Discussion Document

Small-Scale Renewable Embedded Generation: Regulatory Framework for Distributors

Version 10
10 December 2014

Issued by

The National Energy Regulator
526 Madiba Street
Arcadia, Pretoria
0007

Contact Details:

Tel: +27 (0)12 401 4600
Fax: +27 (0)12 401 4700
www.nersa.org.za

Contents

ACRONYMS AND ABBREVIATIONS

CSIR	Centre for Scientific and Industrial Research
CSP	Concentrated Solar Power
CPPA	Central Power Purchasing Agency
DC	Direct Current
DG	Distributed Generation
DoE	Department of Energy
DUOS	Distribution Use of Systems
EIA	Environmental Impact Assessment
EG	Embedded Generation
ER	Energy Regulator
FIT	Feed in Tariff
GWh	Gigawatt hours
IPP	Independent Power Producer
IRP	Integrated Resource Plan
LCOE	Levelised cost of Energy
LV	Low Voltage
MV	Medium Voltage
MW	Megawatt
NEM	Net Energy Metering
NERSA	National Energy Regulator
NIPS	National Integrated Power Systems
NMD	Notified Maximum Demand
NRS	National Rationalised Specifications
OCGT	Open Cycle Gas Turbines
PPA	Power Purchase Agreement
PUC	Point of Utility Connection
PV	Photovoltaic
RE	Renewable Energy
REEEP	Renewable Energy Efficiency Programme
REFIT	Renewable Energy Feed-In Tariff
REGC	Renewable Energy Grid Code
REIPP	Renewable Energy Independent Power Producer
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
REFSO	Renewable Energy Finance and Subsidy Office
RPP	Renewable Power Plant
SMME	Small Medium and Micro Enterprises
SSREG	Small-Scale Renewable Embedded Generation/Generator

SSPVEG	Small-Scale Photovoltaic Embedded Generation
SWH	Solar Water Heater
TOU	Time-of-Use
WEPS	Wholesale Electricity Pricing System

DEFINITIONS

Administration charge	The administration charge covers the costs of the administration of the account. It is a contribution towards fixed costs such as meter reading, billing and meter capital. It is a fixed charge payable every month whether electricity is consumed or not**.**
Bi-directional meter	The bidirectional meter is a meter that is installed for Net Metering customers and records the power flowing in two directions. It measures how much electricity customers use from the embedded generation and how much electricity the utility system supplies to the customer with an embedded generator.
Bi-directional distribution rate	The concept of bi-directional distribution rate is that the customer taking power from the grid needs the grid in order to have reliable service, and should pay the same rate as other customers. This same customer, however, also 'needs' the grid when he or she is in an exporting condition, and pays the same distribution charge when feeding power to the grid.
Customer	Means electricity customer.
Distributor	A regulated business that constructs, operates and maintains the distribution system. The distribution business will also purchase transmission network services and may provide retail services such as purchasing of energy and meter reading, billing, customer services etc.
Distributed Generation	Distributed generation is defined as the installation and operation of electric power generation units connected directly to the

	distribution network or connected to the network on the customer site of the meter
Distribution Grid code	A code of practice that sets minimum technical requirements applicable to all participants operating or connected to the Distribution System as approved by NERSA.
Embedded Customer	A customer whose supply is taken from the distribution system.
Embedded Generator	An entity that operates one or more units that is connected to the Distribution System. Alternatively, a legal entity that desires to connect one or more units to the Distribution System.
Export tariff	A payment for every kilowatt-hour (kWh) of surplus electricity a customer system exports to the electricity grid.
Feed-in tariff	An administrative tariff or standard offer approved by the Energy Regulator for a renewable energy generator or energy efficiency interventions.
Integrated Resource Plan 2010	In terms of the Electricity Regulation Act of 2006, it means a resource plan established by the national sphere of government to give effect to national policy. It refers to the coordinated schedule of generation expansion and demand-side intervention programmes, taking into account multiple criteria to meet the electricity demand.
Generator	A legal entity licensed to engage in the production of electricity through a unit or power station.

Genflex	A new tariff category proposed by Eskom for customers that are consuming and generating energy at the same point of supply.
Import tariff	A payment for every kilowatt-hour (kWh) of electricity imported to a customer system from the electricity grid.
Megawatt	A unit of power equal to one million watts.
Net-metering	Net-metering is a service to an electric consumer under which electric energy generated by that electric consumer from an eligible on-site generating facility and delivered to the local distribution facilities may be used to offset electric energy provided by the electric utility to the electric consumer during the applicable billing period.
Network charges	The network charge is a tariff charge payable per premise every month. The network charge recovers network costs (including capital, operations, maintenance and refurbishment) associated with the provision of the network capacity required and reserved by the customer. The network charge in the retail tariff or in the Distribution use of system charges may or may not be the same in structure and value.
Network Service Provider	A legal entity that is licensed to provide network services through the ownership and maintenance of an electricity network.
Reactive Power	Reactive power is produced when the current waveform is out of phase with the voltage

	waveform due to inductive or capacitive loads.
Participant	In this document, it means the Embedded Generator.
Renewable Energy Feed-in Tariff	A tariff approved by the Energy Regulator for a renewable energy generator. It is also a mechanism to promote the deployment of renewable energy that places an obligation on specific entities to purchase the output from qualifying renewable energy at pre-determined prices.
Reliability service charges	The charge for services provided by the network service provider to ensure short-term reliability to customers.
Renewable Energy Grid code	Grid Connection Code for Renewable Energy Power plants connected to the Transmission System or Distribution System in South Africa.
System Operator	The legal entity licensed to be responsible for short-term reliability of the Integrated Power System (IPS), which is in charge of controlling and operating the Transmission system and dispatching generation (or balancing the supply and demand) in real time.
Tariff	A tariff is a combination of charging parameters applied to recover measured quantities such as consumption and capacity costs, as well as unmeasured quantities such as service costs
Time of Use	The time of day, or season during which electricity is used.

Time-of-Use tariff	A tariff with energy charges that change during time-of-use periods and seasons.
Utility	Reference is made to the ‘electricity distribution supply authority’. In South Africa, this may be Eskom, or the municipal electricity service provider.
Wholesale Electricity Pricing System	A totally unbundled, cost-reflective tariff structure.

1. BACKGROUND

To date, South Africa's renewable energy policy of 2003 has largely been driven by a 10,000GWh target by 2013 and renewable energy project subsidies offered through the Renewable Energy Finance and Subsidy Office (REFSO). From 2009 to 2011, a Renewable Energy Feed-In Tariff (REFIT) was considered and published, which has resulted in great interest by Independent Power Producers (IPPs) to develop renewable energy projects in South Africa. However, due to legislative constraints in 2011, a competitive procurement process entitled the Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) was launched by the Department of Energy (DoE).

In terms of section 34 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the Act'), the Minister has determined that 3,725 megawatts (MW) to be generated from Renewable Energy sources is required to ensure the continued uninterrupted supply of electricity. This 3,725MW is broadly in accordance with the capacity allocated to Renewable Energy generation in the Integrated Resource Plan 2010–2030 (IRP 2010). This IPP Procurement Programme has been designed to contribute towards the target of 3,725MW and towards socio-economic and environmentally sustainable growth, and to start and stimulate the renewable industry in South Africa.

REIPPPP only made provision for large and small scale solar photovoltaic (PV) greater than 5MW and 1MW respectively, which effectively excludes most rooftop systems. In spite of this, the past year has seen a great increase in the number of private rooftop PV systems installed on residential and commercial/industrial premises at the cost of the owners. Ostensibly for generating electricity for own use, these systems are nonetheless grid tied, and could be capable of feeding surplus power back into the grid. A number of residential rooftop grid tied PV systems have also come to light, using net-metering by agreement with the relevant municipalities. Several municipalities have drawn up procedures for connecting such systems, and the National Energy Regulator (NERSA) has also produced documents covering such situations. So it would seem that in spite of exclusion from the large scale REIPPPP, privately installed small scale grid tied rooftop solar is alive and well and growing in South Africa.

The IRP 2010–30 Update [2] states that 9,770MW of solar photovoltaic (PV) capacity is planned to be installed in South Africa by 2030. The IRP 2010–30 Update also estimates that Embedded Generation (EG) residential and commercial PV could reach 22.5GW by 2030 based on *Living Standards Measure 7* (LSM 7) households and 5kWp PV household installations [2]. Even if this estimate is partially correct, this points to a significant level of installed Small-Scale Solar PV Embedded Generation (SSPVEG) capacity in South Africa by 2030.

1. The South African IRP 2010, approved and published in May 2011 by the DoE, outlines the proposed power generation mix for South Africa. The IRP 2010 seeks to increase the overall contribution of new renewable energy generation to 17,800MW by 2030 (42% of all new-build generation).

2. Based on the approved IRP 2010, on 02 July 2011, the Minister of Energy issued a Determination for the IPP procurement programme in accordance with section 34(1) of the Electricity Regulation Act, 2006.

3. The Energy Regulator concurred with the Ministerial determination on 07 July 2011.

4. On 19 December 2012, the Minister of Energy made a new determination for the procurement of an additional 3,200MW capacity to the previous determination of 3,725MW. The total capacity to be procured is currently 6,925MW.

The new capacity allocation is as follows:

Table 1: New capacity allocation

Technology	**Capacity (MW)**
Onshore wind	3 320
Solar photovoltaic (PV)	2 525
Concentrated Solar Power (CSP)	600
Small hydro (≤ 40MW)	135
Landfill gas	25
Biomass	60
Small projects	200

The objective of this discussion paper is to formulate the position of NERSA on qualifying principles, technical and economic conditions for the installation of small-scale renewable embedded generators (SSREGs) in the Electricity Supply Industry (ESI). This paper looks at the following areas:

I. legal mandate and current legislation landscape;
II. technical and safety requirements;
III. licensing requirements;
IV. tariff design and principles; and
V. tariff options for SSREGs.

