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Research paper

Technical and financial analysis of large-scale solar-PV in eThekwini Municipality: Residential, business and bulk customers

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A R T I C L E I N F O

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A B S T R A C T

Regulatory changes, economic challenges, environmental concerns, and changing public perception have contributed to the profound changes observed globally in the electricity industry. Since 2008, South Africa has been experiencing electric power deficits and outages. This has been due in part to generation capacity constraints, belated investment in new electricity infrastructure, deferred maintenance of existing power assets, load growth in areas which were not adequately planned for, high population and economic growth over the last two decades. This has resulted in peak electricity demand outstripping available power generation capacity, leading to electricity shortages and load shedding, which is now impeding economic growth. In South Africa, forced under frequency load shedding, rising electricity tariffs, energy efficiency, declining cost of solar PV systems, the introduction of Carbon taxes, high cost of unserved energy has led consumers to explore embedded generation options to assist with reducing their energy bills, hence investments in solar PV has become an option to municipal customers. The simple payback period of solar PV systems is an important indicator for customers to ascertain whether to invest in these systems or not. Revenue loss remains a significant concern for municipalities who have historically designed single and two-rate bundled tariffs, which rely on municipalities selling electricity to ensure its business's sustainability. Municipalities have now proposed new tariff structures designed to minimize the adverse impact of reducing electricity sales from solar PV by creating net billing tariffs with a built in network access charge component based on the customer's inverter size. Case studies were carried out to better understand the impact on the feasibility of solar PV systems with and without the implementation of these new tariffs and its impact on the customer's payback periods. A calculation of the levelised cost of electricity and customers rate of return for the different customer classes were also calculated to provide a better picture on the financial feasibility of rooftop solar PV. Results obtained from these case studies indicate lucrative payback periods for customers installing solar PV systems with improved revenue recovery for the municipality.

1. Introduction

The features of future energy show a shift towards: the DC power grid, low Carbon future, Carbon-neutrality (with new power generation projects), greenhouse gas (GHG) emissions standards, universal electrification (energy access, affordability), sustainability, advances in cutting edge voltage-source-converter (VSC) high voltage direct current (HVDC) technology and smart infrastructure (Davidson, 2020). These trends, such as decarbonization, decentralization, digitalization, and technology advances, have impacted municipalities and affected traditional utility strategies (Ismael et al., 2019). The revenue model upon which utility business is based is under threat. The 4th industrial revolution (4IR), which is based on the use of cyber–physical systems, underpins the energy transition. The electricity sector in South Africa was historically vertically integrated with Eskom's electricity generation and transmitted by high voltage networks to load centers around the country. However, the introduction of embedded generation (EG), distributed generation (DG), or distributed energy resources (DER) has resulted in a shift in electricity generation from fossil fuels centrally to more decentralized small-scale renewable energy generation at the local load centers, thus making customers become Prosumers (Ismael et al., 2019; Mahmud et al., 2020). This means customers can either import or export electricity at any time. The once simple unidirectional power flow electricity grid now becomes a complex bi-directional power flow power system connected with various variable energy generation sources importing and exporting electricity to and from the grid. The introduction of

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Table 1
Electricity price increase over the past 4 years at eThekwini electricity eThekwini Municipality Electricity Unit (2019).

Electricity price increases (%)				
Tariff-Year	2016/2017	2017/2018	2018/2019	2019/2020
B&G	7.64	1.88	6.84	13.07

these small scale embedded generation (SSEG) projects onto the eThekwini Municipality grid has several technical and financial implications for the Municipality (Mthembu et al., 2018; Gama et al., 2011; anon, 2020).

Municipal customers are constantly seeking ways to reduce their electricity bills whilst the Municipality is constantly trying to adapt their business revenue models to remain sustainable. Historically municipalities created simple bundled residential and business tariffs that allowed them to make profits based on electricity sales: this required cheap electricity meters and simple billing systems. eThekwini Municipality purchases electricity from Eskom on a 275 kV Mega Flex Time of Use (TOU) tariff structure, which is dependent on the day of the week, time of day and season. This tariff was simplified into either a single rate or a two-rate tariff and offered to their residential and Business and General (B&G) customers (eThekwini Municipality Electricity Unit, 2019). The introduction of SSEG (rooftop solar PV) required a review and change to these bundled tariff structures. Table 1 reflects the tariff increase at eThekwini Electricity over the past four years. The increase ranged from 1.88% to 13.07%, with an average of 7.35% over the past four years. The lowest tariff increase was 1.88%, the average tariff increase was 7.35%, and the highest tariff increase was 13.07%. As Municipalities increase and change their electricity tariffs, this then impacts the financial feasibility of the customers solar PV installation.

Studies have shown that solar PV can help South African municipal customers substantially reduce their electricity costs, with systems paying for themselves within 3–12 years of installation, providing free energy for nearly 15 years thereafter. anon (2021) However these payback periods are influenced by numerous technical and commercial factors. Kritzinger (2017) Customers want to understand how installing solar PV systems will assist in reducing their electricity costs and how long will it take for their systems to pay themselves off with the newly proposed municipal net-billing tariffs. Interaction with Municipal customers also reveal that they find it difficult to understand more complex tariff structures such as the two rate tariffs and industrial TOU tariff structures in order to calculate their PV system payback periods. Now with the proposed introduction of the new net billing tariffs, it adds a further dimension and complexity in accurately calculating their PV system payback periods. There has not been any existing work done to date on the financial feasibility of solar PV on the proposed eThekwini Municipality net-billing tariffs. Studies have also shown that Durban has the worst PV production from all the provinces in South Africa. Sewchuran and Davidson (2021) The payback period study outcomes across the different municipal customer classes is critical for municipal customers to make informed decisions on whether to invest in solar PV or not. The results will also help the Municipality to understand the potential uptake figures based on how lucrative the payback periods are, which will ultimately inform the tariff designer on how to plan tariffs going forward to ensure municipal business sustainability.

2. Background

eThekwini Municipality had an increase of 18997 customers in the 2017/2018 (768064) financial year compared to the 2016/2017

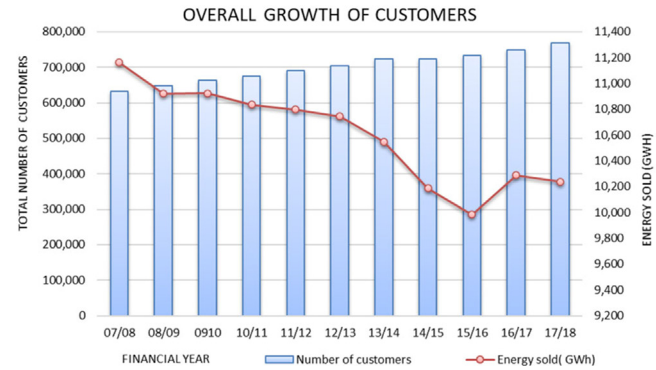


Fig. 1. Growth in customer's vs. energy sold (Mthembu et al., 2018).

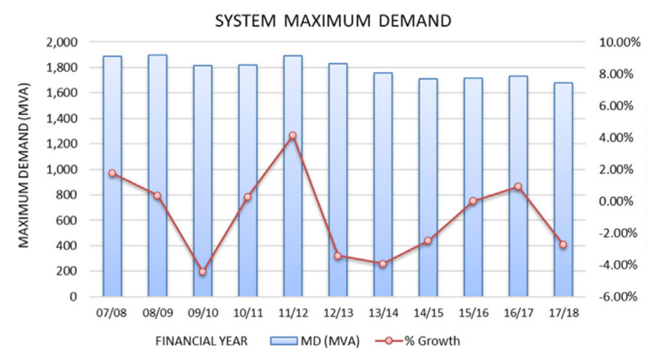


Fig. 2. System maximum demand at eThekwini Electricity (Mthembu et al., 2018).

(749067) financial year as illustrated by Fig. 1. However, there was a decrease of 0.5% in energy sales at eThekwini Municipality in the 2017/2018 (10239 GWh) financial year compared to the 2016/2017 (10290 GWh) financial year as seen in Fig. 1. In the 2003/2004 financial year, with a customer base of 564 527, eThekwini Electricity sold 10 291 GWh of electricity compared to 768064 customers in 2017/2018. The 2017/2018 maximum demand declined by 2.73% from 1729 MVA in the 2016/2017 financial year to 1682 in the 2017/2018 financial year, a decline of 47 MVA (see Fig. 2). In the 2008/2009 financial year, the eThekwini Electricity maximum demand was 1897 MVA whilst in the 2017/2018 financial year, it was 1729 MVA. There is clearly a decline in electricity sales. These may be attributed to weak economic growth, energy efficiency, and customer embedded generation. The municipality can only control and regulate the customer embedded generation connections since it is currently cheaper to use the grid to store excess generation as opposed to expensive battery storage systems. The municipality proposes to offer customers a tariff that will allow them to import energy when they require and pay them for excess energy that is exported to the grid on a feed in tariff (FIT) with a network access charge (NAC) based on the customers inverter size called a net billing tariff (NBT). Revenue loss remains a significant concern to the Municipality.

2.1. Residential customers

Revenue from electricity sales from the residential sector at eThekwini Municipality is 26% (Fig. 3), whilst it accounts for 24% of energy sales (Fig. 4). There is a need to investigate the potential for revenue loss and the impact of the newly proposed NBT on both the municipality and customer. There are 325 817 credit customers, which accounts for 42.42% of the total eThekwini

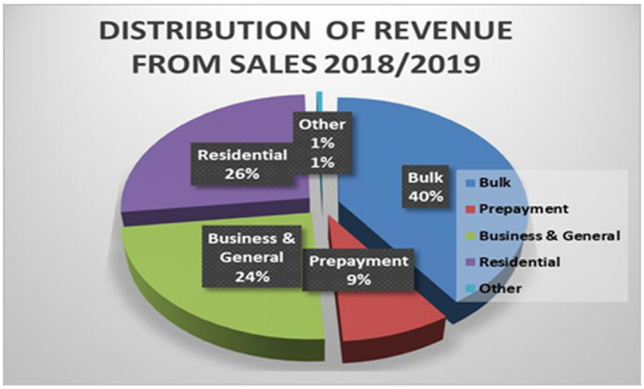


Fig. 3. Distribution of Revenue from sales at eThekwini Municipality (Mthembu et al., 2018).

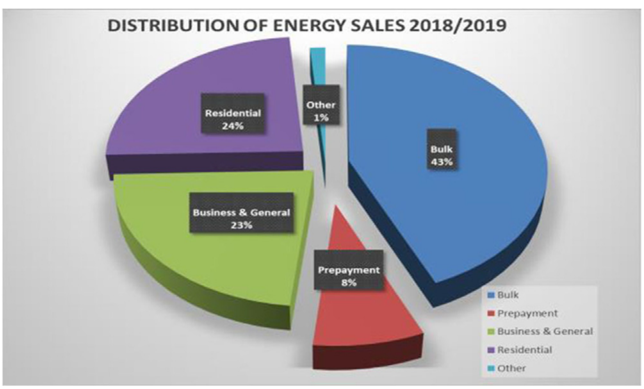


Fig. 4. Distribution of Energy Sales at eThekwini Municipality (Mthembu et al., 2018).

