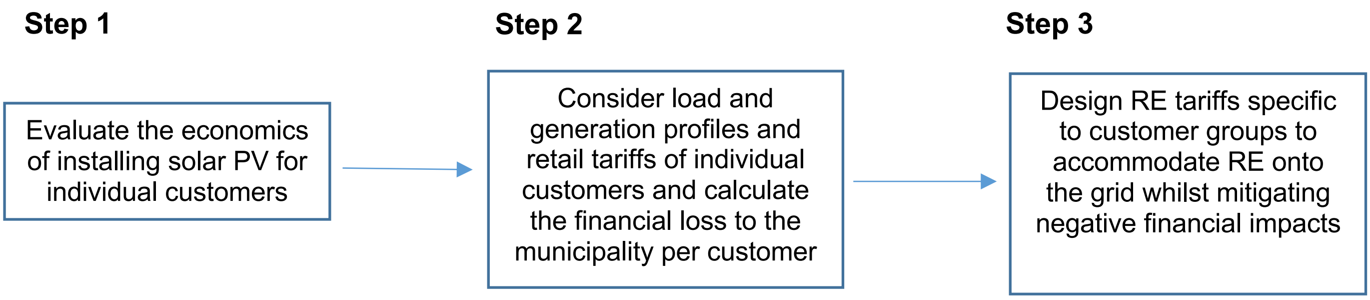


Figure 34 Design method for RE tariffs

3.3.1 Step 1: Evaluating the economics of Installing RE

A study was carried out to evaluate the impact of RE tariffs on PV project feasibility in Bangkok [65]. It was calculated that solar PV was more expensive than grid-supplied electricity. In order to make PV an attractive investment, the author suggests that high incentives or an attractive feed-in tariff were required. A similar study in New Zealand indicated that the RE tariff structure is vital in making RE an attractive investment option. It was found that higher feed-in rates or incentives were needed to make RE attractive [66].

To compare the benefits of two RE tariff mechanisms in Malaysia, economic analysis for a grid-connected residential PV system was carried out. The study focused on analysing the Feed-in Tariff (FiT) and the Net Metering Policy (NMP). The payback period was calculated for both policies. The results indicated that FiT provided a lower payback for low consumption customers while NEM provided a lower payback for higher consumption customers [67].

While the studies mentioned above only considered single generation projects, singular customer classes or individual consumption patterns for analysis (and extrapolated thereafter), the principle of their research highlights that the economic feasibility of PV projects is highly dependent on the RE tariff design and tariff rates.

As a result, the approach in designing optimised RE tariffs for eThekwini Municipality was first to understand the economic feasibility of PV projects based on loading profiles, the loss generated and then design RE tariffs. The tariff should aim to balance financial project feasibility against revenue losses for the municipality [68].

The recovery of cost from different customers is primarily based on the socio-economic conditions, and hence, those with a higher level of affordability will subsidise those with a lower level of affordability. Traditionally this was implemented by way of low usage representing low affordability and vice versa.

The introduction of RE should not be the trigger of recovering costs differently. The reality is that those with higher levels of affordability will seek to invest in RE. Therefore, this modelling exercise takes the view of preserving the grid contributions in the proportions that they are currently being recovered as opposed to trying to recover grid contributions in different proportions.

As the PV sector matures and the socioeconomic conditions of the country improve, there will be an opportunity to build in other priorities within the RE tariffs, including transparency, cost causation and other relevant priorities. To maintain fairness and to introduce a stable RE platform at this stage, the RE tariff aims to balance the following principles in order to promote RE uptake and carbon reduction targets.

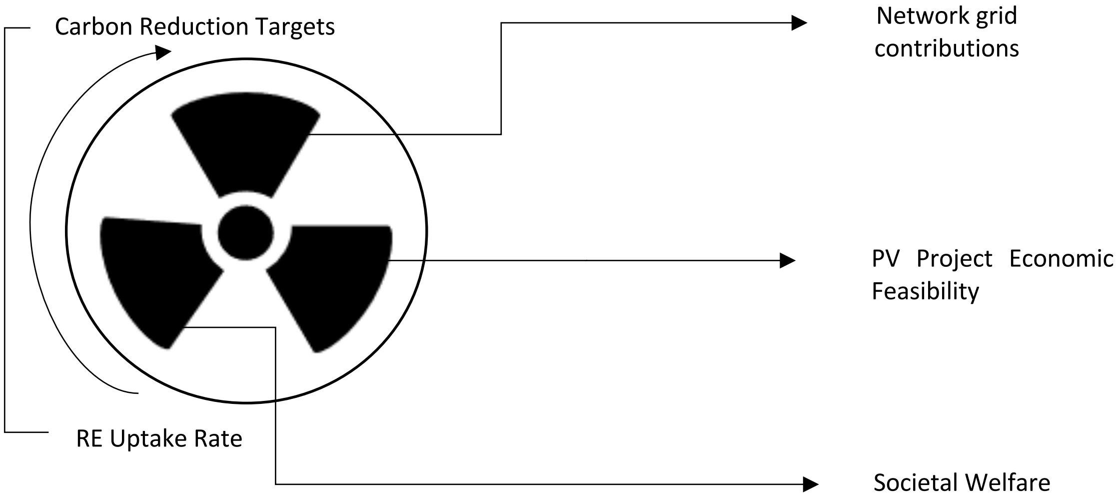


Figure 35 Balancing RE tariff principles

3.3.1.1 Network grid contribution: Allow for the recovery of municipal charges that are inadvertently being offset and bypassed during self-consumption.

3.3.1.2 PV project economic feasibility: Allow the PV system to meet the minimum threshold economic criteria. The RE tariff aims to maintain a minimum IRR of 15% and a maximum SPBP of 10 years.

3.3.1.3 Maintaining societal welfare: The RE tariff will be designed to allow for the continuation of grid contributions at the same level that the customer was contributing before the installation of the PV system. Maintaining the previous level of grid contribution ensures that the societal needs of the grid remain balanced.

Mastropietro [69] demonstrated that RE surcharges included in electricity tariffs represented a regressive tax that has a negative effect on the poor, which exacerbated poverty. The balancing of societal welfare is, therefore, an essential aspect of ensuring that the poor are not adversely affected as the transition to RE continues.

The ability to maintain a harmonious balance between the above principles will dictate the PV uptake rate for eThekwini Municipality and inform the rate at which the municipality could reach its carbon reduction targets.

3.3.2 Step 2: Consider load/generation profiles and calculate the financial loss

The respective loading profiles for each customer category varied as they consume electricity differently. However, generation profiles remained the same for all customers as they are within the same solar irradiation periphery. Superimposing the generation profile onto the load profile for individual customers provided a basis to calculate the self-consumed amount of electricity and hence the revenue losses applicable to the municipality.

Balancing revenues with costs is a crucial element for market efficiency and success. When there is an imbalance of these two parameters, a financial gap will occur. In addition, the implementation of an ambitious RE plan will increase this gap [70].

Customers with PV reduces the utility collected revenue more than the reductions in costs that PV offers. This leads to the erosion of income and lost future earnings opportunity. Further average rates increase as utility costs are now shared over a smaller sales base [71].

3.3.3 Step 3: Design RE tariffs specific to customer categories

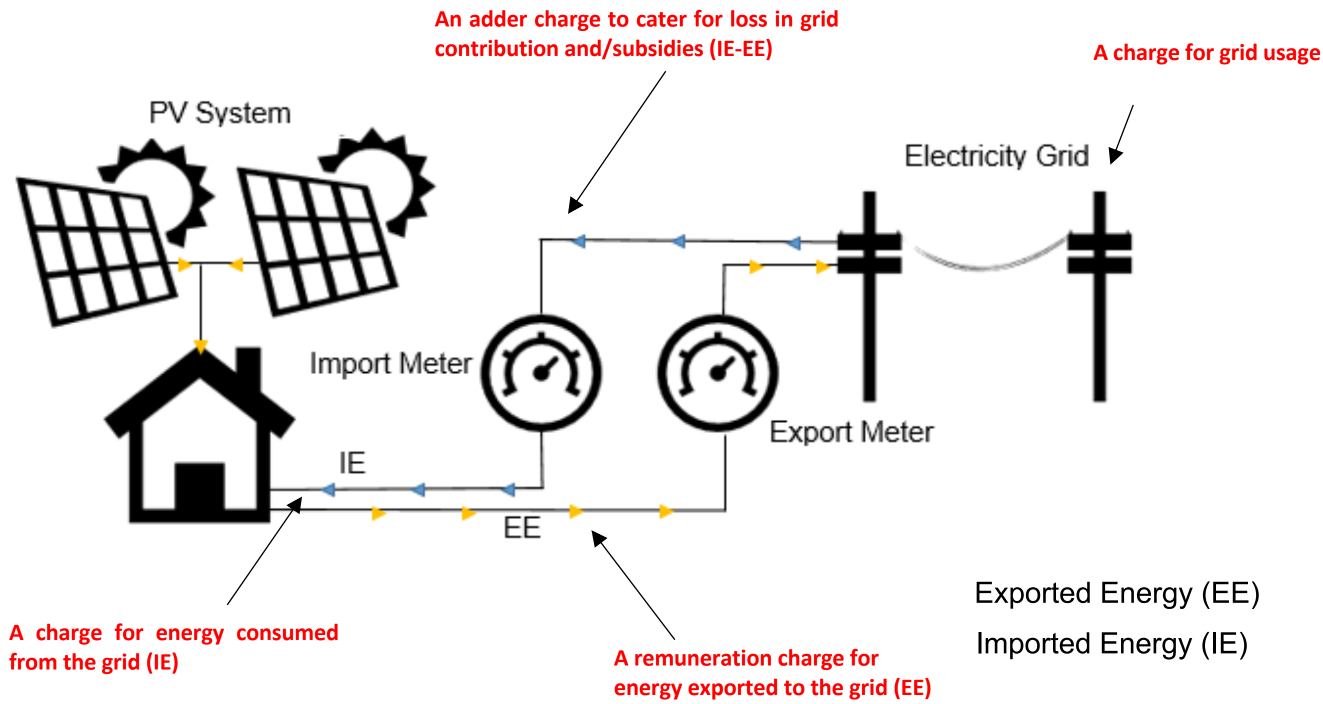


Figure 36 Charges to consider for inclusion within RE tariffs. Own elaboration referencing [66], [67], [71], [72].

3.3.3.1 Charge for grid usage and an adder charge

The revenue loss initiated by PV systems will be recovered via a network access charge, which will be chargeable based on the inverter size (R/kVA). This charge will be priced so that the municipality remains revenue neutral. This will ensure that the revenue recovery will vary as the size of generation varies per customer. This method of charging allows each customer to maintain their level of grid contribution to the municipality irrespective of their change in grid usage pattern. This is because the size of the inverter will influence the amount of energy self-consumed. This is not an additional charge; however, a charge that will recover a portion of grid contribution via a fixed capacity charge.

Monthly fixed charges irrespective of the inverter size was considered; however, this would not allow the customer to make the same level of grid contribution as made before the installation.

3.3.3.2 Remuneration charge for energy exported

Energy exported to the grid will be remunerated on the same tariff structure as what the customer is purchasing electricity from the municipality at. The rate will be an average rate considering the yearly export generation profile and the avoided cost of energy. This ensures that the tariffs remain simple with a high level of customer understanding.

3.3.3.3 Charge for energy imported

Each customer category installing PV will continue to purchase electricity on the same tariff structure and rates as they did before the installation of PV. However, they will be subject to additional RE tariff components.

Broadly, the newly optimised RE tariffs will aim to maintain the following:

3.3.3.3.1 PV customers (prosumers) make the same contribution to the grid as they did when they were pure consumers. Maintaining the same contribution will be implemented via a network access charge (R/kVA), based on the size of the inverter.

3.3.3.3.2 Notwithstanding 3.3.3.1 above, the RE tariffs will be priced with due cognisance of the economic viability (acceptable IRR & SPBP) of the PV project.

3.3.3.3.3 The municipality will remain revenue neutral when customers become prosumers.

3.3.3.3.4 The municipality will buy excess energy at the avoided cost principle. I.e. same prices as what the municipality buys from Eskom.

3.3.3.3.5 The municipality will buy excess energy in line with the same tariff structure (not tariff rate) that energy is being sold to the customer. Maintaining similar tariffs structures for generation and consumption will ensure tariffs are simple to understand and to administer while achieving zero losses to the municipality.

3.4 RE tariff structure

Table 7 RE tariff structure for individual customer categories

Customer category	Imported Energy	Exported Energy	Recovery of revenue losses
Residential	Single rate energy tariff	Single rate energy tariff based on the avoided cost principle	Network Access Charge based on the size of the inverter (R/kVA)
Business			
Industrial	Multi-rate energy tariff that is time, seasonal and voltage differentiated	Multi-rate energy tariff that is time, seasonal and voltage discriminated based on the avoided cost principle	

3.5 The Optimisation Methodology

3.5.1 Optimisation objectives

Table 8 Optimisation objectives for tariff modelling

No	Objective		Available Information	Constraints & Limitations	Means of Assessment	Consequence of Objective	Trade-Off & Linkage of Optimisation
1	Optimise quantity of RE	Maximise the number of customers feasible for PV	PV system costs Load profiles Generation profiles	Assumes roof space is available for all calculated PV sizes Assumes no shading occurs	Calculation of NPC, IRR, SPBP and ROI	Allows for a higher proportion of solar PV to be installed in eThekwini Municipality	Reduced electricity consumption from the grid
2		Maximise PV system size and economics of the PV system					
3	Optimise revenue sustainability	Minimise municipal revenue loss	Retail tariffs Wholesale tariffs Consumption data PV system Sizes	Assumes categories of customers will consume electricity following a representative loading profile	Calculate the amount of energy self-consumed and introduce a tariff charge component to augment the loss	Allows for the municipality to not incur losses and remain financially sustainable	Reduced economic parameters for PV projects

Considering the current circumstances in eThekwini, the objectives 1 & 2, unfortunately, do not support objective 3. They have conflicting priorities. The optimisation exercise will reveal the extent of the imbalance between the optimisation objectives and display the parameters applicable to maintain the objectives in balance.

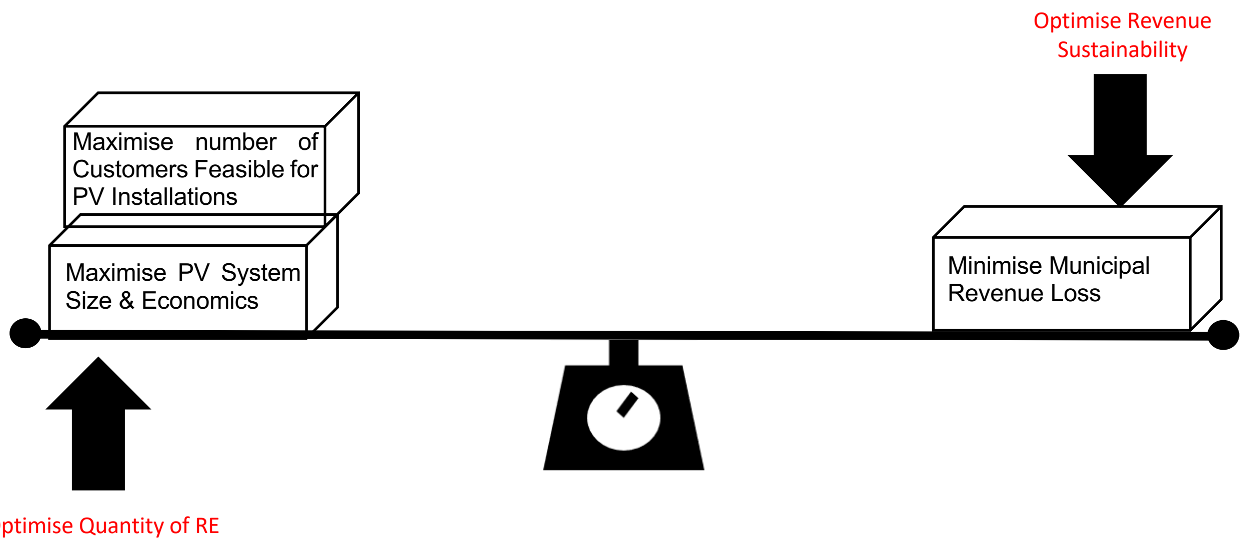


Figure 37 Balancing optimisation objectives

3.5.2 Optimisation tools

There is a range of PV optimisation tools available. The table below highlights the tools used in analysing PV projects amongst other authors.

Table 9 Optimisation tools used in other RE modelling exercises.

NO	AUTHOR	COUNTRY	OPTIMISATION TOOL	DESCRIPTION
1	Islam [73]	France	HOMER Software	Technical and economic optimisation analysis: Office Building
2	Rehman et al. [74]	Saudi Arabia	RETScreen	Technical and economic optimisation analysis: Various Sites
3	Gonzalez et al. [75]	Spain	Genetic Algorithm Optimization Technique	Optimisation of PV/Wind/Biomass Systems
4	Li et al. [76]	China	HOMER Software	Technical and economic optimisation analysis: Various Sites
5	Kazem et al. [77]	Oman	MATLAB developed code	Technical and economic optimisation analysis: 1 MW PV System
6	Bastholm and Fiedler [78]	Tanzania	HOMER Software	Technical and economic optimisation analysis: Hybrid System
7	Algarni et al. [79]	Saudi Arabia	Homer Software	Optimisation analysis: PV tracking system
8	Rehman et al. [80]	Pakistan	Homer Software	Optimisation analysis: Household PV with storage
9	Jahangiri et al. [81]	Iran	Homer Software	Optimisation analysis: Hybrid System
10	Mukisa et al. [82]	Uganda	Google earth/Azimuth Tools	Optimisation analysis: Various sites

In addition to the optimisation tools highlighted above, other optimisation tools available include EasySolar, Onyx Solar, PV Output, Solar Pro and Pvsyst [83].

Each tool focuses on optimising particular aspects of solar PV projects. Where there is a need for cross-functional optimisation, the use of a single tool is not sufficient. The insufficiency of cross-functional optimisation is well portrayed by the paper authored by Wijeratne et al. [83]. The authors acknowledge the inability of a single software tool to satisfy the optimisation needs of multidisciplinary stakeholders with varying aims and objectives. Stakeholders include property owners, technical design teams, financial analysts, installation teams and the utility sector amongst others. The design and analysis features of 23 PV, design and management programs were assessed. The assessment revealed 14 solar PV design and management issues that contributed to the lack of cross-functional optimisation.

Various commercially available software optimisation tools were considered for developing the solar techno-economic model for eThekwini. The cross-functional linkage required were mainly focussed on optimising the technical, financial and utility aspects (tariff design) of PV for eThekwini. Due to the unique cross-functional optimisation requirements and available municipal data sets, Microsoft Excel combined with a Visual Basic Interface (VBI) was deemed as an appropriate platform to carry out simulations and optimisation. The modelling platform was coded from first principles.

3.6 The solar techno-economic model

The solar techno-economic model is a two-stage simulation tool. Stage one of the simulation analysed each customer and the respective inputs to determine the optimum PV system size, key economic criteria and finally, the reduction in municipal revenue due to self-consumption by feasible customers. Customers are deemed feasible only if they at least met the IRR threshold of 15% and a maximum SPBP of 10 years.

Stage two allowed for the input of a network access charge (R/kVA) to manage the drop in revenue from stage one. Stage two iterated with the network access charge and provided updated economic parameters.

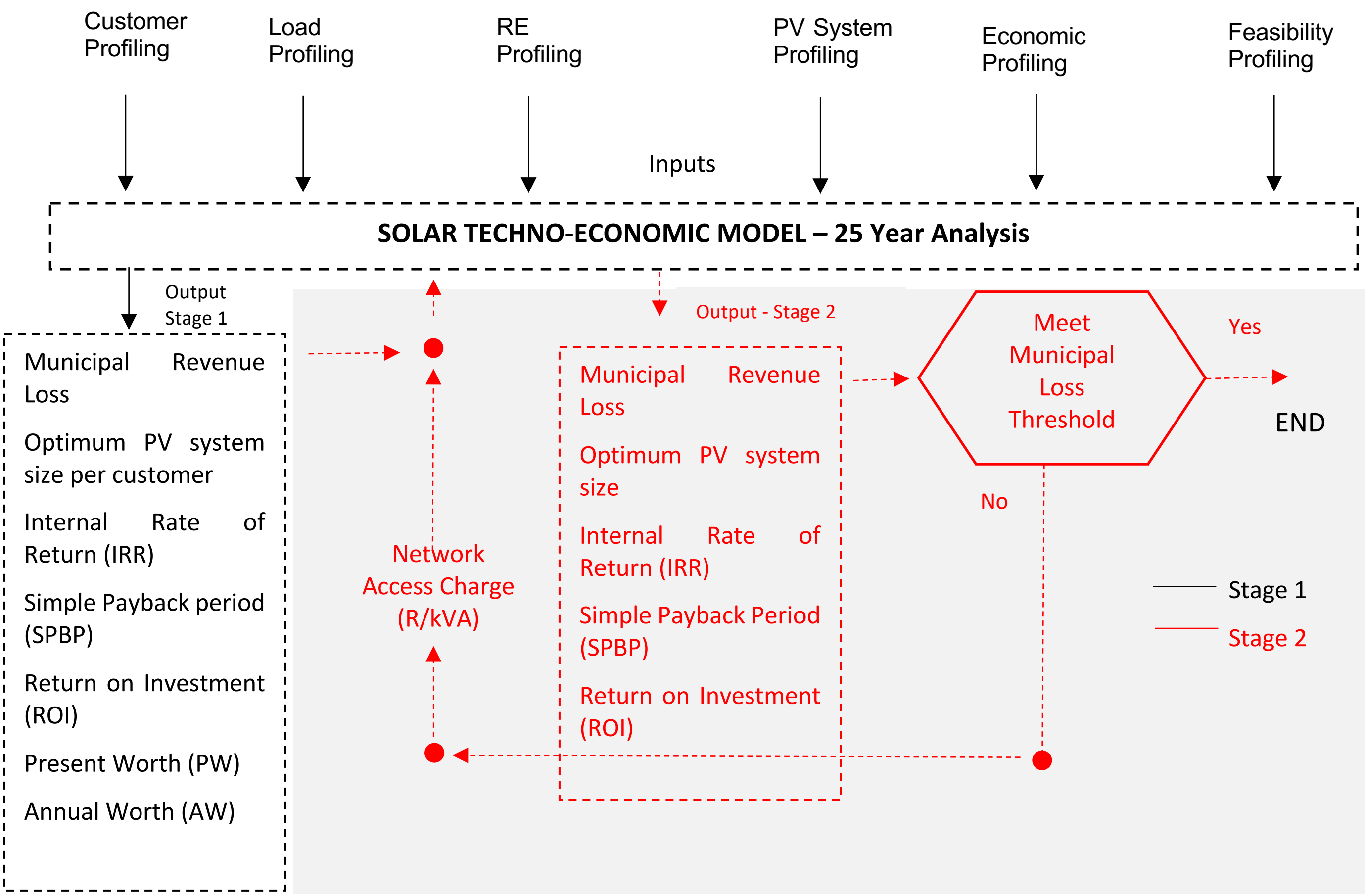


Figure 38 Two-stage techno-economic model

The model was applied to each customer category separately (i.e. residential, business and industrial) because each customer category had:

- Unique loading profiles and unique self-consumption profiles
- Varying tariff structures and rates
- Varying VAT, tax incentives
- Varying PV system costs

3.6.1 The techno-economic model – Graphical User Interface (GUI)

The GUI makes provision for input of variables and the display of results. The inputs are highlighted within the blue lines while the outputs are highlighted outside of the blue lines. There are a further two output tabs contained within the output parameters.

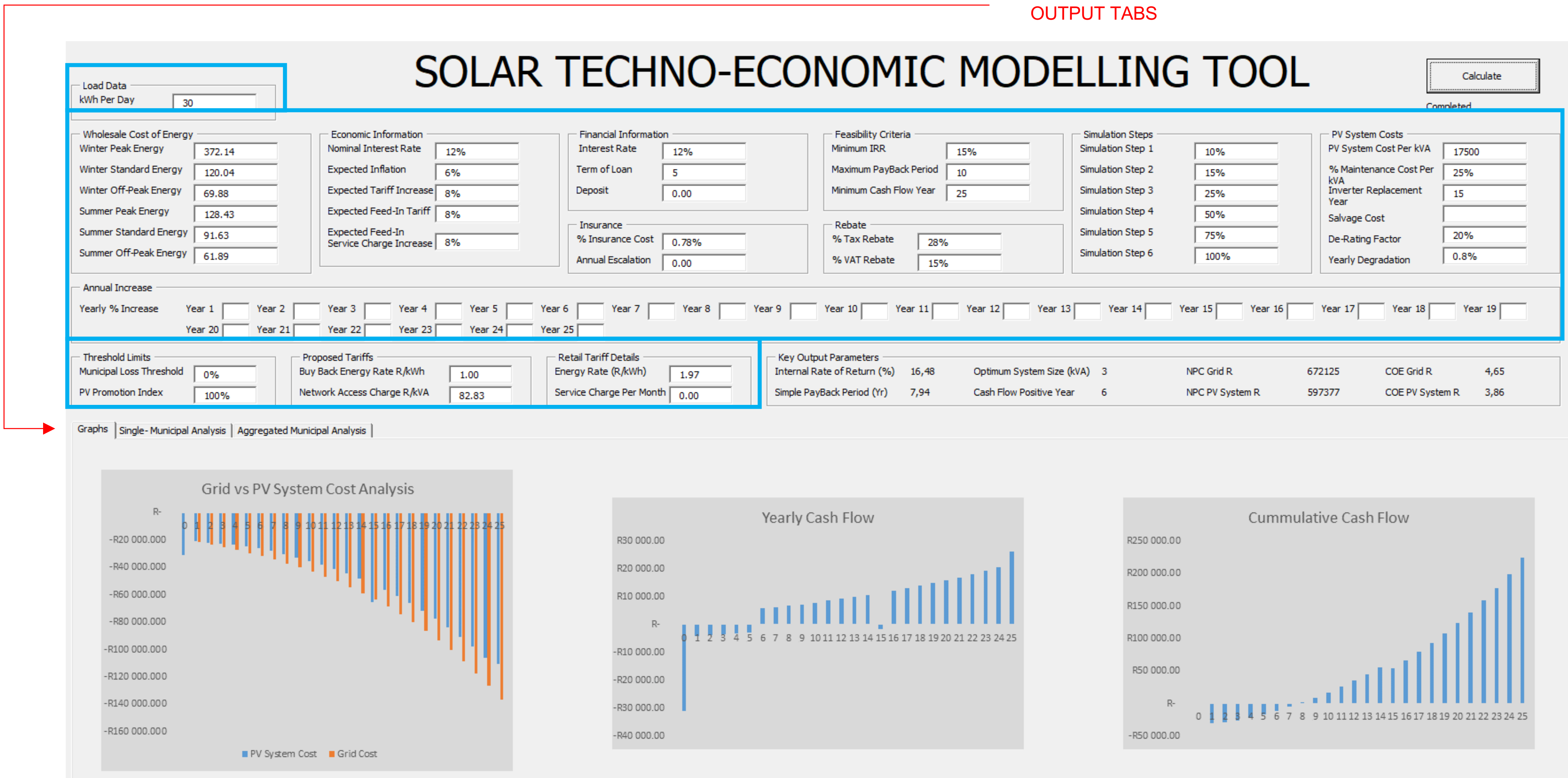


Figure 39 Solar techno-economic model – Graphical User Interface (GUI)

3.7 The calculation methodology

To evaluate the feasibility of the PV projects, an investment appraisal approach has been followed with the following criteria:

3.7.1 Net Present Value (NPV) & Internal Rate of Return (IRR)

The NPV calculation references the future cash inflows and cash outflows of a project (net cash flow) in present terms, taking into account the time value of money, i.e. the discount rate [84]. The formula for the NPV calculation is given by:

$$\text{NPV} = \sum_{t=1}^{n} \frac{Cf_{grid} - Cf_{pv}}{(1+r)^t} \tag{2}$$

Where:

Cf_{grid}	= net cash flow: Grid	(R)	Cf_{pv}	= net cash flow: PV system	(R)
t	= time	(year)	n	= project lifespan	(year)
r	= real discount rate	(%)			

The discount rate that equates the present value of the expected cash inflows with the present value of the expected cash outflows is defined as the Internal Rate of Return (IRR) [85]. The discount rate is calculated by equating the NPV to zero.