2. NATIONAL ENERGY REGULATOR MANDATE

National Energy Regulator (NERSA) is established in terms of section 3 of the National Energy Regulator Act, 2004 (Act No. 40 of 2004) to undertake the functions set out in section 4 of the Electricity Regulation Act, 2006 (Act No. 4 of 2006) ('the Act').

2.1. The Act

The objective of the Act is, among others, to ensure the efficient, effective, sustainable and orderly development and operation of electricity supply infrastructure within South Africa. The objectives of the Act are best achieved through licensing, determination of tariffs, rules and guidelines. In terms of the Act, no person may, without a licence issued by the Energy Regulator, operate any generation facility. The only exemption to not be being required to have a licence, is provided for in schedule II of the Act. In consideration of the development and the discretionary powers that the Energy Regulator has with regard to making guidelines and publishing codes of conduct and practice, this 'framework' is intended to serve as a guideline or code of conduct within the electricity supply industry.

3. DISTRIBUTED GENERATION IN SOUTH AFRICA

Due to the reduced cost of the rooftop PV installations and the levelised cost of electricity of these systems reaching parity with the domestic and commercial tariffs, there is growing interest from South African electricity customers to install rooftop PV systems in order to reduce their electricity bill and supplement their consumption. Table 1 below shows a list of some installations around the country. The number of embedded PV installations that have been captured have a total peak capacity of approximately 10MW[1]. It should be noted that the list shown does not cover all the installations as some connections are not authorised or registered.

Table 1: PV installation list around the country

Project	Location	Province	Capacity (kWp)	When completed
Cronimet Chrome Mining SA (Pty) Ltd, Diesel-PV Hybrid	Thabazimbi	Limpopo	1,000	Nov 2012
Belgotex's factory	Pietermaritzburg Natal	KwaZulu-Natal	1,000	2013

[1] CSIR presentation.

Black River Park	Cape Town	Western Cape	700	2013
Eskom Kendal PV (ground-mounted, fixed)	Eskom's Kendal coal-fired power station	Mpumalanga	620	Nov 2011
Eskom Lethabo PV (ground-mounted, 1-axis tracking)	Eskom's Lethabo coal-fired power station	Free State	575	Nov.11
Rooibos Storage Facilities	Clanwilliam	Western Cape	511	2014
Ceres Koelkamers	Ceres	Western Cape	505	2013
Vodacom Century City	Cape Town	Western Cape	500	2012
Eskom Rosherville PV Eskom's R&D site	Rosherville	Gauteng	400	2014
Eskom Megawatt Park Carport PV	Sunninghill, Johannesburg	Gauteng	398	Nov 2011
Eskom Megawatt Park Rooftop PV	Sunninghill, Johannesburg	Gauteng	358	Dec 13
Bosco Factory PV Plant	Edenvale	Gauteng	304	2013
Pick n Pay distribution centre	Philippe, Cape Town	Western Cape	300	2013
Kriel Mine	Kriel	Mpumulanga	240	Aug 13
Dube Trade Port	Durban	KwaZulu-Natal	220	2011
Vrede en Lust Wine Farm	Franschoek	Western Cape	218	2013
Novo Packhouse	Paarl	Western Cape	200	Unknown
Leeupan Solar PV project	OR Tambo Precinct, Wattville	Gauteng	200	2012
Pick n Pay Distribution Centre	Longsmeadow, Johannesburg	Gauteng	150	2011
Villera Winefarms	Stellenbosch, Cape Town	Western Cape	132	2011
Standard Bank PV Installation,	Kingsmead, Durban	KwaZulu-Natal	105	Unknown
Pick n Pay Store	Hurlingham, Johannesburg	Gauteng	100	2010
Lelifontein wine cellar and Grootfontein admin offices	Stellenbosch	Western Cape	88	2013
BP Offices V&A	Waterfront, Cape Town	Western Cape	67	2011

Mitchells Plain Hospital	Mitchells Plain	Western Cape	64	2013
Cavalli Wine & Stud Farm	Stellenbosch	Western Cape	51	2013
Oldenburg Vineyards	Stellenbosch	Western Cape	45	2013
BMS	Woodmead	Gauteng	36	Jul.13
BT	Woodmead	Gauteng	36	Jul.13
Med	Woodmead	Gauteng	31	Jul.13
WTP	Witbank	Mpumulanga	30	2013
Coca Cola water bottling plant	Heidelberg	Gauteng	30	Unknown
Glaxo Smith Kline	Cape Town	Western Cape	30	Unknown
Impahla Clothing	Maitland	Western Cape	30	Unknown
Eskom Megawatt Park CPV	Sunninghill, Johannesburg	Gauteng		26 Nov.11
Khayelitsha District Hospital	Cape Town	Western Cape	25	2011
TOTAL			**Approx. 10MW**	

Source - CSIR presentation, (2014, November 12th). *How to stimulate the South African rooftop PV market without putting municipalities' financial stability at risk: A "Net Feed-in Tariff" proposal* [PowerPoint slides]. Presented at NERSA Offices, Pretoria.

According to Solarbuzz[2], the prices of installed PV system and PV modules have dropped significantly in the past three years. With the abundance of solar irradiation in South Africa, the levelised costs of energy (LCOE) for PV is very close to the average system price of electricity, hence it is becoming a viable supplemental alternative for commercial and residential electricity customers.

The Centre for Scientific and Industrial Research (CSIR) has identified some views and concerns by various stakeholders regarding rooftop PV development and these are listed in Table 2 below.

Table 2: Some concerns of distributed PV Generators[3]

Municipality	Municipality will lose revenue if no compensation mechanism for self-consumed PV energy is implemented. Administrative burden managing large uptake of embedded PV.

[2] PV-Magazine, 'PV market to become supply-driven in 2014, says NPD Solarbuzz', Available online: http://www.pv-magazine.com/news/details/beitrag/pv-market-to-become-supply-driven-in-2014--says-npd-solarbuzz_100014408/#axzz3KFdtbo7w
[3] CSIR Analysis

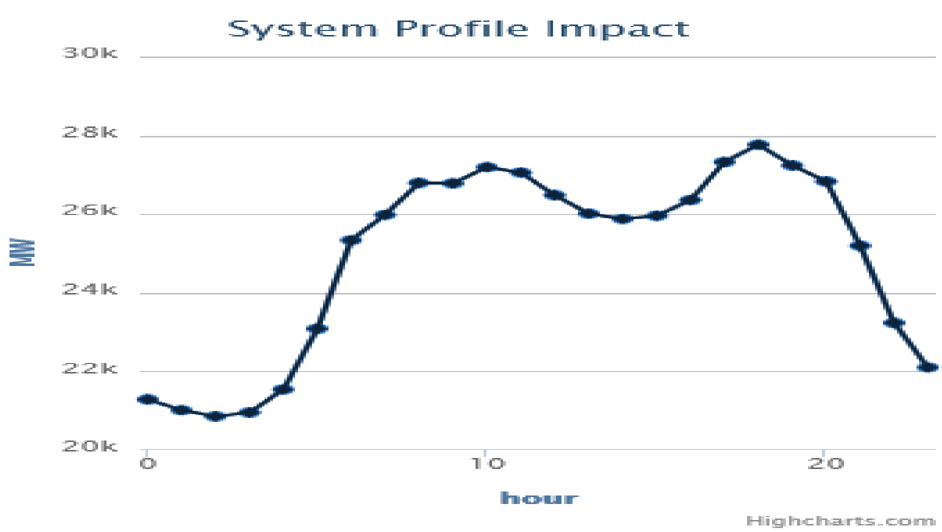
PV Owner	Business case not attractive if excess energy is not financially compensated. Business case too risky if feeding back into grid is compensated, but not adequately or at unpredictable rates over the asset lifetime
Small-Medium Market Enterprises	Utility-scale PV projects are not made for SMMEs as owners/suppliers Rooftop PV market is ideal for SMMEs, but without continuous workflow, small companies are not willing to invest into manpower and skills.
PV Manufactures	REIPPP Programme is very well run, but the demand is not enough to trigger significant investments into local production of modules/inverters. Rooftop PV market attractive, but does not exist.
Electricity Ratepayers	Any incentive to the scheme for rooftop PV must come at the lowest possible cost to the power system.

4. SYSTEM AND FINANCIAL AND CUSTOMER IMPACTS OF SMALL-SCALE RENEWABLE EMBEDDED GENERATION

4.1. System impact

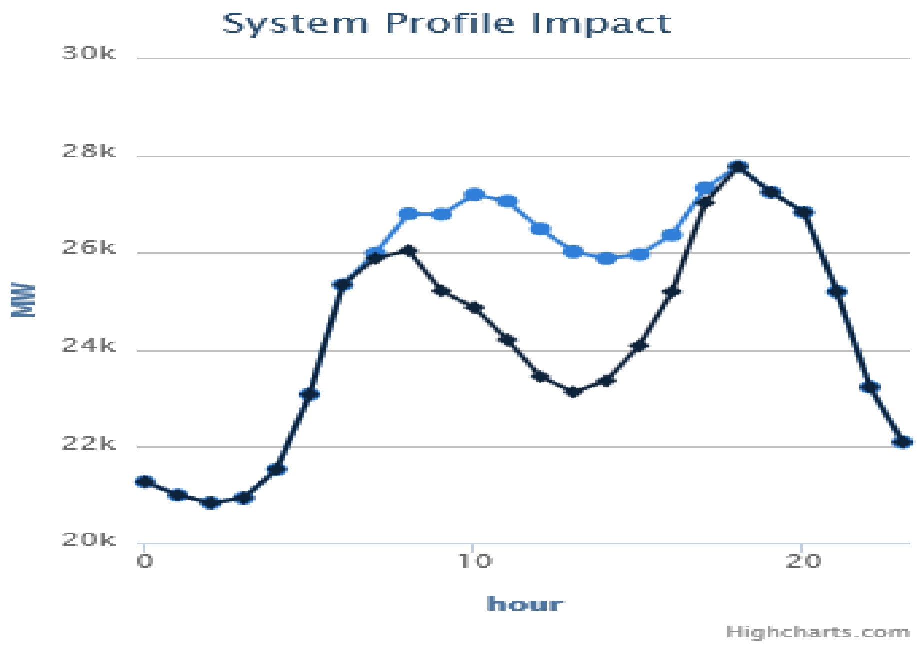
The widespread installation of rooftop solar panels, which is also referred to as embedded generation or distributed generation (although those terms also have a wider meaning), poses a real threat to municipal and Eskom revenues. It also poses a financial threat to lower income customers. There are also largely ignored system issues created with the widespread adoption of rooftop solar.

