UNIVERSITY OF THE WITWATERSRAND

MASTERS DISSERTATION

Implementing electric vehicle focused tariff structures to support electric vehicle adoption and rooftop solar PV integration

Author:

Ouma Enesia Tlou BOSALETSI

Student Number: 1846867

A Dissertation submitted in fulfilment of the requirements for the degree of Master of Science in Engineering

in

Engineering and the Built Environment

School of Electrical and Information Engineering

January 2020

Declaration

I, **Ouma Enesia Tlou Bosaletsi**, declare that this Dissertation titled, "**Implementing electric vehicle focused tariff structures to support electric vehicle adoption and rooftop solar PV integration**" and the work presented in it are my own. I confirm that:

- This work was done wholly or mainly while in candidature for a research degree at this University.
- Where any part of this thesis has previously been submitted for a degree or any other qualification at this University or any other institution, has been clearly stated.
- Where I have consulted the published work of others, this is always clearly attributed.
- Where I have quoted from the work of others, the source is always given. With the exception of such quotations, this dissertation is entirely my own work.
- I have acknowledged all main sources of help.

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Abstract

The research work proposed a three-part dynamic distribution tariff structure comprising of the energy charge (as a price signal for energy efficient consumption), the network losses charge (as a price signal for energy efficient consumption) and the maximum demand charge (as a price signal for managing local transformer rating violation). The novel part of the proposed tariff is that the network voltage violation and network equipment rating violation will be managed by sending price signals to customers.

The energy charge will differ during the day due to the dispatch of generation plants according to the merit order. This makes the tariff time-of-use based. Different ramp rates are applied with the slope of the ramp function based on the averaged local transformer loading to defer costly infrastructure upgrades. The hypothesis is that if tariffs are based on the costs of meeting demand, the customers will have incentives to modify their usage behaviour in ways that reduce the overall network costs.

Acknowledgements

I would like to express my gratitude to my supervisor, Prof John Van Coller, for his continuous guidance and willingness to participate in quality technical discussions with me.

I would like to thank Eskom Group Technology Project Engineering for the opportunity to participate in the Eskom Power Plant Engineering Institute Programme.

Lastly, I would like to express my heartfelt gratefulness to my husband, Letuma Bosaletsi and my two sons, Lesedi and Tumelo Bosaletsi for their endless encouragement and support for me while I worked on this research.

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Abbreviations

ADMD	**A**fter **D**iversity **M**aximum **D**emand
AMI	**A**dvanced **M**etering **I**nfrastructure
CCP	**C**ritical **P**eak **P**ricing
DLMP	**D**istribution **L**ocational **M**arginal **P**ricing
FIT	**F**eed-**I**n **T**ariff
ESI	**E**lectricity **S**upply **I**ndustry
EV	**E**lectric **V**ehicle
kW	**K**ilo**W**att
kWh	**K**ilo**W**att-**H**our
LMP	**L**ocational **M**arginal **P**ricing
LRIC	**L**ong-**R**un **I**ncremental **C**ost
LRMC	**L**ong-**R**un **M**arginal **C**ost
LV	**L**ow **V**oltage
MCS	**M**onte **C**arlo **S**imulation
MDMS	**M**eter **D**ata **M**anagement **S**ystem
NMD	**N**otified **M**aximum **D**emand
PV	**P**hoto**V**oltaic
REIPPP	**R**enewable **E**nergy **I**ndependent **P**ower **P**roducer **P**rocurement
RTP	**R**eal **T**ime **P**ricing
SOC	**S**tate **O**f **C**harge
SRMC	**S**hort-**R**un **M**arginal **C**ost
TOU	**T**ime-**O**f-**U**se

CHAPTER 1

Introduction

1.1 Introduction

This chapter provides the background, problem statement and emphasises the need for changes in the current distribution tariff structures given the expected large uptake of rooftop solar PV and electric vehicles (EV). It also includes the research question to be addressed and requirements to be met by the research in the form of proposed distribution tariff structures which are theoretically defined, designed and then tested for different network scenarios based on simplified examples. Low-voltage (LV) refers to the distribution network with residential customers fed at the standard ac voltage of 400V phase-to-phase (3-phase customers) and 230V phase-to-neutral (single-phase customers) [1].

1.2 Background

The local power utility is currently experiencing declining electricity sales due to changing customer energy consumption behaviour, energy efficiency programmes, distributed generation and the downturn in the country’s economy. Table 1.1 below represents South Africa’s electricity consumption trend as reported by statistics SA in April 2019 [2]. The data records month-on-month changes of -1.5% in March 2019, -1.1% in February 2019 and -0.6% in January 2019. The seasonally adjusted electricity consumption decreased by 1.3% in the three months ending in April 2019 compared with the previous three months. The year-on-year percentage change was reported as -2.8% in March 2019.

TABLE 1.1: South Africa's electricity consumption trend [2]

	Nov-18	**Dec-18**	**Jan-19**	**Feb-19**	**Mar-19**	**Apr-19**
Year-on-year % change, unadjusted	0.9	0.1	0.1	-1.0	-2.8	1.6
Month-on-month % change, seasonally adjusted	-1.1	1.0	-0.6	-1.1	-1.5	2.9
3-month % change, seasonally adjusted[1]	0.0	0.1	-0.3	-0.4	-1.6	-1.3

Figure 1.1 below represents the local utility annual energy sale volumes in GWh over the past fifteen years. A significant drop in energy sales was experienced after 2004/05 with the utility experiencing a further decline in electricity sales since 2013/14 [3].

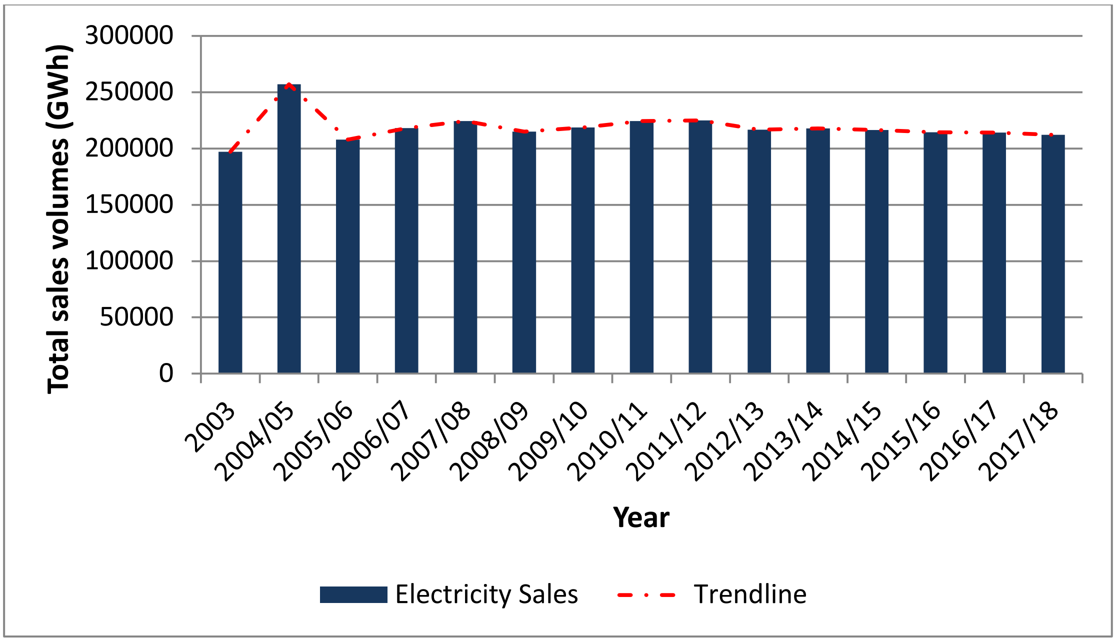


FIGURE 1.1: Eskom total electricity sales

The global cumulative solar PV capacity installed (on-grid and off-grid) increased from 8 GW in 2007 to 402 GW in 2017 [4] as shown in Figure 1.2. The global total installed solar PV capacity increased by 25% to 509.3 GW by the end of 2018 [4]. Globally, the solar PV market expansion was due to the falling solar PV panel prices, rising demand for electricity in

[1] Percentage change between the previous 3 months and the 3 months ending in the month indicated

developing countries, increasing awareness of solar PV's potential to alleviate pollution and government policies that supports renewable energy [4]. According to South Africa's Integrated Resource Plan (IRP) of 2019, the envisaged energy mix by 2030 will consist of 33 364 MW of coal (43%), 1 860 MW of nuclear (2.36%), 4 600 MW of hydro (5.84%), 5 000 MW of pumped storage (6.35%), 8 288 MW of solar (10.52%), 17 742 MW of wind (22.53%), 6 380 MW of gas (8.1%) and 600 MW of concentrated solar power (0.76%) [5]. As per South Africa's IRP of 2019, the expected growth in Solar PV installations is constrained by annual new-build limits of 1000 MW/year to 2030 for utility scale installations and 500 MW/year to 2030 for small-scale embedded generation [5]. The number of solar PV installations in South Africa is expected to grow due to the rollout of renewable energy independent programme (REIPPP), electrification of remote areas and small-scale rooftop solar PV installations at residential areas driven by increasing price of electricity. Figure 1.3 presents the trend in electricity prices for different customer groups supplied directly by the local power utility [3]. Due to the increasing price of electricity, the local power utility is thus faced with two fundamental challenges: retaining existing customers and capturing new markets to increase electricity sales.

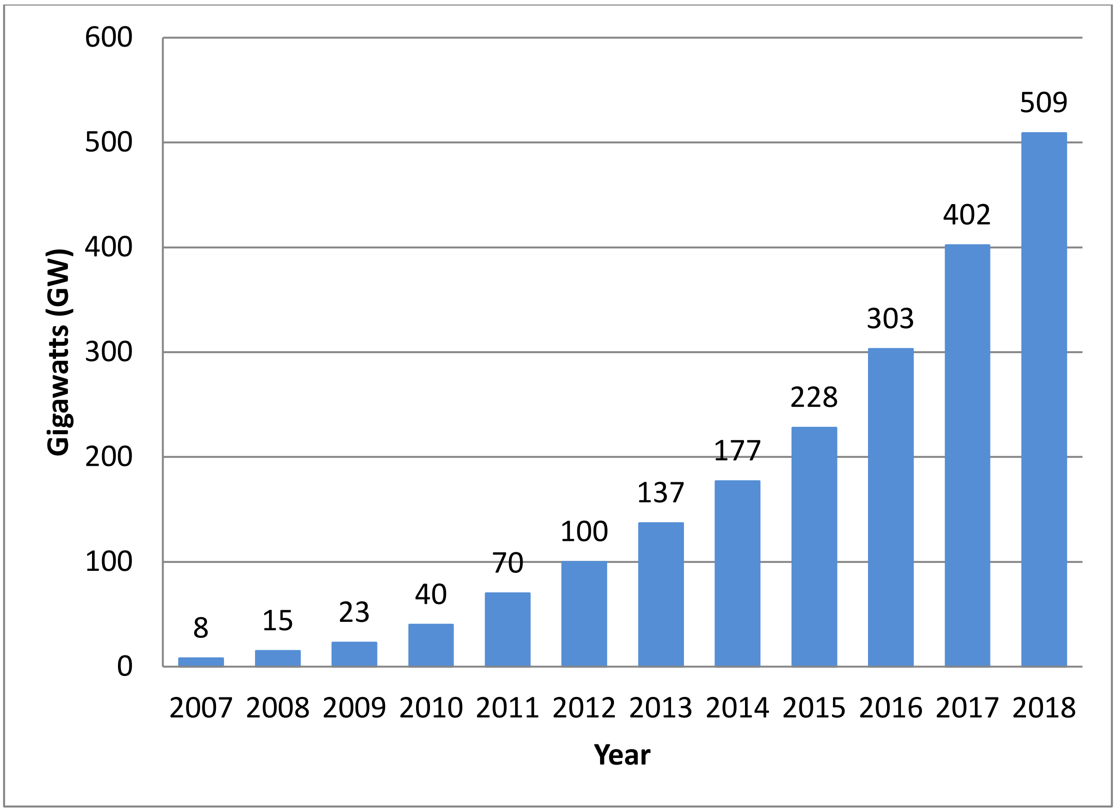


FIGURE 1.2: Solar PV global capacity, 2007-2017 [4]

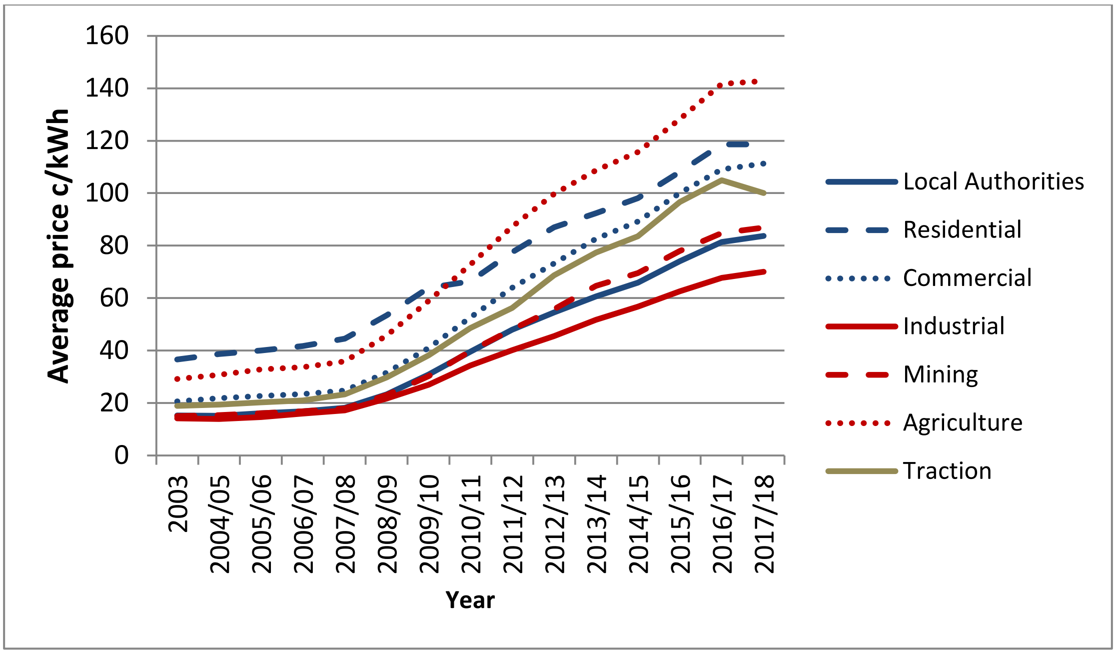


FIGURE 1.3: Eskom average electricity price (c/kWh)

Electrification of the transport sector has increased with the global sales of electric passenger cars reaching an estimated 1.2 million units in 2017 as shown in Figure 1.4 [6]. The expected growth in the EV market could present a strategic opportunity for the power utilities to increase electricity sales through supplying EV charging energy requirements. As of January 2018, there were 375 EVs sold in South Africa since the launch of EVs in South Africa in 2013 [6].

Although the uptake of EVs is low in South Africa, the charging demand will be significant on the LV network if EVs clustered in one area charge simultaneously from the same local distribution LV network. This research work is based on a future where the uptake of solar PV and EV becomes large so it can no longer be ignored in the planning and operation of the LV distribution network.

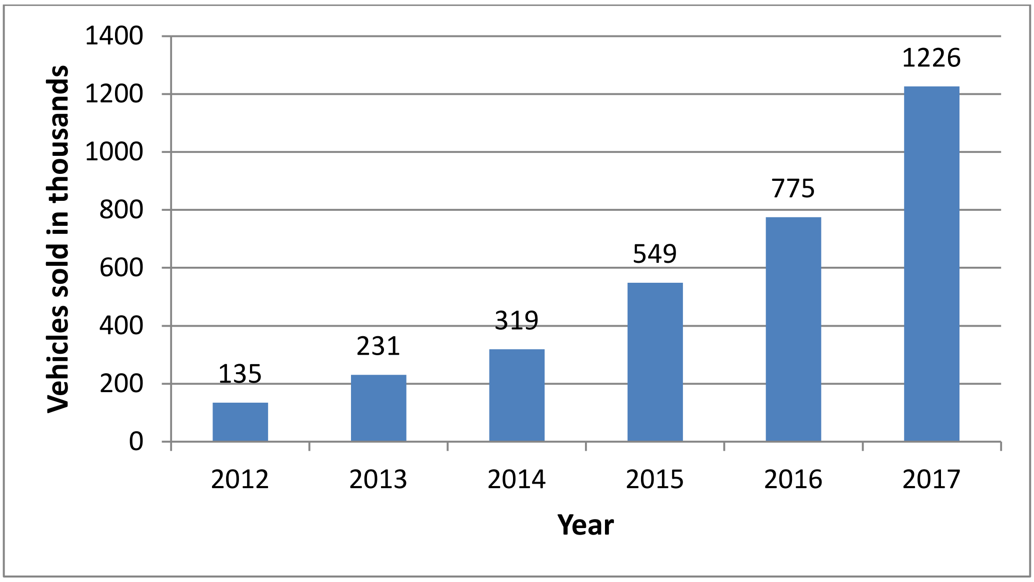


FIGURE 1.4: Electric vehicles sold globally, 2012-2017 [6]

EV load is flexible and potentially controllable. By optimally managing the EV load, the power utility may flatten the local demand profile by shaving peaks (EV charging prevented when the other local demand is high), filling valleys (EV charging encouraged when the other local demand is low) and allowing efficient use of excess available energy generated from solar PV. Several research projects undertaken to estimate the potential impact of high EV penetration on the electric grid had a common finding that uncontrolled EV charging is more likely to coincide with the overall peak load of the electric grid [7]–[9].

Solar PV is a self-dispatchable energy resource in that it cannot adjust its time of energy generation to the overall energy demand. When operating at its maximum, solar PV can generate more electricity than consumed onsite with the surplus electricity exported to the electric grid. This gives rise to transformation in the electricity supply industry from large centralized generation stations to decentralized distributed energy resources located close to end users.

The increasing uptake of solar PV in LV distribution networks will bring about challenges in the power systems such as voltage rise due to reverse power flow along the LV distribution feeder [10], [11]. Voltage control of a distribution network is one of the most important considerations to power utilities and end users. The voltage magnitudes at the points of connection are required to be maintained within statutory limits for efficient and reliable supply. The South Africa's distribution grid code set the allowable voltage levels at the point of connection to V_n ± 10% where V_n is the nominal voltage [1]. The severity of the voltage rise issues due to solar PV depends on the penetration level, location, generating capacity and the configuration of the LV distribution network.

Several approaches have been considered to alleviate the voltage rise due to high penetration of solar PV. Traditional approaches to address voltage rise problems in LV distribution networks include utilizing the transformer online tap changer (OLTC), voltage regulators, switched capacitors, increasing conductor size, energy storage devices and active power curtailment schemes [12]–[16]. The transformer OLTC are rare with MV/LV transformers and therefore not considered in the dissertation as a voltage mitigation solution. The voltage regulators and switched capacitors are rare for urban LV feeders and are not considered in the dissertation as a voltage mitigation solution. The proposed dynamic tariffs are aiming to defer expenditure on upgrading the LV feeder network. The energy storage devices are assumed to be sized according to the storage needs of the customer and not to support voltage and are therefore not considered in this dissertation as voltage mitigation solution. The dissertation assumed active power curtailment as a voltage mitigation solution.

The more recent approach in literature to overcome the voltage regulation problem in LV networks with high solar PV generation involves utilizing the solar PV inverter-based reactive power control by generating or consuming reactive power in an attempt to control voltage [17]–[19]. The flow of reactive power from solar PV inverter-based reactive power control scheme will increase network losses and therefore this voltage mitigation solution is not considered in this dissertation. The current South Africa's solar PV interconnection standards do not allow for the injecting or consuming of reactive power by solar PV in an attempt to control the network voltages [20]. The research work assumed that solar PV units export power at unity power factor in line with the current South Africa's solar PV interconnection standards.