Note: For modelling purposes, the cost to satisfy the electrical load was evaluated by either a PV system or the electrical grid. As a result, reference was made to the Net Present Cost (NPC) as opposed to the NPV.

3.7.2 Simple Pay Back period (SPBP)

The SPBP is defined as the time taken for the accumulated net cash flow to equate to the initial capital investment, i.e. the length of time it takes to recover the original investment [84]. For the purpose of this study, the SPBP was deemed to be the year where the accumulated cash flow equates to the initial capital investment. The formula for the SPBP is given by:

$$\text{SPBP} = \sum_{t=1}^{n} (Cf_{grid} - Cf_{pv}) - I_{pv} = 0 \tag{3}$$

Where:

Cf_{grid}	= net cash flow: Grid	(R)	Cf_{pv}	= net cash flow: PV System	(R)
I_{pv}	= PV Investment	(R)	n	= project lifespan	(year)
t	= time	(year)			

3.7.3 Levelised Cost of Energy (LCOE)

The LCOE method is extensively used to evaluate and compare energy systems that display varying cost and generation characteristics over its lifespan. LCOE defines a unit cost for electricity generated over the lifespan of the system. This creates an even platform to compare generation technologies that experience dissimilar costs over its lifespan. The LCOE is calculated by dividing the total capital cost of the system, over the expected energy output while consideration the time-varying value of money [86].

For the purpose of this study, the LCOE was calculated as follows:

$$LCOE = \frac{C_{ann,tot}}{E_{served}} \tag{4}$$

Where:

$C_{ann,tot}$ = total annualised cost of the system/Annual Worth (R)

E_{served} = total electrical load served (kWh)

The Annual Worth is calculated by multiplying the Present Worth by the capital recovery factor. The capital recovery factor is a ratio used to calculate the present value of an annuity [87].

$$\text{ANNUAL WORTH } = \sum_{t=1}^{n} \frac{Cf_{grid} - Cf_{pv}}{(1+r)^t} \times CFR \tag{5}$$

Where:

Cf_{grid}	= net cash flow: Grid	(R)	Cf_{pv}	= net cash flow: PV System	(R)
t	= time	(year)	n	= project lifespan	(year)
r	= real discount rate	(%)			

The capital recovery factor can be expressed by the following formula:

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1} \tag{6}$$

Where:

i = real discount rate (%)

n = number of years

The real discount rate is used to calculate discount factors and annualised costs from net present costs. The real discount rate is given by the following formula:

$$i = \frac{i' - f}{1 + f} \tag{7}$$

Where:

i	= real discount rate	(%)
i'	= nominal discount rate	(%)
f	= expected inflation rate	(%)

3.7.4 Return on Investment (ROI)

Return on investment is used to evaluate the efficiency of capital investment. It is generally calculated by dividing total investment returns by the total cost of the investment for the specified period [88]. For the purpose of this study, the ROI was calculated as follows:

$$ROI = \frac{\sum_{t=1}^{n}\left(Cf_{grid-}\ Cf_{pv}\right)}{n \times CC_{pv}} \tag{8}$$

Cf_{grid}	= net cash flow: Grid	(R)	Cf_{pv}	= net cash flow: PV System	(R)
CC_{pv}	= capital cost: PV system	(R)	n	= project lifespan	(year)
n	= project lifespan	(year)	t	= time	(year)

3.7.5 Salvage Value (SV)

Salvage value is the residual value in a component at the end of the project lifespan. It is calculated as follows [87] :

$$S = C_{rep} \times \frac{R_{rem}}{R_{comp}} \tag{9}$$

C_{rep}	= replacement Cost	(R)	R_{comp}	= component lifetime	(year)
R_{rem}	= remaining life of component at project termination (year)				

3.8 The model calculation methodology

3.8.1 Stage one

For each customer consumption (kWh/day), a yearly load profile was constructed. Based on the solar irradiation data, an annual generation profile was constructed. The generation profile was superimposed onto the load profile. This allowed for the calculation of the energy self-consumed and the energy exported onto the grid.

Four generation profiles were constructed at 25%, 50%, 75% and 100% of the peak load size to compute the optimum generation size (kW). The generation profile that produced the lowest NPC was deemed the optimum generation size.

The yearly self-consumption, solar export profile and solar costs were modelled over a 25-year period against the cost of grid electricity, taking into consideration anticipated escalations. Electricity savings were then calculated yearly. These annual savings and the upfront capital costs were used to calculate the NPC, IRR, SPBP, LCOE and ROI.

Once the yearly savings to the customer was established, the Municipal loss was calculated by evaluating the energy self-consumed. Each kWh self-consumed represented a revenue loss to the municipality, calculated as follows:

$$R_t = \sum_{Cu=1}^{n} \left((E_{SC} \times E_{rt}) - (E_{SC} \times E_{bk}) \right) \tag{10}$$

Where:

R_t	= revenue loss total (R)	E_{SC}	= energy self-consumed (kWh)
C_u	= number of customers	n	= total number of feasible customers
E_{rt}	= energy rate: retail (R/kWh)	E_{bk}	= energy rate: bulk (R/kWh)

3.8.2 Stage two

Once the loss was established, a network access charge (R/kVA) was automatically calculated to offset the loss. The network access charge (R/kVA) was calculated as follows:

$$M_t = \frac{(E_{sc} \times E_{rt}) - (E_{sc} \times E_{bk})}{I_s} \tag{11}$$

Where:

M_t	= municipal tariff	(R/kVA)	E_{SC}	= energy self-consumed	(kWh)
E_{bk}	= energy rate: bulk	(R/kWh)	I_s	= inverter size	(kVA)
E_{rt}	= energy rate: retail	(R/kWh)			

This network access charge now formed part of the yearly project costs. The model took into consideration this added cost and recalculated the NPC, IRR, SPBP, LCOE and ROI.

Where the IRR & SPBP met the feasibility criteria, it was deemed that the customer would install the system, and the loss was accounted for in the revenue loss calculation to the Municipality. Based on the feasible customers, the PV system sizes were summated to calculate the total RE that could potentially be generated.

$$E_r = \sum_{Cf=1}^{n} \frac{I_s}{1000} \times P_f \tag{12}$$

Where:

E_r	= renewable energy	(MW)	C_f	= feasible customers
I_s	= inverter Size	(kVA)	$\widehat{P_f}$	= power factor
n	= number of feasible customers			

Note: Assumed unity power factor for calculation purposes.

3.9 The solar techno-economic model inputs

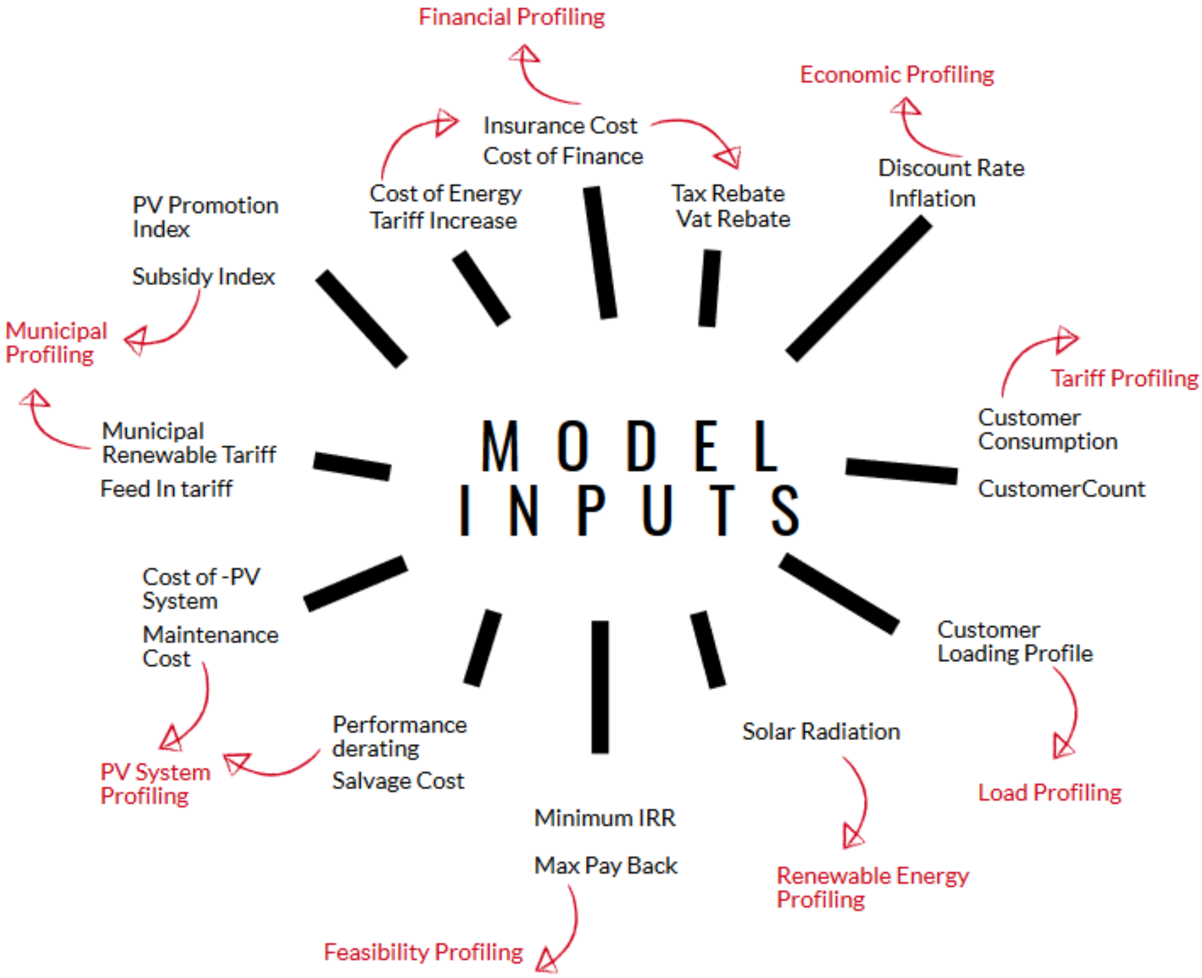


Figure 40 Solar techno-economic model inputs

3.9.1 Customer profiling

3.9.1.1 Residential customer count and consumption

There are 722977 residential customers in eThekwini. There were 69712 residential customers excluded from the modelling due to inaccurate data. This represented a modelled residential customer base of 90.4%.

The residential customers were profiled according to their monthly average consumption. The yearly averages ranged from 365 kWh to 25000 kWh.

The diffusion of residential customers as per the NERSA categories [40] are shown below :

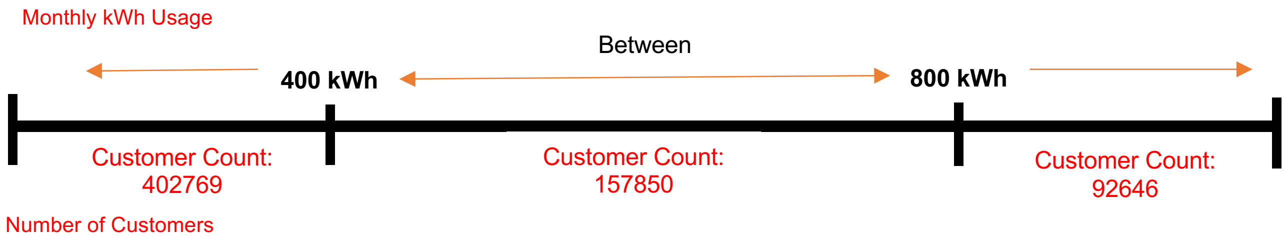


Figure 41 Diffusion of residential customers segmented as per NERSA Categories

3.9.1.2 Business customer count and consumption

There are 44027 business customers in eThekwini. There were a total of 14679 business customers excluded from the modelling due to inaccurate data and customers being on obsolete tariffs. This represents a modelled business customer base of 67%.

The diffusion of business customers, as defined by the NERSA categories, is shown below:

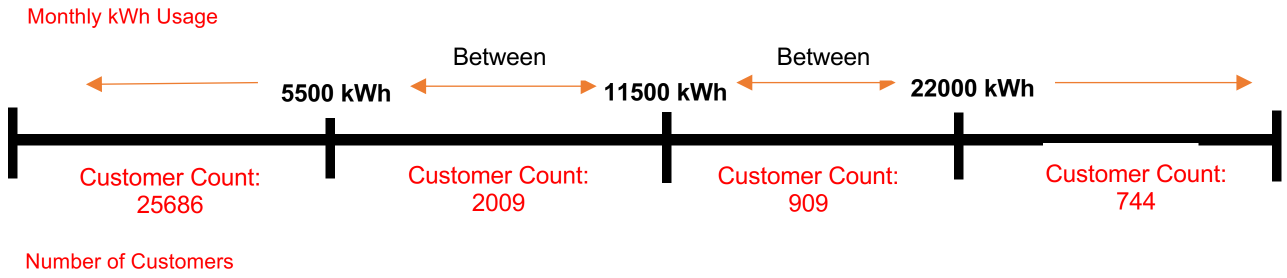


Figure 42 Diffusion of business customers segmented as per NERSA Categories

3.9.1.3 Industrial customer count and consumption

There are 997 Industrial Time of Use customers in eThekwini. There were 218 industrial customers excluded from the modelling due to inaccurate data or without consumption history. This represents a modelled Industrial customer base of 78%.

The diffusion of industrial customers, as defined by NERSA categories, is shown below:

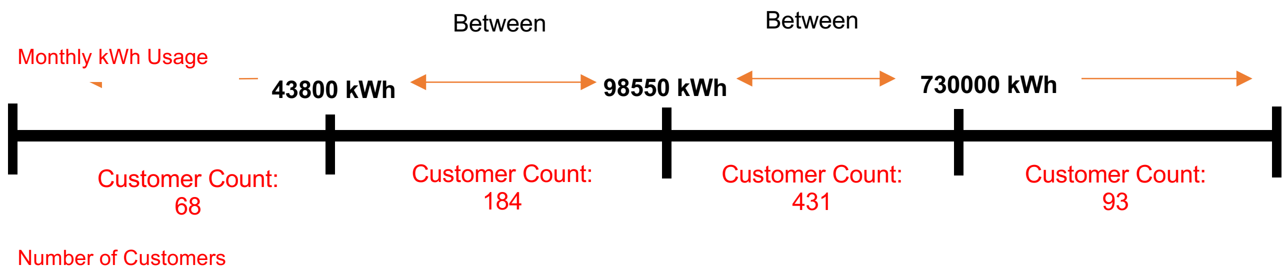


Figure 43 Diffusion of industrial customers segmented as per NERSA Categories

3.9.2 Renewable energy profiling

The monthly solar Global Horizontal Irradiance (GHI) data used for eThekwini (-29.50 latitude, 31.50 longitude) was from the NASA surface meteorology and solar energy database for the period July 1983 – June 2005 [89].

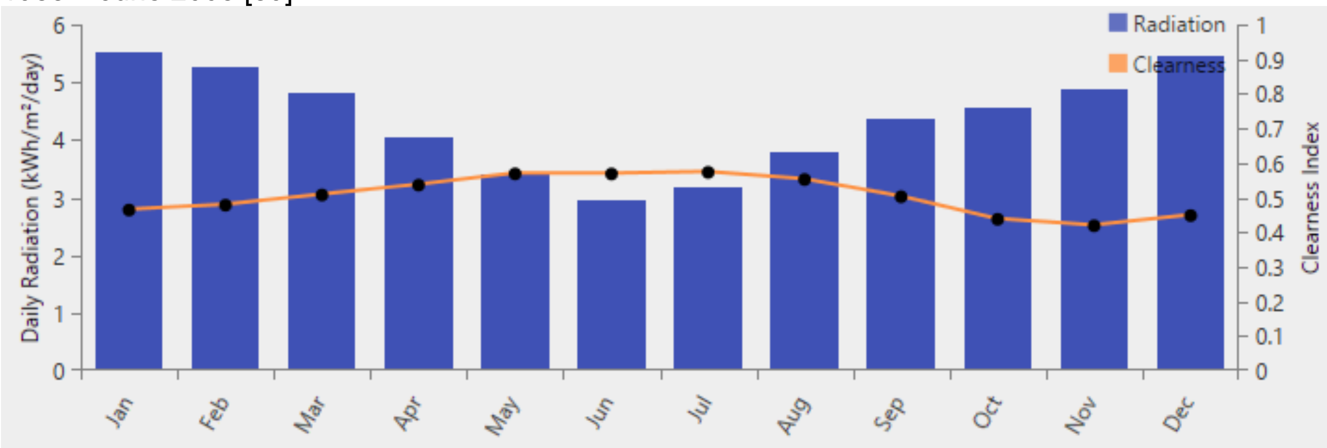


Figure 44 Daily irradiance/clearness index for eThekwini Municipality

There is a considerable variation in generation profiles per day. Varying weather conditions are primarily responsible for the disparities. Shown below is a random weekly profile:

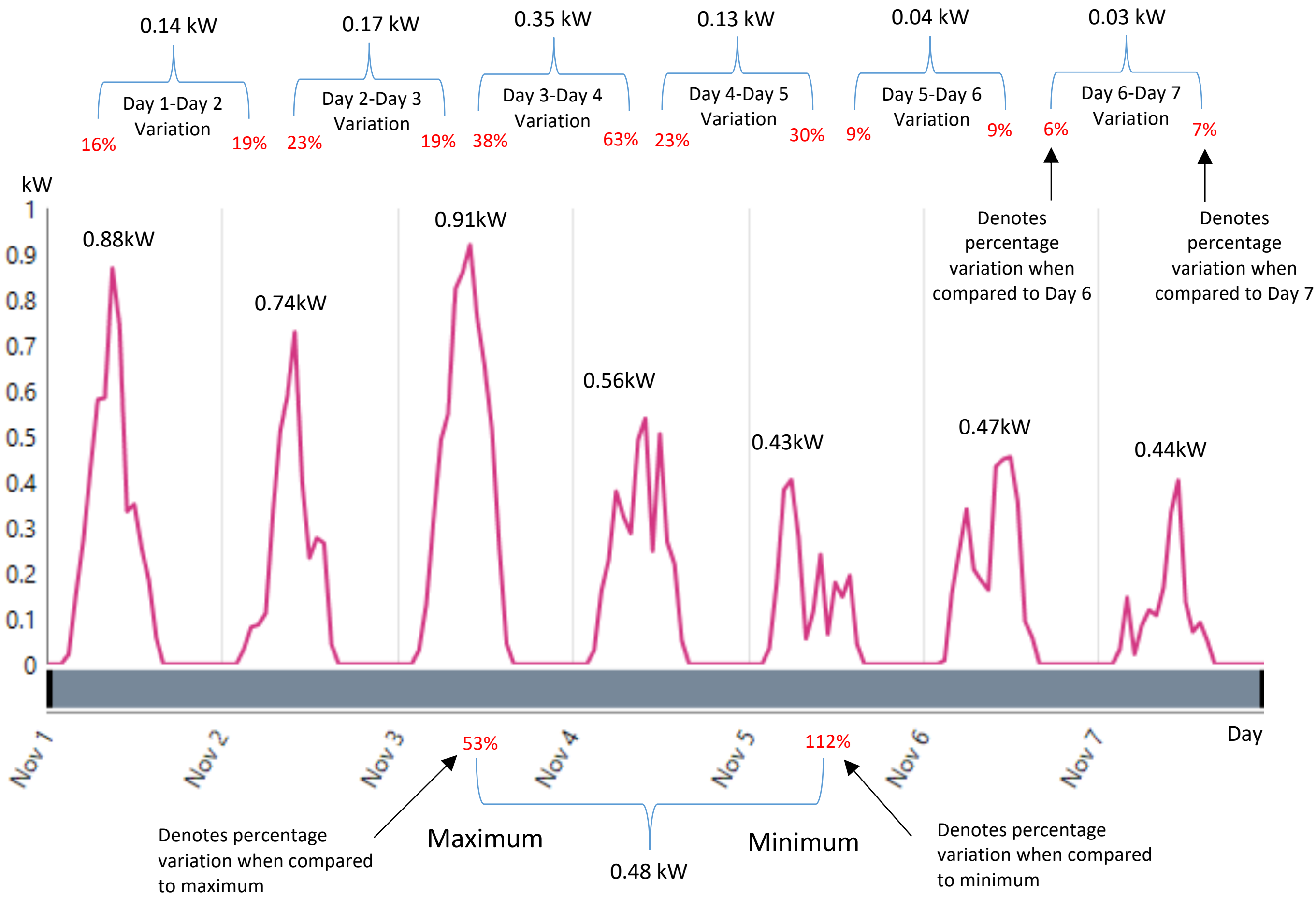


Figure 45 Typical variations of solar generation due to weather variation – 1kW PV system

Below is the typical output in summer, for a 1 kW solar PV generation system in eThekwini over a 24-hour period.

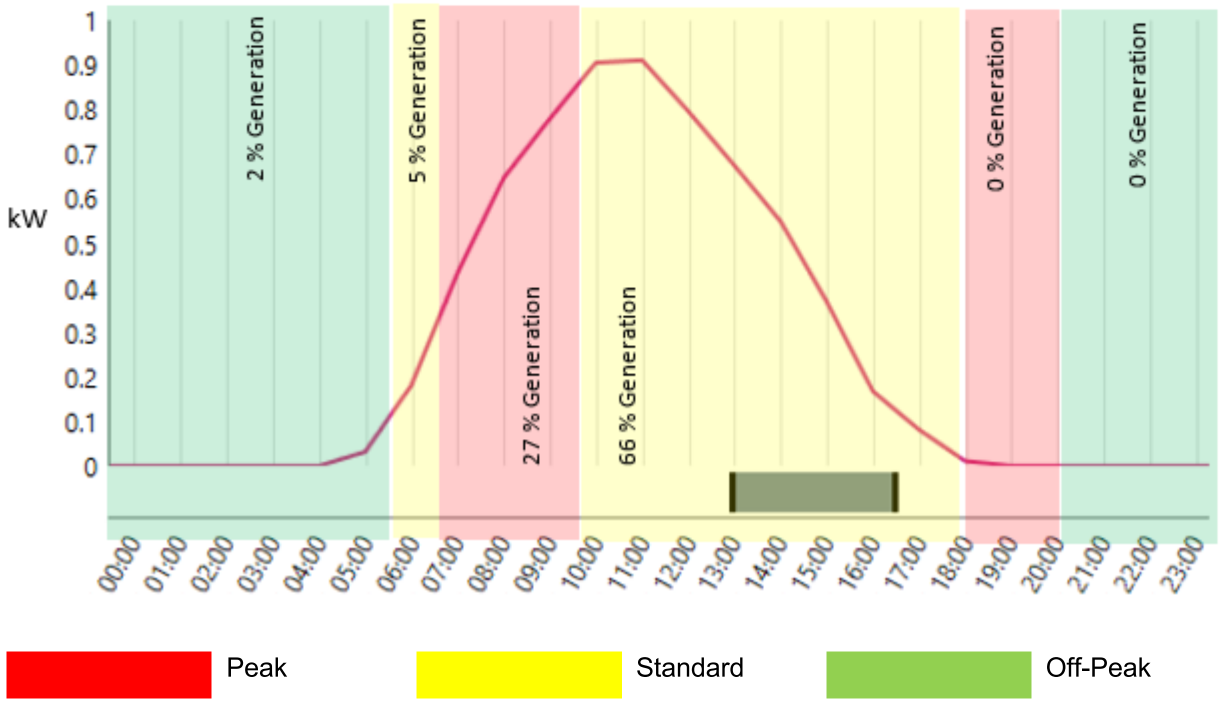


Figure 46 Hourly generation output profile over 24 hours – 1kW system

The earliest generation is recorded from hour 5 and the latest production at hour 17. Within these hours of sunlight exposure for the day, 6.50 kWh was generated for a 1kW system. Under these conditions, the system can generate electricity in varying amounts for 12 hours out of 24 hours. The high generation hours are hour 10 and 11.

The high demand for electricity in South Africa is generally during peak hours. Based on the solar profile of Durban, solar PV is only able to contribute to the morning peak (between 06:00 and 10:00) and to a limited extent the evening peak (16:00 to 21:00). The majority of generation is during the standard period ranging from 10:00 until 17:00.