To understand the issues, consider a typical daily load profile shown below. The peak demand occurs in the 18:00 to 20:00 window, driven mainly by residential load.



Graph 1: Typical System Load Profile [Source: Enerweb]

The impact of the widespread adoption of a typical 3kW rooftop solar system without storage on 1 million rooftops is shown below. 1 million rooftops indicate the impact clearly in the long term, although with the increase in industrial and commercial use of solar energy, the same level of impact can be reached faster as they generally have installations in the range of hundreds of kilowatts.



Graph 2: Impact of Rooftop Solar on demand curve [Source: Enerweb]

The following are important points to notice. The first point is that the rooftop solar installation without storage makes no contribution at all to reducing the peak demand and may in practice actually increase it for reasons related to load shifting. Therefore, from a capacity requirement point of view, rooftop solar does not contribute to the reduction of the peak demand of the system.

The second point to notice is that the load pick-up from 18:00 to 17:00 becomes much steeper than it is currently. This means that at higher penetration of the PV installations, it is likely that an investment will have to be made into a 'dispatchable' flexible mid-merit or peaking generation with relatively faster ramp rate that can perform in a way that allows them to handle this rapid pickup, i.e. pumped storage and gas. In the Rooftop PV scenario of the IRP 2010 Update 2013, the introduction of the rooftop PV installations causes an increase in the Open Cycle Gas Turbines (OCGTs) from 4,680MW to 10,320MW in 2030, as well as a decrease in the wind and Concentrated Solar Power (CSP) capacity. Under this scenario, the nuclear and coal base-load capacity is not affected. During periods of high output of the PV installations, the energy generation of the relatively cheaper base load plant might be curtailed, which would increase the overall system costs. It is estimated that approximately R100 billion would have been invested by the public (which is this example in the above graph) for about 1 000 000 million installations That needs to be proved by the difference in total cost of the IRP 2010 rooftop scenario . Some capacity is reduced, but other OCGT which is the cheapest capacity is increased and therefore balance of the total system cost might even be positive.

The third consideration is the direct financial impact on the municipalities. Eskom will suffer a similar impact, but here the focus will be on the municipalities due to reduced energy sales. Again there are savings to the municipalities due to avoided energy purchases and loss due to the lost energy sales at a tariff substantially higher than the purchase cost (the weighted seasonal and Time-of-Use (TOU) average cost is about R0.7/kWh, while the average tariffs are of the range R1.2-1.4/kWh).

4.2. Financial Impact

When electricity customers within a municipality decide to install rooftop PV systems to supplement their total energy consumption, the municipality loses revenue as self-consumed PV energy replaces energy that would have been purchased from the municipality. Electricity revenue and city financial survival is closely linked in many South African municipalities, due to our particular history of municipalities operating as electricity distributors. Typically 10% of annual municipality electricity revenue is used to cross-subsidise other municipality services[4]. Furthermore, revenue from ‘high-end’ electricity consumers (larger residential and other consumers) is routinely used to cross-subsidise ‘losses’ from providing power to poor households, which are not fully covered by the national Equitable Share grant.

Sustainable Energy Africa, with funding from the Renewable Energy and Energy Efficiency Programme (REEEP), recently completed a project which involved developing a model for determining the impact of photovoltaic installations and energy efficiency (EE) uptake on municipal revenue[5]. Three metropolitan municipalities, Cape Town, eThekwini and Ekurhuleni were used as the case study. The model calculation took into account the tariffs and sought to determine specific times during the day, week and year that electricity sales would be lost as a result of Renewable Energy (RE) and Energy

[4] Janisch A, Euston-Brown M and Borchers M,2012, 'The potential impact of efficiency measures and distributed generation on municipal electricity revenue: double whammies and death spirals'.
[5]Will small-scale renewable crush municipal revenue, Available Online: http://www.sustainable.org.za/resource.php?id=3, Last accessed on 26 November 2014.

Efficiency (EE). For the three metros, the results of the model showed that the financial impact could vary between 3% and 15%, depending on the uptake of residential, commercial and industrial electricity customers.

An analysis and study conducted by Sustainable Energy Africa suggested that possible measures that could be taken in order to mitigate the negative impact on municipal revenue may require decoupling of the tariff, that is, inclusion of an energy charge to cover Eskom charges and the use of a fixed charge to cover distribution costs.

4.3. Customer Impact

Residential customers and an increasing number of commercial customers pay a flat energy charge. This flat energy charge should be arrived at by averaging all the costs associated with their supply and dividing it by the energy sold. Rooftop solar, by taking out the energy in the cheaper time of the day and leaving the energy at the higher tariff, could add extra cost to the bill of all the remaining customers without rooftop PV. However, since Eskom will experience the same impact, the original municipal energy purchase charge might also increase. The peak remains the same with or without rooftop PV.

It is difficult to exactly quantify the impact the end user will see since it depends on the concentration of the installations in a particular distribution area. The customer will rather just experience a steady increase in the electricity price. This is already the case with regard to the City of Cape Town Municipality. Please note that the impact of the REIPPPP constitute a 3% increase on the average electricity price. Energy Efficiency Demand Side Management (EEDSM) also causes minor cost increase. In other words, the implementation of the climate mitigation policies have an impact on the customer bill. There are three issues that arise out of the above. Internationally, the measure that utilities have used to counter the loss of revenue and prevent stranded assets has been to increase the fixed network charges to cover their investment in the network infrastructure. This should be compared to an increasing practice in South Africa to move to a flat energy charge with no fixed charge. This is probably going to cause the municipalities to lose more revenue in the long term and needs to be stopped. The correct tariff should include a fixed charge, except for lifeline tariffs.

The second point is that users with this type of installation should be put on a time-of-use tariff. This is to avoid them shifting their load at specific times to export maximum power.

The third point is that there should be limited energy as well as export tariffs for export to the grid, i.e. the export tariff should be lower than the import tariff from the municipality, the exact number depending on the actual economics of the specific distributor. In fact, there should almost be a disincentive tariff that would encourage users to include storage in their installations rather than to export back onto the grid. The inclusion of storage means that the peak demand also goes down, thus the users are almost going off grid and are therefore not incurring extra costs on behalf of other users.

This also exposes a weakness in the current financing arrangements for the municipalities whereby they rely upon revenue from electricity sales and do not recover sufficient revenue from their other services or rates and taxes. It also exposes a weakness in their current tariff structures. The presence of tariff specialists in the municipality would alert them to the dangers, but these are few.

5. QUALIFYING PRINCIPLES OF SSREG

5.1. Eligibility

The Renewable Energy Grid Code (REGC), known as the 'Grid Connection Code for Renewable Energy Power Plants connected to the Electricity Transmission System or Distribution System in South Africa', shall be used as a basis for technical requirements for potential Embedded Generators.

To view and read the Renewable Energy Grid Code see the link below:
Website: www.nersa.org.za/electricty/technicalstandards.

For the purposes of these rules, Renewable Energy Power Plant (RPP) defined in the Renewable Energy Grid Code shall have the same meaning as 'Embedded rooftop PV generator'.

Qualifying rooftop PV generators shall meet the following requirements:

a) The generator must be connected to the distribution network of the utility or municipality.
b) Rated power must be less than 1 MVA (Power Rating of Category A in REGC) and less than the installed capacity (rating) of the customer.
c) The above requirements in b) shall further be divided into three sub-categories:
    i. **Category A1 (0 - 13.8 kVA):** This sub-category includes rooftop PV generators with rated power in the range of 0 to 13.8 kVA.

ii. **Category A2 (13.8 kVA – 100 kVA):** This sub-category includes rooftop PV generators of Category A with rated power in the range greater than 13.8 kVA but less than 100 kVA.
iii. **Category A3 (100 kVA – 1 MVA):** This sub-category includes generators of Category A with rated power in the range 100 kVA but less than 1 MVA.

d) Rooftop PV generators shall meet REGC requirements of Category A1, A2 and A3, with regard to connection and operation, and these are:
   iv. Normal Operating Conditions;
   v. Synchronising to the National Interconnected Power Systems (NIPS);
   vi. Tolerance to sudden voltage drops and peaks;
   vii. Response to Utility System Recovery;
   viii. Power Frequency curve for sub-categories A1, A2 and A3; and
   ix. Reactive Power Capabilities.

5.2. Grid interconnection of embedded generation NRS 097-2-1:2010 and NRS 097-2-3:2014

The conditions for grid connection of embedded PV generators shall follow the requirements prescribed by NRS 097-2-1:2010 and NRS 097-2-3:2014. These pertain to the following aspects:

5.2.1 Direct current Injection

The static power converter of the Embedded Generator shall not inject more than 1% direct current of the rated alternating current output current into the utility interface under any operating condition. The Embedded Generation shall cease to energise (disconnect) the utility network within 0.5s if this threshold is exceeded.

5.2.2 Point of Isolation of the Embedded Generation

The Embedded Generation shall provide a means of isolating from the utility interface for safe maintenance of the Embedded Generation. The isolation device shall be double pole in a case of a single phase Embedded Generation and a three pole for three phase delta connected Embedded Generation and four pole for three phase star connected Embedded Generation with minimum fault level of 6kA closest to the Point of Utility Connection (PUC).

5.2.3 Quality of Supply Threshold for the Embedded Generation

The operation of the Embedded Generation in conjunction with other existing and future loads at the PUC, in terms of flicker and harmonics, shall not increase beyond the levels specified in NRS 048-2.

