Unlocking the Rooftop PV Market in South Africa

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Executive Summary

The Centre of Renewable and Sustainable Energy Studies (CRSES) conducted this study, funded by The GreenCape Initiative, to identify opportunities and hurdles towards maximising the uptake of rooftop PV within mid-sized municipalities in the Western Cape. The Hessequa Municipality, specifically Riversdale, was selected as a case study.

Primary stakeholders and their motivations

The authors consider the primary stakeholders of this study to be the municipality itself and the owners of PV suitable roofs.

The primary goals and motivations for the municipality in relation to this study were identified as the following:

- Climate change mitigation
- Avoidance of “illegal” connections
- Protection of revenue from electricity sales
- Electricity supply quality and safety
- Avoiding increased administrative burden and costly changes to back-end financial management systems.
- Aligning towards a possible future with high uptake of rooftop PV, by gaining technical and human resources experience with regard to PV systems and related systems like metering.
- Restricting expansion of electricity peak allocation

The main motivation for potential owners of the rooftop PV systems is considered to be financial. Rooftop owners will consider investing in PV systems if they can expect market related returns on this investment.

The current rooftop PV environment in South Africa

A review was done in Chapter 3 of the current rooftop PV environment in South Africa, focusing on four areas:

1. national discussion, planning, policy, acts and regulation documents that are relevant to small-scale embedded generation such as PV,

2. standards and codes that provide the framework within which the rooftop PV industry can operate,
3. existing financial incentive schemes available to small-scale rooftop PV systems in South Africa, and
4. how Eskom and various municipalities currently deal with applications for grid-connection of PV systems.

The review highlights the following:

- rooftop PV is already aligned with and supported in principle throughout the South African government decision making process,
- the Municipal Finance Management Act (MFMA) is not a barrier to the uptake of rooftop PV in municipalities: for example, there is nothing in the MFMA that explicitly states that the municipality cannot buy electricity at a rate above that of Eskom (i.e. feed-in or net-metering tariff schemes). It is also well within the legality of the MFMA for municipalities to generate their own electricity.
- For small-scale embedded generators such as PV, South African standards are still being compiled. Relevant documents within the municipal context include the NRS097-2 series of specifications, and Eskom's proposed "Simplified utility connection criteria for LV connected generators" (Carter-Brown, 2012), which defines the maximum size PV installations that may connect to the distribution grid without requiring additional network studies.
- Current available financial incentives for small-scale renewables include Eskom's pilot small-scale renewable energy programme as part of the larger Standard Offer Programme, the IDC's Green Efficiency Programme, SARS's Accelarated Depreciation Programme, and various carbon mitigation and trading schemes.
- From a technical perspective, unregulated rooftop PV connection to the municipal grid presents no issues where the traditional mechanical disc-type electricity meter is installed at the customer's premise. Most electronic pre-paid meters are however by design unable to run backwards: when the energy flow through the meter reverses direction due to rooftop PV generation, most pre-paid meters will trip and will need to be reset by authorities. Other pre-paid meters will measure a positive energy flow even when the energy flow reverses direction. This effectively means that unregulated rooftop PV installations are not practical where existing prepaid meters are installed.
- Several large municipalities have procedures in place to facilitate connection of small-scale embedded generators to their networks, including the City of Cape Town, eThekwini, City of

Johannesburg, and Ekurhuleni. The requirements and tariffs offered vary widely among these municipalities.

Review of enabling mechanisms for PV

In Chapter 4, enabling mechanisms used internationally by governments to encourage uptake of PV and renewables in general is reviewed. Government can use two different kinds of market based instruments to support renewable energy: investment support and operating support. Examples of investment support are:

- Capital grants
- Capital rebates
- Tax exemptions or reductions on purchase of equipment

Examples of operating support schemes are:

- Feed-in Tariffs
- Green certificates
- Tender schemes
- Tax exemptions or reductions on production of electricity

The following points are highlighted in this review:

- Because investment support is typically not performance based, developers have less of an incentive to design efficient systems that perform over the long-term.
- Since operating support mechanisms are generally provided over a long time period, there is again the risk for the investor that the support will cease to exist before capital costs have been recovered.
- Internationally, investment support mechanisms are often used to supplement operating support mechanisms. Operating support schemes are considered to be far more significant and they account for the vast majority of RE developments world-wide.
- Even if the optimal incentive structure is chosen, other non-economic barriers have a major influence on policy success and failure. Such barriers include lack of long term policy and price certainty, administrative and regulatory barriers lack of clear standards and lengthy application processes.

Potential for rooftop PV in Riversdale

Chapter 5 set out to identify the rooftop PV potential for Riversdale (i.e. the maximum amount of rooftop PV that can practically be installed), using analytical tools to decrease the subjective nature of the resulting estimates. Geographic Information System (GIS) software was specifically used to estimate the potential size and spatial distribution of the installed systems.

Approximately 3638 municipal erven were identified within Riversdale. The unshaded roof space available for PV was calculated for these erven using Google Earth Pro, and a subset of erven were identified which was considered suitable for PV installation. Suitability criteria included the orientation of the roof and the minimum installable system size (larger than 1kWp), resulting in the distribution shown in the figure 1 below.

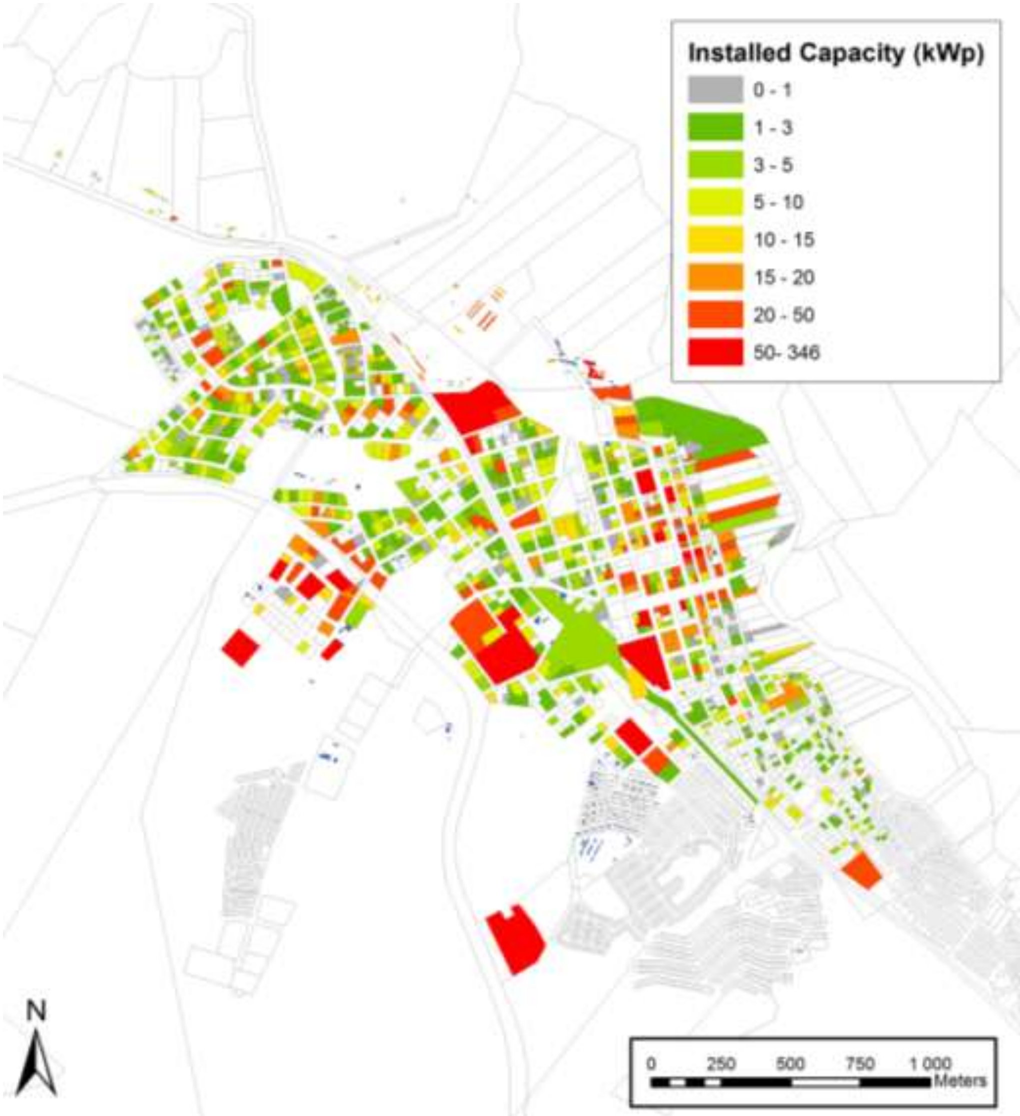

Figure 1: Installed capacity for rooftop PV per erven

Note that Eskom's draft "Simplified utility connection criteria for LV connected generators" would have lowered the actual maximum installed capacity for many of the erven shown below. These criteria could however not be applied to this distribution on an erven by erven basis, as the necessary distribution layout information for Riversdale was not available.

Based on the analysis described above, and assuming no other hindrance to PV installation, the total potential for rooftop PV in Riversdale is estimated at 9.85 MWp, with associated energy generation of 13.7 GWh per year.

It is informative to note that only 1.396MWp of rooftop PV will be allowed when Eskom's connection criteria is applied to Riversdale as a single 'consumer': the medium voltage feeder into Riversdale has a line peak capacity of 9.2 MVA, and the criteria state that embedded generation is limited to 15 % (1.396MW) of the peak demand of this MV feeder.

Financial context of Riversdale

For this study it was deemed crucial to understand the financial context of both Hessequa Municipality and Riversdale, specifically looking at electricity-related costs and income. Details of this context are provided in Chapter 6, but in summary:

- Few businesses means that 85% of the electricity income for Hessequa Municipality is collected from residential customers
- The budgeted income from the resale of electricity was R81 168 000 for Hessequa Municipality for 2011/2012. This makes up 30% of the total income for that year. The surplus budgeted for electricity for the same year was R18 350 000, which is 22% of the electricity revenue.
- If the income and expenses for 2011/2012 for electricity in Riversdale is however analysed, there was a slight deficit for the time. This deficit makes up less than 0.5% of the electricity revenue and could be considered negligible. Note that there are more businesses in Riversdale than the rest of Hessequa.

Financial viability of rooftop PV for the municipality

Rooftop PV impacts on municipal electricity sales revenues in the same way that solar water heating, more efficient appliances and other energy-use reducing strategies will, in the sense that it reduces the amount of kWhs that the municipality can sell. This impact on municipal revenue is an inevitable part of a societal move towards greater energy-efficiency.

The important difference with rooftop PV is however that the system can be sized to reduce the net energy consumption of a customer to zero, or allow the customer to become a net exporter of energy. In this situation the municipality will need to protect the financial viability of its electricity supply operations by ensuring the following:

- when rooftop PV reduces the energy consumed by the rooftop owner to net zero, the cost of providing a network connectivity service to the rooftop owner must still be recovered, and
- when rooftop PV is a net exporter, the municipality must pay the same or less for the exported energy than if the energy was bought from Eskom.

In the light of the above, the following was estimated (for details refer to section 7.1):

1. the cost of providing a network connectivity service to the rooftop owner (a rate of between R3.50 per day for indigent households and R94.50 per day for commercial customers are proposed)
2. the financial value that exported rooftop PV energy represents to the municipality, based on the charges it pays to Eskom (R0.47/kWh in 2011/12 along with a once off R0-720 per 1kWp installed as a measure of the additional capacity benefit to the municipality).

Financial viability of rooftop PV for the rooftop owner

The financial viability of rooftop PV without any financial incentives / enabling mechanisms is only borderline (comparable over 20 years to the returns that an investment in a money market account will bring). Note that smaller residential systems are more expensive to install, but still compare to cheaper large industrial systems in viability as the value of the energy generated is much higher in the residential context.

Financial incentives like Eskom's Standard Offer and SARS's accelerated depreciation moves the viability of rooftop PV for non-residential customers into the more profitable 10-20% IRR over 20 years band.

- Figure 2, however highlights the dilemma that faces the two primary stakeholders in the municipal rooftop PV market: the financial viability of the municipality and the rooftop owner does not overlap at any point on the surface of the graph.

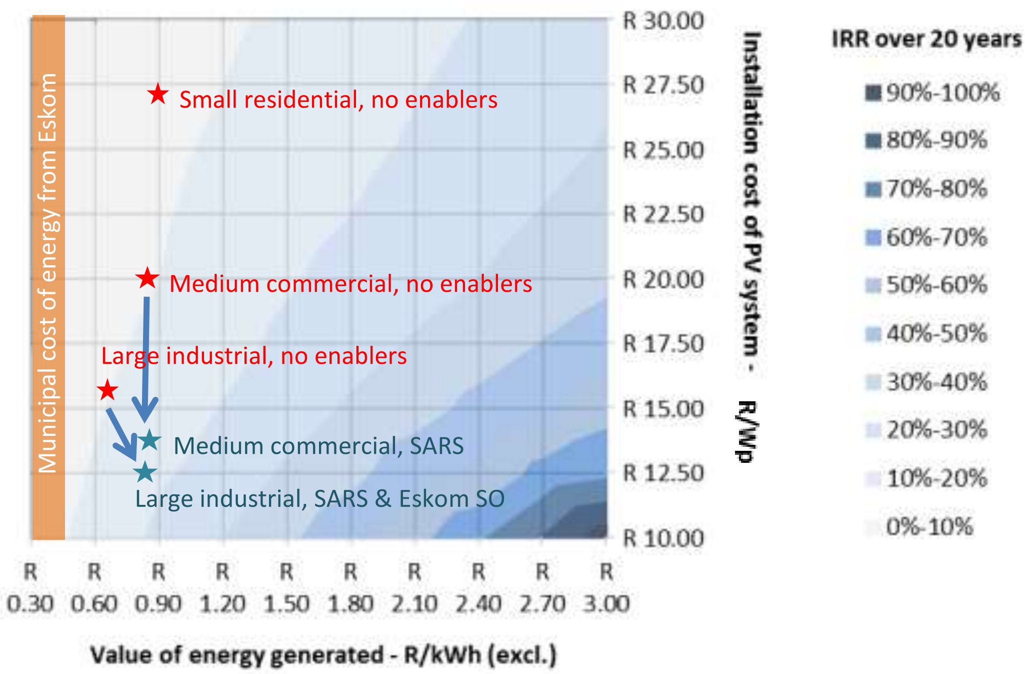

Figure 2: Rooftop owner versus municipal financial viability

The impact on the municipality of unregulated rooftop PV connection

Given the potential for rooftop PV in Riversdale, and the financial viability of rooftop PV to the rooftop owner, the question was asked: "what will the loss to municipal revenue due to unregulated installation of rooftop PV be?", i.e. the financial impact of a "business-as-usual" scenario where rooftop owners are installing PV without the municipality's knowledge / approval.

In such a "business-as-usual" scenario customers with existing prepaid meters was excluded, as these meters in their current state are not compatible with rooftop PV. This only left 274 eligible erven in Riversdale. To these the Eskom connection criteria was applied to limit the maximum installed capacity. To avoid a situation where the net monthly electricity consumption was negative (i.e. the municipality owing money to the customer, thereby flagging the customer as illegally connected), the system size per customer was further limited based on the expected monthly consumption.

Two scenarios were identified: a conservative uptake scenario where only 8 erven / 146kWp of rooftop PV were installed, and a generous scenario where 30 erven / 448kWp of PV was installed.

The conclusion of the analysis was that the impact of unregulated PV installations has a negligible negative impact on the Riversdale municipal revenue. Even in the generous scenario, the impact is less than 1% of electricity income.

Some further theoretical scenarios were develped with an absolute maximum penetration of rooftop PV installations (this is technically unlikely due to Eskoms simplified LV connection criteria, but was done as an experiment)

Even in this theoretical a 100% potential penetration scenario where all customers with prepaid meters were included and the electricity fed into the municipal grid is compensated at municipal tariffs (a net metering scenario), the net impact on electricity income as a percentage of the electricity income in a zero PV installation scenario is a mere 11%.

It is thus unlikely that even an aggressive scenario of rooftop PV installations in Riversdale will have a dramatic affect on municipal income in the short term.

Unlocking the potential for rooftop PV

In the context of the above, the following actions are proposed to unlock the potential for rooftop PV in small South African municipalities:

1. Finalise technical standards that inform rooftop PV.
2. The municipality provides an environment where legal connections are encouraged.
3. Additional incentives are made available that improves the financial viability of rooftop PV.
4. The municipality leads by example.

The municipality cannot greatly impact actions 1 and 3 above, but has several reasons to implement action points 2 and 4, providing an environment where legal connections are encouraged and leading by example, by installing PV systems themselves:

- By providing an environment where legal rooftop PV connections are encouraged, the municipality is aligning itself with national and provincial government policy and decisions.
- By providing an enabling environment the municipality builds competency and gains experience with regards to PV systems, and plays a leading and active rather than re-active role in future embedded generation developments. This also empowers the municipality to make a contribution to the national conversation on related topics.

In section 9.2.1 a “Bridging Scenario” is proposed, where the primary goal for the municipality is to create such an enabling environment for roof top PV systems with the existing moderate incentives. The goal of the municipality is to bridge the gap between the current unregulated situation and possible future national policy, by regulating and controlling moderate PV installations and removing as many non-economic barriers to PV system uptake as possible. As part of this scenario compulsory demand side management measures for rooftop PV owners are proposed to ensure that revenue loss of PV systems is offset to some extent.

This “Bridging Scenario” does not succeed, however, in offering strong financial motivations to both primary stakeholders that would actively stimulate the uptake of rooftop PV. Literature indicates that up to now it is typically national governments that provide the necessary funding to make PV financially viable. Such a national scheme, whether it is an expansion of existing schemes or a completely new incentive most probably falls outside the control of local authorities. It might, however be possible for local authorities to find external funding for rooftop PV from international funding agencies.

Table of Contents

List of Figures

List of Tables

Nomenclature

CRSES	Centre for Renewable and Sustainable Energy Studies
SWH	Solar Water Heating
PV	Photovoltaic
EG	Embedded Generation
RE	Renewable Energy
IDM	Integrated Demand Management
FIT	Feed in Tariff
IEP	Integrated Energy Plan
IRP	Integrated Resource Plan
IPP	Independent Power Producer
REIPPP	Renewable Energy Independent Power Producer Programme
EPC	Engineering, procurement and construction
SANS	South African National Standard
SABS	South African Bureau of Standards
DORA	Division of Revenue Act
PPP	Public Private Partnership
NERSA	National Energy Regulator of South Africa
RE	Renewable Energy
NRS	National Energy Regulator of South Africa

MFMA	Municipal Finance Management Act
EMM	Ekurhuleni Metropolitan Municipality
LV	Low Voltage
NMD	Notified Maximum Demand
CoCT	City of Cape Town
GIS	Geographic Information System
MD	Mechanical Disk

1. Introduction and objectives of study

The Centre of Renewable and Sustainable Energy Studies (CRSES) has been asked by GreenCape[1] to identify opportunities and hurdles towards maximising the uptake of rooftop PV within mid-sized municipalities in the Western Cape. The Hessequa Municipality, specifically Riversdale, was selected as a case study.

Hessequa Municipality was chosen for a variety of reasons, including that it represent a typical mid-sized South African municipality, has some experience in rooftop PV (a 33.12kWp system was installed in Riversdale in 2011), and was willing to share financial information with the researchers.

The study will focus only on the town of Riversdale within Hessequa Municipality, as the other areas that fall under the municipality are either rural, or coastal holiday towns like Stilbaai, that represents atypical annual electricity consumption patterns.

The study aims to provide accurate and objective information to stakeholders in the South African rooftop PV arena, to balance the numerous and often subjective articles in the media commenting on the subject. See for example Figure 1-1, where renewables are painted as an obvious choice for a small town municipality without providing crucial information about the context.

The study has four main goals:

1) Review current South African rooftop PV environment, focusing on the technical, regulatory and financial aspects, and explore the role that municipalities are playing.
2) Review different enabling mechanisms that have been implemented internationally to stimulate the rooftop PV market, and various aspects of policy implementation.
3) Gain an understanding of Riversdale's suitability for rooftop PV, the municipality's financial context and the current financial viability of PV from the perspectives of the municipality and the rooftop PV owner.
4) Provide recommendations on how to encourage uptake of rooftop PV in a typical South African midsize municipality like Riversdale.

[1] The GreenCape Initiative is a sector development agency set up by the Western Cape Government and the City of Cape Town to promote the green economy. See www.green-cape.co.za for more information.

It is important to note already at this stage that each municipality has unique constraints and that stakeholder motivations differ between different municipalities and rooftop owners. For this reason it is not a central objective of this study to provide a one-size fits all solution towards maximising rooftop PV, but rather to inform the various stakeholders and stimulate discussions on the topic.

Wildpoldsried produces 321% more energy than it needs

Wildpoldsried, a small village in Germany produces 321% more energy than it needs, and sells it for $5.7 million.

In the German state of Bavaria, in 1977 the village of Wildpoldsried (population 2,600) began a green initiative when the village council decided that it should build new industries, keep initiatives local, bring in new revenue, and create no debt. Over the past 14 years, the community has equipped nine new community buildings with solar panels, built four biogas digesters (with a fifth in construction now) and installed seven windmills with two more on the way. In the village itself, 190 private households have solar panels while the district also benefits from three small hydro power plants, ecological flood control, and a natural waste water system.

All of these green systems means Wildpoldsried produces 321 percent more energy than it needs – and it's generating $5.7 million in annual revenue by selling it back to the national grid. It is no surprise that small businesses have developed in the village specifically to provide services to the renewable energy installations.

Over the years the village's green goals have been so successful that they have even crafted a mission statement — WIR–2020, Wildpoldsried Innovativ Richtungsweisend (Wildpoldsried Innovative Leadership). The village council hopes that it will inspire citizens to do their part for the environment and create green jobs and businesses for the local area.

As a result of the village's success, Wildpoldsried has received numerous national and international awards for its conservation and renewable energy initiatives known as Klimaschutz (climate protection). The council even hosts tours for other village councils on how to start their own Klimaschutz program. The Mayor has even been doing global tours ever since the Fukushima disaster.

Wildpoldsried is a model for future developments around the world in communities where leaders and the people have the will.

From: http://madmikesamerica.com/2011/08/wildpoldsried-produces-321-more-energy-than-in-needs/

Figure 1-1: An article proclaiming the benefits of renewable energy for small municipalities, without providing sufficient information about the policy, tariff, socio-economic etc.. context to accurately inform the reader.

2. Identifying stakeholders and their motivations

In order to achieve the goals of the study most effectively, it is essential to determine and clearly identify the stakeholders. Further, as much as possible, the motivating factors of each stakeholder should be identified and stated.

Knowledge about the underlying motivation of stakeholders is essential to guide the design of future scenarios and incentive structures (Couture, Cory, Kreycik, & Williams, 2010). Where possible, incentive structures should amplify those effects of PV utilisation which are most desirable to stakeholders (possibly at the expense of less important positive effects) while mitigating effects that are perceived as negative or undesirable[2].

2.1.1 Possible effects of increased PV utilisation

Possible motivations which are cited in the literature for installing grid-connected renewable energy systems (Couture, et al., 2010; Goldemberg, 2004; IEA, 2008) are listed below. The list is by no means exhaustive.

- Climate change mitigation (and other environmental benefits)
- Job creation (and other socio-economic benefits)
- Security of electricity supply (through diversification and decentralisation)
- Potential for reduced electricity costs (short term and/or long term)
- Local ownership of generating capacity
- Peak load shaving
- Stimulating local economy
- Fostering technological innovation
- Mitigate electricity supply bottlenecks
- Favourable investment opportunity

[2] It is considered outside of the scope of this report to analyse whether rooftop PV is the most cost effective vehicle to achieve the desirable effects and outcomes. As stated earlier, the central objective of this report is to identify the opportunities and hurdles towards maximisinging uptake of rooftop PV within mid-sized municipalities.

Utilising more PV energy might also have unwanted negative side effects, especially if special care is not taken to avoid these. The following is a non-exhaustive list of possible negative effects:

- Reduced revenue from electricity sales for the municipality
- Potential safety hazards (fire and electric shock)
- Potential for increased electricity and infrastructure costs
- Potential for increased administrative burden
- Potential for rebound effect, where a reduction in the price of a commodity (electricity) leads to greater use of that commodity
- Potential for theft
- Opportunity costs

2.1.2 Primary Stakeholders

The authors consider the primary stakeholders of this study to be the municipality itself and the owners of PV suitable roofs.

2.1.2.1 Municipality

The primary goals and motivations for the municipality in relation to this study are the following:

- Climate change mitigation (refer to Figure 2-1)
- Avoidance of "illegal" connections
- Protection of revenue from electricity sales
- Electricity supply quality and safety
- Avoiding increased administrative burden and costly changes to back-end financial management systems.
- Aligning towards a possible future with high uptake of rooftop PV, by gaining technical and human resources experience with regard to PV systems and related systems like metering.
- Restricting expansion of electricity peak allocation

The vision for Hessequa Municipality as set out for 2012-2016 and beyond is:

A caring municipality where everyone reaps the fruit of cost effective and innovative service delivery, stimulated economic growth and sustainable use of natural resources

The Hessequa Council has set the following 8 Strategic Objectives ahead of themselves with specific impacts to be made:

- Empowerment of communities through effective communication and participation.
- Ensuring a sustainable future through effective conservation and restoration of natural resources, limiting the impact of our presence in the ecology and returning to a heritage of preservation.
- An innovative approach to maintenance of all services and assets, as we develop infrastructure that secures growth in a sustainable manner.
- Efficient and cost effective service delivery to all our residents, of the best quality.
- Development of socially and culturally prosperous and safe communities through strategic investment in integrated human settlement. ·A special focus on human development to enhance the social well being of our residents.
- Developmental interventions that would stimulate economic growth, to the benefit of all communities.
- A prepared local authority with a fit for purpose workforce, creating equal opportunities for all residents in a transparent, accountable and measurable manner.

http://www.hessequa.gov.za

Figure 2-1: the vision of the Hessequa Municipality, as described on their website.

2.1.2.2 Rooftop owner

The main motivation for potential owners of the rooftop PV systems is considered to be financial. Rooftop owners will consider investing in PV systems if they can expect market related returns on this investment[3].

Some other pertinent drivers influencing the investment decision in PV are;

- Requirement for environmentally sustainable energy
- In the case of business customers the marketing value of visible PV panels on the premises.
- Security of electricity supply / Loss of trust that Eskom / municipalities will be able to supply[4]

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[3] South Africa's SWH programme should act as a warning about the general applicability of this statement: high pressure SWHs with the rebate is obviously financially viable, yet the uptake among residential consumers is limited.

[4] This report focuses only on grid-tied PV systems, i.e. systems without batteries. Such systems do not improve security of supply, as they stop generating as soon as the grid falls away.

2.1.3 Secondary Stakeholders

This section lists some important secondary stakeholders which need to be considered in this study:

- Eskom
- NERSA
- Other electricity users in municipality
- Constituency
- Provincial Government
- National Government
- Installers
- PV industry
- Environmental Departments in Provincial and National Government
- Energy Departments in Provincial and National Government

Secondary stakeholders have a more passive role than the two primary stakeholders. They form part of an enabling environment or are impacted on by measures proposed in this study.

The assumed motivations for the secondary stakeholders are summarised below.

Secondary Stakeholder	Motivation
Eskom	- quality and safety of electricity supply - peak load shaving
NERSA	- quality and safety of electricity supply - avoiding increased costs due to PV - security of supply
Electricity users in municipality	- avoiding increased costs due to PV - quality and safety of electricity supply - security of supply
Constituency	- socio-economic impacts - safety - cost fairness
Installers and PV Industry	- increased PV utilisation
Environmental Departments in National and Provincial Government	- environmental impacts of electricity supply
Energy Departments in National and Provincial Government	- avoiding increased costs due to PV - quality and safety of electricity supply - administrative burden - gaining experience regarding implementation of PV systems - developing PV relevant human resources in South Africa

Table 2-1: Assumed motivations and goals of secondary stakeholders with regard to PV utilisation.

3. Review of current rooftop PV related environment in South Africa

This section outlines the existing regulatory and financial frameworks in place in South Africa that are applicable to small-scale embedded PV systems.

Section 3.1 provides examples of some relevant national discussion, planning, policy, acts and regulation documents that are relevant to small-scale embedded generation such as PV. This is done to show that rooftop PV is in theory supported at all levels of governmental processes.

Section 3.2 investigates to what extent these government processes have been implemented in Standards and Codes that provide the framework in which the electricity industry operates.

Section 3.3 outlines existing financial incentive schemes available to small-scale rooftop PV systems in South Africa.

Section 3.4 provides an overview of how Eskom and various municipalities currently deal with applications for grid-connection of PV systems.

3.1 National Discussion Documents, Policies, Acts and Regulations

This section outlines some fairly general white papers, plans and policies of national government that are relevant to roof top PV. The aim is to clearly show that rooftop PV is aligned with and supported in principle throughout the government decision making process. Lack of energy policy that supports renewable energy at all levels is identified as a factor that can be a significant barrier to investment by private finance practitioners (UNEP, 2012).