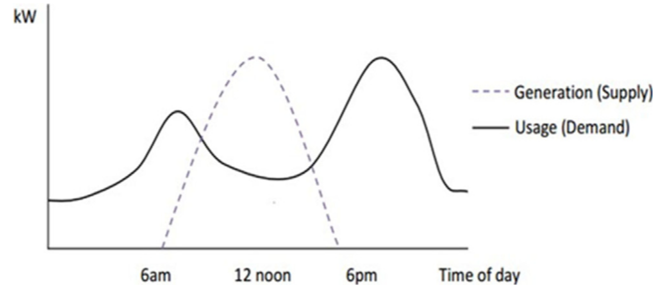


Fig. 5. Typical residential load profile vs PV generation profile (Sewchurran, 2016).

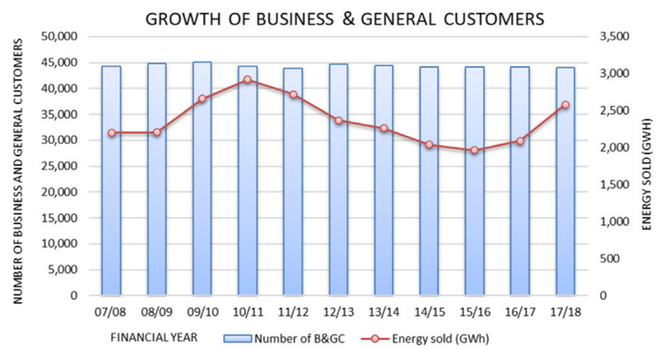


Fig. 6. Growth in Business and Generation Customers (Mthembu et al., 2018).

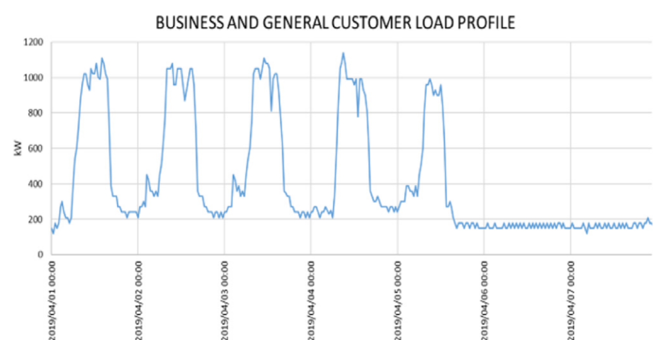


Fig. 7. Typical Business and General Customer load profile.

Electricity customer base. These customers use an average of 632 kWh electricity whilst there are 397 817 prepaid customers at eThekwini Electricity, who use an average of 177 kWh a month. Although the prepaid customer base is 51.71% of the total customer base at eThekwini Electricity, they only consume 8% of the total energy sold and are responsible for 9% of the electricity revenue. 44.47% of the prepaid customer base uses, on average < 150 kWh a month. They are considered indigenous customers and receive a free basic electricity token of 65 kWh per month. There is, however, a mismatch between the PV generation peak at midday, and the residential peak demand, which is at ∼7 am and ∼8 pm, as shown in Fig. 5, due to the mismatch in the customer demand and solar PV generation which results in excess energy being exported to the municipal grid. Thus, the customer uses the municipal grid as an energy storage facility and uses electricity from the grid when their load demand exceeds their solar PV generation output. With the residential sector accounting for 94.13% of the customer base at the eThekwini Municipality, the newly proposed NBT impact needs to be evaluated; the customer's payback period for rooftop PV systems and revenue loss potential to eThekwini Municipality (Mthembu et al., 2018).

2.2. Business customers

Fig. 6 shows there are 44 027 B&G customers at eThekwini Electricity that use 2585 GWh a year. Each customer uses an average of 4425 kWh a month or 53100 kWh a year. The B&G customer base is made up of several tariff structures which includes a single-rate and a two rate bundled tariff structure. The B&G tariffs apply to electricity supplied to business premises including shops, factories, hostels, boarding houses, restaurants, office buildings, religious buildings, and general supplies. Figs. 3 and 4 indicate that the B&G sector accounts for 23% of electricity sales while it accounts for 24% of the revenue brought into the Municipality. Therefore, there is a need to investigate the payback period of B&G rooftop PV customer installations with and without the newly proposed NBT. This will help ascertain B&G customers' financial feasibility of installing rooftop PV and estimate the potential uptake going forward. Fig. 7 is a typical commercial/business load profile, which reflects that the load demand begins to rise from ∼7 am to ∼4:30 pm. This coincides with the sunlight hours and the generation profile of solar PV. Thus, unlike with the residential load profile, the generated electricity from the solar panels can be utilized by the consumer, with the potential to export generated electricity to the grid on weekends, when the business is closed (Mthembu et al., 2018).

There are currently 1062 bulk customers at the eThekwini Municipality who uses 4448 GWh of electricity combined annually, as reflected in Fig. 8. It can further be seen that there has been an increase in the number of bulk customers over the year but a decline in the total GWh energy sold. There is a need to

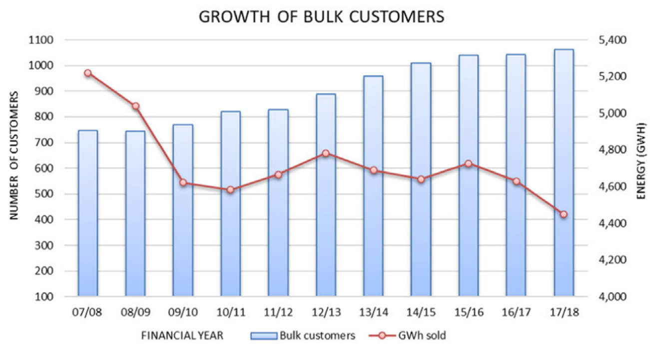


Fig. 8. Growth in Bulk Customers (Mthembu et al., 2018).

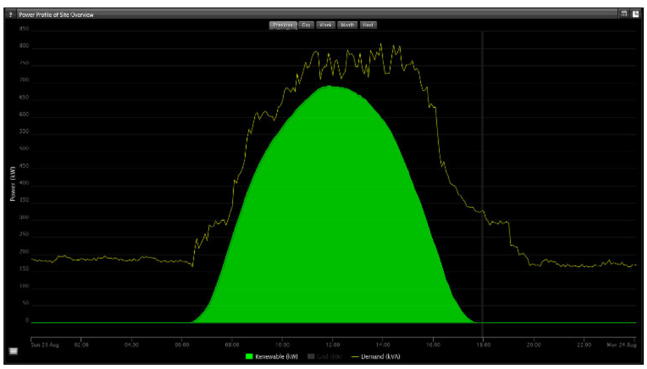
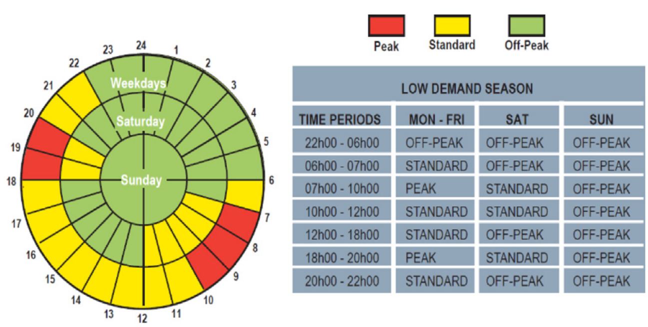


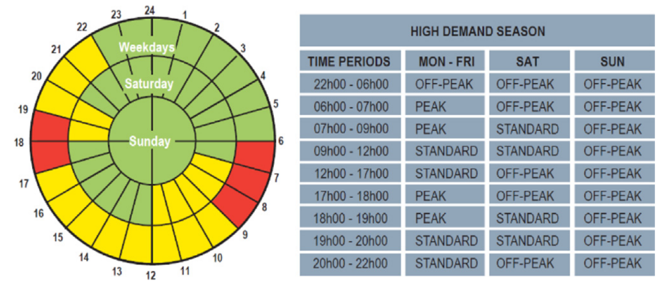
Fig. 9. Bulk customer load profile vs solar PV generation profile.



LOW DEMAND SEASON			
TIME PERIODS	MON - FRI	SAT	SUN
22h00 - 06h00	OFF-PEAK	OFF-PEAK	OFF-PEAK
06h00 - 07h00	STANDARD	OFF-PEAK	OFF-PEAK
07h00 - 10h00	PEAK	STANDARD	OFF-PEAK
10h00 - 12h00	STANDARD	STANDARD	OFF-PEAK
12h00 - 18h00	STANDARD	OFF-PEAK	OFF-PEAK
18h00 - 20h00	PEAK	STANDARD	OFF-PEAK
20h00 - 22h00	STANDARD	OFF-PEAK	OFF-PEAK

Fig. 10. Breakdown of TOU tariff structure for low demand season (eThekwini Municipality Electricity Unit, 2019).

investigate the potential for further revenue loss from eThekwini Municipalities bulk customer rooftop solar PV installations. This will be achieved by calculating the customer's rooftop solar PV's payback period to ascertain the potential for massive uptake amongst the bulk customers going forward. Fig. 9 reflects a typical bulk customers (shopping mall) load profile, which illustrates that the load demand is a near perfect match to that of the solar PV generation profile. Thus all the generated electricity from the solar panels can be utilized by the consumer. Fig. 10 reflects the breakdown of the Industrial Time of Use tariff structure billing period breakdown for peak, standard and off-peak periods for the low demand season (August–May), while Fig. 11 reflects the high demand season (June–August). An investigation will be carried out to investigate the ITOU tariff structure and the newly proposed Industrial Net Billing Tariff (INBT) and look at the impacts on the payback period of the customers solar PV with and without the INBT (eThekwini Municipality Electricity Unit, 2019).



HIGH DEMAND SEASON			
TIME PERIODS	MON - FRI	SAT	SUN
22h00 - 06h00	OFF-PEAK	OFF-PEAK	OFF-PEAK
06h00 - 07h00	PEAK	OFF-PEAK	OFF-PEAK
07h00 - 09h00	PEAK	STANDARD	OFF-PEAK
09h00 - 12h00	STANDARD	STANDARD	OFF-PEAK
12h00 - 17h00	STANDARD	OFF-PEAK	OFF-PEAK
17h00 - 18h00	PEAK	OFF-PEAK	OFF-PEAK
18h00 - 19h00	PEAK	STANDARD	OFF-PEAK
19h00 - 20h00	STANDARD	STANDARD	OFF-PEAK
20h00 - 22h00	STANDARD	OFF-PEAK	OFF-PEAK

Fig. 11. Breakdown of TOU tariff structure for high demand season (eThekwini Municipality Electricity Unit, 2019).

Table 2
Rooftop solar PV monthly generation Sewchurran (2016).