5.2.4 Size of the Small Scale Embedded Generation

The maximum size of the Small-Scale Embedded Generation connected to the utility network should be limited to the rating of the supply point on the premise/customers. This implies that in a shared Low Voltage (LV) feeder the embedded generator size should be limited to at least 25% of the customer's Notified Maximum Demand (NMD) or 75% of the customer's NMD in case of non-shared LV feeder. The size of total embedded generators connected to any Medium Voltage (MV)/LV transformer at a time should also be limited to 75% of the MV/LV transformer's capacity.

6. PROPOSED QUALIFYING CRITERIA

These rules are applicable to customer–generators (i.e. loads and generators at the same time), hereinafter referred to as Small-Scale Renewable Energy Generators (SSREGs) connected at ≤ 11 and 22 kV.

6.1. Technology

The following mature and commercially available SSREG technologies based on 100% renewable energy shall qualify: solar rooftop PV, wind, biomass, landfill gas, biogas and small-hydro. However, the technical requirements for small wind, landfill gas, biogas and small hydro would differ. 'Commercially available' means that the major energy system components are acquired through conventional procurement channels, installed and operational at a project site.

Ineligible equipment includes field demonstrations for proof-of-concept operation of experimental and non-conventional systems partially or completely paid for by research and development funds. Pilot and demonstration systems are also ineligible.

For rooftop PV, new panels added to an existing inverter that is already in service are eligible if the previously installed rooftop solar generating system met programme requirements at the time of installation. Hybrid systems, which are a combination of SSREG technologies, shall be allowed in this scheme and should adhere to all qualifying criteria applying to non-hybrid systems. All SSREGs shall comply with all municipal laws where applicable, such as air pollution, waste management, and building regulations.

All installations should comply with the environment impact regulations, i.e. should have Environmental Impact Assessment (EIA) where applicable.

Systems must be new and in compliance with all applicable codes and standards for grid connected systems (applicable to all components of the installation). Rebuilt, refurbished or relocated equipment is not eligible under this programme.

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.

An electrical design certified by a qualified electrical engineer (technician) will be required as part of the application (if applicable). Adopting the REIPP requirements is not suitable for these small installations.

A structural design certified by a qualified structural engineer (technician) will be required as part of the application (if applicable).

6.2. Eligible Capacity

SSREG must be sized so that the amount of electricity produced by the system primarily offsets part of the host customer's rated capacity at the project site, not greater than the rated capacity of the installation and 1MW, whichever is the smaller.

Net Energy Metering (NEM) will allow the customer to size their generation to meet a portion of their annual energy demand. Since customer energy demand also varies, at any given moment it is very difficult to determine if a solar PV system will be serving onsite load or exporting energy to the grid. NEM means that energy demand and self-generation do not have to be precisely coincident to return value to the customer.

Systems designed to completely off-set the energy demand of the customer shall not be allowed; the customer must still remain a net importer over a 12-month billing period. SSREGs are allowed to be net exporters in any month, but not over a 12-month billing cycle.

6.3. SSREG energy export to the grid

Distributors will be required to purchase from SSREG when available subject to network constraints. It is easier for the distributor to curtail purchases from Eskom than curtailing, for example, household rooftop PV installation output.

Priority export to the grid must be given to customers on the Time-of-Use (TOU) tariff as this minimises revenue loss to distributors, subject to system constraints. The Distributor will also have the right to curtail the exported energy from the SSREG under certain system constraints and conditions.

6.4. Technical evaluation/feasibility of the proposed system

The distributor shall provide the SSREG the option of a preliminary connection quote that would contain readily available information about system conditions at a point of interconnection in order to help that customer select the best site for its facility. The preliminary connection quote serves to promote transparency and efficiency in the interconnection process and to provide information to the SSREG about system conditions at a particular point of connection.

The pre-application report will be provided at a fee determined by the distributor and would contain readily available information, i.e. information that the distributor currently has on hand without having to create new data.

The distributor is not required to conduct any studies after furnishing the preliminary quote, unless the SSREG proceeds with a formal application for connection. The SSREG will be required to pay for additional studies regardless of the conclusions reached. Whenever possible, the distributor should use existing information and studies instead of performing additional analyses in order to reduce costs to the SSREG. The SSREG is responsible for costs associated with any new analysis and any modifications to an existing analysis that are reasonably necessary to evaluate the proposed interconnection.

All embedded generators shall demonstrate compliance with all applicable requirements specified in this grid connection code for category A1 generators and any other applicable code or standard approved by NERSA, as applicable, before being allowed to connect to the distribution system and operate commercially.

6.5. Agreement of energy injection

I. Customers proposing an embedded generator connection are required to enter into a connection and operation contract with the electricity distributor.
II. The terms and conditions for non-standard connections are subject to commercial negotiations between the parties and will encompass both the technical and commercial aspects of the connection and operation, address the access standards and specify the terms and conditions, including the connection charge.
III. The terms and conditions for non-standard connections also require the customer to indemnify the Utility against any liability resulting from the customer’s use of the

distribution network in a manner prejudicial to the safety and efficiency of the network.

IV. It is desirable that the terms and conditions for non-standard connections (if required) be finalised and signed by the duly authorised representatives of both parties at least one month prior to the intended commissioning date.
V. Where required, the Utility will prepare and forward the Utility's terms and conditions for non-standard connections following the receipt of the customer's full and complete application for connection. Commissioning and connection of the embedded generation installation will not be permitted until this contract is signed by both parties.
VI. Customers seeking to be a registered participant should contact their Utility as different terms, conditions and processes may apply.
VII. Any contractual questions surrounding any incentive schemes for generation, and export to the grid, should be directed at the customer's energy retailer.

7. TARIFF DESIGN AND PRINCIPLES

As penetrations of small scale embedded generation grows, pricing and tariffs together with the regulatory policies need to be in place. These pricing/tariffs and regulatory policies need to ensure that the utility can collect enough revenue to cover its cost of supply and continue to safely and reliably provide vital services to all customers.

Most tariffs for residential and small customers are not cost-reflective as they do not reflect the fixed costs associated with the management, operations and maintenance of the grid and the retail-related costs to serve these customers. If the electricity tariff supplying a customer is not cost reflective and own generation is installed, it means that there will be a loss of revenue to the network service provider that needs to be recovered from other customers as there is no commensurate reduction in costs. Many tariffs comprise variable c/kWh only charges and no or limited fixed charges removing fixed costs. This means that if consumption decreases due to own generation, the distributor loses revenue that is not commensurate with a reduction of costs.

7.1. Revenue Impact

From the utility's perspective, revenue erosion is a concern. Embedded generation reduces the utility's sales and the revenues and avoids energy purchase costs.

The Energy Regulator needs to consider mechanisms for orderly development of the rooftop market and mitigation of potential negative impact on the distribution utilities revenues.

The main issues related to the connection of rooftop PV installations are:

I. PV causes a reduction in sales and where tariffs are not structured to recover all fixed costs through fixed charge, there will be a negative revenue impact. Customers may be net zero consumption customers, but still need the grid a backup of variable energy resource.
II. Even though consumption might be lower or even zero, customers may still require the infrastructure to draw the same demand affecting the grid and generation capacity as customers that that do not have PV.
III. There remains a cost to connect and use the grid as a backup and to consume when needed.
IV. This cost is not recovered if fixed charges are not cost-reflective and there a net-metering or net-FIT tariff scheme.
V. It constitutes variable avoided cost of supply (fuel and variable operating costs).
VI. Most tariffs for residential and small customers do not have cost-reflective network charges.
VII. Customers that do not have PV could subsidise the tariffs of customers with PV – unless the PV tariffs can be made cost-reflective.
VIII. The customer should be aware that they will not be getting a credit based on current tariffs – the credit should be related to the total utility's system costs.
IX. The customer's avoided cost could therefore only be related to avoided energy charges associated with the PV tariff and this needs to be factored in when investing in such equipment.

The impact on revenue to the utility should be mitigated through, for example, through SSREG tariff (export and import) design.

Embedded generation reduces the utility's energy purchases, energy sales and the revenues; the Energy Regulator needs to consider mechanisms of dealing with the revenue impact of small scale embedded generation as follows:

7.1.1 Fixed Charges

Ensuring sufficient utility revenues by collecting more revenue through the monthly fixed charge.

7.1.2 Stand-by Charges/Import energy charge

Stand-by charges will apply to customers who sometimes rely on their own on-site generation for power, but who also rely on the grid for power use in excess of on-site generation (supplemental power) when on-site power is out of service for planned maintenance and when on-site power is out of service owing to a forced outage (emergency power).

These rates recover the cost to back up customers with self-generation should their generation facility unexpectedly fail or need scheduled maintenance.

7.1.3 Avoided variable costs

The embedded generation resource provides a broad range of services and values and should be fully compensated for those values. This considering the avoided energy, network and line losses costs as well as avoided primary energy price variation risks.

7.2. Tariff rate Principles

I. Rates should be simple, certain, conveniently payable, understandable, acceptable to the public, and easily administered.
II. Rates should be set so as to promote economically efficient consumption.
III. Rates must be compensatory (recovery of fixed and operating costs to the distributor).
IV. Rates themselves should be stable and predictable.
V. Rates should be apportioned fairly among customer classes and among customers in each class.
VI. Undue discrimination should be avoided.
VII. Rates should promote innovation in supply and demand (dynamic efficiency).

7.3. Distributor recovery of costs

Distributors shall be allowed to recover only the following charges:

a. Network infrastructure charges
b. System operation charge
c. Administration charges
d. Reliability service charges

If there are any additional cost categories that distributors wish to recover, it should be justified in their annual tariff application review based on system impact studies provided by the distributor. Connection charges for Distribution connected generators shall be payable upfront by the SSREG. The distributor should develop connection charges for small SSREGs.

Monetary loss due to reduced sales volumes (MWh) shall not be compensated because distributors get the benefit of avoided energy, network and line losses costs as well as avoided primary energy price variation risks.

7.4 Requirements for SSREGs

Customers are expected to fund the total installed cost of their SSREG. Other financial incentives from any other sphere of government targeted at the SSREG shall not be allowed.

SSREGs should have adequate comprehensive insurance of their installations.