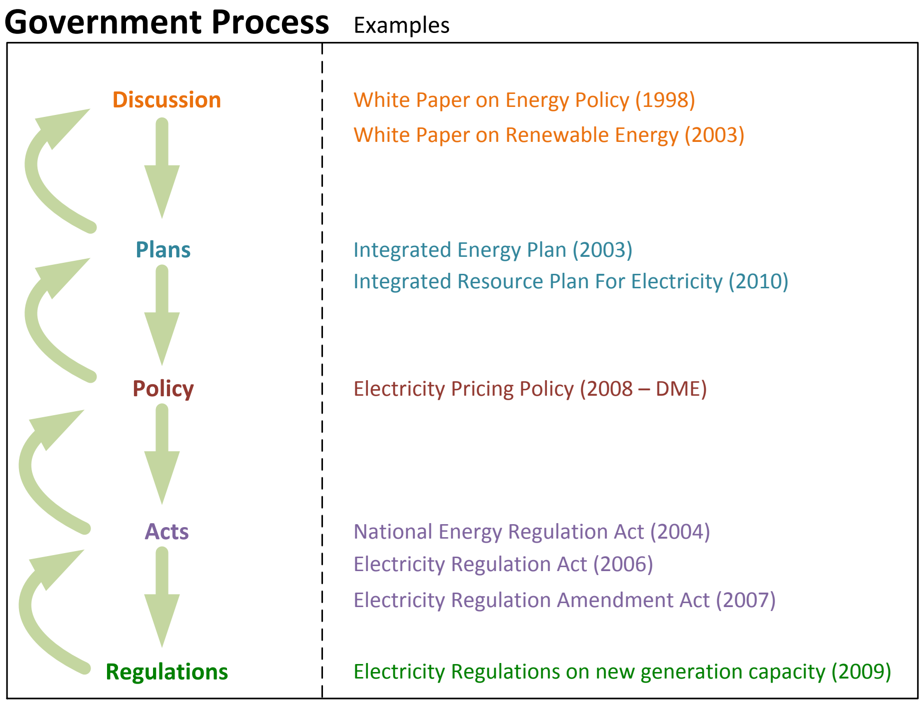

Figure 3-1: Diagrammatic representation of the government's process from Discussions to Regulations.

3.1.1 White Papers

3.1.1.1 White Paper on Energy Policy

The guiding documents for policies and legislation in South Africa are published in White Papers. In 1998 the "*White Paper on the Energy Policy of the Republic of South Africa"* was published. Amongst other things this White Paper calls for:

- environmentally sustainable short and long-term usage of our natural resources
- government to pursue energy security by encouraging diversity of both supply sources and primary energy carriers
- the right of choice of electricity supplier
- competition in especially the generation sector
- open non-discriminatory access to the transmission system; and
- private sector participation in the industry

3.1.1.2 White Paper on Renewable Energy

Five years later, the Department of Minerals and Energy published the *"White Paper on Renewable Energy"* to supplement the Energy Policy White Paper of 1998. This Paper sets out the vision, policy principles, strategic goals and objectives of the South African Government for promoting and implementing renewable energy in South Africa. Amongst other things it states that:

- the medium and long-term potential of renewable energy is significant
- it is the intention of the Government to make a contribution to the global effort to mitigate greenhouse gas emissions
- there is a need for Government to create an enabling environment through the introduction of fiscal and financial support mechanisms within an appropriate legal and regulatory framework to allow renewable energy technologies to compete with fossil-based technologies
- the local content of equipment needs to be maximised in order to minimise the costs associated with implementation and operation, as well as to promote employment opportunities
- an enabling legislative and regulatory framework to integrate Independent Power Producers (IPP's) into the existing electricity system needs to be developed
- development and implementation of appropriate standards and guidelines and codes of practice for the appropriate use of renewable energy technologies need to be promoted

3.1.2 Integrated Resource and Energy Plans

3.1.2.1 Integrated Energy Plan

The department of Minerals and Energy published the "*Integrated Energy Plan*" (IEP) in 2003. The purpose of the IEP is to balance energy demand with supply resources in concert with safety, health and environmental considerations. The IEP provides a framework within which specific energy development decisions can be made. Amongst many other things, the IEP clearly calls for the introduction of "policy, legislation and regulation" for the promotion of "renewable energy".

3.1.2.2 Integrated Resource Plan for Electricity

The Department of Minerals and Energy published the first version of its Integrated Resource Plan (IRP) in 2010. After additional consultation processes a revised version was published in 2011 (IRP2). In the IRP, an electricity vision for the 2010-2030 timeframe is developed that is consistent with the IEP. The revised IRP build plan calls for 300MW of additional PV capacity to be added every year from 2012 until 2024 with further 4500MW to be added in the years thereafter up to 2030 (total 8.4GW_{peak} additional installed capacity by 2030).

3.1.3 Electricity Pricing Policy

This document outlines several relevant policies which NERSA is tasked to implement (DME 2008). Some illustrative examples of policies are shown:

- Fair and non-discriminatory access to, and use of networks to all users of the relevant networks
- The full cost to operate the networks is reflected in the various connection and use of system charges and, therefore, no additional charges for wheeling of electricity will be levied unless the wheeling action introduces incremental costs
- Preferably, renewable generators will compete with non-renewables in terms of price taking into account all forms of support (for example grants, soft loads, CDM, feed-in tariffs, green tariffs, tax incentives)
- Alternatively, in the case where renewable support mechanisms are insufficient and state targets for renewables are thus not reached, renewables could be introduced at a price premium relative to non-renewables, subject to approval by NERSA

3.1.4 Acts and Regulations

This section lists South Africa legislation that is most relevant. The aim is to give the reader a feeling for existing legislation rather than an exhaustive overview.

- National Energy Regulation Act (2004)
- Electricity Regulation Act (2006)
- Electricity Regulation Amendment Act (2007)

The Electricity Regulation Act contains regulations on “New Generation Capacity” which were published in 2011. The New Generation Regulations establish rules and guidelines for the IPP Bid Programme currently under way (Renewable Energy Independent Power Producer Procurement Programme – REIPPP Programme). They facilitate the fair treatment and non-discrimination between IPPs and the buyer of the energy. A new bill is currently under discussions with various stakeholders which will make provision for an Independent Market and System Operator.

3.1.4.1 Municipal Finance Management Act

Another act relevant in the context of this study is the Municipal Finance Management Act No. 56 of 2003 (MFMA), which came in effect in July 2004 and is supported by the annual Division of Revenue Act (DORA). These pieces of legislation have been aligned with other local government legislation, such as the Structures Act, Systems Act, Property Rates Act and others, to form a coherent package. The MFMA aims to modernise budget, accounting and financial management practice by placing local government finances on a sustainable footing in order to maximise the capacity of municipalities to deliver services to communities. It also aims to put in place a sound financial governance framework by clarifying and separating the roles and responsibilities of the council, mayor and officials (National Treasury 2012)

There is a belief in some quarters that the MFMA makes it difficult for municipalities to procure electricity at a price premium above Eskom's electricity prices. This act may therefore act as a barrier for municipalities to implement feed-in or net-metering tariff schemes (Vermeulen, 2012). The MFMA aims to protect municipalities from taking unnecessary financial risks. However, it is the view of Susan Mosdell, property and environmental law adviser at City of Cape Town, that there is nothing in the MFMA which explicitly states that you cannot buy electricity at a rate above the Eskom rate (Mosdell, 2012). The avoidance of the loss of revenue due to long term trends such as the electricity price increase and adoption of new generation technologies, is not within in the scope of the MFMA.

There is also some scope in the MFMA to make an argument for the municipality to incur expenses to avoid illegal connections. It is well within the confines of the MFMA for a mayor to make a principle decision on an issue such as rooftop PV. It needs to be kept in mind that the MFMA aims to avoid wasteful and unlawful expenditure and not to contain a good idea. The MFMA should not be used as an excuse to not move forward.

Section 33 of the MFMA requires that there is a different process for projects with a longer lifespan than three years. This impacts many public private partnerships (PPPs) especially those in the sustainability field as these projects often have a longer lifespan and typically do not show a good return within three years. The MFMA does not exclude contracts of longer than three years, the process for these is merely different and not impossible.. It is specifically section 33 of the MFMA which sets out the different process for projects longer than three years. It is probable that this section was drafted without taking into account the nature of RE and EE projects, with the MFMA having been formulated in the early years of our new Constitutional era, prior to the current energy crisis. Accordingly, there could be good cause for municipalities to lobby government to exclude these projects from the ambit of the section. (Thomson Smeddle, 2012).

It is also well within the legality of the MFMA for municipalities to generate their own electricity.

One way to make sure that a project goes ahead within municipal structures is to include it in the municipal budget as a line item. This will add legitimacy due to the thorough review process of the budget.

The MFMA does not prohibit rooftop owners from selling electricity to tenants or neighbours at any price they wish (there are, however other regulations that makes this difficult, such as NERSA, generating licenses etc.)

In conclusion, it is important to understand that the purpose of the MFMA is to ensure sound financial management, not to prevent municipalities from embarking on work which they must do to fulfil their statutory responsibilities. These responsibilities have been outlined above. It is therefore important to interpret it in a purposive manner, i.e. in a manner which enables municipalities to accomplish the goals towards which they are obliged to work.

3.2 Standards and Codes

The previous section showed that there is political will, acceptance and encouragement for renewable energy technologies such as PV. However, for these technologies to be implemented safely, in a controlled manner and according to best practice, it is imperative for national codes and widely accepted national standards to be in place. Codes and Standards together provide a framework for the electricity industry to operate in.

The main concerns regarding embedded PV generation in the distribution system are related to power quality and safety issues. The following is a list of some concerns raised in the literature:

- Grounding issues (Kroposki 2010, Basso 2008)
- Grid stability (Kroposki 2010)
- Voltage regulation (Basso 2008, Eltawil and Zhao 2010, Braun et. al 2009, Kroposki 2010)
- Reactive power regulation (Basso 2008)
- Flicker (Basso, 2008, Braun et. al 2009, Kroposki 2010)
- DC injection (Basso 2008)
- Frequency fluctuations (Eltawil and Zhao 2010, Braun et. al 2009)
- Grid protection systems not designed for down-stream generation (Basso 2008, Kroposki 2010)
- Harmonics (Basso 2008, Eltawil and Zhao 2010, Braun et. al 2009)
- Unintentional Islanding (Kroposki 2010, Eltawil and Zhao 2010, Basso 2008)

This section will look at the standards and codes that are already in place, or are being put in place to govern the above power quality and safety issues.

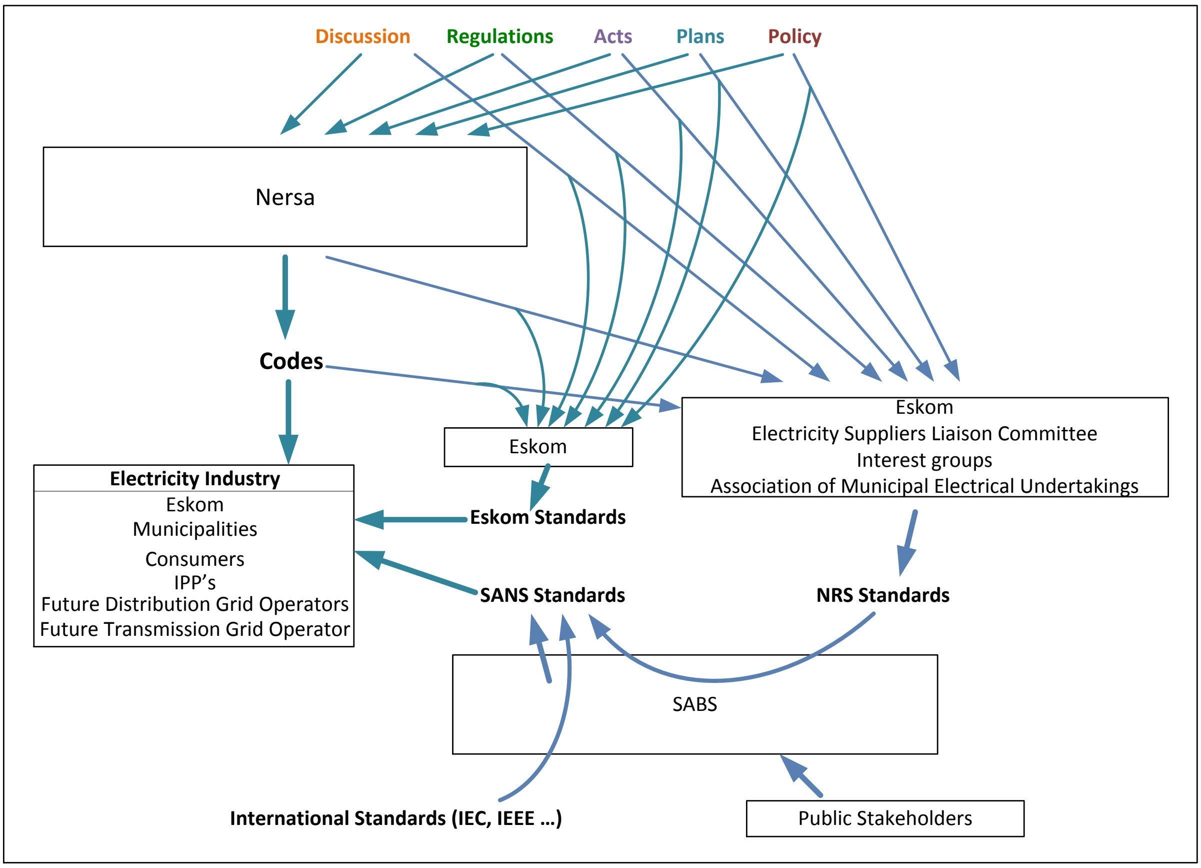

Figure 3-2: Diagrammatic representation of the interaction between different Standards and Codes bodies.

3.2.1 NERSA Codes

The National Energy Regulator of South Africa (NERSA) is tasked with implementing government energy policies, plans and acts. In particular, NERSA is responsible for implementing the unbundling and liberalisation of the electricity sector. Among other things, NERSA publishes Distribution Grid Codes which are enforceable by law. These codes generally make reference to SANS standards which then have to be complied with by law. The following is a list of some NERSA distribution codes which are applicable to small-scale PV systems:

- RSA Distribution Metering Code (2007)
- RSA Distribution Network Code (2007)
- RSA Distribution Information Exchange Code (2007)
- RSA Distribution System Operating Code (2007)
- RSA Distribution Tariff Code (2007)

Transmission Codes and a code for the connection of wind turbines are also available but these are of limited or no relevance to small-scale rooftop PV systems. A code dealing specifically with the connection of RE is under development. This code is likely to reference the NRS 097-2 standard (see section 3.2.3).

In September 2011, NERSA published "Standard Conditions for small-scale (<100kW) Embedded Generation within Municipal Boundaries". These conditions are currently guidelines only, but the intention is to include them in license conditions of the municipalities when they are reviewed. In this document, a net-metering approach is recommended although it is also required that meters must be able to measure flow of energy in both direction separately, be able to record energy flows at different times (time of use meters) and be able to record the peak demand during different periods.

"Scheduling and Dispatch Rules" falling under the South African Grid Code are also currently being drafted.

3.2.2 South African Bureau of Standards

For small-scale embedded generators such as PV, there is no complete set of standards in South Africa. These standards are to a large degree still being compiled.

The South African Bureau of Standards (SABS) is the national institution in South Africa tasked with the promotion and maintenance of standardisation by the Standards Act published in 2008. SABS publishes and maintains the South African National Standards (SANS) of which hundreds exist. Many of the SANS standards are highly relevant for PV installations. However, there is no single reference standard yet that covers all aspects of a PV installation (directly or by reference). SABS does not write all SANS standards. Often international standards are adopted and become SANS standards. In other cases NRS standards are adopted as SANS standards (e.g. SANS 959-2-2:2012 is NRS 052-2-2:2012 Photovoltaic systems for use in individual homes, schools and clinics: Test procedures for main components — Batteries).

3.2.3 National Rationalised Specifications

The National Rationalised Specifications (NRS) Project Management Agency which is closely affiliated with Eskom, produces NRS specifications for the Electricity Supply Industry in collaboration with the SABS on behalf of the Electricity Suppliers Liaison Committee (ESLC). NRS standard development is usually a fairly closed process and generally does not involve public participation. NRS standards can be specified by utilities or municipalities but cannot become part of legislation (in the form of grid codes) before they are endorsed by SABS which usually involves a lengthy public participation process (from three months up to years).

One NRS standard currently under development is the NRS 097 standard for grid interconnection of embedded generation. The NRS 097 standard aims to become the overarching standard to address issues of embedded generation. The first part NRS 097-1 covers embedded generation above 100kW connecting to the medium voltage or high voltage level and is therefore not relevant in the context of small-scale rooftop PV embedded generation. Small-scale rooftop PV systems are covered by the second part 097-2. As part of the revisions process of NRS097-2, it is being considered to move the threshold between NRS 097-1 and NRS097-2 up from 100kW to 1MW. Currently only the first of four planned sections of NRS 097-2 have been published. The first section is already under revision and has not been adopted as a SANS yet.

- Section 1: Utility interface (published but under revision)
- Section 2: Embedded generator requirements (in development)
- Section 3: Utility framework (to be developed in future)
- Section 4: Procedures for implementation and application (to be developed in future)

NRS 097-2-1 and NRS 097-2-2 are being written by a working group that contains experts, equipment manufacturers and other stakeholders. The NRS 097-2 standards to a large degree only make reference to other local and international standards rather than covering all aspects of small-scale embedded generation directly. Compliance with NRS 097-2 standard will therefore imply compliance with many other standards.

Currently under discussion, is to directly include the requirements set out in NRS 097-2-1 in the new NERSA code for renewable energy integration which is currently under development. This would make the requirements of NRS 097-2-1 legally binding but would avoid the lengthy public participation process required to adopt a NRS standard as a SANS standard and then referring to it in the codes. The NRS 097-2-2 requirements would however remain a NRS standard since it refers to specific type testing procedures and is too specific to be incorporated into a code which should be as general as possible and technology independent.

3.2.4 Eskom

Because of the historically vertically integrated structure of Eskom, it is involved at many stages of both development and implementation of standards and codes. This leads to a slightly unclear structure.

For example, Eskom has published a standard called the "Distribution Standard for the interconnection of embedded generation". This standard covers embedded generators >100kW connecting to the distribution system. It is not clear why this standard is not incorporated into the NRS 097 standard.

3.2.5 Eskom's simplified utility connection criteria for LV connected generators

In South Africa, the vast majority of power was traditionally centrally generated by large power stations, transported via the transmission and distribution system to the consumers. This is largely still the case today. The power flow is generally only in one direction, from the central power stations to the end-users. Distribution systems in existence today were designed with this one-way power flow in mind. It is therefore not obvious whether the current electric power systems can handle increased decentralised generation especially at the distribution level where small-scale PV systems are generally connected.

For bigger PV installations a case-by-case analysis by experts is typically required to ascertain the impact of the installation on the network. Conservative criteria fortunately exist that often alleviate the need for a case–by-case analysis. Within the South African context such simplified criteria has been proposed by Eskom: these criteria are relevant to this study and will be discussed in detail below, based on the draft documentation "Simplified utility connection criteria for LV connected generators" (Carter-Brown, 2012) currently still being considered for endorsement by the NRS097 standard.

In essence the criteria ascertain the maximum size PV installation that may connect to the distribution grid without requiring additional network studies.

The maximum sizes are defined within three main distribution network distinctions:

1) shared LV feeders (typical in normal residential areas),
2) dedicated LV feeders and
3) MV (medium voltage) feeder.

3.2.5.1 Shared LV feeder

Where the PV system is installed at a customer connected onto a shared LV feeder, the maximum EG per connection is defined in Table 3-1, so that the maximum generation be less than 25% of Notified Maximum Demand (NMD).

Type	Number of phases	Service circuit breaker size	NMD	Maximum individual generation limit
1	1	20A	4.6kVA	1.2kW
2	1	60A	13.8kVA	3.68kW
3	3	60A	41.4kVA	13.8kW (4.6kW per phase)

Table 3-1: Maximum individual generation limit in a shared LV (400/230V) feeder.

In addition the following criteria apply:

- Generation larger than 4.6 kW in multiphase requires to be balanced across all phases.
- Total shared EG on the feeder should be less than 25% of the transformer rating.
- Maximum allowed individual limit is 20 kW.

3.2.5.2 Dedicated LV feeder

A dedicated LV feeder is common in larger business and industrial areas, and with agricultural connections. Three main rules apply to dedicated LV feeders:

- Maximum generation to be less than 75% of the customer NMD
- Multi-phase supplies require that a generator greater than 4.6 kW must be balanced
- For single phase supplies the maximum generation size is 13.6 kW

3.2.5.3 MV feeder

For customers connected to MV feeders the maximum installation size should not exceed 75% of NMD, and should be less than 15% of the MV feeder peak load.

The criteria is summarised in Figure 3-3 below.

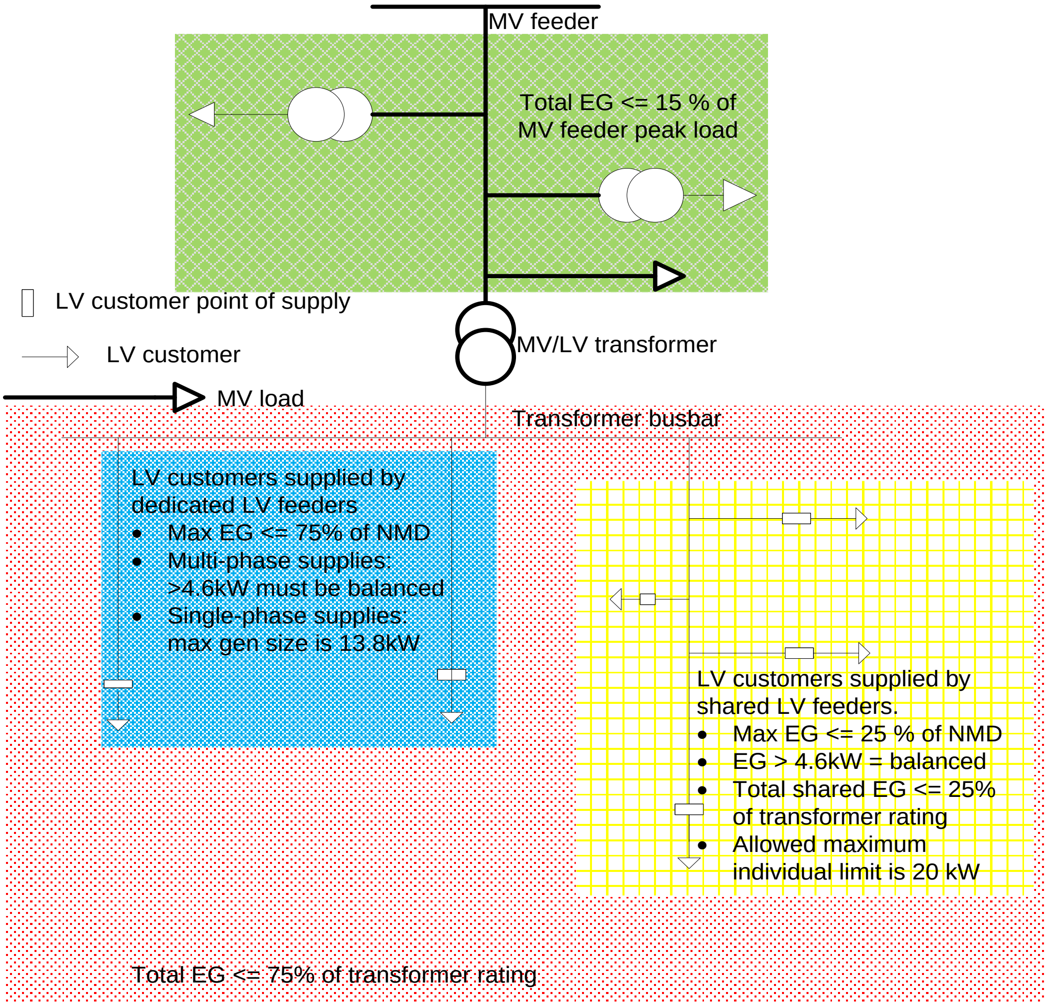

Figure 3-3: Summary of MV/LV connection criteria.[5]

3.3 Financial Incentive Structures for small-scale renewable energy

3.3.1 Eskom IDM Program

The Integrated Demand Management (IDM) business unit of Eskom has a few programmes to incentivise demand reduction on the national grid. The only one of these programmes that currently supports PV installations is the small-scale renewable energy programme. This programme is in pilot phase at present and forms part of the wider Standard Offer Programme for commercial, industrial and agricultural energy consumers. The first 10MW offer was launched in June 2012 and as there was good uptake, the offer has now been extended by another 10MW to 20MW.

[5] Reproduced from the draft "Simplified utility connection criteria for LV connected generators" (Carter-Brown, 2012)

Approved installations are paid for energy savings at a rate of R1.20 / kWh for three years. 70% of this is paid upfront and 10% per year thereafter for three years. Achieved savings have to be verified by an authorised, independent measurement and verification (M&V) organisation. Only the weekday savings obtained between 6am and 10pm will be paid for.

Installations are limited in size from around 15kWp (see section 3.4.2.1) to a maximum 1 MW installed peak capacity and may include a variety of renewable energy solutions.

Another Eskom incentive programme available for demand reduction is the Standard Product. This programme is designed to provide specific rebates for efficiency improvements derived from the implementation of specific approved technologies. Although it is theoretically possible that in time PV installations might be included as a Standard Product, it is unlikely due to the complexity of the modelling requirements.

3.3.2 IDC Green Efficiency Programme

The Industrial Development Corporation (IDC) administers the Green Efficiency Programme (GEEF). This programme is supported by the German Cooperation and Development Ministry.

Loans for renewable energy projects are available to approved lenders at an interest rate of prime less 2%. The loans have to be for an amount between one and five million Rand and needs to be paid back within 15 years or less, depending on the payback period of the investment (IDC 2012).

3.3.3 SARS Accelerated Depreciation Programme

It is normal tax practice for businesses to account for the consumption of fixed assets over time in a way that reflects their reducing value. The term given to this consumption is depreciation. The period over which to depreciate a fixed asset is known as the "useful economic life" of the asset and is different for different classes of assets. As an example, it is common practice to write off computer equipment over three years and motor vehicles over five years.

Depreciation on energy projects such as wind, solar and hydroelectric facilities are eligible for depreciation in this normal manner, however, an extra incentive is given in the depreciation of these structures. This is called accelerated depreciation and the assets are written off over three years on a 50:30:20 base for South African Income tax. This means that 50% of the cost can be written off as an expense in the first year, 30% in the second year and 20% in the third year. An extra 15% would have been able to be written off in the fourth year as an extra financial incentive, but this is not implemented as yet. The foundations and supporting structures associated with these systems have also recently been included as eligible for accelerated depreciation.

It needs to be noted that this accelerated depreciation is a deduction from taxable income and not a tax rebate. The actual financial benefit derived from this would depend on the taxable income and the tax rate charged. This rate is different for different entities. This accelerated depreciation is also only applicable to businesses whose income tax return is based on an income statement. Expenses can only be written off for tax purposes if they are incurred for the purposes of creating an income. Private individuals who earn a salary for instance, will not have taxable income from which to deduct this expense and will thus not be able to deduct this depreciation. This incentive is thus not really applicable to the residential segment.

If, however, a residential property is rented out for an income, it should be possible to deduct the accelerated depreciation from the rental income of the property and the owner will be able to use this tax incentive.

3.3.4 Carbon mitigation projects and carbon trading

Renewable energy projects have the potential to generate carbon credits which are capable of being traded in terms of the Clean Development Mechanism established under the Kyoto Protocol to the United Nations Convention on Climate Change, or in terms of a voluntary carbon standard established under a voluntary carbon registry. They may be sold once earned, or they may be sold at project inception phase or traded for investment into project costs. In the latter instance, they commonly realise lesser prices due to the risk taken by the purchaser/investor.

Carbon credits under the CDM are known as certified emission reductions (CER's) and those issued by a voluntary carbon registry are known as verified emission reductions (VER's). Purchasers of carbon credits are commonly industries or entities from other countries that are obliged by their law to, or wish to, offset their carbon emissions. South African purchasers of carbon credits buy these credits on a voluntary basis, since we do not have an obligatory offset mechanism.

With small-scale renewable energy projects, it may be necessary to bundle them or to incorporate them into programmes of activities, in order to limit the registration and administration costs associated with establishing such projects and obtaining certification or verification. This is possible under the CDM and with voluntary registries.

There may be greater potential for municipalities and rooftop PV owners in the voluntary carbon markets going forward, rather than in the CDM, as the future status of the Kyoto protocol is uncertain. In addition the voluntary markets are able to administer projects at a much more localised level, with costs in the same currency as the project budget. The price of the VER's has also proven to be much more stable and is set at a much higher level at present. VER's are sold in South Africa at about 10 Euro per tonne. The price of CER's have steadily dropped over the last year and market analysts have predicted that CER prices will average €1.60 from now until 2020 (The Trend is Blue, 2012).

There is no minimum project size for VER's, but due to the distributed nature of rooftop PV, the minimum project size for which it would be worth going to the trouble might depend on the amount of installations in a geographical area.

It must be stressed that it is inadvisable to plan projects on the basis that carbon revenue is relied upon for their financial feasibility, due to the uncertainties pertaining to the future of the carbon markets. Carbon revenue should be seen as an add-on which can be utilised for contingent purposes such as expanding or replicating projects, once earned (Thomson-Smeddle, 2012).

There is no provision in the MFMA for trading in the carbon markets, as the promulgation of the Act pre-dates the coming into being of these markets. CER's and VER's do not fall within the ambit of assets as defined in the Act and the Municipal Asset Transfer Regulations, accordingly they would not be bound by the specific processes of the Act relating to disposal of assets. The general principles of sound financial governance which underpin the MFMA would nevertheless have to be followed. A municipality wishing to sell its carbon credits would generally have to engage the services of an external broker, and care would have to be taken to ensure that the remuneration paid for such services, which would normally be a commission, represents good value received.

There is an urgent need for government to exempt carbon market transactions from the ambit of the provision in Section 164 of the MFMA, which prohibits commercial activities by municipalities outside of South Africa, since by its very nature trade in carbon credits is a global activity.

The amount of carbon emitted by Eskom to produce electricity is 99kg / kWh (Eskom 2012). At an exchange rate of R11.29 for a Euro (Standard Bank 2013), this works out to 11c per kWh.

As the municipality will most probably outsource the administration of the VER's and due to the dispersed nature of rooftop PV, as an estimate the income from VER's to the municipality will be taken as 5c per kWh for the purposes of this report.

3.3.5 Carbon Tax

A carbon tax will be phased in from January 1, 2015 as part of South Africa's efforts to mitigate the effects of climate change and encourage energy efficiency measures.