To minimize solar PV energy generation curtailment in hours when excess power is generated relative to the local demand levels, the research work propose that their variable generation behaviour be supplemented with EV to effectively absorb the generated energy. The use of smart metering technologies and dynamic price signals is proposed to influence the charging behaviour of EV. The concept of dynamic pricing implies that customers will pay more for the use of electricity based on their location and time-of-use (TOU). Customers can implement automated systems that constrain electricity usage in periods of higher electricity prices. Therefore dynamic tariff structures could lead to consumers shifting some of their peak period demand to off-peak periods and thus delaying the investments in additional network capacity.

For residential customers in South Africa, the commonly used electricity tariff is the volumetric tariffs that bundle the fixed network charges and variable charges into an energy-based charge. The current move is for a combination of volumetric and fixed tariff structures for residential customers. A combination of volumetric and fixed tariff structures are considered and implemented by some local distribution municipalities when customers install rooftop solar PV [21]. The need for volumetric and fixed charges is to recover the costs of upgrading the network infrastructure incurred by the power utility for a change in customer generation or customer demand. The increasing uptake of solar PV and EV will lead to the expansion of existing distribution infrastructure depending on the existing local distribution network rating, penetration of solar PV and EV, distribution of solar PV and EV, EV charging time management procedures, EV charging behaviour and driving profile. Therefore distribution networks in high solar PV and EV adoption locations will require significant infrastructure investments if the energy consumption and/or energy exports are not locally managed. Location-based price signals will play an important role in controlling EV charging behaviour and solar PV energy exports.

EV charging directly from solar PV presents a technological solution to reduce the country's greenhouse gas (GHG) emissions. The problem is when the sun is covered by clouds and there is not enough power output from the solar PV to charge the EV. EV charging demand would be significant on the LV network if EVs clustered in one area charge simultaneously from the same local LV distribution network. The charging station serves as an important node that connects the EV charging load with the power grid. The power flow distribution, network overloading, voltage violation and power losses associated with EV charging will be directly affected by the geographical location of the charging station. This suggests that location-based price signals will play an important role in controlling EV charging behaviour.

Solutions to the abovementioned problems and constraints are required to address the future distribution networks. Firstly, the current residential energy-based tariff structure that bundles the energy costs and distribution charges needs to be unbundled so that different price signals can be implemented to change the behaviour of end users. Secondly is the allocation of the cost incurred by the distribution utility to customers in a fair manner.

Cost reflectivity suggests that there should be a direct relationship between the tariff the network user pays and the cost incurred by the utility due to the use of its network. Thirdly is the communication of the price signals to customers so that they can adapt to constraints of the electric grid and can change their electricity usage in response to the network conditions and supply characteristics at their points of connection. The distribution tariff structures should have a dual objective of promoting an optimal short-term grid usage and an efficient long-term development of the grid.

1.3 Problem statement

Distribution networks are gradually undergoing a transformation as the uptake of solar PV and the penetration of EV escalates. Modifications to distribution tariff structures aimed at controlling the EV charging behaviour and solar PV energy exports will defer costly distribution networks infrastructure investments. The problem statement of the research work is to develop dynamic distribution tariff structures capable of encouraging energy consumption and export during optimal times of the day and provide a platform for controlled EV charging demand through sending location-based price signals to end users.

1.4 Hypothesis

A distribution level network tariff with dynamic pricing structures can be developed to mitigate the possible negative impact of the increased penetration of solar PV and EVs on the distribution network.

1.5 Research question

What will be the optimal way of restructuring the distribution level network tariff given the expected penetration of solar PV and EVs?

1.6 Justification of study

The study provides direction into how the EV charging behaviour and solar PV energy export can be influenced through dynamic tariff structures. In the supply-demand response curve of Figure 1.5 below, demand_1 response represents the end user consumption behaviour pattern resulting from today's distribution tariffs where the tariff is not reflective of the generation costs and the demand remains the same even if the costs of generation increases. Thus research is needed to create end user consumption behaviour pattern (demand_2 curve in Figure 1.5) that is responsive to costs associated with the supply of electricity. Use of time- and location-based dynamic tariff structures should support the increased penetration of EV and solar PV without violating the local network capacity constraints.

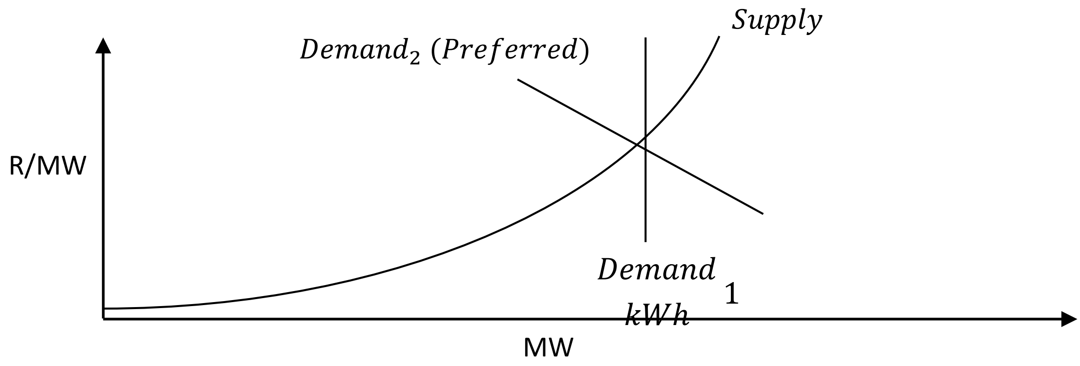


FIGURE 1.5: Supply-demand response curve

1.7 Research methodology and deliverables

The research methodology is to develop and test distribution tariff structures to be used to influence solar PV energy exports and EV charging behaviour for efficient utilization of the existing distribution network.

The deliverables of the research work is tariff structures which are theoretically defined, designed and then tested for different network scenarios based on simplified examples to conclude whether the proposed tariff structures support the increased uptake of solar PV and EV.

The proposed tariff structures will be evaluated on their capability to send price signals that correspond to the increased network losses, possible voltage limit violations and increased demand in LV distribution networks requiring an upgrade of the network due to high penetration of solar PV and EV.

1.8 Limitations and assumptions

- The research work will only consider solar PV co-located with demand at a customer site and will not consider utility-scale PV generators.
- This research work will focus on tariff structures that allocate the network cost to distribution networks users.

- The research work will not focus on the determination of the utility revenue to be generated from tariffs but will focus on the tariff structures that allocate cost of the utility revenue requirements to distribution network users.
- The research work is based on the current South Africa's solar PV interconnection standards where solar PV units export power at unity power factor.

1.9 Organization of Dissertation

The research report is organized into six chapters as follows:

In Chapter 1, the research background and impacts of high solar PV penetration and EV uptake are discussed. The research question, research methodology and deliverables are also provided.

Chapter 2 discusses traditional distribution tariff structures. Tariff structures applied in transmission networks are briefly discussed.

In Chapter 3 location and time differentiated tariff components for distribution networks are proposed. The hypothesis is that if tariffs location and time differentiated, customers will have incentives to modify their usage behaviour in ways that benefits the local distribution network.

Chapter 4 describes smart meter functional requirements required for the proposed distribution tariff structures.

Chapter 5 tests the proposed distribution tariff structures based on simplified examples.

Chapter 6 discusses and concludes whether the proposed distribution tariff structures meet the requirements of the problem statement.

CHAPTER 2

Literature review

2.1 Introduction

Traditional distribution networks were designed for centralized power generation and unidirectional flow of energy from the grid to end users [22]–[24]. The presence of solar PV may result in bidirectional energy flow with some energy flow from end users to the grid. Energy storage technologies are being considered as part of the future smart grid to store excess energy generation during off-peak periods with the intention of utilising the stored excess energy during peak periods to avoid costly infrastructure upgrades.

EVs present an opportunity to minimize solar PV generation curtailment if their charging patterns are responsive and adaptive to the available energy generation through electricity tariffs. Distribution networks in high solar PV and EV adoption location will require significant infrastructure investments if their energy consumption and/or energy exports are not locally managed. Thus the future distribution network will require dynamic tariffs that are based on the averaged local network conditions to avoid the electrical grid thermal limit violation while deferring network investments to meet peak demand. A literature review on dynamic pricing of electricity concluded that peak load reduction of about 30% is registered in the dynamic pricing pilots [25]. A survey conducted in the USA showed a trend of increased reduction in peak demand with dynamic tariffs as compared to static tariffs [26]. Across the range of experiments studied in [26], TOU rates induced a reduction in peak demand that ranges between three to six percent and dynamic critical-peak-pricing (CPP) tariffs induced a reduction in peak demand that ranges between thirteen and twenty percent. By sending the right price signal to grid users regarding the status of the grid and the costs the end users impose on the network, EV charging behaviour and solar PV generation patterns can be controlled.

The introduction of different pricing signals will require the rollout of smart meters that are capable of handling different tariff structures, performing tariff calculations and sending alerts to customers in the event of the electrical grid constraint violations.

2.2 Electricity pricing

The electricity delivered to end users is made up of the energy, transportation service, system operation and other associated services such as maintenance, operation and billing. Electricity demand fluctuates in various time horizons and at present, electricity cannot be economically stored, thus requiring a diversified portfolio of electricity generating technologies to cope with the different demands of electricity at the least cost [27]. Due to the difference in the costs of electricity generation from different generating plants, electricity generation is characterised by a merit order (according to price and availability) of generating plants.

The transportation of electricity is divided into transmission (transportation at higher voltage levels) and distribution (transportation at lower voltage levels). The transmission network is shared by all grid users and provides security of supply to all end users while the distribution networks are specific to a group of end users. System operation refers to the coordination of the electricity transportation service to ensure that the power system is constantly in a state of static electricity equilibrium by controlling energy flows and procuring the ancillary services necessary to maintain the technical reliability of the power grid [27].

In vertically integrated utilities, the electricity supply industry (ESI) structure is such that the power utility owns the generating plants, transmission network and distribution network to provide all aspects of the electricity service to the end user. Electricity tariff design in vertically integrated utilities is regulated. The electricity tariff design can be divided into three parts [28]. Firstly, the allowed utility revenue is determined. Secondly, the tariff structure applicable to each grid user is determined. Lastly, the allocation of revenue requirements to all grid users, both generators and consumers, is determined. To regulate the revenue requirements of the utility, revenue cap regulations set limits to the allowed utility revenue. Likewise, price cap regulations set limits to the electricity prices the utility can charge grid users.

Globally the electricity industry is going through vertical unbundling (separating generation, transmission, distribution, supply and ancillary services), horizontal unbundling (separating generators and suppliers) and introduction of competition and new regulatory regimes [27].

The electricity trading market is necessary for the creation of competition in the electricity industry. The power pool model allows generators to bid their power into a power pool (hour-ahead or day-ahead) and the power pool operator prepares a day-ahead commitment and dispatch schedule on the basis of a demand forecast and merit order of power bids [27]. Power purchasers buy their power from the pool at the market clearing price plus any capacity payments, system operation costs and system balancing costs. In a competitive retail structure, the supply of electricity is further separated to allow power purchasers to compete to sell electricity to end users. Figure 2.1 demonstrates the difference between a vertically integrated utility structure and an unbundled and competitive electricity market and retail structure. This research work will focus on tariff structures that allocate the cost of the vertically integrated utility revenue requirements to distribution networks users.

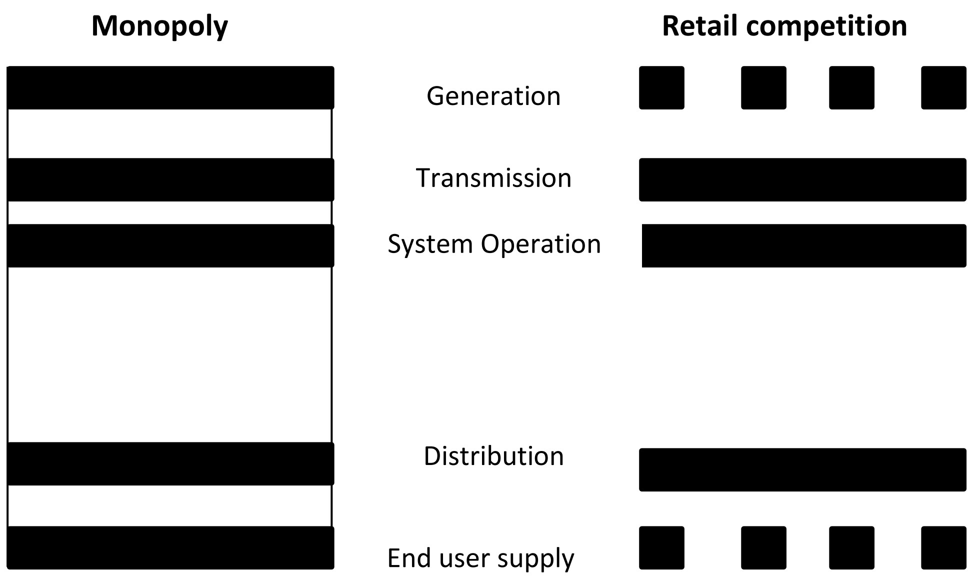


FIGURE 2.1: Monopoly versus Retail Competition ESI

The South Africa's electricity supply industry (ESI) remains dominated by the state-owned and vertically integrated utility namely Eskom Holdings Ltd ("Eskom"). Eskom generates about 90% of the country's electricity requirements. Eskom is the only transmission licensee responsible for the transmission network and system operation. The distribution of electricity to end users is shared between Eskom, the municipalities and other licensed distributors. The current structure of power supply in South Africa is shown in Figure 2.2 [29].

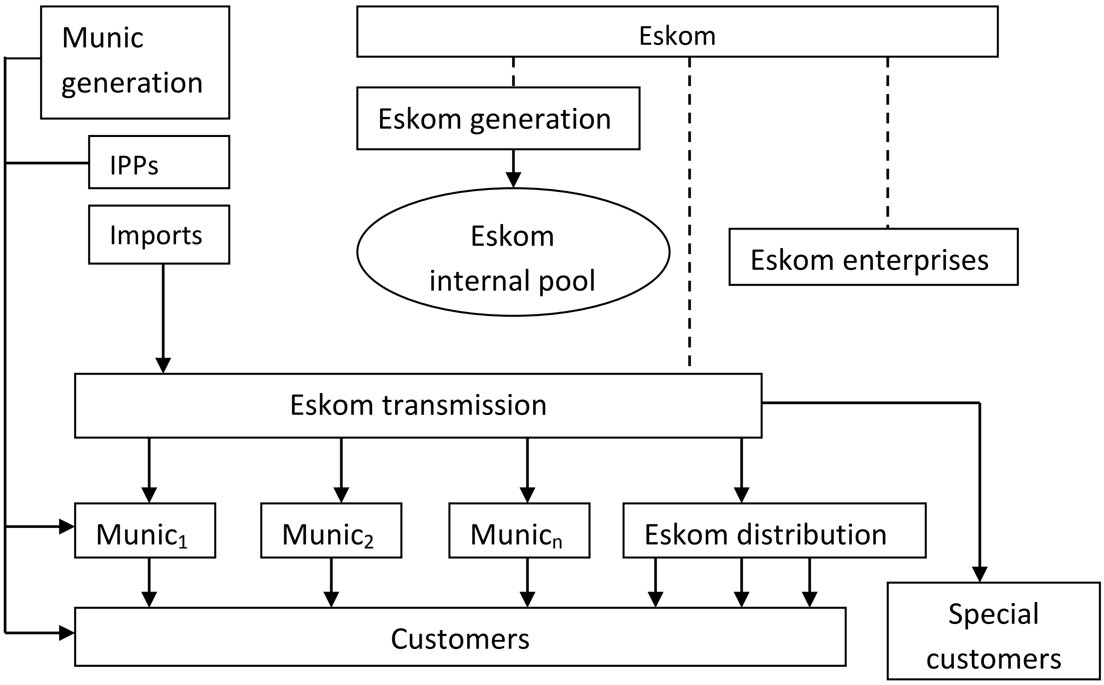


FIGURE2.2: South Africa power supply structure

There are generally accepted guiding principles to be considered when allocating costs to different grid users. Table 2.1 summarises the tariff objectives from the end user and utility perspectives [30].

TABLE 2.1: Summarised tariff objectives

Stakeholder	**Tariff Objectives**	**Description**
Customer	Affordable	Prices should be based on least cost option and exclude inefficiencies.
	Non-discriminatory	Tariffs should be equitable and fair
	Predictable	Prevent price shocks and customers should be informed of future price trends
	Transparent and unbundled	Cost should be unbundled and easy to understand and apply
	Revenue recovery	Revenue from tariffs should reflect the full cost to supply electricity and ensure that the utility is economically viable, stable and fundable in the short, medium and long-term

Utility	Efficient use	Tariffs should promote overall demand and supply side economic efficiency and be structured to encourage sustainable, efficient and effective usage of electricity.
	Cost reflective	There should be a link between the prices the end user must pay to the cost of serving the end user.
	Low cost of implementation	Implementation and transaction costs should be minimised.

Distribution costs are grouped into fixed and variable costs. Fixed costs do not vary with the energy consumption and should be collected in a cost-reflective manner from all consumers and prosumers. Variable costs vary with the level of consumption. Fixed network investment costs associated with capital expenditure and fixed operation and maintenance costs. Variable costs mainly consist of generation fuel costs, variable maintenance and operation costs, network loss costs and costs associated with network congestion.

Existing distribution network cost allocation methods are based on average cost calculations, which consist of averaging the entire distribution variable and fixed costs into a single charge per kWh (energy-based tariff). The cost allocation to customer j, EC_j, is computed by dividing the total network costs (fixed and variable) by the total active energy consumed in the network and multiplied by customer j energy consumption as defined in Equation 2.1 [31]. This method does not provide location or time-of-use signals to end users and provides no incentives to customers to reduce network usage during peak demand periods.

$$EC_j = \frac{network\ cost}{network\ energy\ consumption\ (kWh)} \times Customer\ energy\ consumption\ (kWh) \qquad (2.1)$$

The network energy loss which is embedded in the single energy-based tariff is derived from averaging the network energy loss cost over the total active energy consumed in the network. The average energy loss charge to customer j, LC_j, is obtained by dividing the total losses cost by the total active energy consumed in the network and multiplying by the customers' energy consumption as defined in Equation 2.2 [31]. Although the averaged-based tariff for losses is simple to apply, it does not provide location or time-of-use signals to network users on their impact on network energy loss.

$$LC_j = \frac{network\ energy\ loss\ cost}{network\ energy\ consumption\ (kWh)} \times Customer\ energy\ consumption\ (kWh) \qquad (2.2)$$

Demand side management programmes have been mostly used to modify traditional electricity demand profiles in different ways. These include programmes aimed at decreasing consumption during peak periods (peak clipping), reducing usage at peak time that is offset by usage during off-peak periods (load shifting) and increasing consumption levels during high energy production (valley filling) [32]. Demand response enables deferment of electricity network capacity upgrades, reduces operating costs and provides customers an opportunity to lower their electricity bill. A distinction is made between controlled demand response and price-based demand response [33]. Controlled demand response is aimed at maintaining the security of supply, this include direct load control and load shedding controlled by the system operator. Price-based demand response is responsive to demand changes in the electricity retail price based on different tariff structures. The sections below describe some of the tariff structures used in distribution networks.

2.2.1 Inclining block energy pricing

The commonly used tariff structure in South Africa for LV distribution network residential customers is the inclining block energy tariff [34]. The inclining block energy tariff has some characteristics of marginal pricing in that incremental usage above a set baseline results in higher prices. It however does not reflect true marginal costs incurred by the power utility for an incremental change in supply or demand. The tiers in the inclining block energy tariff are set arbitrarily and are not linked to the cost of additional energy consumption or the time and location of energy consumption. Figure 2.3 represents the inclining block energy tariff structure.