Month	3 kW PV system (kWh)	4.6 kW PV system (kWh)
January	482	672
February	453	632
March	508	707
April	458	638
May	445	619
June	429	598
July	453	631
August	468	652
September	434	604
October	448	624
November	434	604
December	475	662
Total	5487	7645

3. Residential customer solar PV case study

For this case study, a study of a customer's financial feasibility installing a 3 kWp rooftop PV system with and without the proposed eThekwini Electricity NBT is evaluated. This study excludes the prepaid residential tariff customers since their electricity usage is too low to justify rooftop solar PV installation. There is a mismatch between the PV generation peak at midday, and the residential peak demand, which is at ∼7 am and ∼8 pm, as illustrated in Fig. 5. Due to the mismatch in the customer demand and solar PV generation, this result in excess energy being exported to the municipal grid. Thus, the customer uses the municipal grid as an energy storage facility and uses electricity from the grid when load demand exceeds solar PV generation. The case study is carried out for 50%, 75%, and 100% generated electricity usage. Durban climate is humid subtropical, with hot summers and mild winters. There is an average of 2343 h of sunlight a year, with an average of 6.4 h of sunlight a day. The average value of Durban's global radiation is 4.45kWh/m^2/day, which equates to an annual average of 1625 kWh/m^2/year (Zawilska and Brooks, 2011). Table 2 shows the kWhs of electricity generated from a 3 kWp and 4.6 kWp rooftop PV system. A 3 kWp rooftop solar PV system is used in this study at a cost of R15/Wp installed capacity. The assumptions made in this study is that the system is paid for in cash by the customer, cleaning and maintenance of the system will carried out by the customer and the equipment used have a minimum warranty of 10 years. The results in Table 4 were obtained using the PVsyst software simulation package. A typical 3 kWp rooftop solar PV system will produce 5487 kWh annually, while a 4.6 kW rooftop solar PV system will produce 7645 kWh annually.

eThekwini Municipality purchases Eskom's electricity on a 275 kV Mega Flex Time of Use tariff structure and created residential electricity tariffs with single-rate tariffs with no fixed charge. This required simple and cheap electricity rotating disk meters, which

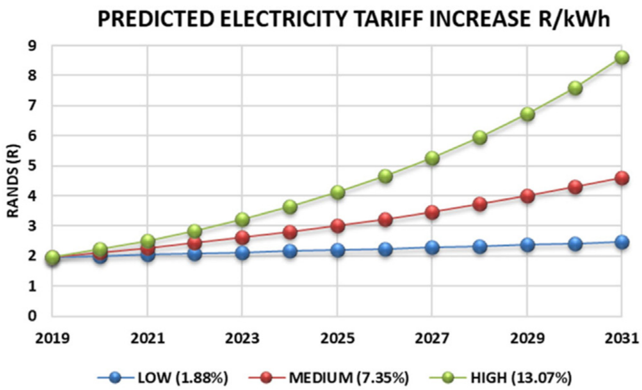


Fig. 12. Predicted future Import electricity tariff increases.

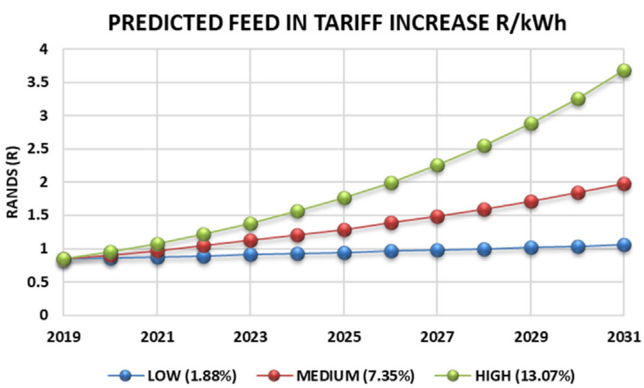


Fig. 13. Predicted future electricity feed-in tariff increases.

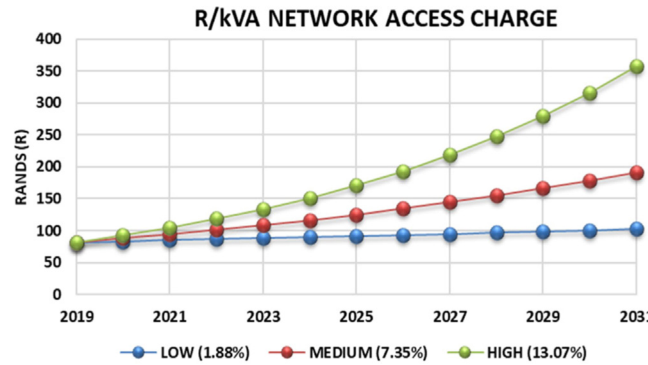


Fig. 14. Predicted NAC increase.

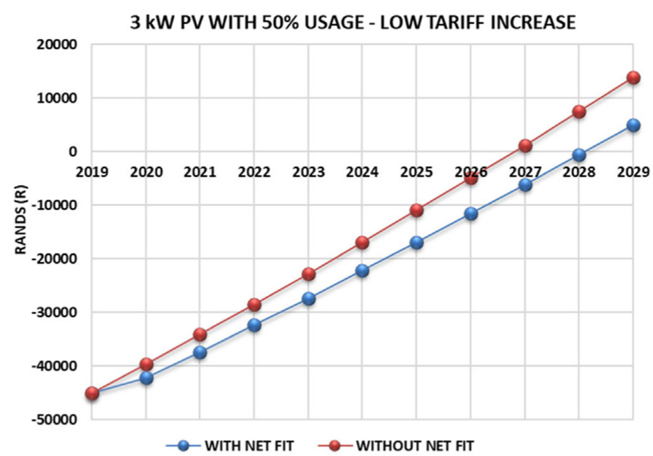


Fig. 15. Low increase scenario with 50% usage.

were read once every three months. Bills were based on average consumption until the meter was read. The single-rate cost of electricity to the residential customer is currently R1.97 kWh in the 2018/2019 financial year. This cost/kWh charge includes the cost of energy that the municipality purchases from Eskom and network-related charges, including administration costs, interests paid on loans, employee costs, repairs, and maintenance. With a reduction in the sale of electricity in the residential sector, the municipality still incurs all costs except for the Eskom energy purchases to make the customers supply available. With increasing embedded generation installations in the city, there has been increasing pressure to implement a more cost-reflective tariff to the Prosumers. The proposed introduction of a NBT by the eThekwini Municipality is made up of three parts:

(a.) A Network Access Charge component
(b.) An electricity Import Tariff component
(c.) An electricity Export Tariff component

The customer's monthly bill is, therefore:

$$\begin{aligned} \text{Monthly bill} &= \text{Network Access Charge} \\ &+ \text{Total import energy charges} \\ &- \text{Total export energy charges} \end{aligned} \quad (1)$$

To evaluate the financial feasibility, a projection has to be made for future increase in the municipal tariff, the NBT, and the NAC. Table 1 reflects the tariff increase over the past 4 years at the eThekwini Municipality. For the study, the future NBT is estimated to increase in three scenarios; low (1.88%), medium (7.35%), and high (13.07%). The low scenario increase was selected using the lowest tariff increase over the past 4 years, the medium scenario was selected using the average tariff over the past 4 years, and the high scenario was selected using the highest tariff increase over the past 4 years, where the current import electricity tariff for the 2019 financial year is R1.97/kWh.

Fig. 12 projects the tariff increase for the three different tariff increase scenarios; low, medium, and high till 2031. Fig. 13 reflects the NBT, which is R0.84/kWh increase until 2031. Fig. 14 shows the NAC increase until 2031. The current NAC is R81.75/kVA installed capacity.

3.1. Case study 1: 3 kWp PV system with 50% electricity generation usage

With the customer using 50% of the generated electricity from the PV system, Fig. 15 reflects the results for the payback period for the low increase scenario. Fig. 16 is for the medium usage scenario, while Fig. 17 is for the high increase scenario. The results reflect an increase in the payback period with the NBT.

3.2. Case study 2: 3 kWp PV system with 75% electricity generation usage

With the customer using 75% of the generated electricity from the PV system, Fig. 18 reflects the results for the payback period for the low increase scenario. Fig. 19 shows the medium usage scenario, while Fig. 20 shows the high increase scenario. The results reflect an increase in the payback period with the NBT.

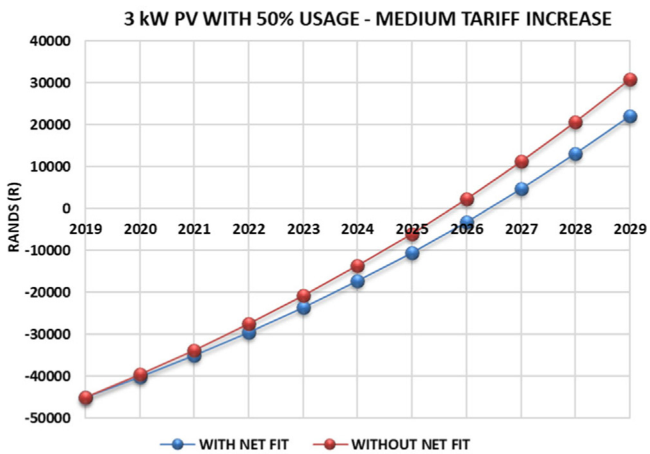


Fig. 16. Medium increase scenario with 50% usage.

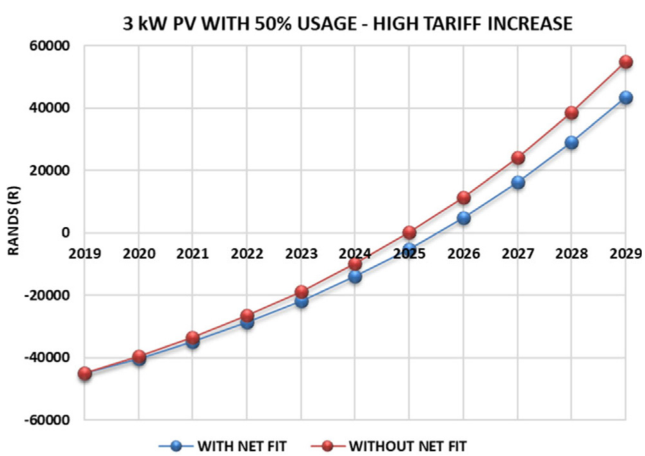


Fig. 17. High increase scenario with 50% usage.

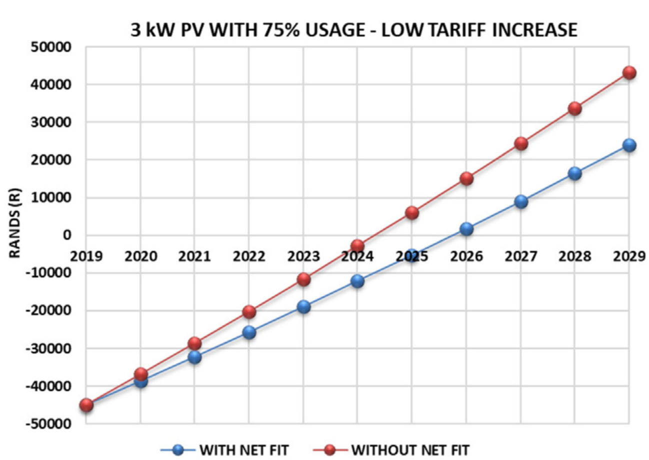


Fig. 18. Low increase scenario with 75% usage.