The plan is to initiate the first carbon-tax phase between 2015 and 2020, starting with a tax at a rate of R120/t of carbon dioxide (CO_2) equivalent, increasing by 10% a year during the first implementation period.

A basic tax-free threshold of 60% is proposed, as well as offset percentages of 5% to 10% to allow "emission-intensive and trade-exposed industries to invest in projects outside their normal operations to help reduce their carbon tax liabilities" (Creamer 2013).

As there is no carbon tax on electricity use in South Africa at present and seeing as the proposed tax has only been announced and not yet promulgated, this is not taken into account for the purposes of this report. Should such a tax become reality in the future, it might be more cost effective to install rooftop PV than pay this tax. The demand for CER's and VER's might also increase with a carbon tax depending on the tax rate and the cost of the certificates.

3.3.6 Incentive Structures for large scale RE

For the sake of completeness, the incentive structures available for large renewable energy projects in South Africa are mentioned here. No detailed information on the programmes is provided since this is not applicable to the small-scale rooftop PV systems:

- Development Bank of Southern Africa's Renewable Market Transformation Project (http://www.remtproject.org/) which is only available for PV systems bigger than 1MW.
- Renewable Energy Independent Power Producer Procurement Programme (REIPPP Programme): a total of 3725MW will ultimately be allocated under this program, which follows a tender-based process.

3.4 Review of current application processes for EG connections

As shown earlier, a complete set of standards does not exist yet for grid connected small-scale rooftop PV systems. Furthermore, there are fairly limited financial incentives in place in South Africa to encourage PV systems. The existing environment is therefore not conducive to mass uptake of small-scale PV. However, some private individuals, organisations and companies have nevertheless been pushing authorities for grid connection of their rooftop PV systems. Others have been connecting "illegally" without the knowledge of authorities.

This section outlines the technical issues related to existing grid connections, and looks at how municipalities are currently dealing with the increasing number of requests for grid connections.

3.4.1 Technical Situation

From a technical perspective, there is often little stopping people from connecting PV systems to the grid without authorities even knowing about such a connection. This section explores the technical situations in which such connections are possible. This is to a large extent related to the type of metering in place[6]. Furthermore, the issues are dependent on the ratio and temporal relationship of energy generation and consumption on site. There are many other technical issues associated with EG with respect to e.g. safety and quality of supply. However, it is assumed here that connections to the grid will utilise professional equipment that takes care of these types of issues.

3.4.1.1 Gross consumer of electricity

In situations where energy consumption is greater than embedded generation at all times, no issues related to metering are experienced. Energy flow remains from the grid to the user at all times and the EG only has the effect of reducing the energy flow rate and it thereby reduces the electricity bill of the user with EG. Many such connections already exist in South Africa.

3.4.1.2 Net consumer of electricity with Mechanical Meter

In many cases, PV generation will exceed local consumptions during certain parts of the day. This results in a temporary energy flow from the user to the grid. If a traditional mechanical disc type meter is installed, the meter will start turning backwards when energy flow changes direction. This effectively means the user is accumulating credits or banking his generation surplus in the grid for later retrieval. Such a situation is referred to as net-metering and there is effectively perfect price symmetry between the price paid for electricity consumed and credits given for excess generation. As long as the user remains a net-consumer of electricity over every complete billing cycle, the authorities are unlikely to detect such an unauthorised connection.

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[6] It is assumed that the user connects the EG on the custumer side of the meter since there is no benefit to the user otherwise.

3.4.1.3 Net consumer of electricity with electronic pre-paid meters

Unlike the traditional mechanical disc-type meter, most electronic pre-paid meters are by design unable to run backwards. When the energy flow reverses direction, most pre-paid meters trip completely and need to be reset by authorities. Other pre-paid meters will measure a positive energy flow even when the energy flow becomes negative (i.e. changes direction). This effectively means that the user is paying for electricity being exported at the same rate that the user is paying for electricity being consumed. In such cases, the user has to take technical measures to avoid reversal of energy flow or must be willing to pay for exported electricity[7].

3.4.1.4 Net producer of electricity

If more electricity is produced than consumed by a user over an entire billing period, authorities will most probably become aware of the embedded generation even when a mechanical disk-type meter is in place. This means that an illegal connection of this type is not possible unless the utility is negligent.

As an example, a customer in the City of Cape Town was told to disconnect his system from the grid after officials noticed a negative consumption (Van Der Riet 2012). The user was however given the opportunity to join the City of Cape Town pilot project.

3.4.2 Non-technical Situation

It is in the interest of utilities and municipalities to avoid illegal connections of EG as much as possible. For planning, monitoring and proper operation of distribution systems, it is important for utilities to know about all EG in their systems. Since it is in many cases difficult to avoid illegal connections (see previous section), it is in the interest of utilities to encourage legal connections by having simple and efficient structures in place for people to register their grid-connected PV systems. As long as PV uptake remains low due to relatively high costs and lack of financial incentives, PV systems will cause negligible technical problems for the distribution systems and will have limited impact on utility revenue streams. However, there is reluctance to officially allow grid connections due to lack of knowledge and unclear legal and safety implications largely caused by the lack of standards. Furthermore, there is the theoretical possibility of enabling an explosion of installations of PV systems once they are legally possible, which will have significant technical and

[7] Some inverters in use in South Africa will automatically throttle PV production to avoid export of energy.

financial implications for the utilities. It is therefore perceived by some to be easier to ban grid-connections altogether which in turn encourages illegal connections. This section presents some case studies on how the municipalities and Eskom are currently dealing with grid connection requests.

3.4.2.1 Eskom

Eskom is a key stakeholder in the Renewable Energy Independent Power Producer Procurement Programme (REIPPP), which deals with large RE plants. For this a dedicated Grid Access Unit has been established to provide EPC companies a single point of contact.

Eskom also has recently (June 2012) launched its small-scale renewable energy pilot programme discussed earlier.

The participating installations in this programme have to meet the following qualification requirements:

- Only equipment installed on the host customer's side of the meter will be eligible.
- Systems must be new and in compliance with all applicable performance and safety standards (applicable to all components of the installation).
- Stand-alone systems (i.e. applications that are not grid tied) must replace an existing connection/supply therefore substituting energy that would have been drawn from the grid.
- Grid-tied systems must comply with all regulatory and embedded generation interconnection requirements. Where relevant a letter from the relevant local authority / electricity utility will be required as part of the application to confirm their knowledge and acceptance of the (proposed/designed) connection onto the network.
- In addition when considering the offer for PV generated energy, there is an additional requirement that averaged over a year period, the two highest consecutive energy production hours per day for the PV system should be able to lower the demand by 10kW. For the Riversdale context (due to solar irradiance) this means installing a PV system size of at least 16.2 -19.8kWp to lower the demand on average by 10kW in the sunniest two hours of a day.
- The incentive will initially only be available for systems that do not feed any electricity onto the grid. This may include isolated systems with no electricity supply from the grid or configurations where the grid is used to supplement the electricity requirements.

- An electrical design certified by a qualified engineer will be required as part of the application.
- A structural design certified by a qualified engineer will be required as part of the application.
- A letter from the electricity supplier (Municipality or Eskom as relevant) confirming knowledge and acceptance of the proposed/designed network connection and registration of the project as per NERSA requirements.
- Close out and the first incentive payment will be subject to an as built confirmation and an audit of the above.
- For a PV system without storage (e.g. no batteries) over 40 standards are listed that system components need to comply with. If standards compliance is enforced strictly (i.e. without the use of common sense), this is likely to cause significant barrier to uptake. For example, both IEEE 1547 and NRS 097-2-1 are required even though these place in some cases different requirements on the inverters.
- Eskom will not pay for any measurement and verification equipment (meters etc.) and these costs will need to be carried by the user. Since this pilot project was only recently launched, no information on its uptake and success is currently available.
- Individual households will be excluded from this program (Workshop Notes July 2012).

3.4.2.2 City of Cape Town Municipality

Currently the City of Cape Town (CoCT) will allow larger installations but no feeding of electricity into the grid is allowed. Smaller systems might be considered in future. The CoCT has a standard application form and guidelines. Systems smaller than 100kW will only be considered once national standards are in place, once a small-scale embedded generator prepayment meter is commercially available and once CoCT policies regarding small-scale embedded generation have been finalised. In the meantime a pilot project for small-scale rooftop PV is in operation which operates according to a net metering tariff (R9.93 per day and R0.9169 per kWh), does not allow net export and in which three projects have enrolled. The following is a list of the documentation required for the three pilot sites:

- Site layout
- Declaration of SSEG installation compliance to the UK's G83/1-1 & NRS 097-2-1 by Professional Engineer
- City of Cape Town Form: GEN/EMB - Application for the connection of embedded generation

- SSEG ENA G83/1-1 Appendices 2 and 3 (excluding declaration)
- CoC for SANS 1042-1 from electrician
- Witnessed inverter type testing declaration of compliance to G83 App 4 tests and NRS097-2-1 in the format of G83: app 4

3.4.2.3 eThekwini Municipality

In August 2011, the executive Council of the eThekwini Municipality gave the Electrical Department go ahead to enter into power purchasing agreements with embedded generators if there are no additional costs to council and electricity is considered "cleaner" than electricity supplied by Eskom. Feeding of electricity into the grid is allowed and a dedicated application form is available. Remuneration is according to Eskom's Megaflex tariff at which the municipality also buys electricity from Eskom. This avoids additional costs to the municipality. This also means that time of use (TOU) metering must be in place since the Megaflex tariff is a TOU tariff. Generators are responsible for all costs of work and equipment required for connection to the municipal network. Due to the high connection rates under the Megaflex tariff (R2046 per month) it is unlikely that a financial incentive will result for small systems. By March 2013 there were approximately ten projects under this program.

The eThekwini Municipality also has its own 200kW PV system. Further 400kW of municipal owned generating capacity will be installed in the near future. They have also set out a tender for a Green Power Tariff feasibility study in eThekwini which will be awarded soon (Morgan, 2013).

3.4.2.4 City of Johannesburg

It is the opinion of the City of Johannesburg that due to Eskom's small-scale renewable energy programme, they cannot disallow requests from customers to connect to the grid. However, customers are required to complete and hand in the following documentation to the municipality:

- An application form (based on the eThekwini form)
- A detailed Single Line Diagram
- A site plan of their proposed installation

These applications will go through a thorough review process to ensure that there are no technical constraints. After this review process the municipality will award a consent letter which allows customers to connect to the grid. No feed in of electricity back into the grid will be allowed at present.

The City of Johannesburg is also already investigating a tariff model with different tariff structures to determine which will incentivise the municipality as well as the consumer when net-metering is applied, this will also include an appropriate service charge to ensure the basic revenue required to cover the network maintenance. Another initiative in City of Johannesburg's pipeline is to make it a pre-requisite for residential applicants to have a solar water heater (or heat pump) installed, as well as to convert to cooking with gas before they can be considered for grid-tie and feed back into the grid. This is to reduce the demand on the grid in peak time (Vermeulen, 2013).

3.4.2.5 Ekurhuleni

Currently Ekurhuleni Metropolitan Municipality (EMM) has a 200kW system which is owned by the municipality itself. The EMM has 6 systems which they have approved for consideration on the Eskom SO program. EMM is not procuring the power but the plants are within EMM jurisdiction. They are also in the process of investigating smart metering options for the municipality (Thenga, 2013).

4. Review of Enabling Mechanisms for PV

This section examines what options and variations there are in designing financial incentives for renewable energy and what other factors influence policy success. The section is based on considerable existing literature on the topic most notably IEA, 2008, Couture et. al 2010 and UNEP 2012b which provide good overviews. Careful policy design is imperative for the overall success of incentive schemes.

4.1 Overview of incentive schemes

This section gives an overview of instruments available to governments to incentivise PV. Since these tools are technology independent, they can be applied to all renewable energy technologies and this section will therefore often refer to renewable energy in general.

Broadly speaking, government can use two different kinds of market based instruments to support renewable energy: investment support and operating support (IEA 2008). These instruments can be used independently or together. Examples of investment support are (IEA 2008):

- Capital grants
- Capital rebates
- Tax exemptions or reductions on purchase of equipment

Because investment support is typically not performance based, developers have less of an incentive to design efficient systems that perform over the long-term (UNEP 2012b). Since operating support mechanisms are generally provided over a long time period, there is always the risk for the investor that the support will cease to exist before capital costs have been recovered. In the South African context this is risk is likely to be perceived as particularly high given the temperamental nature of energy policy especially with regards to renewable energy in South Africa. This suggests that it might be worthwhile to place greater emphasis on investment support schemes as there are no long-term risks associated with investment support schemes. Internationally, investment support mechanisms are often used to supplement operating support mechanisms. Operating support schemes are considered to be far more significant and they account for the vast majority of RE developments world-wide (REN21 2009). Examples of operating support schemes are (IEA 2008):

- Feed-in Tariffs
- Green certificates
- Tender schemes
- Tax exemptions or reductions on production of electricity

Operating support schemes have the significant advantage over investment support schemes in that they incentivise the desired outcome, generation of RE electricity, more directly (IEA 2008).

4.2 Operating Support Mechanisms

There are three broad categories of operating support financial incentive schemes available to policy makers.

4.2.1 Feed-in Tariffs

The first and most widely used scheme is a so called Feed-in Tariff (FIT) (or price based incentive). FIT works by having a, usually long term, power purchasing agreement (PPA) between a producer of renewable energy and the utility or a third party. Often these PPA will pay a premium for the RE above market price in order to incentivise RE and make it cost competitive. By 2008 FIT's accounted for roughly 75% of all PV developments worldwide (Deutsche Bank 2010) and FIT's are also the most widely used policy mechanism to procure other RE generation technologies globally (REN21 2009). As of early 2011, roughly 50 countries have implemented FiT's for RE in some form or another with half of these being in developing countries (UNEP 2012b). The pricing and the legal, technical and administrative framework result in a certain uptake of PV technologies. Incentives can be made more attractive if uptake is insufficient or be reduced if less uptake is desired. The policy maker sets the price structure and thereby only indirectly determines the amount of additional RE generation capacity. FIT's are considered to be less bureaucratic than other alternatives and provide more flexibility for small producers. Further, they are favoured by industry (Winkler, 2005). Setting the price for a FIT correctly is a big challenge especially in the South African context where there is potential uncertainty regarding marginal costs of systems (Winkler, 2005) although regular reviewing of the FIT could alleviate this potential problem. Another potential problem associated with FIT in the South African context are the potentially high costs (Winkler, 2005).

4.2.2 Quantity based schemes

The second available operating support tool for policy makers are so called quantity based schemes (also referred to as quota schemes, tradable green certificates, renewable portfolio standards or quota-obligation systems). Here the policy maker sets the desired percentage of RE generation capacity relative to total capacity. Producers or consumers are legally obliged to comply with this requirement or face penalties. This creates a demand for RE. Producers of RE are issues with green certificates for their generated renewable electricity and these certificates can be sold on a market and will be bought be entities trying to avoid penalties. The revenue for RE producers therefore consists of revenue from normal electricity sales at normal market prices and additionally, revenue from sales of green certificates (Nielsena et. At. 2003). The policy maker therefore sets the desired amount of RE generation capacity directly and the market determines the "correct" price to achieve this target. This means that policy makers might not have accurate upfront knowledge of the costs of the policy and targets (Winkler 2005). Generally speaking, quota obligations are more technology neutral than FIT's although they can also be made technology specific. Quantity based schemes have the advantage that they have no direct upfront costs for government to implement. Eventually, the costs of the policy are likely to be passed on to the consumer (Winkler, 2005). Further there might be issues around enforcing compliance and there is no incentive to do more than the bare minimum (Winkler, 2005).

Economic theory suggests that under ideal conditions, quantity based schemes and FIT's are equivalent.

4.2.3 Tendering Schemes

The third category of operating support mechanisms is tendering schemes. A tender is announced for a certain amount of generating capacity and the best bidder is selected. The goal is to ensure that the cheapest (or otherwise most effective) supplier can be chosen. Tendering schemes are generally not used for small-scale generation since this would generate an excessive administrative burden on the regulating authority. Even for bigger systems, the institutional capacity required for this policy option can be a constraining factor (Winkler, 2005). A further challenge of tendering mechanisms are sometimes very high contract failure rates (67%-78%) caused by unrealistic speculative low bidding (UNEP 2012b, Wieser et Al., 2006).

4.2.4 Historic International Policies

During the late 90s, experience was gained in Europe with some countries adopting FIT's (e.g. Germany and Denmark) and others competitive tenders (e.g. UK and France). Countries with FIT's had considerably more success with rapid additions of wind capacity while countries with tendering schemes had only limited success in installing new capacity. As a result, both France and Ireland switched to FIT's, while the UK switched to tradable credits under its Renewables Obligation (UNEP 2012b). In the 2000's there was a drive to harmonize renewable energy policy within the EU which led to considerable debate regarding the pros and cons of different policies. Harmonisation has not been achieved yet but the majority of countries in the EU now prefer FIT's (UNEP 2012b). Nevertheless, even within countries, different policies are applied. Differentiation is made according to system size (e.g. smaller size systems in UK use FIT scheme) and technologies (e.g. in Italy FIT apply for PV but tradable certificates are used for other technologies) (UNEP 2012b).

In developing countries, FIT's are also more popular (REN21 2011) but countries are still constantly changing the policies and no "better" policy has clearly emerged yet. For example, Brazil has recently moved from a FIT to an auctioning scheme. A similar development has occurred in South Africa. Argentina, Mexico, Peru, Honduras, China, Morocco, Egypt and Uruguay are examples of developing countries introducing tendering schemes. China is an example of a country moving from a tendering scheme to a FIT scheme for wind (UNEP 2012b). In any case, most countries are combining different policy options to best tailor their needs and goals. Only Algeria, Serbia and Sri Lanka use FITs alone (REN21, 2011, UNEP 2012b). Most other countries utilise FITs combined with a mix of other policy instruments and aspects including quotas, investment support mechanisms, net metering, and/or competitive tenders (REN21, 2011, UNEP 2012b).

4.2.5 Comparison

FIT's are generally considered to be simple and easy to administer (Haselip, 2011). Quantity based schemes generally require a market for green certificates which is likely to be costly and inefficient from an administrative point of view in a municipal setting. Further, some studies suggest that in the European context tradable certificates have higher costs than FIT due to less certainty regarding revenue streams which means investors require higher returns to offset the higher perceived risk (de Jager and Rathmann 2008, Ragwitz et al. 2007, Klein et al. 2008, Fouquet and Johansson 2008, Guillet and Midden 2009, Chadbourne and Parke 2009). Lastly, the authors consider tendering schemes to be administratively too intensive to be effective for small-scale embedded generation in a municipal setting. Further, FIT are identified as the best tool if the policy goal is to "promote renewable electricity, but budget constraints are prioritised" which fits the context of this study well (Winkler, 2005). The above policy options are not exclusive and can be combined with each other to best meet the local context. For example, in the context of developing countries, Feed-in tariffs in combination with clear national targets, which are a prerequisite for quantity based schemes, were identified by private finance practitioners as "most powerful" in unlocking private investment (UNEP 2012).

In the South African context, budget and institutional constraints are likely to be of particular concern and keeping electricity affordable is an integral part of government policy (1998 White Paper).

4.3 Enabling environment for effective incentive schemes

In the previous section, different policy options for incentivising PV or renewable energy in general were introduced. Even if the optimal incentive structure is chosen, other non-economic barriers have a major influence on policy success and failure (IEA 2008, Couture et. al 2010, Winkler 2005). Some suggestions of how to mitigate against non-economic barriers are:

- Long term policy and price certainty (Couture et. al 2010, UNEP 2012))
- Power purchase obligation for RE (Couture et. al 2010)
- Minimise administrative and regulatory barriers (IEA 2008)
- Information and training access (IEA 2008)
- Clear standards (Winkler 2005, Couture et. al 2010)
- Guaranteed grid access (Winkler 2005)
- Minimise length of application process
- Regular progress reports and policy optimisation (Couture et. al 2010)
- Appropriate allocation of institutional and administrative resources at all levels (IEA 2008, Couture et. al 2010)
- Market liberalisation (UNEP, 2012)

4.4 Feed-In Tariff (FIT) Schemes

This section starts off by introducing the reader to differences in billing regarding FIT's associated with metering. Thereafter, the variety of design options available to policy makers are explored.

4.4.1 Metering Schemes

For the purpose of discussion, definitions of different metering arrangements are provided in this section. The definitions are to a large extent adopted from current version of NRS 097-2-1.

4.4.1.1 *Net metering*

When the consumption tariff is equal to the embedded generation tariff, it is referred to as net metering. This can be seen as a feed-in tariff where the level of the feed-in tariff is somewhat arbitrarily set equal to the end-user price of electricity. With net metering, often no money is exchanged but the user is given a credit on the electricity bill. This is often done in the absence of a power purchasing contract (UNEP 2012b). The main advantage of net metering is that it is simple, easy to understand and is often perceived to be fair. A simple net metering arrangement is shown in Figure 4-1. Because only a single meter is used, the overall consumption and generation of the customer is not recorded. Only the net import and export of energy is metered and balanced. Many currently illegal connections of PV systems in South Africa with mechanical disc-type meters fall into this category (see section 3.4.1.2). Net metering on its own has historically been insufficient to drive market growth (Mitchell et al., 2011) although excellent solar resources in South Africa and fast dropping PV equipment prices might make this concern less relevant in the South African context.

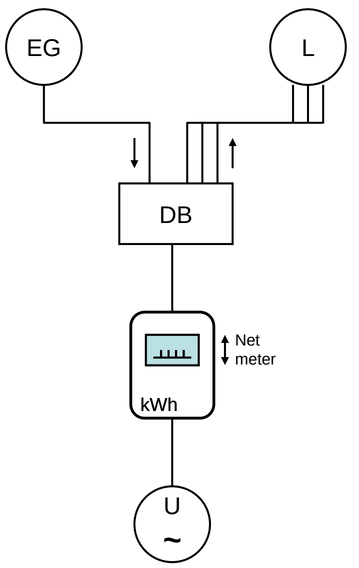

Figure 4-1: Net metering (taken from NRS 097-2-1).

4.4.1.2 *Bi-directional metering*

The net meter in Figure 4-1 only has a single register that either increases or decreases depending on energy flow direction. An alternative to the net meter is a bi-directional meter which records energy import and export in separate registers. This allows separate tariffs to be applied to energy consumptions and energy generation. This arrangement ensures that only energy generated that is not consumed on-site will be for sold by the EG. Thus, users can not be reimbursed for all generated energy but only excess generated energy. This might be desirable or undesirable depending on tariff and incentive structures. It should be noted, that the two registers can also be balanced off against each other to provide the necessary information to implement a Net-metering approach. Net metering is thus in a sense a subset of Bi-directional metering.

4.4.1.3 Separate metering

Separate feed-in tariff metering records all the energy generated from the embedded generator and reimburses the EG customer at the set FIT. The consumption of the EG customer is recorded in full and billed in the conventional manner. A customer with embedded generation and consumption therefore requires two meters. The metering configuration for FIT metering is shown in Figure 4-2 and is referred to as "separate metering". An existing consumption meter, whether prepayment or conventional, can remain in place. The embedded generation meter should be a bi-directional active energy meter that records energy flow in both directions. By balancing the two meter readings against each other, this metering arrangement can also be used to implement tariff schemes in which only exported electricity is compensated for (such as in Net-metering and bi-directional metering).

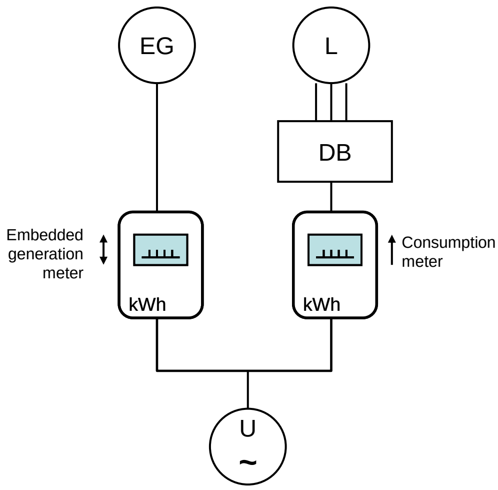

Figure 4-2: Separate Metering (taken from NRS 097-2-1).

4.4.1.4 Separate embedded metering

In some situations it is not practical to take the output of the embedded generator to the main distribution board. In such cases a separate embedded metering approach can be taken which is shown in Figure 4-3. The overall generation of the EG is recorded in the bi-directional embedded generation meter while the overall consumption is balanced off between the net meter and the EG meter.

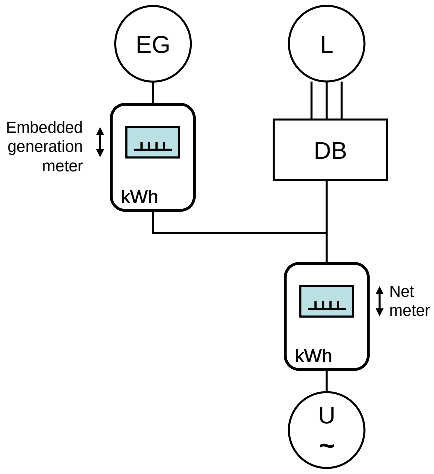

Figure 4-3: Separate embedded metering (taken from NRS 097-2-1).

4.4.2 The Feed-in Tariff

One of the main differentiation factors among FIT is the price paid to generators for electricity. There are four main approaches to determining the FIT level (Couture et. al 2010).

- The first, levelised cost of generation, approach is a cost based approach. The FIT is set at a level so that the costs associated with PV are recovered through the FIT plus a small profit margin which is typically determined by the energy regulator.
- The second approach is to try and determine the real value of the energy generation to society as a whole or the utility. Positive externalities of the generation (environmental aspects, security of supply, health, avoided costs and broader economic impacts such as job creation) need to be taken into account.
- The third approach sets the price more or less arbitrarily independent of costs or value,
- and the final approach is to use a tendering scheme (e.g. South Africa's REIPPP).

Couture et. al 2010, suggests that FIT's based on generation costs are most effective in achieving significant uptake of PV. This is attributed to the fact that investors have less investment risks (Dinica 2006). More generally speaking, policy makers can choose to have higher shorter or longer lower FIT's. Longer lower tariffs are less likely to attract investors if government has a poor track record of long term stable policies and also transfers more costs into the future. These therefore require less capital to implement initially although they are often judged to be more expensive in the long run. They also act as a hedge against volatile fossil fuel prices in future. Shorter higher tariffs might not incentivise optimal operation of equipment over its full lifetime (UNEP 2012b).

The future stability and security of FIT's are extremely important, no matter what structure is chosen. The market needs to have certainty of the future to be able to make reasonable investment decisions.

4.4.3 Fixed Price

The simplest form of billing results from a fixed electricity price. The price per kWh electricity generated or consumed is independent of when electricity is consumed and how much is consumed and generated in total. This system is easy to understand and transparent but has many disadvantages. Utilities have no way of sending price signals to the users to penalise behaviour that increases average costs (e.g. high consumption during peak demand) and no way of incentivising behaviour that reduces costs for the utility (e.g. generation during peak demand times). This causes inefficiencies in the way the system is operated. Government's Electricity Pricing Policy document requires that "Tariffs should promote overall demand and supply side economic efficiency, and be structured to encourage sustainable, efficient and effective usage of electricity" (DME, 2008), which is not always achieved using a fixed electricity price structure.

4.4.4 Static Time of Use

Generally, electricity costs more to generate, transmit and distribute during peak demand times than during off-peak times. This is partly because transmission and distribution systems need to be sized for worst case peak demand and not for average demand. Thus the peak demand level is a significant cost driver for transmission and distribution infrastructure. Furthermore, expensive generating technologies are usually dispatched during peak demand times. Under Time of Use (TOU) billing, electricity prices reflect these varying costs for the utilities. During peak-demand times, electricity is more expensive compared to standard times. To implement TOU billing, sophisticated meters are required that can measure and record when electricity is being consumed and generated and as well as how much. In static TOU billing, the utility specifies in advance how much electricity costs during what time of day, what day of the week and/or time of year.

4.4.5 Dynamic Time of Use

Dynamic Time of Use metering refers to a billing where the electricity price can change dynamically depending on the current situation. If the electricity system is experiencing a high load or capacity shortage, electricity prices can temporarily dynamically increase with little or no prior notice. This type of system requires advanced communication infrastructure and is often associated with future smart grids, where loads, generators and storage facilities intelligently and dynamically turn themselves on or off depending on current electricity price and the expected future price. Although this system is complex, it, at least in theory, allows for the most efficient use of the available infrastructure. This system is most suitable in sophisticated electricity sectors where the electricity price is dynamically determined on the spot-market.

4.4.6 Market Price with Premium

A variation of dynamic TOU pricing for embedded generation is often implemented by paying the generator the wholesale spot-market price for generated electricity which changes dynamically over time and a premium on top of this market price (IEA 2008, Rickerson et al. 2007). This is referred to a premium-price policy or feed-in premiums (IEA 2008, Klein et. Al 2008, Held et. Al 2007). The premium can be dependent on the electricity price to avoid windfall profits for high electricity spot-market prices (sliding scheme). This system generally assumes a sophisticated electricity market is in place where market forces determine the wholesale price of electricity. There is some evidence that seems to suggest that fixed-price FIT payments have generally demonstrated a higher level of cost efficiency compared to market price with premium price FIT payments. This is attributed to the fact that fixed FIT's create more transparent and lower risk market conditions for investors (Couture et. Al 2010, Klein 2008, Ragwitz et al. 2007).

4.4.7 Usage based (Inclining Block Tariffs)

With usage based tariffs, the price paid per kWh is dependent on total consumption or generation over the billing period. Generally, as consumption increases, so does the price per kWh. This is used as a tool to encourage low consumption and in South Africa also for cross subsidisation of users. The same or a similar scheme could be used to reimburse generation.

Inclining block tariffs incentivises high income, excessive electricity users to install energy efficient and energy saving measures, but might be unfair to high use, low income households. Low income households often have more persons living on one premise and the equitable per person allowable electricity use per erf is very difficult to calculate and administer. High income users have the ability to change their habits according to the tariff structure, while poor households have less freedom to do this.