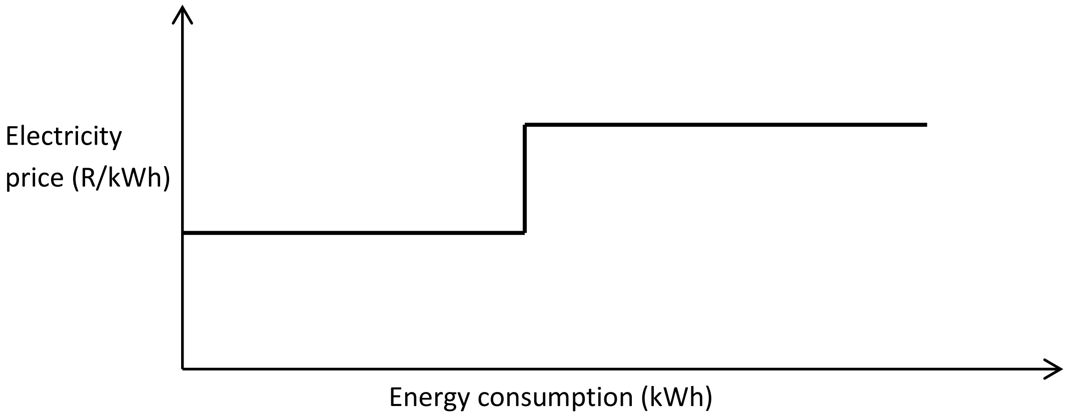


FIGURE 2.3: Inclining block energy tariff structure

2.2.2 Time-Of-Use pricing

Time-of-use (TOU) pricing signals that reflect a long-run marginal cost (LRMC) are considered and implemented at distribution networks based on the time of energy consumption. LRMC is defined as the needed increase in the cost of electricity to meet a sustained rise in demand over a long-term period [30]. In TOU pricing, a day is divided into a fixed number of timeslots grouped into two blocks (peak and off-peak) or three blocks (peak, standard, off-peak) for which different predetermined retail prices apply [35]. Applications of the TOU energy prices make it cheaper to consume energy during predetermined low electricity demand hours and thus have the potential of introducing peak demand during predetermined off-peak hours. Figure 2.4 represents the TOU tariff structure.

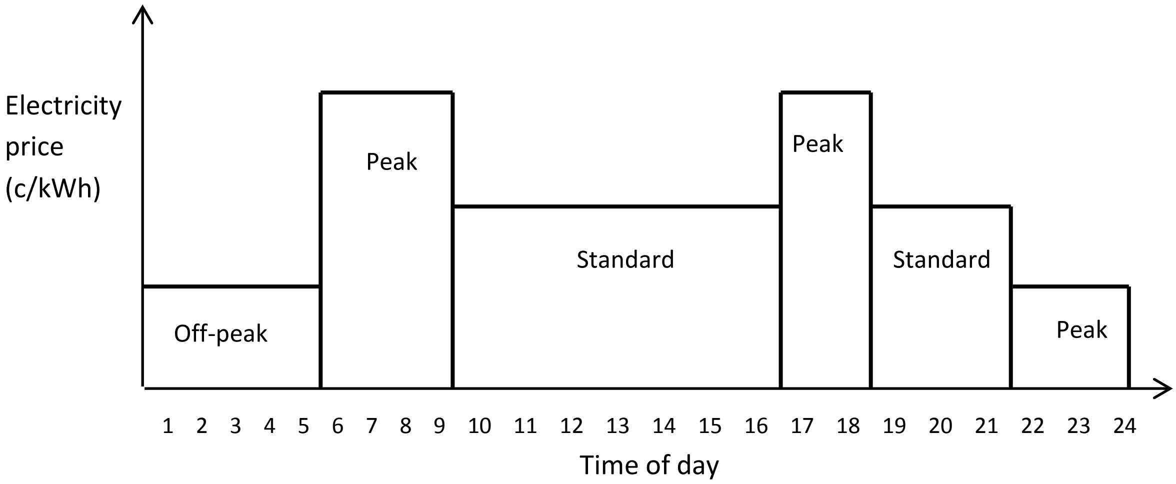


FIGURE 2.4: Time-Of-Use tariff structure

The presence of distributed generators in distribution networks transform the distribution networks such that they take up many of the characteristics of transmission networks in that they become more active than passive. Consequently, cost allocation methods that have been employed in transmission networks can be used in distribution networks. The following sections discuss the pricing method applied in transmission networks.

2.2.3 Nodal Pricing

Nodal prices equate supply and demand of electrical energy at each node of the transmission grid and reflect the relative scarcity of transmission capacity at each point of the transmission grid [27]. With nodal pricing, higher prices are implemented at those nodes on the transmission network where there is not enough transmission capacity to accommodate the scheduled demand. According to reference [27], nodal prices generate revenue below the historical costs and thus need to be complimented with a fixed transmission charge to collect the additional revenue.

The main concern with the implementation of nodal prices is the potential manipulation of prices by the owner(s) of the transmission assets by holding transmission capacity and creating artificial network congestions, thus raising the nodal prices [27].

2.2.4 Zonal pricing

In zonal pricing, the transmission network is divided into zones and prices are set for each zone averaging the cost of congestion of the nodes within the zone. According to [27], the zonal prices generate revenue below the historical costs and thus need to be complemented with a fixed transmission charge to collect the additional revenue.

2.2.5 Postage stamp pricing

In postage stamp pricing, a flat rate is set over a pre-specified time period with non-price related methods applied to manage network congestion if it arises [27]. Postage stamp pricing is simple to implement and transparent since the prices are known in advance and may be efficient in areas where congestion problems are small. However, the transmission charges are allocated to end users based on the amount of transacted power irrespective of the distance and location.

2.2.6 Contract path pricing

In contract path pricing, a contract path that interconnects the points of delivery by the transmission service provider and the point of receipt by the customer is established. Part or all charges associated with power transaction in the established contract path are allocated to the contracted customer. Although the contract path pricing method is simple to implement, the contract path does not reflect the actual path of electricity to the end user [27]. Thus, the contract path pricing may not always provide the correct pricing signal to manage network congestion.

2.2.7 Distance based pricing

In distance based pricing, prices are set as a function of the distance between the point of delivery and the point of receipt [27]. Although this method takes into consideration the location of the end user, the distance between the point of delivery and the point of receipt does not always represent the actual path of the customer's transacted power. Thus, the distance based pricing may not always provide the correct pricing signal to manage network congestion.

2.2.8 Power based pricing

The power based pricing method allocates the transmission charges to end users based on the extent of use of the existing network by end user's power transaction. There exist different methods for determining the power based pricing, including:

- ***Fixed rate***

The fixed rate is the easiest to implement since it consists only of a fixed part and every grid user depending on their main fuse size pays the same amount regardless of the energy consumption. The fixed rate can be defined as [36]:

$$T_{fix} = K \tag{2.3}$$

Where:
T_{fix}*is the fixed tariff in R/month*
K*is the fixed charge in R/month depending on the end user main fuse size*

- ***Peak demand pricing***

The peak demand tariff is determined by a single period in the month when the end user draws maximum power from the grid regardless of whether the maximum demand occurred during peak or off-peak periods. Smart meters are required to record the maximum peak from each grid user and the tariff is defined as [36]:

$$T_{peak} = P_{fix} + P_{peak}|P_{max}| \tag{2.4}$$

Where

T_{peak} is the peak demand tariff in R/month
P_{fix} is the fixed charge in R/month depending on the end user main fuse size
P_{peak} is the peak charge in R/kVA
P_{max} is the maximum peak demand per month in kVA/month

- ***Coincident peak demand pricing***

The consumer's demand at the time of network peak demand is referred to as coincident demand and represents the consumers' contribution to the network peak demand that drives augmentation investment. The coincident peak demand tariff depends on a single moment in a month when the network experiences peak demand. The coincident tariff is defined as [36]:

$$T_{cpd} = P_{fix} + P_{cpd}\left(\frac{P(t_{peak})}{P_{tot}(t_{peak})}\right) \tag{2.5}$$

Where

T_{cpd} is the coincident peak demand tariff in R/month

P_{fix} is the fixed charge in R/month depending on the end user main fuse size

P_{cpd} is the peak load contribution charge in R/month

t_{peak} is the time at which the network experiences peak loading

$P(t_{peak})$ is the customers' demand during the network peak loading in kVA

$P_{tot}(t_{peak})$ is the total network peak demand in kVA

The three parts tariff structure for customers in South Africa with a notified maximum demand greater than 1 MVA consist of the volumetric charge (R/kWh), demand charge (R/kVA/month) and the customer charge (R/account/day). Table 2.2 below presents the three parts tariff used in a South Africa's power utility for customers with a notified maximum demand greater than 1 MVA. The tariff design is based on a fixed set of rules which allocates costs based on the voltage of supply, the transmission zone and the utilized capacity.

TABLE 2.2: Three part tariff structure - South Africa [34]

Cost type	Cost component	Description
Volumetric charge (c/kWh)	Active energy charge	• Seasonally and time-of-use differentiated • Include network loss costs • Based on the voltage of supply and the transmission zone.
	Ancillary service charge	• Recovers the cost of providing ancillary services by the system operator • Based on the voltage of supply applicable during peak and off-peak periods.
	Affordability subsidy charge	• Socio-economic subsidy applied to the monthly total active energy.
	Electrification & rural network subsidy charge	• Socio-economic subsidy applied to the monthly total active energy.
Demand charge (R/kVA/month)	Transmission network charge	• Charge for making the transmission capacity available. • Based on the voltage of supply, the transmission zone and the annual utilised capacity applicable during peak and off-peak periods.
	Distribution network charge	• Charge raised to recover distribution network costs. • Based on the voltage of supply and the chargeable demand applicable during peak and standard periods.
	Urban low voltage subsidy charge	• Network-related cross subsidy
Customer charge (R/account/day)	Service charge	• Daily fixed charge to recover service-related costs • Based on the total monthly utilised capacity.
	Administrative charge	• Daily fixed charge to recover administrative-related costs such as meter reading, billing and meter capital. • Based on the total monthly utilised capacity.

Some research work has dedicated effort in designing dynamic pricing for energy cost that varies with the wholesale market prices. Time-varying energy pricing is aimed at shifting energy consumption during peak hours to off-peak hours. Time-varying pricing allows the retail electricity price to follow the fluctuating nature of the wholesale prices. Time-varying pricing also encourages end users to shift their flexible loads to periods of low demand and thus defer the upgrade of the electricity network infrastructure. The time-varying energy pricing researched in literature includes:

- **Real-time pricing (RTP):** The retail prices vary with the wholesale market prices. The hourly retail prices are either set a day-ahead or in real-time [35].

- **Time-of-use (TOU) pricing:** The day is divided into a fixed number of timeslots with different predetermined retail prices [35].

- **Critical peak pricing (CPP):** Significantly higher rates are applied to several timeslot hours in a year where energy consumption is predicted to be very high [35].

2.3 Marginal cost allocation theory

Power system economics theory suggests that marginal costs are the most efficient economic signals to send to users of the network regarding the costs they impose on the network operation and development [37]. Marginal cost can be estimated in either the short-term or long-term perspective associated with operating the power system efficiently in the short-term and investing effectively in the power system infrastructure in the long-term. The two cost allocation methods which will be discussed in detail highlighting their advantages and disadvantages are the short-run marginal cost and the long-run marginal cost.

2.3.1 Short-run marginal cost

The short-run marginal cost (SRMC), also known as locational marginal pricing (LMP), is the change in operational costs resulting from the change in demand at a particular location in the network at any given time [30]. SRMC signals result from the use of nodal prices that reflect the cost of generation needed to supply the demand at each node in the network as well as the costs associated with network losses and network congestion at each node [30]. At each node, the LMP can be split into three components: the marginal cost of generation, the impact on network losses and the effect on network congestion [30].

The LMP is applied in transmission network congestion management schemes for determining the transmission charge under constrained network conditions. There has been a rapidly increasing interest in extending the LMP concept from transmission networks to distribution networks to alleviate distribution network congestion due to EV charging [38]–[40]. Reference [40] discusses the benefits of using distribution locational marginal pricing (DLMP) for optimal charging management of EVs. Reference [39] presents measures to boosting demand side responses using DLMP. Reference [38] demonstrates how DLMPs can assist in alleviating network congestion from high penetration of EVs and heat pumps.

According to reference [27] and [30] the nodal price does not recover the total cost incurred by the power utility in supplying the demand. According to reference [27] nodal prices generate revenue below the historical costs and thus need to be complimented with a fixed transmission charge to collect the additional revenue. The practical application of the nodal price methodology in transmission networks showed that cost recovery was normally less than 20% of the cost incurred [30]. Reference [41] proposed a cost causation-based distribution tariff in terms of time and location that uses nodal prices to recover network losses and an "extent-of-use" method to recover fixed network costs based on the network use at coincident peak. In reference [41] a reconciliation factor to adjust the marginal loss coefficient is proposed so that the nodal prices derived collect the exact cost of losses.

2.3.2 Long-run marginal cost

The long-run marginal cost (LRMC) is defined as the needed increase in the cost of electricity to meet a sustained rise in demand over a long-term period [30]. The LRMC caters for both the marginal operating and reinforcement costs resulting from accommodating a marginal increase in the transacted power. The marginal operating and reinforcement costs per MW of transaction are locational based. Because of investment lumpiness in power grids, the LRMC is normally replaced by the long-run incremental cost (LRIC) since the decision to invest in additional capacity is discrete and can be determined based on planning models which define the existing grid and optimise an upgrade plan for a given demand growth trend [30].

The LRIC charging method as applied in the UK distribution networks reflects the impacts on future network investments due to power injection or withdrawal at each individual study node [42]. For power demands that impact on planned network reinforcements, there is a cost associated with bringing forward the investment plans or a benefit for deferring the investment plans [42]. The present value of the affected network components is calculated based on the magnitude of the reinforcement cost and the chosen discount rate. The LRIC charges are calculated as the total costs of the present value of all the affected network components. The mathematical formulation is described below [42]:

If a network component l, has a capacity of C_l and supports a power flow of D_l, then the number of years it will take the utilisation to grow from D_l to C_l for a given load growth rate r, can be determined from:

$$C_l = D_l \times (1+r)^{n_l} \tag{2.6}$$

Where n_l is the number of years to reinforcement and it can be derived from rearranging Equation 2.6:

$$n_l = \frac{\log C_l - \log D_l}{\log(1+r)} \tag{2.7}$$

If the power flow along the line l is increased by ΔP_l as a result of additional load connected at node N, the change in the number of years to network reinforcement from n_l to n_{lnew} can be calculated as:

$$n_{lnew} = \frac{\log C_l - \log(D_l + \Delta P_l)}{\log(1+r)} \tag{2.8}$$

The future investment can be discounted back to its present value, which will be a function of how far into the future the investment will be made. If a discount rate of d is chosen, the present value of the future investment in n_l and n_{lnew} will be:

$$PV_l = \frac{Asset_l}{(1+d)^{n_l}} \tag{2.9}$$

$$PV_{lnew} = \frac{Asset_l}{(1+d)^{n_{lnew}}} \tag{2.10}$$

The change in present value for future investment is therefore considered to determine the cost incurred in supporting the additional demand. Since the LRIC consider each node separately, it thus can provide better locational pricing signals.

2.3.3 Extent-of-use cost allocation

The cost-reflective and recovery of fixed network costs for transmission networks has been researched in the literature. The “extent-of-use” method also known as MW-mile, as first proposed by reference [43], has been used to allocate transmission network fixed costs based on the location and impact of loads and generation on the transmission asset relative to total power flows or total capacity of the asset using load flow models. The MW-mile methodology as applied in transmission networks only accounts for the cost associated with real power flow and neglects the cost imposed on the network from reactive power flow. In reference [35] the “extent-of-use” cost allocation methodologies are proposed in distribution networks to allocate fixed distribution network costs.

Unlike the MW-mile approach for transmission networks, the presented methodology in [35] uses power-to-current distribution factors to measure the extent-of-use imposed by customers on the network and the method is thus referred to as the “amp-mile” method for distribution networks. By using the proposed methodology in [35] customers with low network usage will have lower charges than those with high network usage.

Two different pricing schemes using “amp-mile” method are tested in reference [35]. The first pricing option is the time differentiated per unit charge based on extent-of-use prices at each bus in each hour priced on a MWh bases with the remaining fixed network costs related to the unused capacity spread over all load in the distribution network regardless of location. The second pricing option uses fixed charges based on the extent-of-use at each bus at system peak with the remaining fixed network costs related to the unused capacity spread over all load at coincident peak regardless of location. Thus for each customer there are two types of charges, locational and non-locational, for the recovery of distribution fixed network costs. Reference [35] concluded that using fixed charges based on the extent-of-use at coincident peak recovers more of the fixed network costs through locational charges than does the time differentiated per unit charge.

2.4 Feed-in tariff (FIT)

The global uptake of solar PV energy generation (on- and off-grid) has increased considerably over the past years [4]. As per South Africa’s IRP of 2019, the expected growth in Solar PV installations is constrained by annual new-build limits of 1000 MW/year to 2030 for utility scale installations and 500 MW/year to 2030 for small-scale embedded generation. One of the contributing factors to the increased uptake of solar PV installations globally is the introduction of favourable policy mechanisms in the form of feed-in tariffs (FITs) [4]. A variety of approaches are used to determine the FIT payments for the electricity produced from renewable resources. These different approaches can be divided into four basic categories [44]:

- Based on the actual levelized cost of renewable energy generation
- Based on the “value” of renewable energy generation
- Offered as a fixed price incentive
- Based on the results of an auction or bidding process

For grid users the interest in investing in rooftop solar PVs can be linked to two business cases, thus the grid user may want to make a profit by exporting energy to the power grid and/or reduce the electricity bill through self-generation. Both these business cases are directly affected by the distribution tariff design. The net metering or net billing policies compensate the excess energy exports in different ways. The excess energy may be [45]:

- Provided with no compensation to the customer
- Provided with compensation to the customer via the FIT (R/kWh). The FIT can either be a fixed value below the electricity retail price or can be a variable value proportional to the wholesale electricity prices or a premium rate higher than the electricity retail price.
- Provided with compensation to the customer via the renewable energy credits (kWh) where the excess energy exported can be transferred as credit to the next billing period.

2.4.1 Net-metering

A single bi-directional meter is used to measure and record the customer's electricity consumption at the start and end of the billing period. The meter runs forward when the customer uses energy from the grid and runs backwards when the customer exports energy into the grid [45]. There exist different approaches to net metering as described below:

- **Simple net metering**

At the end of the billing period the customer has either:

1. Exported less energy than imported. In this case the customer pays the utility for the excess energy imported.
2. Exported more energy than imported. In this case the utility does not pay the customer for the excess energy imported. Instead the end of the billing period meter reading is the value used at the beginning of the next billing period.

- **Net metering with buy-back**

This is an extension of the simple net metering in which the utility pays the customer for any excess energy exported to the grid. The excess energy can be compensated at a value below the retail rate, at the retail rate or above the retail rate.

- **Net metering with rolling credit**

Excess energy exported by the customer in one billing period is used as a credit to reduce the charges in the subsequent billing period. The credit banking period of excess energy exported extends over a number of billing periods and the credits are forfeited at the end of the banking period with the customer receiving no compensation for the forfeited credits.

- **Net metering with rolling credit and buy-back**

This approach combines net metering with rolling credit and net metering with pay-back schemes such that the customer is compensated in monetary terms for any excess energy exports at the end of the banking period. The excess energy exported can be paid at below the retail rate, at the retail rate or above the retail rate.

2.4.2 Net billing

In net billing two meters are used to measure and record the energy imported and the energy exported by customers in a billing period. Net billing allows the utility to bill the customer on all the energy imported and the customer to be compensated for all the energy exported to the grid. There exist different approaches to net billing as described below:

- **Net billing with buy-back**

In this scheme the customer is not allowed to bank any excess energy generated between billing periods. At the end of each billing period, the customer pays the utility for any energy consumed and the utility pays the customer for the energy exported to the grid either below the retail rate, at the retail rate or above the retail rate.

- **Net billing with rolling credit**

This scheme is functionally similar to net metering with rolling credit except that it uses two meters for the energy imported and exported. The utility thus combines import and export data in order to determine the amount of credit obtained. The credit can be used in the next billing period to offset charges. The credits are forfeited at the end of the banking period with the customer receiving no compensation for the forfeited credits.

- **Net billing with rolling credit and buy-back**

This scheme allows banking of excess electricity between billing periods and the purchasing of any excess credits by the utility at the end of the banking period at rates either below the retail rates, at the retail rates or at the premium rates.

2.4.3 Feed-in tariff in South Africa

In South Africa, a combination of volumetric and fixed tariff structures are considered and implemented by local distribution municipalities when customer install rooftop solar PV. The main provisions of the developed guideline by the City of Cape Town for exporting excess generated energy to the grid include [46]:

- **Installation capacity limits:** Caters for residential, commercial or industrial premises with generation capacity under 1 MVA. Available only to customers who are "net-consumers" and not customers who are "net-generators" in twelve consecutive months.