3.9.2.1 Solar output vs cost of electricity from Eskom

Energy is procured from Eskom in three distinct periods (i.e. peak, standard, off-peak). The energy rates also vary depending on the season (i.e. summer and winter). As a result, the financial value of energy generated will depend on when it is produced (i.e. time of day and season). The table below illustrates the cost of PV generated energy when compared to the Eskom pricing structure [90] :

Table 10 Value of Solar (VOS) per kW installed per day

Season	Summer (Sept-May)	Winter (June – August)
Peak	R 2.00	R 3.97
Standard	R 4.50	R 6.49
Off-Peak	R 0.02	R 0.02
Value of solar-generated energy based on purchasing tariff per day, per kW.	R 6.52	R 10.48

Purchasing Tariff : Megaflex – Local Authority, > 300km<=600km, >132kV

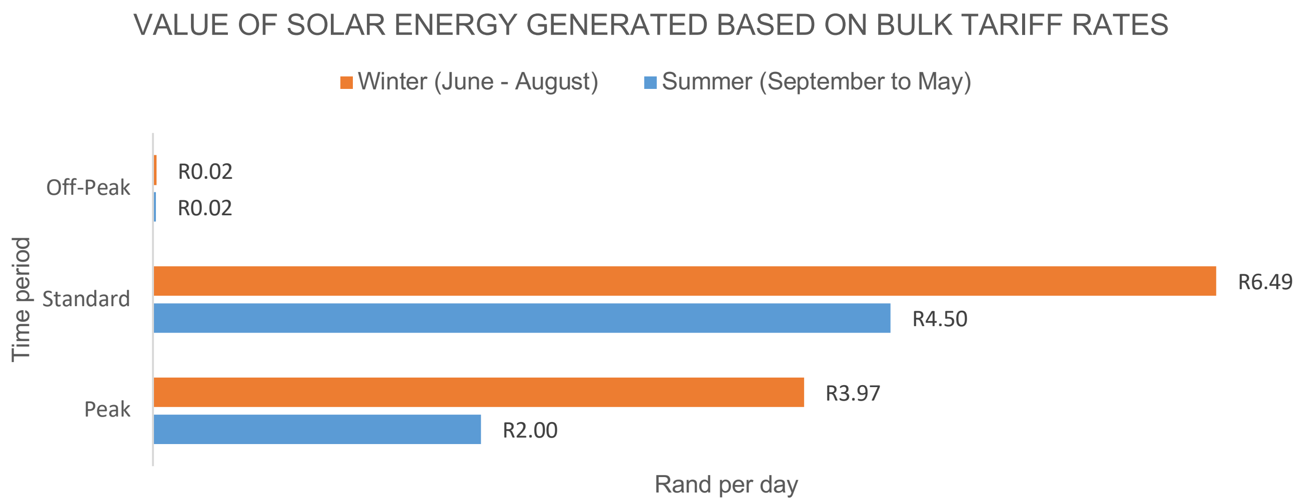


Figure 47 Value of solar (VOS) per kW installed per day

Energy generated during winter (R 10.48) is worth more than energy generated during summer (R 6.52). This is primarily due to higher winter energy rates. The time-based availability of the sun largely dictates the value of the energy generated for a specific day. Due to the variations in weather conditions, the daily performance of the system will vary.

3.9.3 Load profiling

3.9.3.1 Residential load profiling

The residential load profiles (hourly) was attained by means of onsite measurements of substations that were predominately supplying residential customers. The residential low loading profile was based on averaging the load profile data for substation feeders providing electricity to Inanda and Claremont areas.

Averaging feeders supplying Malvern and Hillary areas constructed the medium load profile.

Averaging three feeders supplying the Hillcrest area created a high profile. The load profile for the residential high and residential medium was similar and combined for modelling purposes. The amount of energy generated was dependent on the amount of sunlight that was exposed to the system. The amount of energy offset and financial loss to the municipality will depend on when electricity is being consumed relative to the way electricity is being generated.

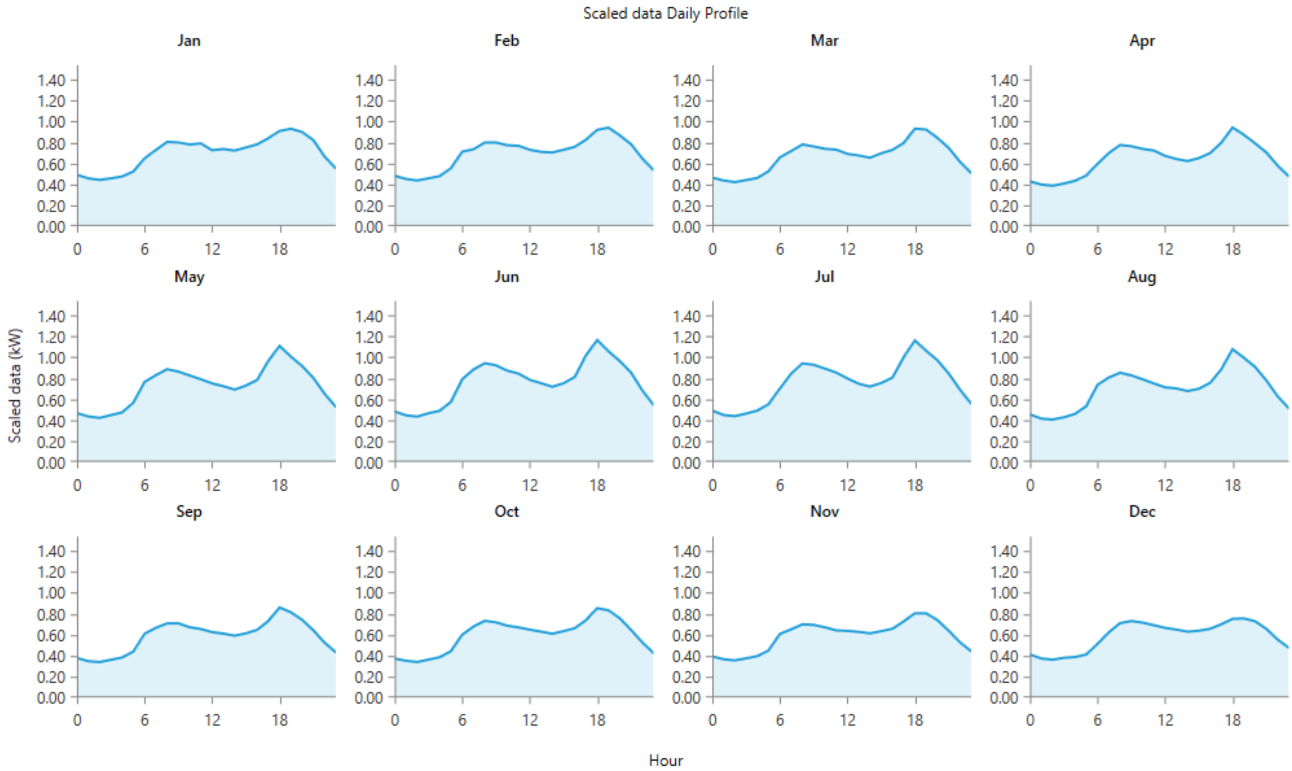


Figure 48 Twelve-month residential load profile

The graph below illustrates the relationship between energy consumed and energy generated by a low load consumption customer based on a typical generation profile.

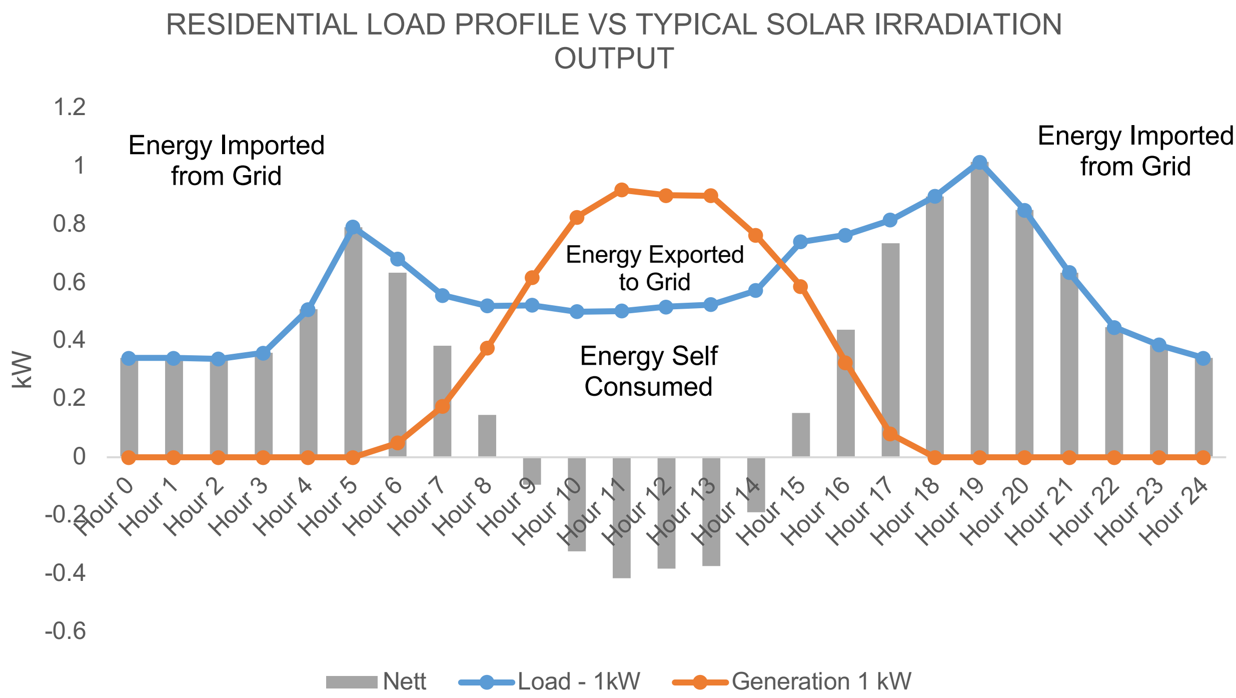


Figure 49 Residential loading profile superimposed onto generation profile

Municipality sells electricity at a loss during winter peak periods

PV systems reduce the loss during winter peak periods

Table 11 Financial relationship between residential load and solar PV generation per hour

Hour	*Load (1kW)*	*Generation (1kW) Summer Profile*	*Generation (1kW) Winter Profile*	*Nett Income Without PV*	*Nett Income With PV*	*Revenue Loss*	*Nett Income Without PV*	*Nett Income With PV*	*Revenue Loss*
	(kW)	(kW)	(kW)	R	R	R	R	R	R
				Summer			Winter		
1	0.34	0.00	0.00	0.46	0.46	-	0.43	0.43	-
2	0.36	0.00	0.00	0.49	0.49	-	0.46	0.46	-
3	0.51	0.00	0.00	0.69	0.69	-	0.65	0.65	-
4	0.79	0.00	0.00	1.07	1.07	-	1.01	1.01	-
5	0.68	0.00	0.00	0.92	0.92	-	0.87	0.87	-
6	0.56	0.03	0.00	0.76	0.72	0.04	0.71	0.71	-
7	0.52	0.15	0.05	0.55	0.39	0.16	-0.91	-0.83	-0.08
8	0.52	0.32	0.16	0.36	0.14	0.22	-0.91	-0.63	-0.29
9	0.5	0.54	0.35	0.34	-	0.34	-0.88	-0.26	-0.62
10	0.5	0.70	0.58	0.34	-	0.34	0.39	-	0.39
11	0.52	0.80	0.77	0.55	-	0.55	0.40	-	0.40
12	0.53	0.89	0.86	0.56	-	0.56	0.41	-	0.41
13	0.57	0.89	0.84	0.60	-	0.60	0.44	-	0.44
14	0.74	0.81	0.84	0.78	-	0.78	0.57	-	0.57
15	0.76	0.66	0.72	0.80	0.10	0.70	0.59	0.03	0.55
16	0.82	0.43	0.55	0.87	0.41	0.45	0.63	0.21	0.42
17	0.9	0.23	0.31	0.95	0.70	0.24	0.69	0.46	0.24
18	1.01	0.05	0.07	1.07	1.01	0.05	-1.77	-1.64	-0.13
19	0.85	0.00	0.00	0.58	0.58	-	-1.49	-1.49	-
20	0.63	0.00	0.00	0.43	0.43	-	0.49	0.49	-
21	0.45	0.00	0.00	0.47	0.47	-	0.35	0.35	-
22	0.39	0.00	0.00	0.41	0.41	-	0.30	0.30	-
23	0.34	0.00	0.00	0.46	0.46	-	0.43	0.43	-
24	0.34	0.00	0.00	0.46	0.46	-	0.43	0.43	-
Total	14.13	6.50	6.11	14.97	9.92	5.05	4.28	1.98	2.30

The generation system is only able to generate electricity from hour 6 until 18 and in winter from hour 7 until 18. Thereafter the load is solely dependent on the grid.

The maximum generation occurs around midday.

In summer, during hour 9 until 14, the amount of generation exceeds the load. During this time, energy is exported to the grid. In winter, export starts an hour later.

In summer, the municipality starts to lose revenue as soon as the generation system starts to generate electricity in hour 6. Revenue losses are maintained until the end of generation in hour 17.

Due to the excess energy generation from hour 9 until 14, the municipality is unable to sell electricity to this customer. However, an opportunity exists to onward sell the generated electricity, which will depend on the respective PV tariff design.

In winter, during hour 7, 8 and 9 the municipality sell electricity at a loss. With the introduction of PV, the loss is reduced.

From hour 10 until 14, the generation system provides more energy than is required. This energy is exported onto the grid. While the municipality is unable to sell electricity to the customer during this time, an opportunity exists to onward sell the generated electricity, which will depend on the respective PV tariff design.

During hour 18 and 19, the municipality continues to sell electricity at a loss however; the PV system is only able to assist in mitigating this loss in hour 18.

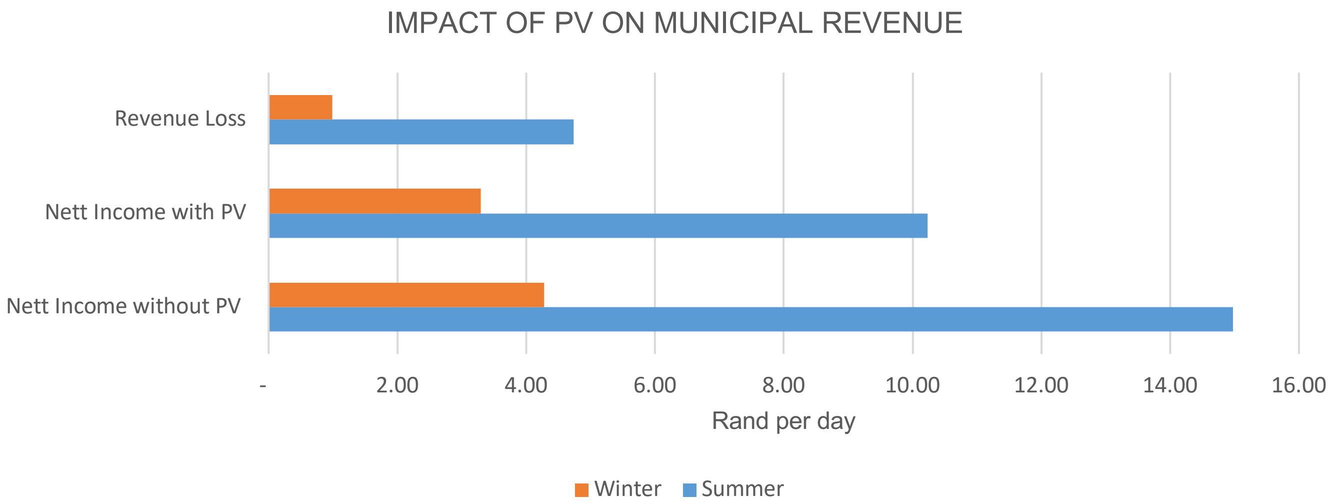


Figure 50 Revenue loss due to PV installation per kW installed per day

In summer, the municipality can generate R 14.97 (nett) from a customer without a PV system installed while it can only generate R 9.92 (nett) with a PV system installed. The R 5.05 revenue loss equates to a 34% reduction. In winter, the municipality can generate R 4.28 without a PV system and R 1.98 with a PV system. The R 2.30 revenue loss equates to a 54% reduction.

Table 12 Energy relationship between residential load profile and PV generation profile as normalised to 1 kW.

Based on the daily (24 Hour) Load Profile above (Total Load kWh: 14.13):

Energy Analysis	**Summer**	**Winter**
Energy Self-Consumed (kWh)	5.24	5.07
Energy Imported from Grid (kWh)	8.89	9.06
Energy Exported to Grid (kWh)	1.26	1.04

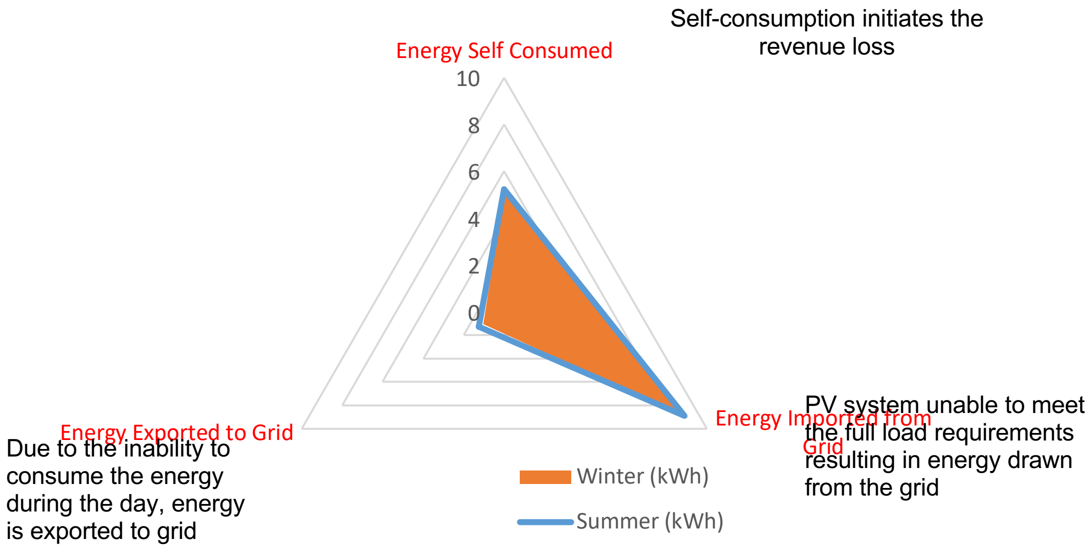


Figure 51 Residential energy analysis for a 1kW residential load operating with a 1kW PV system

3.9.3.2 Business load profiling

The business load profiles (hourly) were attained using onsite measurements of substations that were predominately supplying business customers. The profile was based on averaging the load profile data for two substation feeders providing electricity to Durban Central Business District (CBD).

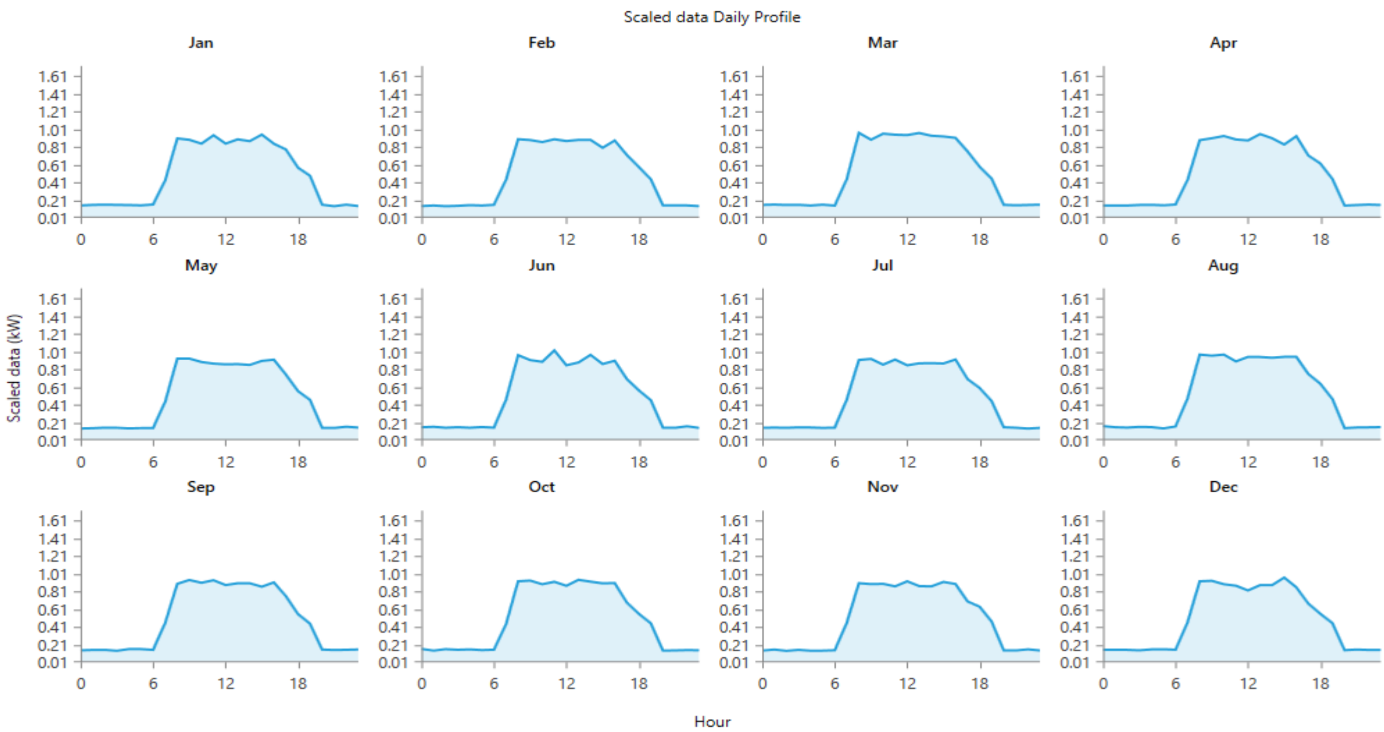


Figure 52 Twelve months generic business loading profile

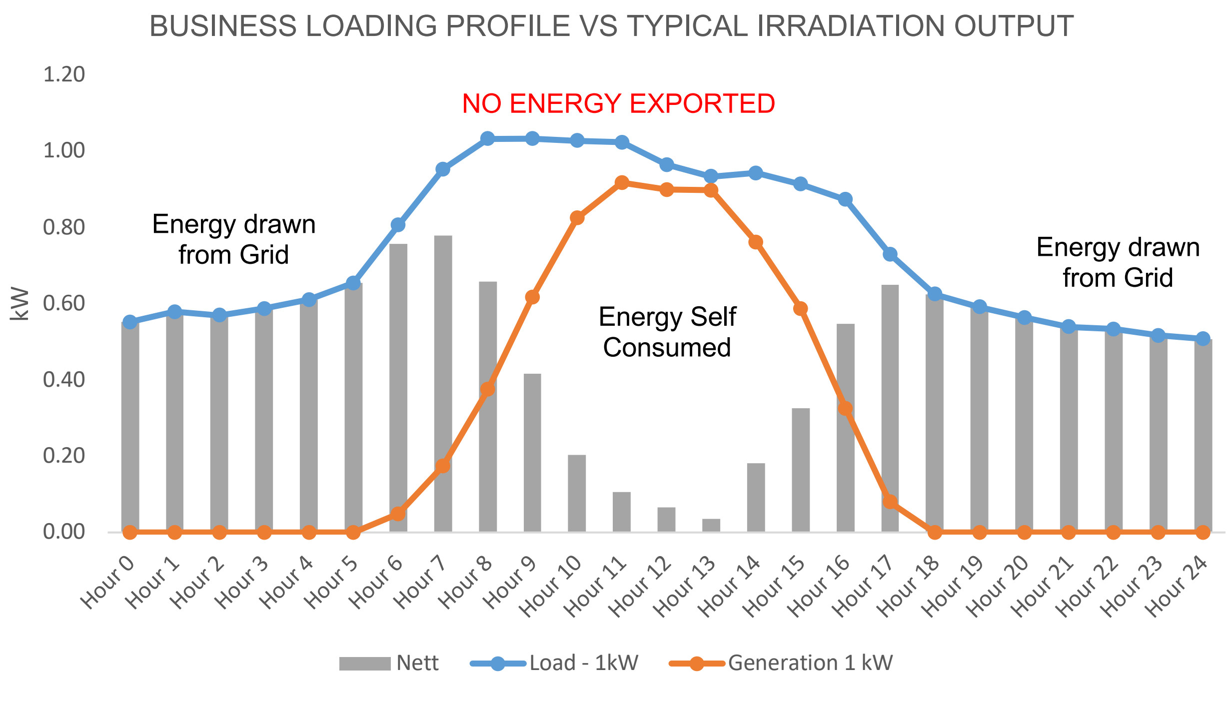


Figure 53 Business loading profile superimposed onto generation profile

Municipality sells electricity at a loss during winter peak periods

PV systems reduce the loss during winter peak periods

Table 13 Financial relationship between business load and solar PV generation per hour

Hour	Load (1kW)	Generation (1kW) Summer Profile	Generation (1kW) Winter Profile	Nett Income Without PV	Nett Income With PV	Revenue Loss	Nett Income Without PV	Nett Income With PV	Revenue Loss
	(kW)	(kW)	(kW)	R	R	R	R	R	R
				Summer			Winter		
1	0.58	0.00	0.00	0.93	0.93	-	0.88	0.88	-
2	0.57	0.00	0.00	0.91	0.91	-	0.87	0.87	-
3	0.59	0.00	0.00	0.95	0.95	-	0.90	0.90	-
4	0.61	0.00	0.00	0.98	0.98	-	0.93	0.93	-
5	0.65	0.00	0.00	1.04	1.04	-	0.99	0.99	-
6	0.81	0.03	0.00	1.30	1.25	0.05	1.23	1.23	-
7	0.95	0.15	0.05	1.24	1.04	0.20	-1.43	-1.36	-0.07
8	1.03	0.32	0.16	0.97	0.66	0.30	-1.55	-1.30	-0.25
9	1.03	0.54	0.35	0.97	0.46	0.50	-1.55	-1.02	-0.53
10	1.03	0.70	0.58	0.97	0.31	0.65	1.05	0.46	0.59
11	1.02	0.80	0.77	1.33	0.29	1.04	1.04	0.25	0.79
12	0.97	0.89	0.86	1.27	0.10	1.17	0.99	0.11	0.88
13	0.93	0.89	0.84	1.21	0.05	1.16	0.95	0.09	0.86
14	0.94	0.81	0.84	1.23	0.17	1.05	0.96	0.10	0.86
15	0.91	0.66	0.72	1.19	0.33	0.86	0.93	0.20	0.73
16	0.87	0.43	0.55	1.14	0.58	0.56	0.89	0.33	0.56
17	0.73	0.23	0.31	0.95	0.65	0.30	0.75	0.43	0.31
18	0.63	0.05	0.07	0.82	0.75	0.07	-0.95	-0.83	-0.11
19	0.59	0.00	0.00	0.55	0.55	-	-0.89	-0.89	-
20	0.56	0.00	0.00	0.52	0.52	-	0.57	0.57	-
21	0.54	0.00	0.00	0.70	0.70	-	0.55	0.55	-
22	0.53	0.00	0.00	0.69	0.69	-	0.54	0.54	-
23	0.52	0.00	0.00	0.83	0.83	-	0.79	0.79	-
24	0.51	0.00	0.00	0.82	0.82	-	0.78	0.78	-
Total	18.10	6.50	6.11	23.51	15.58	7.92	10.24	5.61	4.63

The generation system is only able to generate electricity from hour 6 until 18. Thereafter the load is solely dependent on the grid.