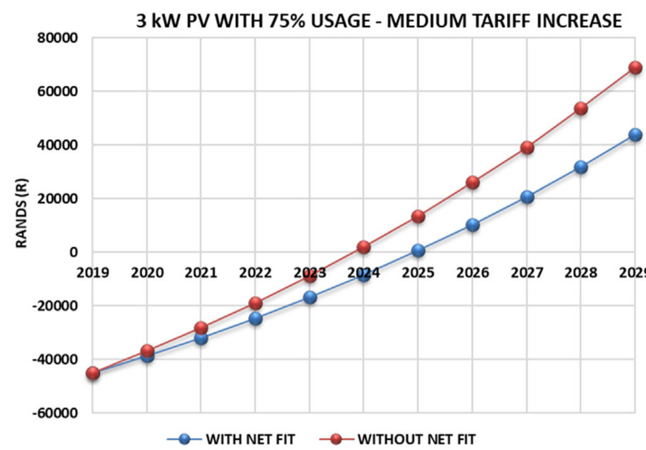


Fig. 19. Medium increase scenario with 75% usage.

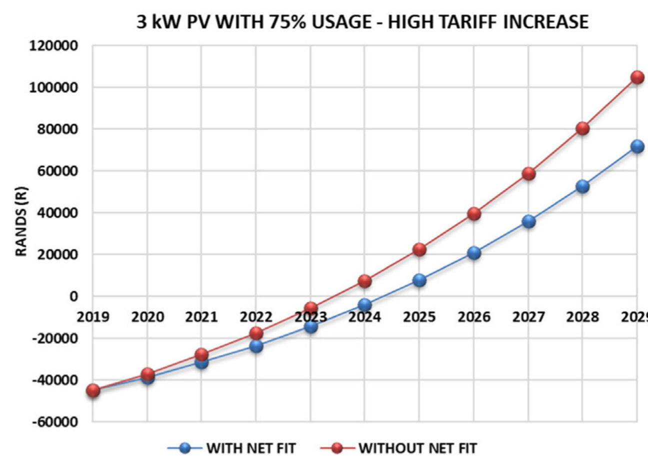


Fig. 20. High increase scenario with 75% usage.

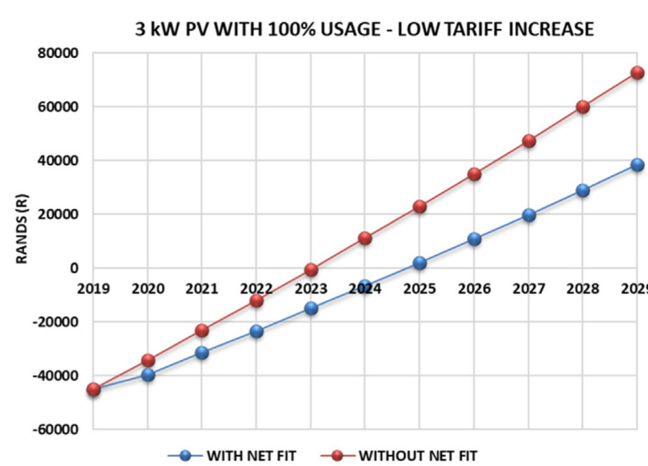


Fig. 21. Low increase scenario with 100% usage.

3.3. Case study 3: 3 kWp PV system with 100% electricity generation usage

With the customer using 100% of the generated electricity from the PV system, Fig. 21 reflects the results for the payback period for the low increase scenario. Fig. 22 reflects the medium usage scenario, while Fig. 23 reflects the high increase scenario. The results reflect an increase in the payback period with the NBT.

3.4. Summary of results for a 3 kW residential solar PV system

In the case study for customer with rooftop solar PV, which was carried out for 3 scenarios (50%, 75%, 100% generated electricity used by the customer) and three tariff increase scenarios (low 1.88%, medium 7.35%, high 13.07), Table 3 gives a summary of the results. The cost of maintenance was not considered in the

Table 3
Rooftop solar PV monthly generation.

Tariff increase scenario	Usage	50%	75%	100%
	Feed in tariff	Payback period	Payback period	Payback period
Low 1.88%	With FIT	10	7	6
	Without FIT	8	6	5
Medium 7.35%	With FIT	8	6	5
	Without FIT	7	5	4
High 13.07%	With FIT	7	6	5
	Without FIT	6	5	4

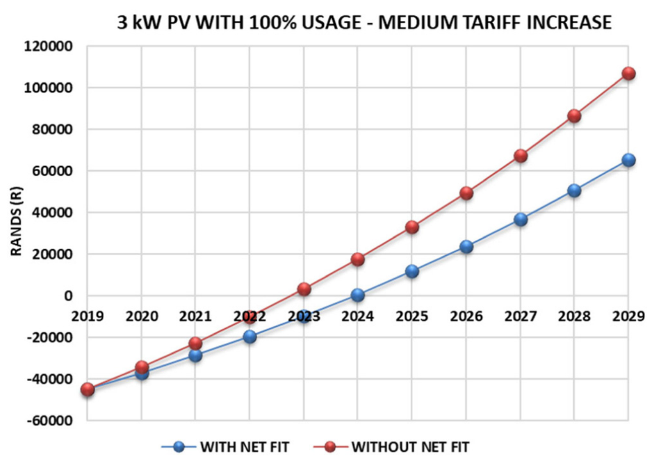


Fig. 22. Medium increase scenario with 100% usage.

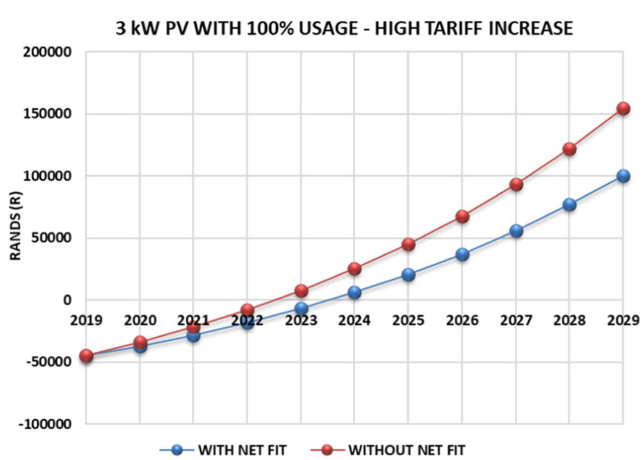


Fig. 23. High increase scenario with 100% usage.

case studies. All case studies indicate an increase in the payback period with the proposed NBT due to the introduction of the NAC. In the low increase scenario, the payback period is increased by 2 additional years with 50% electricity usage, while for all other scenarios and tariff increases, there is an additional year increase to the payback period.

4. Case study of business and general net billing tariff

A study was conducted to determine the payback period with and without the proposed new B&G NBT. This requires predicting the tariff increase for a low, medium, and high scenario. The low increase scenario is 1.88%, a medium increase scenario is 7.35%, and a high increase scenario is 13.07%. The first B&G tariff to be considered is the Scale 2 Tariff. Scale 2 B&G tariff is made up of

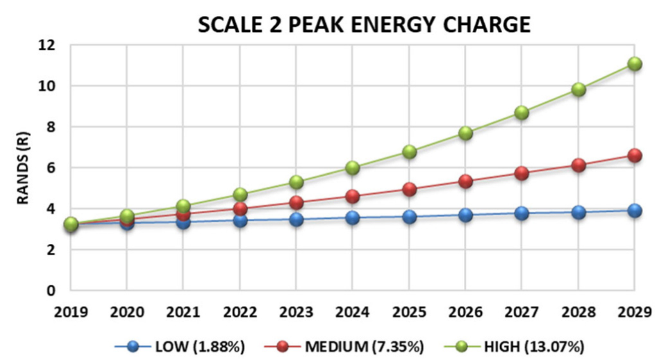


Fig. 24. B&G Scale 2 Peak Energy Charge.

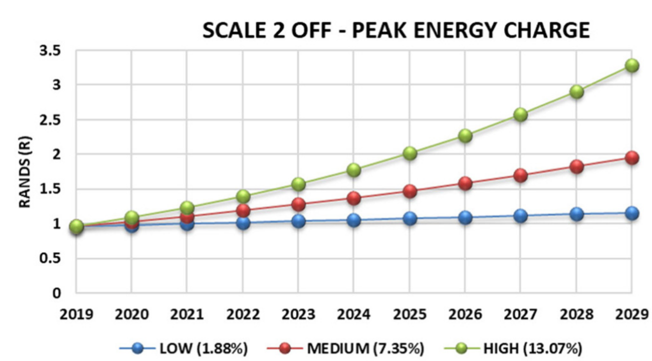


Fig. 25. B&G Scale 2 Off-Peak Energy Charge.

3 parts: a peak energy rate, an off-peak energy rate, and a fixed service charge, as reflected in Table 4.

This is followed by estimating the tariff increase over the next ten years for a low, medium, and high increase scenario. The results of the peak energy rate increase are seen in Fig. 24. The off-peak energy rate results are shown in Fig. 25, and the Service Charge increase in Fig. 26 for the low, medium, and high tariff increase scenario. Scale 1 B&G tariff is seen in Table 5. This estimates the tariff increase over the next 10 years for a low, medium, and high increase scenario. The Scale 1 tariff structure is unlike the Scale 2 tariff structure in that it does not have a peak and off-peak energy rate. However, it is a single rate tariff. Figs. 27 and 28 illustrate the Scale 1 B&G tariff increase, and the Service Charge increase over the next ten years. The new B&G NBT was derived from the Scale 1 tariff and uses the same customer import energy charge and Service Charge rates but includes a customer export energy charge and NAC, as seen in Table 8, Figs. 29 and 30.

The rationale for the proposed B&G NBT is that there are costs associated with making an electricity supply available. The costs involved in making the electricity supply available to the customer can be divided into two main categories, namely; bulk

Table 4
The tariff structure for scale 2 B&G tariff eThekwini Municipality Electricity Unit (2019).

Scale 2 tariff	Amount
Peak rate (07h00–20h00 weekdays)	R3.215151/kWh
Off-peak rate (20h00–07h00 weekdays and all day weekends)	R0.96278/kWh
Service charge	R301.0815

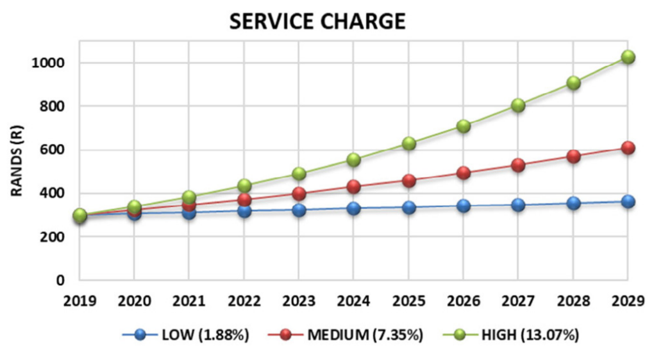


Fig. 26. B&G Scale 2 Off-Peak Energy Charge.