- **Billing period:** The net energy is calculated monthly at the end of the billing period. Net billing is applied wherein the customer is billed for all the energy consumed from the grid using the block inclining tariff structure. For any excess energy exported to the grid, the customer is compensated on a fixed tariff below the retail price (refer to Table 2.3 below for the 2017/18 City of Cape Town residential FIT)
- **Service charge:** The customer also pay a fixed daily service charge

TABLE 2.3: Residential feed-in tariff (City of Cape Town) [21]

SSEG Residential tariffs 2017/18			
	Units	**Tariff excl. VAT**	**Tariff incl. VAT**
Service charge	R/month	R2.16	R2.49
Energy charge – consumption 0 – 600kWh	R/kWh	R1.75	R2.02
Energy charge – consumption 600.1 + kWh	R/kWh	R2.42	R2.78
Energy charge - generation	R/kWh	R0.69	R0.79

2.5 Smart metering and smart meter

Future smart grid components will include integrated communication infrastructure that enables near real-time two-way exchange of information between the end user and the power utility, smart measurement devices that record and communicate energy usage data, sensors and monitoring systems throughout the network that monitor the flow of energy in the electric grid. Smart meters together with the communication network infrastructure and the meter data management system, constitute the advanced metering infrastructure (AMI), which plays a vital role in power delivery systems by collecting and processing load profiles and facilitating bi-directional information flow [47], [48]. As shown in Figure 2.5, smart meters collect energy usage information from end users at certain time intervals (based on the requirement of the data demand) and transmit the data through the Local Area Network (LAN) to the data collector units [49], [50]. The data collector then transmits the smart meter data using the Wide Area Network (WAN) to the meter data management system for different applications such as demand response, load forecasting, load management, outage management and billing [49], [50]. Reference [51] proposed AMI comprising of smart meters in a mesh network, data concentrator units (DCU) and centralised meter data management system. In [51] the DCU collects the smart meter information through the Radio Frequency (RF) communication network and transmits the data to the Head End System via the General Packet Radio Service (GPRS) wireless communication network.

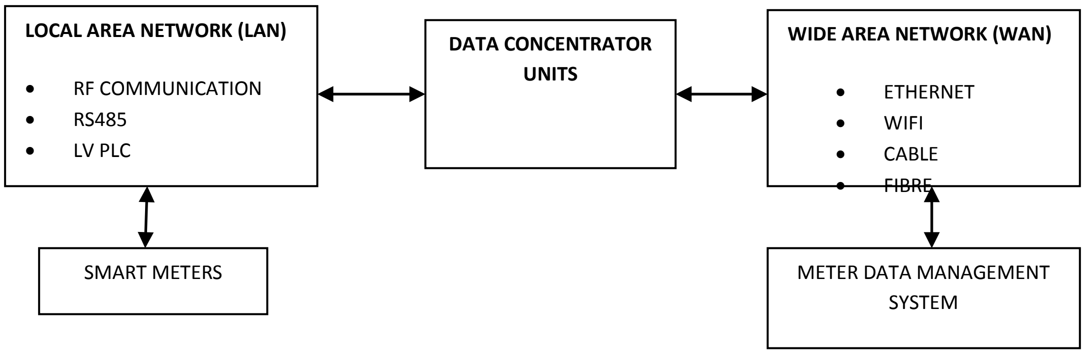


FIGURE 2.5: Advanced Metering Architecture block diagram

Smart meters include a combination of hardware, software and analog to digital converters (ADCs) to support differential inputs. Figure 2.6 represents a block diagram of a smart meter showing the different building blocks for a smart meter solution [48]. As shown in Figure 2.6, the smart meter system may include: accurate real-time clock (to indicate current date and time of measurement), data communication module (for two-way communication between the meter and the data management system), metering system-on-chip processor, security module, power management system, supervisory module, tamper detection, transformer driver and voltage reference. The meter software supports calculation of various parameters during energy computation such as RMS current and voltage, active and reactive power and power factor.

The following describes some common functionalities considered for commercially deployed smart meters [47], [49], [51]:

- Remote meter reading
- Load profile data
- Power quality management
- Dynamic pricing and demand-response
- Remote meter management
- Peak load management
- Tamper and theft detection

- Power outage management system

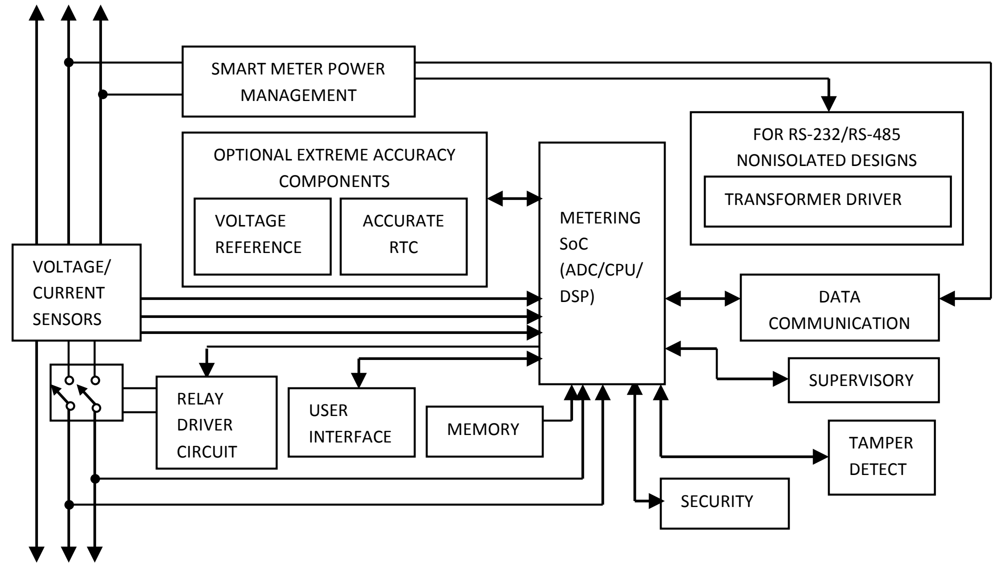


FIGURE 2.6: Smart meter block diagram

The energy usage information collected from smart meters can be used by power utilities to implement real-time pricing and limit the maximum electricity consumption by encouraging end users to reduce their demands during peak load periods. The smart metering concept is employed in this research work to send pricing signals to end users, manage demand during peak load periods, improve the transformer load management and for efficient use of the electric grid energy.

2.6 Conclusion

Traditional distribution tariffs based on averaged cost methodologies do not recover the energy and distribution network costs in a cost reflective manner. The traditional distribution tariffs lack the elements of location and time differentiated approaches and thus have cross subsidies inherently embedded in them.

Different tariff designs exist aimed at influencing certain consumption patterns by network users. But it is expected that these methods when used individually will not recover all the costs associated with providing the electricity service as well as additional investment costs needed to meet future peak demands. The reason for this is that tariff design is either associated with sending short-term operational signals or long-term investment signals. The introduction of smart meters capable of handling different tariff structures make it possible for each network cost driver to have its own tariff design methodology. However, care must be taken to ensure that different tariff structures do not result in price signal distortion.

The locational marginal pricing approach was also discussed, with real-time locational energy prices that reflect the cost of generation needed, the associated network losses and the effects of network congestion at each node. This method will result in different tariffs imposed on EV owners charging at different times of the day in different geographical locations of the distribution network.

The deregulation of electricity markets result in bidding-based wholesale electricity markets guided by the power system security constraints and economic dispatch of generation units (according to price and availability). The increased uptake of solar PV and EV transforms the distribution networks from passive to active networks requiring correct pricing signals for proving correct incentives for improved generation efficiency, reduced distribution line losses, promoting energy consumption from renewable sources and preventing network congestion. Different market design for the distribution system operator will gain considerable research momentum because of the different generation units and flexible loads connecting to the distribution networks.

The following chapters will present a cost reflective tariff structure which is able to accommodate the different scenarios imposed on the network by a large uptake of solar PV and EVs. The tariff structure will also ensure that the utility costs for providing the electricity service are recovered and that the proposed tariff does not create a barrier for the uptake of solar PV and EVs.

CHAPTER 3

Locational dynamic tariff structure

3.1 Overview

Traditional distribution tariff structures founded upon historical average cost methodologies assume that consumers connected at distribution level consume energy in a similar way following the aggregated load profile. The uptake of flexible loads such as EVs implies that end users can change their electricity usage behaviours to gain more economic benefits. This chapter presents the fundamental concepts in the formulation of distribution tariff structures that are location and time based.

3.2 Introduction

Solar PV and EVs are two major technological solutions that would play a significant role in the reduction of the greenhouse gas (GHG) emissions. Significant investments in the network infrastructure need to be made in an efficient and effective manner to cope with the integration of high penetration of solar PV and EVs. The power utility is required to recover all the incurred costs for providing a service to network users in a cost-reflective manner [30].

As the uptake of EVs escalate, distribution networks will be impacted differently depending on the existing local distribution network rating, penetration and distribution of EVs, charging management procedures, charging behaviours and driving profiles. EV owners may cluster in a particular geographical area requiring significant infrastructure investments in high adoption locations to facilitate EV charging requirements as compared to other locations.

It is assumed that with the expected high uptake of solar PV and EVs, the development of information and communication technologies (ICT) and smartmetering technologies would have advanced to allow real-time two-way interaction between the local distribution network and end users to enable customers to respond to variable electricity tariffs or schedule their energy consumption. The hypothesis is that if tariffs are based on the costs of meeting the demand, the customers will have incentives to modify their usage behaviour in ways that reduce the overall network costs.

The proposed distribution tariff structures are to have the following attributes:

- Reduce peak demand to defer network infrastructure expansion costs and ensure efficient use of existing infrastructure.
- Minimise solar PV exports and hence network losses when it could be used for EV charging.
- Reflect the extent of network use by customers connected to the same feeder.

The above mentioned attributes lead to distribution tariff structures that are cost-reflective and location and time based. The components of the proposed tariff structure are derived from network local measurements associated with the customer point of connection.

The advanced metering infrastructure comprising of smart meters, data collectors, communication network infrastructure and the meter data management system (as discussed in section 2.5) is necessary to ensure calculations of the proposed tariff components. The smart meter extracts fundamental components from the distribution network, turning them into electrical circuit equations for calculation of the tariff components. The smart meter functional properties required for the proposed distribution tariff structures are described in chapter 4.

3.3 Location and time differentiated tariff components

The proposed tariff approach is tailored to cater for consumers as well as solar PV owners for their power exports. The proposed tariff is made up of three components namely: 1) the energy charge, 2) the maximum demand charge and 3) the network losses charge. Decomposing the distribution tariff into these three components assumes that these components account for the distribution cost to be recovered and the impacts of these components on the distribution cost can be isolated from one another. Table 3.1 below provides the description of the proposed tariff cost components.

TABLE 3.1: Proposed tariff structure cost components

Cost type	Cost component	Description
Volumetric charge (R/kWh)	Active energy charge	• Seasonally and time-of-use differentiated • Excludes network loss costs
Maximum Demand charge (R/kVA/demand period)	Distribution (low voltage) network charge	• Charge raised to recover future investment network costs due to increased local demand • Applied when the MV/LV transformer averaged loading is equal to or above the specified loading threshold • Location differentiated
Network losses charge (R/kWh)	Distribution (low voltage) network losses charge	• Charge applied to recover costs associated with network losses at the distribution (low voltage) level • Location differentiated
Solar PV export fractional curtailment		• Voltage limit violation mitigation solution due to high penetration of solar PV

The relative difference between the proposed tariff structure and the status-quo is that in the status-quo the regulator determines the increase in the tariff and the distributor attempts to recover both the capital and the operating costs from the customer with very little demand response. In the proposed dynamic tariff the aim is to defer network investment by introducing a form of demand response in order to defer upgrading transformers and feeders (overhead lines or cables). Most of the losses in the power network occur at the distribution (low voltage) level. The proposed dynamic tariff attempts to recover the cost associated with the network losses. The analogy is the cost of the losses which forms part of the wheeling cost at the transmission level.

Implementation of the proposed tariff structure will provide benefits to the customers and the power utility.

Benefits to the customer:

- Customers get more information about their energy usage.
- Customers can adjust their demand behaviour to lower their electricity bills.
- Electricity bills are cost-reflective in that there is a direct relationship between the tariff the network user pays and the cost incurred by the utility due to the use of its network.

- Solar PV owners will be remunerated for the energy exports and their contribution to reduce distribution network losses. Solar PV owners will receive additional payment if the power export occurs when the MV/LV transformer averaged loading is equal to or above the specified loading threshold.
- The solar PV export fractional curtailment ensures that the loss of feed-in tariff is fair to small solar PV owners that are connected to the same node as large solar PV owners.

Benefits to the power utility

- Local network demand peaks are reduced.
- More efficient use of the network infrastructure.
- Distribution network losses are reduced.
- Increased information on the demand on the LV distribution networks.
- Network upgrade investment costs could be deferred.

3.3.1 The energy charge

The energy charge will follow the TOU tariff. The electricity regulator specifies the upper limit of the electricity tariff or how much the electricity tariff increases from year to year and the energy cost is passed on to the customers by the power utility. The smart meter is updated with the respective TOU energy price in R/kWh.

For the customer importing energy from the grid, the energy charge (as a price signal for energy efficient consumption) is given by:

$$EC_k(T) = E_k(T) \times \delta_i(T) \tag{3.1}$$

Where:

$EC_k(T)$ is the energy charge for customer k during demand period T

$E_k(T)$ is the net energy in kWh for customer k during demand period T

$\delta_i(T)$ is the import energy price in R/kWh for demand period T

Net metering based on a single bi-directional meter is used to measure and record the customer's energy import and export during the demand period for customers with on-site solar PV installations. At the end of the demand period the meter calculates the end user's net energy import or net energy export. If the customer exported less energy than imported, the customer pays the utility the net energy imported based on the import energy price in R/kWh during the demand period. If the customer exported more energy than imported, the utility pays the customer for any excess energy exported to the grid based on the export energy price in –R/kWh during the demand period. For customers to be net-exporters current regulatory requirements for small-scale embedded generation will have to be changed to enable customers to be net-exporters. The export energy charge could be time-based as indicated in Equation 3.2.

$$EP_k(T) = E_k(T) \times -\delta_i(T) \tag{3.2}$$

Where:

$EP_k(T)$ is the energy payment to solar PV owner k during demand period T

$E_k(T)$ is the net energy in kWh for customer k during demand period T

$\delta_e(T)$ is the export energy price in -R/kWh for demand period T

3.3.2 Network losses charge

Technical losses in distribution networks are divided into load losses (conductor resistance) and no-load losses (transformer no-load losses). Transformer no-load losses are a function of voltage and include eddy-current losses, hysteresis losses, stray load losses and I^2R DC losses due to no-load currents. Load losses are a function of current and vary according to the loading of distribution networks. Load losses are heat losses (I^2R) caused by the load losses. The network losses allocation of the proposed tariff is based on the load losses as they depend on the customer load profile.

Consider a distribution feeder of Figure 3.1 with all network users connected at the end of the feeder. The total feeder loss is made up of the sum of the loss contributions by the individual network users' loads connected to the same node such that:

$$P_{Loss} = P_1 + P_2 + P_3 + \dots . + P_i \tag{3.3}$$

Where

$P_i(i = 1 - k)$is the loss contribution by the individual network users

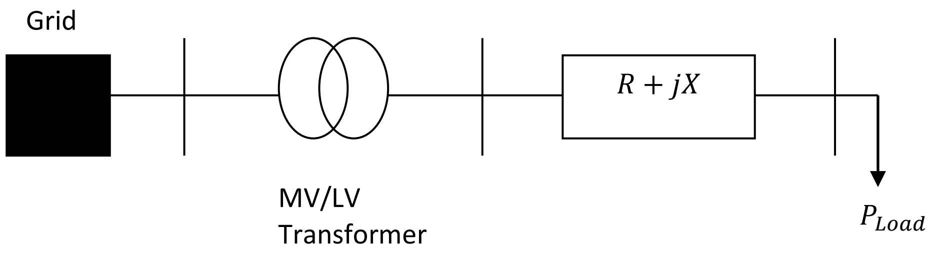


FIGURE 3.1: Simplified LV distribution network

Equation 3.3 can be expressed as:

$$I_{rms}^2 \times R = \left(I_{rms1}^2 + I_{rms2}^2 + I_{rms3}^2 + \ldots + I_{rmsi}^2\right) \times R \qquad (3.4)$$

The contribution of customer j to feeder losses is given by:

$$Customer\ contribution\ to\ losses = \frac{I_{rmsj}^2}{I_{rms}^2} \qquad (3.5)$$

Equations 3.4 and 3.5 demonstrate that the contribution of customers to network losses will require the measurement of the root-mean-squared current at the distribution node.

Consider a distribution feeder of Figure 3.2with *N* nodes.

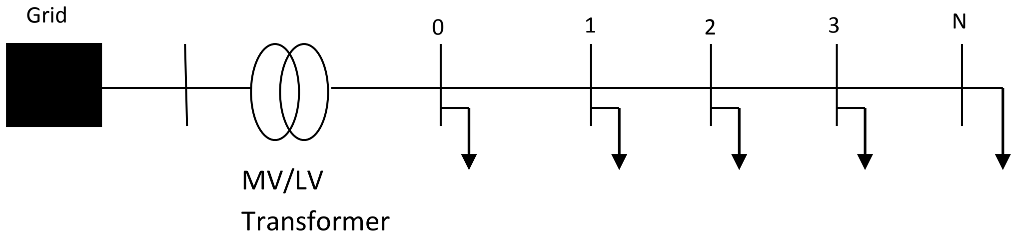


FIGURE 3.2: LV feeder with *N* nodes

The losses contribution of customer j (CCL_j) connected at node *N* is:

$$CCL_j = \frac{I_{rmsj}^2 \times R_{0to1} + I_{rmsj}^2 \times R_{0to1} + I_{rmsj}^2 \times R_{0to1} + \cdots + I_{rmsj}^2 \times R_{0to1}}{Total\ network\ loss} \tag{3.6}$$

Where:

I_{rmsj} is the RMS current of customer j

$R_{(N-1)toN}$ is the feeder resistance between nodes$(N-1)$ to N

Customers will receive an incentive to reduce their demand from the grid as this will contribute to a reduction in their network loss contribution. The power loss contribution will be converted to network energy losses charged at a particular R/kWh. The locational network losses charge sends a price signal for energy efficient consumption.

3.3.3 The maximum demand charge

The purpose of the proposed maximum demand charge is to recover future network upgrade costs to be incurred by the power utility due to the increase in the local demand. The maximum demand charge is proposed to address the local MV/LV transformer loading due to increased demand during peak periods.

The maximum demand charge is allocated according to the local network equipment (typically MV/LV transformer) kVA loading. The maximum demand charge only applies when the transformer loading (averaged over 30 minutes) is equal to or above a specified loading threshold. When the transformer kVA loading is equal to or above the specified threshold, different ramp rates in $R/kVA/kVA$ or $-R/kVA/kVA$ are applied depending on the averaged transformer kVA overloading. The customer kVA demand (averaged over 30 minutes) when the averaged transformer kVA loading is equal to or above a specified loading threshold is used in calculating the customer maximum demand charge. Similarly the solar PV kVA export (averaged over 30 minutes) when the averaged local demand is equal to or above a specified demand threshold is used in calculating the maximum demand payment due to the solar PV owner.

The average transformer kVA loading is given by:

$$Average\ transformer\ loading\ in\ a\ demand\ period = \frac{\sum_{t=0}^{N} Apparent\ power\ (t)}{N} \tag{3.7}$$

Where:

$N$is the number of apparent power readings in the demand period of thirty minutes.

The average demand charge for customer k over the demand period is given by:

$$Average\ customer\ demand\ in\ a\ demand\ period = \frac{\sum_{t=0}^{N} Apparent\ power\ (t)}{N} \tag{3.8}$$

Where:

$N$is the number of apparent power readings in the demand period of thirty minutes.