4.5 Aspects of policy implementation

This section will now briefly explore various aspects of implementing rooftop PV enabling policies, based on international lessons learned:

4.5.1 Tariff Lifetime

For feed-in tariffs to successfully foster PV development, it is important for them to be guaranteed in the long term (Couture et. al 2010, IEA 2008). PV systems are still expensive and it typically takes several years to recover costs. Only if feed-in tariff are guaranteed to be in place for long enough for investors to make reasonable return on their investments will it foster significant PV development. Ideally, FIT should be guaranteed for the expected lifetime of a PV system.

Most PV system components have expected minimum lifetime of 20 years. The FIT does not need to remain constant over the 20 years but could be "front-end loaded". What is important is that investors know exactly what returns to expect for the expected lifetime of their PV system. This reduces the risk of the investment which means investors are likely to settle for a lower return. Longer contracts also result in lower levelised payments, ensure cost recovery, lower the cost of financing, and increase investor confidence (Couture et. al 2010, de Jager and Rathmann 2008, Guillet and Midden 2009).

Apart from guaranteeing the FIT for a certain time period for each project, it is also important to be transparent about the availability of the FIT's for new projects. PV projects can take some time from planning to implementation and planners should have certainty regarding the continued availability of the FIT by the time installation is complete. Long term stability is identified as one of the most important drivers of overall policy success (Couture et. al 2010).

4.5.2 Project size

FIT tariffs can be made dependent on the nominal installed generating capacity (Couture et. al 2010, IEA 2008). Typically, larger systems benefit from economies of scale and will produce cheaper electricity than smaller systems and are therefore feasible at lower FIT. Differentiating FIT by project size is similar but slightly different to using an inclining block tariff for generation. In particular differentiating by project size is likely to incentivise high technical efficiency.

4.5.3 Project location

It is possible to make FIT location dependent (Couture et. al 2010, IEA 2008). Installations in remote rural areas might for instance be paid different tariff than a PV installation in an urban setting. In this way, the real costs of transmission and distribution losses (high in rural remote areas and lower in urban area) can be factored into the FIT. Additionally, standalone PV systems could be differentiated from rooftop systems.

4.5.4 Policy triggers and adjustments

It is generally a good idea to regularly review incentive schemes. Policy should be regularly adjusted so that the revised policy can:

- be fine-tuned to better meet policy goals and targets as more information becomes available and experience is gained.
- Ensure that technical limits regarding RE uptake are not exceeded or appropriate technical measures are taken to allow for increased uptake
- Ensure that resources available for the policy implantation are not over constrained to ensure sustainability of the policy.

Policy adjustments need to be made carefully and in a transparent and planned manner. Otherwise, sudden policy changes are likely to decrease investor confidence. A high degree of transparency regarding when and how policy will be reviewed can increase investor confidence. This can be done by pre-defining policy review triggers in the form of e.g. time intervals, capacity or generation milestones (UNEP 2012b). It should, however be very clear that existing policies and incentive schemes are guaranteed for a certain time so that secure investment decisions can be made.

4.5.5 Interconnection

An important aspect of FIT design is related to the process of how users connect their systems to the grid. This is particularly relevant in South Africa where the market has traditionally been monopolistic and vertically integrated. Issues regarding technical standards, costs and eligibility regarding the interconnection need to be clearly defined (UNEP 2012b). Related to this but slightly different are issues regarding priorities for access to the distribution system, particularly when this access becomes scarce in over utilised networks.

4.5.6 New and existing projects

Any FIT policy needs to address issues of existing systems. For example, the policy needs to determine if existing systems need to conform to new regulations and if existing systems also qualify for incentive schemes.

4.5.7 Ownership eligibility

Incentive schemes can be limited to or differentiated by certain user groups. For example the incentive scheme can be exclusively available to private individual, public institutions and/or commercial entities.

4.5.8 Socio-economic impacts

In order to drive or control socio-economic impacts of a policy, the remuneration scheme can be differentiated by the social economic impacts of an installation. For example the price paid per kWh of energy could be dependent on the local content of the installation. Alternatively, minimum requirements for local content could be made.

The infrastructure development projects associated with the REIPPP programme will be extremely expensive and cost billions of rands which will include large wind and solar farms. The job opportunities created by these infrastructure development projects of the REIPPP will unfortunately mostly be project-based and once the farms are up and running, only a small workforce will be needed for maintenance.

Previous studies on the socio-economic benefit of Renewable Energy were mostly focused on larger scale projects (Agama,2003). The opportunities that can be created by a larger number of small-scale rooftop installations may grow into a much more sustainable market once the PV rooftop market's legislation and obstacles have been dealt with. Rooftop PV market has the potential to create an entire industry populated by suppliers, local manufacturers and skilled artisans. It holds the promise of sustainable employment with the increase of small businesses to service its needs but this still requires more investigation.

4.5.9 Caps

FIT can be limited to a fixed amount of total generating capacity supported or fixed amount of program cost or limited by individual project size. This can avoid concerns that too much PV utilisation can lead to technical difficulties or very high financial costs.

4.5.10 Inflation Adjustment

In order to reduce exposure of investors to impacts in the broader economy, FIT's can be adjusted for inflation or the consumer price index. In this way the returns of an investment in EG remains predictable.

4.5.11 Network Charges

The cost of electricity can, broadly speaking, be divided into two main cost components. Largely variable costs mainly related to generation of electricity and mainly fixed costs related to transmission and distribution of the electricity. This cost structure can be reflected in customers' bills by splitting the bill into a fixed connection fee and a consumption based fee that depends on the amount of energy used. This type of broken down billing makes it easier for a utility to recover costs incurred from a user that is a net exporter of electricity. This type of user might not make use of the utility's generating capacity but very much depends on the distribution system and should therefore be contributing to the costs associated with this utility asset.

4.5.12 Policy Funding

FITs often cost additional money to implement. It is common for prices above market value to be paid for electricity generated from RE technologies. Additional administrative costs are incurred for FIT's and there are potential additional equipment costs. The source of these additional funds is a key element in FIT design and can have a significant impact on the long term stability of the FIT which is crucial for policy success (Couture et. al 2010). Four main sources for funds are identified (Couture et. al 2010):

- Funding through increased electricity prices (ratepayers)
- Funding through Taxes (taxpayers)
- Greenhouse gas auction revenues
- Utility Tax Credit

Detailed descriptions of each funding source and the associated advantages and disadvantages are described in detail in Couture et. al 2010.

In the South African context, international funding might be an additional way to finance PV incentive schemes, even if just in part. Examples of such schemes are the Clean Development Mechanism under the Kyoto Protocol[8], Nationally Appropriate Mitigation Actions and Global Environment Facility (UNEP 2012b). There may be ways of qualifying for such schemes by placing many small-scale roof top systems under the umbrella of a municipality. Other more specific international funding schemes are under discussion such as the Global Energy Transfer Feed-in Tariffs proposed by the Deutsche Bank in 2010. This program provides international financial and institutional assistance for developing countries willing to deploy FITs for renewable energies. Backing up policy funding through international institutions is identified as a significant risk mitigating factor in UNEP 2012. However, current international funding infrastructure has

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[8] The Kyoto Protocol commitment period ends in 2012 but other similar programmes are likely to be or become available.

historically not been flexible enough to support national FITs in a broad and programmatic way (UNEP 2012b). [9]

4.5.13 Purchasing and administrative entity

Closely related to the policy funding source, is the purchasing and administrative entity. The policy should clearly state which entity is ultimately responsible for purchasing the power from the generator. This entity can then obtain its funding from a range of different sources as discussed previously. Having a streamlined single point of contact for all issues related to the embedded generation (e.g. purchasing, billing, administration, certification and interconnection) is likely to significantly reduce non-economic barriers to policy implementation.

4.5.14 Legal Framework

Part of developing the details of an incentive scheme is deciding how the scheme is entrenched in legal or policy framework of the respective jurisdiction. This will depend on the context such as the political system, legal tradition, governmental structure, legislative processes and market structure (UNEP 2012b). For example, the details of the FIT could be entrenched in dedicated laws or the general idea of a FIT could be incorporated in high level mandate law with a regulatory body in charge of the policy details (UNEP 2012b). A trade-off has to be made between providing investors with sufficient confidence and avoiding lengthy and complicated government structures and processes.

[9] The company CAMCO is apparently investigating how international climate change funds can be utilised for a FIT in South Africa (http://africa.camcoglobal.com)

5. Potential for rooftop PV in Riversdale

5.1 Introduction

In this chapter the potential for rooftop PV for Riversdale is identified. Analytical tools, more specifically Geographic information system (GIS) software, was used to decrease the subjective nature of the resulting estimates.

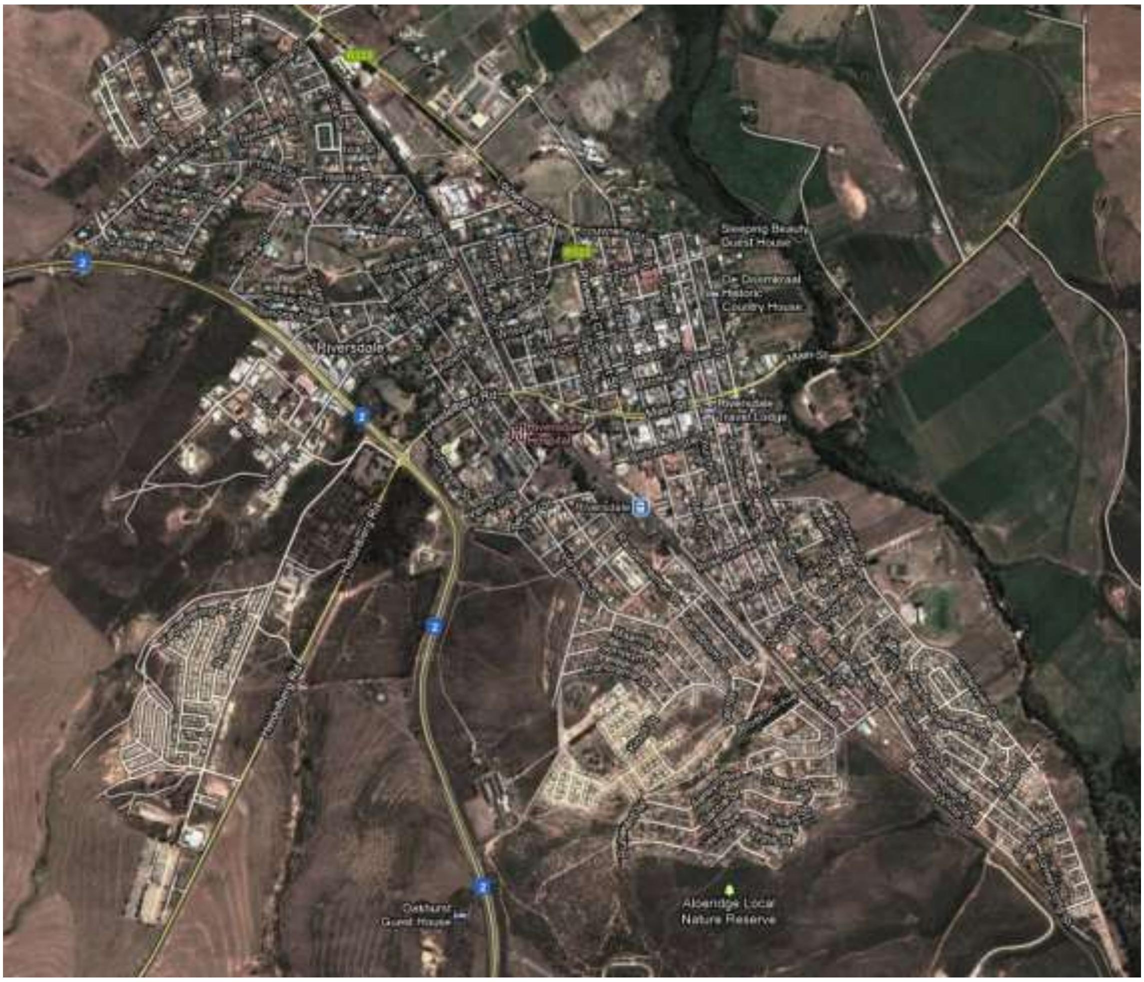

Figure 5-1: Google Earth photo of Riversdale.

5.2 GIS investigation of PV potential - methodology

GIS software was used to estimate the roof space available for PV installation. The method followed was as follows;

- Determine the Roof area (m^2) available
- Azimuth orientation of the inclined roof (approximated into six possible categories; 0°N, 0°N to 10°, 10° to 15°,15° to 30°, 30° to 40° and >40°).
- Roof inclination (approximated to three possible categories; flat, 15°, 30°).
- Annual average solar irradiation incident on the roof.
- From the available roof space and tilt angle determine installed PV capacity per roof (kWp).
- From the installed PV, factoring in positional coefficients, calculate kWp/m^2 per roof and find the annual average generation capacity (kWh/kWp/annual average).
- Use hourly solar irradiance data to derive hourly PV generation (kWh/kWp) in Riversdale.

The use of GIS in this study gives the user a spatially distributed database where roof orientation and other spatial criterias can be applied.

The current project assumptions about the spatial characterisation of certain urban areas were made based on visual inspection and available municipal account data linked to specific erven. Using this data, the urban areas were differentiated.

Hourly solar data was in addition collected to be used for the financial analysis described in later chapters.

5.2.1 Roof area

Some assumptions were used in defining the available roofspace for PV installations. The roof areas of RDP houses and similar small structure were discarded due to the uncertainty in the structural integrity of these roofs to support PV panels and the associated risk of panel damage. Lack of security and technical challenges also played a role in this decision. Another consideration on excluding the roofs of RDP houses was the inverter costs associated with the available roof area: the smaller the inverter, the higher the cost per kWp, with system sizes below 1 kWp resulting in excessive cost. The concentration of roof area is sparsely distributed making a central inverter problematic.

Roofs having an azimuth orientation greater than 70° and less than 290° were also discarded as the generation capacity of PV on these roofs will be reduced by more than 15%[10] as compared to north facing roofs.

To estimate the roof spaces, Google Earth Pro was used together with the ‘create polygon’ tool. All suitable roof areas were drawn as a polygon overlay on the satellite imagery in Google Earth. Care was taken to determine the possibility of shading from chimneys and trees. If an otherwise suitable roof was in close proximity to a large tree (identified by visual inspection considering a crown diameter larger than 4 m), or a chimney was detected north of the inclined roof area, the roof area was excluded. Figure 5-2 shows a screenshot from Google Earth with a polygon indicating a suitable roof area in bright red.

Figure 5-2: Google Earth polygon overlay.

[10] East or West facing PV panels will be effective in reducing the morning or evening peak demand, but due to the significant reduction in yearly kWh generated, these azimuth orientations have been ignored in this study.

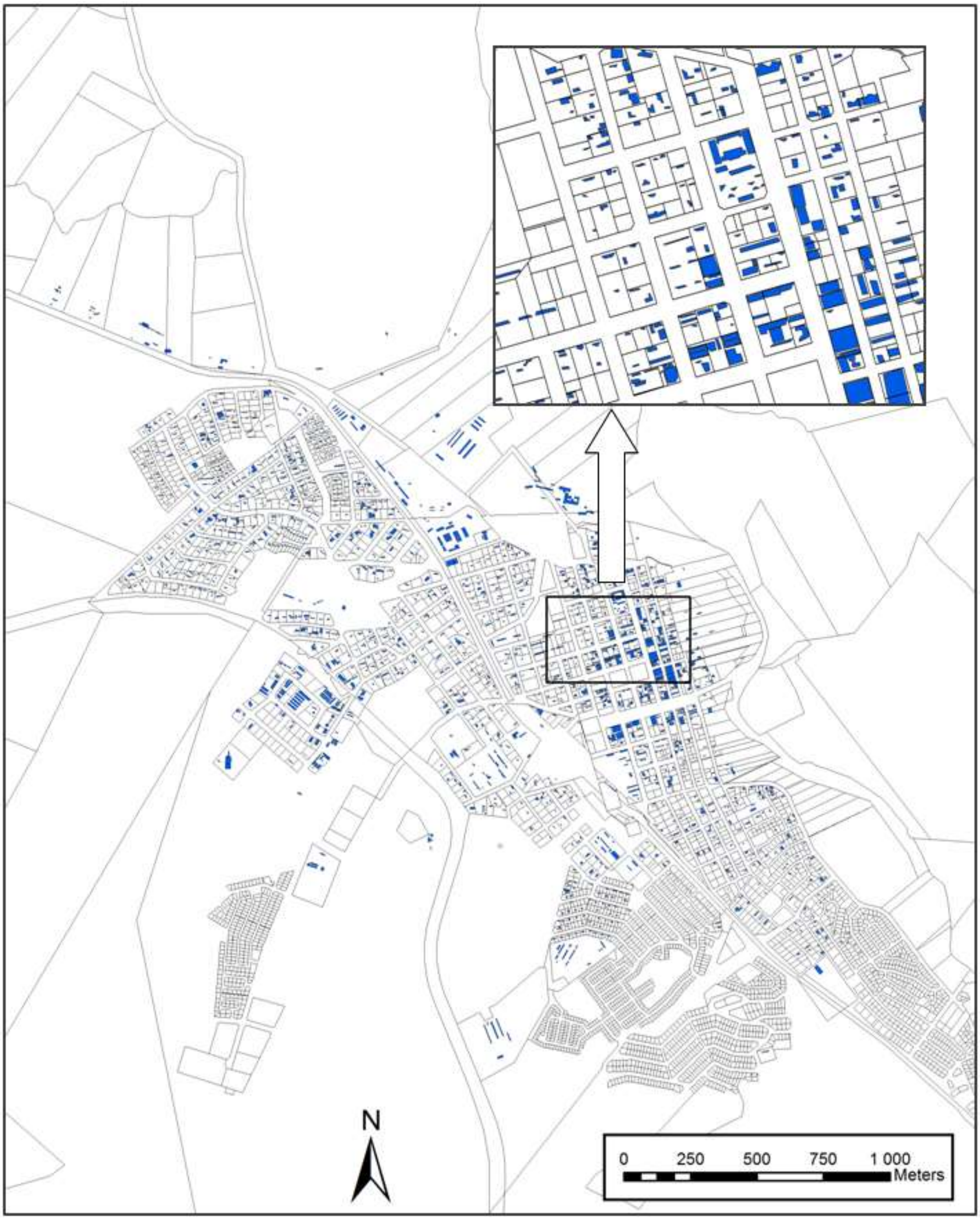

Figure 5-3: Roof area polygons (blue).

This procedure was conducted for all the roofs interpreted as being suitable. The visual inspection of the roofs for suitability was only done using Google Earth imaging and was subject to the amount of detail observable. Tilt angle was estimated from a small amount of streets capable of hosting the 'streetview' option in Google Earth. A module packing density factor of 0.7 was assumed as well as a cosine correction factor related to the roof inclination or tilt.

5.2.2 Azimuth and tilt angle

The azimuth orientation of the Riversdale roof tops was determined by also using Google Earth imaging. The roofs in riversdal tend to be orientated in a similar direction per neighbourhood. The average azimuth angles obtained for the neighbourhood blocks can be seen in Figure 5-4 and average roof tilt areas in Figure 5-5.

Figure 5-4: Average roof azimuth angle.

Figure 5-5: Average roof tilt.

The solar irradiance incident on an inclined plane, the latitude tilt irradiance (LTI) at a plane angle of 30°, in Riverdale was calculated from satellite derived data (HelioClim v2). The data is presented in Figure 5-6 as the average daily total for the year period 2011/2012.

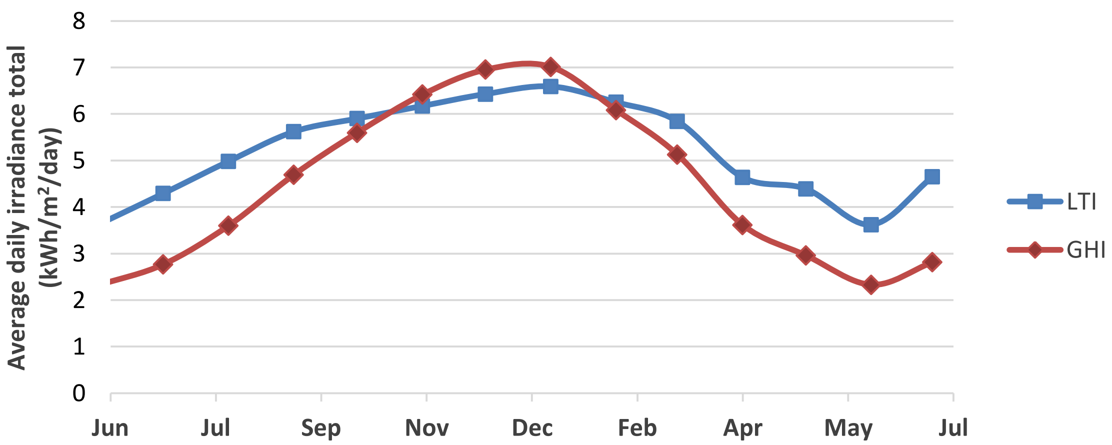

Figure 5-6: LTI and GHI (average daily total) variation over the year 2011/2012 – HC3.

The satellite-derived data is shown geographically in Figures 5-7 (LTI calculated at a plane angle of 30 degrees) and 5-8 (GHI) below.

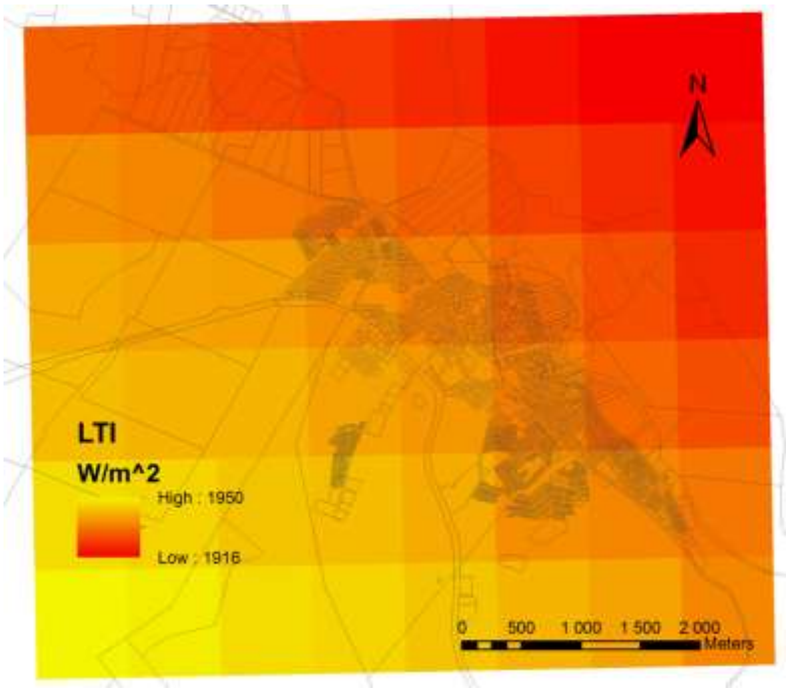

Figure 5-7: Riversdale LTI distribution (kWh/m^2/annual).

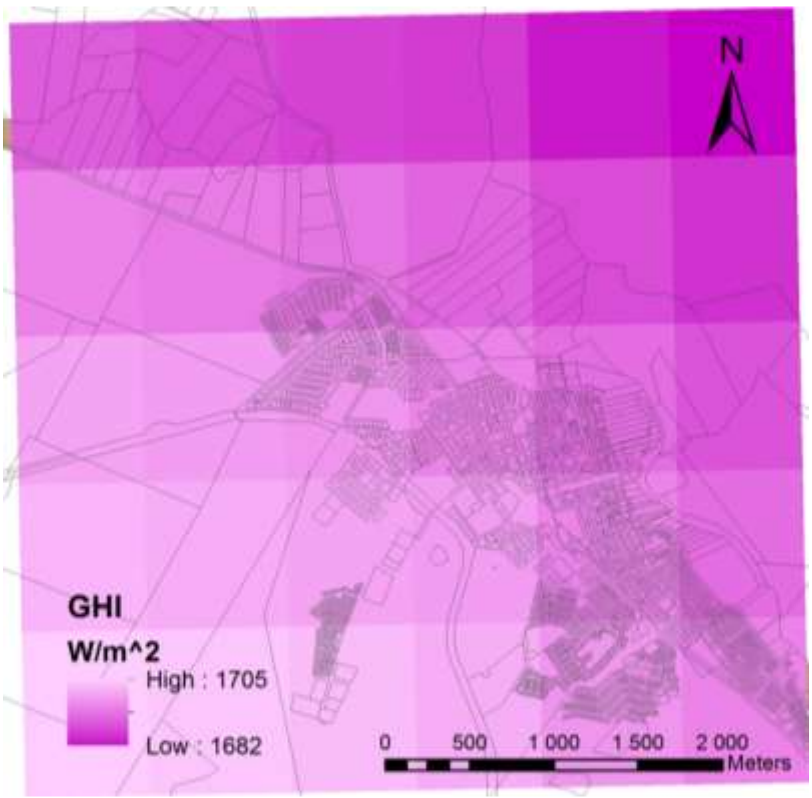

Figure 5-8: Riversdale GHI distribution (kWh/m^2/annual average).

After the resource distribution across the Riversdale and the available roof space and orientation was determined, the installed capacity of potential PV was calculated. In order to do this, a reference polycrystalline PV panel from Tenesol (TEI130/140-36P) was used. An installed capacity factor of 0.133 kWp per meter squared available roof space for the reference panel was estimated.

The installed capacity was derived as:

$$Installed\ Capacity\ (kW_{peak}) = C_{tilt}\left(A_{roof} \times 0.133\right)$$

[equation 1]

Where C_{tilt} is the cosine correction applied to the roof area as if the polygon was drawn from a right angle and needed to account for the roof tilt angle.

Various factors play a role in the electricity production (such as DC/AC conversion losses and topographical influences on availability) and determining the PV generation capacity is quite complex. In order to obtain the most accurate generation production values for a range of roof orientations a decision matrix for the GIS modelling was devised related to three core elements. These are irradiance, azimuth angle and tilt angle. The range of roof azimuth angles ranged from 280° to 70° and the roof tilt angles from a flat roof (0°) to 30°. It was necessary to determine what the deviation from an optimally orientated roof (32° tilt and 0° azimuth) would be for a combination of azimuth and tilt angle at the best irradiance point. To gather the information needed, a software program PVPlanner11 was used. In total 24 reference studies were conducted for a 1 kWp system orientated with different azimuth and tilt angles and the deviation in terms of electricity production recorded and presented in

Table 5-1 where the correction factors are listed as percentages. The percentages represent the reduction in kWh produced for a specific set of roof conditions compared to an optimally orientated panel.

[11] GeoModel Solar

Tilt angle (°)	Azimuth angle (°): 0	10	15	30	40	60	>60
0	12.80	12.80	12.80	12.80	12.80	12.80	12.80
15	3.75	4.02	4.02	5.21	5.80	9.43	12.80
30	0.35	0.35	1.18	3.03	5.20	10.20	12.80

Table 5-1: Correction factors (%) for roof azimuth and tilt angles.

An additional correction factor ranging from 0% - 1.8% was applied related to a LTI range of 1950 kWh/m^2/year to 1916 kWh/m^2/year. Having now determined most of the orientation factors that influence power production it was possible calculate the generating capacity characterising a panel for a specific location in Riversdale. Generation capacity is calculated as:

$$Generation\ Capacity\ \mathrm{per}\ \mathrm{m}^2\ roofspace\ (kWh/m^2/year) = C_{irr} \times 1516 \times (1 - C_{matrix})$$

[equation 2]

$$Generation\ Capacity\ \mathrm{per}\ kW_{peak}\ \left(kWh/kW_{peak}/year\right) = [C_{irr} \times 1516 \times (1 - C_{matrix})] \times C_{tilt}\left(A_{roof} \times 0.133\right)$$

Where C_{irr} is the irradiance correction factor and C_{matrix} is the decision matrix correction factor.

The potential installable PV capacity and generation was calculated by applying equation 1 and 2. The spatially distributed installed amount is shown in Figure 5-9. The total potential installable rooftop PV potential for Riversdale is:

- Installable rooftop PV potential: **9.84 MW**
- Average annual generation potential: **13 .7 GWh**

Some of the erven in Riversdale are not suitable for PV installation and were disregarded due to roof orientation and size. In addition to this, rooftops with installable capacity below 1 were also disregarded.