Table 5
Business and general net billing tariff eThekwini Municipality Electricity Unit (2019).

Scale 1 B&G tariff	Amount
Energy rate/kWh	R2.2261
Service charge	R291.29

Table 6
Business and general net billing tariff eThekwini Municipality Electricity Unit (2019).

Business and general net billing tariff	Amount
Import energy rate/kWh	R2.2261
Service charge	R291.29
Export energy rate	R0.6291
Network access charge rate	R81.075

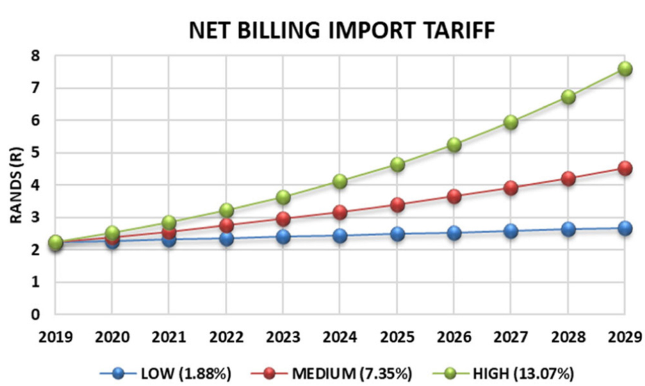


Fig. 27. B&G Net Billing Import Tariff.

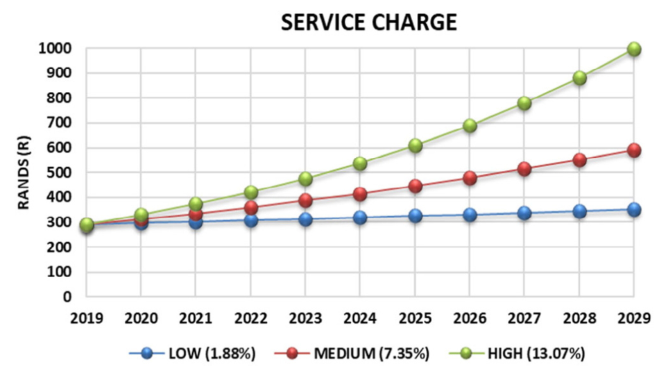


Fig. 28. B&G Scale 1 Service Charge.

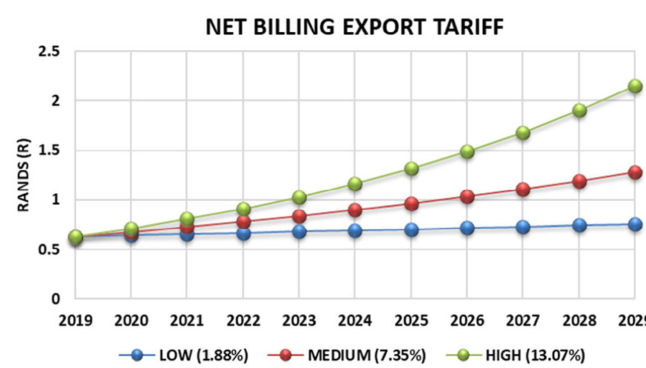


Fig. 29. Net Billing Export Tariff.

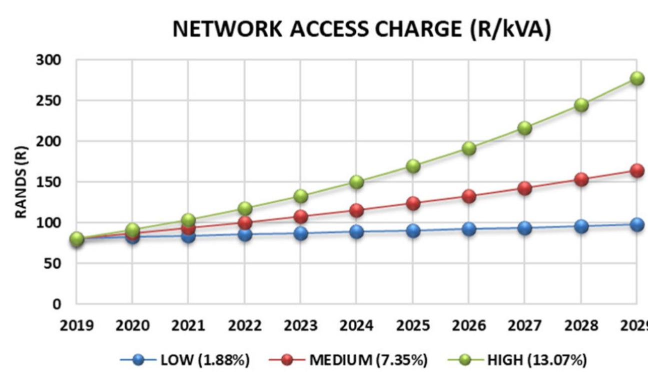


Fig. 30. B&G Net Billing Excess Charge.

energy charges and network charges. The bulk energy charge is a direct pass-through cost to Eskom. In contrast, the network charges can be divided into several costs incurred to make the supply available, namely: repairs and maintenance, depreciation of assets, interest paid on loans, employee-related costs, administration, and general costs.

When the customer installs a rooftop solar PV system, the Municipality now sells less energy, and it becomes challenging to recoup the network charges from energy sales only. The Municipality is therefore required to implement a NAC. The NAC is based on the size of the customer's inverter. This discriminates between a customer with a small PV installation and a customer with a large installation. Furthermore, the Municipality has implemented a NBT to remunerate the customer for any excess energy exported to the grid.

4.1. Case study 1: 55.2 kWp AC

A 55.2 kWp rooftop PV system was installed at a hotel in Durban. Fig. 31 and Table 7 reflect a summary of the system installed. This case study examines the payback period for the PV

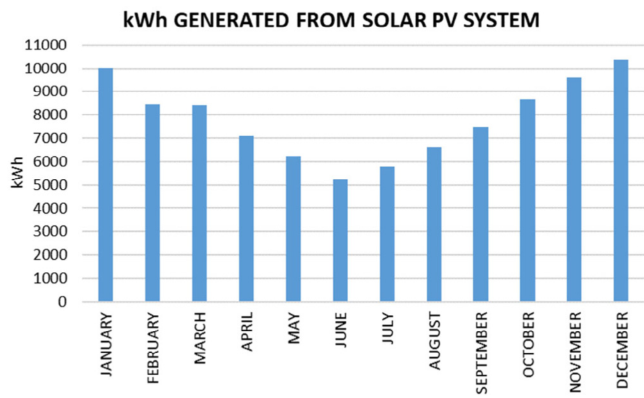


Fig. 31. Generation profile from a 55.2 kWp rooftop solar PV system.

Table 7
55.2 kWp rooftop solar PV system data.

55.2 kWp rooftop solar PV system data	
System size (kWp AC)	55.2
Total generation (kWh)	93922
DC/AC ratio	1.25
Customers tariff	Scale 1
Cost of installation (R)	662400

Table 8
55.2 kWp rooftop solar PV payback period.

Case Study 1: 55.2 kWp rooftop solar PV		
Scenario 1	100% Energy usage	
Tariff increase	Payback period without FIT	Payback period with FIT
Low	4	5
Medium	3	4
High	3	4

system with and without the eThekwini Electricity NBT for two customer usage scenarios. The accelerated depreciated benefit (ADB) from the South African Revenue Services, finance costings, maintenance and operation costs were not considered in this case study as this will vary from customer to customer. The assumed warranty period of the equipment used is minimum 10 years.

4.1.1. 100% energy usage scenario

In this scenario, the customers use all of the generated electricity. It is assumed that the system was sized such that the customer utilized all of the generation production and estimated the payback period for three tariffs (low, medium, and high) increase scenarios with and without eThekwini Electricity NBT. Fig. 32 and Table 8 reflect the payback period for 100% generated electricity usage by the customer with and without the NBT. It is observed that the payback period increased by an additional year with the application of the NBT in the three tariff increase scenarios. This is due to the additional monthly costs added by the NAC component.

4.1.2. 71.5% energy usage scenario

In scenario 2, the customer uses the weekday (71.5%) energy production. In this scenario, the customer utilizes the weekday energy production only. Assuming that of the weekend production is exported to the eThekwini Municipality grid. The payback period under the three tariff increase scenarios with and without the B&G NBT is calculated. The accelerated depreciation benefit (ADB) from the South African Revenue Services, finance costings, maintenance and operation costs were not considered in this case

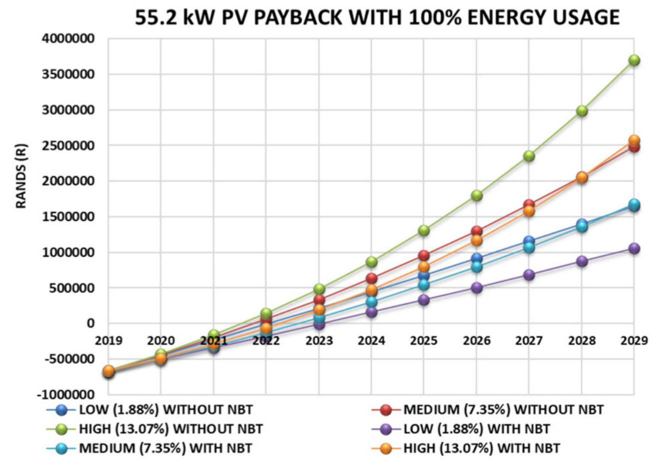


Fig. 32. 55.2 kWp Rooftop Solar PV Payback period with and without the NBT for 100% energy usage.

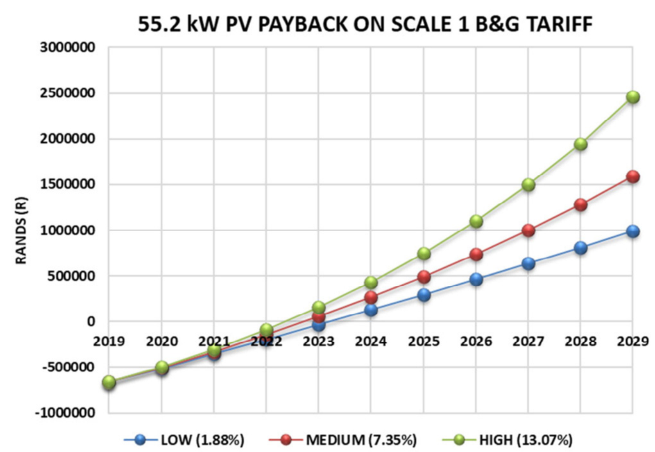


Fig. 33. 55.2 kWp rooftop Solar PV Payback period without FIT for 71.5% energy usage.

study as this will vary from customer to customer. The assumed warranty period of the equipment used is minimum 10 years.

Table 9, Figs. 33 and 34 illustrate the payback period for 71.5% of the customer's generated electricity usage while the balance is exported to the grid with and without the B&G NBT. The results show that the payback period is increased by an additional year in the three tariff increase scenario's. This can be attributed to the additional NAC charge that the customer is now liable to pay. A portion of the NAC is off set from the electricity exported to the grid but it does not cover the full cost of the NAC.

4.2. Case study 2: 250 kWp PV system

This study involves the installation of a 250 kWp solar PV system at a business park. Since the business park consumes more energy than the PV system generates, the business park exports no electricity to the grid. This customer is on Scale 2 B&G tariff. The data in Table 10 was used to calculate the system's payback period on the current Scale 2 B&G tariff. It was then compared to the payback period if eThekwini Municipality had to move the customer onto the new B&G NBT. The ADB from the South African Revenue Services, finance costings, maintenance and operation costs were not considered in this case study as this will vary from customer to customer. The assumed warranty period for the equipment used is minimum 10 years.