SSREG customers shall be on a two-part unbundled tariff with fixed charges and variable charges.

7.5. SSREG recovery of costs

A fixed export tariff shall be applied rather than a TOU export tariff, which requires special metering and has a high administrative burden.

Customer Import tariff = Fixed charge + Variable charge

Fixed Charge (R/kW) = Network charges + Administration charge + Reliability service charge)

Variable Charge (R/kWh) = Variable energy import charge
(Where the Customer Import tariff is the tariff through which the distributor recovers their costs.)

The Administration charge and Reliability service charge should be payable where the same network assets are used for consumption and generation.

The SSREG shall have an export tariff equivalent to the avoided energy costs of the distributor, based on the weighted average energy tariff of Eskom.

Export tariff = Avoided variable purchase cost of the distributor

Import tariff = Customer Import tariff above

Cross-subsidies as discussed in section 9 of the Electricity Pricing Policy will be recovered by the distributor.

7.6. Connection charges

Connection charges will apply to customers who want to connect to the grid. The Utility will determine the connection charges and the manner they are paid.

All costs relating to grid connection, such as network studies, and the distributor reserves the right to allow or disallow disconnection and provide reasons therefor. It is the obligation of the utility to connect customers and generators, therefore it cannot charge for the studies undertaken.

If the SSREG plans to increase the maximum export capacity of an existing generating unit, the additional maximum export capacity will be treated as a new generation interconnection request.

8. TARIFF OPTIONS FOR SSREG

Simple energy charges for import and export should be applied. The public should be requested to propose tariffs, but the aim is simplicity.

8.1. Feed-In Tariff (FIT) scheme

Feed-In Tariff (FIT) enables customers to reduce their bill by feeding excess usage to the grid at the retail price. A FIT pays the customer a different rate for selling energy than the retail rate for consuming energy.

The principal purpose of a FIT is to provide a simplified and defined price that a small power producer can secure with a minimum of negotiation or other transaction costs.

A secondary purpose is to establish, typically, a premium price for a premium (i.e. renewable) resource. Although a FIT could be restricted to premium products where a premium payment is applied, or applied to all qualifying distributed generation without an assumed premium payment, the term ‘Feed-In Tariff’ is used in this paper to include both.

Feed-in tariffs require one extra power meter in order to measure outflow of electricity from a home independently. This enables electricity consumption and electricity generation to be priced separately.

8.1.1 Advantages of feed-in tariffs

I. Having a contract upfront with a utility gives the customer a great advantage to take a loan from the bank with discounted rate because the contract is a proof of the loan will be repaid.

II. From energy grid perspective, decentralising the generation units in the grid will increase reliability, help to minimise transmission losses and improve the stability of the grid.

III. Any producer of renewable energy is allowed to sell electricity generated to the grid by having a fair price contract with the utility.

8.1.2 Disadvantages of feed-in tariffs

I. After a certain amount of time, the state regulators would probably levy a ‘user charge’ on all electric customers to pay for the premiums offered by the renewable contracts and cover the cost of grid upgrades.

II. Second disadvantage of feed-in tariff is actually a mandatory need for further planning.

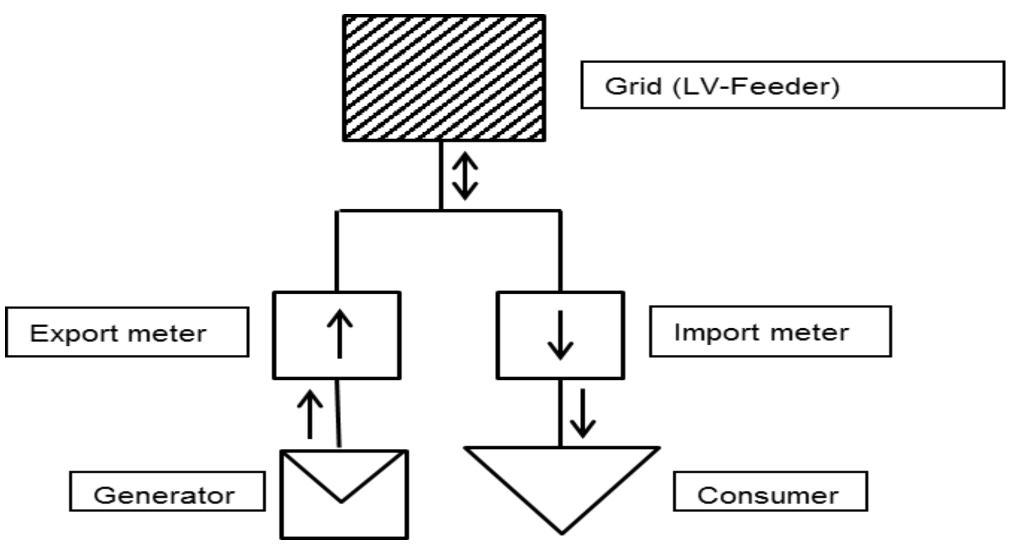


Figure 1: Net feed-in tariff scheme

8.2. Net-Metering (net-billing) scheme

Under this NEM tariff, a customer is billed by his or her utility or load-serving entity based upon net electricity consumption (i.e., the amount consumed minus the amount generated). Net consumption can be measured either with a single meter that measures net energy and is capable of counting forward or backward, or with separate metering of the customer's generation and consumption and a mathematical calculation of the net value computed by the utility. The ability to use one meter represents the virtue of simplicity that characterises NEM in many states**.**

Net metering is a service to a customer under which electricity is generated by that customer from an eligible on-site generating facility and delivered to the local distribution facilities. This may be used to offset electricity provided by the utility to the customer during the applicable billing period.

8.2.1 Advantages of Net Metering scheme

- Financial Credit for Extra Solar Power Produced

The customer receives a credit for excess solar power at the utility's going rate for electricity. When there is not enough electricity from the sun, the utility company will supply customer's electrical needs. The customer will pay only for the difference between the power supplied by the utility and the power produced by the solar panels.

- No Battery Storage System Needed

With net metering the utility company essentially stores customer's extra solar power for times when the customer does not have enough. This means that you don't really need an expensive battery bank, unless you want a small battery backup system for power outages.

- No Backup Generator for when Solar Power is Not Available

The electrical utility provides a backup when solar power is not available.

- No Maintenance

A grid-tied net metering system gives the advantages of producing own clean renewable energy without maintenance hassles and with very durable components.

8.2.2 Disadvantages of net metering scheme

- Customers are tied to the grid and to some extent **still dependent on the utility**. If the utility changes its net-metering policy, customers could find themselves owing money to the utility even though you produced enough electricity to meet all their needs.

- Another disadvantage could arise if too many customers install home energy systems and make use of net metering. Currently, net metering is feasible because most energy customers don't have home energy systems. If all or most of the utility's customers had home energy systems using net metering, however, the utility could find itself swamped with energy during high production times and unable to meet demand during high use times, except by wastefully producing commercial energy to meet the high demands. Conceivably, this problem could be solved by use of industrial scale storage batteries, but at minimum it would require retooling of the energy system as it currently exists.

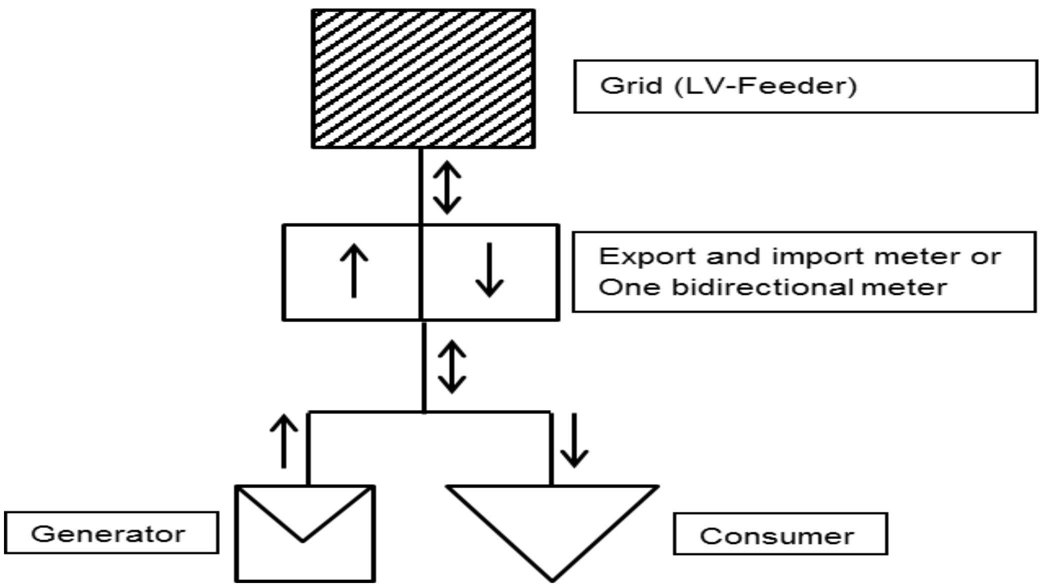


Figure 2: Net Energy Metering scheme

8.3. Net Feed-In Tariff scheme

In this scenario, the annual PV energy of E_{self} is consumed by the customer, while annual energy, E_{Fed}, from PV rooftop is fed to the distribution grid. Over the same year, the customer consumes energy, E_{grid}, from the grid electricity. The net feed-in payment is paid to the rooftop PV owner by the Central Power Purchasing Agency (CPPA), whose role is to handle accounting; billing and settlement of energy resulting from the net feed-in scheme. The energy imported from the grid by the rooftop PV owner is purchased by the municipality at the Eskom wholesale price and sold by the municipality to all its customers with margin. The municipality will lose an amount equal to the value of electricity lost due to self-consumed energy, E_{self}, from the installed PV rooftop. In order to avoid this revenue loss, the municipality receives a 'gross-margin' compensation for self-consumed energy (E_{self}) by the rooftop PV owner. CSIR estimates that the total annual funding requirement for the CPPA for a total PV capacity of 500MW peak will be approximately R530 million. The latter amount includes net feed-in payments for 500MW peak capacity and gross-margin compensation for all self-consumed energy, but excludes staff and other processes.