The maximum PV generation occurs during midday.

Due to the load being constant during the day, it is able to fully utilise the generated energy. Hence, there is no energy exported to the grid.

In summer, the municipality starts to lose revenue as soon as the generation system starts to generate electricity in hour 6. Revenue losses are maintained until the end of generation in hour 18.

In winter, during hour seven, eight and 9 the municipality sell electricity at a loss. With the introduction of PV, the loss is reduced.

During hour 18 and 19, the municipality continues to sell electricity at a loss however; the PV system is only able to assist in mitigating this loss in hour 18.

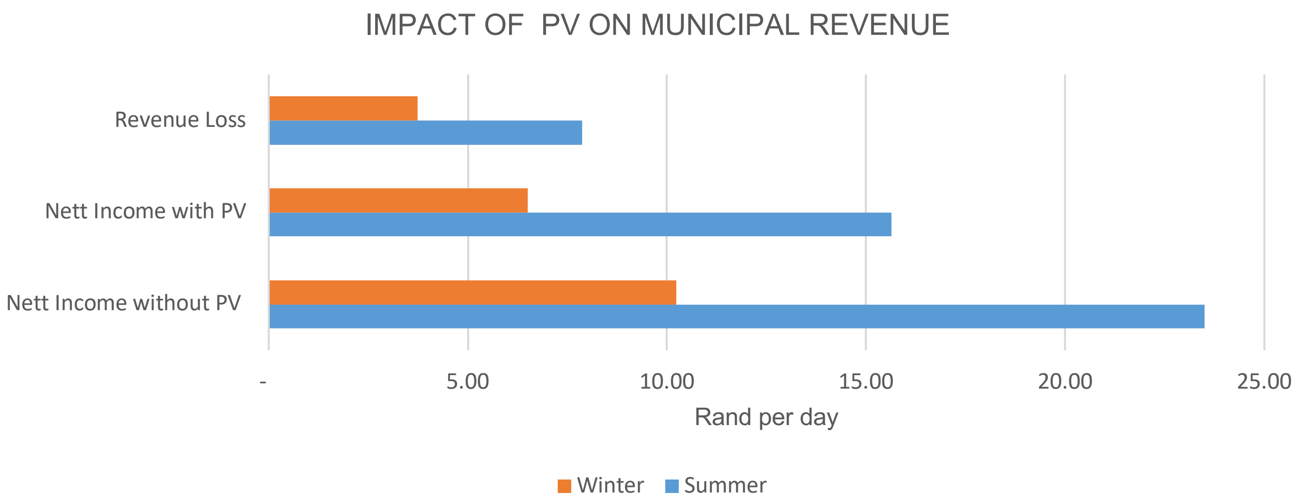


Figure 54 Revenue loss due to PV Installation per kW installed.

In summer, the municipality can generate R 23.51 (nett) from a customer without a PV system installed while it can only generate R15.58 (nett) with a PV system installed. The R7.93 revenue loss equates to a 34% reduction. In winter, the municipality can generate R10.24 (nett) without a PV system and R 5.61 (nett) with a PV system. The R 4.63 revenue loss equates to a 45% reduction.

Table 14 Energy relationship between Business load profile and PV generation profile as normalised to 1 kW

Based on the daily (24 Hour) Load Profile above (Total Load kWh: 18.10):

Energy Analysis	**Summer**	**Winter**
Energy Self-Consumed (kWh)	6.50	6.10
Energy Imported from Grid (kWh)	11.60	11.99
Energy Exported to Grid (kWh)	0.00	0.00

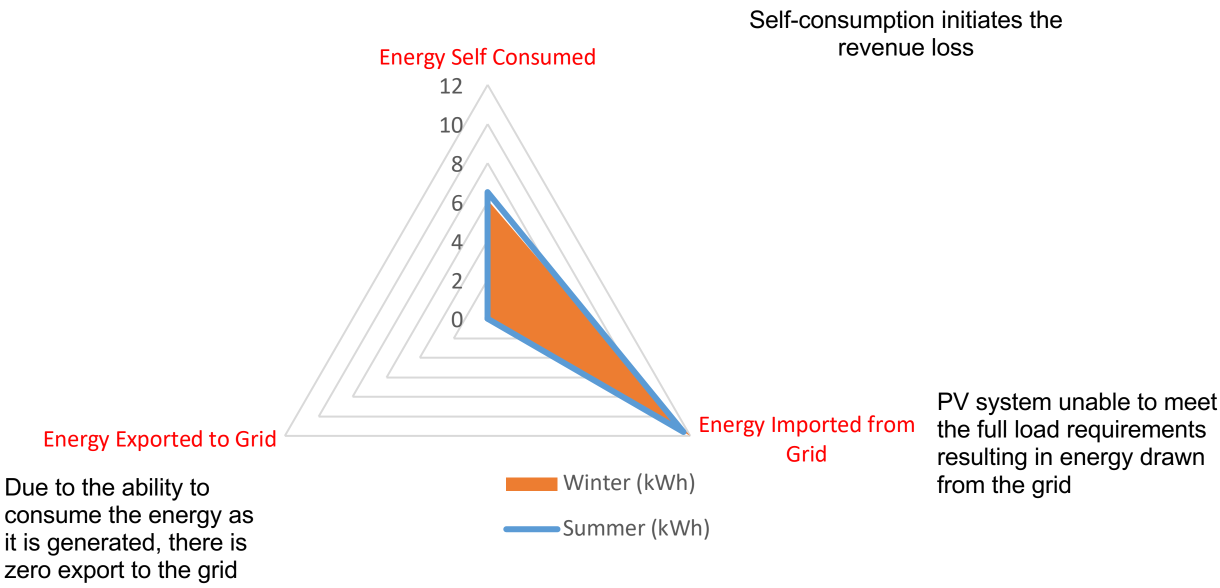


Figure 55 Business energy analysis for a 1kW business load operating with a 1kW PV system

3.9.3.3 Industrial load profiling

A typical loading profile for Industrial is shown below [91]:

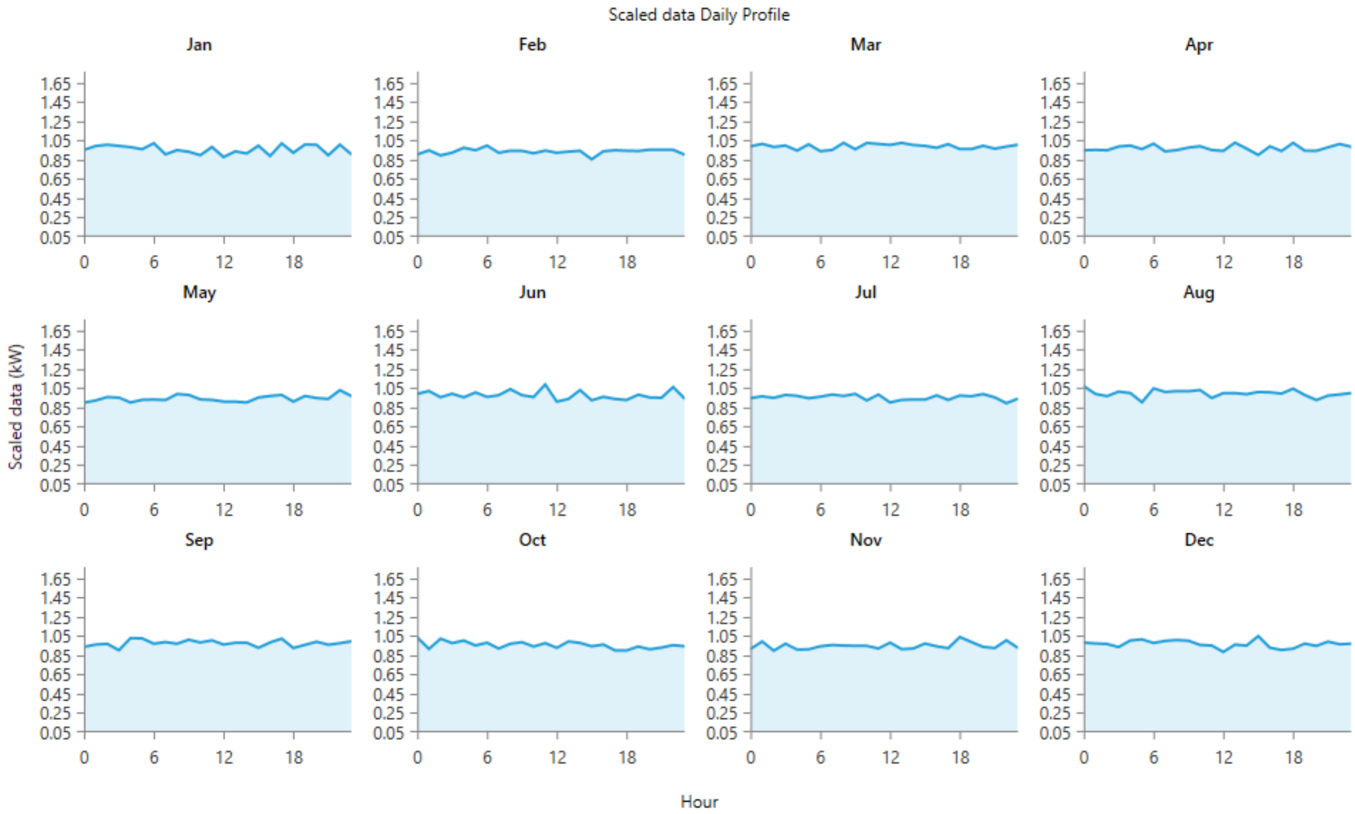


Figure 56 Twelve-month generic industrial loading profile

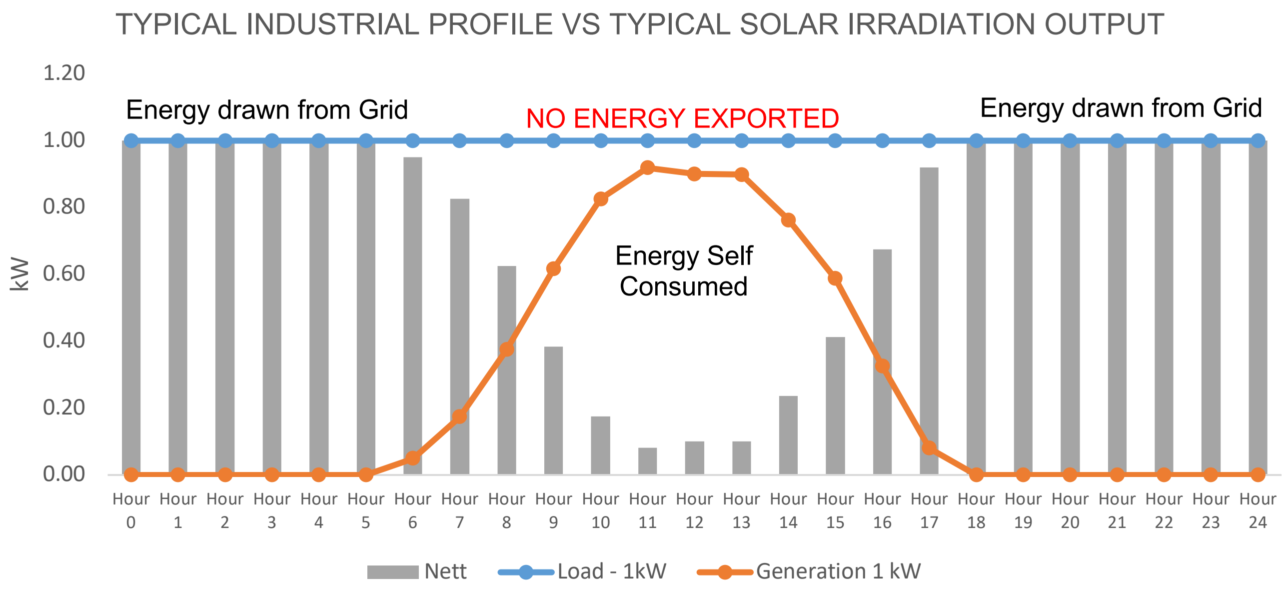


Figure 57 Industrial loading profile superimposed onto generation profile

For the purposing of modelling, the typical load profile was not used however the industrial loading profile was constructed based on the monthly peak, standard & off-peak consumption of the customer for 12 months (2018). Each customer's unique monthly values (peak, standard, off-peak) were used.

The hourly generation profile was categorised into these three distinct periods over 12 months. The hourly profile allowed for the offsetting of generated energy against consumed energy via these times as opposed to hourly as done for residential and business customers.

The generation of energy only affects the energy component of the Industrial Time of Use tariff (ITOU). Hence, the revenue loss to the municipality is dependent on the amount of network-related costs that the municipality collects via the energy charge. The ITOU tariff structure recovers a portion of network costs via the energy rates by levying the voltage surcharge. Losses due to self-consumption will be experienced in the following ratios per kWh self-consumed:

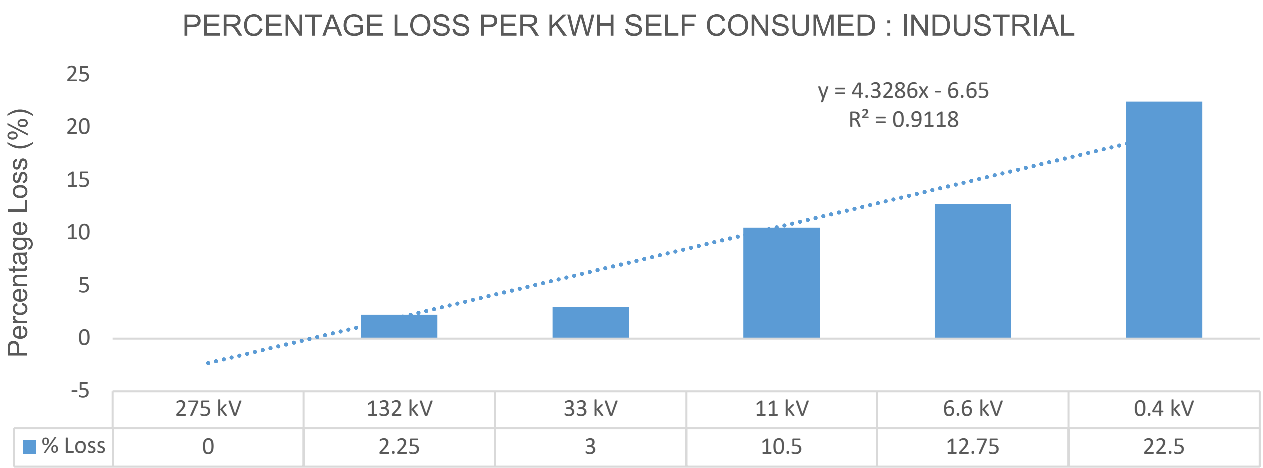


Figure 58 Percentage loss per kWh self-consumed for the industrial category

The highest loss to the municipality for industrial customers will occur at the lowest voltage level (i.e. 400V).

3.9.4 Feasibility profiling

The IRR and SPBP were deemed as the decisive initiators for customers to install SSEG [92]. The returns would have to be comparable (at minimum) or higher than other general investment options available to customers. Investigating the investment performance of major asset classes, provided for a range of returns, depending on the level of risk exposure and period of investment [93], [94].

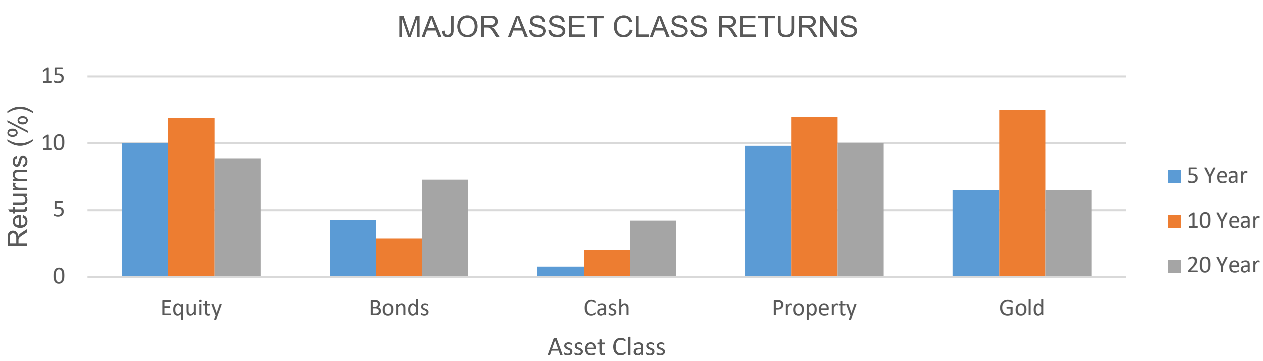


Figure 59 Major asset class returns in South Africa – as at end 2014 [95]

Considering the asset classes: Cash, invested over a five-year period generated a return of 1.5%; while investments in gold generated 12.25% over 10 years. The 20 year performance across all asset classes were capped at 10% at maximum [95]. Returns were volatile and dependent on a variety of factors.

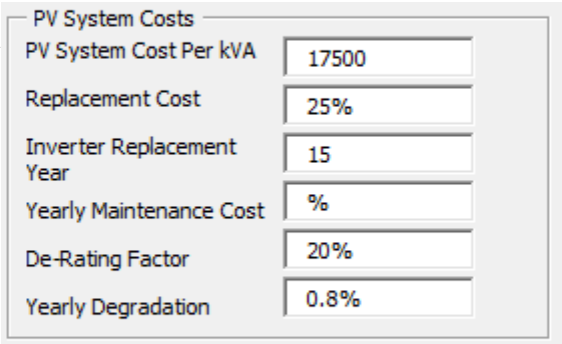
Currently, an investment in solar PV can be considered as optimistic, as it provides returns over its lifespan (typically 25 years), and returns will increase as electricity prices increase. Electricity prices in South Africa have more than doubled over the past 10 years. [90]

Solar PV systems are generally fixed systems and considered long-term assets as it boasts long lifespans, typically 20-25 years. Despite its longevity, an investment horizon (SPBP) of 10 years was set as the feasibility point, catering for the medium term investor horizon as well.

An IRR of 15% and SPBP of 10 years was therefore deemed a fair and acceptable threshold point to set as the feasibility limits.

3.9.5 PV system profiling

Table 15 PV system profiling

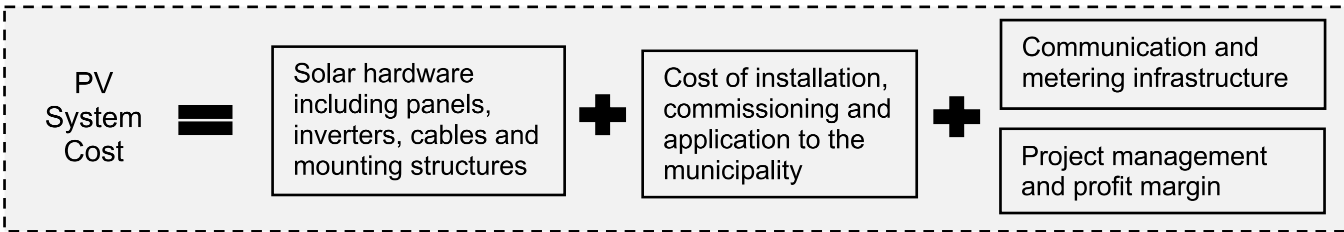


The system costs and maintenance costs were based on average market values attained from installers. A 20% de-rating factor was applied to the original irradiation value to cater for efficiency and other losses. The solar irradiation used for modelling was 1392 kWh/kW per annum.

Description	*Unit*	*Residential*	*Business*	*Industrial*
System cost (VAT Included)	R	17500	15000	12500
Replacement cost (Based on installed costs)	%	25	25	25
Inverter replacement year	Year	15	15	15
Maintenance cost (Based on installed costs)	%	0	0	0
De-rating factor for solar radiation	%	20	20	20
Yearly degradation factor for solar radiation	%	0.8	0.8	0.8

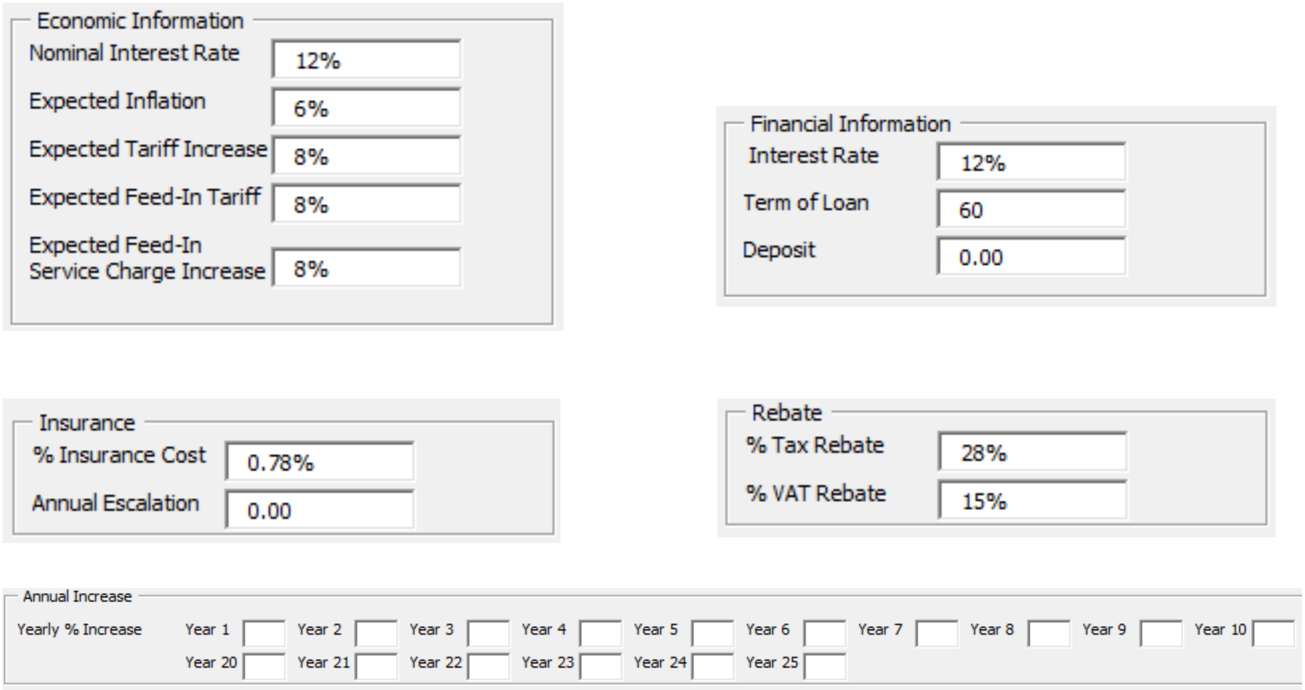
3.9.5.1 Consideration for PV system costs

Solar PV system costs vary depending on the brand of the PV system and the relevant installer. It may also differ geographically. In some instances, the roofing structure may not be suitable to carry the additional weight of the panels and may need to be reinforced at additional costs. Further, higher than average roof structures may necessitate the need for specialised crane systems to facilitate hoisting, which will also increase the base costs.



3.9.6 Financial & economic profiling

Table 16 Financial & economic profiling



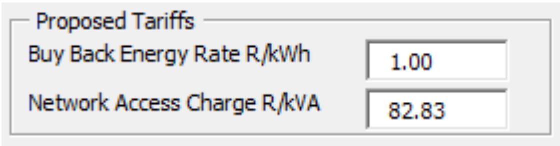
Description	*Unit*	*Residential*	*Business*	*Industrial*
Nominal interest rate	%	12	12	12
Inflation	%	6	6	6
Cost of energy	R	As per retail tariffs – Refer Section 2.7.1		
Future energy increases	%	8	8	8
Finance interest rate	%	12	12	12
Finance term	Months	60	60	60
Insurance cost (% of Project costs)	%	0.78	0.78	0.78
VAT rebate	%	0	15	15
Tax rebate	%	0	28	28

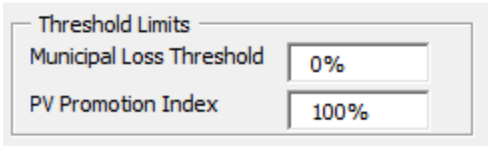
The nominal interest rate used was 12 %, coupled with an inflation rate of 6 %. The cost of energy used was as per the eThekwini municipal tariff rates as of 2019. It was estimated that energy costs would rise by 8 % per annum for the 25-year period. Capital provided for the purchase of the system was financed at an interest rate of 12 % over five years. Insurance costs were deemed applicable for the first ten years and levied at a rate of 0.78 % per annum based on the purchase price.

The model also makes provision to input specific yearly tariff increases should it be necessary. Where the yearly input tabs are blank, the increase would default to the 'Expected Tariff Increase' as input in the economic information section.

3.9.7 Municipal profiling

Table 17 Municipal profiling





Description	*Input Value*	*Residential Business Industrial*
Network Access Charge	R/kVA charge based on inverter size	The RE tariff charge is calculated by the model to mitigate the revenue losses to the municipality.
Buy Back Energy Rate	Based on the avoided cost principle	The rate at which the customer is remunerated for energy exported onto the grid. This rate is automatically calculated based on the average export profile for each customer category.
Municipal Loss Threshold	0 %	The maximum percentage loss (gross) that the municipality is prepared to accept in promoting PV (input by user).
PV Promotion Index	100 %	The percentage representing the number of customers that the municipality wants to promote for the installation of PV (input by user).