The maximum demand charge for customer j over a demand period is given by:

$$(maximum\ demand\ charge)_j = \begin{cases} 0 & if\ P_x^{trf}(t) \leq P_{trf}^{barr}; \\ P_x^j \times \delta_D & if\ P_x^{trf}(t) > P_{trf}^{barr}; \end{cases} \tag{3.9}$$

Where:

P_x^j is the averaged demand of customer j at location x (kVA)

P_x^{trf} is the averaged transformer loading at location x (kVA)

P_{trf}^{barr} is the transformer loading threshold (kVA)

δ_D is a particular maximum demand charge (R/kVA) at a particular level of transformer overloading

The maximum demand charge can be avoided by customers reducing their demand during the time of the day when the network transformer is overloaded. The demand charge is billed at the end of the month for those demand periods when the transformer is equal to or above the specified threshold. The flow diagram of Figure 3.3 represents the steps in calculating the maximum demand charge based on the demand period of 30 minutes.

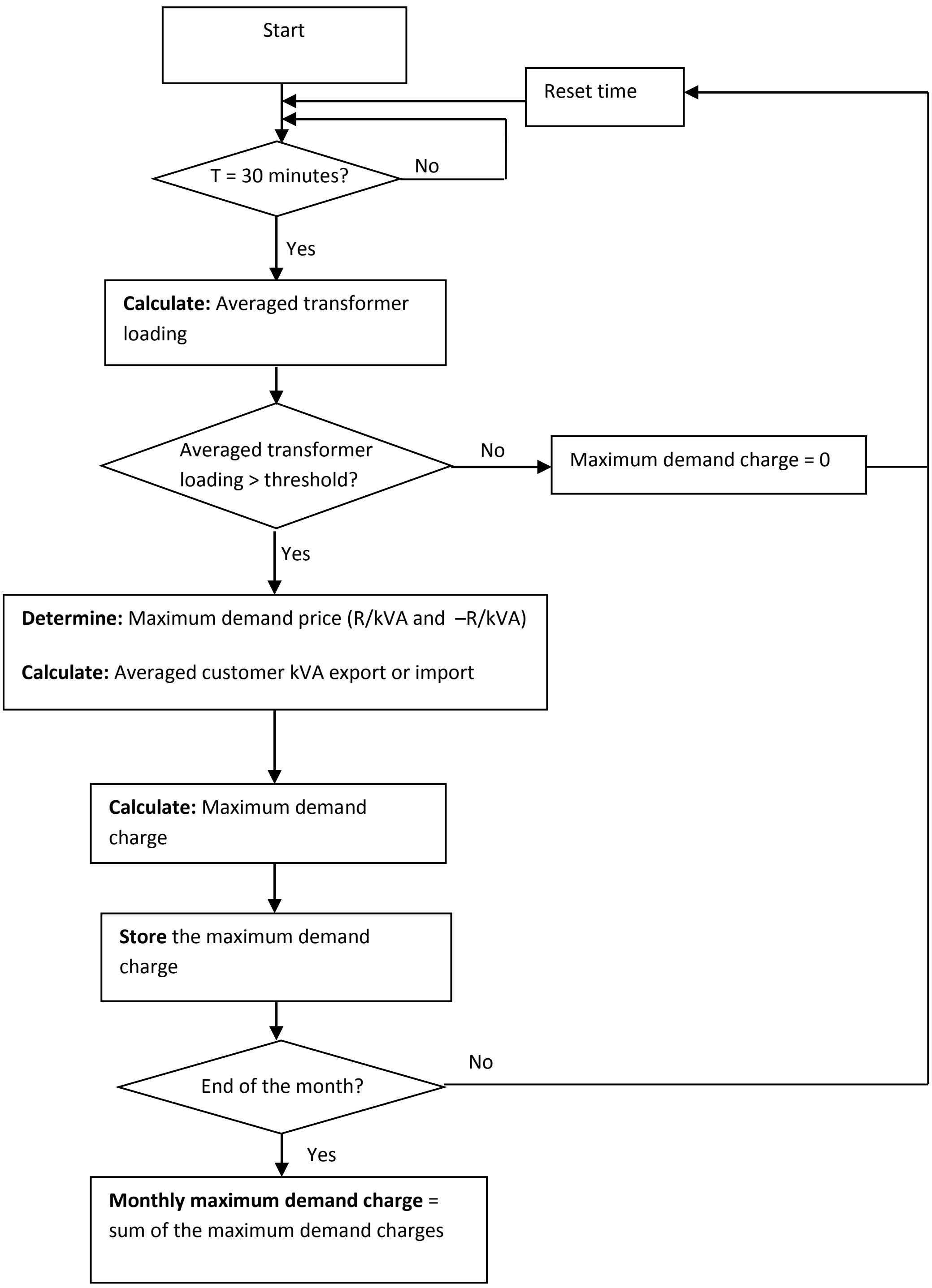


FIGURE 3.3: Maximum demand charge flow diagram

Solar PV located at LV distribution networks can alleviate peak demands and thus deferring network capacity expansion investments. The proposed maximum demand charge remunerates solar PV owners for the kVA export (averaged over 30 minutes) when the

MV/LV transformer loading is equal to or above the predetermined loading threshold and thus encouraging self-consumption during off-peak periods. When the averaged transformer kVA loading is equal to or above the specified transformer kVA threshold loading the averaged solar PV kVA export is multiplied with a particular maximum demand price (-R/kVA). Solar PV owners will still be remunerated the net energy export payment (but not the maximum demand component) and the network losses payment for those periods when the MV/LV transformer loading is below the predetermined loading threshold.

Figure 3.4 illustrates the maximum demand price in relation to the averaged transformer kVA loading for consumers and solar PV owners. To encourage solar PV power export when the transformer is overloaded, there is a step change in the remuneration rate to solar PV owners when the transformer kVA loading is equal to or above the specified threshold

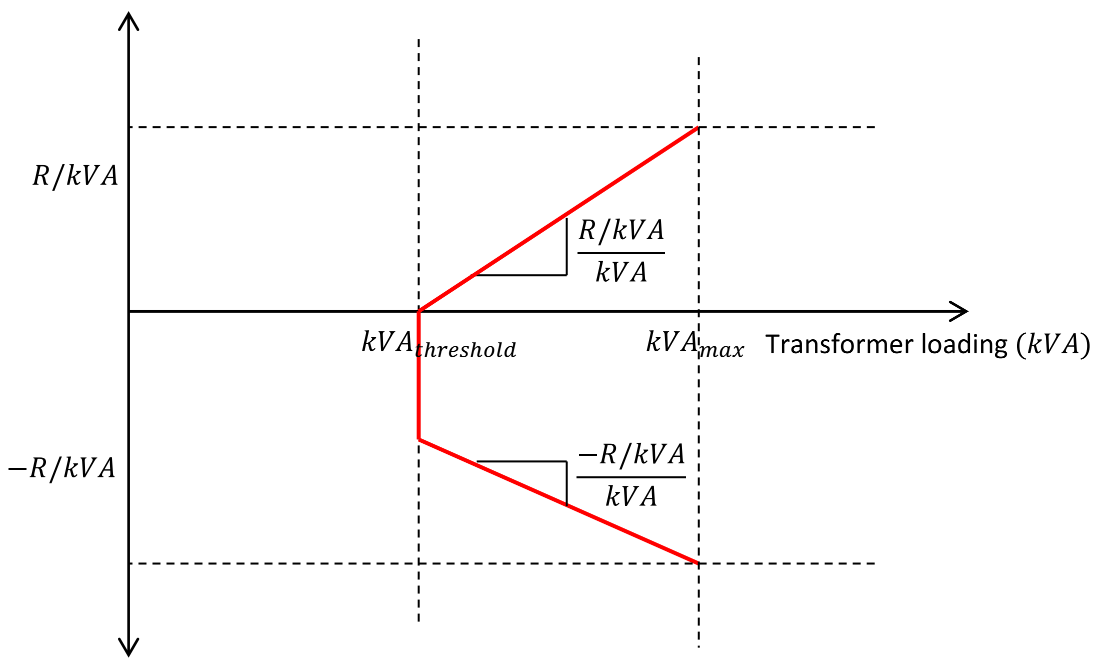


FIGURE 3.4: Maximum demand pricing

When the averaged transformer kVA loading is less than the specified transformer kVA threshold the consumer maximum demand charge is equal to zero. The slope of the consumer demand pricing function in Figure 3.4 is determined by defining the demand price corresponding to the transformer maximum kVA loading (kVA_{max}) and the demand price corresponding to the transformer threshold loading ($kVA_{threshold}$). The slope of the solar PV owner maximum demand pricing function in Figure 3.4 is determined by defining the demand price corresponding to the transformer maximum kVA loading (kVA_{max}) and the demand price corresponding to the transformer threshold loading ($kVA_{threshold}$).

3.4 Solar PV export fractional curtailment

Solar PV power curtailment is applied to manage high voltage violations in LV distribution networks. The loss of feed-in tariff must be fair to small solar PV owners that are connected to the same node as large solar PV owners. This would be achieved if solar PV owners are exposed to the same fractional curtailment when the maximum RMS voltage threshold is exceeded.

Figure 3.5 illustrates the solar PV power export curtailment that solar PV owners will be exposed to when the averaged local RMS voltage is greater than the maximum voltage limit. Solar PV power export curtailment applies when the local averaged RMS voltage exceeds the specified maximum RMS voltage (nV_{RMS_max}) where n would typically be 0.99. 100% Solar PV generation increased curtailment occurs when the averaged local RMS voltage is equal to or greater than the specified maximum RMS voltage (V_{RMS_max}). The current South Africa's solar PV interconnection standards do not allow for the injecting or consuming of reactive power by solar PV in an attempt to control the network voltages [20]. The research work assumes that solar PV units export power at unity power factor in line with the South Africa's solar PV interconnection standards. If the current South Africa's interconnection standards change then solar PV owners will be allowed to individually control the voltage on the LV distribution network. The application of the solar PV export fractional curtailment is outside of tariff structure discussed in this dissertation and will require additional functionalities in the smart meter.

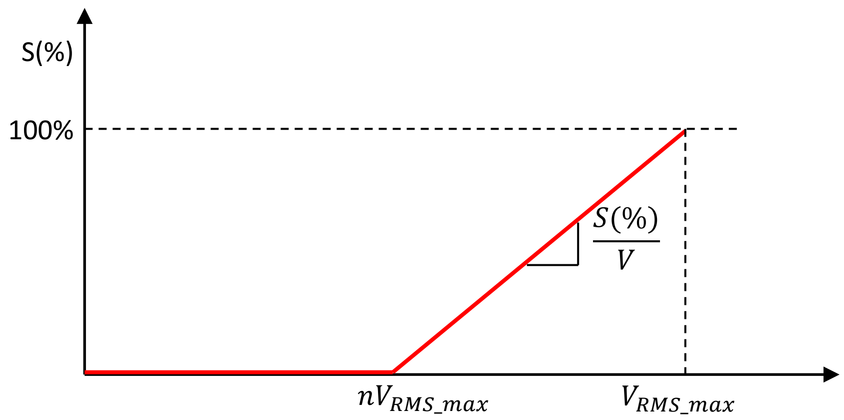


FIGURE 3.5: Solar PV percentage curtailment based on the averaged local RMS voltage ($\boldsymbol{n}$ would typically be 0.99)

3.5 Conclusion

This chapter presents the fundamental concepts in the formulation of the proposed distribution tariff structure based on dynamic cost components that are location and time based.

The cost components of the proposed tariff are the active energy charge (as a price signal for energy efficient consumption), the network losses charge (as a price signal for efficient energy consumption) and the maximum demand charge (as a price signal for managing equipment rating violation). Solar PV power curtailment is applied to manage high voltage violations in LV distribution networks.

The energy charge will differ during the day due to the dispatch of generation plants according to the merit order. The energy charge will follow the TOU tariff.

The maximum demand charge is applied to recover future network upgrade costs to be incurred by the power utility due to the increase in local demand. The maximum demand charge is only applicable when the local MV/LV transformer is overstressed. The novel part of the proposed tariff is that the local distribution network loading is managed by sending price signals to customers.

The proposed tariff is such that solar PV owners are remunerated for the active energy export to the grid plus the network losses component (due to solar PV owners reducing the network losses) and plus the maximum demand component (due to solar PV owners reducing the network equipment loading) which applies only when the MV/LV transformer is overloaded. To avoid overvoltage due to excessive power exports, solar PV generation curtailment is implemented.

CHAPTER 4

Advanced metering infrastructure

4.1 Introduction

This chapter describes how the location and time differentiated metering solution based on the theory presented in the previous chapter can be implemented in practice. The metering solution includes smart meters, communication networks, remote terminal units and a data management system as outlined in Figure 4.1 below. These components using local network measurements, communicate price signals from the utility to the customer meter in real-time.

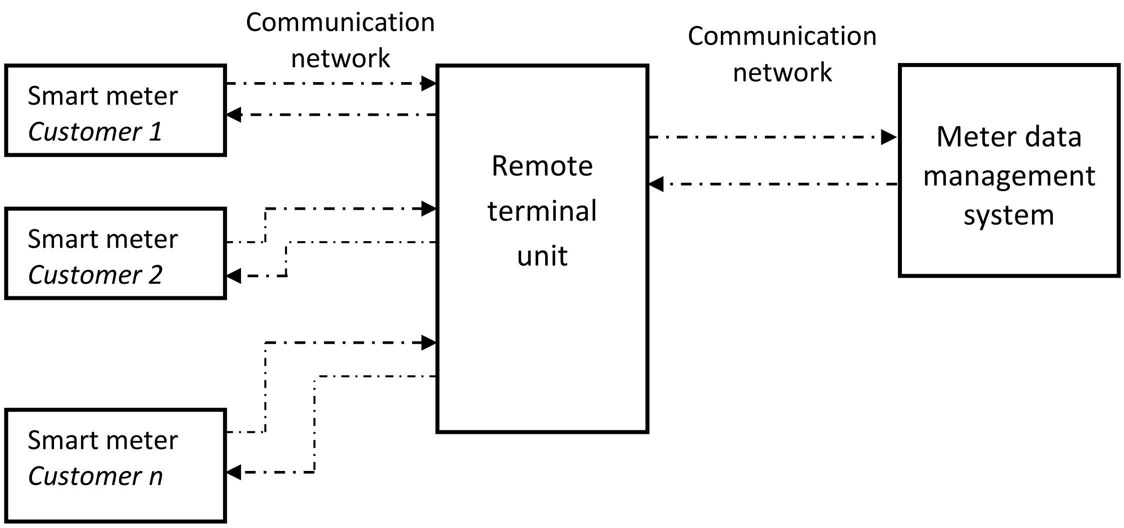


FIGURE 4.1: Proposed AMI block diagram

The ultimate aim of the proposed AMI is to accommodate unbundled tariff components so that each cost driver will have its own cost to be recovered and its own tariff calculation methodology. The second aim is the allocation of the cost incurred by the distribution utility to customers in a cost reflective manner. The third aim is the communication of pricing signals to customers so that they can adapt to the constraints of the grid and can change their demand in response to the network conditions and supply characteristics at their point of connection.

4.2 Smart meter

The smart meter located at the customer's supply side collects demand information from the end user at 30 minutes time intervals and transmit the data through the communication networks to the data management system for tariff calculations. In order for the customer smart meter to implement the tariff structures presented in the previous chapter and allow for real-time communication of pricing signals from the utility to the customer meter, the smart meter must have the following functionalities as a minimum:

- **The ability to handle different tariff structures:** This functionality already exists in a four quadrant smart meter capable of measuring active and reactive power demand.
- **The ability to perform calculations in real-time:** This functionality already exists in commercially available smart meters equipped with real-time clock to indicate the current data and time of measurement.
- **The ability to measure the actual customer RMS voltage:** This functionality already exists in commercially available smart meters; the meter software supports calculations of various parameters during energy computation such as RMS current and voltage, active and reactive power and power factor.
- **The ability to calculate the solar PV export power:** This functionality already exists incommercially available smart meters used in net-metering whereby the meter runs forward when the customer uses energy from the grid and runs backwards when the customer exports energy to the grid.
- **The ability for the tariff to be adjusted periodically based on the local distribution network measurements:** This functionality already exists in the current smart meters where time-of-use tariffs are applied with different predetermined retail prices applied in different timeslots.
- **The ability for customers to respond to varying tariffs and manage customer loads based on the tolerable maximum tariff value:** This functionality already exists in commercially available smart meters; the meters have a user interface module to allow for demand response to dynamic pricing.
- **The ability to communicate in real-time via tariff structures important grid parameters to customers:** This functionality already exists in commercially available smart meters

whereby the data communication module allows for two-way communication between the meter and the power utility.

4.3 Remote terminal unit

The RTU located at various points of the LV distribution network is an important component in the proposed AMI. The RTU is connected with several customer smart meters and the local meter data management system (MDMS) and collects the demand information from the smart meters at 30 minutes time intervals. The information collected from the smart meters is then transmitted to the MDMS through the local communication network. In addition, the RTU enables the communication of data from the MDMS to the smart meters.

The RTU is integrated with a current sensor to measure the RMS current in the network beyond the node as shown in Figure 4.2. The total RMS current upstream of the node is the root of the sum of the squares of the RMS currents measured by the customer smart meter and the RMS current measured by the node current sensor downstream of the node. The total current between node i and node $(i+1)$ is as measured by the current sensor downstream of node i.The need for "beyond the node current sensor" located in the RTU is to measure the RMS current in the network beyond the node for locational network losses allocation.

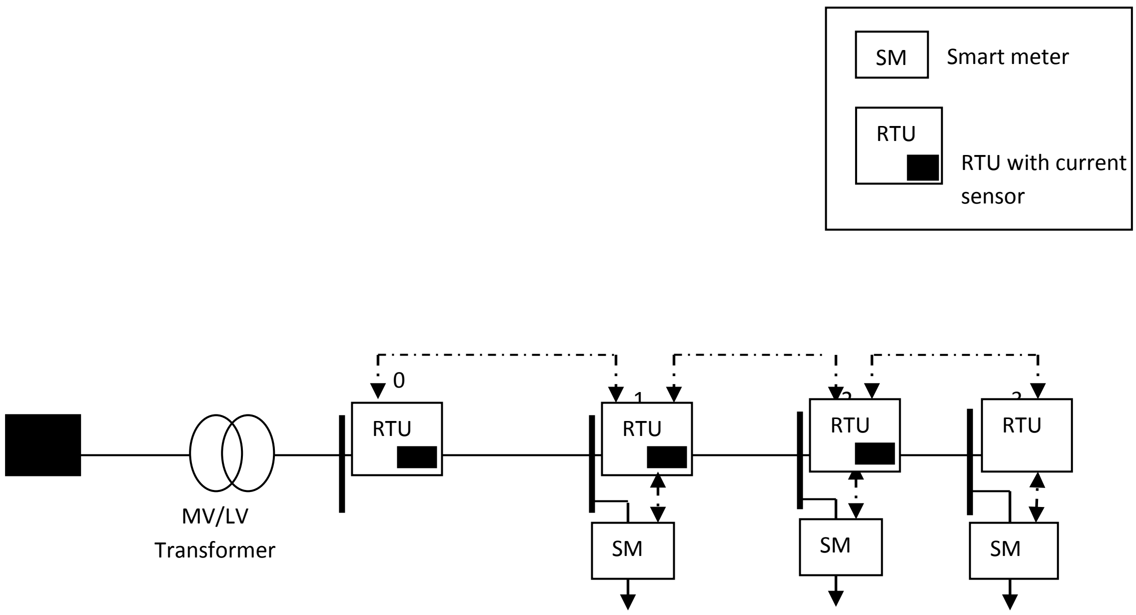


FIGURE 4.2: Metering components interface

The utility-owned RTU located at the MV/LV transformer supplying the LV distribution network will:

- Measure the MV/LV transformer kVA loading over a 30 minutes demand period.
- Calculate the average kVA loading and compares the average transformer loading with the specified loading threshold.

4.4 Meter data management system

The meter data management system (MDMS) receives data from the RTU and processes the data for different tariff calculations. The data stored in the MDMS can also be used for other operations and management functions such as load forecasting, load management, demand response and outage management. Figure 4.3 shows how different RTUs interact with the MDMS located at the local MV/LV transformer.