Table 9
55.2 kWp rooftop solar PV payback period.

Case study 1: 55.2 kWp rooftop solar PV		
Scenario 2	Week day energy usage-No FIT	
Tariff increase	Payback period without FIT	Payback period with a FIT
Low	5	6
Medium	4	5
High	4	5

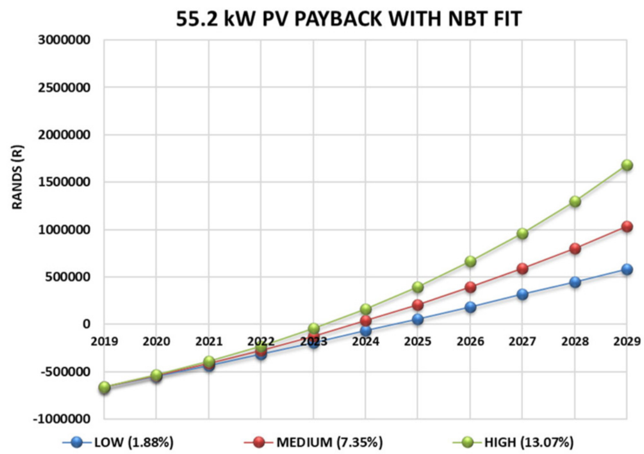


Fig. 34. Rooftop Solar PV Payback period with FIT for 71.5% energy usage and 28.5% export.

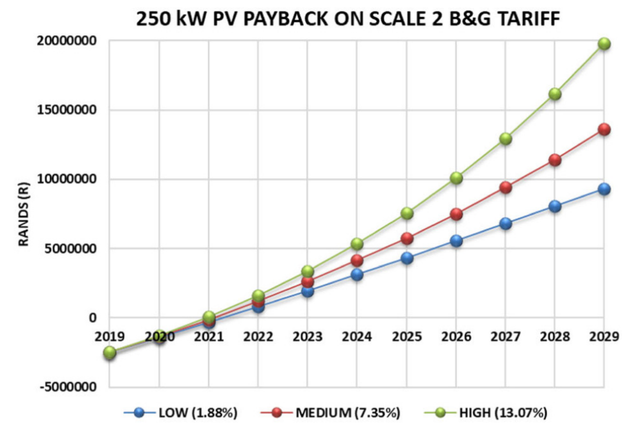


Fig. 35. The rooftop PV Payback period on Scale 2 B&G Tariff.

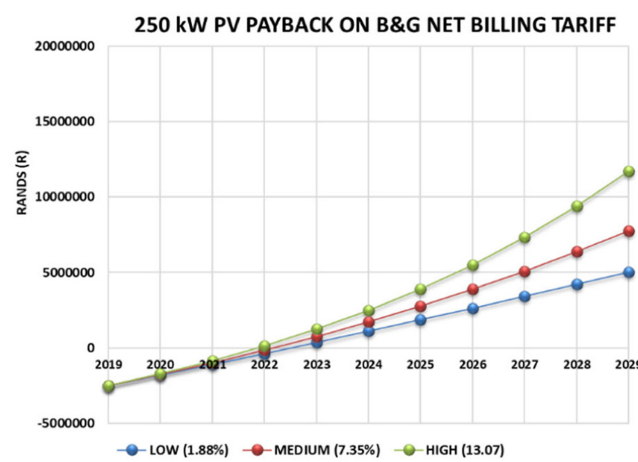


Fig. 36. The rooftop PV Payback period on the B&G Net Billing Tariff.

Table 10
250 kWp rooftop solar PV system data.

250 kWp rooftop solar PV system data	
System size (kWp AC)	250
Total generation (kWh)	414526
Peak generation (kWh)	291 889
Off peak generation (kWh)	122889
DC/AC ratio	1.3
Customers tariff	Scale 2
Cost of installation (R)	2500000

Table 11
250 kWp rooftop solar PV payback period.

Case study 1: 250 kWp rooftop solar PV		
Scenario 1	100% Energy usage	
Tariff increase	Payback period without FIT	Payback period with FIT
Low	3	4
Medium	3	4
High	2	3

Figs. 35 and 36, and Table 11 reflect the payback period for 100% generated electricity usage by the customer with and without the B&G NBT. Results show that the payback period increases by an additional year in the three tariff increase scenarios with the NBT. This increase may be attributed to the NAC component that has been added to the customer's bill.

5. Case study of a bulk customer

For this case study, the financial viability is evaluated for a bulk customer on the eThekwini Electricity industrial time of use (ITOU) tariff structure installing a 1 MW rooftop solar PV system with and without the proposed eThekwini Electricity INBT. Historically municipalities created industrial bulk electricity tariffs, which were unbundled to be cost-reflective of the actual costs incurred to supply electricity to the customers, unlike residential and small business and general tariff structures (Tuson, 2014). These customers were provided with expensive smart meters, which allowed for accurate monthly billing of this complex tariff structure.

5.1. eThekwini electricity industrial net billing tariff

The proposed INBT is a mechanism to remunerate bulk customers who generate and export energy onto the municipal grid. The remuneration is passed on as a credit transaction onto the customer's account. The rate of remuneration per kWh is as per the ITOU tariff rates. The ITOU tariff structure is an unbundled tariff; however, it does include voltage varying fixed grid/reticulation costs dependent on energy usage. A reduction in energy usage creates an undue shortfall in grid contribution. An Ancillary Network Access Charge (ANAC) becomes payable based on the inverter size and voltage level of operation to counteract

Table 12
eThekwini electricity industrial TOU tariff eThekwini Municipality Electricity Unit (2019).

Industrial time of use (ITOU) For customers with a notificed maximum demand greater than 100 kVA	HIGH DEMAND SEASON JUNE–AUGUST		
	Import/Export energy rates (c/kWh) (Excl VAT)		
	PEAK	STANDARD	OFF-PEAK
	323.88	104.38	60.76
	LOW DEMAND SEASON SEPTEMBER–MAY		
	111.67	79.67	53.81
Network demand charge (R/kVA)	Ancillary network access charge	Voltage	Percentage voltage surcharge
96.65	–	275 kV	0
Network access charge (R/kVA)	2.42 3.22	132 kV 33 kV	2.25 3
31.75	11.22	11 kV	10.5
Service charge (R)	12.43	6.6 kV	12.75
4500	24.13	400 V	22.5

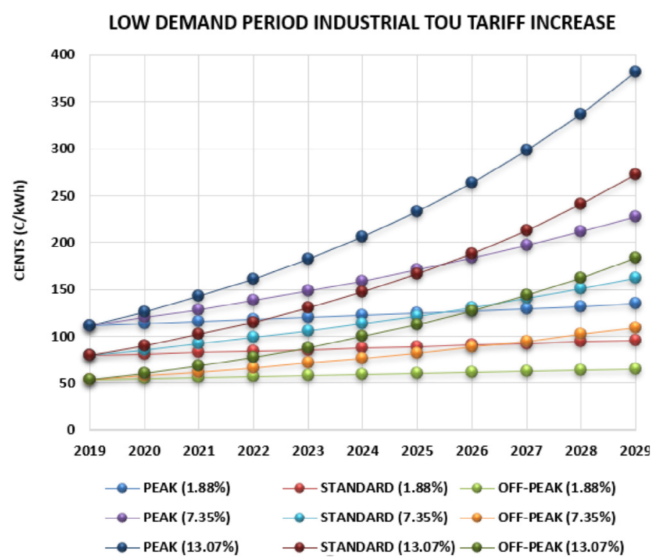


Fig. 37. Projected low demand period INBT increases.

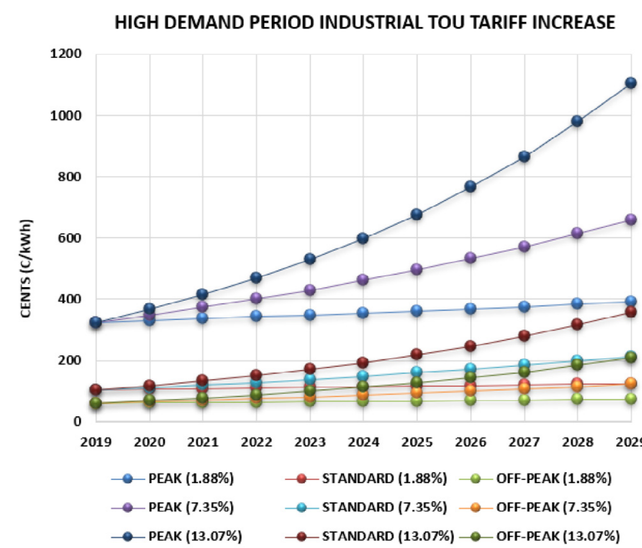


Fig. 38. Projected high demand period INBT increases.

this. Table 12 shows a breakdown of the eThekwini ITOU tariff structure and the new INBT. A key difference between the existing ITOU tariff structure and the INBT structure is the ANAC, the export tariff rates equal to import tariff rates.

In order to determine its financial viability, an estimate of the increase in municipal tariffs and the NAC must be carried out for the future. The existing ITOU customers' Network Demand charge, NAC, Percentage Voltage Surcharge, and Service Charge do not change with solar PV installation and hence not affect the payback period of the solar PV. To determine the tariff increase going forward, the estimated increase is calculated for three scenarios: a low (1.88%), medium (7.35%), and high (13.07%) increase scenario. Figs. 37 and 38 illustrate the estimated INBT peak, standard, and off-peak rates for the low demand and high demand period for a low, medium, and high increase scenario.

Fig. 39 reflects the calculated ANAC increase for the low, medium, and high increase scenarios over the next ten years. These calculated values will be utilized to calculate the payback periods for the 1 MW rooftop solar PV system installed by a bulk customer.

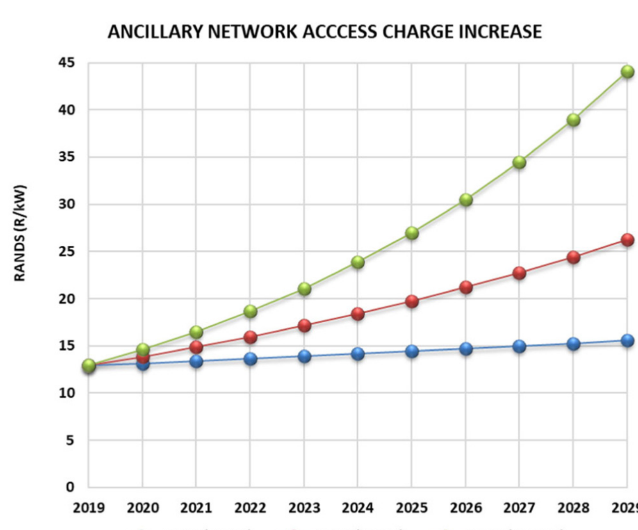


Fig. 39. Projected Ancillary Network Access Charge increase.