3.10 The solar techno-economic model outputs

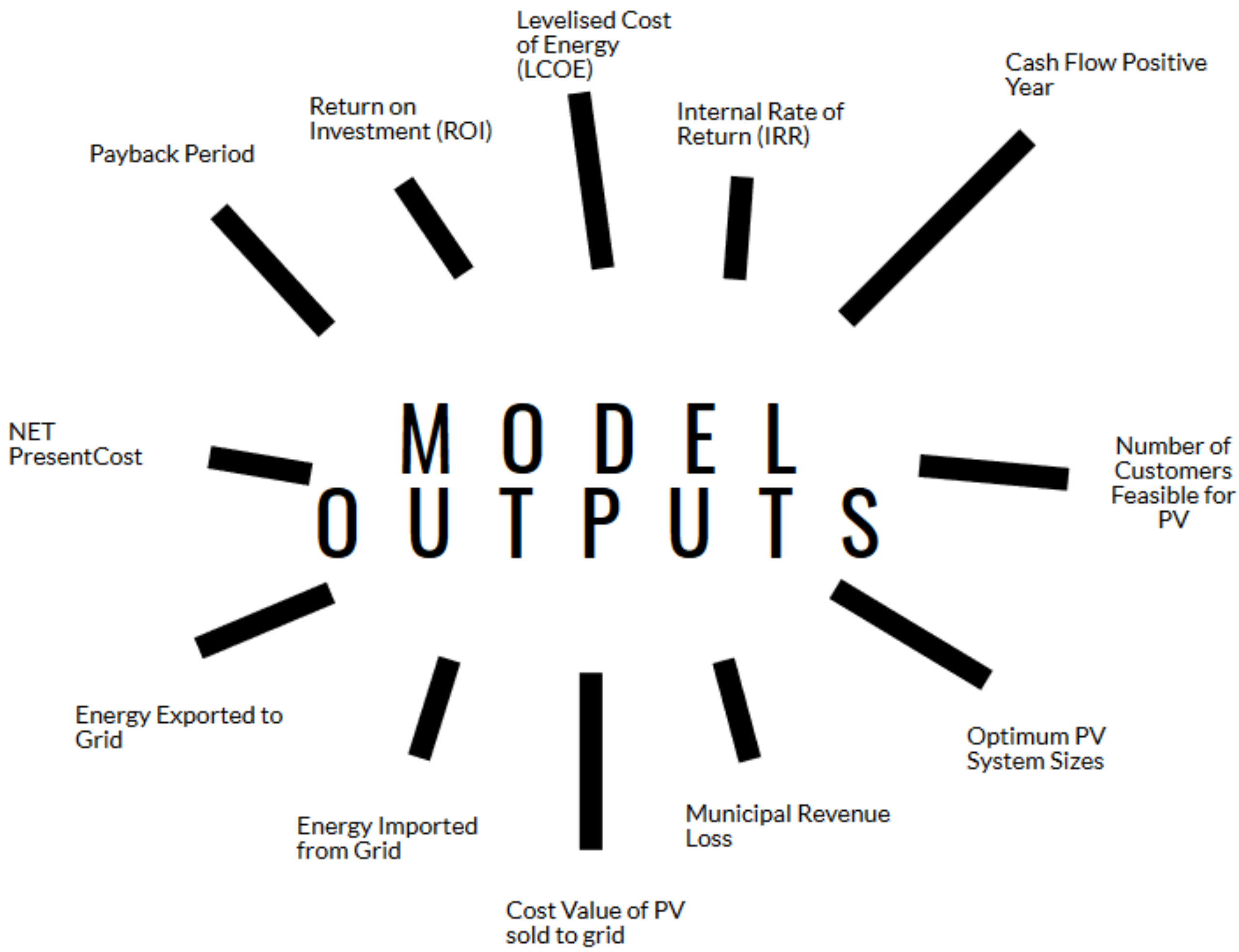


Figure 60 Solar techno-economic model outputs

Key Output Parameters

Internal Rate of Return (%)	16,48	Optimum System Size (kVA)	3	NPC Grid R	672125	COE Grid R	4,65
Simple PayBack Period (Yr)	7,94	Cash Flow Positive Year	6	NPC PV System R	597377	COE PV System R	3,86

Figure 61 Key output parameters displayed via the graphical user interface

Table 18 Techno-economic model outputs

MODEL OUTPUTS	DESCRIPTION
Net present cost	Calculated as the difference between the present value of all costs of installing and operating the PV plant throughout the lifespan and the present value of all the revenues the PV plant earns. Generally referred to as the life cycle cost.
Payback period	Refers to the amount of time it takes for the accumulated income (savings) of the PV plant to equal the value of the original investment.
Return on investment	Annual savings when compared to the upfront investment. Expressed in percentage.

Levelised cost of energy	The average cost per kWh after considering capital and lifecycle costs of the PV plant.
Internal rate of return	Indicator of the profitability of the PV investment.
Cash flow positive year	The year in which the accumulated savings is higher than the accrued expenses.
Number of feasible customers	The number of customers that meet the feasibility criteria i.e. deemed to install solar PV.
Optimum PV system sizes	The PV system size with the least net present cost.
Municipal revenue loss	The amount of revenue that the municipality is deemed to lose due to self-consumption of energy.
Aggregated PV potential	The sum of all the systems (installed sizes) that are deemed feasible.
The cost value of PV sold to the grid	The value of the exported kWh when calculated at the Eskom rates. Cost value will vary depending on when the kWh is generated due to the time of use tariffs.
Energy imported from the grid	Energy consumed from the grid.
Energy exported to the grid	Energy generated and unused by the consumer that flows onto the grid.

3.10.1 Output: Tab One: Graphs

The key output parameter frame details the optimum PV system size and a range of economic criteria. Tab one highlights the system costs and cash flow information graphically. Tab two details the load and generation information as well as the revenue impact analysis. Tab three provides vital technical and economic information at an aggregated level for eThekwini Municipality.

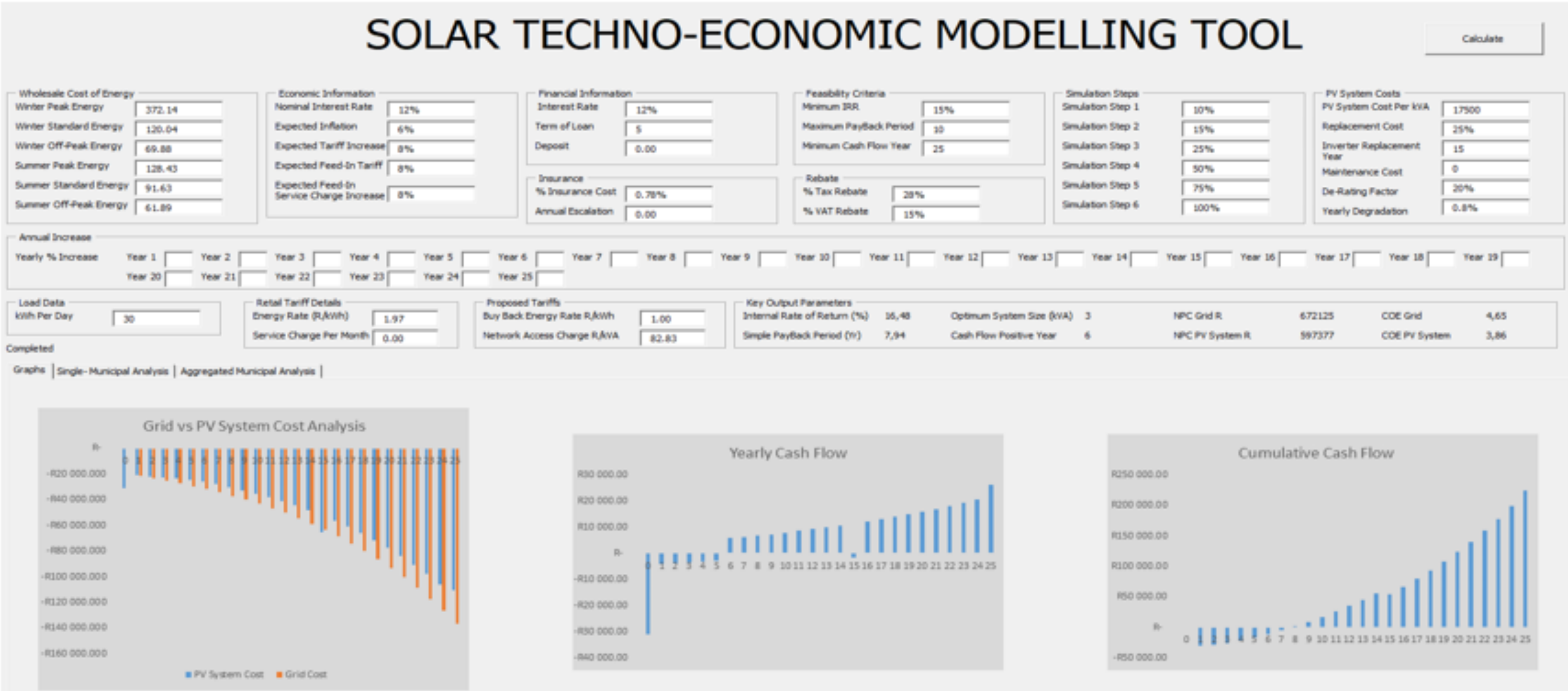


Figure 62 Techno-economic model outputs – Tab 1: Graphs

The first output tab highlights three graphs. The first graph details the yearly costs associated with electricity generated from the grid as well as from the PV system. The second graph details the yearly cash flows, while the third graph details the accumulated cash flows for the 25-year lifespan of the project.

3.10.2 Output: Tab Two: Single-Municipal Analysis

Tab two focuses on displaying the revenue impact of the PV system to the municipality as well as the change in loading due to the localised generation.

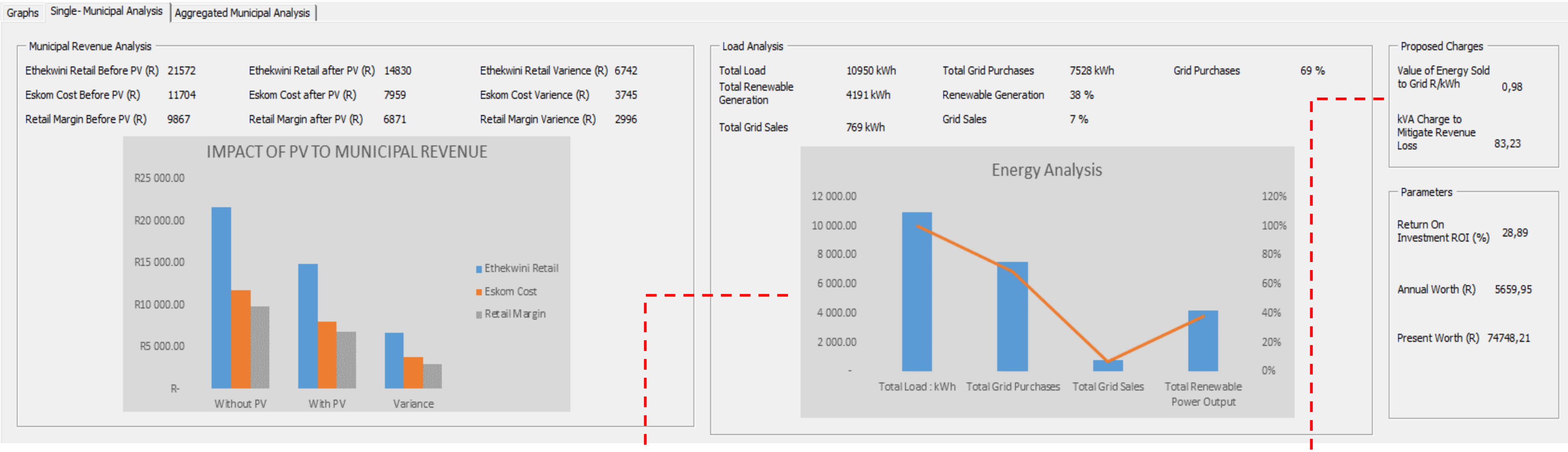


Figure 63 Techno-economic model outputs – Tab 2: Municipal analysis

The municipal revenue analysis provides information relating to the municipal finances.

The retail amount is the amount that the municipality would raise to the customer's account for consumption in the absence of a PV system.

The Eskom cost is the amount that the municipality would pay Eskom for the consumption.

The retail margin is the difference between the retail amount and the Eskom cost.

Without PV: Prior to the installation of the PV system

With PV: Post the installation of the PV system

The retail margin variance is the net revenue that the municipality would be losing.

The load analysis provides information relating to how energy is consumed and generated.

The total load is the load required. The total renewable generation represents the amount of energy generated by the PV system.

The total grid sales represents the amount of energy not used by the customer and exported to the electricity grid.

The grid purchases represents the amount of energy procured from the grid after the self-consumption of generated electricity.

The percentage values are calculated with reference to the total load.

The proposed charges highlights two charges.

The first charge, which is the value of energy, sold to the grid, represents the average cost of the energy generated (exported) onto the grid. The cost is calculated based on the Eskom (bulk) purchase rates as differentiated per hour and per season (summer and winter)

The second charge, which is the kVA charge to mitigate revenue loss, is the charge that the municipality must implement to mitigate ALL of the revenue loss (based on inverter size)

NOTE: This charge will recover the lost retail margin portion ONLY.

The ROI represents the savings relative to the original investment expressed as a percentage.

The annual worth is the annual cost of operating the PV system over its lifespan.

The present worth is the variance between the NPC of the base case (electricity grid) and the PV system.

3.10.3 Output: Tab Three: Aggregated Municipal Analysis

Tab three displays the aggregated results of all feasible customers within the tariff category. Displaying the aggregated results allows for a holistic view of the total revenue losses applicable to the municipality. Further, the total amount of RE that the tariff category could introduce to the municipality is displayed.

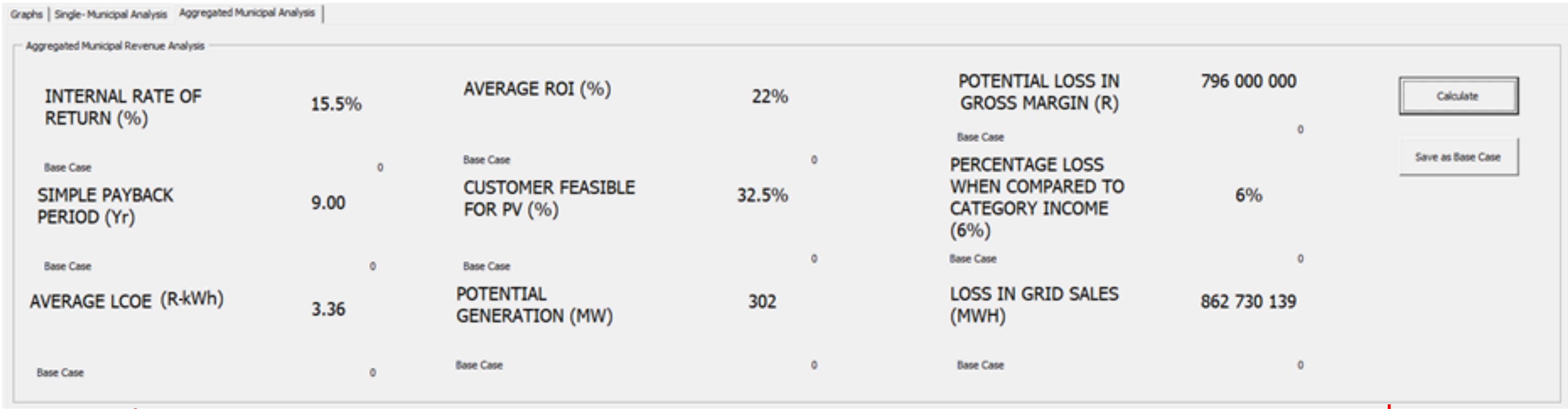


Figure 64 Techno-economic model outputs – Tab 3: Aggregated analysis

The internal rate of return is the average rate calculated across all feasible customers.

The simple payback period is the average calculated across all feasible customers.

The average LCOE is the average calculated across all feasible customers.

The average ROI is calculated across all feasible customers.

The percentage customers feasible for PV represents customers that meet the feasibility criteria.

The potential generation is the sum of all generation projects that meet the feasibility criteria.

The potential loss in gross margin represents the aggregated loss in revenue for the municipality. This loss is aggregated across all feasible customers.

The percentage loss is calculated by dividing the loss in gross margin by the total income of the tariff category.

The “Calculate” button will simulate all customers within the tariff category and update the aggregated results.

The “Save as Base Case” button stores the modelled results below each result for comparison with other scenario results.

4 CHAPTER 4: SCENARIO DEVELOPMENT AND MODELLING

4.1 Scenario Development

4.1.1 Scenario development: Scenario 1 to Scenario 4

The scenarios have been developed to evaluate the impact of the following variables on the feasibility of solar PV projects.

Investment Horizons

The IRR and SPBP are key indicators that determine project feasibility. An IRR of 10 years and 25 years were considered. This was done to understand the impacts of different investment horizons on solar PV project feasibility, municipal revenue loss and RE generation.

Network Constraints

Network connectivity is key for solar PV projects without storage capabilities. As a result, prevailing NRS 097-2-3 generation limiting recommendations have been considered, to evaluate the impact on solar PV project feasibility, municipal revenue loss and RE generation.

Optimised RE Tariffs

Protecting municipal revenue loss via optimised RE tariffs is important for municipal sustainability; however, it does affect project feasibility. RE tariffs have been considered to evaluate the extent of the impact on solar PV project feasibility, municipal revenue loss and RE generation.

Figure 65 Variables considered for scenario modelling

The following scenarios were considered, and the impacts on the feasibility of solar PV projects were evaluated. Municipal revenue loss and quantity of RE generation per scenario were further evaluated.

Table 19 Scenario 1 – 4

Variables/Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4
NRS 097-2-3 Generation Limits Apply	•	•	•	•
IRR: 10 Year	-	-	•	•
IRR: 25 Year	•	•	-	-
SPBP: 10 Year	•	•	•	•
Renewable Energy Tariffs Apply	-	•	-	•
Sensitivity Assesment Applies	-	-	-	-

Scenario 1

This scenario provided the opportunity to understand the scope of the municipal revenue loss, which solar PV would introduce, considering the generation limitations of NRS 097-2-3.

The IRR for this scenario was calculated over a period of 25 years, which would be appropriate for an investor with a long-term investment horizon.

Scenario 2

This scenario provided the opportunity to understand the impact on solar PV project feasibility as RE tariffs are introduced while applying the network generation limits of NRS 097-2-3.

The IRR for this scenario was calculated over a period of 25 years, which would be appropriate for an investor with a long-term investment horizon.

Scenario 3

This scenario provided the opportunity to understand the scope of the municipal revenue loss that solar PV would introduce, considering the current generation limits of NRS 097-2-3.

The IRR for this scenario was calculated over a period of 10 years, which would be appropriate for an investor with a medium-term investment horizon.

Scenario 4

This scenario provided the opportunity to understand the impact on solar PV feasibility as RE tariffs were introduced while applying the network generation limits of NRS 097-2-3.

The IRR for this scenario was calculated over a period of 10 years, which would be appropriate for an investor with a medium term investment horizon.

4.1.2 Scenario development: Scenario 5 to Scenario 6

Scenario five and scenario six provided the opportunity to understand the scope of the revenue loss that solar PV would introduce without being limited by any generation guidelines or investment horizons (i.e. the project investment returns have been calculated over the project lifespan of 25 years). These scenarios provided a long terms holistic view to eThekwini Municipality.

The following two scenarios were considered, and the impacts on the feasibility of solar PV projects were evaluated. Further, the quantity of RE potentially generated was also evaluated.

Table 20 Scenario 5 - 6

Variables/Scenario	Scenario 5	Scenario 6
NRS 097-2-3 Limits Apply	-	-
IRR: 10 Year	-	-
IRR: 25 Year	•	•
SPBP: 10 Year	•	•
Renewable Energy Tariffs Apply	-	•
Sensitivity Assessment Applies	-	•

Scenario 5

This scenario provided the opportunity to understand the scope of the municipal revenue loss that solar PV would introduce, irrespective of generation limitations or investments horizons.

Scenario 6

This scenario provided the opportunity to understand the impact on solar PV project feasibility as RE tariffs were introduced, irrespective of generation limitations or investments horizons.

Sensitivity Analysis

The sensitivity analysis considers the impacts to the project feasibility, IRR and SPBP as key input parameters are varied. Eight parameters were varied in accordance with table 21.

Table 21 Sensitivity descriptions

Sensitivity	Outcome	Description
6.1	Evaluate the impact of financing the PV system	Simulate without finance, i.e. cash deal
6.2	Evaluate the impact of the lending interest rate	Simulate with finance interest rate at 8%
6.3	Evaluate the impact of increasing the finance term	Simulate with finance term at 120 months
6.4	Evaluate the impact of the PV system price	Simulate with a 20 % PV price reduction
6.5	Evaluate the impact of future energy prices	Simulate with a 12 % future price increase
6.6	Evaluate the impact of the tax & VAT rebate	Simulate with the tax and the VAT rebate for residential Simulate without the tax and the VAT rebate for business & industrial
6.7	Evaluate the impact of removing the export rate	Simulate with the export rate reduced to zero
6.8	Evaluate the impact of doubling the export rate	Simulate with the export rate doubled

4.1.3 Base case variables for scenario modelling

Table 22 Base case variables for scenario modelling

Base Case Variables	*Unit of measure*	*Residential*	*Business*	*Industrial*	*Subject to sensitivity testing*
Nominal interest rate	%	12	12	12	No
Inflation	%	6	6	6	No
Expected tariff increase	%	8	8	8	Yes
Expected feed-in tariff increase	%	8	8	8	Yes
Expected service charge increase	%	8	8	8	Yes
PV system costs	R	17500	15000	12500	Yes
PV replacement cost	%	25	25	25	No
PV replacement year	%	15	15	15	No
Annual PV degradation rate	%	0.8	0.8	0.8	No
PV de-rating factor	%	20	20	20	No
Insurance premium (Based of PV system cost)	%	0.78	0.78	0.78	No
Insured period	Year	10	10	10	No
Tax rebate	%	0	28	28	Yes
VAT rebate	%	0	15	15	Yes
Feasibility IRR threshold	%	15	15	15	No
Feasibility SPBP threshold	Year	10	10	10	No
Finance interest rate	%	12	12	12	Yes
Finance term	Month	60	60	60	Yes
Modelling period	Year	25	25	25	Yes

4.2 Scenario modelling

4.2.1 Scenario 1

		IRR		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	•	•		•	-

NRS 097-2-3 provides simplified network criteria for the connection of SSEG to the municipal grid. The graph below depicts the municipal revenue loss and the potential solar PV generation whilst restricting the customer generation sizes in accordance with NRS 097-2-3. The results portrayed below are the results with the feasibility criteria applied (i.e. only PV projects that met the IRR threshold of 15 % and SPBP of 10 years were accounted for). Only 31 % of customers were feasible.

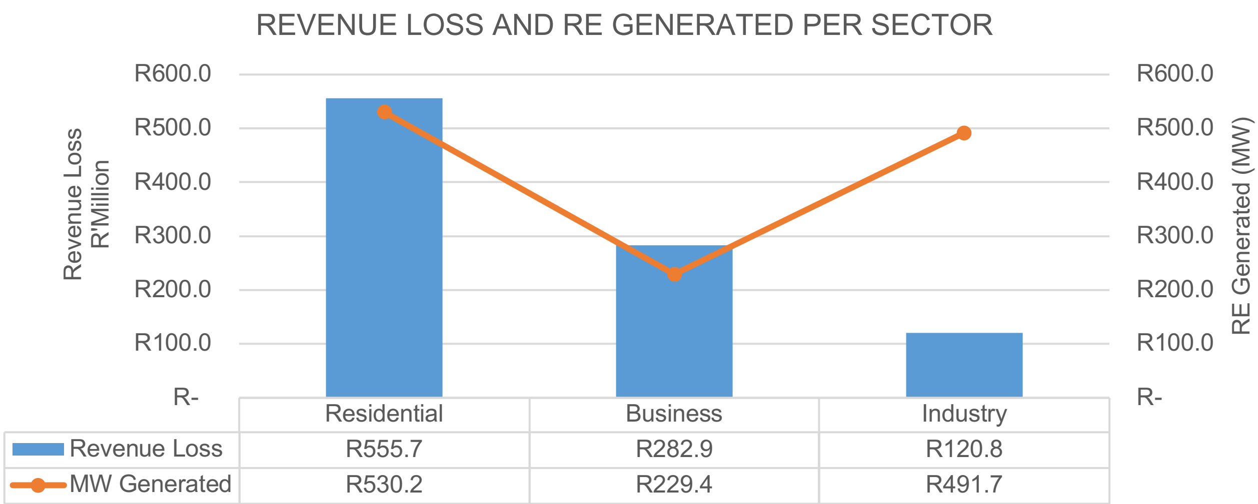


Figure 66 Revenue loss and RE generated per sector

The total revenue loss should all feasible customers go ahead with the installation is R 959 million with a potential to generate 1251 MW. Despite projects being feasible, the uptake rate will be dependent on various factors. The graph below depicts the revenue loss and RE generation based on varying uptake rates, ranging from 10 % to 100 %, differentiated by 10 % intervals.