These tariff is almost similar to Net Metering but differs in terms of energy and financial balance at the end of the tariff cycle. Under NEM, a customer be a net energy consumer over an energy balancing cycle (typically one year) whereas a customer can be a Net energy consumer or **producer** over an energy-balancing cycle (typically one year) under the NFIT.

Under NEM, a customer must be a net payer over a billing cycle (i.e. no cash payments back to the customer) whereas a customer can be a **net receiver** of payments over a billing cycle (i.e. cash payments to the customer) under the NFIT.

8.3.1 Advantages of NET FEED - IN TARIFF (NFIT)

- Transparency & Safety
- Job creation & local content
- Reduced grid losses and system costs
- Reduced transaction costs
- Funding easier due to granularity

8.3.2 Disadvantages of NET FEED - IN TARIFF (NFIT)

- Lost revenues due to reduction in electricity sales
- Administrative burden managing large-scale uptake of embedded PV

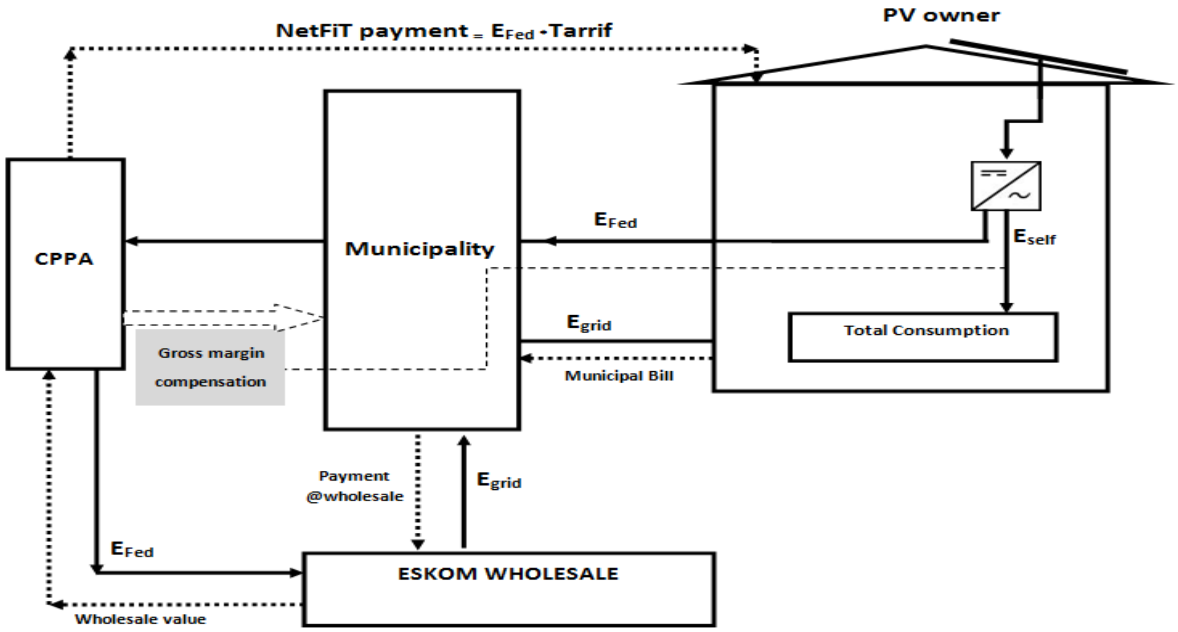


Figure 3: Net Feed-In tariff scheme

9. Alternative Rate design approached for domestic customers

9.1 Fixed Charge rate

In this option, all fixed are costs recovered through a fixed charge, and only variable costs included in the per-kWh charge.

A straight fixed/variable" rate design promotes:

- Significant bill increases for small-use customers;
- Cost shifts from suburban/rural (high-use, high distribution cost) customers to urban (low-use, low distribution cost) customers;
- Significant increases in overall usage, as customers respond to a lower price per kWh for incremental electricity consumption; and
- Significantly less financial incentive for customers to install energy efficiency or onsite generation resources.

9.2. Demand Charge-Based Distribution Charge and TOU Rate

A second approach would be to charge residential customers a monthly fee based on their maximum level of usage at any hour during the month. This could be done through a rate element called a "demand charge" that is applied to the highest kW usage. This is commonly seen in tariffs for commercial and industrial customers

Each component of the distribution grid is sized to a particular level of demand, and the costs are somewhat linear with increased demand. It is still a volumetric form of rate design, but based on the maximum volume during a period of the month, rather than the total volume for the month.

Large commercial customers typically subject to demand charges have diversity of multiple uses on the customer's side of the meter, so that intermittent uses tend to average out at the meter. Individual residential consumers do not have this diversity, but as a group residential customers do have significant diversity.

The level of the demand charge must be carefully calculated to take into account the diversity of customer demands in order to produce the correct level of revenue.

9.3. Bidirectional Distribution Rate

A bidirectional distribution rate is a fundamentally different approach, but would produce similar results to a demand charge for typical customers without imposing a complex rate design on the small customers who do not own embedded systems.

Under this approach, when a customer is taking power from the grid, he or she would pay the full grid cost, including production, transmission, and distribution system expenses. When reverse-metering to the grid, he or she would also pay for grid access, but pay only the distribution rate of a few cents per kWh.

This approach requires metering that is able to measure power flows in either direction. Most smart meter systems can do this, but the meter data management systems must be programmed to collect the data. With these data, at the end of the billing period, the customer would receive a multipart bill with a:

- Fixed charge based on the installed capacity (use of system charges, admin costs
- A set tariff for net-import of electricity or optionally a TOU tariff;
- A set tariff for net-export of electricity

In this approach, customers is pay for network charges whether they receive power or supply it to the grid. The theory is that the customer has built a system that requires a grid in order for all of the power to be used, and should contribute to the cost of the grid for both uses

10. BILLING AND ENERGY ACCOUNTING OF RULES

Net energy metering of kWh instead of Rand shall be used. Each month, electricity the SSREG produces in excess of own consumption will be sent back to the grid and credited to its account for up one yearly billing cycle, after which any remaining credit is forfeited to the distributor and the SSREG begins the new 12month billing period with a zero balance. This reduces any incentive for the customer to oversize generation with respect to load.

The credits received for surplus electricity supplied to the grid will be used to offset all or part of the costs associated with the energy consumed each month. Domestic accounts are billed annually for 'net' energy generated over the previous 12 months, if any. Non-residential accounts are billed monthly for their energy usage. The energy credits accrued will be applied only to energy charges. The credits cannot be used to pay non-energy charges and they cannot be applied to other service accounts like refuse collection, property rates etc.

If in a given month the customer 'net consumed' energy, there will be energy usage charges for that month (customer pays the utility money). If the customer 'net generated' energy, the customer gets energy credit for the month (customer does not pay any money to the utility).

The distributor will read the meter once a month to record the net amount of energy either consumed or generated over the entire month. If in a given month the system generates more electricity than consumed, the surplus energy will be credited to the customer's account at export tariff rate determined by NERSA as above (SSREG cost recovery section).

The PPA shall not be less than one year across all seasons to ensure that electricity generated in summer will be fully remunerated (e.g. high summer production balanced off by the lower production in winter).

The PPA shall not be >3years for municipal distributors because they are not allowed to make financial commitment longer than that without the approval on National Treasury and other stakeholders [this is a legislated position (MFMA section 33)].

Excess credits of kWh shall not be transferred to another account.

Residential customers are not required to take service on TOU rates until NERSA develops and approves TOU tariffs. Non-residential customers already on TOU tariffs shall continue to be on that regime.

Benefits from Renewable Energy Credits (REC) shall not be included under this programme.

11. REGULATION REQUIREMENTS

11.1 Electricity Regulation Act of 2006

The Act stipulates that no person may operate a generation facility without a licence from the Energy Regulator, except for activities listed on Schedule 2 of the Act, namely:

1. *Any generation plant constructed and operated for demonstration purposes only and not connected to an inter connected power supply*
2. *Any generation plant constructed and operated for own use*
3. *Non-grid connected supply of electricity except for commercial use*

The small scale embedded generators will be connected to the grid and will be operated for commercial purposes since they will sell to the municipalities or Eskom. They would therefore need to be licenced or registered as per the Act.

Section (10) (2) requires the application for a generation licence to include:

- *(a) description of the applicant, including vertical and horizontal relationships with other persons engaged in the operation of generation, transmission and distribution facilities, the import or export of electricity, trading or any other prescribed activity relating thereto;*
- *(b) such documentary evidence of the administrative, financial and technical abilities of the applicant as may be required by the Regulator;*
- *(c) a description of the proposed generation, transmission or distribution facility to be constructed or operated or the proposed service in relation to electricity to be provided, including maps and diagrams where appropriate;*
- *(d) a general description of the type of customer to be served and the tariff and price policies to be applied*
- *(e) the plans and the ability of the applicant to comply with applicable labour, health, safety and environmental legislation, subordinate legislation and such other requirements as may be applicable;*

(f) *a detailed specification of the services that will be rendered under the licence;*
(g) *evidence of compliance with any integrated resource plan applicable at that point in time or provide reasons for any deviation for the approval of the Minister; and*
(h) *such other particulars as the Minister may prescribe.*

Once a full application is received by NERSA with all licensing processes, Section 11 of the Act requires the applicant to publish a notice of the application in appropriate newspapers or other appropriate media circulating in the area of the proposed activities in at least two official languages. The advertisement must include:

(a) *the name of the applicant;*
(b) *the objectives of the applicant;*
(c) *the place where the application will be available for inspection by any member of the public;*
(d) *the period within which any objections to the issue of the licence may be lodged with the Regulator;*
(e) *the address of the Regulator where any objections may be lodged;*
(f) *that objections must be substantiated by way of an affidavit or solemn declaration; and*
(g) *such other particulars as may be prescribed*.