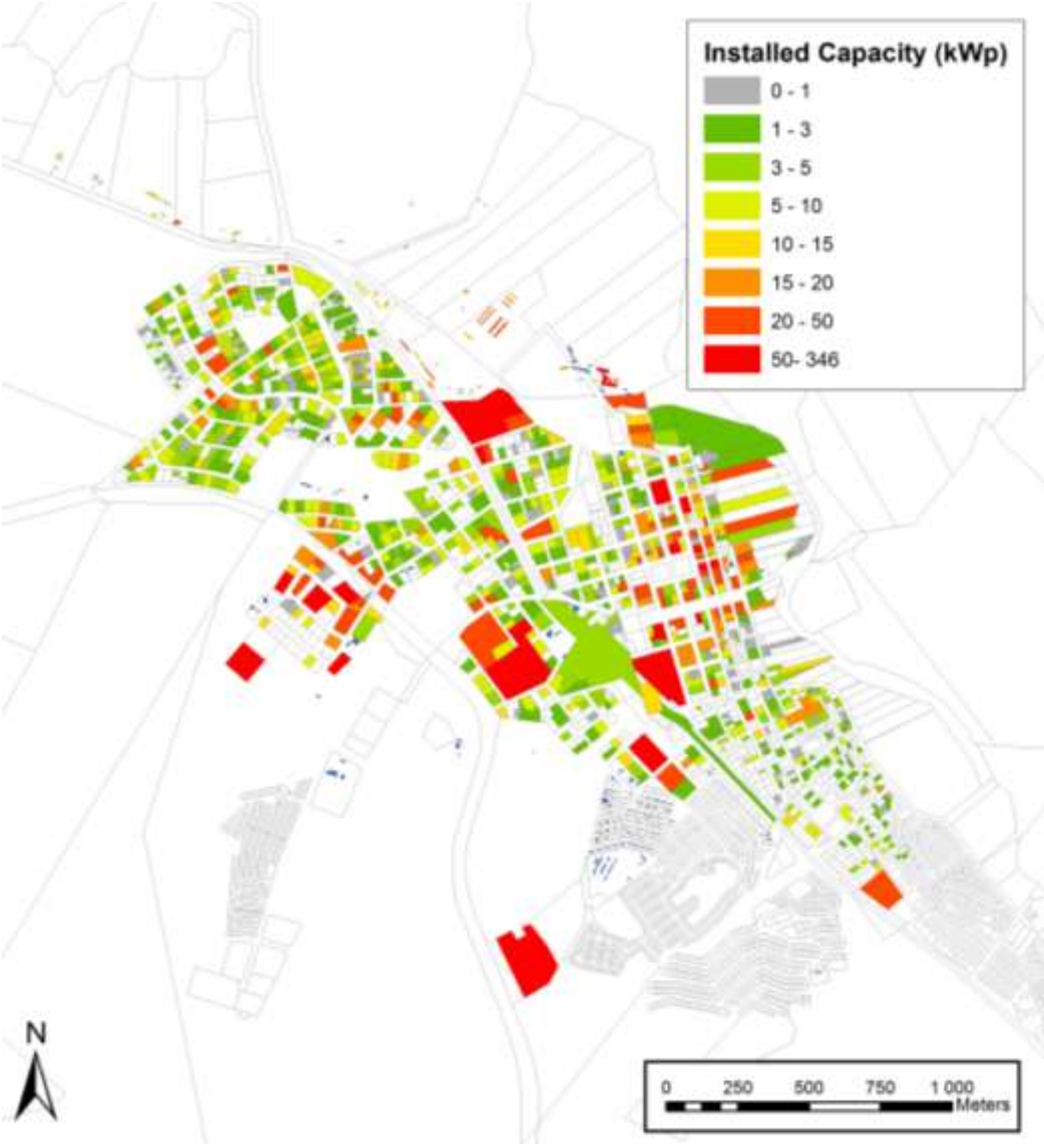

Figure 5-9: Installed capacity for rooftop PV per erven.

5.3 Distributed PV availability

The GIS results from the analysis provided the spatial distribution of maximum installable PV capacity in Riverdale. From this initial layer various scenarios could be generated that estimated certain PV uptake percentages out of this initial maximum based on factors such as urban area, installable PV per roof, cost of current electricity usage etc. The scenario definitions derived from the GIS will be addressed later in the report. This section focuses on estimating the distributed rooftop PV availability by differentiating between urban areas and energy consumers.

Billing data for Riversdale was limited to mechanical disk (MD) metered erven in the urban area. This consisted of approximately 771 entities. It included a mix of erven in residential, commercial and industrial areas. Putting this in perspective using the GIS layer, the amount of discernible entities constituting erven was estimated at 3638. This shows that by far the majority of erven are on prepaid metering and will form an important consideration in proposing feasible scenarios.

From Google Earth observation, identified mainly by roof size, it was estimated that the amount of low income erven accounts for roughly 2175 erven out of the total 3643 erven. Assuming this, approximately 1468 erven is accounted for as being eligible for PV installation assuming it has adequate roof space available.

These 1468 erven was duly categorised into urban areas by visual inspection and using available cost data of nearby buildings to identify commercial and industrial areas. From these investigated 1468 erven only 1074 erven was deemed suitable for PV installation due to roof space available and orientation. A generalised map of the 1074 suitable erven in categorised urban areas can be seen in Figure 5-10.

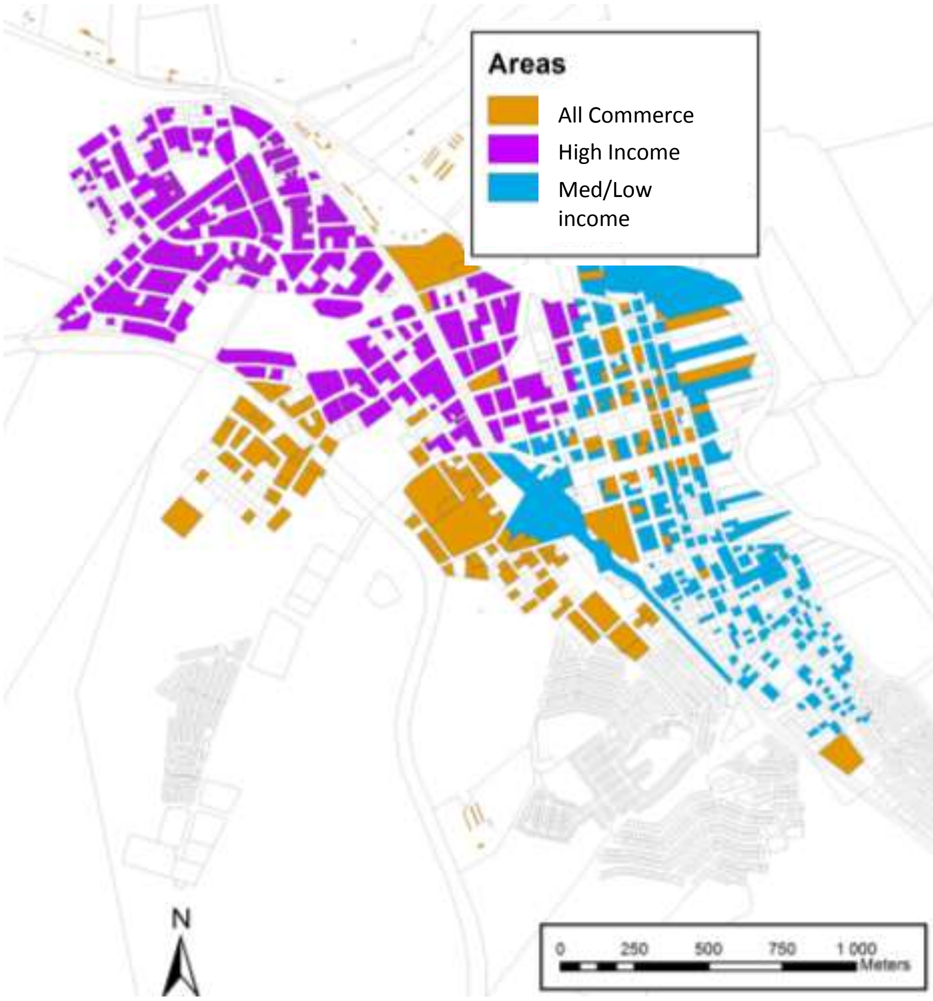

Figure 5-10: Urban areas eligible for rooftop PV installed.

From the 1074 suitable erven only 274 had available cost data to investigate. Having only Google Earth available and some electricity bills, distinguishing between residential, agricultural, industrial and commercial sector was hard to accomplish with the available resources. It was possible to determine, with relative accuracy, if a building was residential or not by investigating the electricity usage and performing visual inspection of the erven from Google Earth.

As previously mentioned differentiating between commercial and industrial properties was more challenging and here the main denominator used involved analysing the electricity bill (where data was available). For example for an electricity bill in excess of 800 R/pm it is assumed to be a commercial entity. Defining high and medium/low income households the same methodology was applied where residential areas (as defined from visual inspection) was split between having an electricity bill of between 300- 800 R/pm and <300 R/pm respectively; refer to Table 5-2.

Urban Area	Financial denominator
Medium/Low income residential	< R 300
High Income residential	R 300 – R 800
All Commerce	> R 800

Table 5-2: Financial metrics applied for differentiating urban areas.

Figure 5-11 identifies the erven where cost data could be found, the other colours did not have cost data but was grouped due to proximity to the erven with available data.

Figure 5-11: Illustration of available billing information (grey).

Figure 5-9 illustrates the ungrouped PV potential across Riversdale. This section through the application of geographical observation and available cost data criteria differentiated the urban areas into three distinct urban categories. This is summarised in the charts of Figure 5-12 and Figure 5-13. This applies for the 1074 feasible erven. In the other categories, entities that did not fit according to the criteria were grouped. These ranged from a police station to what seems to be a large pack house.

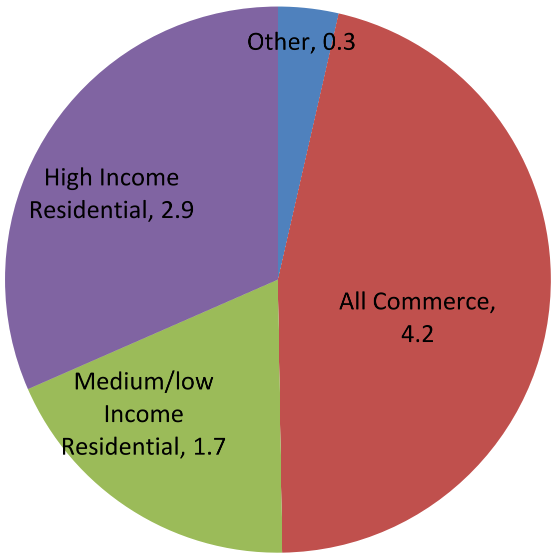

Figure 5-12: Installed PV capacity according to urban area (Installed Capacity kWp).

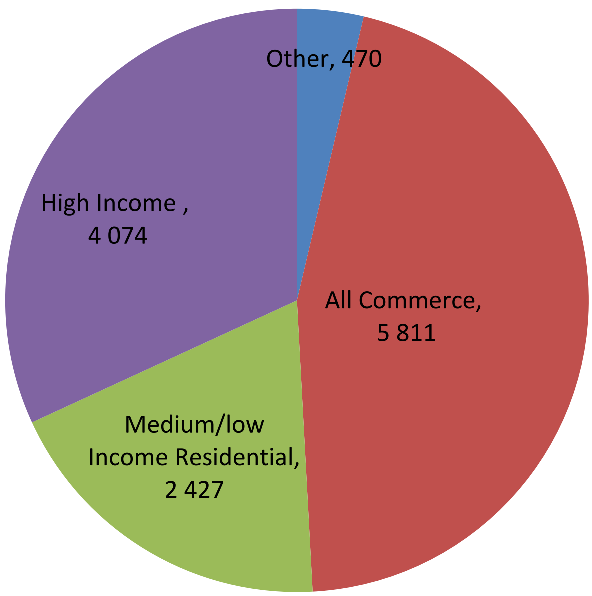

Figure 5-13: PV generation capacity according to urban area (Generation kWh).

5.4 Limiting criteria on PV adoption and analysing generation profile

In the previous sections, the total potential from rooftop PV in Riversdale was estimated and erven were categorised into urban areas. An important link that has to be made is to group erven to single shared/dedicated LV feeder lines, to establish wich transformer feeds to which erven. This is important as the EG criteria on LV/MV feeder lines will need to be applied to estimate the allowable PV on a LV feeder line.

The distribution network for Riverdale in GIS format was acquired to do this. The spatial distribution of LV and MV substations and feeder lines were obtained, indicating transformer sizes and line capacity (where available). However, from discussions with the responsible engineers, little to no connection data between transformers and shared LV consumers exist for Riversdal. Thus it was not possible to establish which erven is connected to which transformer or LV feeder. Having no connection data and no load data it was not possible to apply Eskom's EG on LV network framework on an erven by erven basis and was omitted in this study.

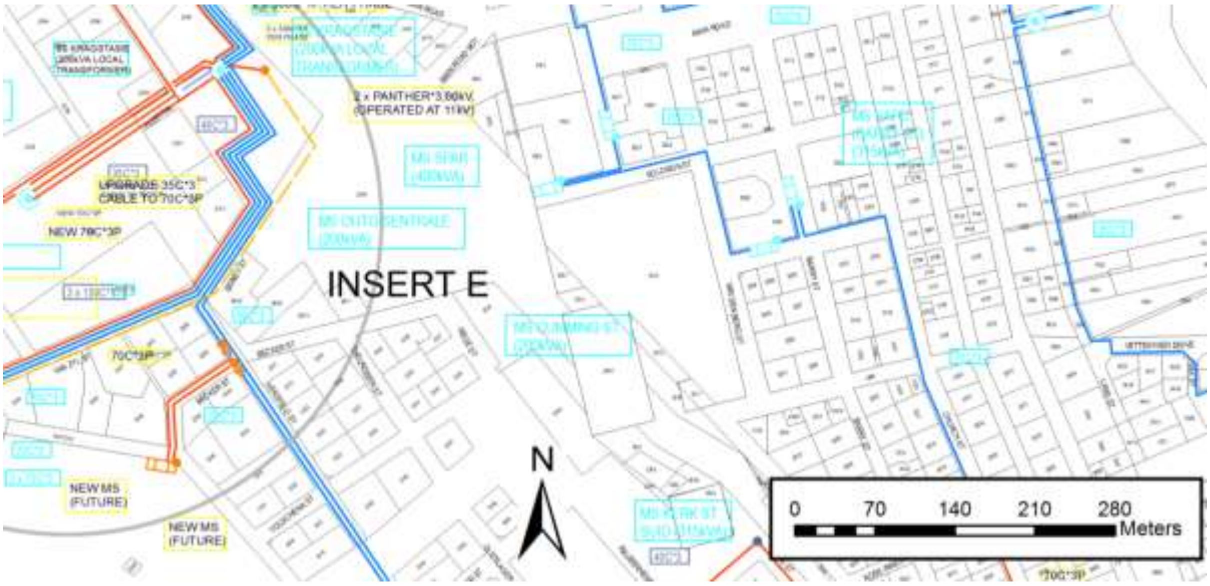

Figure 5-14: Available distribution network data for Riverdale CBD.

However, the line capacity that feeds Riverdale was available and as a simplified analysis, the entire Riversdale was looked at as a single 'consumer' and the EG on LV network criteria was applied according to Riversdale as being a single entity. According to the LV criteria, EG is limited to 15 % of the peak demand of the MV feeder. For Riversdale this means having an MV line peak capacity of 9300 kVA; thus only 1.395 MWp of rooftop PV in Riversdale can be allowed.

If we were to install all 1.395 MWp of PV it translates to an annual reduction in required electrical energy (from a municipality perspective) of 6% (1.95 GWh produce from rooftop PV). The effect of 1.395 MWp distributed rooftop PV in Riversdale on the daily load profile can be seen in Figure 5-15 for a week in October/November 2011. The light grey line shows the load profile at the Riversdale main supply transformer station, whereas the red line indicates the power production from the PV system. The dark line is the integrated effect of the PV system on the original load profile.

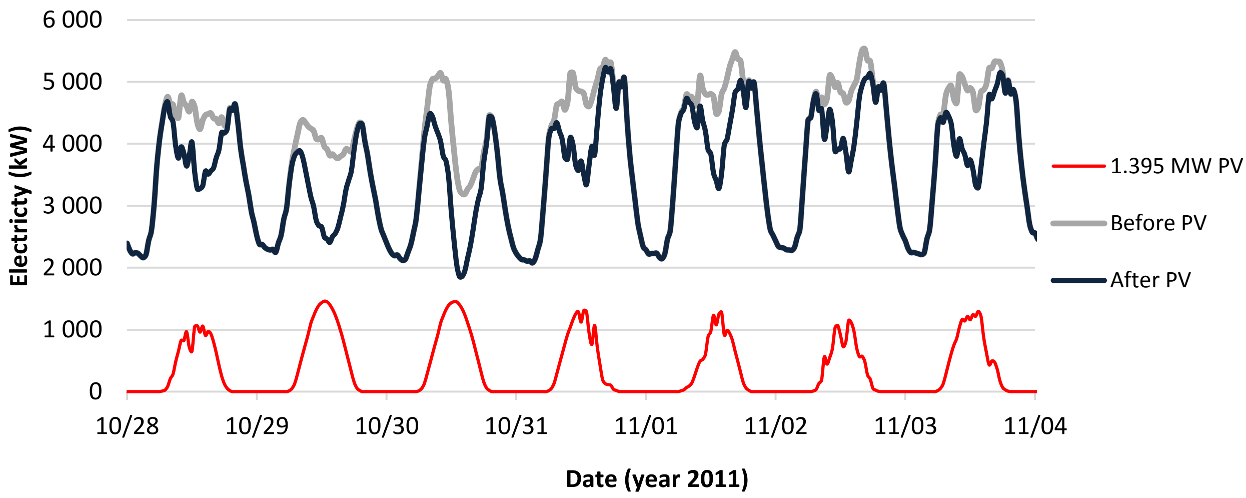

Figure 5-15: Load displacement by a 1.395 MW PV system for Riversdale.

The need for Riversdale to purchase electricity from Eskom can be greatly reduced during daytime hours. However, as the municipality sells electricity at a flat rate and buys from Eskom at a TOU tarrif, it would have been better had it been possible to generate PV electricity during peak times.

It is ideat if the PV intervention could address the peak energy usage that translates in the municipality paying lower demand charges. From the characteristics of the PV production it was found that in summer the morning peak usage is reduced but this diminishes in the winter period. In order to understand the seasonal effects on the electricity usage and PV production, Figure 5-16 and Figure 5-17 was drawn up. Typical summer and winter days were calculated by averaging a two week period in high summer and high winter.

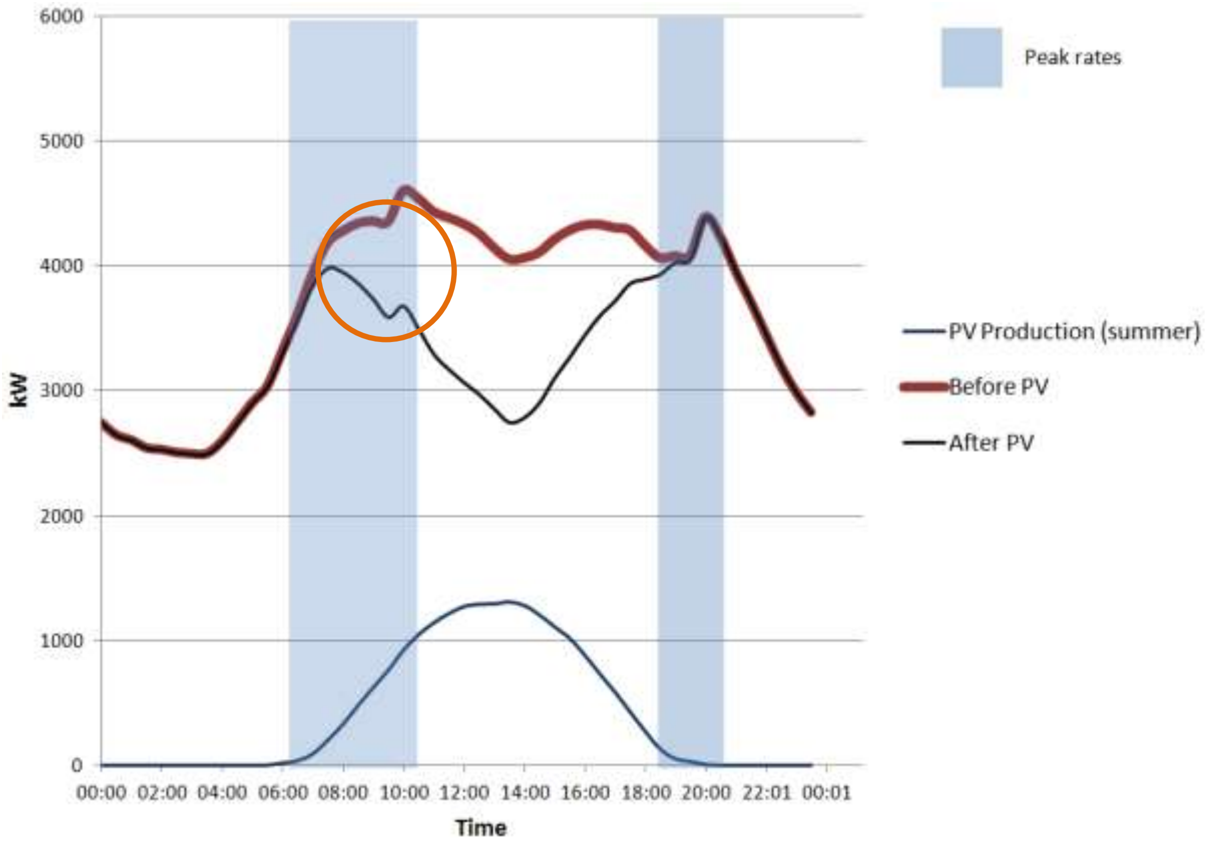

Figure 5-16: Load for a typical summer day assuming a 1.395 MWp PV intervention.

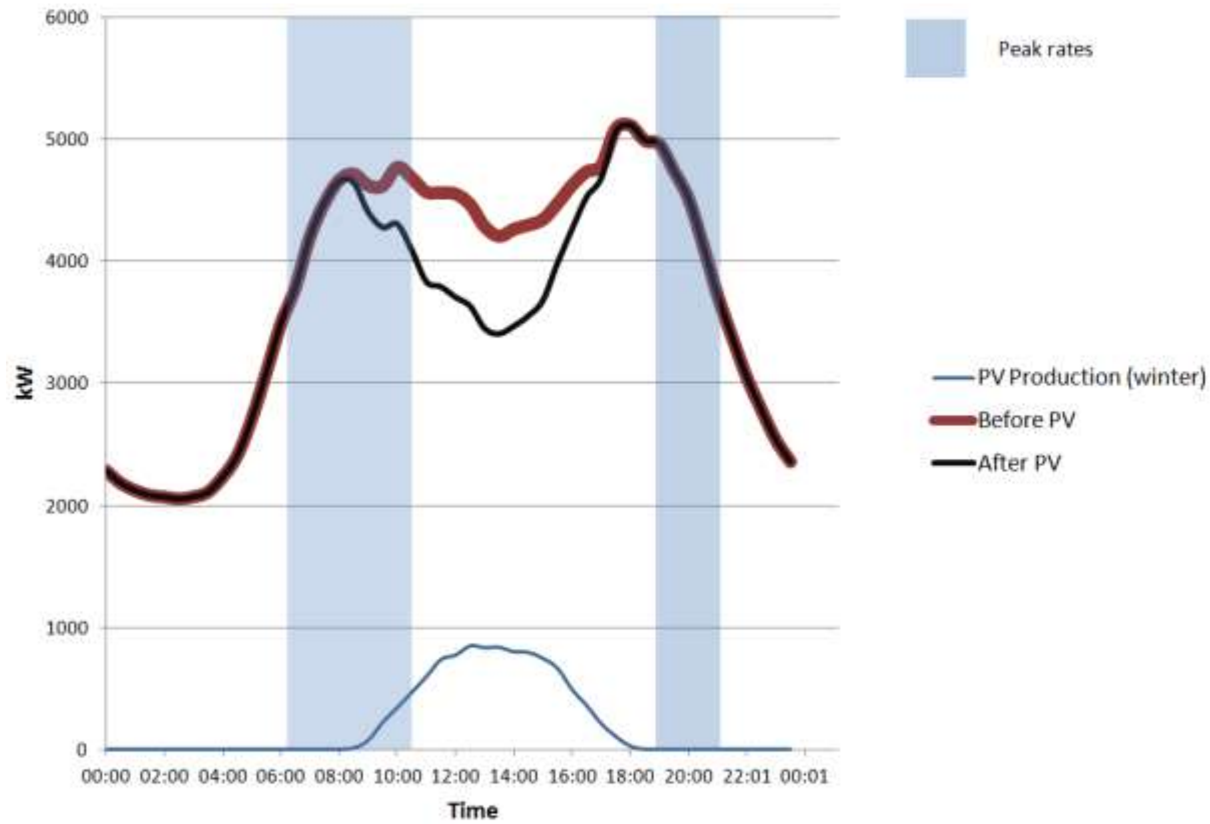

Figure 5-17: Load for a typical winter day assuming a 1.395 MWp PV intervention.

It can be seen in Figure 5-16 and Figure 5-17 that PV production of typical summer and winter days differ considerably. What is interesting to note from the figures is the reduction in morning load if a 1.395 MWp PV intervention is assumed - refer to the orange circle in Figure 5-16.

The municipality sells electricity to for the residential sector electricity is sold at a fixed price. The municipality in-turn buys electricity from Eskom but at different time-of-use (Megaflex structure) rates. This mean that in general during peak periods (peak tariff) the municipality will buy electricity at a price higher than what is charged to the homeowner. In off-peak periods (standard tariff) the electricity is bought from Eskom at a price lower to that charged to the homeowner. Therefore during peak periods the municipality loses income through electricity sales and during off-peak periods the municipality generates revenue through electricity sales. Thus the greater the reduction in electricity usage during peak rate periods the less money the municipality will lose.

5.5 Conclusion

In this chapter, the methodology used to estimate the rooftop PV potential in Riverdale was described. The main constraints of this analysis were identified such as the lack of the Eskom distribution network. Assumptions made to differentiate urban areas were mentioned as well as the available data on erven.

From the available information and assumptions the potential rooftop PV installations across Riversdale was estimated in terms of installed capacity and generation. If zero hindrance to PV installation is assumed and the only requirement is taken as available and suitable roofs, the total installed capacity would be 9.85 MWp and the associated generation will be 13.7 GWh. This is the upper limit of rooftop PV potential in Riversdale as aligned with project assumptions. However after application of the LV framework the potential for potential Riversdale rooftop PV installations is reduced to 1.395 MWp installable capacity and maximum generation of 1.95 GWh.

The daily effect of 1.385 MWp of PV in Riversdale was presented and this illustrated the seasonal variance as well as the potential load displacement in summer during peaking hours. The ability to reduce the consumption in peak hours will save the municipality money as in these periods they sell to the resident at a lower tariff than what they purchase the energy from Eskom.

6. Financial context of Riverdale

6.1 Introduction

The previous section identified the rooftop PV potential for Riversdale, using analytical tools to decrease the subjective nature of the resulting estimates. In this section, the financial context of Riversdale is analysed.

Municipalities in South Africa operate as electricity distributors and the revenue from electricity is often closely linked to their financial survival. Typically 10% of annual electricity revenue generated is fed into the city coffers, subsidising a range of other important municipal services (Janisch 2012). Revenue from larger residential and other consumers is in addition routinely used to cross subsidise 'losses' from providing power to poor households which are not fully covered by the national Equitable Share Grant.

To provide the perspective from which the viability of various rooftop PV enabling mechanisms will be viewed, it is crucial to understand the financial context of both Hessequa Municipality and Riversdale, specifically looking at electricity-related costs and income.

The town of Riversdale is part of the bigger Hessequa Municipality, which is unique in that it delivers services to six geographically dispersed towns. Riversdale is only one of six major towns in Hessequa municipality. The other towns are Stilbaai, Witsand and Gouritsmond, which are mainly holiday towns and Albertinia and Heidelberg, which are located inland.

The financials for both Hessequa and Riversdal from 2011 / 2012 were taken for the financial analysis in the this report. The financial impact that rooftop PV installations would have had on the municipal coffers of Riversdal town had these been installed at the beginning of the 2011 / 2012 financial year is calculated. Although this method is unconventional, it was decided that an analysis based on real figures would give more accurate results than a calculation on projected or budgeted figures.

Service delivery in Hessequa Municipality is expensive and the income base from which costs can be recovered is very small and consist mostly of residential customers. According to documents on the Hessequa website, there are relatively few businesses in the municipal area and thus the income that can be recovered from the business sector is very low. In fact, 85% of the electricity income for Hessequa Municipality is collected from residential customers. See figure 5.1 below for the breakdown. This figure includes residential vacant land (Hessequa 2012). Due to this, there is much less scope than in other municipalities to cross subsidise to the residential users. Surrounding municipalities' ratio on for example rates tariffs is up to 1:2, resulting in a bigger possibility for subsidisation of the residential tariff.

Type of property	Contribution to income from electricity
Residential	68.4%
Businesses	5.5%
Rural (farms)	6.2%
State owned land	3.3%
Vacant land (residential)	16.6%

Figure 6-1: Electricity Income: Hessequa Municipality (Hessequa 2012)

6.2 Hessequa financial context

The budgeted income from the resale of electricity was R81 168 000 for Hessequa Municipality for 2011/2012. This makes up 30% of the total income for that year (Hessequa 2012).

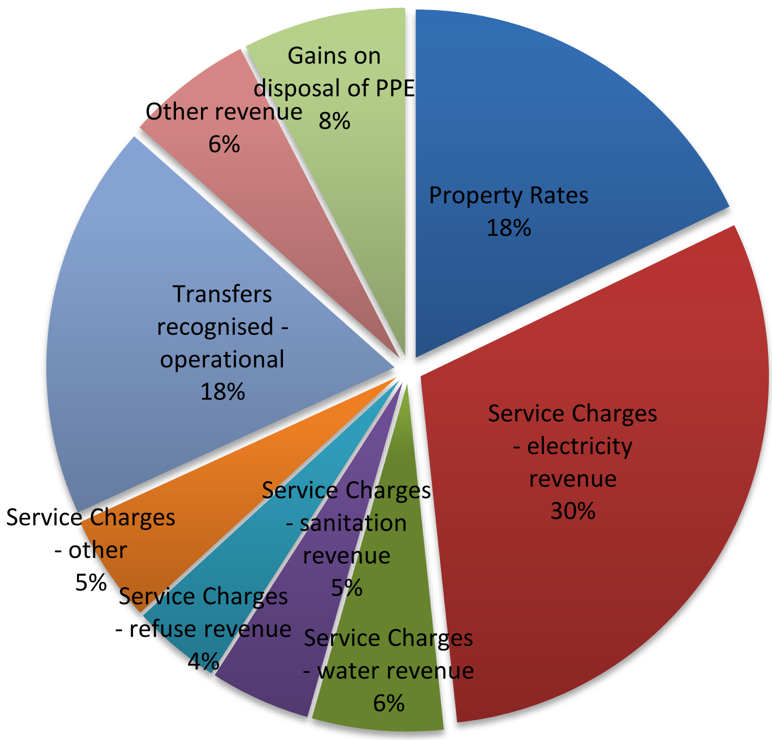

Figure 6-2: Revenue by source, Hessequa Municipality

The surplus budgeted for electricity for the same year was R18 350 000, which is 22% of the electricity revenue. However, this surplus includes R4 360 000 in capital donations, while the relevant capital expenditure is not included in the expences. If this is taken into account, the surplus is reduced to 16,9% (Bergh 2013). This is slightly more than the 10% quoted by Janisch (2012) and does not tie in with the statement by Hessequa Municipality that the surplus on their electricity sales is low.