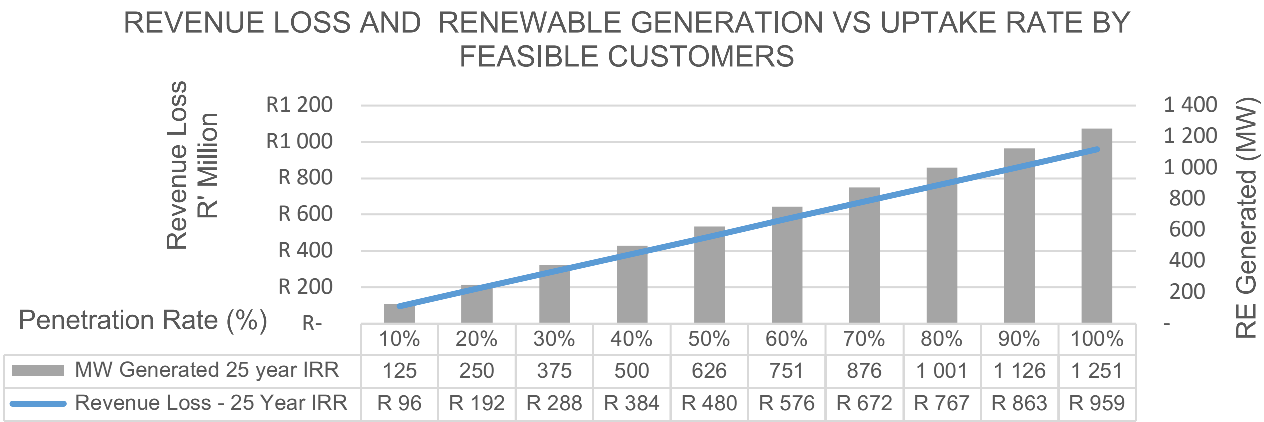


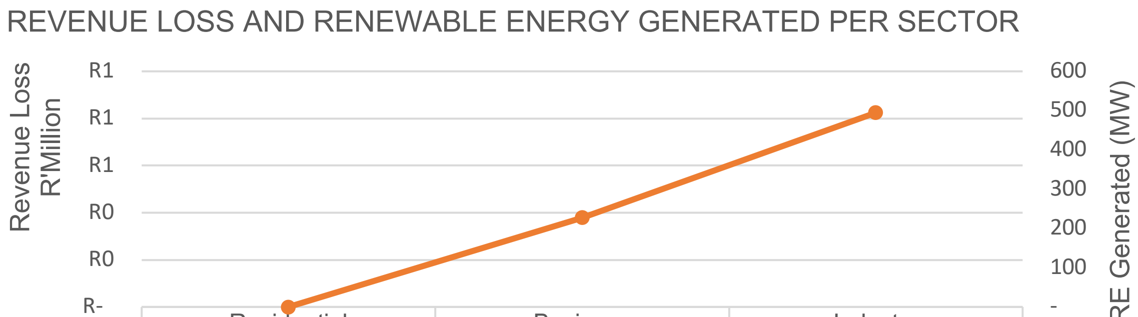
Figure 67 Revenue Loss and RE generation vs penetration rate by feasible customers

Considering an uptake rate ranging between 30% and 50%, the potential revenue loss to eThekwini Municipality ranges between R 288 million and R 480 million with a plausible generation output ranging between 375 MW and 626 MW respectively.

4.2.2 Scenario 2

		IRR		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	•	-	•	•	•
Refer section 5.3 for RE tariff parameters					

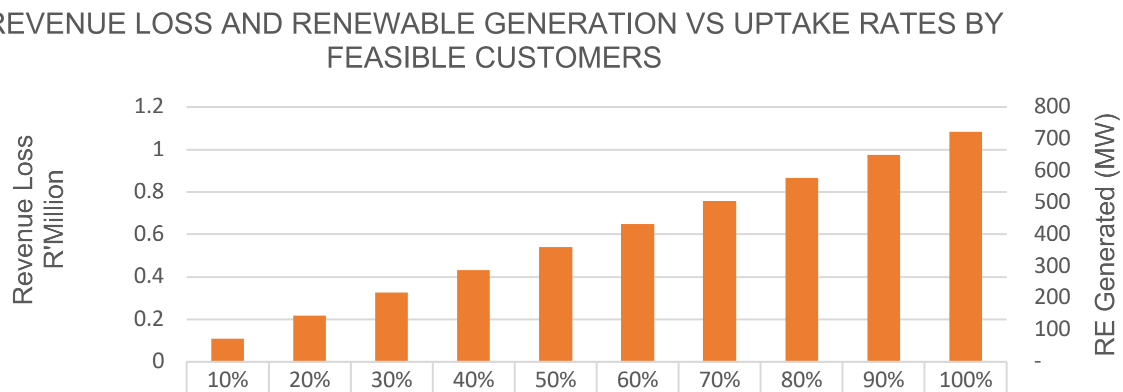
In the current tariff structure, the network costs are embedded within the energy rate (at various rates for different customer categories). Therefore, for every kWh that the solar PV system generates and the customer self-consumes, the customer inadvertently offsets the network costs as well. Introducing RE tariffs had the effect of only allowing the solar PV project to offset the energy costs and NOT the network costs per kWh generated. Subsequently there was a total of 3.9% of the total customers that met the feasibility criteria, however none within the residential sector



	Residential	Business	Industry
Revenue Loss	R-	R-	R-
MW Generated	-	228	494

Figure 68 Revenue loss and RE generated per sector

There is zero revenue loss should all feasible customers go ahead with the installation as RE tariffs have been introduced. The uptake rate will be dependent on various factors. The graph below depicts the RE generation based on varying uptake rates, ranging from 10% to 100% differentiated by 10% intervals.



	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
Revenue Loss - 25 Year IRR										
MW Generated 25 year IRR	72	144	217	289	361	433	505	578	650	722

Figure 69 Revenue Loss and RE generation vs uptake rate by feasible customers

4.2.3 Scenario 3

		IRR		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	•	•		•	-

Currently PV panels are offered with either a 20 year or a 25 year performance warranty with an estimated 1% power loss each year [96], [97]. Some manufacturers provide a 25 year performance guarantee with less than 0.7% loss per annum [98]. The overall PV system lifespan is usually dictated by the lifespan of the PV panels. PV systems are able to function at low operating cost levels, utilising "free" solar energy, however requiring high initial capital investments. Due to the large disparity between upfront and running costs, evaluating the IRR over a longer period or the project lifespan generally yields the best returns. The graph below highlights the IRR yield for typical projects over its lifespan in the residential, business and industrial categories without RE tariffs.

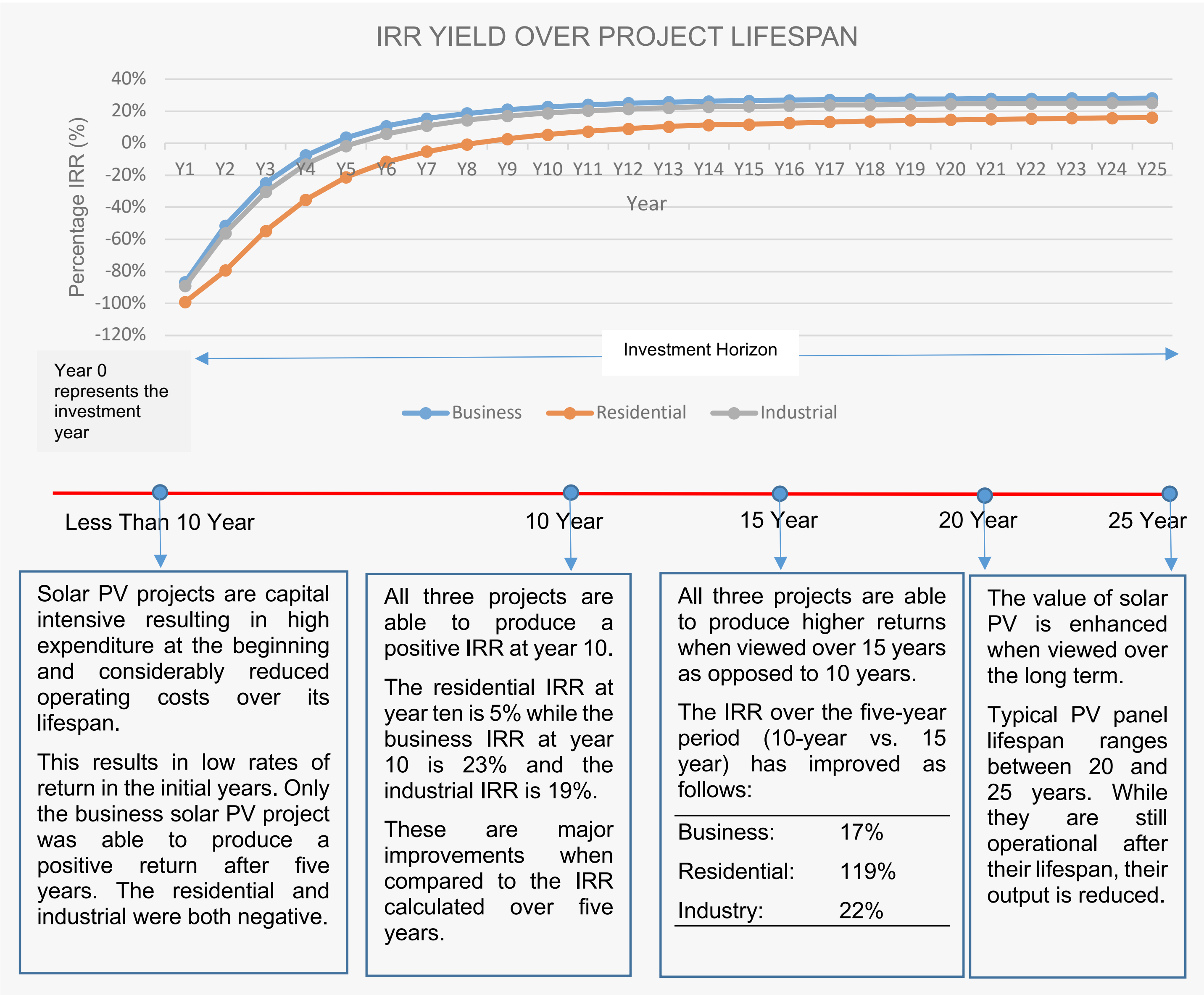
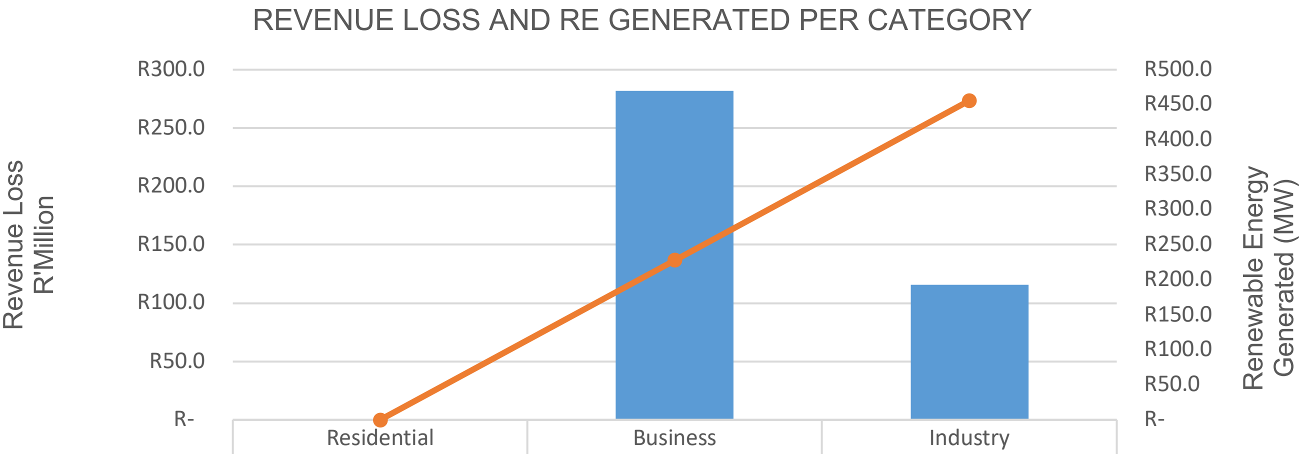


Figure 70 IRR yield over project lifespan

The investment horizon is an important aspect of determining the IRR yield. All sectors benefit from longer-term investment horizons; however, projects with shorter payback periods (business and industrial) produce better yields sooner, than projects with longer payback periods (residential).

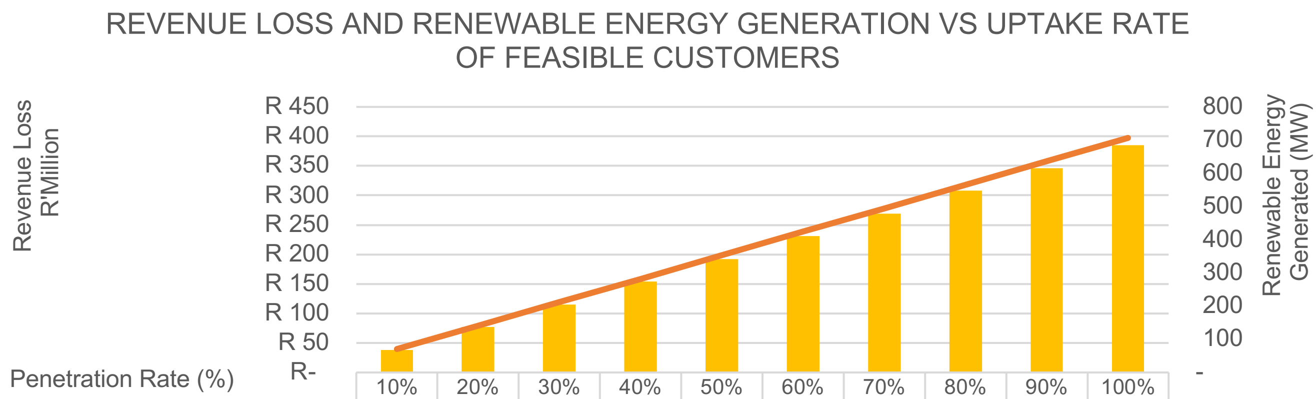
Evaluating the municipal revenue loss whilst calculating the project IRR over a ten-year period as opposed to 25 years resulted in lower losses for the municipality as fewer customer met the feasibility criteria. There were only 3.9% customers that were feasible; however, none of the residential projects was feasible.



	Residential	Business	Industry
Revenue Loss	R-	R281.7	R115.7
MW Generated	R-	R227.8	R456.0

Figure 71 Revenue loss and RE generated per category

It is unlikely that all feasible customers would carry out their installations at the same time. The graph below depicts the revenue loss and RE generation based on varying uptake rates, ranging from 10% to 100%, differentiated by 10% intervals.



Penetration Rate (%)	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
MW Generated - 10 year IRR	68	137	205	274	342	410	479	547	615	684
Revenue Loss - 10 Year IRR	R 40	R 79	R 119	R 159	R 199	R 238	R 278	R 318	R 358	R 397

Figure 72 Revenue loss and RE generation vs uptake rate of feasible customers

Analysing the IRR over 10 years coupled with an uptake rate of 50%, the municipality stands to lose R 199 million with a RE generation gain of 342 MW. This represents a decrease of 45% when compared to the IRR period of 25 years for the same level of penetration. At a penetration level of 100%, the municipality stands to lose R 397 million while gaining 684 MW of renewable generation.

4.2.4 Scenario 4

		IRR		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	•	•		•	•
Refer section 5.3 for RE tariff parameters					

In this scenario, an additional fixed charge (based on inverter size: R/kVA) was introduced to reduce the municipal loss to zero. Further, exported energy was remunerated by the introduction of a buy back tariff component. The tariff for energy exported to the grid varies per category and is calculated based on the avoided cost principle for the varying load and generation profiles.

Unfortunately calculating the IRR over a 10-year period does not allow any solar PV projects in any of the categories to meet the feasibility IRR threshold of 15%. This results in zero projects going ahead, resulting in zero revenue loss to the municipality and zero RE gain by the municipality.

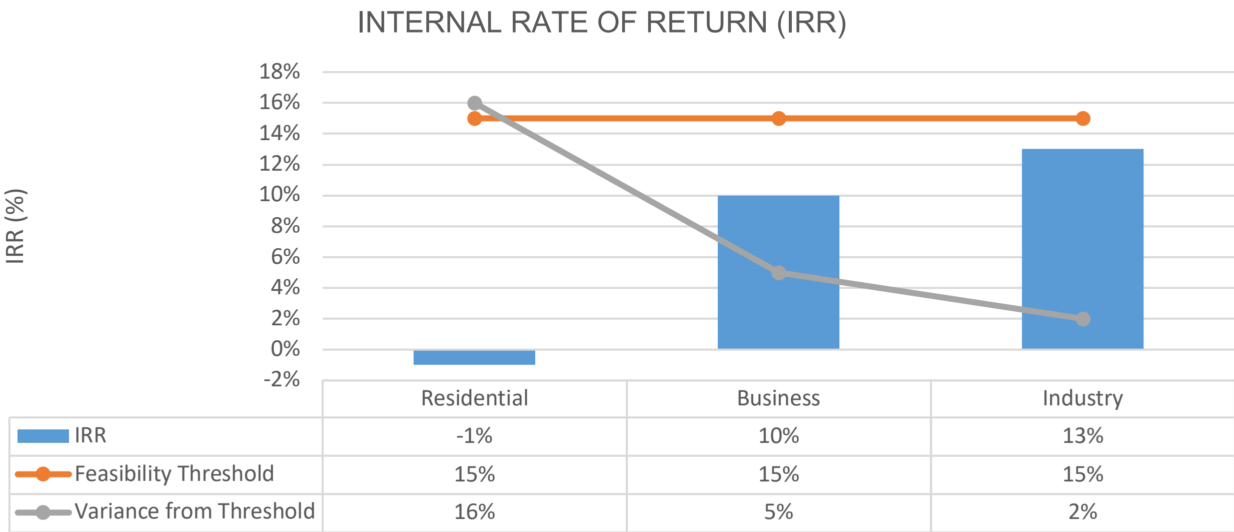


Figure 73 Internal Rate of Return (IRR) per category

The residential sector produced a negative return over a ten-year period while the business and industrial categories produced a return of 10% and 13% respectively. The business sector was 5% short of meeting the feasibility criteria, while the industrial sector was only 2% away from meeting the criteria.

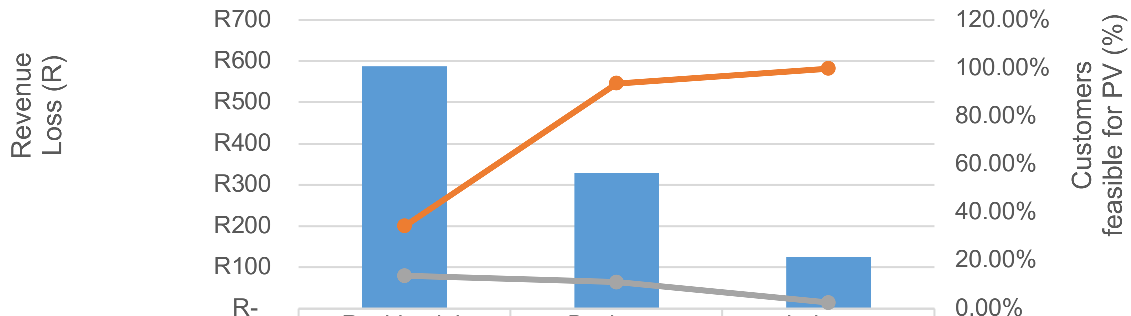
The uptake rate of RE within eThekwini will be influenced by numerous factors. These include inter alia, generation limiting guidelines and customer preferred investment horizons. These factors could change over time, affecting the municipal revenue loss and potential RE generation for eThekwini Municipality. Scenario five and six are, therefore, modelled to exclude the above-mentioned variabilities. Excluding these variabilities, offers an overarching, holistic perspective, for the potential of solar PV within eThekwini municipality's customer base.

4.2.5 Scenario 5 **Business as usual**

		IRR		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	**-**	-	•	•	-

This scenario is considered as the business as usual scenario as it excludes any intervention from the municipality (i.e. municipality does not react). The results portrayed below are the results with the feasibility criteria applied (i.e. only PV projects that met the IRR threshold of 15% and SPBP of 10 years were accounted for). Only 37% of customers were found feasible.

REVENUE LOSS AND CUSTOMERS FEASIBLE FOR PV PER CATEGORY

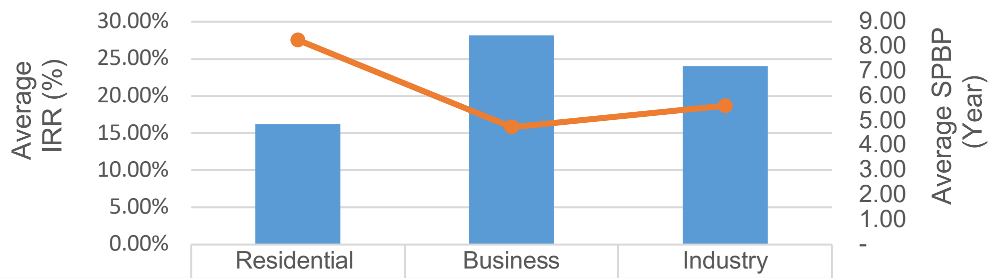


	Residential	Business	Industry
Revenue Loss	R588	R329	R124
% Customers Feasible for PV	34.25%	93.64%	99.74%
% Revenue Loss when compared to total revenue of customer category	13.67%	10.97%	2.54%

Figure 74 Revenue Loss and customers feasible for PV per category

In the instance where the municipality does not react to the PV revolution, then the municipality stands to lose R 1.041 billion should ALL customers meeting the threshold feasibility criteria install PV. The most significant contributors to the financial loss are the residential category, followed by the business and industrial category.

AVERAGE IRR AND AVERAGE SPBP PER CATEGORY



	Residential	Business	Industry
Average Internal Rate of Return (IRR)	16.18%	28.17%	24.07%
Average PayBack Period (Yr)	8.26	4.74	5.60

Figure 75 Average IRR & average SPBP per category

The IRR for the residential category is 16.18% with an SPBP of 8.26 years The IRR for the business category exceeds the residential by 11.99% and the industrial category by 4.10%. The most gains in PV projects will be in the business category. Coupled with the higher IRR's in the business category is lower SPBP's. The business category projects will be paid off in 4.74 years on average, which is 3.52 years faster than the residential projects and 0.86 years sooner than the industrial projects.

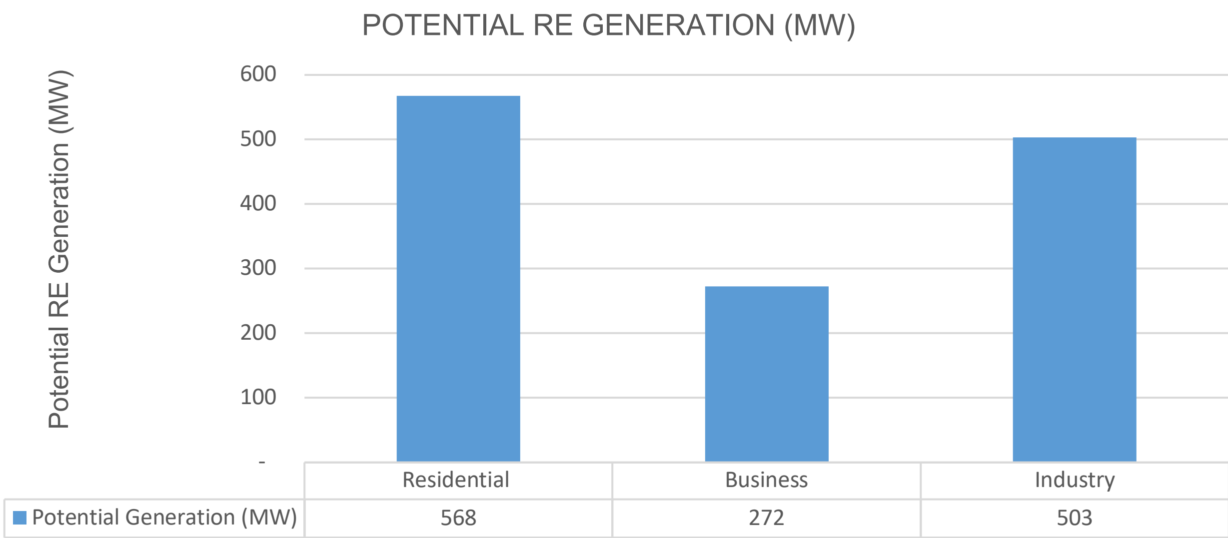


Figure 76 Potential RE generation (MW)

While the municipality could lose R 1.041 billion in this scenario, they would reap 1343 MW of RE installations. Where the municipality allows this scenario to unfold, each MW installed would cost the municipality R 774 963 per annum (excluding inflationary adjustments). The aggregated loss of R 1.041 billion, expressed as a percentage equates to 8.53% of the total annual current tariff revenue of the Electricity Unit.

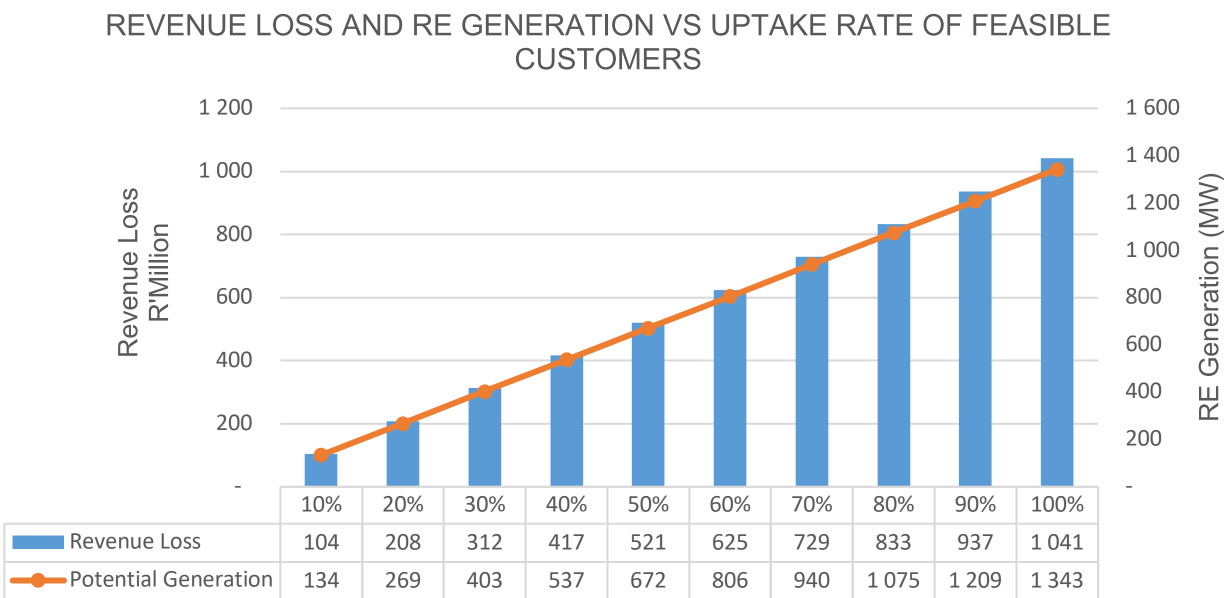


Figure 77 Revenue loss and RE generated vs PV uptake rates of feasible customers

4.2.6 Scenario 6 **Base case**

		IRR Period		SPBP	
Modelling Inputs	NRS 097-2-3 Limits	10 Year	25 Year	10 Year	RE Tariffs
Applicable	•	-	•	•	•
Refer section 5.3 for RE tariff parameters					

In this scenario, an additional fixed charge (based on inverter size: R/kVA) is introduced to reduce the municipal loss to zero. Further exported energy is being remunerated by the introduction of a buy back tariff component. The tariff for energy exported to the grid varies per category and is calculated based on the avoided cost principle for the varying load and generation profiles. Applying this scenario resulted in only 3.9% customers being feasible, however, none of the residential projects was feasible.