Once objections or comments are received by the Energy Regulator, the applicant will be given a chance to respond. A public hearing will then be held where interested parties, including the applicant, will be afforded a chance to present their case. The Energy Regulator may request additional information during the public hearing. Once all information is received, the Energy Regulator is required to make a decision on the Act within 120 days from the date of receipt of all information.

Due to the envisaged high volumes of solar rooftop installations, the licensing of such embedded generators using the above process will be a burden to the applicants who have little resources and will put constraints on the National Energy Regulator. Therefore, registration of these plants may be a viable option.

In 2011, NERSA approved the *Standard Conditions for Embedded Generation within Municipal Boundaries* where embedded generators up to 100kW are registered and allowed to sell power to municipalities. This cut-off point of 100kW is too small for most proposed embedded generators. It is proposed that the cut-off point for embedded generators for registration be increased to 500kW per installation and the *Standard*

Conditions for Embedded Generation within Municipal Boundaries approved in 2011 be replaced by this document.

12. REPORTING REQUIREMENTS OF THE DISTRIBUTING UTILITY TO NERSA

SSREG shall report to NERSA as published in the approved standard conditions published on 22 September 2011. NERSA approved the following standard conditions for small scale (less 100kW) embedded generation within their area of supply states:

a) That the distributors must register and maintain a database of all small scale (1<1000kW) embedded generation within their area, which will incorporate, as a minimum, the following information:
   I. the technology of the generator;
   II. the capacity installed;
   III. its location (both of the network and GPS);
   IV. whether there is energy storage associated with it; and
   V. customer name and account.
b) That the distributors must report to the Energy Regulator on an annual basis the following information:
   I. the number of installations for each technology;
   II. the total capacity for each technology installed;
   III. the total energy each technology has generated onto their system in each 'Time-of-Use tariff' metered time period;
   IV. complaints that they have received from customers on the same circuit as the generation about quality of supply;
   V. all safety related incidents involving generation;
   VI. the tariffs applicable to these installations; and
   VII. the Standard Supply Agreement.

13. CONCLUSION

It is clear from international experience and the above analysis that small scale renewable embedded generation is upon us. Counties like Germany, Spain, Italy and the US have had a fair share of the implementation and management of the systems and they still do today. Some of those countries have used some incentives for rooftops solar, e.g. Feed-In Tariffs and credit programmes funded by banks to promote the systems. This is because these countries had an attractive market for the rooftop solar and their objectives would be different to those of South Africa. Their governments also securitised the tariff by government guarantees, which is something that the South African Government cannot engage in at this stage with so many programmes where guarantees are currently offered.

The fear of revenue erosion by distributors is addressed and tariff options are discussed in this document to allow distributors to propose which one is the best to choose and easy to implement.

In light of what the discussion paper proposes, the Energy Regulator would like to engage with stakeholders and comment on proposals raised.

ACKNOWLEDGEMENTS

Project Team:

1. Moefi Moroeng – Team Leader
2. Lucky Ngidi
3. Charles Geldard
4. Bianka Belinska
5. Velly Malaza
6. Andile Gxasheka
7. Ezekiel Ngwasheng
8. Melusi Nyoni
9. Lehuma Masike
10. Tamai Hore
11. Bongi Masemola
12. Donald Nkadimeng
13. Siphiwe Khumalo

REFERENCES

1) NERSA South Africa, Grid Connection Code for Renewable Power Plants (RPPs) connected to the electricity transmission system (TS) or the Distribution System (DS) of South Africa, 2012
2) NERSA Decision on standard conditions for small scale embedded generation within Municipal Boundaries, September 2011
3) Dr N Bischof-Niemz, How to stimulate the South African PV market without putting municipalities financial stability at risk, ‘A Net feed-in tariff proposal’, CSIR presentation to NERSA, 12 Nov 2014
4) NRS 097-2-2010: Grid interconnection of embedded generation, utility interface, 2010
5) NRS 097-3 -2014: Grid interconnection of embedded generation, simplified utility connection for low voltage connected generators, 214.
6) Electricity Regulation Act: Act No.4 of 2006, Electricity Regulation
7) IRP 2010: Integrated Resource plan for electricity 2010, Rev 2
8) SALGA/AMEU/ESKOM reference group: Comments on NERSA’s standard conditions for small scale embedded generators

ANNEXURE A

Research and Mini-Benchmark Study

During the late 90s, experience was gained in Europe with some countries adopting Feed-In Tariffs (FITs) (e.g. Germany and Denmark) and others competitive tenders [e.g. United Kingdom (UK) and France]. Countries with FITs 32 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 FITs, while the UK switched to tradable credits under its Renewables Obligation (UNEP 2012b). In the 2000s, there was a drive to harmonise renewable energy policy within the European Union (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 FITs (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 FITs apply for photovoltaic (PV) but tradable certificates are used for other technologies] (UNEP 2012b).

In developing countries, FITs 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).

This study focuses on two of the largest electricity markets in Europe – Germany and Spain. Both countries are part of the Union for the Coordination of the Transport of Electricity, one of the largest interconnected systems in the world.

The German Experience

The German programme, which is the most advanced in the world with approximately 17 GW total installed (7 GW alone in 2011) began with the ‘1000 roofs programme’ in

1991, in which the government gave subsidies to individuals to cover the cost of installing a grid tied PV rooftop systems in the range 1 – 5 kWp. Systems were fitted with three meters measuring generation, supply and demand. Costs for a 2.2kW system in 1993 were around €30 000 (modules around €15 000), owners participation around €9000. By the mid-1990s, 2000 grid-connected PV systems had been installed on Germany's rooftops. In 1999 the 100 000 roofs programme was launched to drive further expansion of the industry, and was marked by a reduced interest credit programme funded by KfW bank for systems with private persons, freelance individuals, and SMMEs. The programme ended after 2003 with a limit of 300 MW being reached, with the successful installation of 100 000 grid-connected rooftop solar systems.

The country's renewable energy law introduced in 2000 also supported the solar roofs programmes by establishing a feed-in tariff which guarantees a higher-than market price for electricity generated by solar PV which is fixed for 20 years beyond the installation date, providing investment certainty for firms and individuals. Recent changes in feed-in tariffs have taken place which alter the initial goals. The feed-in tariff is paid by the distributor to the customer, and is then rolled up to the power purchasing utility or authority, where the additional costs of Renewable Energy are spread out into the overall cost of electricity to all consumers. Latest figures show that more than 1 million systems have been installed to date, with 85% of all PV systems being rooftop types.

What mostly pushes small PV installations in Germany is the possible reform the Renewable Energy Law in Germany, put forth through a white paper by Federal Environment. It called for a limitation of free field installations to 400MW and controlled through tender offers. The efforts to reform the Germany Renewable Energy Act (Erneuerbare-Energien-Gesetz or EEG) seem to be driven by the government’s wish to keep the energy turnaround affordable and by some backdoor attempts to gain more influence on national energy policy.

Self-consumption and independence from the utilities has become the main motive for German end-consumers to buy a PV system. The majority of the systems bought last year in 2013 have a share of self-consumption of around 30%. Profit-driven motives are of minor importance nowadays in Germany. This development could also push PV storage systems that have been promoted by subsidies from banks.

The Spanish Experience

Spain also earned a reputation for leadership in the development of the renewable energy industry, more especially the rooftop solar PV. The original indicative plan for Spain was for 400MW of Solar PV, which attracted more than 4500 MW of solar PV, which is about 60 000 installations. This is mainly because the regulation introduced a regulated payment (feed-in tariff) per MWh produced that was higher than required to induce investment, and there was no limit to the amount of PV that could receive this payment under 25 year contracts, only a deadline for when the door shut.

This model caused an accumulated tariff deficit, which is in fact debt, and is now 30 billion Euro. It continues to grow and is supposed to be recovered from all customers over the next 15 years though the access tariff. The access tariff has grown along with the subsidies and other regulated costs it reflects. It now accounts for about 55% of a typical customer's electricity cost, with remaining 45% associated with the wholesale price of energy. In other words, more than half of a customer's electricity bill reflects regulated costs, on-going subsidies and part of the accumulated deficit.

Recently the Spanish government has drafted a legislation that aims to stop this deficit from growing and to introduce regulatory stability. This is as a result of setting regulated (grid) access tariff too low to recover all the recognised costs of regulated activities.

UK incentive scheme for distributed generators

In UK, there are four key organisations in the electricity business, namely the National Grid Electricity Transmission (NGET); Distribution Network Operator (DNO); Suppliers or Traders; OFGEM (the regulator of the power system in Great Britain); and the Balancing Settlement Code company whose role is to facilitate the effective delivery, implementation, operation and development of the electricity trading arrangements.

FITs are the financial incentive used to support distributed renewable energy generation up to 5 MW. Technologies that are eligible for the incentive include Anaerobic digestion; Combined Heat and Power (CHP); Solar PV; Wind and Hydro. There is a limit of 30,000 domestic CHP units that are supported by the pilot scheme. The CHP units must have a capacity of not more than 2kW each. Generators have an option of choosing between the options shown in Table A below.

Table A: Incentive scheme for distributed generation[6]

Generation tariff (FITs):	It is a fixed price for each unit of electricity generated, depending on the generation technology. The tariffs are reviewed regularly. The tariff level that the generator receives remains the same throughout the eligible lifetime of the project, which for most technologies is 20 years.
Export tariff:	There is guaranteed price for each unit of electricity exported to the grid. The tariffs are reviewed regularly.
Import Reduction:	Generators reduce their electricity bill by using their own electricity rather than importing from the grid.

Generators are charged for connection to the network. In addition to the connection charge, Generation Distribution Use of System (UoS) are levied for the operation and maintenance of the distribution network. The UoS are levied by the distribution network operator to the electricity traders, who in turn charge these from electricity consumers.

Southern California Edison (SCE) support for embedded generators[7]

In Southern California, Net Energy Metering (NEM) is used for programmes designed to benefit customers who generate their own electricity using eligible renewable technology.

The NEM programme uses a bi-directional meter to track the 'net' difference between the amount of electricity you produce and the amount of electricity you consume during each billing period. This can be accomplished on a cumulative basis or on a time-of-use basis, depending upon the customer's rate schedule.