Hessequa Electricity Revenue and Expenses budgeted 2011/2012 (R thousand)		
Revenue By Source		
Service charges - electricity revenue	81 168	
Service charges – other	3 971	
Other revenue	57	
Transfers recognised - operational	4 000	
Total Revenue (excluding capital transfers and contributions)	89 196	
Expenditure By Type		
Employee related costs	8 295	
Debt impairment	805	
Depreciation & asset impairment	1 694	
Finance charges	2 756	
Bulk purchases	52 711	64.94%
Contracted services	30	
Transfers and grants	4 000	
Other expenditure	5 185	
Total Expenditure	75 476	
Surplus/(Deficit)	13 720	
Contributions recognised - capital	4 630	
Contributed assets		
Surplus/(Deficit) after capital transfers & contributions	18 350	22.61%

Table 6-1: Hessequa Electricity Revenue and Expenses budgeted 2011/2012

6.3 Hessequa Eskom charges

Hessequa Municipality purchases electricity for resale from Eskom at the Megaflex tariff for Local Authorities. This is a time of use tariff (TOU) and is in addition seasonally differentiated in the c/kWh active energy charge. The tariffs are based on the voltage of the supply and the transmission zone. In addition there is a c/kVARh reactive energy charge for electricity supplied in excess of 30% (0,96 PF) of the kWh recorded during the peak and standard periods. The excess reactive energy is determined per 30-minute integrating period and accumulated for the month and is only applicable during the high-demand season

There is also a c/kWh electrification and rural charge as well as a c/kWh environmental levy charge, applied to the total active energy supplied in the month as well as a R/day service charge based on monthly utilised capacity of each premise linked to an account.

Eskom Local Authorities MegaFlex rate for > 900km and >500V & < 66kV						
Active Energy Charge (c/kWh)						
High demand season (Jun-Aug)			Low demand season (Sep-May)			Transmission Network Charge (R/kVA/mth)
Peak	Standard	Off Peak	Peak	Standard	Off Peak	
194.93	50.62	27.01	54.38	33.27	23.28	4.59

Figure 6-3: Eskom Local Authorities Megaflex rate (Eskom 2011)

Eskom Local Authorities MegaFlex rate for > 900km and >500V & < 66kV	
Other charges	
Electrification & Rural Subsidy (c.kWh) all Seasons	4.11c
Environmental levy charge (c/kWh) all seasons	2.00c
Reactive Energy charge (c/kvarh) high season only	7.86c
Network access charge (R/kVA/m)	R8.92
Network demand charge (R/kVA/m)	R16.92
Service Charge (R/Account/day)	R50.09
Administration charge (R/POD/day)	R111.16

Figure 6-4: Eskom Local Authorities MegaFlex Rate (Eskom 2011)

6.4 Hessequa Electricity Tariffs

The electricity tariffs for Hessequa Municipality are similar to those of other local authorities by mostly relying on a kWh charge, with the exception that the unoccupied beach houses are charged a set monthly tariff. This is done to keep the electricity network operational throughout the year and for the grid to be stable in the peak holiday season. Most of the residential customers are on a prepaid tariff structure and indigent residential customers who qualify for the free 50kWh per month need to apply for this status with the municipality (Hessequa 2012a). The tariffs are summarised below in Table 6-2.

	Energy charges (R/kWh)		Monthly Charge		R/Amp/m		Demand (R/kVA/m)	
	2011/2012	2012/2012	2011/2012	2012/2012	2011/2012	2012/2012	2011/2012	2012/2012
Prepaid Residential >600kWh/m	R 1.1400	R 1.3435						
Prepaid Commercial	R 1.0200	R 1.1628						
Conventional Residential >600kWh/m	R 0.8200	R 0.9104	R116	R129	R4.30	R4.80		
Conventional Commercial	R 0.6800	R 0.7752	R131	R145	R4.80	R5.30		
Large Power Users	R 0.4500	R 0.4996	R4 969	R5 214			R 100	R 111
Farming	R 0.6000	R 0.6662	R606	R673				
Departmental / streetlights	R 1.7360	R 1.9270	R15	R17				
Old age homes	R 0.5500	R 0.6107	R624	R693				

Table 6-2: Tariffs charged by Hessequa Municipality excl VAT (Hessequa 2012)

6.5 Riversdale revenue and expenses

The financial information for the electricity revenue and costs of Riversdale for the period 1 July 2011 to 30 June 2012 was received from municipal officers (Carina Oosthuizen, Louw Saayman). Note the following:

- The income figures obtained from the billed customers are actual, but the income from prepaid electricity was deduced from the actual figures for the whole of Hessequa.
- All prepaid businesses in Hessequa were presumed to be in Riversdale (as advised by Louw Saayman) and the remainder was presumed residential.
- The indigents were taken as 1 864 (the amount of indigent households in Riversdale in October 2012)

- The "not paid" portion for indigents was taken as the budgeted amount of R781 166. This is included as both an income and an expense as it is presumed that it will be covered by the grants from Treasury.
- All the Eskom expenses are actual figures taken directly from the Eskom monthly accounts. Riversdale is billed as a separate unit by Eskom.
- All other income and expenses are the budgeted figures for the period
- An amount of R706 200 for capital expenses of was not taken into account, as this is considered to be included in the depreciation expense
- The departmental income from electricity was not taken into account (but it is shown in the income analysis graph)[12]

Electricity Revenue and Expenses for Riversdale Municipality 2011 / 2012		
Income		R27 590 263
	Electricity sales	R27 142 318
	Service Charge Income	R419 175
	Electrician services and special meter readings	R28 770
Expenses		R26 521 557
	Eskom account	R17 654 582
	Employee related costs	R4 156 874
	Prepaid commission	R191 232
	Depreciation	R944 737
	Repairs and Maintenance	R999 312
	Interest	R814 778
	Other Expenses	R1 582 170
	Provisions	R177 872
	Surplus / (deficit) for the year	R1 068 706 (4,0%)

[12] We understand that departmental electricity use (offices, streetlights, etc.) is seen as a service which should be accounted for via the rates and not purely as an expense to the electricity department. However, seeing as it could theoretically be billed at any chosen rate as a interdepartmental budget transfer, it is left out.

Table 6.3 Electricity Revenue and Expenses for Riversdale Municipality 2011/2012

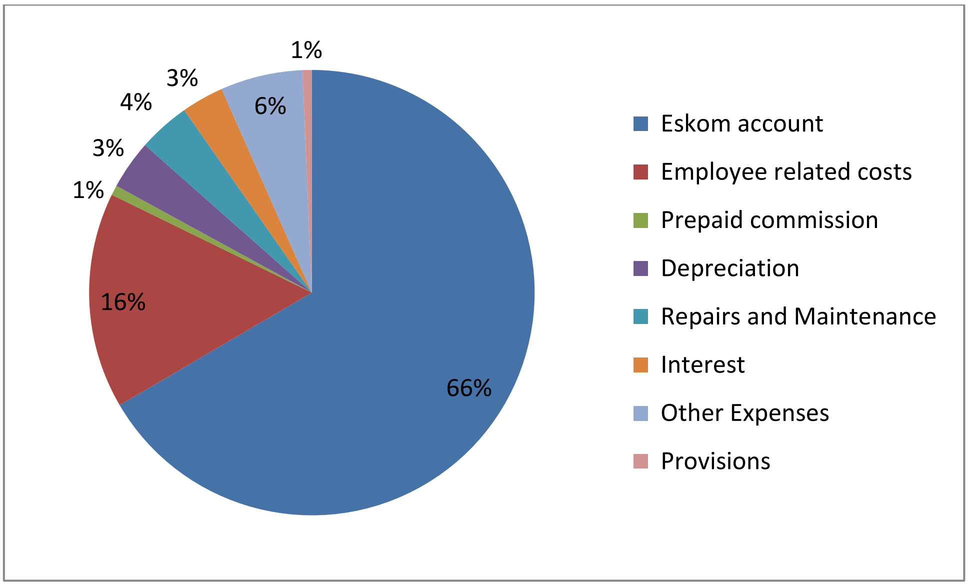

Figure 6-5: Riversdale Electricity Expenses

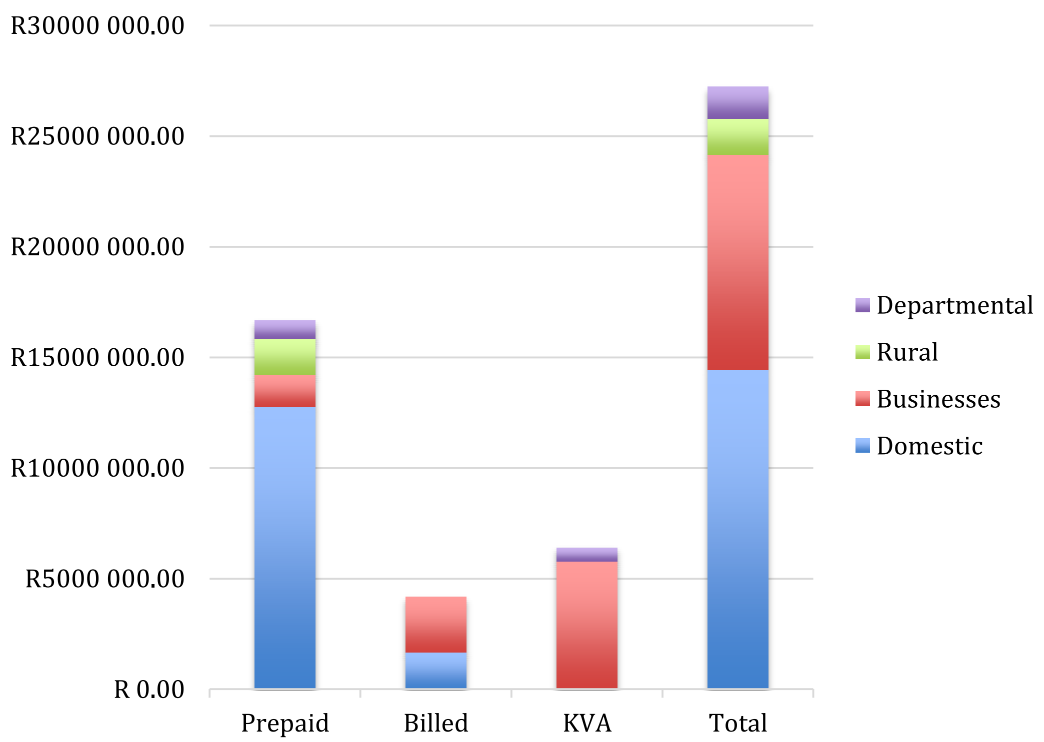

Figure 6-6: Electricity Income Riverdsale - 2011/2012

If the income and expenses for 2011/2012 for electricity in Riversdale is analysed, there was a slight surplus for the time. This surplus makes up 4% of the electricity revenue and can be considered negligible. This is in stark contrast with the 16% surplus shown for electricity in Hessequa Municipality as a whole. There are also many more businesses in Riversdale than the rest of Hessequa.

It is quite possible that the detail of the Riversdale financials for electricity is due to the context of the greater municipal area where the bulk of the electricity income in derived from residential customers. Even though for the purposes of this study, only Riversdale financials will be analysed for the impact of rooftop PV, this context should be remembered.

It is interesting to note that 66% of the expenses of the electricity department in Riversdale is for the Eskom account. 85% of the Eskom bill is calculated as a kWh charge and should reduce in line with reduced demand.

The total fixed costs for the year to June 2012 for Riversdale Municipality is R10 697 955, made up of R2 509 015 in fixed charges on the Eskom bill plus R8 188 940 in internal operating costs.

6.6 Conclusion

It is often considered that municipalities in South Africa make a surplus with electricity sales though which they subsidise other costs. Riversdale town might thus be unique in that it does not seem to generate a huge surplus from electricity sales. The monthly Eskom bills make up a large portion of the electricity expense and 85% of this expense is charged per usage.

7. Financial viability of rooftop PV

This section investigates the financial viability of rooftop PV from the perspective of the two primary stakeholders identified in this report: the municipality and the rooftop owner.

7.1 Financial viability of rooftop PV for the municipality

Rooftop PV impacts on municipal electricity sale revenues in the same way that solar water heating, more efficient appliances and other energy-use reducing strategies will. It reduces the amount of kWhs that the municipality sells. This impact on municipal revenue, from the perspective of this report, is an inevitable part of a societal move towards greater energy-efficiency[13].

The important difference between rooftop PV and the use of energy efficient appliances or other energy saving methods, is that the PV system produces electricity and it can be sized to reduce the net energy consumption of a customer to zero. It could even be sized to allow the customer to become a net exporter of electricity. Should this happen, municipalities will need to protect the financial viability of their electricity supply operations by ensuring the following:

- when rooftop PV reduces the electricity consumed by the rooftop owner to net zero, the cost of providing a network connectivity service to the rooftop owner must still be recovered, and
- when rooftop PV is a net exporter, the municipality will have to pay the same or less for the exported electricity than if the energy was bought from Eskom.

In the light of the above, the following sections will estimate:

1) the cost of providing a network connectivity service to the rooftop owner, and
2) the financial value that exported rooftop PV electricty represents to the municipality, based on the charges it pays to Eskom
3) the impact that unregulated rooftop PV installations will have on municipal revenues

[13] Price elasticity also plays a role in lowering energy consumption: Statistics South Africa has reported a decline in electricity use of 2,6% for 2012 as compared to 2011. In this same time the gross domestic product rose by 2.5%. In the past, the growth in electricity consumption of South Africa was closely linked to the growth in the economy. It is possible that the price of electricity has caused this shift as this has more than doubled in the past five years (Mantshantsha, 2013).

The impact of rooftop PV on municipal revenues can also be mitigated by the requirment of other peak period demand-reducing options as a pre-requisite for rooftop PV installation. Because of this a section is added here to estimate the value of this.

7.1.1 The cost of providing a network connectivity service

This section aims to estimate the cost of providing a network connectivity service to a customer connected to the municipal network, with the aim to inform subsequent discussions. A more accurate analysis will be required if this value is to be used as part of any future tariff implementation, but this falls outside the scope of this study.

As mentioned in section 6.5, the total fixed costs to maintain electricity in Riversdale was R10 697 955 for 2011/2012, which includes all fixed cost charges to Eskom, as well as electricity departmental costs. In the extreme scenario where no customers use any net kWh electricity from the municipality during a month, this amount will still be payable by the municipality. It is therefore assumed that this amount divided between all the customers represents the cost of network connectivity to the customers.

From the GIS database it is estimated that there are 157 industrial, commercial and agricultural customers. The residential customers are estimated at 316 high income and 526 medium/low income customers. In addition to this there are 1 864 indigent customers.

It should be possible for Riversdale to restructure the way electricity is billed for – Figure 7-1 offers an estimate on what these fixed charges might be. Keep the following in mind:

- With indigent customers, some of this cost will be covered by the free basic electricity grant from Treasury.
- The monthly costs are averages, so larger commercial customers might pay more and smaller ones less.
- With these fixed costs the energy usage will be charged at cost (R0.47 per kWh from section 7.1.2).
- It can be argued that a net zero consumption or net export customer does not make use of the utility's generating capacity, but only depends on the distribution system and should therefore be contributing only to the costs associated with this utility asset. For simplicity's sake this adjustment is not made in this report, but it should be considered when a more detailed tariff study is executed.

	Customers	Daily charge	Per month per customer	Per year per customer	Total income to Riversdale
Commercial	157	R94.50	R2 874	R34 493	R5 415 323
High Income	316	R12.00	R365	R4 380	R1 384 080
Medium / low income	526	R8.00	R243	R2 920	R1 535 920
Indigent households	1 864	R3.50	R106	R1 278	R2 381 260
Total income to Riversdale from daily charge					R10 716 583

Figure 7-1: Daily charge for electricity income for Riversdale per group

7.1.2 The financial value to the municipality of exported PV energy

The energy generated by rooftop PV represents value to the municipality in at least three ways:

- the kWh energy that is generated,
- the potential to reduce the monthly peak kVA demand, and
- the additional capacity that can be added to Riversdale

In this report the assumption is made that distribution network losses within Riversdale town are negligible.

7.1.2.1 The financial value of rooftop PV per kWh

As explained in chapter 6, Riversdale buys electricity from Eskom on the Megaflex tariff structure, which charges for energy on a time-of-use basis.

The equivalent per kWh value of rooftop PV was calculated by investigating the amount of energy that is generated by 1kWp of rooftop PV in 2011/2012 within each of the time-of-use periods (peak, standard, and off-peak; summer and winter), and then applying the 2011 / 2012 Eskom Megaflex tariff prices. The results are shown in Table 7-1.

Month	kWh generated by 1kWp of rooftop PV (kWh):			kWh cost (R excl. 2011/12):			Total value
	Peak	Standard	Off-peak	Peak	Standard	Off-peak	
Jan	20.92	97.40	35.85	R 0.60	R 0.39	R 0.29	R 61.55
Feb	14.63	86.55	30.58	R 0.60	R 0.39	R 0.29	R 51.92
Mar	16.17	97.68	31.89	R 0.60	R 0.39	R 0.29	R 57.62
Apr	12.38	85.16	32.54	R 0.60	R 0.39	R 0.29	R 50.59
May	10.33	68.68	27.47	R 0.60	R 0.39	R 0.29	R 41.37
Jun	6.65	59.34	16.00	R 0.60	R 0.39	R 0.29	R 32.09
Jul	6.22	62.69	22.69	R 2.01	R 0.57	R 0.33	R 55.59
Aug	8.72	77.52	20.23	R 2.01	R 0.57	R 0.33	R 68.22
Sep	12.17	81.68	27.28	R 2.01	R 0.57	R 0.33	R 79.84
Oct	17.71	89.71	34.36	R 0.60	R 0.39	R 0.29	R 56.14
Nov	23.53	91.85	31.74	R 0.60	R 0.39	R 0.29	R 59.73
Dec	24.40	100.12	32.68	R 0.60	R 0.39	R 0.29	R 63.79
			1515.56	Total value	R 678.46		
						Total energy (kWh)	1515.56
						Total R/kWh	R 0.45

Table 7-1: Calculation of the equivalent rooftop PV energy cost when it offsets Eskom's Megaflex tariff

7.1.2.2 The potential to reduce the monthly peak demand through PV

Analysis of Riversdale's demand between July 2011 and June 2012 indicates that the peak monthly demand almost consistently occurs during the late afternoon between 16h00 and 17h30, as shown in column 2 of Table 7-2 below.

Month	Date and time of peak demand (without PV)	Date and time of peak demand (with PV)	Peak kVA decrease as a % of PV installed capacity
Jan	Thu 19 Jan 16:30	Thu 19 Jan 16:30	20%
Feb	Mon 20 Feb 16:00	Wed 22 Feb 16:00	29%
Mar	Tue 13 Mar 16:00	Wed 07 Mar 16:30	32%
Apr	Wed 04 Apr 16:00	Wed 25 Apr 17:30	17%
May	Tue 29 May 17:30	Tue 29 May 17:30	1%
Jun	Tue 12 Jun 17:30	Tue 12 Jun 17:30	2%
Jul	Mon 04 Jul 17:30	Mon 04 Jul 17:30	2%
Aug	Thu 04 Aug 17:30	Thu 04 Aug 17:30	8%
Sep	Fri 02 Sep 11:00	Wed 14 Sep 17:30	28%
Oct	Wed 12 Oct 17:30	Wed 19 Oct 16:30	15%
Nov	Tue 08 Nov 16:30	Wed 09 Nov 17:30	26%
Dec	Tue 06 Dec 16:30	Mon 05 Dec 16:00	38%

Table 7-2: The potential impact of rooftop PV on the reduction of the monthly peak kVA value used to calculate the peak demand charge in Eskom's Megaflex tariff.

In order to analyse the impact that rooftop PV can have on this peak, a simulation using 2011/12 solar irradiation data was run, where the output from an optimally orientated 1MWp rooftop PV system was subtracted from the 2011/2012 kVA demand of Riversdale. The simulation results are documented in the third and fourth columns of Table 7-2.

During summer the rooftop PV installations are still generating strongly around 16h00-17h30, which explains why during summer months the reduction in peak demand due to PV can be as high as 38% of the total installed capacity of the rooftop PV, i.e. the example 1MWp PV system used in the simulation can reduce the peak load by up to 380kVA[14].

Figure 7-2 below explains the process: the top line represents the demand on the day of peak demand in December 2011: the peak occurs around 16h30 (note that the peak occurrence differ from the average weekday for December, which represents the times where most energy is used, rather than monthly peak demand). At this time the PV array is still generating, which lowers the peak on 6 Dec to such an extent that the peak demand now occurs on a different day, 5 Dec.

[14] A power factor of one is assumed throughout this report, equating kW and kVA

Note that, as shown in Figure 7-3, PV does not impact peak demand much in June, as the sun sets too early to allow generation of significant power at the time of peak demand.

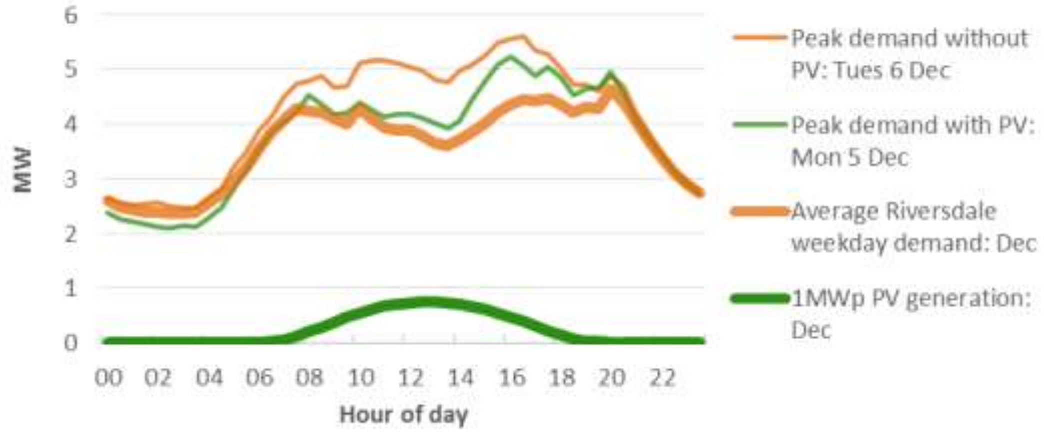

Figure 7-2: The potential impact of rooftop PV on Riversdale's December 2011 monthly peak demand

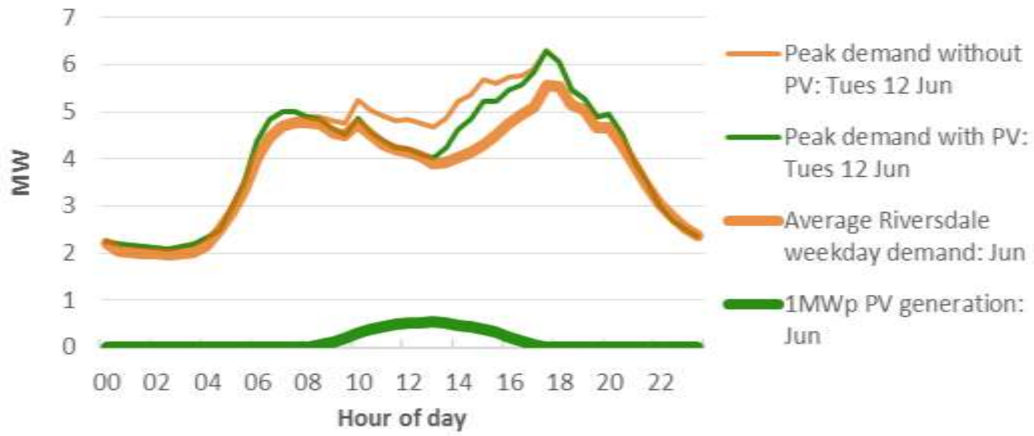

Figure 7-3: The potential impact of rooftop PV on Riversdale's June 2012 monthly peak demand

Table 7-3 calculates the average value of this peak demand reduction in terms of kWh, by deviding the total value by the amount of energy generated per year by a 1kWp PV system.

Month	Peak kVA reduction (kVA):	Peak kVA cost (R excl 2011/12):	Total value
J	0.20	R 16.92	R 3.35
F	0.29	R 16.92	R 4.87
M	0.32	R 16.92	R 5.35
A	0.17	R 16.92	R 2.88
M	0.01	R 16.92	R 0.23
J	0.02	R 16.92	R 0.30
J	0.02	R 16.92	R 0.33
A	0.08	R 16.92	R 1.34
S	0.28	R 16.92	R 4.70
O	0.15	R 16.92	R 2.49
N	0.26	R 16.92	R 4.46
D	0.38	R 16.92	R 6.39
		Total value	R 36.68
		Total energy (kWh)	1515.56
		Total R/kWh	**R 0.02**

Table 7-3: Calculating the equivalent per kWh value of the peak demand reduction of 1kWp of rooftop PV

7.1.2.3 The financial value of additional capacity

If Eskom is able to offer extra electricity capacity to a local authority that needs this, it is very expensive, in the region of R2 000 / kVA. In most cases there is a minimum size such as the size of the smallest transformer. In case of a 132kVA to 11 kVA, this would be 5MW. It will thus cost a local authority a minimum of R10 million to be able to offer new electricity connections should this constraint exist (HB Barnard, 2013).

Rooftop PV is capable of alleviating this constraint, but obviously only while the sun is shining (except where batteries are used, which is outside the scope of this report). If the customer's demand profile exactly follows this generation curve, then rooftop PV is capable of fully replacing the capacity offered by Eskom. That is however unlikely given the daily and seasonal changes in solar irradiation, and varying customer energy usage patterns.

In the light of this, it is difficult to estimate the financial value of the additional capacity that e.g. a 1kWp rooftop PV system might provide. To estimate a value, it is assumed that the peak periods of the day (early morning and late evening) will be the times when the network are at its most constrained, and where additional capacity is the defining factor. Looking at the peak reduction results summarised in Table 7-2, a range of between 0-38% of the PV generator's peak load can be assumed to be available during this time.

A 1kWp system will therefore add around 0-38% of its rated value to the municipality – the value of this 0-380Wp is therefore around R0-R720 once-off for a 1kWp installation.

7.1.3 The financial value of non-PV demand-reducing actions during peak periods

As shown in section 6.3 municipalities pay a premium for electricity during peak demand periods, which they might be unable to pass on to consumers given their fixed price structure. This can result in a net revenue loss for municipalities for every kWh consumed during peak periods (Vermeulen, 2012). It might therefore be in the interest of the municipality to implement measures that reduce the consumption of energy during peak periods. These measures are also likely to impact the peak monthly demand component of the municipality's electricity costs, as the monthly peak typically occurs during peak periods (see Table 7-2).

The "after work" peak in a residential context can be largely attributed to electric cooking appliances and water heating. By moving to gas stoves and solar hot water heaters, the "after work" peak can be significantly reduced (Vermeulen, 2012). Further effective measures to reduce the peak and therefore costs for municipalities are:

- Remote control of geysers (or backup heating elements) by municipality[15]
- Remote load shedding by municipalities of other non-time critical loads (fridges, swimming pool pumps, dish washers, washing machines)

The above two measures might be perceived as inconveniences by some users and are therefore unlikely to be implemented voluntarily.

Calculating the value of such interventions within the context of Riversdale cannot be done accurately given that the actual demand and time of use varies from household to household.

[15] This enables municipalities to leverage the thermal storage capacities of residential geysers to smooth out the demand curve. About 160,000 remote geyser controls have already been installed by City Power Johannesburg (Vermulen 2012).

Hoever placing some value to it might provide a feel for the potential financial impact. The impact of reducing the peak energy consumption by 3kWh per day (2kW stove/oven used for 30 minutes, and a 2kW electrical geyser used for one hour during the peak period) and the associated monthly peak demand reduction (assuming a load factor of 0.5) is calculated below in Table 7-4 as R585 per year. It was assumed that the savings will be in the tariff band of 351-600kWh.

	Municipal costs (peak periods)		**Residential energy costs**		**Reduction per month**		**Impact of lowered peak on municipality**		
	Energy (R/kWh)	Monthly peak (R/kVA)	Conventional (R/kWh)	Prepaid (R/kWh)	Energy (kWh)	Demand (kVA)	Conventional (R)	Prepaid (R)	Demand (R)
Jan	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Feb	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Mar	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Apr	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
May	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Jun	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Jul	R 2.01	R 16.92	R 0.70	R 1.13	91.25	1.50	R 119.57	R 80.34	R 25.38
Aug	R 2.01	R 16.92	R 0.70	R 1.13	91.25	1.50	R 119.57	R 80.34	R 25.38
Sep	R 2.01	R 16.92	R 0.70	R 1.13	91.25	1.50	R 119.57	R 80.34	R 25.38
Oct	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Nov	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
Dec	R 0.60	R 16.92	R 0.70	R 1.13	91.25	1.50	-R 8.68	-R 47.92	R 25.38
						Total losses:	**R 280.62**	**-R 190.23**	**R 304.56**

Table 7-4: Estimate of the value of demand reduction during peak periods.

7.2 Financial viability of rooftop PV for the rooftop owner

Although the financial viability of rooftop PV from a rooftop owner perspective is relatively easy to calculate in terms of metrics like payback period or internal rate of return, the results become more meaningful when compared against the financial viability of other investments that can be made with the same capital expenditures.

For that reason this section is split in two: in the first part the performance of alternative investments to PV, like shares and property, are estimated. In the second part the financial viability of rooftop PV is investigated.

To start with, however, some financial modelling assumptions will be introduced.