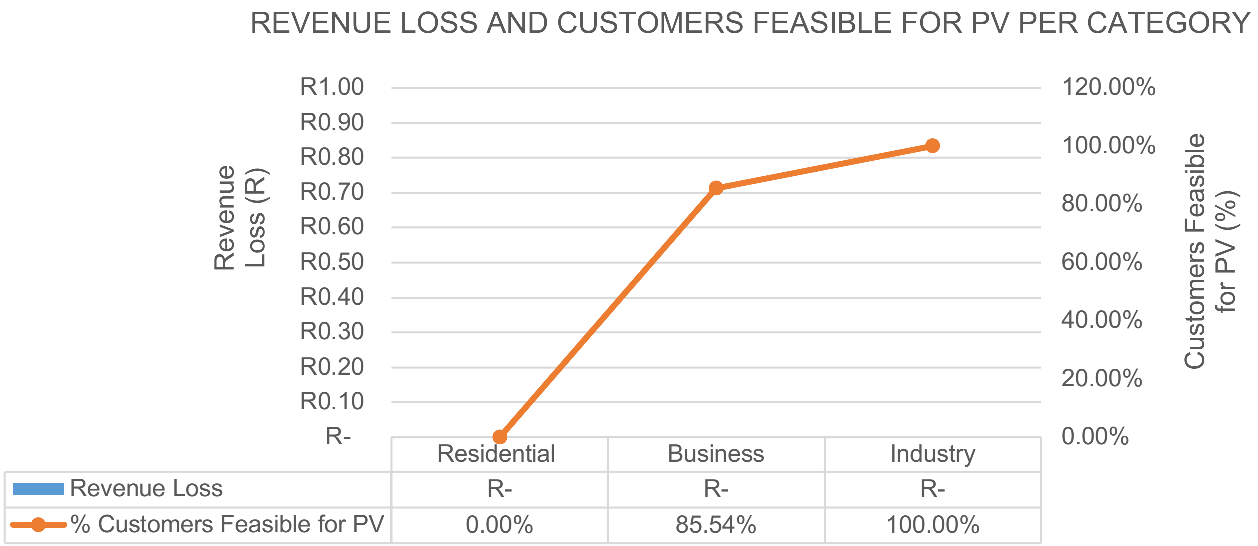


Figure 78 Revenue loss & percentage customers feasible for solar PV per category

With the introduction of the R/kVA charge, the municipal loss because of PV integration is ZERO. While this bodes well for eThekwini Municipality, the overall feasibility and economics of PV projects were affected.

The residential category is severely affected, as none of the residential customers can meet the feasibility criteria. Prior to the introduction of the charge, 34.25% of customers were deemed feasible to install PV. By introducing the R/kVA charge, the municipality is recovering the grid contribution that the customer was previously paying and correctly preventing it from being offset via the PV project. The economic case for residential PV is unable to justify itself based on offsetting the energy costs alone.

The business category has 85.54% of its customers meeting the feasibility criteria. The impact of the R/KVA charges, which allows the customer to make the same contribution to the grid, prior to the PV project being installed reduces customer feasibility by 8.1% when compared to scenario five. The business category of PV projects can largely support itself without needing to offset municipal grid charges to maintain its economic viability.

None of the customers within the industrial category became unfeasible when the R/kVA charge was introduced.

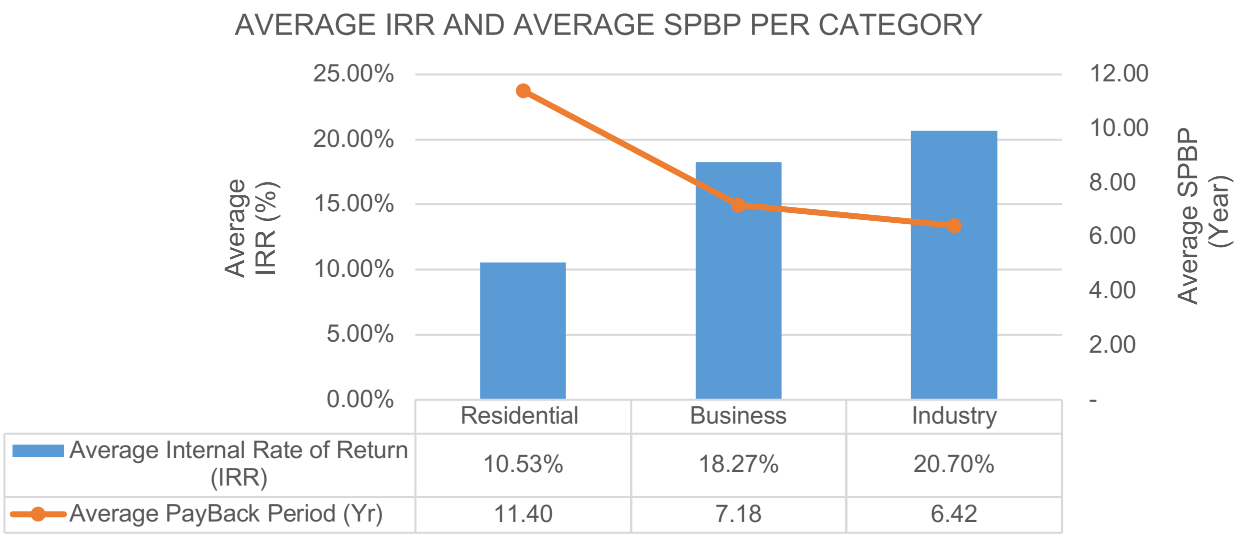


Figure 79 Average IRR and average SPBP per category

Residential customers have an average IRR of 10.53% and an SPBP of 11.40 years. This does not meet the feasibility criteria. None of the residential customers would be deemed feasible to go ahead with installations. The business category lost 9.9% on its return and gained 2.44 years in the SPBP. However, overall, the IRR and SPBP are still within reasonable limits for PV projects to go ahead. The feasibility criteria for the industrial category improved slightly. The IRR was negatively affected by 3.37%, and the SPBP gained 0.82 years.

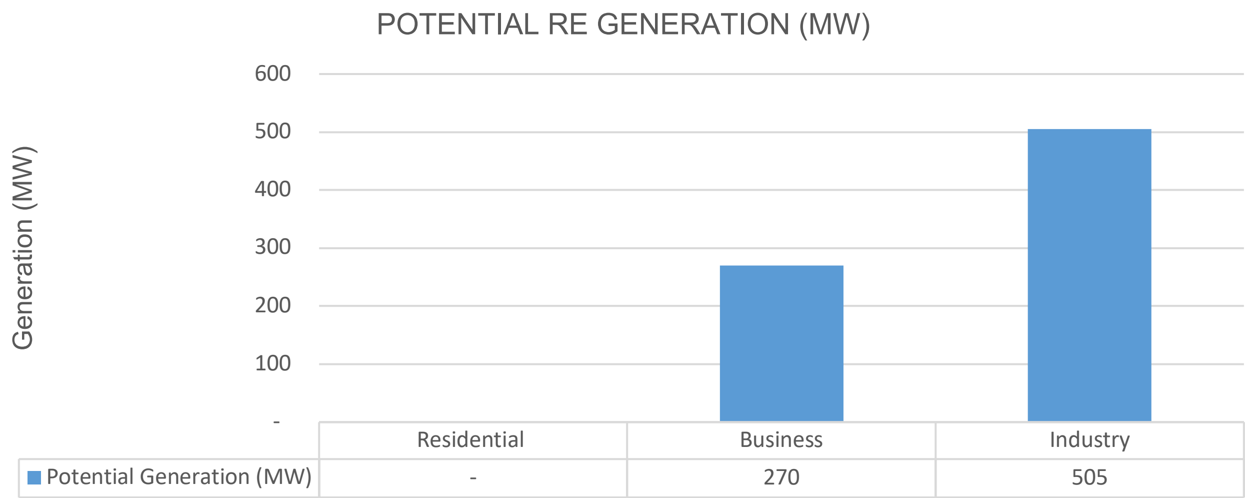


Figure 80 Potential RE generation (MW)

With full municipal revenue protection, the residential sector does not contribute to the RE targets, as zero customers were feasible. The business category will introduce 270 MW while the industrial category will add 505 MW to the grid.

4.2.7 Sensitivity analysis: Scenario 6

The table below provides the key economic parameters of solar PV projects based on varying input parameters, as described in table 21.

Table 23 Results of scenario five, six and sensitivity analysis

Business As Usual & Base Case Scenario	**Residential**			**Business**			**Industrial**		
	% Feasible Customers	**IRR (%)**	**SPBP (Year)**	**% Feasible Customers**	**IRR (%)**	**SPBP (Year)**	**% Feasible Customers**	**IRR (%)**	**SPBP (Year)**
Business As Usual Case									
Scenario 5 No Municipal Intervention	34.25	16.18	8.26	93.64	28.08	4.76	99.74	24.07	5.60
Scenario 6 Introduction of fixed kVA charge and export tariff	No Residential Customers Feasible			Base Case					
	0.0	10.53	11.40	85.54	18.27	7.18	100	20.70	6.42

The results below indicate the deviation from the base case for the relevant scenarios

↑ Incline ↓ Decline — No Change

Comparison with Base Case	**Residential**			**Business**			**Industrial**		
	% Feasible Customers	**IRR (%)**	**SPBP (Year)**	**% Feasible Customers**	**IRR (%)**	**SPBP (Year)**	**% Feasible Customers**	**IRR (%)**	**SPBP (Year)**
Scenario 6.1 Cash Funded as opposed to financing	No Residential Customers Feasible			↑	↑	↓	—	↑	↓
	0.00	+ 2.98	- 2.50	+ 4.06	+ 3.22	-1.54	0.00	+ 3.50	- 1.42
Scenario 6.2 Financing Interest rate reduced to 8%	No Residential Customers Feasible			↑	↑	↓	—	↑	↓
	0.00	+ 0.77	-0.72	+2.03	+ 1.04	-0.53	0.00	+ 1.12	-0.48
Scenario 6.3 Increasing the repayment period from 60 months to 120 months	No Residential Customers Feasible			↓	↓	↑	—	↓	↑
	0.00	-1.00	+1.36	-2.02	-1.82	+ 1.32	0.00	-1.88	+ 1.11

Comparison with Base Case	Residential			Business			Industrial		
	% Feasible Customers	IRR (%)	SPBP (Year)	% Feasible Customers	IRR (%)	SPBP (Year)	% Feasible Customers	IRR (%)	SPBP (Year)
Scenario 6.4 Reduce the PV system price by 20%	No Residential Customers Feasible			↑	↑	↓	–	↑	↓
	0.00	+ 3.03	-1.96	+ 4.06	+ 3.92	-1.20	0.00	+ 4.23	- 1.07
Scenario 6.5 Increase the future electricity tariff increase to 12%	No Residential Customers Feasible			↑	↑	↓	–	↑	↓
	0.00	3.39	-1.03	+ 4.06	+ 2.71	- 0.17	0.00	+ 5.09	-0.68
Scenario 6.6 Impact of VAT and tax rebate	↑	↑	↓	↓	↓	↑	↓	↓	↑
	37.90	7.06	- 3.92	-85.54	-6.83	+ 3.33	-100.00	-7.39	+ 3.17
Scenario 6.7 Reduce export rate to zero	No Residential Customers Feasible			↓	↓	↑	↓	↓	↑
	0.00	-0.55	+ 0.76	-7.32	-2.36	+ 0.96	-1.16	-0.25	+ 0.09
Scenario 6.8 Double the export rate	No Residential Customers Feasible			↑	↑	↓	–	↑	↓
	0.00	+ 1.50	-1.11	+ 8.10	+ 2.27	-0.75	0.00	+ 0.46	- 0.12

Most Influential Factor

TAX AND VAT REBATE

The ability to claim the VAT and the tax allowance is the most influential factor in promoting the number of customers that would install solar PV.

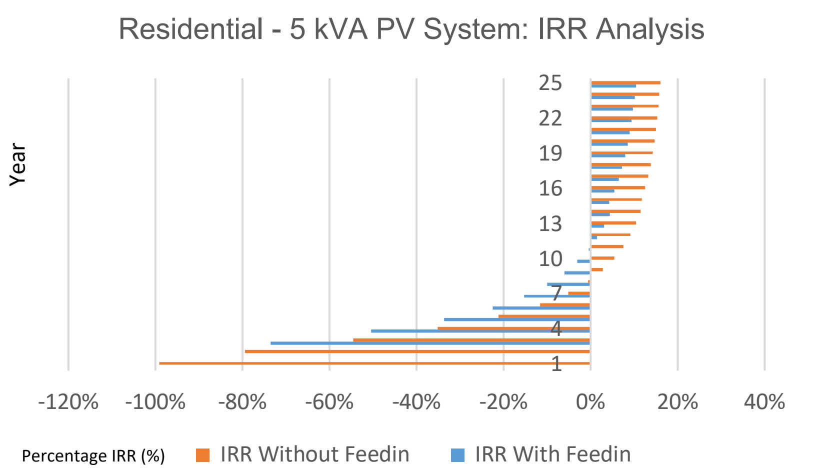
For the residential sector, 37.9% of the customers become feasible to install solar PV if they were presented with the opportunity to claim the VAT and tax rebates. Unfortunately, none of these rebates is available to the residential sector.

None of the business and industrial customers meet the feasibility criteria should they not be able to claim the VAT and tax rebates.

5 CHAPTER 5: DISCUSSION

5.1 IRR yield over project lifespan

Table 24 IRR yields for typical projects across customer categories

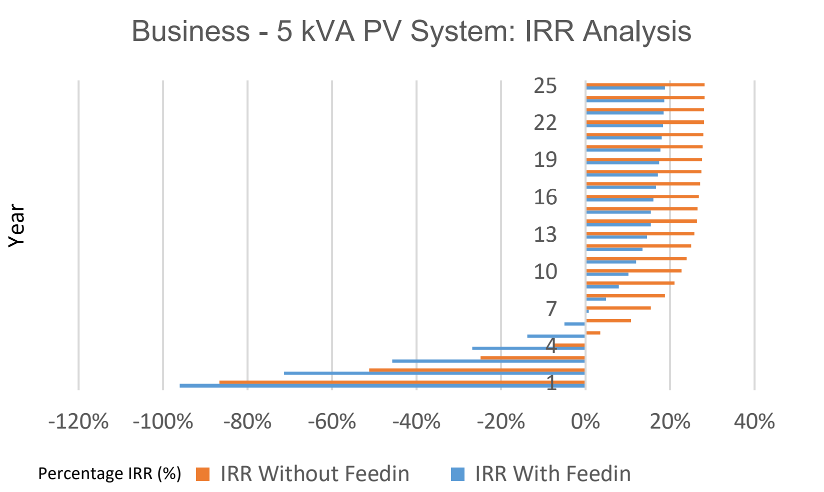
<table>
<tr><th>IRR yields for typical projects across customer categories</th><th>Discussion</th></tr>
<tr><td>
</td><td rowspan="3">The period over which the IRR is calculated is an important factor in determining the rate of return.

Solar PV has a high upfront cost and a typical lifespan ranging between 20 and 25 years. Most PV panels available in South Africa are being sold with a 25-year performance warranty. Because of its longevity and its ability to operate over 25 years, it can continue to generate financial returns over the 25-year period.

Despite the performance warranty and its long lifespan, not all investors may appreciate the value of PV over the long term.

Short-term investors seeking lucrative returns from solar PV in less than five years will be disappointed, as none of the categories is able to generate reasonable returns over the short term.

Investors with a ten-year investment horizon will be able to seek returns ranging between 19% and 23% in the industrial and business sectors respectively, however, only without the implementation of the RE tariffs. This signifies that the current energy price alone, cannot justify a solar PV installation and a reasonable return over ten years. The project has to offset the network costs to meet the feasibility criteria.

Investors willing to reap the rewards over the long term (i.e. 25 years) seek to gain the highest returns. Investments in the industrial system will yield 25% (21% with RE tariffs), investments in business systems will yield 28% (19% with RE tariffs) and residential systems will yield 16% (10% with RE tariffs).</td></tr>
<tr><td>
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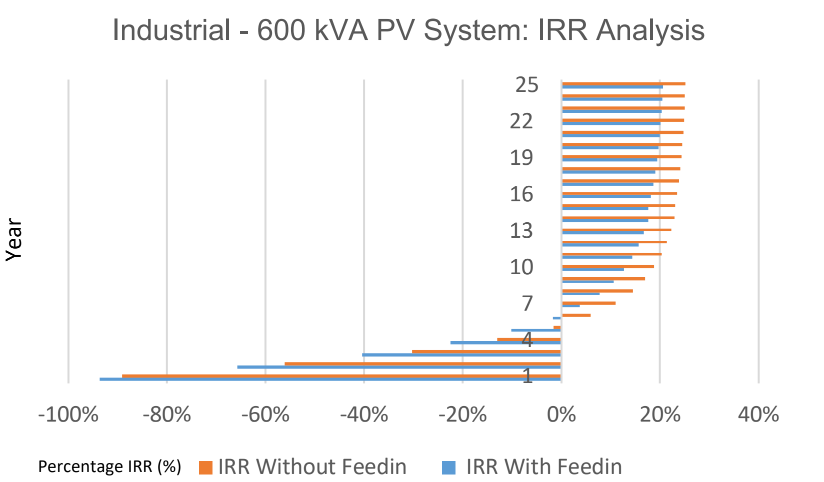
<tr><td>
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5.1.1 NRS 097-2-3: Simplified utility connection criteria for low voltage generators

Applying the generator limits as per NRS 097-2-3 in scenario one, resulted in an 8% reduction in the revenue loss when compared to the scenario where the generation limits do not apply (scenario five). The RE potential generation reduced in similar proportions when comparing the scenarios.

Where the generator size does not comply with the NRS 097-2-3 criteria, it does not indicate that the project cannot go ahead. It merely implies that the municipality would need to carry out a detailed network study and evaluate the impacts of connecting the generator to the grid prior to the connection [5]. There may be a need to reconfigure, upgrade the network/equipment or parts thereof, to allow for the increased generation size as per the customer request, to be grid connected. NRS 097-2-3 was prepared based on typical network configurations, which makes its application generic and not specific to eThekwini Municipality.

5.2 Results of Sensitivity Analysis

5.2.1 Residential category

Only 34.25% of residential customers met the feasibility criteria of 15% IRR and an SPBP less than 10 years, in the scenario where the municipality does not introduce any additional network access charges or buyback rates (i.e. business as usual case, scenario five). This is a relatively small percentage and is an indication that the residential PV category needs to be supported to enable widespread uptake. The current combination of technology prices and residential electricity tariffs alone is not able to significantly influence the uptake of PV. The municipality stands to lose a total of R 588 Million, should 34.25% of the residential customers that meet the threshold criteria install PV. They would be able to contribute 568 MW of RE to the grid.

Under the base case, scenario six, (i.e. municipality introduces network access charges and a buy-back tariff), none of the residential customers met the feasibility criteria. While the municipality would be protecting its revenue, it will not be promoting the uptake of PV.

A 20% reduction in price was unable to sufficiently stimulate the residential PV sector nor was a reduction in the interest rate or removing the cost of funding altogether. While modelling a further 4% annual electricity increase, in addition to the 8% base case, did strengthen the economics of the PV project, it was not sufficient to make any residential customers meet the threshold criteria.

The only scenario that promoted the residential uptake of PV was scenario 6.6, where there was an introduction of a tax and VAT rebate for residential customers. This allowed for an initial write off in the capital costs of the system. As a result, 37.9% of customers met the feasibility criteria with an average internal rate of return of 17.59% and an SPBP of 7.48 years.

5.2.2 Business category

Within the business category, 93.64% of customers meet the feasibility criteria of 15% IRR and an SPBP less than 10 years in scenario five, where the municipality does not introduce any additional network charges or buyback rates (i.e. business as usual case). The high level of customer feasibility is an indication that the business PV category requires little or no support to enable uptake.

The current combination of technology prices and retail business electricity tariffs was able to significantly influence the uptake of PV. The average IRR was 28.08% with an average SPBP of 4.76 years. Considering this scenario, the municipality stands to lose a total of R 329 million should the 93.64% of the business customers that met the threshold criteria install PV. They would be able to contribute 272 MW of RE to the grid.

Considering the base case, scenario five (i.e. municipality introduces network access charges and a buy-back tariff), 85.54% of the business customers meet the feasibility criteria. The average IRR was 18.27%, and the average SPBP was 7.18 years. Implementation of the charges to protect the municipal revenue reduced the IRR by 9.81% and extended the SPBP by 2.42 years. Whilst the economic indicators did weaken; the returns were still deemed acceptable for projects to go ahead.

Cash funded PV systems improved the IRR by 3.22% while reducing the SPBP by 1.54 years. Reducing the interest rate of funding by 4% increased the IRR by 1.04% while the SPBP reduced by 0.53 years. Increasing the capital-funding period from 5 years to 10 years did not yield any positive results and caused the IRR to decrease by 1.82 % and the payback to increase by 1.32 years. A 20% reduction in PV price influenced the indicators positively as the IRR gained 3.92%, and the SPBP was reduced by 1.2 years. A further 4% increase in electricity prices above the base case strengthened the IRR by 2.71% while the SPBP was decreased by 0.17 years.

The removal of the VAT and tax rebate from the business category resulted in all customers becoming unfeasible for the installation of PV, as they did not meet the feasibility criteria. All customers being unfeasible is clear evidence that the support received via government incentives is enabling the business PV category of customers.

While the export rate did contribute to the income of PV projects, the removal of the export rate only affected 7.32% of business customers by reducing the IRR by 2.36% and extending the SPBP by 0.96 years. Doubling the export rate had the opposite effect on the IRR and SPBP of near similar proportions.

5.2.3 Industrial category

Within the industrial category, 99.74% of customers met the feasibility criteria of 15% IRR and an SPBP less than 10 years in the scenario where the municipality does not introduce any additional network charges or buyback rates (i.e. business as usual case, scenario five). This is a relatively high percentage and is an indication that the industrial PV category does not require support to enable uptake.

The current combination of technology prices and retail industrial electricity tariffs is able to significantly influence the uptake of PV. The average IRR was 24.07% with an average SPBP of 5.60 years. The municipality could lose a total of R 124 Million should 99.74% of the industrial customers that met the threshold criteria install PV. They would be able to contribute 503 MW of RE to the grid.

Under the base case, scenario six, (i.e. municipality introduces network access charges and a buy-back tariff), 100% of the industrial customers met the feasibility criteria. The average IRR was 20.70%, and the average SPBP was 6.42 years. Implementation of the charges to protect the municipal revenue reduced the IRR by 3.37% and extended the SPBP by 0.82 years. Whilst the economic indicators did weaken; the returns were still deemed acceptable for projects to go ahead.

Cash funded PV systems improved the overall IRR by 3.50% while it reduced the SPBP by 1.42 years. Reducing the interest rate by 4% boosted the IRR by 1.12% while the SPBP reduced by 0.48 years.

Increasing the capital-funding period from 5 years to 10 years did not reduce the number of feasible customers; however, it had an overall negative effect to the IRR and SPBP.

A 20% reduction in PV system pricing influenced the indicators positively as the IRR gained 4.23%, and the SPBP was reduced by 1.07 years.

An additional 4% increase in annual electricity prices above the base case of 8% strengthened the IRR of projects by 5.09% and reduced the SPBP by 0.68 years.

The removal of the VAT and tax rebate from the industrial category resulted in all customers not meeting the feasibility criteria. With all of the industrial customers not meeting the feasibility criteria, it is clear evidence that the support received via government incentives is enabling the industrial PV category of customers.

While the export rate does contribute to the income of PV projects, the removal of the export rate does not significantly affect the IRR or the SPBP; however, 1.16% of the customers did become unfeasible. Doubling the export rate did not significantly affect the number of feasible customers, the IRR or the SPBP.

5.3 Renewable energy tariffs

5.3.1 Residential RE tariff option

It is recommended that eThekwini Municipality implement the residential RE tariff structure as shown below to fully protect the municipal revenue. Unfortunately, this would result in zero customers being feasible to implement PV projects.

Table 25 Residential PV tariff structure

Residential Tariff Structure	***Scale 3,4***
Energy Charge Import Energy	197.14 c/kWh
Service Charge (R/Month)	R 0.00
Energy Rebate: Export Energy	100.00 c/kWh
Network Access Charge: Based on Inverter Size	R 83.73/kVA/per month

The import energy charge is a flat rate charge for all energy drawn from the grid.	The service charge is priced within the energy rate and hence the charge is zero.	The export energy refers to energy generated onto the grid. The energy is credited to the account via a flat rate irrespective of the time of generation.	The network access charge is levied per kVA based on the PV inverter size. Rates are fixed for all voltage levels.

5.3.2 Business RE tariff option

To fully protect the municipal revenue, eThekwini Municipality must implement the business RE tariff structure as shown below. Implementing the tariff would reduce the municipal revenue loss to zero and would promote 85.54% of all business PV projects with an average IRR of 18.27% and an SPBP of 7.18 years. There is no subsidisation required.

Table 26 Business PV tariff structure

Business Tariff Structure	***Scale 1***
Energy Charge: Import Energy	222.61 c/kWh
Service Charge (R/Month)	R 291.29
Energy Rebate: Export Energy	75.00 c/kWh
Network Access Charge: Based on Inverter Size	R 90.47/kVA/per month

The import energy charge is a flat rate charge for all energy drawn from the grid.	The service charge is a fixed charged levied on a monthly basis to recover service related costs	The export energy refers to energy generated onto the grid. The energy is credited to the account via a flat rate irrespective of the time of generation.	The network access charge is levied per kVA based on the PV inverter size. Rates are fixed for all voltage levels.

The tariff components highlighted in red with the yellow background is the additional RE tariff components. The tariff components in black are the components of the existing tariff structure.

5.3.3 Industrial RE tariff option

To fully protect the municipal revenue, eThekwini Municipality must implement the industrial RE tariff structure as shown below. Implementing the tariff would reduce the municipal revenue loss to zero and would promote all industrial PV projects, with an average IRR of 20.70% and an SPBP of 6.42 years. There is no subsidisation required.