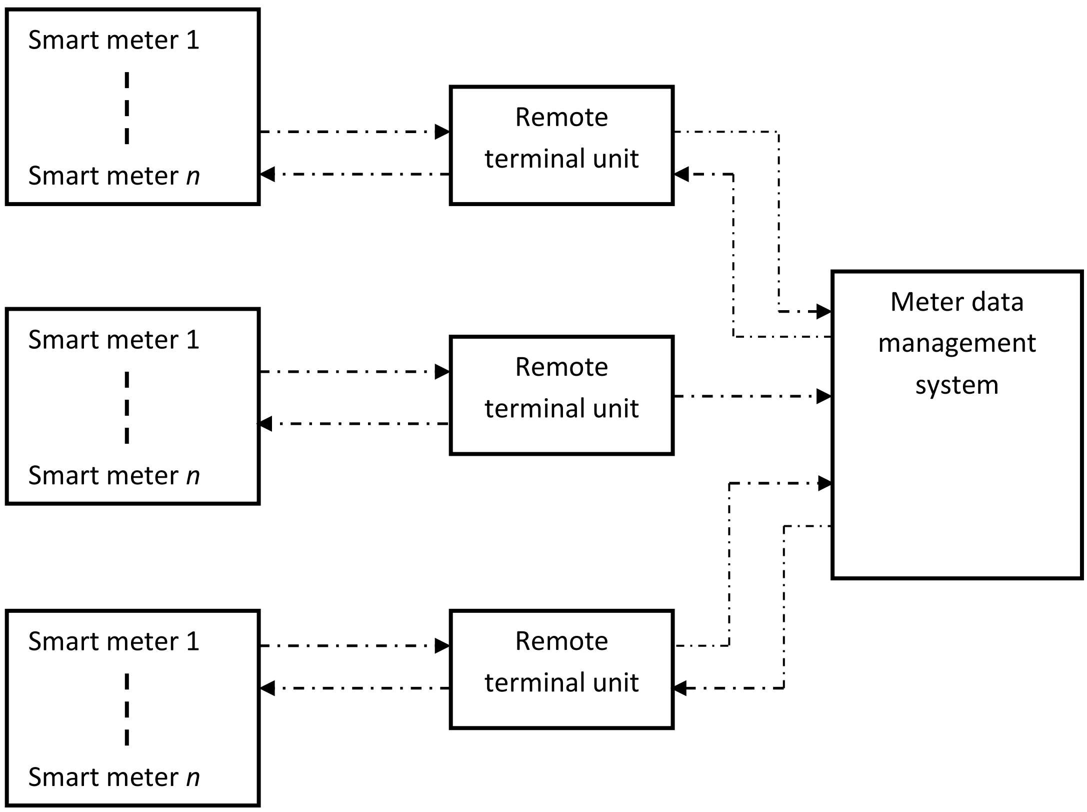


FIGURE 4.3: Meter data Management System (MDMS)

4.5 Barriers to the proposed smart metering

The following have been identified as barriers for the implementation of the proposed smart metering:

- Data communication time lag
- Data storage requirements and computational needs
- Transitioning from the current metering technology to the proposed metering technology.
- Managing the public acceptance of the proposed technology.
- Increased cost for meters and the required infrastructure.
- Managing the security of metering data.
- Verification of the data collected for tariff calculations.
- Protection of the customer's privacy.

Placing the MDMS at the local MV/LV transformer has the following advantages:

- **Data communication:** The high number of customers connected to the LV distribution network will result in a high amount of information that needs to be processed. By placing the MDMS at the local MV/LV transformer makes the processing of data quicker (since it only process data for customers supplied from the local MV/LV transformer) thus reducing communication delays and data loss.
- **Communication network:** The information from the customer smart meter needs to reach the MDMS for processing and tariff calculations. By placing the MDMS at the local MV/LV transformer, the distance between the RTU and the MDMS is reduced thus avoiding high amounts of communication resources.

4.6 Conclusion

The metering solution consisting of the smart meters, RTUs and MDMS was discussed in this chapter. The properties of these components and their interface to ensure locational and time-of-use cost allocation to end users were explained.

The communication network allows for bi-directional data exchange between the customer's smart meter and the power utility enabling dynamic pricing applications. The customers get more information regarding their energy usage and the quality of supply while the power utility implement cost tariffs to signal customers of the cost incurred by the power utility due to the use of its network.

CHAPTER 5

Tariff applications and results

5.1 Introduction

This chapter gives examples and results of how the proposed tariff structures provide cost-reflective cost allocation corresponding to the customer extent of network use. It will also be shown how the proposed tariff structures address the problem statement and research question mentioned in Chapter 1.

The scenarios to be discussed in detail in this chapter are summarised below to show the calculations of the proposed tariff structures under different grid conditions.

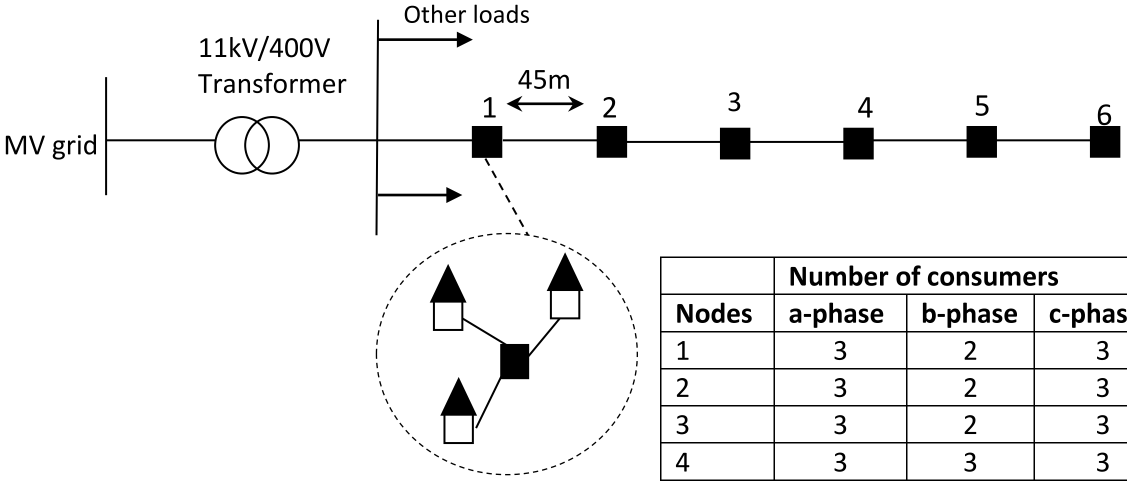
- The application of the network losses charge as a price signal for efficient energy consumption
- The application of the maximum demand charge as a price signal to reduce demand when the MV/LV transformer loading is equal to or greater than the loading threshold.

The electricity regulator implements a revenue requirement for the dominant national wholesale electricity provider along with associated sales projections. This results in an average tariff trajectory as part of the MYPD. The smart meter takes its reference from the latest tariff determinations following the MYPD, and it is updated annually.

5.2 System modelling

5.2.1 LV network

The radial LV network used to study the impact of increasing EV penetration and solar PV installations on the local LV network is supplied from the 11/0.4 kV 500kVA transformer as shown in Figure 5.1. The LV feeder supply 48 single phase residential customers connected along a 270m conductor with six nodes spaced at 45m.



	Number of consumers		
Nodes	**a-phase**	**b-phase**	**c-phase**
1	3	2	3
2	3	2	3
3	3	2	3
4	3	3	3
5	2	3	3
6	3	3	2

FIGURE 5.1: Radial LV distribution network

The LV feeder model configuration used in this study has 3-phases and a neutral conductor as shown in Figure 5.2. The LV conductor is a 35mm^2 copper conductor templated at 20°C.

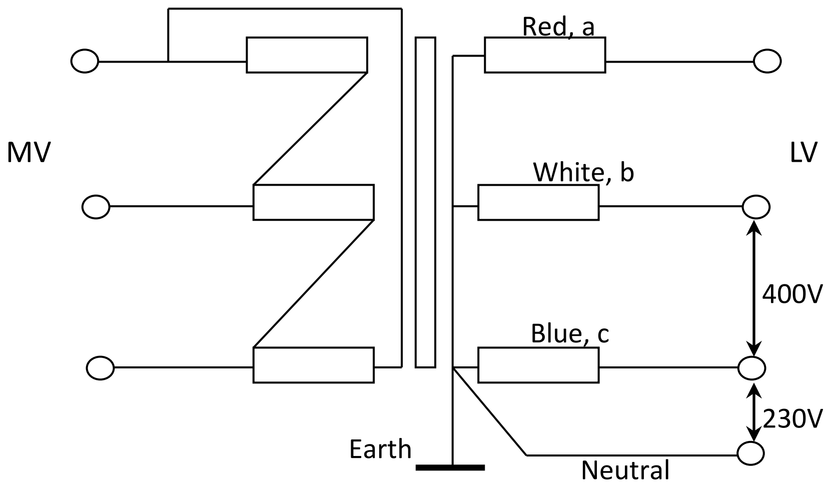


FIGURE 5.2: LV feeder configuration

5.2.2 Domestic load

Based on the analyses of a significant amount of data collected from South African domestic electric loads it was found that the domestic electric loads can be modelled as constant current sinks [52]. According to SANS 507-1, the total load of a large number of customers can be regarded as the number of customers multiplied by the mean value of after diversity maximum demand (ADMD). Thus a composite load can be derived from individual load models based on known values of a group of customers that account for the specific characteristics describing the group of customers. For the purpose of this research, the load profile referenced was from the NRS 034 Domestic Load Research Project, 1998 [53]. The demand profile used is for a high end customer most likely to afford to purchase solar PV panels and electric vehicle. Figure 5.3 shows the 5 minutes average load current profiles recorded for a typical winter and summer day for the selected customer group in South Africa [53].

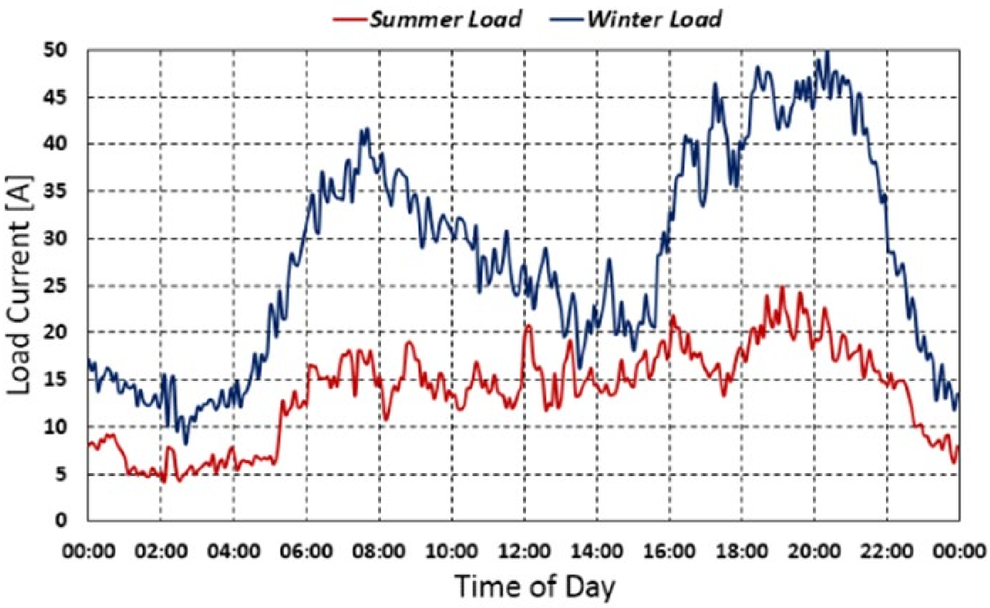


FIGURE 5.3: Load profile for summer and winter load

Domestic loads are stochastic by nature and therefore their random variations with respect to time require statistical model approach at a given time of occurrence. At any given time the customer's load current varies from a minimum value to a maximum value limited by the current circuit breaker size. Beta PDFs have been successful in developing load models in South Africa, especially for samples of more than ten customers with the error in estimation within acceptable levels for practical purposes [52]. The shape parameters of the Beta PDF determine the spread of the distribution loads about the mean and by varying these shape parameters about the mean, a family of curves can be derived to fit most practical distribution loads. The parameters of a Beta PDF are the shape parameters α, β and a scaling factor C. The shape parameters α and β can be derived from Equations (5.1) and (5.2) respectively.

$$\alpha = \frac{\mu(C\mu - \mu^2 - \sigma^2)}{C\sigma^2} \tag{5.1}$$

$$\beta = \frac{(C - \mu)\,(C\mu - \mu^2 - \sigma^2)}{C\sigma^2} \tag{5.2}$$

Where

μ − The mean of the load

σ – The standard deviation of the load

For this research work the Beta PDF is used to determine the customer load current.

5.2.3 Electric vehicle load model

The EV charging demand depends on uncertain variables that vary from one EV owner to another such as driving behaviour, state of charge of the EV battery, the charging rate of the charging infrastructure and the charging times. Different probability density functions to estimate the EV charging load are being investigated. In [54] the EV charging start time is modelled with and without a time delay assuming a Poisson distribution. In [55], the queuing theory is presented to model EV charging loads where EVs with different battery capacities are modelled for residential and public charging proposing probabilistic power flow model to handle uncertainties in EV charging. Monte Carlo simulations (MCS) are used in [56] to model EV charging uncertainties.

The MCS uses randomly sampled input covering a wide range of possible input variables to arrive at output variables. The process is executed iteratively over a number of times to obtain efficient samples to reflect the probability distribution of the output variables. The MCS is adopted in this study to analyse the impact of EV charging loads and solar PV export on the customer’s electricity charge based on the proposed tariff structures. Multiple Monte Carlo iterations are simulated by randomizing the EV charging start times and SOC of EV battery. The starting time for EV charging events and the SOC of EV battery are modelled as random variables represented by the Gaussian distribution function.

5.2.4 Solar PV model

The solar PV is modelled as a current source randomly allocated to the LV distribution customers. The solar PV generation is considered to be constant and is not affected by the environmental parameters at the location of installation such as the solar irradiance and the air temperature.

5.3 Impact on network voltage

The following steps which are translated into a MATLAB code are followed in the computation of the customer voltage at the point of supply on the distribution feeders.

Step 1: Generate random load currents from the load Beta parameters and allocate load currents to consumers (it is assumed that the customer load current remains constant for the 30 minutes demand period).

Consider the total current for phase *A* given by:

$$I_a = I_{L1} + I_{L2} + I_{L3} \dots \dots \dots \dots .. + I_{LN} \tag{5.3}$$

Where:

I_a denotes the total conductor current for phase *A* and

I_{LN} are the load currents for customer 1 to *N* connected on phase *A.*

The snippet of the MATLAB code used to randomly allocate load currents to customers on the LV feeder at different nodes is shown below. The *betarnd MATLAB function* is used to sample the load currents based on the Beta PDF parameter inputs α and β obtained from the South African domestic load research data. The simulation code is based on the following variables:

TABLE 5.1: Matlab simulation load currents input

	No. Of Customers			Load parameters		
Nodes	Red	White	Blue	Alpha	Beta	C
	a	b	c	α	β	[A]
1	3	2	3	0.4366	1.2877	60
2	2	2	3			
3	3	2	3			
4	3	3	3			
5	2	3	3			
6	3	3	2			

```
%%%%%%%%%%Assigning customers per phase at differentnodes%%%%%%%
a1=3; a2=2; a3=3; a4=3; a5=2; a6=3; a=a1+a2+a3+a4+a5+a6;
b1=2; b2=2; b3=2; b4=3; b5=3; b6=3; b=b1+b2+b3+b4+b5+b6;
c1=3; c2=3; c3=3; c4=3; c5=3; c6=2; c=c1+c2+c3+c4+c5+c6;

%%%%Generating random load currents following the Beta PDF%%%%%%%%
Y = 60*betarnd(0.4366,1.2877,sum([a b c]),1);

%%%%Allocate load currents to customers at different nodes%%%%%%%
```

```
%%%%%%%%%%%Node 1
I1 = sum(Y(1:a1));
I2 = sum(Y((a1+1):(a1+b1)));
I3 = sum(Y((a1+b1+1):(a1+b1+c1)));
%%%%%%%%%%%Node 2
I4 = sum(Y(1:a2));
I5 = sum(Y((a2+1):(a2+b2)));
I6 = sum(Y((a2+b2+1):(a2+b2+c2)));
%%%%%%%%%%%Node 3
I7 = sum(Y(1:a3));
I8 = sum(Y((a3+1):(a3+b3)));
I9 = sum(Y((a3+b3+1):(a3+b3+c3)));
%%%%%%%%%%%Node 4
I10 = sum(Y(1:a4));
I11 = sum(Y((a4+1):(a4+b4)));
I12 = sum(Y((a4+b4+1):(a4+b4+c4)));
%%%%%%%%%%%Node 5
I13 = sum(Y(1:a5));
I14 = sum(Y((a5+1):(a5+b5)));
I15 = sum(Y((a5+b5+1):(a5+b5+c5)));
%%%%%%%%%%%Node 6
I16 = sum(Y(1:a6));
I17 = sum(Y((a6+1):(a6+b6)));
I18 = sum(Y((a6+b6+1):(a6+b6+c6)));
```

Step 2: Calculate customer connection voltages per phase per note

The voltage drop for phase *A* at node i is derived from:

$$\Delta V_i = I_a(R_a + jX_a) + I_n(R_n + jX_n) \tag{5.4}$$

Where R_a , X_a , R_n , X_n denotes the conductor resistance and reactance for phase *A* and the neutral conductor respectively. Unbalanced feeder loads between phases result in current flows in the neutral conductor associated with voltage drop or voltage rise at the customer's point of connection. For this study it is assumed that the phases and neutral conductors have the same cross-section area. The voltage at the customer connection point (V_{con}) for a feeder with *N* nodes is calculated by taking into consideration the total voltage drop due to individual nodes such that:

$$V_{con,N} = \sqrt{(V_s - \sum_{i=1}^{N} \Delta V_{i_R})^2 + \sum_{i=1}^{N} \Delta V_{i_j}{}^2} \tag{5.5}$$

Where:

$V_{con,N}$is the voltage at the customer's connection point

V_s is the source voltage

$\Delta V_{i_R}$is the real part of the voltage drop

$\Delta V_{i_j}$is the imaginary part of the voltage drop

The MCS outlined in the flow diagram of Figure 5.4 below is adapted in this study to determine the voltages at the customer's point of connection.