7.2.1 Financial modelling assumptions

7.2.1.1 Future electricity pricing

The electricity price forecasting for payment to Eskom by the municipality is based on the following:

- An average price increase of 8% per year from 2013 for 5 years has been announced on 28 February 2013 by NERSA.
- An educated guess of another 8% increase per year for the next 5 years. This guess is based on the above, increases in the last five years and the planned infrastructure investment and repayment plans at Eskom.
- An educated guess of 5.5% increase annually for the remainder of the forecast period.

7.2.1.2 Building insurance

0.24% per year is a typical insurance value for buildings, which include geysers. According to an expert in the field, geysers make up around 50% of the risk profile: this means that adding PV should increase the premium by the value of the PV installation times 0.12% (Harkema, 2013) - PV is however an unknown risk factor, so it was decided to model the additional building insurance due to PV at 0.18% per year.

7.2.1.3 Method used to compare financial viability

Investments in rooftop PV typically have long payback periods and are compared to other investment opportunities over twenty years.

Investment in PV is most often explained in terms of a "pay-back" method. As this method does not allow comparison to other investments, the internal rate of return (IRR) is used in this report.

It is often possible for customers to reduce their electricity with a lower (or even no) investment cost than PV, such as behaviour change (switching off), changing to energy efficient appliances and by fuel switching.

This technology switch and energy saving behaviour changes are difficult to predict as price elasticity of electricity is highly dependent on the pricing level (Fan, 2012). The electricity price is also more elastic in the short term than the long term as it is easier to switch technologies over time.[16]

It is possible that consumers who take the trouble to install PV on their rooftops might, just by engaging with the process, become more aware of their electricity use and adjust their usage accordingly.

In a reasonably price elastic situation, a rebound effect is sometimes noticed (Davis et al 2011). In this instance, consumers use more electricity because it "doesn't cost them anything" after energy saving technologies are installed.

Investment in rooftop PV is also often done for reasons other than the financial benefit.

As all the above scenarios is impossible to model, for the purposes of this report a rational investment view is taken and the investment in rooftop PV is compared to other investments purely from a financial perspective.

7.2.2 Estimated performance of alternative investment to rooftop PV

In this section several alternative investment scenarios to rooftop PV are discussed in terms of their estimated internal rate of return.

7.2.2.1 Property

An investment could be made in property in Riversdale to be rented out. This might be a bought property or newly built. The potential for expansion in Riversdale and the likelihood of full occupation and rental income is presumed even though in reality this will be dependent on supply and demand in the town. An investment in property can also be done for own use, but in this scenario rental is presumed. The assumed price for the investment will be R1 000 000.00.

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[16] The price elasticity refers to how easily consumers adjust to price changes. In a highly elastic electricity price situation, there will be no difference in consumption no matter what the price. In an inelastic price situation, consumers will adjust their electricity usage according to the price.

A rental income starts at R4 000 per month and is increased yearly with 5.5%. Property rates are taken as 0.4604% and insurance at 0,204% of the investment. Maintenance costs of R25 000 is taken every five years. The capital growth for the investment was based on the capital growth in property over the past 20 years adjusted for CPI. The projected CPI up to 2032 was taken as 5.5%.

The IRR for this investment scenario is 16.7%

7.2.2.2 Money Market

A 20 year interest rate projection was obtained from the Bureau of Economic Research at Stellenbosch University and this investment scenario was based on this.

The IRR for this investment scenario is 6.6%

7.2.2.3 Stock Market

The stock market projection was based on the FTSE / JSE index over the past 20 years, adjusted with CPI. A CPI of 5.5% was presumed for the time 2013 – 2032.

The IRR for this investment scenario is 23.4%

7.2.3 Financial viability of rooftop PV from a rooftop owner perspective

7.2.3.1 Scenario without any enabling mechanism

The analysis of the financial viability of installing rooftop PV was done based on the following:

- VAT can be claimed back
- No SARS accelerated depreciation applies
- No Eskom standard offer rebate programme applies
- All energy generated by PV system is paid for (either as electricity cost avoided or credited by municipality)
- No cost of capital or loan servicing payments applicable
- Any peak monthly demand charge tariff cost component is incorporated with the /kWh charge into an equivalent kWh charge, based on the potential for PV to reduce peak demand analysed in section 7.1.2.2.

- Fixed monthly tariff charges are not offset by PV generation, and are therefore not included into the equivalent R/kWh cost.

The surface graph in Figure 7-4 below represents the results of the analysis: as can be seen, the lower the cost of installation and the higher the tariff applied to the energy that is offset by the PV system, the more financially viable the installation becomes.

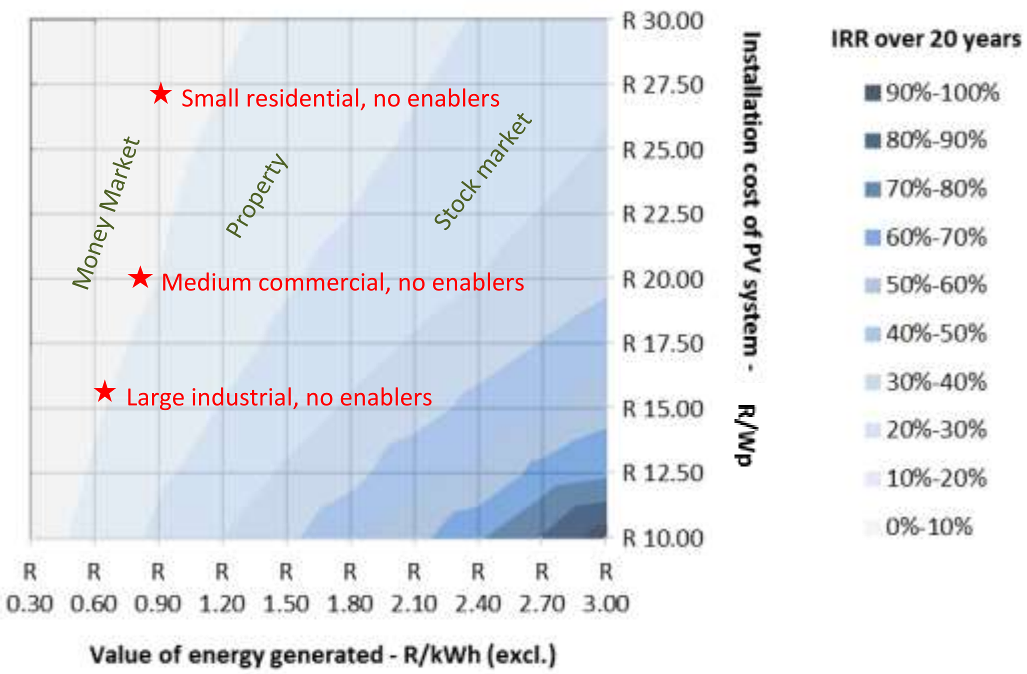

Figure 7-4: Surface graph showing financial viability (Internal Rate of Return) for a rooftop PV owner as a function of installation capital cost and the equivalent kWh value of the electricity generated

Three systems (with no enabling mechanisms) are placed on this surface in Figure 7-4 to illustrate the impact of installation capital cost, and equivalent kWh cost:

1) Small-sized Residential System (see appendix B for calculations, resulting in an IRR of 7%, and payback of 14 years):
    a. 2kWp installed at R27 / Wp excl. VAT
    b. VAT not claimable
    c. Conventional meter residential tariff, assumed at highest tier of R0.91/kWh

2) Medium-sized Commercial System (resulting in an IRR of 9%, and payback of 12 years):
    a. 10kWp installed at R20/Wp excl. VAT
    b. VAT claimable
    c. Conventional meter commercial tariff, eq. value of R0.81/kWh
3) Large-sized Industrial System (resulting in an IRR of 9%, and payback of 12 years):
    a. 40kWp installed at R16/Wp excl VAT
    b. VAT claimable
    c. LPU tariff, eq. value of R0.66/kWh

As can be seen in Figure 7-4, even though larger systems cost less to install, the value of the energy generated is also less, resulting in broadly similar returns on investment for residential, commercial and industrial systems, of around 12 to 14 years payback and IRRs in the region of 7 to 9% over 20 years.

7.2.3.2 Scenarios that include current enabling mechanisms

SARS accelerated depreciation and Eskom's Standard Offer significantly improve the financial viability of systems where the benefits can be claimed. Two such scenarios are analysed:

1) Medium sized commercial system as before, but in addition
    a. SARS accelerated depreciation is claimed – this depreciation value is modelled as equivalent to a 31% reduction in capital installation cost.
2) Large-sized industrial system as before, but in addition
    a. Eskom's Standard Offer rebate is claimed – this rebate's value is equivalent to a R0.19/kWh (over 20 years) increase in the kWh value of the PV energy.
    b. SARS accelerated depreciation is claimed – because of the Eskom rebate the amount that can be depreciated is decreased, decreasing the value of SARS to 22% of installation value.

The results of scenarios 1 and 2 are shown in Figure 7-5, as having moved to a financially more viable position.

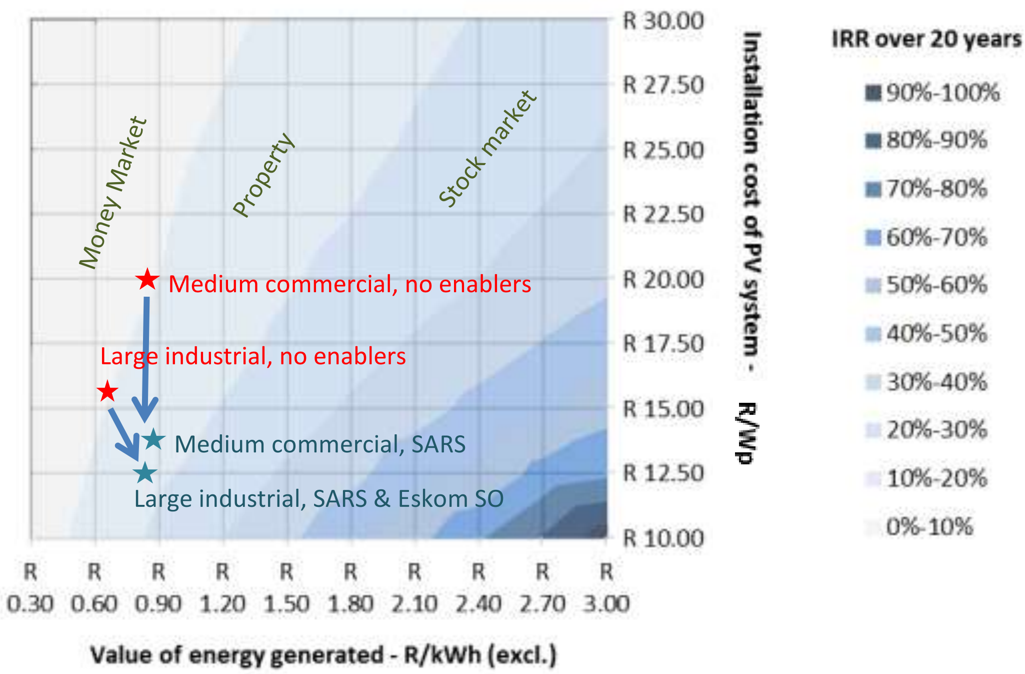

Figure 7-5: Surface graph showing financial viablility (Internal Rate of Return) for a scenario 1 and 2 rooftop PV owner as a function of installation capital cost and the equivalent kWh value of the electricity generated

7.2.4 Conclusion

Finally, it is interesting to place the 20 year performance of all the investment alternatives onto a graph, together with the two extremes of PV system financial viabilities: Large industrial with and residential without enablers (Figure 7-6). From this figure it can be seen that Residential PV systems are only borderline financially viable.

Best case large industrial rooftop PV ultimately is overtaken by property and stocks, but it is important to note that property and even more so stocks are difficult to predict into the future.

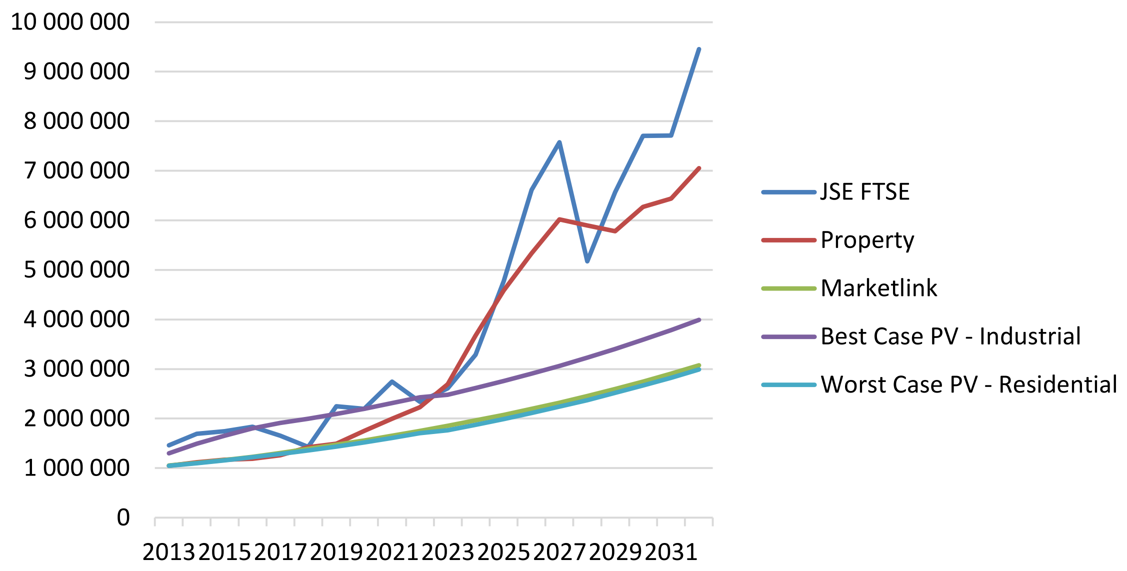

Figure 7-6: Rooftop PV predicted performance over the next 20 years, compared to alternatives

8. The impact on the municipality of unregulated rooftop PV connection

Unregulated connections of rooftop PV to the municipal grid have a number of impacts. From a technical perspective non-compliant equipment might be used, which can impact power quality on the network or even endanger the life of municipal employees doing maintenance on the distribution grid infrastructure by not stopping generation when the grid is powered off. From a financial perspective the municipality might lose revenue as the rooftop owner's electricity bought from the municipality decreases. This will have associated socio-economic impacts.

There are three different scenarios that are usually considered when evaluating the potential resource of renewable energy:

Total available resource: This is the total resource available at a certain location without considering the efficiencies of the technology to extract the energy and convert it to say electrical energy or any other constraints that may exist.

Technical resource: This is the resource available considering the technology used to convert the available resource to electricity and its associated efficiencies as well as the space it will require to install the converters in the available topology. This is the 9,85 MWp calculated considering the conversion efficiency of the PV panels as well as the available roof area, with the correct orientation available in Riversdale.

Practical resource: This is the resource available taking all the other issues into consideration including environmental constraints, available grid, land use and other issues such as aviation, etc. and is used for the "business-as-usual" scenarios below.

The stage is now set to attempt to answer the question "what will the loss to municipal revenue due to unregulated installation of rooftop PV be?", i.e. the financial impact of a "business-as-usual" scenario where rooftop owners are installing PV without the municipality's knowledge / approval.

This business-as-usual scenario serves to inform decision makers of likely consequences of non-action. This is the most likely scenario for municipalities in the short to medium term.

The methodology of investigating this impact is:

1) Based on the financial viability of rooftop PV as estimated in the previous chapter, and taking into consideration the rooftop PV potential identified in chapter 4, estimate how many Riversdale rooftop owners of what category will install PV in the short to medium term, and how big these systems will be.
2) Given these uptake estimates, model the financial and socio-economic impacts within the municipality.

8.1 Estimating unregulated rooftop PV uptake

In order to estimate the likely number of unregulated rooftop PV installations in Riversdale over the short to medium term, the motivations of rooftop owners in Riversdale to invest in rooftop PV need to be understood.

As mentioned in Chapter 2, the decision by the rooftop owner to invest in rooftop PV is influenced by a wide range of factors, not all rational and/or based in financial viability. For this reason, it is extremely difficult to predict what kind of investment decisions will be made and which indicators will persuade investment decisions.

8.1.1 Methodology

The methodology followed here to estimate the uptake of unregulated rooftop PV in Riversdale is as follows:

1) Of all the roofspace available for PV, ignore any owners with prepaid meters, low-income owners that is likely not to be able to afford the cost of a rooftop PV system, and local / provincial/national government owned roof space. As explained earlier, only MD metered households and establishments can at present install unregulated rooftop PV, as prepaid meters will trip or continue incrementing as soon as energy is exported.
2) Of the remaining roof space, estimate the uptake grouped into three categories (identified in section 7.2 as having differing motivations to install due to the different enabling mechanisms that apply to each). The estimated uptake will be based mainly on financial viability, but also acknowledging the sometimes irrational nature of investment decision making:
    a. Small residential systems <3.68kWp single phase or <13.8kWp three phase owned by private individuals (not eligible for Eskom standard offer or SARS accelerated depreciation)

b. Medium commercial systems <16.2-19.8 kWp owned by business (not eligible for Eskom standard offer)
c. Large industrial system >16.2 – 19.8 kWp owned by business (eligible for Eskom standard offer)

3) For each of the three categories, estimate the average size of the installed system based on constraints like Eskom's "EG on LV networks criteria" and the criteria to avoid negative monthly net metering.
4) A likely range of unregulated PV rooftop uptake can now be found.

8.1.2 Using GIS to identify eligible erven for potential unregulated rooftop PV

From the GIS database only 274 erven were identified as having MD meters, along with having feasible roof space as indicated in the previous sections. These erven included residential, commercial, industrial, agricultural and other erven.

The erven was then grouped according to the three categories discussed earlier – the following GIS criteria were used to define members of each group:

- Single phase residential (not eligible for Eskom standard offer or SARS accelerated depreciation):
    - erven located in the high income residential area
    - an average monthly consumption between 500-3000 kWh.
- Three phase residential system (not eligible for Eskom standard offer or SARS accelerated depreciation):
    - erven located in the high income residential area
    - an average monthly consumption greater than 3000 kWh.
- Commercial (<16.2-19.8 kWp not eligible for Eskom standard offer):
    - commercial, industrial or agricultural areas
    - an average monthly consumption of between 3000-40 000 kWh
    - where cost data was not available for agricultural rural areas the assumption of having at least an installable system larger than 3.68 kWp was used.
- Industrial (>16.2 – 19.8 kWp eligible for Eskom standard offer):
    - commercial, industrial or agricultural areas
    - an average monthly consumption greater than 10 000 kWh.
    - PV suitable roofspace > 20 kWp

Applying the criteria described above it was possible to estimate the amount of qualifying erven. Out of the 274 erven only 176 erven qualified according to this criteria – they are listed in Table 8-1.

Only a small number of the 176 qualifying erven will adopt unregulated rooftop PV installations, for both financial and non-rational reasons. In order to estimate the reasonable uptake two scenarios were devised based on a conservative and generous uptake. The conservative uptake scenario took a pessimistic view on the rooftop PV uptake, and the generous uptake scenario an optimistic view. The actual numbers were decided upon through a consensus approach among the authors based on the financial viability discussed earlier and current uptake in places like the City of Cape Town.

Group	Qualifying erven	Conservative uptake erven	Generous uptake erven
Residential Single Phase	91	3	15
Residential Three Phase	1	0	1
Commercial	72	2	5
Industrial	12	3	9
Total	176	8	30

Table 8-1: Erven qualifying for unregulated rooftop PV, and estimates of actual uptake of unregulated rooftop PV assuming a conservative and generous approach.

8.1.3 Estimating the sizes of the unregulated rooftop PV systems

8.1.3.1 Eskom's "EG on LV networks" connection criteria

Even though Eskom's proposed "EG on LG networks" connection criteria has not been formalised as a standard or code, it is assumed here that most rooftop installation companies will be aware, and will abide by this in the short to medium term.

As previously discussed the feeder and transformer data available in GIS was not sufficiently detailed to be useful in applying Eskom's connection criteria. Simplified assumptions are therefore made that define /constrain only the maximum installed size for each of the three uptake groups, irrespective of whether more roofspace was available, as shown in Table 8-2.

Eskom criteria	Application area	Allowable EG
Shared LV feeder	Residential	< 3.68 kW
Dedicated LV feeder	Light commercial, industrial and agricultural areas	< 75% of NMD
Dedicated LV feeder or MV	Industrial and agricultural	<75% of NMD, < 350 kW

Table 8-2: Eskom's embedded generation size restrictions

8.1.3.2 Sizing of rooftop PV to avoid negative monthly net metering

A further constraint that informs the average system sizes per group is that the net energy generated by a rooftop PV system in any given month should not exceed the energy consumed by the rooftop owner. This decreases the likelihood of the municipality detecting the installation.

The following assumptions are made:

- For medium to high income residential households the lowest energy consumption for any given month in the year will be 40% below the monthly average per year, i.e. if the household use 1000kWh per month on average, the lowest monthly consumption will by 600kWh. The month with lowest consumption is assumed to be December, when the family leaves for the annual holiday, and when there is no space heating energy requirements.
- Variation in commercial and industrial monthly energy consumption is assumed to be less, with the lowest month assumed to be 20% below the monthly average. This lowest month is assumed to be in the winter months, when sales turnover, air-conditioning and cooling loads, will be low.
- For residential households consumption is mostly at night, while commercial and industrial consumption is mostly during the day.

Simulation results based on these assumptions is shown below in Figure 8-1, for a residential household consuming on average 1000kWh per month, and a commercial entity consuming 3000kWh on average per month.

As can be seen in this figure, an optimally sized system will never export more energy in one month than what is used by the rooftop owner. In the case of a residential site using an average of 1000kWh per month, the maximum rooftop PV system size according to this constraint is 3kWp, for a commercial entity consuming 3000kWh per month the maximum size is 18kWp, and for an industrial entity consuming 14000kWh per month the maximum size is 45kWp. These system sizes are obviously dependant on the actual monthly consumption profile of the entity, but are sufficient to inform the next section.

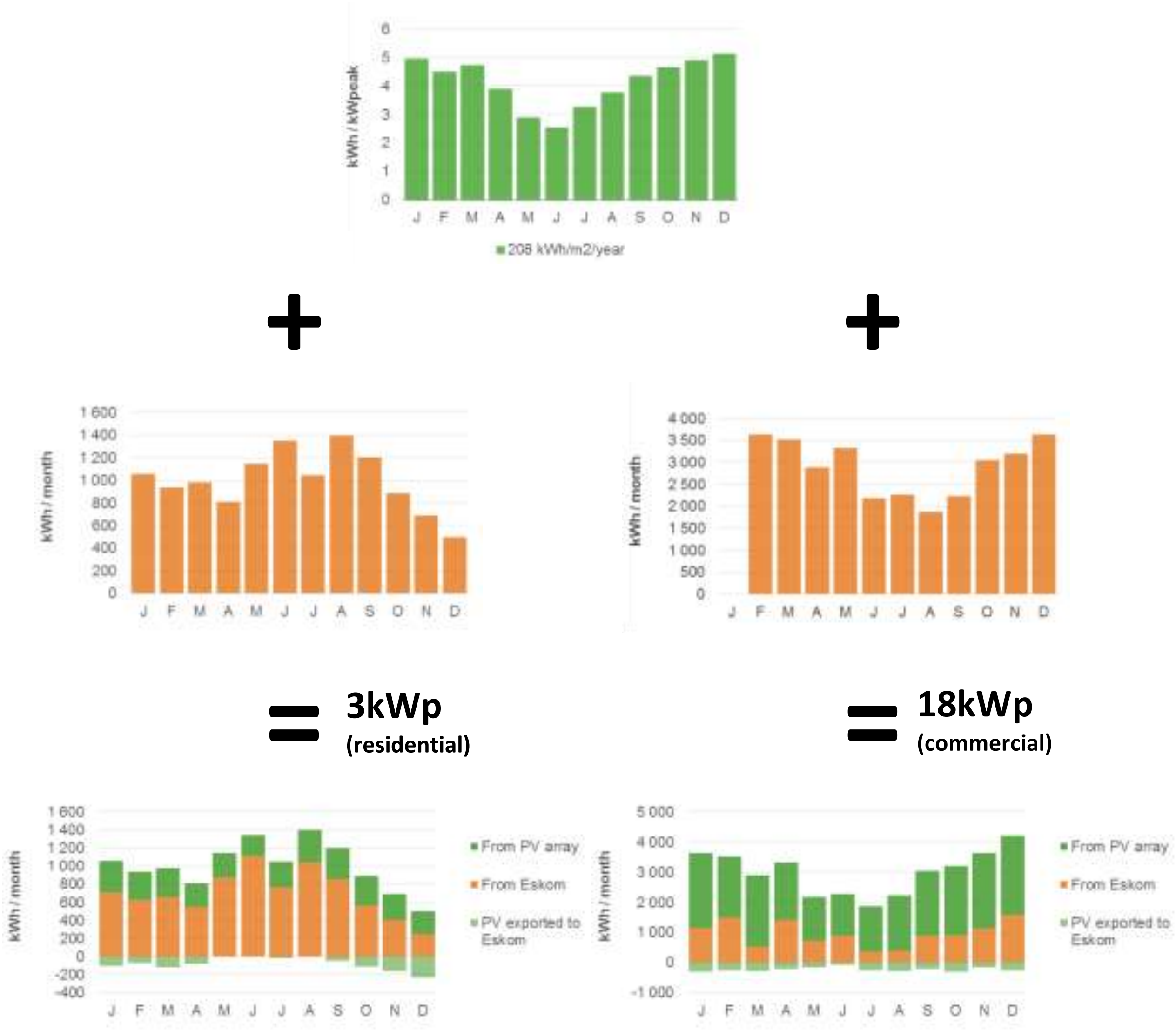

Figure 8-1: The process of finding a rooftop PV size that will avoid net monthly export during all months of the year. Output from PV array (top green graph) + energy consumption from Eskom before PV (middle orange graphs) becomes energy displaced by PV (dark green in bottom graphs) with energy still from Eskom (orange) with PV energy exported (light green).

8.1.3.3 Calculating installed sizes

Informed by the above, it was assumed that the average installations for unregulated residential PV systems was 2 kW system (single phase) and 8 kWp (three phase), and 10 kWp for commercial and 40 kWp for industrial. This results in the estimated installed capacities and annual energy generation as shown in Table 8-3 and Table 8-4.

Conservative		Erven	PV ins (kWp)	Gen (kWh)
	Residential Single Phase	3	6	8 874
	Residential Three Phase	0	0	0
	Light Commercial	2	20	29 582
	Heavy Industrial	3	120	177 496
Total		8	146	215 954

Table 8-3: Conservative uptake scenario

Generous		Erven	PV ins (kWp)	Gen (kWh)
	Residential Single Phase	15	30	44 374
	Residential Three Phase	1	8	20 412
	Light Commercial	5	50	73 957
	Heavy Industrial	9	360	422 022
Total		30	448	560 765

Table 8-4: Generous uptake scenario

8.2 The impact of unregulated rooftop PV on municipal revenue

In the previous section two scenarios of unregulated rooftop installations were described. In this section the impact of these scenarios on municipal revenue is modelled on the 2011/2012 figures (these were chosen as the rest of the report also uses these numbers).

It should be clear from Table 8-5 below that the impact of unregulated PV installations has a negligible negative impact on the municipal revenue. Even in the generous scenario, the impact is less than 1% of electricity income. This amount can easily be covered by an increase in the billed tariff per kWh of just over 5c.

Electricity Revenue and Expenses for Riversdale Municipality 2011 / 2012 Impact of unregulated Rooftop PV installations on municipal revenue			
	No PV installations	Conservative Scenario	Generous Scenario
Income	R26 239 457	R26 083 250	R25 751 281
Electricity sales (KWh)	R20 018 910	R19 862 703	R19 530 734
KVA charges	R5 772 602	R5 772 602	R5 772 602
Service Charge Income	R419 175	R419 175	R419 175
Electrician services and special meter readings	R28 770	R28 770	R28 770
Expenses	R26 361 184	R26 258 516	R26 046 146
Eskom account	R18 172 244	R18 069 576	R17 857 206
Employee related costs	R4 156 874	R4 156 874	R4 156 874
Prepaid commission	R191 232	R191 232	R191 232
Depreciation	R944 737	R944 737	R944 737
Repairs and Maintenance	R993 068	R993 068	R993 068
Interest	R744 778	R744 778	R744 778
Other Expenses	R980 379	R980 379	R980 379
Provisions	R177 872	R177 872	R177 872
Surplus / deficit for the year	-R121 728	-R175 266	-R294 866
Difference		R53 538	R173 138
As a percentage of Electricity Sales		0.20%	0.66%

Table 8-5: Impact of PV installations on Municipal revenue of Riversdale based on 2011/2012 figures for realistic penetration figures

8.3 Maximum penetration of rooftop PV in Riversdale in the short term

The financial impact on municipal revenues in a realistic but conservative situation of rooftop PV installations was described in the previous section. It was seen that the impact on municipal revenues is negligible in these situations.

In this section the "technical resource" as desribed in the introduction of Chapter 8 is further investigated. Note that these scenarios are impracticle in the present climate, so the results are highly theoretical. The impact on municipal revenue will shown for such an aggressive installation scenario with maximum uptake of PV installations in the town. The current billing tariffs are still used as this is still a "business as usual" impact assessment.

Two different billing types are considered. The first is a simple "net metering" billing (scenarios 1 – 4) and the second (scenarios 5-8) is where the consumer is compensated for electricity fed into the municipal grid at the Eskom Megaflex tariff for local authorities (the same that Riversdale pays to Eskom). The percentage of yearly usage fed back into the grid by these installations are taken as 20% for residential customers (as they will mostly use the electricity when the sun is down) and 80% for all customers other than residential (as they are considered to use electricity in the day time).

These two billing types is further split into 50% and 100% potential penetration scenarios calculating only the billed customers and also calculating for the billed as well as prepaid customers. There are thus 8 different scenarios. The penetration figures are derived from the same principles as set out in section 5.