Table 27 Industrial PV tariff structure

Industrial Tariff Structure			Industrial Time of Use (ITOU)		
Summer September to May			***Winter June to August***		
Import Energy Rate			*Import Energy Rate*		
Peak : *128.42*	*Standard: 91.62*	*Off-Peak: 61.88*	*Peak : 372.46*	*Standard: 120.04*	*Off-Peak: 69.87*
Export Energy Rate			*Export Energy Rate*		
Peak : *128.42*	*Standard: 91.62*	*Off-Peak: 61.88*	*Peak : 372.46*	*Standard: 120.04*	*Off-Peak: 69.87*

Network Access Charge	***Network Demand Charge***	***Service Charge***	***Voltage***	***Voltage Surcharge (%)***	***Renewable Energy Access Charge (R/kVA) per month***
(R/kVA)	***(R/kVA)***	***(R/pm)***	*275kV*	*0.00*	*R 0.00*
			132kV	*2.25*	*R 2.83*
R 36.51	*R 111.15*	*R 5175.00*	*33kV*	*3.00*	*R 3.67*
			11kV	*10.50*	*R 13.19*
			6.6kV	*12.75*	*R 16.10*
			0.4kV	*22.50*	*R 28.00*

The network access charge is payable monthly based on the anticipated / actual highest annual demand.

The network demand charge is payable monthly based on the actual monthly demand.

The service charge is a fixed charge payable per month.

The voltage surcharge is a percentage raised to all tariff components (excluding the service charge, renewable energy access charge and export energy) depending on the voltage of operation.

The renewable energy access charge is levied per kVA based on the PV inverter size. The rates vary based on the voltage of operation.

Import energy refers to energy drawn from the grid. It is charged based on the time of use and the relevant season

Export energy refers to energy generated onto the grid. Energy is credited at the time of use rates applicable during the relevant season. It will appear as a credit on the customer's account.

The tariff components highlighted in red with the yellow background is the additional RE tariff components. The tariff components in black are the components of the existing tariff structure. The export energy rates are as per the import energy rates, allowing customers to sell energy back to the municipality at the same rate as self-consumption. Export rates vary based on the time and the season of export.

5.4 The role of subsidies and incentives for PV

5.4.1 Promoting residential PV installations

Implementing RE tariffs in accordance with section 5.3.1 allows the municipal loss to be reduced to zero. However, none of the residential customers is able to meet the feasibility threshold criteria. This may not be well received by aspiring PV customers. In order to promote PV projects amongst the residential sector, there would need to be an introduction of a subsidy mechanism. The PV promotion wheel below indicates the subsidy that is required to support the various levels of PV uptake. Based on the affordability of the municipality, the appropriate level of PV promotion can be attained. The subsidy would be passed to the PV customers by way of an R/kVA rebate on the upfront system costs.

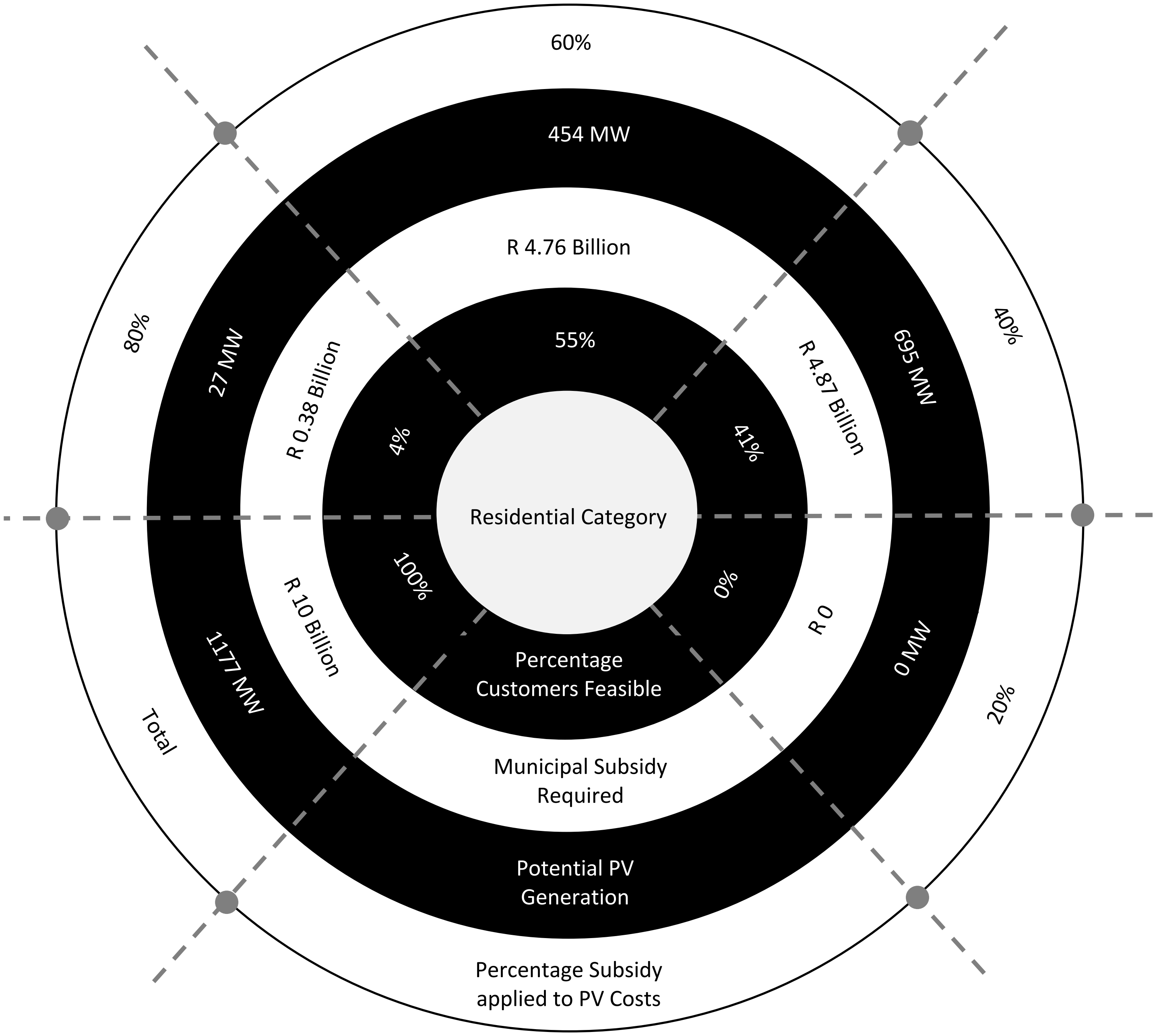


Figure 81 PV Subsidy wheel for the residential category

Stimulating the residential PV category proves to be expensive. In the case where the PV installation cost is subsidised by 20%, zero customers are able to meet the feasibility criteria.

However, subsidizing the PV costs by 40% will cost R 4.872 billion and will introduce 695 MW of RE to the grid. Subsidizing the price by 20% more will make 55% more customer feasible, bringing on another 454 MW of RE for R 4.76 billion. Providing more money and subsidising the price by another 20% will add 27 MW more to the grid at the cost of R 378 million. In total, to make all residential customers feasible, it will cost R 10 billion.

5.4.2 Promoting Business PV installations

Implementing the RE tariffs in accordance with 5.3.2 allows the municipal loss to be reduced to zero. However, only 85.54% of business customers were feasible. Where the municipality would like to promote higher PV penetration levels, they would need to provide a subsidy. The PV promotion wheel below indicates the subsidy that is required to develop the various levels of PV uptake. Based on the affordability of the municipality, the appropriate level of PV promotion can be attained. The subsidy would be passed to the PV customers by way of an R/kVA rebate on the upfront system costs.

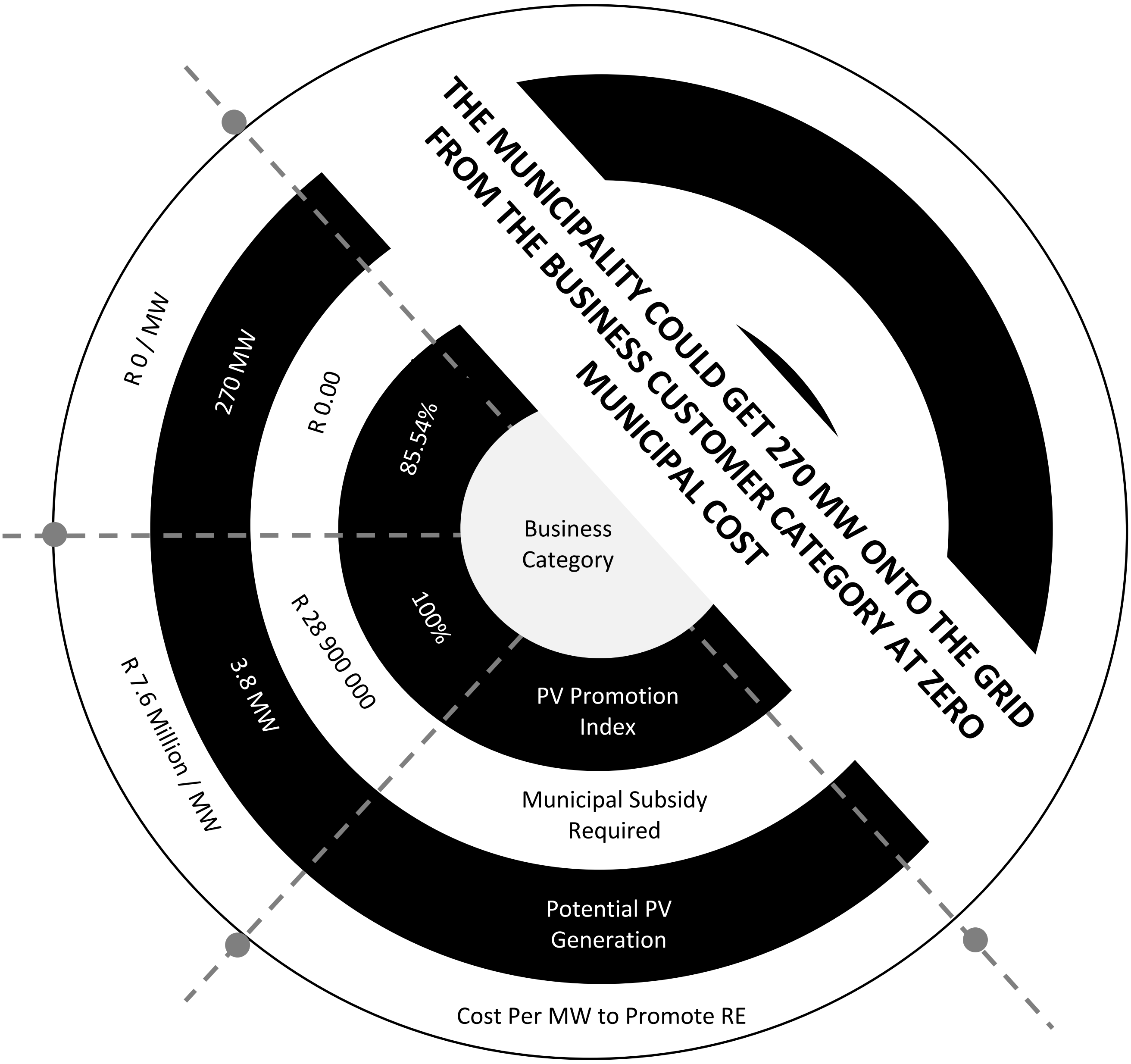


Figure 82 PV subsidy wheel for the business category

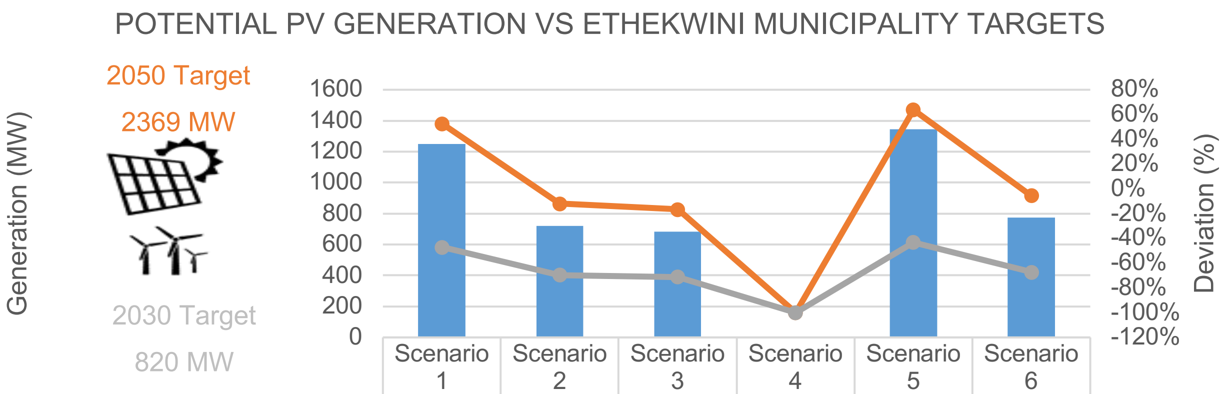
A municipal subsidy of R 28.9 million would be required to promote the 14.5% of business customers that currently do not meet the threshold criteria. This would result in an additional 3.8 MW of RE being connected to the grid. This equates to a cost of R 7.6 million per MW

5.4.3 Promoting Industrial PV installations

To protect the municipal revenue, eThekwini Municipality must implement the industrial RE tariff structure in accordance with section 5.3.3. Implementing the RE tariff would reduce the municipal revenue loss to zero and would promote all industrial PV projects with an average IRR of 20.70% and an SPBP of 6.42 years. There is no subsidisation required.

5.5 Leveraging solar PV potential to meet RE targets

The adoption of a PV platform will stimulate RE generation within eThekwini Municipality that will contribute positively to the RE targets. However, the amount of RE generated will depend on several factors as highlighted by the variability in the scenario results.



	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
MW Generated	1251	722	684	0	1343	775
Deviation from 2030 Target	53%	-12%	-17%	-100%	64%	-5%
Deviation from 2050 Target	-47%	-70%	-71%	-100%	-43%	-67%

Figure 83 Potential PV generation vs eThekwini Municipality RE targets

Where solar PV unfolds in accordance with scenario one, then there is a potential for the municipality to gain 1251 MW of RE. This exceeds the 2030 target by 53% however, is 47% short of the 2050 target. Should scenario two unfold, then there is a potential for the municipality to gain 722 MW of RE. This is 12% below the 2030 target and 70% below the 2050 target. Scenario three materialising would create a potential for the municipality to gain 684 MW of RE. This is 17% below the 2030 target and 71% below the 2050 target. Unfortunately, the municipality would gain zero RE generation under scenario four, as none of the projects met the feasibility criteria.

Scenario five yielded the greatest RE generation for the municipality however; it will also create the greatest revenue loss. This is unfavourable. Scenario six allowed the municipal revenue to be fully protected, via the implementation of the RE tariffs. Despite the introduction of the tariffs, the municipality could gain 775 MW of RE if all feasible projects go ahead. This is 5% lower than the 2030 target and 67% lower than the 2050 target.

6 CHAPTER 6: CONCLUSION

Numerous factors are driving the PV revolution. The significant factors are the rapid drop in technology costs and the rapid increase in electricity prices. Technology costs have experienced a decline of 70% when compared to technology prices of 2010, while electricity tariffs have risen by 150% over the same period. Other enabling factors include embedded generation tax allowances and inclusion of embedded generation within the draft IRP determinations with a specified allocation of 500 MW per annum. Whilst there are many enablers for local generation, not all projects can meet favourable investment criteria.

To understand the feasibility of PV projects and potential losses that feasible PV customers could introduce to eThekwini municipality, a two stage solar techno-economic model was designed utilising the unique customer category and generation profiles for eThekwini municipality.

Stage one of the model simulated the installation of optimally sized PV projects for individual customers by analysing their loading, and calculated key project criteria including NPC, IRR and SPBP. Customers were deemed feasible to go ahead with the project if they met the feasibility criteria i.e. IRR threshold of 15% or higher and the SPBP of ten years or less.

Six scenarios were modelled to evaluate the impact that solar PV would have on municipal revenue and RE generation within eThekwini Municipality. The scenarios were developed considering three main criteria:

- Generation Limitations in accordance with NRS 097-2-3.
- Investment Horizons: IRR calculated over a ten-year period and IRR calculated over a 25-year period.
- Optimised RE tariffs to protect municipal revenue.

The establishment of the number of feasible PV projects and the optimum PV size per project, allowed for the calculation of the municipal revenue loss due to self-consumption and for the quantity of RE that could be introduced respectively. Depending on the criteria applied, the impact on the municipality varied.

6.1.1 Scenario criteria and results

Table 28 Impact to eThekwini municipality, considering six scenarios.

	Scenario	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Scenario 6
Criteria	NRS 097-2-3 Limits Apply	•	•	•	•	-	-
	IRR Period: 10 Year	-	-	•	•	-	-
	IRR Period: 25 Year	•	•	-	-	•	•
	SPBP: 10 Year	•	•	•	•	•	•
	RE Tariffs Apply		•		•		•
Results	Customers Feasible (%)	31	3.9	3.9	0	37	3.9
	Municipal Revenue Loss (R million)	959	0	397	0	1041	0
	RE Generation (MW)	1251	722	684	0	1343	775

6.1.2 Customer feasibility

The number of customers within eThekwini municipality that met favourable investment criteria varied based on the input parameters of the solar techno-economic model. Limiting generation sizes in accordance with NRS 097-2-3, and calculating the IRR over a 25-year period resulted in 31% of the customer base meeting the feasibility criteria. Calculating the IRR over a ten-year period reduced the number of feasible customers by 27.1%. Without considering, the generation limits of NRS 097-2-3, and calculating the IRR over a 25 period resulted in 37% of the customer base being able to meet the IRR threshold of 15% and a SPBP of 10 years.

6.1.3 Municipal revenue loss

The revenue losses initiated by PV depended on the number of customers within eThekwini municipality that met the feasibility criteria. This varied based on the input parameters. Limiting generation sizes in accordance with NRS 097-2-3, and calculating the IRR over a 25-year period resulted in a revenue loss of R 959 million. Calculating the IRR over a ten-year period reduced the revenue loss to R 397 million. Without considering the generation limits of NRS 097-2-3 and calculating the IRR over 25 years, resulting in a revenue loss of R 1.041 billion.

6.1.4 Introduction of RE tariffs

Stage two of the solar techno-economic model introduced a network access charge (R/kVA) based on the PV inverter size. The R/kVA charge reduced the municipal revenue loss to zero. An energy buyback tariff rate has also been introduced to compensate for energy generated onto the grid at the avoided cost rate. Only network costs would be recovered via the R/kVA charge.

Because of the introduction of these charges, the economics of the PV projects were affected. With the adoption of the RE tariffs, it was possible to avert the revenue losses associated with the introduction of PV; however, the economic criteria for PV projects weakened as depicted by scenario two, four and six.

The introduction of RE tariffs proved successful in limiting the revenue loss to the municipality as PV was introduced; however, the number of customers meeting the feasibility criteria decreased. The introduction of the RE tariff resulted in the number of customers meeting the feasibility criteria decreasing by 27.1%. Unfortunately, the introduction of the tariff only allowed for 3.9% of the customers to remain feasible. Promoting higher levels of project feasibility required the introduction of incentives and/or subsidies.

6.1.5 Solar PV subsidy

Depending on the subsidy budget, various levels of PV uptake could be promoted in the different categories.

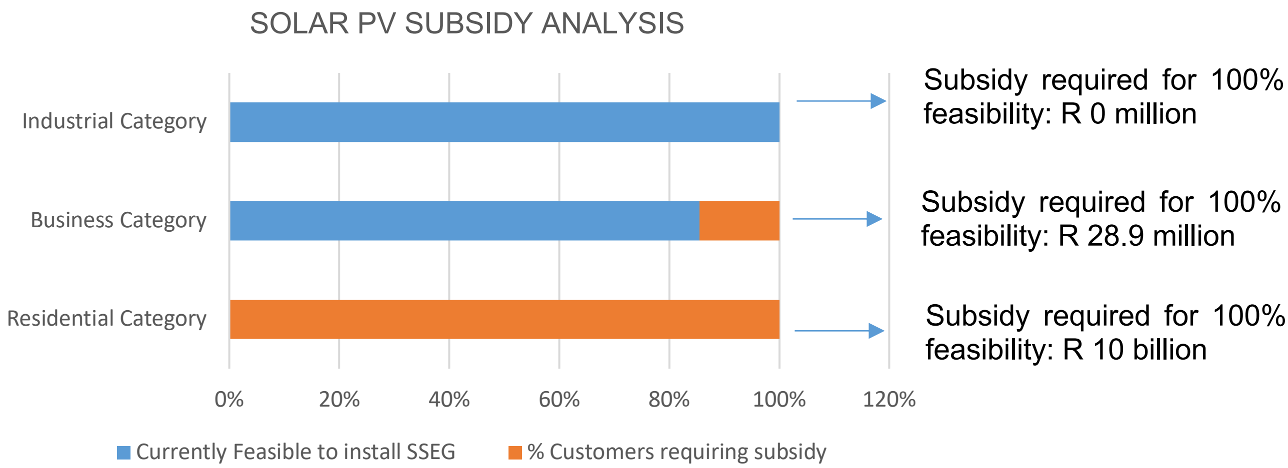


Figure 84 PV Subsidy analysis per category

The large subsidy requirement for the residential sector and to a lesser extent the business sector brings to reality, the need for PV projects to be supported. It clearly depicts that not all PV projects are feasible. However, with the mounting pressure to meet RE targets, there is a need to activate a suitable subsidy mechanism, not only for eThekwini Municipality but also for the country. While the national narrative is to promote RE, the reality as unpinned by the results of this study indicate that there is a cost involved in doing so. Other than the tax incentives, there are no other financial forms of support for the PV sector. The introduction of the buyback tariff by eThekwini municipality provides an enabling lever to promote PV projects.

6.1.6 Contribution to RE targets

The plausible amount of RE generation that PV could introduce was dependant on the number of feasible customers, which varied as input parameters varied. This was highlighted in the results of scenario one to six. The best case scenario without any RE tariffs (scenario five), indicated the generation of 1343 MW, which exceeded the 2030 target however deviates from the 2050 target by -43%. The best-case scenario with RE tariffs (scenario six), allows the municipality to gain 775 MW of RE if all feasible projects go ahead. This is 5% lower than the 2030 target and 67% lower than the 2050 target. The worst case, scenario four, had zero feasible customers for RE generation, hence deviating from the 2030 and 2050 target by -100%.

Should municipalities not react to the PV revolution, they would inadvertently be subsidising the PV sector by sacrificing the recovery of the grid and other related costs. Unfortunately, this would be at the detriment of non-PV customers, as the revenue loss would have to be recovered through a price increase, in the absence of subsidies.

6.2 EThekwini Municipality's view and way forward

EThekwini Municipality acknowledges the results of the study and supports the approach of balancing the need to attract RE against the need to promote municipal revenue sustainability. As a result, the recommended tariff structures as per this study have been approved for implementation in the 2021 financial year, subject to the approval of the NERSA. There is a sincere appreciation of the variability of the municipal revenue loss based on uptake rates and investment horizons based on customer preferences. As a result, it was recommended that the network charges be phased in and adjusted over a period; however, the buyback of energy be implemented at the full rate as of the 2021 financial year. This will allow the municipality an opportunity to gauge the sector appetite and willingness to pursue solar PV projects while introducing RE tariffs.

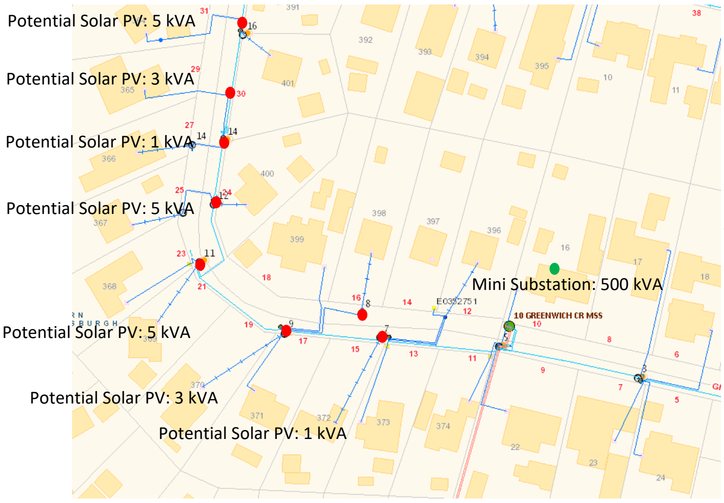
6.3 Future work

Calculating the economic value of PV projects and its associated revenue loss to the municipality is a difficult task that is reliant on several external variables. However, it has significant value to the municipality in terms of understanding the potential revenue losses that PV could initiate. It also has substantial value to policy and regulatory institutions as these results can be instrumental in paving the path for regulatory and policy development at a local and national level in South Africa.

The completion of this study and the relevant results, makes provision to trigger future studies that will enable the municipality to better prepare for the introduction of RE and associated storage options.

6.3.1 Network studies to evaluate technical impacts of PV integration to eThekwini Municipality

This study has evaluated the potential PV generation within eThekwini Municipality considering customer loading and the PV project meeting favourable investment criteria. This has resulted in the creation of a geospatial mapping arrangement, for plausible customer connected PV within eThekwini Municipality.



Knowing the location of potential RE generators will allow for the generators to be accurately superimposed onto the electricity connected network model.

This will allow detailed technical studies to be carried out to evaluate the readiness of the grid for RE generation at varying uptake rates.

It will also strategically inform future network planning decisions and upgrade plans.

Figure 85 PV Geospatial location of solar PV to allow for technical network studies

With a consolidated view of the location of potential generation sources and their optimised generation sizes, the municipality could carry out further studies to evaluate the technical impact of such generation on the municipal electricity network. The results of the technical study would inform future strategic planning, upgrading and pricing philosophies of the network.

6.3.2 Municipal RE tariff design considering PV and battery storage

Utilities in Australia are planning for the looming large-scale uptake of PV connected to battery storage and analysing how this uptake may be managed with alternative tariff structures [99]. Implementing a similar study for eThekwini Municipality would prove to be valuable, as battery storage in conjunction with PV will change the consumption profile as well as the export energy profile of the customer. The introduction of batteries, in conjunction with PV, will introduce a renewed form of financial losses to the municipality.

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