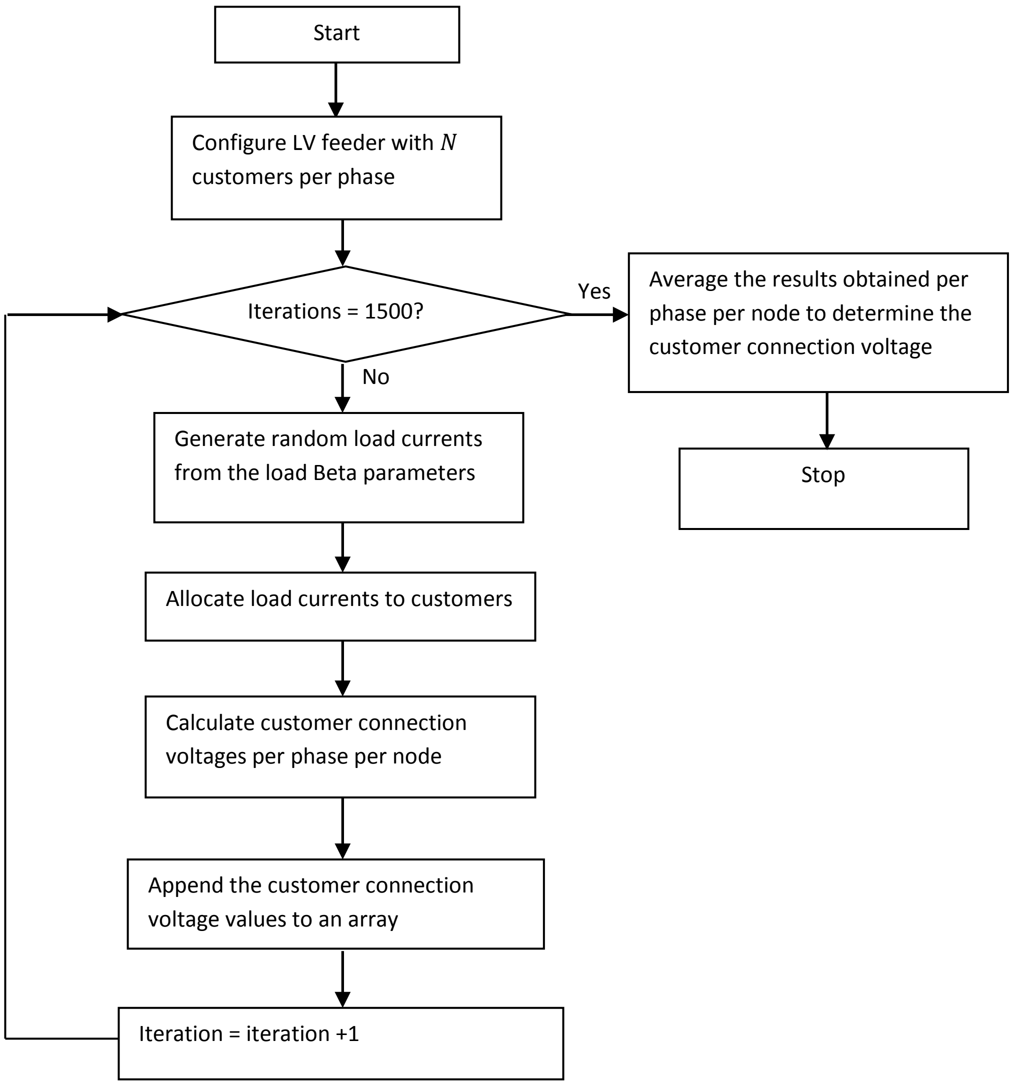


FIGURE 5.4: Monte Carlo Simulation for customer's node voltages

Figure 5.5 demonstrates the density of the voltages at the customer's connection point for different solar PV percentage penetration, where solar PV percentage penetration is given by:

$$Solar\ PV\ \%\ penetration = \frac{customers\ with\ solar\ PV\ installations}{Total\ customers\ on\ the\ LV\ feeder} \tag{5.6}$$

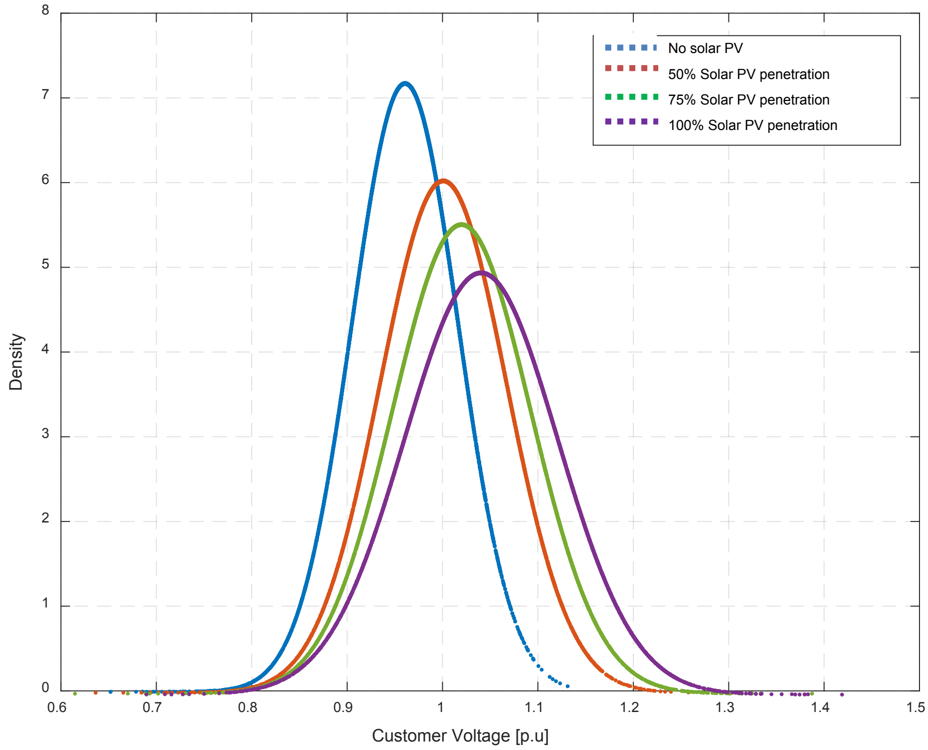


FIGURE 5.5: Customer voltage with solar PV % penetration

From Figure 5.5 it can be seen that the probability of voltage rise at the customer's point of connection increases as the solar PV % penetration increases. Solar PV power curtailment is applied to manage high voltage violations in LV distribution networks. Solar PV power export curtailment applies when the local averaged RMS voltage exceeds the specified lower maximum RMS voltage (nV_{RMS_max}) where n would typically be 0.99 and V_{RMS_max} is $230V + 10\% = 253V$. 100% Solar PV generation increase curtailment occurs when the averaged local RMS voltage is equal to or greater than the specified maximum RMS voltage (V_{RMS_max}). Figure 5.6 demonstrate the percentage solar PV power export curtailment when the local averaged RMS voltage exceeds the specified lower maximum RMS voltage (nV_{RMS_max}). 100% Solar PV generation increase curtailment occurs when the averaged local RMS voltage is equal to or greater than the specified maximum RMS voltage (V_{RMS_max}).

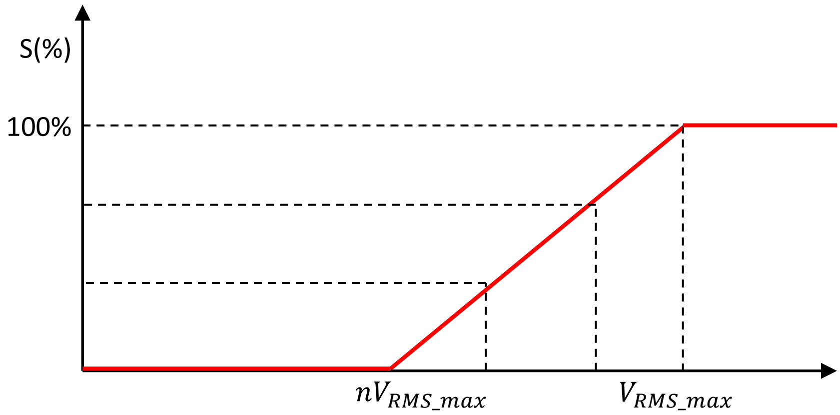


FIGURE 5.6: Solar PV generation increase curtailment

5.4 Application of the maximum demand charge

The residential loads supplied from LV distribution networks are characterised by a daily load profile with the morning peak demand between 06:00am and 08:00am and evening peak demand between 18:00pm and 21:00pm. Uncontrolled residential EV charging events influenced by EV owner's home arrival times are more likely to coincide with the evening peak demand. The largest increase in the demand due to EV charging load is recorded for different EV penetration scenarios to demonstrate the impact of EVs on the MV/LV transformer loading of Figure 5.1. The steps of the Monte Carlo simulations are summarised in Figure 5.7 for different EV penetration scenarios.

- 0% EV penetration: No EVs
- 50% EV penetration: (50% x 48 = 24 EVs randomly distributed)
- 75% EV penetration: (75% x 48 = 36 EVs randomly distributed)
- 100% EV penetration: (100% x 48 = 48 EVs randomly distributed)

$$EV\ \%\ penetration = \frac{customers\ with\ EVs}{customers\ supplied\ from\ the\ LV\ feeder} \qquad (5.7)$$

The unscheduled charging scenarios representing the case when electricity tariffs do not influence charging events are simulated. Figure 5.8 shows that EV penetration greater than

50% will most likely result in the transformer under study exceeding the rated capacity when the EVs charging time coincide with the evening peak demand.

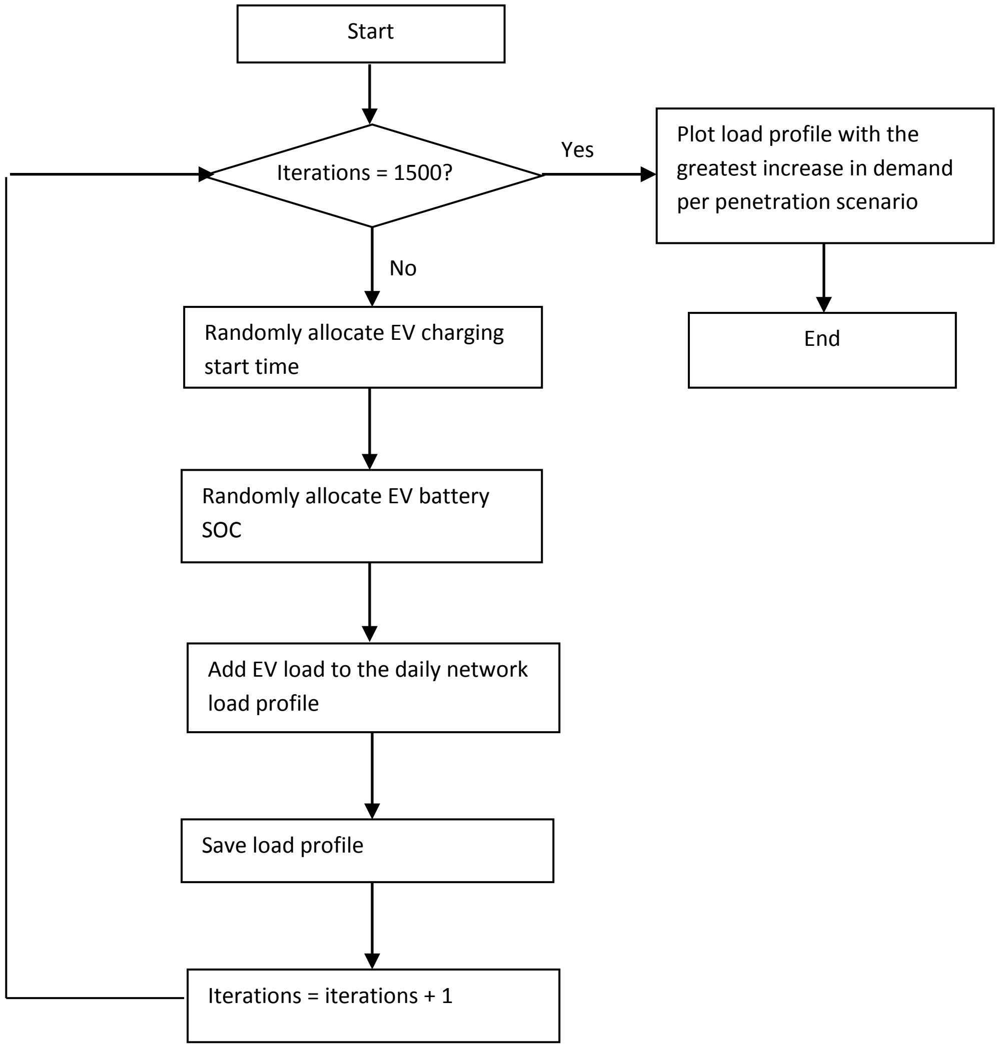


FIGURE 5.7: Transformer loading investigation

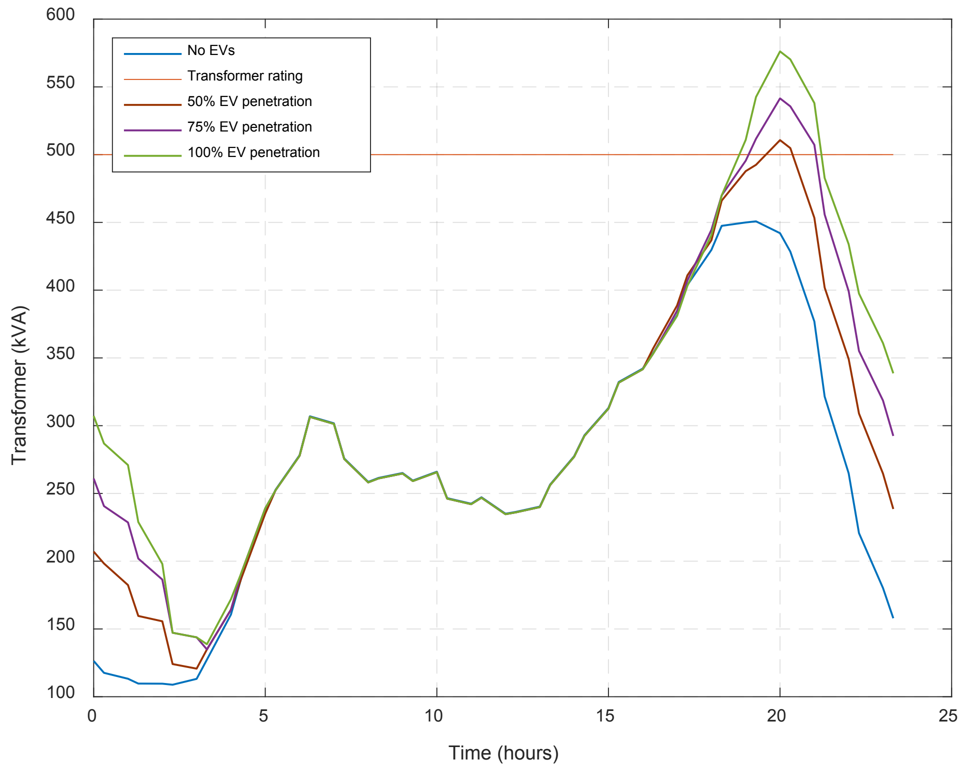


FIGURE 5.8: Transformer loading with EV charging start time mean at 20:00pm

The duration of EV charging events can extend to 8 hours depending on the initial SOC of the EV battery, the capacity of the battery and the rating of the charging infrastructure used. Figure 5.9 demonstrates the probability of MV/LV transformer capacity violation under different EV penetrations on the LV radial feeder of Figure 5.1 using 1500 Monte Carlo simulations. For example, there is a 6.66% probability of 30 minutes transformer capacity violation under 50% EV penetration (24 EVs randomly distributed). The probability of longer transformer capacity violation duration increases as the EV penetration increases.

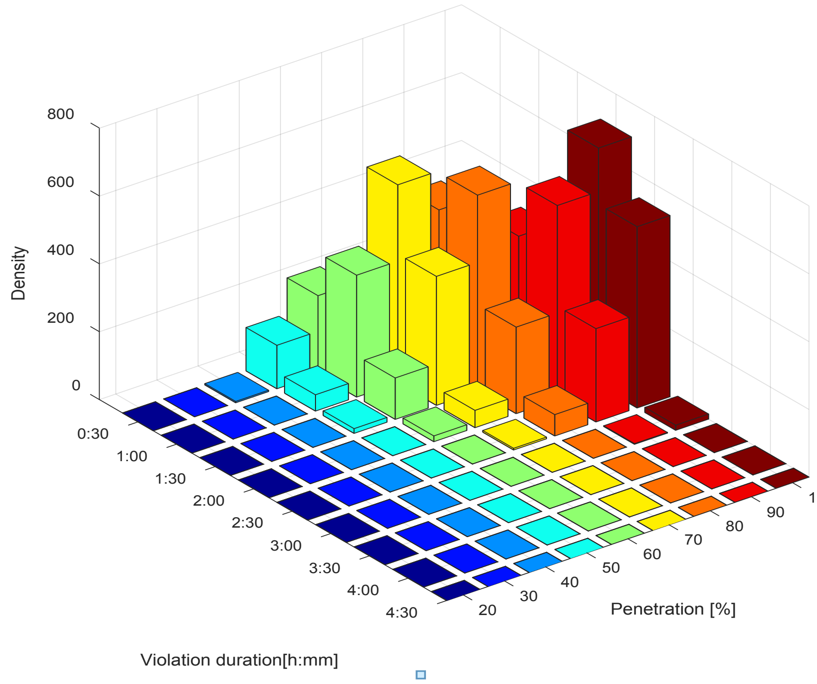


FIGURE 5.9: Probability density of transformer capacity violation duration

Assuming that the customer demand without EV is calculated from:

- Monthly electricity bill : *R1000*
- Electricity tariff: *R2.00/kWh*
- Energy consumption per month: *500kWh*
- Averaged demand (kVA) assuming unity power factor: *0.7kVA*

Assuming the 230V/15A EV charging outlet and constant charging demand profile, the EV charging load is calculated as: *3.4kVA*

The difference between the proposed maximum demand charge applied as a penalty and the conventional maximum demand charge is that the penalty maximum demand charge is applied per demand period and the conventional demand charge is applied per month. The penalty maximum demand charge is typically R5/kVA/demand period (30 minutes) corresponding to the transformer maximum kVA loading and the conventional maximum demand charge is typically R35/kVA/month.

Case study 1

Consider the 30 minutes averaged parameters detailed in Table 5.2 below for demonstrating the application of the maximum demand charge.

TABLE 5.2: Averaged parameters for maximum demand charge

Parameters	**Case 1**	**Case 2**
Transformer rating (kVA)	500	500
Specified transformer threshold (kVA)	470	470
Averaged transformer loading (kVA)	480	490
Averaged customer 1 demand (kVA) (without EV)	0.7	0.7
Averaged customer 2 demand (kVA) (with EV)	4.1	4.1

The slope of the consumer maximum demand pricing function determined by defining the maximum demand price corresponding to the transformer maximum kVA loading (kVA_{max}) and the maximum demand price corresponding to the transformer threshold loading ($kVA_{threshold}$). The slope is given by:

$$Slope = \frac{5-0}{500-470} = R0.16/kVA/kVA \tag{5.8}$$

Where:

- *R5/kVA* is the maximum demand price corresponding to the transformer rating of *500kVA*
- *R0/kVA* is the maximum demand price corresponding to the specified transformer threshold of *470kVA*

Case 1

At *480kVA* averaged transformer loading, the maximum demand charge is: *R1.67/kVA/demand period (30 minutes)*

- The maximum demand charge for customer 1 (without EV) is: *R1.17/demand period (30 minutes)*
- The maximum demand charge for customer 2 (with EV) is: R6.85/demand period (30 minutes)

Assuming 50% EV penetration and 30 minutes transformer loading threshold violation as demonstrated in Figure 5.9 for 12 days in a month. The monthly maximum demand charge payable by customer 1 and customer 2 is:

- The monthly maximum demand charge for customer 1 (without EV): *R14.04/month*
- The monthly maximum demand charge for customer 2 (with EV): *R82.2/month*

Table 5.3 below compares the customers' monthly maximum demand charge based on the proposed maximum demand charge applied as a penalty and the conventional maximum demand charge (assuming R35/kVA/month).

TABLE 5.3: Case 1 customer's maximum demand charge

	Customer 1 (without EV)	**Customer 2 (with EV)**
Proposed maximum demand charge	R14.04	R82.2
Conventional maximum demand charge	R24.5	R143.5

Case 2

At 490kVA averaged transformer loading, the maximum demand charge is: *R3.2/kVA/demand period (30 minutes)*

- The maximum demand charge for customer 1 (without EV) is: *R2.24/demand period (30 minutes)*
- The maximum demand charge for customer 2 (with EV) is: R13.12/demand period (30 minutes)

Assuming 50% EV penetration and 30 minutes transformer loading threshold violation as demonstrated in Figure 5.9for 12 days in a month. The monthly maximum demand charge payable by customer 1 and customer 2 is:

- The monthly maximum demand charge for customer 1 (without EV): *R26.88/month*
- The monthly maximum demand charge for customer 2 (with EV): *R157.44/month*

Table 5.4 below compares the customers' monthly maximum demand charge based on the proposed maximum demand charge applied as a penalty and the conventional maximum demand charge (assuming R35/kVA/month).

TABLE 5.4: Case 2 customer's maximum demand charge

	Customer 1 (without EV)	**Customer 2 (with EV)**
Proposed maximum demand charge	R26.88	R157.44
Conventional maximum demand charge	R24.5	R143.5

Case study 2

If the EV charging time is delayed until the off-peak periods, with the EV charging start time modelled as a random variable represented by the Gaussian distribution function with the mean at 23:00pm and a standard deviation equal to 1.5hours, the distribution transformer can accommodate 100% EV penetration without exceeding specified transformer loading threshold of *470kVA*as shown in Figure 5.10, resulting in the customer maximum demand charge of *R0/kVA/demand period(30 minutes)* for customers with and without EV.