The data used is the same as the sections above and the detail of this can be seen in Table 8-6 below.

Billed customers only					
	Erven	PV ins (kW)	Average installed (kW)	Generated 100% (kWh)	Generated 50% (kWh)
Residential metered	106	363	3	548 114	274 057
Light commercial, industrial, state	30	560	15	805 310	402 655
Agricultural (rural area)	43	659	17	902 550	451 275
Heavy industrial (metered)	11	936	97	1 358 838	679 419
Total	**190**	**2518**		**3 614 812**	**1 807 406**

All customers					
	Erven	PV installed (kW)	PV installed mean (kW)	Generated 100% (kWh)	Generated 50% (kWh)
Residential metered	106	363	3	536 928	268 464
Residential prepaid	375	1116	3.2	1 604 868	802 434
Light commercial, industrial, state. Shared LV feeder metered	30	560	15	805 310	402 655
Light commercial, industrial, state. Shared LV feeder prepaid (town area)	54	513	9.87	737 722	368 861
Agricultural (rural area)	43	659	17	902 550	451 275
Heavy industrial (metered)	11	936	97	1 371 657	685 828
Heavy industrial; dedicated LV or MV feeder (prepaid or not in other scenario)	79	3428	44.5	4 929 649	2 464 824
Total	**698**	**7575**		**10 888 684**	**5 444 342**

Table 8-6 Maximum rooftop PV generation data

It needs to be noted that although these aggressive scenarios are maybe technically possible, this will not be allowed due to the resulting voltage rise. It is for this reason that Eskom's simplified LV connection criteria were developed. The maximum allowable PV installations for Riversdale according to these criteria comes to a total of 1 396kWp.

The finacial impact of the eight resulting scenarios can be seen Table 8-7 and Table 8-8 below.

Electricity Revenue and Expenses for Riversdale Municipality based on 2011 / 2012 figures						
		No PV installations	**50 % only Metered**	**100% only metered**	**50% including prepaid and heavy industrial**	**100% including prepaid and heavy industrial**
Income		**R26 239 457**	**R24 992 150**	**R23 744 843**	**R22 124 691**	**R18 009 925**
	Electricity sales (KWh)	R20 018 910	R18 771 603	R17 524 296	R15 904 144	R11 789 378
	KVA charges	R5 772 602	R5 772 602	R5 772 602	R5 772 602	R5 772 602
	Service Charge Income	R419 175	R419 175	R419 175	R419 175	R419 175
	Electrician services	R28 770	R28 770	R28 770	R28 770	R28 770
Expenses		**R26 361 184**	**R25 478 695**	**R24 596 206**	**R23 706 356**	**R21 051 529**
	Eskom account	R18 172 244	R17 289 755	R16 407 266	R15 517 416	R12 862 589
	Employee related costs	R4 156 874	R4 156 874	R4 156 874	R4 156 874	R4 156 874
	Prepaid commission	R191 232	R191 232	R191 232	R191 232	R191 232
	Depreciation	R944 737	R944 737	R944 737	R944 737	R944 737
	Repairs and Maintenance	R993 068	R993 068	R993 068	R993 068	R993 068
	Interest	R744 778	R744 778	R744 778	R744 778	R744 778
	Other Expenses	R980 379	R980 379	R980 379	R980 379	R980 379
	Provisions	R177 872	R177 872	R177 872	R177 872	R177 872
Surplus / (deficit) for the year		**(R121 728)**	**(R486 545)**	**(R851 363)**	**(R1 581 666)**	**(R3 041 604)**
Net Impact of Rooftop PV installation on Municipal Revenue			R364 818	R729 635	R1 459 938	R2 919 876
Impact as % of Electricity turnover			-1.4%	-2.8%	-5.6%	-11.1%

Table 8-7 Impact of maximum Rooftop PV installation on the municipal revenue of Riversdale municipality for a net metering scenarios

Electricity Revenue and Expenses for Riversdale Municipality based on 2011 / 2012 figures						
80/20 scenarios - Residential 20% own usage / 80% sell and buy back from municipality						
All others 80% own usage / 20% sell and buy back from municipality						
		No PV installations	**50 % only Metered**	**100% only metered**	**50% including prepaid and heavy industrial**	**100% including prepaid and heavy industrial**
Income			**R26 239 457**	**R24 471 956**	**R23 579 296**	**R20 919 135**
	Electricity sales (KWh)	R20 018 910	R19 135 160	R18 251 409	R17 358 749	R14 698 588
	KVA charges	R5 772 602	R5 772 602	R5 772 602	R5 772 602	R5 772 602
	Service Charge Income	R419 175	R419 175	R419 175	R419 175	R419 175
	Electrician services	R28 770	R28 770	R28 770	R28 770	R28 770
Expenses			**R26 361 184**	**R25 101 867**	**R24 548 331**	**R22 735 478**
	Eskom account	R18 172 244	R17 542 586	R16 912 927	R16 359 391	R14 546 538
	Employee related costs	R4 156 874	R4 156 874	R4 156 874	R4 156 874	R4 156 874
	Prepaid commission	R191 232	R191 232	R191 232	R191 232	R191 232
	Depreciation	R944 737	R944 737	R944 737	R944 737	R944 737
	Repairs and Maintenance	R993 068	R993 068	R993 068	R993 068	R993 068
	Interest	R744 778	R744 778	R744 778	R744 778	R744 778
	Other Expenses	R980 379	R980 379	R980 379	R980 379	R980 379
	Provisions	R177 872	R177 872	R177 872	R177 872	R177 872
	Surplus / (deficit) for the year	**(R121 728)**	**(R375 819)**	**(R629 911)**	**(R969 035)**	**(R1 816 343)**
	Net Impact of Rooftop PV installation on Municipal Revenue		R254 092	R508 183	R847 308	R1 694 616
	Impact as % of Electricity turnover		-1.0%	-1.9%	-3.2%	-6.5%

Table 8-8 Impact of maximum Rooftop PV installations on the municipal revenue of Riversdale municipality based on 2011 / 2012 figures should electricity fed into the grid be compensated for at Eskom Megaflex tariff

It is clear from Table 8-7 and Table 8-8 above that the maximum net impact on municipal revenues in a technically possible (yet unlikely) scenario is 11% of electricity income. This loss of income can be mitigated by paying the consumer at Megaflex tariffs (as is paid to Eskom) instead of municipal tariffs (a net metering scenario). The tariff can also be adjusted by the municipality to mitigate this potential loss as long as it is consulted with ratepayers and stays in line with NERSA guidelines.

The tariff at which the municipality compensate consumers for electricity fed into the municipal grid will influence the investment decisions that the consumers make in regards to rooftop PV installations as it will affect the investment income (calculated as reduction in electricity cost).

9. Unlocking the potential for rooftop PV

The storyline that unfolded in the preceding chapters can now be concluded by attempting to answer the central question of the study, "how can the potential for rooftop PV be unlocked in municipalities like Riversdale?"

The storyline in short:

- A review of South Africa's national discussion documents, policies, acts and regulations showed that rooftop PV aligns well with and is supported in principle throughout the government's decision making process. The review made it apparent that the political will, acceptance and encouragement for renewable energy technologies such as PV also exist.
- From a technical perspective a complete set of standards does not exist yet for grid connected small-scale rooftop PV systems, which in general discourages municipalities (who are responsible for the safety and operational integrity of their electricity networks) from allowing rooftop PV connections. This encourages "illegal" connection of PV systems without the knowledge of authorities. Partially completed standards like the NRS097 range and draft documents like Eskom's EG on LV networks connection criteria do however provide a framework within which a small number of municipalities have put in place processes to handle applications to connect PV onto their networks.
- Fairly limited financial incentives are currently in place in South Africa to encourage PV systems: the most important in terms of improving financial viability of PV systems are SARS's accelerated depreciation for renewable energy systems and Eskom's standard offer for renewables. Neither of these are available for the average residential customer.
- Installing rooftop PV systems in South Africa, in the case where financial incentives like the above does not apply (e.g. small residential systems), will provide owners with similar financial returns as investing in a money-market account, i.e. not a strong motivation to install. Where incentives do apply (larger commercial and industrial applications) the financial viability improves and can be compared to the historic performance of property.
- The municipality can protect the financial viability of its electricity supply operations by ensuring that 1) the cost of network connectivity of each customer is recovered even when PV zeros the net energy consumption of the PV owner, and 2) the cost at which energy is bought from a PV exporter is no more than the equivalent cost paid by the municipality to Eskom.

- The case study of Riversdale has shown that the risk that unregulated rooftop PV connections pose to municipalities like Riversdale in terms of revenue loss is negligible, even when a generous uptake of unregulated PV systems over the short term is simulated.
- Even in a maximum potential uptake scenario, the impact on municipal revenue is lower than is often expected.

In the context of the above, the following actions are proposed to unlock the potential for rooftop PV in small South African municipalities:

- Finalise technical standards that inform rooftop PV.
- The municipality provides an environment where legal connections are encouraged.
- Additional incentives are made available that improves the financial viability of rooftop PV.
- The municipality leads by example.

9.1 Finalise technical standards that inform rooftop PV

As discussed earlier, technical specifications like NRS097 are currently still being developed (NRS097-2-1 has already been published), in general discouraging municipalities from allowing rooftop PV connections. Until a full set of South African standards and specifications are available, municipalities that do allow rooftop PV connections have to refer to international standards that sometimes contradict each other, and that might have different requirements from those stipulated in the ultimate South African versions.

An important technical specification that needs to be completed is NRS-097-2-2 "*Grid interconnection of embedded generation: Small-scale embedded generation - Embedded generator requirements*". This document, along with the already published NRS097-2-1 "Utility interface", Eskom's EG on LV networks connection criteria and existing wiring and metering codes, will provide a basic framework within which rooftop PV can be enabled.

The next working group meeting for NRS097-2-1 (edition 2) and NRS097-2-2 is scheduled for April 2013 - it is hoped that these specifications will be published soon afterwards.

9.2 Provide an environment where legal connections are encouraged

A number of challenges face the municipality that wish to provide an enabling environment for rooftop PV:

- If the tariff offered by the municipality for PV generation is equivalent to that which the municipality pays to Eskom (calculated as R0.47/kWh for 2011/2012), very little motivation exist for the rooftop owner to install PV. This is illustrated in Figure 9-1: the R/kWh region that the municipality can afford to pay (on the left) is outside the financially viable range for PV systems. Financial viability decrease further if the municipality adds a further fixed cost component to the tariff for PV net generators, that reflects the cost of network connectivity (estimated in section 7.1.1 at R8-R12 per day for residential customers).

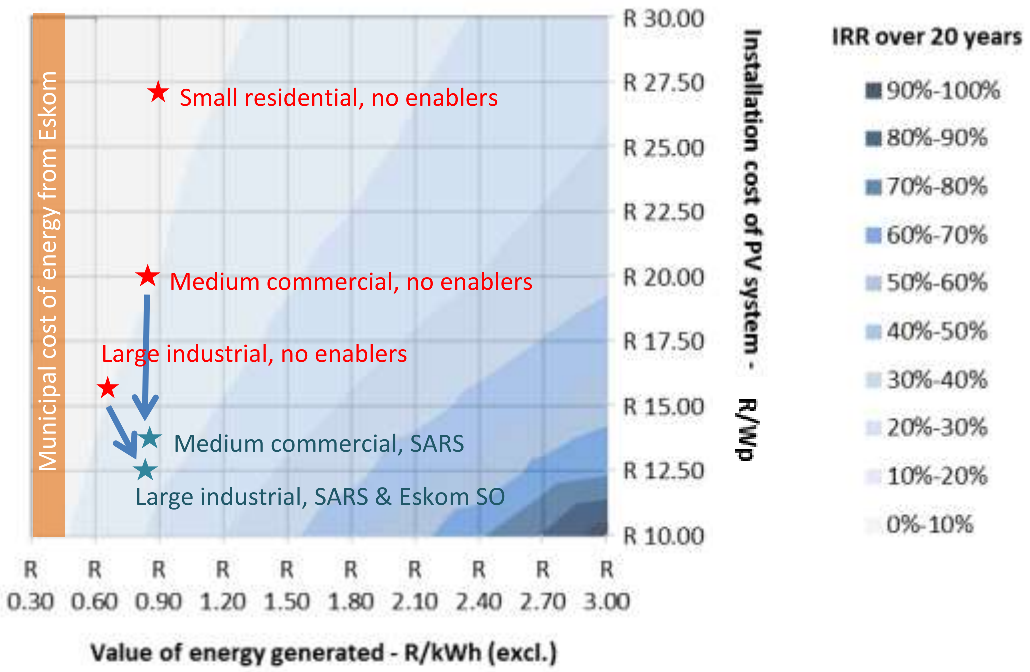

Figure 9-1: Rooftop owner versus municipal financial viability

- The technical framework for the grid connection of PV is still being developed. A lack of applicable standards exposes the municipality to liabilities associated with allowing potentially unsafe / interference causing equipment to operate on their network. This problem can be circumvented by requiring adherence to international standards and ensuring compliance through site inspections, as is required by the City of Cape Town in their rooftop PV pilot project.

Compliance checking like site inspections however adds significant cost to each installation[17], again lowering the motivation of rooftop owners to install PV.

- Rooftop PV can potentially place an administrative burden on the municipality: applications for connection need to be processed, PV net exporters need to be credited, rooftop PV related technical queries need to be answered, etc.

Given these challenges, why not just do nothing and wait to see what others are doing? After all, the business as usual section of this report showed that the financial cost of doing nothing about unregulated rooftop PV connections is negligible.

Several reasons exist, including:

- By providing an environment where legal rooftop PV connections are encouraged, the municipality is aligning itself with national and provincial government policy and decisions.
- It is assumed that national incentive measures for roof-top systems are likely to be available in the medium term or that PV technology will become competitive without incentives in the medium term. By providing an enabling environment the municipality builds competency and gains experience with regards to PV systems, and plays a leading and active rather than re-active role in future embedded generation developments. This also empowers the municipality to make a contribution to the national conversation on related topics.

In this section a "Bridging Scenario" is proposed, where the primary goal for the municipality is to create an enabling environment for roof top PV systems with the existing moderate incentives. The goal of the municipality is to bridge the gap between the current unregulated situation and possible future national policy, by regulating and controlling moderate PV installations and removing as many non-economic barriers to PV system uptake as possible. As part of this scenario compulsory demand side management measures for rooftop PV owners are proposed to ensure that revenue loss of PV systems is offset to some extent.

[17] The CoCT pilot project required that a new CoC be issued for each installation (around R1200), as well as a site inspection by a professional engineer (minimum R1500). This can add 4-5% to the cost of a small 2kWp residential PV system.

9.2.1 The Bridging Scenario

9.2.1.1 Metering

Both net metering and separate metering are allowed although separate metering is preferred. Net-metering is only allowed if a mechanical disc type meter is already in place.

Net-metering means that implementation is cheaper since no new meter needs to be bought. When a new meter needs to be installed, separate metering is required since it is the most flexible with regards to possible billing structures and more likely to be compatible with future national incentive structures.

Further, embedded generation can be implemented without any impact on municipal revenue if the feed-in tariff is funded from non-municipal sources. This leaves far greater flexibility in policy funding. Last but not least, more information becomes available regarding energy usage and generation compared to for example a net-metering arrangement. Time of use capable meters should be used to enable time of use tariffs implementation at a later stage, and to accurately record energy flows.

In the event where a prepaid meter is currently installed, the customer is responsible for the cost of the new separate metering system, except if this meter forms part of a wider rollout of e.g. "smart" meters by the municipality, in which case the customer will receive the same treatment as the rest of the roll-out target group. The municipality should ensure that required separate metering system is compatible with their medium term metering strategy (communication protocols etc.).

9.2.1.2 Pricing

9.2.1.2.1 Tariff rates

The rooftop PV related tariffs should be designed to maintain a careful balance between:

- the municipality's ability to cover its costs of providing and maintaining the customer's connectivity to the network, while also covering its energy & demand costs.
- the rooftop owner's motivation to connect legally rather than choosing to connect in an unregulated way,
- minimising the administrative burden that the tariff implementation impose on the municipality.

In the light of ensuring at least borderline financial viability to the rooftop PV owner, while protecting revenue to the municipality, it is proposed that the tariff be structured according to three components:

1. Continuation of the pre-rooftop PV tariff: In the scenario where rooftop PV energy lowers the consumption of the customer, up to the point where the customer becomes a net zero energy consumer, the addition of rooftop PV should be viewed by the municipality as an energy efficiency measure similar to solar water heating or more efficient appliances, and should not be penalised through lowered tariffs. The existing pre-rooftop PV tariff should be maintained, including any fixed costs, kVA and kWh charges (in the case of a prepaid customer installing PV, the tariff is changed to a conventional metered tariff that has a lower kWh cost but also has a fixed charge).

   This means that while the customer remains a net importer from the municipality, the financial viability is similar to that calculated in section 7.2, along with the limited motivation to install.
2. The network connectivity component: the rooftop PV installation has the potential to decrease the net monthly energy consumption of the customer to zero, resulting in the municipality not recovering the network connectivity / administration costs for that specific customer through profit on the kWh or kVA charges, in effect subsidising the customer.

   An additional fixed “network connectivity and admin charge” is therefore proposed: the charge is a multiple of the installed kWp of the PV system. The thinking behind increasing the charge as the system size is increased is that the larger the system, the less the kWh consumed by the customer, and the less the chances that the municipality is recovering its base costs. In addition, larger systems benefit from economies of scale and will typically produce cheaper electricity than smaller systems.

   The charge might be chosen, for example, so that the maximum single phase residential PV system of 3.68kWp, which generates around 460kWh per month on average, is charged at R249 per month (R365 per month connectivity cost to municipality as estimated in section 7.1.1, minus R116 existing fixed charge for conventional metered residential)
3. The export component: In the event of net-export in a month, the municipality only pays what the energy is worth to it, estimated in section 7.1.2 as R0.47 / kWh in 2011/2012. Again the thinking is that neither the municipality nor the rooftop PV owner is penalised.

9.2.1.2.2 Waiving of network connectivity & admin charge

It is proposed that the network connectivity & admin charge is waived in full if the rooftop PV owner provides evidence that a specific selection of peak demand-reducing actions have been installed / completed.

The thinking behind this proposal is demonstrated for medium-to high income residential customers: based on calculations done in section 7.1.3 the value of peak-period demand-reducing actions are around R585 per year for the probable 3kWh/day reduction. This is not enough to offset the R243 to R365 per month estimated network connectivity cost. However, the customer already pays a fixed monthly cost for the service (R116 for residential), and the municipality gets further potential advantages through carbon credits (explained later) and the financial value of additional capacity (estimated at R720 or less per installed kWp once off).

9.2.1.2.3 Tariff Lifetime

The net-metering tariff arrangement in this scenario will most likely be in place until a national tariff becomes available in the medium term. However, no guarantees or promises regarding availability are made. The net-metering arrangement will be reviewed annually but a six month notice period will be provided for any policy changes.

The above arrangements are not optimum for PV uptake since they result in high investment risk. However, they achieve the scenario goals of avoiding illegal connections without having long term financial implications for the municipality.

9.2.1.2.4 Inflation Adjustment

Inflation adjustments are built into net-metering since the end-user electricity price is likely to increase with inflation. Since the policy is not likely to be in place for very long, inflation related aspects are not that critical.

9.2.1.3 Project Size

The net-metering arrangement is available for all rooftop systems that comply in size with Eskom's simplified criteria for distribution network integration (Clinton 2012). No minimum size limit is made. Further, the scheme is only available for building integrated roof-top installations. No distribution network upgrades will be made to allow additional generation capacity unless the generator is willing to pay for these or they are necessary anyway.

9.2.1.4 Ownership eligibility

The scheme is not limited to any particular ownership group.

The type of peak-demand reducing measures to be implemented will however vary between ownership groups. A residential owner, for example, might be required to install a gas stove and solar water geyser in order to waive the connection cost component, while an industrial customer might be required to install Variable Speed Drives in his factory.

Determining the exact measures that are to be required is considered outside the scope of this report. Further, the list of required measures will need to be reviewed regularly to ensure that it takes account of changing prices and technical efficiencies.

9.2.1.5 New and existing projects

Both new and existing project can qualify for this scheme.

Existing projects should be included in the scheme so that owners of existing illegal installations have an incentive to register their systems with authorities.

9.2.1.6 Purchasing and administrative entity

A dedicated one stop contact should be established within the municipal electricity department.

In order to fast track projects and avoid non-economic barriers, it is important to have dedicated resources within the municipality for the implementation of the scenario. This is in line with international best practice identified in the literature. This will obviously have a cost impact to the municipality, which can be absorbed to some extent in the “network connectivity & admin” charge – this report chose not to estimate it, as this admin function is part of the wider responsibility of the municipality, and should not be recovered solely from the electricity departmental budget.

To minimise admin for the municipality, monetary credits should only occur once a year if a generator is a net-exporter over the entire preceding year.

9.2.1.7 Technical Framework

A clear and easy to follow process must be put in place to ensure that PV installations in Riversdale comply with the necessary standards and regulations where they exist.

It is proposed that the one-stop department be trained to assist in this process, which in essence will be a checklist covering wiring, structure, interconnection and other requirements of the installation. The owner can check certain sections personally and take responsibility and liability for these to minimise cost, while other critical safety features like grounding and anti-islanding tests will need to be witnessed by a municipal representative (e.g. an electrician working within the municipality with the necessary training).

9.2.1.8 Legal Framework

No legal framework for the policy needs to be implemented. It should be ensured that the net-metering policy itself is legal in the existing municipal and national context.

Since no long term guarantees are provided by the municipality, extensive legal guarantees for the policy are not required.

9.2.1.9 Carbon credits

The value of carbon credits was estimated in section 3.3.4 as R0.05 per kWh. The municipality should subscribe to such a scheme with the admin burden outsourced, and require that the rooftop owner enrol the rooftop PV system into this scheme for the financial benefit of the municipality, as a condition to connecting to the municipality's network.

9.2.1.10 Ensuring compliance

With the above bridging scenario in place, any new or existing unregulated rooftop PV installation that the municipality becomes aware of will be assisted in enrolling, with the embedded generator disconnected from the municipal network until this application is completed.

9.3 Improve the financial viability of rooftop PV

It is difficult for municipalities to incentivise the installations of PV via tariff structures alone. To find a balance between the needs of the rate payers and the electricity department itself will be an on-going challenge. Keeping this in mind, we should remember that the aim of the municipality should be to work for the residents of the municipality. The municipality is there to do collectively what cannot be done individually. The municipality should aim to work towards incentives as well as a tariff structure that ensures their own viability and benefits their residents.

The financial implications with rooftop installations are also wider than what is immediately apparent. There are many externalities in the choices of electricity generation as by far the most of our electricity comes from coal fired power stations. These externalities include the implications of climate change on the future energy use within the municipality, the health of its citizens, the productivity of the agricultural land and possible extreme weather conditions with associated disaster management costs.

In this report, the cost of PV is implicitly compared to the price of electricity from existing coal fired power stations run with coal at a relatively low cost. This is the current situation in South Africa, but at some stage these power stations will have to be replaced with a completely different cost scenario. The health implications of coal fired power stations in other parts of our country are also not calculated into this report.

The previous section described a "Bridging Scenario" where it was attempted in the tariff design to find a balance between municipal and rooftop owner financial motivation. Although such a balance could be obtained, the resulting financial motivation for the rooftop owner is borderline, especially in the residential context, while the municipal revenue stream is also only somewhat protected and requires additions like carbon credit trading.

It was impossible to structure the interaction between the two stakeholders in such a way that would actively stimulate the uptake of rooftop PV in the bridging scenario. Literature indicates that up to now it is typically national governments that provide the necessary funding to make PV financially viable (IEA, 2013). Such a national scheme, whether it is an expansion of existing schemes or a completely new incentive most probably falls outside the control of local authorities. It might, however be possible for local authorities to find external funding for rooftop PV from international funding agencies and this might be worth some investigation.

The investment viability map that was developed earlier is again of use here (see Figure 9-1). National or local incentives should be designed to reduce the capital cost of rooftop PV systems and/or increase the value of the kWh saved so that the financial viability to the rooftop owner increase to at least the 10-20% IRR region, or more for higher uptake of rooftop PV.

It should be clear from this report that the financial viability of Riversdale municipality is not threatened in the short term by unregulated installations of PV. They should, however, lead by example and actively seek out innovative financial solutions should they wish to stimulate the uptake of rooftop PV.

9.4 Lead by example

Lastly, Riversdale can lead by example. The already installed PV plant positions the town as a leader in PV installed capacity among Western Cape municipalities. If the municipality can tap into the Eskom Standard Offer and carbon financing, the financial viability of such systems also start making sense. Considering that 33 kWp PV has already been installed in Riversdale by the municipality, future installations on state owned roofspace can be more easily considered.

Figure 9-2: Riversdale's 33 kWp PV system.

9.5 Next steps

This report aimed to inform the Riversdale municipality on a broad range of aspects important to large scale uptake of rooftop PV. The steps to be taken by the municipality going forward should be informed by the aspects documented in this report, which aimed to provide a base from which actions can be launched around stimulating the uptake of rooftop PV in Riversdale.

On a municipal level the following next steps are recommended:

- **Identify a System Champion:** Identify an individual in the municipality mandated to establish and prepare the municipality to integrate PV systems into the local distribution network. This person will be responsible for the internal working group and providing strategic vision.
- **Establish internal rooftop PV working group**: This might be an internal group within the municipality and could consist of representatives from the electrical as well as the finance departments. The aim should be to develop strategies as informed from the report and the actions of other municipalities, which will prepare the municipality to deal with rooftop PV installations in the short and medium term. Typical discussion points can be technical regulations required to be adhere to by PV installers, and tariff structuring that will ensure a mutual beneficial environment for the municipality as well as the rooftop owner.
- **Join existing regional/national working groups:** identified individuals should participate in working groups that exist to develop aspects related to EG and PV specific systems. For example the NRS-097 working group seeking to establish technical guidelines for EG installations.
- **Further studies**: Identify areas in the report deemed important to continue detailed investigation on an internal level in order to get the municipality to a position where it is geared towards rooftop PV uptake in Riverdale, e.g detailed tariff design studies.

On a provincial government level, once specifications like NRS097-2-1 and 2-2 have been finalised:

- **Develop guideline for installations**: Develop a document that will “translate” the sometimes highly technical specifications and standard into easy to apply guidelines aimed at all rooftop PV installers. The aim is to ensure high quality installations along with minimising the risk to the municipality due to installers not applying the relevant standards.

The steps above are proposed as initial drivers to stimulate the discussion around rooftop PV uptake in Riversdale. The key is for the municipality to digest the report and come up with their own plan of action that will address creating a favourable environment for both rooftop PV installers and the municipality.

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Appendix A

Electricity Revenue and Expenses for Riversdale Municipality 2011 / 2012					
Income	Billed	Prepaid	Total		R26 239 457
Domestic Users (KWh)	R1 667 232	R11 967 157	R13 634 389	R25 791 512	
Indigent grant from Treasury for free units			R781 166		
Businesses (KWh)	R2 510 811	R1 466 760	R3 977 571		
Rural (KWh)	R1 625 785		R1 625 785		
KVA charges	R5 772 602		R5 772 602		
Service Charge Income			R419 175	R447 945	
Electrician services and special meter readings			R28 770		
Expenses					R26 361 184
Eskom costs		R18 172 244			
Eskom KWh charges	R13 534 683				
Eskom KVA charges	R2 453 490				
Eskom - Other charges	R2 184 071				
Employee related costs		R4 156 874			
Prepaid commission		R191 232			
Depreciation		R944 737			
Repairs and Maintenance		R993 068			
Interest		R744 778			
Other Expences		R980 379			
Provisions		R177 872			
Surplus / (deficit) for the year					(R121 728)

DETAIL OF INCOME	Unit	Tariff	Amount	Totals
Billed Electricity				R6 615 374
Domestic	R539	1.51	R816	
Domestic	R1 919 295	0.69	R1 326 814	
Huis Wallace Anderson	R63 218	0.54	R34 014	
Old Age homes	R351 134	0.86	R303 436	
Businesses	R3 740 330	0.67	R2 510 999	
Businesses Single Phase	R749	0.25	R188	
Street lights (departmental)	R275 184	1.72	R472 013	
Rural	R2 741 875	0.59	R1 625 785	
Indigents	R4 195	0.51	R2 153	
Departmental	R505 594	0.67	R339 535	
Prepaid Electricity				R13 433 917
Businesses	R1 321 405	1.11	R1 466 760	
Indigents	R3 741 659	0.83	R3 105 577	
Residential	R8 687 824	1.02	R8 861 580	
Indigents not paid	R1 088 868		R781 166	
KVA charges				R6 394 857
Bulk 71 - 500 KVA (128170005)	R6 523	0.00	R0	
Bulk 71 -500 KVA (Units)	R7 268 850	0.45	R3 245 617	
Bulk 71 -500 KVA (Units) Departmental	R948 480	0.45	R424 855	
Bulk 71 -500 KVA	R25 713	98.28	R2 526 985	
Bulk 71 -500 KVA Departmental	R1 974	100.00	R197 400	
TOTAL INCOME FROM ELECTRICITY SALES				R26 444 148

DETAIL OF ESKOM ACCOUNT				
	High Season off peak charge (KWh)	R805 052		
	High Season std peak charge (KWh)	R1 789 616		
	High Season peak peak charge (KWh)	R2 877 611		
	Low Season off peak charge (KWh)	R2 226 252		
	Low Season std peak charge (KWh)	R3 520 675		
	Low Season peak peak charge (KWh)	R2 315 476	R13 534 683	74%
	Premium connection charge	R50 085		
	Standard connection charge	R93 508		
	Admin charge	R18 175		
	Network demand charge	R1 278 014		
	District network access charge (KVA)	R748 005		
	TX Network Access charge (KVA)	R384 895		
	High Season reactive charge (kvarh)	R42 577		
	Electrification and rural subsidy	R1 331 391		
	Environmental levy	R653 562		
	Service Charge	R37 350	R4 637 561	26%
				R18 172 244