The Residential NEM customer receives monthly bills, but only for non-energy related charges such as taxes and fees. On an annual basis, the customer is billed for electricity based on net use for the previous year – for example, the amount of electricity used

[6] Distributed Generation Connection Guide, June 2014, Available online: http://www.energynetworks.org/modx/assets/files/electricity/engineering/distributed%20generation/DG%20Connection%20Guides/June%202014/G59%2050kW%20Summary%20June%202014.pdf

[7] https://www.sce.com/wps/portal/home/business/generating-your-own-power/net-energy-metering/faq/

minus the amount generated. Large Commercial/Industrial NEM Customers receive monthly bills, which will require payment of the monthly non-energy related charges (taxes and standard billing fees) and ‘net’ energy charges.

In order to be eligible for the programme, the system must be sized to historic electric use up to 1MW, located on customer premises and interconnected to operate in parallel with distributor electrical system. Renewable technologies such as Solar PV, wind, biogas, biomass, municipal solid waste up to 1MW are allowed.

The NEM solar programme is designed to enable customers to offset their usage, not to generate surplus energy to sell to the distributor. The system must be sized to offset annual onsite consumption.

If system size is increased, a revised Interconnection Application must be submitted to Generation Interconnection Services for the new system, including all additional equipment. An engineering analysis is conducted to ensure that the distributor’s facilities can accommodate the increased generation capabilities of the new system. The customer must still meet all the requirements of the NEM programme to continue on the NEM rate, including the size limitations.

All customers participating in NEM must have a bi-directional meter, one that measures electricity flow in two directions.

The payment to customer is done as follows:

I. The customer may receive a cheque through the mail for the value of the net surplus generation, excluding any amount owed to the distributor. At the end of each Relevant Period, the customer’s account will be zeroed out, and the new Relevant Period will begin on the next regularly scheduled meter read date.

II. The customer receives credit at the same rate that would have been charged had he/she purchased the electricity from the utility. The customer may roll the credit over to the next Relevant Period. The utility reconciles the customer’s account and apply the Net Surplus Compensation (NSC) earned toward the customer’s next Relevant Period. At this point, the account is zeroed out and the new Relevant Period begins on the next regularly-scheduled meter read date. Any NSC credit can be applied to energy or non-energy charges. The utility maintains a customer’s NSC credit indefinitely, until it is fully used, or until the account is closed. If the account is closed, the utility will return any unused credit in the customer’s account in the form of a cheque.

Distribution Generation in Australia[8]

In Australia, the retail price of electricity for small customers typically comprises the following:

(i) a relatively small proportion of the bill as a fixed supply charge usually set in cents per day; and
(ii) a variable usage charge based on the volume of electricity consumed, in cents per kWh.

A typical small customer's bill, or the price of an average unit of electricity, is mainly attributable to the variable charge. By contrast, a significant portion of the cost of supplying electricity to customers is fixed, that is, the cost is the same regardless of how much electricity the customer uses over time. The largest of the fixed cost is the cost of providing distribution network services, though retailer and some green scheme costs are also fixed.

In recent years, Australia has experienced rapid growth in the use of Distributed Generation (DG) systems. By far the most commonly used technology today is solar PV. PV systems are now a common sight in most Australian cities, whereas they were rare only around five years ago. This rapid acceleration has been driven by a range of factors, namely:

I. generous government subsidies motivated by a desire to reduce greenhouse gas emissions and promote 'green' technologies; subsidies have included rebates, feed-in tariffs and implicit rebates through the creation of renewable energy certificates;
II. rapid reductions in capital costs in Australia driven by manufacturing innovations, increasing manufacturing competition and a strengthening Australian dollar;
III. reductions in solar system installation costs largely driven by innovation in local installation businesses and emergence of a competitive mass-market for PV installations in Australia; driven in turn by the scale effect of generous subsidies and reducing capital costs; and
IV. a distortion in the way electricity retail prices are structured.

[8] ACIL Tasman Economic Policy Strategy,(2013), Distributed Generation- Implications for Australian Electricity markets.

Government subsidies to PV systems have been unwound rapidly in recent years, so the first factor listed above is unlikely to be a major driver of DG uptake in future, although it has clearly contributed to the emergence of a competitive mass-market for PV today.

The impact DG has on the wholesale market is influenced by its output profile, that is, the quantity of electricity generated and when it is generated.

Reflecting the impact that DG has on the electricity system, it is limited mainly to a discussion of the different output profiles that could be expected from generators of different technologies. The output profile of a DG system is of course also influenced by whether or not the system incorporates the capacity to store power, such as through a battery system. In effect a storage system gives greater control to the operator over when, and how much, to generate.

From the perspective of their output profile, DG technologies can be placed into the following three groups:

1. Solar photovoltaic technologies
2. Wind powered technologies
3. Technologies whose output is at the discretion of the operator such as micro turbines or fuel cells.

Table B below provides an overview of the status of technologies used for distributed generation. The figures for micro turbines, fuel cells and battery storage are treated as indicative as volumes are very small and case specific. Further, for technologies that are not yet commercial, the figures should be interpreted cautiously as they may be optimistic or may reflect costs that could be achieved by larger systems that may not be suitable as DG.

Table B: DG technology status and outlook

Technology	Market status	Scale of system	Current cost	Future cost	Comments	Estimated export value[g]
Solar PV	Commercially available (high volumes)	1kW to MW scale	$224/MWh[a]	$133/MWh [a] (2020)	Flat plate no tracking.	$80 to $100 /MWh
Wind	Commercially available (high volume)	~10kW to 5MW (per turbine)	$40-$100/MWh (for large turbines) $80 - $300 / MWh [b] (for small turbines)	$62 – 233 / MWh[c] (2020)	Small scale wind system	
Micro turbine	Commercially available (low volumes)	30kW - 200kW	$160 / MWh[d]	$190 / MWh[e]	Gas fired	$70/ MWh in 'always on' mode Higher if operated as a peaker, though revenue is lower due to reduced volume.
Fuel cells	Early stage commercialisation. (very low volumes)	1kW – MW scale	$150/MWh[f]	$90-110 / MWh[f] (mid term projection)	Natural gas fuelled. Can also provide hot water.	
Battery Storage	Commercially available	scalable	Very high cost and relatively short life (about 1000 cycles)	Li ion battery costs could fall significantly if EV use becomes significant.	Lead acid, Li ion	
Cogeneration	Commercially available	kW to MW scale	$98/MWh[h]	Costs are highly case specific	Gas fired	
Trigeneration	Commercially available	kW to MW scale	$66/MWh[h]	Costs are highly case specific	Gas fired	

The figures for cogeneration and trigeneration are also highly case specific and sensitive to the assumptions made, including gas prices, capacity factors and heat rates. The assumptions for the figures include a gas cost of $6/GJ, an operating life of 30 years, a capacity factor of 80% and a carbon price of 20/tCO2-e.

ANNEXURE B

EXISTING LEGISLATION, STANDARDS, CODES AND LIMITATIONS

There are a number of clauses in the Acts, standards and codes with limitations that are making it difficult for small-scale embedded generation to be implemented effectively. These are listed in the table below.

Legislation, code, standard	**Quote**	**Limitations**
Constitution of South Africa 1996, Section 156 (1)	'A municipality has executive authority in respect of, and has the right to administer […] electricity and gas reticulation.'	Gives municipalities a competency only in terms of electricity reticulation. Generation is in effect classified as a national competency.
Electricity Regulation Act (2006), Section 34 (1)	'The Minister may, in consultation with the Regulator […] require that new generation capacity must- (i) be established through a tendering procedure which is fair, equitable, transparent, competitive and cost-effective; (ii) provide for private sector participation.'	Minister of Energy to determine who will produce, generate, procure or buy RE; no specific involvement of Municipality, or municipality or Eskom customer in these processes.
Electricity Regulation Act (2006), Section 35 (1)	'The Regulator may, after consultation with […] municipalities that reticulate electricity […] make guidelines and publish codes of conduct and practice, or make rules by notice in the *Gazette*.'	Defines partial involvement of Eskom and municipalities into regulation activities.
Electricity Regulation Act on New Generation Capacity (2009), Definition IPP	'"Independent Power Producer" or "IPP" means any undertaking by any person or entity, in which the government of South Africa does not hold a controlling ownership interest (whether direct or indirect) […]'	Effectively implies that local government cannot hold a direct or indirect controlling interest in an IPP.

The Electricity Pricing Policy GN 1398 of 19 December 2008	N/A	The electricity Pricing policy is silent on these types of systems and does not indicate how they should be treated.
The Renewable Code	This code outlines grid connection conditions to comply with for all sizes of renewable energy generators	The grid connection conditions in this code are more relevant to a bigger size of generation plants connecting to higher levels of voltage and not at low voltage levels. As a result, this code warrants much more stringent performance from these plants.
The Distribution code	The distribution code outlines all requirements for: • Metering • Connection conditions for embedded generators but assuming it would be thermal or hydro power stations. • Limitation of liability • Information exchange Designing of tariffs etc.	This code is rather limited with regard to dealing with issues of embedded renewable generation. It assumes that all renewable energy related issues will be dealt with within the scope of the renewable energy grid code.
The NRS 097-2-1:2010 The NRS 097-2-3:2014	This specification sets out the minimum technical statutory requirements for the utility interface, the embedded generator and the utility distribution network with respect to embedded generation. The specification applies to embedded generators smaller than 100kW which are connected to an LV utility network. This specification sets out the technical requirements for the utility interface, the embedded generator and the utility distribution network with	This is limited to only LV connected embedded generators and by implication no embedded generator of this size will be or is expected to be connected to the MV utility network. Also according to this specification, the limit does not cover the correct threshold up-to or just below 1000kW. This NRS is in the course of being reviewed to cater for the correct threshold. This is limited to only LV connected embedded generators and by implication no embedded generator of this size will be or is expected

	respect to embedded generation. The specification applies to embedded generators smaller than 1000kVA connected to low voltage networks.	to be connected to the MV utility network.