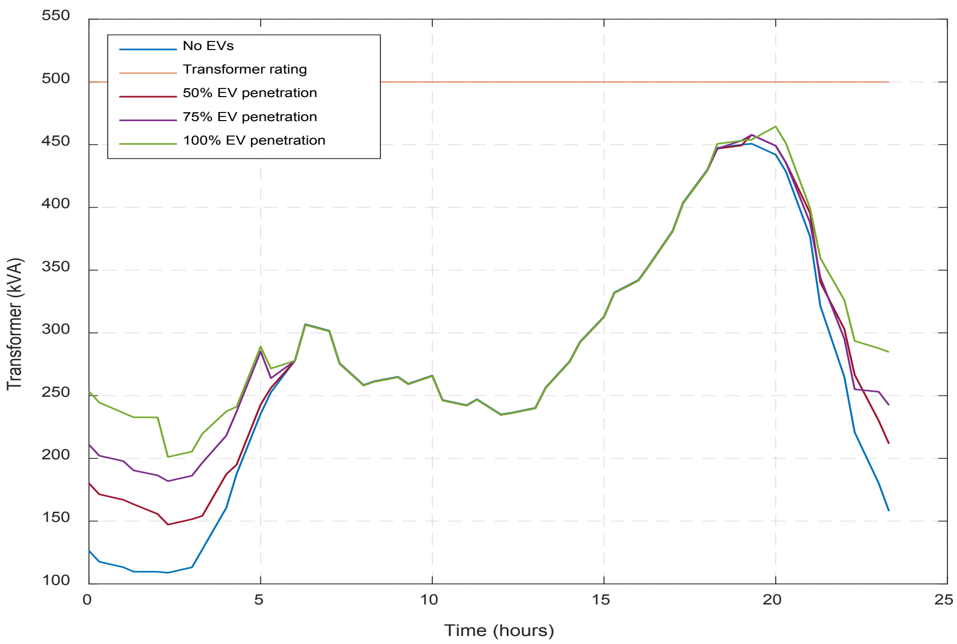


FIGURE 5.10: Transformer loading with EV charging start time mean at 23:00pm

Table 5.5 below compares the customers' monthly maximum demand charge based on the proposed maximum demand charge applied as a penalty and the conventional maximum demand charge (assuming R35/kVA/month).

TABLE 5.5: Case study 2 customer's maximum demand charge

	Customer 1 (without EV)	**Customer 2 (with EV)**
Proposed maximum demand charge Case 1 & case 2	R0.00	R0.00
Conventional maximum demand charge Case 1 & case 2	R24.5	R143.5

5.5 Application of the locational network losses

An example is presented to show the allocation of network losses based on the theory presented in Chapter 3 and Chapter 4.

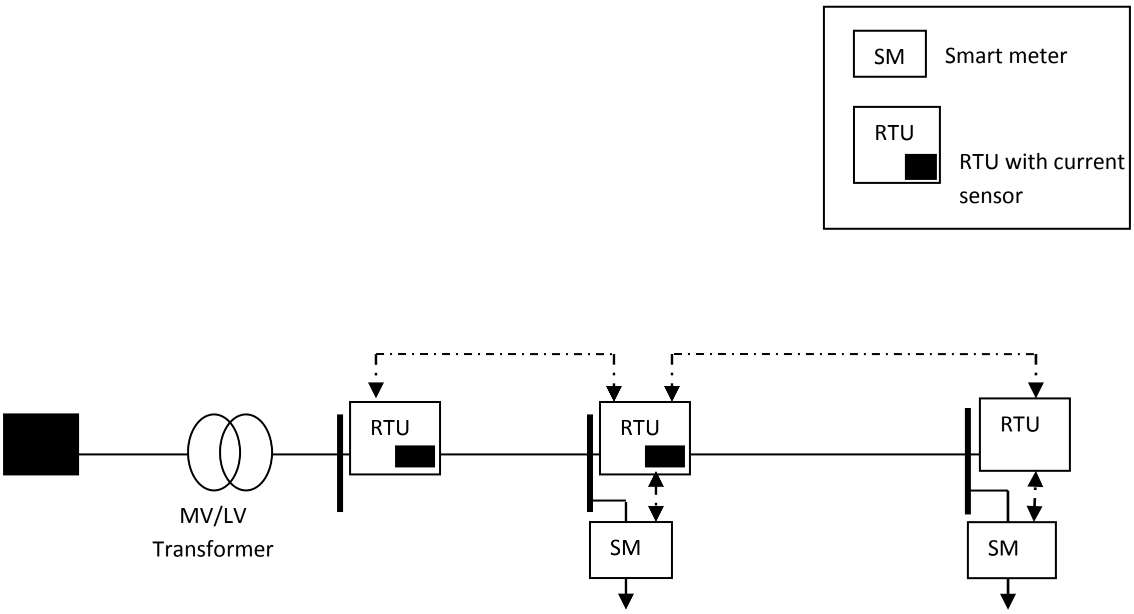


FIGURE 5.11: Metering components interface

Assuming that the customer RMS current of 20A (at unity power factor) at each node of Figure 5.11 with equal resistance of 0.168 Ω between the nodes. The total RMS current upstream of the node is the root of the sum of the squares of the RMS current measured by the customer smart meter and the node current sensor. The allocation will be as follows:

The network loss between node 0 and node 1 is given by:

$$loss = \left(I^2_{rms_{C1}} + I^2_{rms_{s1}}\right) \times 0.168\Omega = 134.4W$$

Where:

$I_{rms_{C1}}$ is the RMS current for customer at node 1 measured from the customer smart meter

$I_{rms_{s1}}$ is the RMS current in the network section downstream of node 1 measured from the current sensor located downstream of node 1.

The network loss between node 1 and node 2 is given by:

$$loss = I^2_{rms_{C2}} \times 0.168\Omega = 67.2W$$

Where:

$I_{rms_{C2}}$ is the RMS current for customer at node 2 measured from the customer smart meter

The total network loss is the sum of the losses between node 0-1 and node 1-2.

Thus the total network loss is: 201.6W

The network loss contribution for the customer at node 1 is given by:

$$Loss\ contribution = \frac{I^2_{rms_{C1}} \times\ R_{0to1}}{Total\ network\ loss} \times 100\% = 33.33\%$$

The network loss contribution for the customer at node 2 is given by the sum of the customer loss contribution between node 0 to node 1 and node 1 to node 2.

$$Loss\ contribution = \frac{I^2_{rms_{C2}} \times\ R_{0to1} +\ I^2_{rms_{C2}} \times\ R_{1to2}}{Total\ network\ loss} \times 100\% = 66.67\%$$

The locational network losses charge sends a price signal to reduce locational losses. The customer at node 2 can reduce the network loss contribution by reducing consumption.

Assuming that the customer RMS current for the customer at node 2 is reduced to 10A (at unity power factor) and for the customer at node 2 remains at 20A (at unity power factor) then the network loss allocation per node will be as follows:

The network loss between node 0 and node 1 is given by:

$$loss = \left(I^2_{rms_{C1}} +\ I^2_{rms_{s1}}\right) \times 0.168\Omega = 84W$$

Where:

$I_{rms_{C1}}$ is the RMS current for customer at node 1 measured from the customer smart meter

$I_{rms_{s1}}$ is the RMS current in the network section downstream of node 1 measured from the current sensor located downstream of node 1.

The network loss between node 1 and node 2 is given by:

$$loss = I_{rms_{C2}}^2 \times 0.168\Omega = 16.8W$$

Where:

$I_{rms_{C2}}$ is the RMS current for customer at node 2 measured from the customer smart meter

The total network loss is the sum of the losses between node 0-1 and node 1-2.

Thus the total network loss is: 100.8W

The network loss contribution for the customer at node 1 is given by:

$$Loss\ contribution = \frac{I_{rms_{C1}}^2 \times R_{0to1}}{Total\ network\ loss} \times 100\% = 66.67\%$$

The network loss contribution for the customer at node 2 is given by the sum of the customer loss contribution between node 0 to node 1 and node 1 to node 2.

$$Loss\ contribution = \frac{I_{rms_{C2}}^2 \times R_{0to1} + I_{rms_{C2}}^2 \times R_{1to2}}{Total\ network\ loss} \times 100\% = 33.33\%$$

From the example presented it can be seen that customers will receive an incentive to reduce their demand from the grid as this will contribute a reduction in their loss contribution. The power loss is converted to an energy loss charged at a particular R/kWh.

5.6 Conclusion

This chapter demonstrated the application of the proposed tariff structure under different grid scenarios. The chapter demonstrated the location-based charge for network losses using the smart metering solution described in Chapter 4. It could be seen from the examples provided that customers will receive an incentive by reducing their demand as this will contribute a reduction in the customer network loss contribution.

The chapter demonstrated that the proposed maximum demand charge can be avoided by customers shifting their demand to off-peak periods when the transformer loading is below the specified transformer threshold. The novelty in the proposed maximum demand charge is that price signals are used to manage the equipment rating violation and the maximum demand charge is location based depending on the loading of the local MV/LV transformer.

CHAPTER 6

Conclusions and future work

6.1 Conclusions

Distribution networks are gradually undergoing a transformation as the uptake of rooftop solar PV and the penetration of EVs require modification of the distribution tariff structures. The inclining block energy tariffs currently applied for most LV customers in South Africa are aligned with electricity policies by encouraging energy conservation such that electricity consumption below a baseline usage is priced at a lower rate and any electricity consumption above the baseline usage is priced at a higher rate. Although inclining block energy tariffs as applied in distribution networks have some characteristics of marginal pricing in that incremental usage above a set baseline results in higher price, it however does not reflect true marginal costs incurred by the power utility for an incremental change in supply or demand.

The problem statement of this dissertation was then to develop dynamic distribution tariff structures capable of encouraging energy consumption during optimal times of the day, allocate distribution network costs in a cost-reflective manner and provide a platform for improved customer demand response using price signals.

Price-based demand response mechanisms have been used to influence energy consumption behaviours of end users to benefit the power system. Traditional distribution tariff structures founded upon historical average cost methodologies assume that customers at distribution level consume energy in a similar way following the aggregated load profile. Although the average based tariff approach is very simple to apply, it does not provide location and time differentiated price signals to network users with regard to their impact on the grid operation and development.

The presence of solar PV in distribution networks transforms the distribution network to take up many of the characteristics of transmission networks in that it becomes more active than passive. Consequently, cost allocation methods that have been employed in transmission networks are good candidates for use in distribution networks. Thus, as part of the dissertation, cost-reflective allocation and recovery of network costs referred to transmission networks were briefly discussed.

The application of the proposed dynamic tariff structures is achieved through firstly unbundling the distribution tariff and ensuring that the right pricing signals are communicated to the grid users regarding the status of the grid and the costs the grid users impose on the network. Secondly the roll-out of smart metering technologies capable of handling different tariff structures, performing tariff calculations and sending alerts to customers to assist with the management of the use of the distribution network.

The components of the proposed tariff structures are derived from the network measurements associated with the consumer’s point of connection. The hypothesis is that if tariffs are charged based on the costs of meeting demand, the customers will have incentives to modify their usage behaviour in ways that reduce the overall network costs. The proposed advanced metering infrastructure extracts fundamental components from the distribution network, turning them into electrical circuit equations for calculation of the tariff components.

The cost components of the proposed tariff are the active energy charge (as a price signal for energy efficient consumption), the network losses charge (as a price signal for energy efficient consumption) and the maximum demand charge (as a price signal for managing equipment rating violation). The proposed maximum demand charge can be avoided by customers shifting their demand to off-peak periods when the transformer loading is below the specified transformer threshold. The novel part of the proposed tariff is that voltage violation and equipment rating violation will be managed by sending price signals to consumers.

6.3 Future work

Future work for the presented research work may include:

1. Additional tariff charges: The proposed distribution tariff components are the active energy charge, the maximum demand charge and the network losses charge. For future distribution networks additional tariff components may be required to address the impact of different technologies on the distribution (low voltage) networks.
2. Distribution market design: The different generating units and flexible loads connecting to the distribution networks transform the distribution networks from passive to active

networks requiring correct pricing signals for improved generation efficiency, reduced distribution losses and reduced network congestion. The distribution market design guided by the power system security constraints and economic dispatch of generation units as reference is to be investigated.

3. Negative exporting feed-in tariff (as a price signal for managing high voltage violation): The negative exporting feed-in tariff that applies to customers exporting power when the averaged local RMS voltage exceeds the maximum RMS voltage limit is to be investigated. To avoid the negative exporting feed-in tariff, solar PV owner can cease to export power when the averaged local RMS voltage is greater than the maximum RMS voltage limit. Since the LV distribution network voltage profile is such that customers at different locations of the network experience different RMS voltage levels, the negative exporting feed-in tariff will not result in all solar PV owners ceasing to export power at any instant.

APPENDIX A: Tariff Plans

Megaflex – Non local authority charges

TOU electricity tariff for urban customers with notified maximum demand greater than 1 MVA.

		Active energy charge [c/kWh]												Transmission network charges [R/kVA/m]	
		High demand season [Jun - Aug]						Low demand season [Sep - May]							
Transmission zone	Voltage	Peak		Standard		Off Peak		Peak		Standard		Off Peak			
			VAT incl		VAT incl		VAT incl		VAT incl		VAT incl		VAT incl		VAT incl
≤ 300km	< 500V	**333,51**	*383,54*	**101,47**	*116,69*	**55,41**	*63,72*	**109,21**	*125,59*	**75,36**	*86,66*	**48,04**	*55,25*	**R 9,54**	*R 10,97*
	≥ 500V &< 66kV	**328,28**	*377,52*	**99,45**	*114,37*	**54,01**	*62,11*	**107,07**	*123,13*	**73,71**	*84,77*	**46,76**	*53,77*	**R 8,72**	*R 10,03*
	≥ 66kV & ≤ 132kV	**317,88**	*365,56*	**96,29**	*110,73*	**52,30**	*60,15*	**103,71**	*119,27*	**71,36**	*82,06*	**45,29**	*52,08*	**R 8,49**	*R 9,76*
	> 132kV*	**299,60**	*344,54*	**90,75**	*104,36*	**49,29**	*56,68*	**97,76**	*112,42*	**67,26**	*77,35*	**42,68**	*49,08*	**R 10,73**	*R 12,34*
> 300km and ≤ 600km	< 500V	**336,24**	*386,68*	**101,88**	*117,16*	**55,31**	*63,61*	**109,69**	*126,14*	**75,52**	*86,85*	**47,91**	*55,10*	**R 9,61**	*R 11,05*
	≥ 500V &< 66kV	**331,56**	*381,29*	**100,43**	*115,49*	**54,54**	*62,72*	**108,17**	*124,40*	**74,44**	*85,61*	**47,22**	*54,30*	**R 8,80**	*R 10,12*
	≥ 66kV & ≤ 132kV	**321,01**	*369,16*	**97,23**	*111,81*	**52,79**	*60,71*	**104,71**	*120,42*	**72,07**	*82,88*	**45,72**	*52,58*	**R 8,55**	*R 9,83*
	> 132kV*	**302,60**	*347,99*	**91,68**	*105,43*	**49,75**	*57,21*	**98,69**	*113,49*	**67,92**	*78,11*	**43,08**	*49,54*	**R 10,83**	*R 12,45*
> 600km and ≤ 900km	< 500V	**339,58**	*390,52*	**102,87**	*118,30*	**55,84**	*64,22*	**110,78**	*127,40*	**76,25**	*87,69*	**48,35**	*55,60*	**R 9,72**	*R 11,18*
	≥ 500V &< 66kV	**334,89**	*385,12*	**101,46**	*116,68*	**55,09**	*63,35*	**109,24**	*125,63*	**75,19**	*86,47*	**47,70**	*54,86*	**R 8,88**	*R 10,21*
	≥ 66kV & ≤ 132kV	**324,28**	*372,92*	**98,24**	*112,98*	**53,34**	*61,34*	**105,77**	*121,64*	**72,81**	*83,73*	**46,19**	*53,12*	**R 8,61**	*R 9,90*
	> 132kV*	**305,65**	*351,50*	**92,58**	*106,47*	**50,30**	*57,85*	**99,70**	*114,66*	**68,61**	*78,90*	**43,54**	*50,07*	**R 10,99**	*R 12,64*
> 900km	< 500V	**343,00**	*394,45*	**103,94**	*119,53*	**56,42**	*64,88*	**111,90**	*128,69*	**77,00**	*88,55*	**48,87**	*56,20*	**R 9,78**	*R 11,25*
	≥ 500V &< 66kV	**338,22**	*388,95*	**102,45**	*117,82*	**55,61**	*63,95*	**110,31**	*126,86*	**75,91**	*87,30*	**48,17**	*55,40*	**R 8,98**	*R 10,33*
	≥ 66kV & ≤ 132kV	**327,54**	*376,67*	**99,21**	*114,09*	**53,87**	*61,95*	**106,83**	*122,85*	**73,54**	*84,57*	**46,65**	*53,65*	**R 8,69**	*R 9,99*
	> 132kV*	**308,62**	*354,91*	**93,53**	*107,56*	**50,82**	*58,44*	**100,74**	*115,85*	**69,36**	*79,76*	**44,02**	*50,62*	**R 11,07**	*R 12,73*

* 132 kV or Transmission connected

Distribution network charges						
Voltage	Network capacity charge [R/kVA/m]		Network demand charge [R/kVA/m]		Urban low voltage subsidy charge[R/kVA/m]	
		VAT incl		VAT incl		VAT incl
< 500V	**R 18,96**	*R 21,80*	**R 35,95**	*R 41,34*	**R 0,00**	*R 0,00*
≥ 500V &< 66kV	**R 17,39**	*R 20,00*	**R 32,98**	*R 37,93*	**R 0,00**	*R 0,00*
≥ 66kV & ≤ 132kV	**R 6,21**	*R 7,14*	**R 11,50**	*R 13,23*	**R 15,32**	*R 17,62*
> 132kV*	**R 0,00**	*R 0,00*	**R 0,00**	*R 0,00*	**R 15,32**	*R 17,62*

* 132 kV or Transmission connected

Voltage	Ancillary service charge [c/kWh]	
		VAT incl
< 500V	**0,44**	*0,51*
≥ 500V &< 66kV	**0,43**	*0,49*
≥ 66kV & ≤ 132kV	**0,41**	*0,47*
> 132kV*	**0,39**	*0,45*

* 132 kV or Transmission connected

Customer categories	Service charge[R/account/day]		Administration charge[R/POD/day]	
		VAT incl		VAT incl
> 1 MVA	**R 217,67**	*R 250,32*	**R 98,10**	*R 112,82*
Key customers	**R 4 265,54**	*R 4 905,37*	**R 136,23**	*R 156,66*

Reactive energy charge [c/kVArh]			
High season		Low season	
	VAT incl		VAT incl
15,34	*17,64*	**0,00**	*0,00*

Electrification and rural network subsidy charge [c/kWh]		Affordability subsidy charge[c/kWh] Only payable by non-local authority tariffs	
	VAT incl		VAT incl
8,48	*9,75*	**3,82**	*4,39*

Homelight – Non local authority rates

Electricity tariff for residential customers based on the size of supply

Homelight 60A	Energy charge [c/kWh]	*VAT incl*
Block 1 [> 0 - 600 kWh]	**126,61**	*145,60*
Block 2 [>600 kWh]	**215,21**	*247,49*

Homelight 20A	Energy charge [c/kWh]	*VAT incl*
Block 1 [> 0 - 350 kWh]	**111,87**	*128,65*
Block 2 [>350 kWh]	**126,76**	*145,77*

Homelight 20A	20A supply size (NMD) typically for low consuming supplies
Homelight 60A	60A prepayment or 80A conventional or smart metered supply size (NMD) typically for medium to high consuming supplies

APPENDIX B: Conference proceedings

[1] O.E.T Bosaletsi and J. Van Coller, "Electricity tariff design for future distribution networks", POWERGEN Africa conference, Johannesburg, South Africa, July 2018.

[2] O.E.T Bosaletsi and J. Van Coller, "What is the appropriate export tariff of locally generated power from distributed energy resources", Proceedings of the 26th Southern Africa Universities Power Engineering Conference (SAUPEC), Johannesburg, South Africa, January 2018.

[3] O.E.T Bosaletsi and J. Van Coller, "Implementing electric vehicle focused tariff structures to support electric vehicle adoption and rooftop solar PV integration", Eskom Power Plant Engineering Institute (EPPEI) student conference, Johannesburg, South Africa, July 2018.

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