Table 13
1 MW rooftop solar PV installation data.

System size	1 MWp
Inverter make	Sungrow SG 80KTL-MSungrow SG 60KTL-M
Inverter size	80 kW and 60 KW
Number of inverters	11 x 80 kW and 2 x 60 kW
AC rating	1000 kW
Panel make	Canadian solar CS6U
Panel rating	330 Wp
Number of panels	3980
DC rating	1313.5 W
DC:AC ratio	1.31:1
Cost of system	R9000000

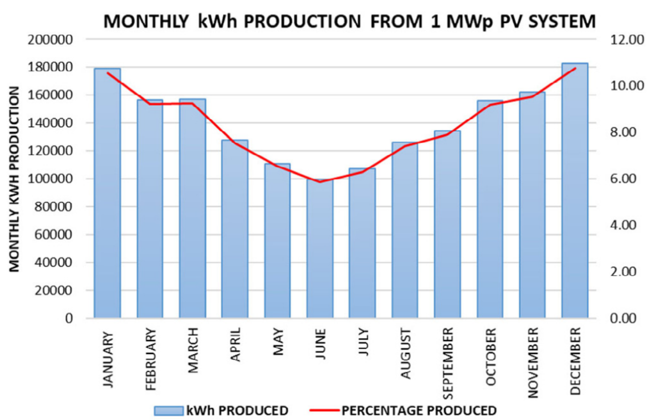


Fig. 40. Monthly energy production breakdown from a 1 MW PV system.

5.2. Energy production simulations from a 1 MWp rooftop PV system in Durban

Fig. 40 reflects the monthly solar PV generation for the solar PV system as reflected in Table 13 using the PVsyst simulation software package. Unlike residential customers, where there is a mismatch between the PV generation production and the customer load profiles, the PV production and the bulk customers load profiles closely correlate, resulting in most of the generation produced being utilized by the customer as seen in Fig. 9. Examples of these include shopping malls, industrial factories whose load demand exceeds the 1 MWp generation limit set by the National Energy Regulator of South Africa. Installing a solar PV system less than 1 MW does not require a generation license. The software simulation considers AC system losses, DC system losses, inverter losses, reflection losses, soiling losses, wiring losses, PV panel mismatch, temperature losses, and the inclination and orientation production to provide a monthly solar-PV generation estimate. Table 13 reflects the results obtained from a 1 MW solar PV system. The simulation results show that the 1 MW rooftop solar PV system's total annual generation production is 1699563.02 kWh. Fig. 40 illustrates the monthly generation figures and percentage of total generation. The ADB from the South African Revenue Services, finance costings, maintenance and operation costs were not considered in this case study as this will vary from customer to customer. The assumed warranty period of the equipment used is minimum 10 years.

5.3. Classification of PV generation into ITOU tariff periods

To calculate the payback period for a 1 MW rooftop PV system, the kWh monthly production in Fig. 41 needs to be classified into the respective ITOU (peak, standard and off-peak) periods as seen in Figs. 10 and 11. It is challenging to break down energy

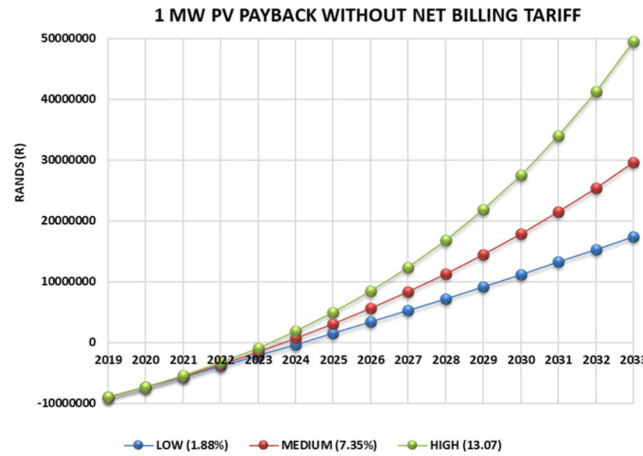


Fig. 41. 1 MW Solar PV system payback period without INBT.

production into the correct tariff billing periods to accurately work out the payback period. The first step is to use PVsyst software to simulate the monthly solar PV generation per hour. This is reflected in Table 14. It provides an hourly generation production break down per month.

Table 15 reflects the breakdown classification for each month in terms of weekdays, Saturdays, and Sundays according to the ITOU tariff using the 2019/2020 financial year tariff booklet, which defines how to classify the public holidays into either Saturday or Sunday for ITOU billing. Table 15 also provides the monthly breakdown of solar PV generation, which will be utilized for the calculations in Tables 16 and 17.

Table 16 presents the procedure to breakdown the monthly generation into the ITOU billing periods. The ratios of each is used to calculate the ratios seen in column 3 of Table 16. This is then multiplied to obtain the kWh Production for each period. This process was then repeated for the other 11 months of the year, and the results are then seen in Table 17. Table 17 reflects the total annual production, with only 15.16% is generated during the peak billing period, 64.96% during the standard billing period, and 23.88% during the off-peak period. This is further broken down to 13.6%, 47.11%, and 19.73% during low billing period peak, standard, and off-peak periods; and 1.56%, 13.85%, and 4.15% high demand season peak, standard, and off-peak periods.

5.4. Bulk customers 1 MWp rooftop solar PV payback period

Figs. 41 and 42, and Table 18 demonstrate minimal changes to the bulk customer's payback period for a 1 MW rooftop solar PV system installed. There is only a change in the payback period from 5 years to 6 years in the low and medium increase scenario with the introduction of the INBT, which can be attributed to the additional charges introduced by the ANAC. For the high increase scenario, the payback period remains the same, even with the addition of the ANAC. However, there is a reduction in revenue to the customer over the project's life with the addition of the ANAC.

5.5. Calculation of the levelised cost of electricity from the 1 MWp rooftop solar PV over the life of the project

To determine the cost of electricity from the customers 1 MWp rooftop PV installation over the life span of the installation, the following assumptions have been made to calculate the cost per kWh for the project:

Table 14
Durban average percentage hourly generation production from solar PV Sewchurran (2016).

Hour\Month	JAN	FEB	MAR	APRIL	MAY	JUNE	JULY	AUG	SEP	OCT	NOV	DEC
00:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
01:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
02:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
03:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
04:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
05:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%	1%
06:00	2%	1%	1%	0%	0%	0%	0%	0%	1%	2%	3%	2%
07:00	5%	4%	4%	4%	4%	3%	3%	4%	5%	6%	7%	6%
08:00	9%	8%	8%	8%	8%	8%	7%	8%	9%	9%	10%	9%
09:00	11%	10%	11%	11%	11%	12%	11%	11%	11%	12%	12%	11%
10:00	12%	12%	12%	13%	13%	14%	13%	13%	13%	13%	13%	12%
11:00	13%	13%	13%	14%	15%	15%	15%	14%	13%	13%	12%	12%
12:00	12%	13%	14%	14%	14%	14%	14%	14%	14%	13%	11%	12%
13:00	12%	12%	12%	13%	13%	14%	14%	13%	13%	11%	11%	11%
14:00	10%	11%	11%	11%	11%	11%	12%	11%	10%	10%	9%	10%
15:00	8%	8%	8%	8%	7%	7%	8%	8%	7%	7%	7%	8%
16:00	5%	6%	5%	4%	3%	1%	4%	4%	4%	3%	4%	5%
17:00	2%	2%	1%	0%	0%	0%	0%	0%	0%	0%	1%	2%
18:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
19:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
20:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
21:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
22:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
23:00	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

Table 15
Monthly breakdown of days according to the ITOU tariff and generation production.

	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE
WEEK-DAYS	23	21	20	23	21	19	22	20	21	19	20	21
SATURDAYS	4	6	5	4	5	4	4	5	5	5	6	5
SUNDAYS	4	4	5	4	4	8	5	4	5	6	5	4
TOTAL	31	31	30	31	30	31	31	29	31	30	31	30
MONTHLY PRODUCTION	107122.90	125988.30	134281.97	156150.71	161938.02	182880.22	179227.58	156572.91	157199.35	127777.33	110994.10	99429.61

Table 16
Example of the method used to break down the monthly generation into the ITOU billing periods.

January Total	179227.6	Ratio of Total	kWh Production	Peak	Standard	off-peak	Peak	Standard	off-peak
Weekdays	22.00	0.71	127193.78	0.25	0.75	0.00	31798.44516	95395.33548	0
Saturdays	4.00	0.13	23126.14	0.00	0.50	0.50	0	11563.07097	11563.07097
Sundays	5.00	0.16	28907.68	0.00	0.00	1.00	0	0	28907.67742
TOTAL	31.00	1.00	179227.60				31798.44516	106958.4065	40470.74839

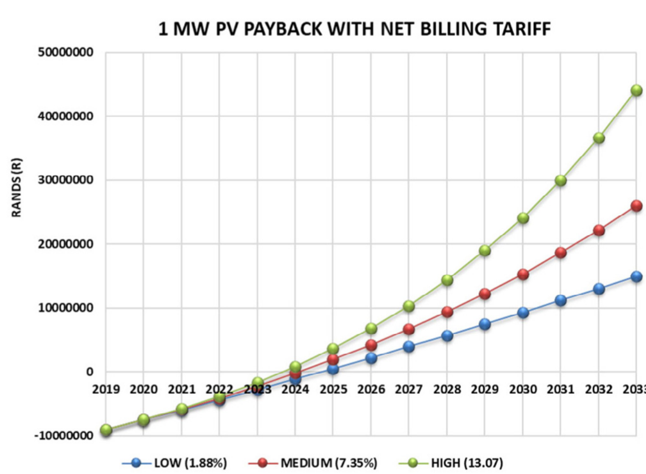


Fig. 42. 1 MW rooftop Solar PV system payback period with INBT.

(i.) The project life span is 30 years.
(ii.) Production degradation of 0.67% per year
(iii.) PV panels have a 30-year production warranty (90% after 15 years and 80% after 30 years)
(iv.) Inverters have a 10-year warranty (replacement costs of 30% of capital cost)
(v.) Average annual repairs and maintenance costs over the 30 years are 4% of the capital cost
(vi.) The capital cost of the project is R9000000.

Using this data, it was calculated that over the 30-year life span of the project, 46033514.17kWh would be produced while a total repair and maintenance budget of R15,000,000 will be spent over the term for cleaning of the panels, replacing of the inverters twice during the life of the project and installation insurance, monitoring, etc. The average single rate cost of the energy produced is R0.4275/kWh over the life of the project. Presently, the ITOU tariff's lowest rate is the low demand season off-peak rate, which is R0.53/kWh. Table 18, however, shows that, for the total annual production, 15.16% is generated during the peak billing period, 64.96% during the standard period, and 23.88% during the off-peak period. This equates to 13.6%, 47.11%, and 19.73% during low demand season peak, standard, and off-peak periods; and 1.56%, 13.85%, and 4.15% during the high demand season peak, standard, and off-peak periods.

This indicates that the project is financially viable for the INBT customers to install solar PV systems, given the uncertainty in the

Table 17
Monthly generation production and breakdown of peak, standard and off-peak tariff periods.

MONTH	PEAK	STANDARD	OFF-PEAK	MONTHLY kWh
JANUARY	31798.45	106958.41	40470.75	179227.60
FEBRUARY	23755.89	96913.23	35903.79	156572.91
MARCH	24492.67	94167.48	38539.20	157199.35
APRIL	18612.90	72960.86	36203.58	127777.33
MAY	16470.09	66095.20	28428.81	110994.10
JUNE	8352.09	69865.87	21211.65	99429.61
JULY	7947.83	78303.38	20871.69	107122.90
AUGUST	10241.63	87297.70	28448.97	125988.30
SEPTEMBER	22380.33	78554.95	33346.69	134281.97
OCTOBER	29512.48	93326.07	33312.15	156150.71
NOVEMBER	28783.18	80760.06	52394.79	161938.02
DECEMBER	35278.18	110849.01	36753.03	182880.22
TOTAL kWh GENERATED	257625.72	1036052.22	405885.08	1699563.02
HIGH DEMAND PERIOD GENERATION	26541.54	235466.96	70532.31	332540.81
PERCENTAGE HIGH DEMAND BREAKDOWN	1.56	13.85	4.15	
LOW DEMAND PERIOD GENERATION	231084.17	800585.27	335352.77	1367022.21
PERCENTAGE LOW DEMAND BREAKDOWN	13.60	47.11	19.73	
TOTALS	15.16	60.96	23.88	1699563.022

Table 18
1 MW rooftop solar PV payback period with/without INBT.

1 MWp rooftop solar PV payback		
Tariff increase	Payback period without INBT	Payback period with INBT
Low (1.88%)	6	6
Medium (7.35%)	5	6
High (13.07%)	5	5

future Eskom Tariff hikes and energy shortages in South Africa. There are other benefits to the customer and society, such as:

(a.) Reduction in greenhouse gas emissions (GHG).
(b.) Reduction in carbon footprint.
(c.) Reduced Carbon Taxes.
(d.) Potential to integrate the PV system to operate with the diesel standby generator to reduce electricity production costs during load shedding.
(e.) Reduced electricity bills.
(f.) Cheaper electricity over the life of the project.
(g.) Higher rate of return (16.82% in year 1 excluding 28% ADB) of the capital investment, which is better that what is offered by banks (PKF South Africa, 2019).

6. Summary of case study results

The financial analysis of the different case studies carried out is summarized in Table 19. The results indicate that the best rate of return (ROR) and levelised cost of electricity is achieved when the customer sizes his PV system such that he consumes all of the generated electricity. This can be achieved by ensuring that a complete energy audit of the property is carried out and energy efficiency products are retrofitted before carrying out data logging in order to correctly size the PV system. Table 19 indicates that in the case of a residential solar PV installation, the payback period can range from 5 years up to 10 years dependent on the amount of the generated electricity utilized by the customers. The LCOE is R0.76/kWh over the 30 year life of the project and the ROR is 17.48% for the first year. The residential consumer unlike the business/bulk consumers do not qualify for the accelerated depreciated benefit (ADB) from the South African Revenue Services hence the lower first year ROR compared to the B&G and Bulk customer categories.

The B&G Scale 1 and Scale 2 customers have lucrative payback periods between 4–6 years on the new B&G NBT structure. These tariffs offer the customers R0.57/kWh and R0.49/kWh LCOE over the 30 year period. These payback periods are also dependent on the customer consuming all of the energy that is generated. The lucrative payback period on the B&G NBT can be attributed to the use of the generated electricity by the customer and off setting it against his higher import tariff instead of the lower NBT. The NAC adds to the customers payback period by a small margin. The ROR for the B&G Scale 1 and B&G Scale two tariffs 51.46% and 55.18% in the first year due the accelerated depreciation benefit from the South African Revenue Service and the saving from the energy purchased from the grid. The ROR will be lower in the second year onwards due to there being no ADB and maintenance costs, inverter replacement costs, monitoring, insurance, etc.

The bulk customer category has a slightly longer payback period than the B&G sector with a payback period of between 5–6 years but offers the lowest LCOE from the other sectors. The LCOE over the 30 year period is R0.43/kWh. The higher payback period is due to the lower costs of energy during the low demand

Table 19
Case study financial feasibility summary.

kW rooftop solar PV system	3	55.2	250	1000
DC rating (kWp)	3.75	69	325	1313.5
AC rating (kW)	3	55.2	250	1000
Tariff structure	Residential	B&G scale 1	B&G scale 2	Industrial TOU
Production by kW	1829	1701	1658	1700
R/kW installed capacity	15000	12000	10000	9000
YEARS	30	30	30	30
Annual generation production (kWh)	5487	93922	414526	1699563
Total cost of system (R)	45000	662400	2500000	9000000
Accelerated depreciation benefit (R)	0	216384	700000	2520000
Total production over 30 years (kWh)	148618	2543924	11227644	46033514
Production warranty after 15 years (%)	90	90	90	90
Production warranty after 30 years (%)	80	80	80	80
Annual maintenance costs (%)	4	4	4	4
Inverter replacement costs (Year 10 and 20) (% of system cost)	30	30	30	30
Total cost over 30 years (R)	112500	1439616	5550000	19980000
LCOE over 30 years (R/kWh)	0.76	0.57	0.49	0.43
ROR tax depreciation year 1 (%)	0	28	28	28
ROR YEAR 1 excluding tax depreciation (100 generation usage)	17.48	23.46	27.18	16.82
Total ROR year 1	17.48	51.46	55.18	44.82
Payback period range (years) with net billing tariff	5–10	5–6	4–5	5 –6

Table 20
Factors influencing solar PV payback period.

	Factor	Influence
1	The capital cost of the system.	The higher the capital cost of the installation the longer the payback period.
2	The size of the system.	The cost (R/W) installed solar PV reduce with larger system sizes and hence the payback period.
3	DC:AC ratio of the system.	The DC:AC ratio of the PV system affects the total annual kWh generated. Higher DC to AC ratio of the PV system produces more kWh which will reduce the payback period.
4	Actual PV panel annual percentage performance degradation.	The actual percentage annual performance degradation of the PV system will affect the annual kWh generated by the PV system and hence the payback period.
5	Actual annual electricity tariff increases.	Higher annual electricity tariff increases will reduce the PV system payback period.
6	Shading, and cleanliness of the solar panels.	This will reduce the kWh production and hence increase the payback period.
7	The orientation and inclination angle of the panels (for optimum insolation).	The optimum is 30° North facing panels which will produce the maximum kWh that can be obtained from the PV system, deviation from this optimum will reduce the annual kWh produced and increase the payback period.
8	The percentage of generated electricity utilized.	The shortest payback period is obtained when 100% of the generated electricity is utilized.
9	Potential changes to the electricity tariffs.	Any reduction in the export energy rates or increase in the NAC will increase the payback period.
10	The warranty period of equipment.	The longer the warranty period of the solar equipment used, the lower the maintenance costs (cost to replace solar equipment and extend the warranty) and will hence reduce the payback period.
11	The cost of finance and insurance.	Should the customer finance his PV system, this will increase the payback period depending on the cost of the finance. Other costs such as insurance of the system will also increase the payback period.
12	Efficiency of the solar equipment used	The higher the efficiency of the solar panels and inverters the more the annual energy produced and hence reduce the payback period. Also the efficiency of the solar system design will also affect the overall production depending on the DC and AC cable losses, etc.

months (September–May) which ranges from R0.5381/kWh to R1.1167/kWh (Excluding VAT) vs the all year round off-set of R2.2261/kWh on the B&G NBT structure. The first year ROR is 44.82% which is affected by the lower energy costs during most of the year on the INBT.

The simple payback periods calculated may however be affected by several other factors as depicted in Table 20.

7. Conclusion

This paper investigates the simple payback period of eThekwini Electricity customers installing solar PV systems. This was due to the introduction of new NBT to customers opting to install solar PV systems. Customers have also indicated that they often have challenges to calculate the payback period of PV systems especially on more complex tariff structures such as the multi-rate Business and General and ITOU. The investigations was hence carried out and took the following into account:

1. Tariff increases going forward for a low, medium and high tariff increase scenario.
2. Different percentage usage of the generated electricity.
3. Assumption that the PV system was purchased by the customer and no finance costs were incurred.

The following were not considered:

1. The cost of financing the solar PV system.
2. Energy storage systems.
3. Any subsidies for the PV system.
4. Carbon Tax benefits.
5. Carbon reduction benefits.
6. Carbon Credits.
7. Tax accelerated depreciation benefit for payback period calculation.
8. Time value of money.

Whilst the following were taking into account when calculating the ROR and LCOE over the project life:

4. Cost of operation and maintenance of the PV system over the life of the project.
5. The LCOE over a 30 year life of the project.
6. The annual performance degradation of the solar panels.
7. Year 1 ROR for the solar PV system taking into account the Tax accelerated depreciation benefit.

This study revealed that the payback period for customers installing rooftop solar PV systems is extremely lucrative even on the new Municipal NBT. These systems offers lower LCOE over the life of the project than the current electricity costs that the customer pays.

In the case of the residential sector, the payback period varies between 5–10 years based on the amount of customers generation usage when calculated from 50% to 100% respectively. It also has a much lower than municipal energy costs of R0.76/kWh over the 30 year life of the project and a year 1 ROR of 17.48%.

In the Business and General sector, the payback period is between 4–6 years with larger systems offering a lower payback period in comparison to a smaller system. These systems offered much lower than municipal energy costs of between R0.49 kWh–R0.57/kWh and year 1 ROR of between 51.46%–55.18%.

Whilst the payback period for the Bulk Energy users on the TOU tariff structure ranging between 5–6 years. These systems offered the cheapest energy rate over the 30 year life of the project of R42c/kWh which is currently lower than the low demand season off-peak energy rates. The systems also offer a year 1 ROR of 44.82%.

Hence the eThekwini Municipalities new NBT is fairly designed to assist both the municipality and the customer in that it helps the customer with compensation for excess energy exported to the grid. Whilst it assists the municipality with additional revenue from the NAC to compensate for the reduction in electricity sales to the customer to make up for the fixed costs incurred in making the electricity supply available to the customer. The studies carried out will assist the eThekwini Municipality customers in making informed decisions with regards to installing solar PV systems. Implementation of new unbundled tariff structures are critical to ensure Prosumers are paid for excess energy exported to the grid and also assist the Municipality to remain financially stable. However, this model could change in the next 3–5 years with the declining price of energy storage. The Municipality needs to explore other revenue streams to remain in business.

CRediT authorship contribution statement

Sanjeeth Sewchurran: Conception and design of study, Acquisition of data, Analysis and/or interpretation of data, Writing – original draft, Writing – review & editing. **Innocent E. Davidson:** Conception and design of study, Acquisition of data, Analysis and/or interpretation of data, Writing – original draft, Writing – review & editing.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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